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November 30, 2016

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

Attention: Ms. Laurel Ross, Acting Commission Secretary and Director

Dear Ms. Ross:

Re: FortisBC Inc. (FBC)

2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan)

On August 15, 2012, the British Columbia Utilities Commission (the Commission) issued Order G-110-12 and Decision which, among other things, generally accepted FBC's 2012 Long Term Resource Plan.

In accordance with the Commission's Resource Planning Guidelines and section 44.1 of the *Utilities Commission Act* (the UCA), FBC respectfully submits the LTERP (as Volume 1) and LT DSM Plan (as Volume 2) for the Commission's review.

FBC is seeking acceptance of this LTERP, including the LT DSM Plan, pursuant to section 44.1(6) of the UCA.

If further information is required, please contact Joyce Martin at 250-368-0319.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties to the FBC 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan Review proceeding
2016 LTERP Resource Plan Advisory Group (RPAG) Members

FortisBC Inc.
2016 Long Term Electric Resource Plan and
2016 Long Term Demand Side Management Plan

FORTIS BC

FORTISBC INC.

2016 Long Term Electric Resource Plan

Volume 1

November 30, 2016

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EXECUTIVE SUMMARY

1.1 *INTRODUCTION*

This FortisBC Inc. (FBC or the Company) 2016 Long Term Electric Resource Plan (LTERP) presents a long-term plan for meeting the forecast peak demand and energy requirements of customers with demand-side and supply-side resources over the 20-year planning horizon (2016 to 2035). The LTERP analyzes the external planning environment within which FBC operates, compares energy and capacity load forecasts against current resource capabilities and evaluates the potential for load reduction with demand-side management (DSM) initiatives and portfolios of resource options to meet forecast customer needs under different scenarios. The LTERP includes a preferred portfolio to meet customers' long term requirements. It also includes an action plan that identifies activities that FBC expects to take during the first four years of the 20-year planning horizon. The LTERP is intended to meet the following objectives:

- Ensure cost-effective, secure and reliable power for customers;
- Provide cost-effective demand-side management, and
- Ensure consistency with provincial energy objectives (for example, the applicable *Clean Energy Act (CEA)* objectives).

Volume 1 of the 2016 LTERP contains discussion of the planning environment and the long-term load forecast and determines the Load-Resource Balance (LRB) gap based on existing and committed resources. Both demand-side and supply-side resources are then evaluated to determine alternative portfolios to meet any future gaps. A preferred portfolio, including contingency plans for unexpected circumstances, is then recommended.

Volume 2 contains the Company's 2016 Long Term Demand Side Management (DSM) Plan (LT DSM Plan). DSM continues to be a cost-effective means of reducing customers' load requirements over the long-term planning horizon. The LT DSM Plan includes an assessment of the energy efficiency and conservation potential for FBC customers, which is supported by the province-wide Conservation Potential Review (CPR) study concluded in mid-2016. This provides FBC with different levels of demand-side resource options to assess along with supply-side resource options in meeting the forecast load-resource balance gaps over the planning horizon identified of the LTERP.

The analysis provided in this LTERP shows that, based on the reference case load forecast, existing resources and contracts in place and the proposed level of DSM, FBC does not require any new supply-side resources for the next ten years. Optimization of market purchases and the Power Purchase Agreement with BC Hydro and Power Authority (BC Hydro) (the PPA) provide FBC with enough energy and capacity until 2025 to meet customers' requirements in a cost-effective and reliable manner. Even after 2025, the additional resource requirements are not significant and are primarily for energy and not capacity. The portfolio analysis provided in Section 9 provides a high-

level indication of the potential combination of resources that could meet future requirements and will be reviewed again in FBC's next long term resource plan.

The LTERP meets the requirements of the *Utilities Commission Act (UCA)*, is consistent with the British Columbia Utilities Commission's (Commission) Resource Planning Guidelines, and complies with directives from the Commission with regard to FBC's long term resource plan.

FBC files this 2016 LTERP under section 44.1(2) of the *UCA* and is seeking its acceptance as being in the public interest pursuant to section 44.1(6).

1.2 *PLANNING ENVIRONMENT*

It is important that FBC understand the planning environment in order to meet its resource planning objectives. The planning environment includes relevant external factors that impact FBC's demand-side and supply-side resource options and their future costs and prices as well as those factors that could influence customers' energy and capacity needs over the planning horizon. FBC focuses on three key areas in its assessment of the planning environment. These include the following:

- The relevant energy and environmental policies in both Canada and the United States (U.S.) and their potential impacts on resource options, market and carbon prices and customers' behaviour regarding energy use in the future;
- The customer demand environment, including how technology and customers' energy needs are changing and how the relationship between the customer and the utility is evolving, and
- The supply environment, in particular the changes occurring in British Columbia (B.C.), Alberta and the Pacific Northwest region that will influence FBC's resource options and market electricity prices.

Energy and environmental policies in Canada and the U.S. are constantly evolving as federal, provincial and state governments are implementing a number of initiatives to reduce greenhouse gas (GHG) emissions. These policy actions will impact the electricity generation mix in western Canada and the U.S. Pacific Northwest region as generators in the U.S. and provinces like Alberta move towards greater adoption of renewable resources like wind and solar. This in turn will likely impact market electricity prices. Market prices for power currently remain low relative to historical values, largely because of low market gas prices due to the impacts from the shale gas supply boom. As gas-fired generation is expected to make up the regional capacity shortfall cause by coal retirements, intermittent resources, and load growth, the interdependency between natural gas and electricity prices in the Pacific Northwest region will continue to strengthen in the coming years.

At the same time, environmental policies in B.C., such as the Climate Leadership Plan (CLP), may increase electricity demand in certain areas such as the transportation sector and impact the level of carbon pricing in B.C.

The ways in which customers use, monitor and even generate electricity continues to evolve, presenting both challenges and opportunities for FBC in meeting the future needs of its customers. Technology is a large driver in this evolution, impacting how customers connect and interact with FBC and influencing the supply and demand of electricity on the system. DSM also continues to evolve and remains a key resource option for customers to cost effectively reduce their energy consumption.

FBC is continuing to meet these customer demands in a number of ways, including:

- Supporting small customer-owned clean or renewable generation with the net metering tariff;
- Supporting electric vehicle adoption by funding charging stations;
- Promoting informed electricity use by providing more detailed and up-to-date consumption data;
- Evaluating a community solar project, and
- Providing customers with cost-effective DSM programs to reduce their energy consumption.

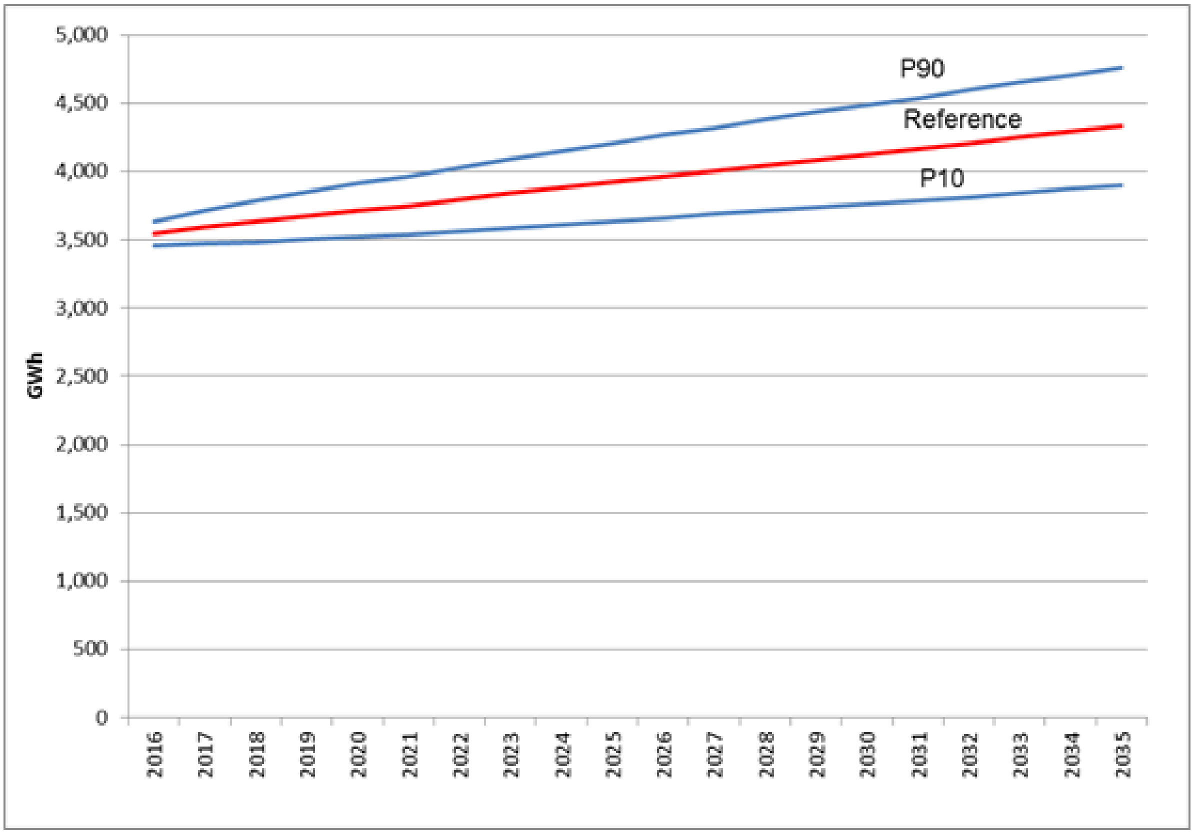
1.3 *LONG TERM LOAD FORECAST*

FBC's reference case load forecast anticipates a modest rate of load growth over the twenty-year planning horizon of the LTERP. This is due to the expectations for slowing population growth and modest GDP growth particularly for industries including agriculture, forestry, manufacturing, utilities and commercial service.

In order to account for future variability in the load forecast inputs, FBC developed a Monte Carlo range around the reference load forecast to provide a degree of certainty regarding traditional load drivers inherent in the forecast. FBC has developed a standard P10/P90 range where P10 means there is a 10 percent probability that the load will be less than this forecast value in a particular year and P90 means there is a 90 percent probability that the load will be less than this forecast value in a particular year.

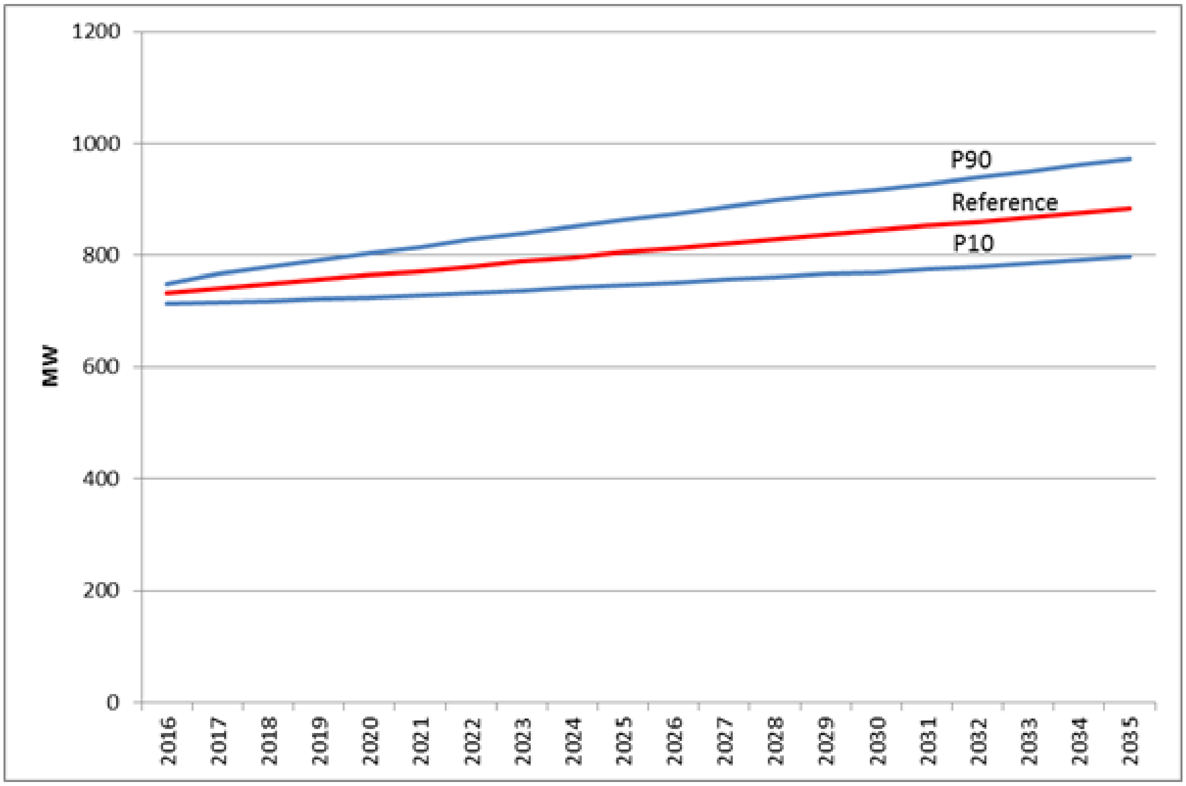
For the reference case load forecast, the Company is forecasting an increase in gross energy load from 3,544 GWh in 2016 to 4,334 GWh by 2035, an average compound annual growth rate of 1.1 percent. This forecast with the Monte Carlo range is shown in the following figure.

Figure ES-1: Gross Energy Load Forecast and Monte Carlo Range (GWh)



The reference case winter peak demand forecast increases from 731 MW in 2016 to 885 MW in 2035, growing at a compound annual growth rate of 1.0 percent. This forecast and the Monte Carlo range is show in the following figure.

Figure ES-2: Winter Peak Forecast and Monte Carlo Range (MW)



1.4 *LOAD SCENARIOS*

FBC employed the consulting services of Navigant Consulting Ltd. (Navigant) to assess the energy and capacity impacts of various load scenarios in the 2016 LTERP. The scenarios provide examples of what the impacts on FBC's future load requirements might be if specific load drivers that are not captured in the reference case load forecast occurred at specific growth or penetration levels. Details are provided in Section 4. These load scenarios will help inform FBC's potential future resource requirements and how FBC might adapt its resource portfolio if they were to occur. FBC's portfolio analysis, discussed in Section 9, includes alternative resource portfolios to meet the reference case load as well as the alternative load scenarios discussed in this section. This may include, for example, more generation resources to meet higher than reference case load or ensuring flexibility in FBC's resource portfolio to handle decreasing load requirements.

Eight specific load drivers were included to develop the load scenarios. These load drivers are the building blocks for the five scenarios modeled by Navigant. Navigant developed two boundary scenarios based on the load drivers that could increase loads and the drivers that could decrease loads. In addition to modelling scenarios where all load drivers push system load in the same direction, Navigant also considered three scenarios where off-setting effects can exist. This is helpful for appreciating the potential dynamics of how load drivers may interact with one another.

Navigant's principal finding is that the load drivers that may have the most impact to FBC going forward are (in order): electric vehicles (EVs), residential rooftop solar photo-voltaic (PV), and fuel switching from gas to electric and vice versa. In addition, a new large industrial user, such as a hospital, college or data centre, would certainly be a load driver that could come on relatively quickly and have significant impacts on the FBC load requirements.

The results, provided in Section 4, show a potential increase in energy consumption of over 800 GWh per year and an increase in peak demand of almost 200 MW by 2035 for the upper boundary scenario compared to the reference load forecast. The lower boundary scenario shows a potential decrease of nearly 900 GWh per year by 2035 and 80 MW by 2035 compared to the reference load forecast.

The portfolio analysis (in Section 9) provides an indication of the incremental resources FBC might require to meet the high boundary load scenario if it occurred as well as the adjustments to FBC's existing resources if the low boundary scenario were to materialize. The potential impacts to the FBC transmission and distribution of two load drivers in particular, EVs and rooftop solar distributed generation (DG), are discussed in Section 6.

1.5 *TRANSMISSION AND DISTRIBUTION SYSTEM*

A key aspect of ensuring cost-effective, secure and reliable supply of electricity to customers is identifying the transmission and distribution system infrastructure that FBC needs to construct over the planning horizon. At the present time, only two bulk transmission reinforcement projects have been identified within the 20-year planning horizon. These include the Grand Forks terminal transformer addition in 2018-2020 to improve system reliability and the Kelowna bulk transformer capacity addition in 2019-2020 for reliability and capacity purposes.

As part of this LTERP, FBC has explored the potential impacts from various load drivers and scenarios that could materialize in the future (see Section 4). The potential impacts from these load drivers on the transmission and distribution system are discussed. While the increase or decrease in peak load requirements resulting from these scenarios have implications for transmission and distribution system planning, the potential impact of the individual load drivers is also important. Two load drivers in particular which could have significant impacts are distributed generation and electric vehicles.

If DG uptake increases significantly in the near future, FBC transmission and distribution planners will need to have the tools and knowledge for planning and modeling a high-penetration of rooftop solar or other DG technology into the system. Alternative engineering designs, technology solutions, and new and updated planning and operations practices may be needed for the FBC transmission and distribution system of the future.

Currently, EV uptake within FBC's service territory has been limited. However FBC is monitoring charging station installations and will analyze the impact on distribution networks. The more powerful EV chargers will result in much higher demand than that imposed by charging through a conventional 120 volt (V) outlet. Several electric vehicles on one residential street could overload the local distribution transformer unless demand management measures are implemented to enforce load diversity and prevent a possible overload. The potential stresses on the electric grid can be mitigated through asset management, system design practices, and, to some degree, managing the timing of charging EVs to shift the load away from system peak. A proactive FBC approach that includes understanding where EVs are appearing in the system, addressing near-term localized impacts, and developing both customer programs and technologies for managing long-term charging loads will effectively and efficiently support EV adoption.

1.6 *LOAD-RESOURCE BALANCE*

Section 7 identifies the LRB before incremental demand-side and supply-side resources are included to determine if there are any energy and/or capacity gaps over the planning horizon. This is done by comparing the long-term reference load forecast to the existing and committed resources in the FBC portfolio. The comparison will identify any LRB gaps that need to be filled with DSM and/or supply-side resource options.

The following figure illustrates the annual energy load-resource balance and potential gaps over the 20-year planning horizon.

Figure ES-3: Annual Energy Load-Resource Balance (GWh)

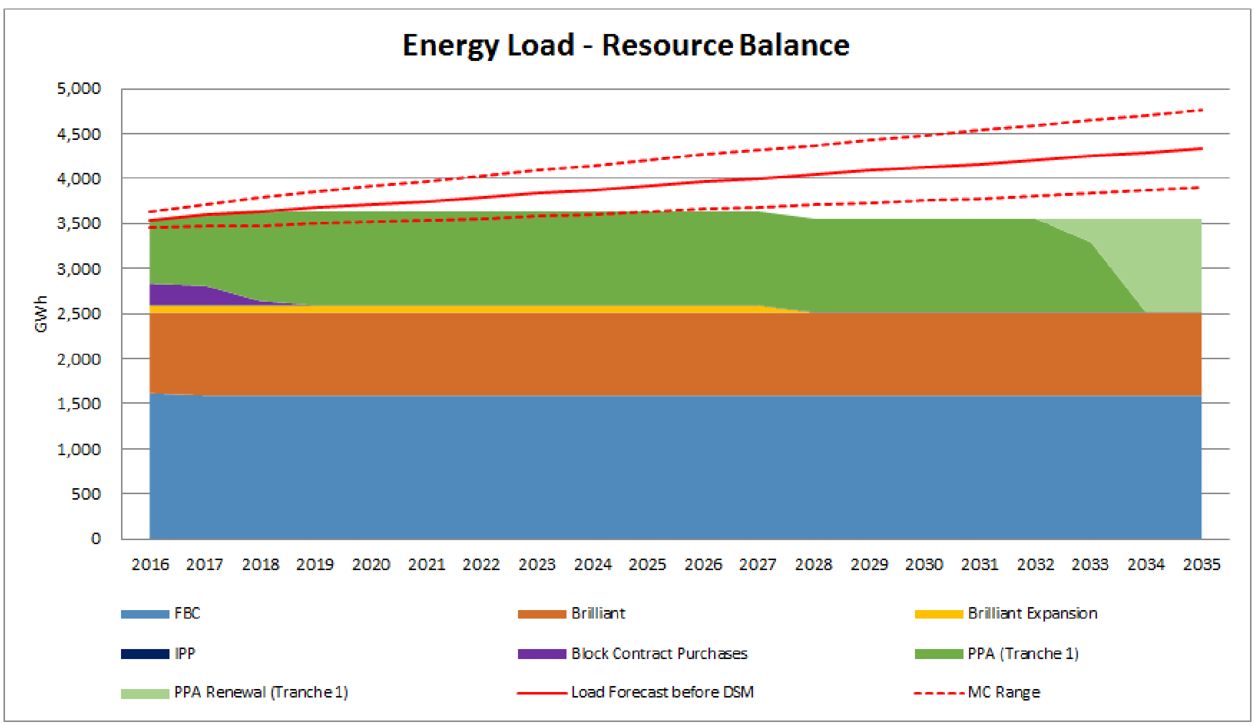


Figure ES-3 shows that there are gaps starting in 2019 based on the reference case forecast increasing to about 900 GWh by 2035 if the PPA is renewed. If the PPA is not renewed, then the gaps are more significant after 2033, increasing to almost 2,000 GWh per year by 2035 for the reference case. For the low end of the Monte Carlo range, this gap is reduced by about 400 GWh.

The following figure illustrates the annual capacity load-resource balance and potential gaps over the 20-year planning horizon before any new DSM. The capacity requirements represented in the figure by the lines are based on the peak demand requirements during each year's winter period.

Figure ES-4: Capacity Load-Resource Balance (MW)

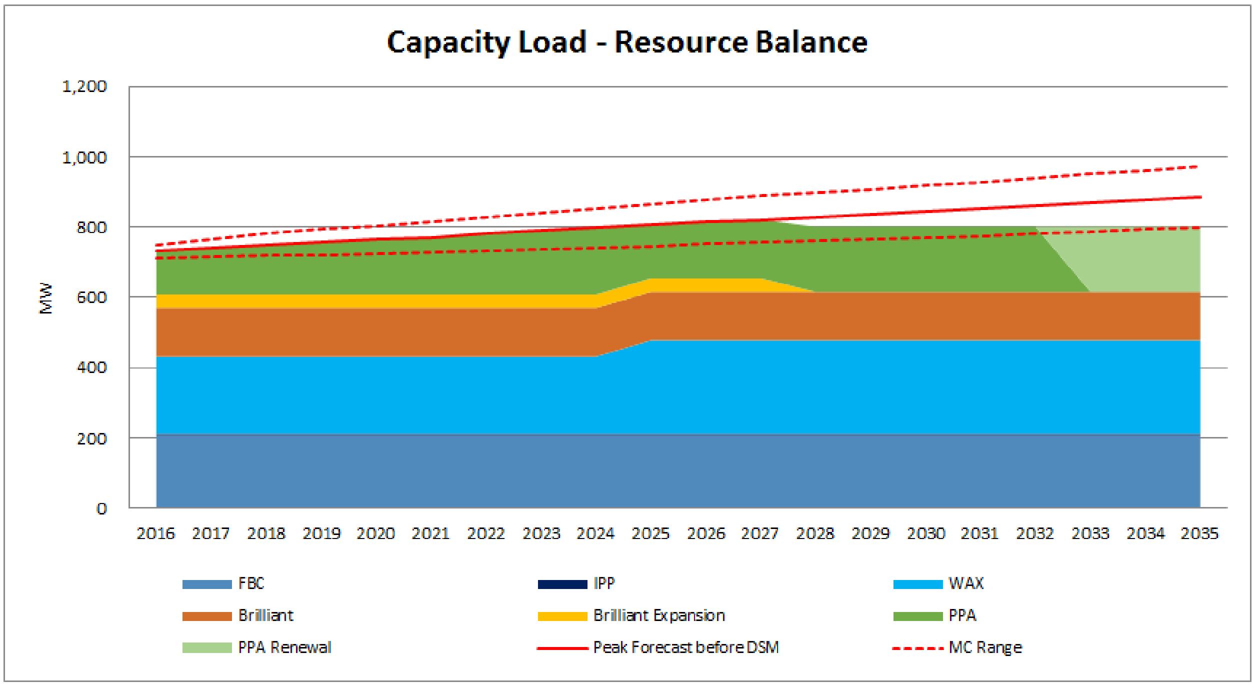


Figure ES-4 shows that, based on the reference case forecast, there are minimal capacity gaps throughout most of the 20-year planning horizon which increase up to about 100 MW by 2035 if the PPA is renewed. There are no gaps at the low end of the Monte Carlo range. More significant gaps, in the order of 300 MW, appear if the PPA is not renewed based on the reference case forecast.

Section 8 describes the demand-side and supply-side resource options available to meet the forecast energy and capacity gaps.

1.7 *RESOURCE OPTIONS*

FBC has a number of different resource options to meet the future energy and capacity needs of its customers. These include demand-side as well as supply-side resource options. As many demand-side resource options are typically more cost-effective than supply-side resource options and enable customers to reduce their energy consumption, thereby reducing their energy costs, FBC looks to demand-side resources first to meet any future LRB gaps.

1.7.1 DSM Options

In this LTERP and in the LT DSM Plan, FBC has evaluated different levels of DSM to meet future load growth. These are discussed in LT DSM Plan Section 3 and LTERP Section 8.1 and include the following.

FBC assessed several different levels of DSM load growth offset to help meet future LRB gaps. The 2007 BC Energy Plan referenced a DSM target of 50 percent while the *CEA* provides a target of at least 66 percent of load growth. Although both targets were only stated to apply to BC Hydro, FBC adopted the 50 percent DSM offset target in its 2012 LTRP (50 percent is considered the Low scenario in the current LT DSM Plan) and is using the 66 percent DSM offset target as its Base DSM scenario in the LT DSM Plan. The Base scenario represents approximately the same level of target savings that was approved pursuant to FBC's 2016 DSM Plan and that was provided for in the 2017 DSM Plan filing and so could be characterized as a continuation of the current plan.

The High scenario is a midpoint scenario between the Base and Maximum (Max) scenarios. The High scenario begins with 66 percent load growth offset in 2018 and then, after 2020, starts ramping up to 80 percent load growth offset by 2023 to optimize greater utilization of PPA Tranche 1 Energy before energy LRB gaps after DSM appear in 2025. Over the planning horizon, the High scenario averages 77 percent load growth offset.

The Max DSM scenario exhibits a similar ramp-up to 100 percent annual average energy load growth offset, resulting in an average offset of 89 percent over the planning horizon.

The High DSM scenario is FBC's preferred option for the LT DSM Plan. The incremental cost for the High scenario of $104 per MWh is similar to the B.C. clean energy resources LRMC of $100 per MWh, discussed in Section 9.4.1. Thus, it includes the majority of cost effective DSM from an LRMC perspective. Furthermore, ramping up to 80 percent of load starting in 2021 will mitigate some of the opportunity cost of offsetting the relatively inexpensive PPA in the near term and provides higher DSM levels close to when LRB gaps after DSM appear starting in 2025.

1.7.2 Supply-Side Resource Options

Customer load that cannot be met with demand-side measures must then be met with supply-side resource options. Potential resource options include several types of generation, as well as market purchases and supply from larger, industrial self-generating customers. FBC has taken into account a number of attributes when evaluating the various resource options. In addition to financial attributes (i.e. unit costs) FBC considers a number of factors when evaluating its resource options. These include operational and technical characteristics and environmental and socio-economic impacts. Geographic diversity of resources is also a consideration given that all of the generation plants FBC owns are located in the Kootenay region whereas most of the customers and expected load growth is in the Okanagan region. Locating new generation resources closer to the primary load centres would help mitigate risks relating to transmission disruptions and reliability in the future. FBC has identified the most cost-effective resource options as market purchases, PPA Tranche 1 Energy and capacity, biogas, wind and gas-fired generation. Details regarding the supply-side resource options are provided in Section 8.2 and the Resource Options Report (ROR) in Appendix J.

FBC's portfolio analysis, discussed in Section 9, assesses several portfolios of different resource options to determine the preferred portfolio to meet the LTERP objectives.

1.8 *PORTFOLIO ANALYSIS AND LONG RUN MARGINAL COSTS*

The portfolio analysis in Section 9 helps to determine the optimal mix of resources to meet customers' future energy and capacity requirements. It includes the development of several portfolios in order to determine the trade-offs between portfolios with different attributes. The portfolios are also subject to sensitivity analysis to determine how they perform under potentially changing conditions in the future. Each portfolio has a LRMC value based on the attributes of the particular portfolio. The outcome of the analysis is a preferred portfolio which meets the objectives of the LTERP. Note that FBC does not require any new generation resources until 2026 if it continues to access market purchases until 2025.

FBC has evaluated portfolios based on several different base characteristics and then explored sensitivities around these base characteristics. These characteristics and sensitivities include the following:

- Different levels of DSM (as discussed in the LT DSM Plan and Section 8.1);
- Market reliance versus self-sufficiency;
- Percentage of clean or renewable resources;
- Varying load requirements, and
- Renewal of the PPA versus non-renewal.

Based on the portfolio analysis presented in Section 9, FBC has determined a set of portfolios that should be considered for the preferred portfolio. These include the market-based portfolio, the two portfolios that meet the 93% clean or renewable target with a Combined Cycle Gas Turbine (CCGT) plant or a Simple Cycle Gas Turbine (SCGT) plant and the portfolio based on B.C. clean and renewable generation resources. These portfolios include the high level of DSM, renewal of the PPA, market purchases until 2025 and meet the Planning Reserve Margin (PRM) adequacy requirements.

The preferred portfolio which best balances the LTERP objectives is the portfolio that exceeds the 93% clean or renewable target with market purchases until 2025 and new resources including wind, biogas and a SCGT plant used mostly for peaking capacity purposes. This portfolio balances cost effectiveness with the other B.C. energy objectives relating to self-sufficiency, the environment and socio-economic benefits. The contingency plans for this preferred portfolio are discussed in Section 9.3.6.

1.9 *STAKEHOLDER AND FIRST NATIONS ENGAGEMENT*

FBC has a strong record of conducting effective stakeholder and First Nations engagement activities. In particular, for this LTERP, FBC has consulted a dedicated Resource Planning Advisory Group (RPAG), hosted a number of Community Consultation workshops to engage diverse perspectives on FBC's planning activities across the communities that the utility serves, and conducted online discussion boards to gain feedback directly from customers. FBC also met with the Ktunaxa Nation at its request. This First Nations and stakeholder consultation adheres to the BCUC's stakeholder input guidelines and has been beneficial to the development of this LTERP. FBC also met with Commission staff to discuss various resource planning topics and obtain feedback.

The information gained through these activities is incorporated into the LTERP process in a number of ways, such as by informing FBC's planning and analysis and identifying long term planning issues of concern to a number of stakeholder groups. FBC recommends continuing with the RPAG and community consultation activities prior to the Company's next long term resource planning process in order to build on the interest and input gained through these initiatives.

1.10 *ACTION PLAN*

The action plan describes the activities that FBC intends to pursue over the next four years based on the discussion and recommendations provided in this LTERP. It includes actions relating to monitoring the planning environment and strategies for optimizing short-term resource requirements as well as future DSM spending requirements. The specific action items include the following:

- Continue to monitor the energy planning environment;
- Monitor potential load drivers to determine if a particular load scenario is emerging;
- Continue to assess the potential requirements and timing for new resource options within B.C.;
- Continue to optimize the PPA and market purchases in the short term;
- Complete final phase of the B.C. Conservation Potential Review, and
- Prepare submission of next LTERP and LT DSM Plan with continuing input from First Nations, stakeholders and customers.

1. INTRODUCTION

This FBC 2016 LTERP presents a long-term plan for meeting the forecast peak demand and energy requirements of customers with demand-side and supply-side resources over the 20-year planning horizon (2016 to 2035). The LTERP analyzes the external regulatory, policy and planning environment within which FBC operates, compares energy and capacity load forecasts against current resource capabilities, and evaluates the potential for load reduction with DSM initiatives and portfolios of resource options to meet forecast customer needs under different scenarios. The LTERP includes a preferred portfolio to meet customers' long term requirements. It also includes an action plan that identifies the activities that FBC intends to take during the first four years of the 20-year planning horizon. This LTERP will enable FBC to achieve its primary objective of providing cost effective, secure and reliable power for customers.

The LTERP is consistent with the applicable sections of the *UCA* and the Commission's Resource Planning Guidelines, and complies with directives from the Commission arising from the acceptance of FBC's 2012 Long Term Resource Plan (2012 LTRP), filed as part of the 2012 Integrated System Plan on June 30, 2011, as well as Commission directives stemming from other FBC applications. These requirements are discussed further in Sections 1.4 and 1.5.

Volume 1 of the 2016 LTERP contains discussion of the long-term planning environment and the long-term load forecast and determines the load-resource balance gaps based on existing and committed resources. Both demand-side and supply-side resources are then evaluated to determine the preferred portfolio to meet any future gaps. Alternative portfolios as well as several load scenarios are also explored. Contingency plans are included for the preferred portfolio to specify how FBC would respond to changed circumstances.

Volume 2 contains the Company's LT DSM Plan. DSM continues to be a cost-effective means of reducing customers' load requirements over the long-term planning horizon. The LT DSM Plan includes an assessment of the energy efficiency and conservation potential for FBC customers, which is supported by the province-wide CPR study concluded in mid-2016 and determines cost-effective demand-side management programs. This provides FBC with different levels of demand-side resource options to assess along with supply-side resource options in meeting the load-resource balance gaps over the planning horizon of the LTERP.

The analysis provided in this LTERP shows that, based on the reference case load forecast, existing resources and contracts in place and the proposed level of DSM, FBC does not require any new supply-side resources for the next ten years. Optimization of market purchases and the BC Hydro PPA provide FBC with enough energy and capacity until 2025 to meet customers' requirements in a cost-effective and reliable manner. Even after 2025, the additional resource requirements are not significant and are primarily for energy and not capacity. The portfolio analysis provided in Section 9 provides a high-level indication of the potential combination of resources that could meet future requirements and will be reviewed again in FBC's next long term resource plan.

FBC files this 2016 LTERP under section 44.1(2) of the *UCA* and is seeking its acceptance as being in the public interest pursuant to section 44.1(6). Any requests for approval of specific resource projects that are identified within this plan will be further evaluated and brought forward through a separate application to the Commission if warranted in the future. The LTERP is not a substitute for the analysis done to support specific resource acquisitions or projects in the future but rather it helps to inform the acquisition process.

1.1 RESOURCE PLANNING PROCESS

The long-term resource planning process involves several iterative steps in identifying resource options to meet expected load requirements. This process is one that is used by many utilities in resource planning and is consistent with the steps included in the Commission's Resource Planning Guidelines. The following figure shows the steps included in the FBC long-term resource planning process.

Figure 1-1: FBC Long-Term Resource Planning Process

The long-term resource planning process begins with examining the planning environment, which encompasses the external factors that will influence resource options decisions and present risks and opportunities.

Next, FBC determines its customers' energy and capacity needs over the planning horizon. This includes the development of the long-term reference load forecast as well as some potential load scenarios that provide insight into different potential futures for which FBC should be prepared.

To meet the future load requirements, FBC must determine DSM potential to help reduce the requirements for other potentially more costly supply-side resources. Additionally, various supply-side resource options are evaluated to help meet any load-resource balance gaps.

Next, alternate resource options portfolios are evaluated in terms of meeting the resource planning objectives and a preferred portfolio is selected. Contingency plans are developed for the preferred portfolio to ensure that it can meet the Company's resource planning objectives if assumptions and conditions change.

The process concludes with a four-year action plan to implement the LTERP's conclusions and to ensure continuing assessment of resource requirements and alternatives.

Stakeholder and First Nations engagement is an important element of long-term resource planning as resource planning decisions ultimately impact FBC's customers in terms of electricity rates and other preferences regarding electricity supply. Stakeholder and First Nations engagement occurred throughout the LTERP planning process. In developing the LTERP, FBC met with Commission staff, stakeholders and First Nations representatives as part of the RPAG. Several workshop sessions were used to inform participants about various aspects of the LTERP and gather their input and feedback to help inform the LTERP. FBC also visited municipalities within the FBC service area as part of its community consultation and met with the Ktunaxa Nation, at its request. Online discussion boards were also used to probe FBC customers directly on their thoughts regarding long term resource planning objectives, resource options and DSM levels. More details regarding FBC's stakeholder and First Nations engagement are provided in Section 10.

1.2 *FBC OVERVIEW*

FBC is an integrated electric utility that generates, transmits and distributes electricity to customers in the southern interior of B.C. It is a subsidiary of Fortis Inc., the largest investor-owned gas and electric distribution utility company by assets in Canada. The following figure shows the FBC electric service area.

Figure 1-2: FBC Service Area

FBC currently serves approximately 132,000 direct customers plus approximately 36,000 indirect wholesale customers in the communities of Summerland, Penticton, Grand Forks and Nelson. FBC's current forecast annual energy requirements for 2016 are 3,544 GWh while winter and summer peak capacity requirements are 731 MW and 590 MW, respectively[1].

FBC owns four hydroelectric generating plants located on the Kootenay River between Nelson and Castlegar, B.C. which supply about 45 percent of FBC's energy requirements and about 28 percent of the Company's peak demand[2]. The remainder of FBC's energy and capacity supply comes from power purchase agreements with Brilliant Power Corporation, Brilliant Expansion Power Corp., BC Hydro, and the Waneta Expansion Limited Partnership, contracts for market

[1] Appendix F, Tables 2.1 and 2.10.
[2] 1,595 GWh FBC generation (Table 5-1) ÷ 3,544 GWh gross load (Appendix F, Table 2.1) = 45 percent.
208 MW FBC generation (Table 5.1) ÷ 731 MW peak load (Appendix F, Table 2.10) = 28 percent.

power from Powerex Corporation (the wholly owned energy marketing subsidiary of BC Hydro) about 7,200 kilometres of transmission and distribution power lines.

1.3 LONG TERM RESOURCE PLANNING OBJECTIVES

FBC's resource planning objectives form the basis for meeting any potential load-resource balance gaps in the future and for identifying and evaluating potential resource options and portfolios in the LTERP. These objectives reflect the Company's commitment to deliver quality service to customers, manage resources prudently and operate a safe and reliable electricity system. The objectives of the LTERP are as follows:

- Ensure cost-effective, secure and reliable power for customers;
- Provide cost-effective demand side management, and
- Ensure consistency with provincial energy objectives (for example, the applicable *CEA* objectives).

These objectives are consistent with the Commission's view of resource planning objectives as stated within the Commission's Decision regarding the 2012 LTRP: "The Commission's mandate in assessing the resource plans of energy utilities is intended to assure the cost-effective delivery of secure and reliable energy services in a manner congruent with British Columbia's energy objectives".[3]

Customers and stakeholders expect the Company to procure and deliver electricity in a cost-effective and efficient manner. FBC's existing resource base along with the preferred resource portfolio, if required in the future, will provide cost effective, reliable and secure energy and capacity for customers over the next 20 years. FBC also considers geographical diversity of its resources as important in meeting the objective of ensuring secure and reliable power for customers given that its owned generation is located in the Kootenay region while the majority of its load requirements are in the Okanagan region. DSM initiatives will reduce the Company's requirements for more costly supply-side resources and enable customers to reduce their electricity consumption. This is consistent with the *CEA*'s objective to take demand-side measures and conserve energy. The Company's DSM initiatives are governed in part by B.C.'s *UCA* and the Demand-Side Measures Regulation. It is also important that the LTERP's conclusions are consistent with the provincial energy objectives. These are discussed in the following section.

1.4 REGULATORY FRAMEWORK

While it is good utility practice to conduct long term resource planning, it is also a requirement to file a long term resource plan under section 44.1(2) of the B.C. *UCA.* The *UCA* outlines the requirements for utilities' resource plans. The Commission's Resource Planning Guidelines

[3] Commission Order G-110-12, page 143.

provide general guidance as to the Commission's expectations for the development of resource plans. FBC must also comply with any directives from the Commission related to FBC's long-term resource plans. Furthermore, the LTERP conclusions should be consistent with the energy objectives as outlined in the *CEA*. These requirements and guidelines are discussed in the following sections.

1.4.1 *Utilities Commission Act*

The *UCA* includes the requisite contents for a public utility's long-term resource plan, as set out in section 44.1(2) of the *Act*, "Long-term resource and conservation planning". The following table outlines the specific elements that are to be included in resource plans and indicates the corresponding sections of this LTERP in which these requirements have been met.

Table 1-1: Requisite Contents for a Long-Term Resource Plan

Section of the *UCA*	Requirement Defined in the *UCA*	Section of LTERP 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 during the period addressed by the plan	Load Forecast Section 3
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	DSM Section 8.1, LT DSM Plan
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	DSM Section 8.1.2
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)	Portfolio Analysis and LRMC Section 9
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)	Portfolio Analysis and LRMC Section 9
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	DSM Section 8.1.3
44.1(2)(g)	Any other information required by the Commission	Commission Directives Section 1.5.2.

In determining whether to accept a long-term resource plan, section 44.1(8) of the *UCA* requires the Commission to consider several items. These are listed in the following table along with the applicable sections of the LTERP where they have been addressed.

Table 1-2: Commission Considerations for Accepting a Long-Term Resource Plan

Section of the *UCA*	Considerations for Acceptance	Section of LTERP Addressing Requirement
44.1(8)(a)	The applicable of British Columbia's energy objectives	Section 1.4.2 below discusses LTERP consistency with applicable B.C. energy objectives.
44.1(8)(b)	The extent to which the plan is consistent with the applicable requirements of Sections 6 and 19 of the *CEA*	FBC has considered self-sufficiency and clean and renewable resources in Portfolio Analysis and LRMC Section 9.
44.1(8)(c)	Whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures	LT DSM Plan and Section 8.1 discuss demand-side measures.
44.1(8)(d)	The interests of persons in British Columbia who receive or may receive service from the public utility	Portfolio analysis results include DSM and supply-side resource options which are cost-effective, environmentally sound and provide socio-economic benefits to the region and FBC's customers as discussed in Section 9.

FBC submits that this LTERP meets the requirements of the *UCA.*

1.4.2 B.C. *Clean Energy Act* Objectives

As discussed in Section 1.4.1 above, section 44.1(8) of the *UCA* requires the Commission to consider certain factors when accepting a utility's long-term resource plan, including:

- The applicable of British Columbia's energy objectives as defined in the *CEA*, and
- The extent to which the long-term resource plan is consistent with the applicable requirements under sections 6 and 19 of the *CEA*.

In 2010 the Government of British Columbia enacted the *CEA.* The *CEA* contains a set of sixteen specific energy objectives for the Province of BC. It provides a guide to help the Province meet its self-sufficiency goals and to reduce greenhouse gas (GHG) emissions. The *CEA* includes several social and economic 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.

The following table lists the *CEA* objectives and describes how they are supported, if applicable, by the LTERP. It is important to note that these are provincial objectives and some of the objectives are specific to BC Hydro, as referenced in the *CEA* by the term 'the authority'.

Table 1-3: Applicable *CEA* Objectives Relevant to the LTERP

Section of the *CEA*	*CEA* Objective	How LTERP Supports Objective
2(a)	To achieve electricity self-sufficiency.	FBC interprets this to mean using generation resources located within B.C. Self-sufficiency requirement by 2016 for BC Hydro; other utilities must consider this objective. FBC's supply is currently sourced mainly from within B.C. and market purchases are not recommended in the long term (see Section 9).
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%	The 66 percent target applies to BC Hydro. FBC has assessed DSM scenarios and voluntarily adopted a target of 66 percent for 2018-2020 then ramping up to 80 percent by 2023 based on the LT DSM Plan.
2(c)	To generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity	Requirement to take actions to meet this target applies to BC Hydro or a prescribed utility. FBC-owned resources and long-term contracts are hydro-based. BC Hydro resources are currently 98 percent clean.[4] FBC alternative and preferred portfolios include clean or renewable resources.
2(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	FBC's LT DSM Plan provides support for energy conservation and efficiency including the use and development of innovative technologies and the LTERP portfolio analysis includes clean or renewable resources.
2(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	Specific to BC Hydro. FBC ratepayers are indirect customers of BC Hydro and receive the benefits of BC Hydro heritage assets via the PPA (see Section 2.2.1.2).
2(f)	To ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America	Specific to BC Hydro. FBC strives to provide cost-effective, secure and reliable service for its customers while also meeting other LTERP objectives.

[4] https://www.bchydro.com/news/conservation/2016/electric-vehicle-range-climate-fight.html

Section of the *CEA*	*CEA* Objective	How LTERP Supports Objective
2(g)	To reduce BC GHG emissions (i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007, (ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007, (iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007, (iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and (v) by such other amounts as determined under the Greenhouse Gas Reduction Targets Act	Provincial targets not specific to individual utilities. FBC GHG emissions represent only about 0.078 percent of total provincial emissions[5]. FBC recommendations include DSM to encourage energy conservation and clean and renewable resources to continue keeping FBC emissions low. GHG emissions for preferred portfolio including clean or renewable resources and gas-fired generation are minimal.
2(h)	To encourage the switching from one kind of energy source to another that decreases greenhouse gases in British Columbia	Load scenarios explore EV growth which encourages switching from gasoline to electricity. FBC is installing EV charging stations throughout its service area to meet the future needs of its customers. LT DSM Plan Section 5.1 discusses fuel switching related to gas and electric space heating.
2(i)	To encourage communities to reduce greenhouse gas emissions and use energy efficiently	LT DSM Plan and EV penetration discussed in LTERP Load Scenarios Section 4 encourage conservation and reduce GHG emissions.
2(j)	To reduce waste by encouraging the use of waste heat, biogas and biomass	FBC has considered these options in its assessment of resource options (see Section 8.2 and Resource Options Report in Appendix J).
2(k)	To encourage economic development and the creation and retention of jobs	Socio-economic attributes for resource options are discussed in Section 8.2 and the Resource Options Report in Appendix J.
2(l)	To foster the development of First Nation and rural communities through the use and development of clean or renewable resources	Section 8.2 and Resource Options Report discuss socio-economic development. FBC will consider opportunities with First Nations and local communities in the future when such opportunities arise (see Section 8.2.9).

5 Based on FBC 2014 GHG emissions of 0.049 million tCO2e reported to the BC Ministry of Environment (http://www2.gov.bc.ca/gov/content/environment/climate-change/reports-data/industrial-facility-ghgs) and the 2014 value of BC GHG emissions of 62.7 million tCO2e in the BC Greenhouse Gas Inventory (http://www2.gov.bc.ca/gov/content/environment/climate-change/reports-data/provincial-ghg-inventory).

Section of the *CEA*	*CEA* Objective	How LTERP Supports Objective
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	LTERP provides a framework for agreements and strategies that maximize value. For example, FBC optimizes Waneta Expansion capacity surplus and coordinates with BC Hydro (e.g. Canal Plant Agreement, Residual Capacity Agreement) and Powerex (CEPSA) which helps to maximize use of provincial hydro resources.
2(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	FBC has limited export ability due to restrictions embedded within BC Hydro PPA (see Section 5.4). Furthermore, current market price environment (see Section 2.4.1) limits any opportunities for exports as noted in BC Hydro 2013 IRP.[6]
2(o)	To achieve British Columbia's energy objectives without the use of nuclear power	FBC does not use, or plan to use, nuclear power.
2(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	Specific to BC Hydro; not applicable for FBC.

Section 19 of the *CEA* requires BC Hydro or a prescribed utility to pursue actions to meet the target of generating at least 93 percent of the electricity in British Columbia from clean or renewable resources and build the infrastructure necessary to transmit that electricity. In August 2016, the B.C. government released its CLP, provided in Appendix B, which recommends that 100 per cent of the supply of electricity acquired by BC Hydro in B.C. for the integrated grid must be from clean or renewable sources, except where concerns regarding reliability or costs must be addressed. This CLP requirement is not specifically directed to FBC and this policy is not yet enacted in legislation, such as an amendment to the *CEA*. However, FBC has included alternative portfolios using 100 percent clean or renewable resources in its portfolio analysis.

6 BC Hydro 2013 Integrated Resource Plan, Chapter 5, page 51-54.

1.5 COMMISSION GUIDELINES AND DIRECTIVES

1.5.1 Commission Resource Planning Guidelines

In 2003, the Commission issued Resource Planning Guidelines which outline a process to assist in the development of resource plans to be filed with the Commission. According to the guidelines, "resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run." The Commission reviews resource plans in the context of the unique circumstances of the utility in question. FBC adheres to the Commission's Resource Planning Guidelines. The following table outlines the key elements of the Resource Planning Guidelines and the sections of the LTERP in which they are addressed.

Table 1-4: Commission Resource Planning Guidelines

Resource Planning Guideline	Section of LTERP Addressing Guideline
1. Identification of the planning context and the objectives of a resource plan	Planning Environment Section 2 and Introduction Section 1.3
2. Development of a range of gross (pre-DSM) demand forecasts	Load Forecast Section 3 and Load Scenarios Section 4
3. Identification of supply and demand resources	DSM Section 8.1 and Supply-Side Resources Section 8.2
4. Measurement of supply and demand resources	DSM Section 8.1 and Supply-Side Resources Section 8.2
5. Development of multiple resource portfolios	Portfolio Analysis and LRMC Section 9
6. Evaluation and selection of resource portfolios	Portfolio Analysis and LRMC Section 9
7. Development of a four-year action plan, including contingency plan	Action Plan Section 11, Portfolio Analysis and LRMC Section 9.3.6.2
8. Solicit stakeholder input during the planning process	Stakeholder and First Nations Engagement Section 10
9. Seek regulatory input from Commission staff	Stakeholder and First Nations Engagement Section 10
10. Consideration of government policy	Planning Environment Section 2.2
11. Regulatory review once resource plan is filed	Review process to be determined by the Commission – FBC recommendations provided in Section 1.6

FBC submits that the 2016 LTERP is consistent with the resource planning guidelines.

1.5.2 Past Commission Directives

The LTERP and LT DSM Plan address several Commission directives related to long term resource planning. These directives stem from the 2012 LTRP as well as other FBC applications which have some impact or tie to resource planning. These directives are summarized in the following table and are discussed further in the following sections.

Table 1-5: Past Commission Directives

FBC Application and Commission Order	Commission Directive	Section of LTERP Addressing Directive
1. 2012 LTRP (G-110-12)	Conduct full portfolio analysis in next long term resource plan	Portfolio Analysis and LRMC Section 9
2. 2012 LTRP (G-110-12)	File next long term resource plan by June 30, 2016.	Commission approved FBC extension to November 30, 2016
3. Stepped Transmission Rates Stage 1 (G-67-14)	Review potential effectiveness of stepped rate and appropriate basis for determining LRMC in conjunction with next resource plan.	See Section 1.5.2.2 for stepped rates and Section 9 for Portfolio Analysis and LRMC
4. Residential Inclining Block Rate (G-3-12)	Update full long-run marginal cost of acquiring energy from new resources, including the cost to transport and distribute that energy to the customer as part of the Residential Inclining Block reporting to be submitted in 2014.	Portfolio Analysis and LRMC Section 9.3

1.5.2.1 Commission Directives from 2012 LTRP

FBC was directed to include a full portfolio analysis as described in the Resource Planning Guidelines in its next long term resource plan. The Resource Planning Guidelines describe portfolio analysis as including the development of several plausible resource portfolios consisting of a combination of supply and demand resources needed to meet the gross demand forecasts. These portfolios should then be assessed against the resource plan objectives, leading to the selection of a set of preferred resource portfolios. FBC has conducted such portfolio analysis and it is included in Section 9 of this LTERP.

FBC was also directed to file its next long-term resource plan by no later than June 30, 2016. FBC made a request to the Commission to extend the filing date deadline beyond June 30, 2016 to November 30, 2016 in a letter dated March 2, 2016. The Commission approved this filing extension request in Order G-43-16 dated April 1, 2016.

1.5.2.2 Other Commission Directives Related to the LTERP

There have been other directives from the Commission relating to long term resource planning that are addressed within this LTERP or the LT DSM Plan. These include directives stemming from the Commission decisions regarding the FBC Stepped Transmission Rates Stage 1 and the Residential Inclining Block (RIB) Rate Applications.

The Commission decision (Order G-67-14) regarding the FBC Stepped and Stand-by Rates for Transmission [Voltage] Customers - Stage 1 Application accepted that there was no reason to vary from the existing flat rate as evidenced by the lack of both customer desire for stepped rates and any indication that a stepped rate structure would in fact result in positive behavioural changes. As such, the Commission determined that the appropriate time for FBC to review the potential effectiveness of a stepped rate for Rate Schedule 31 (RS 31) customers and the appropriate basis for determining LRMC would be in conjunction with next resource plan.[7] FBC does not believe that the circumstances regarding RS31 customers have changed since that decision. Therefore, the Company does not plan to apply for the implementation of a stepped rate at this time. With regard to the appropriate basis for determining LRMC, FBC has outlined its approach and has determined LRMC values for different portfolios in Section 9 of this LTERP.

In the Commission decision regarding the FBC RIB Rate Application (Order G-3-12), FBC was directed to update the full long-run marginal cost of acquiring energy from new resources, including the cost to transport and distribute that energy to the customer as part of the RIB Rate reporting to be submitted in 2014. In its Residential Conservation Rate (RCR) Report to June 30, 2014, FBC stated that it intended to provide an in-depth analysis of LRMC in its next Long Term Resource Plan and Long Term DSM plan expected to be filed in 2016. FBC has provided this analysis for the LRMC in Section 9.

1.5.3 Other Items from 2012 LTRP and Other Applications

The Commission accepted the 2012 LTRP, filed as part of the 2012 Integrated System Plan on June 30, 2011, with the exception of the Planning Reserve Margin (PRM) requirement. At that time, the Commission agreed with FBC's suggestion to complete a PRM methodology study and submit any recommendations to the Commission which would include consideration of the implications of the new PPA with BC Hydro, at that time expected to be finalized later in 2012. However, the new PPA with BC Hydro was not finalized until later in 2013, with Commission approval in mid-2014. Since the filing of the 2012 LTRP, FBC has reviewed its PRM methodology and presented its approach to stakeholders as part of the LTERP RPAG workshop sessions. This updated methodology is discussed in Section 9.4.6.1 and has been applied to the PRM requirements for the preferred portfolio as recommended in this LTERP in Section 9.3.6. The PRM Report discussing FBC's methodology and detailed results for the preferred portfolio is included in Appendix L.

In the Commission decision regarding the FBC Self-Generation Policy Application Stage I (Commission Order G-27-16 dated March 4, 2016), FBC was encouraged to address DSM programs for self-generation customers as part of its next resource plan or next DSM expenditure filing (page iii). The Commission also suggested that FBC establish a policy that

[7] Decision, Order G-67-14, page 18.

defines how it measures cost-effectiveness when evaluating potential long term energy purchase contracts with a self-generation customer and establish a policy that sets out those criteria it will consider (page iii). FBC submitted the Self Generation Policy Stage II Application to the Commission on November 10, 2016. This application sets out how it will interact with self-generating customers taking into consideration the choices that a customer makes regarding the use of the self-generation output within the context provided by the High Level Self-Generation Policy Application (Stage I Application) decision and the framework provided by the policies that FBC proposes. FBC discusses the eligibility of self-generators for DSM programs in section 5.2 of the LT DSM Plan. FBC discusses potential supply from self-generators in the Supply-Side Resource Options Section 8.2.8.

1.6 *ORDER SOUGHT AND PROPOSED REGULATORY PROCESS*

FBC submits that the 2016 LTERP meets the requirements of the *UCA* and seeks the Commission's acceptance of the 2016 LTERP, including the LT DSM Plan, as being in the public interest pursuant to section 44.1(6) of the *UCA*. A draft Order is attached as Appendix M-2.

The Company submits that a written hearing is appropriate for the review of the 2016 LTERP and proposes the following regulatory timetable, which includes two rounds of Information Requests. A draft Procedural Order is attached as Appendix M-1.

Table 1-6: Proposed Regulatory Review Timetable

ACTION	DATE	
	2016	
Commission Issues Procedural Order	Friday, December 16	
	2017	
FBC Publishes Notice of Filing by	Friday, January 6	
Registration of Interveners and Interested Parties	Thursday, January 12	
Commission Information Request No. 1	Thursday, January 19	
Intervener Information Request No. 1	Thursday, January 26	
FBC Responses to Information Requests No. 1	Thursday, March 2	
Commission and Intervener Information Request No. 2	Thursday, March 23	
Notification by Interveners of Intent to file Evidence	Thursday, April 13	
FBC Responses to Information Requests No. 2	Thursday, April 20	
	No Intervener Evidence	If Intervener Evidence
Intervener Evidence	n/a	Thursday, May 4
Commission and Intervener Information Request No. 1 on Intervener Evidence	n/a	Thursday, May 18
Intervener Responses to Information Requests No. 1	n/a	Thursday, June 15
FBC Final Submission	Thursday, May 4	Thursday, June 29

ACTION	DATE	
Intervener Final Submissions	Thursday, May 18	Thursday, July 13
FBC Reply Submission	Thursday, June 1	Thursday, July 27

2. PLANNING ENVIRONMENT

2.1 *INTRODUCTION*

It is important that FBC understands the planning environment in order to meet its resource planning objectives. The planning environment includes relevant external factors that could impact FBC's demand-side and supply-side resource options and their future costs and prices as well as those factors that could influence customers' energy and capacity needs over the planning horizon.

This section describes the key factors of the planning environment and is organized as follows:

- It begins with an overview of the relevant energy and environmental policy in both Canada and the U.S. as this will impact resource options, market prices and influence customers' behaviour regarding energy use in the future.
- Then an overview of the customer demand environment is examined to assess how technology and customers' energy needs are changing and how the relationship between the customer and the utility is evolving.
- Next, the supply environment is examined as the changes occurring in B.C., Alberta and the Pacific Northwest region will impact FBC's resource options and market electricity prices.
- And finally, FBC presents long-term market forecasts for natural gas and electricity prices, as well as carbon price and rate scenarios under the PPA that impact the cost of existing and potential resource options in the future.

2.2 *ENERGY AND ENVIRONMENTAL POLICY*

Energy and environmental legislation, regulation and policies of municipal, provincial and federal governments directly impact FBC's resource planning process. Regional collaborative policy initiatives of provincial and state governments on each side of the Canada-U.S. border are also directly relevant to FBC's planning process.

Various other legislative and policy initiatives of the federal and certain state governments in the U.S. may affect the wholesale electricity market in the western U.S. This market operates adjacent to FBC's service territory and is currently a source of energy and capacity products for FBC. FBC must remain aware of, and where appropriate, responsive to, the changing regulatory regime governing U.S. markets in order to adequately fulfill its planning mandate.

Relevant governmental initiatives are discussed in the following sections.

2.2.1 Province of British Columbia

Energy policy in the Province of B.C. has been historically rooted in the four cornerstones of low electricity rates, secure and reliable supply, private sector opportunities, and environmental responsibility. In the years between 2007 and 2010, the B.C. Government took aggressive action to align the province's energy policy with a plan to address the issue of climate change. During this time, the government's plan included a number of major climate change policies such as the *Carbon Tax Act* and the *CEA*. Since introducing the *CEA* in 2010, B.C.'s energy policies have been largely directed at establishing a path to low carbon energy self-sufficiency. More recently, some of these initiatives have been revisited in the face of systemic shifts in North American natural gas and electricity markets. In 2015 the B.C. government formed a Climate Leadership Team to provide recommendations for meeting B.C.'s climate goals. In August 2016, the B.C. government released the Climate Leadership Plan which outlined action items to reduce GHG emissions while promoting development and creating jobs.

Key legislative and regulatory actions are outlined in the sections below.

2.2.1.1 Clean Energy Act

The key legislative act supporting energy policy in B.C. is the *CEA.* Passed in April 2010, the *CEA* outlines 16 objectives aimed at turning B.C. into "a leading North American supplier of clean, reliable, low carbon electricity and technologies that reduce GHG emissions while strengthening [the] economy in every region."[8] A summary of the objectives follows:

- for B.C. to achieve energy self-sufficiency;
- to take demand-side measures and to conserve energy, including the objective for BC Hydro to reduce its expected increase in demand for electricity by the year 2020 by at least 66 percent;
- to generate at least 93 percent of the electricity in B.C. from clean or renewable resources;
- for ratepayers to continue to receive the benefits of BC Hydro's low-cost "Heritage Assets" (existing Hydro generation assets);
- to reduce B.C. greenhouse gas emissions;
- to ensure BC Hydro's rates remain among the most competitive of rates charged by public utilities in North America;
- economic development, including for First Nations and rural communities, and
- to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians.

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

In July 2012, the B.C. Government amended the *CEA* through B.C.'s *Energy Objectives Regulation* to redefine natural gas as a clean energy source when used to generate power for liquefied natural gas (LNG) facilities.

2.2.1.2 The Heritage Contract and the BC Hydro Power Purchase Agreement

The *CEA's* treatment of BC Hydro's heritage resources has an impact on FBC's resource planning process. The 2002 Energy Plan legislated a "Heritage Contract" for an initial term of ten years to ensure that BC Hydro's customers benefit from existing low cost heritage resources. 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.

In May 2014, FBC entered into an agreement with BC Hydro to replace the 1993 Power Purchase Agreement. The new PPA is a 20-year fixed term agreement that continues to provide for up to 200 megawatts (MW) of capacity and 1,752 gigawatt hours (GWh) per year of associated energy for FBC to meet a portion of its load service obligations. The PPA ensures that FBC, as a customer of BC Hydro receiving power under Rate Schedule 3808 (RS3808), continues to be eligible to benefit from BC Hydro's heritage energy.

2.2.1.3 B.C. Carbon Tax

On May 29, 2008, the Government of British Columbia enacted the *Carbon Tax Act*, 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 of 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 in 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. The carbon tax rate was subject to further review pursuant to the development of B.C.'s recently released CLP, which is discussed below.

In September 2016, the Canadian government announced a new plan to implement a national price on carbon. It will require the provinces to have a price of at least $10 per tonne of carbon dioxide equivalent emissions starting in 2018. The price would rise by $10 a year for the next four years, reaching $50 a tonne by 2022. Based on this announcement, it is expected that B.C.'s carbon tax will increase above its current level by 2022.

2.2.1.4 Climate Leadership Plan

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

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

In August 2016, the B.C. government released the CLP, provided in Appendix B, which adopted some of the recommendations from the CLT's report. The CLP includes 21 action items intended to help put B.C. on course to meet the target of an 80 percent reduction in GHG emissions from 2007 levels by 2050. The CLP states that the carbon tax rate could be increased from the current level ($30 per tonne) in the future but only once other jurisdictions catch up. It also provides for expanding support of zero-emission vehicle charging stations in buildings and expanding the Clean Energy Vehicle program to support new vehicle incentives and infrastructure. The CLT recommended that 100 percent of B.C.'s electricity generation be clean or renewable by 2025 while allowing the use of fossil fuels for generation for reliability. The CLP states that 100 percent of the supply of electricity acquired by BC Hydro in B.C. for the integrated grid must be from clean or renewable sources except where concerns regarding reliability or cost must be addressed.

The CLP also encourages the development of net zero[9] buildings, including accelerating increased energy requirements in the B.C. Building Code by taking incremental steps to make buildings ready to be net zero by 2032. Another relevant item from the CLP includes a strategy to reduce methane emissions from the oil and gas sector. If there is increased regulation or more standards relating to natural gas extraction or venting, this could increase the costs for natural gas production and lead to higher natural gas market prices. The CLP also discusses increasing the rate of forest replanting and wood fiber recovery in B.C. This may increase the availability of wood fiber as biomass fuel in the future that could be used for power generation. Biomass is one of the generation sources considered by FBC as a resource option.

The B.C. government has indicated that it expects to work with the provinces toward developing a pan-Canadian approach to climate action later in 2016.[10]

FBC has addressed relevant items from the CLP in its load scenarios, market price forecasts and portfolio analysis. FBC discusses scenarios involving fuel switching between natural gas

[9] A Net Zero building is a building with zero net energy consumption, meaning the total amount of energy used by the building on an annual basis is roughly equal to the amount of renewable energy created on the site https://en.wikipedia.org/wiki/Zero-energy_building

[10] B.C. Climate Leadership Plan, Appendix B, page 44.

and electricity, increased electricity demand and increased use of electric vehicles in its load scenarios in Section 4 and includes clean and renewable resources in its alternative and preferred portfolios in Section 9.

2.2.2 Other Province's Actions

Other provinces have also recently announced climate leadership plans to combat greenhouse gas emissions and the impacts of climate change. Alberta's plan has the greatest impact on the B.C. energy industry, and on FBC.

Pursuant to Alberta's Climate Leadership Plan[11], Alberta will introduce a carbon tax of $20 per tonne of CO_2e in 2017, rising to $30 per tonne by 2018 with further increases limited to the rate of inflation. Under Alberta's plan, carbon pricing will cover 90 percent of emissions (on-site combustion in conventional oil and gas sectors will be exempted until 2023). Revenues are proposed to be re-invested in clean technology, infrastructure, energy efficiency, and helping the most-impacted Albertans transition to a fiscal regime that includes a carbon tax.

With regard to the electricity sector, Alberta is also aiming to phase out pollution from coal-fired sources of electricity completely by 2030. In place of coal, cleaner sources of generation (e.g., natural gas, wind, solar, biomass) will meet Alberta's power needs. This phase out of coal could drive demand for B.C.'s clean electricity to help Alberta meet electricity needs. This could impact the way the regional electricity grid is operated, B.C.'s electricity supply and generation, and the electricity prices in the regional electric markets. These changes could impact FBC's electricity market access and the price it pays, or receives, for electricity.

Alberta is also targeting an emissions cap on oil sands production, and a reduction in fugitive methane emissions from Alberta's oil and gas production. These upcoming regulations could add cost to natural gas production and impact regional market natural gas and electricity prices. Emissions caps on oil sands production could result in changes to self-generation practices and drive demand for clean electricity sources in the region. Much will depend on the final regulations set in place by the Alberta government.

2.2.3 Municipal Policy Actions

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

In B.C., the City of Vancouver (COV) is moving forward with an aggressive "Greenest City Action Plan,"[12] which includes aspirational goals of moving toward 100 percent renewable

[11] Alberta Climate Leadership Plan. Available: http://www.alberta.ca/climate-leadership-plan.cfm.
[12] "Greenest City 2020 Action Plan." City of Vancouver, 2015. Available: http://vancouver.ca/files/cov/greenest-city-2020-action-plan-2015-2020.pdf.

energy by 2050 and reducing GHG emissions by 80 percent below 2007 levels by 2050. Detailed goals include reducing energy use and GHG emissions in existing buildings by 20 percent below 2007 levels, and requiring all buildings constructed from 2020 onward to be carbon neutral in operations. COV also hopes to increase public transit rideshare, expand the public transit system, and transition light-duty vehicles (cars and light trucks) to predominantly electric, plug-in electric, or sustainable biofuel powered. On March 23, 2015, Vancouver City Council voted unanimously to support a shift toward the city deriving 100 percent of its energy from renewable sources, including energy for transportation and buildings.

In July 2016, COV released a new Zero Emissions Building Plan where all new buildings are required to achieve zero operational GHG emissions by 2030.[13] Key plan features include time-based constricting GHG intensity (GHGI) targets for each major building type, complemented by Thermal Energy Demand Intensity (TEDI) targets to focus on building envelope performance improvements for all buildings. Section 2.2 of the plan states that its focus is on "reducing the demand for fossil fuel-based natural gas used primarily for space heating and hot water, and transitioning these functions to renewable sources such as electricity (including heat pumps), biogas and neighbourhood renewable energy systems (NRES)." Eliminating or significantly reducing the choice of natural gas from new developments and new housing builds, and implementing an electrified transportation system, will result in increased electricity demand in the COV. Although this demand growth is not in FBC's service area, the interconnected nature of B.C.'s grid means that all new electric demand in B.C. has the potential to impact FBC's electric business. Furthermore, it is possible that other municipalities in B.C. could follow Vancouver's lead in reducing GHG emissions with similar policies. If so, this could increase electricity demand from FBC's customers.

Municipalities are also investing in renewable energy generation. One example is the proposed Nelson Community Solar Garden.[14] Through its municipal utility, the City of Nelson is proposing to build a small solar PV array, funded through the sale of subscriptions for a portion of the produced energy directly to interested community members. Such initiatives, if pursued on a large enough scale, could reduce the demand on B.C.'s electricity grid, and impact the traditional utility business in which FBC is engaged.

2.2.4 Regulatory Framework in the U.S.

Various other legislative and policy initiatives of the federal and state governments in the U.S. may affect the wholesale electricity market in the western U.S. This market operates adjacent to FBC's service territory and is currently a source of energy and capacity products for FBC. FBC must remain aware of, and where appropriate, responsive to, the changing U.S. regulatory regime governing that market in order to adequately fulfill its planning mandate.

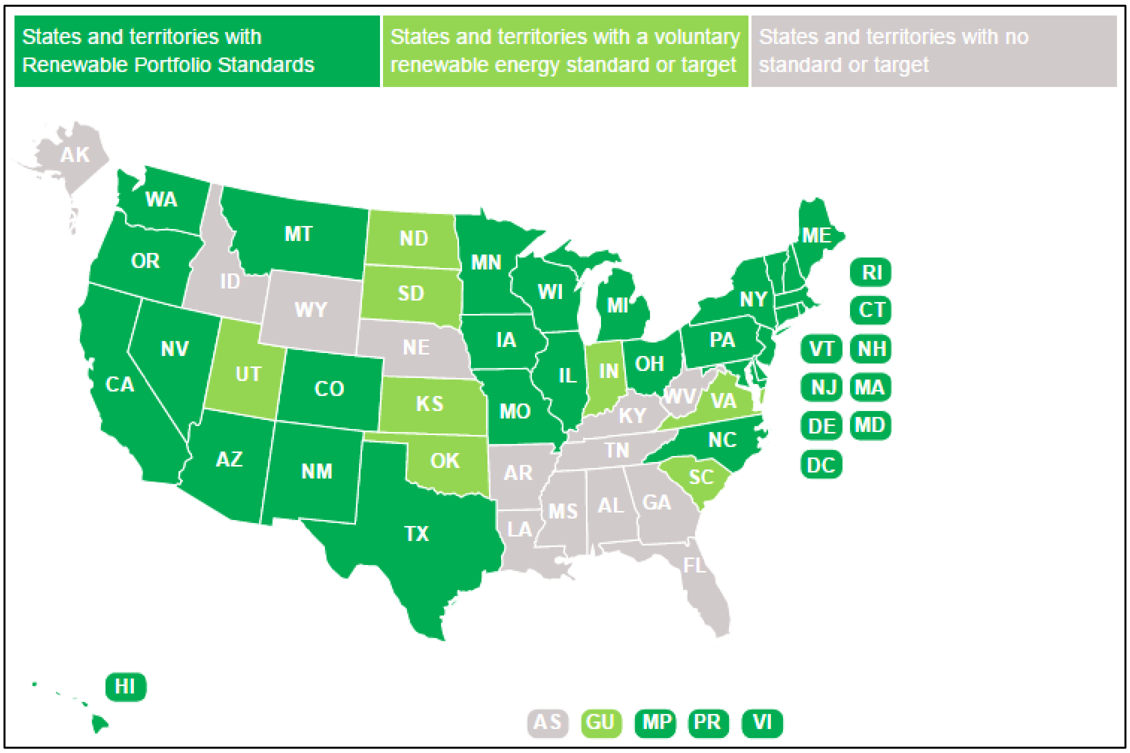
[13] http://council.vancouver.ca/20160712/documents/rr2.pdf

[14] Nelson Community Solar Garden. Information available: http://www.nelson.ca/EN/main/services/electrical-services/energy-grants/solar-garden.html.

2.2.4.1 U.S. Renewable Portfolio Standards

Renewable portfolio standards (RPS) are policies designed to increase generation of electricity from renewable resources. These policies require or encourage electricity producers within a given jurisdiction to generate and supply a minimum share of their electricity from designated renewable resources. Generally, these resources include wind, solar, geothermal, biomass, and some types of hydro-electricity. Some RPS policies may also include other resources such as landfill gas, municipal solid waste, and tidal energy.[15] Presently, 30 states and the District of Columbia have enforceable RPS or Alternative Energy Portfolio Standards, and eight states have a voluntary Renewable or Alternative Energy Goal.[16] These programs vary widely in terms of program structure, enforcement mechanisms, size, and application. The following figure shows the states with RPS or voluntary targets versus those without any standard or target.

Figure 2-1: State Renewable Portfolio Standards or Voluntary Targets[17]



According to the Northwest Power and Conservation Council's (NPCC) 7th Power Plan, 250 to 400 MW of installed capacity is expected to be required by 2035 to fulfil existing renewable portfolio standards.[18] Renewable development in the region has historically consisted primarily

[15] "Most states have Renewable Portfolio Standards." EIA, 2012. Available: http://www.eia.gov/todayinenergy/detail.cfm?id=4850.

[16] National Conference of State Legislatures, http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx, Accessed July 25, 2016.

[17] Ibid.

[18] Northwest Power and Conservation Council 7th Power Plan, https://www.nwcouncil.org/energy/powerplan/7/home/, page 3-5.

of wind resources. However, the declining cost of utility-scale solar means that future renewable growth will increasingly come from this resource option. Although renewable generation resources will make a material contribution to the total installed generation capacity in the future, their contribution to the electricity system's ability to meet its peak demand is modest given the intermittent nature of wind and solar resources.

2.2.4.2 EPA Clean Power Plan

The U.S. Environmental Protection Agency's (EPA) Clean Power Plan (CPP) aims to reduce carbon dioxide emission from power plants by 32 percent below its 2005 levels by 2030.[19] The CPP sets emissions standards for electric generating units and provides a number of options for states to meet these standards, including inter-state collaboration to demonstrate emissions performance. This recognizes that electricity is transmitted across state lines.

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

One likely outcome of the CPP, if it is implemented, includes less reliance on coal and more development of natural gas-fired generation. It could also provide states and developers additional incentives to rapidly expand their non-hydro renewable capacity to displace existing coal generation. The incremental increases in renewable generation would consist primarily of new wind and solar capacity.[20] This adoption of intermittent renewables could produce vulnerability to the power system through reliability issues. It could also provide market opportunities for exporters of renewable generation such as Canadian wind and hydro-electric generation.

However, a number of legal challenges are underway after the release of the final CPP rule. 27 states and dozens of industry groups comprising almost 150 total identified parties have sued the EPA[21] to suspend the rule and ultimately have it invalidated. It will likely be several years before all the legal challenges and appeals are exhausted. Furthermore, uncertainty now exists over the future of climate action including the CPP rule in the U.S. as a result of the upcoming change in administration.

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19 US EPA, *CPP Final Rule*, August 3, 2015 http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf.

20 https://www.epa.gov/cleanpowerplan/fact-sheet-clean-power-plan-clean-energy-now-and-future.

21 http://www.eenews.net/interactive/clean_power_plan/fact_sheets/legal.

2.2.5 Summary

Energy and environmental policies in Canada and the U.S. are constantly evolving as federal, provincial and state governments are implementing a number of initiatives to reduce GHG emissions. These policy actions will impact the electricity generation mix in western Canada and the U.S. Pacific Northwest region as generators in the U.S. and provinces like Alberta move towards greater adoption of renewable resources like wind and solar. This in turn will likely impact market electricity prices. At the same time, these policies may also increase electricity demand in certain areas such as the transportation sector and impact the level of carbon pricing in B.C. This could provide both challenges and opportunities for FBC.

2.3 *CUSTOMER DEMAND ENVIRONMENT*

The ways in which customers use, monitor and even generate electricity is evolving, presenting both challenges and opportunities for FBC in meeting the future needs of its customers. Technology is a large driver in this evolution, impacting how customers connect and interact with FBC and influencing the supply of and demand for electricity on the system. DSM also continues to evolve and remains a key resource option for customers to cost-effectively reduce their energy consumption. These factors, in turn, have implications for FBC's product and rate offerings which need to appropriately reflect how customers use electricity.

FBC is continuing to meet customer demands in a number of ways, including by:

- Supporting small customer-owned clean or renewable generation with the net metering tariff;
- Supporting EV adoption by funding charging stations;
- Promoting informed electricity use by providing more detailed and up-to-date consumption data;
- Evaluating a community solar project, and
- Providing customers with cost-effective DSM programs to reduce their energy consumption.

2.3.1 Connected Home and Business

Technology is changing the way customers interact with FBC and the information available to both customers and FBC regarding energy use.

The recently-completed Advanced Metering Infrastructure (AMI) project provides customers with access to real-time, detailed load data from customer endpoints, allowing them to better manage their electricity use. The Company's secure web-based Customer Information Portal (CIP) will soon be enhanced to allow customers to select certain types of "push" notifications via text or email. For example, customers could opt to be notified three days before their bill is due or when their electricity consumption exceeds a certain threshold in a billing period. FBC is also working on making more granular consumption data available on-demand to customers through the CIP. Hourly electricity use data will generally be available to customers within 24 hours after usage, which is expected to meet the needs of most customers.

For those customers that have more demanding requirements for monitoring their energy use, FBC will allow customers to connect electricity monitoring devices to their advanced meters. These devices provide real-time energy use information via dedicated in-premise devices that communicate directly with advanced meters. This type of device is expected to be used on a more limited basis than the web portal, however, partly because the devices must be relatively close to the electric meter and partly because the no-cost web portal provides sufficient information for most purposes.

The increased availability of energy use information available is likely to drive customers' interest in controlling their energy use. Remote monitoring and control of energy-consuming devices is becoming increasingly commonplace with the advent of products such as "smart" thermostats. These thermostats monitor building occupancy patterns and will change temperature set points to reduce energy use when buildings are unoccupied. They also allow remote temperature adjustments via a web browser or mobile phone app. Automation technology allows better control of devices other than thermostats in customers' homes and businesses as well. Lighting controls can turn off or dim lighting based on room occupancy. Hot water controls could anticipate higher demand periods, reducing set points at other times.

In Section 4, FBC explores load scenarios that include a load driver relating to this increased energy use awareness and automation (the "internet of things") to determine potential impacts on annual energy load and peak demand for the FBC system.

2.3.2 Electric Vehicles

B.C. currently leads the country in EV sales (on a per-capita basis) and is second only to Quebec in terms of EV ownership[22]. As of September 30, 2016, there were 4,698 EVs registered in B.C. FBC expects that as vehicle manufacturers continue to introduce EVs with more range and that are priced at a level that targets mass market adoption, consumer uptake of EVs will continue to increase. FBC must be prepared to meet the changing and future needs of customers as they relate to EVs and the associated charging infrastructure.

FBC is preparing to meet customer needs for EV transportation in two ways. First, FBC is providing financial, logistical and engineering support for the federal/provincial direct current (DC) fast-charging programs. This has resulted in the installation of three Level 3 DC fast-charging stations in Keremeos, Penticton and Princeton, with an additional six DC fast-charging station locations identified for further investigation. FBC is also currently working with BC Hydro, the Community Energy Association and municipalities along Highway 3 to complete an East-West Level 2 charging station route through the FBC electric service territory. Second, FBC

[22] Based on Canada EV fleet ownership figures http://www.fleetcarma.com/ev-sales-canada-2016-q3/, http://www.fleetcarma.com/ev-sales-canada-2015/ and 2016 Canadian provincial population estimates https://en.wikipedia.org/wiki/List_of_Canadian_provinces_and_territories_by_population_growth_rate.

considers on an annual basis the potential capital for designing and installing EV charging infrastructure in its service territory. FBC recently supported the installation of two Level 2 electric vehicle chargers in the City of Kelowna's downtown core and is in discussions with other municipalities on possible charging opportunities. A key benefit to FBC from this support includes additional research and insight into the infrastructure requirements necessary to support EV charging stations, as well as an improved understanding of customer uptake of these public charging resources.

Increased consumer adoption of EVs in B.C., with their associated energy and demand charging requirements, has the potential to place significantly greater demands on utility infrastructure as further discussed in section 6.4.2. However, depending on customers' charging strategies, there is the opportunity for these types of loads to improve the utilization of the electric grid without significantly impacting infrastructure. FBC's continued involvement in supporting transportation electrification will help to ensure the development of a robust EV charging network that appropriately takes into consideration the forecast number of EVs expected to replace conventional internal combustion engine vehicles.

In Section 4, FBC explores load scenarios that include various levels of EV penetration to determine potential impacts on the FBC system in terms of annual energy load and peak demand. Section 6 discusses, at a high level, potential impacts of higher levels of EV growth on FBC's transmission and distribution system.

2.3.3 Small-Scale Distributed Generation

Generation technologies continue to evolve, both at the utility-scale level and in terms of smaller scale distributed generation by customers. Technologies such as micro-hydro and solar photovoltaic have made residential-scale generation more feasible, reducing customer demand from the utility, and placing different burdens on the distribution system.

Small-scale distribution generation technology is gaining traction with customers for a few reasons:

- The perception that distributed generation is "greener" than utility generation.
- The desire to become more energy-independent.
- The perception that they are saving money.

Small-scale distributed generation technologies present some challenges for FBC. These include the following:

- Safety – potential for back-feeding onto the distribution grid must be properly addressed.
- Grid stability – the distribution grid must be able to handle unpredictable distributed generation output without causing power quality problems for other customers.

- Cost – the fixed charges in current rate structures do not adequately recover the cost of connection to the distribution system.

Despite these challenges, FBC has been supporting customer-owned distributed generation through its Net Metering tariff since 2009. The key features of the program currently are that it is:

- Available to residential, smaller commercial, and irrigation customers;
- Available for installations defined as a clean or renewable resource in the *CEA*;
- Limited to annual consumption and a capacity of not more than 50 kW;
- Available for installations located on the customer's premises;
- Required to operate in parallel with the Company's transmission or distribution facilities, and
- Intended to only offset part or all of the customer's requirements for electricity.

Currently, about 110 customers are enrolled in the Net Metering Program, with the majority generating power using small-scale residential solar photovoltaic installations. Customer participation has been trending upwards over the last few years. FBC assumes that this trend will continue and that net excess generation, while minor on an individual customer basis, will grow in the aggregate. The presence of net excess generation on the distribution grid will continue to be monitored as it has the potential to create grid stability issues.

In Section 4, FBC explores load scenarios that include various levels of residential rooftop solar penetration to determine potential impacts on the FBC system in terms of annual energy load and peak demand. Section 6.4.1 discusses, at a high level, potential impacts of higher levels of distributed generation on FBC's distribution system.

2.3.3.1 Community Solar

Solar costs fall as the size of an individual installation increases, all else equal. As a result, there is a growing interest in "community solar", in which the output of a larger solar array is divided between a number of customers.

For many FBC customers, the ownership, as well as placement and operation of solar PV system, are not desirable or feasible. Customer ownership and operation requires upfront capital costs, as well as ongoing expenses associated with system operation and maintenance. Beyond cost considerations, rooftop or ground-mounted solar installations are feasible only for certain property owners. Customers who live in rental properties, multi-unit residential buildings (MURBs), or townhomes are necessarily limited in their options. Other customers that have aging rooftops, or an unsuitable rooftop orientation may also be unable to install a PV system.

The Company is interested in helping customers interested in solar generation (and potentially other forms of distributed generation), but who have limited access to capital or who are not willing or able to install solar panels on their home. FBC is examining options that would allow participating customers to pay for the additional revenue requirement of community solar in exchange for a share of the solar output and is considering filing an application for a pilot program in late 2016 or early 2017.

2.3.4 Rate Design Considerations

The emerging technologies described in the previous sections have the potential to change the manner in which the Company interacts with its customers. By extension, this may impact whether the rates FBC has in place are able to appropriately reflect changes in how customers use power.

FBC's practice is to allocate costs to customer rate classes on the basis of cost-causation and not simply with regard to the end use of the power. That is, rates are typically designed such that the revenues collected from a rate class will recover the costs that have been allocated to it, within a range of reasonableness. Should an emerging use, such as EVs for example, be shown to have a unique usage profile that impacts costs, the Company may need to consider rate options that reflect such new or changing electricity use by its customers. In this way, any benefits or incremental costs that result from the widespread adoption of new technologies will predominantly accrue to those customers that choose to participate without unduly impacting the rates of other customers. In the near term, FBC will monitor emerging market trends and consider new or amended rate structures as part of a future rate design process.

The Company does however have a small number of current or pending programs that may require new rates, or amendments to current rates within the next few years.

First, as discussed above, FBC is examining options for a solar pilot project in 2017 in response to customer interest in renewable generation and to gather information and insight into the location of such an installation in the service area.

Second, the growth in interest and participation in small scale customer-owned generation, such as the installations that qualify for the Company's Net Metering Program, may begin to pose rate stability challenges for all customers. While the current participation rates and installed capacity are not a cause for concern, FBC recognizes that a proliferation of grid-connected customers with greatly reduced, zero, or periodic load is problematic for the current regulatory model where the costs of providing all aspects of service are recovered primarily through volumetric rates. FBC, like many other utilities, is concerned that the result of the widespread installation of customer-owned generation will be the transfer of costs to customers who either cannot participate, or choose not to participate. These concerns have led utilities and regulatory bodies in other jurisdictions to explore solutions such as residential demand charges or higher fixed charges that better reflect the fixed costs of providing service. FBC intends to explore this potentiality in its next rate design process.

2.3.5 Demand-Side Management Trends

Advances in technology, and new behaviour research and marketing approaches are impacting DSM strategies and practices. The following outlines some of these developments and how they may impact DSM program delivery over the next several years. FBC will continue to monitor these trends and may implement future change to address the changing market if warranted.

2.3.5.1 Climate Change and Regulatory Requirements

With increasing federal, provincial and local government interest and development of new regulatory frameworks to reduce GHG emissions, FBC anticipates that there will be a greater requirement for DSM programming. This would increase DSM budgets and ultimately customer rates.

With increasing B.C. building code baselines and the anticipated adoption of "stretch" building codes to improve the energy performance of new homes in B.C., it will become more challenging to achieve energy savings within DSM programs. Increased customer communications, more creative program planning and higher rebate values may be needed to drive greater participation and to move market transformation.

2.3.5.2 Rising Price of Electricity

The Company anticipates that, as the cost of providing electrical service increases, electricity prices will continue to rise over the next decade. Although electricity prices are considered fairly inelastic amongst middle and upper-income households, these rate conditions should help drive DSM participation. Recent research shows a tendency for homeowners to value energy efficiency in their homes, particularly when purchasing a new home.[23]

Although the rising price of electricity and a general interest in energy efficiency in homes are signals that more customers will invest in energy efficiency measures in the future, low-income households, with limited access to capital, may experience an increased "energy burden". DSM programs may have to focus more resources on this customer segment.

2.3.5.3 Advanced Analytics

Customer engagement tools (CETs) provide customers with deeper insights into their energy use and are changing the way DSM programs are marketed to customers. With the ability to operate across digital channels, CETs are improving customer experience and driving greater DSM program participation. For example, CETs can provide:

- Digital or paper Home Energy Reports to give customers a personalized view of their energy use and reach them when they are receptive.

[23] Survey indicates 4 of 10 of the preferred new home features are energy-efficiency related. CHBA, *Home Owner Preference Survey*, 2016, retrieved from: http://ottawacitizen.com/life/homes/survey-says-chba-looks-at-what-buyers-want-in-new-homes

- Advanced web portals that include Home Energy Analysis audits to provide an easy way for customers to better understand and take control of their energy use.
- Gamification (e.g. energy saving competition with neighbours or other social groupings) to create interest in energy efficiency topics and to drive customers online and to improve DSM program participation.
- Measurement and verification (M&V) of individual customer savings and a roll-up of program energy savings. CET programs designed with control groups provide baseline usage against which to measure verifiable energy savings.
- Integrated DSM by combining different elements — energy efficiency assessment (reports), program offers (conservation, demand response), savings confirmation (M&V) etc. — resulting in a series of customer interactions.
- Cost-effective and personalized marketing efforts to grow DSM program participation. This can be accomplished through improved:
  - Customer segmentation;
  - Two-way and personalized communication, and
  - Social media – sharing.

2.3.5.4 Becoming part of the utility's customer engagement strategy

Increasingly, DSM is being used to build long-term relationships with customers. Whether through participation in rebate programs or the use of CETs, customers report higher levels of satisfaction when the utility helps them better understand how they use and can manage their energy use. Other elements of CETs, like gamification, market segmentation and two-way and personalized messaging, and the use of social media help build a sense of community.

2.3.5.5 Connecting homes and businesses to energy services they need

A limited number of utilities are starting to enter the marketplace and selling energy efficiency products like LED lamps, low-flow showerheads and smart thermostats.[24] In addition to on-line stores, utilities are providing information and/or promotion about trade allies' businesses and forwarding offers from third parties. They are also making appliance and equipment comparisons and giving recommendations. Utilities that provide these services are perceived, by customers, to be the energy efficiency authorities and are helping to meet customer demand.

With increased interest in solar PV and EVs it is likely more utilities will follow some other utilities' lead in increasing participation in EV programs.[25]

[24] For example, Central Hudson launched its CenHub on-line store in early 2016: www.cenhubstore.com.
[25] Dr. Mladen Kezunovic, Electric Vehicles Could Offer More Gain than Drain, as referenced at http://www.electricenergyonline.com/show_article.php?mag=88&article=741.

It is expected that by promoting efficiency offers beyond traditional types of programs, utilities will enable customers to reduce energy demand while providing innovative, personalized experiences.

2.3.6 Summary

The customer demand environment continues to evolve as customers change the ways they use, monitor and generate their own electricity. This presents both challenges and opportunities for FBC in meeting the future needs of its customers. Technology is impacting how customers interact and connect with FBC as they have more options for monitoring and controlling their energy use. This technology will likely reduce the demand for electricity in the future.

Distributed generation technologies, such as rooftop solar PV, will also change customer demand and places different burdens on the distribution system. While customers may install their own distributed generation in order to save money or gain energy independence, small-scale distributed generation technologies present some challenges for FBC related to safety, grid stability and cost recovery through rates.

Given that the ownership, placement and operation of a customer-owned distributed generation system is not desirable or feasible for many customers, FBC is evaluating the use of a community solar pilot project as an alternative to allow these customers to have an option for making solar power part of their energy options.

FBC expects consumer uptake of EVs to increase in the future as vehicle manufacturers continue to introduce EVs with more range and priced at a level that targets mass market adoption. FBC is preparing to meet the changing and future needs of customers as they relate to EVs and the associated charging infrastructure by providing financial, logistical and engineering support for the design and installation of EV charging infrastructure in its electric service territory.

The emerging technologies described in this section have the potential to change the manner in which the Company interacts with its customers. By extension, this may impact how the rates FBC has in place are able to appropriately reflect changes in how customers use power. FBC intends to explore this area potentiality in its next rate design.

Demand-side management also continues to evolve and remains an important of meeting customer demand. Climate change and related regulatory requirements, the rising price of electricity, advanced analytics and engagement tools will enable customers to reduce energy demand while providing innovative, personalized experiences.

2.4 *CHANGING SUPPLY ENVIRONMENT*

An important part of FBC's long-term resource planning is monitoring developments in the regional power marketplace, including Alberta, B.C. and the U.S. Pacific Northwest. Market purchases are an important part of FBC's resource portfolio and FBC needs to understand any potential changes that may impact market supply availability and pricing. FBC keeps apprised of market developments through research and review of regional planning documents, such as the NPCC power plans, attending conferences and forums focused on relevant market topics and monitoring other Pacific Northwest utilities' planning requirements as published in their Integrated Resource Plans (IRPs). FBC also belongs to a number of organizations involved in regional resource planning such as the Western Energy Institute (WEI) and the Northwest Gas Association (NWGA).

The following sections describe some of the key developments shaping the regional power marketplace. A summary of other regional utilities' latest IRPs is provided in Appendix C.

2.4.1 Market Price Environment

Regional market electricity prices continue to be highly correlated with regional natural gas prices. This is largely because natural-gas fired power plants are often the marginal generating unit for generating electricity. Natural gas prices continue to remain low relative to historical values prior to the shale gas surge after 2008. Advances in drilling technology and cost reductions for producers have led to an abundance of low-cost shale gas in North America and increases in shale gas production are only expected to continue. Low gas prices are providing opportunities for increased natural gas use, particularly in power generation, LNG exports, and the transportation sector. Natural gas supply has kept up with this increased demand, keeping prices at low levels.

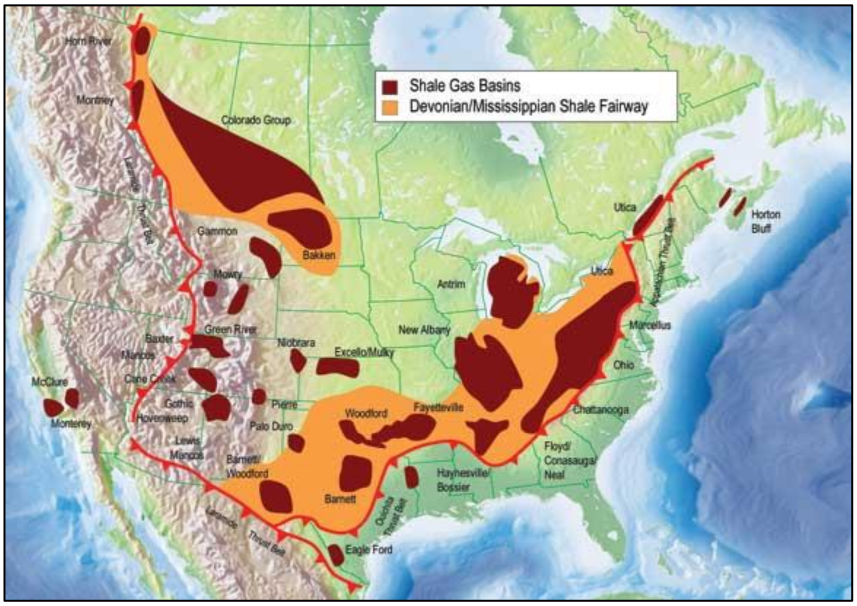
2.4.1.1 North American Gas Supply

Advances in technology and horizontal drilling have been able to unlock previously known natural gas reserves trapped in shale deposits. Not only is the gas supply abundant, shale gas supplies are located throughout North America, providing cost effective supply within close proximity to major load centres. The Pacific Northwest depends on external sources for natural gas, but is conveniently located between two natural gas basins, with approximately 75 percent of the gas coming from the Western Canadian Sedimentary Basin (WCSB)[26] and 25 percent from the U.S. Rocky Mountain region[27]. The figure below shows the key North American shale gas regions.

[26] The Western Canadian Sedimentary Basin (WCSB) is a vast natural gas production area of Western Canada including southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia and the southwest corner of the Northwest Territories.

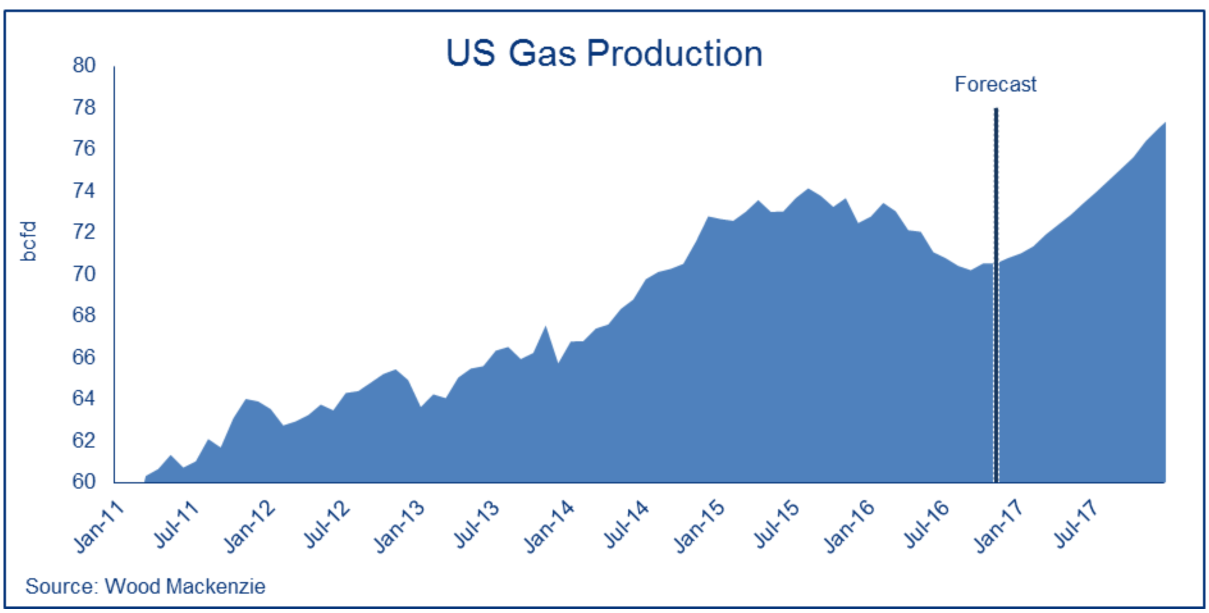
[27] Northwest Power and Conservation Council Seventh Power Plan, page 8-6, https://www.nwcouncil.org/energy/powerplan/7/plan/.

Figure 2-2: North American Shale Gas Plays[28]



During 2015, U.S. natural gas production reached record high levels. Current U.S. natural gas production in 2016 is below last year's levels largely as a response to low natural gas prices. However, production remains above the average levels experienced prior to 2015 and is forecast to grow even further in 2017. The following figure shows historical and forecast U.S. natural gas production.

Figure 2-3: U.S. Natural Gas Production[29]



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[28] National Energy Board, Understanding Canadian Shale Gas - Energy Brief, November 2009 https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/archive/prmrndrstndngshlgs2009/prmrndrstndngshlgs2009nrgbrf-eng.pdf.

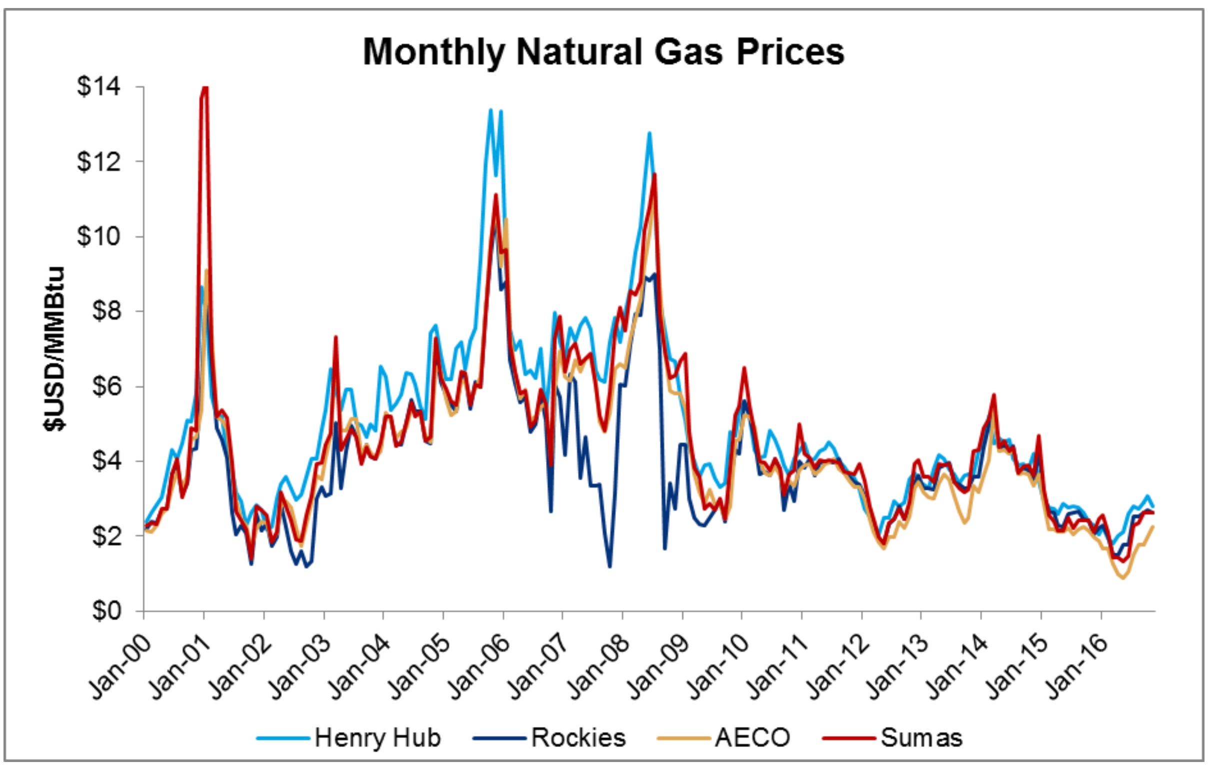
[29] Wood Mackenzie, North America Natural Gas Short-Term Outlook, October 2016.

2.4.1.2 Regional Market Fundamentals

Due to the ability to transport natural gas with relative ease throughout North America, natural gas is often priced relative to the price for delivery at the Henry Hub in Louisiana. The Henry Hub price is the benchmark price of natural gas in North America and is the point of delivery used in the New York Mercantile Futures Exchange (NYMEX) futures contract. Changes in natural gas prices are generally based on the supply and demand balances for natural gas.

Production in the WCSB is often priced relative to the Alberta Nova Inventory Transfer (NIT, also known as 'AECO/NIT' price[30]) market price hub and production in the Rocky Mountain region is priced at the Rockies Hub. The Sumas Hub is another key location where much of the natural gas is bought and sold in the Pacific Northwest. While no production sources exist near Sumas, it is located on the Canadian/U.S border where Spectra Energy's Westcoast pipeline interconnects with Williams' Northwest Pipeline. Historically, prices at the AECO/NIT and the Rockies Hubs, where the majority of the gas in the Pacific Northwest is sourced, have traded at a discount to the Henry Hub price. Sumas generally trades at a discount to Henry Hub in the summer months and at a premium over Henry Hub prices during the winter. Figure 2-4 below shows how natural gas prices at Henry Hub, AECO/NIT, Sumas, and Rockies hubs have traded relative to each other since 2000. Natural gas prices are trading at close to ten-year lows and natural gas is expected to continue to be a low-cost fuel for use in the power generation sector.

Figure 2-4: Monthly Natural Gas Prices



[30] AECO stands for AECO stands for Alberta Energy Company, and is the Canadian benchmark price for natural gas.

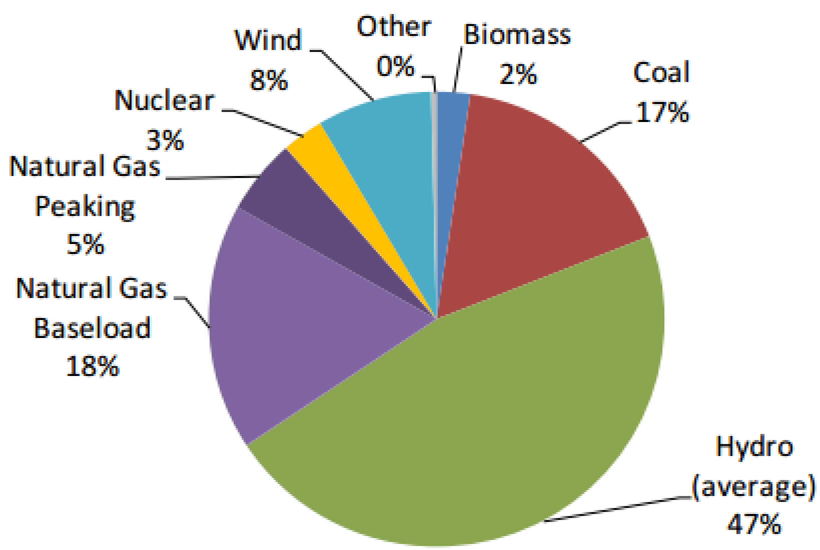
As shale gas production in the northeastern portion of the U.S. expands, there will be less of a need to export western produced gas to the eastern consuming regions. This fundamental change will create a surplus of available natural gas in the western portion of the continent and help sustain the regional price advantage for consumers in the Pacific Northwest.

Section 2.5 provides more details regarding market gas and power price forecasts.

2.4.2 Natural Gas and Electricity Price Integration

As shown in Figure 2-5 below, the Pacific Northwest power system is largely composed of hydroelectric generation which makes up approximately 47 percent of the region's firm energy generation capacity[31]. The second largest source of firm energy generating capacity in the region is natural gas fired generation (shown as Natural Gas Peaking and Natural Gas Baseload in the figure below), providing 23 percent, followed by coal comprising 17 percent of the total.

Figure 2-5: Pacific Northwest Electricity Generating Capability[32]



However, in 1983 hydropower made up approximately 78% of the regions' firm energy generation capacity[33]. The decrease in hydro's share of the generation capacity has largely been a result of the addition of non-hydroelectric resources, the largest being gas-fired and wind generation.

The Pacific Northwest has historically been a winter peaking region, however river flows are highest in late spring when electricity load is generally at its lowest. As a result, natural gas generation has been directly correlated to hydroelectric generation - in good water years less

[31] Average hydro generation capability is based on the five year average of actual hydroelectric generation, as hydroelectric generation can vary depending on the water year.
[32] Northwest Power and Conservation Council Seventh Power Plan, page 9-7.
[33] Northwest Power and Conservation Council Seventh Power Plan, page 9-5.

gas-fired generation is dispatched and poor water years result in more gas-fired generation. Due to this relationship the price of natural gas strongly influences the electricity price. Natural-gas fired power plants are often the marginal generating unit that set prices, so the variable cost of fuel for these power plants influences the electricity price[34].

The West Coast energy crisis of the early 2000s resulted in an expansion of new gas-fired combined-cycle power plants in order to meet the market's capacity deficit. As a result, the Mid-Columbia (Mid-C) power market[35] has generally been in an energy and capacity surplus since the mid-2000s. This provides a cost effective way for utilities in the region to meet their load as it has generally been cheaper to buy energy and capacity in the wholesale market rather than building new generation plants[36]. The majority of the electric utilities in the Pacific Northwest region rely on wholesale market purchases to some extent (see Comparison Table in Appendix C).

In the next decade, the Pacific Northwest is forecast to face a capacity deficit due to load growth, coal plant retirements, and increasing growth of intermittent resources such as solar and wind generation. Due to increased environmental regulations, several coal plants in the region are scheduled for retirement. Portland General Electric is scheduled to cease coal-fired operation at Boardman in 2020, TransAlta's Centralia units one and two will be retired in 2020 and 2025, and the North Valmy coal plant in Nevada (co-owned by Idaho Power) is scheduled to be retired by 2025[37].

Due to the Pacific Northwest's proximity to natural gas producing regions in the WCSB and the U.S. Rocky Mountain region along with low natural gas prices, gas-fired power plants have become a low-cost alternative for power generation. Gas-fired generation is expected to make up the capacity shortfall caused by coal retirements, intermittent resources, and load growth. This will further strengthen the interdependency between natural gas and electricity prices in the Pacific Northwest region.

2.4.3 Regional Power Security

2.4.3.1 B.C. Developments

Development of new generation has been active in B.C. over the last few years with a total of 114 suppliers currently selling electricity to BC Hydro under Electricity Purchase Agreements (EPAs) as of November 1, 2016. This represents 19,762 GWh and 4,836 MW of installed

[34] Northwest Power and Conservation Council Seventh Power Plan, page 8-6.
[35] Mid-C power market hub is located on the Columbia River on the border between Washington and Oregon.
[36] Puget Sound Energy 2015 Integrated Resource Plan, page G5-G8, https://pse.com/ABOUTPSE/ENERGYSUPPLY/Pages/Resource-Planning.aspx.
[37] Northwest Power and Conservation Council Seventh Power Plan, page 9-16.

capacity.[38] Approximately 567 MW and 2,385 GWh are still in development[39] and may come on-line in future years.

In addition to this, BC Hydro has been active as well, with Mica Unit 5 completed in 2014 and Unit 6 in 2015. Units 5 and 6 each added 500 MW of capacity to the electrical system – enough to power 80,000 homes – bringing the total capacity of Mica Dam to 2,805 MW.[40] The Waneta Expansion plant, owned by the Waneta Expansion Limited Partnership (WELP) was completed in 2015 and produces 627 GWh and 335 MW.[41]

Revelstoke Unit 6 is also currently available to be constructed by BC Hydro which would supply an additional 500 MW of capacity should it be required within B.C. As well, Site C is currently under construction and is expected to be available in 2024 and to provide approximately 5,100 GWh/year and 1,100 MW.[42]

Future needs within B.C. are uncertain and will largely depend on developments within the LNG sector. However, as explained further in Section 8.2.6, some of this power may be considered surplus and could be available to FBC at potentially attractive prices.

2.4.3.2 Alberta Developments

Major growth in renewables within the region may shift to places such as Alberta where the provincial government has proposed to add over 5,000 MW of renewable generation by 2030.[43] In 2015, 41,378 GWh, or 51 percent of Alberta's electricity was produced from a total of 6,267 MW of coal-fired generators.[44] By 2030, one-third of Alberta's coal generating capacity will be replaced by renewable energy; two-thirds will be replaced by natural gas.[45] What role B.C. may play in supplying Alberta's future needs is not yet known, but if a significant amount of electricity from B.C. is transported to Alberta, it could reduce the amount of potentially surplus generation available in B.C. to meet FBC requirements. The following tables provide a summary of Alberta's recent energy generation and installed capacity resource mix.

38 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/ipp-supply-list-in-operation.pdf.
39 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/ipp-supply-list-in-development.pdf.
40 https://www.bchydro.com/news/conservation/2016/mica-5-6-words-videos.html.
41 The Waneta Expansion is also included in the BC Hydro list.
42 BC Hydro November 2013 IRP, page 9-28.
43 http://www.energy.alberta.ca/electricity/682.asp.
44 Ibid.
45 http://www.alberta.ca/climate-coal-electricity.aspx.

Table 2-1: Alberta's Electricity Generation as of December 2015[46]

Generation	Gigawatt Hour (GWh)	Generation Share By Fuel
Coal	41,378	51%
Natural Gas	32,215	39%
Hydro	1,745	2%
Wind	3,816	5%
Biomass	2,149	3%
Other*	318	0%
Total	**81,621**	**100%**

* Other includes solar, wind, fuel oil and waste heat.

Table 2-2: Alberta's Installed Generation Capacity as of June 2016

Generation	Megawatt (MW)	Capacity By Fuel
Natural Gas	7,081	44%
Coal	6,267	39%
Hydro	902	6%
Wind	1,491	9%
Biomass	424	3%
Other*	97	1%
Total**	**16,261**	**100%**

*Other includes oil, diesel and waste heat.

2.4.3.3 Pacific Northwest Developments

In the Pacific Northwest, load is expected to grow between 1,800 aMW[47] and 4,400 aMW by 2035.[48] However, as nearly 4,300 aMW of cost effective DSM is technically achievable[49] and is the recommended DSM amount[50], if the recommendation comes to pass then actual load growth in the region could be very limited.

By 2014, the Pacific Northwest had added about 8,700 MW of wind power[51] but an additional 2,000 MW of coal is expected to shut down by 2025.[52] However, until about 2026, low growth

46 http://www.energy.alberta.ca/electricity/682.asp.
47 One Average MW (aMW) is equivalent to 8,760 MWh, which is the energy produced by 1 MW if run all hours in the year.
48 Northwest Power and Conservation Council Seventh Power Plan, page 1-4.
49 Northwest Power and Conservation Council Seventh Power Plan, page 12-45.
50 Northwest Power and Conservation Council Seventh Power Plan, page 1-6.
51 Northwest Power and Conservation Council Seventh Power Plan, page 2-4.
52 Northwest Power and Conservation Council Seventh Power Plan, page 2-3.

combined with high wind development results in the Pacific Northwest having a significant energy surplus yet under critical water conditions the region faces the probability of a peak capacity shortfall.[53] Therefore, it is likely that additional peaking resources will be built in the region.

2.4.4 Regional Market Opportunities

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

FBC 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 B.C. and Alberta, the northern portion of Baja California and all or portions of the 14 western 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)[54] to monitor and enforce compliance with U.S. reliability standards.

FBC 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 that have surplus power available for sale. 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. These large amounts of clean or renewable energy tend to be highly variable in energy output with the result that at times market supply of energy can be at very attractive prices. Alternatively, energy may be procured from independent asset owners such as self-generators that have under-utilized capacity and available fuel.

The WECC region is dual peaking – the southern part is summer peaking while the northern part is winter peaking. At present, FBC is primarily concerned about the availability and cost of energy and capacity during the winter months.

Surplus power is typically available in B.C. 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)

[53] Northwest Power and Conservation Council Seventh Power Plan, page 1-12 and page 11-5.
[54] 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.

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.

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

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. In a change from when FBC filed its 2012 LTRP, NERC now expects that the NWPP Canadian sub-region (B.C. and Alberta) is expected to have resources in excess of the Reference Margin Level[55] throughout the 2016 to 2025 assessment period.[56]

A further key consideration for FBC is the transmission transfer limit at the three interconnections on the B.C./United States border[57] and at the two interconnections on the B.C./Alberta border. These transmission interconnections often operate at their maximum available transfer limits; therefore wheeling additional power between utilities in the region is frequently impossible. It should be noted that FBC has no transmission facilities that connect directly with markets outside of B.C. Accordingly, FBC is dependent on the availability of adequate third-party transmission capacity to serve its customers' needs, putting at risk the long-term reliable availability of wholesale market electricity to serve its growing demand. However, market energy and capacity is expected to remain adequate through the short to medium term. This is particularly true if the CEPSA agreement with Powerex is assumed to continue. On a longer term basis, market capacity and transmission availability are expected to continue to tighten and therefore FBC may not be able to rely upon them, but sufficient supply of market energy will likely be available.

2.5 Market Price Forecasts and Carbon Price and PPA Rate Scenarios

This section examines some of the key inputs required for the evaluation of resource options in the portfolio analysis discussed in Section 9 of this LTERP. These include the long-term market price forecasts for natural gas and electricity, based on the discussions in Section 2.4 regarding the changing market supply environment. It also includes some scenarios for carbon prices, based on the discussion in Section 2.2 regarding environmental policy in B.C. and Canada, and the PPA rate based on potential rate increases for BC Hydro customers. The gas price forecast is used as an input for estimating the costs for gas-fired generation while the electricity price forecast is used to provide a cost for market purchases. The carbon prices scenarios are also

[55] The level of Planning Reserve Margin that is recommended.

[56] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015LTRA%20-%20Final%20Report.pdf, NERC 2015 Long-Term Reliability Assessment, December 2015, page 82.

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

inputs into the cost of gas-fired generation. The PPA rate scenarios provide potential future costs of the PPA over the planning horizon beyond what has already been established by the B.C. government for BC Hydro for rates until March 2019 (BC Hydro year F2019) and based on BC Hydro's LRMC. Assumptions regarding exchange and inflation rates and other adders are also included in this section.

As in any long-term market prices forecast, certain assumptions about supply and demand factors have been made based on current information. As these factors constantly change over time, it is not likely that these price forecasts will be accurate over the long run. They are merely an indication, based on current information, of where prices could be in the future. Because of this uncertainty, the market price forecasts and rate scenarios include high and low ranges to cover a wide range of potential circumstances that could occur over the planning horizon. In the case of the market price forecasts, FBC does not develop its own forecasts but rather relies on market price forecasts produced by others in the energy industry. FBC often compares forecasts from different sources in order to determine which forecast(s) seem the most reasonable.

In terms of the carbon price scenarios, FBC has made some assumptions based on the current price of carbon in B.C. and recommendations by the CLT to the B.C. government in November 2015 in terms of energy and environmental policy as well as the Canadian federal government announcement in September 2016 regarding minimum carbon pricing requirements for the provinces.

With regard to the PPA rate scenarios, FBC has made some assumptions in terms of future rate increases based on recent historical rate increases for BC Hydro customers and expectations discussed in the B.C. 10 Year Plan[58] as well as BC Hydro's proxy for the LRMC for energy.

The market and carbon price forecasts and PPA rate scenarios were presented to the RPAG stakeholders and discussed in the April 27, 2016 workshop. The forecasts and rate scenarios are all presented here in 2015 real Canadian dollar terms. In most cases, FBC has presented a low, base and high case to provide a range of possible prices and rates.

This section includes the market price forecasts and rate scenarios on an annual basis. Appendix D provides the market price forecasts and rate scenarios data on a monthly basis.

2.5.1 Natural Gas Market Price Forecasts

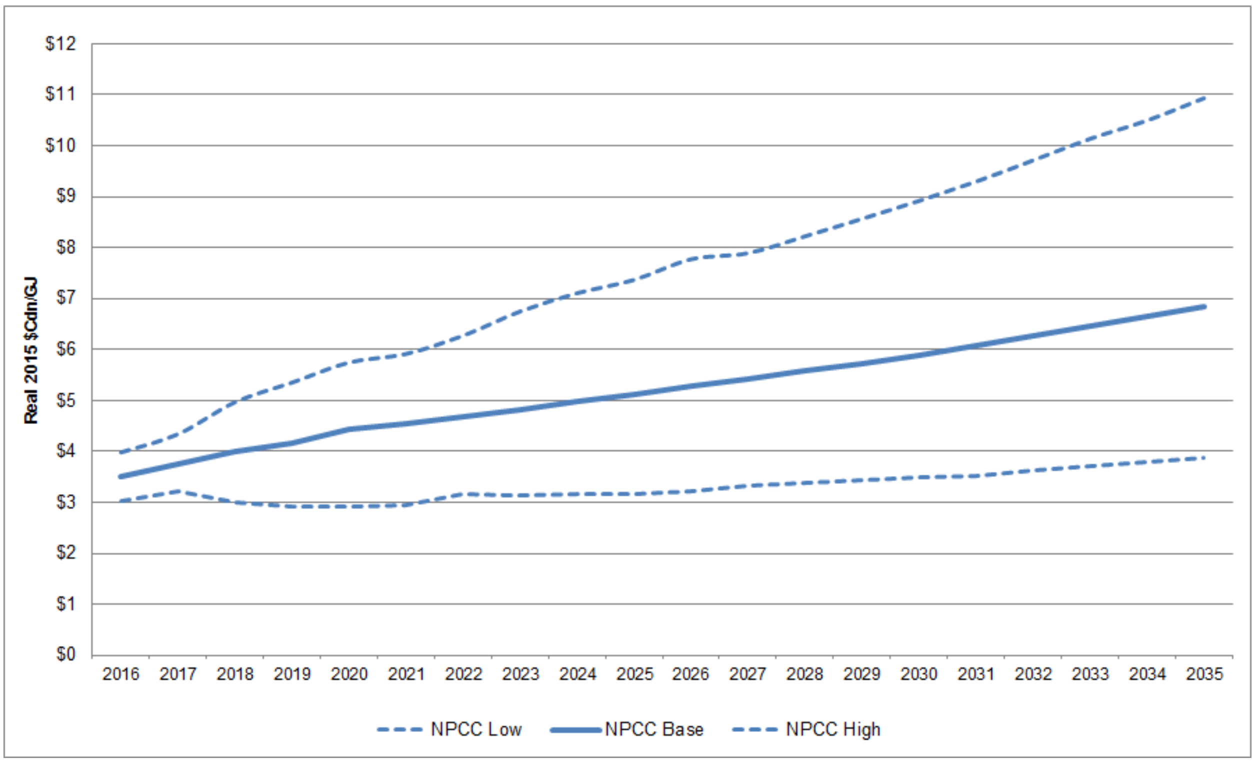
The natural gas market price forecasts are based on the market price forecasts provided within the NPCC Seventh Power Plan, released in February 2016. The NPCC develops a Power Plan, updated every five years, to ensure the power supply for the region (including Washington, Oregon, Montana and Idaho) and acquire cost-effective energy efficiency. The process relies on broad public participation to inform the plan and build consensus on its recommendations. The NPCC forecasts regional demand for electricity, wholesale market prices for natural gas and

[58] https://news.gov.bc.ca/stories/10-year-plan.

electricity in developing its Power Plan. The forecasts are also used by utilities, regulatory agencies, state energy policy offices, and other organizations in their planning.

The Seventh Power Plan provides a market price forecast based on the Sumas market price hub, located on the B.C.-Washington border. The Sumas market hub is one of the main natural gas market trading hubs in the Pacific Northwest and is the transfer point for northern B.C. gas flowing south across the border. The Sumas market annual price forecast in real Canadian dollars per gigajoule (GJ) is presented in the following figure.

Figure 2-6: Sumas Natural Gas Annual Price Forecast



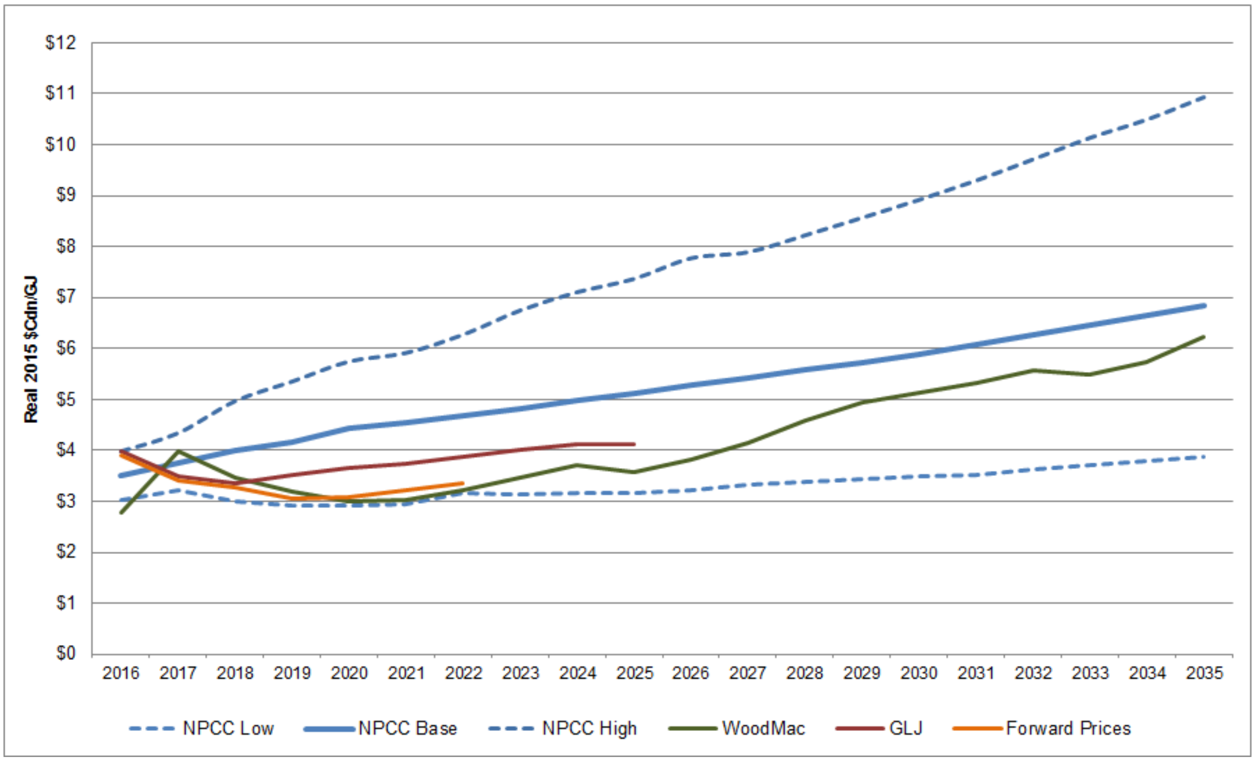
The base case is based on current expectations for natural gas prices, with prices increasing over time as supply and demand become more balanced than the current low-priced over-supplied market environment. The high and low price forecasts provide reasonable extremes of possible future prices. The high case assumes rapid world economic growth, increasing the demand for natural gas supplies[59]. The low case assumes slow economic growth with reduced demand for natural gas in favour of lower-carbon renewable energy sources[60].

FBC has also examined other recent gas price forecasts and forward market prices to see how they compare to the NPCC base case and high and low price forecasts. FBC has reviewed the Sumas market price forecast produced by Wood Mackenzie (Spring 2016 H1 forecast) and GLJ

[59] NPCC Seventh Power Plan, Appendix C, Page C-9.
[60] NPCC Seventh Power Plan, Appendix C, Page C-9.

Petroleum Consultants (GLJ) (October 1, 2016 forecast). The figure below includes these and the forward market prices as of October 3, 2016. In general, these other price forecasts and the forward market prices are lower than the NPCC base case forecast but higher than the NPCC low price forecast. The Wood Mackenzie price forecast increases from near the NPCC low price forecast at the start of the planning horizon to closer to the NPCC base case price forecast by the end of the twenty-year period. The GLJ price forecast and forward market prices do not extend out for the full twenty year period.

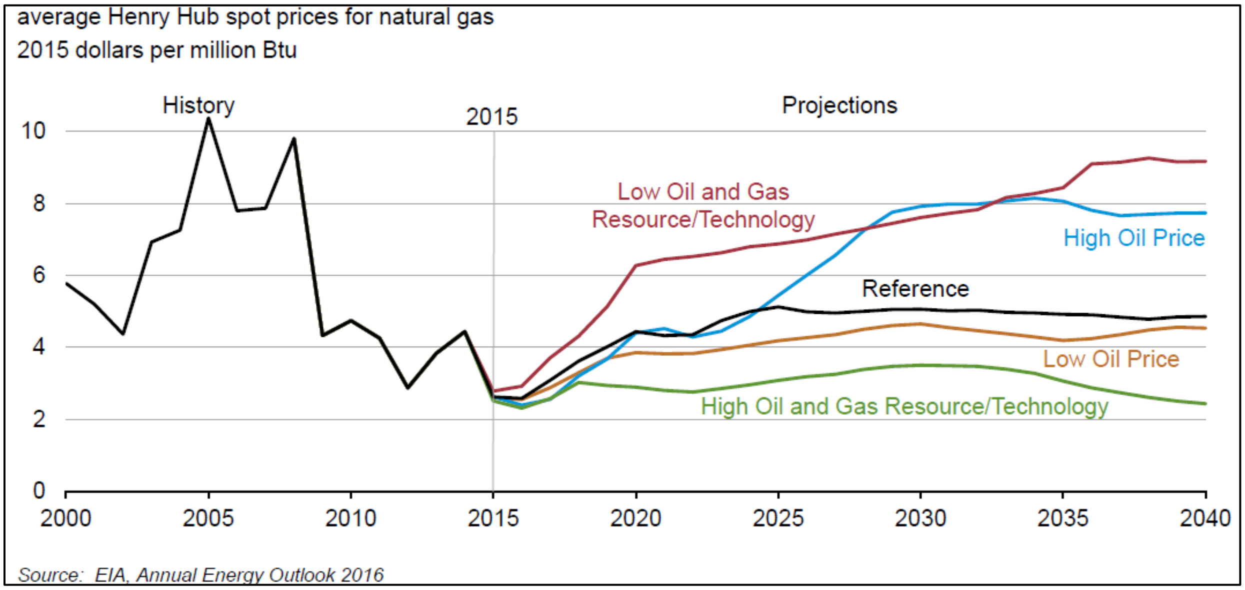
Figure 2-7: Comparison of Sumas Price Forecasts (Base Case) and Forward Prices



FBC also reviewed the U.S. Energy Information Administration (EIA) Henry Hub market price forecast, which includes several scenarios for future market prices, as provided in their 2016 Annual Energy Outlook (AEO) Rollout Presentation[61]. As the EIA does not produce a long-term price forecast for Sumas, FBC has instead provided the Henry Hub reference price forecast and scenarios for comparison purposes (which are presented in U.S. dollars per million British thermal unit (Btu)). Generally speaking, on average over the next 20 years, the Sumas annual average basis to Henry Hub, as forecast per Wood Mackenzie and GLJ, is close to zero; i.e. Sumas prices will be similar to Henry Hub prices over the long term.

[61] EIA Annual Energy Outlook 2016 Rollout Presentation, June 28, 2016, slide 33, http://www.eia.gov/pressroom/presentations/sieminski_06282016.pdf.

Figure 2-8: EIA Henry Hub Price Forecasts[62]



The NPCC gas price forecasts are slightly higher than the EIA's price forecast cases, on an equivalent Canadian dollar per GJ basis.

2.5.2 Electricity Market Price Forecasts

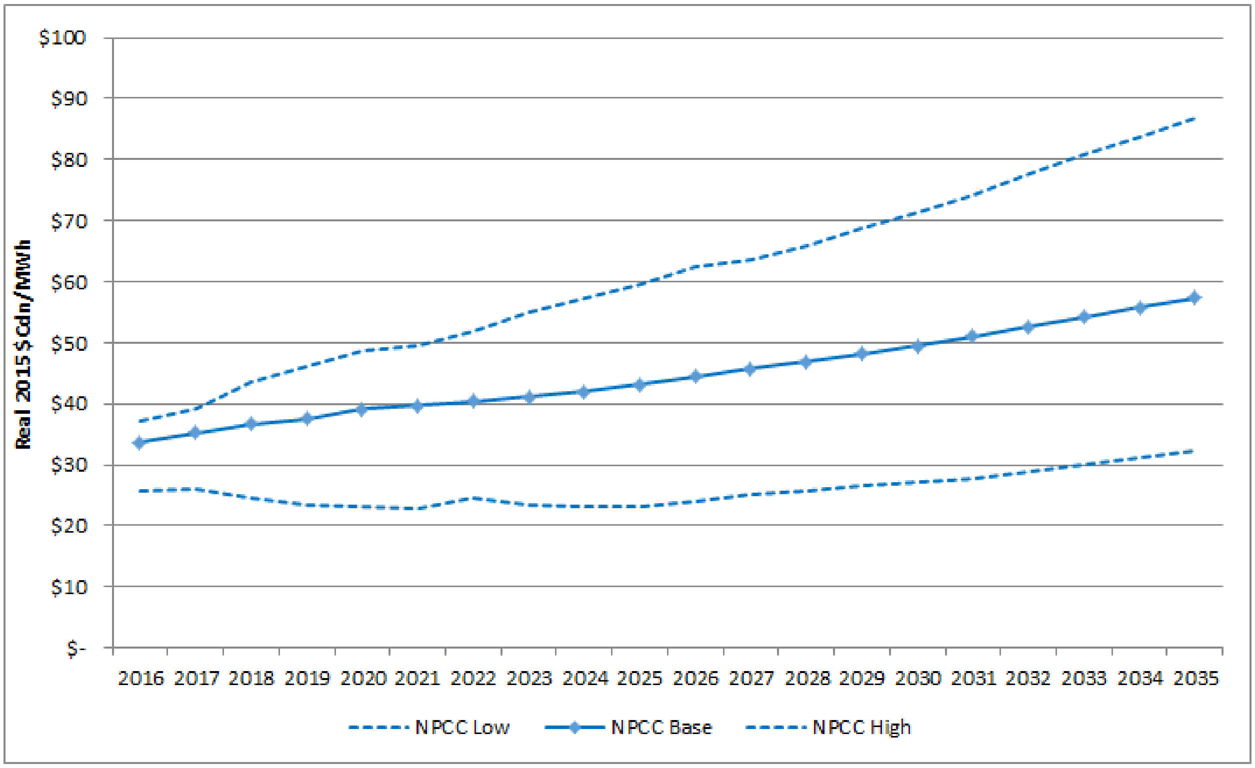
The NPCC Seventh Power Plan Mid-C electricity market price forecast is largely based on the Sumas natural gas price forecast. This is because natural gas-fired plants are often the marginal generating resource in the region to meet load requirements. As such, natural gas prices exert a strong influence on electricity prices. The high and low cases for the forecast electricity prices were set by the associated high and low natural gas price forecasts.

The Seventh Power Plan provides market electricity price forecasts, with high and low cases, based on the Mid-C market trading hub. Mid-C is the primary market electricity trading hub for the Pacific Northwest.

The Mid-C market annual price forecasts in real Canadian dollars per megawatt-hour (MWh) are presented in the following figure.

[62] EIA Annual Energy Outlook 2016 Rollout Presentation, June 28, 2016, slide 33, http://www.eia.gov/pressroom/presentations/sieminski_06282016.pdf.

Figure 2-9: Mid-C Electricity Annual Price Forecasts[63]



2.5.3 B.C. Carbon Price Scenarios

There is uncertainty regarding the level of the B.C. carbon tax beyond 2018. As discussed in Section 2.2, the carbon tax in B.C. was introduced in 2008 at a level of $10 per tonne and increased to $30 per tonne by 2012. In April 2015, the B.C. government announced the formation of a CLT to provide recommendations to build upon B.C.'s existing Climate Action Plan. The CLT released its report in late November 2015. The report provides recommendations, including the development of several new strategies, and increasing B.C.'s existing $30 per tonne carbon tax by $10 per tonne per year starting in 2018. The CLT further recommended that the annual increases in the carbon tax are reviewed in five years; however, the CLT indicates that increases in the range of $10 per tonne per year will be required through to 2050 in order to achieve B.C.'s 2050 emissions targets. However, the CLP, released in August 2016, noted that the B.C. government would not be increasing the carbon tax until other jurisdictions caught up.

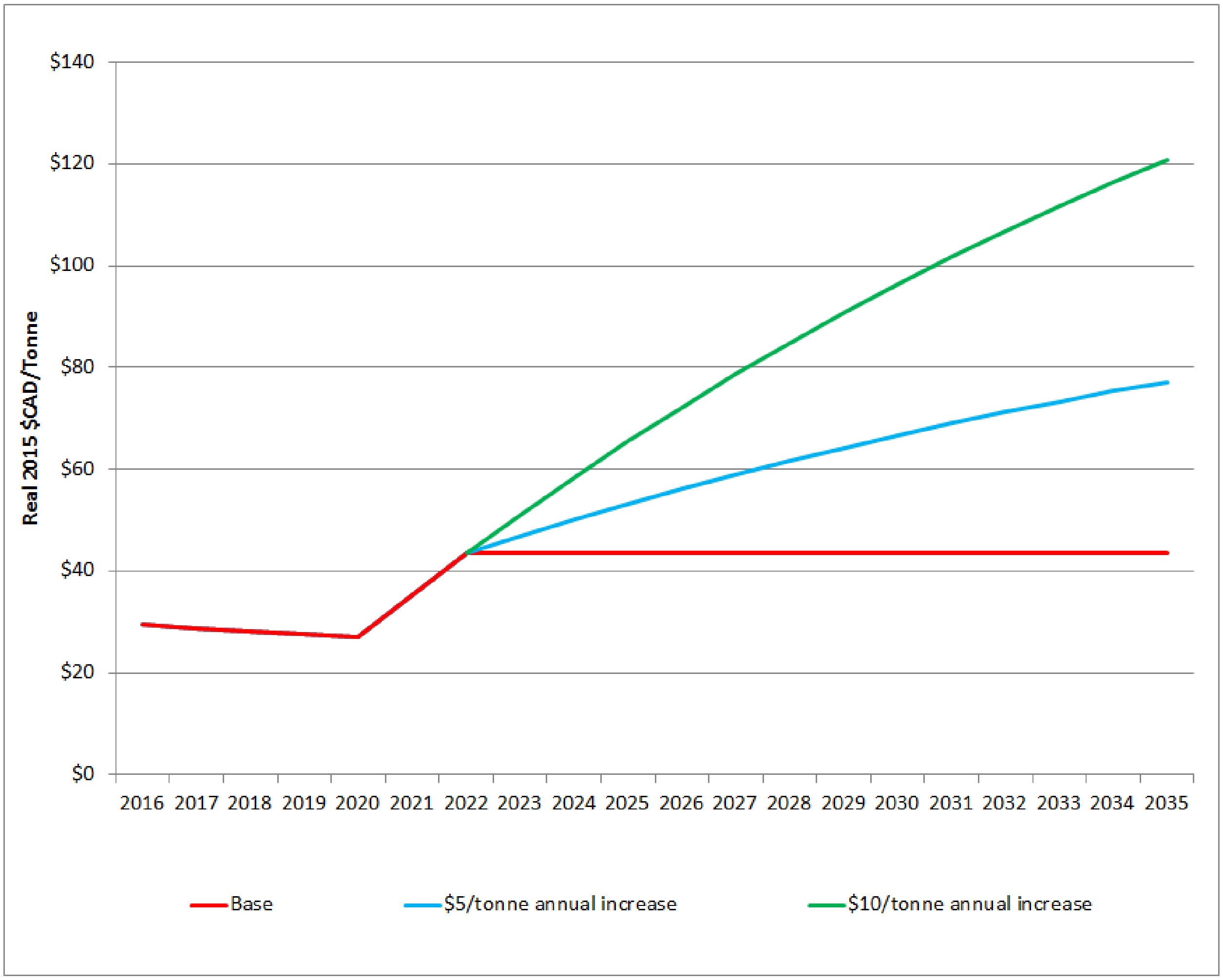
In September 2016, the Canadian federal government announced that it is planning to require the provinces to have a price of at least $10 per tonne of carbon dioxide equivalent emissions

[63] Based on Northwest Power and Conservation Council Seventh Power Plan, Chapter 8 and Appendix B Mid-C prices in 2012 $US/MWh converted to 2015 $Cdn/MWh using exchange and inflation rates per Section 2.5.5 and transmission costs per Section 2.5.6.

starting in 2018. The price would rise by $10 per tonne a year for the next four years, reaching $50 a tonne by 2022.[64]

FBC has developed its carbon price scenarios based on this information. FBC has assumed the current level of $30 per tonne (in nominal terms) as the base case until 2020 after which time it increases by $10 per tonne per year until it reaches $50 per tonne (in nominal terms) by 2022. After this time, the base case holds the carbon price constant in real terms, assuming that the carbon tax is increased to keep up with inflation over time. FBC has also included a high case based on the assumption of annual increases of $10 per tonne and a more moderate case assuming annual increases of half of this or $5 per tonne.

Figure 2-10: B.C. Carbon Price Scenarios[65]



[64] http://www.cbc.ca/news/politics/canada-trudeau-climate-change-1.3788825.

[65] Base case 2022 to 2035 values are lower than $50 per tonne (nominal) because they are presented in real 2015 dollars per tonne.

2.5.4 BC Hydro PPA Rate Scenarios

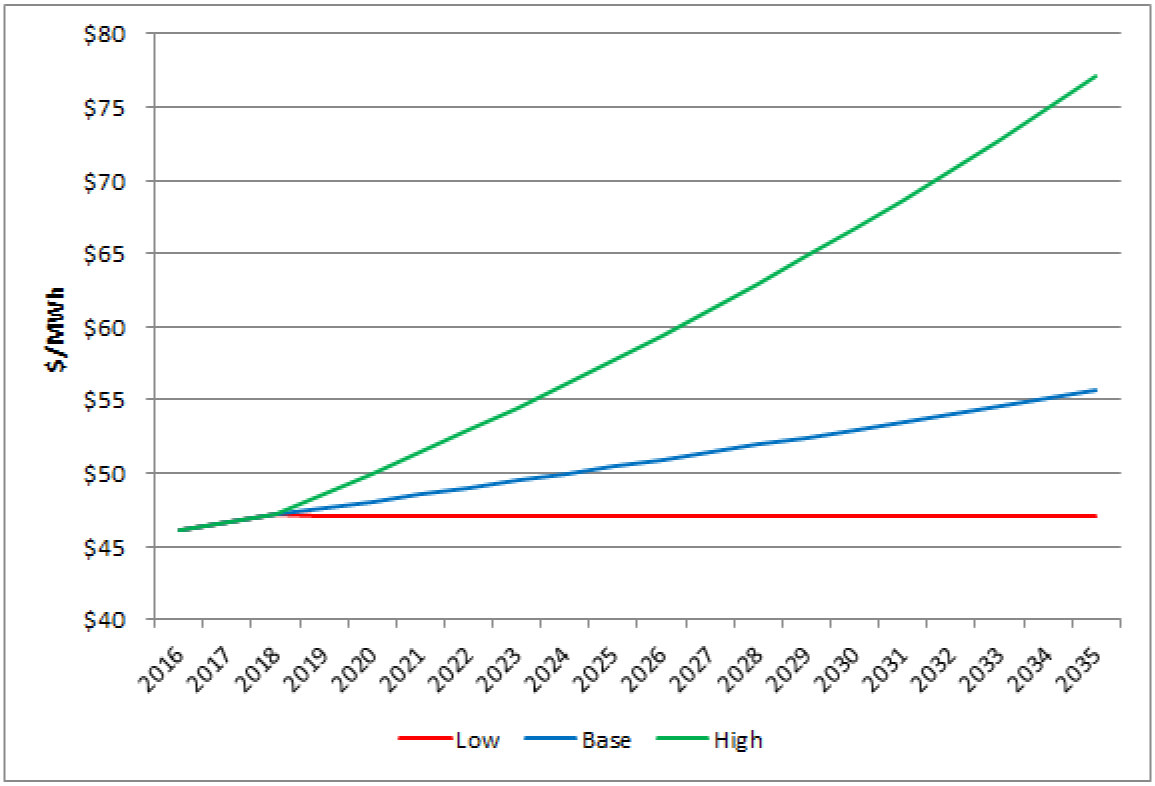
In order to estimate the potential costs for the BC Hydro PPA in the future, FBC has developed some PPA scenarios based on annual percentage increases in residential rates and BC Hydro's LRMC. The percentage increases in the PPA Tranche 1 energy and capacity rates are the same as those applicable to BC Hydro's residential customers. The B.C. government has set BC Hydro residential rate increases until F2019 (which are effective from April 1, 2018 to March 31, 2019) based on its 10 Year Plan announced in November 2013[66]. These rate increases are capped at 3.5 percent effective April 1, 2017 (F2018) and 3 percent effective April 1, 2018 (F2019). For the last 5 years of the 10 Year Plan out to F2024, the B.C. government has set target rate increases of 2.6 percent for each year, subject to Commission review and approval[67]. FBC has assumed these are nominal, not real, rate increases. At this point in time, there is less certainty in terms of rate increases beyond March 2024.

In developing its PPA rate scenarios, FBC has made the following assumptions which it believes are reasonable given the recent historical rate increases by BC Hydro and the target rate increases to F2024. In the low case, rate increases keep up with inflation of about 2 percent per year and so rates do not increase in real terms (see Section 2.5.5 below regarding the inflation rate forecast). In the base case, rate increases are 1 percent per year in real terms. In the high case, rate increases are 3 percent in real terms. The following figure shows the PPA rate scenarios for Tranche 1 Energy.

66 https://news.gov.bc.ca/stories/10-year-plan.

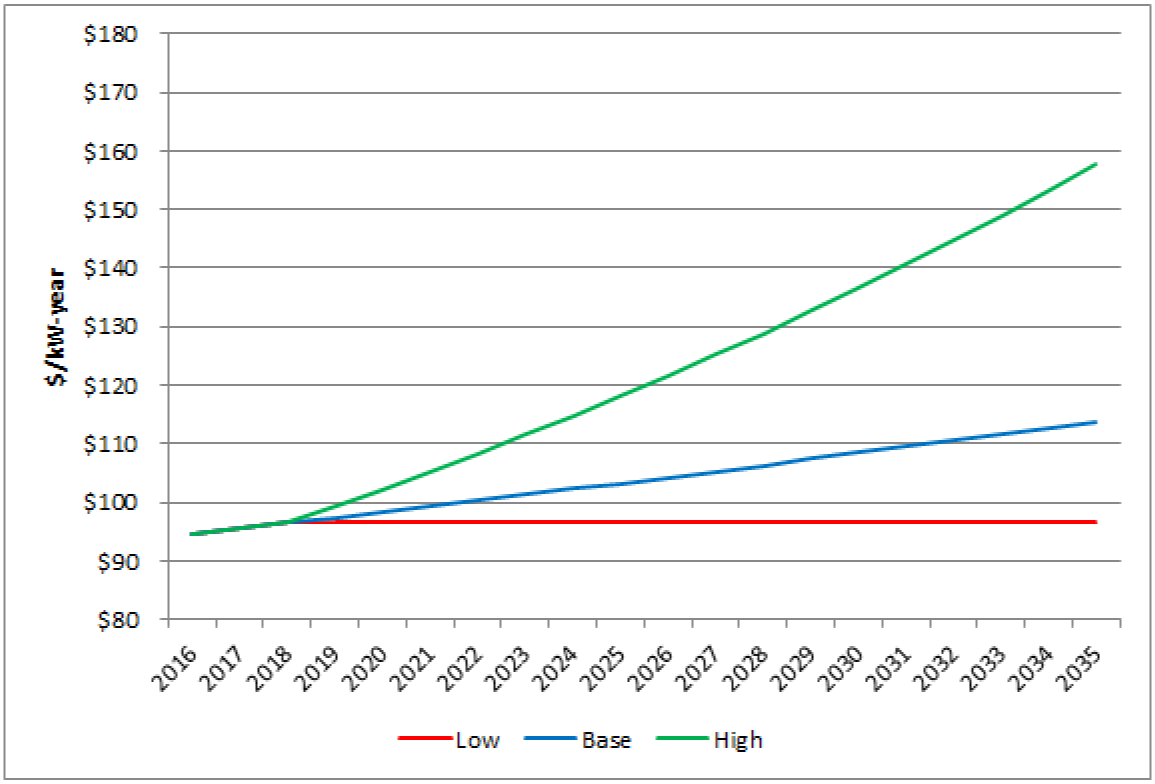
67 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf, page 1-17.

Figure 2-11: PPA Rate Scenarios for Tranche 1 Energy



The rate scenarios for capacity under the PPA using the same annual percentage increases are provided in the following figure.

Figure 2-12: PPA Capacity Rate Scenarios

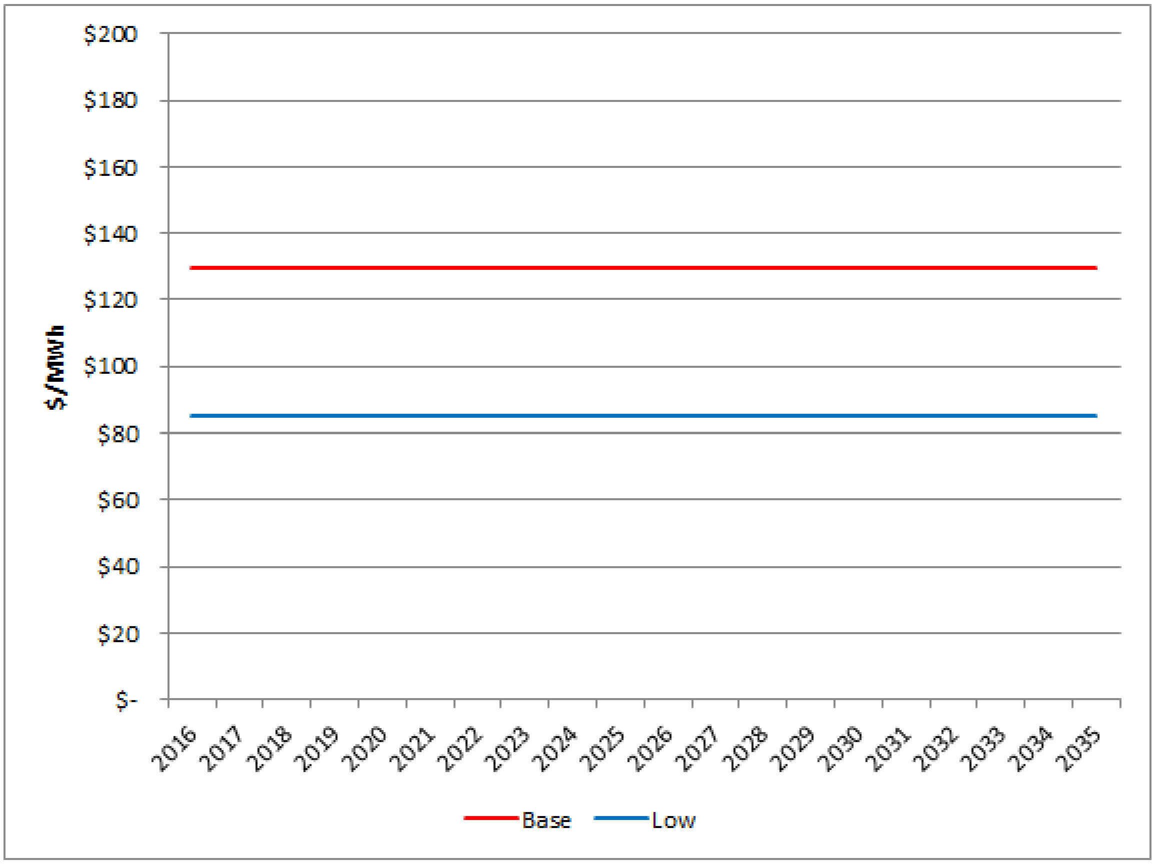


The PPA tranche 2 energy rate is set based on a proxy for BC Hydro's LRMC of new supply. Currently, the PPA Tranche 2 energy rate is $129.70 per MWh[68], which is tied to BC Hydro's proxy for long run marginal cost based on the BC Hydro 2008 Clean Power Call. However, BC Hydro's LRMC for energy has since been updated and is significantly lower than this as stated in BC Hydro's recent 2015 Rate Design Application Evidentiary Update on Load Resource Balance and Long Run Marginal Cost dated February 18, 2016. In this update BC Hydro states that the LRMC has shifted towards $85 per MWh from a range of $85 per MWh to $100 per MWh[69]. Therefore, FBC has assumed that the PPA Tranche 2 energy rate could be lowered to the BC Hydro LRMC value of $85 per MWh in the future and has treated this as a PPA Tranche 2 rate scenario. FBC has assumed this $85 per MWh value is adjusted for inflation and so does not increase in real terms. The following figure shows the base case $129.70 per MWh PPA Tranche 2 rate and the $85 per MWh rate scenario.

68 BC Hydro Rate Schedules effective April 1, 2016, Schedule 3808 – Transmission Service – FortisBC.

69 BC Hydro 2015 Rate Design Application proceeding, Exhibit B-37 - Evidentiary Update on Load Resource Balance and Long Run Marginal Cost dated February 18, 2016, page 9.

Figure 2-13: PPA Rate Scenarios for Tranche 2 Energy



FBC believes that these scenarios provide a reasonable range for the potential cost of the PPA energy and capacity over the next twenty years.

2.5.5 Financial Assumptions

FBC has made some assumptions regarding future exchange rates and inflation factors in order to develop the market price forecasts and PPA rate scenarios.

2.5.5.1 Exchange Rate Forecast

In order to convert the NPCC market price forecasts for natural gas and electricity from U.S. dollars to Canadian dollars, FBC has utilized a Canadian/US dollar exchange rate forecast. The forecast is based on available recent projections from Canadian Chartered banks and the B.C. Ministry of Finance.

Table 2-3: Canadian/US Dollar Exchange Rate Forecast

Year	Exchange Rate
2016	1.34
2017	1.32
2018	1.30
2019	1.26
2020	1.25
2021 to 2035	1.24

2.5.5.2 Inflation Rate Forecast

FBC requires an inflation rate forecast in order to convert the market price forecasts and PPA rate scenarios into real 2015 dollars. FBC has based its inflation rate forecast on available recent projections made by Canadian Chartered banks, the Conference Board of Canada and the B.C. Ministry of Finance.

Table 2-4: Inflation Rate Forecast

Year	Inflation Rate
2016	1.9%
2017	2.2%
2018	2.0%
2019	2.1%
2020 to 2035	2.0%

2.5.6 Adders to the Market Price Forecasts

The market price forecasts presented in the previous sections are based on the market hub locations and do not include any costs to move this commodity supply of natural gas or electricity to the FBC service area.

To move gas purchased at Sumas to the FBC service area for consumption by a natural gas-fired generator, gas pipeline transportation should be added to the commodity cost of the gas. FBC has estimated this to be in the order of $1 per GJ (in real $2015 terms) including Westcoast Energy Inc. T-South toll costs (about $0.14 per GJ[70]) and FortisBC Energy Inc. (FEI) interior system transmission tariff (about $0.86 per GJ[71]).

[70] Based on Westcoast Energy Inc. 2016 Interim Transmission Tolls for Firm Transportation Service (Southern – Kingsvale) Kingsvale (SCP) 5-Year Toll revised December 8, 2015 and Yearly Heat Content Values effective May 1, 2016 Kingsvale last updated April 19, 2016. $162.67/103m3/month x 12 / 366 x 38.25 heat content = $0.1394/GJ.

[71] Per FEI Rate Schedule 22 delivery charge per GJ of $0.864 (inclusive of applicable rate riders), for the Mainland Service Area, effective January 1, 2016.

In order to move market electricity purchases from the Mid-C market hub to the FBC service area, FBC incurs transmission wheeling costs and line losses. FBC has assumed the cost for this transmission is based on the Bonneville Power Administration (BPA) transmission rates and loss rates effective October 1, 2015[72], escalated based on inflation. These equate to about $7.50 per MWh for wheeling costs and 3 percent of the market prices for line losses.

Within its portfolio analysis, discussed in Section 9, FBC has included these market price forecast adders. The PPA rate and carbon price scenarios do not require any adders as the prices for these are already based on energy and capacity within B.C. and the FBC service area.

2.5.7 Conclusions

Based on the information presented in the previous sections, FBC can draw several conclusions regarding the market price forecasts and rate scenarios. First, the current gas market environment continues to experience relatively low price levels compared to those seen in recent years. This has resulted in low market electricity prices, which is reflected in the market price forecasts. Market purchases, at least in the short to medium term, continue to remain well below the cost of other supply-side resource options, discussed in Section 8.2.

Second, PPA Tranche 1 Energy is also a cost-effective resource relative to other supply-side resource options (also discussed further in Section 8.2). However, there is uncertainty regarding the PPA rate increases beyond 2018 and it is possible that the cost of the PPA may exceed that of other resource options by the end of the planning horizon. This is analysed further in the portfolio analysis in Section 9.

Third, as with the PPA rates, there is significant uncertainty in terms of the carbon and market price forecasts. It is unlikely that the price forecasts will be accurate over the long term. FBC has provided some scenarios to assess the impacts of potential high and low ranges. The portfolio analysis in Section 9 analyses the impacts of these scenarios on the different portfolios being evaluated.

[72] BPA 2016 Transmission, Ancillary and Control Area Service Rate Summary Effective October 1, 2015, PTP-16 Point-To-Point, Short-Term (firm and non-firm), Days 6 and Beyond.

3. LONG-TERM LOAD FORECAST

3.1 INTRODUCTION

FBC forecasts the expected load over the planning horizon in order to determine the energy and peak demand requirements of customers. All forecast loads presented in this section are after Savings, as defined on page E-2 of Appendix E, and before adjustments for incremental DSM, which is discussed in Section 8.1 and the LT DSM Plan.

Both gross and net load include the residential, commercial, wholesale, industrial, irrigation and lighting customer classes. However, gross load includes system losses while the net load excludes system losses. Further information regarding the load forecast methods and detailed forecasts by customer class are found in Appendix E.

This section provides the following information:

- The reference case (expected) forecast for gross load, net load and peak demand;
- The factors and conditions that influence FBC's load growth over the planning horizon for the reference case; and
- The load forecast drivers or factors that result in variability of the forecast and provide a probability range around the reference case.

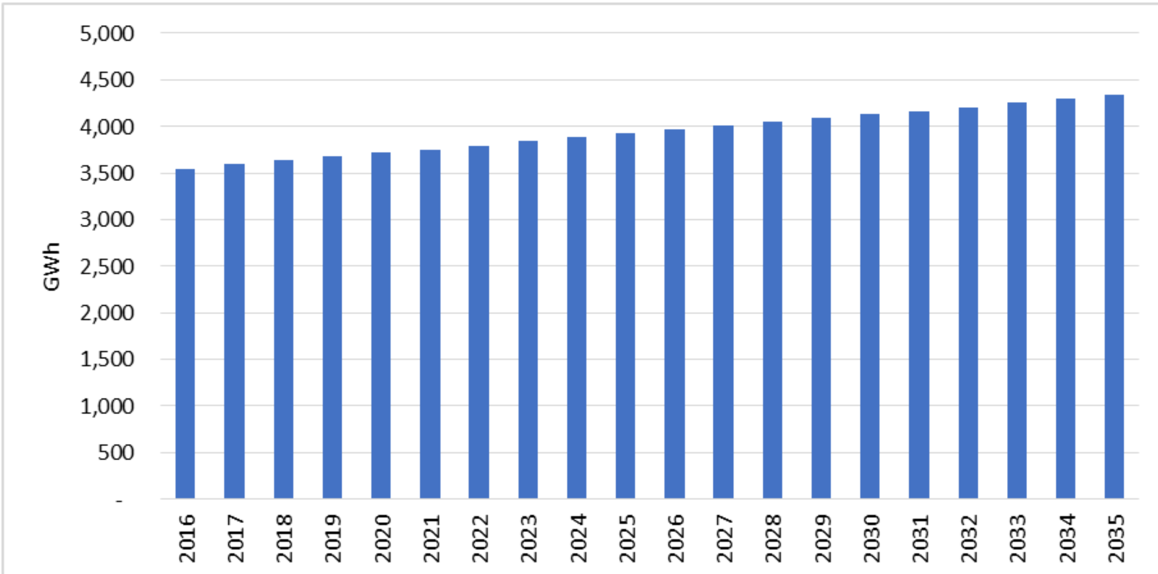
In this section short, medium and long term forecast time frames are referenced. The short term covers the first five years while the medium term compromises the five to ten year time frame and the long term compromises the ten to twenty year time frame.

3.2 LOAD FORECAST SUMMARY

3.2.1 Gross Load Forecast

FBC's reference case load forecast anticipates a modest rate of load growth over the twenty-year planning horizon of the LTERP. The Company is forecasting an increase in gross load from 3,544 GWh in 2016 to 4,334 GWh by 2035, a compound annual growth rate of 1.1 percent.

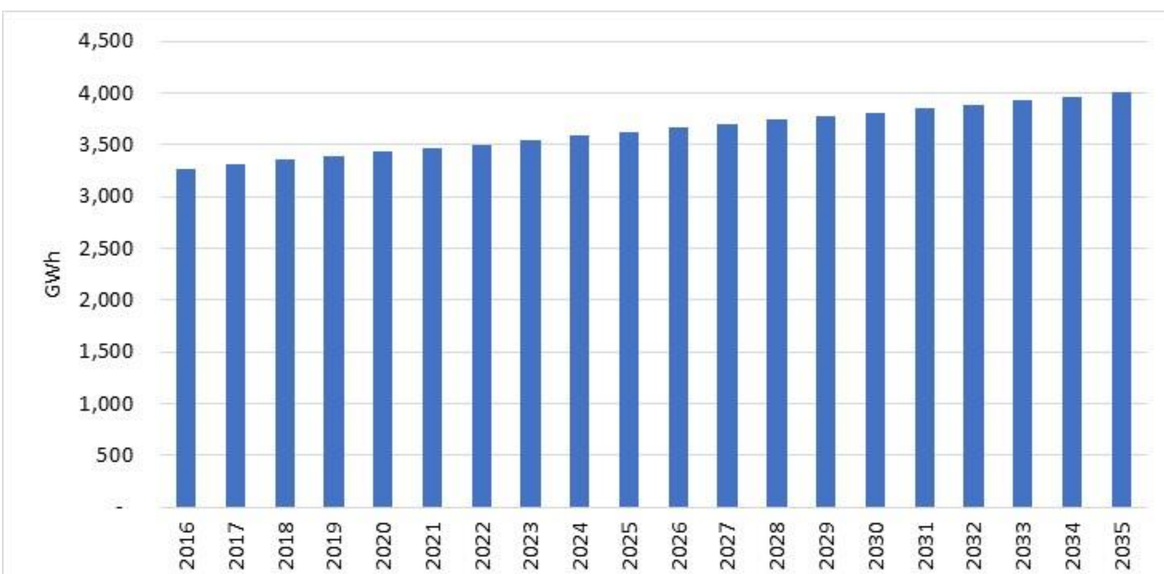
Figure 3-1: Gross Load Forecast (GWh)



3.2.2 Net Load Forecast

FBC's load forecast net of losses also anticipates a modest rate of load growth over the twenty-year planning horizon. The Company is forecasting an increase in net load from 3,264 GWh in 2016 to 4,003 GWh by 2035, also at a compound annual growth rate of 1.1 percent. Losses are assumed to be 8 percent of gross load as discussed in Section 4.7 of Appendix E.

Figure 3-2: Net Load Forecast (GWh)

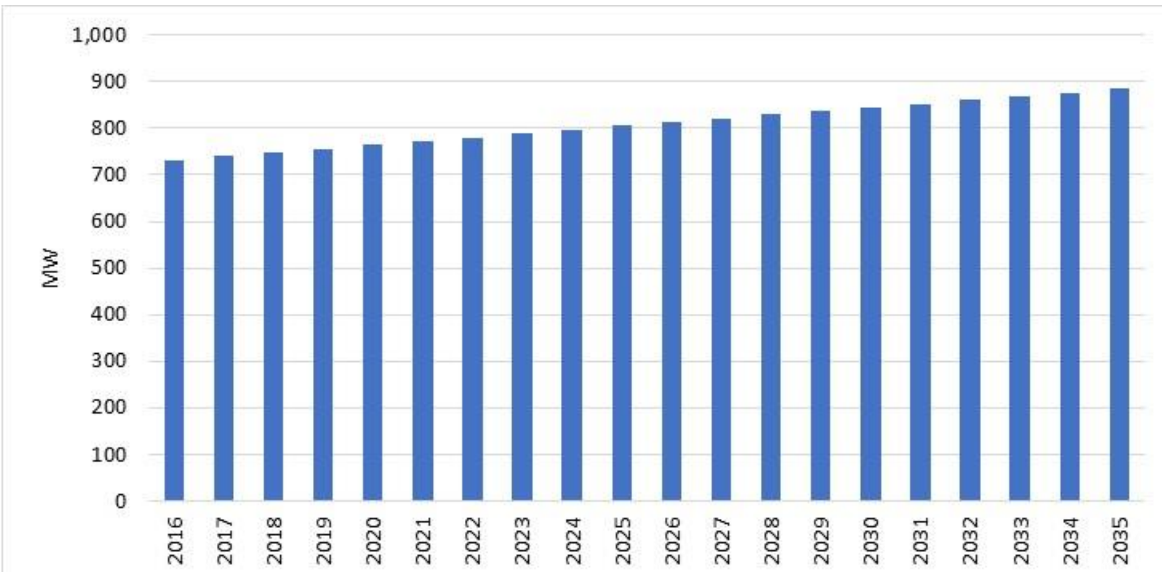


3.2.3 Peak Demand Forecast

The peak demand forecast is the largest amount of capacity expected at one point in time on the FBC system due to high customer demand, which is affected by weather and system growth. FBC's system is dual peaking, with annual winter and summer peaks. Winter peaks have historically been larger than the summer peak and are forecast to continue to be larger in the future.

The winter peak is when the most capacity is needed at a single point in time during the months of November to February and is usually on one of the coldest days of the year. The reference case winter peak demand forecast increases from 731 MW in 2016 to 885 MW in 2035, growing at a compound annual growth rate of 1.0 percent.

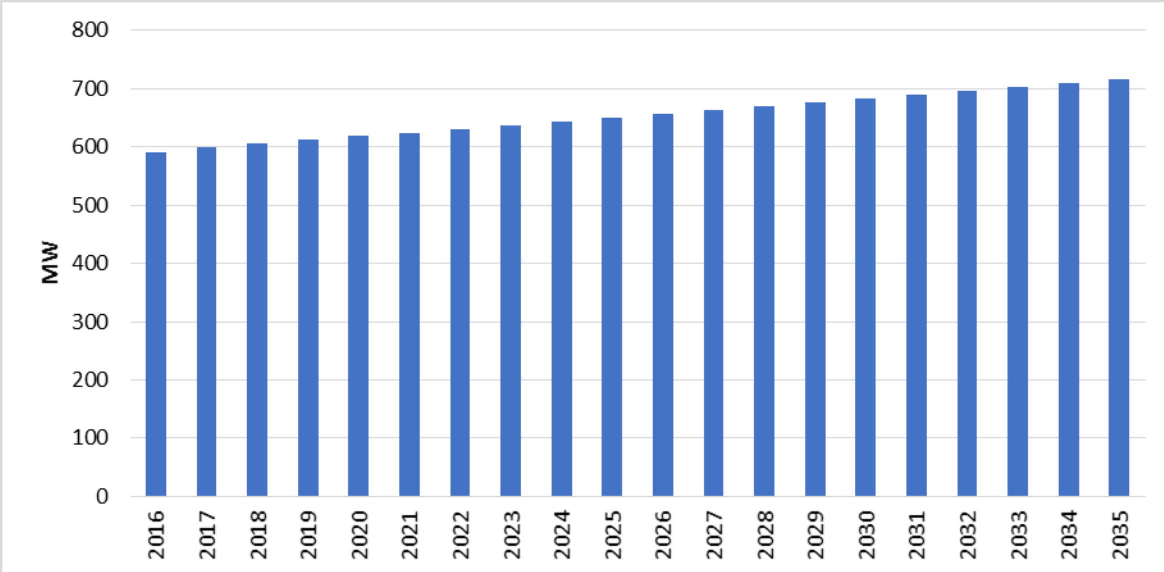
Figure 3-3: Winter Peak Forecast (MW)



The summer peak is when the most capacity is needed at one point in time during the summer months, between July and August, and is usually on one of the warmest days of the year. The warmer the weather, the more energy is required to cool homes, which increases capacity requirements on the FBC system.

The reference case summer peak demand forecast increases from 590 MW in 2016 to 716 MW in 2035, growing at a compound annual growth rate of 1.0 percent.

Figure 3-4: Summer Peak Forecast (MW)



3.3 DETERMINANTS OF LOAD GROWTH

The Company relies on third party forecasts of the economic drivers of load growth for its service territory. The two primary inputs to the load forecast are the following:

- British Columbia Gross Domestic Product (GDP) as forecast by the Conference Board of Canada (CBOC).[73],[74] The CBOC's forecast provides an overview of the expected economic climate and is used directly in the forecasts of the load growth in FBC's commercial and industrial rate classes; and
- FBC's service territory population as forecast by the Ministry of Technology, Innovation & Citizens' Services, B.C. Statistics branch (BC Stats), which is used to forecast the number of residential customers FBC will serve over the planning horizon.

The Company also relies on forecasts provided by individual customers for its wholesale and industrial rate class.

3.3.1 Forecast Economic Conditions

FBC uses GDP as a quantitative measure of economic activity to forecast economic conditions. GDP forecasts from the CBOC are employed to forecast load for both the commercial and industrial classes.

The CBOC forecasts a compound annual GDP growth rate of 2.2 percent in B.C. over the planning horizon. This is higher than the compound annual growth rate of 1.7 percent

[73] Provincial Outlook Long-Term Economic Forecast 2016 by the Conference Board of Canada, May 17, 2016.
[74] Provincial Outlook Executive Summary Winter 2016 by the Conference Board of Canada, March 8, 2016.

experienced in the last 10 years. The GDP growth is forecast to be strongest during the near to medium term and then is predicted to soften slightly in the long term. According to the CBOC the softening of the economy will be a result of slowed population growth and an increasingly aging population.

The CBOC's analysis predicts that the forestry sector will decline in the short term due to the mountain pine beetle infestation but will then recover somewhat in the medium to long term. The manufacturing sector is forecast to have strong growth in the near term due to increases in wood product manufacturing and the low Canadian dollar. In the medium to long term the manufacturing sector is expected to slow due to the weak forestry sector and slower growth of exports to China due to their weakening economy. The mining sector is forecast to see strong growth over the planning horizon due to a large number of projects currently underway and the anticipated stabilization of commodity prices.

3.3.1.1 Commercial Load

There is a high statistical correlation between the provincial GDP and FBC's commercial load, which is explained in further detail in Appendix E. The commercial class is a mix of different types of businesses, from small store-front operations and restaurants to larger operations such as hotels and ski resorts. In 2015, there were 14,976 customers in the commercial class, representing 25 percent of the gross load.

Commercial load growth is expected to increase at a compound annual growth rate of 1.6 percent over the planning horizon. The commercial load is forecast to increase significantly during the near to medium term and then slow somewhat due to reduced economic growth.

3.3.1.2 Industrial Load

In 2015, there were 50 customers in the industrial class, representing 11 percent of FBC's gross load.

Industrial load growth is expected to increase at a compound annual growth rate of 1.5 percent over the planning horizon. The industrial load is forecast to have consistent strong growth during the planning horizon except for during the short term which is partly due to the forecast decline of the forestry sector from the mountain pine beetle epidemic.

The CBOC provides GDP forecasts for various industrial sectors. Those individual sector GDP projections are used for industrial customers who do not return their annual FBC industrial survey. Since the survey and individual sector GDP projections only include forecasts for five years, the composite GDP growth rate is used for the long term forecast.

The GDP composite rate is used to forecast the industrial long term load because FBC's industrial customer base is a mix of diverse industries including agriculture, forestry, manufacturing, utilities and commercial service. Further information about the industrial load forecast method can be found in Appendix E.

3.3.2 Population Growth

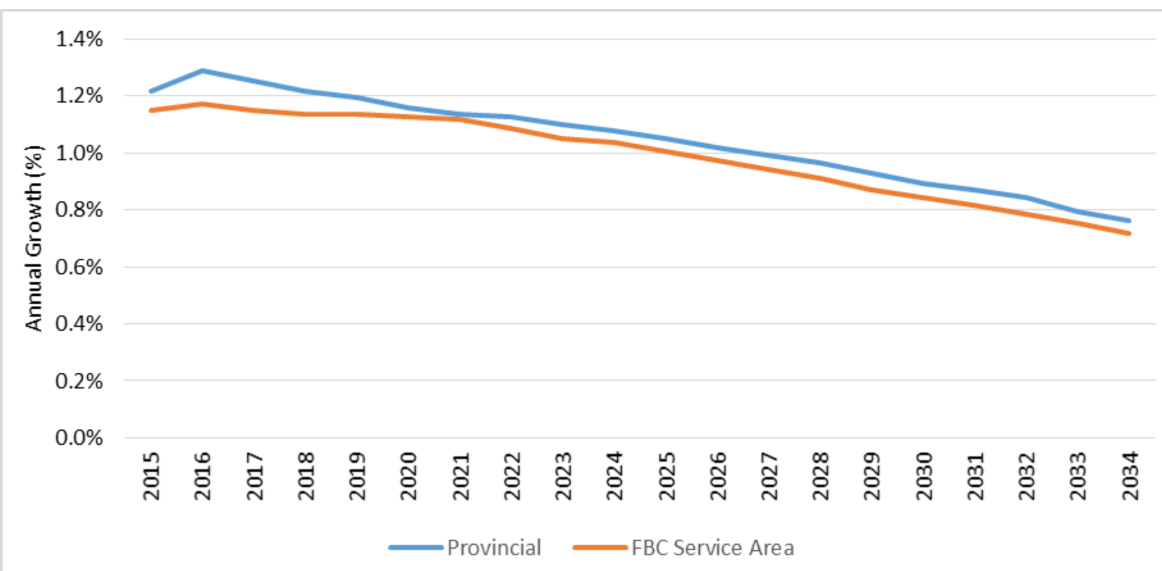
BC Stats forecasts annual population growth of 1.0 percent on average over the planning horizon for FBC's service territory. This is consistent with the 1.0 percent annual average growth rate experienced in the last 10 years. Population growth is forecast to be strongest at the start of the planning horizon at 1.2 percent and then is predicted to fall gradually to 0.7 percent by 2035.

According to BC Stats forecast, B.C.'s population growth will decline over the planning horizon due to declining birth rates and increased mortality. Birth rates are lower due to women having children later in life and fewer children being born to each woman. The current birth rate in B.C. is approximately 1.4 percent lower than in 1971 and 4.0 percent lower than in 1960. Even though life expectancy is forecast to increase slightly, the mortality rate will increase over the time period covered by the LTERP due to the aging of the baby boomer population. The cumulative effect of both of these factors will cause the population growth rate to diminish.

Net migration into B.C. is forecast to remain relatively constant over the time period except for increases in the net interprovincial migration in the short-term due to the recent downturn in the Alberta economy.

FBC receives a custom population forecast for its service area from BC Stats but that forecast does not include any commentary about or explanation for the results. Since both the provincial and FBC service area forecasts are based on the same growth patterns it is assumed that the reasons stated above for the lower growth rate in B.C. apply equally to FBC's service area.

Figure 3-5: BC Stats Provincial and FBC Service Area Population Annual Growth Forecasts



Population growth for FBC's service area is used to forecast the residential customer count which, along with customer usage, is used to forecast residential loads. Customer usage is forecast by averaging the most recent three years' usage rates and then assuming the average rate remains constant over the planning horizon. The calculations for the residential load are further explained in section 1.4.1 of Appendix E. In 2015, there were 114,166 residential customers, which represented 38 percent of FBC's gross load.

Residential customer growth is expected to increase at an average annual rate of 0.7 percent over the planning horizon. The residential customer growth is forecast to be strongest at the start of the planning horizon at 0.8 percent and then is predicted to fall gradually to 0.5 percent by 2035.

3.4 *LOAD FORECAST UNCERTAINTY*

In order to account for future variability in the load forecast inputs, FBC developed a Monte Carlo range for the reference load forecast. FBC has developed a standard P10/P90 range where:

- P10 means there is a 10 percent probability that the load will be less than this forecast value in a particular year; and
- P90 means there is a 90 percent probability that the load will be less than this forecast value in a particular year.

Generally speaking, a Monte Carlo analysis uses the variability in historic data to forecast possible variance ranges from the reference case forecast. The variables used in the Monte Carlo analysis are:

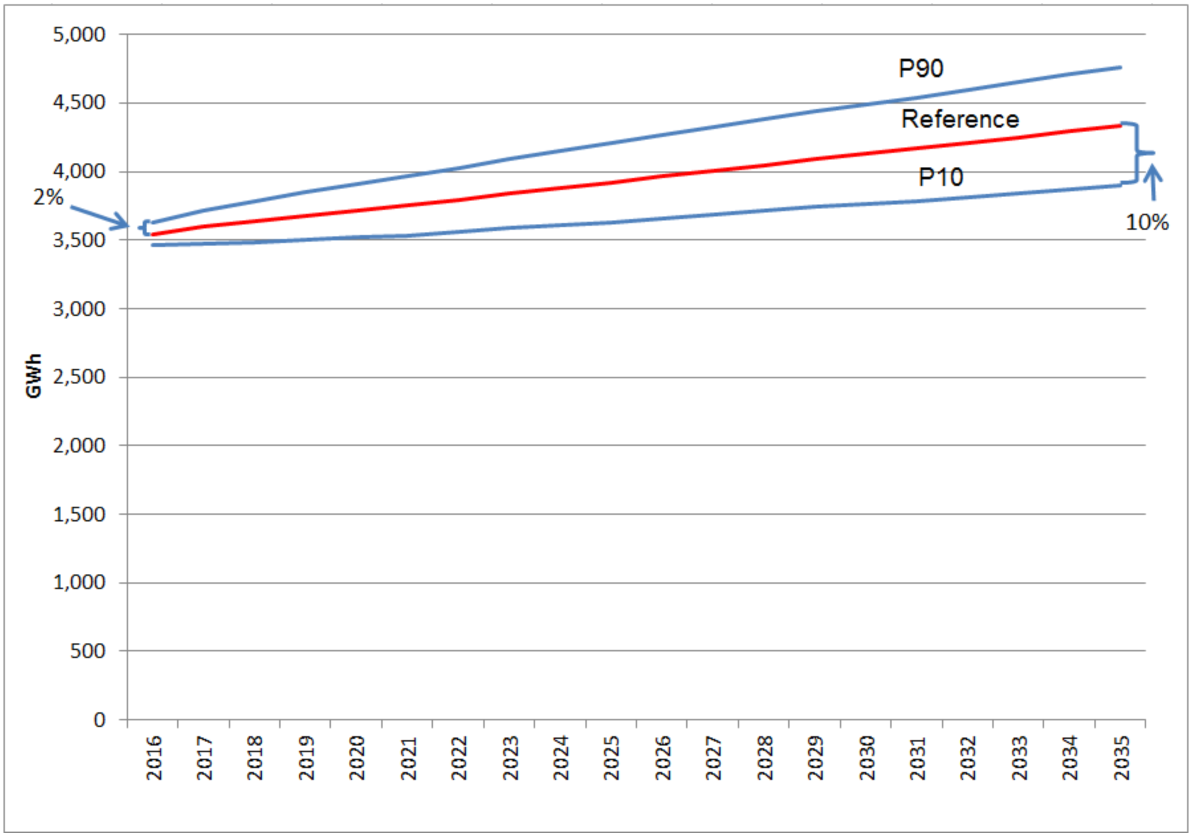
- Use Per Customer (UPC) and BC Stats Population for the residential rate class;
- GDP for the commercial rate class, and
- Historical loads for all other rate classes.

The Monte Carlo method FBC used for the purposes of the load forecast is further explained in Appendix E.

The following figures show the Monte Carlo range forecasts for energy and peak demand requirements over the planning horizon of the LTERP.

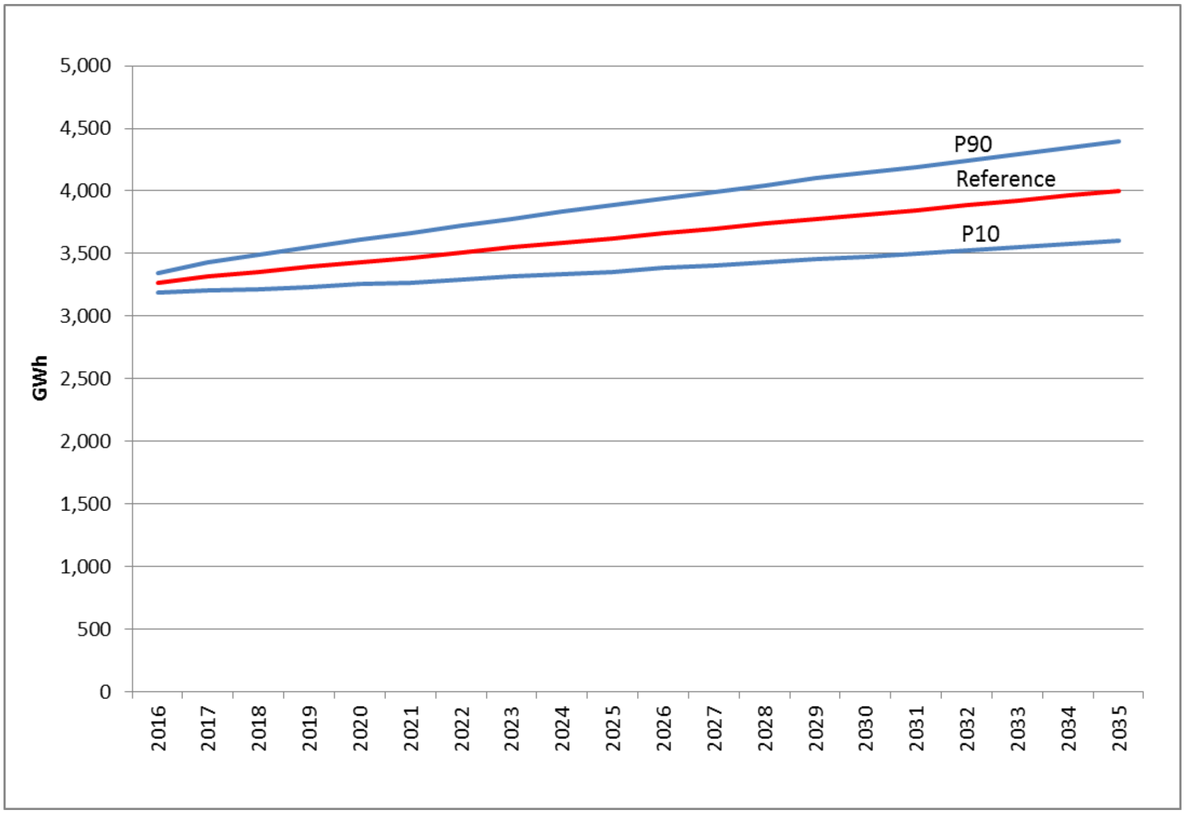
The gross load Monte Carlo high-low range is forecast to trend between 2 to 10 percent from the reference case.

Figure 3-6: Gross Energy Monte Carlo Range (GWh)



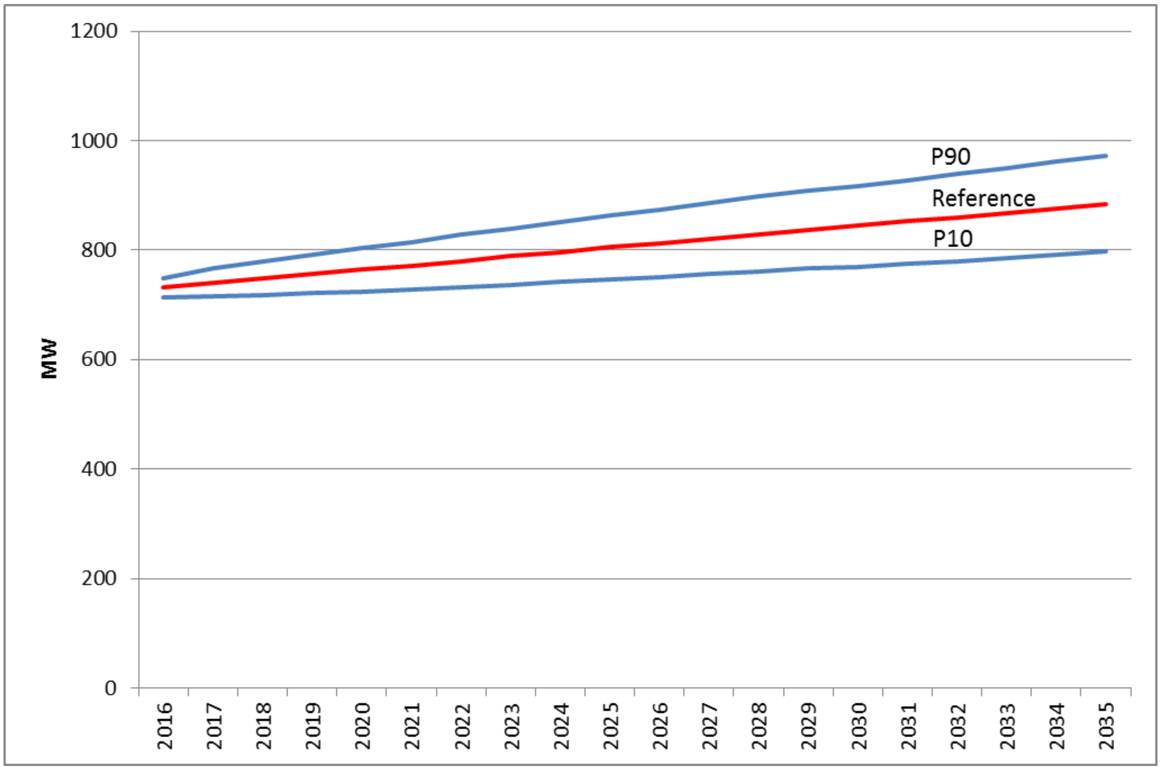
The Net load Monte Carlo high-low range is also forecast to trend between 2 to 10 percent from the reference case.

Figure 3-7: Net Energy Monte Carlo Range (GWh)



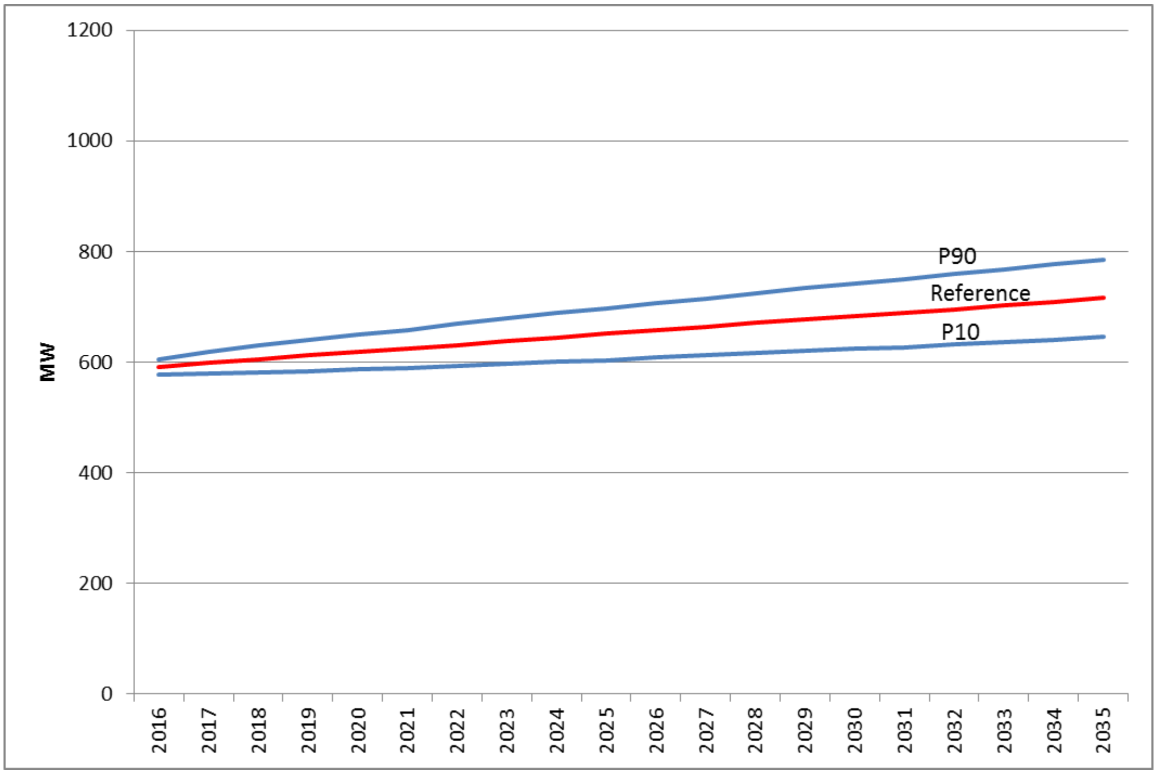
The winter peak Monte Carlo high-low range is forecast to trend between 3 to 10 percent from the reference case.

Figure 3-8: Winter Peak Monte Carlo (MW)



The summer peak Monte Carlo high-low range is forecast to trend between 2 to 10 percent from the reference case

Figure 3-9: Summer Peak Monte Carlo (MW)



3.5 *SUMMARY*

FBC has forecast the reference case load for its customers' annual energy and peak demand requirements over the next twenty years. FBC is forecasting gross and net loads to have a compound annual growth rate of 1.1 percent per year. Growth will be stronger in the near to medium term and then begin softening due to slowed economic conditions and lower population projections. Winter and summer peaks are both projected to have a compounded annual growth rate of 1.0 percent and remain relatively constant for the planning horizon. For further information on the load and peak forecasts and methods used to develop them please refer to Appendix E.

In Section 7, FBC compares these reference case load forecasts against existing resources to derive the Load-Resource Balance. This helps FBC to determine when gaps between load and resources may occur in the future and how big these gaps may be. In Section 8, FBC examines the demand-side and supply-side resource options that could be used to fill these gaps.

4. LOAD SCENARIOS

Section 3 described the long-term reference case load forecast which is based on historical load drivers. FBC recognizes, however, that emerging technology and changes in how customers use and provide energy could impact load drivers that are not captured in the reference case. This section of the LTERP discusses these non-historical load drivers and some alternative load scenarios. FBC employed the consulting services of Navigant Consulting Ltd. (Navigant) to identify emerging trends and technologies not reflected in the reference case load forecast and to examine their potential uptake or penetration levels. Navigant then developed several alternative scenarios based upon these potential load drivers, which may increase or decrease FBC's load requirements relative to the reference case forecast in the future. Note that there is significant uncertainty in how these scenarios will actually play out in the future and, as such, FBC has not assigned any probabilities to them. The scenarios provide examples of what the impacts on FBC's future load requirements might be if specific load drivers occurred at specific growth or penetration levels. They are not alternate load forecasts.

These load scenarios will help inform FBC's potential future resource requirements and how FBC might adapt its resource portfolio if they were to occur. FBC's portfolio analysis, discussed in Section 9, includes alternative resource portfolios to meet the reference case load as well as the alternative load scenarios discussed in this section. This may include, for example, more generation resources to meet higher than reference case load or ensuring flexibility in FBC's resource portfolio to handle decreasing load requirements.

Many of the non-historical load drivers are not expected to ramp up or grow significantly in the short term but could have longer-term impacts instead. For example, FBC's service area currently contains low amounts of residential rooftop solar installations and FBC does not expect them to ramp up significantly in the near future. However, rooftop solar could be a significant driver over the longer term and certainly within the LTERP's twenty-year planning horizon. Some of the other load drivers could significantly impact FBC's short-term load requirements. For example, if a large data centre, hospital or college was built in FBC's service area within a relatively short period of time, electricity requirements could significantly increase as a result. FBC needs to plan for both the short-term and long-term requirements of its customers and needs to have an understanding of what actions it might need to take under alternative scenarios.

These scenarios are based on load requirements before DSM initiatives and are consistent with the Commission's *Resource Planning Guidelines*, in particular the development of a range of gross (pre-DSM) demand forecasts (item 2 of the *Resource Planning Guidelines*).

The load scenarios were discussed in detail with the RPAG stakeholders in the April 27, 2016 workshop. At that session, FBC received some feedback regarding the load drivers and scenarios. FBC also provided stakeholders with a load scenario tool to allow them to develop their own load driver penetration levels and scenario impacts. This feedback is presented in Section 4.3 below.

The following sections describe the development of the load drivers and the alternative scenarios as well as the results of Navigant's analysis of their potential impacts on FBC's future energy and capacity requirements for its customers. More details, including the assumptions used for the load drivers within each scenario, are provided in Navigant's Load Scenario Assessment Report, which is included in Appendix G and Navigant's Load Scenarios Presentation to the RPAG in Appendix H. The data relating to the energy and capacity impacts of the load scenarios are provided in the Load Scenarios Modelling Outputs in Appendix I.

4.1 *LOAD SCENARIOS APPROACH*

In developing the load scenarios, Navigant and FBC focused on determining the impacts of various plausible future scenarios on FBC's energy and capacity requirements rather than attempting to address all potential factors that might influence the load drivers included in the scenarios. FBC believes this to be more productive and appropriate for high-level long-term resource planning. The scenarios can be refined over time and in future resource plans as better information becomes available.

FBC engaged Navigant to:

- Help determine what potentially significant drivers of structural change in electricity consumption behaviour could be;
- Estimate the energy and capacity impacts of these load drivers; and
- Model the potential impacts of these drivers as part of five different load scenarios, the parameters of which were developed collaboratively by Navigant and a cross-disciplinary internal group of FBC staff. The results were shared with stakeholders and their feedback obtained.

The purpose of Navigant's Load Scenario Assessment Report was to provide a quantitatively robust answer to the following question: what would be the impact on FBC's peak demand and energy if a given set of circumstances were to arise? It is important to note that the scenarios were developed without determining and measuring the impacts of all of the potential drivers. For example, the impact of a substantial increase in the penetration level of EVs in FBC's territory is quantified; however, determining what might drive increased uptake in EVs, such as the price of gasoline versus electricity, is beyond the scope of the work.

The future impact of the load drivers included in these scenarios is, at present, so uncertain that no objective probabilities can be assigned to the scenarios. It is for this reason that these load drivers are included in this exercise, as opposed to a more formal empirical forecast.

FBC's purpose in engaging Navigant was to help understand the potential impacts of the load drivers and scenarios. FBC has no immediate plans to adjust its current resource requirements in response to these drivers. FBC will explore the impacts of the load scenarios on its preferred resource portfolio as part of its portfolio analysis as discussed in Section 9.

4.1.1 Load Drivers

Eight specific load drivers were included to develop the load scenarios. These were selected from a broader list developed by Navigant and FBC staff as those believed to have the most substantial potential impact on future loads. The eight load drivers are:

1. **Residential Rooftop Solar and Integrated PV Storage Systems.** Behind-the-meter rooftop PV generation by residential customers. This load driver includes battery-supported PV, referred to as Integrated Photovoltaic Storage Systems (IPSS).
2. **Electric Vehicles.** Plug-in hybrid electric vehicles (PHEVs) and battery electric vehicles (BEVs), supported by Level 1 (standard 120 V) home charging, Level 2 (240 V) work-place and home charging as well as DC fast charging.
3. **Fuel Switching – Electricity to Gas.** Residential fuel switching from electric to gas space- and water-heating, applicable only to residential customers within 50 metres of a gas main.
4. **Fuel Switching – Gas to Electricity.** Residential fuel switching from gas to electric space- and water-heating.
5. **Consistent and Persistent Weather Changes due to Climate Change.** The effect on customer energy consumption due to climate-change-driven temperature increases forecast by the U.S. Geological Survey (USGS) National Climate Change Viewer.
6. **Large Load Sector Transformation.** Unanticipated growth of large load customers not associated with traditional energy intensive industries (i.e., primary resources and manufacturing).
7. **The Internet of Things (IoT).** The combined effect of an increasing number of household appliances and devices being connected to a home network, information collected by those devices being delivered to residential consumers to allow for optimal decision making, and the presence of systems that allow consumers to take control of their consumption in response to this information.
8. **Combined Heat and Power (CHP).** Very large industrial customers investing in CHP cogeneration facilities, reducing the amount of electricity they require from the system and potentially allowing them to become net generators of electricity.

These load drivers are the building blocks for the five scenarios modeled by Navigant. The assumed uptake, or penetration, of each load driver will vary from scenario to scenario, from zero in some scenarios to a very aggressive level in others. It should be noted that all load driver uptake assumed in any given scenario is incremental to any that may be already embedded in the reference case load forecast. The directional impacts of the load drivers on the FBC system load are summarized in the following table.

Table 4-1: Load Drivers Directional Impacts

Load Driver	Short Form	Effect on System Load (+/-)
Residential Rooftop Solar and Integrated Storage Systems	**PV**	▼
Electric Vehicles	**EV**	▲
Fuel Switching – Electricity to Gas	**FS – E2G**	▼
Error! Reference source not found. Fuel Switching – Gas to Electricity	**FS – G2E**	▲
Consistent and Persistent Weather Changes due to Climate Change	**Weather**	▼
Large Load Sector Transformation	**LLST**	▲
The Internet of Things	**IoT**	▼
Combined Heat and Power	**CHP**	▼

4.1.2 Scenario Descriptions

Each of the five scenarios modelled is comprised of a different combination of load drivers. Although an infinite number of potential combinations of load drivers into scenarios is possible, the five scenarios selected for this analysis were chosen based on two guiding principles:

1. The analysis should include "boundary" scenarios. Boundary scenarios are those scenarios that define major deviations from existing empirical forecasts driven by the cumulative effects of emerging technologies and structural shifts that overwhelmingly affect system load in one direction or the other. Scenarios 1 and 5 (described below) are the boundary scenarios of the five analysed.
2. The analysis should include "offsetting" intermediate scenarios. In addition to modelling scenarios where all load drivers push system load in the same direction, it is important to consider scenarios where off-setting effects can exist. This is helpful for appreciating the potential dynamics of how load drivers may interact with one another. Scenarios 2, 3 and 4 are the intermediate scenarios.

The descriptions of the five scenarios are as follows:

- **Scenario 1** ("Low Carbon World") is the first of the boundary scenarios and is designed to quantify the potential energy and demand impacts on the FBC system if there is substantial growth in the penetration of the three load drivers that *increase* load: large load sector transformation, gas-to-electric fuel switching and EVs.

- **Scenario 2** ("Low Carbon World with Climate Change") is an offsetting scenario and is designed to quantify the potential energy and demand impacts on the FBC system if there is some growth in the penetration of load drivers that *increase* load (EVs and gas-to-electric fuel-switching) accompanied by some growth in the penetration of a load driver that decreases load (weather changes).

- **Scenario 3** ("A Connected World") is an offsetting scenario and is designed to quantify the potential energy and demand impacts if there is some growth in the penetration of a load driver that *increases* load (EVs) accompanied by some growth in the penetration of load drivers that decrease load (weather changes, the IoT and residential solar PV).

- **Scenario 4** ("A Connected World II") is an offsetting scenario designed to quantify the potential energy and demand impacts if there is some growth in the penetration of load drivers that *increase* load (EVs and large load sector transformation) accompanied by some growth in the penetration of load drivers that decrease load (weather changes, CHP, the IoT and residential solar PV).

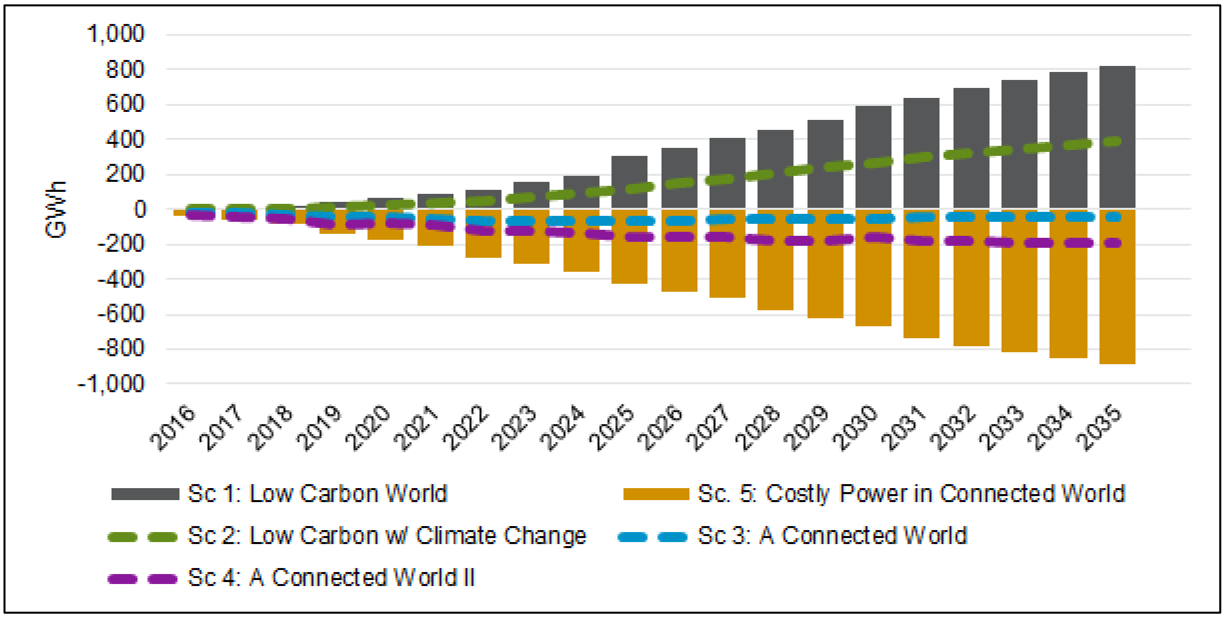
- **Scenario 5** ("Costly Power in a Connected World") is the second of the boundary scenarios and quantifies the potential energy and demand impacts if there is substantial growth in the penetration of the five load drivers that *decrease* load. These drivers include weather, IoT, electric-to-gas fuel switching, CHP and residential solar PV.

4.2 *LOAD SCENARIOS RESULTS*

This section discusses the results of the load scenarios analysis in terms of the potential impacts to FBC's energy and capacity requirements.

The following figure shows the overall energy consumption impact of each scenario relative to the reference case (at zero on the vertical axis), by year.

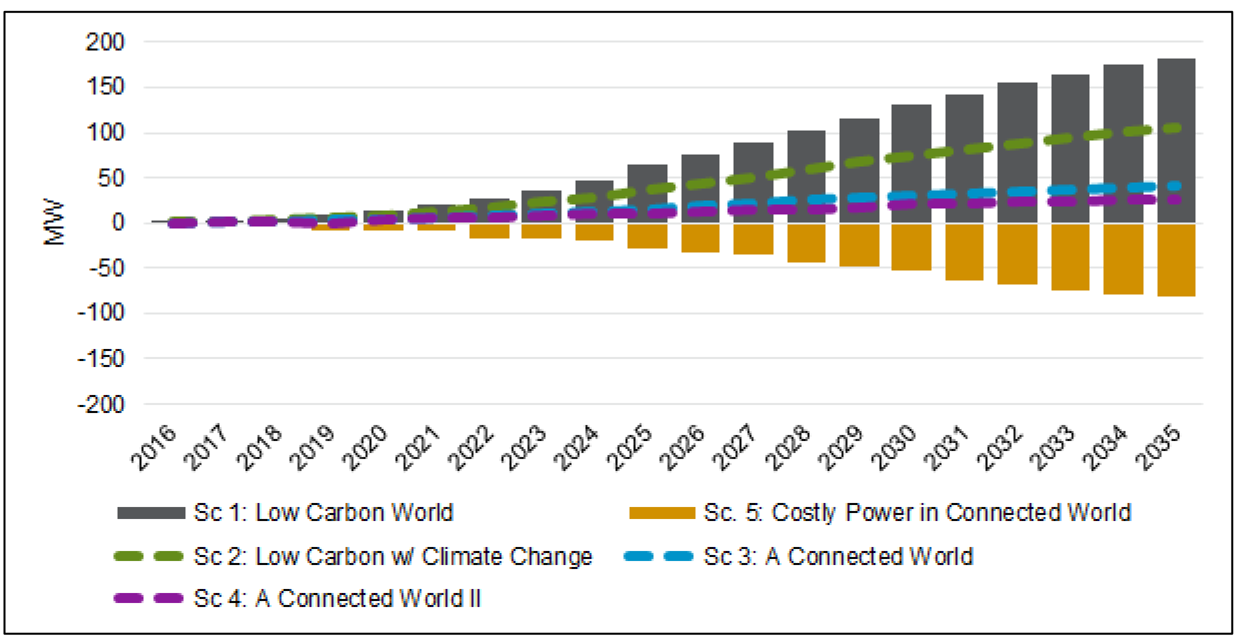
Figure 4-1: Energy Impacts by Scenario and Year



As shown in this graph, Scenario 1 results in an increase in energy consumption of over 800 GWh per year by 2035 compared to the reference scenario, whereas Scenario 5 results in a decrease of nearly 900 GWh per year by 2035 compared to the reference scenario. The off-setting scenarios all fall somewhere in the middle, with Scenario 3 having the least impact. Scenario 3 results in a decrease of only approximately 40 GWh per year by 2035.

The following figure shows the overall peak demand impact of each scenario relative to the reference case, by year.

Figure 4-2: Peak Demand Impacts by Scenario and Year



As shown in this graph, Scenario 1 results in an increase in peak demand of nearly 200 MW by 2035 compared to the reference scenario, whereas Scenario 5 results in a decrease of approximately 80 MW by 2035 compared to the reference scenario. As with energy consumption, the intermediate scenario impacts fall in the middle between these two extremes.

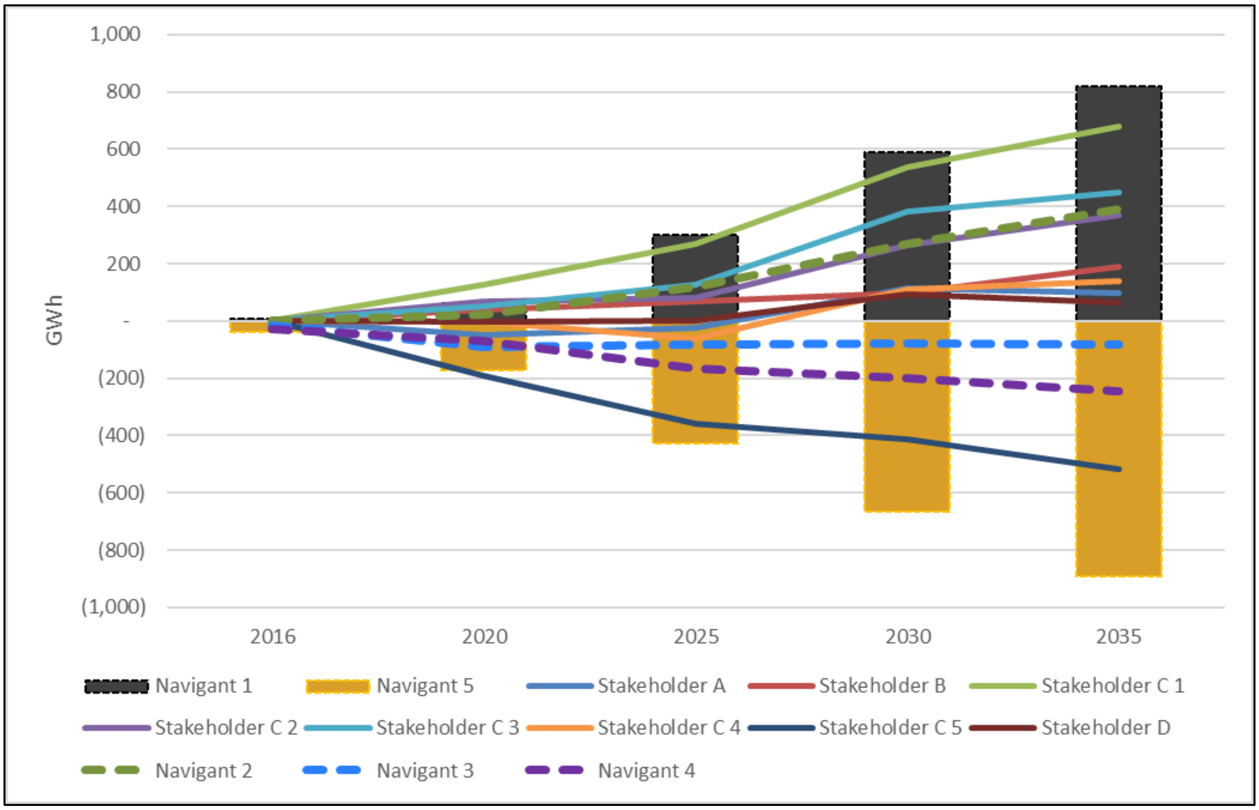
The most noteworthy feature of a comparison of the energy and demand impacts by scenario is that Scenarios 3 and 4 are directionally different. That is, Scenarios 3 and 4 both indicate a decrease in energy consumption but an increase in peak demand. This counter-intuitive effect is due to the combination of the two most impactful load drivers, PV and EVs. Increasing installations of PVs more than offsets the incremental energy offset by the EVs, but the timing of the delivery of that electricity is constrained by the hours of sunlight, the capacity of the energy storage system (assumed as part of the IPSS installations) and average residential demand in the early evening hours. Very little, if any, electricity is being provided by rooftop PV between 5 p.m. and 6 p.m., but it is at just this time that the majority of the electricity required to recharge EVs is being demanded.

4.3 RPAG FEEDBACK

The load scenarios described above were discussed with the RPAG stakeholders in the April 27, 2016 workshop. At that session, FBC received feedback regarding the load drivers and scenarios. For example, one stakeholder commented that the electric vehicle penetration included in the high consumption boundary scenario (Scenario 1) might be overstated if electric vehicle manufacturers are not able to keep up with the demand from customers. Another stakeholder commented that the generally older population in the FBC service area relative to other cities, such as Vancouver, might lead to lower adoption of EVs in the FBC territory. Another stakeholder commented that the level of solar PV with storage seemed high without time-of-use rates providing an incentive for the use of energy storage. FBC notes that while the high and low boundary scenarios represent plausible extremes, the three intermediate scenarios cover less-extreme scenarios and may be more aligned with those situations described by stakeholders in the workshop.

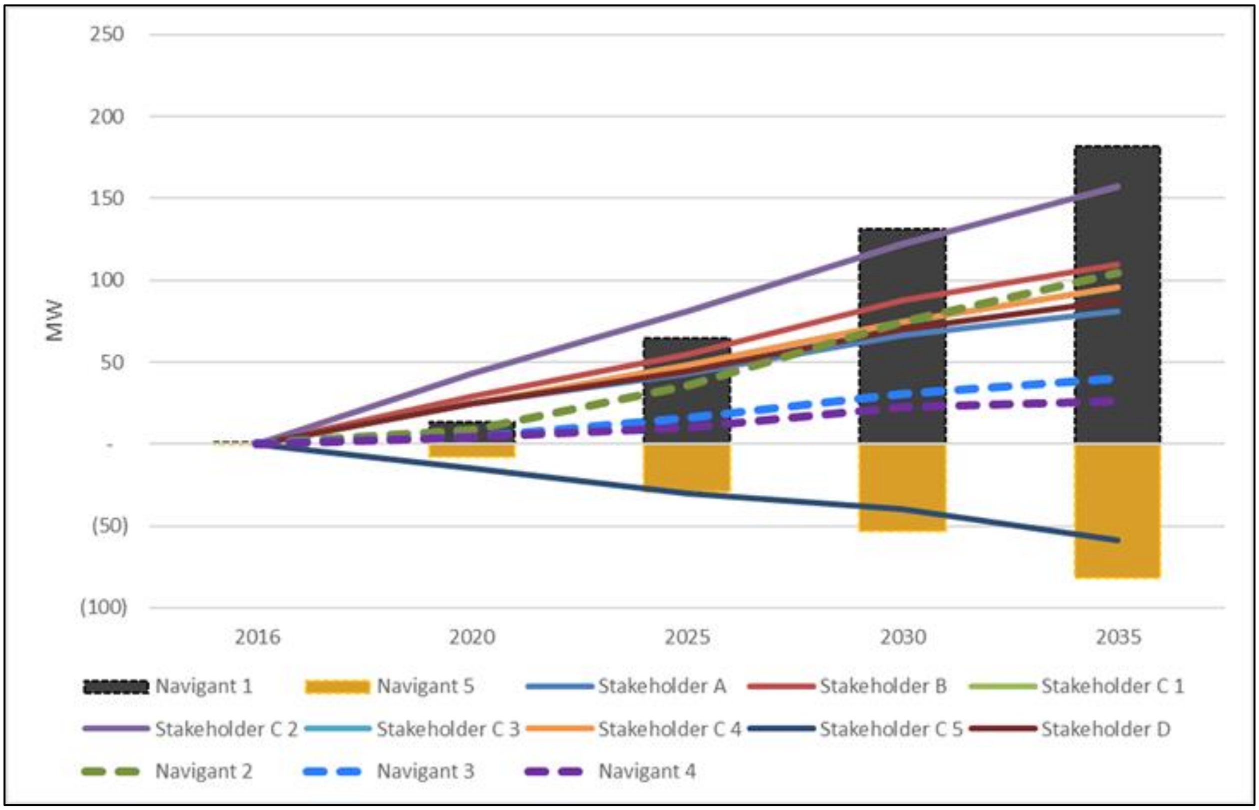
FBC also provided stakeholders with a load scenarios tool to give them the opportunity to model their own load driver penetration levels and scenario impacts. The tool was an excel-based model which allowed stakeholders to adjust the growth rate of the load drivers based on their own views of the driver growth and penetration levels over time. Several stakeholders used the tool provided and submitted their results to FBC. FBC then aggregated the load driver results from each stakeholder into scenario results. The stakeholders' results compared to the Navigant scenarios are presented in the following figures. Stakeholder C provided five scenarios rather than a single set of load driver growth and penetration levels. FBC has kept the stakeholder results anonymous.

1 **Figure 4-3: Stakeholder and Navigant Load Scenarios – Energy Impacts**



2

Figure 4-4: Stakeholder and Navigant Load Scenarios – Winter Peak Demand Impacts



Two key conclusions can be drawn from the stakeholder feedback represented in the figures above. First, there is no consensus regarding the degree of impact the load drivers might have on the energy and capacity requirements of FBC's customers. This is evident by the wide range of scenarios provided by stakeholders within the Navigant boundary scenarios. It also supports FBC's belief that it is difficult to assign probabilities to the load scenarios given the high degree of uncertainty and difference of opinion regarding how the drivers will play out over time. However, many of the stakeholders' results for energy impacts ended up in between Navigant's scenarios 2 and 3. For peak demand impacts, many of the stakeholders' results ended up close to Navigant's scenario 2. Therefore, the stakeholders' views were not significantly different than those presented by Navigant in terms of the load scenarios.

Second, stakeholders clearly believe there is more potential for increased energy and peak capacity requirements above the reference case forecast rather than decreased requirements. This is illustrated by most of the scenario impact results being positive rather than negative values in the figures above. The stakeholders that participated in this exercise generally believe that drivers like EVs, which increase load, will more than offset other drivers like rooftop solar, which decrease load. Only time will tell, but FBC's contingency planning will assess the impacts of scenarios that both increase and decrease load.

4.4 CONCLUSIONS

In this analysis, Navigant and FBC explored two boundary scenarios and three intermediate scenarios. Load driver penetrations or uptake in the boundary scenarios, were deliberately selected by Navigant and FBC to "push the envelope". They were selected to help FBC understand the potential impact that each of these load drivers could have under extreme, but plausible, penetration scenarios.

Observing the estimated impacts in the boundary scenarios, Navigant's principal finding is that the load drivers that may have the most impact to FBC going forward are (in order): EVs, residential rooftop PV, and fuel switching from gas to electric and vice versa. Based on the modeling results there appears to be less potential impact from the LLST, CHP, IoT and Weather load drivers. However, a new large industrial user, such as a hospital, college or data centre, would certainly be a load driver that could come on relatively quickly and have significant impacts on the FBC load requirements.

Navigant's secondary finding is that, based on the intermediate scenarios, the possibility exists that demand during peak times could increase despite energy consumption falling. Such an impact could be driven by a strong move toward the electrification of transportation combined with increasing self-generation and other energy-efficiency efforts.

FBC will continue to monitor, where possible, the various load drivers and, in particular, the three which may have the most impact on FBC's loads: EVs, rooftop solar PV and fuel switching. This will enable FBC to determine if a particular scenario is emerging or if penetration levels and growth for a particular driver are occurring faster than expected and what actions may need to be taken. For example, if EV growth increases significantly or becomes concentrated in certain neighbourhoods, FBC may need to ensure that EV charging occurs outside peak demand times to avoid the potential requirement for increasing transmission and distribution system infrastructure and more peak capacity generating resources.

The ability of FBC to meet customer load requirements that are significantly higher or lower than the reference case is part of FBC's portfolio analysis and helps determine the requirement for resource flexibility. FBC has included this portfolio analysis within Section 9. The potential impacts of the load drivers and scenarios to the transmission and distribution system have also been considered and are discussed in the section of this LTERP on the Transmission and Distribution System, Section 6.

5. EXISTING SUPPLY-SIDE RESOURCES

This section describes FBC's existing and committed supply-side resources as well as any constraints that these resources impose on FBC's resource planning. These include resources owned by FBC as well as contracts FBC has with other parties to provide energy and capacity to FBC. FBC resources consist of FBC-owned Entitlements under the Canal Plant Agreement (CPA), Brilliant Power Purchase Agreement (BPPA) Entitlements, Waneta Expansion Capacity Purchase Agreement (WAX CAPA) Entitlements, purchases under the BC Hydro PPA, purchases from IPPs and market and other contracted purchases. Each will be further explained below and graphs of FBC's expected to be utilized annual energy and December capacity resources through 2035 are presented in Section 7. FBC's existing available energy and capacity resources in 2016 are provided in the following table.

Table 5-1: FBC's 2016 Available[75] Energy and Capacity Resources

FBC Existing Resources (2016)	Available Energy (GWh)	Available Capacity (MW)
FBC-Owned Generation	1,595	208
BPPA	917	138
BRX	79	39
PPA Tranche 1 Energy	1,041	-
PPA Tranche 2 Energy	711	-
PPA Capacity	-	200
WAX CAPA (net of RCA)	-	218
IPP	3	5
Market and Other Contracts	241	0
Total	4,588	808

5.1 *FBC-OWNED GENERATION ENTITLEMENTS*

FBC owns the Corra Linn, Upper Bonnington, Lower Bonnington and South Slocan generating plants (collectively, the FBC Plants) located on the Kootenay River between Nelson and Castlegar, B.C. The FBC Plants supplied about 50 percent of FBC's energy requirements and about 27 percent of the Company's peak demand in 2015.

The Company operates the FBC Plants in accordance with the CPA. The original CPA was entered into in 1972 to enable the Province of British Columbia to obtain the benefits of the improved water flow control provided by the construction of the Libby Dam in Montana and the Duncan Dam in B.C. The original CPA became effective in 1975 and expired in 2005 and ensured that FBC received entitlements of both capacity and energy equal to the average that would have been available to FBC without the Libby and Duncan Dams. In 2005, BC Hydro, FBC, Teck Metals Ltd. (Teck), Brilliant Power Corporation, and Brilliant Expansion Power

[75] FBC is not required to utilize all available resources.

Corporation entered into a renewed CPA, which amended, restated and extended the original CPA for a further 30 year term. The parties other than BC Hydro are referred to in the 2005 CPA as the "Entitlement Parties". In 2011, the CPA was further amended to incorporate the WAX and its owner the Waneta Expansion Limited Partnership.

The CPA enables BC Hydro and the Entitlement Parties (collectively, the CPA 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' respective 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 relevant generating plants and are thus insulated from the hydrology risk of water availability.

For the purposes of its 2016 LTERP, FBC is proceeding on the expectation that the CPA will continue indefinitely in its current form. However, there is some uncertainty in this regard. The main risk is that, pursuant to the terms of the 2005 CPA, any time after December 31, 2030, any party to the agreement is able to deliver a five year termination notice. Given the degree to which the operations of the CPA Parties are interconnected, it would be very difficult to separate them to operate without the CPA or a similar agreement. It is far more likely that rather than resulting in termination, any major issue would be resolved through negotiation and could therefore potentially take effect within the time horizon of the LTERP. It is possible that such a negotiation could result in a reduced FBC entitlement or additional restrictions on how the existing entitlement is used. If this were to occur, additional resources could be required to make up the difference. An example of an issue that could bring this scenario about is if climate change results in significant changes to the amount and timing of water availability as compared to that assumed under the CPA.

In addition, it is not known how potential changes to the Columbia River Treaty (CRT) between Canada and the United States might impact FBC CPA entitlements. While the CRT will not directly impact FBC CPA entitlements since Kootenay Lake is outside the CRT, indirect impacts may be possible. For example, if salmon runs were to be restored to the Canadian Upper Columbia as part of the CRT, then Kootenay River operations may need to be modified to support that. Depending on the nature of what modifications may be required, there may or may not be a risk to FBC entitlements.

Finally, there are risks through the International Joint Commission (IJC) management order for Kootenay Lake[76]. If the IJC order were to be reopened to consider what changes may be required to update the order, it is expected that various proposals to modify the order would be brought forward by both the Company and other interested organizations. Any new proposal

[76] The IJC order for Kootenay Lake can be found at http://ijc.org/en_/iklbc/home. Kootenay Lake storage operations resulting from the FBC owned Corra Linn Dam impact Kootenay(ai) River levels in the United States. Therefore, Canada and the US have agreed that the IJC has jurisdiction over Kootenay Lake levels and the IJC has ordered the limits to which FBC can store water in Kootenay Lake.

that was accepted into the IJC order would have the potential to either increase or decrease the available generation and therefore potentially the FBC entitlements. A similar risk occurs if a water use plan for Kootenay Lake is mandated by the B.C. government. While the LTERP does not directly consider these risks, it is important that any new resources that are acquired are as flexible as possible to assist in meeting any future uncertainties that may occur.

In 2012, FBC completed an Upgrade and Life Extension Program (ULE Program) on the majority of the FBC Plants thereby assuring power production at the refurbished FBC Plants through the planning period of this 2016 LTERP. The remaining four generating units, all of which are installed at the Upper Bonnington Plant, provide approximately 10 percent of the capacity entitlement of the FBC Plants under the CPA. Subject to Commission approval, FBC intends to refurbish these units in the 2017-2020 timeframe in order to extend their useful lives, and as such they are included in the 2016 LTERP.

5.2 *BRILLIANT POWER PURCHASE AGREEMENT*

FBC is party to the BPPA, a power purchase agreement with Brilliant Power Corporation made as of April 4, 1996. Under the BPPA, which expires in 2056, FBC has agreed to purchase (a) the energy and capacity Entitlement allocated to the Brilliant Plant[77] pursuant to the CPA and (b) after the termination, if any, of the CPA, the actual electrical output generated by the Brilliant Plant. The BPPA uses a take-or-pay structure which requires that FBC pay for the Brilliant plant's Entitlement, irrespective of whether FBC actually takes it.

Included in the BPPA is an amendment made in May, 1996 (Second Amendment) that added an additional 65 GWh of energy and 20 MW of capacity through the term of the agreement once the Brilliant Plant unit upgrades were fully completed. The Brilliant Plant provided approximately 26 percent of FBC's energy requirement and 19 percent of the peak capacity needs in 2015.

5.3 *WANETA EXPANSION CAPACITY PURCHASE AGREEMENT*

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

Under the WAX CAPA, FBC has agreed to purchase from the Waneta Expansion Power Corporation all unused WAX-related capacity (Residual Capacity) that remains after BC Hydro has acquired the energy entitlements associated with the plant (as defined by the CPA). FBC began receiving power under the WAX CAPA on April 2, 2015. The WAX CAPA, which was

[77] The Brilliant Plant is located on the Kootenay River downstream of the FBC plants and just above Castlegar where the Kootenay River joins the Columbia River.

accepted and is held in confidence by Order E-15-12, has a 40 year term and expires on April 2, 2055. The capacity entitlements obtained by FBC under the WAX CAPA vary by month and are suitably shaped to meet FBC's winter and summer peak demand requirements when capacity is needed the most and provides less capacity during the three freshet months when it is needed the least. This capacity profile is an ideal match for FBC's seasonal load shape. The WAX CAPA was reviewed by the Commission in 2010, and accepted pursuant to Order E-29-10.

The amount of Residual Capacity provided under the WAX CAPA is greater than FBC's current capacity requirements in most months and, as a result, FBC sells the surplus capacity to mitigate power purchase expense. FBC has contracted to sell a 50 MW block of WAX CAPA Residual Capacity to BC Hydro under the Residual Capacity Agreement (RCA), entered into as of July 15, 2013. The Commission approved the RCA in Order G-161-14. The RCA expires September 30, 2025. FBC will sell the remaining surplus WAX CAPA Residual Capacity to Powerex Corp. (Powerex) on a day-ahead basis, under the terms of the CEPSA, dated February 17, 2015, if and when the capacity is not required to meet FBC load requirements. The Commission accepted the CEPSA for filing in Order E-10-15. The CEPSA expires on September 30, 2018, but can be renewed on an annual basis through September 30, 2025 by mutual agreement. In absence of the CEPSA, FBC would continue to sell surplus capacity to the market.

5.4 *BC HYDRO POWER PURCHASE AGREEMENT*

Under the PPA, FBC's customers have access to BC Hydro supply up to a maximum of 200 MW and 1,752 GWh of annual energy. The term of the PPA continues through to September 30, 2033. In 2015, the PPA supplied 15 percent of FBC's energy requirement and 22 percent of the Company's peak capacity needs.

FBC's access to BC Hydro's embedded cost energy (at a rate of $46.99 per MWh as of April 1, 2016) under the PPA is limited to 1,041 GWh (Tranche 1 Energy). Above 1,041 GWh and up to the maximum of 1,752 GWh, the energy cost increases to $129.70 per MWh (Tranche 2 Energy), which is tied to BC Hydro's proxy for long run marginal cost that was used in BC Hydro's 2010 Residential Inclining Block Rate Re-pricing Application.[78] FBC is required to submit a nomination by June 30th of each year, for PPA energy deliveries in the following October to September period (PPA Nomination). Regardless of the PPA Nomination, FBC maintains access to 1,752 GWh of energy under the PPA in that year and is free to schedule in any amount of energy that is required up to the 1,752 GWh. Only the cost of the energy will change depending on the PPA Nomination. If energy is delivered above the PPA Nomination, but below the Tranche 1 Energy limit of 1,041 GWh, there is an additional surcharge of 50 percent to the Tranche 1 rate. Energy delivered above the PPA Nomination and above the Tranche 1 Energy Limit is subject to a 15 percent surcharge on the Tranche 2 Energy rate.

[78] The Tranche 2 energy does not increase by the general BC Hydro rate increases but is set to the most recent BC Hydro Long Run Marginal Cost of firm energy used for rate-making purposes.

FBC is required to take or pay for 75 percent of the PPA Nomination, even if it does not schedule the energy. FBC manages its portfolio in a manner that ensures it uses at least 75 percent of the PPA Nomination in order to avoid paying for energy that it does not require. The difference between the PPA Nomination and the 75 percent minimum take provides the flexibility to manage the variability of actual annual loads compared to forecast. If actual load is close to forecast load, FBC has the ability to displace the 25 percent variability with market purchases if market conditions would create additional savings for FBC customers compared to PPA energy rates.

FBC cannot change the annual PPA Nomination by more than 20 percent from the previous year. This needs to be considered when FBC sets the PPA Nomination in each year to ensure that the most cost effective firm resources are in place to meet the expected load, without relying on higher cost PPA deliveries above the PPA Nomination in future years.

The Energy Export Agreement (EEA) was entered into at the same time as the PPA as one of the related agreements connected to the PPA. Prior to the EEA, any new generation resources that FBC obtained would have to be fully used to meet load rather than just to meet the resource gaps between existing resources and load. As a result, PPA usage could be expected to decrease as FBC obtained new resources. This was not intended under the PPA and therefore the EEA was entered into allowing, at FBC's option, to export the surplus from the new resource if that was the most cost effective usage and would not result in increased PPA load compared to if the new resource had not been obtained. This ensures that the actual cost of entering into new resouces in the LTERP is not artificially higher than it should be by forcing BC Hydro purchases to be displaced.

FBC's base case assumption for its portfolio analysis in Section 9 assumes that the PPA will continue in a similar form past the current expiry date in 2033. The portfolio analysis also includes a scenario where the PPA is not renewed beyond 2033 to provide an indication of the resources that may be required to replace the PPA energy and capacity.

5.5 *MARKET AND OTHER SHORT TO MEDIUM TERM CONTRACTED PURCHASES*

FBC has market and other short to medium term contracted purchases for the delivery of electricity that have been accepted by the Commission. These include contracts with suppliers inside the FBC system, and purchases from the wholesale market. The power markets are influenced by several factors that are reviewed in Section 2.4 and a forecast of market prices is presented in Section 2.5.

FBC has contracted to purchase CPC's unused CPA Entitlements from the Brilliant and Brilliant Expansion Plants over the period of 2013 to 2017, providing approximately 2 per cent of FBC's energy requirements in 2015. FBC is in discussions to extend the purchase of this power through to 2027 but as of the date of filing of the LTERP has not yet reached agreement. Any agreement that may be reached would also require subsequent Commission approval. FBC assumes that this power will remain available through 2027 but after that time availability can't be assumed since it will likely be packaged with another block of power that may be available from the plant. While this larger block of power could potentially present additional opportunities to secure cost effective locally generated power to meet the Company's resource needs, it has not been included in the analysis of the Company's 2016 LTERP.

FBC purchases energy and capacity from the wholesale market when it is more competitively priced than purchases under the PPA, or when FBC does not have sufficient resources to meet peak demand requirements. In 2015, market and contracted purchases accounted for 10 percent of FBC's annual energy requirements.

FBC access to the market is mainly through its transmission rights on Teck's 71 Line, which provides transmission both across the B.C./U.S. border and to the FBC system. For long-term planning purposes such as the 2016 LTERP, this access is treated as firm but it must be recognized that the Company does not own the line. Also, additional U.S. transmission is required to access the Mid-C trading hub, which is located along the Columbia River on the border between Washington and Oregon. Additional firm transmission cannot be reliably obtained on the U.S. side of the border and as such, while the market remains an excellent source of energy to meet FBC customer requirements and could meet the relatively small energy gaps that the Company expects through 2035, it cannot be considered a long-term resource to meet capacity requirements (as described in more detail in Section 8.2.4). The Company intends to continue to explore what B.C.-based market options may be available to meet future needs.

5.6 *INDEPENDENT POWER PRODUCERS*

The Company purchases energy through eight power purchase contracts with IPPs located within the FBC service area. IPPs provide less than 1 percent of FBC annual energy requirements. In the future, this could also potentially include larger purchases of power from FBC self-generation customers.

6. TRANSMISSION AND DISTRIBUTION SYSTEM

6.1 INTRODUCTION

A key aspect of ensuring cost-effective, secure and reliable supply of electricity to customers is identifying the transmission and distribution system infrastructure that FBC may need to construct over the planning horizon. This section discusses FBC's examination of the power system and identification of any system resource needs in terms of peak capacity to ensure that the FBC system continues to serve the needs of its customers. The interrelationship between resource planning and system planning is also discussed.

This section includes a system overview as well as a discussion of planning criteria and studies that help define the requirements of FBC's power system over the planning horizon. Potential impacts on the system from new generation resources are also described along with the potential impacts from emerging technologies such as solar PV and EVs. While there is uncertainty regarding the amount and timing of new generation requirements as well as the adoption and penetration of new technologies, FBC will continue to monitor developments in order to plan system requirements appropriately.

It should be noted that this section provides a level of detail that FBC considers appropriate for long term resource planning with respect to transmission and distribution infrastructure. More specific information with respect to detailed transmission and distribution capital infrastructure additions and upgrades will be provided separately in future capital plans.

6.1.1 Transmission and Distribution System Overview

FBC operates in the southern interior of B.C. transporting and distributing energy within and between communities including Kelowna, Oliver, Osoyoos, Trail, Rossland, Castlegar, Creston, and Princeton and surrounding areas. In addition, FBC supplies power to wholesale municipal customers in the communities of Summerland, Grand Forks, Penticton and Nelson as well as to BC Hydro near the communities of Kaslo, Lake Country, Creston and Kingsgate. Figure 1-2 in Section 1.2 provides a map outlining FBC's service area.

High voltage transmission lines are vital for the integration of energy resources needed to serve FBC customers and other municipalities. FBC transmission interconnections improve reliability by providing the flexibility to move energy between FBC and other utilities (primarily BC Hydro), to transfer FBC's own resources from the point of generation in the Kootenays to its major load centre in the Okanagan[79], to import power from IPPs and also provide economic benefits based on the ability to share generation operating reserves. These interconnections are discussed further in Section 6.1.3 below.

[79] FBC owns and operates a single 160 kV transmission line between the two regions and this line has insufficient capacity to supply the Okanagan load.

As a system overall, FBC is a winter peaking utility, and hence the transmission and distribution system has been designed and constructed to meet peak demand during extreme low temperature conditions. Although the trends are evolving, there is some evidence that in some areas of the system the summer peaks are growing faster than the winter peaks. Regardless, FBC does not expect that the overall system will become summer peaking within the foreseeable future.

FBC's transmission network consists of approximately 1,300 kilometres of high voltage transmission lines. Table 6-1, below, provides the length of overhead transmission lines by voltage class for each FBC region. Figure 6-1, further below, is a high-level overview of the FBC transmission network showing key transmission lines.

Table 6-1: Transmission Line Lengths by Region and Voltage Class (kilometres)

Region	63 kV	138 kV	160 kV	230 kV	Total
North Okanagan	0	120	0	114	234
South Okanagan	126	105	16	99	346
Kootenay	451	0	23	50	524
Boundary	83	0	103	0	186
Total	660	225	142	263	1,290

FBC's bulk transmission system is operated fully meshed[80] from Kelowna through to the Kootenay River generating stations, which improves system reliability and reduces transmission system losses.

[80] In a meshed system transmission lines to substations operate in parallel. As a result, if an outage occurs to one of the transmission lines supplying a substation, then an alternate line is immediately available to provide continued supply - no manual reconfiguration of the system is necessary and no customer outages occur.

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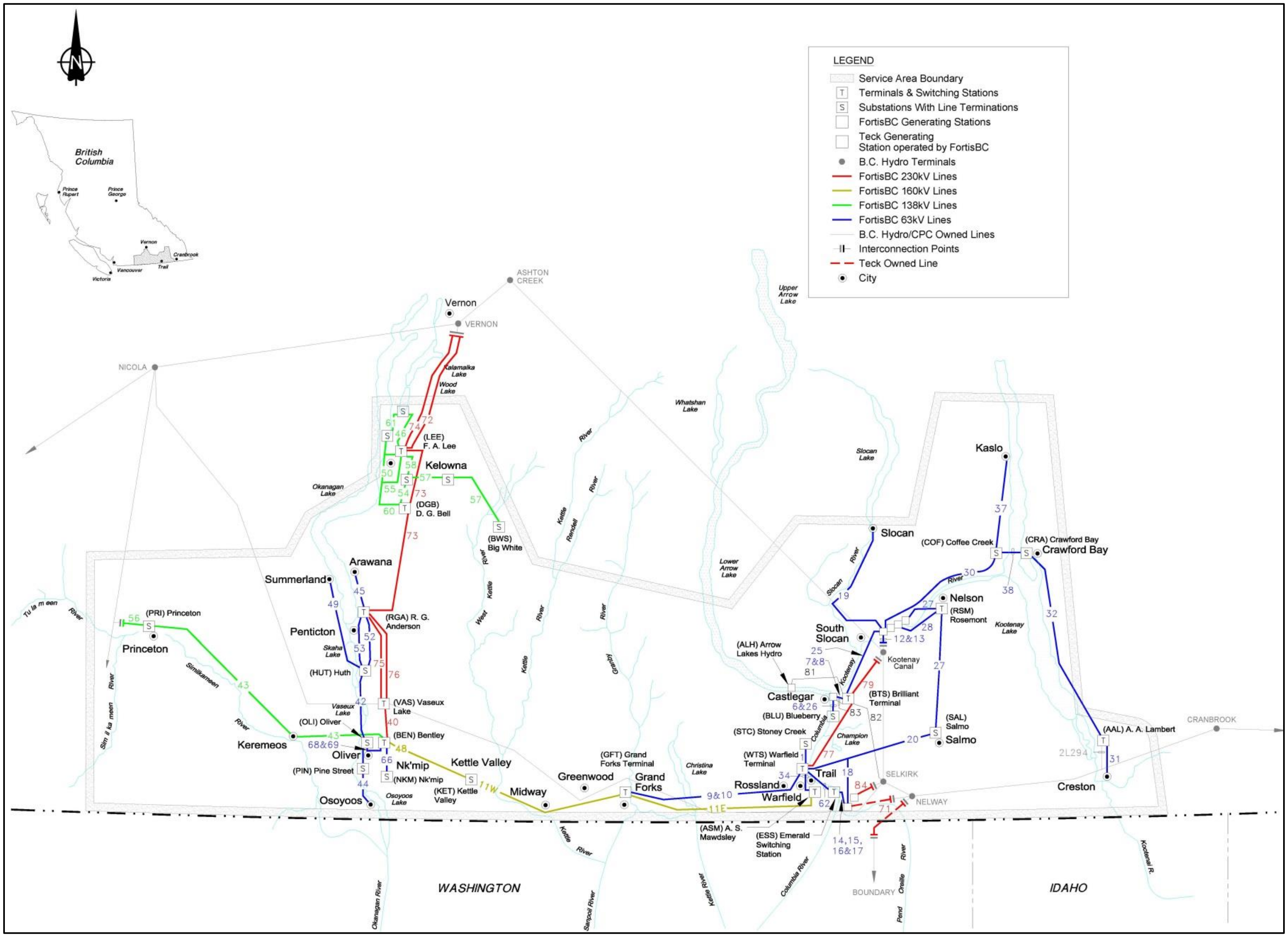
Figure 6-1: FBC Transmission System Map



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6.1.2 Transmission Interconnections

Transmission interconnections with neighbouring transmission entities enable FBC to import and export electricity from other members of the Western Interconnection[81]. This improves system reliability and has economic benefits for FBC by allowing the Company to access transmission and generation resources that it would not otherwise be able to access. Combined, there are eight transmission interconnections between the FBC system and other transmission entities.

As shown in Figure 6-1, the FBC system is connected to the following five major BC Hydro transmission stations:

- Kootenay Canal Generating Station (at 63 kV and 230 kV);
- Vaseux Lake Terminal Station (500 kV);
- Vernon Terminal Station (230 kV;
- Selkirk Substation (230 kV), and
- Nelway Substation (230 kV).

In addition, there are two lower capacity interconnections with BC Hydro at Princeton and Creston that are only used radially to supply local FBC load.

As noted previously, the only FBC-owned interconnection between the Okanagan and Kootenay networks is a single 160 kV transmission line. The two regional networks are quite different; the Okanagan region has 65 percent of the FBC load, while the remaining 35 percent is in the Kootenay region. All FBC generation resources are in the Kootenay region. The Okanagan region has no generation resources and thus all demand is met by external generation delivered either directly through FBC's system or wheeled via the BC Hydro network. As such, reliance on these transmission interconnections and the surrounding BC Hydro bulk transmission system is critical to reliable operations of the FBC system.

6.1.3 Recent System Upgrades and Expenditures

To ensure ongoing safe and reliable operation of the electric system, FBC undertakes both growth and sustainment capital investments in the transmission and distribution system on an annual basis. Some of the more significant transmission projects completed within the last five years include:

- The Okanagan Transmission Reinforcement (OTR) Project, which supplies reliable transmission service to the entire Okanagan region;

81 The Western Interconnection refers to the interconnected electric transmission grid which stretches from Western Canada south to Baja California in Mexico, and from the Pacific Coast reaching eastward over the Rockies to the Great Plains. All of the electric utilities in the Western Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency.

- A reconfiguration of the existing Huth Substation was completed to allow the parallel operation of 52L and 53L transmission lines in Penticton to increase capacity and reliability;
- Modified protection schemes to enable meshed operation of 42L between Penticton and Oliver to prevent voltage collapse following single contingency outages in the south Okanagan area;
- The addition of reactive compensation (63 kV capacitor banks) at Oliver to prevent voltage collapse following single contingency outages in the south Okanagan area; and
- The addition of the Ellison to Sexsmith Transmission Tie which provides a 138 kV loop between major substations in the north Kelowna area to improve reliability.

Table 6-2 below outlines capital expenditures during the period between 2011 and 2016.

Table 6-2: Transmission and Distribution Capital Expenditures 2011 – 2016 ($000s)

Expenditure Categories	2011A	2012A	2013A	2014A	2015A	2016P
Transmission, Stations, Protection & Control, Telecommunications	27,101	19,412	16,681	23,659	12,024	8,691
Distribution	26,434	25,994	60,866	34,121	28,409	24,052

6.2 *SYSTEM PLANNING METHODOLOGY*

6.2.1 Load Forecasting for System Planning

In order to ensure that FBC's network infrastructure is sufficient to provide a safe and reliable electricity supply to all customers, the transmission and distribution system must be planned, constructed, and operated to meet peak load requirements during extreme weather conditions. This contrasts with the resource planning requirement to acquire energy resources to meet energy and peak demand requirements under "normal" or "expected" weather conditions as set out in the reference case load forecast presented in Section 3.[82] Consequently, FBC requires and develops load forecasts for two different purposes: system planning (for transmission and distribution infrastructure planning) and resource planning (for system capacity and energy resource planning).

The system planning forecast is a per-substation forecast that is developed from the "bottom up" using historical per-feeder peak demand data. The per-feeder data is aggregated to the substation level and then by area for use in transmission and distribution infrastructure project identification and planning. The feeder and substation forecasts are based on actual demand peaks, which are typically recorded during weather extremes in the summer (June through

[82] This is also referred to as a "top-down" forecast since it presents the entire FBC system as a single load quantity.

August) and in the winter (November through February). The substation forecast forms the basis for the expected winter and summer peak loads in future years and is used to determine how much transmission, substation, and distribution infrastructure is needed to supply FBC's customers during peak demand periods.

Recognizing that these per-substation forecasts represent load peaks that may or may not occur at the same time, it is necessary when aggregating the per-substation forecasts to account for customer load diversity[83] within the system. This is achieved by forecasting the total system load from the "top down" under extreme (1 in 20 year) weather conditions, and then rationalizing the two forecasts by uniformly scaling the per-substation peak forecasts such that their total load matches the total winter and total summer peak loads given in the system load forecast. The result is a "1 in 20" peak demand forecast which is not the same as the "expected" peak demand forecasts shown in Section 3 of this LTERP.

The load forecast methodology for system planning purposes was reviewed in conjunction with FBC's 2012 Long Term Capital Plan, which was accepted by the Commission as part of the Company's 2012 Integrated System Plan (ISP) application.[84]

6.2.2 Transmission Planning Criteria

FBC's planning criteria require that the system be planned, designed and operated to serve all customer loads both during normal operations and during contingency operations (i.e. one or more system elements out of service). The most basic criterion is that the system infrastructure must be sufficient to meet all reasonably forecast customer demand with all system components (e.g. transmission lines and transformers) in service. This is referred to as "all elements in-service" or N-0[85] operation. The next, more limiting, condition is single contingency (N-1[86]) operations. FBC's planning criteria state that the transmission system infrastructure must also be sufficient to meet all reasonably forecast customer demand even with the single most limiting transmission component out of service. Exceptions are allowed for customer loads supplied radially by the faulted element or affected area. For double contingency (N-2[87]) and higher conditions, the criteria allow planned and controlled disconnection of customer loads. Remedial Action Schemes[88] may be employed during system operations to minimize the scope of customer outages for N-2 contingencies. These planning criteria are consistent with those used by other utilities in the Western Interconnection region.

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83 Diversity refers to the concept that the potential customer load always exceeds the actual demand at any given time. This is because usage patterns vary (i.e. heating loads are cyclical) and, as a result, not all customers consume energy at the same time. This diversity effect occurs not just from customer to customer, but also between rate classes; residential, commercial, irrigation, etc. have differing usage patterns. Consequently, different feeders and substations typically experience their peak loads at different times.

84 See BCUC Order G-110-12

85 N-0 refers to there being some number ("N") system elements, with zero of them out of service.

86 N-1 refers to there being some number ("N") system elements, with one (typically the most impactful) element out of service.

87 N-2 refers to there being some number ("N") system elements, with two elements out of service.

88 A scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation, tripping load, or reconfiguring a system.

The task of providing reliable and cost-effective electric service requires the ability to assess the reliability of performance of various system configurations. FBC transmission planners employ both deterministic and probabilistic methods to assess system reliability. The contingency analysis used in transmission system assessment is deterministic as the required infrastructure needs to be in place to meet the most adverse operating conditions. If necessary, probabilistic analysis is used for selecting the optimal solution once a need or constraint has been identified.

6.2.3 Transmission Planning Studies

The FBC transmission planning group conducts system studies to ensure that the system will continue to reliably meet capacity demand in the presence of growing customer load during the planning horizon used for these studies, typically 20 years. These studies are performed annually and result in the identification of transmission system upgrades required in the short term and medium term. The intent of these long-term studies is not necessarily to identify specific system upgrades but, rather, the system load levels at which a new set of reinforcement options must be considered. The results of these annual studies are shared with BC Hydro as the Balancing Authority[89] and to allow for coordination of the overall FBC and BC Hydro electrical system.

Transmission studies are based on computerized power flow and transient stability analyses conducted using power systems simulation software. In the current FBC study cycle, the power flow analysis was carried out for the years 2017, 2021 and 2025 both for winter and summer peak conditions. In addition, power flow analysis was performed for 2017 light load conditions. The transient stability analysis was carried out for the year 2017 winter peak, summer peak and light load conditions. Longer term studies of the bulk system beyond the 20-year planning horizon were also conducted to determine the potential need for future large transmission upgrades.

The power flow study includes an analysis of all possible single contingencies (N-1) in the FBC system. Thermal violations, or overloads, are recorded on elements that show a power flow exceeding 90 percent of their respective winter or summer emergency rating. Voltage violations are also flagged on system buses that show a voltage less than 90 percent or greater than 110 percent of nominal voltage. All buses at and above 63 kV in the FBC system and major 230 kV and 500 kV buses of neighboring systems are monitored in the study.

The transient stability study is based on simulations of three-phase and single-line-to-ground faults. Both normal fault clearing as well as the slower backup clearing is simulated, followed by the tripping of the faulted line. The dynamic performance of the system is assessed based on observations of post-fault behavior of important system quantities, such as generator rotor angle, power flows, bus voltages and system frequency. Analysis of post-fault oscillations in

[89] “The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.” Glossary of Terms Used in NERC Reliability - Updated October 1, 2014.

these studies will reveal how quickly the oscillations stabilize, leading to a quick system recovery from the disturbance.

An assessment of reactive power[90] capabilities is also necessary. As previously noted, the FBC system consists of two areas, the Kootenay region, with surplus generation, and the Okanagan, with a total absence of generation. The lack of dynamic reactive support in the Okanagan (due to absence of generation resources which can respond to load changes in real-time) can lead to low voltages or voltage collapse during contingency conditions.

Each thermal or voltage violation found in the studies is then analyzed in order to define the most cost-effective mitigation plan. These studies identify a collection of transmission reinforcement projects that are required within the 20 year planning horizon.

Projects are identified as the system reaches various load thresholds to mitigate violations and for continued reliable and operations. It must be noted that the timing for projects change as annual studies are completed with updated information. Longer term projects will be subject to further review as load growth trends become more certain in the future.

6.3 *ANTICIPATED SYSTEM REINFORCEMENTS*

FBC filed a Long Term Capital Plan in June 2011, which identified short term (2012-2013), medium term (2014-2016) and long term (2017 onward) transmission projects. The timing of projects is assessed annually based on the updated load forecasts and consequently the timing of some projects may either be advanced or delayed.

At the present time, only two transmission reinforcement projects have been identified within the 20-year planning horizon; in both cases these projects were intended to be the subject of future CPCN applications. These are shown below in Table 6-3. The locations of these projects are shown in Figure 6-2 below.

Table 6-3: Transmission Reinforcement Projects

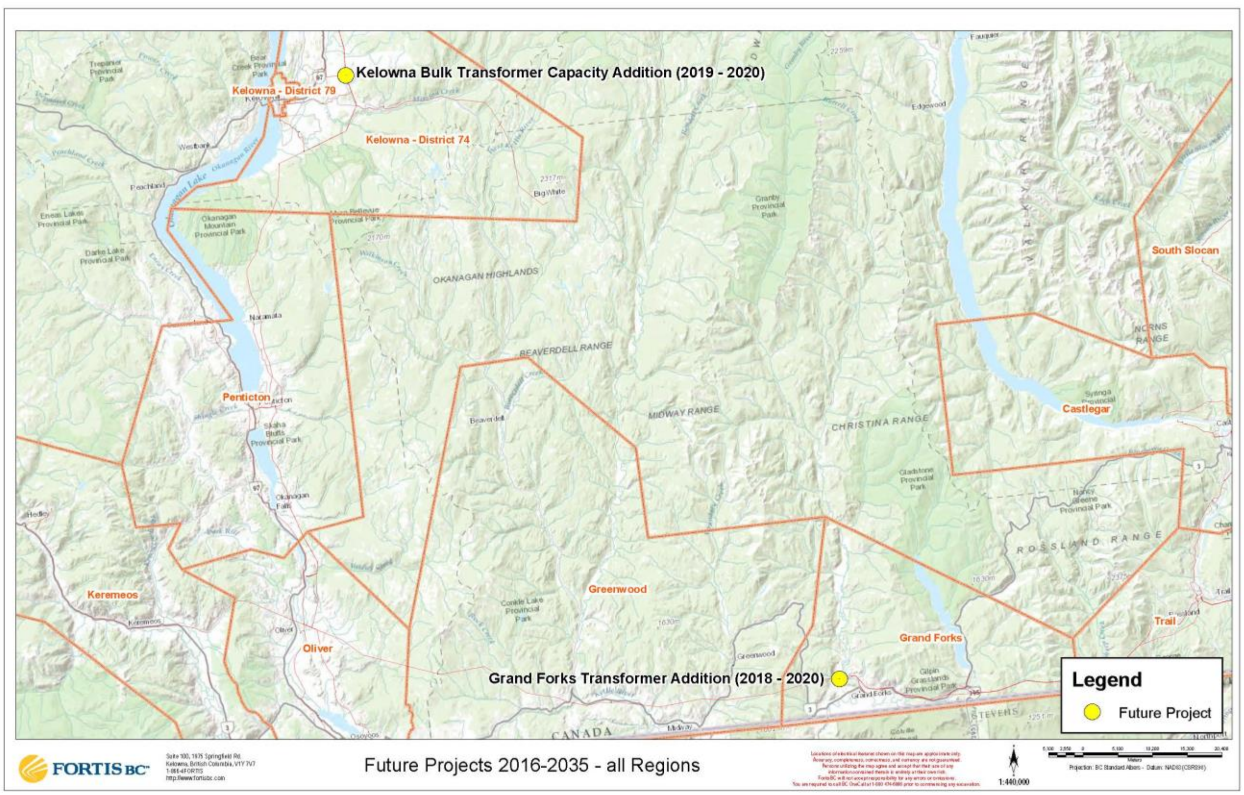
Time Frame	Project	Purpose	Primary Driver	
			Capacity	Reliability
2018-2020	Grand Forks Terminal Transformer Addition	Add a second terminal transformer to maintain adequate single-contingency reliability for load in the Grand Forks area.		X
2019-2020	Kelowna Bulk Transformer Capacity Addition	Add additional 230/138 kV transformation capacity in Kelowna to adequately supply area load	X	X

[90] Reactive power flow occurs in power systems containing reactive (inductive or capacitive) components and can be either produced or consumed by different load/generation elements.

As discussed above, changes in load forecasts may result in the advancement or deferral of some projects. This has occurred in the case of the Kelowna Bulk Transformer Capacity Addition Project. Until recently, system studies indicated that this project would be required due to equipment loading constraints during winter peak load conditions. In the 2014 PBR application this reinforcement project was identified as required by 2019 and was to be the subject of a future CPCN. Subsequent to the PBR application, as the winter load forecasts decreased, studies indicated that the project would not be required until the mid-2020s.[91] However, updated summer peak load forecasts and the constraints associated with equipment emergency loading limits now indicate that this project or an alternative project or resource[92] may be required sooner.

The other reinforcement project listed in Table 6-3 is the addition of a transmission transformer at the existing Grand Forks Terminal. This project was originally proposed in the 2012 Long Term Capital Plan. FBC is assessing this project and other solutions to address the reliability issues associated with aging transmission lines which are used to provide a reliable backup supply for the Grand Forks area.

Figure 6-2: Location of Transmission Reinforcement Projects



[91] In the Application for Approval of Treatment for Major Project Capital Expenditures under the Multi-Year Performance Based Ratemaking Plan for 2014-2019, FBC indicated that the Kelowna Bulk Transformer Capacity Addition was deferred beyond PBR Term.

[92] Project alternatives that could be considered include the addition of a third bulk transmission transformer, reinforcement of existing transmission lines, or adding a generation resource in the Kelowna area.

6.3.1 Impacts of Supply-Side Resource Options

FBC considers supply-side resource option location assumptions to determine transmission and distribution requirements as part of the LTERP development process. Regardless of the location, supply-side resources included in the LTERP typically require some amount of local transmission and distribution improvements to allow them to interconnect with FBC's electrical system.

The most impactful resource addition currently identified would be the integration of a new large-scale generation resource, such as a gas-fired generation plant, within the Kelowna 138-kV sub-transmission network. This is because this resource could defer the requirement for the proposed third 230/138-kV bulk transformer at the Lee Terminal in Kelowna (as discussed in section 6.3).

6.4 POTENTIAL IMPACTS OF NEW LOAD/GENERATION TECHNOLOGIES

As part of the system planning process associated with the development of the LTERP, FBC has explored the potential impacts from various load drivers and scenarios that could materialize in the future (see Section 4). The potential impacts from these load drivers on the transmission and distribution system are discussed in this section. While the increase or decrease in peak load requirements resulting from these scenarios has implications for transmission and distribution system planning, the potential impact of the individual load drivers is also important. Two load drivers in particular which could have significant impacts are distributed generation and electric vehicles.

6.4.1 Distributed Generation

Currently, FBC has approximately 110 Net Metering Program customers with Distributed Generation (DG) facilities (mostly rooftop solar PV installations) interconnected on the distribution system.[93] Combined, these facilities represent less than 1 MW of non-firm generating capacity, which is less than 0.5 percent of the approximate 225 MW firm generating capacity of FBC's four hydroelectric generating plants. As a result, the near-term impacts of existing DG facilities on transmission and distribution grid operations and reliability are currently relatively low.

However, the pace of FBC DG interconnections has increased over the past few years. Recent studies predict further cost declines in solar PV and associated increases in solar PV penetration rates. Additionally, provincial or federal incentives and/or federal tax credits, *CEA* or RPS legislation or feed-in tariffs for the purchase of renewable generating capacity from small facilities could make solar PV more cost-effective for customers. Further study will be required to ensure that potential system impacts and necessary mitigation are understood and addressed in the FBC system.

[93] FBC also has two interconnected independent power producers (one transmission and one distribution) which use FBC facilities to wheel generated power to BC Hydro.

DG facilities could provide value if they are able to generate electricity during peak demand times. This is beneficial because it could reduce the need for FBC to purchase energy from BC Hydro or other parties and decrease transmission line congestion. By meeting customer electricity needs closer to the point of consumption, DG facilities could reduce FBC incremental resource requirements and reduce loading on distribution and transmission lines. However, for DG systems to operate in this way, they must be interconnected, controlled, measured and operated as an integral part of the FBC electricity system.

Notwithstanding the limited impacts given current adoption rates, the potential future impacts on transmission and distribution system planning and operations are more complex. Intermittent renewable generation creates many new challenges not experienced with conventional distributed generation. Distributed solar PV increases the complexity of managing voltage regulation on circuit feeders due to its intermittent nature. These facilities will have increasing impacts on the distribution system first and then the transmission system later as DG growth continues.

The extent to which DG affects power losses and voltage profiles depends on the type of DG technology, penetration levels, and the location of its connection to the grid. Depending on its location, the integration of DG can reduce power losses on the transmission and distribution network, but as the penetration level increases, the power losses may begin to increase.

If DG uptake increases significantly in the near future, FBC transmission and distribution planners will need to have the tools and knowledge for planning and modeling a high-penetration of solar PV or other DG technology into the system. Alternative engineering designs, technology solutions, and new and updated planning and operations practices may be needed for the FBC transmission and distribution system of the future.

6.4.2 Electric Vehicles

Currently, EV uptake within FBC's service territory has been limited, however FBC is monitoring charging station installations and will analyze the impact on its distribution networks.

The peak demand imposed by a Plug-in Hybrid Electric Vehicle (PHEV), Extended Range Electric Vehicle (EREV) or Battery Electric Vehicle (BEV) on the grid depends on the size of the on-board battery, the owners' driving patterns, the charging strategy and the charger characteristics. The more powerful chargers will result in much higher demand than that imposed by charging through a conventional 120 V outlet. Several electric vehicles on one residential street could overload the local distribution transformer unless demand management measures are implemented to enforce load diversity and prevent a possible overload.

Connecting BEVs (on Level 2 chargers) to the infrastructure in many older neighborhoods requires planning and support from FBC. Transformer and conductor capacity in these areas could be an issue. Increasing the capacity of several transformers on a circuit may not be sufficient to address all issues, and a circuit rebuild may be required to mitigate overloaded conductors.

The Electric Power Research Institute (EPRI) has analyzed distribution system impacts of Plug-in Electric Vehicle (PEV) charging and, in its report[94], concluded that:

- Diversity of vehicle location, charging time, and energy demand will minimize the impact on utility distribution systems;
- Level 1 (standard residential voltage; no extra cost) charging generates the fewest distribution system impacts;
- Higher power (Level 2) charging generates stronger system impacts and is typically not required for most customer charging scenarios with light duty vehicles;
- Short-term PEV impacts for most utility distribution systems are likely minimal and localized to areas where the available capacity per customer is already low; and
- Controlled or managed charging could defer system impacts for a significant period of time.

FBC intends to use the recommendations from the EPRI study as a guide. The potential stresses on the electric grid can be mitigated through asset management, system design practices, and, to some degree, managing the timing of charging PEVs to shift the load away from system peak. A proactive FBC approach that includes understanding where PEVs are appearing in the system, addressing near-term localized impacts, and developing both customer programs and technologies for managing long-term charging loads will effectively and efficiently support PEV adoption.

6.5 SUMMARY

FBC plans, constructs and operates its transmission and distribution system to safely and reliably deliver electricity to customers throughout the Company's service area under reasonably foreseen operating conditions and weather extremes. To accomplish this, FBC develops substation load forecasts, conducts computer-based system modelling and coordinates system planning and operations with neighbouring transmission entities. Infrastructure reinforcements are identified when load forecasts indicate that the system has insufficient capacity to meet planning criteria during normal or contingency operations.

The future system impacts of new technologies such as distributed generation and electric vehicles are uncertain at this time and will depend on the rate of adoption by customers. To date, uptake rates have been low and hence the system impacts have been minimal. FBC will continue to follow industry research and adopt new practices and guidelines to integrate new technologies into the system as they become more prevalent.

[94] Electric Power Research Institute "Transportation Electrification: A Technology Overview", July 2011. http://www.smartgridinformation.info/pdf/4525_doc_1.pdf, Pages 1-4.

7. LOAD-RESOURCE BALANCE

This section identifies the LRB before incremental demand-side and supply-side resources are included to determine if there are any energy and/or capacity gaps over the planning horizon. This is done by comparing the long-term reference load forecast to the existing and committed resources in FBC's portfolio. The comparison will identify any LRB gaps that need to be filled with DSM and/or supply-side resource options.

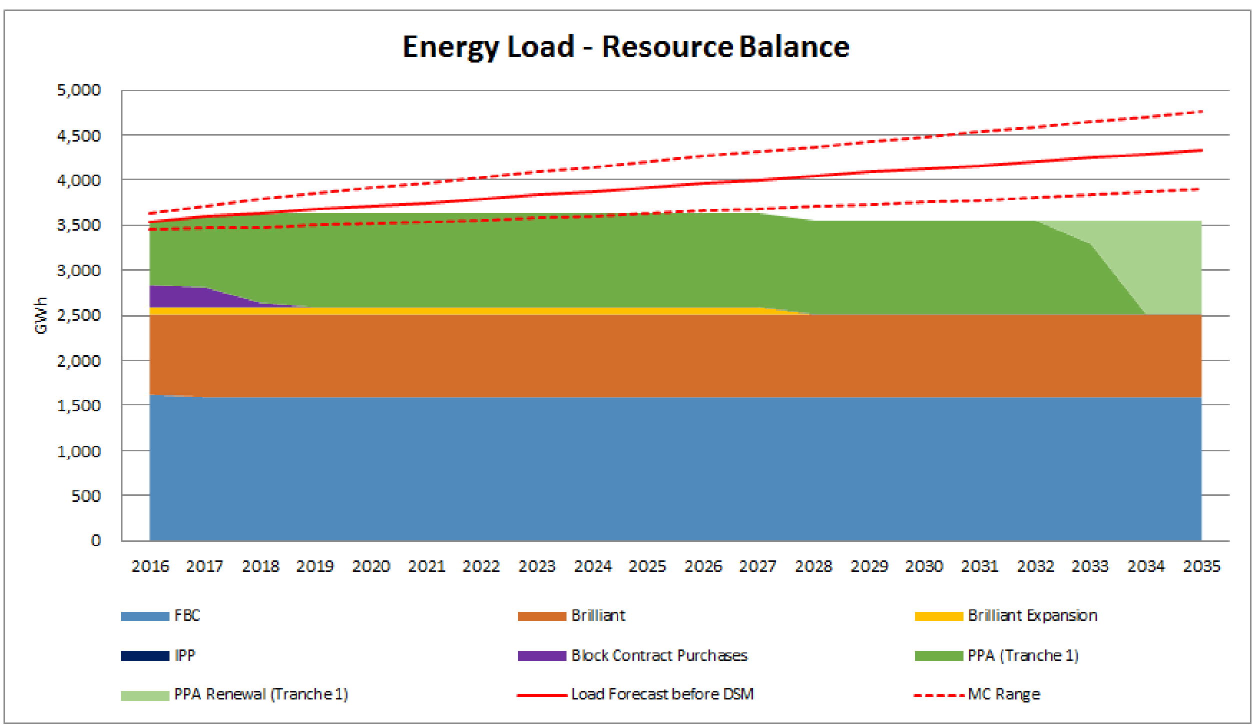
Section 8.1 identifies the DSM resources that FBC proposes to apply to the LRB gap and the resulting after-DSM LRB which shows the remaining gaps to be filled with supply-side resource options. The portfolio analysis (Section 9) evaluates several alternative portfolios including DSM and supply-side resources to meet any future energy and capacity gaps. This approach is consistent with the BCUC Resource Planning Guidelines described in Section 1.4.2.

The annual energy LRB is presented first in Section 7.1, below, followed by the capacity LRB in Section 7.2. The LRBs have been developed using the long-term reference load forecast discussed in Section 3 and the existing/committed resources discussed in Section 4. The resource options considered to meet any LRB gaps are discussed in Section 8.

7.1 *ENERGY LOAD-RESOURCE BALANCE*

The following figure illustrates the annual energy load-resource balance and potential gaps over the 20-year planning horizon.

Figure 7-1: Annual Energy Load-Resource Balance (GWh)



The red line in the figure above represents the reference case load forecast, including the impacts from other savings, but before new DSM resources. The dashed red lines represent the Monte Carlo range for the reference case load forecast, as discussed in Section 3.4.

The coloured areas in Figure 7-1 represent FBC's existing and committed supply-side resources (which are discussed in Section 5).

A number of assumptions regarding FBC's current long-term energy supply contracts have been made for the purposes of the resource stack in the LRB.

With respect to the PPA with BC Hydro, FBC has assumed that, in the base case, the agreement is renewed and continues beyond the September 2033 expiration date. As part of the scenario analysis in Section 9, FBC has developed a scenario which includes non-renewal of the PPA. Therefore, in the figure above, the PPA is shown in dark green until 2033 and a lighter green beyond that. As discussed in Section 5, FBC has assumed that the Brilliant Expansion contract is extended to 2027 and discontinues after that.

With regard to the BC Hydro PPA, it is also important to note that the figure reflects PPA Tranche 1 Energy available to FBC up to the maximum of 1,041 GWh. In the portfolio analysis, discussed in Section 9, the portfolio model will optimize the amount of PPA Tranche 1 Energy with the other resource options available to FBC and, as a result, the maximum Tranche 1 Energy available may not always be selected within the various alternative portfolios. PPA Tranche 2 Energy is also available to FBC but at a much higher cost, as discussed in Section 5. Based on the supply-side resource options presented in Section 8.2, FBC expects that it would be able to build or contract for new energy resources at a lower cost than the PPA Tranche 2 Energy cost. For this reason, the energy LRB is presented here with only the PPA Tranche 1 Energy amount.

For the first few years in the LRB figure, the amount of PPA Tranche 1 Energy has been reduced slightly to match FBC's energy load requirements. If the PPA Tranche 1 Energy was included at the maximum amount of 1,041 GWh per year, FBC would have excess energy. This excess energy would be very difficult to manage in a cost effective manner under the terms of the PPA, which restrict FBC exports. Instead, FBC would reduce its PPA Tranche 1 Energy take from BC Hydro so that energy surpluses do not occur.

Figure 7-1 shows that, even if the PPA is renewed, there are gaps starting in 2019 based on the reference case forecast increasing to about 900 GWh by 2035. If the PPA is not renewed, then the gaps are more significant after 2033, increasing to almost 2,000 GWh per year by 2035 for the reference case. At the low end of the Monte Carlo range, this gap is about 400 GWh smaller. The portfolio analysis in Section 9 discusses options for meeting these gaps.

7.2 *CAPACITY LOAD-RESOURCE BALANCE*

The following figure illustrates the annual capacity load-resource balance and potential gaps over the 20-year planning horizon before any new DSM. The capacity requirements, which are represented in the figure by the solid and dashed red lines, are based on FBC's peak demand requirements during each year's winter period.

Figure 7-2: Capacity Load-Resource Balance (MW)

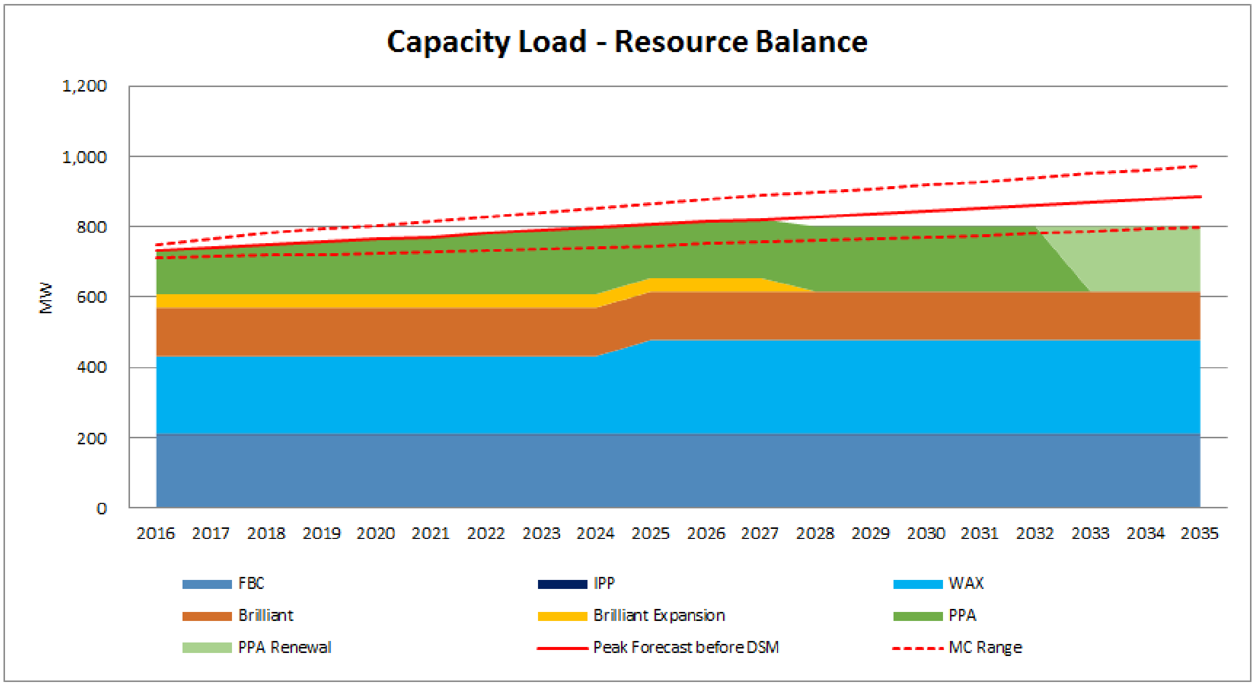


Figure 7-2 includes FBC generation, the Brilliant contract, BRX capacity, PPA capacity and WAX CAPA, the latter of which provides up to 200 MW of capacity to the portfolio. The WAX CAPA is presented net of the RCA sale of 50 MW to BC Hydro until 2024 and therefore increases after 2024 when the RCA expires. The Brilliant Expansion contract is assumed to be renewed until 2027 after which time it expires. This capacity LRB figure assumes that 200 MW of capacity is available to FBC from the PPA, but can be reduced if not required to meet the load forecast. Therefore, to avoid surplus capacity, the figure reflects FBC reducing the amount of the capacity it would take under the PPA during the first ten years so that its resource portfolio matches the peak capacity load requirements. As with the energy LRB figure, Figure 7-2 also assumes the renewal of the BC Hydro PPA in 2033.

Figure 7-2 shows that, based on the reference case forecast, minimal capacity gaps start in 2028 and increase up to about 100 MW by 2035 if the PPA is renewed. There are no gaps at the low end of the Monte Carlo range. More significant gaps, in the order of 300 MW, appear if the PPA is not renewed based on the reference case forecast.

The following sections describe the demand-side and supply-side resource options available to meet the forecast energy and capacity gaps.

8. RESOURCE OPTIONS

FBC has a number of different resource options to meet the future energy and capacity needs of its customers. These include demand-side as well as supply-side resource options. Demand-side resource options are typically more cost-effective than new supply-side resource options and enable customers to reduce their energy consumption, thereby reducing their energy costs. Accordingly, FBC looks to demand-side resources first to meet any future LRB gaps. In this LTERP and in the LT DSM Plan, FBC has evaluated different levels of DSM to meet future load growth. These are discussed in Section 8.1 below. Customer load that cannot be met with demand-side measures must then be met with supply-side resource options, which are discussed in Section 8.2. FBC includes a discussion of why all load growth is not met with DSM in Section 8.1.4 below.

The table below (Table 8-1) summarizes the unit costs for the demand-side and supply-side resource options FBC has considered to meet the energy and capacity gaps that are forecast to arise over the planning horizon. The unit energy cost (UEC) and unit capacity cost (UCC) for the resource options are presented in real $2015 dollars based on a 6 percent weighted average cost of capital (WACC) discount rate (DR) (as discussed in Section 8.2.2.2). The resources in the table are sorted by DSM (in yellow), PPA (in green), market (in orange) and supply-side generation (in blue). More details, including available energy and capacity and environmental and socio-economic attributes of the various resource options, are provided in the following sections.

Table 8-1: FBC Demand-Side and Supply-Side Resource Options

Resource Option	UEC ($/MWh)	UCC ($kW-year)
Base DSM	$88	N/A
High DSM	$104	N/A
Max DSM	$114	N/A
PPA Tranche 1 Energy	$47 - $56	N/A
PPA Tranche 2 Energy	$85 - $130	N/A
PPA Capacity	N/A	$96 - $115
Market Purchases	$34 - $64	$169 - $355
Wood-Based Biomass	$118 - $188	$663 - $774
Biogas	$77 - $101	$621 - $838
Municipal Solid Waste	$134	$1,031
Geothermal	$132 - $217	$857 - $1,506
Gas-Fired Generation (CCGT)	$82 - $100	$147 - $279
Similkameen Hydro Project	$202	$1,298
Gas-Fired Generation (SCGT)	N/A	$80 - $143
Pumped Hydro Storage	N/A	$217
Onshore Wind	$111 - $145	$1,219 - $1,618
Run-of-River Hydro	$87 - $150	$1,230 - $1,924
Solar	$169 - $184	$1,399 - $1,413

FBC has not included DG supply from net-metering customers in this table. FBC does not treat DG supply in the same manner as other generation resource options. This is because the availability of DG in the future is not predictable or within FBC's control to operate or call upon on demand when needed. As discussed in the FBC Net Metering Program Update Application dated April 15, 2016: "The Company does not consider small-scale customer-owned renewable power to be a secure or reliable firm resource".[95] FBC has treated DG as a potential load driver within the load scenarios, as discussed in Section 4, rather than as a resource option.

FBC has also not included power supply from self-generators within FBC's service area in the table above. This is because FBC does not have any information regarding available energy or capacity, timing or cost related to any self-generation supply at this time. However, FBC would consider purchases from self-generators if FBC needed the supply and it met FBC's LTERP objectives and other criteria for supply as outlined in Section 8.2.8.

FBC has included market purchases in the table above. While they are a reliable and secure source of energy supply in the short to medium term, there are risks with relying on market supply for the long term as discussed in Section 8.2.4.

[95] FBC Net Metering Program Update Application dated April 15, 2016, page 11.

The various demand-side and supply-side resource options available to FBC are discussed in the following sections. Different DSM levels are discussed in Section 8.1, while supply-side resource options are discussed in Section 8.2.

8.1 *DEMAND-SIDE MANAGEMENT*

This section summarizes the DSM level scenarios considered for this LTERP, which are discussed in detail in Section 3 of the LT DSM Plan, including the load reductions provided by different levels of DSM over the planning horizon.

8.1.1 DSM Levels

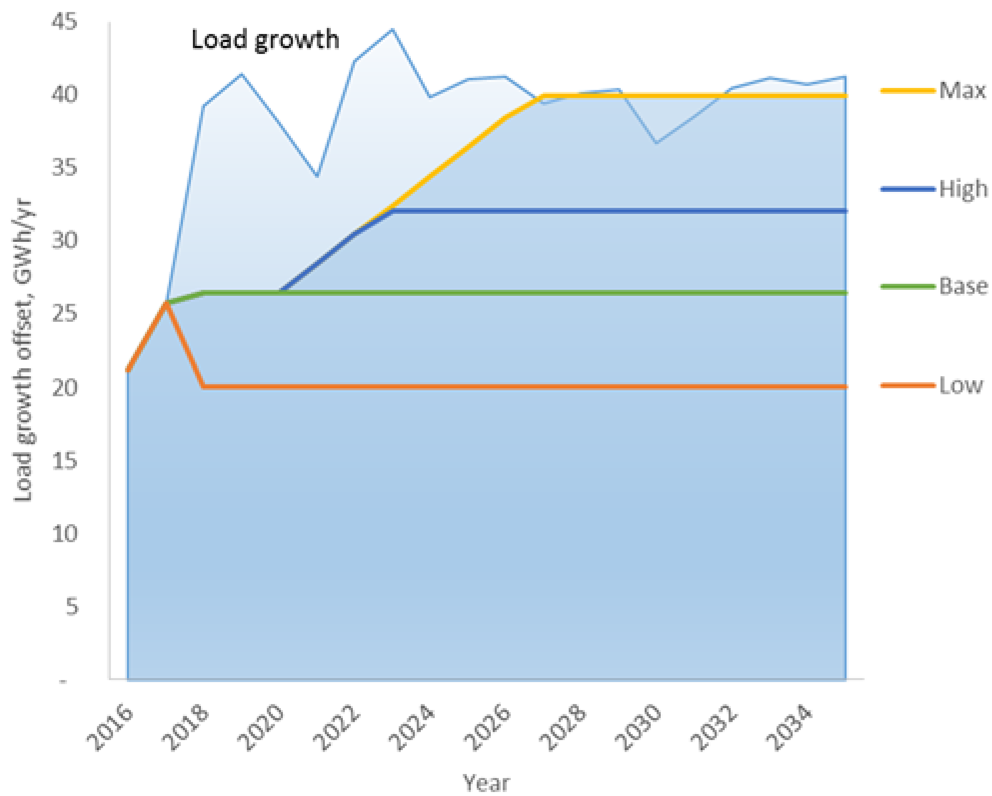
FBC assessed several different levels of DSM load growth offset to help meet future LRB gaps. The 2007 BC Energy Plan referenced a DSM target of 50 percent while the *CEA* provides a target of at least 66 percent of load growth. Although both targets were only stated to apply to BC Hydro, FBC adopted the 50 percent DSM offset target in its 2012 LTRP (50 percent is considered the Low scenario in the current LT DSM Plan) and is using the 66 percent DSM offset target as its Base DSM scenario in the LT DSM Plan. The Base scenario represents approximately the same level of target savings that was approved pursuant to FBC's 2016 DSM Plan and that was provided for in the 2017 DSM Plan filing and so could be characterized as a continuation of the current plan.

The High scenario is a midpoint scenario between the Base and Maximum (Max) scenarios. The High scenario begins with 66 percent load growth offset from 2018 to 2020 and then, after 2020, starts ramping up to 80 percent load growth offset by 2023 to optimize greater utilization of PPA Tranche 1 Energy before energy LRB gaps appear in 2025. Over the planning horizon, the High scenario averages 77 percent load growth offset. The LRMC used in the evaluation of DSM amounts supports the increase from FBC's current DSM offset level of 66% up to 80% by 2023 as the LRB gaps are approached.

The Max DSM scenario exhibits a similar ramp-up to 100 percent annual average load growth offset, resulting in an average offset of 89 percent over the planning horizon.

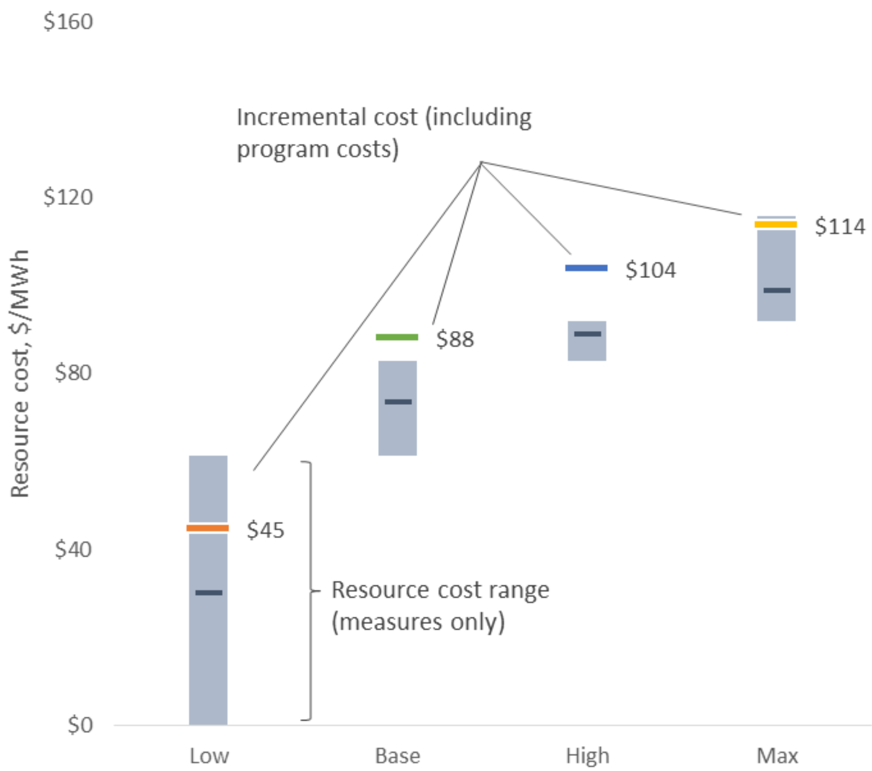
The following figure shows the proposed roll-out of the four DSM scenarios FBC considered, against the backdrop of the Company's gross reference case load forecast annual growth.

Figure 8-1: DSM Scenarios



The next figure below illustrates the supply cost curve of the DSM scenarios FBC considered. Each DSM scenario draws from a portfolio of measures, sourced from the FBC CPR results that have a range of resource costs. The incremental cost of each DSM scenario increases as higher cost DSM resources are tapped to achieve a higher percentage of load growth offset with DSM. A proxy for DSM program implementation costs is added to the average incremental measure (i.e. tranche) costs to estimate the total cost of acquiring DSM as a resource for each of the scenarios.

Figure 8-2: Cost of DSM Scenarios



The DSM costs provided here are based on the Total Resource Cost (TRC) metric which is the governing test used to determine the cost-effectiveness of a utility's DSM portfolio. The TRC comprises of benefits (the present value of the measures' energy savings, over their effective measure life, valued at the utility's avoided costs) divided by the costs (incremental cost of the measures plus program administration costs). The TRC can be expressed on an individual measure basis, for a program (group of measures), on a sector level and/or at the portfolio level. More details are provided in Section 2.4 of the LT DSM Plan.

The following Table 8-2 shows key DSM Scenario data, including the percentage of forecast load growth to be offset by DSM and the sum total of annual DSM savings to be targeted over the planning horizon.

Table 8-2: Key DSM Scenario data

Category	DSM Scenario			
	Low	Base	High	Max
Annual Savings, GWh				
Average per annum ('18-'35)	20	26	31	36
% of load growth ('18-'35)	50%	66%	77%	89%
Total (2016 to 2035)	407	523	602	686
Resource Cost, 2016 $/MWh				
Incremental cost incl. program costs	$45	$88	$104	$114

The High DSM scenario is FBC's preferred option for the LT DSM Plan. The incremental cost for ramping up to the High scenario of $104 per MWh is similar to the LRMC for clean or renewable B.C. energy of $100 per MWh, discussed in Section 9.4.1. Thus, it includes the majority of cost-effective DSM from an LRMC perspective. Furthermore, ramping up to 80 percent of load growth by 2023 will mitigate some of the opportunity cost of offsetting the relatively inexpensive PPA in the near term and provides higher DSM levels close to when LRB gaps are expected to appear, as discussed in the next section.

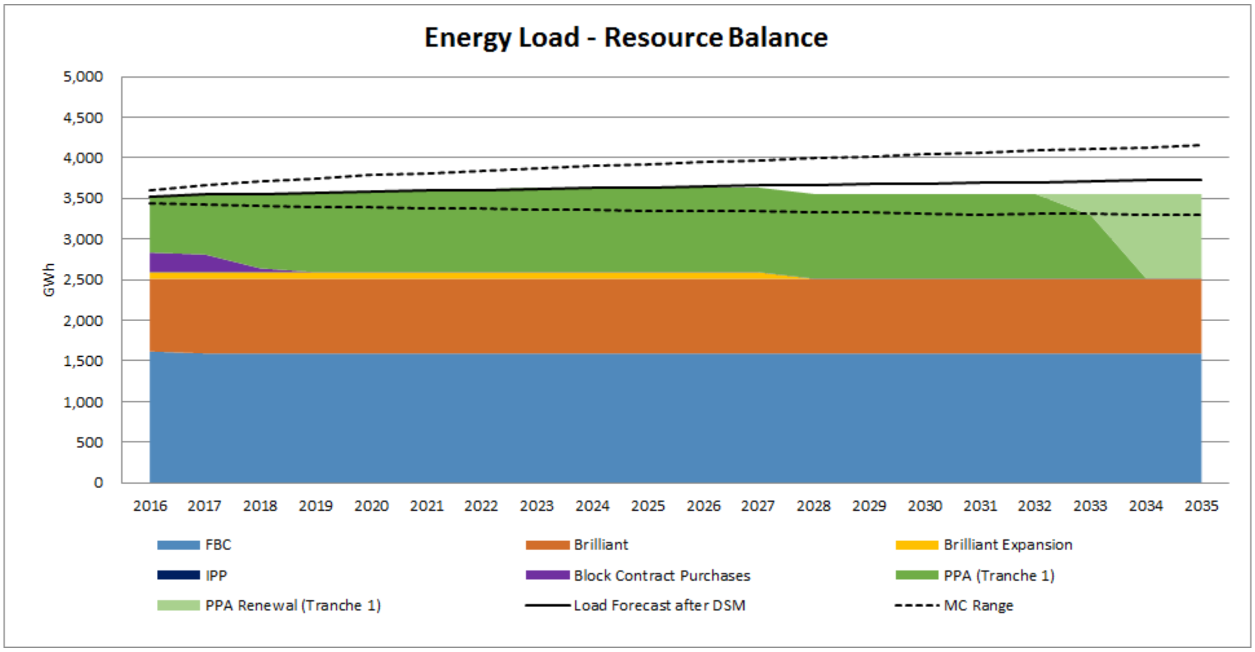
8.1.2 Load-Resource Balance after DSM

This section of the LTERP addresses Section 44.1(2)(c) of the *UCA*, which requires FBC to include an estimate of the demand for energy that it expects to serve after taking cost-effective demand side measures.

8.1.2.1 Energy Load-Resource Balance after DSM

The following figure shows the LRB for annual energy after netting off the proposed level of DSM savings in the High scenario from the reference case load forecast.

Figure 8-3: Energy Load-Resource Balance after DSM



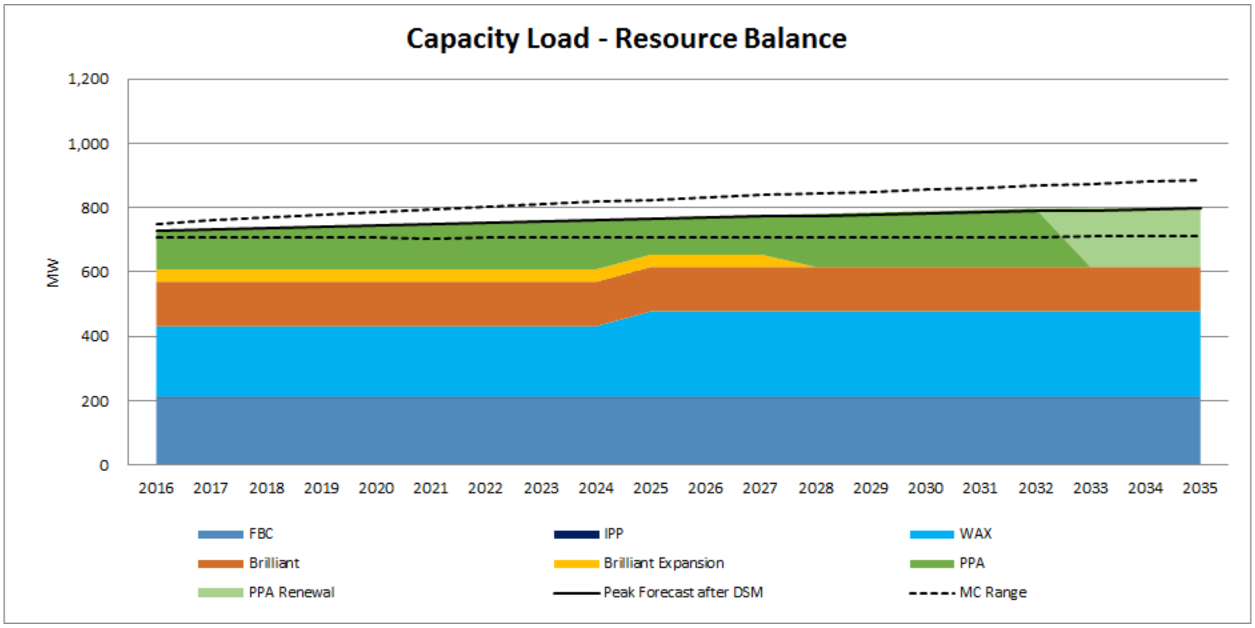
The dashed lines in the figure above show the Monte Carlo range for the reference load forecast after the high level of DSM. The solid line in the figure above shows that, with the high level of DSM, there are no energy gaps out to 2024. Slight gaps start in 2025, which increase to almost 200 GWh by 2035 if the PPA is renewed. The ramping up of the DSM load growth offset from 66 percent after 2020 to 80 percent by 2023 enables FBC to use more cost-effective PPA Tranche 1 Energy and market purchases than if the DSM offset level was not ramped up but rather started at the 77 percent target average immediately in 2018.

If the PPA is not renewed, then the gaps after 2033 are more significant, increasing up to about 1,200 GWh per year by 2035. The low end of the Monte Carlo range indicates that no new resources are required and surpluses of capacity will occur if the maximum amount of PPA Tranche 1 Energy is used. At the high end of the Monte Carlo range, the energy gaps occur throughout the next twenty years and increase to about 600 GWh by 2035 if the PPA is renewed.

8.1.2.2 Capacity Load-Resource Balance after DSM

The following figure shows the LRB for peak capacity during the winter after netting off the high level of DSM from the reference case forecast.

Figure 8-4: Capacity Load-Resource Balance after DSM

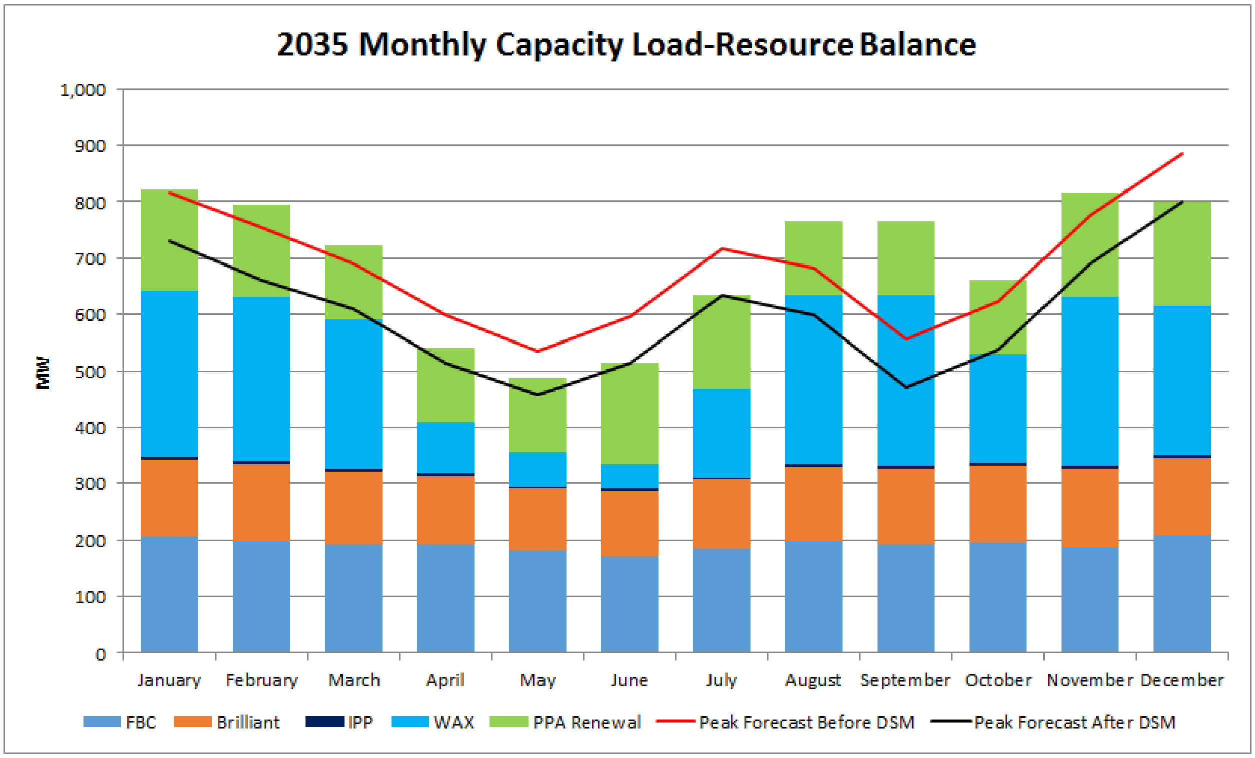


The figure above shows that with the High scenario level of DSM offsetting about 56 percent of future peak load growth, there are no gaps that need to be filled if the PPA is renewed based on the reference load forecast peak after DSM. In fact, based on the peak load forecast after DSM, there would be surpluses of capacity for most years if the PPA is assumed to provide its full peak supply of 200 MW. However, the figure reflects the reduction in the PPA to match what is required to meet the peak demand forecast. If the PPA is not renewed, then gaps on the order of about 200 MW occur in the period from 2033 to 2035.

At the low end of the Monte Carlo range, assuming PPA renewal, the PPA would have to be reduced further to avoid surplus capacity throughout the entire planning horizon. On the high end of the Monte Carlo range, capacity resources would be needed each year, increasing to about 170 MW by 2035.

FBC also examines the LRB on a monthly basis to see if there are any capacity gaps in months other than for the winter peak period, such as during the summer months. The following figure shows this monthly LRB for 2035, the last year in the planning horizon, when the gaps are at their highest levels. The figure shows the peak forecast both before and after the High level of DSM. The figure assumes that the PPA is renewed.

Figure 8-5: Monthly Capacity Load-Resource Balance for 2035, Before and After DSM



The figure above shows the full PPA capacity available so that surpluses, as well as any gaps, can be identified. It shows that for most months there will be surplus capacity if the PPA capacity take is not reduced (assuming PPA is renewed). These surpluses are at their largest in September. It also shows that there are some months where slight deficits, or gaps, occur. These gaps occur in June and July and are minimal amounts of about 1 MW in each month.

As the previous figures show, there are minimal gaps for peak capacity if the PPA is renewed beyond 2033. Therefore, the main focus for FBC in filling any gaps will be related to energy.

8.1.3 Why Supply-Side Resources are Needed

This section of the LTERP addresses section 44.1(2)(f) of the *UCA*, which requires a long term resource plan to include an explanation of why the demand for energy to be served by supply-side resources are not planned to be replaced by demand-side measures.

The proposed High level of DSM offset discussed above and in Section 3 of the LT DSM Plan satisfies the requirement to provide cost-effective DSM. The average cost of the high DSM offset level is \$104 per MWh, which is similar to the DSM cost-effectiveness threshold LRMC of \$100 per MWh. Implementing higher levels of DSM than this would require higher-cost DSM with marginal costs averaging \$114 per MWh, which would increase rates for customers. This is reflected in Section 9.4.1, which shows that the LRMC for the portfolio with the Max DSM level is higher than the portfolio with the High level of DSM.

Furthermore, DSM levels higher than the High scenario create risks in terms of managing the LRB. DSM is neither available on demand nor as reliable as a supply-side resource option because DSM programs require voluntary participation by customers. Therefore, there is no guarantee that actual DSM program uptake will materialize as planned and an over-reliance on DSM could leave unexpected gaps in the LRB that still need to be filled to meet customer load requirements.

Based on this analysis and discussions in Section 3 of the LT DSM Plan, FBC considers the High level of DSM to be appropriate. FBC does not believe it would be prudent to replace additional supply-side resources with more DSM to meet forecast load over the planning horizon.

The next Section 8.2 will discuss the supply-side resource options FBC has considered to meet the remaining customer load requirements.

8.2 SUPPLY-SIDE RESOURCE OPTIONS

8.2.1 Overview

This section discusses the various supply-side energy and capacity resource options that are available to FBC to meet any load-resource balance gaps over the 20 year resource planning horizon covered by this LTERP. These options include resources that could potentially be available either within or outside of FBC's service area. Resources from outside the FBC service area would require external transmission arrangements to serve FBC load. Potential resource options include several types of generation, as well as market purchases and supply from larger, industrial self-generating customers. Distributed generation, available from residential or commercial customers self-generating their own electricity, can also be considered a form of supply. More details regarding the resource options discussed in this section are provided in the Resource Options Report (ROR) in Appendix J.

The supply-side resource options discussed in this section and in the ROR are included, along with demand-side resource options discussed in Section 8.1, in the portfolio analysis provided in Section 9. The technical, financial, environmental and socio-economic characteristics of various resource options are also included in this section to help evaluate portfolios to meet future load-resource balance gaps.

The resource options information is provided at a level appropriate for long term resource planning. If and when particular resources are required in the future, Commission approval will be obtained by way of applications for approval of CPCNs or acceptance of energy supply contracts, as appropriate.

The supply-side resource options and their costs and energy and capacity profiles were developed in collaboration with BC Hydro as it updated its Resource Options Inventory in 2015.

FBC has taken into account a number of attributes when evaluating the various resource options. In addition to financial attributes (i.e. costs), these include operational/technical characteristics and environmental and socio-economic impacts, which are discussed in the following sections. Geographic diversity of resources is also a consideration given that all of the generation plants FBC owns are located in the Kootenay region whereas most of the load and expected load growth is in the Okanagan region. Locating new generation resources closer to the primary load centres would help mitigate risks relating to transmission disruptions and reliability in the future.

A number of financial assumptions must be made in order to cost the resource options, such as wholesale market gas and electricity prices, PPA rates and the cost for carbon emissions. These forecasts, scenarios and assumptions are provided in Section 2.5.

FBC has pre-screened the resource options for any emerging resource technologies that are not yet viable or cost effective or those that are not consistent with the *CEA*. This does not mean that some of these resource options could not be considered in the future; however, for the purposes of this LTERP these resources have not been evaluated as identified in the Resource Options Summary table. These non-viable resource options are discussed in Section 3.9 of the ROR in Appendix J.

8.2.2 Resource Options Attributes

The following is a summary of the various attributes FBC takes into consideration when evaluating supply-side resource options.

8.2.2.1 Technical Attributes

FBC has grouped its resource options into three distinct dispatch categories: base load resources, peaking resources and variable/intermittent resources.

Base load resources provide dependable capacity[96] and are expected to operate at a high capacity utilization factor[97], generating significant amounts of electrical energy over the entire year.

Peaking resources can be dispatched to provide dependable capacity but are expected to operate at a low capacity utilization factor generating electricity when it is needed. Peaking resources typically have a low cost to construct per unit of capacity, but high per unit energy costs. These resources can also act as planning reserve margin assets which can be brought into service quickly following a contingency event (e.g. loss of a base load facility), meet sudden changes in customer load requirements or help firm up intermittent resources. Although these

[96] Dependable Capacity is defined as the generation capacity available for the peak hours during each month of the year.

[97] Capacity utilization factor is the ratio of the actual output from a plant over the year to the maximum possible output from it for a year under ideal conditions.

resources can produce energy when generating, they are primarily evaluated for their capacity attributes.

Variable/intermittent resources provide little dependable capacity and typically operate at lower capacity utilization rates than base load resources. Variable/intermittent resources are often renewable resources and generate electricity when their fuel source is available; therefore, generation from these resources cannot be increased on demand in response to changes in customer load. For example, generation from wind or solar resources is determined by external environmental factors such as wind speeds and amount of sunshine. Generation from these resources may not coincide with high system load demand or high market prices. Variable/intermittent resource 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 some variable/intermittent resources can provide at least a small quantity of dependable capacity, they are not able to be ramped up or down on demand to respond to customers' load requirements and therefore are primarily valued for their energy attributes.

8.2.2.2 Financial Attributes

To enable comparisons of the costs of resources that represent a wide range of technologies and fuel sources, capital and operating costs and project lifespans, the financial characteristics of the different resource options are described by two simplified cost metrics: UCC and UEC. UCC is the annualized cost of providing dependable capacity for each resource option, expressed in $ per kW-year. UEC is the annualized cost of generating a unit of electrical energy using a specific resource option, expressed in $ per MWh. As these metrics both include common costs, the value of a project can only be expressed as one or the other, they should not be added.

The UCC and UEC values are based on a levelized net present value (NPV) cost in order to enable comparison between the different resources with different cost structures and energy and capacity values. The UECs and UCCs are presented in real 2015 dollars. FBC has assumed a WACC of 6 percent[98] (in real terms) as the discount rate in determining the UECs and UCCs. Adders, such as those relating to wheeling costs and intermittent resources' integration costs, are also included in the UEC and UCC values. More discussion of these assumptions is provided in the ROR in Appendix J.

8.2.2.3 Environmental Attributes

Environmental considerations are an important objective of the *CEA* and energy policy in B.C. Environmental attributes describe the estimated environmental impact of the various resource options. While demand-side management resources are assumed to have no negative environmental impacts, some supply-side resources can. For the purposes of this LTERP and the portfolio analysis in Section 9, FBC has characterized resource options as either clean or

[98] Based on FBC's after-tax WACC, per the FBC Annual Review for 2017 Rates Application (Section 8.3.5) filed August 8, 2016.

renewable, or not, according to what the *CEA* defines as clean or renewable resources generated in B.C. The *CEA* defines clean or renewable resources as including biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource. FBC also considers energy and capacity under the PPA to be clean and renewable. Based on the regional electricity generation source mix as discussed in Section 2.4.2, market purchases would include a mix of clean or renewable and non-clean or renewable resources.

8.2.2.4 Socio-Economic Attributes

Social and economic development and job creation are included among B.C.'s energy objectives in the *CEA*. Socio-economic development attributes include contributions to provincial GDP, employment and government revenue and supporting community and First Nations development. FBC has categorized the socio-economic development attributes for each resource option into low, medium and high impact categories using employment contributions as a proxy for all the socio-economic development benefits. A high impact rating means that a particular resource option contributes more to provincial job creation than a resource option categorized as low impact (in terms of full-time equivalents per MW of installed plant capacity). Details are provided in Section 2.2.4 of the Resource Options Report in Appendix J.

8.2.3 Resource Options Evaluation

The following table provides a summary of the resource options that were evaluated including their resource type, dependable capacity, annual energy as well as environmental and socio-economic attributes. For those resource options showing a range of capacity and energy, a number of different-sized plants were considered for that particular resource option. For gas-fired generation, FBC has included both Combined Cycle Gas Turbine (CCGT) plants as well as Simple Cycle Gas Turbine (SCGT) plants as described in the ROR. The resources are sorted in the table by type with the PPA energy and capacity in green, market purchases in orange and generation resources in blue.

Table 8-3: Resource Options Type, Size, Environmental and Socio-Economic Attributes

Resource Option	Type	Dependable Capacity (MW)	Annual Energy (GWh)	Clean/ Renewable	Socio-Economic Benefits
PPA Tranche 1 Energy	Baseload	N/A	Up to 1,041	Yes	N/A
PPA Tranche 2 Energy	Baseload	N/A	1,042 to 1,752	Yes	N/A
PPA Capacity	Baseload	Up to 200	N/A	Yes	N/A
Market Purchases	Baseload or Peaking	Up to 150	Up to 1,314	Mixed	N/A
Wood-Based Biomass	Baseload	12 – 63	98 - 503	Yes	High
Biogas	Baseload	1 – 2	7 - 18	Yes	Medium
Municipal Solid Waste	Baseload	25	211	No	High
Geothermal	Baseload	8 – 89	57 - 657	Yes	High
Gas-Fired Generation (CCGT)	Baseload	67 – 279	411 – 1,712	No	Medium
Similkameen Hydro Project	Baseload	32	215	Yes	High
Gas-Fired Generation (SCGT)	Peaking	48 – 192	75 - 303	No	Low
Pumped Hydro Storage	Peaking	500	0	Yes	Low
Onshore Wind	Intermittent	8 – 81	100 – 1,239	Yes	Medium
Run-of-River Hydro	Intermittent	2 – 13	34 - 314	Yes	Medium
Solar	Intermittent	1	7	Yes	Low

The following table shows the unit energy and capacity costs for the resource options. The range of unit costs reflects the different plant sizes available for some of the resource options. No UEC is presented for SCGT gas-fired generation or Pumped Hydro Storage because these resources are primarily used for providing capacity and not energy. The UEC and UCC ranges for market purchases and PPA Tranche 1 and 2 energy and PPA capacity reflect the high and low range of market price forecast scenarios and PPA rate scenarios as described in Section 2.5.

Table 8-4: Supply-Side Resource Options Unit Cost Summary

Resource Option	UEC ($/MWh)	UCC ($kW-year)
PPA Tranche 1 Energy	$47 - $56	N/A
PPA Tranche 2 Energy	$85 - $130	N/A
PPA Capacity	N/A	$96 - $115
Market Purchases	$34 - $64	$169 - $355
Wood-Based Biomass	$118 - $188	$663 - $774
Biogas	$77 - $101	$621 - $838
Municipal Solid Waste	$134	$1,031
Geothermal	$132 - $217	$857 - $1,506
Gas-Fired Generation (CCGT)	$82 - $100	$147 - $279
Similkameen Hydro Project	$202	$1,298
Gas-Fired Generation (SCGT)	N/A	$80 - $143
Pumped Hydro Storage	N/A	$217
Onshore Wind	$111 - $145	$1,219 - $1,618
Run-of-River Hydro	$87 - $150	$1,230 - $1,924
Solar	$169 - $184	$1,399 - $1,413

When looking at the unit costs in the table above, it is important to remember that a resource option with the lowest unit cost may not be the best fit in terms of meeting customers' load requirements. For example, while pumped storage hydro has one of the lowest UCCs ($217 per kW/year), the size of this resource option, with a capacity of 500 MW and no energy contribution, makes it an impractical option for FBC's requirements. It would provide FBC with too much capacity, given the size of the Company's projected capacity gaps, and no energy. The portfolio analysis in Section 9 helps determine the optimal mix of resources based on cost and FBC's monthly energy and capacity requirements.

The following figures graphically show the range of unit costs for the resource options that were considered. Resources are sorted from lowest to highest unit costs. The first figure shows the unit energy costs; the second shows the unit capacity costs. These figures help illustrate the costs of the various resource options relative to each other.

Figure 8-6: Resource Options Unit Energy Costs

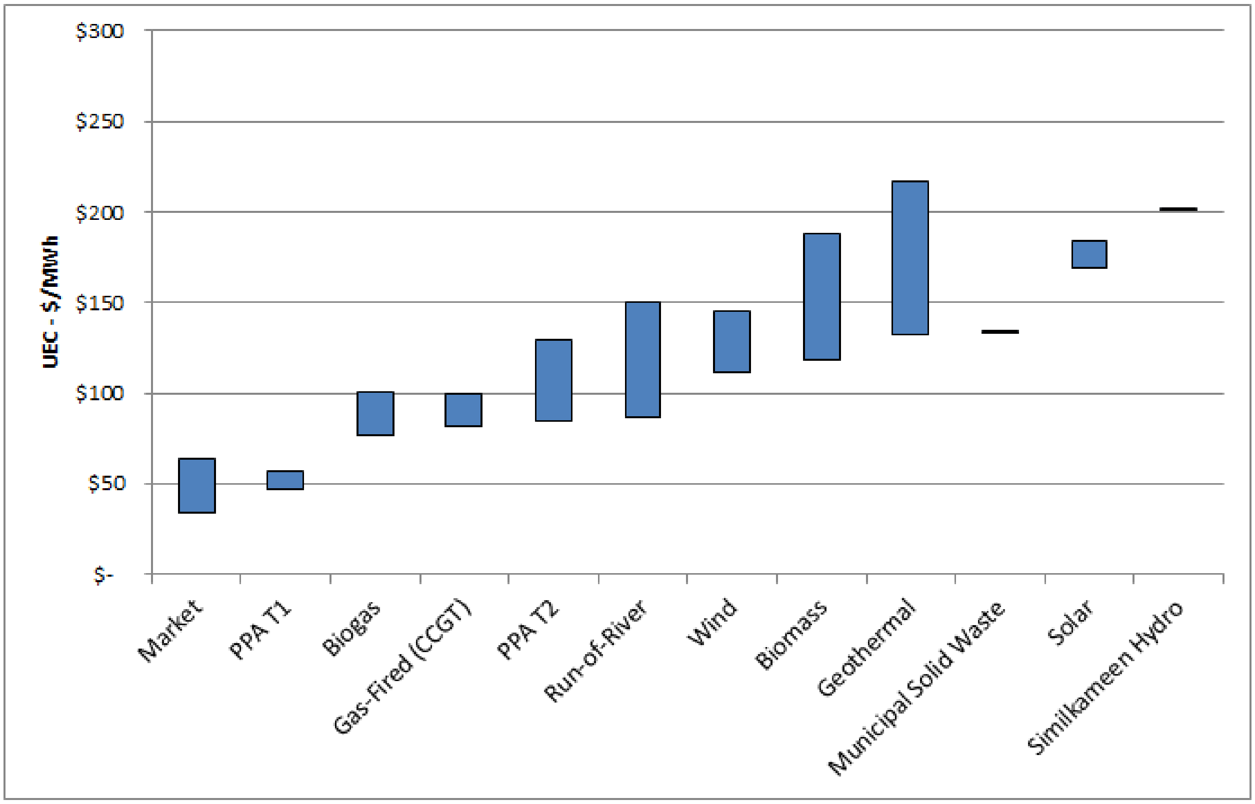
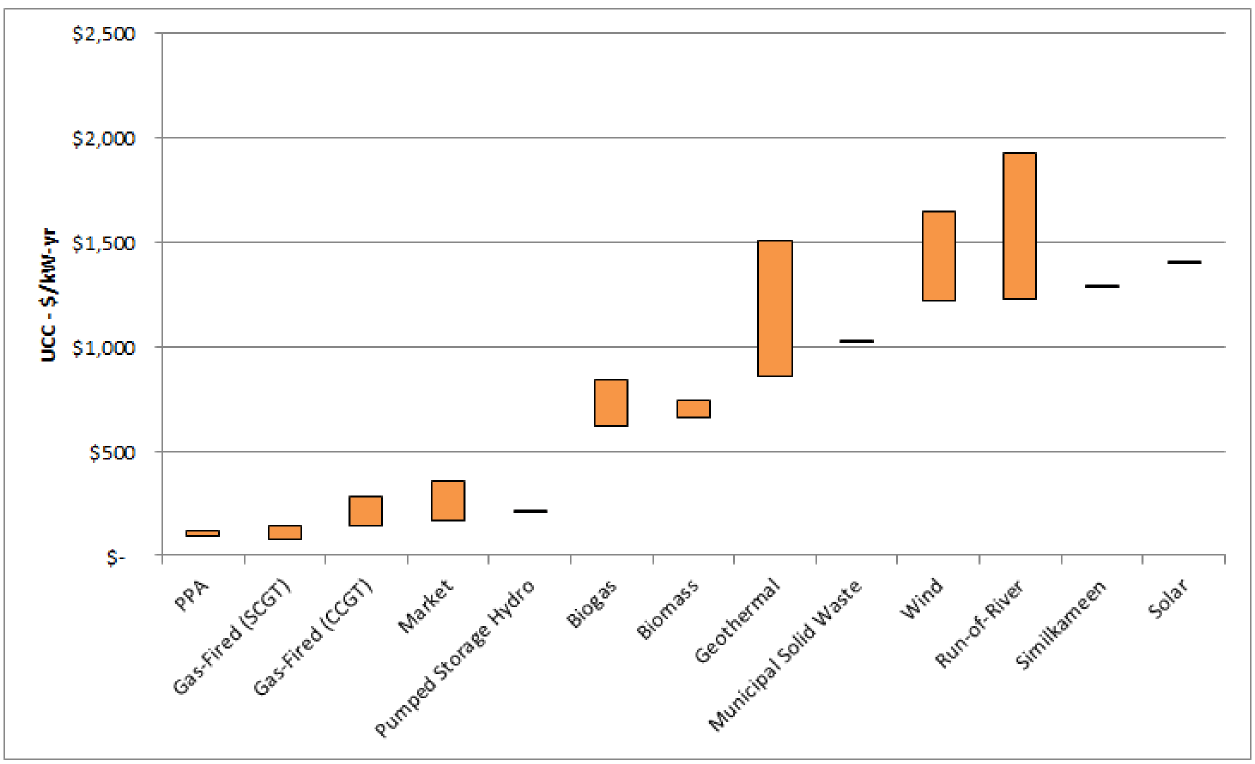


Figure 8-7: Resource Options Unit Capacity Costs



8.2.4 Market Purchases

Market purchases of energy and capacity can be a cost-effective and reliable resource within the FBC portfolio. FBC has relied on short-term market electricity purchases in the past and this strategy has proven cost effective in recent years given the decrease in market gas and power prices relative to the costs of other resource options, such as the PPA with BC Hydro. On an annual basis, FBC determines the optimal amount of market purchases within its Annual Electric Contracting Plan (AECP), taking into account its forecast load requirements, the annual PPA energy nomination and the price of market supply compared to the PPA tranche 1 energy rate.

On a long term planning basis, FBC can compare the forecast price of market purchases to the forecast price of the PPA and other resources to help evaluate market purchases within the resource options portfolio. Based on current base forecasts for market prices, some reliance on market purchases of energy and capacity is more cost-effective than other resource options, at least over the short to medium term. Figure 2-9 in Section 2.5.2 shows the base case long-term market price for electricity at Mid-C. The range of unit energy cost for market purchases in the base case is about $42 per MWh to about $67 per MWh, including transmission costs and losses from Mid-C to the FBC system. On a levelized basis over the twenty-year planning horizon (using a 6 percent DR), the unit cost of market energy is about $51 per MWh. Overall, this is significantly lower than the unit costs of the other supply-side resource options listed in Table 8-1 which have levelized energy unit cost ranges of $77 per MWh to $217 per MWh.

The market price range plus transmission costs and losses is only slightly lower than the base case PPA Tranche 1 Energy rate in the short-term and exceeds the PPA Tranche 1 Energy rate over the medium and long term. The range for the PPA Tranche 1 Energy rate base case is from about $46 per MWh in 2016 to about $56 per MWh by 2035, with a levelized unit cost over twenty years of about $50 per MWh. The PPA tranche 1 rate scenarios are discussed in Section 2.5.

Section 6 of the *CEA* addresses the B.C. energy objective of electricity self-sufficiency. While the specific requirement mandating self-sufficiency is applicable only to BC Hydro, FBC is required to consider the energy objective to achieve electricity self-sufficiency "in planning in accordance with section 44.1 of the *UCA*" in two circumstances: construction or extension of generation facilities and energy purchases. The addition of WAX capacity into the FBC portfolio in 2015 improved FBC's degree of self-sufficiency from a capacity perspective. However, FBC believes that market purchases, at current price levels, are more cost effective than other supply-side resource options and so should not be ruled out in favour of self-sufficiency, at least in the short to medium term.

Relying on market purchases over the long term, however, can be risky in terms of price and supply availability. While there are market price forecasts for future electricity prices, there is no guarantee that market prices will remain at these levels given the degree of price volatility and uncertainty in the marketplace. This is why FBC has presented varying market price forecast scenarios in Section 2.5. There is also no guarantee that FBC will be able to access market supply reliably, especially if there is no access to long term firm transmission (as discussed in Section 5.5). Therefore, FBC does not believe that market supply can be relied on as a long-term resource option.

8.2.5 BC Hydro PPA

The PPA with BC Hydro provides long-term dependable capacity and energy. FBC has access to up to 200 MW of capacity, up to 1,041 GWh of Tranche 1 Energy and up to 1,752 GWh of Tranche 2 Energy. The cost for this energy and capacity is provided in Section 2.5 and different rate scenarios are also discussed. The PPA is a very flexible resource in the FBC portfolio, enabling FBC to increase or decrease the amount of energy and capacity requirement from year to year, subject to specific limits. Because of this flexibility, FBC has included the PPA in its list of resource options even though it is already an existing contract. More details regarding the PPA are provided in Section 5.4.

8.2.6 Expiring Energy Purchase Agreements

Energy currently provided to BC Hydro from IPPs under Electricity Purchase Agreements (EPAs) may become available to the market when these EPAs expire. In its 2013 IRP, BC Hydro has assumed, for planning purposes, that about 50 percent of its bioenergy EPAs will be renewed, about 75 percent of its run-of-river EPAs that are up for renewal in the next five years will be renewed, and that all of its other EPAs will be renewed. BC Hydro also amended its Standing Offer Program rules to specifically exclude generators with expiring EPAs. BC Hydro's F2017-F2019 Revenue Requirements Application also addresses expiring EPAs. Fourteen of BC Hydro's existing EPAs with IPPs are expiring by the end of fiscal 2019. Consistent with the approved 2013 Integrated Resource Plan (IRP), BC Hydro continues to assume renewal of 50 percent of the energy and capacity contributions from biomass EPAs and 75 percent from the run-of-river hydroelectric EPAs that are due to expire within the remaining years of the 10 Year Rates Plan the BC government announced in 2013.

BC Hydro is targeting renewal of contracts for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. However, there may be opportunities for FBC to acquire power from the other facilities on a cost-effective basis. In addition, BC Hydro will need to address expiring EPAs after 2019. FBC will continue to monitor the BC Hydro contract renewals for any resource option opportunities.

8.2.7 Distributed Generation

DG, such as residential or commercial rooftop solar power, can be considered either a supply-side resource or a variable that reduces customer demand. FBC has captured the DG potential for the FBC system as a load-reducing driver within its load scenarios as discussed in section 4 of this LTERP. While a unit cost value of this DG to FBC as an energy supply-side resource can be determined for illustrative purposes, it should be done with caution for resource planning. This is because DG is not within FBC's control and cannot be considered a reliable resource option for long-term planning purposes. FBC has no assurances that the customer-generated electricity will be available on its system when needed or in the appropriate location. Furthermore, DG provides virtually no capacity during peak winter demand periods.

As per FBC's Net Metering Update Application dated April 15, 2016, FBC has proposed to reimburse DG net metering customers based on the BC Hydro PPA Tranche 1 Energy rate, currently about $47 per MWh. The rate for Tranche 1 Energy is essentially the cost of DG to FBC for the short term.

8.2.8 Purchases from Self-Generators

Electricity purchases from self-generating customers may be a supply option for FBC in the future. Self-generating customers, for the purposes of this LTERP, refers to larger, industrial customers that can provide electricity to FBC as opposed to smaller, residential or commercial customers that could provide distributed generation to FBC. Self-generation supply, in addition to benefitting the self-generator, can also have the following benefits for FBC and its customers:

- self-sufficiency and less reliance on market supply;
- reduction of transmission losses depending on location on the FBC system;
- improved reliability depending on location; and
- complement traditional power generation.

When assessing the value of self-generation supply, in addition to these benefits, FBC must consider other relevant criteria in terms of its supply requirements and its LTERP objectives, as it does with other supply-side resource options. These include the energy and capacity profile (i.e. when the electricity is provided to FBC during each month of the year), adherence to provincial energy and environmental policy and cost effectiveness. The energy and capacity profile of the self-generation supply needs to meet FBC's customer load requirements, providing energy throughout the year and capacity during peak demand periods. Any self-generation must be consistent with B.C.'s energy and environmental policies, such as meeting clean or renewable generation requirements. In terms of cost, long-term self-generation supply would need to meet FBC's LRMC requirements, as discussed in section 9, to be considered cost effective. If the self-generation supply is short term in nature, then FBC would compare the cost to its short-term resource options, such as market supply or PPA.

At this point in time, FBC does not have any specifics or indications of costs or other attributes such as environmental or socio-economic characteristics. FBC is not seeking additional sources of supply at this time and is therefore not actively looking to purchase power from self-generator customers. However, if a self-generator could provide power at a cost lower than FBC's alternatives, there may be an opportunity for FBC to purchase the output of the self-generation.

8.2.9 First Nations and Community Resource Development

The FBC portfolio analysis, discussed in Section 9, determines the different bundles of resource options required to meet future energy and capacity gaps when they occur. The LRB provided in Section 8.1.2 indicates that, after incremental DSM, FBC does not have significant resource needs in the short to medium term and that new resources are not expected to be required until 2026. As FBC moves closer to the period when new resource options are required, further portfolio analysis can be done to determine the resource requirements and optimal mix of incremental DSM and/or generation.

If new supply-side resources are needed in the future, FBC would consider generation projects that promote First Nations and community development if they are competitive with the cost of alternative resources and meet FBC's LTERP objectives. FBC expects that it would continue to build effective community and First Nations' relationships as it has done in the past.

8.2.10 Summary

As discussed throughout this section and the ROR, there are many potential supply-side resource options available to FBC to meet its future energy and capacity gaps. These include base load, peaking and intermittent generation resources as well as purchases from the market and supply from self-generators. With the decline in natural gas prices over the last few years, natural gas-fired generation is one of the most cost-effective generation options for FBC. Of the clean or renewable resources, biogas, biomass, run-of-river and wind are among the lower cost options. Based on current market price forecasts and PPA rate scenarios, market purchases and the PPA are the lowest cost resources available to FBC, at least in the short to medium term.

However, it is important to remember that unit cost alone is not the only factor to consider when selecting resources. The size and generation profile of the resource options needs to match FBC's monthly energy and capacity gaps to be of value to FBC in meeting customer loads. Environmental and socio-economic attributes should also be considered in meeting the LTERP objectives. The portfolio analysis, discussed in Section 9, will help to determine the optimal mix of these various resource options and their attributes, taking into account the resource planning objectives.

9. PORTFOLIO ANALYSIS AND LONG RUN MARGINAL COST

Portfolio analysis helps to determine the optimal mix of resources to meet customers' future energy and capacity requirements. It includes the development of several portfolios in order to determine the trade-offs between portfolios with different attributes. For example, how does a portfolio including only clean and renewable resource options compare to one with gas-fired generation in terms of meeting the LTERP's objectives such as reliability, cost effectiveness and consistency with B.C.'s energy policy objectives. The portfolios are also subject to sensitivity analysis to determine how they perform under potentially changing conditions in the future. These changing conditions could include, for example, changes in market natural gas, power prices or carbon costs. The analysis includes portfolios that meet the reference case load forecast requirements as well as the load scenarios discussed in Section 4. The outcome of the portfolio analysis is a preferred portfolio that meets the objectives of the LTERP.

This approach to portfolio analysis is consistent with the BCUC Resource Planning Guidelines discussed in Section 1.4.2.

In this section, FBC will first describe its methodology for the portfolio analysis and what the LRMC values represent and their purpose. FBC then discusses the alternative portfolios, assessment of results and the preferred portfolio. This section also includes a discussion of how the preferred portfolio meets the requirements for the Planning Reserve Margin, which is further discussed in Appendix L, as well as contingency plans for the preferred portfolio.

It is important to note that the portfolio analysis presented in this section provides a high-level indication of how load-resource balance gaps may be filled in the future. It is likely that before specific resource options are required, load forecasts, load-resource balances and resource options and costs will change. Based on the portfolio analysis results presented in this section and assuming the reference case load forecast, proposed High DSM level and market access until 2025, FBC does not require any new generation resources until 2026. As FBC moves closer to actually requiring incremental generation resources, more specific analysis regarding options will be performed and requests for approval will be brought forward to the Commission.

9.1 *PORTFOLIO ANALYSIS METHODOLOGY*

FBC has assessed different portfolios of resource options to meet its potential load-resource balance gaps as described in Section 7. The resource options available include different levels of DSM, as discussed in Section 8.1 and the LT DSM Plan Section 3, and supply-side resources, discussed in Section 8.2. The available resources also include the existing PPA which includes energy and capacity that FBC can adjust up or down subject to the conditions of the PPA. The portfolios are designed to meet both energy and capacity gaps on a monthly and annual basis for the reference case load forecast as well as the boundary load scenarios for the next twenty years.

FBC's portfolio model incorporates an optimization routine to find the lowest cost of satisfying the forecast load requirements given a set of constraints and determines what new resources should be acquired and when. The portfolio analysis takes into consideration B.C. energy and environmental policies, as discussed in Section 2.2, such as the objective of at least 93 percent of generation from B.C. clean or renewable resources in the *CEA* and the requirement in the CLP for BC Hydro's supply of electricity to be 100 percent clean or renewable. It also includes constraints on the amount of wholesale market purchases FBC is able to import based on transmission limitations. The costs and the LRMC values of the various portfolios FBC evaluated are based on the Average Incremental Cost (AIC) approach as discussed below in Section 9.3 and in Appendix K regarding the LRMC.

9.1.1 Alternative Portfolios and Sensitivities

FBC has evaluated portfolios based on several different base characteristics and then explored sensitivities around these base characteristics. These characteristics and sensitivities are outlined in the following table.

Table 9-1: Portfolio Analysis Base Characteristics and Sensitivity Cases

Portfolio Base Characteristics	Sensitivity Cases
DSM Level • Proposed High level	• No DSM • Max DSM • Low DSM
Reliance on Market Purchases • Self-sufficiency by 2025	• No self-sufficiency • Self-sufficiency by 2020 • High market and carbon prices
Percent Clean or Renewable • 93 percent clean or renewable	• 100 percent clean or renewable • High market and carbon prices
Load Requirements • Reference case load forecast	• High load scenario • Low load scenario
PPA Renewal • PPA renewed in 2033	• PPA not renewed

FBC's proposed High DSM load growth offset level is outlined in Section 8.1 and in the LT DSM Plan, Section 3. FBC has also explored different sensitivity levels of DSM offset in the portfolio analysis per the DSM scenarios discussed in Section 3 of the LT DSM Plan. These sensitivities include no DSM offset at all, maximum DSM and low DSM levels. The portfolio with no DSM is used to determine the LRMC based on clean or renewable resources in B.C. for the purposes of evaluating the cost effectiveness of DSM in accordance with the Demand-Side Measures Regulation[99]. This portfolio without DSM is not a realistic portfolio for FBC as it is expected that FBC will continue with its DSM programs and initiatives to help customers conserve electricity

[99] Demand-Side Measures Regulation, B.C. Reg. 326/2008 (including amendments up to B.C. Reg. 141/2014), section 4(1.1) (Cost effectiveness).

and help reduce their electricity bills. The maximum DSM level is based on meeting 89 percent of annual average forecast load growth for customers' energy requirements with DSM. The High DSM level is FBC's proposed DSM offset level while the Base DSM level is close to FBC's current level of DSM.

FBC currently accesses market supply to complement its existing resources with reliable and low-cost power. There is no indication at this time that market supply will increase significantly in price or that FBC will not be able to access it reliably over the next ten years. However, market conditions can change over time and market prices and access could change in the future. FBC's base case assumption is that it will be able to access low-cost and reliable market supply for the next ten years, out to 2025. After this time, FBC has assumed that it will become self-sufficient, with incremental supply coming from its own generation and/or long-term contracts from B.C. suppliers. This also provides consistency with the *CEA* objective of achieving electricity self-sufficiency. As sensitivity cases, FBC has developed portfolios that do not include self-sufficiency within the planning horizon (i.e. long term market reliance) and self-sufficiency by an earlier date of 2020. FBC has also modelled the impacts of higher market power and carbon prices based on the price forecasts and scenarios provided in Section 2.5.

The minimum level of clean and renewable resources in the base resource portfolio is 93 percent, which is based on the current requirement under the *CEA* in respect of BC Hydro. Note that this is a minimum level for clean or renewable resources and some portfolios exceed the 93 percent level and include resources such that it is closer to 100 percent clean or renewable. Given the requirement in the CLP for BC Hydro to target 100 percent clean and renewable resources (unless there are reliability issues), FBC has also modelled a portfolio based on 100 percent clean and renewable resources. FBC has also modelled high scenarios for market natural gas and carbon prices to determine the effects on a portfolio that includes natural gas-fired generation.

The base assumption in the portfolio analysis regarding the load forecast is the reference case load forecast as presented in Section 3. As sensitivity cases, FBC has also modelled the effects of higher and lower loads using the load scenarios presented in Section 4. The high load portfolio provides an indication of the extra resources FBC may require in the future if load drivers such as EVs, fuel switching from gas to electricity or additional large industrial or commercial facilities increase the load requirements of FBC's customers. The low load scenario provides insight into how much FBC might have to reduce the PPA to avoid having significant surplus energy and capacity if load drivers like rooftop solar and fuel switching from electricity to gas that decrease load requirements outweigh the load drivers that increase load requirements.

As discussed in Section 5.4, the PPA expires in 2033. FBC's base case assumption is that the PPA will be renewed as it is currently a cost-effective, reliable, flexible and clean/renewable supply of energy and capacity. However, there is the possibility that the PPA will not be renewed and FBC will require other resources to meet customers' requirements. FBC has included not renewing the PPA in 2033 as a sensitivity case in the portfolio analysis.

9.2 *LONG RUN MARGINAL COST*

The LRMC values represent the cost to FBC of incremental resources needed to meet load requirements over the planning horizon. The LRMC includes both energy and capacity generation components. FBC's LRMC values are outcomes of the portfolio analysis and are dependent upon which demand-side and supply-side resource options are included within a particular portfolio.

The LRMC values determined in the portfolio analysis serve two distinct purposes. As discussed above, the LRMC for the portfolio with no DSM is used in the cost effectiveness test for DSM in accordance with the Demand-Side Measure Regulation. The LRMC values for the portfolios that include DSM serve as a point of reference when evaluating power supply options and are the appropriate LRMCs for the purpose of making long-term resource decisions. Power supply options with costs below the LRMC values could be considered viable resource options for FBC provided that they also meet FBC's monthly and annual energy and capacity requirements and LTERP objectives. While a particular resource option may be cost effective relative to a given LRMC value, it may not fit the energy or capacity requirements of customers in the future. For this reason, FBC believes the LRMC values presented here should be viewed as price signals, rather than threshold targets, for resource options.

FBC has adopted the AIC approach to estimating the LRMC values. The AIC approach takes the present value of the incremental costs expected to be incurred over the planning horizon and divides the incremental costs by the present value of the additional load expected to be served within the same period. The AIC approach does not directly link a particular increment of load with the resulting change in cost, but rather expresses the LRMC as the average cost of satisfying the incremental forecast load requirements over the planning horizon. More details regarding LRMC, including definitions, methodology and background information, are provided in Appendix K.

The next section discusses the results of the portfolio analysis including the LRMC values associated with the various portfolios.

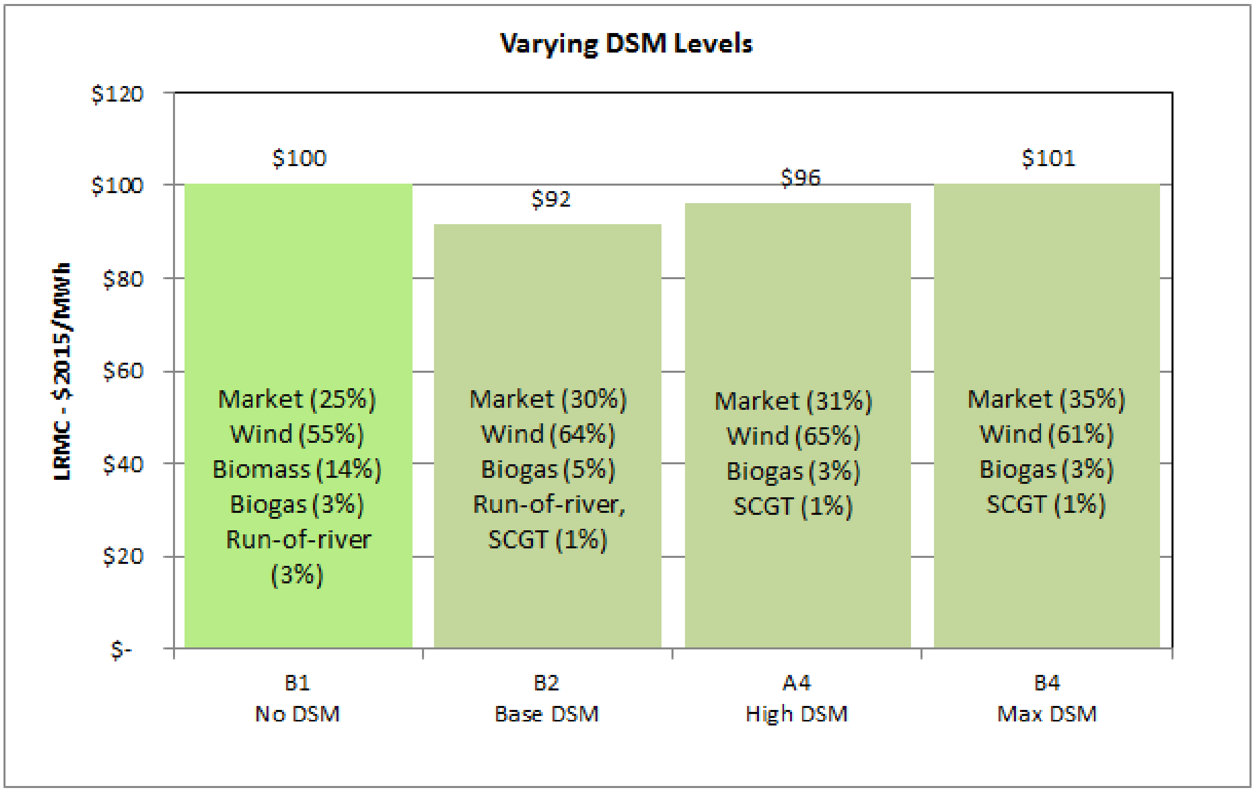
9.3 *PORTFOLIO ANALYSIS RESULTS*

The portfolio analysis results are presented here based on the categories discussed in Table 9-1. The results show the incremental resources included within each portfolio analysed based on their percentage contribution to incremental energy and the LRMC values associated with the new resources for each portfolio. Based on these results, a set of portfolios is selected from which the preferred portfolio is determined.

9.3.1 DSM Levels

The following figures show the results of portfolios with different levels of DSM.

Figure 9-1: Portfolios with Different DSM Levels



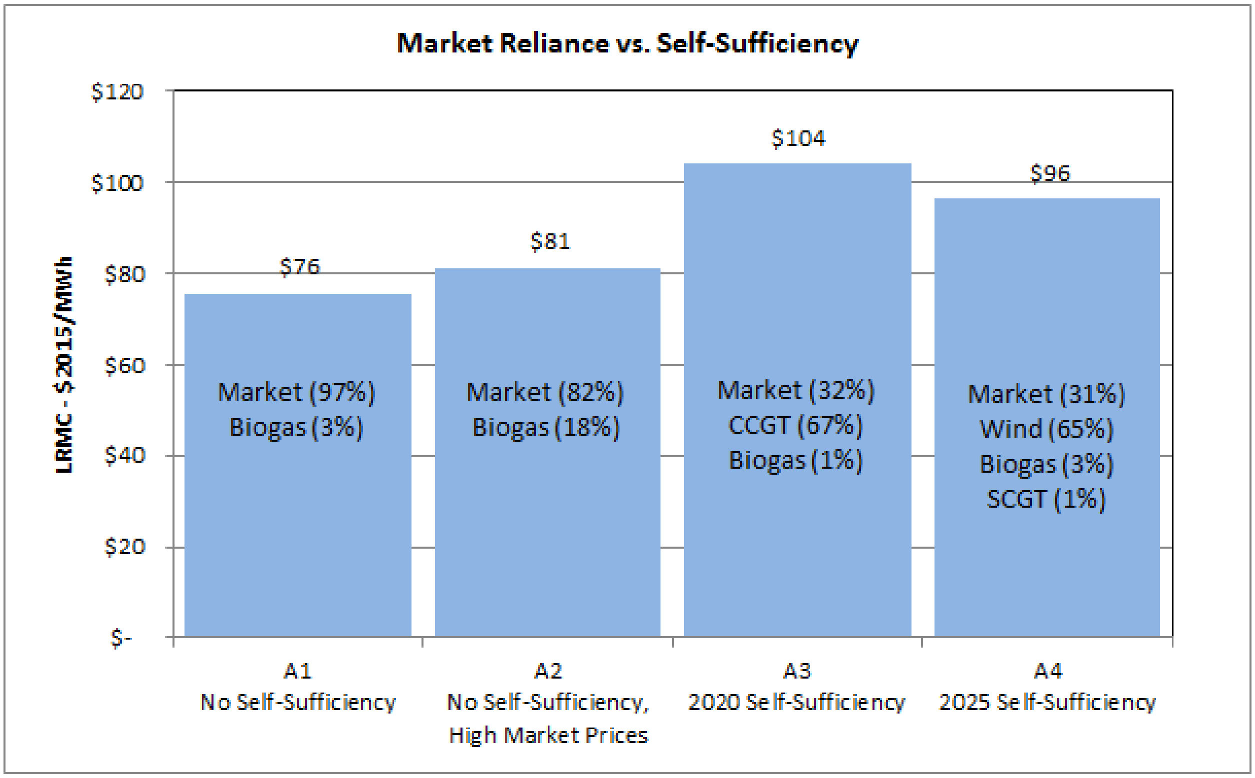
The first column (B1) represents the portfolio of clean or renewable resources without any DSM, which, as described above, is used to determine the LRMC for the purposes of evaluating cost effective DSM (per the DSM Regulation). The LRMC for this portfolio is $100 per MWh and it includes wind, biomass, biogas, and run-of-river resource options as well as some market purchases out to 2025.

The other columns (B2 to B4) show three portfolios with different levels of DSM and which include the requirement that the total portfolio mix meet the *CEA* objective of at least 93 percent clean or renewable resources. These portfolios have LRMC values that range from $92 per MWh to $101 per MWh and all include market access to 2025, wind, biogas and minor contributions from SCGT. The least-cost portfolio (B2) includes the base amount of DSM while the highest cost portfolio (B4) includes the maximum level of DSM. This is because the cost of the higher DSM offset levels is greater than alternative supply-side resource options, including lower-cost market supply and PPA Tranche 1 Energy.

9.3.2 Market Access versus Self-Sufficiency

FBC has assessed portfolios that include access to the market until 2020, until 2025 and throughout the entire planning horizon. The results are provided in the following figure.

Figure 9-2: Portfolios with Market Access versus Self-Sufficiency



The results show that continued access to the market throughout the planning horizon, without any self-sufficiency requirement, provides a lower LRMC than portfolios where self-sufficiency is required by 2020 or 2025. This is because of the low cost of market supply relative to the cost of other resource options. The LRMC for this portfolio (A1) is $76 per MWh and increases to $81 per MWh in the scenario where higher market and carbon prices are assumed (A2). In the portfolio where there is no market access after 2020 (A3), the LRMC is the highest at $104 per MWh. In this case, the portfolio analysis indicates that FBC would require a new resource, a CCGT plant, as early as 2021. The LRMC of the portfolio where there is no market access after 2025 (A4) falls in between at $96 per MWh. This portfolio includes incremental wind and biogas resources after 2025. It also includes a SCGT plant, which is not required until 2032, and is needed only for low amounts of energy and capacity.

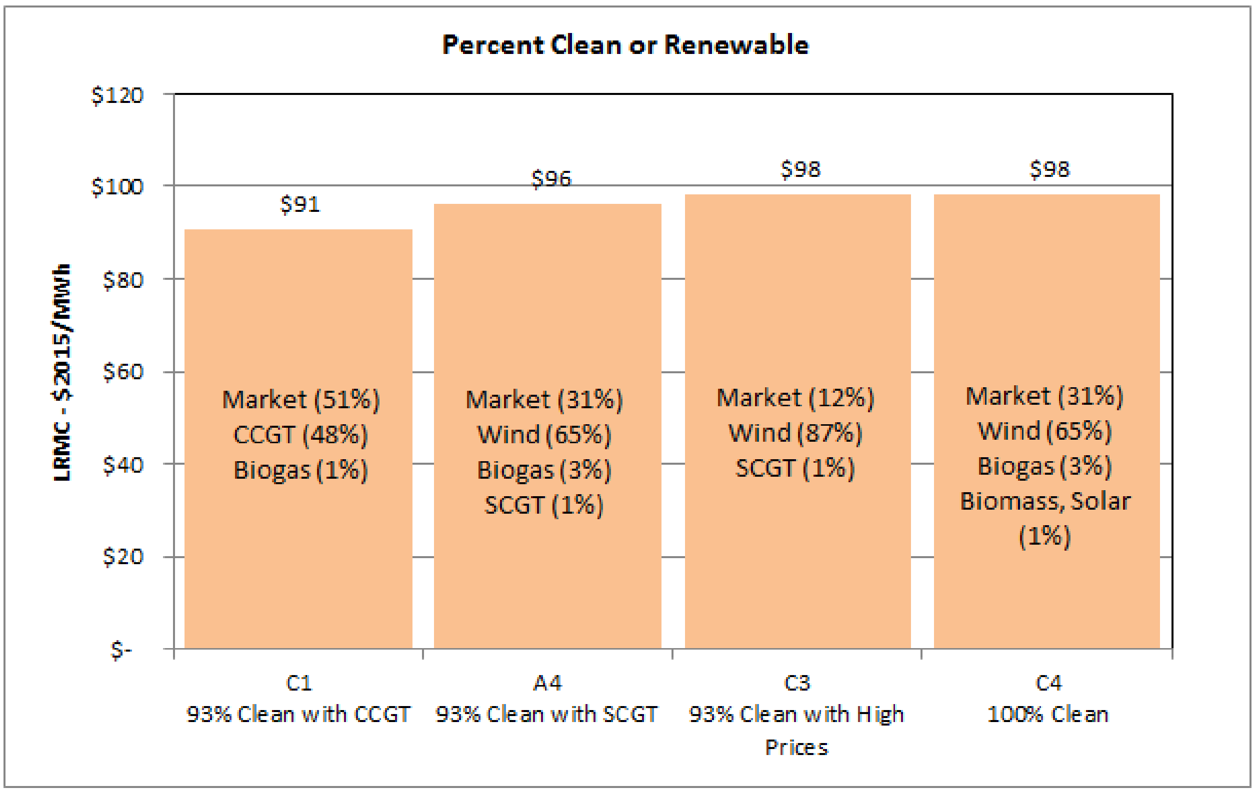
Due to the risks of relying on market access indefinitely into the future (as discussed in Section 5.5 and 8.2.4), FBC believes that self-sufficiency at some point in the planning horizon is a more prudent approach to resource planning. Self-sufficiency by 2020 results in a significantly higher LRMC and would mean that FBC would need to secure incremental resources within the next few years to meet the 2020 target. Self-sufficiency by 2025 allows more time to plan for new resources and to assess the LRB, as well as market conditions, at the time FBC prepares its next long term resource plan. This is a more balanced approach to market access. Self-sufficiency is also a B.C. energy objective in the *CEA*.

9.3.3 Percentage of Clean or Renewable Energy

FBC has evaluated portfolios with different percentages of clean or renewable resources. Three portfolios (C1, A4 and C3 in the figure below) include resources that ensure the total FBC resource mix meets the *CEA*'s objective of 93 percent clean or renewable electricity. These portfolios can include natural gas-fired generation, either CCGT or SCGT plants. FBC has also assessed a portfolio with 100 percent B.C. clean or renewable generation resources (C4). Note that market purchases, which do not comprise 100 percent clean or renewable power, are included in the portfolio until 2025 after which time FBC is assumed to be self-sufficient. FBC has also performed a sensitivity case of higher gas and carbon prices for the portfolio that includes gas-fired generation to consider what the effects might be of a scenario where gas and carbon prices are higher, which would increase the costs for the fuel for gas-fired generation (C3).

The following figure shows the results of the portfolios with the different percentages of clean or renewable resources.

Figure 9-3: Portfolios with Different Percentages of Clean or Renewable Resources

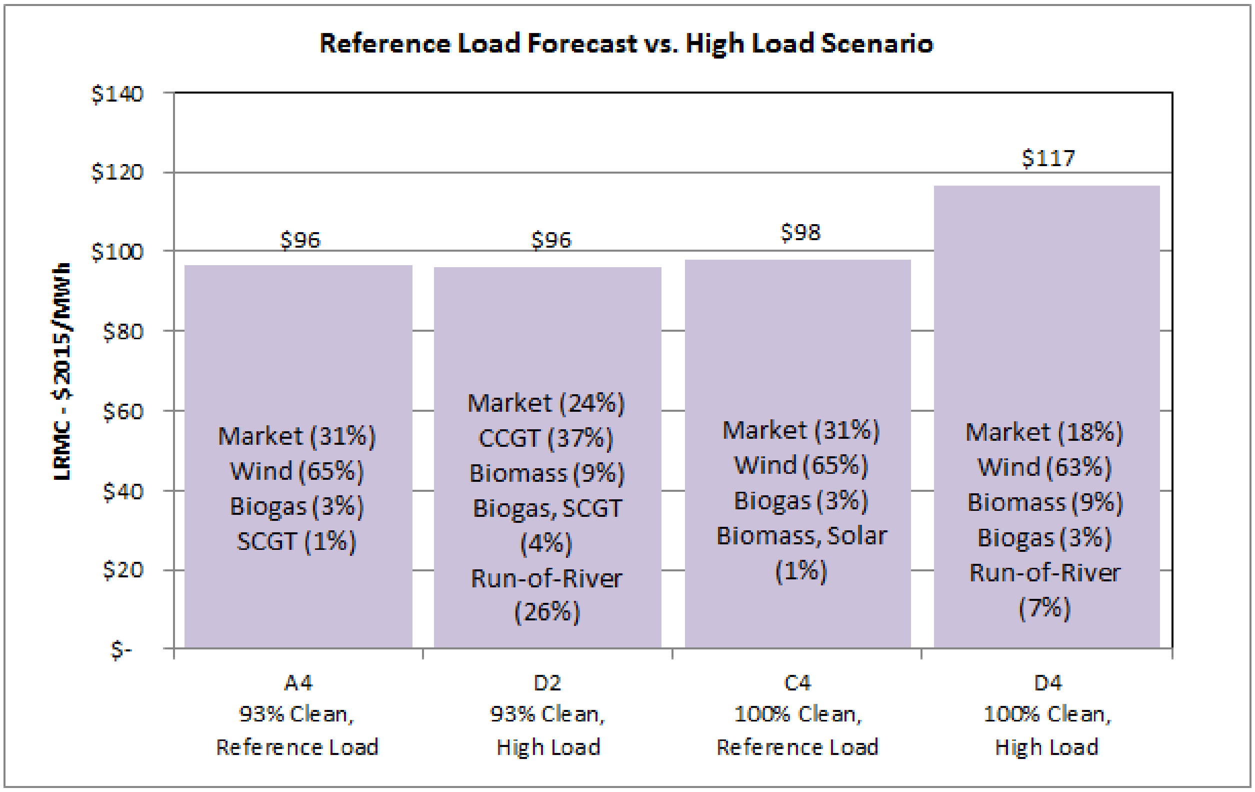


The results show that the LRMC of $91 per MWh for the portfolio with a CCGT plant (C1) is lower than the LRMC of $96 per MWh for the portfolio with a SCGT plant (A4). This is because natural gas-fired generation is lower cost relative to the cost of other incremental supply-side resources and the portfolio with CCGT uses more gas-fired generation in terms of annual energy than the portfolio with SCGT. Both of these portfolios also have lower LRMC values than the 100 percent clean or renewable portfolio (C4), which has an LRMC of $98 per MWh. This is due to the lower cost of gas-fired generation relative to the cost of other supply-side resource options (as described in Section 8.2).

9.3.4 Load Requirements

FBC's base case assumption for load requirements is the reference case load forecast for energy and capacity as provided in Section 3. FBC has also modelled the effects of higher and lower loads based on the load scenarios presented in Section 4. The results are provided in the following figure.

Figure 9-4: Portfolios based on Reference Case Forecast vs. High Load Scenario

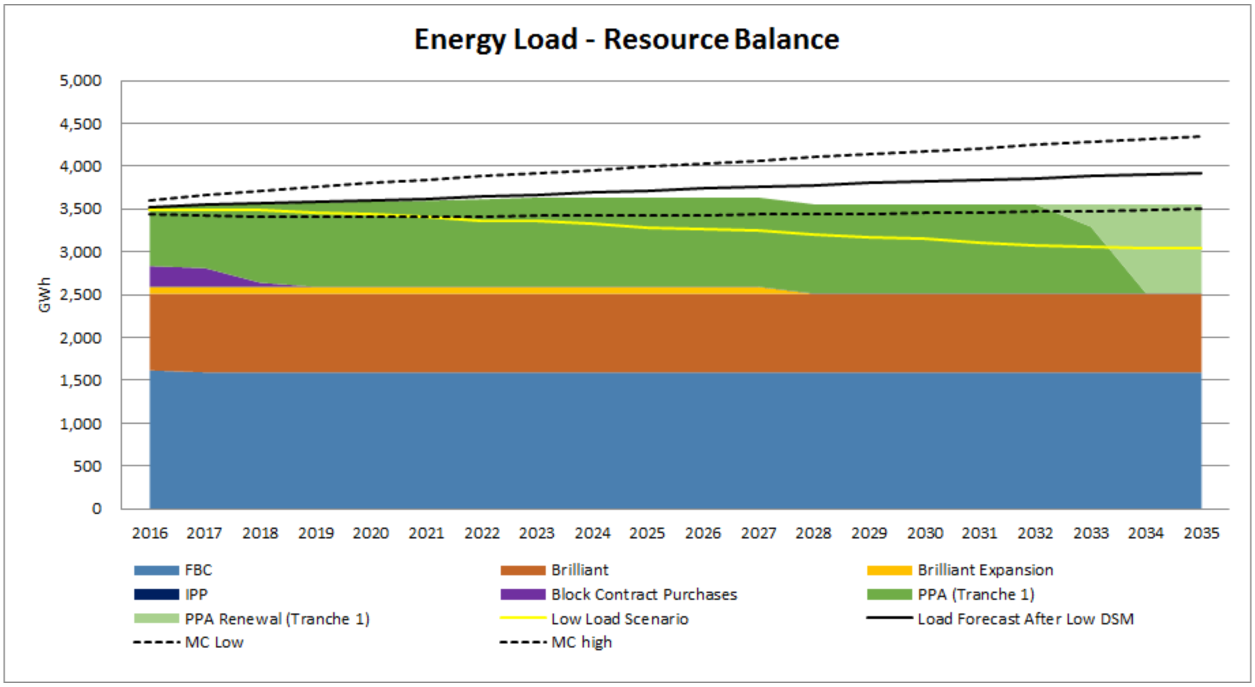


The results show that the LRMC values for the portfolios meeting the 93% clean or renewable objective are similar for the portfolios required for the reference case load (A4) and the high load (D2). This is because more low-cost natural gas-fired generation is used in portfolio D2 to meet the incremental load requirements. However, for the 100% clean portfolios, the LRMC of the portfolio required to meet the high load (D4) increases significantly above the portfolio meeting the reference case load (C4). This is because portfolio D4 requires incremental clean resources that are more costly than those required for the reference load portfolio to meet the incremental load requirements without access to low-cost gas-fired generation.

It may be possible that more DSM could be used to offset some of the incremental load growth requirements and thereby reduce some of the need for incremental supply-side resource options. However, there is uncertainty in terms of how much, if any, DSM could offset the load requirements from load drivers such as EVs. This could be assessed in future long term resource and DSM planning if the higher load growth scenario starts to emerge.

The portfolio and associated LRMC for the low load scenario is not presented in the previous figure because no incremental resources are required and therefore there is no LRMC. If this scenario were to occur, FBC would reduce the amount of energy and capacity from the PPA over time to match the load requirements (represented by the yellow line in the following figure). The following figures illustrate this scenario.

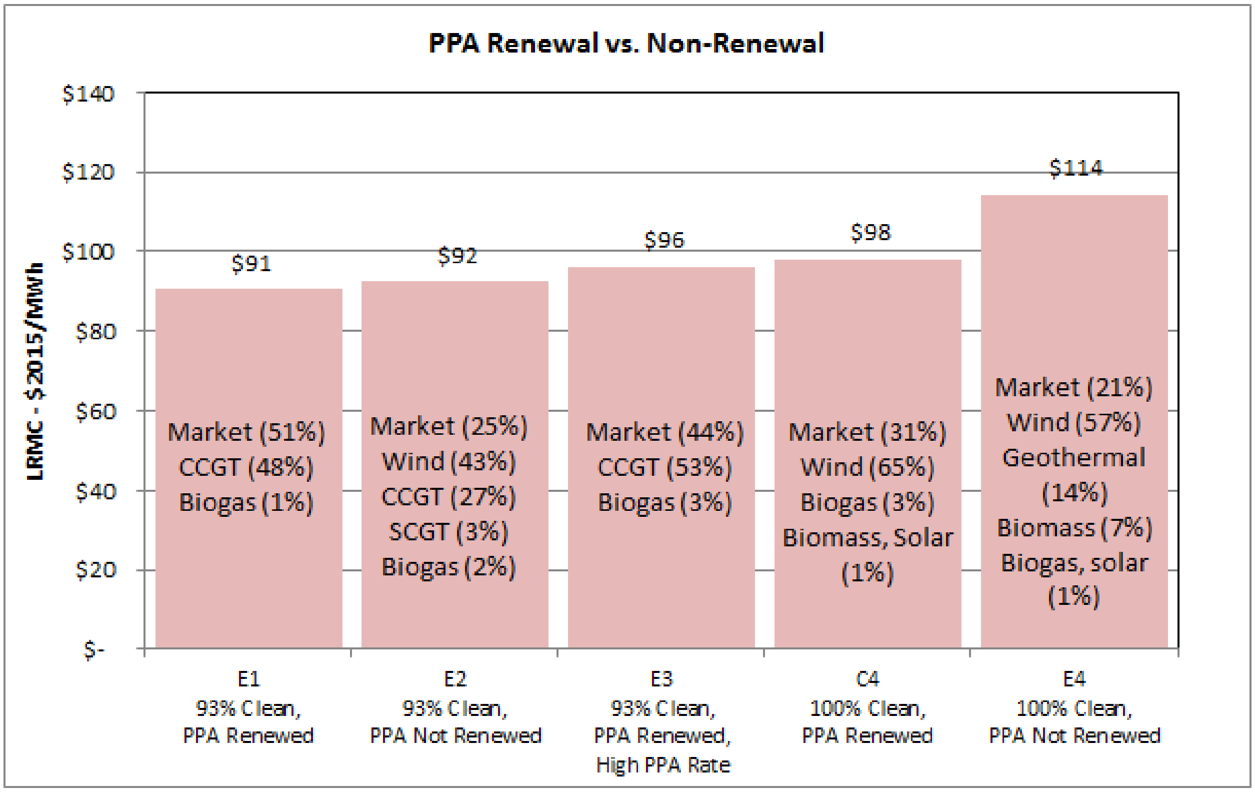
Figure 9-5: Energy LRB with Low Load Scenario



9.3.5 PPA Renewal

FBC has evaluated portfolios that include renewal of the PPA beyond 2033 and those that do not include renewal of the PPA. The results for portfolios that meet the 93 percent clean or renewable objective and the mix of clean or renewable resources included in the portfolios are provided in the following figure. FBC has also analysed a portfolio based on the high PPA rate scenario, as described in Section 2.5.

Figure 9-6: Portfolios with and without PPA Renewal



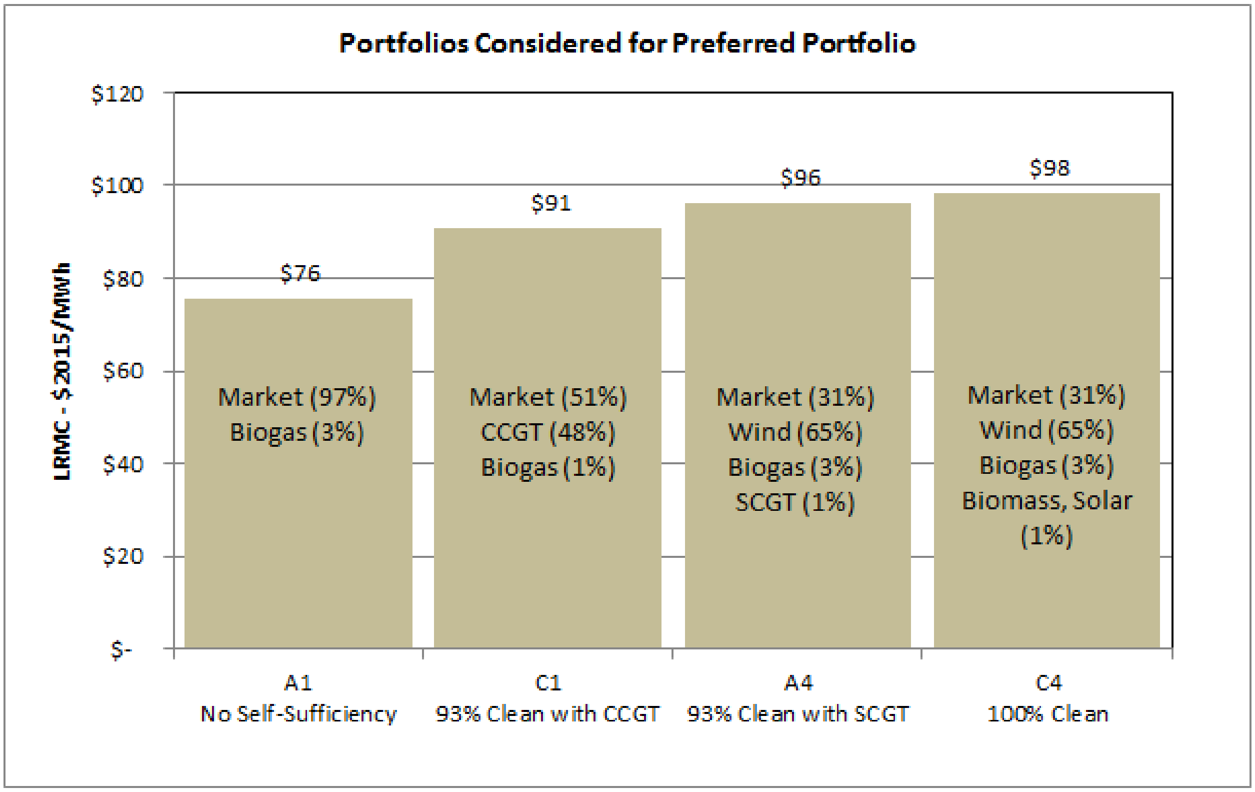
The LRMC values for the portfolios without PPA renewal (E2 and E4) are higher than those with PPA renewal. This is because the PPA is one of the lowest cost resource options and replacing it with other supply-side resource options increases the LRMC value.

As discussed in Section 2.5, FBC's base case assumption for future increases in the PPA rates is 1 percent per year (in real terms) for PPA Tranche 1 Energy and capacity. If BC Hydro rates increase by 3 percent per year (in real terms) as per the high PPA rate scenario, the LRMC value for the portfolio with PPA renewal (E3) would increase.

9.3.6 Preferred Portfolio

Based on the portfolio analysis presented in the previous sections, FBC has determined a set of portfolios that are considered for the preferred resource portfolio. This set comprises several portfolios from the discussion and figures in the previous sections and is presented in the following figure.

Figure 9-7: Portfolios Considered for Preferred Portfolio



The portfolios considered for selection as the preferred portfolio are the market-based portfolio (A1), the two portfolios that meet the 93 percent clean or renewable target with a CCGT plant (C1) or a SCGT plant (A4) and the portfolio based on 100% B.C. clean or renewable generation resources (C4). These portfolios include the high level of DSM and power from renewal of the PPA. FBC believes that they best meet the LTERP's objectives of cost-effectiveness, reliability, inclusion of cost-effective DSM and consideration of B.C.'s energy objectives.

Note that for portfolios C1, A4 and C4, market purchases are selected until 2025 and incremental supply-side resources are not required until at least 2026. Market purchases are selected because they are lower cost than the PPA Tranche 1 Energy, at least for the first few years of the planning horizon. For portfolio A1 with no self-sufficiency, market purchases are selected throughout the 20 years because market power is lower cost than the other resource options.

The criteria to determine the preferred portfolio include cost (i.e. LRMC), reliability, geographic diversity of generation resources and consistency with the *CEA* objectives of encouraging socio-economic development and the creation and retention of jobs (i.e. employment full-time equivalents (FTEs) per year) and reducing environmental impacts in terms of GHG emissions. The following table provides these attributes for each of these portfolios.

1 **Table 9-2: Attributes of Portfolios Considered for Preferred Portfolio**

Portfolio		Incremental Resources	LRMC ($/MWh)	Max % Non-Clean BC Resources (based on energy)	GHG emissions produced in BC (tonnes CO2e)	Full-Time Equivalents per year	Geographic Resource Diversity
A1	No Self-Sufficiency	Market (97%) Biogas (3%)	$76	0.0%	0	14	Low
C1	93% Clean with CCGT	Market (51%) CCGT (48%) Biogas (1%)	$91	3.9%	189k	164	Medium
A4	93% Clean with SCGT	Market (31%) Wind (65%) Biogas (3%) SCGT (1%)	$96	0.2%	3k	145	High
C4	100% Clean BC Resources	Market (31%) Wind (65%) Biogas (3% Biomass, Solar (1%)	$98	0.0%	0	216	Medium

2

The portfolio with no self-sufficiency (A1) is the least cost portfolio considered for the preferred portfolio. It mostly includes market purchases and also a small amount of biogas. However, as discussed in Section 8.2.4, long term market reliance has some risks in terms of access to supply and market price risk and is not consistent with the *CEA*'s objective of achieving electricity self-sufficiency. While this portfolio does not include any B.C. generation that emits GHGs, it provides little socio-economic benefit in terms of employment in B.C. (only 14 FTEs per year) and does not improve FBC's geographic resource diversity.

The portfolio that meets the 93% clean or renewable objective with CCGT and biogas (C1) is the next lowest cost of the four portfolios. This portfolio provides more socio-economic benefits in terms of employment, with 164 FTEs per year, and provides some geographic resource diversity given that the CCGT could be located in the Okanagan region (with FBC's other generation plants being located in the Kootenay region). This portfolio would also be considered more reliable than the market-based portfolio (A1) due to the inclusion of a CCGT plant. However, this portfolio increases GHG emissions by producing 189,000 carbon dioxide equivalents over the planning horizon.

The portfolio that includes 100% clean or renewable B.C. resources (C4), in the form of wind, biomass, biogas and solar, has a higher LRMC than the portfolio with the CCGT (C1). It produces no GHG emissions in B.C. and has the highest socio-economic contribution with 216 FTEs per year. It also provides some geographic resource diversity since wind and solar resources would likely be located in the Okanagan while biomass would be in the Kootenay region.

Portfolio A4 includes wind, biogas and SCGT as generation resources. It has a lower LRMC of $96 per MWh than the 100% clean portfolio (C4) at $98 per MWh, but a higher LRMC than the other two portfolios (A1 and C1). The resources in this portfolio produce minimal GHG emissions of only 3,000 CO2 equivalents over twenty years. This is due to the SCGT resource not being required until 2033 and also because the SCGT is only required to run during peak demand periods, unlike a CCGT plant that would run more frequently as a base load resource. Furthermore, including a SCGT plant in the portfolio provides FBC with additional reliability and flexibility for unforeseen capacity and/or energy requirements because it can be used to run more frequently than required for peak demand periods. The portfolio also provides socio-economic benefits of 145 FTEs per year and provides high geographic resource diversity with wind and the SCGT resources likely being located in the Okanagan. This portfolio best meets the LTERP objectives in terms of balancing cost, reliability and geographic resource diversity with B.C.s energy objectives as so it the preferred portfolio.

9.3.6.1 Planning Reserve Margin

Planning Reserve Margin (PRM) is the dependable capacity above the expected peak demand and is measured in MW or percentage of the expected peak. PRM's role is to ensure resource adequacy when dealing with unforeseen increases in demand and forced outages in the system. It serves the ultimate goal of "keeping the lights on" over the planning horizon. Negative PRM indicates that the system capacity is not sufficient to meet the expected demand.

A PRM that is positive but falling below some targeted margin signals that additional capacity is needed to meet a resource adequacy target. The Company adopted Loss-Of-Load-Expectation (LOLE), or the expected number of days in a year the generation capacity fails to meet load, as the reliability metric for PRM, and targeted 1 day in 10 years or 0.1 day per year, used by most utilities, in its evaluation of resource adequacy.

FBC has applied the LOLE resource adequacy test to the preferred portfolios to ensure that they meet the PRM requirements. One of the portfolios FBC considered for the preferred portfolio, the 100% clean or renewable B.C. resources portfolio (C4), did not meet the PRM requirements as originally configured and so the resources included in that portfolio were changed to meet PRM requirements. This included the addition of biomass to the portfolio to provide some back-up base load supply that is not intermittent like wind or solar. In these portfolios, market supply is also utilized to meet any unforeseen increases in demand or forced outages of plants. Therefore, at this time, FBC has no incremental requirements or costs relating to PRM.

FBC has provided a PRM report describing its methodology and results for the preferred portfolio in Appendix L.

9.3.6.2 Contingency Plans

This section discusses contingency plans for the preferred portfolio to ensure that it can meet the objectives previously discussed if assumptions and conditions change (i.e. changes beyond those covered by the PRM discussed above). Such changes could include, for example, increases in market gas or power prices or a new large load requirement on the FBC system.

The preferred portfolio includes several types of resources such as market purchases, SCGT, wind and biogas. Increases in market gas prices would not have a material effect on the costs of the SCGT given that it is used for limited amounts of energy and capacity for peaking and reliability purposes. Increases in market power prices, however, could have a more significant impact on the portfolio costs. This was discussed in Section 9.4.3, above, where the impacts of higher market prices increased the LRMC value from $96 per MWh (A4) to $98 per MWh (C3). With higher market prices, FBC selected more energy from wind generation and less from the market for the portfolio.

Section 4 discusses load scenarios and the potential for increased load due to fuel switching, EVs and the addition of new large loads to the FBC system. While the load increases from fuel switching from gas to electricity and EVs would likely occur gradually over time, a new large load addition, from a datacentre or hospital for example, could occur much more quickly. In this scenario, discussed in Section 9.4.4, FBC could rely on more market purchases but may also be required to add new resources such as wind, solar and gas-fired generation. Depending on the timing of the additional load requirements, FBC would have to accelerate the acquisition or building of new generation before 2026, when new resources are otherwise required based on the reference case load forecast. The inclusion of SCGT in the preferred portfolio does provide some additional flexibility to handle any new large loads, as this resource can be used for energy and capacity needs.

The SCGT would also provide additional reliability in the event that the primary resource in the portfolio, wind, does not provide dependable energy and capacity when required. The SCGT plant could provide back-up capability during critical periods when the wind is not blowing.

9.4 CONCLUSIONS

Based on the analysis of the various portfolios and determination of the preferred portfolio, the following conclusions can be stated.

First, FBC has no need for incremental generation resources until 2026. FBC does not expect any energy gaps until 2025 or any capacity gaps until 2035. The market continues to be a reliable and cost effective source of electricity supply for FBC. If self-sufficiency is required earlier, additional energy resources will be required before 2026.

Second, FBC will continue to optimize market supply and PPA Tranche 1 Energy in the short to medium term. The flexibility of the PPA enables FBC to increase its energy take when market prices are higher than the PPA rate and lower the PPA take when market prices are lower.

Third, the DSM High level of load growth offset has been selected as it provides cost effective DSM and includes a ramp up higher DSM levels (80% of load growth) close to when energy LRB gaps are expected to appear.

The preferred portfolio includes a mix of market supply, wind, biogas and SCGT resources. As the cost for these and other resources, as well as the reference case load forecast, may change over time, FBC will continue to assess resource options and examine the LRB to determine what new resources may be required and when. Updates will be provided in FBC's next long term resource plan. Also, as discussed in Section 8.2.6, market supply options may arise in B.C. in the future as BC Hydro's expiring EPAs may provide FBC with the opportunity to acquire power from EPA facilities on a cost-effective basis. FBC will continue to monitor BC Hydro contract renewals for any resource option opportunities.

The following table provides a summary of these conclusions.

Table 9-3: Portfolio Analysis Conclusions

Time Frame	Conclusion
Short Term (2016 - 2020)	• Optimization of PPA and market purchases • Monitor expiring EPAs for market opportunities within B.C.
Medium Term (2021 - 2025)	• Optimization of PPA and market purchases • Assess energy resource options in next LTERP • Be prepared to accelerate energy resource options based on updated LRB
Long Term (2026 – 2035)	• Optimization of PPA and market purchases if market continues to be cost-effective and reliable • Build new energy resources, such as biogas and wind, for 2026 or contract with B.C. market supply • Plan for new capacity resources, such as SCGT, for 2033 or sooner if PPA not renewed

10. STAKEHOLDER AND FIRST NATIONS ENGAGEMENT

Connecting with customers, communities, other stakeholders and First Nations on long range planning issues is valuable to FBC. Effective stakeholder engagement provides insight and feedback that can impact the energy planning process, including load forecasting and scenario analysis, DSM program development, as well as the development of portfolios and determination of a preferred portfolio and an action plan.

When soliciting stakeholder input during the resource planning process, the Commission's Resource Planning Guidelines encourage utilities to "focus such efforts on areas of the planning process where it will prove most useful and to choose methods that best fit their needs." For this 2016 LTERP, FBC has pursued a number of initiatives to offer customers, stakeholders and First Nations the opportunity to participate in discussions that have informed the planning process. These activities included:

- Workshops with the RPAG;
- Community consultation workshops in communities served by FBC;
- A meeting with Ktunaxa Nation representatives;
- Customer consultation through online discussion boards; and
- Other activities that indirectly inform the resource planning process, including dialogue with First Nations, industry associations and other stakeholders.

The RPAG included a member of the First Nations Energy and Mining Council and representatives from local First Nations in the FBC service area were invited to attend the community consultation workshops.

FBC considers stakeholder consultation for resource planning to be an ongoing process and one element of the many stakeholder activities that the Company undertakes for a range of purposes. This section summarizes the range of stakeholder consultation initiatives leading up to the 2016 LTERP. It also includes a summary of discussions with Commission staff.

10.1 *RESOURCE PLANNING ADVISORY GROUP*

The RPAG engages strategic stakeholders representing municipalities, government, First Nations, customers, associations and organizations in the development of the LTERP. The group consists of members with interest and experience in the resource planning process and significant industry knowledge that provide key insight and feedback to FBC. The following table lists the organizations represented in the RPAG.

Table 10-1: RPAG Members

Organization
B.C. Ministry of Energy & Mines - Electricity & Alternate Energy Division
B.C. Municipal Electric Utilities
B.C. Public Interest Advocacy Centre
B.C. Sustainable Energy Association
B.C. Utilities Commission
BC Hydro
Clean Energy Association of B.C.
Commercial Energy Consumers Association of B.C.
First Nations Energy & Mining Council
Industrial Customers Group
Irrigation Rate Payers Group
Lower Columbia Community Development Team Society
Tolko Industries

RPAG workshops provided a forum for discussing many broad themes, including, but not limited to, the following:

- Resource planning process, inputs and assumptions;
- Planning environment, including energy and environmental policy and regulation;
- Long term load forecasting;
- Demand-side management;
- Supply-side resource options;
- Development of load scenarios;
- Planning reserve margin;
- Long Run Marginal Cost;
- Portfolio analysis and results, and
- Other FBC initiatives.

FBC held five RPAG workshops between 2014 and 2016 to review key steps in the LTERP process, discuss inputs into the 2016 LTERP and gain feedback on results. The following table provides the workshop meeting dates and list of major topics discussed. Engagement from attendees was in the form of questions and discussion throughout each presentation and also included an interactive load scenario tool (discussed in Section 4.3) to gather more feedback regarding load drivers and scenarios.

Table 10-2: RPAG Meetings and Major Topics Covered

RPAG Meeting Date	Topics Discussed
December 11, 2014	• Resource planning process and objectives • Planning environment • Load forecasting • DSM overview • FBC generation resources • Regional power markets • Portfolio analysis • Load-Resource Balance
July 28, 2015	• B.C. electricity policy and emissions • Market price forecasts and PPA rate scenarios • Reference load forecast, Monte Carlo range and scenarios approach • Load-resource balance with updated load forecast • FBC resources including potential climate change impacts • Preliminary unit costs for supply-side resource options • Portfolio analysis, including possible alternative portfolios • Planning Reserve Margin overview • Transmission system planning
November 5, 2015	• Long Run Marginal Cost background and approach • Planning Reserve Margin approach and results
April 27, 2016	• Conservation Potential Review and LT DSM Plan • Supply-side resource options and financial assumptions • Market price forecasts and PPA rate scenarios • Long Run Marginal Cost overview and approach • Potential future load drivers and scenarios • Electric vehicles and charging infrastructure in B.C.
October 27, 2016	• Conservation Potential Review results and levels of DSM • Updated long-term load forecast and Monte Carlo range • Updated Load-Resource Balance • Results of portfolio analysis • Alternative and preferred portfolios given LTERP objectives • Long Run Marginal Cost values • LTERP Outline

The feedback received by FBC from the RPAG has been useful in helping FBC to develop the 2016 LTERP. Through the RPAG workshop sessions, stakeholders have been able to provide FBC with input and feedback on areas such as the load forecasting method, load drivers and scenarios, development of portfolios and the preferred portfolio, as well as preferences in terms of demand-side and supply-side resource options. More specifically, some of the feedback and areas of stakeholder interest in the workshops included the following items:

- FBC's consideration of different DSM levels and costs;
- Impacts of climate change on load forecast and resources;
- Consideration of resource option flexibility to reduce risk of stranded assets;
- Consideration of level of correlation between EVs and rooftop solar penetration in load scenarios;
- Excluding a resource portfolio which falls below the 93% clean or renewable *CEA* threshold;
- Consideration of First Nations resource projects in portfolios;
- PRM and impacts on costs for customers;
- Discussion of FBC market access in the LTERP;
- Consideration of FBC purchasing only clean or renewable market power;
- Accounting for continuing declining cost of utility-scale solar power;
- Including rooftop solar and DSM in the listing of resource options;
- Consideration of high carbon price in portfolio analysis, and
- Consideration of EV charging impacts in a future FBC rate design application.

As resource planning is an iterative and ongoing process, some of the feedback and recommendations received from the RPAG during this planning period will also be considered by FBC in the next iteration of the resource planning process to the extent they remain relevant.

10.2 *COMMUNITY CONSULTATION WORKSHOPS*

FBC recognizes the importance of considering diverse community perspectives when planning for the future, and has established resource planning Community Consultation workshops to inform and gather feedback from stakeholders throughout FBC's service territory. Individuals from a variety of roles and backgrounds were invited to attend these ongoing events, including:

- Community planners and developers;
- Energy and sustainability managers and professionals;
- First Nations representatives;

- Municipal community leaders;
- Energy and sustainability non-profit organizations;
- Real estate builders and developers;
- Large businesses and manufacturers;
- Local businesses and business associations; and
- Other interested parties.

Seven Community Consultation workshops were held between 2014 and 2016 in communities within the FBC electricity service area, involving 63 registered participants. These workshops were conducted in collaboration with the FEI gas resource planning group and therefore included presentations and discussions regarding FBC electricity resource planning as well as FEI gas resource planning. This made for the most efficient use of stakeholders' time for those within the combined gas and electric service area and also reduced costs related to the workshops. The following table provides the dates and locations of the workshops.

Table 10-3: Community Consultation Workshops

Workshop Date	Location
October 28, 2014	Kelowna
October 29, 2014	Osoyoos
October 30, 2014	Rossland
October 14, 2015	Penticton
October 15, 2015	South Slocan
October 19, 2016	Penticton
October 20, 2016	Rossland

These workshops sought input on a variety of topics related to electricity resource planning including load forecasting, resource options and transmission planning. FBC presented plans to meet the future needs of customers and communities, and discussed issues affecting energy supply and demand. Also discussed were other FBC initiatives to help meet future energy needs and community GHG emission goals, such as energy efficiency and conservation programs, AMI and electric vehicle infrastructure. The workshops included interactive sessions with stakeholders to promote discussions about potential electricity demand and scenarios and resource options. Site visits were included during the workshops to help with stakeholders' understanding of FBC's generation resources and operations. These included a tour of one of the FBC-owned hydroelectric generating stations (South Slocan) and a tour of the FBC System Control Centre.

Some key themes and areas of interest that were identified as important to stakeholders included:

- Continuing to receive reliable electricity supply;
- Programs and initiatives to help customers and communities manage energy costs;
- Finding solutions to reduce GHG emissions;
- Fuel switching potential between natural gas and electricity;
- Street light conversion to LEDs;
- Concerns with rate increases and the two-tiered rate;
- Emerging technologies such as electric vehicles and rooftop solar; and
- More educational resources for customers and communities regarding energy savings and new technologies.

Overall, the Community Consultation workshops facilitated the sharing of valuable long term planning information between stakeholders and FBC/FEI. In particular, the workshops assisted FBC in identifying energy issues or planning opportunities in municipalities throughout B.C. Stakeholders indicated that they appreciated the opportunity to learn about FBC's initiatives, make direct connections with FBC staff, and offer feedback on the utilities' future plans. Attendees gave positive feedback on the workshop evaluation forms and overwhelmingly stated that they found the workshops both valuable and informative. The workshop discussions were robust and customer-focused, and they demonstrated that FBC's long term planning considerations align well with stakeholder expectations.

10.3 *ONLINE DISCUSSION BOARDS*

To complement FBC's community consultation and RPAG workshops, FBC also conducted online discussion boards, also known as bulletin boards. This method of consultation enabled FBC to engage with about 50 residential and commercial customers of FBC on a number of key items related to DSM and resource planning. FBC used Sentis Research to conduct the consultation process, with FBC providing essential background information and questions for the participants. With these discussion boards, FBC was able to probe customers on their thoughts about resource portfolios and FBC's LTERP objectives. The results are provided in Appendix C of the LT DSM Plan. The results show that customers are in favour of FBC reducing demand through energy conservation over buying electricity from other parties or building additional generation facilities. Customers ranked the LTERP objective of providing cost-effective, secure and reliable power first, following by providing cost-effective DSM and then consistency with provincial energy objectives last. Some customers were sensitive to paying more for clean and renewable resources, stating that their bills were high enough already.

10.4 *DIALOGUE AND ENGAGEMENT WITH FIRST NATIONS*

FBC strives to develop and build mutually beneficial working relationships with First Nations communities. Understanding, respect, open communication and trust continue to be FBC's aim when working with First Nations groups throughout the province.

FBC works to ensure that First Nations' interests are represented in the Company's various stakeholder engagement initiatives. The RPAG includes a member that represents B.C. First Nations, which ensures that First Nations play an active role in the ongoing resource planning process. In addition, First Nations representatives from within the electric service area, including the Okanagan Nation Alliance, the Ktunaxa Nation, and the Secwepemc Nation, were invited to attend the Community Consultation workshops throughout the preparation of this LTERP.

FBC also met with representatives of the Ktunaxa Nation in Cranbrook on October 31, 2016. In this meeting, FBC provided an overview of its long term gas and electric resource planning. During the discussions, the Ktunaxa Nation expressed its concerns about not having access to lower-cost energy given the current unavailability of natural gas for space and water heating and a primary reliance on more expensive electricity for space and water heating. FBC will continue to engage with the Ktunaxa Nation to explore options to help meet its energy needs.

FBC makes every effort to ensure that its business operations are conducted with respect for First Nations' social, economic and cultural interests. This includes a commitment by FBC to dialogue through clear and open communication with Aboriginal communities on an ongoing and timely basis for the mutual interest and benefit of both parties.

To meet this commitment, FBC aims to establish an open dialogue with First Nations at the earliest planning stages of resource and community development to ensure that First Nations' perspectives and interests are understood and considered. For example, the award winning Ecosage Project was a collaboration between the Penticton Indian Band and FBC with the goal of building energy efficient houses within a relatively tight budget. Seven of the eight single family homes involved in the project achieved an Energuide 88 rating, with the other home achieving Energuide 90. From a utility standpoint, being actively involved during the design and build process helped FBC to become part of the solution early while building lasting relationships. The intention is to use Ecosage as a springboard for future First Nations collaborations, where both successes and lessons learned can be incorporated in future projects. The lessons learned from such community development collaborations between FBC and First Nations also help inform how the Company addresses First Nations interests in its long term planning processes.

10.5 *INDUSTRY AND MARKET INVOLVEMENT*

FBC meets regularly with industry associations and other organizations such as the Canadian Home Builders' Association (CHBA), Southern Interior Construction Association (SICA), the Urban Development Institute (UDI), the Union of British Columbia Municipalities (UBCM) and local government associations in order to share information and insight. This dialogue is mutually beneficial as it allows FBC to stay abreast of industry trends and developments while facilitating the dissemination of important information to stakeholders. FBC's involvement with such organizations allows the Company to develop a more comprehensive picture of how the energy market is evolving.

10.6 *DISCUSSIONS WITH COMMISSION STAFF*

The Commission Resource Planning Guidelines encourage utilities to seek regulatory input from Commission staff during resource plan preparation. FBC met with Commission staff periodically to discuss various components of the LTERP. This was to inform Commission staff of LTERP developments and to also obtain comments and feedback from Commission staff. The following table details the meeting dates and topics discussed.

Table 10-4: Meetings with Commission Staff

Meeting Date	Topics Discussed
October 2, 2014	• LTERP objectives • Resource planning guidelines and process • Planning environment • Load forecasting • DSM overview • Supply-side resource options • Long Run Marginal Cost • Stakeholder consultation • LTERP timelines
November 19, 2015	• LTERP filing date extension • CPR schedule • Load-Resource Balance • Load forecast and scenarios • Supply-side resource options • Portfolio analysis • Long Run Marginal Cost • Planning Reserve Margin • Stakeholder consultation • LTERP outline
November 15, 2016	• Load scenarios • CPR results and levels of DSM • Load-Resource Balance • Results of portfolio analysis • Alternative and preferred portfolios given LTERP objectives • Long Run Marginal Cost values • LTERP overview

As noted in Table 10-1 above, Commission staff was also represented on the RPAG.

10.7 *SUMMARY*

FBC has a strong record of conducting effective stakeholder and First Nations engagement activities. In particular, for this LTERP, FBC has consulted a dedicated RPAG planning group, hosted a number of Community Consultation workshops to engage diverse perspectives on FBC's planning activities across the communities that the utility serves, and conducted online discussion boards to gain feedback directly from customers. FBC also met with the Ktunaxa Nation at its request. This First Nations and stakeholder consultation adheres to the Commission's stakeholder input guidelines and has been beneficial to the development of this LTERP. FBC also met with Commission staff to discuss various resource planning topics and obtain feedback. The information gained through these activities is incorporated into the LTERP process in a number of ways, such as by informing FBC's planning and analysis, identifying long term planning issues of concern to a number of stakeholder groups, and identifying interested stakeholders who may become more engaged in the LTERP process. FBC recommends continuing with the RPAG and community consultation activities prior to the Company's next long term resource planning process in order to build on the interest and input gained through these initiatives.

11. ACTION PLAN

This action plan describes the activities that FBC intends to pursue over the next four years based on the discussion and conclusions provided in this LTERP and LT DSM Plan. It includes actions relating to monitoring the planning environment and strategies for optimizing short-term resource requirements as well as future DSM spending requirements. Contingency plans that enable FBC to respond to changed circumstances have been discussed in Section 9 as they relate to the preferred portfolio. This action plan is consistent with the requirements of the BCUC *Resource Planning Guidelines.*

1. Continue to monitor the energy planning environment

Being aware of and understanding the many factors that influence FBC's planning environment is critical for long term resource planning and is an ongoing activity for FBC. FBC will continue to monitor energy and environmental policy in Canada and the U.S. as well as regional market developments that may impact market supply, demand and pricing, resource options and costs. In addition, FBC will continue to monitor and examine emerging technologies and changing demand and uses for electricity by its customers. FBC's monitoring activities will ensure that it is aware of and able to respond to relevant changes in the planning environment to meet the LTERP objectives.

2. Monitor potential load drivers to determine if a particular load scenario is emerging

As discussed in respect of the Load Scenarios (Section 4), there are a number of load drivers that have the potential to significantly impact FBC's load requirements over the planning horizon. FBC will continue to monitor, where possible, the various load drivers and, in particular, the drivers that may have the most impact on FBC's loads: EVs, rooftop solar PV and fuel switching. This will enable FBC to determine if a particular scenario is emerging or if penetration levels and growth for a particular driver are occurring faster than expected and if the forecast LRB gaps are changing.

3. Continue to assess the potential requirements and timing for new resource options within B.C.

The LRB presented in this LTERP indicates that new supply-side resources are not required until 2026 based on existing resources and committed contracts, the reference case load forecast and the proposed level of DSM. However, actual load requirements and DSM program uptake by customers may not match the forecasts, meaning that resources may be needed sooner or later than expected. As part of its ongoing resource planning activities, FBC will continue to assess the LRB on a periodic basis to see if any changes in resources might be required.

4. Continue to optimize the PPA and market purchases in the short term

As explained in Section 5.4, FBC is required to submit an annual nomination for PPA energy deliveries in the following operating year, but retains the ability to displace up to 25 percent of the amount nominated with market purchases, if market conditions would create additional savings for FBC customers compared to PPA energy rates. The Company will continue to purchase market power when it will result in savings to customers and doing so is in accordance with the Company's overall resource requirements.

5. Complete final phase of BC CPR

The FBC CPR report attached as Appendix A of the LT DSM Plan was the result of the base services phase of the BC CPR, and included assessing the technical and economic savings potential available in the Company's service area. The base services focused on economic energy savings measures, but also estimated the commensurate demand (capacity) savings associated with the measures.

The next and final phase of the BC CPR will cover additional scope services including: Demand Response and Market potential plus supporting activities (e.g. DSMSim model enhancements and utility staff training). The final phase of the BC CPR is expected to be completed in 2017 and will be used to inform future DSM expenditure filings.

6. Prepare submission of next long term electric resource plan and long term DSM plan

Given that FBC requires no new supply-side resources in the next ten years, FBC expects that it would submit its next long term electric resource plan and long term DSM plan in approximately five years from the submission date of this LTERP. This would provide FBC with enough lead time to assess the updated LRB and available resource options and costs before any new resources may be required by 2026. As part of the development of its next long term electric resource plan and long term DSM plan, FBC expects that it would continue its engagement with customers, First Nations and other stakeholders to ensure their energy and conservation priorities are met.

Appendix A

GLOSSARY OF TERMS AND ACRONYMS

APPENDIX A – GLOSSARY OF TERMS AND ACRONYMS

Acronym or Term	Definition
AECP	Annual Electric Contracting Plan – document prepared by FBC Inc. which outlines plans to meet the peak demand and annual energy requirements for the next operating year.
AIC	Average Incremental Costs - approach takes the present value of the incremental costs expected to be incurred over the planning horizon and divides the incremental costs by the present value of the additional load expected to be served within the same period.
AMI	Advanced Metering Infrastructure Project – replacement of electricity meters with new advanced meters across the FBC service territory. In order for the meters to communicate with FBC, software infrastructure was also installed along with a communications network. The project provides real-time and more granular load data from customer endpoints and reduces theft on the system.
Base Load Resources	Resources that provides dependable capacity and are expected to operate at a high capacity utilization factor, generating significant amounts of electrical energy over time.
BC Clean or Renewable Resource	*Clean Energy Act* definition includes biomass, biogas, geothermal heat, hydro,solar, ocean, wind or any other prescribed resource.
BC Hydro PPA	Power Purchase Agreement between BC Hydro and FBC - 20-year agreement that expires in 2033 and that provides up to 200 MW of capacity and 1,752 GWh/year of associated energy to FBC from BC Hydro.
BCUC	British Columbia Utilities Commission - independent regulatory agency of the B.C. government that operates under and administers the Utilities Commission Act. The Commission regulates B.C.'s natural gas and electricity utilities, intra-provincial pipelines and universal compulsory automobile insurance.
BEV	Battery Electric Vehicle - type of electric vehicle (EV) that uses chemical energy stored in rechargeable battery packs.
BPA	Bonneville Power Authority – non-profit power marketing administration based in the Pacific Northwest, which includes Washington, Oregon, Idaho and B.C.

Acronym or Term	Definition
BPPA	Brilliant Power Purchase Agreement - agreement with Brilliant Power Corporation where FBC has agreed to purchase the energy and capacity entitlement allocated to the Brilliant Plant pursuant to the CPA and after the terminationof the CPA, the actual electrical output, if any, generated by the Brilliant Plant.
Canal Plan Agreement Entitlement	The average water year generation of the generating facilities included in the CPA. 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	The instantaneous output of a power plant or system electricity demand at any given time, normally measured in kilowatts (kW) or megawatts (MW)
Capacity Utilization Factor	The ratio of the actual output from a plant over the year to the maximum possible output from it for a year under ideal conditions.
CBOC	Conference Board of Canada - non-profit organization dedicated to researching and analysing economic trends, as well as organizational performance and public policy issues.
CBT	Columbia Basin Trust - created by the *Columbia Basin Trust Act* in 1995 to benefit the region most adversely affected by the Columbia River Treaty (CRT) in the province of B.C.
CCGT	Combined Cycle Gas Turbine - natural gas-fired generation resource that couples a combustion turbine with a steam cycle plant, in order to generate electricity.
CEA	*Clean Energy Act* - legislation outlining the BC government's commitment to clean energy and the environment which includes key objectives relating to GHG emissions, clean or renewable resources, DSM and socio-economic development.
CEPSA	Capacity and Energy Purchase and Sale Agreement - agreement between Powerex and FBC where FBC will sell the remaining surplus WAX CAPA residual capacity to Powerex on a day-ahead basis.
CET	Customer Engagement Tools - DSM tool with the ability to operate across digital channel which improves customer experience and drives greater DSM program participation. Some examples of CET's are digital or paper home energy reports and advanced webpotals.
CHBA	Canadian Home Builders' Association - not-for-profit organization that brings together builders and industry experts from across the country to share information and ideas, and to formulate recommendations to governments to improve the quality and affordability of homes for Canadians.

Acronym or Term	Definition
CHP	Combined Heat and Power - cogeneration facilities for large industrial customers that reduces the amount of electricity they require from the system and potentially allows them to become net generators of electricity.
CIP	Customer Information Portal – online tool that allows customers to view historic billing and consumption data, which can result in behavioural changes in energy use.
Clean Energy Vehicle Program	B.C. government program intended to encourage and accelerate the adoption of clean electric vehicles in the Province for their environmental and economic benefits.
CLP	Climate Leadership Plan – B.C. government plan released in 2016 that outlines action items to reduce GHG emissions while promoting development and creating jobs, based on CLT recommendations.
CLT	Climate Leadership Team - a team comprised of leaders from the business, academic and environmental communities, including First Nations, to provide advice and recommendations to government on how to maintain B.C.'s climate leadership.
CPA	Canal Plant Agreement - enables BC Hydro and the Entitlement Parties (collectively, the CPA 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.
CPC	Columbia Power Corporation - crown corporation that develops, owns and operates hydro power projects in the Columbia Basin.
CPCN	Certificate of Public Convenience and Necessity - a certificate obtained from the BCUC under Section 45 of the *Utilities Commission Act* for the construction and/or operation of a public utility plant or system, or an extension of either, that is required, or will be required, for public convenience and necessity.
CPP	Clean Power Plan - U.S. Environmental Protection Agency's (EPA) plan that aims to reduce carbon dioxide emission from power plants by 32 percent below their 2005 levels by 2030.
CPR	Conservation Potential Review - collaborative province-wide study between FBC, FEI, Pacific Northern Gas and BC Hydro that determines cost-effective demand-side management potential in B.C.
CRT	Columbia River Treaty - a treaty signed in 1961 between Canada and the U.S. that enables storage reservoirs to be built and operated in B.C. to regulate Columbia River flows into the U.S. for power production and flood control.

Acronym or Term	Definition
Dependable Capacity	The generation capacity available for the peak hours during each month of the year.
DG	Distributed Generation - Individual use generation resource, such as solar or small wind turbines, distributed amongst and utilized by customers. Typically offset individual customer power consumption and is connected to the utility system via some form of net metering facility.
DR	Discount Rate - rate used to determine the present value of an expenditure that will occur over a period of time, reflecting the cost of capital.
DSM	Demand-Side Management - actions that modify customer demand for electricity helping to reduce their consumption and defer the need for new utility energy and capacity supply additions.
Energy	The electricity produced or used over the a period of time, usually measured in kWh, MWh or GWh.
EV	Electric Vehicles - a vehicle that uses one or more electric motors or traction motors for propulsion. It may be powered through a collector system by electricity from off-vehicle sources, or may be self-contained with a battery or generator to convert fuel to electricity.
FBC	FortisBC Inc. – the utility that provides electricity service in the southern interior or B.C.
FEI	FortisBC Energy Inc.- the utility that provides natural gas service in B.C. and propane service for Revelstoke.
FERC	Federal Energy Regulatory Commission - independent U.S. federal agency that regulates the interstate transmission of natural gas, oil, and electricity. FERC also regulates natural gas and hydropower projects.
GHG	Greenhouse Gas - any gaseous compound in the atmosphere that is capable of absorbing infrared radiation, thereby trapping and holding heat in the atmosphere. The primary greenhouse gases in Earth's atmosphere are water vapor, carbon dioxide, methane, nitrous oxide, and ozone.
GJ	Gigajoule - a unit of energy equivalent to one billion joules. One joule of energy is equivalent to the heat needed to raise the temperature of one gram of water by one degree Celsius (ºC) at standard pressure (101.325 kPa) and standard temperature (15ºC).
GLJ	GLJ Petroleum Consultants Ltd. - a private energy industry consultancy serving clients who require independent advice relating to the petroleum industry, including the preparation of natural gas and oil price forecasts on a quarterly basis.
GWh	Gigawatt hour - a unit of energy equal to 1 million kilowatt-hours.

Acronym or Term	Definition
Henry Hub	Distribution hub on the natural gas pipeline system in Erath, Louisiana. The Henry Hub price is the benchmark price of natural gas in North America and is the point of delivery used in the New York Mercantile Futures Exchange (NYMEX) futures contract.
Heritage Contract	A per year contract (in perpetuity) between BC Hydro's Generation and Distributed Lines of Business to ensure BC Hydro customers (including FBC) benefit from the existing low-cost hydroelectric and thermal resources in the BC Hydro system.
HLH	Heavy Load Hours - The time of day in which peak demand occurs from 0600h through 2200h, Monday to Saturday, excluding holidays.
Huntingdon/Sumas	Natural gas market hub on either side of the B.C. /Washington state (U.S.) border through which much of the Pacific Northwest regional gas supply is traded.
IJC	International Joint Commission - Commission to help prevent and resolve disputes about the use and quality of boundary waters and to advise Canada and the U.S. on questions about water resources.
Installed Capacity	The maximum rating of a generator or transmission station equipment as identified by the manufacturer under specified conditions.
IoT	Internet of Things - the combined effect of an increasing number of household appliances and devices being connected to a home network, information collected by those devices being delivered to residential consumers to allow for optimal decision making, and the presence of systems that allow consumers to take control of their consumption in response to this information.
IPP	Independent Power Producer - privately owned electricity generating facility that produces electricity for sale to utilities or other customers.
IPSS	Integrated Photovoltaic Storage Systems - power system designed to store and supply usable solar power by means of photovoltaics (PVs).
IRP	Integrated Resource Plan - document that details the resource planning process and outcomes that guide a utility in planning to serve its customers over the long term.
kW	Kilowatt - unit of energy equal to 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.
kWh	Kilowatt hour - equal to one thousand watts used for a period of one hour - the basic unit of measurement of electric energy. On average, residential customers in B.C. use about 10,000 kWh per year.

Acronym or Term	Definition
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).
LLH	Light Load Hours - all hours that are not Heavy Load Hours (HLH).
LLST	Large Load Sector Transformation - unanticipated growth of large load customers not associated with traditional energy intensive industries.
LNG	Liquefied Natural Gas - natural gas stored under high pressure, which turns to liquid form. Approximately 600 times as much natural gas can be stored in its liquid state than in its typical gaseous state.
LOLE	Loss of Load Expectation - the expected number of days in a year the generation capacity fails to meet load.
Losses	Loss of electric energy due to line losses, losses due to wheeling through the BC Hydro system, company use, and unaccounted for energy (meter inaccuracies and theft).
LRB	Load Resource Balance – difference between existing and committed resources and load forecast. Used to determine quantity and timing of new resources.
LRMC	Long Run Marginal Cost - the cost of incremental resources to meet load requirements over the planning horizon.
LT DSM Plan	Long Term Demand Side Management Plan which outlines DSM potential, scenarios and programs on a long-term basis.
LTERP	Long Term Electric Resource Plan - examines future demand and supply resource options over the planning horizon to cost effectively and reliably meet customers' energy and capacity needs.
Mid-C	Mid-Columbia River electricity trading hub located along the Columbia River on the border between Washington and Oregon. One of the top three electricity trading hubs in North America by volume.
Monte Carlo	Analysis that uses the variability in historic data to forecast possible high and low ranges around the reference case load forecast.
MW	Megawatt - a unit of power equal to one million watts or one thousand kilowatts, commonly used to measure both the capacity of generating stations and the rate at which electric energy can be delivered.
MWh	Megawatt Hour (MWh) - 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.

Acronym or Term	Definition
NPV	Net Present Value – the sum of the present values of a series of individual cash flows. Present value is the value in the present of a sum of money or cash flow, in contrast to some future value it will have when it has been invested at compound interest.
Peak Demand	The largest amount of capacity needed at one point in time on the electrical system.
Peaking Resources	Resources that can be dispatched to provide dependable capacity but are expected to operate at a low capacity utilization factor generating electricity only when it is needed.
PEV	Plug-in Electric Vehicle - any motor vehicle that can be recharged from an external source of electricity and the electricity stored in the rechargeable battery packs drives or contributes to drive the wheels.
PHEV	Plug-in Hybrid Electric Vehicles - electric vehicle that uses rechargeable batteries, or another energy storage device, that can be recharged by plugging it in to an external source of electric power. A PHEV shares the characteristics both of a conventional hybrid electric vehicle, having an electric motor and an internal combustion engine,
PHS	Pumped Hydro Storage – electricity generation facility that stores and produces electricity to supply high peak demands by moving water between reservoirs at different elevations.
PNW	Pacific Northwest - a region that is commonly referred to as the three northwestern states of Washington, Oregon, Idaho and the Province of B.C.
PPA	See BC Hydro PPA.
PRM	Planning Reserve Margin - dependable capacity above the expected peak demand and is measured in MW or percentage of the expected peak. PRM is to ensure resource adequacy when dealing with unforeseen increases in demand and forced outages in the system.
PV	Photo-Voltaic - includes the conversion of light into electricity using semiconducting materials that exhibit the photovoltaic effect.
RPAG	Resource Planning Advisory Group - group of stakeholders representing municipalities, government, First Nations, customers, associations and organizations that provide feedback and advise in the development of the FBC LTERP.
RPS	Renewable portfolio standards - policies designed to increase generation of electricity from renewable resources in the U.S.

Acronym or Term	Definition
SCGT	Simple Cycle Gas Turbine - natural gas-fired generation resource that operates by propelling hot gas through a turbine in order to generate electricity.
UCA	*Utilites Commission Act* - legislation which provides the BCUC with the authority to oversee natural gas and electricity utilities, intra-provincial pipelines and universal compulsory automobile insurance in B.C.
UCC	Unit Capacity Cost - the annualized cost of providing dependable capacity for a specific resource option, expressed in $/kW-year.
UEC	Unit Energy Cost - the annualized cost of generating a unit of electrical energy for a specific resource option, expressed in $ per MWh.
ULE Program	Upgrade and Life Extension Program - program completed in 2012, which involved upgrading the majority of the FBC-owned plants.
WACC	Weighted Average Cost of Capital - the rate that a company is expected to pay on average to all its security holders to finance its assets.
Watt	The basic unit of measurement of electric power, indicating the rate at which electric energy is generated or consumed.
Watt-hour (Wh)	An electrical energy unit measure equal to one watt of power supplied to, or taken from, and electric circuit steadily for one hour.
WAX	Waneta Expansion - the addition of a second powerhouse located immediately downstream of the Waneta Dam on the Pend d'Oreille River. The expansion shares the existing hydraulic head and generates power from water that would otherwise be spilled.
WAX CAPA	The Waneta Expansion Capacity Purchase Agreement - a 40-year capacity purchase agreement with the Wanata 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).
WECC	The Western Electricity Coordinating Council - a non-profit corporation that assures a reliable Bulk Electric System in the geographic area known as the Western Interconnection. The WECC Region extends from Canada to Mexico and includes the provinces of Alberta and B.C., the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between.
Zero Emissions Building Plan	City of Vancouver's plan requiring all new buildings to achieve zero operational GHG emissions by 2030.

Appendix B

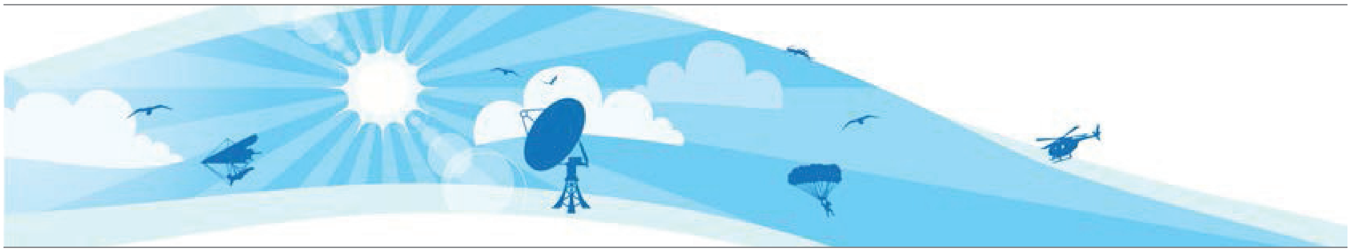
BRITISH COLUMBIA’S CLIMATE LEADERSHIP PLAN

Climate Leadership Plan

AUGUST 2016

BRITISH COLUMBIA

Climate Leadership Plan



AUGUST 2016

For more information visit the website:
gov.bc.ca/ClimateLeadership

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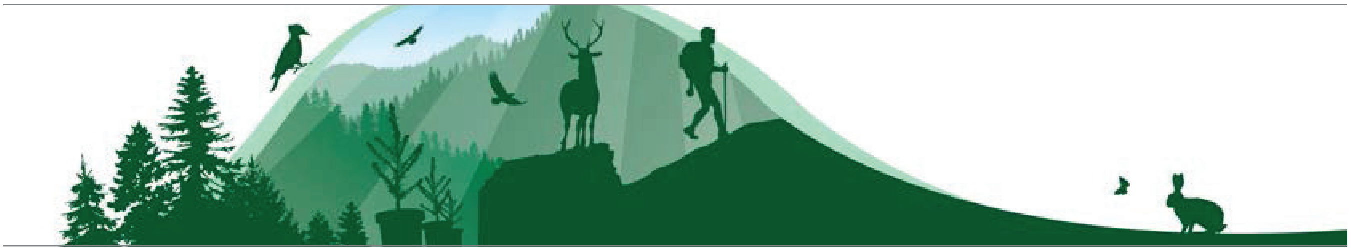
B.C.'s Vision for Climate Leadership



British Columbians are proud to be recognized worldwide as leaders in the fight against climate change. We have proven that you can cut emissions while creating jobs.

In 2008, the Province released our Climate Action Plan and the world took notice. Since then it has provided us with the foundation we needed to reach our first target to reduce greenhouse gas (GHG) emissions to 6 per cent below 2007 levels by 2012.

We knew then that carbon pricing had to be central to any plan to fight climate change. That is why British Columbia was the first jurisdiction in North America to introduce a broad-based, revenue-neutral carbon tax. We knew we had to get our own public sector emissions in order before asking industry and the general public to do the same, so we implemented our Carbon Neutral Government legislation. Along with California, we were also the first to implement a low carbon fuel standard.

Our plan recognized that there were fundamental policies that everyone had to get going on — like addressing the emissions that come from our built environment, helping buyers afford low-emission, electric and hydrogen fuel cell vehicles, and preparing our province for climate change with an adaptation strategy.

Since 2011, I have had the honour to serve as British Columbia's Premier, and I am proud to say we have continued this passionate commitment to fighting climate change through actions such as: renewing the Clean Energy Vehicle program; expanding the Carbon Neutral Capital Program to health authorities and public post-secondary institutions; providing funding for energy efficiency improvements in our local governments and First Nations; and working with partners here in Canada and the U.S. on initiatives to fight climate change.

Through these actions and others, British Columbia has demonstrated that we can reduce emissions while continuing to grow the economy and create jobs. We are already seeing proof — our province now has over 60,000 clean economy jobs.

Today, we continue to build on the work we started in 2008 by launching our new Climate Leadership Plan. While our 2008 strategy laid the foundation for large scale change, we are now developing a strategy to add targeted, coordinated, sector-specific actions. We started by consulting with experts and listening to British Columbians. Now we are taking action with an approach that recognizes that real sustainability means balancing environmental concerns with social and economic issues, such as affordability and job creation.

B.C. has the highest and most comprehensive carbon tax in North America. As climate leaders, we know we can achieve more working together with Canada's provinces, territories and the federal government, while respecting each other's jurisdictions. We support the adoption of B.C.'s price on carbon as a national benchmark, and increasing that price together in an effective and affordable way, once others catch up.

Revenue neutrality remains the core principle of British Columbia's carbon tax. The carbon tax can only increase if every dollar is returned to citizens in the form of tax relief. In that way, we tax the pollution we don't want and use the money for what we do want — money in people's pockets, jobs and opportunity.

The Province will also protect jobs by ensuring B.C.'s global competitiveness. As our Climate Leadership Team recommended, we will design a mechanism to protect the competitiveness of our industries that depend on energy and trade.

> *"British Columbia has the highest and most comprehensive carbon tax in North America."*

Carbon pricing is one of several key tools to tackle climate change. Technological breakthroughs and innovations are also required, as well as targeted actions to reduce greenhouse gas emissions, like the ones we are announcing today.

We are taking action across key areas where emissions are created, including upstream methane emissions mitigation, new transit options and energy-efficient building improvements. We are ensuring that we develop industries like liquefied natural gas in ways that are cleaner than competing jurisdictions, allowing us to ship it to other nations where it can reduce their reliance on higher carbon energy sources like coal and oil. By seizing the opportunity of a low carbon economy and securing global trade partnerships, we can create thousands of green jobs in areas like clean technology and clean energy, contributing to reductions in emissions not just here at home, but around the world.

Photo Credit: Adam Ryder/World Bank (https://creativecommons.org/licenses/by-nc-nd/2.0/legalcode)

B.C.'s Climate Leadership Plan must be a living, breathing strategy. It has to grow as we work with our partners across Canada to align policies to produce the most effective results. It must also engage our industry, communities and First Nations to find ways to achieve our goals together. This first set of actions cannot solve all of the issues we face — many will require complex strategies that account for a wide range of related factors. So we need to take the time to get them right.

B.C. is committed to reaching our 2050 target to reduce GHG emissions to 80 per cent below 2007 levels. That means continuing to update our plan, which we will do over the course of the following year and every five years after that.

This document will help you learn about the first new steps we are taking, as well as the ways that industry, First Nations, communities and individuals can participate in our mission to fight climate change.

The world is moving towards a lower carbon future and B.C. is well positioned to continue to lead this movement. With over 200 clean tech companies, abundant clean energy and natural resources, and a strategy to support innovation across all sectors, B.C.'s green economy is creating jobs today and the foundation for a secure tomorrow.

We applaud the federal government's renewed commitment to the fight against climate change, and look forward to working with them on the Pan-Canadian Framework. This is a critical issue that requires every level of government working together, alongside industry and communities, to create an integrated strategy to achieve our climate action goals. Our province is committed to being at the forefront of this fight and continuing to demonstrate climate action leadership.

We hope that you will join us in this important mission.

Sincerely,

Christy Clark

HONOURABLE CHRISTY CLARK
PREMIER OF BRITISH COLUMBIA

Climate Leadership Plan at a Glance

The Climate Leadership Plan is British Columbia's next step to fight climate change. This plan highlights the first set of actions we are taking to help meet our 2050 emissions reduction target of 80 per cent below 2007 levels, while building a clean economy.

These actions are expected to reduce annual greenhouse gas emissions by up to 25 million tonnes below current forecasts by 2050 and create up to 66,000 jobs over the next ten years.

Natural Gas

Natural gas offers an opportunity to grow British Columbia's economy, while helping other jurisdictions reduce their carbon footprint by transitioning to this cleaner burning fuel.

We are taking action in three key areas:

☑ Launching a strategy to reduce upstream methane emissions by 45 per cent;

☑ Developing regulations to enable carbon capture and storage; and

☑ Investing in infrastructure to power natural gas projects with British Columbia's clean electricity.

This action area is expected to reduce annual emissions by up to 5 million tonnes by 2050.

Transportation

Transportation is essential to keep British Columbia moving, but a significant source of our emissions.

The Province is launching new actions to reduce the impact of transportation, including:

☑ Increasing the requirements for our Low Carbon Fuel Standard;

☑ Amending regulations that encourage switching commercial fleets to renewable natural gas;

☑ Expanding support for zero emission vehicle charging stations in buildings; and

☑ Expanding the Clean Energy Vehicle program to support new vehicle incentives and infrastructure.

This is in addition to our 10-year transportation plan that will:

☑ Invest in infrastructure to reduce congestion;

☑ Create new rapid transit lines; and

☑ Shift more public transit to low carbon fuels.

In total, this action area is expected to reduce annual emissions by up to 3 million tonnes by 2050.

Forestry & Agriculture

Forestry and agriculture are foundational industries in British Columbia's economy. Our forests also offer incredible potential for storing carbon, so we are taking further action to:

- ☑ Rehabilitate under-productive forests;
- ☑ Recover more wood fibre; and
- ☑ Avoid emissions from burning slash.

Additionally, we are expanding a nutrient management program that will help improve the environmental performance of B.C.'s farms. This action area is expected to reduce annual emissions by up to 12 million tonnes by 2050.

Industry & Utilities

B.C.'s industrial sectors create good jobs for British Columbians, but they also require significant amounts of energy to power production. That is why we are taking action to reduce these emissions, including:

- ☑ Developing new energy efficiency standards for gas fired boilers;
- ☑ Enabling further incentives to promote adoption of efficient gas equipment; and
- ☑ Facilitating projects that will help fuel marine vessels and commercial vehicles with cleaner burning natural gas.

We are working with utilities on their demand-side management programs to make electrification projects and natural gas equipment more efficient. We are also committing to making B.C.'s electricity 100 per cent clean or renewable, with allowances to address reliability. These actions are expected to reduce annual emissions by up to 2 million tonnes by 2050.

Communities & Built Environment

Communities across B.C. play a critical role in the fight against climate change, particularly in the areas of buildings, waste, and planning. To build on progress already made in our communities, we are:

- ☑ Working with local governments to refresh the Climate Action Charter;
- ☑ Identifying tools to focus growth near transit corridors; and
- ☑ Supporting more resilient infrastructure.

We are also amending regulations to promote more energy efficient buildings, developing requirements to encourage net zero ready buildings, and creating a strategy to reduce waste and turn it into valuable resources. This action area is expected to reduce annual emissions by up to 2 million tonnes by 2050.

Public Sector Leadership

B.C.'s public sector is already leading the way in demonstrating how climate action can help reduce emissions. To continue this leadership, we are taking action with new strategies, including:

- ☑ Promoting use of low carbon and renewable materials in public sector buildings; and
- ☑ Mandating the creation of 10-year emissions reduction and adaptation plans for provincial public sector operations.

This action area is expected to reduce annual emissions by up to 1 million tonnes by 2050.

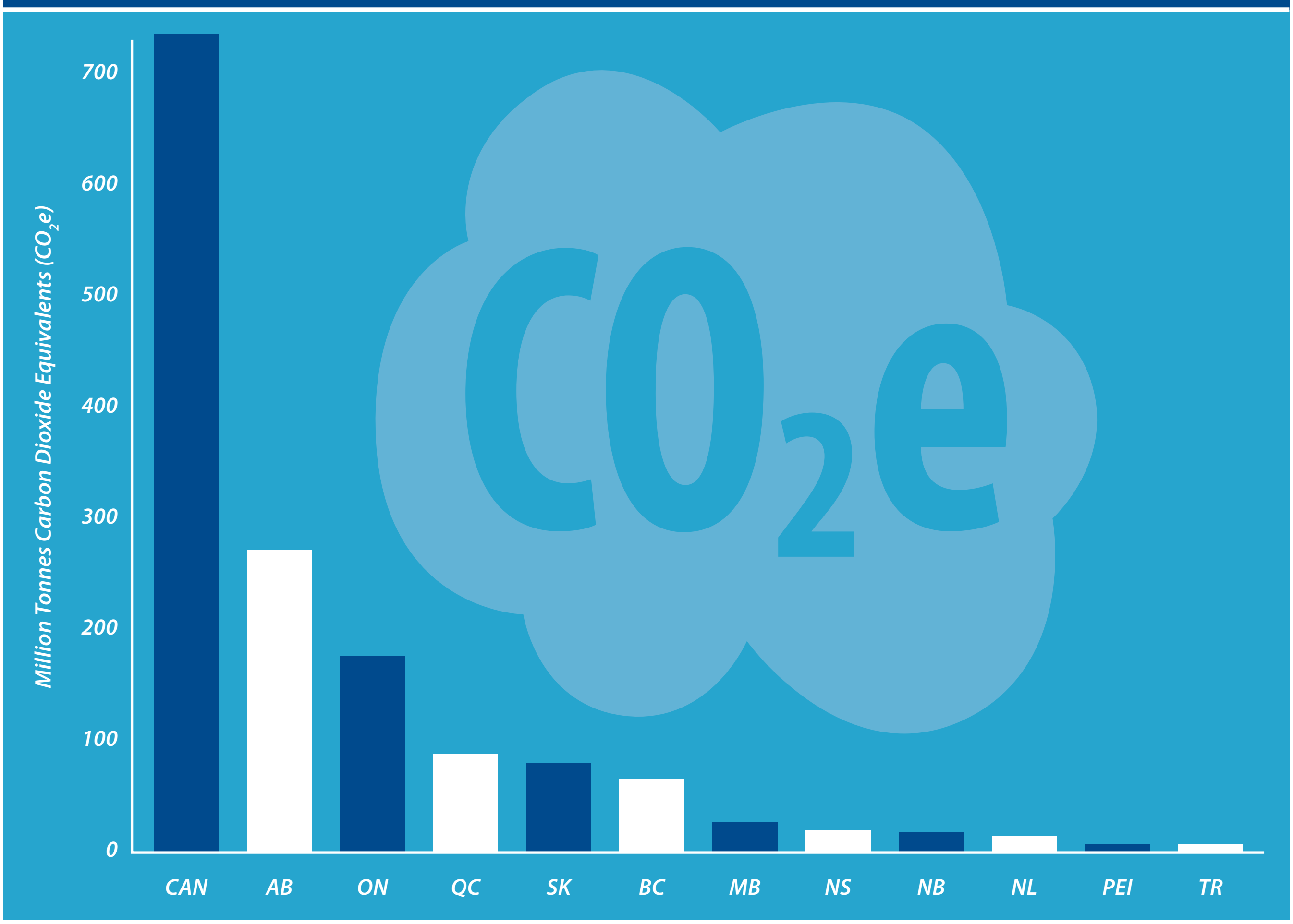
This set of 21 actions targets key areas we can act on now. The Climate Leadership Plan will be updated over the course of the following year as work on the Pan-Canadian Framework on climate action progresses.

Pathway to the Plan

The strategic actions included in this document represent the first steps the B.C. government is taking to update our climate action plan to work towards our 2050 goal. This plan is informed by the recommendations of our Climate Leadership Team, as well as our public engagement with British Columbians, industry, First Nations, communities and key stakeholders.

As we work with the federal government and our provincial and territorial partners to establish and implement a coordinated climate action plan, more actions will be announced. In this section you will learn what has driven the development of the actions being taken today, as well as a report on our progress to the 2050 target to date.

CANADIAN 2014 GREENHOUSE GAS EMISSIONS



Climate Change is Happening

Climate change is one of the most critical issues humanity faces. It is an important battle that all governments need to demonstrate leadership on.

This year in Canada, we saw its impacts happening in real time, as out-of-control wildfires in British Columbia and Alberta displaced thousands of workers, families and residents. The evidence is in front of us — we have already seen considerable climate change in British Columbia over the past century.

ENVIRONMENTAL CHANGE IN B.C. LOOKING BACK

TEMPERATURE: Average temperature has increased over all of B.C. since 1900 (1.4°C per century).*

PRECIPITATION: Average precipitation has increased over most of southern B.C. (1900 – 2013).

GLACIERS: All glaciers in British Columbia have retreated from 1985 to 2005.

SEA LEVEL RISE: Average sea level has risen along most of the B.C. coast over the past 95 years.

* *Winter is warmer on average than it was 100 years ago. Higher temperatures drive other climate systems and affect our environment and ecosystems.*

The impacts of climate change will become more pronounced as we head towards 2050. That is why it is critical we continue to work to achieve our climate action goals. We must take action to mitigate these impacts today.

LOOKING TO 2050

TEMPERATURE

» By 2050, B.C. is projected to be at least 1.3°C warmer and may be as much as 2.7°C warmer than in recent history.

» Growing seasons will be longer; species ranges will shift; the winter tourism season will be shorter.

PRECIPITATION

» By 2050, average annual rainfall may increase from 2 per cent to 12 per cent, with the potential for increased frequency of drier summers and increases in extreme rain events.

» Dry conditions contribute to forest fire season severity; heavy rain impacts buildings and infrastructure.

GLACIERS

» By 2100, B.C. is projected to lose up to 70 per cent of its glaciers.

» This will impact the timing and volume of river flow, drinking water quality and quantity, agriculture and winter alpine tourism.

SEA LEVEL RISE

» Sea level will continue to rise at most locations on the B.C. coast.

» Coastal flooding frequency and magnitude is expected to increase.

Sources: Plan2Adapt, Pacific Climate Impacts Consortium; http://www.plan2adapt.ca; Relative Sea-level Projections in Canada and the Adjacent Mainland United States; Geological Survey of Canada. James, TS, et al, 2014; and Projected Deglaciation of Western Canada in the 21st Century; Nature, Clarke et al, 2015.

British Columbia is Taking Action

Increasing knowledge of the impacts of climate change is what drove the launch of our world-leading Climate Action Plan in 2008. This plan included a wide range of large-scale policies designed to reduce British Columbia's impact on the environment, and was foundational in driving us to reach our first target to reduce GHG emissions to 6 per cent below 2007 levels by 2012.

To read the original plan in detail, go to: http://www2.gov.bc.ca/gov/content/environment/climate-change/policy-legislation-programs.

By the end of 2012, all of the actions outlined in the first plan were underway or complete, including more than $1 billion in climate action programs and tax incentives to encourage cleaner choices.

Since 2012, British Columbia has continued to invest in the innovation and infrastructure that will help us reach our 2050 target.

To date, an additional $1.9 billion has been dedicated to keeping British Columbia on the path to a lower carbon economy, including investments such as:

» $50 million in clean energy and technology;

» $831 million for clean transportation;

» $300 million for transportation infrastructure;

» $24 million to improve the energy efficiency of homes and businesses; and

» $704 million for clean electricity infrastructure.

In 2016, British Columbia has continued engagement on climate action by participating in initiatives that align our climate action goals with our neighbours within Canada and internationally, including:

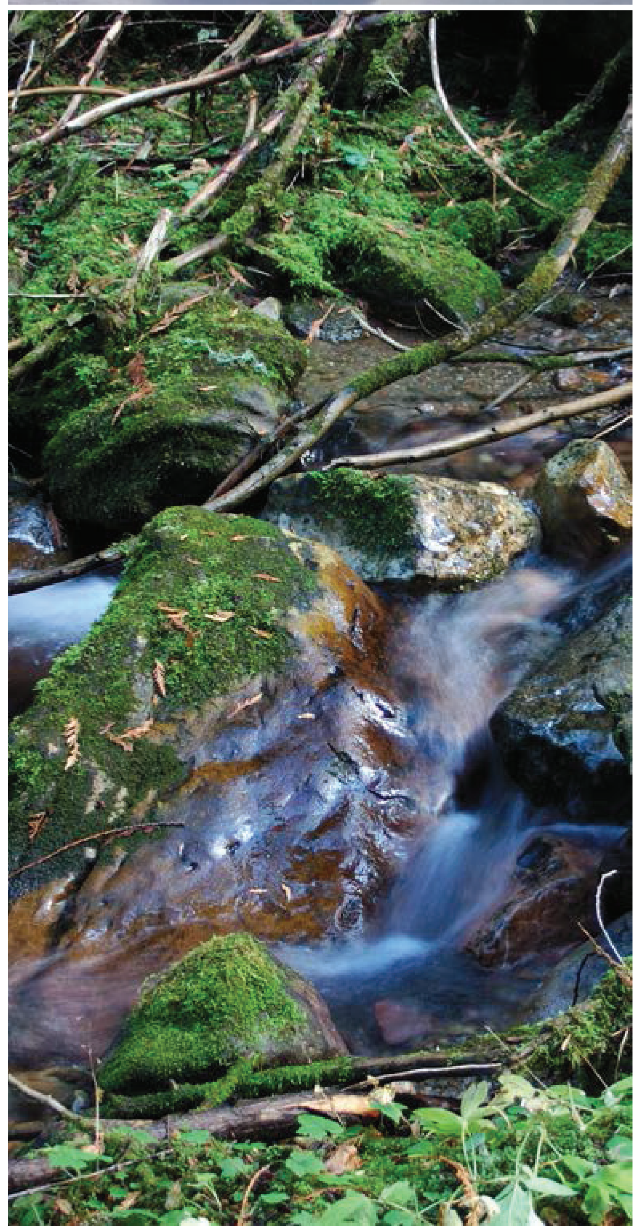
- The ***Vancouver Declaration on Clean Growth and Climate Change***;
- The ***Carbon Pricing Leadership Coalition***;
- ***Under 2 MOU*** (Subnational Global Climate Leadership Memorandum of Understanding);
- ***Pacific Coast Collaborative*** Climate Leadership Action Plan;
- ***RegionsAdapt*** Initiative; and
- ***International Zero-Emissions Vehicle Alliance***.

Now, the actions presented in this document outline the first steps we are taking under our new Climate Leadership Plan. This plan, which we will continue to update over the course of the following year and every five years after that, is creating strategies, programs, infrastructure, initiatives and incentives that will help us reach our 2050 target.

The Climate Leadership Team

In 2015, Premier Christy Clark challenged the world to meet or exceed the standard B.C. has set for climate action. She also announced that work was beginning to build on B.C.'s world-leading plan, including the formation of a Climate Leadership Team (CLT), made up of diverse leaders from British Columbia businesses, First Nations, local governments, communities, academia, and the environmental sector.

Through a series of collaborative working sessions, this team was asked to develop recommendations for actions that would maintain B.C.'s climate leadership. The CLT recommendations largely address carbon pricing and taking action to reduce emissions across the industry, transportation and built environmental sectors, while maintaining a strong economy.



The actions presented in this plan are driven by the hard work of the CLT. Throughout the action area descriptions, we have identified where they align with the CLT's recommendations. While they do not represent a full-scale implementation of all the CLT recommendations, we will continue to work on ways to take further action on their recommendations, particularly as our work with the federal government progresses and more funding opportunities for climate action become available.

To review the CLT's recommendations in detail, please visit: http://engage.gov.bc.ca/climateleadership/.

Public and Stakeholder Engagement

To inform the Province and the CLT's work, B.C. launched a public engagement campaign to invite input on the values and priorities British Columbians wanted to see in B.C.'s new climate action plan. We also conducted sector-specific engagements with stakeholders in B.C.'s various industries. Across two engagement periods we received considerable feedback, and affirmed the passionate commitment of British Columbians to fighting climate change.

Our engagement results to date include:

» 27,000+ website visits;

» 7,600+ feedback forms completed;

» 300+ detailed submissions;

» 7,400+ discussion guide downloads;

» 8,200+ emails received; and

» Input from over 300 organizations, local governments, and businesses via webinars, meetings, teleconferences, and email.

The initial survey presented four visionary goals for climate action, and asked British Columbians to prioritize which areas were most important to take action on, as well as priorities within each of those areas.

VISIONARY GOALS FOR CLIMATE ACTION

THE WAY WE LIVE:

» Focus: buildings, communities, and waste.

» Goal: communities are thriving and resilient in the face of climate change.

THE WAY WE TRAVEL:

» Focus: movement of people and goods.

» Goal: people and goods move efficiently and reliably, using clean transportation.

THE WAY WE WORK:

» Focus: business, industry, products and services.

» Goal: B.C.'s economy remains strong, and jobs continue to be created, while greenhouse gas emissions fall.

WHAT WE VALUE:

» Focus: how we consider the cost of climate change to society when making decisions.

» Goal: the cost of climate change to society is considered whenever British Columbians make important decisions.

Overall, the importance of a number of themes were repeated across the two engagement periods, particularly on issues such as transportation, clean technology and clean energy, the carbon tax, communities, climate adaptation and employment.

To see a summary of results from our consultations, go to: http://engage.gov.bc.ca/climateleadership/.

To achieve our goals, we need a shared vision that unites British Columbians in this important battle. That is why we listened to the priorities identified by British Columbians when developing this plan — fighting climate change must be a collaborative effort across government, industry, First Nations and communities.

The Province of British Columbia would like to thank all of the stakeholders that contributed to the development of this plan, from the Climate Leadership Team, to the individuals, communities, First Nations, businesses and organizations that participated in our public engagement campaigns.

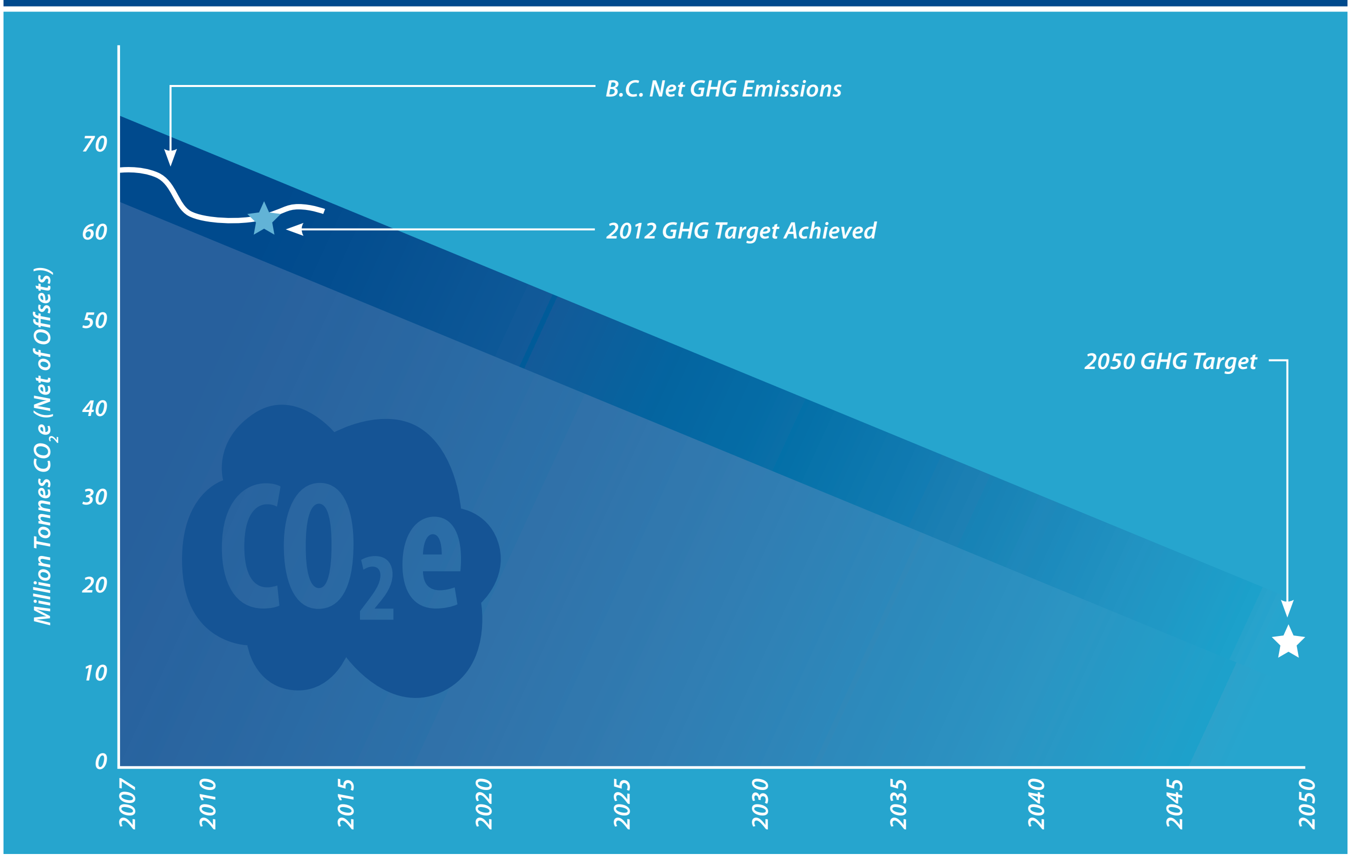
Fighting climate change is one of the most critical issues our world faces today, and any plan to combat it requires we listen to the voices of all those affected.

Progress to 2050 Target

Across all of this hard work and valuable contributions, one thing has clearly emerged — B.C. is committed to reaching our 2050 target of reducing GHG emissions to 80 per cent below 2007 levels. We have already made considerable strides towards that goal. In 2012, we reached our first interim target to reduce emissions to 6 per cent below 2007 levels.

Since that time, B.C.'s emissions levels have remained relatively unchanged. B.C.'s greenhouse gas emissions in 2014 were 62.7 million carbon dioxide equivalent tonnes (tCO_2e), including 1.8 million tonnes CO_2e in offsets from forest management projects, for a net reduction of 5.5 per cent since 2007. The 2014 greenhouse gas inventory for British Columbia can be viewed online at: http://www2.gov.bc.ca/gov/content/environment/climate-change/reports-data/provincial-ghg-inventory.

B.C. NET GHG EMISSIONS AND TARGETS



Without renewed action, emissions may begin to rise again. So we are taking action starting with the release of this plan.

Beyond overall GHG emissions reductions, further proof that our plan is working is evidenced in the way that carbon pollution is decoupling from Gross Domestic Product (GDP) growth. In their recommendations, the CLT noted that:

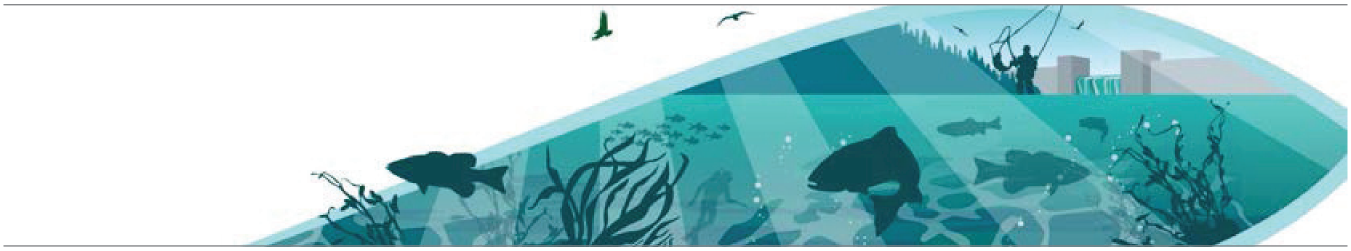
> *"This past year, global carbon pollution from fossil fuels levelled off, even as GDP continued to grow. It was the first time in nearly half a century that carbon pollution decoupled from GDP globally. The International Energy Agency, which reported the finding, cited policy action on energy efficiency and renewable energy as the main factor driving the change.*
>
> *It was a remarkable signal and — as the impacts of climate change become increasingly visible and acute — it telegraphed a clear message to governments: Your efforts are essential, and you are making a difference. Keep going."*

In B.C., both GDP and population have been growing at rates comparable to the national average. Between 2007 and 2014, population growth in B.C. has been 8.1 per cent. Real GDP growth has been 12.4 per cent. With relatively stable emissions, this demonstrates a reduction in GHG intensities, both per capita and per dollar of economic output.

This decoupling shows that British Columbia has the ability to continue growing our economy and creating jobs, without a proportional increase in GHG emissions. However, we must be cautious in our approach, and each policy we implement must be tested before it is put into place to ensure that it is both environmentally and economically sustainable.

B.C.'s emissions per capita and per unit of GDP are well below the national average. Going forward, the rate of this decoupling needs to accelerate to hit our target. However, this information sends a clear message — our plan is working.

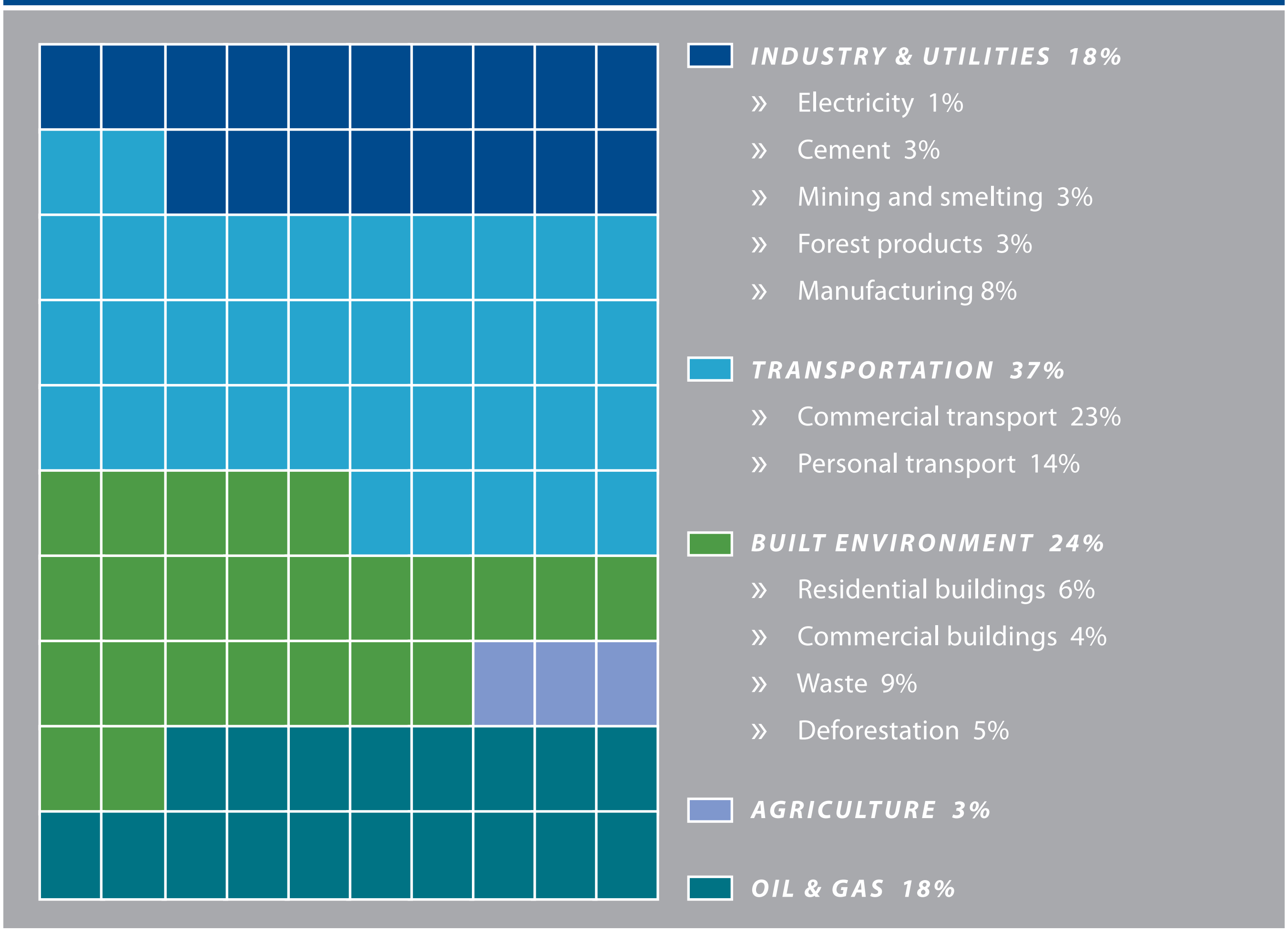
Action Areas



In the following sections of British Columbia's Climate Leadership Plan, we have identified the key areas where we can take action today: natural gas; transportation; forestry and agriculture; industry and utilities; communities and built environment; and public sector leadership.

While further actions will be announced over the course of the following year, these areas represent critical priorities where B.C. can take action to reduce GHG emissions that are not dependent on the work we are undertaking with the federal government on a Pan-Canadian Framework to fight climate change.

2014 GHG EMISSIONS BY SECTOR



Note: In 2014, British Columbia's emissions were 62.7 million tonnes CO_2e, including 1.8 million tonnes CO_2e in offsets from forest management projects.

Action Area: Natural Gas

WHY NATURAL GAS MATTERS

Natural gas is a growing industry in B.C. that can secure our economy for generations to come, while creating good jobs for our citizens. Natural gas is also the cleanest burning fossil fuel, representing an opportunity to shift global economies off GHG-intensive fuels like coal and oil to reduce worldwide emissions. The sector is reducing emissions intensity as it grows and currently contributes about 18 per cent of B.C.'s total emissions.

B.C.'s climate action strategy and implementation of new technology by the natural gas industry has already contributed to a 37 per cent decrease in emission intensity per unit of production since 2000. We have also eliminated all routine flaring at oil and gas wells and production facilities. Our carbon tax, together with offset payments, has encouraged improved efficiency in the sector, including waste heat recovery, methane leak reduction and electrification of facilities.

Yet we must still do more. B.C.'s natural gas sector needs to meet the challenge of becoming one of the world's cleanest producers and distributors of this fuel, so that the benefits of this cleaner burning fuel can contribute to global GHG reductions when we ship it to markets seeking to transition away from more emissions intensive fuels.

Almost 40 per cent of the natural gas sector's emissions come from non-combustion sources such as venting and leaks. Establishing standards for these processes that will lead in North America will help the sector to curb emissions as operations continue.

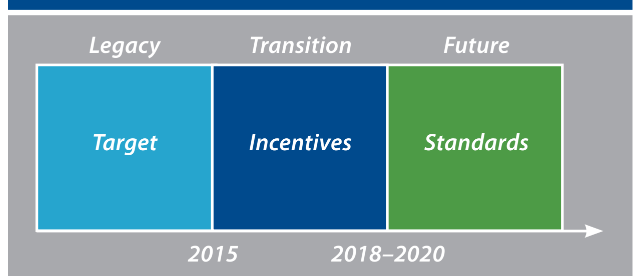
TAKING ACTION: LAUNCHING A STRATEGY TO REDUCE METHANE EMISSIONS

Oil and gas production accounts for approximately 11 million tonnes of annual GHG emissions in our province. Approximately 2.2 million tonnes of that total come from fugitive and vented methane emissions released during the production process.

As such, the CLT recommended that B.C. should set a goal to reduce fugitive and vented methane emissions by 40 per cent within five years, through regulating best practice leak detection and repair activities, as well as developing methane reduction and reporting best practices. They also recommended that after five years we determine if a more ambitious action is necessary.

Our first action for the natural gas sector is a methane emissions reduction strategy. This strategy is targeted at producing real, tangible reductions in emissions, while ensuring the industry remains competitive and has room to grow. B.C. will tackle methane emissions in three phases, using a combination of tools.

THE THREE PHASES



» The legacy phase will include targets for reducing fugitive and vented emissions from extraction and processing infrastructure built before January 1st, 2015. This will include:

- A 45 per cent reduction of these emissions by 2025, estimated at an annual reduction of 1 million tonnes for 2025; and
- A midpoint check in fall 2020 to determine progress towards this target, establish what happens if the target is not attained by 2025, and make adjustments if the target is not technically feasible.

» The transition phase will offer incentives to drive methane emissions reductions for all applications built between 2015 and 2018, and to help tackle legacy infrastructure retrofitting. Incentives will include:

- A Clean Infrastructure Royalty Credit Program, which will help stimulate investments in new technology to convert current infrastructure to less carbon intensive machinery. The pilot program will provide royalty deductions of up to 50 per cent of the cost of developing infrastructure that reduces fugitive or vented methane emissions from oil and gas; and
- A new offset protocol to further encourage innovative projects that reduce methane emissions.

» The future phase will establish standards that will guide the development of projects after the transition phase. This will include:

- Developing and enforcing standards to reduce methane emissions for all applications; and
- Making leak detection and repair mandatory, with protocols to be developed and enforced in alignment with other jurisdictions.

» Coordination with western Canadian provinces and the federal government will also be a key part of our methane emissions reduction strategy, to ensure regulatory alignment, while allowing for flexible provincial approaches accounting for resource base and individual provincial needs.

GET INVOLVED:
SWITCH YOUR TRUCK FLEET TO NATURAL GAS

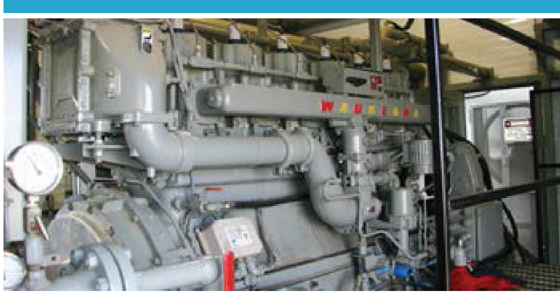
Cleaner burning natural gas can help you reduce the environmental impact of your industrial truck fleet.

FortisBC will cover up to 90 per cent of the cost to convert your medium/heavy duty fleet to compressed natural gas or liquefied natural gas.

Check out the full range of transportation fuel incentives available: https://www.fortisbc.com/NaturalGas/Business/NaturalGasVehicles/Howwecanhelp/Incentives/Pages/default.aspx.

MORE EFFICIENT ENGINES MEAN FEWER EMISSIONS

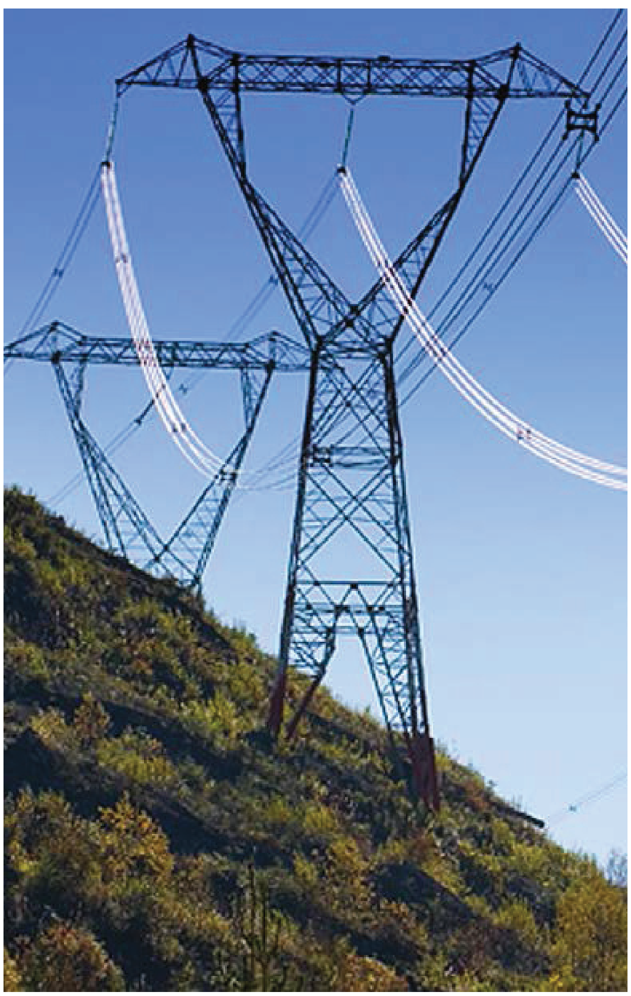
REM Technology Inc. is helping the natural gas industry lower its emissions through the use of two innovative new technologies called REMVue® AFR and SlipStream®. The REMVue® AFR is an engine management system used to control natural gas engines that compress natural gas from well-sites to processing plants. The system enables these engines to run more efficiently and reliably, while lowering the emissions created in the process. SlipStream® is designed to capture vented hydrocarbons like methane, and utilize them as fuel, either for a natural gas engine or process burner. Not only does this technology significantly reduce greenhouse gases, it reduces fuel costs for the engine or burner by up to 50 per cent. B.C.'s provincial offset standards and carbon pricing are helping drive these innovative offset projects.



TAKING ACTION: REGULATING CARBON CAPTURE AND STORAGE PROJECTS

Another important area where we have taken action to reduce the impact of natural gas development on climate change is Carbon Capture and Storage (CCS). CCS involves using innovative technology to capture waste carbon dioxide from industrial facilities and then transport it to a storage site, such as an underground geological formation, so it will not enter the atmosphere.

The Ministry of Natural Gas Development has developed a CCS regulatory policy framework to guide CCS development, ensure it is done safely, and provide transparency. In fall 2015, the first piece of legislation needed to enable CCS was passed. The Province is now collaborating with the BC Oil and Gas Commission to complete the regulatory policy framework and develop the additional legislative changes needed to allow CCS projects to proceed.



TAKING ACTION: USING ELECTRICITY TO POWER NATURAL GAS PRODUCTION AND PROCESSING

B.C.'s planned liquefied natural gas projects will create thousands of jobs and require additional volumes of natural gas production. The Province is committed to capitalizing on this opportunity while minimizing its carbon footprint. Production and processing (referred to as the "upstream" natural gas sector) typically requires the use of natural gas and diesel as fuel for industrial processes. Replacing those fuels with B.C.'s clean electricity could contribute to significant GHG reductions.

Capital funding will be necessary to develop upstream electrification of several key projects:

» Peace Region Electricity Supply Project;

» North Montney Power Supply Project; and

» Other upstream electrification infrastructure.

Electrification of natural gas developments in the Montney formation in Northeast B.C. is currently proceeding with existing infrastructure to avoid GHG emissions by up to an estimated 1.6 million tonnes per year. Full electrification of the Montney Basin could avoid up to 4 million tonnes of emissions per year, minimizing the GHG footprint of upstream natural gas development to ensure that B.C. has the cleanest LNG in the world.

Broader electrification of the Montney formation will require considerable capital investments in electricity transmission from both the federal government and B.C. It will also require the design of programs to make electricity costs comparable to natural gas costs for upstream applications. To support this action, the B.C. government is in dialogue with the federal government to provide the necessary capital to develop the required infrastructure. Programs are also being developed to close the gap between electricity and natural gas costs. Construction of this infrastructure would begin once LNG companies make their final investment decisions.

Action Area: Transportation

WHY TRANSPORTATION MATTERS

Transportation is essential to our economy and way of life. It also accounts for 37 per cent of B.C.'s total emissions, making it a key area where climate action can make a significant impact.

Climate action in the transportation sector must focus on supporting interconnected communities and the efficient movement of goods and people. That means: encouraging adoption of efficient vehicles and creating associated cost savings; supporting innovation in clean vehicles and fuels that improve our air quality, while creating new jobs in the clean tech industry; and working to guide the development of safe and reliable transportation infrastructure that is built to withstand extreme weather events.

We have already made significant progress in this action area. Our low carbon fuel requirement is driving innovation and growing the diversity of commercially available low carbon fuels, leading to the avoidance of over 2.3 million tonnes of GHG emissions between 2010–2012.

B.C.'s 10-year transportation plan includes a commitment to one third of the funding for new rapid transit projects and expanding compressed natural gas fleets. Building on the success of the 2009 rapid transit Canada Line, the new Evergreen rapid transit line will link the communities of Burnaby, Port Moody and Coquitlam with Vancouver, increasing transit integration and capacity in Metro Vancouver.

We have also invested in an incentive program for clean energy vehicles, supported by aggressive charging infrastructure installations, which has led to the purchase of 2,700 electric and hydrogen fuel cell vehicles and the development of over 1,100 charging stations in the province. We now lead the country in clean energy vehicle sales per capita.

As our economy grows, so will our transportation needs. It is imperative that we maximize the efficiency of the entire goods movement chain, to lower our impact on the environment and ensure the competitiveness of our economy.

We also need to provide more transit alternatives to British Columbians, to reduce the overall rate of vehicle kilometres travelled per capita.

REDUCING DIESEL USE IN NANAIMO

Public transit helps people get where they need to go, while lowering the number of emission-producing vehicles on the road.

The Regional District of Nanaimo (RDN) is taking this a step further by committing to switching its remaining diesel-powered buses to buses powered by compressed natural gas (CNG) by 2017.

This switch will cut greenhouse gasses and make the RDN Transit the first conventional fleet in Canada to be completely CNG powered. The co-benefits of CNG buses include lower fuel costs and quieter engines.

Photo Credit: BC Transit

TAKING ACTION: INCREASING THE LOW CARBON FUEL STANDARD

British Columbia's Low Carbon Fuel Standard is reducing the carbon intensity of transportation fuels by 10 per cent by 2020, relative to 2010.

The Climate Leadership Team recommended that we increase this requirement in the future to continue to drive greenhouse gas reductions.

We are now taking action to increase British Columbia's Low Carbon Fuel Standard to 15 per cent by 2030. This action is expected to achieve up to a 3.4 million tonne reduction in annual greenhouse gas emissions.

TAKING ACTION: INCENTIVES FOR USING RENEWABLE NATURAL GAS

Natural gas is considered renewable when it is produced from sources of biogas such as organic waste or wastewater. B.C. will be amending the Greenhouse Gas Reduction Regulation to encourage emission reductions in transportation. This amendment will allow utilities to double the total pool of incentives available to convert commercial fleets to natural gas, when the new incentives go towards vehicles using 100 per cent renewable natural gas. The program will also:

» Promote investments in natural gas fuelling stations at customers' facilities; and

» Support the production of renewable natural gas resources through increased demand.

MOVING PEOPLE WITH TRANSIT

Transit is the backbone of a low carbon community and an integral part of a healthy built environment. That is why the Province is working to improve public transportation infrastructure in Metro Vancouver and in BC Transit communities across the province. This will include the purchase of more SkyTrain cars, improvements to bus exchanges and SkyTrain stations, enhanced SeaBus service, initial work towards new major rapid transit in Vancouver and Surrey, and the modernization of a variety of TransLink's transit infrastructure. Outside of the Lower Mainland, the Province will build new maintenance yards and bus depots, and purchase new, cleaner and more efficient buses. Combined with contributions from federal and local governments, these improvements will benefit residents across the province opening up more affordable, transit-friendly communities.

TAKING ACTION:
INCENTIVES FOR PURCHASING A CLEAN ENERGY VEHICLE

B.C.'s Clean Energy Vehicle program is designed to encourage the use of zero emission vehicles (ZEVs) throughout the province. Residents, businesses, organizations and local governments that purchase or lease qualifying new ZEVs are eligible for incentives off the pre-tax sticker price for battery electric, fuel cell electric, plug-in hybrid electric, and hydrogen fuel cell vehicles. These incentives can be combined with B.C.'s SCRAP-IT program to get older, higher emission vehicles off the road.

The Clean Energy Vehicle program is being expanded to support new vehicle incentives and infrastructure, as well as education and economic development initiatives.

GET INVOLVED:
BUY A CLEAN ENERGY VEHICLE

Thinking of buying a clean energy vehicle? Learn about point-of-sale incentives that are available to help you purchase one through the Clean Energy Vehicle Program: www.gov.bc.ca/cleanenergyvehicleprogram.

Also, if you have an old gas guzzler that needs to be scrapped, see how we can help at: scrapit.ca.

If you're purchasing a clean energy vehicle and scrapping a gas guzzler, you could be eligible for both incentive programs.

TAKING ACTION:
SUPPORTING VEHICLE CHARGING DEVELOPMENT FOR ZERO EMISSION VEHICLES

Since vehicles represent such a significant portion of our emissions profile, policies that facilitate the adoption of zero emission vehicles like electric cars can make a significant impact in the fight against climate change. A major challenge for adoption of these vehicles is ensuring that owners can access charging stations.

That is why we are taking action to support the development of charging stations across the province. These actions include:

» Developing regulations to allow local governments to require new buildings to install adequate infrastructure for electric vehicle charging; and

» Developing policies to facilitate installing electric vehicle charging stations in strata buildings and developments.

TAKING ACTION:
10-YEAR PLAN TO IMPROVE B.C.'S TRANSPORTATION NETWORK

B.C. on the Move is our 10-year plan to improve the province's transportation network that is already underway. It includes a comprehensive set of strategies that were driven by engagement of the public and key stakeholders, including actions that will help drive GHG reductions in a number of areas.

» Transitioning to low carbon fuels:
  - Increasing the number of B.C. Transit compressed natural gas (CNG) buses and fuelling stations; and
  - BC Ferries is investing in 3 new vessels and conversion of 2 large vessels to dual fuel capable ferries that can run on either liquefied natural gas or ultra-low sulphur diesel.

» Expanding transit:
  - Supporting the construction of new rapid transit in Vancouver; and
  - Developing rapid transit in Surrey.

» Reducing congestion:
  - Replacing the George Massey Tunnel to reduce idling; and
  - Optimizing movement through Canada's Pacific Gateway.

To review the entire B.C. on the Move plan, visit: https://engage.gov.bc.ca/transportationplan/.

GET INVOLVED:
RIDE THE HOV LANE AND FIND A CHARGING STATION

Did you know B.C. allows approved electric vehicles to use high occupancy vehicle (HOV) lanes? Getting around in your electric vehicle has never been easier — especially with an ever growing network of charging stations. To find a station, go to: http://pluginbc.ca/charging-stations/finding-stations/.

CLEANING UP WASTE COLLECTION IN SURREY

In 2012, the City of Surrey mandated that its waste collection services be carried out using compressed natural gas vehicles. As a result, the city's contractor, Progressive Waste Solutions (PWS), launched a state-of-the-art CNG fleet for waste collection in Surrey, helping reduce emissions while diverting waste from landfills. These trucks emit 23 per cent less carbon emissions and 90 per cent less air particulates compared to diesel trucks. The city is also developing the first fully integrated organic waste biogas processing facility in North America that will be completed in 2017. The facility will turn organic waste collected at curbside into biogas and nutrient rich compost. The biogas will in turn be used to fuel the waste collection fleet, while the compost will be used by local farmers to produce fruits and vegetables. It is another step Surrey is taking to close the loop and become a zero-waste city.

Action Area: Forestry and Agriculture

WHY FORESTRY AND AGRICULTURE MATTER

Forestry and agriculture are foundational sectors of the B.C. economy, and areas that offer significant opportunities to take action against climate change.

Agriculture accounts for about three per cent of our emissions, arising from manure management, agricultural soils, and the methane produced when animals such as cattle and sheep digest food.

Greenhouse gas emissions from vehicles and mills used in forestry are counted as a component in the transportation and industrial sectors. The level of carbon stored in British Columbia's forests fluctuates from year to year based on natural factors such as fires, pests or weather.

In 2014, forestry offset projects alone removed 1.8 million tonnes of CO_2 from the atmosphere, creating jobs and unlocking new revenue streams for First Nations, communities, forest companies and private owners.

In the agriculture sector, changes in fertilizer use and soil management hold the promise of reducing greenhouse gas emissions. Many greenhouse growers are taking innovative steps to reduce their use of fossil fuels by incorporating clean tech solutions such as biomass boilers, thermal curtains and heat storage systems. Provincial offset standards and carbon pricing are making these changes more economically viable, driving their adoption in the sector.

Furthermore, many farmers in B.C. are also reducing emissions while creating new business opportunities by maximizing the value of agricultural byproducts, turning their waste into valuable resources and demonstrating the way one of our oldest industries is adapting to climate change.

PRINCE GEORGE'S WOOD INNOVATION AND DESIGN CENTRE

The award-winning Wood Innovation and Design Centre in Prince George was designed to demonstrate the way that innovative forms of wood production and use can lead to a more sustainable and beautiful future.

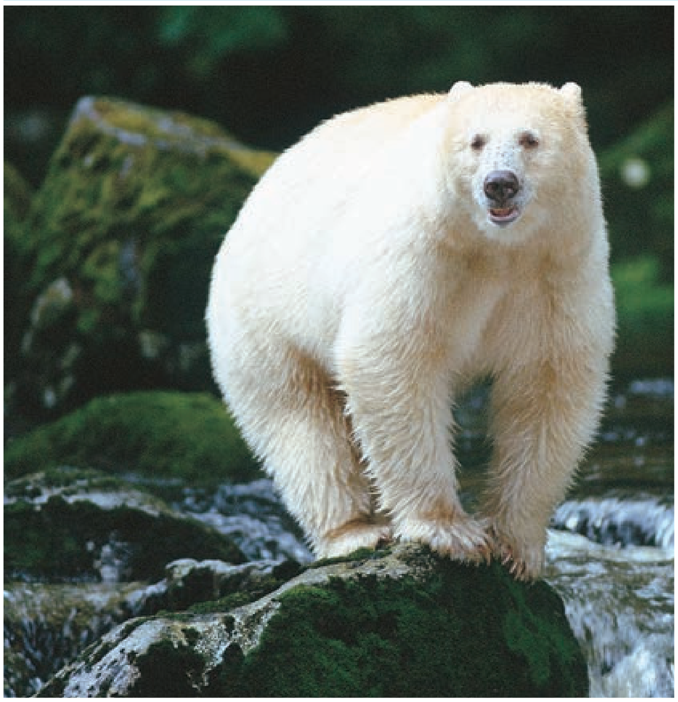
It makes use of mass timber, a wood product made from laminating together many smaller pieces of spruce, pine or fir. This centre showcases how British Columbia forest products can be made to order with powerful structural properties, while having a much smaller carbon footprint than steel or concrete.

Most recently, it was awarded the Governor General's Medal in Architecture in 2016 for its use of innovative and sustainable building technologies, the highest honour that can be given to an architectural project in Canada.

PROTECTING THE GREAT BEAR RAINFOREST TO REMOVE GREENHOUSE GASSES

The Great Bear Rainforest is one of British Columbia's most spectacular natural wonders — and an effective means of removing significant GHG emissions from the atmosphere. Great Bear's North and Central Mid-Coast, South Central Coast and Haida Gwaii forest carbon projects use ecosystem-based management practices that protect areas of the forest that were previously slated for logging.

These projects were enabled through the British Columbia Forest Carbon Offset Protocol and atmospheric benefit sharing agreements, developed in collaboration with First Nations leaders. In addition to reducing emissions, they also support the area's biodiversity and cultural heritage, while creating local economic opportunities.



TAKING ACTION:
ENHANCING THE CARBON STORAGE POTENTIAL OF B.C.'S FORESTS

B.C.'s forest ecosystem covers more than 54 million hectares and provides us with significant potential for climate change mitigation.

We can harness this opportunity to sequester atmospheric carbon dioxide in this tremendous public asset through intensive forest management practices and storing carbon in long-lived wood products. That is why the Climate Leadership Team recommended that we update current forest policy and regulation to increase carbon sequestration.

So we are taking action to do even more to harness the incredible power of our forests through the new Forest Carbon Initiative, which will:

» Enhance the carbon storage potential of British Columbia's public forests; and

» Increase the rate of replanting and fiber recovery by 20,000 hectares per year.

This initiative will focus on enhancing the carbon sequestration of Mountain Pine Beetle and wildfire impacted sites — capturing the carbon benefits of new reforestation, while avoiding emissions from burning slash. This work will build on existing forest management programs, such as the recently announced Forest Enhancement Society and Forest for Tomorrow.

The Forest Carbon Initiative will rehabilitate up to 300,000 hectares of impacted sites over the first five years of the program. By 2050, the ten-year program is expected to lead to an annual reduction in greenhouse gas emissions of up to 11.7 million tonnes.

IMPROVED WOOD FIBRE USE

B.C.'s Fibre Action Plan is helping to generate more value and less greenhouse gas emissions from the province's forest resources. Through a pilot project with primary harvesters and Zellstoff Celgar Pulp Mill in Castlegar, approximately 500,000 cubic metres of residual wood (the equivalent of over 12,000 loaded logging trucks) that would once have been left in the forest were utilized as a source of fibre for the mill over the past three years. This not only helped to decrease the risk of wildfire, it saved approximately 185,000 tonnes of CO_2e from reduced slash pile burning. Additionally, the project created new jobs and economic benefits for the forest sector.

THE CHEAKAMUS COMMUNITY FOREST

The Cheakamus Community Forest carbon offset project is located adjacent to the Resort Municipality of Whistler, within the traditional territories of the Squamish and Lil'wat Nations.

The project retains more carbon in the forest by using ecosystem-based management practices that include increasing protected areas and using lower-impact harvesting techniques. Revenues from this B.C. offset project help overcome barriers to balancing environmental and economic sustainability, boosting additional uses for the forest such as recreation, tourism, and habitat protection.

Photo Credits: Bob Brett

TAKING ACTION:
DEVELOPING A NUTRIENT MANAGEMENT PROGRAM TO REDUCE EMISSIONS

In the agriculture sector, a nutrient management program is being developed to demonstrate best practices to reduce fertilizer use and GHG emissions, and is expected to lead to a nearly 100,000 tonne reduction of annual GHG emissions. This Nutrient Management Program will include:

» Expanding trials to develop and demonstrate nutrient management best practices to the agriculture industry;

» Increasing funding to the sector to implement Beneficial Management Practices that will promote better nutrient management and further reductions in GHG emissions; and

» Scaling up monitoring of nutrient management benefits and developing longer term performance indicators to measure their success.

GET INVOLVED:
ADAPT YOUR FARM FOR CLIMATE CHANGE

The Farm Adaptation Innovator Program supports projects that help build capacity for British Columbia farmers to adapt to climate change. Learn more about this and other resources to enhance agriculture's ability to adapt to climate change: www.bcagclimateaction.ca/farm-level/adaptation-innovator-program/.

GET INVOLVED:
BECOME A MORE SUSTAINABLE FARM

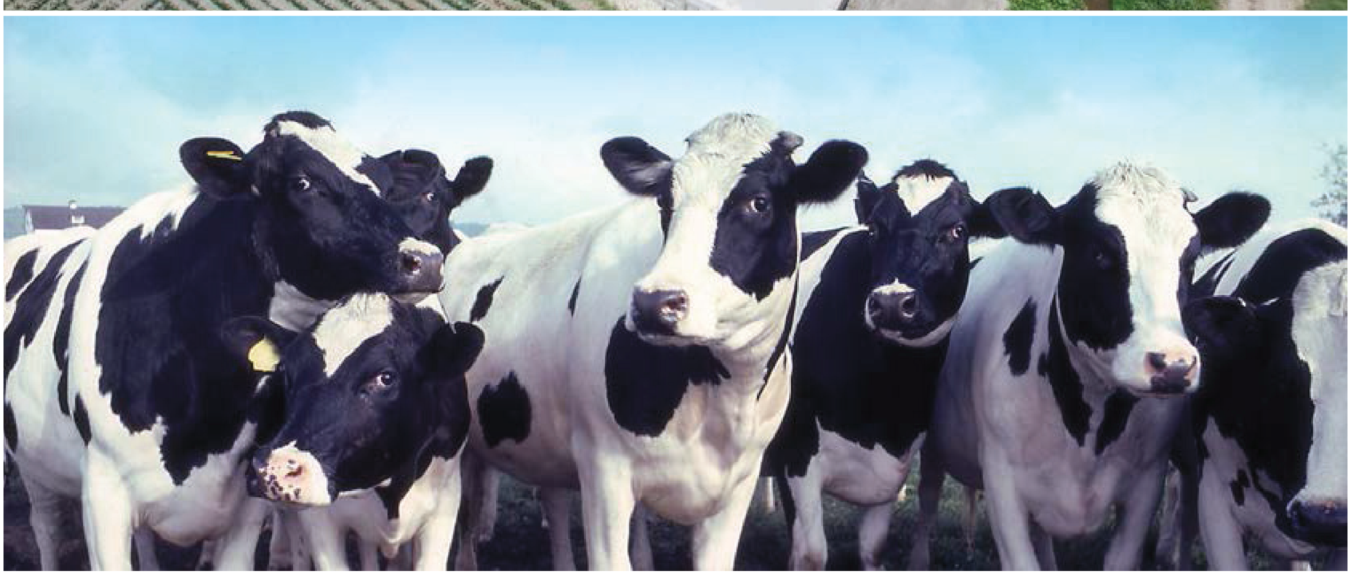
Farming sustainably is good for the planet and good for business. The Environmental Farm Plan Program supports farm operations to complete agri-environmental risk assessments. After completing an Environmental Farm Plan, farmers can apply for funding to implement Beneficial Management Practices that help to increase agricultural and environmental sustainability. Learn more at: https://www.bcac.bc.ca/ardcorp/program/environmental-farm-plan-program.

CREATING RENEWABLE NATURAL GAS FROM MANURE AND ORGANIC WASTE

Expanding agricultural production in the Lower Mainland requires solutions to the issue of manure produced by the large numbers of dairy cattle. With support from the Ministry of Agriculture's innovation program, Seabreeze Farms in Delta has built an anaerobic digester that is turning manure and other organic waste into biogas, digestate (organic fertilizer) and bedding for cows.

The biogas is created by capturing methane that would otherwise have gone into the atmosphere. The biogas is cleaned and upgraded into renewable natural gas that displaces conventional natural gas with a renewable energy source.

Photo Credit: Delta Farmers Institute



Action Area: Industry and Utilities

WHY INDUSTRY AND UTILITIES MATTER

B.C. industry creates thousands of good jobs, but requires significant amounts of energy to drive their production systems. These large-scale users of energy represent almost 18 per cent of our total emissions.

We are already driving innovation in this area with our carbon tax, which covers approximately 60 per cent of the emissions in this sector. As the world shifts to a low-carbon economy, B.C.'s low-carbon electricity has become a competitive advantage for B.C.'s businesses, driving industry to create green jobs and products that are helping the world reduce GHG emissions.

The portion of BC Hydro's power generation portfolio that comes from clean or renewable resources is currently 98 per cent, already above the 93 per cent requirement in B.C.'s Clean Energy Act. Furthermore, B.C.'s abundant supply of clean burning natural gas represents enormous potential to shift our industrial sectors and global partners off the use of more GHG intensive fuels, particularly in areas such as fuelling marine transportation vessels.

British Columbia has also established the Innovative Clean Energy Fund, through which we have invested over $70 million to support the development of clean energy and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.

TAKING ACTION: MAKING B.C.'S ELECTRICITY 100% RENEWABLE OR CLEAN

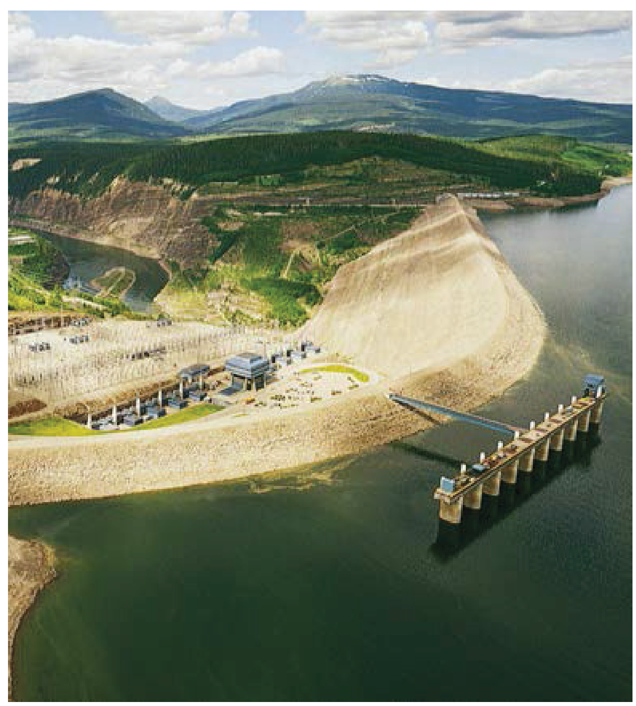
B.C.'s clean electricity supply is activating numerous opportunities to reduce GHG emissions across our industrial sectors. When an industry switches to electricity instead of fossil fuels, their emissions go down. The CLT recommended that we increase the target to 100 per cent clean energy on the integrated grid by 2025, while allowing for the use of fossil fuels for reliability. BC Hydro will focus on acquiring firm electricity from clean sources.

Going forward, 100 per cent of the supply of electricity acquired by BC Hydro in British Columbia for the integrated grid must be from clean or renewable sources, except where concerns regarding reliability or costs must be addressed. Acquisition of electricity from any source in British Columbia that is not clean or renewable must be approved by government through an Integrated Resource Plan, where it will be aligned with the specific reliability or cost concerns.

TAKING ACTION: EFFICIENT ELECTRIFICATION

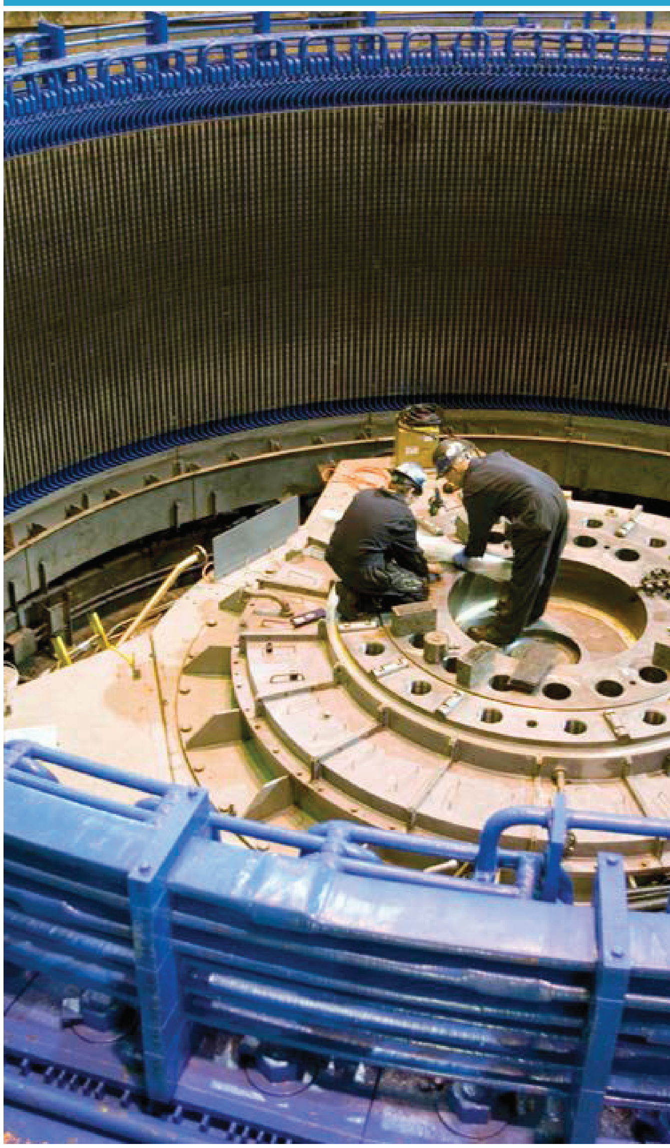
Demand-side management (DSM) programs help customers reduce energy bills by fostering awareness of energy use and providing incentives to increase energy efficiency. These programs can take on an expanded role in climate leadership, helping customers to understand their GHG emissions and providing incentives for efficient electric technologies to reduce GHG emissions.

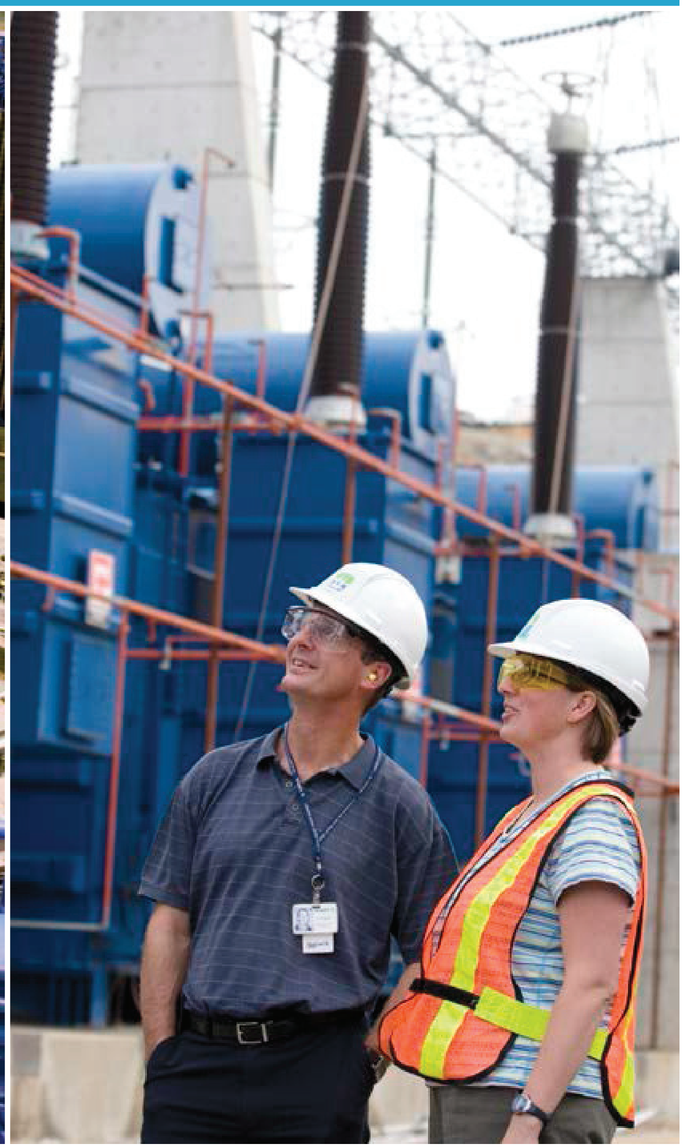
To advance efficient electrification, we are taking action by working with BC Hydro to expand the mandate of its DSM programs to include investments that increase efficiency and reduce GHG emissions.



RENEWABLE ENERGY IS CREATING GREEN JOBS

British Columbia's clean energy producers have reported investment of more than $6 billion in First Nations communities and local economies, while fighting climate change and creating thousands of jobs throughout the north and interior regions. This growing sector has to date supported 15,970 direct, full-time equivalent (FTE) person years of construction employment in every region of the province, with another 4,543 FTE person years of employment projected for forthcoming projects. Furthermore, renewable power companies now employ 641 people in operational roles around the province, and new projects now under construction will support an additional 165 positions once completed. About 25 per cent of BC Hydro's energy supply now comes from independent power producers. The Province is also working with our neighbours in Alberta to investigate the opportunity for greater integration of our power systems, which would allow British Columbia to deliver more clean electricity to Alberta to reduce their reliance on fossil fuels to power industrial processes, thereby reducing their climate impact. British Columbia is truly demonstrating the business opportunity of renewable energy, while lowering our impact on the environment in the process.





SOLAR-POWERED T'SOU-KE

In 2013, T'Sou-ke Nation became the first Aboriginal community in the world to be designated a solar community. They have installed three solar demonstration projects. One demonstrates how remote 'off grid' communities can economically switch from diesel to solar. Another demonstrates how to be 'Net Zero' — which means no more electricity bills. Solar panels on their reservation are used to power all the administrative buildings, while sending their excess solar power back to the grid to contribute to British Columbia's clean energy profile. On sunny days, that excess can be up to 90 per cent of the power produced.

The profits of selling this power back to B.C. Hydro offsets their power bills during darker months. The project received $400,000 in funding from the Province's Innovative Clean Energy Fund. Solar programs in Colwood, the Capital Regional District and several First Nations throughout B.C. have been modelled after T'Sou-ke's leadership. T'Sou-ke is now working on harnessing the energy of the wind and waves to create more clean energy for their community and the province. T'Sou-ke Eco Tourism has been boosted by this project, with over 2,000 people from all over the world visiting each year for solar tours and workshops.

TAKING ACTION: FUELLING MARINE VESSELS WITH CLEANER BURNING LNG

B.C.'s abundant supply of natural gas represents a significant opportunity for industry to lower their impact on the environment. For example, B.C. can help the world replace high-emission marine transport fuels with cleaner burning natural gas, leading to global reductions in GHG emissions.

The Greenhouse Gas Reduction Regulation allows utilities to invest in clean transportation and infrastructure to reduce GHG emissions by replacing the use of higher emitting diesel with natural gas in a variety of sectors.

In particular, FortisBC has been expanding the use of compressed natural gas (CNG) and liquefied natural gas (LNG) in the heavy duty transportation sector since 2012, under its Natural Gas for Transportation initiative. Since 2012, FortisBC has committed $48 million in incentive funding towards the purchase of CNG and LNG vehicles.

These incentives translate to 485 CNG vehicles, 138 LNG vehicles, 6 mine haul trucks and 7 marine vessels that are in operation currently or will be in operation soon. These efforts will result in the reduction of over 74,000 tonnes of GHG emissions annually.

Recent amendments to the regulation will allow utilities to provide further incentives for the marine, mining and remote industrial power generation sectors. It is expected that by 2022 there will be an additional reduction of at least 300,000 tonnes of annual GHG emissions.

GET INVOLVED: MINIMIZE YOUR CARBON FOOTPRINT WITH AN ENERGY MANAGEMENT SYSTEM

Companies that implement energy management systems reduce energy costs and increase business competitiveness, while also minimizing their environmental impacts. The ISO 50001 Implementation Incentive offers up to $80,000 of assistance to implement energy management projects that help facilities pursue compliance with the ISO 50001 standard. Learn more at: www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/innovative-clean-energy-solutions/innovative-clean-energy-ice-fund/iso-50001-implementation-incentive.

LNG FOR THE GLOBAL MARINE SECTOR

FortisBC is proposing to facilitate new investments in LNG marine bunkering in order to further transform the adoption of LNG as a marine fuel. This will also help position B.C. as a global marine bunkering centre on the west coast capable of providing LNG to a large number of natural gas vessels. The current level of global GHG emissions from ships coming into British Columbia is 70 million tonnes per year — higher than the total GHG emissions attributed to British Columbia in its entirety.

TAKING ACTION:
NEW ENERGY EFFICIENCY STANDARDS FOR GAS FIRED BOILERS

Gas fired package boilers are used in industrial systems across the province, contributing to B.C.'s overall emissions profile. New technologies can be used to improve the efficiency of these boilers, which will reduce emissions and operating costs. As such, the Province will develop a regulation to be implemented by 2020 that will set energy efficiency requirements for new and replacement gas fired package boilers, driving down emissions across a number of industries.

GET INVOLVED:
SAVE YOUR BUSINESS MONEY BY BECOMING MORE ENERGY EFFICIENT

Reduce the operating costs of your business by making energy efficiency upgrades. BC Hydro and FortisBC offer a variety of programs to help you improve your business' energy efficiency, including incentives for upgrades and opportunities to learn from experts. Find out more at: https://www.bchydro.com/powersmart/business/programs.html *and* https://www.fortisbc.com/Rebates/RebatesOffers/Pages/default.aspx.

TAKING ACTION:
EXPANDING INCENTIVES TO PROMOTE ADOPTION OF EFFICIENT GAS EQUIPMENT

Gas fired equipment is used for a variety of purposes, from space and water heating in industrial processes, to home fireplaces and commercial cooking equipment. FortisBC offers incentives to promote adoption of more efficient gas equipment for the residential, commercial and industrial sectors.

Now the Province is taking action to amend the Demand-Side Measures Regulation and allow FortisBC to expand their incentives by at least 100 per cent, to encourage further adoption of technologies that reduce the emissions of gas fired equipment.

MINING THE SUN IN KIMBERLEY

The City of Kimberley launched an innovative project to convert Teck's former Sullivan Mine Concentrator site into a solar energy project called SunMine. It includes 4,032 solar-cell modules, mounted on 96 solar trackers that follow the sun's movement to maximize the amount of energy captured. This has made it B.C.'s largest solar project and Canada's largest solar tracking facility. It was also the first solar project in British Columbia to begin selling power back to the BC Hydro grid. This important project was made possible through the Province's Innovative Clean Energy Fund, as well as an investment from Teck, who provided the land and site infrastructure, as well as a $2 million contribution. SunMine is a community owned project that is well suited to capitalize on Kimberley's clear and sunny conditions.

Photo Credits: City of Kimberley

Action Area: Communities and Built Environment

WHY COMMUNITIES AND BUILT ENVIRONMENT MATTER

Communities and our built environment are key factors in the fight against climate change. While the built environment is a significant contributor to our overall emissions profile, it also represents a real ongoing opportunity for change.

From the way we construct buildings to the way we develop communities and manage our waste, our built environment is a significant area where new innovations are demonstrating what a sustainable future could look like. However, we must balance our choices, to ensure that our climate solutions are affordable.

Emissions from the built environment (including buildings, deforestation and waste) represent 24 per cent of British Columbia's total emissions. Yet emissions in this area are down 9.4 per cent since 2007, due to climate action in community planning, building regulations and waste diversion.

Changes in the realm of communities and the built environment have been driven by policies such as Official Community Plans and Regional Growth Strategies, the Climate Action Charter, and the Climate Action Revenue Incentive Program, which returns the carbon tax to local governments to support GHG reduction projects.

The Building Code and Energy Efficiency Act have improved standards for residential and commercial buildings, while programs like LiveSmart BC and the Home Energy Retrofit Offer have promoted efficiency upgrades. In the area of waste, B.C.'s Landfill Gas Management Regulation has required landfill operators to increase the amount of methane they capture. 60 per cent of British Columbians have access to curbside organic diversion programs that are helping us reduce the amount of methane that will be emitted from waste we send to landfills every year.

With life spans of 50–100 years, today's buildings and infrastructure will impact our energy use and emissions for the next century. Incorporating climate action in planning and development leads to less energy and infrastructure spending. Over time, these actions will result in lower emissions and reduced congestion, as well as improved air quality, liveability and health.

NORTH VANCOUVER'S CLIMATE ACTION LEADERSHIP

The City of North Vancouver has shown how communities can make impressive strides to lead in the fight against climate change. It prides itself on being a compact community that puts pedestrians, cyclists, and transit first, and for reducing its corporate emissions by 19 per cent since 2007. Overall community emissions have decreased by 6 per cent between 2005 and 2010. The city has made this progress through initiatives that focus on sustainable energy, development planning that enhances public transit, building bike and pedestrian routes, and making upgrades to city buildings to make them more energy efficient.

TAKING ACTION:
REGULATIONS FOR MORE ENERGY EFFICIENT BUILDINGS

Combustion of fossil fuels for heating in buildings accounts for the majority of building emissions. When we use fossil fuels, we need to make sure we are using them as efficiently as possible.

With 98 per cent of electricity generated in British Columbia coming from clean sources, promoting the efficient use of electricity represents another opportunity to cut emissions further. At the same time we must ensure that we do not intensify issues around housing affordability. That is why we are amending the energy efficiency standards regulation to include:

» Increased efficiency requirements for gas fireplaces and air source heat pumps, effective in 2018; and

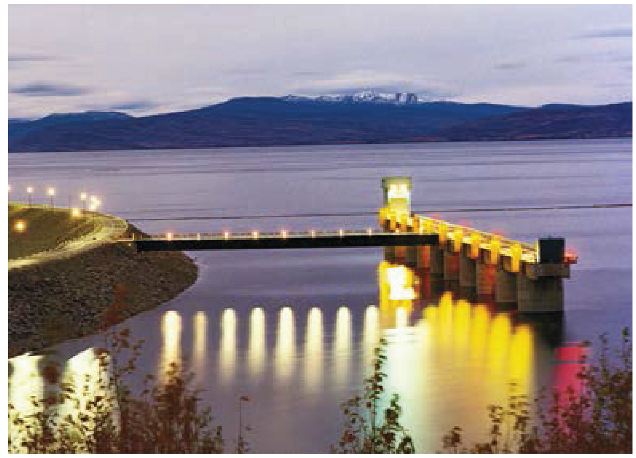
» High-efficiency technology requirements for natural gas space and water heating equipment, effective in 2020 and 2025 respectively.

GET INVOLVED:
USE THE FIRST NATIONS CLEAN ENERGY TOOLKIT

First Nations in British Columbia are well placed to take advantage of the clean energy sector.

The British Columbia First Nations Clean Energy Toolkit is a step-by-step manual designed to inform First Nations about the kinds of clean and renewable energy sources available, how to begin looking into doing a clean energy project, and where to find resources.

Check it out at:
https://www.cleanenergybc.org/wp-content/uploads/2016/04/BC-FN-Toolkit.pdf.



TAKING ACTION: ENCOURAGING DEVELOPMENT OF NET ZERO BUILDINGS

Cleaner, more energy-efficient buildings can save owners and tenants money in the long run by lowering energy costs and avoiding carbon costs. Additionally, improved building envelopes and efficient technologies such as new heat pumps can make significant improvements in buildings. As such, we are implementing a number of policies to encourage the development of net zero buildings, including:

» Accelerating increased energy requirements in the BC Building Code by taking incremental steps to make buildings ready to be net zero by 2032;

» Developing energy efficiency requirements for new buildings that go beyond those in the BC Building Code, called Stretch Codes, that interested local governments could implement in their communities; and

» Creating innovation opportunities and financial incentives for advanced, energy-efficient buildings, including an increase in funding for design and innovation.

The international Passive House standard is one of the most rigorous and advanced building performance standards in the world, achieving reductions in heating energy of up to 90 per cent compared to other buildings. Through a partnership between the Province's Innovative Clean Energy Fund and the Canadian Passive House Institute, architects, builders and building inspectors are receiving training in Passive House design principles.

GET INVOLVED: LEARN ABOUT PASSIVE HOUSING DESIGN

Take a passive house design course and find out about training subsidies for building professionals at: http://canphi.ca/passive-house-courses/.

TAKING ACTION: REFRESHING THE CLIMATE ACTION CHARTER FOR COMMUNITIES

The Climate Leadership Team recommended that British Columbia update the Climate Action Charter to align provincial and community goals. In response, we are refreshing our actions under the Climate Action Charter this year, which sets out a framework for British Columbia communities to become carbon neutral and to create complete, compact, energy-efficient urban and rural communities.

The Province will work with local governments to expand the progress made to date on reducing GHG emissions. The goal is to establish a plan for community action that takes advantage of provincial and federal actions, to maintain momentum at the community level through policies, programs and regulations that will:

» Focus growth near major transit corridors for large urban communities;

» Increase the use of decision support tools that provide the information needed to create more resilient green infrastructure; and

» Strengthen the ability of communities to adapt to the impacts of climate change.

GET INVOLVED: UPGRADE YOUR HOME'S ENERGY EFFICIENCY

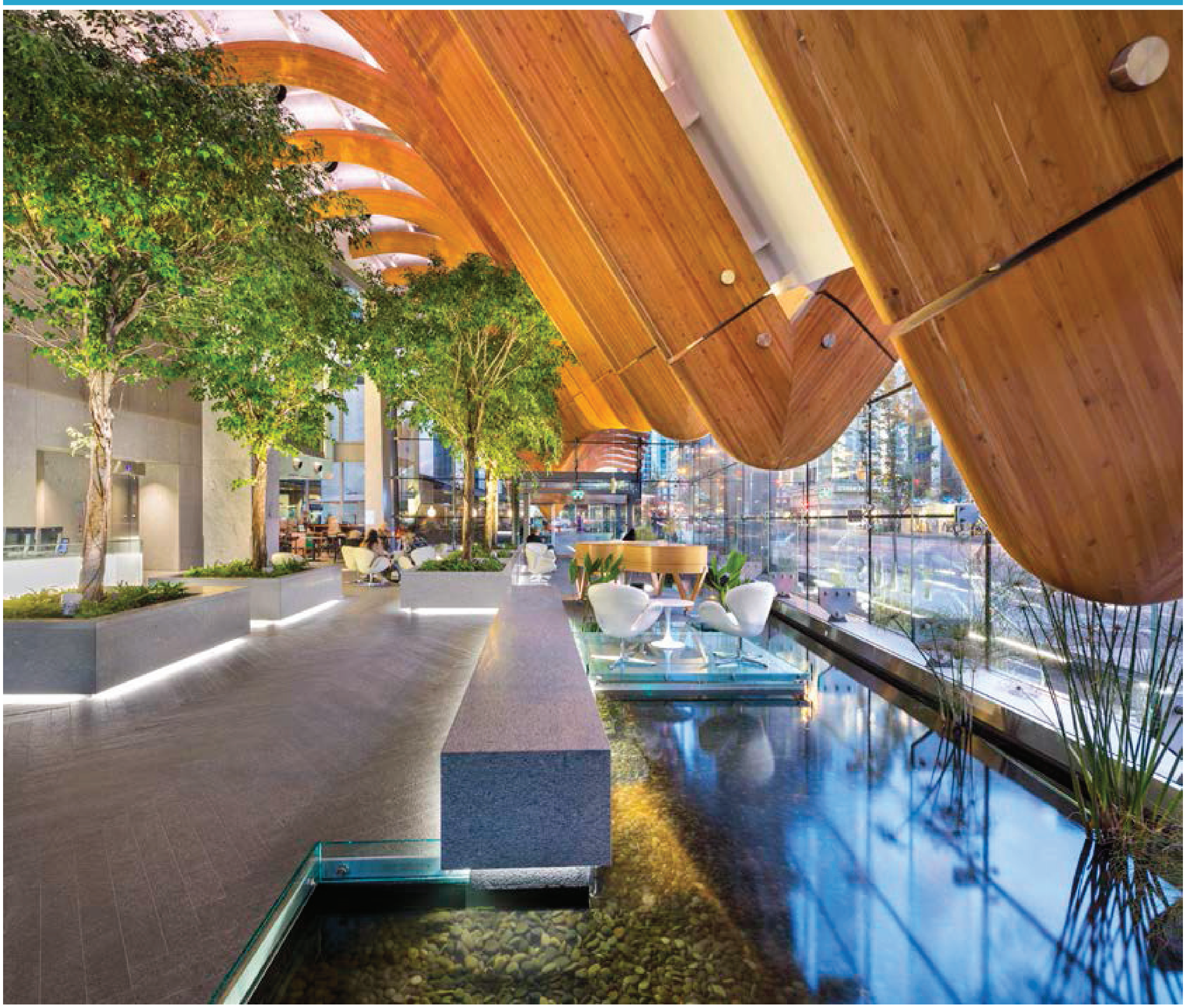
Home energy efficiency upgrades are a great way to save money and protect the environment. Did you know you can receive a rebate of up to $1,700 for upgrading from oil heating to an electric heat pump?

For more information on this and other programs, check out British Columbia's energy efficiency programs: www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/energy-efficiency-conservation/programs.

TELUS GARDEN AWARDED LEED PLATINUM CERTIFICATION

TELUS Garden, the company's new office in downtown Vancouver, is one of North America's greenest buildings. That is why the Canada Green Building Council awarded it the prestigious Leadership in Energy and Environmental Design (LEED) Platinum certification and it also received the impressive 2016 Architizer A+ Award for Office High Rise. Its innovative design includes: a district energy system that recovers energy that would normally be wasted and uses it to heat and cool air and water for both the office and residential towers, as well as the retail space; Vancouver's largest solar panel array; a rainwater capture system to irrigate its 10,000 sq. ft. of garden terraces; high-efficiency motion sensor lighting; charging stations for electric vehicles; and numerous other design elements that improve its environmental performance.

These sustainability features will contribute to a reduction in carbon emissions of more than 1,000 tonnes annually. Its innovative design was inspired by nature and advances the company's mission to create a healthier, more sustainable future, demonstrating what the built environment of the future could look like.



TAKING ACTION:
CREATING A STRATEGY TO TURN WASTE INTO RESOURCES

Landfill waste is a significant source of emissions, and an area where significant opportunity for improved performance on GHG emissions exists. The CLT recommended that British Columbia create a waste-to-resource strategy that reduces GHG emissions from organic waste. In response, we are taking the following actions:

» Supporting materials exchange pilot projects that create innovative uses for waste products;

» Creating a waste-to-resource strategy to reduce waste sent to landfill; and

» Establishing a food waste prevention target of 30 per cent and increasing organics diverted from landfills to 90 per cent.

These actions are expected to reduce annual GHG emissions by up to 1.4 million tonnes.

TURNING WASTE INTO ENERGY

Emergent Waste Solutions (EWS) is a B.C. business that is deploying clean tech solutions to turn waste into valuable products and reduce greenhouse gas emissions, without using incineration.

Using a process called thermolysis, EWS's technology produces carbon from waste, such as wood fibre, rubber and plastics, for a wide variety of applications including biochar for agricultural uses, activated carbon for filtration, and carbon black for rubber product applications. The energy byproducts are syngas, used primarily to power its own operations, as well as bio oil and light diesel fuel, which can be used for home heating and other applications. Beyond the potential applications of this technology in B.C., EWS is opening a plant in Alberta, helping our neighbours turn their waste into valuable resources.

Action Area: Public Sector Leadership

WHY PUBLIC SECTOR LEADERSHIP MATTERS

Public sector operations are present in almost every community in the province, through schools, universities, colleges, crown corporations, health care services and others. B.C.'s public sector is also a significant buyer of clean tech goods, equipment and services.

As such, the Province is well positioned to serve as a catalyst for climate action at both the community and provincial levels. Public sector leadership engages 300,000 public servants to take action on climate change, and in turn reaches the two million British Columbians that work, learn or visit government buildings each year. Buildings account for almost 77 per cent of B.C.'s provincial public sector emissions.

That is why as of 2010, the Greenhouse Gas Reduction Targets Act has required all public sector organizations (PSOs) to operate at carbon neutral. The Carbon Neutral Government commitment is achieved by measuring and reducing PSO emissions and offsetting the remainder by purchasing carbon offsets.

Over the first six years of this commitment, the provincial public sector has successfully achieved carbon neutrality each year, reducing a total of 4.3 million tonnes of emissions through reduction activities and investment of $51.4 million in offset projects.

SURREY'S HIGH PERFORMANCE HOSPITAL

In 2014, the Fraser Health Authority partnered with Integrated Team Solutions to deliver a state-of-the-art critical care tower at Surrey Memorial Hospital. Recently LEED Gold certified, the eight storey tower incorporates efficient and sustainable design solutions, including air-to-water heat pumps, central lighting controls and electric vehicle charging stations. The tower, with estimated annual emissions of less than 1,100 tonnes C0$_2$e, is predicted to save nearly 4 GWh equivalent of energy each year compared to a standard building.

PhotoCredit: Ed White Photographics

TAKING ACTION: PROMOTING USE OF LOW CARBON AND RENEWABLE MATERIALS IN INFRASTRUCTURE

Public sector infrastructure represents a considerable portion of B.C.'s built environment and is an area where the Province is demonstrating leadership in taking action to reduce GHG emissions. That is why we are developing policies to increase the use of low carbon and renewable materials in all public sector infrastructure, including:

» Approving use of Portland-limestone cement in public sector infrastructure. This material reduces GHG emissions associated with existing cement manufacturing by approximately 10 per cent, while producing concrete with similar strength and durability. This cement has been popular in Europe for over 25 years now, but is new to Canada; and

» Increasing use of B.C.'s wood products that store carbon and reduce emissions, through our Wood First program that drives innovation in forestry products, while promoting climate-friendly construction and supporting our forest-dependent communities.

GET INVOLVED: IMPROVE YOUR ENERGY MANAGEMENT PRACTICES

Looking for ways to improve the energy efficiency of your organization?

Check out FortisBC's Commercial Custom Design Program to learn about natural gas upgrade opportunities and their Custom Business Efficiency Program for electricity upgrade opportunities for customers. Learn about the full range of energy management programs for BC Hydro customers.

Find out more at:
https://www.fortisbc.com/Rebates/RebatesOffers/Pages/default.aspx?type=business *and* https://www.bchydro.com/powersmart/business/programs/partners.html.

TAKING ACTION: REDUCING EMISSIONS AND PLANNING FOR ADAPTATION IN THE PUBLIC SECTOR

It is important for the Province to lead the way on developing emission reductions and adaptation planning strategies, and demonstrating them through our public sector operations. Not only does it reduce the overall emissions profile of our province, it helps industry and individuals understand how they can join the fight against climate change. These areas were clear priorities for public sector leadership that were identified in the CLT's recommendations.

To continue capitalizing on this opportunity, the Province is committing to:

» Developing guidelines for public sector operations to reduce emissions and plan for climate change adaptation; and

» Mandating the creation of 10-year emissions reduction and adaptation plans for provincial public sector operations.

CANADA'S GREEN UNIVERSITY

A forestry seedling greenhouse started the University of Northern British Columbia (UNBC) on the road to using renewable energy. Now the Prince George university is the first in Canada with its own wood-fuelled district heating system and has been branded as "Canada's Green University." This system, designed by Vancouver-based clean tech company Nexterra, uses wood pellets made from wood waste such as sawmill shavings from Prince George's local forestry industry to create bioenergy. This energy is then used to heat water, which is circulated to the existing hot water district heating system that heats the UNBC campus. This has reduced fossil fuel consumption at UNBC by 72 per cent, avoiding 3,700 tonnes of carbon emissions every year. This has shown both the City of Prince George, as well as visiting students and faculty, what is possible when you use wood waste as a fuel.

GOING SOLAR AT THE COLLEGE OF THE ROCKIES

The College of the Rockies has installed solar panels on the roof of the Cranbrook campus' Kootenay Centre, which will allow it to generate electricity year-round. This solar technology will produce 109,000 kilowatt-hours per year of electricity, enough to power 14 houses in the region for a year. It will also act as a teaching tool for students, both during construction and once the system is running. This project will continue the college's mission to be leaders in alternative energy, having already installed solar technology to power the heating system for their residence building, and a solar wall at Pinnacle Hall that draws heat into the building, improving air quality and reducing heating costs.

Next Steps on Climate Leadership

Taking action on climate change is a critical priority for the Province of British Columbia and the citizens we serve. In B.C., we know that climate action is necessary to protect our environment, while seizing the opportunity of a low carbon economy that creates good jobs for British Columbians.

We are committed to achieving B.C.'s goal of reducing GHG emissions to 80 per cent below 2007 levels by 2050. However, the pathway to that goal is not always clear, as true sustainability means balancing environmental, economic and social concerns. An action that improves environmental performance cannot be considered sustainable if it works against our economic competitiveness, driving jobs and emissions to other jurisdictions, or if it raises the cost of living so that British Columbians struggle to make ends meet. There is no silver bullet here — real climate action demands careful planning, a flexible approach, and coordination with our partners here in Canada and around the world.

The federal government has signalled a reinvigorated commitment to climate action, and we look forward to the opportunity to help develop a Pan-Canadian Framework later this year, which will align provincial policies to work together to achieve our GHG reduction goals.

While there are areas we know we still need to take action on, many are dependent on our work with the federal government, whether that means identifying additional available funding opportunities or developing policies that align with our provincial and territorial partners to protect B.C.'s economic competitiveness.

A key area that we know will require further action is carbon pricing. Our carbon tax already leads the country — now we must work with our provincial and federal partners to develop a carbon pricing model that works for all. It is a complex issue that will require extensive coordination to ensure that it is effective.

We know that First Nations are interested in ensuring their communities are prepared to adapt to climate change, and are able to capture the economic benefit of mitigation activities, including reforestation and clean energy projects. With the establishment of this new framework for provincial action on climate change, the Province will be seeking the participation of First Nations in the economic and adaptation opportunities we have identified. We look forward to collaborating with them to capitalize on these new opportunities.

Another key area where you can expect to hear more in the coming year is adaptation. In 2010, the Province created a comprehensive strategy to address the changes we will see in B.C. as a result of climate change. We are now working with the federal government and other Canadian jurisdictions to improve our management of the risks associated with a changing climate.

The Province is also collaborating internationally through the Regions Adapt Initiative and the Pacific Coast Collaborative. Recent investments in flood protection and forest stewardship here in British Columbia will also increase our resilience to a changing climate.

Adapting to a changing climate depends on action by all levels of government, the private sector and civil society. As we move forward on climate action, we will look to maximize opportunities to extend our leadership in responding to the impacts of a changing climate.

While the actions we have outlined here represent what we can do today, it is important that we lay the foundation to support solutions with the potential to make an even bigger impact. That is what programs like British Columbia's Innovative Clean Energy (ICE) Fund are designed to do.

A recent investment from the ICE Fund is generating a lot of excitement — Carbon Engineering Ltd. has built the world's first direct air capture plant in Squamish. This technology captures atmospheric carbon dioxide right out of the air, and targets emissions that traditional fluestack carbon capture cannot reach. Their demonstration plant is already capturing and purifying a tonne of CO_2 every day. Carbon Engineering is looking at ways to turn the captured CO_2 into fuels like gasoline and diesel, which upon combustion would simply return the carbon to the air.

These innovations, along with continued deployment of clean and renewable electricity generation, could allow for the mass production of low carbon fuels, helping the world become less reliant on fossil fuel production and consumption. The technology represents an enormous opportunity for B.C. to bolster its economy while fighting climate change.

The Province will continue to identify opportunities where we can reduce GHG emissions today, while working with our partners to plan for the future, and investing in innovative projects that can help us reach our 2050 target even sooner. Additionally, our Climate Leadership Plan will be updated over the course of the following year as work on the Pan-Canadian Framework on climate action progresses.

We hope that you will get engaged, do your own part where you can, and continue to work with us on this important mission. If we want to ensure a great future for our children and grandchildren, then climate action must be a key priority. Join us in imagining what this bright future looks like and in taking action to make it a reality.

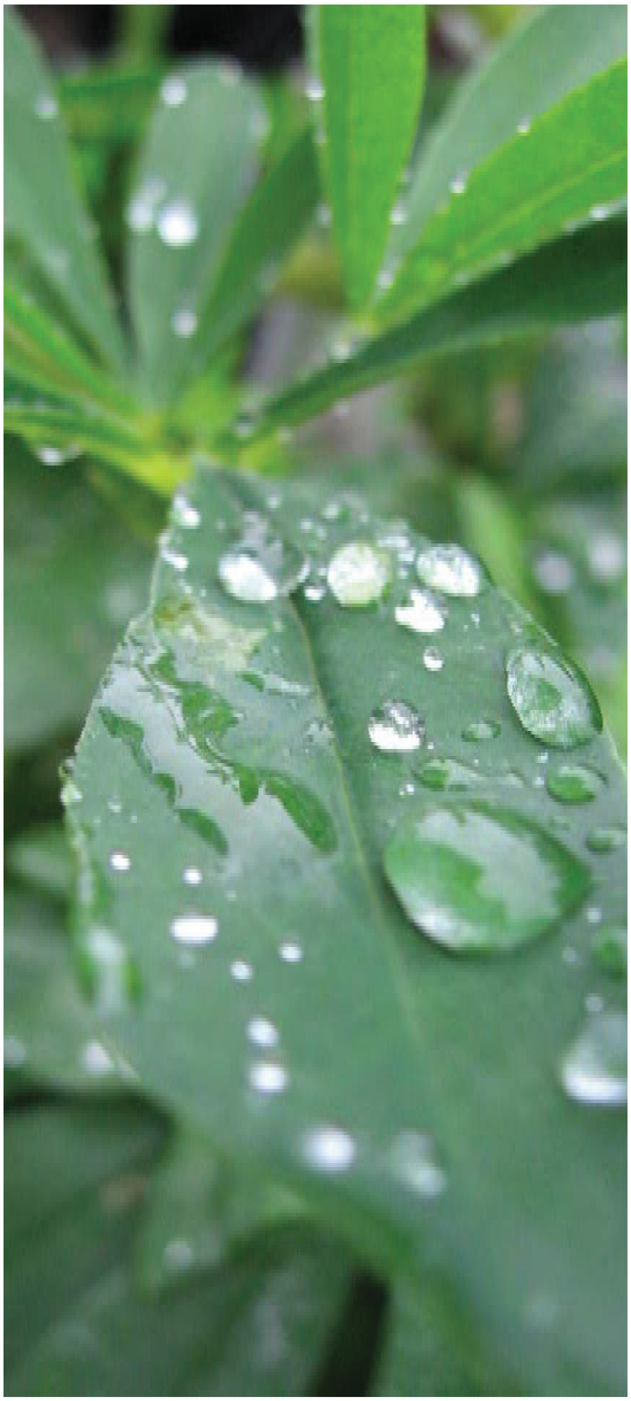
Sincerely,

Mary Polak

HONOURABLE MARY POLAK
MINISTER OF ENVIRONMENT

Photo Credit: Stephen Hui

Appendix



Summary of Action Areas

The table on the following page summarizes the 21 climate actions across 6 sectors.

Emission reductions have been forecast through economic modelling or direct calculation by the responsible ministries. Input/output modelling was used to forecast cumulative direct and indirect economic activity (Gross Domestic Product) and jobs resulting from policies, except forest sector policies, which were forecasted by the Ministry of Forests, Lands and Natural Resource Operations.

The input/output modelling was undertaken using relevant economic and jobs factors provided by BC Stats.

All numbers in the following table are forecasts and subject to final policy decisions and budgets.

* *25,000,000 tonnes CO_2e is equal to 8.3 million new cars off the road for a year.*

An average B.C. house creates 2 tonnes CO_2e per year. 25,000,000 tonnes CO_2e is equal to the emissions from 12.5 million B.C. homes in one year.

Action Areas	Emission Reductions in 2050 (Millions of tonnes CO_2e)	Job Creation	Economic Activity ($ Millions)
NATURAL GAS	**5**	**4,043**	**527**
» Strategy to Reduce Methane Emissions » Regulating Carbon Capture and Storage » Electricity to Power Natural Gas Production and Processing			
TRANSPORTATION	**3**	**41,525**	**4,573**
» Increasing the Low Carbon Fuel Standard » Incentives for Renewable Natural Gas » Incentives for Purchasing a Clean Energy Vehicle » Charging Stations for Zero Emission Vehicles » 10-Year Plan to Improve B.C.'s Transportation Network			
FORESTRY & AGRICULTURE	**12**	**19,942**	**681**
» Enhancing the Carbon Storage Potential of B.C.'s Forests » Nutrient Management Program			
INDUSTRY & UTILITIES	**2**	**554**	**53**
» Making B.C.'s Electricity 100% Renewable or Clean » Efficient Electrification » Fuelling Marine Vessels with Cleaner Burning LNG » New Energy Efficiency Standards for Gas Fired Boilers » Expanding Incentives for Efficient Gas Equipment			
BUILT ENVIRONMENT	**2**	**230**	**19**
» Regulations for More Energy Efficient Building » Encouraging Development of Net Zero Buildings » Refreshing the Climate Action Charter for Communities » Strategy to Turn Waste into Resources			
PUBLIC SECTOR LEADERSHIP	**1**	**3**	**–**
» Promoting Use of Low Carbon and Renewable Materials in Infrastructure » Reducing Emissions and Planning for Adaptation in the Public Sector			
TOTAL	**25***	**66,297**	**5,853**

Notes

Notes

FOR MORE INFORMATION VISIT THE WEBSITE:

GOV.BC.CA/CLIMATELEADERSHIP

BRITISH COLUMBIA

Appendix C

PNW UTILITIES' INTEGRATED RESOURCE PLANS COMPARISION TABLE

PNW Utilities - Comparison Table

	Idaho Power Company	Avista Utilities	PacifiCorp	Puget Sound Energy	Portland General Electric	Seattle City Light
Latest Plan	June 2015 IRP (2015-2034)	August 2015 IRP (2016-2035)	March 2015 IRP (2015-2034)	November 2015 IRP (2016-2035)	March 2013 IRP (2014-2033)	2016 Progress Report (2016-2035)
Service Area(s)	Idaho and Oregon	Eastern Washington and Northern Idaho	Pacific Power: Oregon, Washington and California Rocky Mountain Power: Utah, Wyoming and Idaho	Washington	Oregon	Washington (City of Seattle & outlying communities)
Number of electric customers	515,763[1]	340,000	1,800,000	1,100,000	835,000	780,000
Current Energy/ Capacity[2] Requirement	Capacity: 10,994 MW Energy: 16,313 GWh	Capacity: 1,718 MW[3] Energy: 1,074 aMW	Capacity: 10,368 MW[4] Energy: 63,594 GWh	Capacity: 4,929 MW[5] Energy: 2,629 aMW	Capacity: 2,419 MW[6] Energy: 1,564 aMW	Capacity: 2,841 MW Energy: 10,068 GWh
Annual Load Growth Forecast[7]	Energy: 1.2% Capacity: 1.5%	Energy: 0.6% Capacity: 0.74%	Energy: 0.85% Capacity: 0.89%	Energy: 1.5% Capacity: 1.6%	Energy: 1.3% Capacity: 1%	Energy: 0.4%
Current Energy Portfolio Mix	36% Hydro 34% Coal 7% Natural Gas 23% Purchased Power (13% PURPA, 3% PPA, 7% Market Purchases)	42% Natural Gas 28% Owned Hydro 10% Contracted Hydro 13% Coal 7% Biomass & Wind	61% Coal 14% Natural Gas 6% Hydro 9% Wind, Solar, Geothermal 10% DSM, Term & Market Purchases	35% Coal 24% Natural Gas 36% Hydro Nuclear 1% Wind 3% Other 1% (Biomass, landfill gas, oil, waste)[8]	29% Coal 27% Natural Gas 20% Hydro 10% wind and solar 9% Market Purchases, 5% Long Term Contracts	92% Hydro 8% Market Purchase, Wind, Biomass

[1] *https://www.idahopower.com/AboutUs/CompanyInformation/Facts/default.cfm*
[2] *8,760 hrs / year (non-leap year) * aMW - If leap year – 8,784 hrs / year*
[3] *Avista 2015 IRP – Table 3.7 Energy and Peak Forecasts (for year 2016)*
[4] *Appendix II: Table A.1 and Table A.2 – excluded class 2 DSM which are included as resources in the System Optimizer model*
[5] *Puget Sound 2015 IRP – Figure 5-20, 5-17*
[6] *2014 peak load - https://www.portlandgeneral.com/our-company/pge-at-a-glance/quick-facts*
[7] *All after DSM*
[8] https://pse.com/aboutpse/EnergySupply/Pages/Electric-Supply.aspx

	Idaho Power Company	Avista Utilities	PacifiCorp	Puget Sound Energy	Portland General Electric	Seattle City Light
Planning Reserve Margin	>10%	22.6% (includes operating reserves)	13%	13.7%[9]	12% (6% operating and 6% contingency reserves)	Only provide WECC Target Margins: Summer: 17.5% Winter 19.2%
DSM	Energy efficiency reduces annual energy demand by 301 aMW and peak demand by 473 MW by 2034	By 2035, achievable potential of 1,090 GWh or 124.5 aMW	Meets 86% of forecast load growth from 2015 through 2024	Energy efficiency 706 aMW by 2035.	Energy efficiency resource supply of 361 aMW by 2032	New conservation reaching 125 aMW by 2020 and 227 aMW by 2031
Owned Supply Resource	17 hydroelectric projects, 3 natural gas-fired plants, 1 diesel-powered plant, share ownership in 3 coal-fired facilities	8 hydroelectric developments, share ownership of 2 coal-fired units, 5 natural gas-fired projects, and a biomass plant.	10 coal facilities, 6 natural gas facilities, 2 geothermal and other, 41 hydro systems, 13 wind facilities, 2 coal mines	Shared ownership in 4 coal-fired generation units, 6 CCCT, 4 SCCTs, 3 hydro plants, 3 wind farms	7 hydroelectric plants, 3 natural gas plants, 2 coal-fired plants, 1 wind facility 2014 additions: 1 gas plant and 1 wind farm	4 major hydroelectric projects, 2 small hydroelectric projects, Landfill gas plant BPA Hydro PPA (40%)
Load-Resource Balance	Energy deficit: 2026 Capacity deficit: 2025	Energy deficit: 2026 Capacity[10] deficit: 2021	Energy Deficit: 2028 Capacity: Lots of transmission projects under construction	Capacity deficit: 2021 Energy deficit: 2021	Energy deficit: 2019 Winter deficit: 2019 Summer deficit: 2018	Energy deficit: 2028 Capacity deficit: 2028
Preferred Resource Strategy	Market purchase and PPA before 2025, complete the B2H transmission line project by 2025, a CCCT by 2031	Adequate resources before 2020, acquisition of natural gas peaker by 2020, thermal upgrades by 2025, a CCCT by 2026	DSM and short term market purchases through 2027. Additional thermal resource (CCCT) added in 2028	Energy efficiency and demand-response additions until 2021. Additional natural-gas-fueled peaking plant in 2021-22. Addition 206 MW of wind by 2023, followed by another 131 MW by 2028.	Additional CCCT in 2019 and 2021, along with wind resources through 2030	Acquisition of energy efficiency, renewable resources, and improvements in hydro generation efficiency. Major resource required earliest by 2028

[9] *2021 Planning Margin*
[10] *Net of energy efficiency*

General Themes

Regional Resource Adequacy

- Relying on short-term wholesale market purchases to meet peak demand has traditionally been a low cost and low risk strategy for many Pacific Northwest utilities.
- Pacific Northwest's long-term regional load/resource studies developed by major energy organizations forecasted that the region's energy and capacity would shift from surplus to deficit in the next decade, unless new resources are developed
- By 2021, after the planned retirements of the Boardman and Centralia-1 coal plants, the likelihood of a shortfall increases and would lead to a supply deficit.
- Puget Sound Energy incorporated wholesale market risk for the first time in their most recent 2015 IRP; assuming wholesale market purchases may no longer be 100% reliable.

Preferred Resource Strategy

- Under current market conditions, utilities across the Pacific Northwest are trending toward meeting future demand by demand-side management programs, gas-fired generation plants, as well as renewables in part to comply with state and federal compliance of environmental regulations and renewable portfolio standards
- Utilities are engaging in various enabling studies and pilot projects examining emerging technologies such as; energy storage, community solar, and electric vehicle charging stations to be incorporated into future resource plans.

Environmental Regulations

- Federal, state, and regional climate and environmental policies continue to impact the resource planning strategies for utilities across the Pacific Northwest.
- The US Environmental Protection Agency (EPA) issued a final rule on the proposed Section 111(d) of the Clean Air Act (CAA) in late 2015 and utilities in PNW are currently reviewing the new rule and would be incorporating the effect of the rule in their future resource plans. In February 2016, the U.S. Supreme Court issued a stay of enforcement of the existing plant rule. The Supreme Court will wait until the U.S Court of Appeals for the District of Columbia Circuit reviews the case in a pending lawsuit. The Clean Power Plan (CPP) will most likely remained stayed until after the next presidential election, however the EIA has assumed that the plan will hold in their annual energy outlook, and a number of states are moving forward to meets the CPP's requirements.

Appendix D

PRICE FORECAST AND RATE SCENARIOS TABLES

Sumas Gas Price Forecast $CAD/GJ 2015 Dollars - Low

Adders Included

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	$4.16	$4.14	$4.06	$4.07	$4.06	$3.89	$3.87	$3.82	$3.72	$3.94	$4.19	$4.32
2017	$4.37	$4.35	$4.26	$4.27	$4.27	$4.08	$4.06	$4.01	$3.91	$4.14	$4.40	$4.54
2018	$4.16	$4.13	$4.05	$4.06	$4.05	$3.88	$3.86	$3.81	$3.72	$3.93	$4.18	$4.31
2019	$4.07	$4.05	$3.97	$3.98	$3.97	$3.81	$3.78	$3.73	$3.64	$3.85	$4.10	$4.22
2020	$4.07	$4.05	$3.97	$3.98	$3.97	$3.81	$3.78	$3.74	$3.64	$3.86	$4.10	$4.22
2021	$4.08	$4.06	$3.98	$3.99	$3.98	$3.82	$3.79	$3.74	$3.65	$3.86	$4.11	$4.23
2022	$4.31	$4.29	$4.21	$4.21	$4.21	$4.03	$4.00	$3.95	$3.85	$4.08	$4.34	$4.48
2023	$4.29	$4.27	$4.19	$4.19	$4.19	$4.01	$3.98	$3.93	$3.84	$4.06	$4.32	$4.45
2024	$4.31	$4.28	$4.20	$4.21	$4.20	$4.02	$4.00	$3.95	$3.85	$4.07	$4.34	$4.47
2025	$4.32	$4.29	$4.21	$4.22	$4.21	$4.04	$4.01	$3.96	$3.86	$4.09	$4.35	$4.48
2026	$4.38	$4.35	$4.27	$4.28	$4.27	$4.09	$4.06	$4.01	$3.91	$4.14	$4.41	$4.55
2027	$4.48	$4.45	$4.37	$4.37	$4.37	$4.18	$4.15	$4.10	$4.00	$4.23	$4.51	$4.65
2028	$4.54	$4.51	$4.42	$4.43	$4.42	$4.23	$4.21	$4.15	$4.05	$4.29	$4.57	$4.71
2029	$4.59	$4.57	$4.48	$4.49	$4.48	$4.29	$4.26	$4.20	$4.10	$4.34	$4.63	$4.77
2030	$4.65	$4.62	$4.53	$4.54	$4.53	$4.34	$4.31	$4.25	$4.14	$4.39	$4.68	$4.83
2031	$4.70	$4.67	$4.58	$4.59	$4.58	$4.38	$4.35	$4.30	$4.19	$4.44	$4.73	$4.88
2032	$4.79	$4.76	$4.67	$4.68	$4.67	$4.47	$4.44	$4.38	$4.27	$4.53	$4.83	$4.98
2033	$4.89	$4.86	$4.76	$4.77	$4.76	$4.55	$4.52	$4.46	$4.35	$4.61	$4.92	$5.08
2034	$4.98	$4.95	$4.85	$4.86	$4.85	$4.64	$4.61	$4.55	$4.43	$4.70	$5.01	$5.17
2035	$5.07	$5.04	$4.94	$4.95	$4.94	$4.72	$4.69	$4.63	$4.51	$4.79	$5.11	$5.27

Sumas Gas Price Forecast $CAD/GJ 2015 Dollars - Base

Adders Included

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	$4.67	$4.64	$4.55	$4.56	$4.55	$4.35	$4.32	$4.27	$4.16	$4.41	$4.70	$4.85
2017	$4.93	$4.90	$4.81	$4.82	$4.81	$4.60	$4.57	$4.51	$4.39	$4.66	$4.97	$5.13
2018	$5.19	$5.16	$5.05	$5.07	$5.06	$4.83	$4.80	$4.73	$4.61	$4.90	$5.23	$5.40
2019	$5.37	$5.33	$5.23	$5.24	$5.23	$4.99	$4.96	$4.89	$4.76	$5.06	$5.41	$5.58
2020	$5.64	$5.60	$5.49	$5.50	$5.49	$5.24	$5.20	$5.13	$5.00	$5.31	$5.68	$5.87
2021	$5.75	$5.72	$5.60	$5.61	$5.60	$5.35	$5.31	$5.24	$5.10	$5.42	$5.80	$5.99
2022	$5.91	$5.87	$5.75	$5.76	$5.75	$5.49	$5.45	$5.37	$5.23	$5.56	$5.95	$6.15
2023	$6.06	$6.02	$5.90	$5.91	$5.90	$5.63	$5.59	$5.51	$5.36	$5.71	$6.11	$6.31
2024	$6.21	$6.17	$6.04	$6.06	$6.05	$5.77	$5.73	$5.65	$5.49	$5.85	$6.26	$6.47
2025	$6.37	$6.33	$6.19	$6.21	$6.20	$5.91	$5.86	$5.78	$5.62	$5.99	$6.41	$6.63
2026	$6.53	$6.48	$6.35	$6.36	$6.35	$6.05	$6.01	$5.92	$5.76	$6.14	$6.57	$6.80
2027	$6.68	$6.64	$6.50	$6.51	$6.50	$6.20	$6.15	$6.06	$5.89	$6.28	$6.73	$6.96
2028	$6.84	$6.79	$6.65	$6.67	$6.65	$6.34	$6.29	$6.20	$6.03	$6.43	$6.89	$7.13
2029	$7.00	$6.95	$6.80	$6.82	$6.81	$6.48	$6.43	$6.34	$6.17	$6.58	$7.05	$7.29
2030	$7.16	$7.11	$6.95	$6.97	$6.96	$6.63	$6.58	$6.48	$6.30	$6.72	$7.21	$7.46
2031	$7.36	$7.31	$7.15	$7.17	$7.15	$6.81	$6.76	$6.66	$6.48	$6.91	$7.41	$7.67
2032	$7.56	$7.51	$7.35	$7.36	$7.35	$7.00	$6.94	$6.84	$6.65	$7.10	$7.62	$7.88
2033	$7.76	$7.71	$7.54	$7.56	$7.54	$7.18	$7.13	$7.02	$6.82	$7.29	$7.82	$8.09
2034	$7.96	$7.91	$7.74	$7.76	$7.74	$7.37	$7.31	$7.20	$7.00	$7.47	$8.02	$8.30
2035	$8.16	$8.11	$7.93	$7.95	$7.94	$7.55	$7.49	$7.38	$7.17	$7.66	$8.23	$8.52

Sumas Gas Price Forecast $CAD/GJ 2015 Dollars - High

Adders Included

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	$5.17	$5.14	$5.04	$5.05	$5.04	$4.82	$4.78	$4.72	$4.60	$4.88	$5.21	$5.38
2017	$5.55	$5.51	$5.40	$5.41	$5.40	$5.16	$5.12	$5.05	$4.92	$5.23	$5.59	$5.77
2018	$6.21	$6.16	$6.04	$6.05	$6.04	$5.76	$5.72	$5.64	$5.48	$5.84	$6.25	$6.46
2019	$6.61	$6.56	$6.43	$6.44	$6.43	$6.13	$6.08	$6.00	$5.83	$6.22	$6.66	$6.88
2020	$7.02	$6.97	$6.83	$6.84	$6.83	$6.51	$6.46	$6.36	$6.19	$6.60	$7.07	$7.32
2021	$7.20	$7.15	$7.00	$7.01	$7.00	$6.67	$6.62	$6.52	$6.34	$6.76	$7.25	$7.50
2022	$7.57	$7.52	$7.36	$7.38	$7.36	$7.01	$6.95	$6.85	$6.66	$7.11	$7.63	$7.89
2023	$8.07	$8.01	$7.84	$7.86	$7.84	$7.46	$7.41	$7.30	$7.09	$7.57	$8.13	$8.42
2024	$8.45	$8.39	$8.20	$8.22	$8.21	$7.81	$7.75	$7.63	$7.41	$7.92	$8.51	$8.81
2025	$8.72	$8.66	$8.47	$8.49	$8.47	$8.06	$7.99	$7.88	$7.65	$8.18	$8.79	$9.10
2026	$9.14	$9.08	$8.88	$8.90	$8.88	$8.44	$8.38	$8.25	$8.01	$8.57	$9.21	$9.54
2027	$9.27	$9.20	$9.00	$9.02	$9.00	$8.56	$8.49	$8.37	$8.12	$8.69	$9.34	$9.67
2028	$9.61	$9.55	$9.33	$9.36	$9.34	$8.88	$8.81	$8.67	$8.42	$9.01	$9.69	$10.04
2029	$9.97	$9.90	$9.68	$9.71	$9.69	$9.20	$9.13	$9.00	$8.73	$9.35	$10.05	$10.41
2030	$10.34	$10.27	$10.04	$10.06	$10.04	$9.54	$9.46	$9.32	$9.05	$9.69	$10.42	$10.80
2031	$10.74	$10.66	$10.42	$10.45	$10.43	$9.90	$9.82	$9.68	$9.39	$10.06	$10.82	$11.22
2032	$11.17	$11.09	$10.84	$10.87	$10.85	$10.30	$10.22	$10.06	$9.76	$10.46	$11.26	$11.67
2033	$11.62	$11.53	$11.27	$11.30	$11.28	$10.71	$10.62	$10.46	$10.15	$10.87	$11.71	$12.14
2034	$11.99	$11.91	$11.64	$11.67	$11.64	$11.05	$10.96	$10.79	$10.47	$11.22	$12.09	$12.53
2035	$12.45	$12.36	$12.08	$12.11	$12.09	$11.47	$11.38	$11.20	$10.87	$11.65	$12.55	$13.01

Mid-C Electricity Price Forecast $CAD/MWh 2015 Dollars - Low

Adders Included

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	$35.80	$34.58	$33.76	$31.90	$31.31	$31.35	$32.88	$35.06	$34.66	$35.66	$35.93	$36.46
2017	$36.37	$34.96	$33.96	$31.97	$32.44	$31.43	$32.82	$35.27	$34.77	$35.76	$36.22	$36.94
2018	$35.12	$33.98	$32.85	$30.52	$29.86	$29.17	$31.45	$33.89	$33.75	$34.42	$34.35	$35.80
2019	$33.61	$32.46	$31.20	$29.28	$29.55	$28.44	$30.02	$32.10	$32.26	$32.88	$32.87	$34.27
2020	$33.51	$32.29	$31.15	$29.19	$28.43	$28.33	$30.04	$31.90	$32.14	$32.76	$32.93	$34.32
2021	$32.76	$31.81	$30.78	$28.70	$28.63	$28.84	$29.97	$31.67	$31.41	$32.34	$32.59	$33.64
2022	$34.69	$33.53	$32.50	$30.21	$29.60	$30.28	$31.57	$33.48	$33.03	$34.23	$34.47	$35.48
2023	$33.66	$32.39	$31.34	$29.01	$29.58	$29.80	$30.56	$32.43	$31.81	$33.15	$33.43	$34.35
2024	$33.22	$32.12	$30.94	$28.79	$28.31	$28.56	$30.17	$31.93	$31.79	$32.70	$32.56	$34.03
2025	$33.21	$32.07	$30.97	$28.81	$29.07	$29.21	$30.24	$31.90	$31.94	$32.75	$32.63	$34.37
2026	$34.04	$32.89	$31.82	$29.62	$28.81	$30.01	$31.31	$32.79	$32.69	$33.67	$33.63	$35.19
2027	$35.18	$34.08	$33.05	$30.58	$30.60	$31.49	$32.33	$34.03	$33.60	$34.68	$34.93	$36.50
2028	$36.28	$34.84	$33.77	$30.96	$30.70	$31.85	$33.13	$35.08	$34.19	$35.82	$36.01	$37.26
2029	$37.07	$35.78	$34.59	$31.47	$31.95	$32.25	$33.48	$35.87	$35.31	$36.41	$36.16	$38.09
2030	$37.93	$36.68	$35.20	$32.18	$31.65	$32.50	$34.48	$36.52	$36.26	$37.25	$37.01	$38.99
2031	$38.62	$37.23	$35.46	$32.59	$33.06	$33.52	$34.72	$36.82	$36.96	$37.97	$37.71	$39.92
2032	$40.03	$38.63	$36.98	$33.93	$32.80	$34.27	$35.81	$38.24	$38.08	$39.08	$39.37	$41.31
2033	$41.11	$39.62	$37.91	$34.58	$35.20	$35.61	$36.61	$39.44	$39.09	$40.42	$40.59	$42.29
2034	$42.65	$41.11	$39.08	$35.48	$35.10	$36.27	$37.88	$40.64	$40.37	$41.89	$42.14	$43.79
2035	$43.76	$42.32	$40.40	$36.60	$36.83	$37.04	$38.48	$41.87	$41.92	$43.24	$42.91	$45.01

Mid-C Electricity Price Forecast $CAD/MWh 2015 Dollars - Base

Adders Included

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	$44.43	$42.77	$41.78	$39.24	$38.67	$38.80	$40.71	$43.38	$42.62	$44.12	$44.37	$45.29
2017	$46.43	$44.48	$43.19	$40.39	$41.28	$40.17	$41.87	$44.94	$43.95	$45.59	$45.96	$47.28
2018	$48.55	$46.91	$45.15	$41.63	$41.03	$40.56	$43.20	$46.83	$46.05	$47.41	$47.16	$49.56
2019	$49.48	$47.66	$45.66	$42.52	$42.75	$41.66	$43.92	$47.05	$46.94	$48.27	$48.04	$50.53
2020	$51.39	$49.39	$47.35	$44.29	$42.96	$43.42	$45.72	$48.66	$48.75	$50.19	$50.06	$52.80
2021	$51.40	$49.73	$47.89	$44.11	$44.07	$44.87	$46.34	$49.10	$48.73	$50.56	$50.91	$52.89
2022	$52.37	$50.65	$48.78	$44.93	$44.08	$45.58	$47.03	$50.25	$49.44	$51.56	$51.75	$53.70
2023	$53.32	$51.16	$49.41	$45.33	$46.08	$46.50	$47.85	$51.00	$49.82	$52.28	$52.40	$54.46
2024	$54.15	$52.41	$50.57	$46.88	$45.14	$46.26	$48.83	$51.79	$51.32	$53.22	$52.93	$55.64
2025	$55.18	$53.43	$51.36	$48.08	$47.42	$47.97	$50.17	$52.77	$52.33	$54.32	$54.13	$56.96
2026	$56.31	$55.01	$52.93	$49.28	$46.87	$49.28	$51.61	$54.10	$53.79	$56.10	$56.01	$58.22
2027	$57.35	$56.43	$54.08	$50.13	$49.27	$50.77	$52.42	$55.60	$54.65	$57.21	$57.43	$59.56
2028	$58.98	$57.93	$55.43	$50.62	$49.61	$51.66	$53.79	$57.31	$55.66	$59.07	$59.13	$61.10
2029	$60.35	$59.54	$57.05	$51.72	$51.39	$52.30	$54.51	$58.65	$57.48	$60.18	$59.75	$62.74
2030	$61.52	$61.18	$58.28	$53.35	$50.94	$53.04	$56.17	$59.74	$59.12	$61.74	$61.46	$64.51
2031	$63.75	$62.77	$59.14	$54.83	$53.53	$54.94	$57.31	$60.61	$60.74	$63.45	$63.10	$66.64
2032	$65.44	$64.99	$61.08	$56.47	$53.33	$56.53	$58.60	$62.28	$62.23	$65.20	$65.79	$68.58
2033	$66.82	$66.79	$63.18	$56.91	$56.49	$58.39	$59.30	$63.86	$63.48	$67.13	$67.51	$70.41
2034	$69.06	$69.04	$64.80	$58.17	$56.27	$59.14	$61.00	$65.69	$65.21	$69.44	$69.63	$72.55
2035	$70.84	$71.18	$67.04	$58.95	$58.38	$59.82	$62.22	$67.45	$67.57	$70.92	$70.77	$74.61

Mid-C Electricity Price Forecast $CAD/MWh 2015 Dollars - High

Adders Included

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	$48.20	$46.57	$45.14	$42.40	$41.89	$42.34	$44.17	$46.96	$46.17	$47.83	$47.91	$49.17
2017	$50.95	$49.14	$47.38	$44.00	$44.93	$44.35	$45.96	$49.18	$48.11	$50.18	$50.03	$51.99
2018	$56.25	$54.84	$52.07	$48.14	$47.03	$47.10	$49.81	$53.86	$53.18	$55.17	$54.49	$57.71
2019	$58.95	$57.30	$54.10	$50.42	$50.47	$49.58	$52.08	$55.77	$55.72	$57.86	$57.31	$59.62
2020	$61.26	$60.24	$56.66	$53.21	$51.30	$52.19	$54.66	$58.26	$58.31	$60.70	$60.87	$63.50
2021	$61.74	$61.03	$57.53	$52.95	$52.27	$53.98	$55.78	$59.24	$58.74	$61.58	$62.17	$64.74
2022	$64.62	$63.83	$60.06	$54.94	$53.49	$56.17	$58.02	$62.03	$60.93	$64.50	$64.72	$67.35
2023	$67.89	$67.05	$63.31	$57.48	$58.37	$59.60	$61.16	$65.18	$63.78	$67.94	$68.26	$70.86
2024	$70.78	$70.07	$66.10	$60.95	$58.42	$60.06	$64.23	$67.95	$67.00	$70.62	$70.21	$73.69
2025	$72.54	$72.24	$67.95	$62.91	$61.56	$62.53	$66.04	$69.35	$68.82	$72.38	$72.44	$76.22
2026	$75.95	$75.57	$71.45	$65.51	$61.82	$65.50	$69.33	$72.54	$72.44	$76.57	$76.65	$80.19
2027	$76.49	$76.53	$72.54	$66.28	$63.82	$67.09	$69.68	$73.34	$72.55	$77.32	$78.07	$81.25
2028	$80.31	$79.95	$75.15	$66.40	$65.07	$69.04	$71.87	$76.62	$75.31	$81.07	$81.36	$84.37
2029	$83.32	$83.61	$79.34	$68.87	$67.93	$70.14	$73.89	$79.55	$78.28	$83.47	$83.31	$87.67
2030	$86.73	$86.43	$81.76	$72.61	$68.03	$71.43	$77.36	$82.22	$81.47	$86.54	$86.81	$91.44
2031	$89.88	$89.91	$83.50	$75.11	$71.91	$75.20	$79.62	$84.50	$84.44	$89.88	$90.23	$94.73
2032	$94.17	$93.81	$86.89	$77.25	$71.96	$78.01	$82.61	$88.10	$87.86	$93.57	$94.89	$99.50
2033	$97.10	$97.65	$91.06	$78.31	$78.63	$81.84	$84.51	$91.42	$90.56	$96.87	$98.06	$103.08
2034	$101.17	$100.80	$93.75	$80.72	$78.44	$83.42	$86.99	$94.68	$93.53	$100.66	$101.98	$107.19
2035	$105.16	$105.35	$97.96	$83.81	$81.61	$84.03	$89.89	$99.02	$98.04	$104.23	$105.33	$110.74

PPA Tranche 1 Energy Rate Scenarios $CAD/MWh $2015 Dollars

Year	LOW	BASE	HIGH
2016	$46.11	$46.11	$46.11
2017	$46.70	$46.70	$46.70
2018	$47.16	$47.16	$47.16
2019	$47.11	$47.57	$48.49
2020	$47.11	$48.04	$49.92
2021	$47.11	$48.51	$51.39
2022	$47.11	$48.98	$52.90
2023	$47.11	$49.46	$54.46
2024	$47.11	$49.95	$56.06
2025	$47.11	$50.44	$57.71
2026	$47.11	$50.93	$59.40
2027	$47.11	$51.43	$61.15
2028	$47.11	$51.94	$62.95
2029	$47.11	$52.45	$64.80
2030	$47.11	$52.96	$66.71
2031	$47.11	$53.48	$68.67
2032	$47.11	$54.00	$70.69
2033	$47.11	$54.53	$72.77
2034	$47.11	$55.07	$74.91
2035	$47.11	$55.61	$77.11

PPA Tranche 2 Energy Rate Scenarios $CAD/MWh $2015 Dollars

Year	BASE	LOW
2016	$129.70	$85.00
2017	$129.70	$85.00
2018	$129.70	$85.00
2019	$129.70	$85.00
2020	$129.70	$85.00
2021	$129.70	$85.00
2022	$129.70	$85.00
2023	$129.70	$85.00
2024	$129.70	$85.00
2025	$129.70	$85.00
2026	$129.70	$85.00
2027	$129.70	$85.00
2028	$129.70	$85.00
2029	$129.70	$85.00
2030	$129.70	$85.00
2031	$129.70	$85.00
2032	$129.70	$85.00
2033	$129.70	$85.00
2034	$129.70	$85.00
2035	$129.70	$85.00

PPA Capacity Rate Scenarios $CAD/kW-year $2015 Dollars

Year	LOW	BASE	HIGH
2016	$94.40	$94.40	$94.40
2017	$95.60	$95.60	$95.60
2018	$96.54	$96.54	$96.54
2019	$96.45	$97.39	$99.28
2020	$96.45	$98.35	$102.20
2021	$96.45	$99.31	$105.21
2022	$96.45	$100.28	$108.30
2023	$96.45	$101.27	$111.49
2024	$96.45	$102.26	$114.77
2025	$96.45	$103.26	$118.14
2026	$96.45	$104.28	$121.62
2027	$96.45	$105.30	$125.20
2028	$96.45	$106.33	$128.88
2029	$96.45	$107.37	$132.67
2030	$96.45	$108.43	$136.57
2031	$96.45	$109.49	$140.59
2032	$96.45	$110.56	$144.72
2033	$96.45	$111.65	$148.98
2034	$96.45	$112.74	$153.36
2035	$96.45	$113.85	$157.87

BC Carbon Price Scenarios $CAD/Tonne $2015 Dollars

Year	Base	$5/tonne annual increase	$10/tonne annual increase
2016	$29.44	$29.44	$29.44
2017	$28.81	$28.81	$28.81
2018	$28.24	$28.24	$28.24
2019	$27.66	$27.66	$27.66
2020	$27.12	$27.12	$27.12
2021	$35.45	$35.45	$35.45
2022	$43.44	$43.44	$43.44
2023	$43.44	$46.85	$51.11
2024	$43.44	$50.11	$58.46
2025	$43.44	$53.22	$65.50
2026	$43.44	$56.19	$72.24
2027	$43.44	$59.02	$78.70
2028	$43.44	$61.72	$84.87
2029	$43.44	$64.29	$90.77
2030	$43.44	$66.74	$96.40
2031	$43.44	$69.07	$101.78
2032	$43.44	$71.28	$106.91
2033	$43.44	$73.37	$111.81
2034	$43.44	$75.36	$116.46
2035	$43.44	$77.24	$120.90

Appendix E

LONG-TERM LOAD FORECAST AND MONTE CARLO RANGE

FORTISBC INC.

Appendix E

2016 Long Term Electric Resource Plan

Long-Term Load Forecast and Monte Carlo Range

November 2016

Table of Contents

1. INTRODUCTION

Two key elements of this LTERP are the reference case load forecasts for annual energy and peak demand. The annual energy forecast represents annual consumption by customer class while the peak demand forecast provides an estimate of the maximum hourly electricity demand under expected peak summer and winter conditions. The reference case after savings load forecast is used to determine the LRB before incremental demand- and supply-side resources (discussed in the LTERP, Section 7).

FBC also develops a Monte Carlo range by customer class for the reference case load forecasts. This provides a probability range around the reference case given that there is a degree of uncertainty in the load forecast drivers.

1.1 *DEFINITIONS*

Term	Definition
Savings	Load reductions due to FBC's Residential Conservation rate (RCR), Consumer Information Portal (CIP), Advanced Metering Infrastructure (AMI), and rate-driven impacts (price elasticity).
Gross Load	The sum of the residential, commercial, industrial, wholesale, lighting, irrigation and losses loads.
Losses	Loss of electric energy due to line losses, losses due to wheeling through the BC Hydro system, company use, and unaccounted for energy (meter inaccuracies and theft).
Net Load	Gross loads minus losses.
Direct Customer	A customer who is served directly by FBC.
Indirect Customer	A customer who receives energy from a FBC wholesale customer that owns and operates its own electrical distribution system.

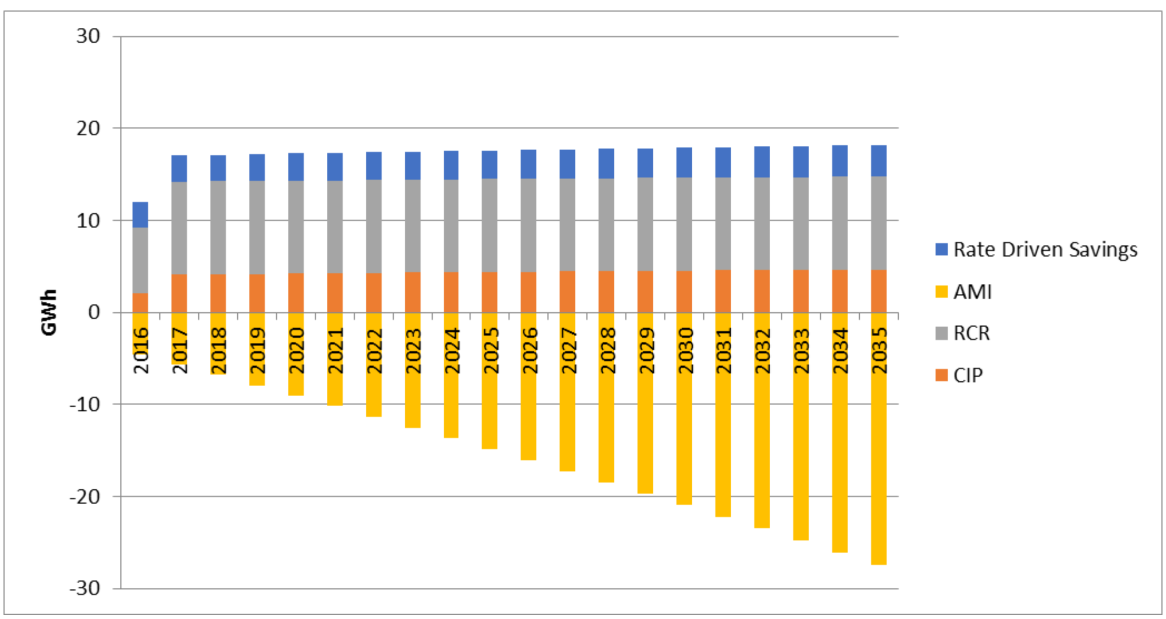
2. SAVINGS

Load savings include the impacts of the RCR,, AMI) and rate-driven reductions in load due to price elasticity. Each of these items is discussed in further detail below.

- RCR savings reflect the conservation impact of changing FBC's residential rate structure in 2012 from a flat rate to an inclining block rate. The RCR forecast is a result of analysis performed for the Residential Conservation Rate Information Report submitted to the Commission in November 2014; RCR savings are expected to be fully realized by 2017.
- AMI savings are the incremental sales that occur due to deterrence of theft, mainly from marijuana grow operations (as opposed to the closure of illegal unmetered marijuana grow sites, which are reflected in lower system losses).
- CIP savings refer to potential savings due to the implementation of the CIP, which allows customers to view historic billing and consumption data, and may result in behavioural changes in energy use.
- Rate-Driven impacts reflect customer load changes due to changes in the price of electricity (price elasticity). The current price elasticity estimate of -0.05 percent is consistent with BC Hydro.

RCR, CIP, and AMI are forecast for the residential class only. RCR, CIP, and rate-driven impacts are calculated as a percentage of the corresponding load. The rate-driven impact savings is independent of the RCR savings and applied to all rate classes.

Figure E-1: Load Savings (GWh)

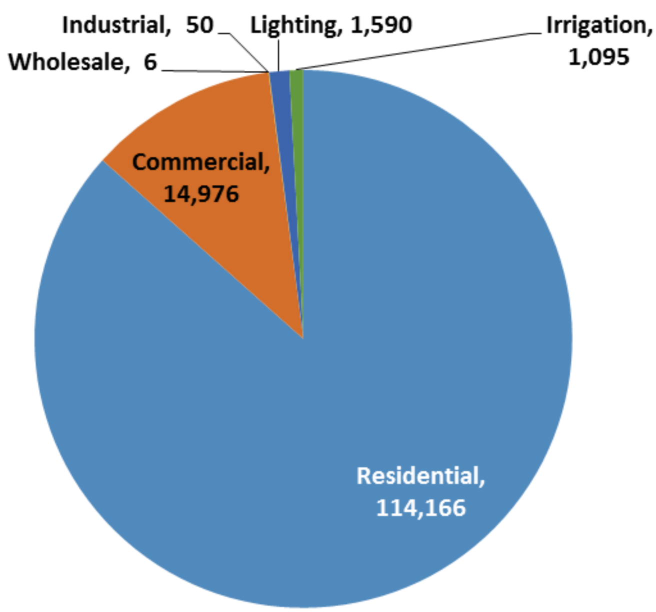


3. CUSTOMER BASE

The FBC customer base is a mix of residential, commercial, industrial, wholesale, irrigation and lighting customers. Residential customers include the occupants of houses, condominiums, apartment and mobile homes. The commercial customer base is mostly small to medium size businesses, from small store-front operations and restaurants to larger operations such as hotels and ski resorts, while the industrial class covers large businesses like lumber mills. FBC's wholesale customers purchase power for distribution to individual customers via the wholesale customers' electrical system. Irrigation customers use electricity to run irrigation equipment on properties such as farms and orchards, while the lighting class is comprised of street lights in the FBC service area. At the end of July 2016, FBC had 132,421 direct customers and 35,682 indirect customers for a total customer base of 168,103 customers.

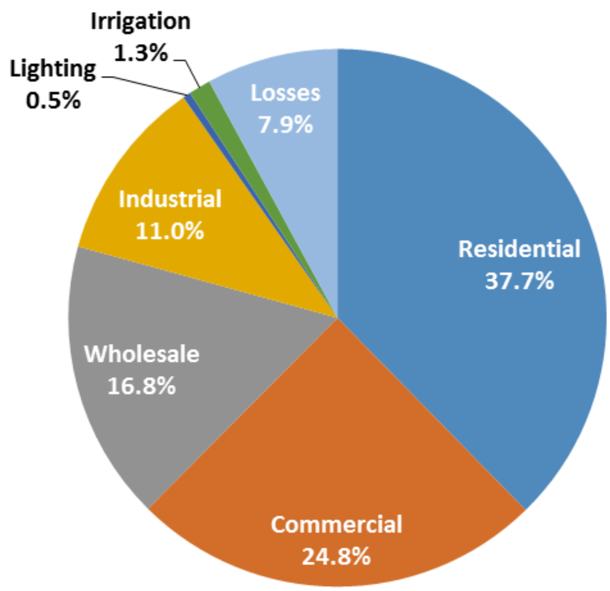
As can be seen in the figure below, residential customers made up the majority of the FBC customer base in 2015 with 87 percent of the total being direct customers while commercial customers made up 11 percent of total direct customers. The wholesale, industrial, lighting and irrigation rate classes make up the remaining 2 percent of the customer base.

Figure E-2: 2015 Customer Counts



As far as energy usage is concerned, the residential class is the largest sector with 37.7 percent of the 2015 gross load, followed by the commercial, wholesale and industrial classes with 24.8 percent, 16.8 percent and 11.0 percent, respectively. The losses, irrigation and lighting classes compromise the remaining 9.7 percent of the 2015 load composition.

Figure E-3: 2015 Gross Load Composition

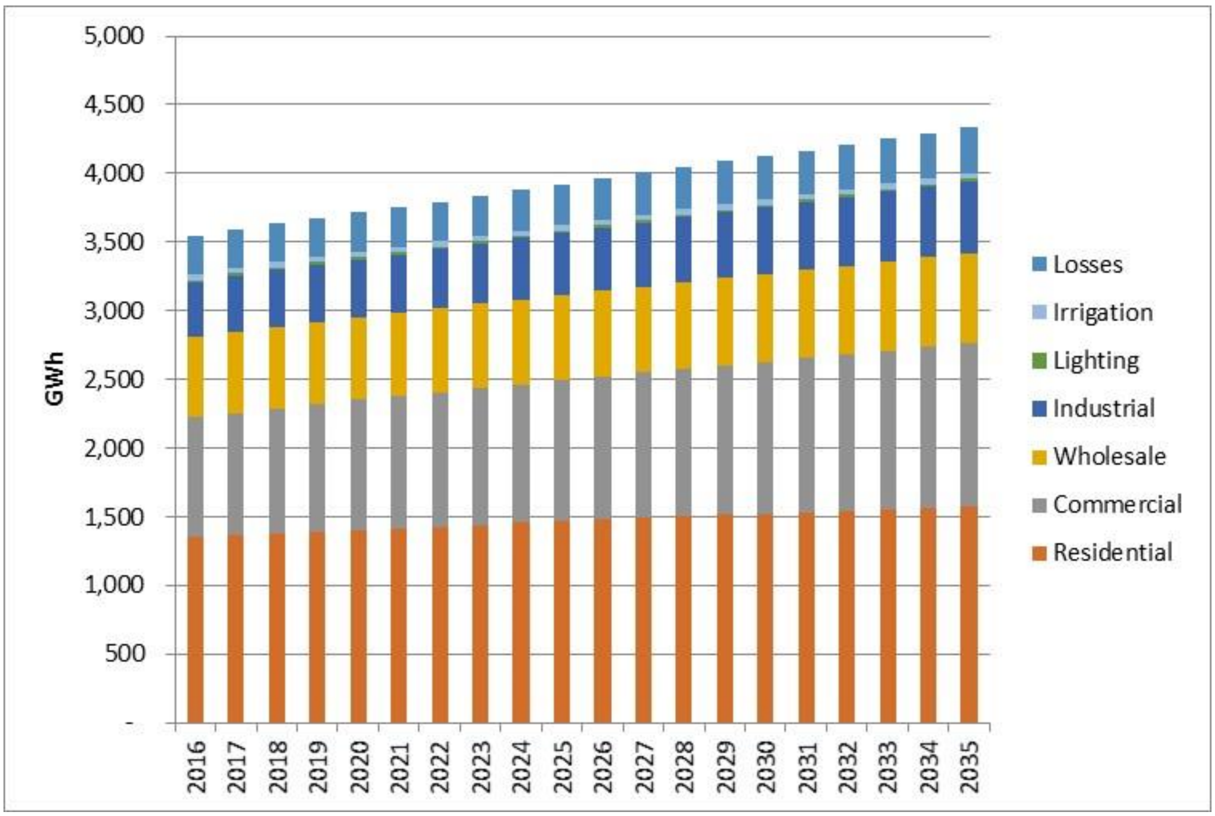


4. RATE CLASS REFERENCE CASE LOAD FORECASTS

FBC's load forecast is composed of individual forecasts for each of the residential, wholesale, industrial, commercial, irrigation and lighting classes and as well as system losses. The method is primarily econometric in nature and projects traditional load drivers. For some rate classes survey data is also employed. Forecasts of service territory population and provincial GDP by sector are primary drivers of sales. GDP forecasts are provided by the CBOC, while service territory population forecasts are provided by BC Stats.

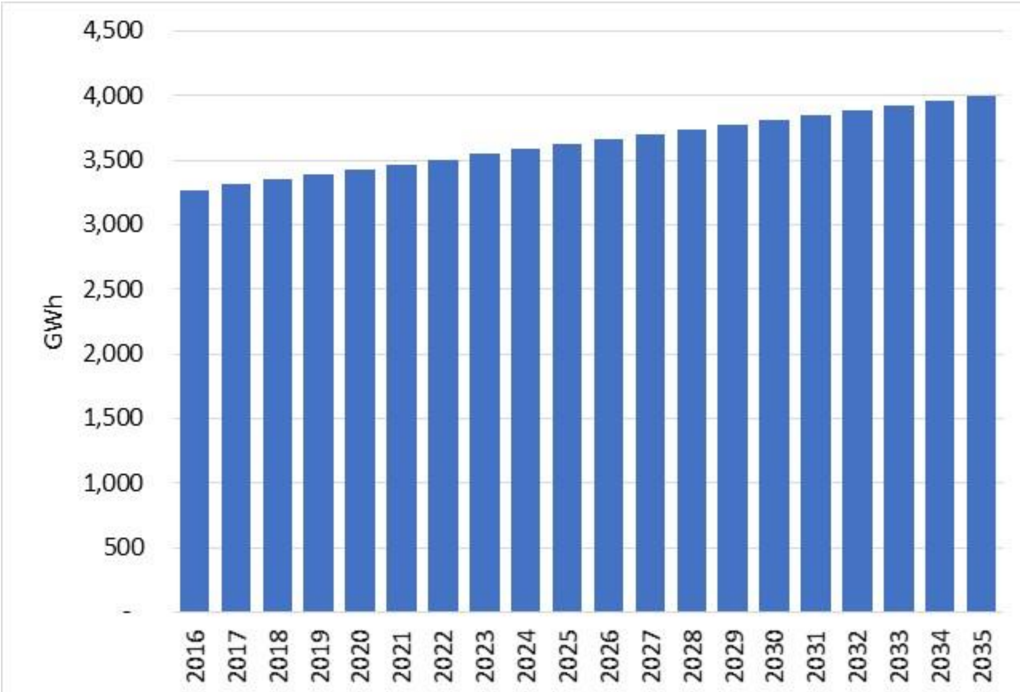
Gross system energy load by customer class is provided below for the forecast period.

Figure E-4: Total Load Forecast (GWh)



Net Load, which is comprised of all load classes except for losses, is forecast to grow at a compound annual growth rate of 1.1 percent per year over the next 20 years.

Figure E-5: Net Load (GWh)



The following sections describe the reference case (expected) energy load forecasts for each of the FBC rate classes.

4.1 *RESIDENTIAL*

Residential load growth is driven by the increase in customer count, which itself is determined econometrically as a function of population in the FBC service area. This is then combined with the forecast use per customer (UPC) to determine the residential load forecast.

4.1.1 Customer Count

Forecast residential customer counts are determined by a regression analysis of the year-end customer accounts on population in the FBC direct service area. The population forecast for the FBC service area is provided in a custom BC Stats report produced for FBC. The least square regression model equation and results used for the year-end residential customer count are below.

$$Yearend\ Customers_t = b_0 + b_1 \times Population_t$$

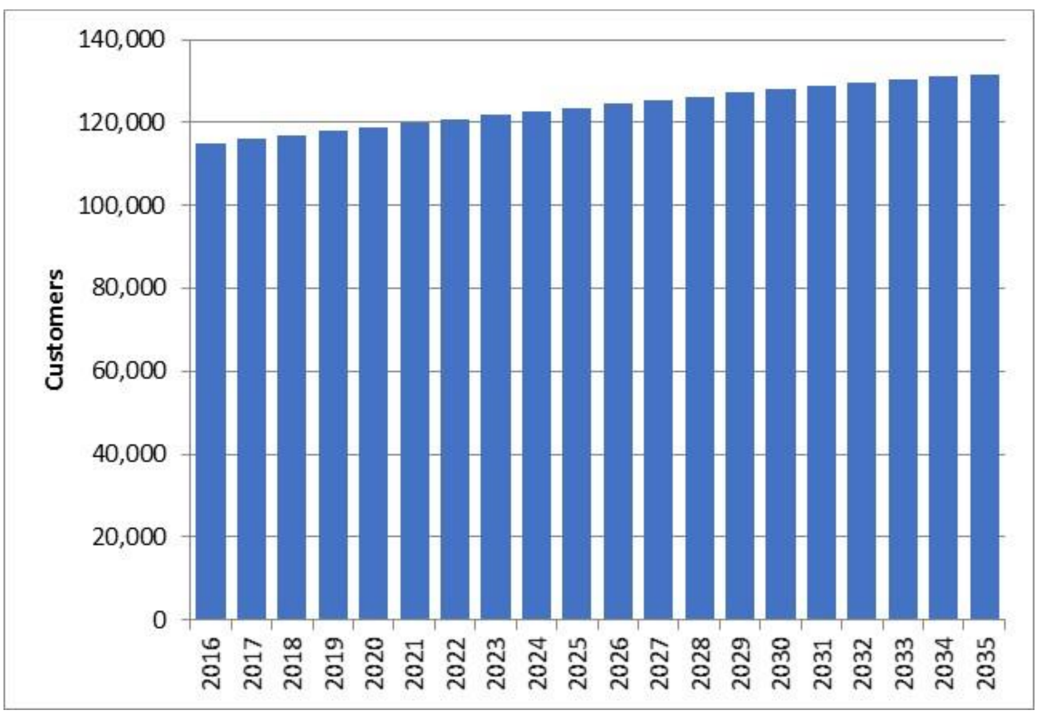
Table E-1: Results of Residential Regression

Regression	Residential
Start Year	2011
End Year	2015
R^2	0.90
Adjusted R^2	0.87
df	3
Intercept (b0)	33,787
Slope Population (b1)	0.33

According to BC Stats, the population for the FBC service area is forecast to grow at a rate of 1.6 percent in 2016 and then grow at a reduced rate over the forecast period to 1.0 percent in 2035. This is in line with the CBOC) Long Term Economic Forecast for the Province which indicated that the population growth will slow down in the future due to an aging population.

The residential customer count is forecast to grow at a compound annual growth rate of 0.7 percent per year over the next 20 years. Larger forecast customer increases occur at the beginning of the forecast which then grow at a reduced rate over the time period due to slower population growth for the service area, as noted in the above paragraph.

Figure E-6: Residential Customer Count

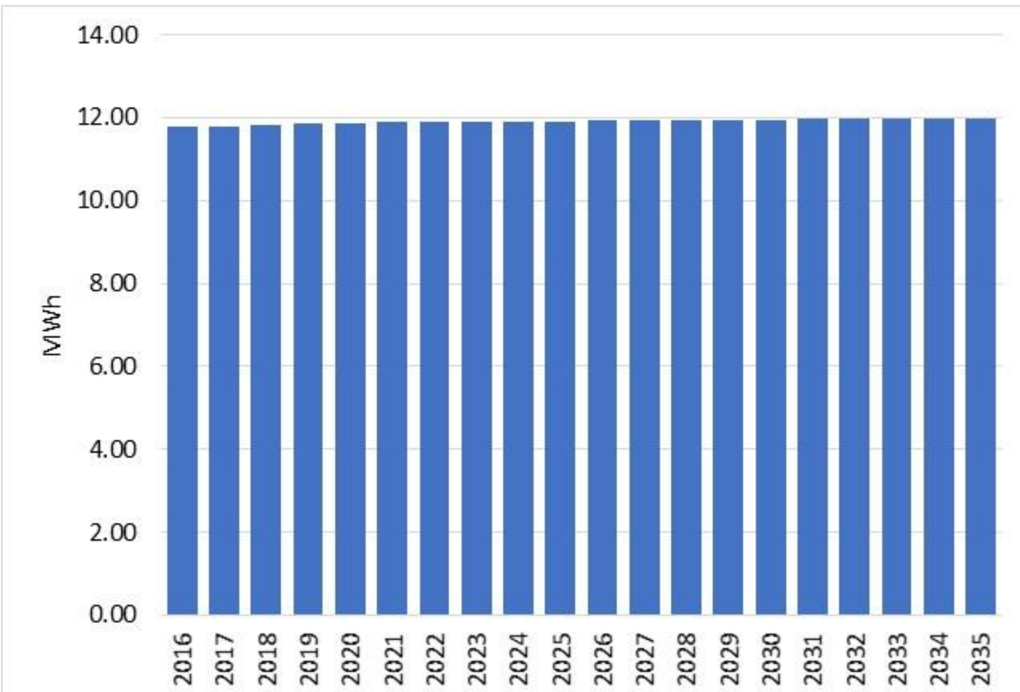


4.1.2 UPC

The UPC is forecast by averaging the most recent three years' normalized historical UPCs (2013, 2014, 2015), and each year after this is assumed to remain constant at the 2016 level of 11.80 MWh. This value was assumed to remain constant since there is no significant long term trend in the UPC at this point in time.

The graph below shows the UPC, which was calculated by taking the forecast residential loads and then dividing it by the average customer count. After adjusting for savings, UPC increases slightly over the planning horizon.

Figure E-7: Residential UPC (MWh)



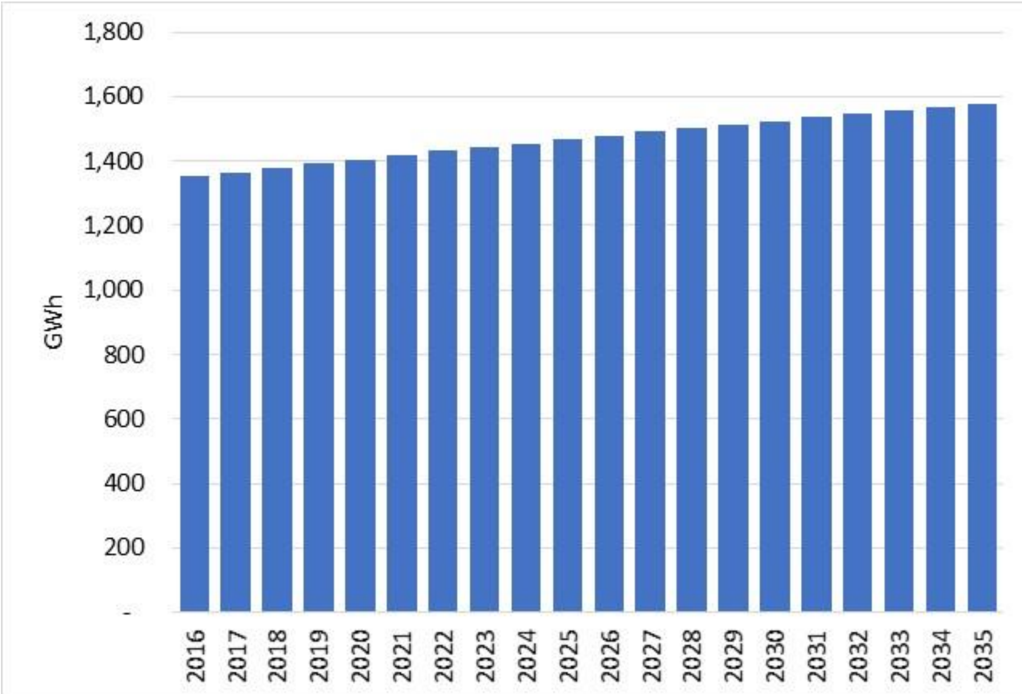
4.1.3 Load

Consistent with past practice, the total energy load for the residential class is the product of the average annual residential customer count multiplied by the residential UPC.

$$Residential\ Load_t = UPC_t \times Average\ Customer\ Count_t$$

The load is produced by taking the forecast load and then subtracting savings. The residential load is forecast to increase at a compound annual growth rate of 0.8 percent over the time period due to population increases in the service territory. The growth in the early years is larger and then the growth rate declines over the time period due to a lessening customer growth forecast as discussed in Section 4.1.1 of this Appendix.

Figure E-8: Residential Energy (GWh)



4.2 COMMERCIAL

The commercial load is forecast based on a regression analysis using the provincial GDP supplied by the CBOC. This class is comprised of many diverse industries including agriculture, forestry, manufacturing, utilities and commercial service. As such, the energy use in this class has been found to be well correlated with provincial real GDP growth and has been forecast on that basis. The equation and regression statistics used to forecast the commercial class are shown below.

$$Load_t = b_0 + b_t \times GDP_t + b_2 \times Princeton\ Event_t + b_3 \times CoK\ Event_t$$

Princeton $Event_t$ is a binary variable for the Princeton Light and Power integration event in 2007, CoK_t is a binary variable for the City of Kelowna integration event in 2013 and coefficients b0, b1, b2, and b3 are obtained from an ordinary least squares regression analysis on the 2001 to 2015 data.

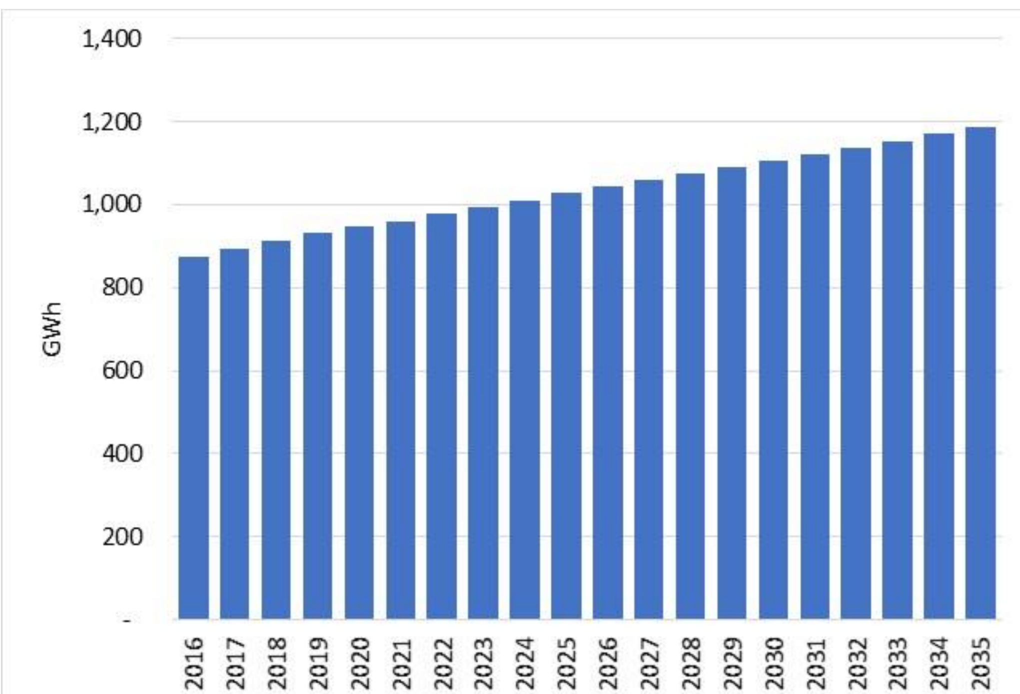
Table E-2: Results of Commercial Regression

Regression	Commercial
Start Year	2001
End Year	2015
R^2	0.98
Adjusted R^2	0.98
df	11
Intercept (b0)	78,275
Slope GDP (b1)	3.52
Slope PLP Event (b2)	45,287
Slope CoK Event (b3)	130,726

The CBOC forecasts that GDP for the province will slow down over the planning horizon due to the aging population slowing the labour market which will in turn soften economic growth. According to the CBOC, in the near to medium term the mining and manufacturing sectors are forecast to experience solid growth while the forestry sector will have challenges due to supply reduction due to the mountain pine beetle epidemic.

The Commercial load is forecast to grow at a compound annual growth rate of 1.6 percent per year over the next 20 years. Growth will be stronger in the near to medium term forecast and then will begin to decline due to reduced economic growth.

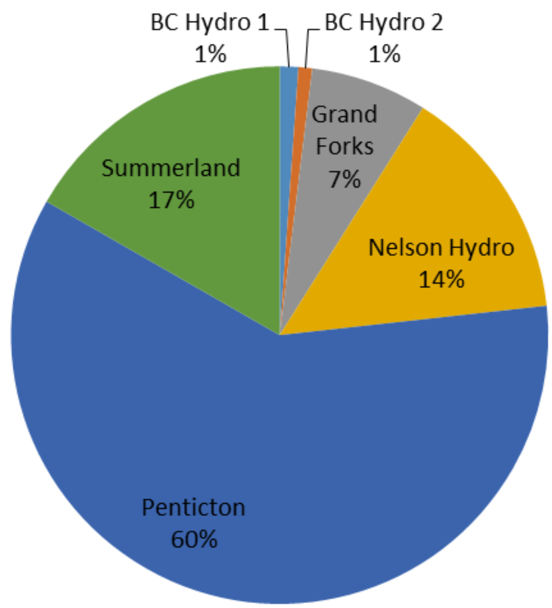
Figure E-9: Commercial Energy (GWh)



4.3 WHOLESALE

FBC sells wholesale power to municipalities within its service territory that own and operate their own electrical distribution systems. FBC has six wholesale customers that make up 16.8 percent of the total gross load. FBC's wholesale customers consist of the communities of Penticton, Grand Forks, Summerland, Nelson, and two communities in the BC Hydro service territory. These customers' loads are primarily a mix of residential and commercial in nature. The City of Penticton is the largest wholesale customer, comprising 60 percent of the wholesale load in 2015.

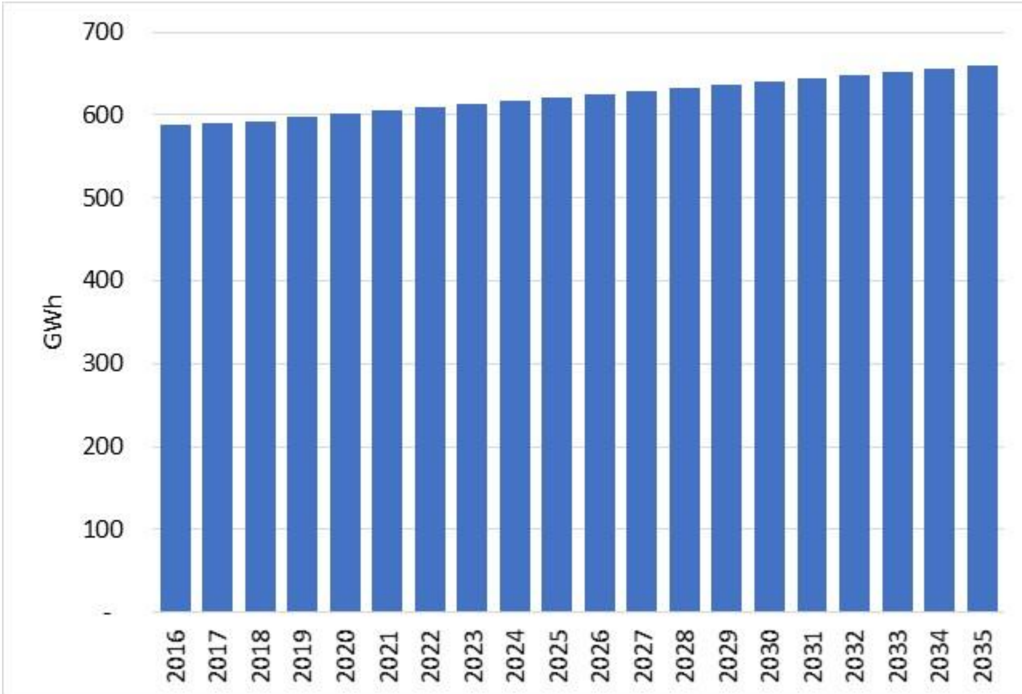
Figure E-10: 2015 Wholesale Load Composition



Consistent with past practice the wholesale class is forecast using survey information from each of the individual wholesale customers. The FBC survey included five years of data from the wholesale customers. After that time period an average of each individual customer's forecasted growth rate is used to project the long term forecast. FBC believes that the individual wholesalers are best able to forecast their future load growth based on their knowledge of their customer mix, load behaviors and development projects with associated energy requirements

All of the wholesale customers responded to the surveys with their forecast growth projections. The wholesale load is forecast to grow at a compound annual growth rate of 0.6 percent per year over the next 20 years.

Figure E-11: Wholesale Energy (GWh)

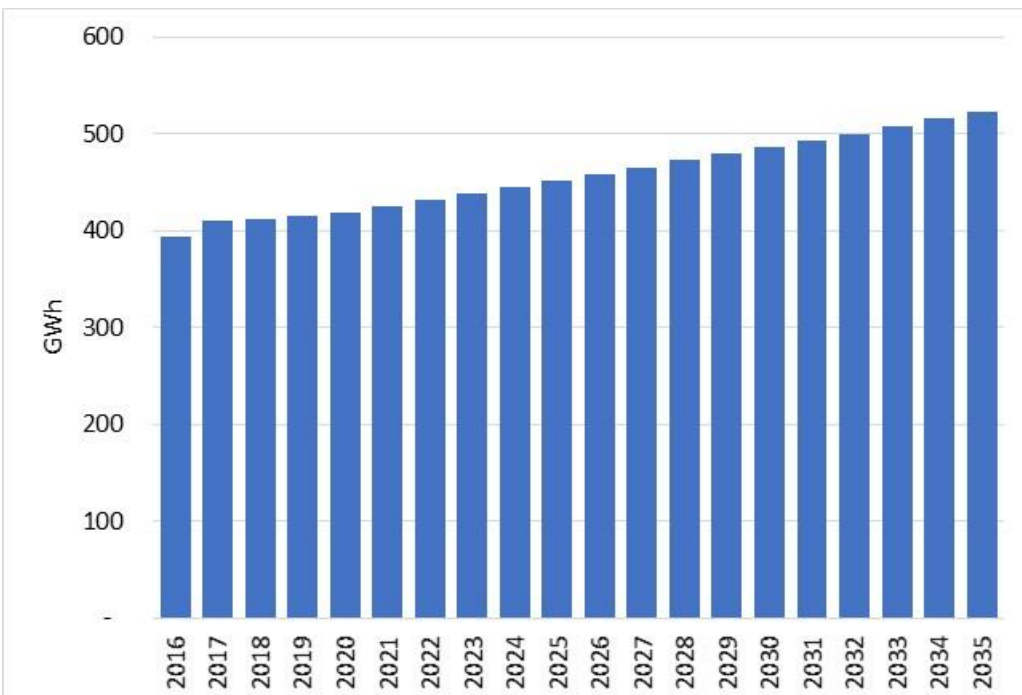


4.4 INDUSTRIAL

Industrial loads are forecast based 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. FBC sends all industrial customers a load survey that requests the customer's anticipated use for the next 5 years. A survey method is utilized because FBC believes that individual industrial customers have the best understanding of what their future energy usage will be. FBC's industrial load is mostly composed of agriculture, forestry, manufacturing, education, healthcare, and commercial service customers.

FBC received a response from 88 percent (44 of 50) of the surveys sent out. The responding customers also represent approximately 88 percent of the total industrial load. The Industrial load is forecast to grow at a compound annual growth rate of 1.5 percent per year over the next 20 years.

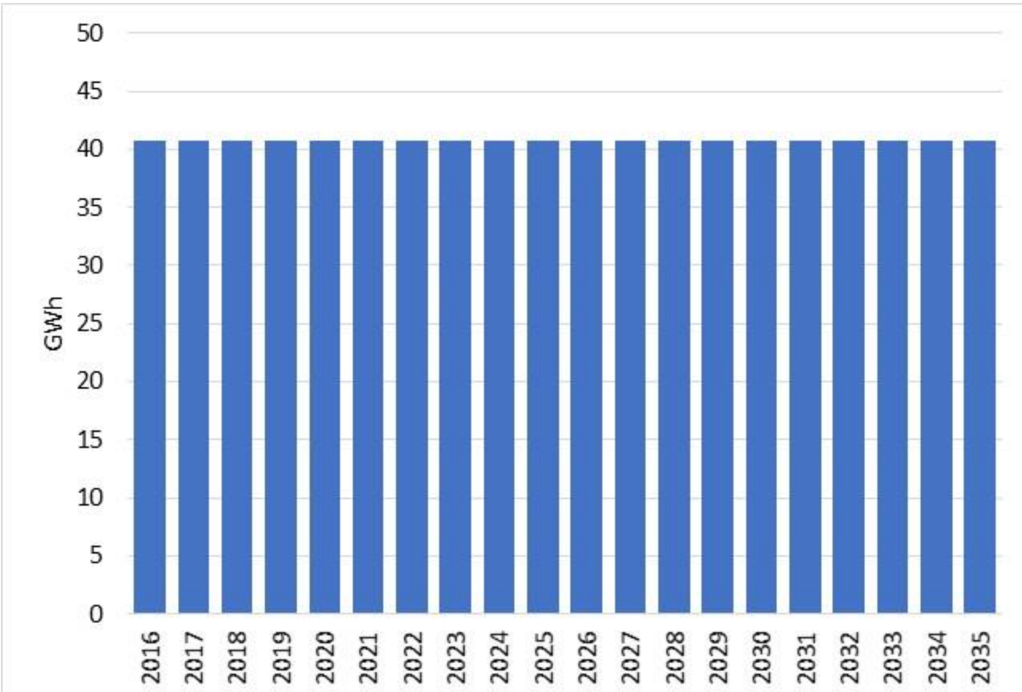
Figure E-12: Industrial Energy (GWh)



4.5 *IRRIGATION*

The irrigation forecast is developed using a historic average which is then forecast to remain constant. Consistent with past practice, the average for the most recent five-year period for which FBC has actual data (2011 to 2015) is used to forecast load for this class. The average is forecast to remain constant since no significant trend has been established for this class at this time.

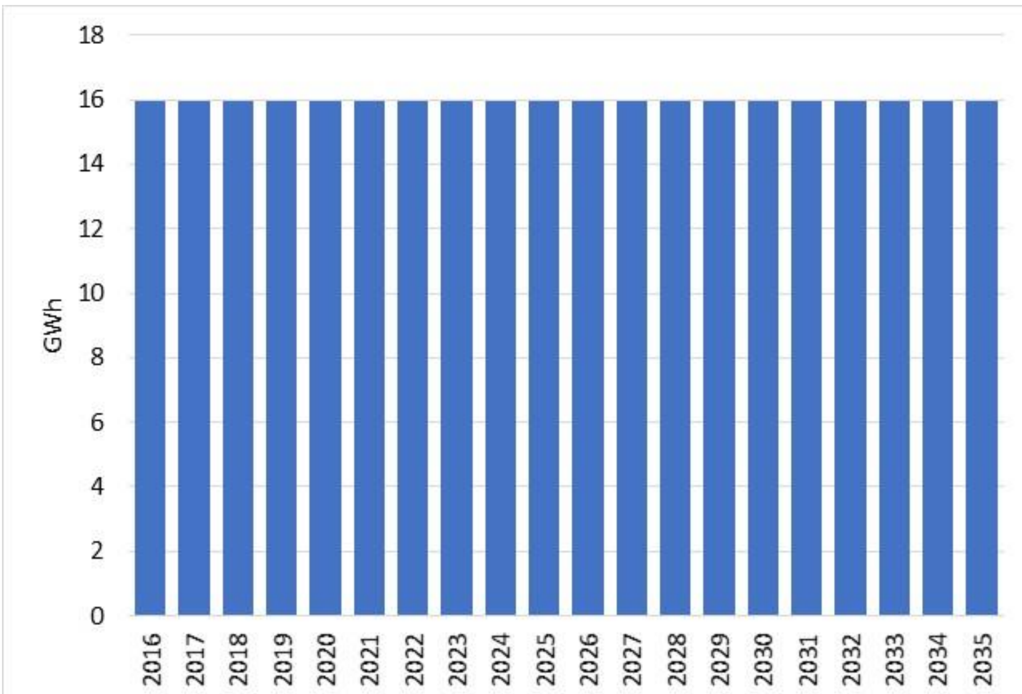
Figure E-13: Irrigation Energy (GWh)



4.6 *LIGHTING*

Consistent with past practice, a trend analysis for lighting load for the most recent five-year period for which FBC has actual data (from 2011 to 2015 in this case) is used to forecast the 2016 load, after which the load is assumed to remain constant for the remainder of the planning horizon. FBC forecasts a constant load for the lighting class, since historically it has remained relatively flat.

Figure E-14: Lighting Energy (GWh)



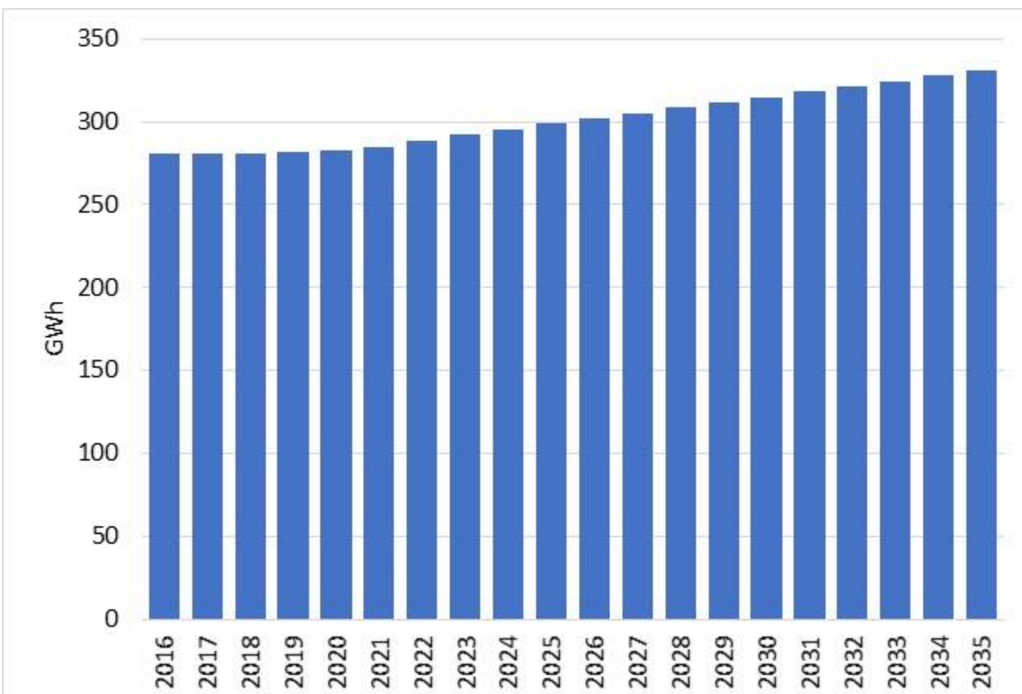
4.7 LOSSES

System losses consist of the following:

- Losses in the transmission and distribution system;
- Losses due to wheeling through the BC Hydro system;
- Company use, and
- Unaccounted-for energy (meter inaccuracies and theft).

Consistent with past practice FBC assumed a loss rate of eight percent of gross load, before the AMI impact. AMI loss reduction is expected to further reduce the losses in the future by reducing theft from the system from illegal marijuana grow operations. The losses load is forecast to grow at a compound annual growth rate of 0.9 percent per year over the next 20 years.

Figure E-15: Energy Losses (GWh)



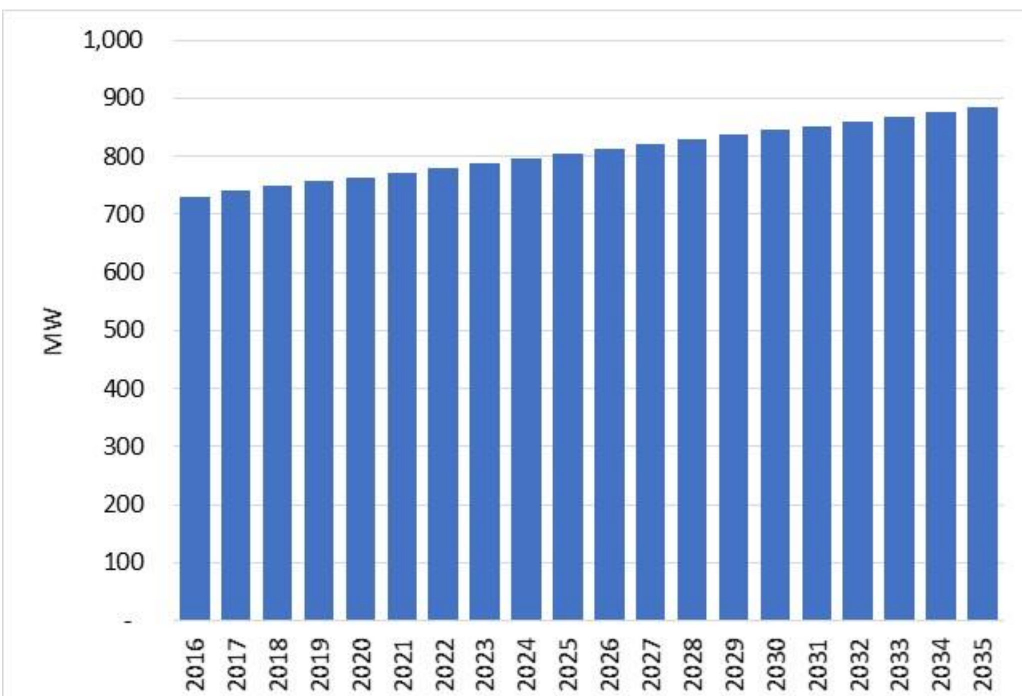
5. PEAK DEMAND FORECAST

Peak demand is the largest amount of capacity needed at one point in time on the FBC system due to high customer demand, which is affected by weather and system growth. The peak demand forecast is produced by taking the ten year average (2006-2015) of historic peak data. The historic peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system. Self-generating customers are removed from the historical load data since the underlying trends that impact other loads do not apply. A separate forecast of 16 MW a month was completed for those customers and was then added to the forecast.

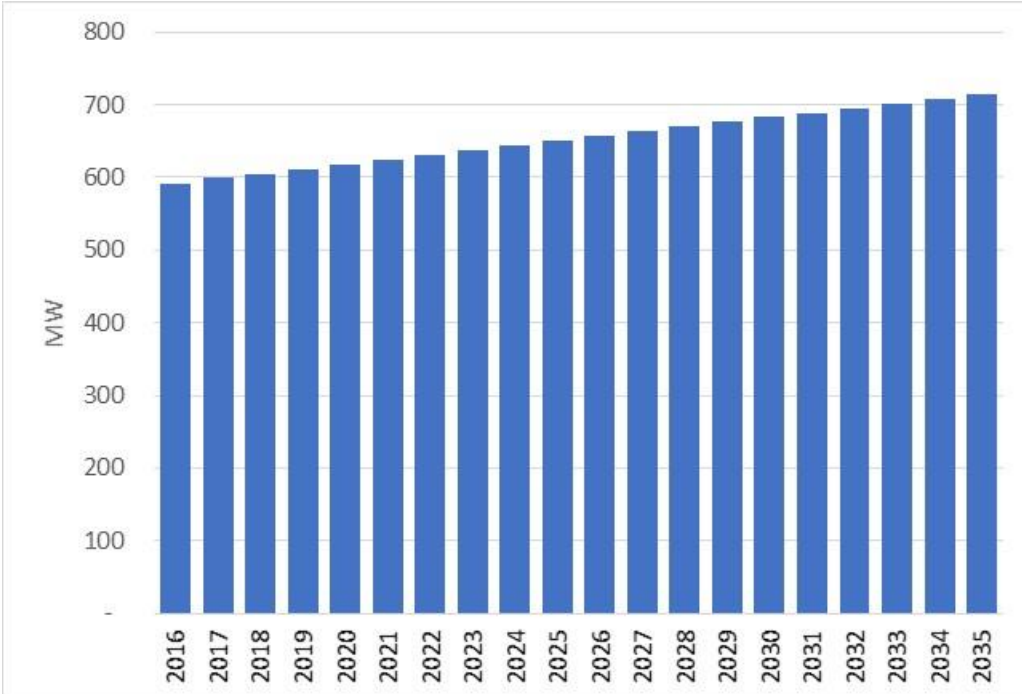
Seasonal peaks were used for both the winter and the summer. The twelve monthly peaks, as well as the seasonal peaks, were then escalated by the annual load growth rates in the forecast period to produce forecast monthly peaks. The winter peak happens between the months of November and February and is usually on one of the coldest days of the year. The summer peak happens between July and August and would be on one of the warmest days of the year. Peak demand in the Load Forecast does not include Planning Reserve Margin (PRM) requirements. PRM is discussed in the LTERP, Section 9 and Appendix L.

Both the winter and summer peaks are forecast to grow at a compound annual growth rate of 1.0 percent over the next 20 years.

Figure E-16: Winter Peak (MW)



1 **Figure E-17: Summer Peak (MW)**



2

6. MONTE CARLO RANGE

FBC derives a Monte Carlo (MC) range around the Reference load forecast to provide a high degree of certainty regarding traditional load drivers inherent in the forecast. A typical low-high range is P10 and P90 where:

- P10 means there is a 10 percent probability that the load will be less than this value in a particular year; and
- P90 means there is a 90 percent probability that the load will be less than this value in a particular year.

As there are many interacting factors that may influence the load forecast and contribute to uncertainty, a popular method to obtain such a range forecast is MC simulation. Because the load forecasting model is Excel based, FBC uses MC add-in software called @RISK from Palisade Corporation.

The MC software uses the variability or standard deviation in historic data to forecast possible variance ranges from the reference case forecast. Seven[1] years of historical data was used in calculating the standard deviation, which is used as an input to develop the high-low range forecasts for energy and peak demand. The following table illustrates the historical data used for each load class.

Table E-3: Monte Carlo Inputs

Load Class	Driver
Residential	UPC and Population
Commercial	GDP
Wholesale	Load
Industrial	Load
Irrigation	Load
Lighting	Load

To develop the high-low range forecast for each load class, the following steps were used:

1. The standard deviation of the historic growth driver is calculated.
2. The calculated standard deviation is an input to the @Risk software.
3. The forecast load growth is also an input to the @Risk software.

[1] City of Kelowna historical data records by load class are limited to seven years. Therefore, seven years of data was used to maintain consistency in calculating the MC forecast.

4. The @Risk software calculates thousands of possibilities around the forecast growth using the standard deviation.

5. The outcomes are displayed in the forecast load output, resulting in a high-low range of outcomes.

Historical actual load growth captures weather and customer count variability. Historical load as a random variable in year *t* is

$$Load_t = Load_{t-1} + Load\ Growth_t$$

where $Load_t$ is a normally distributed random variable with a mean equal to the corresponding growth in the Reference case and standard deviation equal to that computed from the historical growth.

The load range forecast is obtained as a direct output from a MC simulation in which loads vary.

Because residential load uses UPC and Population drivers, the formulas are as follows

$$UPC_t = UPC_{t-1} + UPC\ Growth_t$$

$$Population_t = Population_{t-1} + Population\ Growth_t$$

where UPC_t and $Population_t$ are normally distributed random variables with mean equal to the corresponding growth in the Reference case and standard deviation equal to that computed from the historical growth.

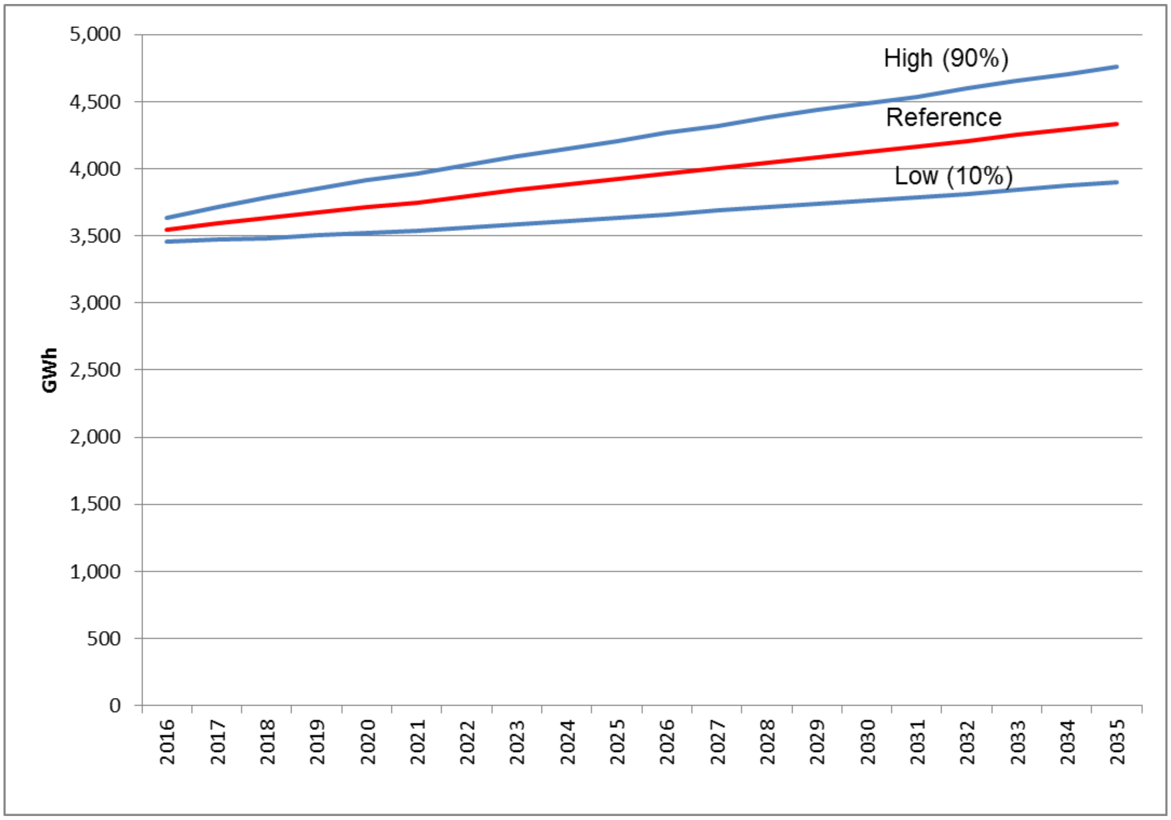
The commercial load class uses GDP drivers, so the formula would be as follows

$$GDP_t = GDP_{t-1} + GDP\ Growth_t$$

where GDP_t is a normally distributed random variable with mean equal to the corresponding growth in the Reference case and standard deviation equal to that computed from the historical growth.

MC range forecasts for energy requirements and peak demand are displayed in the graphs below.

1 **Figure E-18: Gross MC Energy (GWh)**

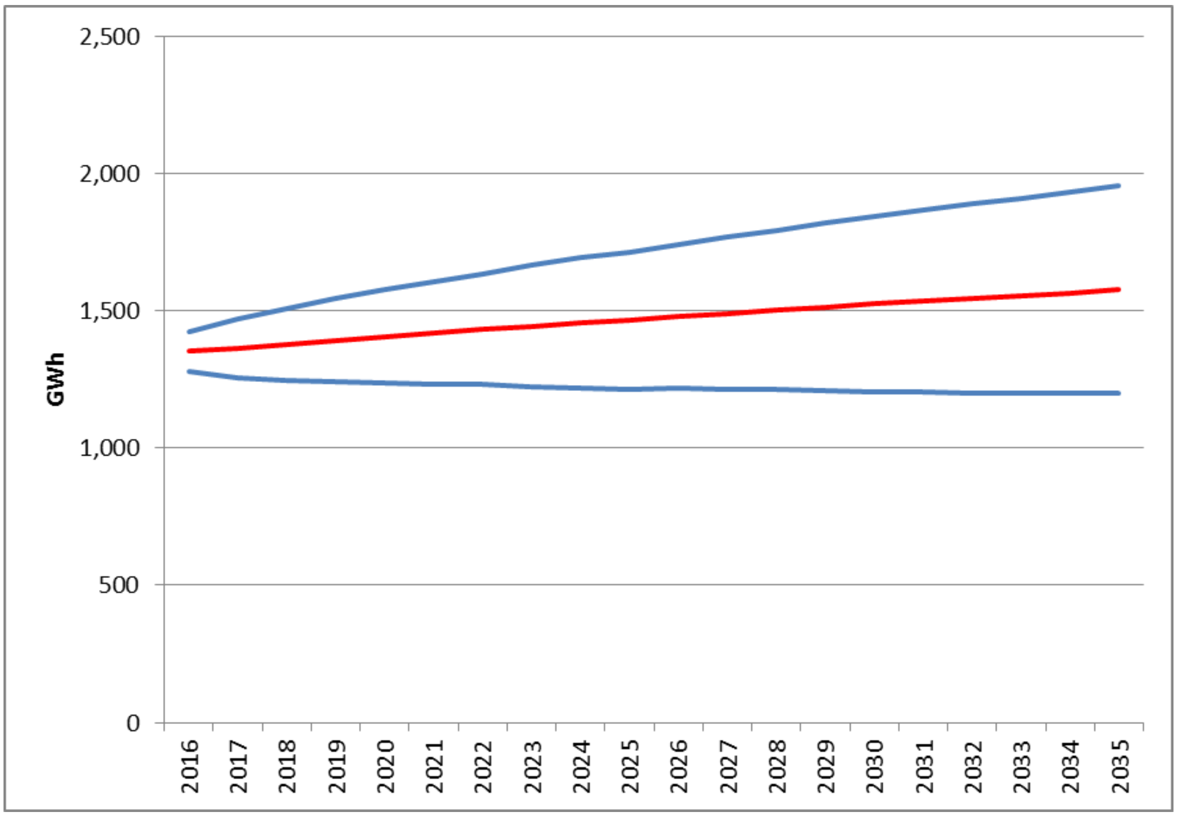


2

6.1 *RESIDENTIAL*

The residential load MC high-low range is forecast to trend between 7 to 32 percent from the reference case. Residential load increases have historically resulted from customer growth. MC uses a combination of 7 year actual historical UPC standard deviation and population standard deviation to calculate the high and low ranges.

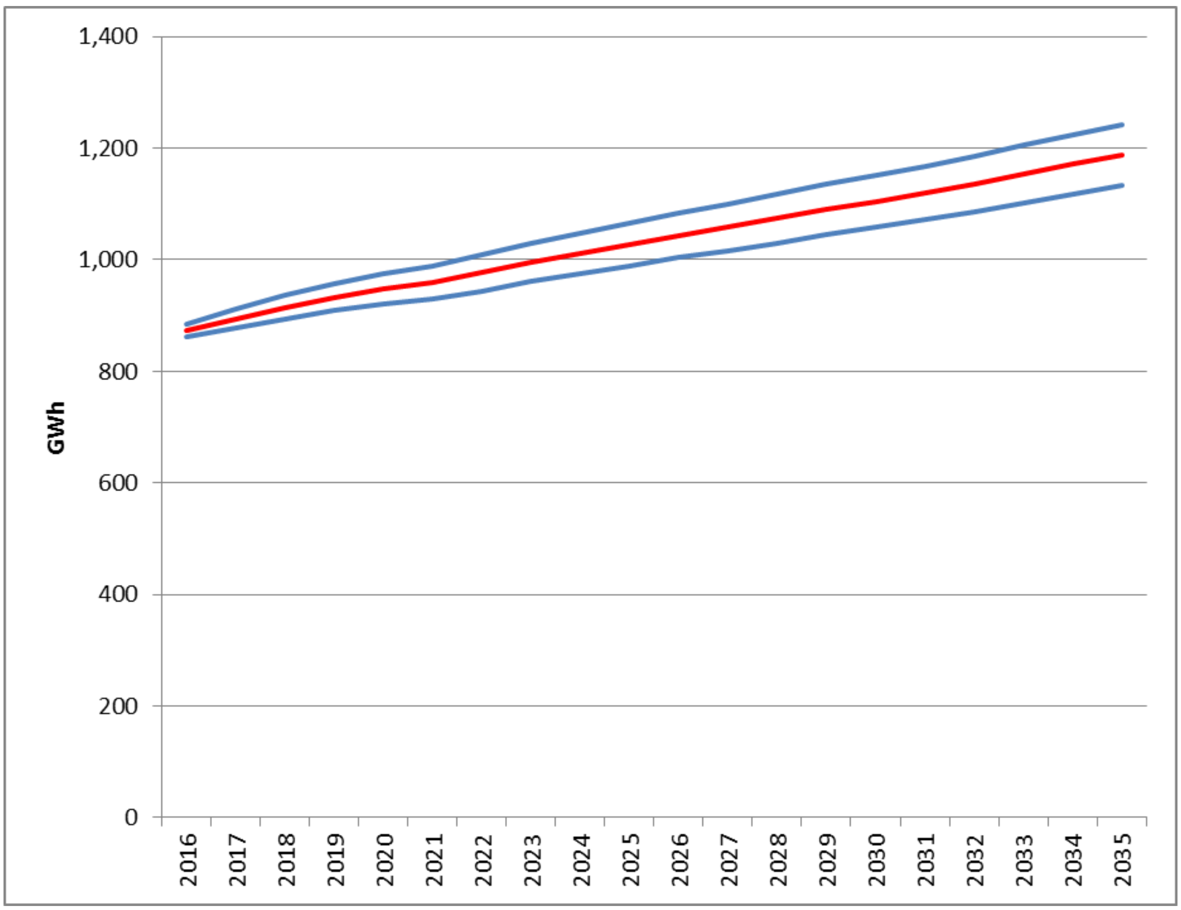
Figure E-19: Residential MC Energy (GWh)



6.2 COMMERCIAL

The commercial load MC forecast high low ranges are calculated using the 7 year historical standard deviation in GDP. The ranges from expected are between 1 and 6 percent. The lack of volatility in historic GDP has resulted in tighter range bands than for other load classes. A shorter more recent CBOC GDP forecast was used to forecast the first 5 years, while a long-term CBOC forecast was used to forecast after this.

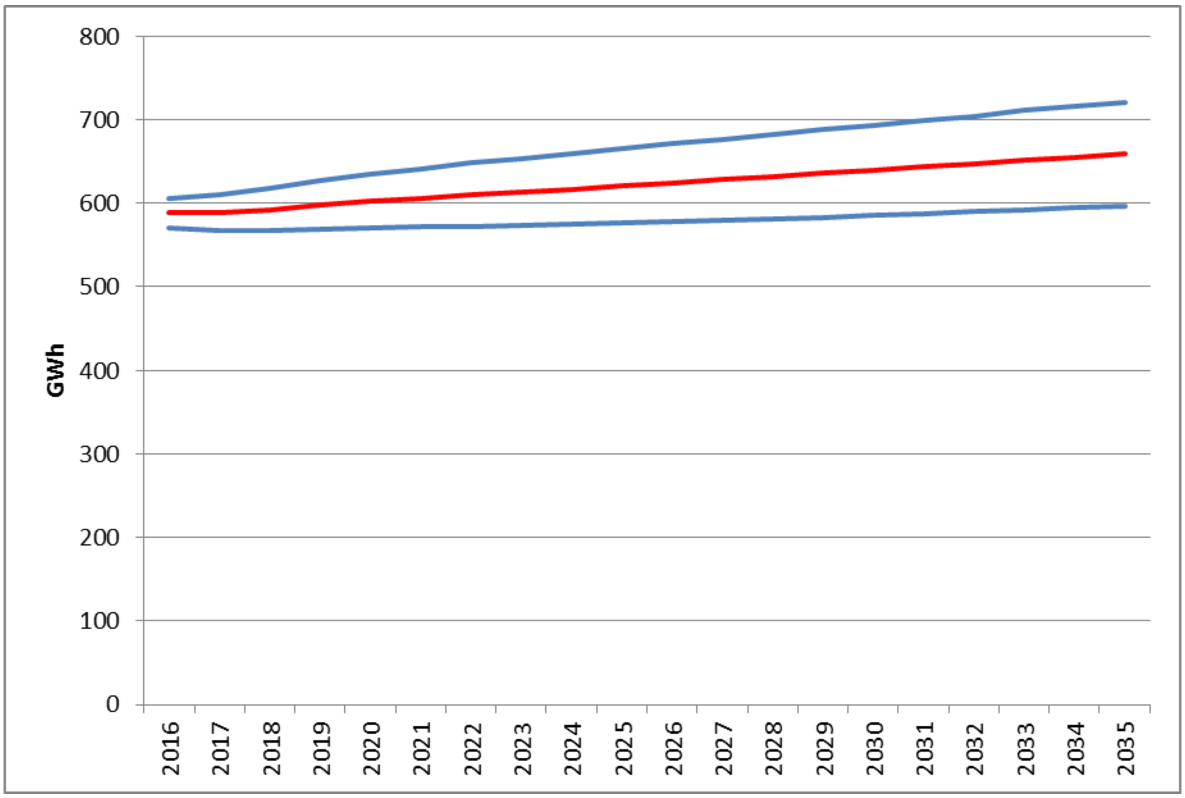
Figure E-20: Commercial MC Energy (GWh)



6.3 *WHOLESALE*

The wholesale MC forecast bands are calculated using a 7 year historical standard deviation of wholesale load. The MC high low bands range from 3 to 10 percent of the reference case. Wholesale customers serve mainly residential and commercial customers and follow a similar trend.

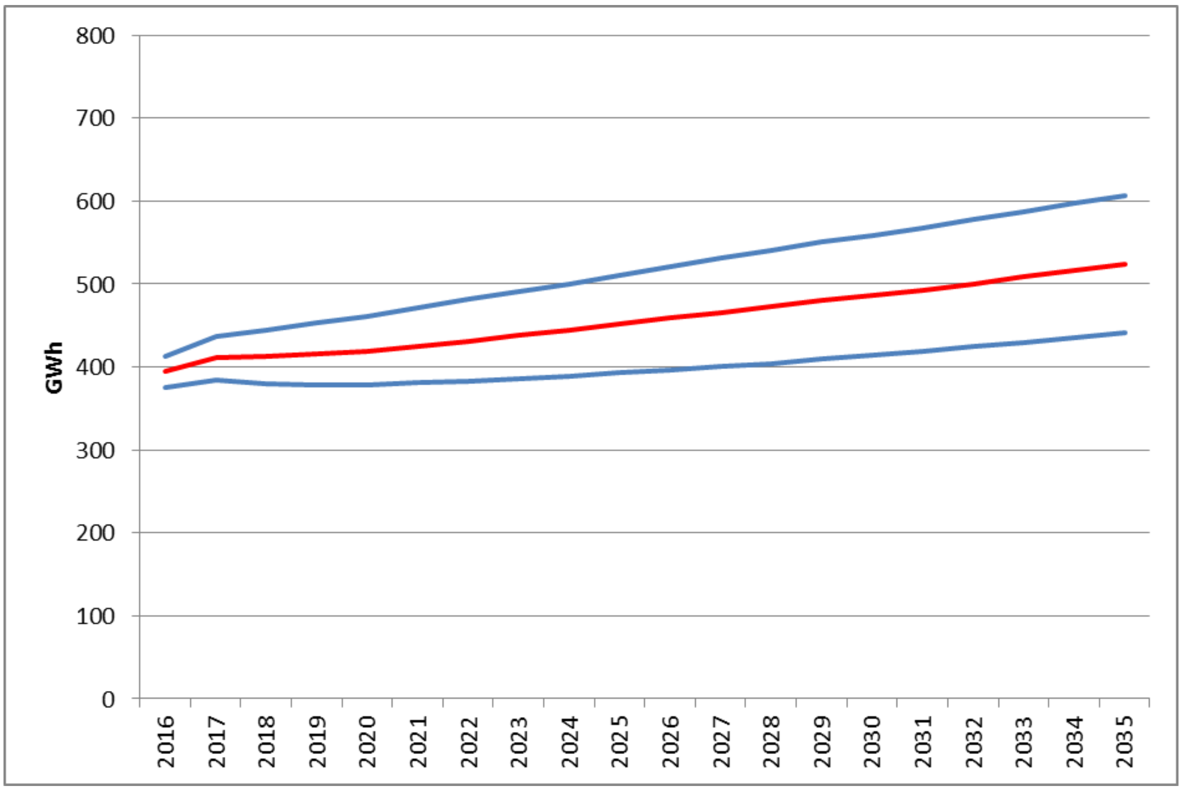
Figure E-21: Wholesale MC Energy (GWh)



6.4 *INDUSTRIAL*

Industrial Loads have historically been in both upward and downward trends based on local and global economic environments. The industrial MC forecast bands are calculated using a 7 year standard deviation of historical industrial load. The MC high low bands range from 5 to 18 percent of the reference case.

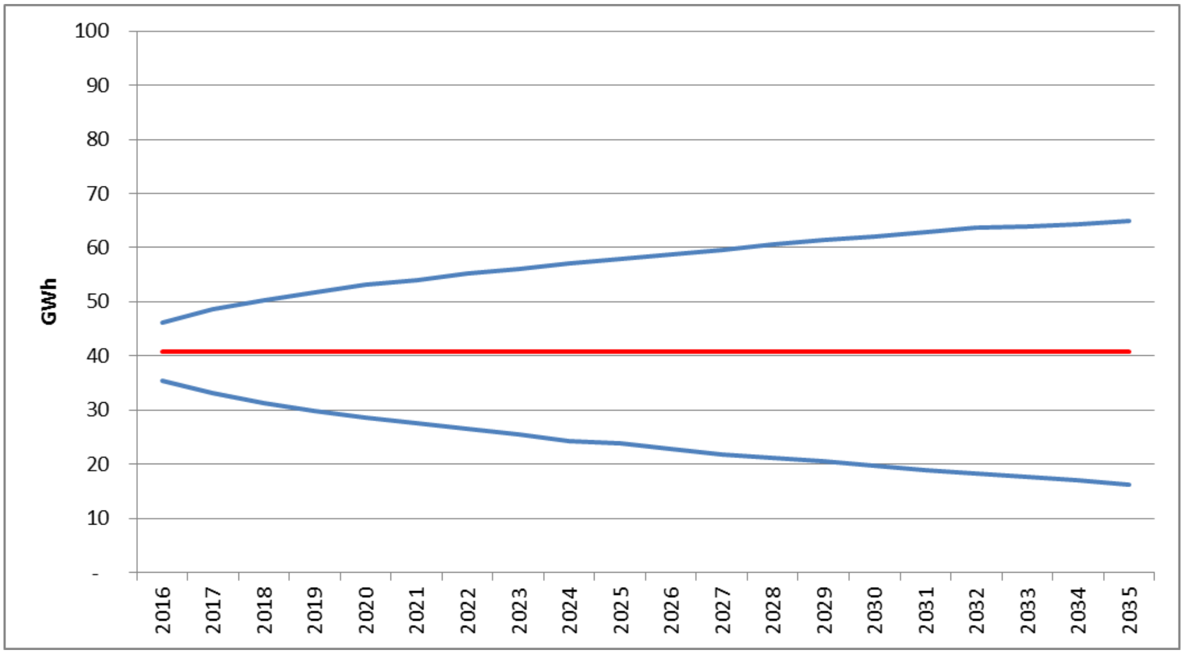
Figure E-22: Industrial MC Energy (GWh)



6.5 IRRIGATION

The irrigation MC forecast bands are calculated using a 7 year standard deviation of historical irrigation load. The MC high low bands range from 13 to 60 percent of the reference case.

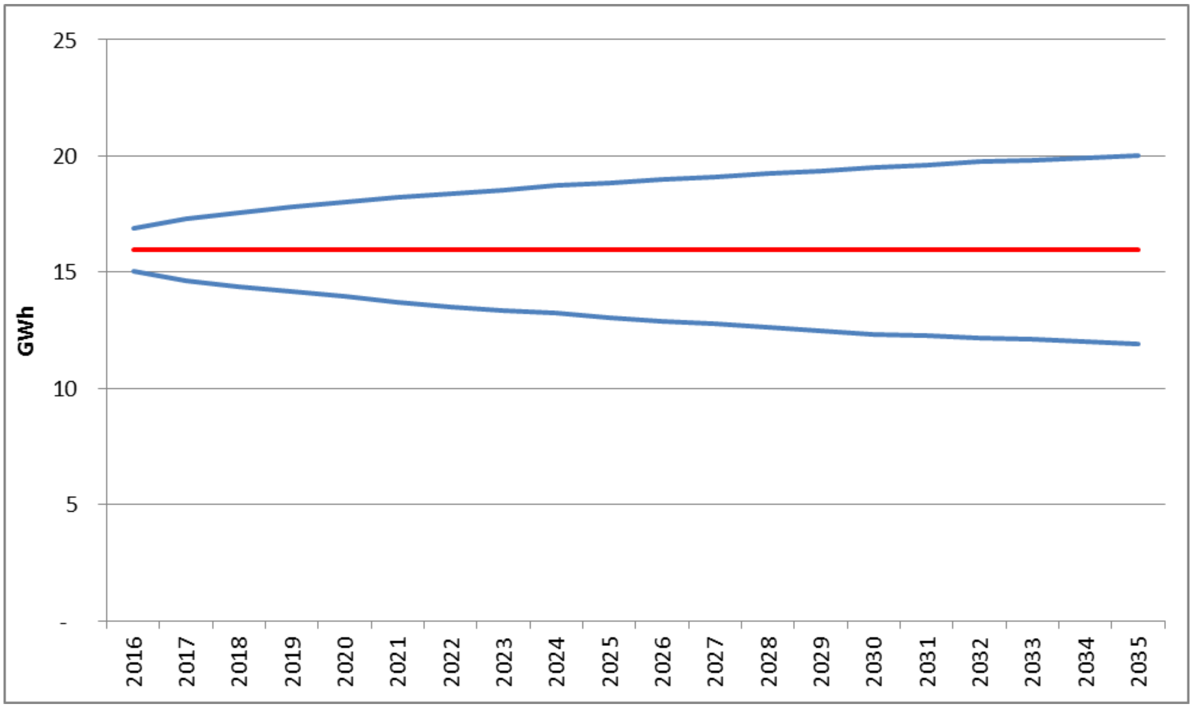
Figure E-23: Irrigation MC Energy (GWh)



6.6 *LIGHTING*

Lighting load is forecast to remain relatively flat. The lighting MC forecast bands are calculated using a 7 year standard deviation of historical lighting load. The MC high low bands range from 6 to 25 percent of the reference case.

Figure E-24: Lighting MC Energy (GWh)



6.7 PEAK

Both the summer and winter peak MC forecast bands are calculated using a 7 year standard deviation of historical peak load. The MC high low bands range from 3 to 10 percent of the reference case for winter and 2 to 10 percent of the reference case for the summer. The winter peak range is on average 24 percent higher than the average summer peak range.

Figure E-25: Winter Peak Monte Carlo (MW)

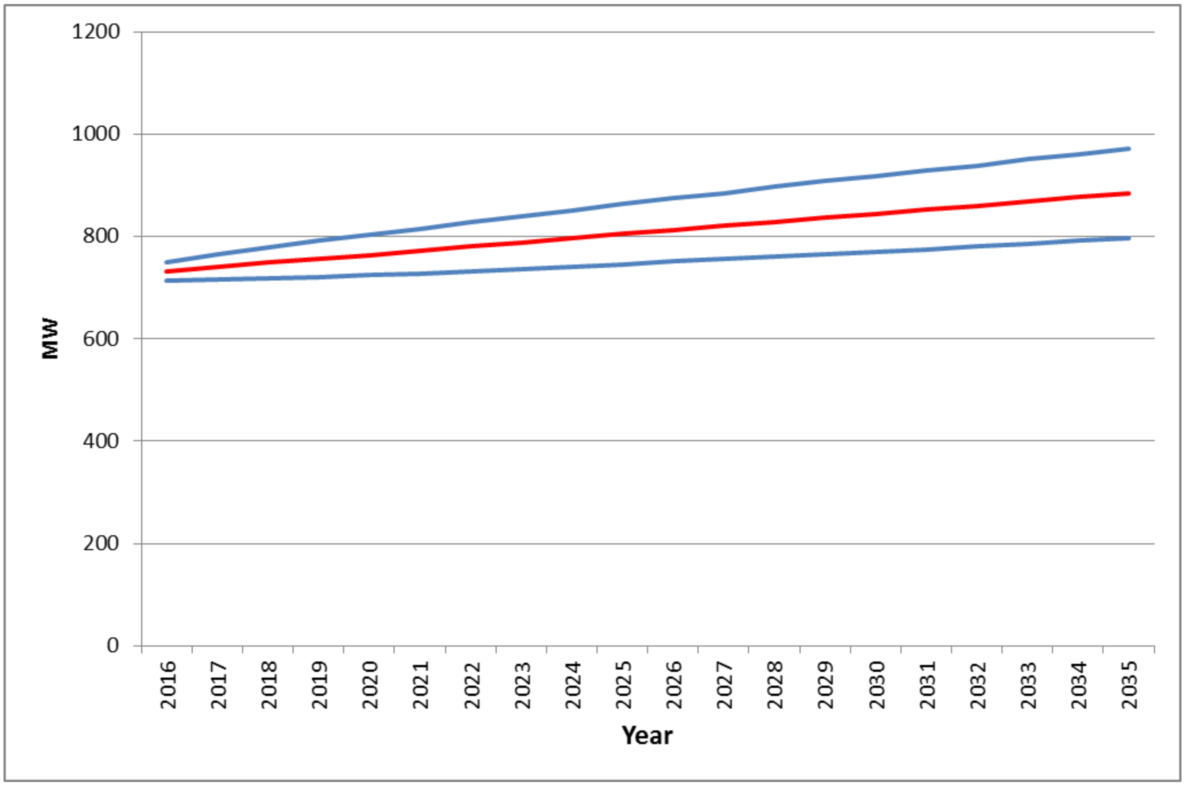
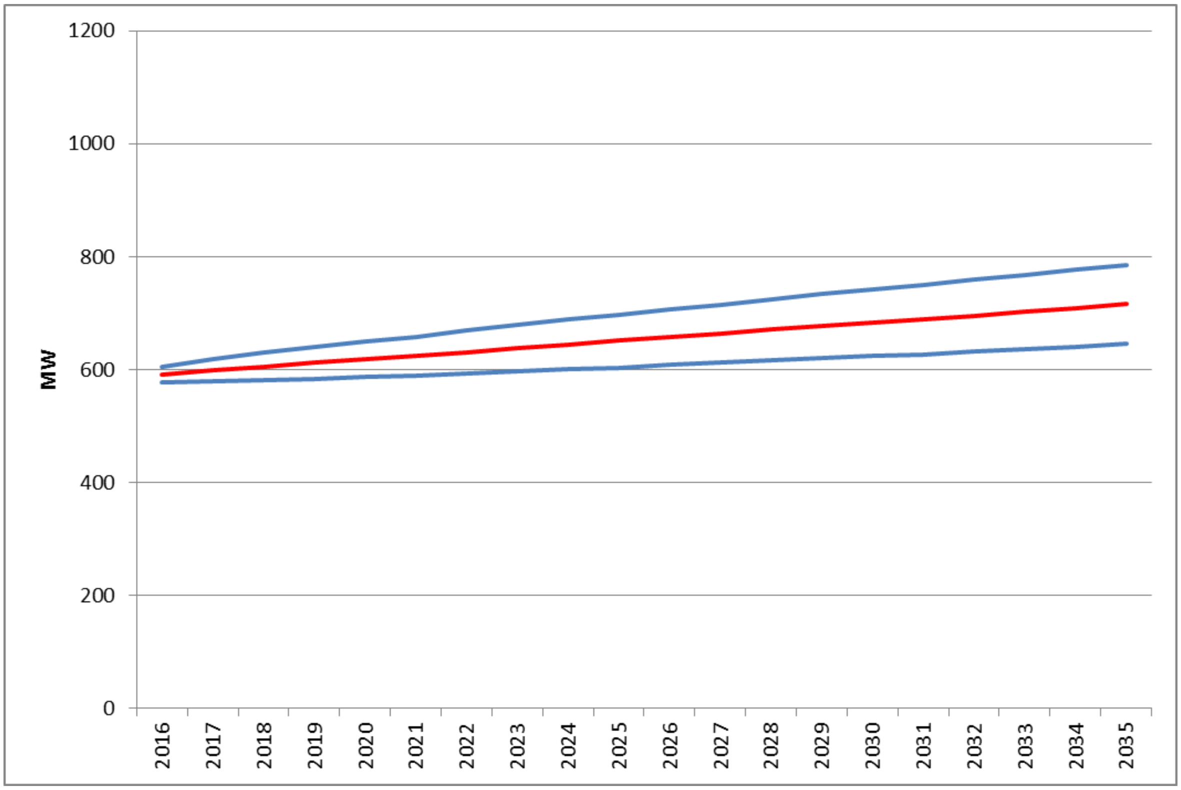


Figure E-26: Summer Peak Monte Carlo (MW)



7. SUMMARY

FBC is forecasting long term load growth to average about 1.1 percent per year. Growth in the residential and commercial sectors is forecast to be larger in the short term and then slow down based on an expected reduction in population growth in FBC's service area, as well as UPC and GDP projections. The industrial and wholesale classes are forecast to remain steady over the planning horizon based on industrial GDP projections and survey data. Lighting and irrigation loads are forecast to remain constant over the planning horizon.

Appendix F

LONG-TERM LOAD FORECAST TABLES

FORTISBC INC.

Appendix F
2016 Long Term Electric Resource Plan

Load Forecast Tables

Table of Contents

1. INTRODUCTION

This appendix provides the historical and forecast load data used in Section 3 of the LTERP Application. Tables 2.1 to 2.10 show ten years of historical data and the load forecast for 2016 to 2035. As explained in Appendix E – Long Term Load Forecast and Monte Carlo Range, the forecasts include savings from RCR, CIP, AMI and rate-driven impacts.

The tables in this appendix reflect the acquisition by FBC of the assets and customers of the City of Kelowna electric utility effective March 31, 2013. The acquisition resulted in an increase in direct customers to FBC and a re-distribution of load from wholesale to other rate classes in 2013 and 2014.

Gross load is calculated by adding the residential, commercial, wholesale, industrial, lighting, irrigation and losses loads together, which are provided in tables 2.3 to 2.9. Net load excludes losses and is the sum of the information in tables 2.3 to 2.8.

2. MONTHLY LOAD FORECAST

2.1 GROSS LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2006	370,078	309,284	305,670	255,581	240,065	237,225	274,816	260,925	231,742	267,853	310,004	366,727	3,429,970
2007	362,696	318,187	300,725	251,383	254,740	238,900	280,425	261,986	228,445	261,607	298,971	356,106	3,414,170
2008	351,478	312,547	288,943	248,550	243,211	235,861	276,961	258,486	223,859	260,879	300,150	349,985	3,350,908
2009	357,560	302,739	305,539	244,978	242,249	242,735	276,801	262,866	234,668	269,945	315,009	360,679	3,415,766
2010	358,574	304,251	288,022	253,247	237,451	232,285	274,190	265,937	227,770	258,133	303,172	365,668	3,368,701
2011	374,096	313,764	312,059	254,039	235,722	242,276	268,421	273,732	242,593	260,877	307,093	362,607	3,447,280
2012	354,376	315,497	304,411	253,594	237,899	233,308	272,143	275,122	236,457	262,538	313,757	362,555	3,421,657
2013	372,939	327,919	300,296	255,888	249,987	235,093	291,183	274,786	241,239	266,317	303,923	380,406	3,499,975
2014	363,245	306,420	303,949	253,146	241,945	242,396	285,626	270,799	229,532	256,624	301,612	380,684	3,435,977
2015	364,636	317,325	299,476	250,366	249,815	247,921	287,307	276,774	233,611	256,959	300,534	361,093	3,445,816
Forecast													
2016	376,435	323,534	311,704	262,794	249,945	246,419	291,070	285,626	240,242	265,638	309,025	381,992	3,544,423
2017	381,158	327,992	316,002	266,869	253,945	250,292	295,219	289,806	244,104	269,699	313,292	386,850	3,595,229
2018	384,987	331,333	319,211	269,717	256,856	253,139	298,432	292,970	246,861	272,555	316,521	390,767	3,633,346
2019	389,350	335,144	322,844	272,878	260,007	256,234	301,955	296,411	249,851	275,734	320,121	395,205	3,675,734
2020	393,445	338,668	326,221	275,770	262,860	259,041	305,201	299,551	252,563	278,652	323,507	399,335	3,714,814
2021	397,099	341,867	329,307	278,469	265,435	261,563	308,072	302,409	255,007	281,341	326,582	403,084	3,750,237
2022	403,259	345,346	329,400	280,910	272,249	263,776	314,490	300,923	259,196	286,376	329,679	407,987	3,793,591
2023	407,860	349,388	333,214	284,378	275,744	267,126	318,269	304,596	262,500	289,864	333,555	412,676	3,839,171
2024	412,037	353,044	336,669	287,492	278,849	270,097	321,651	307,867	265,427	293,000	337,059	416,932	3,880,125
2025	416,325	356,805	340,219	290,705	282,065	273,174	325,140	311,248	268,461	296,234	340,662	421,299	3,922,337
2026	420,621	360,579	343,778	293,934	285,295	276,260	328,631	314,630	271,509	299,487	344,275	425,672	3,964,671
2027	424,751	364,198	347,194	297,018	288,375	279,205	331,975	317,867	274,414	302,594	347,740	429,874	4,005,205
2028	428,937	367,874	350,660	300,160	291,518	282,208	335,373	321,160	277,381	305,759	351,256	434,130	4,046,417
2029	433,148	371,576	354,148	303,328	294,696	285,243	338,799	324,485	280,382	308,949	354,794	438,409	4,087,957
2030	437,023	374,967	357,350	306,205	297,566	287,990	341,926	327,512	283,092	311,846	358,035	442,346	4,125,858
2031	441,058	378,513	360,691	309,232	300,602	290,890	345,201	330,690	285,960	314,895	361,420	446,441	4,165,592
2032	445,262	382,223	364,177	312,418	303,810	293,948	348,631	334,027	288,993	318,105	364,959	450,704	4,207,257
2033	449,526	385,992	367,714	315,662	307,085	297,070	352,121	337,427	292,094	321,372	368,552	455,025	4,249,641
2034	453,743	389,721	371,213	318,871	310,327	300,161	355,573	340,792	295,163	324,603	372,104	459,295	4,291,567
2035	458,000	393,490	374,747	322,121	313,621	303,299	359,068	344,204	298,284	327,876	375,692	463,603	4,334,006

2.2 NET LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2006	323,051	272,294	272,267	230,781	218,543	215,584	247,266	235,858	211,010	241,560	274,833	320,453	3,063,500
2007	319,345	281,021	269,786	228,457	231,883	218,021	253,178	237,923	209,218	237,608	267,532	314,154	3,068,127
2008	313,562	279,252	262,392	227,860	223,882	217,082	252,395	236,852	206,815	238,874	270,905	312,359	3,042,230
2009	318,969	271,732	276,533	225,115	223,331	223,208	252,599	240,861	216,326	246,835	283,506	321,479	3,100,494
2010	322,764	275,389	264,054	233,827	220,707	215,751	252,308	245,260	211,831	238,568	276,095	328,561	3,085,116
2011	333,975	282,076	283,208	233,733	218,542	223,679	246,555	251,059	223,951	240,135	278,304	324,686	3,139,902
2012	321,730	286,779	279,732	235,517	222,312	217,842	252,099	254,667	220,598	243,793	286,926	328,517	3,150,511
2013	337,728	297,641	276,667	237,842	233,199	219,696	268,867	254,751	225,078	247,419	279,078	343,897	3,221,865
2014	329,517	279,546	279,656	235,365	226,070	226,002	263,980	251,199	214,732	238,897	276,987	343,940	3,165,892
2015	330,474	288,500	275,700	232,842	232,855	230,716	265,292	256,237	218,219	239,080	275,925	327,535	3,173,373
Forecast													
2016	341,022	294,324	286,713	244,090	233,390	229,830	269,071	264,371	224,413	247,093	283,735	345,632	3,263,683
2017	345,785	298,745	291,039	248,144	237,351	233,670	273,242	268,533	228,219	251,147	288,029	350,541	3,314,443
2018	349,613	302,073	294,284	251,013	240,250	236,508	276,468	271,691	230,956	254,033	291,287	354,469	3,352,645
2019	353,848	305,763	297,855	254,123	243,333	239,535	279,926	275,056	233,875	257,166	294,826	358,788	3,394,092
2020	357,774	309,144	301,139	256,946	246,108	242,263	283,085	278,105	236,507	260,020	298,113	362,762	3,431,966
2021	361,164	312,112	304,035	259,492	248,544	244,649	285,792	280,795	238,820	262,563	300,994	366,236	3,465,197
2022	366,617	315,309	304,373	261,804	254,675	246,756	291,530	279,736	242,654	267,130	303,883	370,651	3,505,118
2023	370,802	318,993	307,892	265,017	257,918	249,866	295,018	283,133	245,723	270,367	307,446	374,910	3,547,086
2024	374,600	322,324	311,079	267,902	260,801	252,627	298,142	286,160	248,445	273,278	310,667	378,774	3,584,799
2025	378,499	325,751	314,354	270,878	263,786	255,486	301,363	289,288	251,266	276,279	313,979	382,740	3,623,670
2026	382,407	329,190	317,636	273,869	266,784	258,352	304,587	292,418	254,099	279,297	317,300	386,713	3,662,654
2027	386,162	332,487	320,788	276,727	269,643	261,089	307,676	295,414	256,800	282,181	320,485	390,529	3,699,981
2028	389,969	335,837	323,985	279,637	272,561	263,878	310,814	298,461	259,558	285,118	323,718	394,396	3,737,933
2029	393,799	339,210	327,203	282,571	275,510	266,698	313,978	301,537	262,347	288,077	326,972	398,284	3,776,187
2030	397,323	342,300	330,157	285,237	278,176	269,250	316,866	304,339	264,867	290,767	329,951	401,860	3,811,093
2031	400,993	345,531	333,239	288,042	280,993	271,944	319,891	307,280	267,533	293,596	333,064	405,581	3,847,685
2032	404,819	348,912	336,456	290,993	283,968	274,783	323,059	310,367	270,350	296,574	336,318	409,457	3,886,056
2033	408,700	352,347	339,721	293,997	287,006	277,681	326,283	313,512	273,229	299,604	339,623	413,387	3,925,087
2034	412,538	355,744	342,950	296,968	290,012	280,550	329,471	316,624	276,079	302,601	342,890	417,271	3,963,698
2035	416,413	359,180	346,212	299,977	293,065	283,462	332,699	319,780	278,976	305,636	346,191	421,190	4,002,781

2.3 RESIDENTIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2006	129,951	99,060	100,792	76,647	67,004	65,050	81,435	70,346	60,882	78,885	93,787	140,556	1,064,394
2007	133,283	110,758	109,301	80,854	84,765	70,147	92,330	83,263	69,225	90,062	107,143	133,921	1,165,052
2008	136,053	115,157	109,364	89,438	80,721	72,251	97,949	85,591	74,307	91,773	109,092	133,820	1,195,516
2009	138,654	111,321	124,105	89,024	87,454	83,579	97,792	88,147	71,111	92,827	114,789	140,106	1,238,909
2010	144,415	116,176	112,135	94,505	85,285	75,333	96,222	91,300	72,613	94,047	110,964	148,667	1,241,663
2011	150,580	112,169	121,527	98,312	80,093	79,957	85,233	91,744	76,608	88,720	117,345	146,806	1,249,094
2012	134,187	105,958	112,447	88,508	81,808	82,946	97,309	91,118	73,417	89,175	117,807	154,029	1,228,709
2013	145,263	115,730	114,637	112,100	90,869	85,319	120,666	100,397	73,591	97,867	124,661	171,845	1,352,945
2014	147,191	120,724	129,852	84,813	80,792	77,673	105,443	102,753	73,260	95,314	119,531	159,107	1,296,452
2015	150,230	122,084	120,304	91,957	76,652	84,441	110,145	97,235	73,384	99,324	125,839	146,556	1,298,150
Forecast													
2016	151,523	122,721	124,862	98,876	84,993	84,692	115,094	102,816	75,383	100,119	126,655	163,443	1,351,178
2017	152,894	123,831	125,992	99,770	85,762	85,458	116,135	103,746	76,065	101,025	127,801	164,921	1,363,400
2018	154,379	125,035	127,216	100,739	86,595	86,288	117,264	104,755	76,804	102,007	129,042	166,524	1,376,648
2019	156,016	126,360	128,564	101,807	87,513	87,203	118,506	105,865	77,618	103,088	130,410	168,289	1,391,238
2020	157,600	127,643	129,870	102,841	88,402	88,088	119,710	106,940	78,406	104,135	131,735	169,998	1,405,370
2021	159,051	128,818	131,066	103,788	89,216	88,899	120,812	107,924	79,128	105,093	132,947	171,563	1,418,305
2022	160,440	129,944	132,211	104,695	89,995	89,676	121,867	108,867	79,819	106,011	134,109	173,062	1,430,696
2023	161,823	131,064	133,350	105,597	90,771	90,449	122,918	109,806	80,507	106,925	135,265	174,553	1,443,027
2024	163,181	132,163	134,469	106,483	91,532	91,208	123,949	110,727	81,183	107,822	136,400	176,018	1,455,135
2025	164,523	133,250	135,575	107,359	92,285	91,958	124,968	111,638	81,850	108,709	137,521	177,466	1,467,102
2026	165,853	134,327	136,671	108,226	93,031	92,701	125,978	112,540	82,512	109,588	138,633	178,900	1,478,959
2027	167,159	135,385	137,747	109,079	93,764	93,431	126,971	113,426	83,162	110,451	139,725	180,309	1,490,609
2028	168,441	136,423	138,803	109,915	94,483	94,148	127,944	114,296	83,799	111,298	140,796	181,691	1,502,037
2029	169,696	137,440	139,837	110,734	95,187	94,849	128,898	115,148	84,424	112,127	141,845	183,045	1,513,228
2030	170,919	138,430	140,845	111,532	95,873	95,533	129,827	115,978	85,032	112,935	142,867	184,365	1,524,136
2031	172,113	139,398	141,830	112,312	96,543	96,200	130,734	116,788	85,626	113,724	143,866	185,653	1,534,785
2032	173,283	140,345	142,793	113,075	97,199	96,854	131,622	117,582	86,208	114,497	144,843	186,914	1,545,216
2033	174,425	141,270	143,735	113,820	97,839	97,492	132,490	118,357	86,776	115,252	145,798	188,147	1,555,401
2034	175,539	142,172	144,652	114,547	98,464	98,115	133,336	119,112	87,330	115,988	146,729	189,348	1,565,331
2035	176,619	143,047	145,543	115,252	99,070	98,719	134,157	119,846	87,868	116,702	147,632	190,513	1,574,968

2.4 COMMERCIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2006	54,810	52,105	49,302	47,269	49,149	52,078	52,684	51,555	49,179	48,978	52,736	56,451	616,295
2007	57,625	54,282	51,787	50,427	52,321	55,372	55,996	53,312	51,185	52,063	55,272	60,163	649,803
2008	60,679	56,323	52,557	51,300	52,601	55,870	56,404	52,930	51,191	52,238	56,934	61,945	660,971
2009	60,319	57,143	55,134	52,468	52,802	56,015	57,628	55,929	54,675	55,551	57,688	60,004	675,356
2010	58,527	55,666	53,799	51,561	52,546	56,272	56,380	52,416	51,844	54,570	57,594	58,382	659,556
2011	57,742	59,980	55,524	50,675	51,759	55,477	59,401	55,911	50,918	50,637	53,116	55,779	656,918
2012	64,101	63,452	59,292	53,673	54,431	49,553	55,968	62,008	56,661	52,596	57,398	51,423	680,553
2013	65,750	60,623	56,214	57,036	69,494	61,665	67,834	73,941	72,704	67,185	66,229	69,533	788,208
2014	80,354	73,607	69,309	70,566	73,342	72,255	76,262	75,406	66,710	60,531	66,112	81,292	865,746
2015	80,156	72,259	68,665	64,591	71,392	74,678	72,149	71,980	68,558	62,811	67,227	78,701	853,168
Forecast													
2016	78,815	71,928	67,643	66,948	74,623	72,662	75,326	77,096	72,444	66,367	69,517	79,952	873,322
2017	80,730	73,675	69,287	68,574	76,436	74,428	77,157	78,970	74,205	67,980	71,206	81,895	894,541
2018	82,539	75,327	70,840	70,111	78,150	76,096	78,886	80,740	75,868	69,504	72,802	83,731	914,593
2019	84,185	76,829	72,252	71,509	79,708	77,614	80,459	82,350	77,381	70,890	74,254	85,401	932,832
2020	85,585	78,106	73,453	72,698	81,033	78,904	81,797	83,719	78,667	72,068	75,488	86,820	948,339
2021	86,521	78,961	74,257	73,494	81,920	79,767	82,692	84,635	79,528	72,857	76,314	87,770	958,717
2022	88,131	80,430	75,639	74,861	83,444	81,252	84,230	86,210	81,008	74,213	77,734	89,403	976,555
2023	89,861	82,008	77,124	76,331	85,082	82,846	85,884	87,902	82,598	75,669	79,260	91,158	995,722
2024	91,246	83,273	78,313	77,507	86,394	84,124	87,208	89,257	83,871	76,836	80,482	92,564	1,011,075
2025	92,729	84,626	79,585	78,767	87,797	85,490	88,625	90,707	85,234	78,084	81,789	94,067	1,027,499
2026	94,175	85,945	80,826	79,995	89,167	86,824	90,007	92,122	86,563	79,302	83,065	95,534	1,043,523
2027	95,550	87,201	82,006	81,163	90,469	88,092	91,321	93,467	87,827	80,460	84,278	96,930	1,058,763
2028	96,961	88,488	83,217	82,362	91,805	89,392	92,670	94,847	89,124	81,648	85,522	98,361	1,074,398
2029	98,420	89,820	84,470	83,601	93,186	90,738	94,064	96,275	90,465	82,877	86,809	99,841	1,090,567
2030	99,712	90,999	85,579	84,699	94,410	91,929	95,299	97,538	91,653	83,965	87,949	101,152	1,104,884
2031	101,100	92,266	86,770	85,878	95,724	93,209	96,626	98,896	92,929	85,134	89,174	102,560	1,120,266
2032	102,580	93,617	88,040	87,135	97,125	94,573	98,040	100,344	94,289	86,380	90,479	104,061	1,136,664
2033	104,125	95,027	89,366	88,447	98,588	95,998	99,517	101,855	95,710	87,681	91,842	105,629	1,153,785
2034	105,662	96,429	90,685	89,753	100,043	97,414	100,986	103,359	97,122	88,975	93,197	107,188	1,170,813
2035	107,256	97,884	92,053	91,107	101,552	98,884	102,509	104,918	98,587	90,317	94,603	108,804	1,188,473

2.5 WHOLESALE (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2006	104,740	87,653	86,284	70,910	67,094	65,924	77,822	79,281	66,626	76,585	98,120	97,957	978,996
2007	97,305	84,118	78,385	66,546	61,822	58,282	72,200	64,135	54,997	65,136	77,393	97,674	877,994
2008	95,009	83,999	79,094	66,892	69,677	66,114	71,212	70,951	57,242	70,540	82,793	94,718	908,240
2009	95,727	81,925	76,294	64,159	63,412	59,985	72,433	70,682	64,375	73,304	87,106	98,864	908,266
2010	98,545	83,945	77,442	67,108	59,780	59,833	72,144	70,068	60,545	64,123	82,201	99,603	895,337
2011	100,725	84,225	82,112	65,996	58,766	60,441	68,427	71,106	64,187	70,871	84,304	98,386	909,548
2012	96,036	85,333	81,119	66,560	58,307	59,084	69,719	70,177	60,311	72,646	82,146	97,532	898,971
2013	103,661	88,423	80,309	42,225	37,653	34,630	44,414	42,889	38,531	44,175	51,637	66,656	675,204
2014	64,115	50,647	51,900	41,917	35,985	34,959	43,081	42,482	38,972	41,116	53,678	68,270	567,123
2015	65,841	58,564	51,584	41,088	41,147	36,029	45,222	43,897	37,441	42,668	51,945	65,059	580,485
Forecast													
2016	74,488	62,952	58,673	40,622	37,264	34,303	43,055	41,958	37,299	41,444	51,085	64,917	588,061
2017	74,617	63,061	58,774	40,692	37,328	34,363	43,130	42,031	37,364	41,516	51,174	65,029	589,078
2018	75,038	63,417	59,106	40,922	37,539	34,557	43,373	42,268	37,575	41,750	51,463	65,397	592,405
2019	75,646	63,931	59,585	41,253	37,843	34,837	43,725	42,610	37,879	42,089	51,880	65,927	597,205
2020	76,286	64,472	60,089	41,602	38,163	35,131	44,094	42,971	38,200	42,444	52,318	66,484	602,254
2021	76,746	64,860	60,451	41,853	38,393	35,343	44,360	43,230	38,430	42,700	52,634	66,885	605,886
2022	77,206	65,249	60,813	42,104	38,623	35,555	44,626	43,489	38,660	42,956	52,949	67,286	609,517
2023	77,669	65,640	61,178	42,356	38,855	35,768	44,894	43,750	38,892	43,214	53,266	67,689	613,170
2024	78,134	66,034	61,544	42,610	39,088	35,982	45,163	44,012	39,125	43,473	53,586	68,095	616,845
2025	78,602	66,429	61,913	42,865	39,322	36,198	45,433	44,275	39,360	43,733	53,907	68,503	620,542
2026	79,073	66,827	62,284	43,122	39,558	36,415	45,706	44,541	39,596	43,995	54,230	68,913	624,260
2027	79,547	67,228	62,658	43,381	39,795	36,633	45,980	44,808	39,833	44,259	54,555	69,326	628,002
2028	80,024	67,631	63,033	43,641	40,033	36,853	46,255	45,076	40,072	44,524	54,882	69,742	631,765
2029	80,504	68,036	63,411	43,902	40,273	37,074	46,532	45,346	40,312	44,791	55,211	70,160	635,552
2030	80,986	68,444	63,791	44,165	40,515	37,296	46,811	45,618	40,553	45,060	55,542	70,580	639,360
2031	81,471	68,854	64,173	44,430	40,757	37,519	47,092	45,892	40,796	45,330	55,875	71,003	643,192
2032	81,960	69,267	64,558	44,696	41,002	37,744	47,374	46,167	41,041	45,601	56,209	71,429	647,047
2033	82,451	69,682	64,945	44,964	41,247	37,970	47,658	46,443	41,287	45,875	56,546	71,857	650,925
2034	82,945	70,099	65,334	45,234	41,495	38,198	47,943	46,722	41,534	46,149	56,885	72,287	654,826
2035	83,442	70,520	65,725	45,505	41,743	38,427	48,231	47,002	41,783	46,426	57,226	72,721	658,750

2.6 *INDUSTRIAL (MWH)*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2006	32,169	31,766	34,606	34,204	31,283	27,474	26,731	23,420	24,749	30,771	27,229	23,877	348,279
2007	29,351	30,288	28,555	28,792	28,203	25,897	22,857	25,798	23,811	24,761	24,910	20,828	314,051
2008	19,981	22,004	19,570	18,082	16,331	16,765	16,700	15,303	15,758	18,412	18,815	20,129	217,849
2009	22,496	19,712	19,195	17,101	15,353	13,975	14,634	15,213	17,528	18,602	21,176	20,726	215,710
2010	19,449	17,896	18,991	18,389	18,616	18,603	18,551	20,146	19,259	21,495	22,097	20,207	233,699
2011	23,160	24,129	21,555	17,261	24,902	22,812	25,671	21,690	22,374	24,978	20,262	21,971	270,764
2012	24,973	30,356	25,036	25,285	23,707	21,432	22,094	22,115	22,666	22,863	26,328	23,917	290,771
2013	19,966	30,774	23,744	24,489	31,517	33,006	29,815	29,726	31,598	32,105	32,500	33,084	352,325
2014	35,943	32,746	26,411	34,532	30,112	32,770	29,719	22,362	30,032	38,104	35,138	33,043	380,912
2015	32,138	33,574	32,797	31,186	36,574	26,261	27,971	34,078	32,395	29,853	27,852	34,997	379,676
Forecast													
2016	33,989	34,670	33,422	34,793	31,738	31,396	27,525	33,356	31,544	33,774	33,131	35,028	394,365
2017	35,337	36,124	34,873	36,255	33,053	32,645	28,750	34,643	32,843	35,237	34,502	36,404	410,666
2018	35,449	36,241	35,009	36,388	33,194	32,790	28,875	34,785	32,967	35,384	34,633	36,526	412,242
2019	35,793	36,590	35,340	36,701	33,496	33,105	29,166	35,087	33,255	35,712	34,935	36,880	416,060
2020	36,096	36,869	35,614	36,952	33,738	33,363	29,414	35,332	33,492	35,985	35,225	37,168	419,247
2021	36,638	37,420	36,149	37,505	34,243	33,862	29,858	35,862	33,992	36,524	35,752	37,726	425,532
2022	38,632	37,633	33,597	37,292	37,841	33,497	32,736	32,027	35,424	38,562	35,743	38,609	431,593
2023	39,242	38,228	34,128	37,881	38,439	34,026	33,253	32,533	35,984	39,171	36,308	39,218	438,411
2024	39,831	38,801	34,640	38,449	39,015	34,537	33,752	33,021	36,524	39,759	36,853	39,807	444,987
2025	40,438	39,393	35,168	39,035	39,610	35,063	34,266	33,524	37,080	40,365	37,414	40,414	451,770
2026	41,099	40,037	35,743	39,673	40,257	35,636	34,827	34,072	37,686	41,024	38,026	41,074	459,154
2027	41,698	40,620	36,264	40,252	40,844	36,156	35,334	34,569	38,236	41,623	38,580	41,673	465,850
2028	42,336	41,242	36,819	40,867	41,469	36,709	35,875	35,097	38,821	42,259	39,170	42,310	472,975
2029	42,972	41,861	37,372	41,481	42,092	37,260	36,414	35,625	39,404	42,894	39,759	42,946	480,083
2030	43,498	42,374	37,829	41,989	42,607	37,716	36,859	36,061	39,886	43,419	40,245	43,472	485,955
2031	44,100	42,960	38,353	42,570	43,197	38,238	37,370	36,560	40,439	44,020	40,803	44,074	492,685
2032	44,789	43,631	38,951	43,234	43,871	38,835	37,953	37,130	41,070	44,707	41,439	44,761	500,372
2033	45,491	44,315	39,562	43,913	44,559	39,444	38,548	37,713	41,714	45,408	42,089	45,463	508,219
2034	46,185	44,991	40,166	44,582	45,239	40,046	39,136	38,288	42,350	46,101	42,731	46,157	515,971
2035	46,889	45,676	40,778	45,262	45,928	40,656	39,732	38,871	42,995	46,803	43,382	46,860	523,833

2.7 LIGHTING (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2006	1,043	984	1,064	1,034	1,061	1,033	1,021	1,029	1,014	1,144	1,102	1,062	12,591
2007	1,056	1,041	1,121	1,040	1,073	1,057	1,080	1,057	1,064	1,129	1,056	1,062	12,835
2008	1,168	1,104	1,151	1,128	1,111	1,055	1,196	1,094	1,111	1,140	1,083	1,066	13,406
2009	1,097	1,044	1,133	1,024	1,163	1,154	1,112	1,136	1,089	1,153	1,077	1,114	13,297
2010	1,132	1,100	1,172	1,047	1,184	1,513	1,767	1,246	1,123	1,111	1,045	1,041	14,480
2011	1,114	1,027	1,674	582	1,092	1,098	1,086	1,113	1,615	560	1,121	1,153	13,233
2012	1,618	1,031	1,232	601	1,666	601	1,661	1,137	611	1,127	1,137	1,064	13,487
2013	1,532	863	1,003	1,112	1,186	1,101	1,151	1,069	1,135	1,132	1,080	1,114	13,479
2014	1,282	1,273	1,251	1,310	1,327	1,331	1,329	1,374	1,257	1,255	1,260	1,382	15,633
2015	1,319	1,339	1,261	1,321	1,372	1,382	1,299	1,347	1,248	1,349	1,295	1,359	15,891
Forecast													
2016	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2017	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2018	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2019	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2020	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2021	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2022	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2023	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2024	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2025	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2026	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2027	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2028	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2029	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2030	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2031	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2032	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2033	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2034	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973
2035	1,318	1,323	1,273	1,333	1,368	1,375	1,331	1,379	1,269	1,320	1,295	1,389	15,973

2.8 *IRRIGATION (MWH)*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2006	338	726	219	716	2,953	4,026	7,573	10,227	8,560	5,196	1,858	551	42,945
2007	726	534	637	800	3,699	7,265	8,715	10,359	8,937	4,456	1,758	507	48,393
2008	672	666	656	1,019	3,441	5,028	8,933	10,984	7,206	4,771	2,190	682	46,248
2009	675	588	673	1,340	3,147	8,501	9,000	9,754	7,548	5,399	1,669	664	48,957
2010	698	605	514	1,217	3,296	4,198	7,243	10,085	6,448	3,223	2,194	660	40,381
2011	654	545	816	908	1,931	3,894	6,737	9,495	8,249	4,369	2,156	590	40,345
2012	816	650	606	890	2,393	4,226	5,348	8,113	6,933	5,385	2,109	552	38,019
2013	1,557	1,228	759	880	2,480	3,974	4,986	6,729	7,519	4,955	2,970	1,666	39,704
2014	633	549	932	2,227	4,512	7,013	8,146	6,822	4,501	2,578	1,267	847	40,025
2015	790	680	1,089	2,698	5,718	7,925	8,506	7,700	5,192	3,074	1,768	863	46,003
Forecast													
2016	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2017	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2018	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2019	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2020	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2021	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2022	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2023	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2024	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2025	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2026	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2027	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2028	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2029	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2030	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2031	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2032	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2033	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2034	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784
2035	889	730	840	1,519	3,404	5,402	6,739	7,765	6,473	4,069	2,053	903	40,784

2.9 *LOSSES (MWH)*

Losses loads are only added to the gross load and are not included in the net load calculations.

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2006	47,027	36,990	33,403	24,799	21,522	21,641	27,551	25,067	20,732	26,294	35,171	46,273	366,470
2007	43,350	37,166	30,939	22,926	22,856	20,879	27,247	24,063	19,227	23,999	31,439	41,952	346,043
2008	37,916	33,295	26,551	20,690	19,329	18,779	24,566	21,634	17,044	22,005	29,245	37,626	308,679
2009	38,590	31,008	29,005	19,862	18,918	19,527	24,202	22,005	18,342	23,110	31,503	39,200	315,272
2010	35,810	28,862	23,967	19,421	16,744	16,534	21,882	20,677	15,939	19,564	27,076	37,108	283,585
2011	40,122	31,688	28,851	20,306	17,180	18,597	21,867	22,673	18,642	20,743	28,789	37,921	307,379
2012	32,646	28,718	24,679	18,077	15,587	15,466	20,044	20,455	15,860	18,745	26,831	34,038	271,146
2013	35,211	30,278	23,630	18,045	16,788	15,397	22,316	20,034	16,160	18,898	24,845	36,509	278,110
2014	33,719	26,868	24,287	17,776	15,871	16,390	21,640	19,595	14,796	17,723	24,619	36,841	270,127
2015	34,162	28,825	23,776	17,524	16,960	17,205	22,015	20,538	15,392	17,879	24,609	33,557	272,442
Forecast													
2016	35,414	29,210	24,991	18,704	16,555	16,589	21,999	21,255	15,829	18,545	25,290	36,360	280,740
2017	35,373	29,247	24,964	18,726	16,595	16,622	21,978	21,272	15,886	18,552	25,263	36,310	280,786
2018	35,374	29,260	24,927	18,704	16,606	16,631	21,963	21,279	15,904	18,522	25,233	36,298	280,701
2019	35,502	29,381	24,990	18,755	16,675	16,700	22,028	21,355	15,976	18,567	25,295	36,417	281,641
2020	35,670	29,524	25,082	18,824	16,753	16,778	22,116	21,446	16,055	18,632	25,394	36,573	282,848
2021	35,936	29,755	25,271	18,977	16,891	16,915	22,279	21,614	16,187	18,778	25,588	36,848	285,039
2022	36,642	30,037	25,027	19,106	17,574	17,020	22,960	21,186	16,542	19,245	25,797	37,337	288,473
2023	37,058	30,395	25,322	19,362	17,826	17,260	23,251	21,463	16,777	19,497	26,109	37,766	292,084
2024	37,437	30,720	25,590	19,591	18,048	17,470	23,510	21,707	16,981	19,722	26,392	38,158	295,326
2025	37,825	31,054	25,866	19,827	18,279	17,688	23,777	21,960	17,195	19,955	26,683	38,558	298,667
2026	38,214	31,389	26,141	20,065	18,511	17,908	24,044	22,212	17,410	20,190	26,975	38,959	302,018
2027	38,589	31,711	26,406	20,292	18,731	18,116	24,299	22,454	17,614	20,413	27,254	39,345	305,224
2028	38,968	32,037	26,675	20,523	18,957	18,330	24,559	22,699	17,823	20,642	27,538	39,734	308,485
2029	39,348	32,366	26,945	20,757	19,186	18,546	24,821	22,948	18,035	20,872	27,823	40,125	311,771
2030	39,700	32,667	27,193	20,967	19,391	18,740	25,060	23,173	18,225	21,079	28,084	40,486	314,766
2031	40,065	32,982	27,452	21,190	19,609	18,946	25,310	23,411	18,427	21,299	28,356	40,860	317,907
2032	40,444	33,311	27,721	21,426	19,841	19,165	25,572	23,660	18,643	21,531	28,641	41,247	321,202
2033	40,827	33,645	27,994	21,666	20,079	19,389	25,838	23,915	18,865	21,768	28,929	41,638	324,554
2034	41,206	33,976	28,263	21,903	20,315	19,611	26,102	24,168	19,084	22,002	29,214	42,025	327,869
2035	41,587	34,310	28,535	22,144	20,555	19,837	26,370	24,424	19,308	22,239	29,501	42,413	331,225

2.10 *SYSTEM PEAK (MW)*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
Historical Normalized Actuals														
2006	719	666	582	523	561	415	493	490	474	541	638	733	733	493
2007	676	644	555	514	540	393	520	487	471	535	627	704	704	520
2008	660	660	543	535	476	380	502	494	443	504	666	677	707	502
2009	707	643	624	507	481	415	496	446	564	514	660	704	704	496
2010	683	629	536	499	486	420	566	554	448	487	652	726	726	566
2011	722	666	593	516	472	448	529	537	509	508	632	691	702	537
2012	702	675	560	523	493	418	589	540	453	501	624	723	723	589
2013	720	631	549	493	515	442	600	565	523	502	598	698	698	600
2014	651	580	562	469	403	482	620	605	412	467	572	645	693	620
2015	693	679	568	488	501	523	611	587	437	514	669	631	669	611
Forecast														
2016	673	621	570	494	442	493	585	563	459	514	639	686	731	590
2017	683	631	578	501	449	500	593	572	466	521	649	696	741	599
2018	691	637	585	507	454	505	600	578	471	527	656	703	749	605
2019	698	644	591	512	459	511	606	584	476	533	663	711	757	612
2020	705	651	597	517	463	516	612	590	481	538	670	718	764	618
2021	712	657	602	522	467	520	618	595	485	543	676	725	771	624
2022	719	664	609	528	472	526	625	602	491	549	683	733	780	631
2023	728	672	616	534	478	532	632	609	496	555	691	741	789	638
2024	735	678	622	539	483	537	638	615	501	561	698	749	797	644
2025	743	685	628	545	487	543	645	621	506	566	705	756	805	651
2026	750	692	635	550	492	548	651	628	511	572	713	764	813	658
2027	758	699	641	556	497	554	658	634	516	578	719	772	821	664
2028	765	706	647	561	502	559	664	640	521	583	726	779	829	670
2029	772	713	654	566	507	564	670	646	526	589	734	787	837	677
2030	779	719	659	571	511	569	676	652	531	594	740	794	844	683
2031	786	726	665	576	516	575	683	658	536	599	747	801	852	689
2032	794	733	672	582	521	580	689	664	541	605	754	809	860	696
2033	802	740	678	587	526	586	696	670	546	611	761	816	869	702
2034	809	747	684	593	531	591	702	677	551	617	768	824	877	709
2035	817	754	691	599	535	596	709	683	556	622	775	832	885	716

Appendix G

NAVIGANT LOAD SCENARIOS REPORT

Load Scenario Assessment

Exploring Structural Change in Electricity Consumption Drivers

Prepared for:

FORTIS BC™

July 15, 2016

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DISCLAIMER

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EXECUTIVE SUMMARY

FortisBC plans for the future energy and capacity needs of its electricity customers through the development and periodic updating of a Long Term Electric Resource Plan (LTERP). The LTERP, currently in development, is expected to be submitted to the British Columbia Utilities Commission in November of 2016.

A core component of the LTERP is FortisBC's long-term forecast of peak demand and energy consumption. While this reference forecast does account for uncertainty and variability in existing load drivers (through a Monte Carlo simulation) it does not capture any major structural changes in the way electricity is consumed. Given the rapid development of emerging technologies, and the effects that these technologies may have on customer behaviour, FortisBC has deemed it prudent to explore what the potential impacts of highly uncertain major structural changes could be.

FortisBC engaged Navigant to:

- Identify a set of potentially significant drivers of structural change in electricity consumption;
- Estimate the unit impacts[1] of eight of these load drivers, as selected by FortisBC and;
- Model the potential impacts of these drivers as part of five different load scenarios, the parameters of which were developed collaboratively by Navigant and a cross-disciplinary internal group of FortisBC staff in consultation with FortisBC stakeholders.

Of the load drivers identified by Navigant, FortisBC identified eight for which detailed unit load impacts were to be developed. These eight load drivers are as follows (with descriptions provided in Section1):

- Residential Rooftop Solar (PV) and Integrated PV Storage Systems (IPSS);
- Electric Vehicles (EVs)
- Fuel Switching – Electricity to Gas;
- Fuel Switching – Gas to Electricity;
- Consistent and Persistent Weather Changes due to Climate Change;
- Large Load Sector Transformation (LLST);
- The Internet of Things" (IoT); and,
- Combined Heat and Power (CHP).

Once the unit load impacts had been estimated, Navigant grouped them together into five different scenarios. Initiatives were combined to deliver all five scenarios according to two guiding principles:

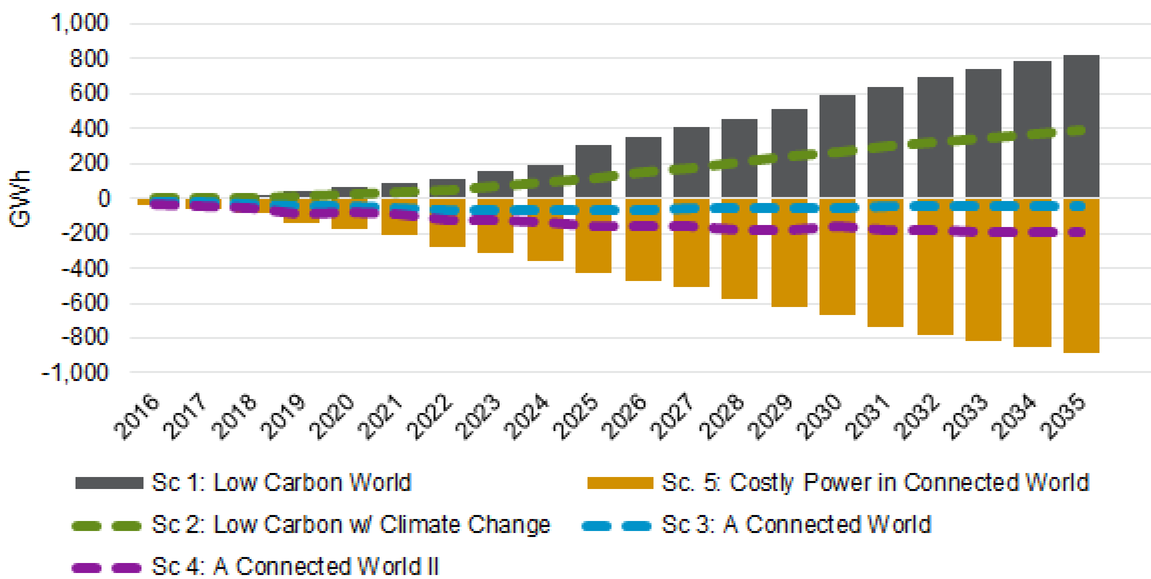
1. **The analysis should include "boundary" scenarios.** Boundary scenarios are those scenarios that define major deviations from existing empirical forecasts driven by the cumulative effects of emerging technologies and structural shifts that overwhelmingly affect system load in one direction or the other.
2. **The analysis should include "offsetting" scenarios.** In addition to modeling scenarios where all load drivers push system load in the same direction, it is important to consider

[1] The "unit impact" of a load driver refers to the load impact that a single unit of that load driver has. For example, the unit impact for electric vehicles would be the average impact of a single EV.

scenarios where off-setting effects can exist. This is helpful for appreciating the potential dynamics of how load drivers may interact with one another.

The first guiding principle led to the development of two boundary scenarios, one that examined combinations of load drivers that all increased (or decreased) load, Scenario 1, and Scenario 5. The second guiding principle led to three offsetting scenarios that examined combinations of load drivers that both increase and decrease load, Scenarios 2, 3, and 4. Navigant then worked with FortisBC staff to determine a plausible level of penetration for load drivers in the two most extreme, "boundary" scenarios. The energy impacts of the two boundary scenarios as well as the three intermediate scenarios are shown below in Figure ES - 1.

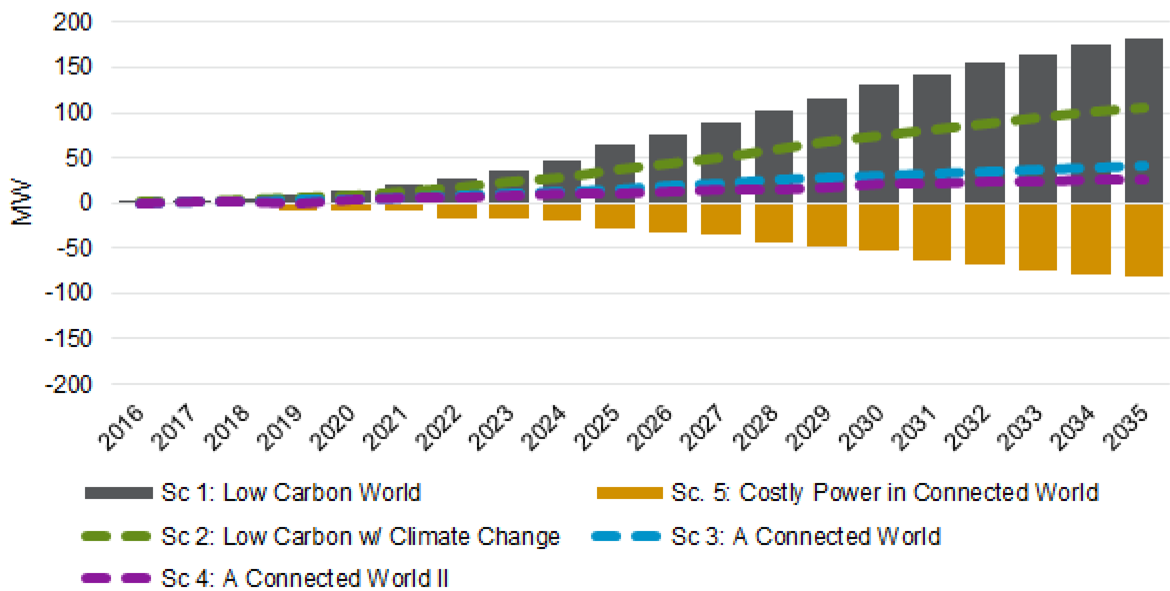
Figure ES - 1: Scenario Energy Impacts



The peak demand impacts[2] of the five scenarios are presented in Figure ES - 2. What is particularly noteworthy about this chart and Figure ES - 1 (besides the magnitude of the impacts of the boundary scenarios) is the fact that for two of the offsetting scenarios, the demand and energy impacts move in opposite directions. This is the result of interactions between PV installations (which generate a great deal of electricity, but none of it during peak winter demand periods) and EVs, (which require a very high proportion of the energy they use during peak evening dinner times).

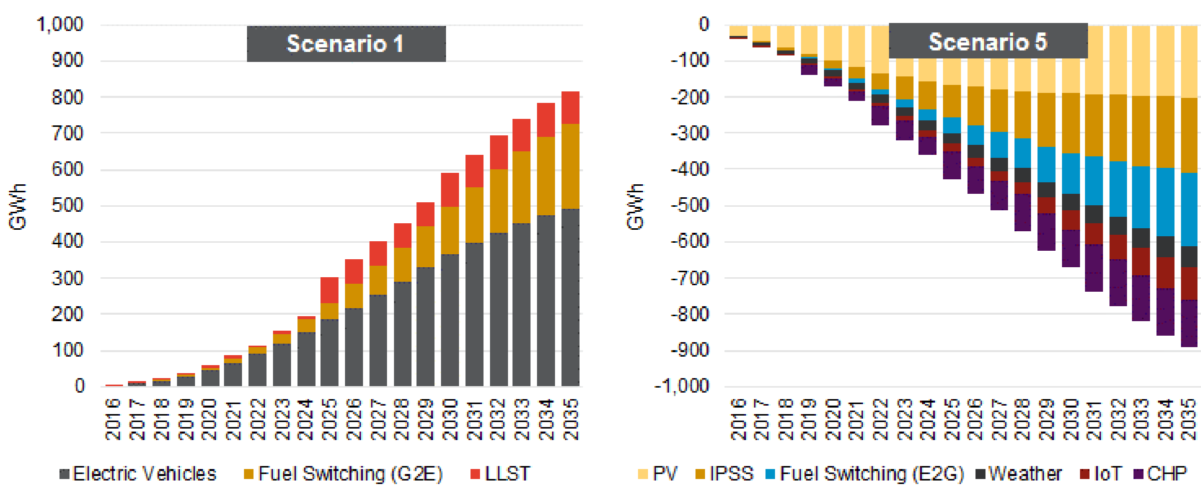
[2] Peak demand is assumed to be the period from 5pm to 6pm on January weekdays.

Figure ES - 2: Scenario Demand Impacts



The energy impacts for the two boundary scenarios, by year and load driver are shown in Figure ES - 3. In Scenario 1, impacts are dominated by EVs and fuel switching. In Scenario 5, impacts are dominated by PV and IPSS as well as fuel-switching.

Figure ES - 3: Boundary Scenario Impacts by Load Driver



Observing the estimated impacts in the boundary scenarios, **Navigant's principal finding is that the load drivers that could have the largest impacts going forward are (in order): electric vehicles, residential rooftop PV, and fuel switching.** Based on the modeling results thepotential impact from the

LLST, CHP, IoT and Weather load drivers appears relatively small at the system level, relative to the the other load drivers.[3]

Navigant's secondary finding is that, based on the offsetting scenarios, the possibility exists that demand during peak times could increase despite energy consumption falling. Such an impact could be driven by a strong move toward the electrification of transportation combined with increasing self-generation and other energy-efficiency efforts.

Navigant's principal recommendation is that **FortisBC continue to monitor the adoption of electric vehicles, rooftop solar PV and fuel switching**. This could be done by monitoring items like the following, which may represent "signposts" of accelerated adoption trends:

- PV uptake through FortisBC's net metering tariff;
- Regional EV uptake, and
- Fuel switching through the use of existing load research being conducted within FortisBC.

[3] An important distinction should be noted here: LLST impacts are relatively small at the system level, but may be substantial in relation to available distribution infrastructure.

1. INTRODUCTION

FortisBC plans for the future energy and capacity needs of their electricity customers through the development and periodic updating of a Long Term Electric Resource Plan (LTERP). The LTERP, currently in development, is expected to be submitted to the British Columbia Utilities Commission in November of 2016.

A core component of the LTERP is FortisBC's long-term forecast of peak demand and energy consumption. While this reference forecast does account for uncertainty and variability in existing load drivers (through a Monte Carlo simulation) it does not capture any major structural changes in the way electricity is consumed. Given the rapid development of emerging technologies, and the effects that these technologies may have on customer behaviour, FortisBC has deemed it prudent to explore what the potential impacts of highly uncertain major structural changes could be.

FortisBC engaged Navigant to:

- Identify a set of potentially significant drivers of structural change in electricity consumption;
- Estimate the unit impacts[4] of eight of these load drivers, as selected by FortisBC and;
- Model the potential impacts of these drivers as part of five different load scenarios, the parameters of which were developed collaboratively by Navigant and a cross-disciplinary internal group of FortisBC staff in consultation with FortisBC stakeholders.

This report presents the outcome of these efforts.

The purpose of this report is to provide a quantitatively robust answer to the question: "*what would be the impact on FortisBC demand and energy if one of five given sets of circumstances were to arise?*"

The reader should therefore bear in mind that:

- **The scenarios presented are cause-agnostic.** For example, this report quantifies what the impact of a substantial increase in the penetration of electric vehicles (EVs) in FortisBC territory would be. Determining what might drive such increased uptake in EVs is beyond the scope of this work.
- **No probability can reasonably be assigned to these scenarios.** The future development of the load drivers included in these scenarios is so uncertain that no objective probabilities can be assigned to the scenarios – it is for this reason that these load drivers are included in this exercise, as opposed to a more formal empirical forecast.
- **The purpose of this report is informational, not immediately actionable.** FortisBC's purpose in engaging Navigant is to help understand the potential impacts of the load drivers and scenarios. FortisBC will explore the impacts of the load scenarios on its preferred resource portfolio as part of its contingency analysis.

[4] The "unit impact" of a load driver refers to the load impact that a single unit of that load driver has. For example, the unit impact for electric vehicles would be the average impact of a single EV.

Eight load drivers are considered in this report. These were selected from a broader list developed by Navigant and FortisBC staff as being those that were judged to have the most substantial potential impact on future loads. The eight load drivers are:

1. **Residential Rooftop Solar (PV) and Integrated PV Storage Systems** (IPSS)**.** Behind-the-meter rooftop solar photovoltaic (PV) generation by residential customers. This load driver includes battery-supported PV, referred to in this report as Integrated Photovoltaic Storage Systems (IPSS).[5]
2. **Electric Vehicles.** Plug-in hybrid electric vehicles (PHEVs) and battery electric vehicles (BEVs)[6], supported by Level 1 (standard 120V) home charging, Level 2 (240 V) work-place and home charging as well as DC fast charging.
3. **Fuel Switching – Electricity to Gas.** Residential fuel switching from electrically-fired to gas-fired space- and water-heating, applicable only to residential customers within 50 metres of a gas main.
4. **Fuel Switching – Gas to Electricity.** Residential fuel switching from gas-fired to electrically-fired space- and water-heating.
5. **Consistent and Persistent Weather Changes due to Climate Change.** The effect on customer energy consumption due to climate change driven temperature increases forecast by the USGS National Climate Change Viewer.
6. **Large Load Sector Transformation.** Unanticipated growth of large load customers not associated with traditional energy intensive industries (i.e., primary resources and manufacturing).
7. **The Internet of Things.** The combined effect of an increasing number of household appliances and devices being connected to a home network, of information being collected by those devices being delivered to residential consumers to allow for optimal decision making, and of the presence of systems that allow consumers to take control of their consumption in response to this information.
8. **Combined Heat and Power.** Very large industrial customers investing in CHP cogeneration facilities, reducing the amount of electricity they require from the system, and potentially allowing them to become net generators of electricity.

These load drivers are the building blocks for five scenarios modeled by Navigant. The assumed "uptake" of each load driver will vary from scenario to scenario, from zero in some scenarios to a very aggressive level in others. It should be noted that all load driver uptake assumed in any given scenario must be understood to be incremental to what is already embedded in the reference case load forecast.

The remainder of this report is comprised of three chapters:

1. **Load Drivers.** This chapter provides a detailed description of how the unit load impact of each load driver was estimated, and a more precise definition of the load driver itself.

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[5] This usage was coined by the Australian Energy Market Operator. See for example:

Australian Energy Market Operator, *Emerging Technologies Information Paper; National Electricity Forecasting Report*, June 2015

http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/NEFR-Supplementary-Information

[6] Automobiles only.

2. **Load Scenarios.** This chapter describes the five scenarios modeled, outlines the input assumptions driving each scenario, and describes the estimated impacts of each scenario relative to the reference case forecast.
3. **Findings and Recommendations.** This chapter summarizes Navigant's findings based on the analysis and makes some recommendations to FortisBC, including some suggestions for monitoring growth in each of the load drivers over time, and "signposts" that might indicate a need for FortisBC to take a more active role in considering the impact of these drivers in the future.

2. LOAD DRIVERS

This chapter describes each of the eight load drivers considered in this analysis and outlines the assumptions and calculations employed to estimate approximate unit load impacts for each driver. The eight load drivers described below include:

- Residential Rooftop Solar (PV) and Integrated PV Storage Systems (IPSS);
- Electric Vehicles
- Fuel Switching – Electricity to Gas;
- Fuel Switching – Gas to Electricity;
- Consistent and Persistent Weather Changes due to Climate Change;
- Large Load Sector Transformation;
- The Internet of Things"; and,
- Combined Heat and Power.

2.1 Residential Rooftop Solar (PV) and Integrated PV Storage Systems (IPSS)[7]

The average estimated impact per household with deployed solar rooftop photovoltaic (PV) is presented in Figure 1, below. The underlying assumptions and approach to generating these unit impacts are presented below that.

Figure 1. Solar Rooftop PV Unit Impacts

Month	Monthly kWh	kW (9am - 10am)	kW (6pm - 7pm)
January	402	1.3	0.0
February	585	2.0	0.0
March	959	3.4	0.0
April	1,024	3.7	0.1
May	1,071	3.7	0.3
June	1,059	3.6	0.4
July	1,165	3.9	0.4
August	1,170	4.0	0.2
September	1,126	3.9	0.0
October	893	3.4	0.0
November	491	1.9	0.0
December	345	1.3	0.0

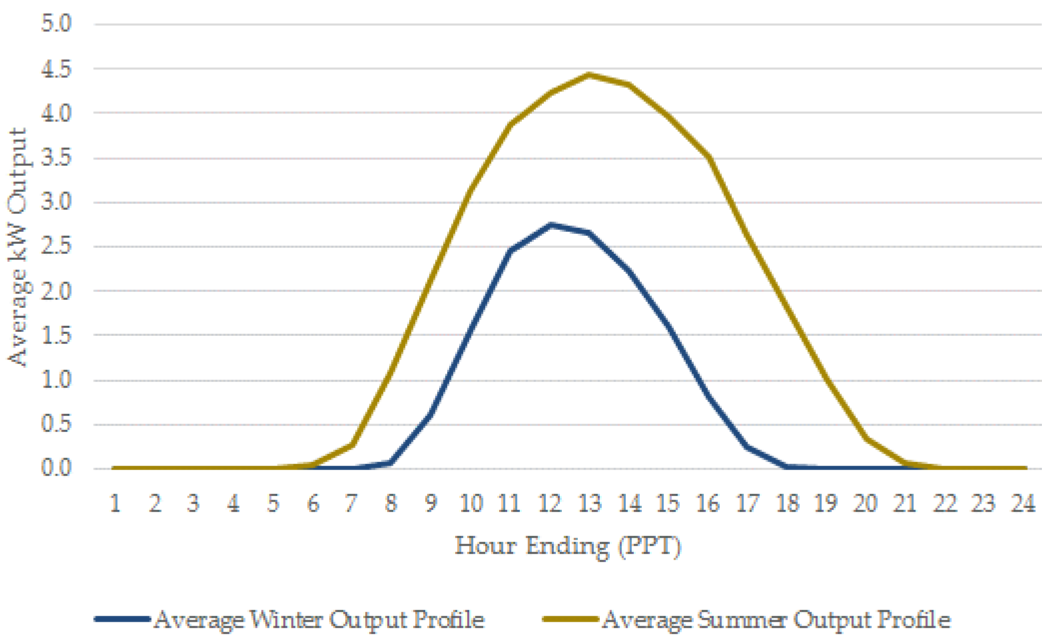
Navigant has estimated the unit load impact of rooftop PV panels based on the following factors:

[7] Distributed wind generation has not been included as a potential load driver based on discussions between Navigant and FBC which concluded that the probability of any substantial growth in small-scale (i.e., residential rooftop) wind generation is sufficiently remote that it need not be considered in this analysis.

- Average nameplate capacity of rooftop installed PV panels: 9.9 kW;[8]
- A region-specific (Penticton, B.C.) historical average capacity factor by month of year[9]; and,
- A region-specific average hourly distribution of solar output by month[10].

The single day hourly profile of PV output, estimated based on the factors detailed above, is presented in Figure 2, where “winter” is defined as December, January and February, and “summer” is defined as June, July and August.

Figure 2. Seasonal Solar Profile (9.9 kW Unit)



[8] As per the average capacity of all Ontario microFIT installations that were: pending a utility offer to connect, approved, and connected, as of December 2015.

Independent Electricity System Operator, *BI-WEEKLY microFIT REPORT: Data as of December 11, 2015*, 2015 http://microfit.powerauthority.on.ca/sites/default/files/bi-weekly_reports/Bi-Weekly-microFIT-Report-2015-12-11.pdf

[9] Natural Resources Canada, *Photovoltaic potential and solar resource maps of Canada*, accessed (for Penticton B.C.) December 2015

http://pv.nrcan.gc.ca/index.php?n=2208&m=u&lang=e

These capacity factors implicitly account for a number of factors, including the type of mounting (fixed vs. tracking) and the system efficiency. For the purposes of future scenario analysis Navigant anticipates holding these capacity factors unchanged over the course of the scenario.

[10] National Renewable Energy Laboratory, *PVWatts® Calculator*, accessed December 2015

http://pvwatts.nrel.gov/index.php

Location: Summerland, B.C. All input parameters available on request.

A secondary impact of this load driver is that which occurs when residential solar photovoltaic installations are supported by energy storage, sometimes known as integrated PV and storage systems (IPSS).[11]

Navigant estimated the unit impacts of IPSS using the sources cited above applied to:

- Residential hourly load profiles (by month and weekend/weekday day-type)[12]
- Average monthly FortisBC residential customer electricity use[13]
- The technical characteristics of an existing energy storage device[14]

The storage charging algorithm adopted for this analysis assumes that, in any given hour of the day:

1. As much of the given home's electricity consumption as possible is satisfied by PV output.
2. Electricity needs exceeding solar output are satisfied by storage output (subject to quantity of energy stored).
3. Solar output in excess of the home's electricity needs is stored, subject to the storage and charge capacities and efficiency of the storage device).
4. Solar output in excess of the home's electricity needs that exceeds either the storage device's storage or charge capacities is returned to the grid.

Figure 3, below presents the average residential load profile and solar output profiles for summer weekdays. As may be seen solar output from approximately hour ending 7 through to approximately hour ending 17 (6am – 5pm) completely satisfies the home's electricity requirements. Under the storage algorithm assumed by Navigant, storage output would occur in the hours following hour ending 17, when solar output (yellow line) is less than the given home's demand (black line).

[11] This is the terminology preferred by the Australian Energy Market Operator (AEMO), an agency that has done a considerable amount of research into the future potential of this technology, see for example:

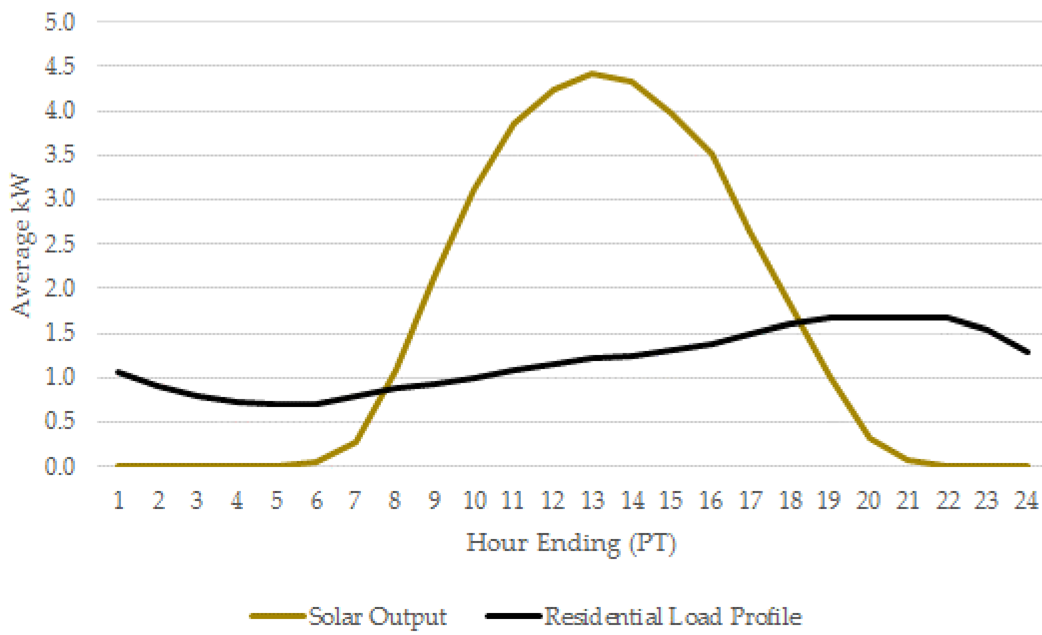
Australian Energy Market Operator, *Emerging Technologies Information Paper (National Electricity Forecasting Report)*, June 2015 http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report/NEFR-Supplementary-Information

[12] Based on internal Navigant Canadian single family home residential load profiles.

[13] These figures are based on averaged monthly numbers from 2011-2014 provided by Fortis

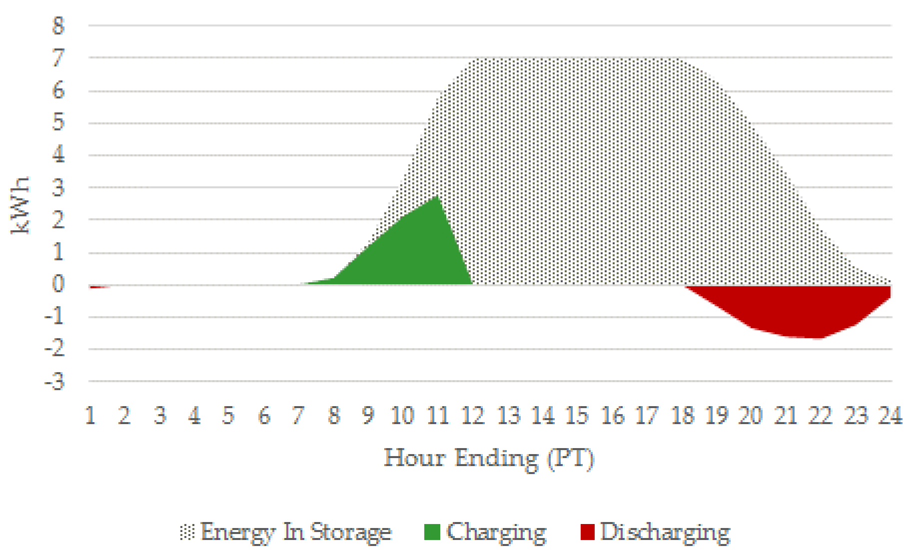
[14] The storage device was assumed to have the same technical characteristics as the Tesla Powerwall: 7 kWh of storage capacity, 92% efficiency, and a charge capacity of 3.3 kW.

Figure 3: Summer Solar Output and Residential Load Profile[15]



The charging, discharging and amount of electricity maintained in storage in any given weekday summer hour is shown in Figure 4 below. This charging behaviour occurs in response to the differentials between residential requirements and solar output shown above, and limited by the parameters of the storage device (storage and charging capacity). The grey patterned area represents the cumulative total of the green (charging) and red (discharging) areas.

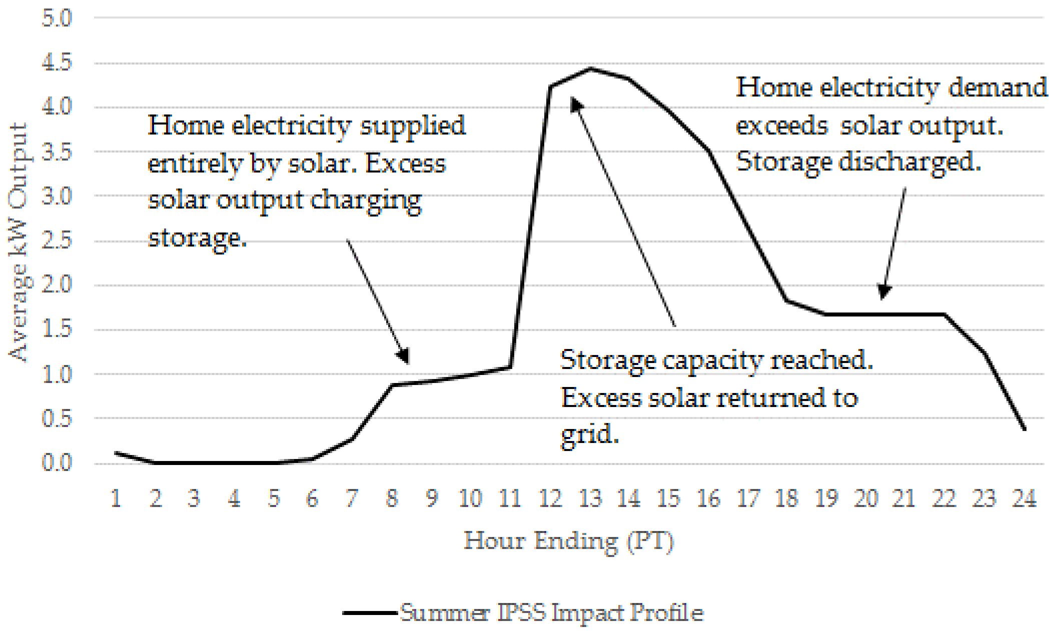
Figure 4: Summer Charging and Discharging



[15] "PT" refers to "prevailing time", i.e., daylight savings time in the summer and standard time in the winter.

The ultimate impact on FortisBC system load of the algorithm assumed above is shown for summer months in Figure 5, below. Although the scale of this chart is positive, these should be understood to be the unit *reductions* in load imposed by IPSS.

Figure 5: Summer Load Reductions due to IPSS



2.2 Electric Vehicles (EVs)

The average estimated unit impact per electric vehicle, by vehicle type and charging type is presented in Figure 6, below. The underlying assumptions and approach to generating these unit impacts are presented below that. Average demand impacts between 9am and 10am and 6pm to 7pm are presented for illustrative purposes.

The three types[16] of vehicles for which impacts are presented are:

- **PHEV10**[17]**:** a plug-in hybrid vehicle with a 16 kilometer (10 mile) equivalent all-electric range, e.g., Toyota Prius plug-in.
- **PHEV20:** a plug-in hybrid vehicle with a 32 kilometer (20 mile) equivalent all-electric range, e.g., Mercedes S550 PHEV.
- **PHEV40:** a plug-in hybrid vehicle with 64 kilometer (40 mile) equivalent all-electric range, e.g., Chevy Volt.
- **BEV:** a battery electric vehicle (no combustion engine), e.g., Nissan Leaf.

The two types of charging presented in the table below are:

[16] The classification of vehicle types chosen here reflects the classification of these vehicles in the literature sourced for this memorandum.

[17] PHEV nomenclature in the source documents is derived from quasi-arbitrary range designations based on miles, rather than kilometers. For consistency with source documents we have maintained the mile-based naming conventions here.

- **Level 1:** 120V AC home charging station with a 1.44 kW charging capacity
- **Level 2:** 240V AC home charging station with a 6.6 kW charging capacity

Level 1 and Level 2 charging stations are typically mutually exclusive – a home or workplace charging station will generally be equipped with one or the other. DC fast charging (not shown in the table below) is applicable only to BEVs and would be used in parallel with a Level 1 or Level 2 charging station. DC fast charging stations are, in effect, BEV "gas stations" and are designed to extend the practical range of BEVs. At present only a very small fraction of the energy required by BEVs is provided by DC fast charging (see below), but Navigant anticipates that this proportion will grow as a function of the total number of BEVs on the road.

One consequence of growth in DC fast charging will also be the increase in average BEV vehicle miles traveled (VMT) and thus the energy consumed by this type of vehicle, a factor that will be accounted for in the scenario analysis.

Figure 6: Electric Vehicle Unit Impacts

Vehicle Type	Charging Type	Monthly kWh	kW (9am - 10am)	kW (6pm - 7pm)
PHEV10	Level 1	107	0.03	0.20
PHEV20	Level 1	213	0.04	0.30
PHEV40	Level 1	326	0.05	0.37
BEV	Level 1	314	0.05	0.36
PHEV10	Level 2	107	0.03	0.25
PHEV20	Level 2	213	0.06	0.50
PHEV40	Level 2	326	0.09	0.69
BEV	Level 2	314	0.08	0.67

An important distinction must be made about the kW impacts reported above. These are not strictly speaking unit impacts (i.e., the impact of a single vehicle charging at that time), but rather the average impact per vehicle. This reflects the diversity of times across the day at which individuals (unconstrained by a time-differentiated electricity rate) typically charge their vehicles.

Also noteworthy in the impacts presented above is that PHEV40s consume more electricity than BEVs. This is due to the more limited range of BEVs. It is anticipated that in the scenario analysis, vehicle range, and thus miles traveled and energy use, for BEVs will increase as the number of DC fast charging stations grows (which itself will be modeled as a function of the overall growth in the number of EVs on the road).

Navigant has estimated the unit load impacts of EVs based on the following factors:

- The average annual consumption of electricity by type of vehicle[18];

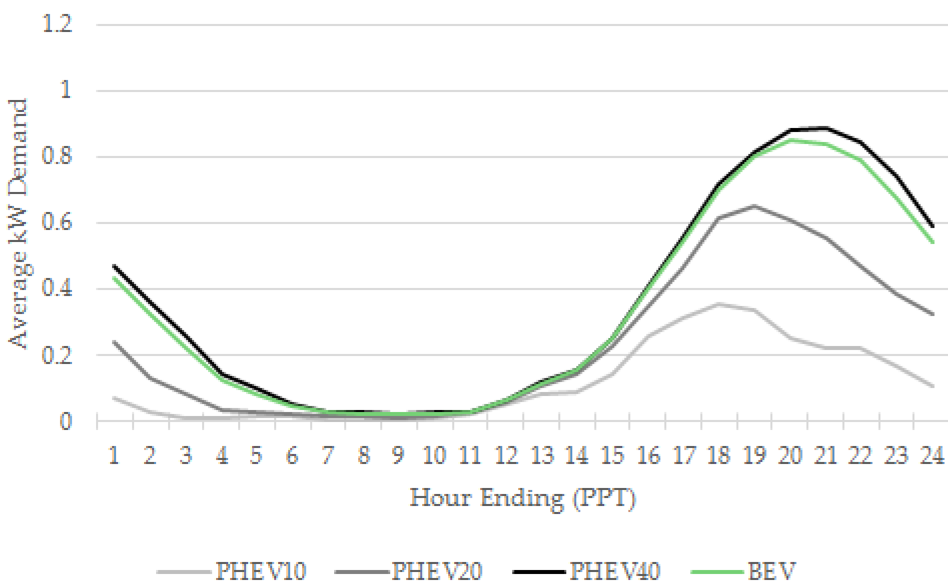
[18] ICF International and E3 on behalf of California Electric Transportation Coalition, *California Transportation Electrification Assessment – Phase 2: Grid Impacts*, October 2014. Drawn from Table 1.
http://www.caletc.com/wp-content/uploads/2014/10/CalETC_TEA_Phase_2_Final_10-23-14.pdf

- Navigant's estimated charging load profiles, developed based on modeled results for California[19] and the survey findings of an EV-specific study conducted in B.C.[20]; and,
- The typical charging capacity of Level 1 and Level 2 charging stations.[21]

Residential (i.e., home charging) charging profiles were estimated based on the vehicle data-diary reported home arrival times for 528 vehicles in B.C., as well as the daily energy requirements and charging capacities of the charging technology in use as reported by the California Transportation Electrification Assessment (CTEA). The embedded assumption is that vehicle charging begins in the same hour at which participants arrive home.

The average Level 1 home charging profile, for each vehicle type is shown in Figure 7, below.

Figure 7: Level 1 Home Charging Profiles



The average Level 2 home charging profile, for each vehicle type is shown in Figure 8, below.

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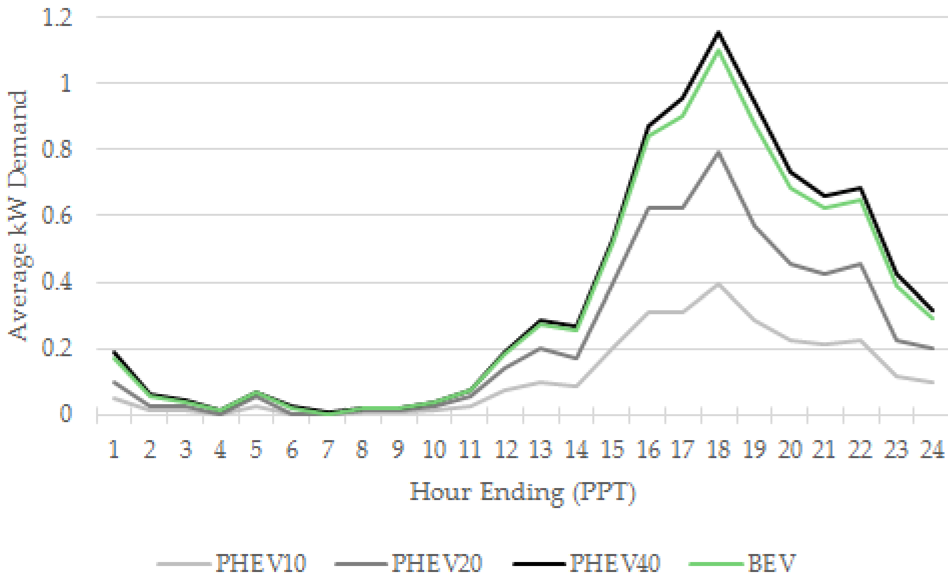
[19] Ibid, Figure 6

[20] Axsen, Goldberg, et al, *Electrifying Vehicles (Early Release): Insights from the Canadian Plug-in Electric Vehicle Study,* Energy and Materials Research Group, Simon Fraser University, August 2015
http://rem-main.rem.sfu.ca/papers/jaxsen/Electrifying_Vehicle_(Early_Release)-The_2015_Canadian_Plug-in_Electric_Vehicle_Study.pdf

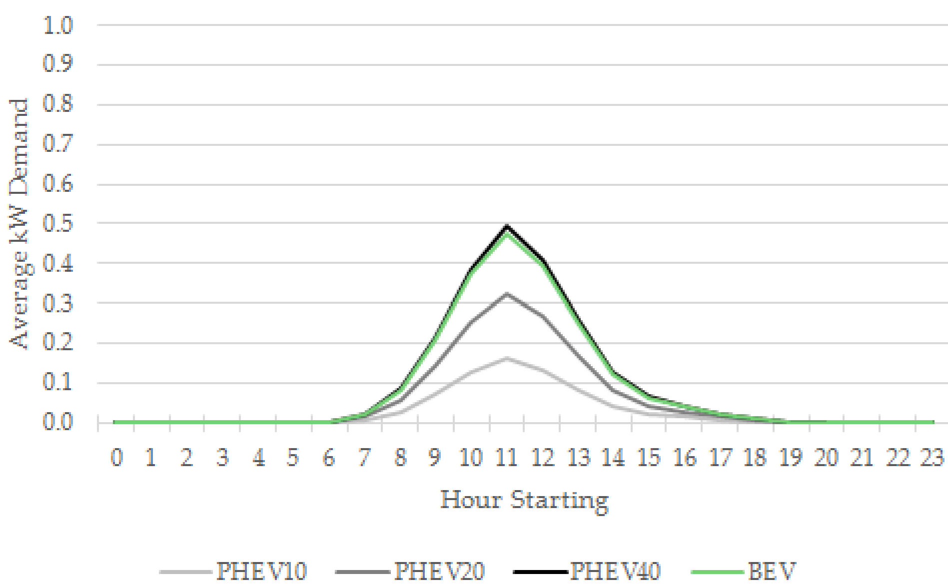
[21] National Research Council, *Overcoming Barriers to Electric Vehicle Deployment: Interim Report*, 2013
http://www.nap.edu/catalog/18320/overcoming-barriers-to-electric-vehicle-deployment-interim-report

Figure 8: Level 2 Home Charging Profiles



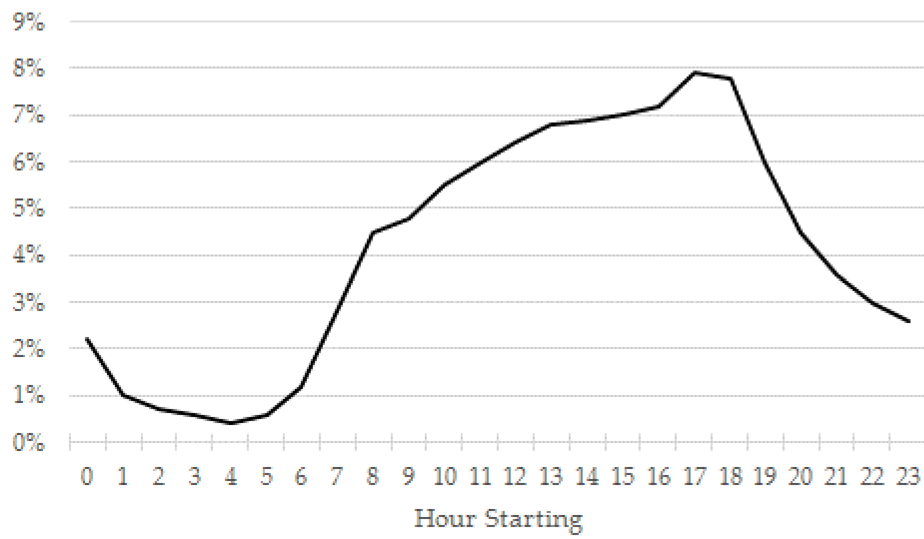
In addition to home charging the CTEA reported consumption figures include a proportion of EV electricity consumption that is driven by workplace charging. This workplace charging is assumed to be all Level 2. The load profile of Level 2 workplace charging is shown in Figure 9 below. Note that the consumption profiles below are additive with *both* the Level 1 and Level 2 profiles above for an average EV, since the embedded source assumption is that all workplace charging is Level 2, regardless of home equipment.

Figure 9: Level 2 Workplace Charging Profile



As noted above, DC fast charging would be additive to the profiles above. Navigant has not found any studies that provide an estimated fast DC charging profile, but has developed one based on historically observed traffic volumes, this is presented in Figure 10 below.

Figure 10: Estimated Average DC Fast Charging Profile (% of Daily Charging by Hour)



This profile is based on rural traffic volumes in Washington State.[22] Rural car, as opposed to urban car, volumes have been used as a proxy for the distribution of charging across the day since urban traffic patterns are dominated by short-haul commuting for which DC fast charging is unnecessary. Rural traffic, on the other hand, captures the longer-haul travel patterns which would be enabled (for BEVs) by DC fast charging.

2.3 Fuel Switching – Electricity to Gas

The average estimated unit impact of a switch of a residential space-heating and water-heating system from electricity to natural gas is presented in Figure 11, below. The underlying assumptions and approach to generating these unit impacts are presented below that.

Figure 11: Annual Energy Impact of Fuel Switching – Electricity to Gas

System Type	Annual Impact (kWh)
Space-Heating	-8,161
Water Heating	-3,848

[22] Chaparral Systems Corporation and Washington State Transportation Center, *Vehicle Volume Distributions by Classification*, July 1997. Figure 6.
http://depts.washington.edu/trac/bulkdisk/pdf/VVD_CLASS.pdf

Navigant has estimated the unit load impact of fuel-switching based on the following factors:

- The estimated unit energy consumption (UEC) of primary and secondary electric space-heating equipment, and of electric water heating equipment, for FortisBC territory;[23]
- The distribution of heat pump and non-heat pump equipment installations in FortisBC territory;[24] and,
- The average efficiency of space-heating equipment in British Columbia.[25]

Impacts have been calculated under the assumption that only customers with non-heat pump electric space-heating equipment would elect to switch space-heating fuel.

Hourly space-heating demand impacts are based on the assumption that annual energy impacts are distributed across the hours of the year proportionate to the average historical heating degree hours observed in those years. Water heating demand impacts are based on internal Navigant hourly water heating demand profiles derived from appliance logger data.

2.4 Fuel Switching – Gas to Electricity

The average estimated unit impact of a switch of a residential space-heating and water-heating system from natural gas to electricity is presented in Figure 12, below. The underlying assumptions and approach to generating these unit impacts are presented below that.

Figure 12: Annual Energy Impact of Fuel Switching – Gas to Electricity

System Type	Annual Impact (kWh)
Space-Heating	4,766
Water Heating	3,848

Navigant has estimated the unit load impact of fuel-switching based on the following factors:

- The total residential electricity consumption in B.C. for space-heating, from 2007 to 2012[26];
- The total stock of residential electric space- and water-heating systems in B.C., from 2011 to 2012;[27]

[23] FortisBC, *2012 Residential End-Use Study,* August 2014

[24] Personal communication with FortisBC staff, 2016-01-04.

[25] NRCan, *Comprehensive Energy Use Database*, Accessed December 2015. Residential Sector, B.C.,, Table 26 http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm

[26] NRCan, *Comprehensive Energy Use Database*, Accessed December 2015. Residential Sector, B.C., Table 8 (Space Heating) and Table 10 (Water Heating)
http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm

[27] Ibid, Table 21 (Space Heating) and Table 28 (Water Heating)

- The weighted (based on stock) average of existing gas space-heating efficiencies[28] and of electric system efficiencies[29] (82% and 177%[30], respectively); and,
- The estimated unit energy consumption (UEC) of primary and secondary electric space-heating equipment, and of electric water heating equipment, for FortisBC territory.[31]

Multiple years of energy use (2007 through 2012) were used to account for inter-annual variation due to the weather.

Space-heating impacts were estimated by comparing the estimated electric energy requirement for replacing natural gas equipment with electrically-fueled equipment at the provincial level (as per the NRCan data), scaled using the more locally-specific annual electricity space-heating UEC (as a proportion of the B.C.-wide NRCan-reported UEC) for FortisBC territory cited above.[32]

Since a considerable divergence exists between the FortisBC service territory electric water heating UEC, and the UEC implied for replacing natural gas-fueled equipment with electrically-fueled equipment based on the NRCan provincial data, Navigant believes that the FortisBC-specific water heating electricity UEC is the most reasonable figure to use to quantify the impact of a shift from gas water heating to electric water heating.

Hourly space-heating demand impacts are based on the assumption that annual energy impacts are distributed across the hours of the year proportionate to the average historical heating degree hours observed in those years. Water heating demand impacts are based on internal Navigant hourly water heating demand profiles derived from appliance logger data.

2.5 Consistent and Persistent Weather Changes due to Climate Change

The average estimated impact of consistent and persistent changes to local weather patterns as a result of global climate change is presented in Figure 13, with underlying assumptions immediately following. Due to the nature of this load driver, its impact is aggregated according to heating degree days (HDD) and cooling degree days (CDD)[33] instead of being in 'unit' form.

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[28] Ibid, Table 26

[29] The FortisBC staff team, in discussion with Navigant believes that it is reasonable to assume that approximately 85% of space-heating loads switched from natural gas to electricity will be satisfied by heat pumps, with the balance of space-heating loads satisfied by electric resistance heating.

[30] Heat pumps are listed in the NRCan data set as having a stock efficiency of 190%.

[31] FortisBC, *2012 Residential End-Use Study,* August 2014

[32] This approach was deemed preferable to using the FortisBC-specific natural gas UEC for two related reasons: firstly, the FortisBC natural gas territory is much larger than the FortisBC electric territory and encompasses a different set of climatic regions, and secondly there is no electric heating UEC available for the same territory which could be scaled using the FortisBC electricity territory UEC, as has been done with the B.C.-wide NRCan data.

[33] Heating and cooling degree days are a convention used to express average drybulb temperatures in such a way as to never show negative values. Typically, the number of heating degree days (Celsius-based) observed in a single day is calculated as $MAX\{18 - TEMP, 0\}$ and the number of cooling degree days observed in a single day is calculated as $MAX\{TEMP - 18{,}0\}$, where "TEMP" is the average daily drybulb temperature in degrees Celsius.

Figure 13. Change in Local Weather Load Impacts

Month	Change in HDD	Change in CDD	MWh for each HDD	MWh for each CDD	Energy Impact (MWh)
JAN	-42	0	292	0	-12,314
FEB	-35	0	292	0	-10,210
MAR	-25	0	183	0	-4,630
APR	-18	0	183	0	-3,333
MAY	-9	0	183	0	-1,560
JUN	-2	3	0	311	877
JUL	0	11	0	311	3,562
AUG	0	8	0	311	2,560
SEP	-71	0	141	0	-10,022
OCT	-23	0	141	0	-3,297
NOV	-33	0	292	0	-9,766
DEC	-43	0	292	0	-12,557
Total	**-302**	**22.5**			**-60,691**

Navigant estimated the load impacts of variations to local weather due to global climate change based on the following factors:

- The change in average monthly temperature forecast for Grant and Benton counties in Washington State for the 2030 – 2039 period (Navigant has assumed that these average temperature changes capture the forecast temperature change for the mid-point of the specified period - 2035);[34]
- The historical average monthly temperatures for Penticton, B.C.[35]
- The historical average monthly temperatures for Summerland, B.C.[36]
- The average HDD and CDD for the FortisBC area from 2006 through 2015 (weather values used for FortisBC's base forecast);[37] and,
- The impact of each HDD and CDD on FortisBC electricity consumption.[38]

The general approach for estimating the impact of climate change was to:

1. Transform the forecast average monthly temperature changes output by the USGS Climate Change Viewer for two counties in Washington State into HDD and CDD.

[34] USGS, *Regional Climate Change Viewer*, Accessed December, 2015. http://regclim.coas.oregonstate.edu/teaching-examples/teaching-examples/visualization/rccv/states-counties/index.html

Geographic zone used: Okanogan, WA, USA.

[35] Environment Canada. Monthly average temperature values reported for weather station Penticton A for the period 1980 through 1999.

[36] Environment Canada. Monthly average temperature values (aggregated from daily) reported for weather station Summerland CS for 2006 through 2015. Summerland is less than 13 km from Penticton (linear distance) and was selected because no monthly weather data were available for Penticton A after 2012.

[37] Provided by FortisBC

[38] Based on estimated weather sensitivity parameters provided by FBC.

2. Adapt the forecast 2035 HDD and CDD to FortisBC territory based on a comparison of historical weather.
3. Convert the adapted forecast changes in monthly HDD and CDD to daily HDD and CDD (see below for more details), and account for already apparent under-forecasting by the USGS Climate Viewer.
4. Apply the estimated future change in HDD and CDD to the FortisBC estimated weather parameters to obtain an annual energy load impact.

The two Washington State counties from which USGS Climate Change Viewer data were extracted were Grant and Benton counties. These were selected because of the degree to which temperatures reported for the winter (Grant) and summer (Benton) months during the period of 1980 through 1999 (the base period for the USGS Climate Change Viewer) were similar to those reported by Penticton. The average monthly temperatures reported for Penticton and for Grant/Benton (blended by season) are shown below, in Figure 14.

Figure 14: Average Temperature Comparison

Month	Average Temperature (Celsius) 1980 – 1999	
	Penticton	Grant/Benton Counties
JAN	-0.9	-1.0
FEB	0.9	0.5
MAR	4.9	5.3
APR	9.2	8.5
MAY	13.9	13.0
JUN	17.5	17.0
JUL	20.4	20.8
AUG	20.1	20.4
SEP	15.0	15.9
OCT	8.7	9.6
NOV	3.2	3.0
DEC	-1.2	-0.4

These temperatures were converted to HDD and CDD, as were the USGS forecast temperatures for 2035. The USGS forecast HDD and CDD for 2035 were adjusted for the FortisBC territory based on the ratio of the historical B.C. to WA HDD and CDD.

The USGS temperature changes use a base of the period 1980 through 1999, whereas the existing FortisBC forecast uses as a base the period from 2006 through 2015. The change in HDD and CDD from present to 2035 was then calculated by taking the difference between the forecast HDD and CDD for

2035 adapted for B.C. and the historical average HDD and CDD for B.C. based on monthly average temperatures.[39]

Some further adjustment of the USGS forecast temperature changes for July, August and September was required at this stage. Although the average difference between monthly B.C. temperatures from 1980 through 1999 and monthly B.C. temperatures from 2006 through 2015 was only -0.05, the average difference for July was over 2 degrees, and for August and September was approximately 1.3 degrees. These average increases in temperature are more than twice what the USGS Climate Change Viewer predicts for the comparable counties to occur by 2035. Using these summer numbers would therefore suggest that average summer temperatures are predicted to *fall* between the present and 2035.

Navigant therefore assumed that for these three months, the average monthly temperature change would be 1.5 times what it had been from the USGS base period (1980 – 1999) to the FortisBC forecast base period (2006 – 2015).

The penultimate step required was to calculate the average seasonal percentage impact on HDD and CDD by 2035, and apply these percentages to the currently used FortisBC base period HDD and CDD. A more direct application would be inappropriate due to the manner in which the two sets of HDD and CDD are calculated. HDD and CDD used for the FortisBC forecast are calculated on a daily basis, comparing average daily temperature to the 18 degree threshold, with monthly values simply being the sum of the relevant degree days across the month. The USGS reports only average monthly temperatures. The output degree days differ across both approaches sufficiently, that a direct comparison is inappropriate, hence the approach used by Navigant and outlined above.[40]

Finally, the change in HDD and CDD are applied to the FortisBC supplied model parameters that deliver the energy impacts.

The temperature changes used for this driver represent averages over time. As such, while they are suitable for estimating the impact of consistent and persistent weather changes as a result of climate change on total energy consumption they are not appropriate for the purpose of calculating peak demand impacts. The scientific consensus generally holds that climate change significantly increases the volatility of weather, and may, in certain circumstances result in sudden sharp drops in temperature (e.g., the "polar vortex" that can affect central and eastern North America) that can substantially *increase* loads at times of winter peak demand. These sudden shifts are a result of the complex interactions between many different factors, and some evidence exists that Arctic warming could result in abrupt shifts in weather in mid-latitudes, the direction of which is highly uncertain.[41]

Due to the very high level of uncertainty associated with the potential for sudden short-term shifts in temperature and extreme weather events, Navigant, in consultation with FortisBC believes that it would

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[39] The FBC-provided historical HDD and CDD could not be used at this stage because of an important difference in the manner that they were calculated as detail in the text below this note.

[40] The most obvious example of the difference may be seen in considering "shoulder" months. Using monthly average temperatures, a given month may only have either HDD or CDD. Under the daily approach (impossible with the USGS data) a month may have both positive HDD and CDD.

[41] See for example: Francis, J. and Vavrus, S. *Evidence Linking Arctic Amplification to Extreme Weather at Mid-Latitudes*, Geophysical Research Letters Vol 39 Issue 6, March 2012
http://onlinelibrary.wiley.com/doi/10.1029/2012GL051000/abstract

be inappropriate at this time to quantify the peak demand impacts of sudden weather events as a result of consistent and persistent changes in local weather patterns.

2.6 Large Load Sector Transformation

FortisBC asked Navigant to explore the possibility of large load sector transformation – the phenomenon of the growth of large loads in FortisBC territory unrelated to traditional large load customer industries (pulp and paper, manufacturing, etc.)

In consultation with FortisBC, it was determined that the most appropriate way to derive unit load impacts for this driver is to base them on the average loads of existing customers. Based on a review of FortisBC's large customers, Navigant has identified four segments matching the criteria outlined above:

- Breweries
- Community/Trades Colleges
- Data Centres
- Hospitals

Load scenario impacts will be based on a rounded average historically observed consumption level across all customers within each segment, scaled by a factor deemed appropriate to the scenario. For example, in a scenario in which there is expected to be substantial large load sector transformation the assumption may be of the connection of a data centre customer with an annual consumption level that is ten times the average of the historical annual consumption of all data centres in its territory. In this case the factor applied to the unit load impact is ten.

All of the segments outlined above contain very few customers. To ensure the privacy of these customers' data the unit load impacted presented here is just the average across all customers in all segments (after individual customers' consumption levels have been rounded to the nearest 1,000 MWh).

The average unit load impact is 8,800 MWh/year.

2.7 The Internet of Things

The average estimated unit impact from residential adoption of the "internet of things" (IoT) is shown, by month, below in Figure 15. These impacts are equivalent to a 10% decrease in current average residential consumption for FortisBC residential customers from 2011 through 2014.[42] The details of how the IoT is defined, and how the impacts were estimated may be found below.

[42] Provided by FortisBC

Figure 15: IoT Unit Impact by Month

Month	Energy Savings (kWh)
January	142
February	115
March	116
April	92
May	80
June	76
July	96
August	93
September	70
October	87
November	115
December	145
Total	**1,228**

For the purposes of this scenario analysis, Navigant has defined the IoT load driver as a combination of three (sometimes overlapping) elements:

(1) **Connected Devices**. Devices whose consumption and performance may be monitored by customers in real-time or near-real-time, that could interact with other connected devices in the home to optimize performance or could allow remote control by customers. This category includes Smart Thermostats, web-connected appliances and consumer electronics.

(2) **Customer Feedback.** Ongoing feedback regarding household energy use to customers, including granular social-benchmarking, and potentially integration with social media platforms. This category includes home energy reports (physical paper or as a software application) and real-time monitoring capabilities, either delivered by a stand-alone device, or as a feature of some other device (e.g., a Smart Thermostat).

(3) **Control Systems.** Automated or semi-automated home energy management systems (HEMs) that adjust household energy end-uses to reduce consumption without intruding on customer comfort. This category includes smart motion sensors, smart phone-enabled geo-fencing, and devices capable of “learning” behaviour patterns and customer preferences (e.g., Nest thermostats).

Although examples of each of these elements exist in some form or another today, many of the potential components of these elements is some distance from market maturity. As such, Navigant has been unable to locate any forward-looking meta-studies of conservation and demand response programs that incorporate all three elements.

To estimate the average unit impact of the internet of things, therefore, Navigant has synthesized the results of a number of studies that each touch on at least one of these elements to estimate an approximate savings impact of a single bundle of all elements. Based on the findings reported for each of the elements of the IoT (connected devices, customer feedback and control systems), and assuming that in the future the effectiveness of IoT-like technologies will improve, and additional devices (particularly appliance automation devices) will come to market, it seems reasonable to assume an average annual energy savings of 10% per integrated home. This savings factor was then applied to historical monthly consumption figures for FortisBC to generate the estimated impacts shown above in Figure 15.

Most of the studies consulted were evaluations of existing programs, and not inherently forward-looking. The one study of perhaps the most interest of this group is also the most recent, a study by the Northeast Energy Efficiency Partnerships (NEEP) to quantify the potential for home energy management systems.[43] This study develops a potential range of the energy-efficiency impact of control-based home energy management systems (HEMS) by residential end-uses.[44] This study estimates that such a control based system could reduce space-heating energy consumption by as much as 13%, water heating by 15%, appliances by 6%, plug loads by 5% and lighting by 3%.

The studies consulted by Navigant for developing this measure, along with the estimated savings they report, and the types of elements identified above that they cover are summarized in Figure 16 below.

Figure 16: Percent Energy Savings from Selected Internet of Things Studies

Source	Connected Devices	Customer Feedback	Control Systems	% Energy Savings
ACEEE, 2014		✓	✓	0% - 7%
Alahmad, A., et al., 2012	✓	✓		0%
Cadmus, 2013	✓	✓	✓	8%
CEATI International, Inc., 2008 (Nfld)		✓		18%
CEATI International, Inc., 2008 (B.C.)		✓		3%
Deremer, K., 2007	✓	✓		13%
Henryson, J., et al. 2000		✓		2-12%
Hydro One Networks., 2006	✓	✓		7%
Nexant, 2014	✓	✓		0%
NEEP, 2015	✓	✓	✓	1% - >20%*
US Department of Energy, 2010	✓	✓	✓	1-10%
Wilhite, H., & Ling, R., 1999b		✓		8%
Wilhite, H., & Ling, R., 1999a	✓	✓		6-8%

*More details in text.

[43] NEEP, *Opportunities for Home Energy Management Systems in Advancing Residential Energy Efficiency Programs*, August 2015 http://www.neep.org/file/3434/download?token=LbSa2pM2

[44] See Table 11 of the referenced report.

2.8 Combined Heat and Power

The unit impact factor of large commercial and industrial (C&I) electricity customers investing in combined heat and power (CHP) generating capacity is estimated to be approximately **1,000 MWh per month**, on average, per large C&I customer installing cogeneration facilities that would provide the capability of generating electricity.

Navigant estimated the unit impact factor for CHP based on individual large C&I annual electricity gas and electricity consumption provided by FortisBC, as well as the following assumptions:

- Customer gas consumption serves primarily thermal loads;
- 90% of the thermal output produced by the CHP facility is useable in the central system;
- Customer thermal loads parallels electricity loads (i.e., peak thermal demand is coincident with peak electricity demand);
- Customers thermal processes operate on average 252 hours per month (operations run 12 hours per day, five days per week);
- Only existing FBC customers with average monthly electricity demand above 2 MW and monthly gas consumption above 1,000 GJ are likely to invest in CHP (there are currently 10 FortisBC customers that meet these criteria and do no already possess on-site cogeneration);
- Regardless of thermal demand, a C&I customer investing in CHP will not invest in a plant with a capacity more than five times its average monthly peak demand.
- A customer's CHP technology type is based on its thermal demand;[45] and,
- A power-to-heat ratio that varies as a function of the customer's CHP technology. [46]

The average monthly estimated potential CHP electricity generation varies between approximately 250 MWh and more than 1,400 MWh per month, with an average of 1,078 MWh.

[45] Customers with an estimated peak gas demand greater than or equal to 18 GJ are assumed to invest in a 50 MW combustion turbine. Customers with an estimated peak gas demand between 5 and 18 GJ are assumed to invest in a 5 MW reciprocating engine. Customers with an estimated peak gas demand below 5 GJ are assumed to invest in a 1 MW reciprocating engine.

[46] Brattle Group, 2014. *Exploring Natural Gas and Renewables in ERCOT, PART III: The Role of Demand Response, Energy Efficiency, and Combined Heat & Power.*

3. LOAD SCENARIOS

This chapter describes the five scenarios modeled as part of this analysis, outlines the load driver assumptions (e.g., penetration level, turnover, etc.) underlying each scenario, and presents the estimated potential impact of each scenario, relative to the reference forecast.

This chapter is divided into three sections:

- **Scenario Descriptions.** This section describes the five scenarios modeled and outlines the motivation driving the combinations of load drivers included in each scenario.
- **Scenario Assumptions.** This section describes the assumptions applied to each scenario, including both "global" assumptions (e.g., stock turn-over rate) and scenario-specific assumptions (final measure uptake or penetration).
- **Scenario Impacts.** This section provides the estimated impact of the five scenarios. Additional contextual supporting details (e.g., number of EVs vs number of combustion vehicles) are provided for the two "boundary" scenarios (for more details see below).

3.1 Scenario Descriptions

Each of the five scenarios modeled for this analysis is comprised of a different combination of load drivers. Although an infinite number of potential combinations of load drivers into scenarios is possible, the five scenarios selected for this analysis were chosen based on two guiding principles:

1. **The analysis should include "boundary" scenarios.** Boundary scenarios are those scenarios that define major deviations from existing empirical forecasts driven by the cumulative effects of emerging technologies and structural shifts that overwhelmingly affect system load in one direction or the other.
2. **The analysis should include "offsetting" scenarios.** In addition to modeling scenarios where all load drivers push system load in the same direction, it is important to consider scenarios where off-setting effects can exist. This is helpful for appreciating the potential dynamics of how load drivers may interact with one another.

The first guiding principle led to the development of two boundary scenarios, one that examined combinations of load drivers that all increased (or decreased) load, Scenario 1, and Scenario 5. The second guiding principle led to three offsetting scenarios that examined combinations of load drivers that both increase and decrease load, Scenarios 2, 3, and 4.

To better understand how load driver combinations were selected for each scenario, the principles above should be compared to the directional impacts characterized for each load driver, as presented in Figure 17 below. This figure also includes the short-form description of each load driver used further below in the graphical representations of each scenario.

Figure 17: Load Driver Directional Impacts

Load Driver	Short Form	Effect on System Load (+/-)
Residential Rooftop Solar (PV) and Integrated PV Storage Systems (IPSS)	**PV**	↓
Electric Vehicles	**EV**	↑
Fuel Switching – Electricity to Gas	**FS – E2G**	↓
Fuel Switching – Gas to Electricity	**FS – G2E**	↑
Consistent and Persistent Weather Changes due to Climate Change	**Weather**	↓
Large Load Sector Transformation	**LLST**	↑
The Internet of Things	**IoT**	↓
Combined Heat and Power	**CHP**	↓

The impacts of five scenarios were estimated. Graphical representations of each of the five scenarios, including the load drivers and their directional impact are shown below in Figure 18 through Figure 22. The scenarios are presented in order from that anticipated to most increase system loads, to that anticipated to most *decrease* system loads.

Figure 18, below, provides a graphic illustration of Scenario 1. This is the first of the boundary scenarios and is designed to quantify the potential energy and demand impacts on the FortisBC system if there is substantial growth in the penetration of the three load drivers that *increase* load.

Figure 18: Scenario 1 – Boundary Scenario (Load Increases)

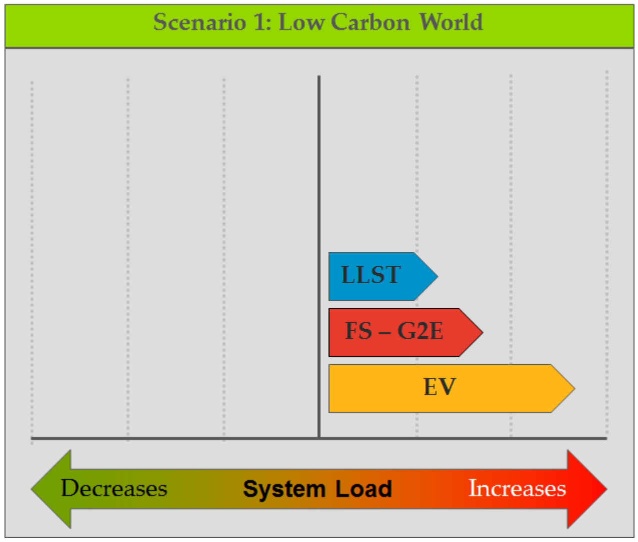


Figure 19, provides a graphic illustration of Scenario 2. This is one of the offsetting scenarios and is designed to quantify the potential energy and demand impacts on the FortisBC system if there is some growth in the penetration of load drivers that *increase* load (EVs and gas to electric fuel-switching) accompanied by some growth in the penetration of a load driver that decreases load (weather changes).

Figure 19: Scenario 2 – Offsetting Scenario

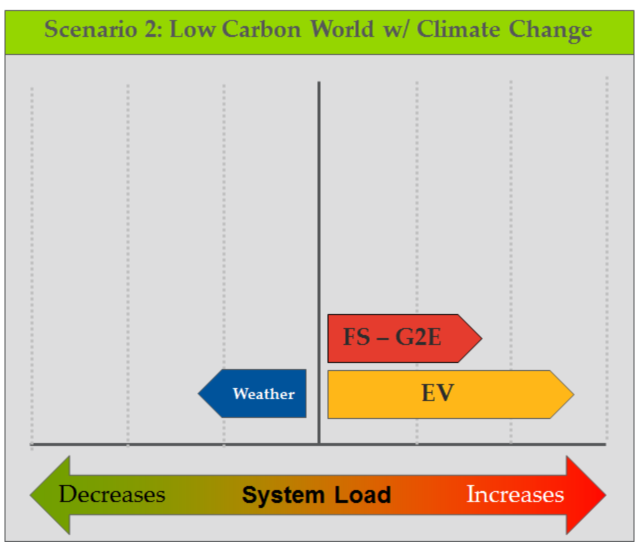


Figure 20, provides a graphic illustration of Scenario 3. This is one of the offsetting scenarios and is designed to quantify the potential energy and demand impacts on the FortisBC system if there is some growth in the penetration of a load driver that *increases* load (EVs) accompanied by some growth in the penetration of load drivers that decrease load (weather changes, the internet of things and residential solar PV).

Figure 20: Scenario 3 – Offsetting Scenario

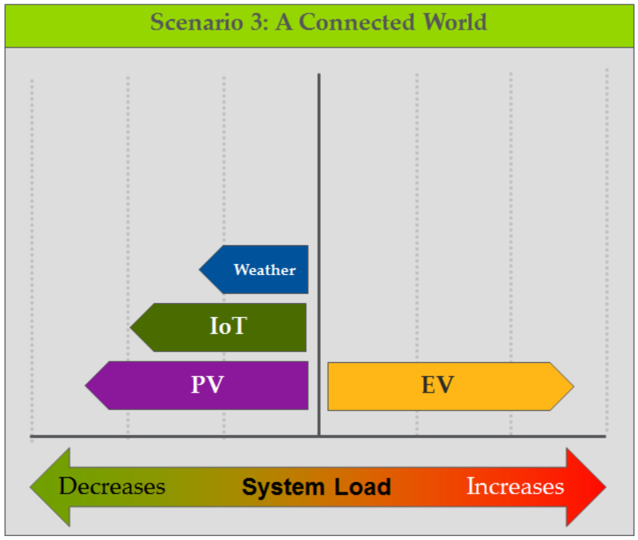


Figure 21, provides a graphic illustration of Scenario 4. This is one of the offsetting scenarios and is designed to quantify the potential energy and demand impacts on the FortisBC system if there is some growth in the penetration of load drivers that *increase* load (EVs and LLST) accompanied by some growth in the penetration of load drivers that decrease load (weather changes, CHP, the internet of things and residential solar PV).

Figure 21: Scenario 4 – Offsetting Scenario

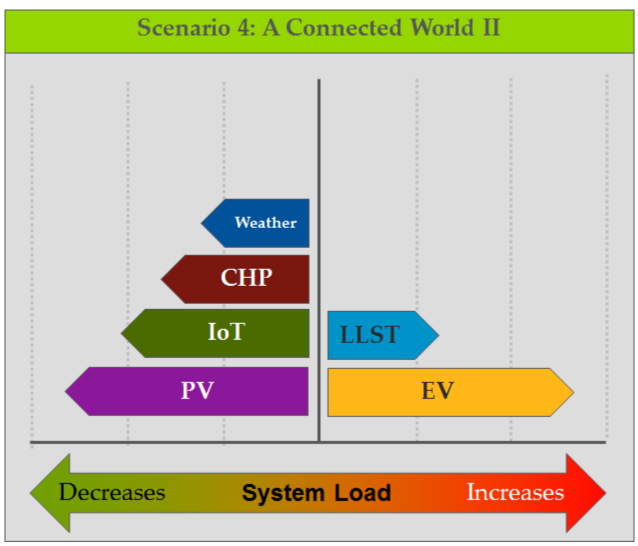
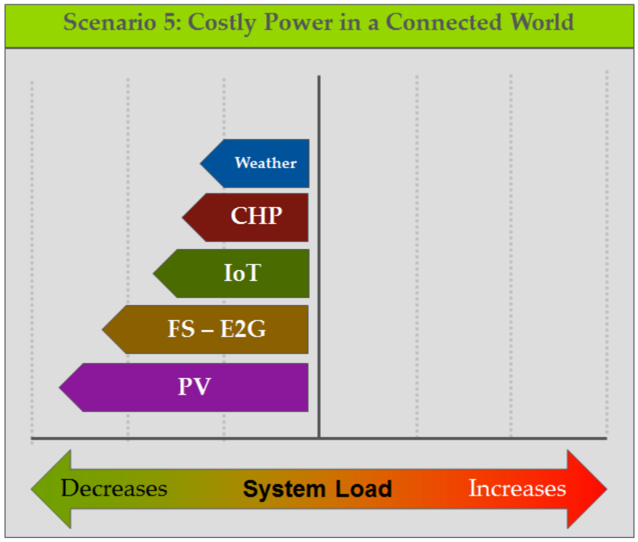


Figure 22, below, provides a graphic illustration of Scenario 5. This is the second of the boundary scenarios and is designed to quantify the potential energy and demand impacts on the FortisBC system if there is substantial growth in the penetration of the five load drivers that *decrease* load.

Figure 22: Scenario 5 – Boundary Scenario (Load Decreases)



3.2 Scenario Assumptions

This section of the Scenarios chapter outlines the major assumptions driving the scenario impacts. This section is sub-divided into eight sub-sections, one for each load driver. Each sub-section outlines the "global" assumptions for the given load driver, followed by the scenario-specific penetrations/uptake assumptions for that load driver.

The assumed penetration/uptake rates for each load driver in each scenario (e.g., the assumed proportion of all personal vehicles sold by 2035 that are EVs for each scenario) were selected by Navigant in close collaboration with FortisBC staff over a period of several months. These were discussed with FortisBC's standard group of electricity sector stakeholders in a workshop on April 27, 2016. The assumed values used for this analysis are not a forecast or a projection. Values were selected beginning from the boundary scenarios. For each boundary scenario, a 2035 level of penetration/uptake was assumed such that the analytic purpose of testing extremes was served but also such that the consensus of FortisBC and Navigant staff was that the selected penetration was believed to be within the realm of possibility. The penetration/uptake values selected for the off-setting values were derived by Navigant by scaling down the boundary scenario extreme values.

In most cases, the assumed penetration or uptake of load drivers for each scenario is presented as a value "by 2035" (the end of the scenario period). The escalation from the status quo to the final assumed level of penetration is modeled in each case using an S-curve to mimic the generally understood network effects of emerging technologies adoption.

3.2.1 Residential Rooftop Solar (PV) and Integrated PV Storage Systems (IPSS)

For the residential rooftop PV, the major global assumptions that affect this load driver in all scenarios are:

- Residential rooftop solar can be deployed only on the roofs of single-family detached (SFD) homes. Approximately 64% of residential dwellings in FortisBC territory are estimated to fall into this category.[47]
- IPSS availability and deployment is assumed to be a function of residential rooftop PV deployment. It is assumed that once a third of all residential SFDs are equipped with rooftop solar PV, half of those PV installations will be IPSS (i.e., supported by electricity storage).

The assumed proportion of homes with rooftop solar PV varies by scenario. For Scenarios 1 and 2, no incremental (to the reference case demand projection) residential rooftop solar is assumed to be deployed. In the remaining scenarios:

- For Scenario 3, it is assumed that 15% of all SFDs have installed rooftop PV by 2035.
- For Scenario 4, it is assumed that 25% of all SFDs have installed rooftop PV by 2035.
- For Scenario 5, it is assumed that 33% of all SFDs have installed rooftop PV by 2035.

3.2.2 Electric Vehicles

For EVs, the major global assumptions that affect this load driver in all scenarios are:

- The distribution of home charging type (i.e., Level 1 or Level 2) is assumed to be a function of EV penetration. It is assumed that by the time half of all vehicles purchased are EVs, then three quarters of all home charging will be delivered using a Level 2 charger.
- It is assumed that there is an average of 1.4 vehicles per residential customer in the FortisBC service territory. This is derived from the assumption that there are 1.4 vehicles per household in B.C.[48]
- Personal vehicle stock is assumed to turn-over at a rate of 7.1% per year. This is based on:
  - Estimated new motor vehicle sales in B.C. for 2014[49]
  - The total number of BC road vehicle registrations in 2014[50]
- BEVs continue to be sold in same proportion (relative to PHEVs) as 2015: two-thirds BEVs, remainder PHEVs.[51]

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[47] Calculated based on provincial total number of households (1,764,635) and the total number of single detached homes (842,120), as drawn from the StatCan's 2011 Census data, table 98-313-XCB.

[48] Natural Resources Canada Office of Energy Efficiency, *Canadian Vehicle Survey: 2009 Summary Report*, 2010

http://oee.nrcan.gc.ca/publications/statistics/cvs09/pdf/cvs09.pdf

See Figure 10

[49] Statistics Canada, *CANSIM Table 079-0003 New motor vehicle sales by province (British Columbia)*, accessed February 2016

http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/trade36j-eng.htm

[50] Statistics Canada, *CANSIM Table 405-0004 Motor vehicle registrations, by province and territory,* accessed February 2016

http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/trade14c-eng.htm

[51] Klippenstein, Matthew*, Canadian Plug-In Electric Vehicle Sales*, GreenCarReports, accessed February 2016

https://docs.google.com/spreadsheets/d/1dLFJwZVdvNLRpmZqPznlzz6PB9eHMe5b-bai_ddRsNg/edit#gid=25

NB: vehicle sales are listed by vehicle make and model, not by BEV/PHEV classification. Vehicles were classed as BEVs, PHEV10s, PHEV20s and PHEV40s by Navigant staff.

- PHEV10 and PHEV20 sales as a percentage of all EVs sold are assume to decline steadily over time and be replaced by PHEV40 sales. No new PHEV10 sales are assumed after 2020 and no new PHEV20 sales are assumed after 2025.

The assumed proportion of new cars sold each year (incremental to the reference case) that are EVs varies by scenario. The percentage of new vehicle sales that are assumed to be EVs by 2035 for each scenario are:

- Scenario 1: 50%
- Scenario 2: 35%
- Scenario 3: 20%
- Scenario 4: 20%
- Scenario 5: 0%

3.2.3 Fuel Switching – Electricity to Gas

For the residential space- and water-heating fuel switching from electricity to gas, the major global assumptions that affect this load driver in all scenarios are:

- Approximately a third (32%) of residential customers in FortisBC territory use either electric baseboards or an electric furnace[52] as their primary space-heating equipment.[53]
- Approximately half (51.3%) of residential customers in FortisBC territory use electricity for water heating.[54]
- A fifth of residential customers with electric space- and water- heat *cannot* switch to natural gas (e.g., due to distance of premise from gas mains).[55]
- Water heaters are assumed to have an average expected useful life of 13 years (~8% stock turnover per year), and electric space-heating systems are assumed have an average expected useful life of 20 years (5% stock turnover per year).[56] Fuel switching is assumed to be driven exclusively by end-of-life equipment replacement.

No electricity to gas fuel switching incremental to that included in the reference case is assumed to occur in Scenarios 1 through 4. For Scenario 5, it is assumed that by 2035, **half** of all the equipment purchasing decisions being made by customers *that would otherwise have purchased an electrically-fueled system in*

[52] The same source indicates that 7% of residential customers in FortisBC territory use heat pumps. It is assumed that no fuel switching takes place within this sub-group.

[53] Correspondence with FortisBC staff, citing 2012 residential end-use study (REUS), 2016-01-05.

[54] FortisBC, *2012 Residential End-Use Study,* August 2014

Table 97

[55] As per correspondence from FortisBC 2016-02-11, approximately 24% of FortisBC residential customers premises are more than 50m from a gas main. Navigant has assumed that future residential development will be denser, thus allowing slightly more customers access to gas.

[56] As per the B.C. Utilities Conservation Potential Review.

that year and for whom fuel switching is possible (see the assumed restriction above) result in the customer fuel switching from electricity to gas.

3.2.4 Fuel Switching – Gas to Electricity

For the residential space- and water-heating fuel switching from gas to electricity, the major global assumptions that affect this load driver in all scenarios are:

- Approximately half (50.4%) of residential customers in FortisBC territory use natural gas for space heating.[57]
- Approximately half (46.8%) of residential customers in FortisBC territory use natural gas for water heating.[58]
- Water heaters are assumed to have an average expected useful life of 13 years (~8% stock turnover per year), and electric space-heating systems are assumed have an average expected useful life of 20 years (5% stock turnover per year).[59] Fuel switching is assumed to be driven exclusively by end-of-life equipment replacement.

No gas to electricity fuel switching incremental to that included in the reference case is assumed to occur in Scenarios 3 through 5. For Scenario 1, it is assumed that by 2035 half of all the equipment purchasing decisions being made by customers *that would otherwise have purchased a gas-fueled system in that year* result in the customer fuel switching from gas to electricity. For Scenario 2, it is assumed that a quarter of applicable customer decisions result in fuel switching.

3.2.5 Consistent and Persistent Weather Changes due to Climate Change

For the weather load driver, it is assumed that, in scenarios in which the load driver appears, the average temperature change is linear, scaling from current average temperatures out to the estimated average temperature by 2035. The values applied and assumptions underlying them are detailed extensively in Section 2.5. Weather changes are applied to Scenarios 2 through 5.

3.2.6 Large Load Sector Transformation

For the LLST load driver, assumptions have been made regarding when specific types of large customers come online. In the scenario-specific descriptions provided below, the “size” nomenclature refers to average annual energy consumption.

Scenario-specific “penetration” of this load driver is summarized immediately below.

Scenario 1:

- Breweries:

[57] FortisBC, *2012 Residential End-Use Study,* August 2014

Table 97

[58] FortisBC, *2012 Residential End-Use Study,* August 2014

Table 97

[59] As per the B.C. Utilities Conservation Potential Review.

    - One that's a quarter the size of the average existing brewery begins operation in 2016
    - One that's a quarter the size of the average existing brewery begins operation in 2020
- Colleges:
    - One that's the same size as the average existing college begins operation in 2020
    - One that's the same size as the average existing college begins operation in 2030
- Data Centres:
    - One that's ten times the size as the average existing data centre begins operation in 2025.
- Hospital:
    - One that's the same size as the average existing hospital begins operation in 2030.

Scenario 2, 3, and 5: No large load sector transformation.

Scenario 4:

- Breweries:
    - One that's a quarter the size of the average existing brewery begins operation in 2020
    - One that's a quarter the size of the average existing brewery begins operation in 2025
- Colleges:
    - One that's the same size as the average existing college begins operation in 2025.
- Data Centres:
    - One that's five times the size as the average existing data centre begins operation in 2025.
- Hospital:
    - One that's the same size as the average existing hospital begins operation in 2030.

3.2.7 The Internet of Things

For the IoT load driver, assumptions have been made regarding what proportion of residential customers in FortisBC territory have access to a full-feature IoT deployment in their home by 2035. In this case, it is assumed that the savings estimated for the unit load impacts (see Section 2.7, above) apply to residential customers with a full-feature IoT installation.

For example, if 25% of residential customers have access to a full-feature IoT installation, in a given year, it is assumed that total savings will be 2.5% (10% savings times 25% penetration) of average residential electricity consumption between 2011 and 2014 (see Section 2.7, above for more details).

The assumed percentage of homes that have full-featured IoT access by 2035 is:

- Scenario 1: 0%
- Scenario 2: 0%

- Scenario 3: 10%
- Scenario 4: 25%
- Scenario 5: 40%

3.2.8 Combined Heat and Power

Navigant has assumed that CHP capacity will come online in blocks at three year intervals. Navigant has assumed that 20% of total assumed CHP comes online in 2019, with an incremental 20% coming online every three years until 2031, when all CHP is assumed to be online.

No CHP incremental to that which exists in the reference case has been assumed for Scenarios 1 through 3. For Scenario 4, five large industrial customers eligible to implement CHP are assumed to do so. For scenario 5, 10 large industrial customers eligible to implement CHP are assumed to do so.

3.3 Scenario Impacts

This section of Chapter 3 summarizes the estimated impacts estimated as part of this analysis. It is divided into three sub-sections:

- Overall impacts. This sub-section summarizes the overall system energy and demand impacts for each of the five scenarios.
- Scenario 1 – Detailed Impacts. This sub-section provides additional detail surrounding the impacts for Scenario 1 (increasing loads). Graphs illustrating some load driver deployment are provided to illustrate scenario evolution, and annual impacts by load driver are provided.
- Scenario 5 – Detailed Impacts. This sub-section provides additional detail surrounding the impacts for Scenario 5 (decreasing loads). Graphs illustrating some load driver deployment are provided to illustrate scenario evolution, and annual impacts by load driver are provided.

Additional scenario details (i.e., impact by driver and year) may be found in Appendix B, in a separate Excel spreadsheet.

3.3.1 Overall impacts

Figure 23, below, shows the overall energy consumption impact of each scenario relative to the reference case, by year. As may be seen from this graph, Scenario 1 results in an increase in energy consumption of over 800 GWh per year by 2035 compared to the reference scenario, whereas Scenario 5 results in a decrease of nearly 900 GWh per year by 2035 compared to the reference case. The off-setting scenarios all fall somewhere in the middle, with Scenario 3 having the least impact. Scenario 3 results in a decrease of only approximately 40 GWh per year by 2035.

Figure 23: Energy Impacts by Scenario and Year

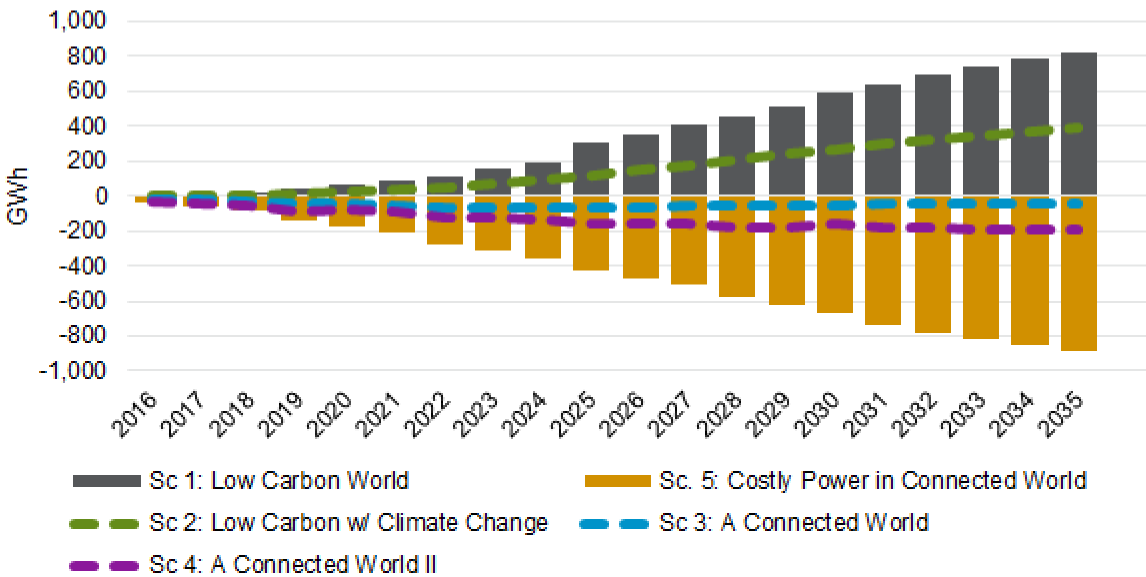
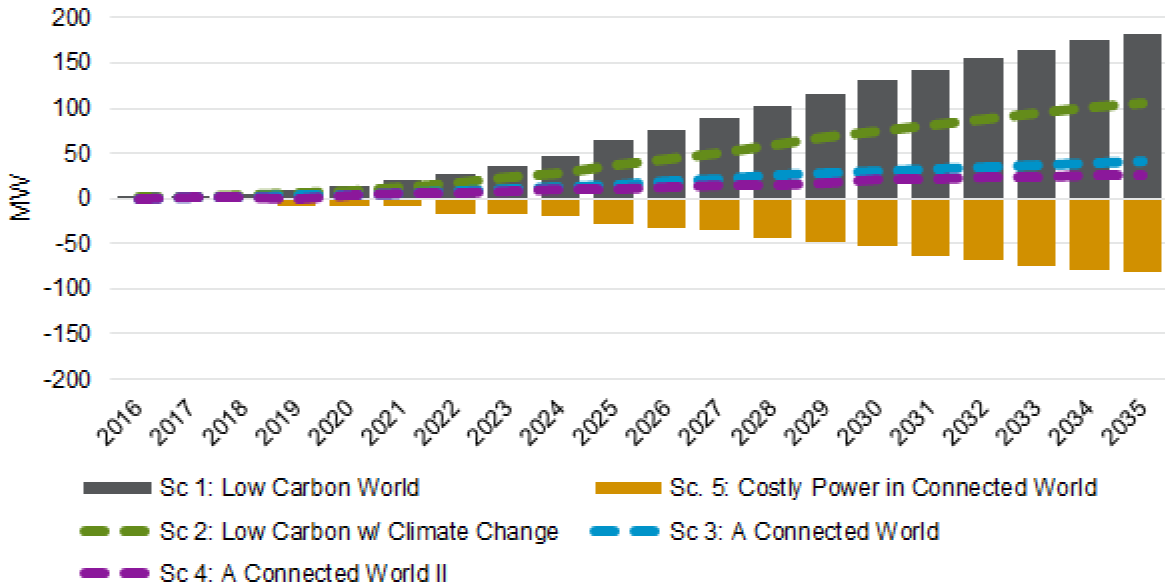


Figure 24, below, shows the overall peak demand impact of each scenario on the reference case, by year. As may be seen from this graph, Scenario 1 results in an increase in demand of nearly 200 MW by 2035 compared to the reference case, whereas Scenario 5 results in a decrease of approximately 80 MW by 2035 compared to the reference case.

As with energy consumption, the off-setting scenario impacts fall in the middle between these two extremes. The most noteworthy feature of a comparison of the energy and demand impacts by scenario, is that Scenario 3 and 4 are directionally different. That is, Scenarios 3 and 4 both indicate a decrease in energy consumption but an *increase* in demand during peak evenings.

Figure 24: Demand Impacts (HE18) by Scenario and Year



This counter-intuitive effect is due to the combination of the two most impactful load drivers; PV and EVs. Increasing installations of PVs more than off-set the incremental energy offset by the EVs, but the timing of the delivery of that electricity is constrained by the hours of sunlight, the capacity of the energy storage system (assumed as part of the IPSS installations) and average residential demand in the early evening hours. Very little, if any, electricity is being provided by rooftop PV between 5pm and 6pm, but it is just at this time that the majority of the electricity required to recharge EVs is being demanded.

3.3.2 Scenario 1 – Detailed Impacts

Scenario 1 is one of the two boundary scenarios, and captures the estimated impacts of three load drivers, fuel switching, LLST and EVs that increase load. This sub-section of Section 3.3 provides some additional context for the estimated scenario impacts in terms of the absolute penetration of some load drivers. This sub-section also provides a breakdown of annual impacts by load driver.

Figure 25 shows the total number of personal vehicles estimated to be in circulation in each year of the period of analysis. This chart shows the total number of incremental PHEVs and BEVs in this scenario, as well as the balance of all other vehicles assumed for each period, as determined by the input assumptions outlined above. Note that the assumed uptake of 50% of vehicle purchases being EVs by 2035 results in approximately 40% of vehicles in circulation by 2035 being EVs.

Figure 25: Light-Duty Passenger Vehicles by Year

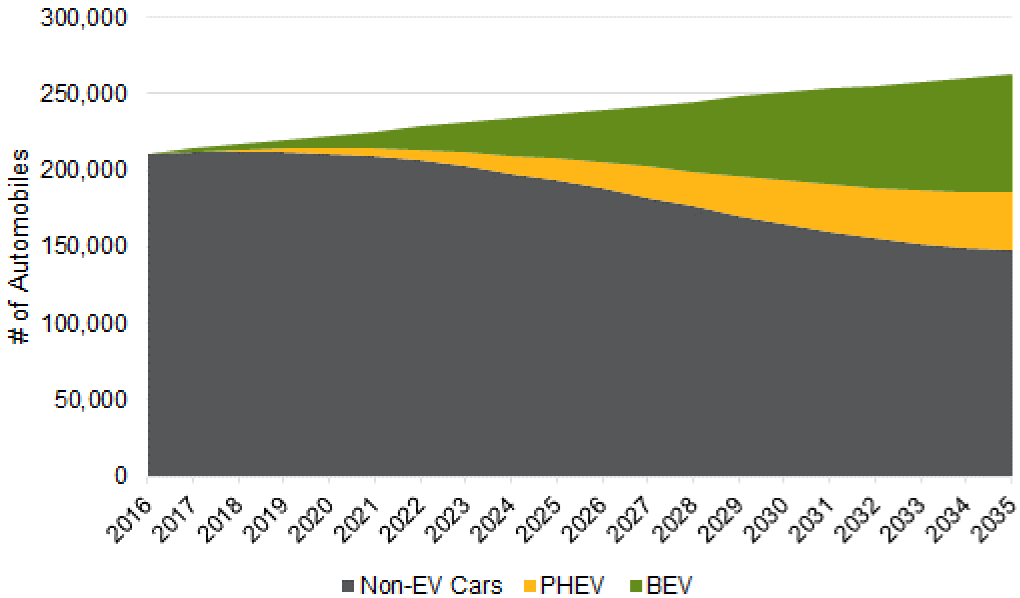


Figure 26, below shows the total energy required for charging EVs by 2035, under the assumptions outlined above. Given the range of most recent generation EVs, and the expectation that most consumers will use them principally as commuter vehicles, a very high proportion of energy used by these vehicles will be consumed by home charging. Under the assumptions outline above in the Load Drivers chapter, and assuming no change in FortisBC's rate structure, most of that energy consumption will occur in the hours immediately follow the end of the work day at 5pm.

Figure 26: Energy Required for EV Charging in 2035 – by Charging Type

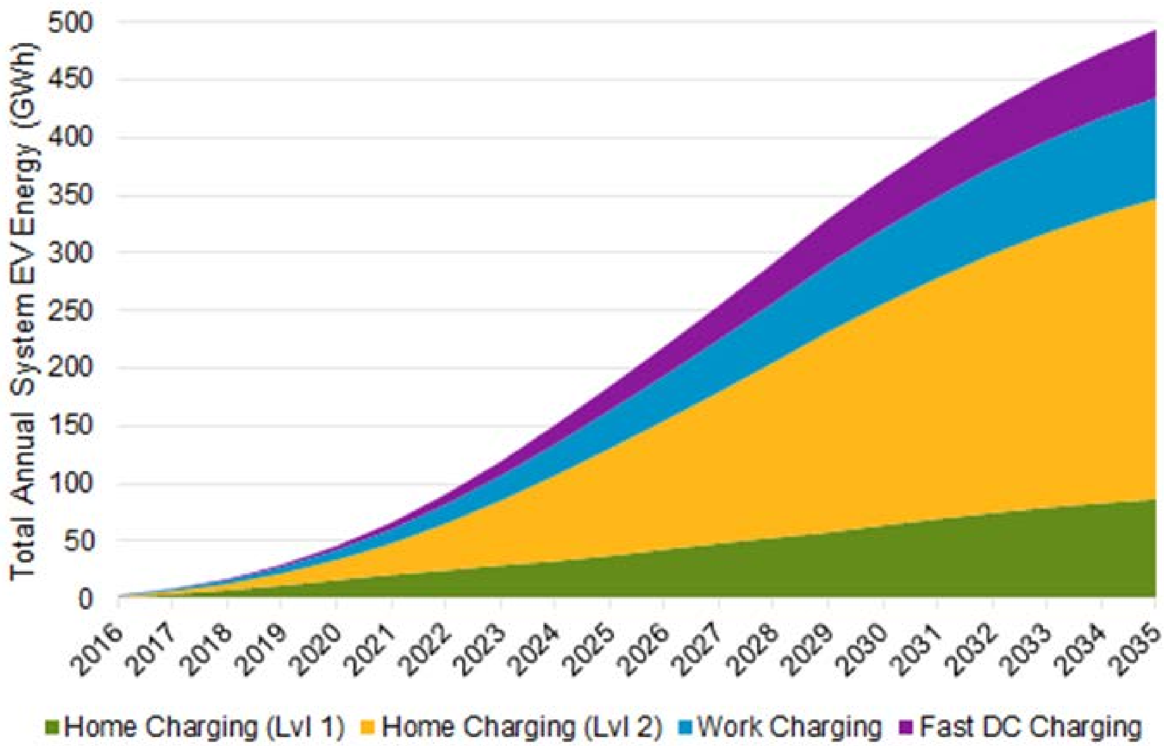


Figure 27 shows the water heating fuel share over time of customers by year. This chart shows customers already assumed to have electric water heating (the existing fuel share is assumed to apply going forward to all new FortisBC customers) as well as customers switching from natural gas to electricity as their water heating fuel.

Figure 27: Consumers by Water Heating Fuel Type

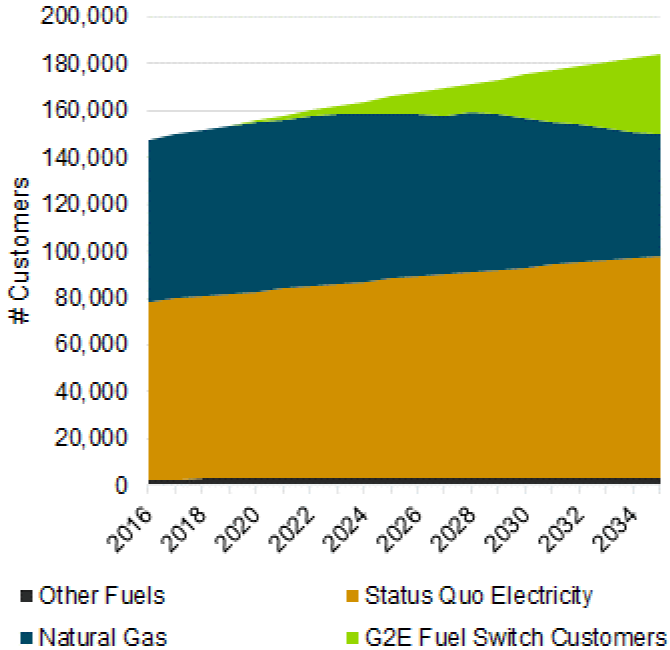


Figure 28, below, is very similar to Figure 27, but for space-heating instead of water heating. In both cases, the total stock does not shift as quickly as for personal vehicles due to the longer expected useful life of water heaters and space-heating equipment, and also due to the fact that opportunities for incremental fuel switching are somewhat limited due to the substantial existing penetration of electricity as a water- and space-heating fuel.

Figure 28: Consumers by Space-Heating Fuel Type

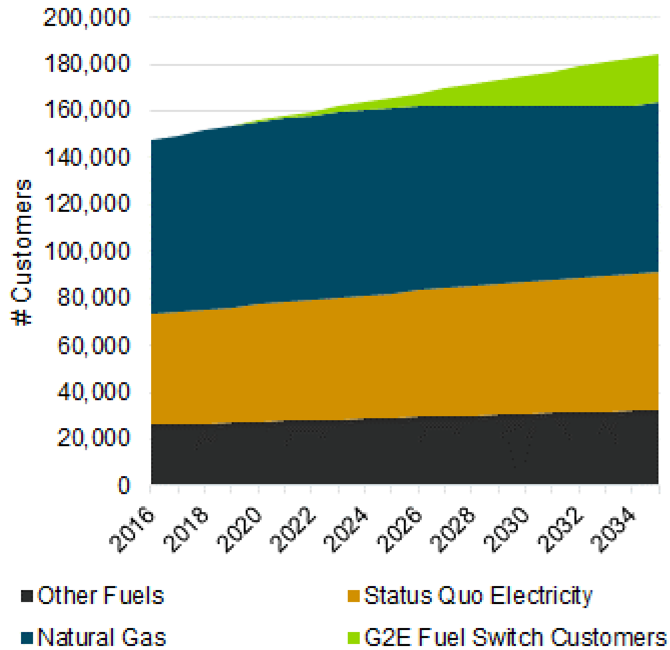


Figure 29, below summarizes the energy impact of Scenario 1 in each year of the period of analysis, split by load driver. As may clearly be seen in this figure, the majority of the energy impact by 2035 derives from the impact of electric vehicles. The impact of the LLST load driver, though substantial in absolute terms, is not really material relative to the reference scenario. The 2035 LLST load driver impact is only approximately 2% of the reference case energy consumption in the same year. The EV load driver energy impact in 2035, in contrast, is approximately 11% of the reference case energy consumption in the same year.

Figure 29: Scenario 1 Energy Impact by Year and Load Driver

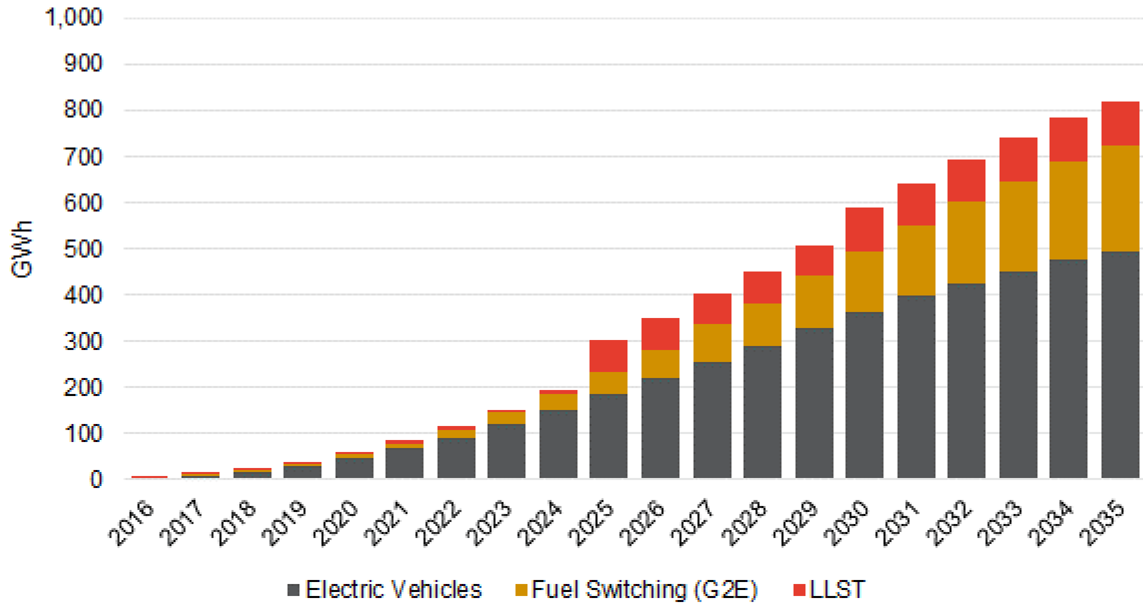


Figure 30 and Figure 31 show peak demand impacts in the 5pm to 6pm period (prevailing time) from two different perspectives. Figure 30 shows the total scenario demand impact in five year intervals by month. The curve of this chart is driven by the gradual uptake of fuel-switching. The slow rate of space-heating stock turn-over is clear from the manner in which the monthly demand profile moves from completely flat in 2020 (when very little incremental space-heating fuel switching has taken place) to having a downward curve in 2035 when space-heating fuel switching has reached its ultimate penetration level.

Figure 30: Total Scenario Demand Impacts by Month and Year

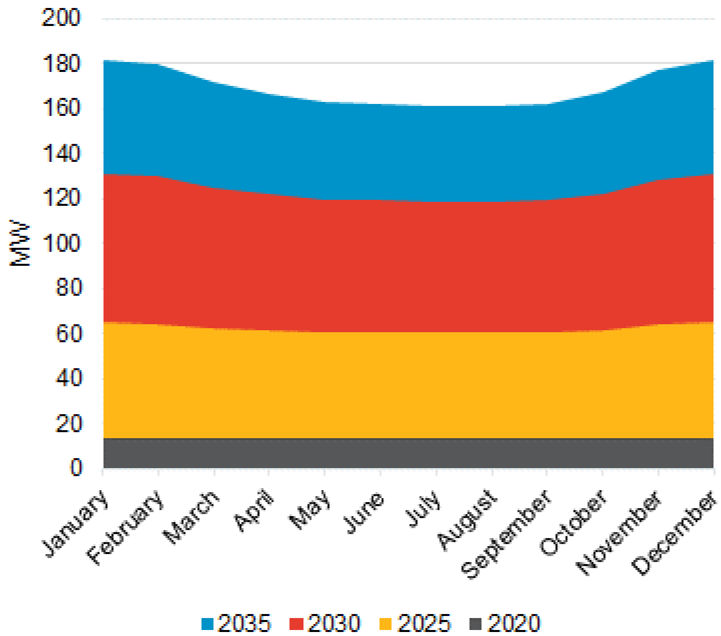
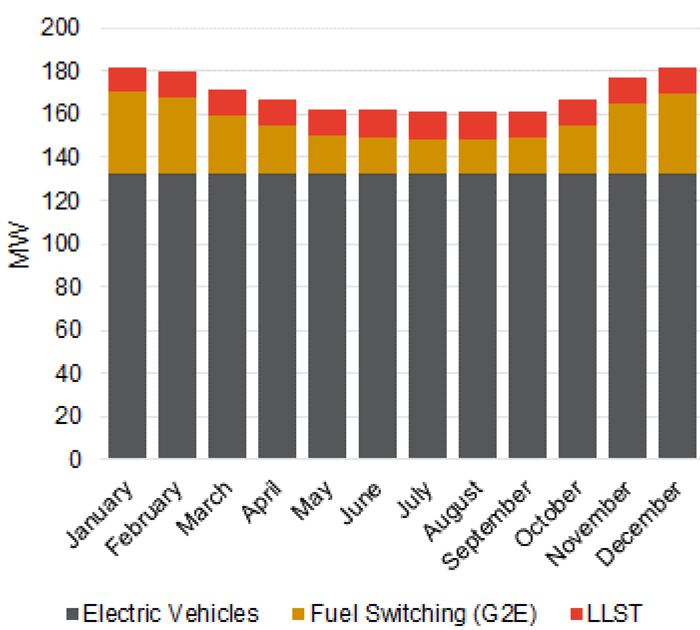


Figure 31 makes the seasonal impact of the differing load drivers even more explicit by showing the 2035 demand impact in each month, split up by load driver. The EV impact is constant throughout the year, as is the LLST impact. The fuel-switching impact, however is highly seasonal. The non-seasonal component of the fuel switching impact (i.e., the demand impact in July) is due to the water-heating component of this load driver.

Figure 31: Total Demand Impacts by Load Driver and Month



3.3.3 Scenario 5 – Detailed Impacts

Scenario 5 is the second boundary scenario. It captures the estimated impacts of five load drivers that all reduce energy consumption: weather impacts, CHP, the IoT, fuel switching from electricity to gas, and residential rooftop PV. This sub-section of Section 3.3 provides some additional context for the estimated scenario impacts in terms of the absolute penetration of some load drivers. This sub-section also provides a breakdown of annual impacts by load driver.

Figure 32, below, shows the penetration of IPSS and non-storage supported residential rooftop PV during the period of analysis. This graphic helps to underscore the fact that although the assumed uptake for this scenario is aggressive, it is not outlandish. The end result of the assumptions above is that a fifth of all residential customers are assumed to have some form of rooftop PV by 2035.

Figure 32: Scenario 5 Residential Rooftop PV Penetration

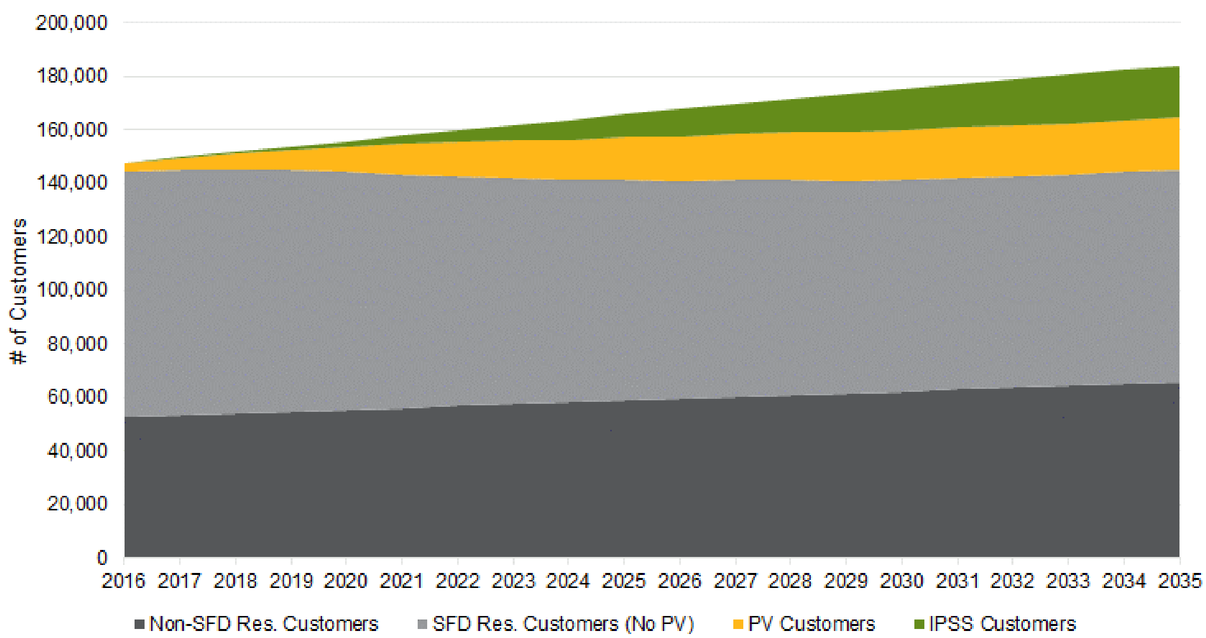


Figure 33 shows the water heating fuel share over time of customers by year. This chart shows customers already assumed to have electric water heating (the existing fuel share is assumed to apply going forward to all new FortisBC customers) as well as customers switching from electricity to natural gas as their water heating fuel.

Figure 33: Consumers by Water Heating Fuel Type

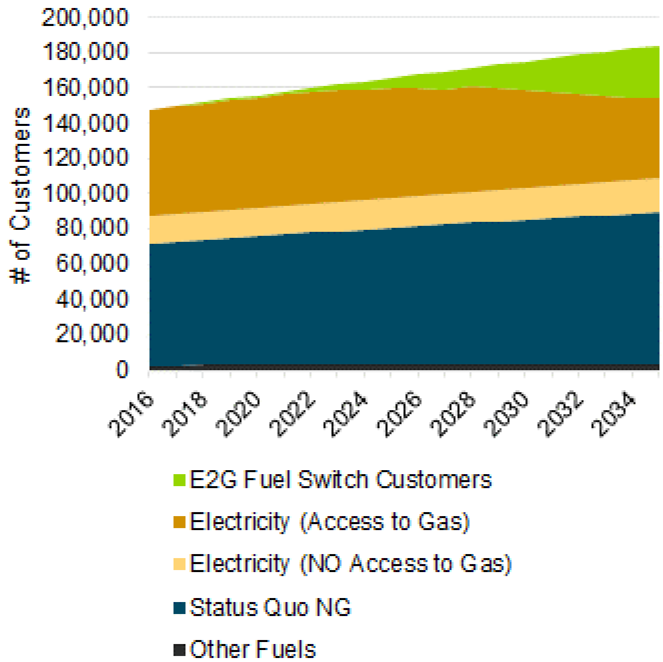


Figure 34, below, is very similar to Figure 33, but for space-heating instead of water heating. As with the gas-to-electricity example presented for Scenario 1, the total space-heating stock that shifts is relatively small due to: the long expected useful life of the equipment, the fact that a substantial proportion of customers already use natural gas for space heating, and the fact that a material proportion of those that use electricity for home heating are too far from a gas main to effect a switch to natural gas.

Figure 34: Consumers by Space-Heating Fuel Type

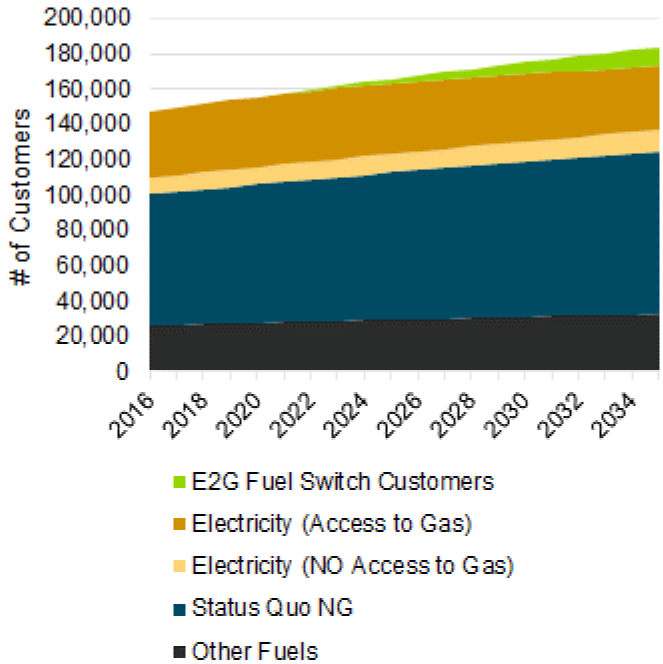


Figure 35, below summarizes the energy impact of Scenario 5 in each year of the period of analysis, split by load driver. The majority of the impacts are delivered by the PV load driver – a combination of IPSS and non-storage-supported rooftop PV. Fuel switching also contributes considerably to energy impacts, approximately as much as either IPSS or “standard” rooftop PV. The impacts of the IoT driver and CHP, though substantial in absolute terms (91 GWh and 129 GWh by 2035, respectively) are relatively small compared to the other load drivers. The impact of the IoT driver, for example contributes approximately 10% to the overall 2035 impacts. The energy impact of the weather is the smallest of all, contributing less than 7% to the overall 2035 impacts. It seems clear that the principal risk of long-term changes in weather due climate change is not a substantial shift in overall energy consumption, but rather the increasing frequency of extreme weather events, which have not been modeled as part of this exercise.

Figure 35: Scenario 5 Energy Impact by Year and Load Driver

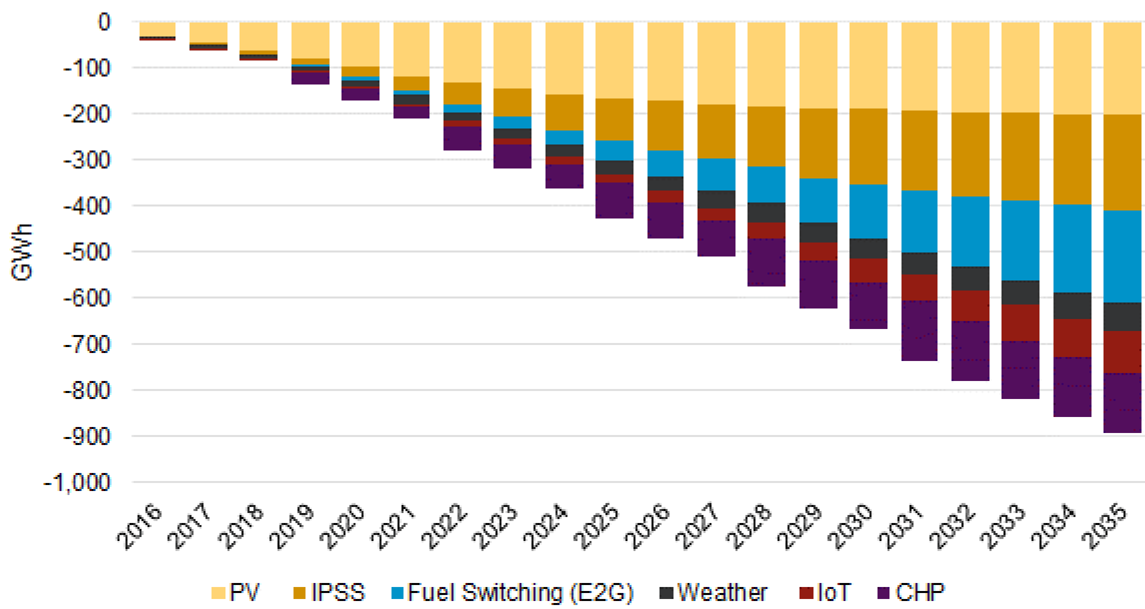
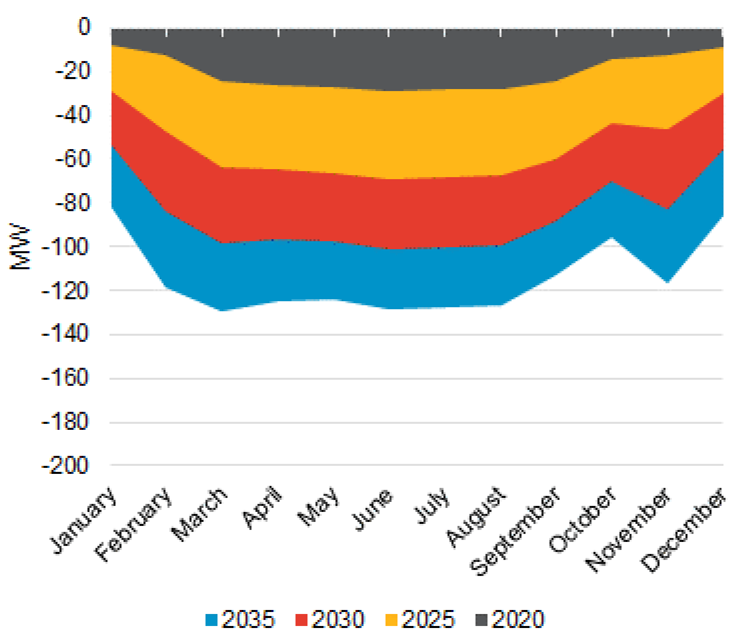


Figure 36 and Figure 37 show peak demand impacts in the 5pm to 6pm period (prevailing time) from two different perspectives. Figure 36 shows the total scenario demand impact in five year intervals by month. The monthly profile of demand impacts begins as a reasonably smooth curve reflecting the seasonality of PV in 2020 and gradually assumes a somewhat jagged shape by 2035 that appears counter-intuitive – why would demand reductions from 5pm to 6pm be higher in November than October?

Figure 36: Total Scenario Demand Impacts by Month and Year

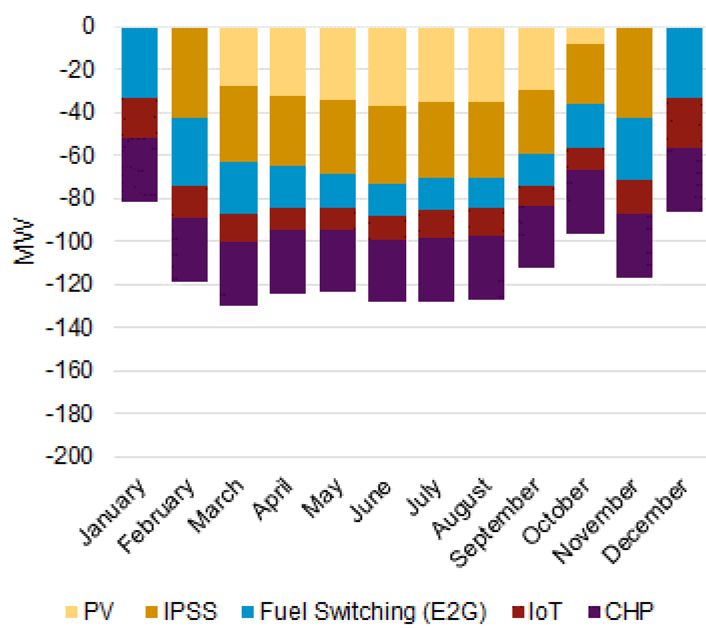


The counter-intuitive shape of the monthly demand impact profile can be better understood by examining Figure 37, which shows the 2035 demand impacts by load driver, and bearing in mind the dynamics of the various load drivers.

The key feature to note in Figure 37 is that by November, "standard" PV impacts have disappeared (it is dark by 5pm) and that IPSS impacts are substantially higher than they were in October. This effect is driven by the assumed IPSS operating behaviour. That is, this load driver has been developed under the assumption that residential customers will begin discharging electricity from storage as soon as the PV generation on its own is insufficient to cover household requirements, and will continue to do so in each hour until either the household requirements are met or until battery storage is expended (see Figure 4 and Section 2.1 for more details).

Household requirements between 5pm and 6pm in November are considerably higher than during the same period in October due to both heating and lighting requirements. Under the assumed operating behaviour of the IPSS, this additional load is covered by electricity from storage, increasing the load displaced by IPSS load driver. In the coldest, darkest months, storage has been exhausted prior to the 5pm – 6pm window, so IPSS cannot displace any load, resulting in the lowest monthly demand impacts.

Figure 37: Total Demand Impacts by Load Driver and Month



4. FINDINGS AND RECOMMENDATIONS

This chapter of the report presents Navigant's conclusions based on the analysis, and some recommendations for how the information provided in this report may be used by FortisBC in the future. In this analysis, Navigant and FortisBC explored two boundary scenarios and three off-setting scenarios. Load driver penetrations or uptake in the boundary scenarios were deliberately selected by Navigant and FortisBC to "push the envelope". They were selected to help FortisBC understand the potential impact that each of these load drivers could have under extreme, but plausible, penetration scenarios.

Observing the estimated impacts in the boundary scenarios, **Navigant's principal finding is that the load drivers that may have the greatest impacts are (in order): electric vehicles, residential rooftop PV, and fuel switching.** Based on the modeling results thepotential impact from the LLST, CHP, IoT and Weather load drivers appears relatively small at the system level, relative to the the other load drivers.[60]

Navigant's secondary finding is that, based on the offsetting scenarios, the possibility exists that demand during peak times could increase despite energy consumption falling. Such an impact could be driven by a strong move toward the electrification of transportation combined with increasing self-generation and other energy-efficiency efforts.

The bulleted list below identifies significant features of the four load drivers identified in Navigant's principal finding.

- **Electric Vehicles.** Navigant believes that of all eight load drivers, EVs could pose the greatest risk of disruption for FortisBC in the period of analysis.
    - EVs, though still an emerging technology are becoming normalized and are migrating out of the "early adopter" phase. Increasing vehicle range and generous incentives have made EVs a reasonable choice for two-car families selecting a new commuter vehicle.
    - The immensely successful release of the Tesla Model 3, for which there are currently approximately 373,000 pre-orders outstanding[61], indicates a strong appetite among consumers for electric vehicles. As production ramps up, and network effects take hold, prices are likely to continue to fall and demand for EVs increase.
    - Of the high-impact load drivers, EVs are the most modular and the least trouble to acquire. For many customers that already have a garage with power, no additional work needs to be done after buying the car. Even should customers wish to upgrade to Level 2 charging, this is a non-disruptive upgrade that can be accomplished quickly and reasonably cheaply in many homes.
    - With no change in rate structure or incentives to shift charging timing, customers with EVs will likely substantially increase their demand during the peak hour, between 5pm and 6pm.

[60] An important distinction should be noted here: LLST impacts are relatively small at the system level, but may be substantial in relation to available distribution infrastructure.

[61] Electrek, *Tesla Model 3 will have Supercharger access but as an optional package, says Musk*, June 2016, accessed June 2016 http://electrek.co/2016/06/01/tesla-model-3-supercharger-access-but-as-an-optional-package-says-musk/

- **Residential Rooftop Solar PV.** Although likely a lower disruption risk than EVs, rooftop solar PV has the potential to significantly affect the energy consumption of customers in FortisBC territory.
    - Unlike EVs or fuel-switching, there is no stock-turnover effect to smooth PV acquisition over time. A customer that decides to acquire an EV or switch space-heating fuel will likely wait until their existing equipment needs to be replaced before investing in the change. In the case of rooftop solar, however, there is relatively little lag between the decision to acquire and installation.
    - PV module and installation costs are likely to continue to fall over time, improving the economics for households. The U.S. Department of Energy has reported that between 1998 and 2014 the total installed cost of residential solar PV systems fell from over $12 per watt to approximately $4 per watt[62], and the consensus appears that prices will continue to fall as manufacturing processes become more efficient, and installers become more experienced.
    - Although PV is more disruptive to the customer than the acquisition of an EV, it is less disruptive than fuel-switching; most of the disruptive activity occurs outside the house. Further, installation of PV panels is a highly visible commitment to the social good and thus likely to require a less attractive economic inducement than fuel switching.
- **Fuel Switching.** Although to some degree limited by stock turn-over, and unlikely to be embraced by customers as enthusiastically as EVs or PV, fuel switching should be monitored simply due to the very substantial unit impacts, the highest of any of the load drivers examined in this study.
    - Existing trends in fuel switching to natural-gas fired space- and water-heating could accelerate if natural gas prices stay low and new residential development continues focus on in-fill and densification.
    - Alternatively, legislative action could result in a substantial push in the opposite direction, with a substantial shift away from fossil-fuel heated homes. Ontario's recently released Climate Change Action Plan (CCAP) is one example of the kind of provincial legislation that could result in a significant shift in fuel share by 2035.

Navigant's principal recommendation is that **FortisBC continue to monitor the adoption of electric vehicles, rooftop solar PV and fuel switching**. This could be done by monitoring items like the following, which may represent "signposts" of accelerated adoption trends:

- PV uptake through FortisBC's net metering tariff
- Regional EV uptake
- Fuel switching through the use of existing load research being conducted within FortisBC.

[62] U.S. Department of Energy Sun Shot, *Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections 2015 Edition*, August 2015

https://emp.lbl.gov/sites/all/files/pv_system_pricing_trends_presentation_0.pdf

Appendix H

NAVIGANT LOAD SCENARIOS PRESENTATION

Load Scenario Assessment

Appendix A: Presentation to the Resource Planning Advisory Group

Prepared for:

FORTIS BC™

July 15, 2016

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Reference No.: 185437
2016-06-01

LOAD SCENARIO MODELING

RPAG CONSULTATION

APRIL 27, 2016

FORTIS BC™

NAVIGANT

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NAVIGANT

INTRODUCTION *– THIS STUDY*

STUDY PURPOSE: Quantify the potential impact of major structural changes in FortisBC's electricity load drivers through scenario analysis.

STUDY FOCUS: Boundary scenarios that define major deviations from existing empirical forecasts. Anticipating the cumulative effects of emerging technologies and structural shifts in load behaviour that are unaccounted for in FortisBC's current base forecast.

FOR EXAMPLE, what is the impact on system load <u>if</u>, by 2035….

- Half of all new cars being sold are EVs?
- A quarter of all single-family homes have rooftop photovoltaic solar?
- Half of those replacing their electric space-heating systems switch fuels?
- Etc.

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INTRODUCTION *– THIS STUDY AND THE CPR*

- How does this study relate to the CPR?

Conservation Potential Review	
STUDY PURPOSE:	Estimate baseline technical and economic DSM potential in B.C. consistent with the B.C. utilities' reference load forecasts. The CPR itself is not a load forecast.
STUDY FOCUS:	Identifying DSM opportunities for further investigation, both in reference case and in sensitivity (economic/policy) cases.

FOR EXAMPLE, what is the economic DSM potential in 2035 of….

- The entire residential sector?
- The office segment of the commercial sector?
- Heat pump water heaters belonging to residential customers?
- Etc.

- FortisBC load scenarios may be used by FortisBC to define some of the CPR DSM potential scenarios, to provide consistent scenarios across studies.

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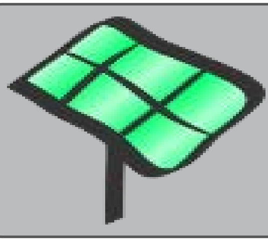
LOAD DRIVERS *– DESCRIPTION OF DRIVERS*

1

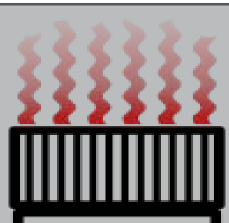


Rooftop Solar.
Residential rooftop solar photovoltaic (PV) generation and integrated photovoltaic storage systems (IPSS)

2

Electric Vehicles
Plug-in and battery (fully electric) electric vehicles (PHEV & BEV) supported by level 1 (120V), level 2 (240V) and "fast DC" charging

3



Fuel Switching – Gas to Electric
Residential customers converting from natural gas to electric space (mostly heat pumps) and water heating.

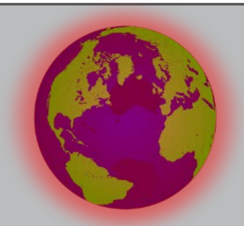
4

Fuel Switching – Electric to Gas
Residential customers converting from electric to natural gas space and water heating.

NAVIGANT

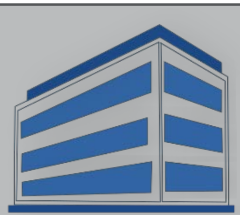
LOAD DRIVERS *– DESCRIPTION OF DRIVERS*

5



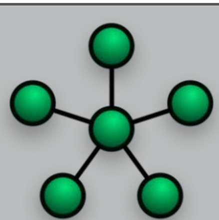
Consistent & Persistent Weather Changes
Gradual increases in average monthly temperatures as predicted by models of climate change.

6



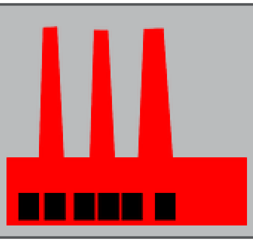
Large Load Sector Transformation
Unanticipated growth of large load customers not associated with traditional energy intensive industries (forestry/manufacturing).

7



Internet of Things
Connected devices, information feedback and residential control systems working together to reduce consumption.

8



Combined Heat and Power
Very large C&I customers investing in cogeneration facilities.

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LOAD DRIVERS – *DRIVER DIRECTIONAL IMPACTS*

Load Driver	Short Form	Effect on System Load (+/-)
Rooftop Solar	PV	▼
Electric Vehicles	EV	▲
Fuel Switching – Gas to Electric	FS – G2E	▲
Fuel Switching – Electric to Gas	FS – E2G	▼
Consistent & Persistent Weather Changes	Weather	▼
Large Load Sector Transformation	LLST	▲
Internet of Things	IoT	▼
Combined Heat and Power	CHP	▼

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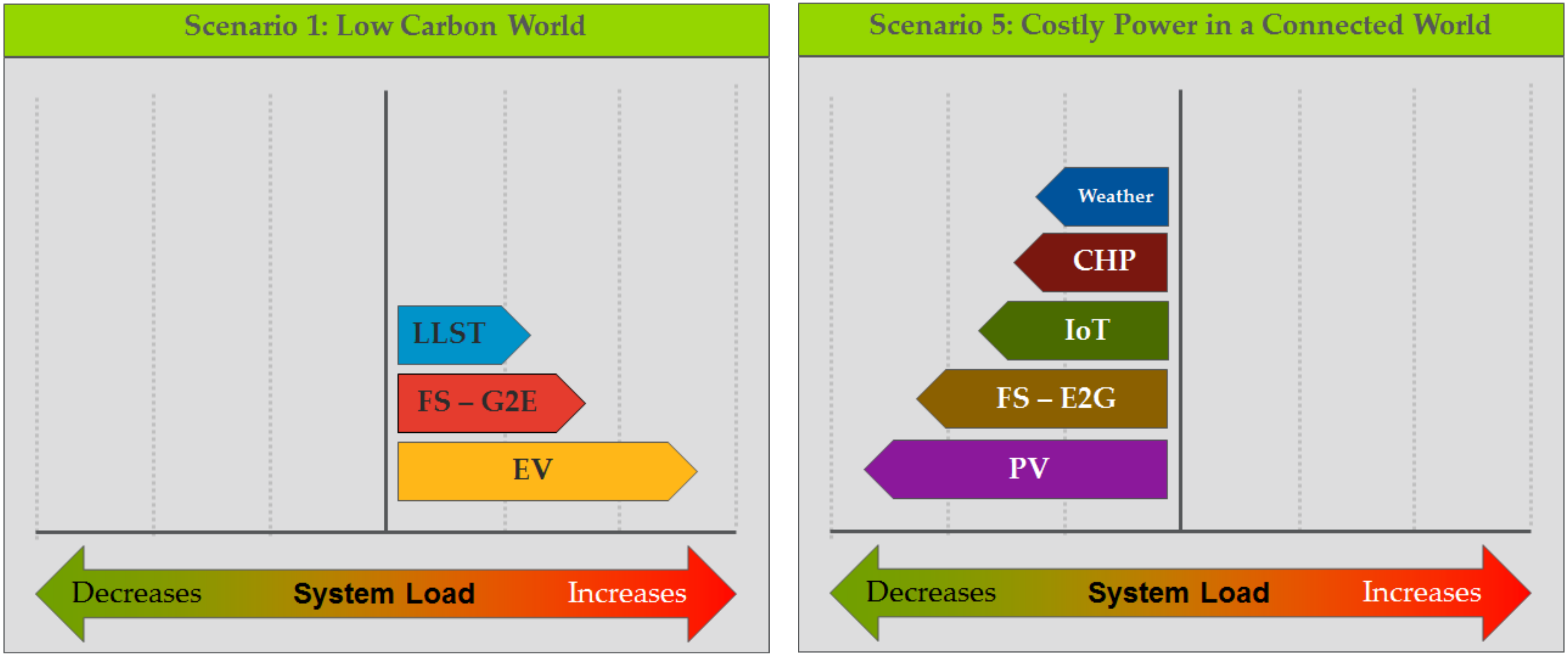
SCENARIOS – *BOUNDARY SCENARIOS*

- Five scenarios explored – two boundary scenarios, & three intermediate/offsetting scenarios.

Boundary Scenarios



Impact arrows are directional only – not to scale.

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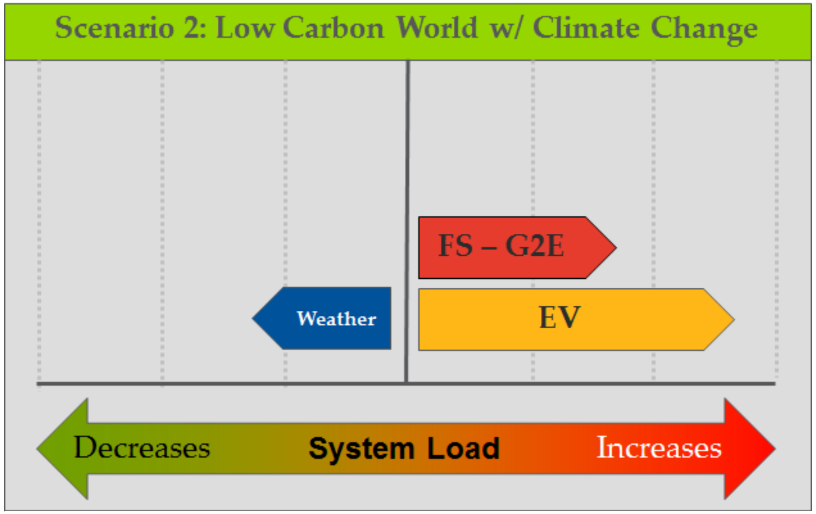
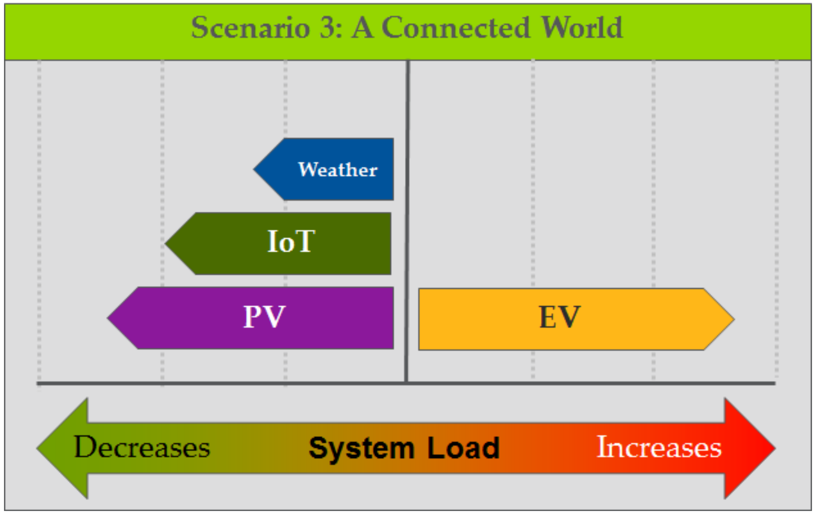
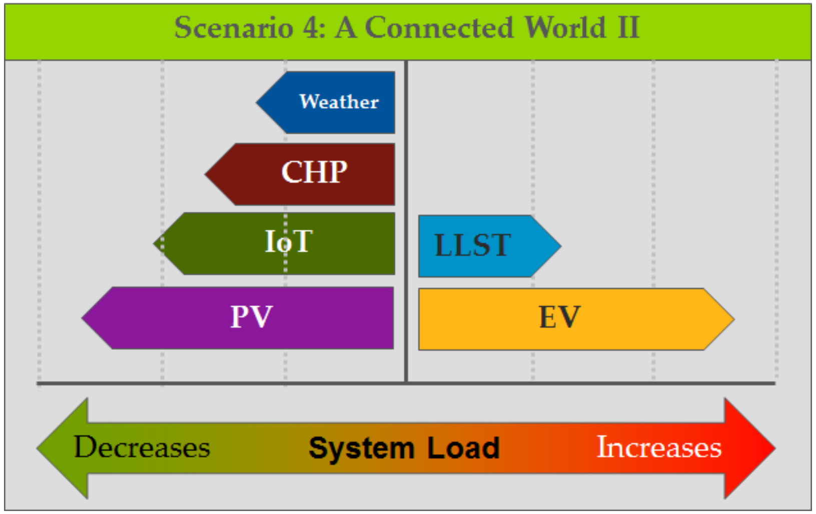
SCENARIOS – *INTERMEDIATE & OFFSETTING SCENARIOS*

- Boundary scenarios define the potential *extremes* of load driver impacts.
- Intermediate scenarios define the impacts in scenarios where load drivers *are offsetting* and the potential consequences of such interactions.

Impact arrows are directional only – not to scale.







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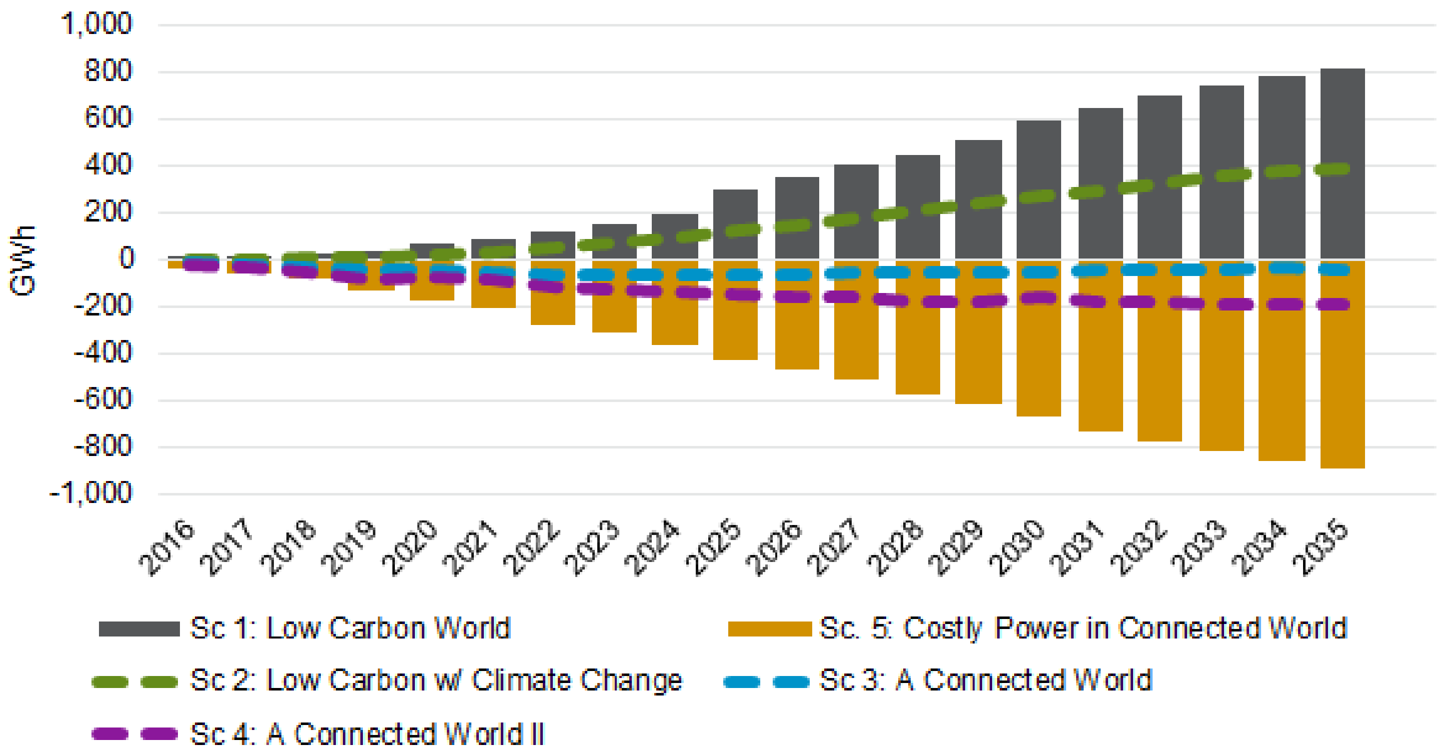
SCENARIOS –*SCENARIO IMPACTS (ENERGY)*

- By 2035, the energy impacts of the boundary scenarios are substantial.
  - Scenario 1: Increase in consumption by more than 800 GWh/year (largely due to EVs and fuel-switching)
  - Scenario 5: Decrease in consumption by nearly 900 GWh/year (largely due to PVs and fuel-switching).



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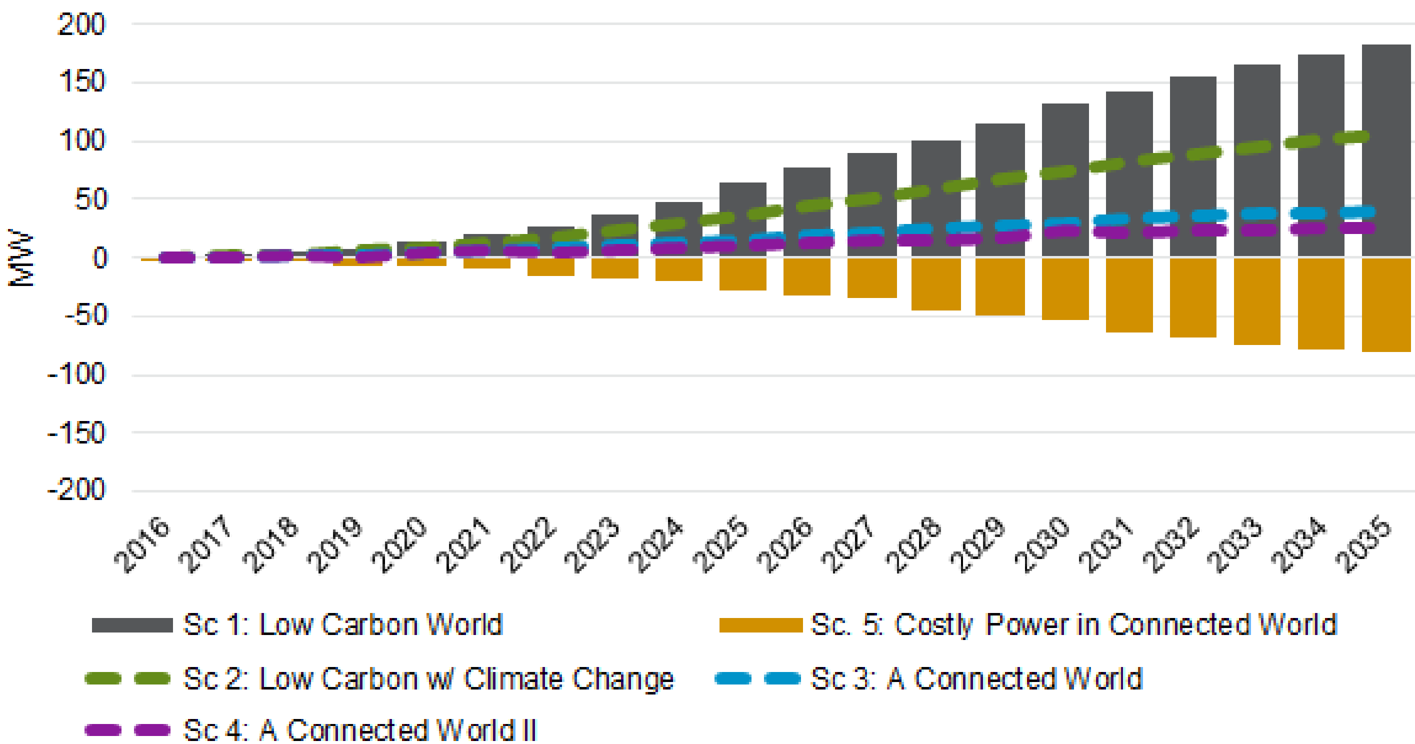
SCENARIOS *–SCENARIO IMPACTS (DEMAND)*

- Correlation between impacts on energy and demand in HE18 varies by scenario .
  - Scenario 3 & 4: increase in HE18 demand despite net decrease in energy consumption, principally as a result of PV/EV interactions.



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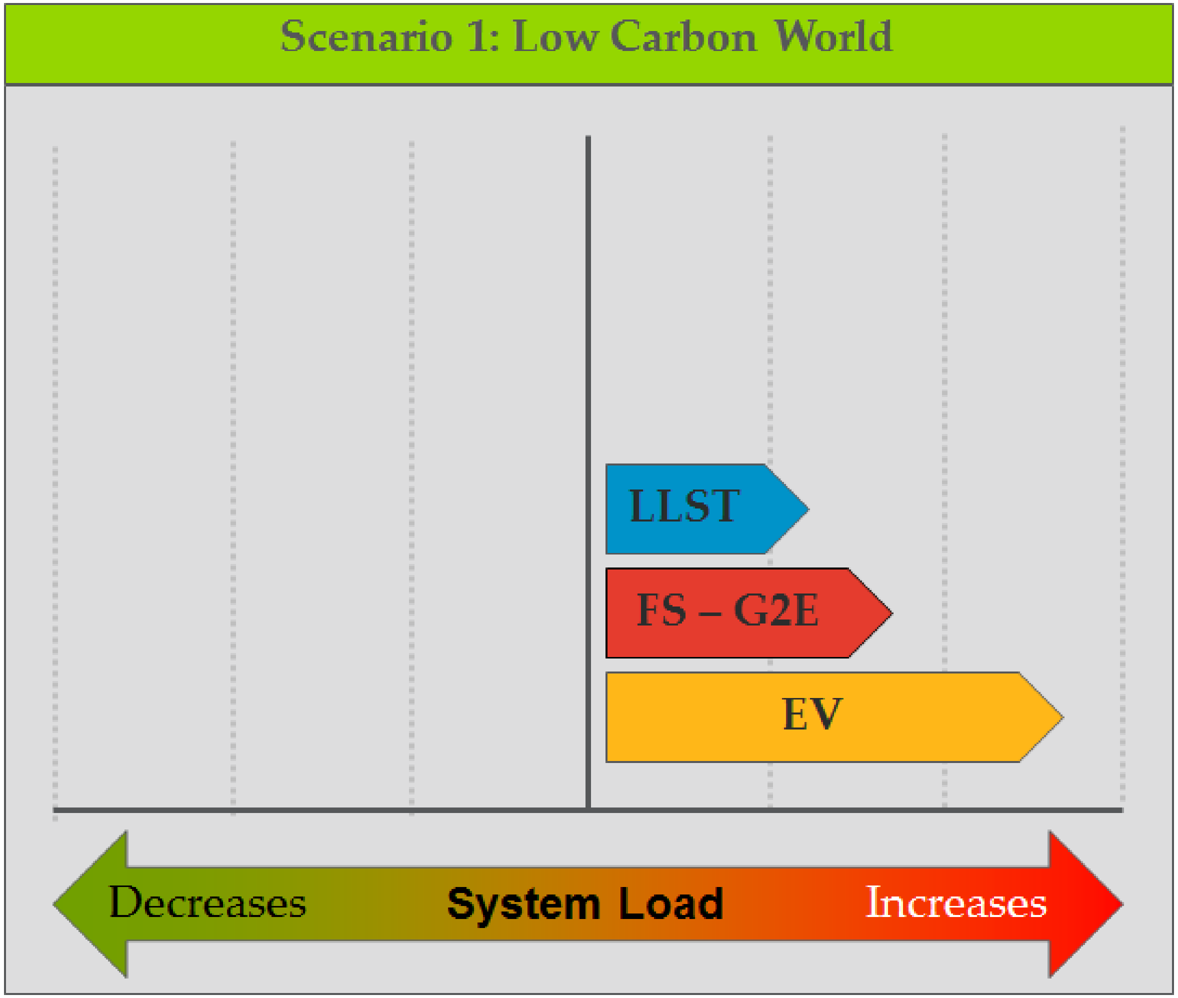
SCENARIO 1: ALL DRIVERS INCREASE LOAD



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SCENARIO 1: INPUT ASSUMPTIONS

Electric Vehicles

- By 2035, 50% of automobile purchases will be EVs (scenario assumption)
- When 50% of automobile purchases are EVs, 75% of home charging will be Level 2 charging (scenario assumption)
- When 50% of automobile purchases are EVs, sufficient DC fast charging stations are deployed to allow BEVs to increase average daily travel distance by 20% (scenario assumption)
- PHEV10 and PHEV20 sales are displaced by PHEV40 sales entirely by 2025 (current sales are 3% and 7% of EVs, respectively).
- Vehicle stock turn-over: approximately 7% per year (CANSIM)
- Approximately 1.4 vehicles per household/customer (NRCan)
- PHEV/BEV proportions stay consistent w/ 2015 sales levels:~ 67% of EVs sold in 2015 were BEV (GreenCarReports)

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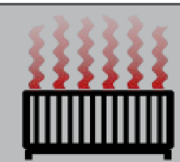
SCENARIO 1: INPUT ASSUMPTIONS

Fuel Switching – Gas to Electric



- By 2035 50% of purchasing decisions made by residential customers that would otherwise use gas select electricity for space and water heating.
- Space heating stock turnover is 5% per year. Water heating stock turnover is ~8% per year (in line with CPR assumptions).

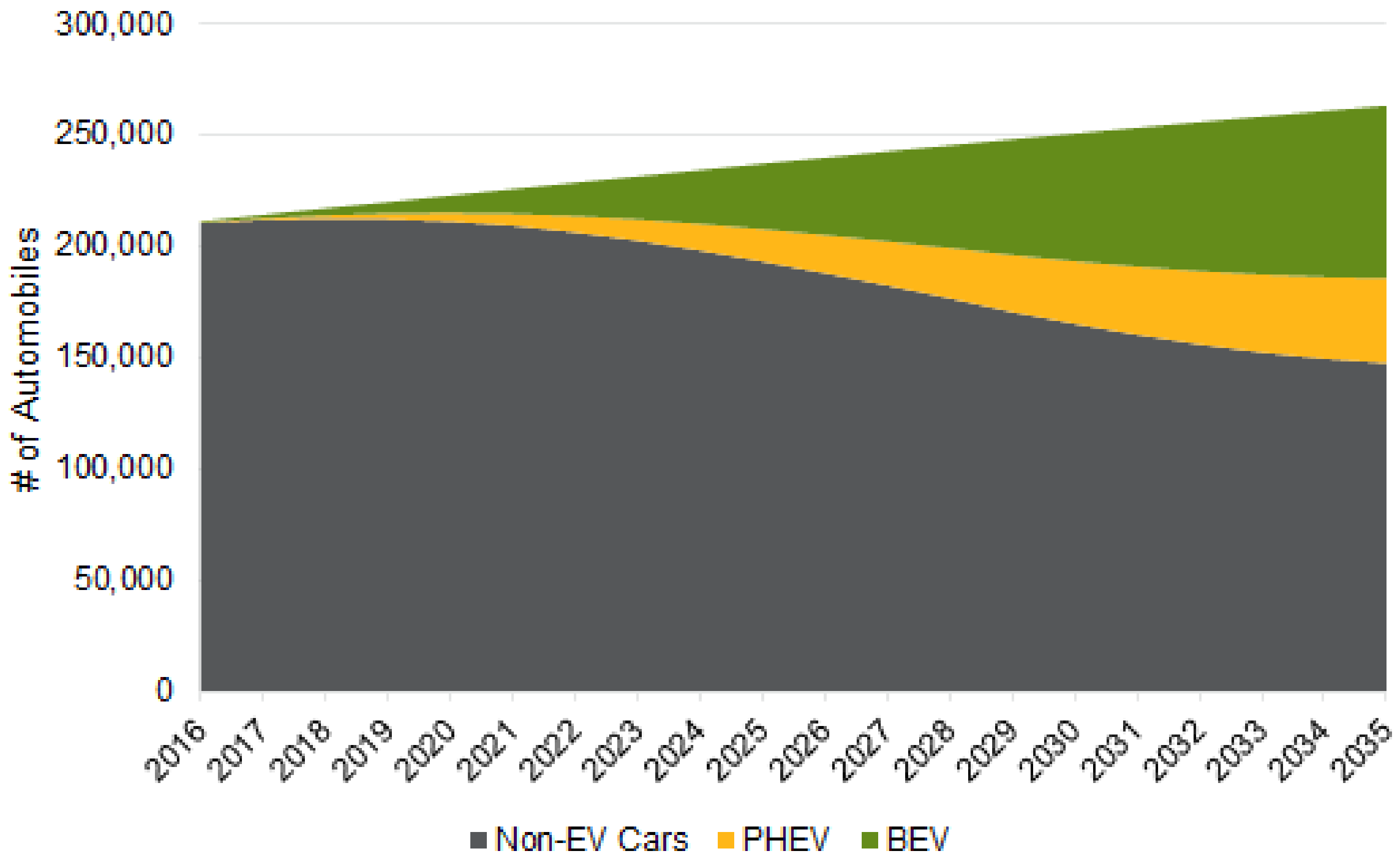
Large Load Sector Transformation

- Two new breweries (each 25% size of current average breweries in Fortis territory)
- One new data centre (10 times the size of current average data centres in Fortis territory).
- Two new community colleges (each the same size as current average community colleges in Fortis territory).
- One new hospital (the same size as current average hospitals in Fortis territory).

The scenario input assumptions dictate driver penetrations (next slide).

SCENARIO 1: DRIVER PENETRATION

- Total number of EVs by year (Scenario 1)



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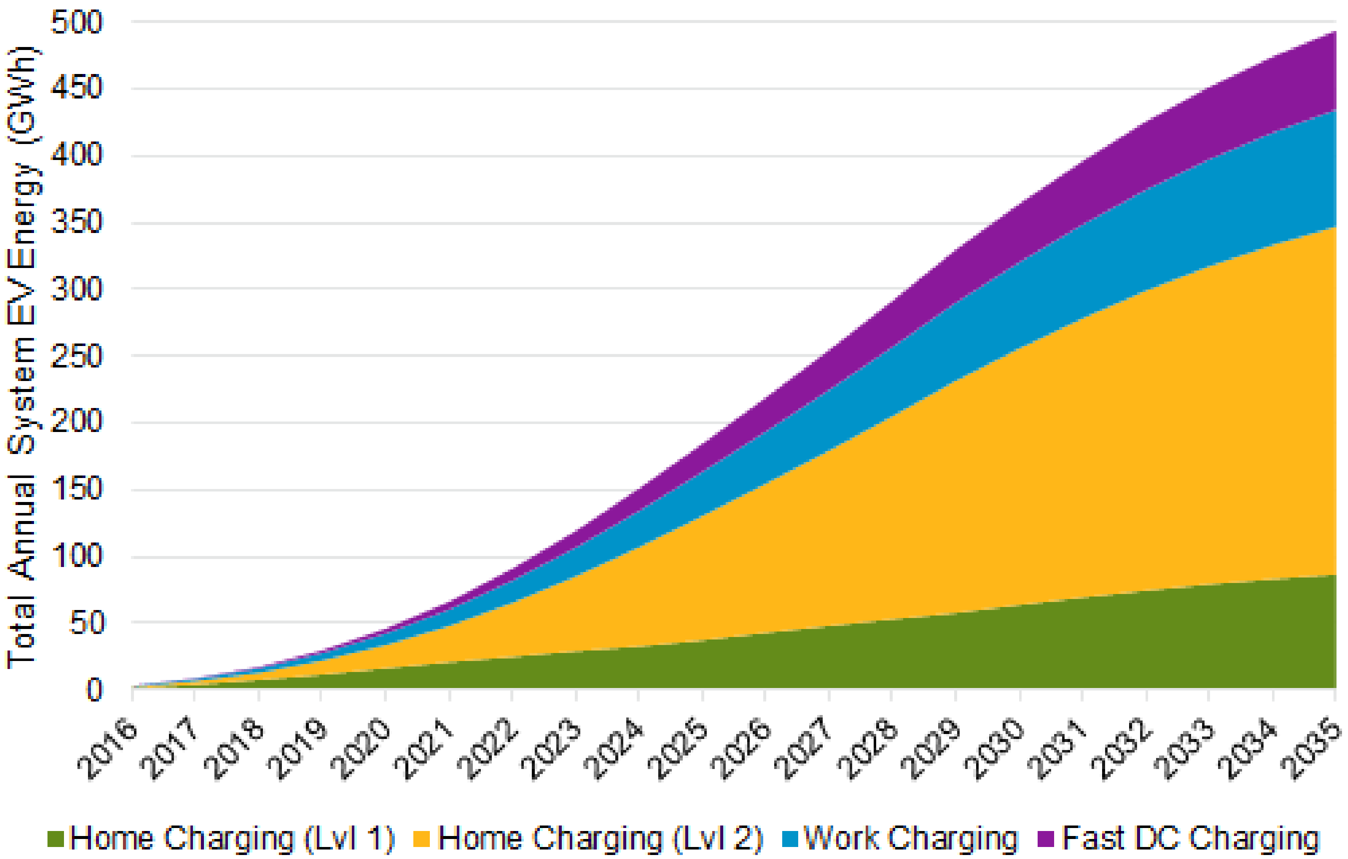
SCENARIO 1: DRIVER PENETRATIONS

- Proportion of total average annual EV charging (all cars) by charge type.



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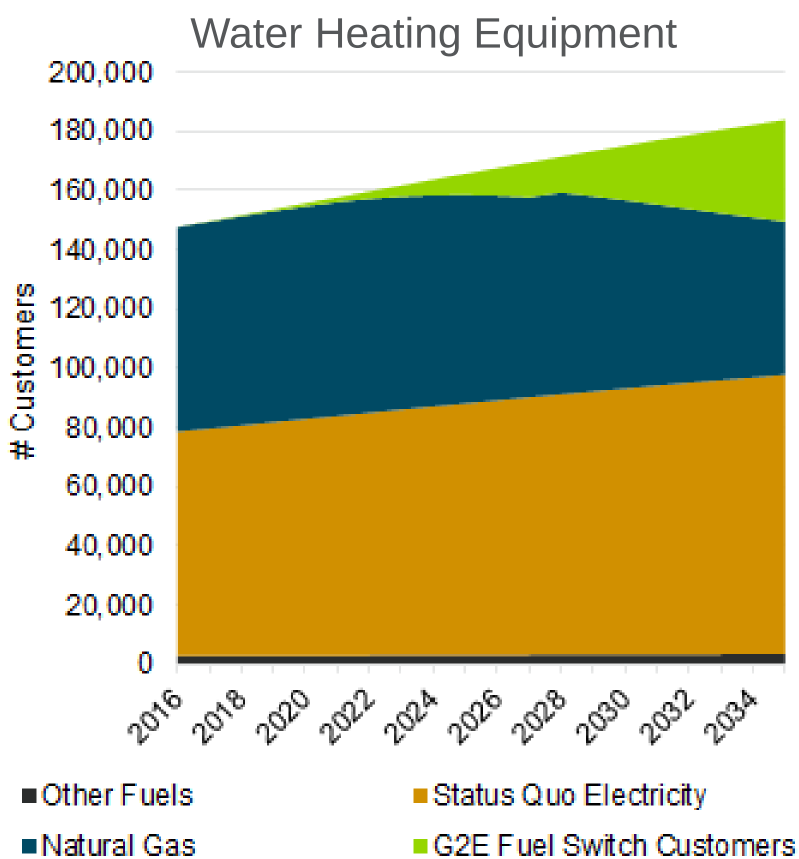
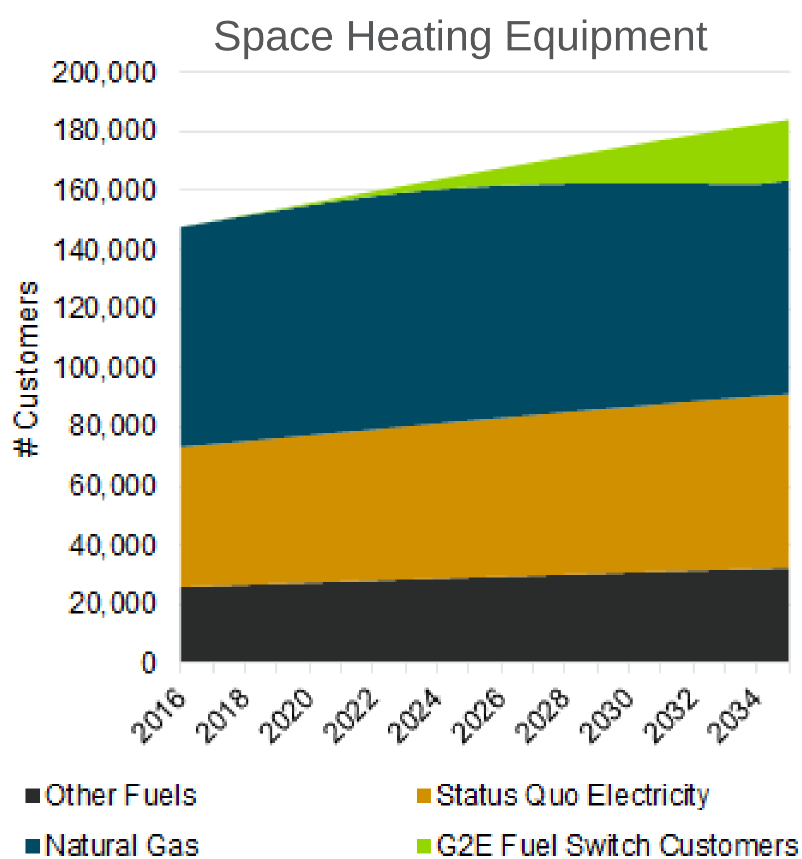
SCENARIO 1: DRIVER PENETRATIONS

- Number of customers switching from gas to electricity for space or water heating.





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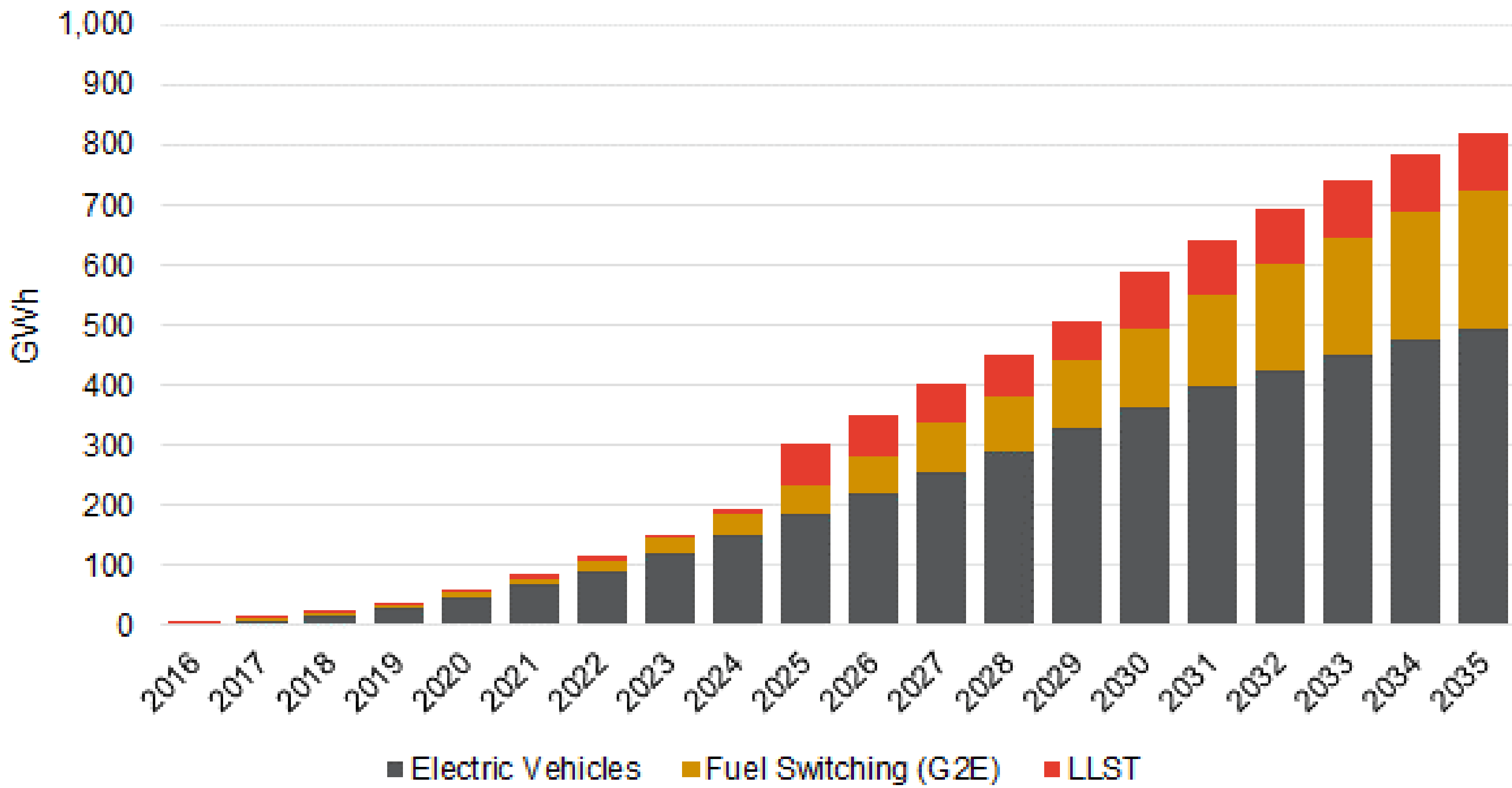
SCENARIO 1: IMPACTS - ENERGY

- Under Scenario 1, total annual system load increases by ~800 GWh by 2035.



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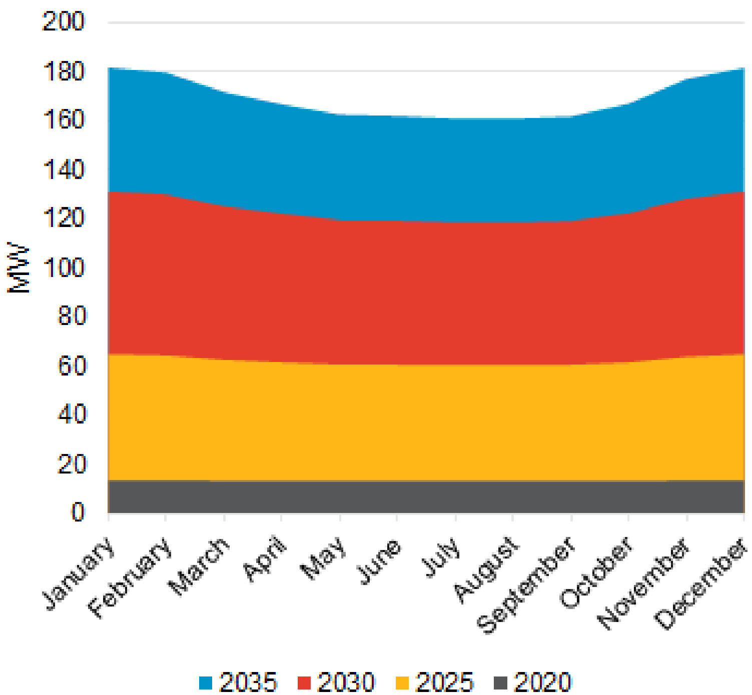
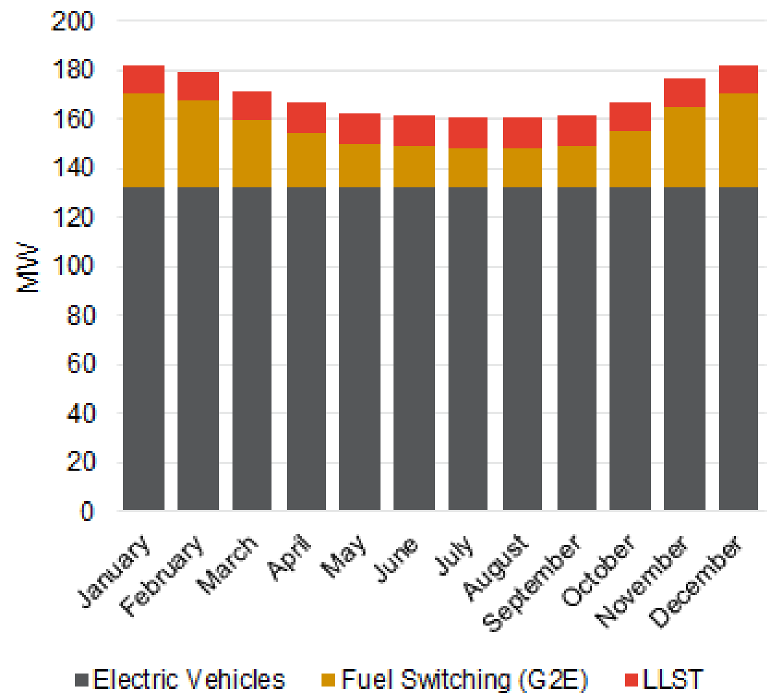
SCENARIO 1: IMPACTS – DEMAND

- Under Scenario 1, demand from 5pm – 6pm in January increases by nearly 200 MW.
- Seasonal variation in impacts is driven principally by fuel-switching.

Total Scenario Demand Impacts by Year



Driver Demand Impacts in 2035



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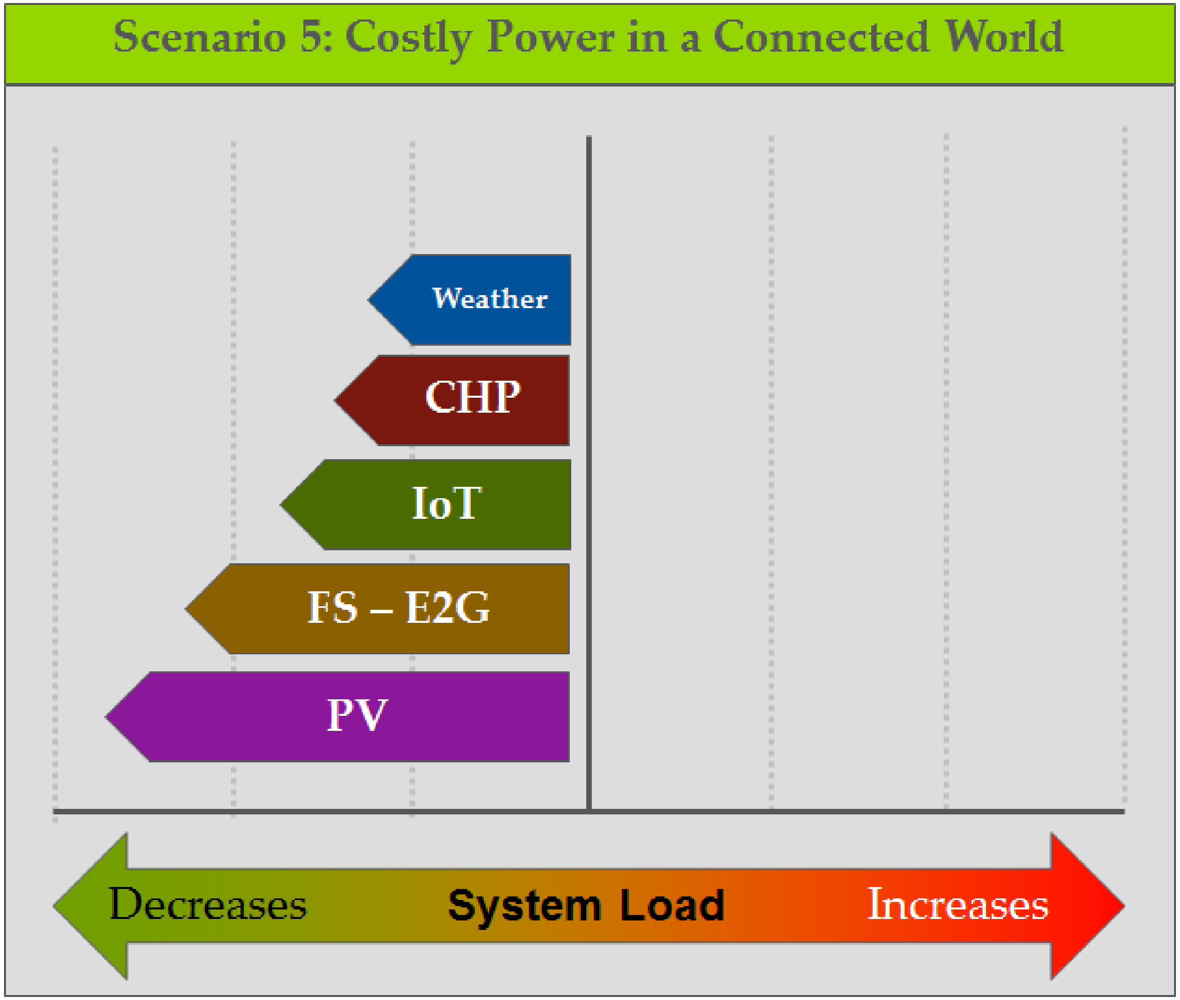
SCENARIO 5: ALL DRIVERS DECREASE LOAD



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SCENARIO 5: INPUT ASSUMPTIONS

Rooftop Solar

- By 2035, 33% of residential customers in single-family detached (SFD) homes will have rooftop PV (scenario assumption)
- When 33% of residential SFD customers have rooftop PV, half of those homes will have energy storage – “integrated photovoltaic solar storage” (IPSS). (scenario assumption)
- 64% of FortisBC residential customers live in SFD (as per FortisBC)

Internet of Things

- By 2035, the equivalent of 50% of residential customers will live in homes fully connected with the IoT.

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SCENARIO 5: INPUT ASSUMPTIONS

Fuel Switching – Electric to Gas

- By 2035 50% of purchasing decisions made by residential customers that would otherwise use electricity, and are within 50m of a gas main, select gas for space and water heating.
- Space heating stock turnover is 5% per year. Water heating stock turnover is ~8% per year (in line with CPR assumptions).

Combined Heat & Power

- By 2035, all existing very large FortisBC C&I meeting the criteria defined for this driver will deploy cogeneration capacity of up to 5MW each.
- Deployment is assumed to occur smoothly – incremental capacity coming online every 3 years.

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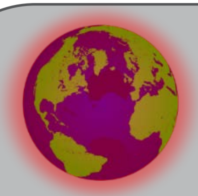
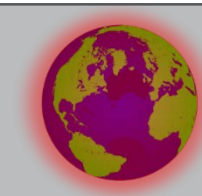
SCENARIO 5: INPUT ASSUMPTIONS



Consistent & Persistent Weather Changes



- Change from current temperatures to assumed 2035 temperatures is linear (annual)
- Persistent weather may be accompanied by increased short-term volatility and extreme events with ambiguous peak demand impacts, therefore, as per FortisBC, no peak demand impacts are estimated for this driver.

The scenario input assumptions dictate driver penetrations (next slide).

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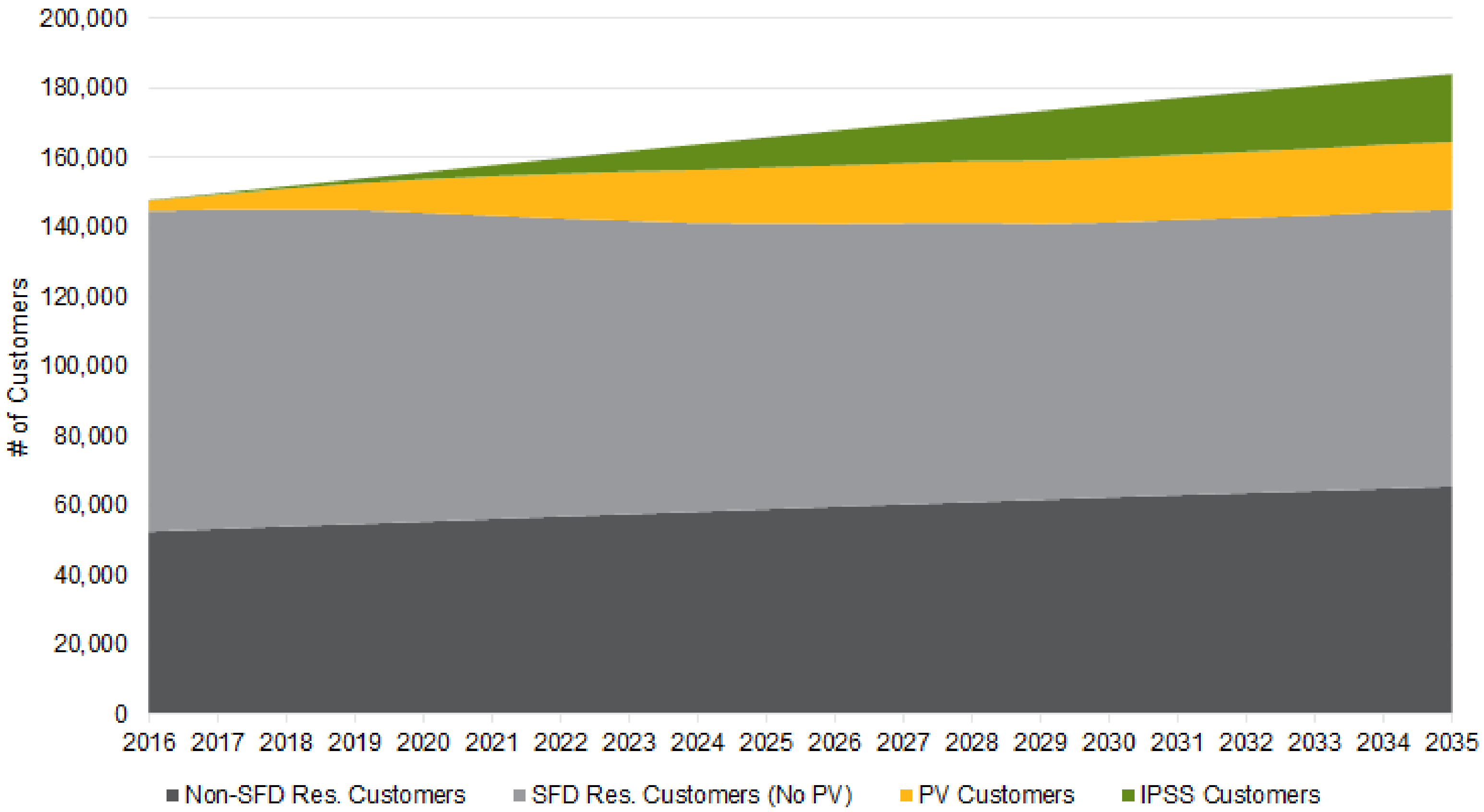
SCENARIO 5: DRIVER PENETRATIONS

- Total number of FortisBC customers with PV or IPSS by year, compared with non-PV/non-IPSS customers



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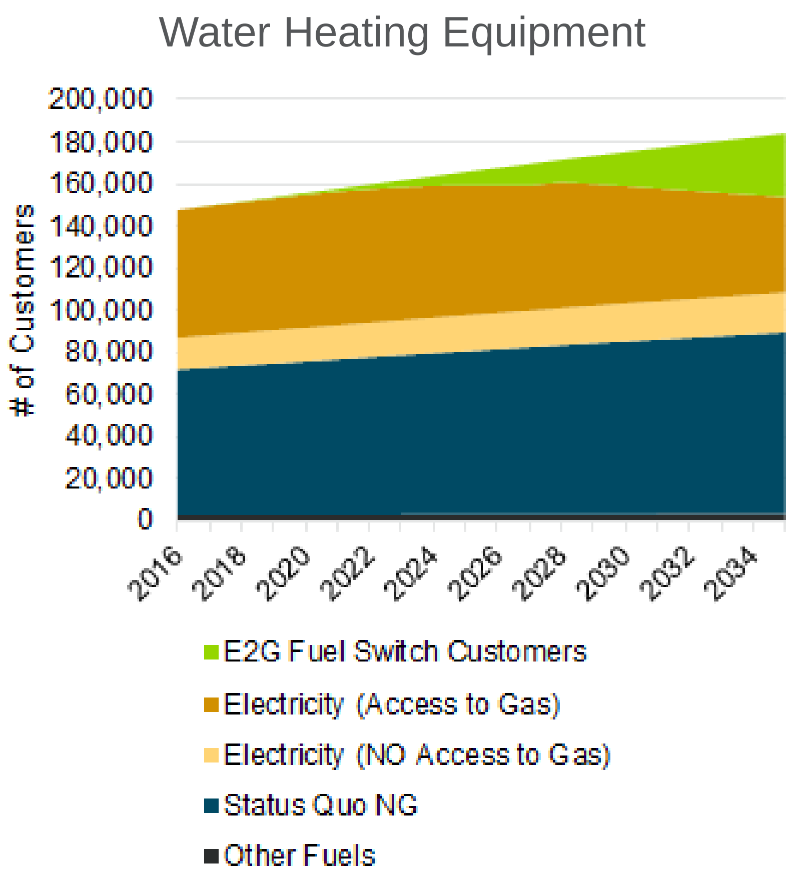
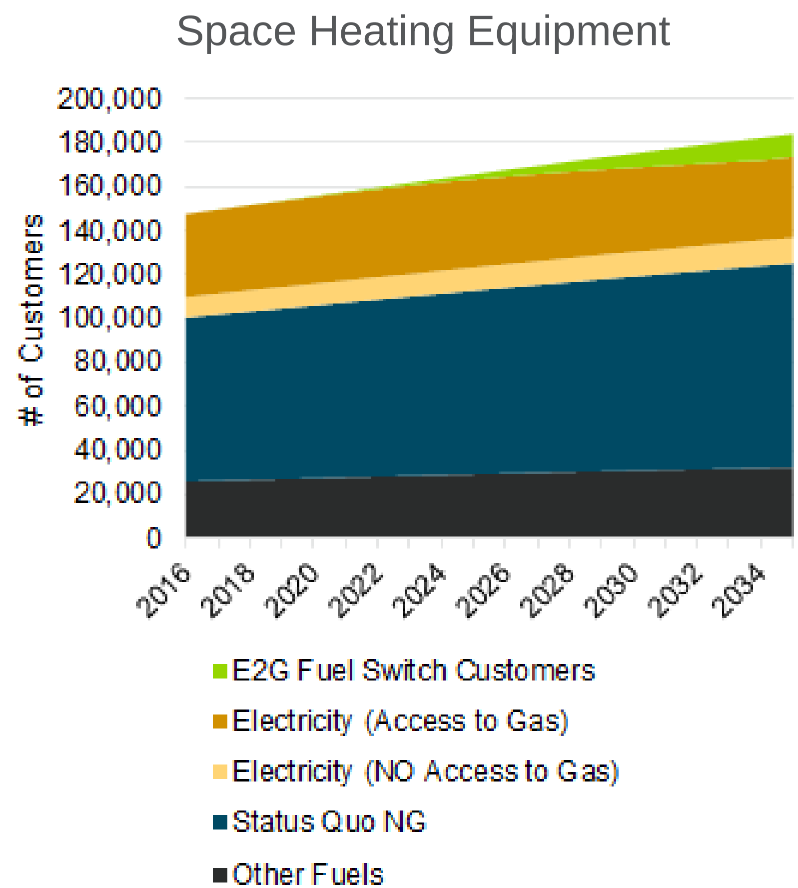
SCENARIO 5: DRIVER PENETRATIONS

- Number of customers switching fuels from electricity to gas





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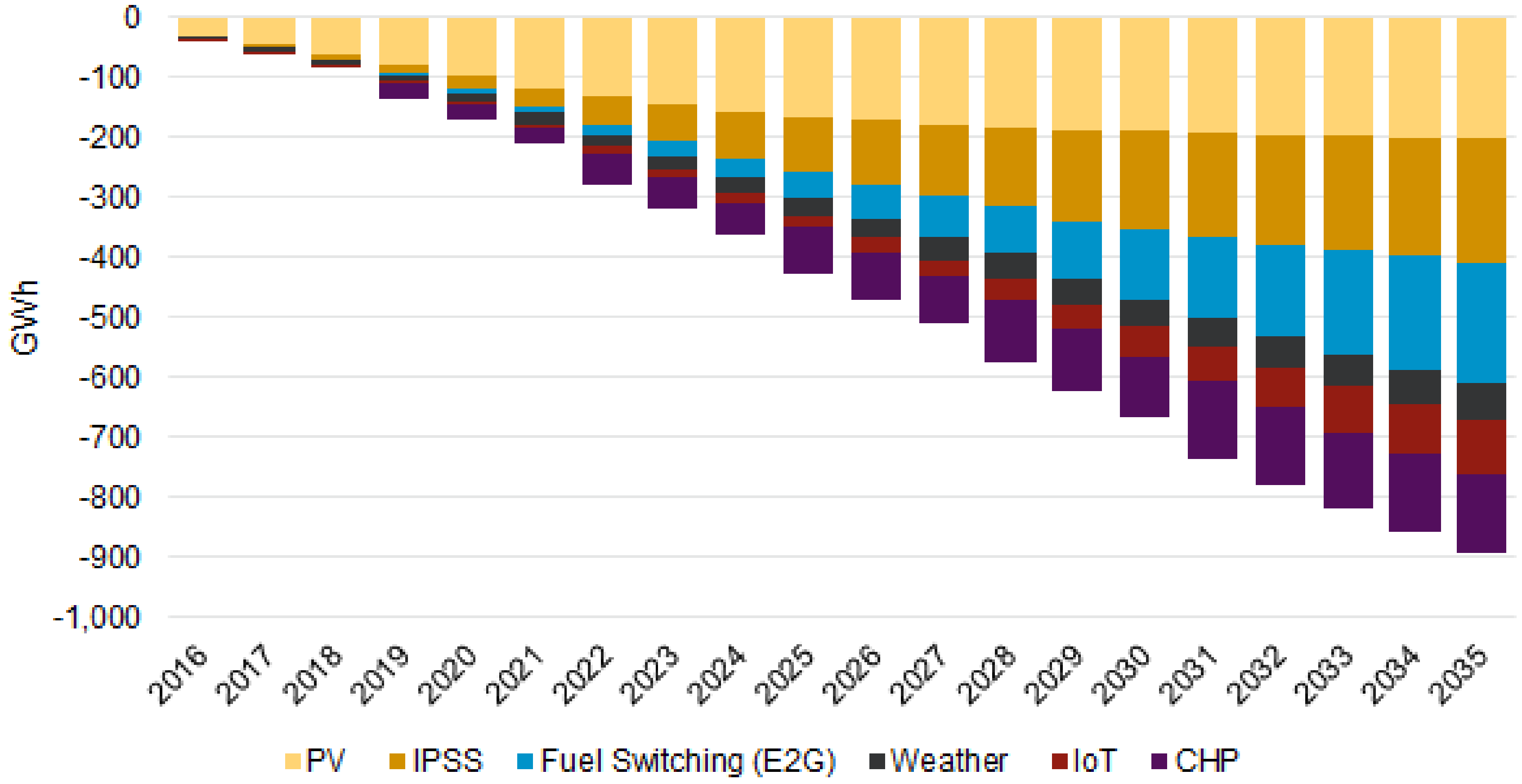
SCENARIO 5: IMPACTS - ENERGY

- Under Scenario 5, total annual system load decreases by ~900 GWh by 2035.



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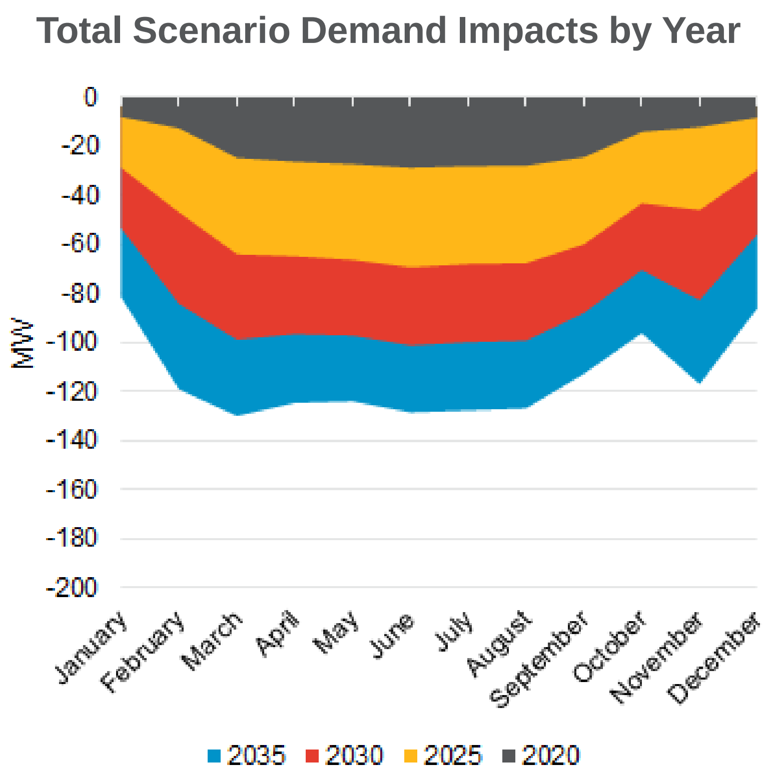
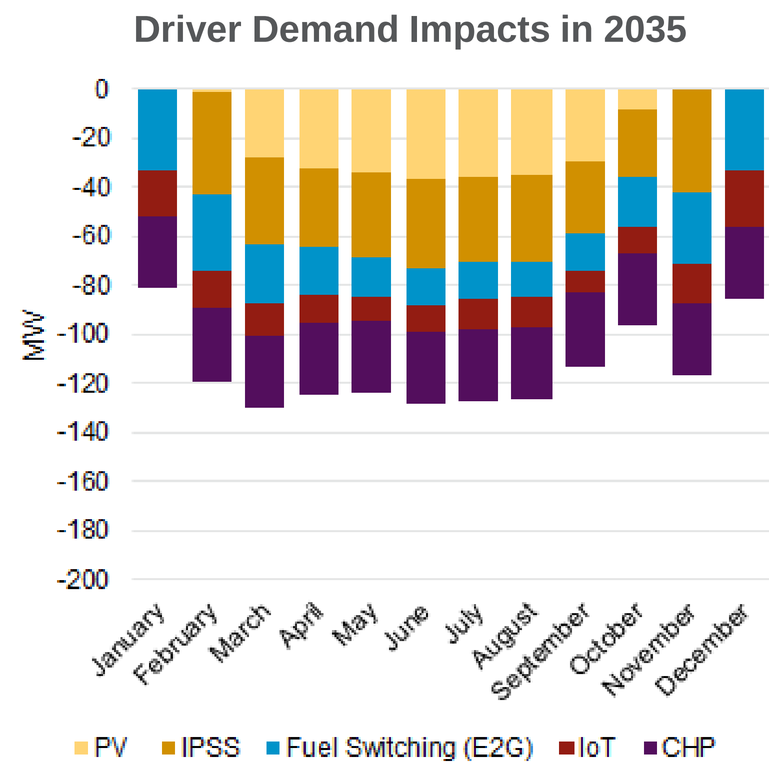
SCENARIO 5: IMPACTS – DEMAND

- Under Scenario 5, demand from 5pm – 6pm in January decreases by ~ 80 MW.
- Seasonal variation in impacts is driven by fuel-switching, PV and IPSS.





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Appendix I

NAVIGANT LOAD SCENARIOS MODELLING OUTPUTS

Load Scenario Assessment

Appendix B: Modeling Outputs

Prepared for:

July 15, 2016

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Reference No.: 185437
2016-06-01

TABLE OF CONTENTS

1. IMPORTANT INFORMATION

Scenario 1 through Scenario 5 provide annual GWh and MW scenario impacts.

If no column exists for a load driver, impacts in the given scenario are 0.
Impact tables are divided in two:

- The leftmost side of each table (divided from the right by a black column) provides the total impact across all customer classes.
- The right-hand side of the table provides the impact of each driver by customer class.

Although both IPSS and PV impacts are components of the “PV” load driver, they are presented in separate columns. As per the report, MW impacts are not reported for the “Weather” load driver.

2. SCENARIO 1 - LOW CARBON WORLD

Figure 1. Scenario 1 – System Load

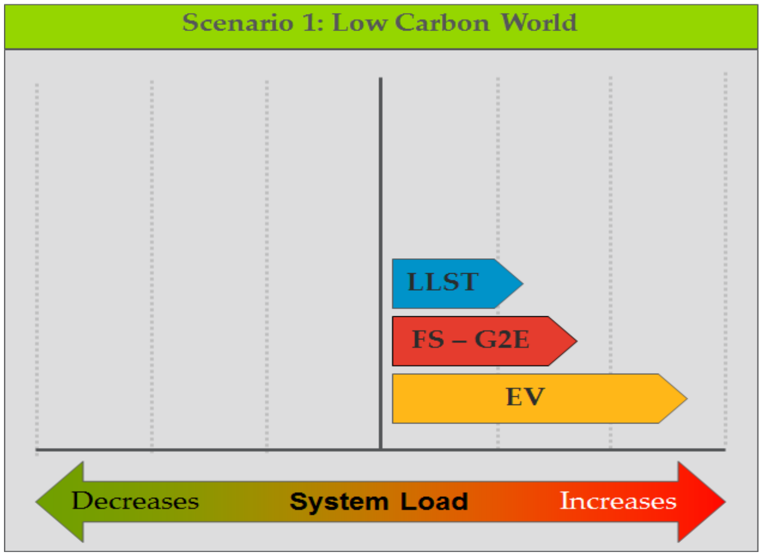

Table 1. Scenario 1 - Energy Impacts (GWh/Year)

Energy Impacts (GWh/Year)											
Customer Class:	All	All	All	All	Residential	Wholesale	Commercial	Residential	Wholesale	Commercial	Industrial
Load Driver	EV	FS - G2E	LLST	Total	EV	EV	EV	FS - G2E	FS - G2E	LLST	LLST
2016	3	0	2	6	2	1	1	0	0	0	2
2017	9	1	2	13	6	2	2	1	0	0	2
2018	18	3	2	22	10	4	3	2	1	0	2
2019	30	4	2	37	18	6	6	4	1	0	2
2020	46	7	8	61	27	10	10	6	1	4	5
2021	66	11	8	86	38	14	14	9	2	4	5
2022	91	17	8	117	52	19	20	14	4	4	5
2023	119	26	8	153	68	25	27	20	5	4	5
2024	151	36	8	195	85	31	35	29	7	4	5
2025	185	49	68	302	104	38	43	39	10	64	5
2026	219	64	68	351	123	45	51	51	13	64	5
2027	255	81	68	404	143	53	60	64	17	64	5
2028	292	90	68	450	163	60	69	72	19	64	5
2029	330	111	68	509	184	68	78	88	23	64	5
2030	364	132	94	590	203	75	86	104	27	89	5
2031	396	153	94	643	221	82	93	121	32	89	5
2032	426	174	94	694	237	88	100	138	36	89	5
2033	452	196	94	741	252	94	107	155	41	89	5
2034	475	217	94	785	265	98	112	172	45	89	5
2035	494	230	94	818	275	102	116	182	48	89	5

Table 2. Scenario 1 - Peak Demand Impacts* (MW/Year)

Peak Demand Impacts* (MW/Year)											
Customer Class:	All	All	All	All	Residential	Wholesale	Commercial	Residential	Wholesale	Commercial	Industrial
Load Driver	EV	FS - G2E	LLST	Total	EV	EV	EV	FS - G2E	FS - G2E	LLST	LLST
Year											
2016	0.8	0.1	0.3	1.1	0.6	0.2	0.0	0.1	0.0	0.0	0.3
2017	2.2	0.2	0.3	2.6	1.6	0.4	0.1	0.2	0.0	0.0	0.3
2018	4.2	0.4	0.3	4.9	3.1	0.9	0.3	0.3	0.1	0.0	0.3
2019	7.3	0.7	0.3	8.3	5.3	1.5	0.5	0.6	0.2	0.0	0.3
2020	11.4	1.2	1.0	13.7	8.3	2.4	0.8	1.0	0.2	0.5	0.5
2021	16.7	1.9	1.0	19.6	12.0	3.5	1.3	1.5	0.4	0.5	0.5
2022	23.4	2.9	1.0	27.3	16.7	4.8	1.9	2.3	0.6	0.5	0.5
2023	31.0	4.3	1.0	36.3	22.0	6.4	2.6	3.4	0.9	0.5	0.5
2024	39.8	6.0	1.0	46.8	28.1	8.2	3.4	4.8	1.2	0.5	0.5
2025	48.9	8.2	7.9	64.9	34.5	10.1	4.3	6.5	1.7	7.4	0.5
2026	58.2	10.7	7.9	76.7	41.0	12.0	5.1	8.5	2.2	7.4	0.5
2027	67.8	13.5	7.9	89.2	47.8	14.0	6.0	10.7	2.8	7.4	0.5
2028	77.9	15.5	7.9	101.2	54.8	16.1	7.0	12.3	3.2	7.4	0.5
2029	88.4	18.8	7.9	115.0	62.1	18.3	8.0	14.9	3.9	7.4	0.5
2030	97.5	22.3	11.4	131.1	68.5	20.2	8.8	17.6	4.6	10.9	0.5
2031	106.1	25.7	11.4	143.2	74.6	21.9	9.6	20.4	5.3	10.9	0.5
2032	114.0	29.3	11.4	154.7	80.1	23.6	10.3	23.2	6.1	10.9	0.5
2033	120.9	32.8	11.4	165.1	85.0	25.0	10.9	26.0	6.8	10.9	0.5
2034	127.0	36.3	11.4	174.7	89.3	26.3	11.4	28.8	7.5	10.9	0.5
2035	132.2	38.1	11.4	181.7	92.9	27.4	11.9	30.2	7.9	10.9	0.5

*Peak demand defined as demand between 5pm and 6pm on non-holiday January weekdays

3. SCENARIO 2 - LOW CARBON WORLD WITH CLIMATE CHANGE

Figure 2. Scenario 2 - System Load

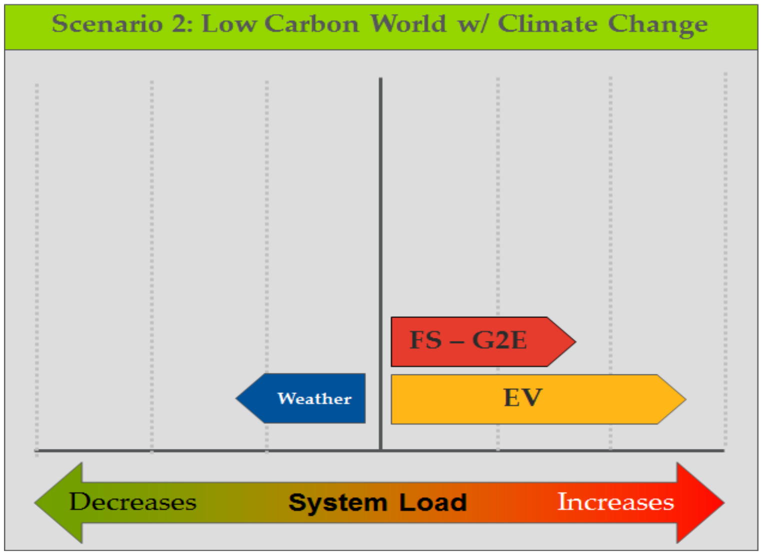

Table 3. Scenario 2 - Energy Impacts (GWh/Year)

Energy Impacts (GWh/Year)													
Customer Class:	All	All	All	All	Residential	Wholesale	Commercial	Residential	Wholesale	Residential	Wholesale	Commercial	Industrial
Load Driver	EV	FS - G2E	Weather	Total	EV	EV	EV	FS - G2E	FS - G2E	Weather	Weather	Weather	Weather
Year													
2016	3	0	-3	0	2	1	1	0	0	-1	-1	-1	0
2017	7	1	-6	1	4	1	1	0	0	-3	-1	-2	-1
2018	13	1	-9	5	8	3	2	1	0	-4	-2	-2	-1
2019	21	2	-12	11	13	4	4	2	0	-5	-2	-3	-1
2020	33	4	-15	21	19	7	7	3	1	-7	-3	-4	-2
2021	47	6	-18	34	27	10	10	5	1	-8	-3	-5	-2
2022	63	9	-21	51	37	13	13	7	2	-9	-4	-6	-3
2023	83	13	-24	71	48	17	18	10	3	-10	-4	-7	-3
2024	103	18	-27	94	60	21	22	14	4	-12	-5	-7	-3
2025	126	24	-30	120	73	26	27	19	5	-13	-5	-8	-4
2026	150	32	-33	148	86	31	33	25	7	-14	-6	-9	-4
2027	174	40	-36	178	100	36	38	32	8	-16	-7	-10	-4
2028	199	45	-39	205	114	41	44	36	9	-17	-7	-11	-5
2029	225	55	-42	238	129	47	50	44	11	-18	-8	-11	-5
2030	248	66	-46	268	142	51	55	52	14	-20	-8	-12	-5
2031	270	77	-49	298	155	56	59	61	16	-21	-9	-13	-6
2032	290	87	-52	326	166	60	64	69	18	-22	-9	-14	-6
2033	307	98	-55	351	176	64	68	78	20	-23	-10	-15	-7
2034	323	109	-58	374	185	67	71	87	23	-25	-10	-16	-7
2035	336	116	-61	391	192	69	74	92	24	-26	-11	-16	-7

Table 4. Scenario 2 - Peak Demand Impacts* (MW/Year)

Peak Demand Impacts* (MW/Year)								
Customer Class:	All	All	All	Residential	Wholesale	Commercial	Residential	Wholesale
Load Driver	EV	FS - G2E	Total	EV	EV	EV	FS - G2E	FS - G2E
2016	0.7	0.0	0.7	0.5	0.1	0.0	0.0	0.0
2017	1.6	0.1	1.7	1.2	0.3	0.1	0.1	0.0
2018	3.0	0.2	3.2	2.2	0.6	0.2	0.2	0.0
2019	5.1	0.4	5.5	3.7	1.1	0.3	0.3	0.1
2020	7.9	0.6	8.5	5.8	1.6	0.5	0.5	0.1
2021	11.4	1.0	12.3	8.2	2.3	0.8	0.8	0.2
2022	15.7	1.4	17.1	11.3	3.2	1.1	1.1	0.3
2023	20.6	2.1	22.8	14.8	4.3	1.5	1.7	0.4
2024	26.0	3.0	29.0	18.7	5.4	1.9	2.4	0.6
2025	31.9	4.1	36.0	22.9	6.6	2.4	3.2	0.8
2026	38.0	5.3	43.3	27.2	7.9	2.9	4.2	1.1
2027	44.4	6.8	51.1	31.7	9.2	3.5	5.4	1.4
2028	50.6	7.7	58.4	36.2	10.5	4.0	6.1	1.6
2029	57.4	9.4	66.8	41.0	11.9	4.5	7.5	1.9
2030	63.3	11.1	74.4	45.2	13.1	5.0	8.8	2.3
2031	68.8	12.9	81.7	49.2	14.2	5.4	10.2	2.7
2032	73.9	14.7	88.6	52.8	15.3	5.8	11.6	3.0
2033	78.4	16.5	94.9	56.0	16.2	6.2	13.1	3.4
2034	82.3	18.2	100.5	58.8	17.0	6.5	14.5	3.8
2035	85.7	19.2	104.9	61.2	17.7	6.7	15.2	4.0

*Peak demand defined as demand between 5pm and 6pm on non-holiday January weekdays

4. SCENARIO 3 - A CONNECTED WORLD

Figure 3. Scenario 3 - System Load

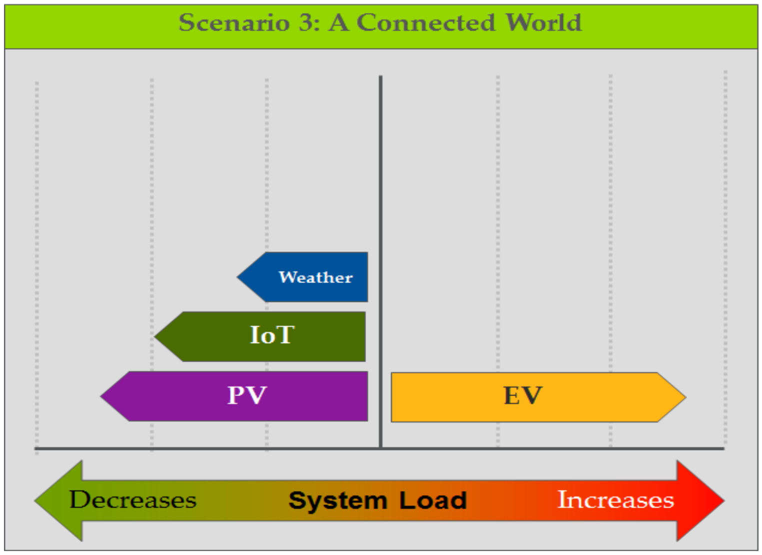

Table 5. Scenario 3 - Energy Impacts (GWh/Year)

Energy Impacts (GWh/Year)																			
Customer Class:	All	All	All	All	All	All	Residential	Wholesale	Commercial	Residential	Wholesale	Residential	Wholesale	Residential	Wholesale	Residential	Wholesale	Commercial	Industrial
Load Driver	EV	PV	IPSS	IoT	Weather	Total	EV	EV	EV	PV	PV	IPSS	IPSS	IoT	IoT	Weather	Weather	Weather	Weather
Year: 2016	2	-15	0	-1	-3	-17	1	0	0	-12	-3	0	0	0	0	-1	-1	-1	0
2017	4	-22	0	-1	-6	-25	2	1	1	-18	-5	0	0	0	0	-3	-1	-2	-1
2018	8	-32	0	-1	-9	-34	5	2	1	-25	-7	0	0	-1	0	-4	-2	-2	-1
2019	12	-39	-2	-1	-12	-42	7	3	2	-31	-8	-2	0	-1	0	-5	-2	-3	-1
2020	19	-50	-4	-1	-15	-52	11	4	4	-40	-10	-3	-1	-1	0	-7	-3	-4	-2
2021	26	-62	-5	-2	-18	-61	16	5	5	-49	-13	-4	-1	-1	0	-8	-3	-5	-2
2022	35	-73	-9	-2	-21	-70	21	7	7	-58	-15	-7	-2	-2	0	-9	-4	-6	-3
2023	46	-84	-10	-3	-24	-75	27	10	9	-66	-17	-8	-2	-2	-1	-10	-4	-7	-3
2024	57	-92	-15	-4	-27	-80	34	12	12	-73	-19	-12	-3	-3	-1	-12	-5	-7	-3
2025	70	-100	-16	-5	-30	-81	41	14	14	-79	-21	-13	-3	-4	-1	-13	-5	-8	-4
2026	83	-108	-17	-6	-33	-82	49	17	17	-86	-22	-14	-4	-5	-1	-14	-6	-9	-4
2027	96	-110	-24	-7	-36	-81	57	20	20	-87	-23	-19	-5	-6	-2	-16	-7	-10	-4
2028	111	-117	-26	-9	-39	-80	65	23	23	-93	-24	-20	-5	-7	-2	-17	-7	-11	-5
2029	125	-125	-27	-11	-42	-81	74	26	25	-99	-26	-22	-6	-8	-2	-18	-8	-11	-5
2030	137	-131	-29	-13	-46	-80	81	28	28	-104	-27	-23	-6	-10	-3	-20	-8	-12	-5
2031	150	-135	-30	-15	-49	-78	88	31	31	-107	-28	-23	-6	-12	-3	-21	-9	-13	-6
2032	161	-133	-37	-17	-52	-78	95	33	33	-105	-27	-30	-8	-13	-4	-22	-9	-14	-6
2033	170	-137	-39	-19	-55	-79	100	35	35	-108	-28	-31	-8	-15	-4	-23	-10	-15	-7
2034	179	-139	-39	-21	-58	-78	105	37	36	-111	-29	-31	-8	-17	-4	-25	-10	-16	-7
2035	186	-144	-41	-23	-61	-81	110	39	38	-114	-30	-32	-8	-18	-5	-26	-11	-16	-7

Table 6. Scenario 3 - Peak Demand Impacts* (MW/Year)

Peak Demand Impacts* (MW/Year)														
Customer Class:	All	All	All	All	All	Residential	Wholesale	Commercial	Residential	Wholesale	Residential	Wholesale	Residential	Wholesale
Load Driver	EV	PV	IPSS	IoT	Total	EV	EV	EV	PV	PV	IPSS	IPSS	IoT	IoT
Year 2016	0.4	0.0	0.0	-0.1	0.3	0.3	0.1	0.0	0.0	0.0	0.0	0.0	-0.1	0.0
2017	0.9	0.0	0.0	-0.1	0.8	0.7	0.2	0.0	0.0	0.0	0.0	0.0	-0.1	0.0
2018	1.7	0.0	0.0	-0.2	1.6	1.3	0.4	0.1	0.0	0.0	0.0	0.0	-0.1	0.0
2019	2.9	0.0	0.0	-0.2	2.7	2.1	0.6	0.2	0.0	0.0	0.0	0.0	-0.2	0.0
2020	4.3	0.0	0.0	-0.3	4.1	3.2	0.9	0.2	0.0	0.0	0.0	0.0	-0.2	-0.1
2021	6.2	0.0	0.0	-0.4	5.8	4.5	1.3	0.4	0.0	0.0	0.0	0.0	-0.3	-0.1
2022	8.4	0.0	0.0	-0.5	7.9	6.2	1.7	0.5	0.0	0.0	0.0	0.0	-0.4	-0.1
2023	11.0	0.0	0.0	-0.6	10.4	8.0	2.3	0.7	0.0	0.0	0.0	0.0	-0.5	-0.1
2024	13.8	0.0	0.0	-0.8	13.0	10.1	2.9	0.9	0.0	0.0	0.0	0.0	-0.6	-0.2
2025	16.8	0.0	0.0	-1.0	15.8	12.2	3.5	1.1	0.0	0.0	0.0	0.0	-0.8	-0.2
2026	20.0	0.0	0.0	-1.2	18.8	14.6	4.1	1.3	0.0	0.0	0.0	0.0	-1.0	-0.2
2027	23.2	0.0	0.0	-1.5	21.7	16.9	4.8	1.5	0.0	0.0	0.0	0.0	-1.2	-0.3
2028	26.8	0.0	0.0	-1.8	24.9	19.5	5.5	1.8	0.0	0.0	0.0	0.0	-1.5	-0.4
2029	30.2	0.0	0.0	-2.2	28.0	22.0	6.3	2.0	0.0	0.0	0.0	0.0	-1.8	-0.5
2030	33.3	0.0	0.0	-2.6	30.7	24.2	6.9	2.2	0.0	0.0	0.0	0.0	-2.1	-0.5
2031	36.2	0.0	0.0	-3.1	33.1	26.3	7.5	2.4	0.0	0.0	0.0	0.0	-2.4	-0.6
2032	38.8	0.0	0.0	-3.5	35.3	28.3	8.0	2.5	0.0	0.0	0.0	0.0	-2.8	-0.7
2033	41.2	0.0	0.0	-3.9	37.3	30.0	8.5	2.7	0.0	0.0	0.0	0.0	-3.1	-0.8
2034	43.3	0.0	0.0	-4.3	39.0	31.5	9.0	2.8	0.0	0.0	0.0	0.0	-3.4	-0.9
2035	45.1	0.0	0.0	-4.7	40.4	32.8	9.3	3.0	0.0	0.0	0.0	0.0	-3.7	-1.0

*Peak demand defined as demand between 5pm and 6pm on non-holiday January weekdays

5. SCENARIO 4 - A CONNECTED WORLD II

Figure 4. Scenario 4 - System Load

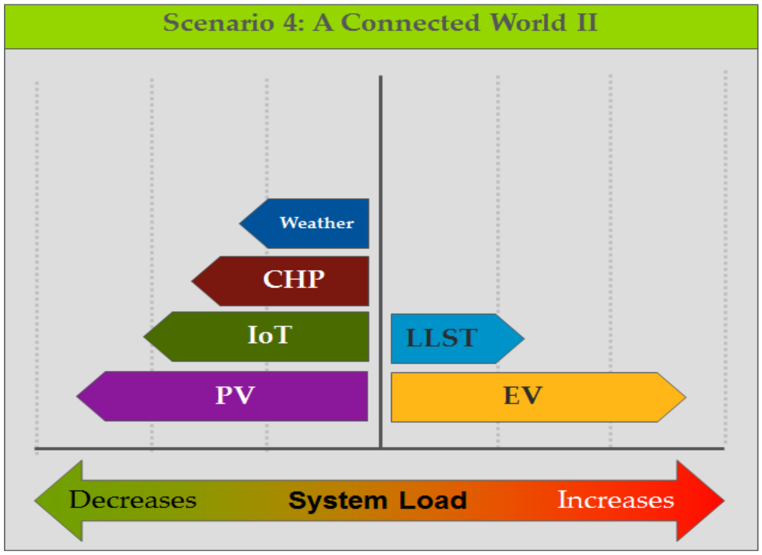

Table 7. Scenario 4 - Energy Impacts (GWh/Year)

Energy Impacts (GWh/Year)

Customer Class:	All	All	All	All	All	All	All	All
Load Driver (Year)	EV	PV	IPSS	IoT	LLST	CHP	Weather	Total
2016	2	-24	0	-1	0	0	-3	-27
2017	4	-35	-2	-1	0	0	-6	-41
2018	8	-49	-4	-2	0	0	-9	-56
2019	12	-64	-5	-2	0	-13	-12	-84
2020	19	-81	-10	-3	32	-13	-15	-71
2021	26	-97	-16	-4	32	-13	-18	-90
2022	35	-111	-24	-6	32	-26	-21	-121
2023	46	-122	-34	-7	32	-26	-24	-136
2024	57	-138	-39	-10	32	-26	-27	-151
2025	70	-143	-51	-12	38	-39	-30	-167
2026	83	-155	-55	-14	38	-39	-33	-176
2027	96	-158	-66	-18	38	-39	-36	-183
2028	111	-168	-71	-22	38	-52	-39	-203
2029	125	-171	-85	-27	38	-52	-42	-214
2030	137	-178	-89	-31	60	-52	-46	-198
2031	150	-177	-99	-37	60	-65	-49	-217
2032	161	-183	-102	-42	60	-65	-52	-223
2033	170	-189	-105	-47	60	-65	-55	-230
2034	179	-192	-107	-52	60	-65	-58	-235
2035	186	-191	-118	-57	60	-65	-61	-244

Customer Class:	Residential	Wholesale	Commercial	Residential	Wholesale	Residential	Wholesale	Residential	Wholesale	Commercial	Industrial	Industrial	Residential	Wholesale	Commercial	Industrial
Load Driver (Year)	EV	EV	EV	PV	PV	IPSS	IPSS	IoT	IoT	LLST	LLST	CHP	Weather	Weather	Weather	Weather
2016	1	0	0	-19	-5	0	0	-1	0	0	0	0	-1	-1	-1	0
2017	2	1	1	-28	-7	-2	0	-1	0	0	0	0	-3	-1	-2	-1
2018	5	2	1	-39	-10	-3	-1	-1	0	0	0	0	-4	-2	-2	-1
2019	7	3	2	-50	-13	-4	-1	-2	0	0	0	-13	-5	-2	-3	-1
2020	11	4	4	-64	-17	-8	-2	-3	-1	30	2	-13	-7	-3	-4	-2
2021	16	5	5	-77	-20	-12	-3	-3	-1	30	2	-13	-8	-3	-5	-2
2022	21	7	7	-88	-23	-19	-5	-5	-1	30	2	-26	-9	-4	-6	-3
2023	27	10	9	-97	-25	-27	-7	-6	-2	30	2	-26	-10	-4	-7	-3
2024	34	12	12	-110	-29	-31	-8	-8	-2	30	2	-26	-12	-5	-7	-3
2025	41	14	14	-114	-30	-40	-10	-9	-2	34	5	-39	-13	-5	-8	-4
2026	49	17	17	-123	-32	-43	-11	-11	-3	34	5	-39	-14	-6	-9	-4
2027	57	20	20	-125	-33	-53	-14	-14	-4	34	5	-39	-16	-7	-10	-4
2028	65	23	23	-133	-35	-56	-15	-18	-5	34	5	-52	-17	-7	-11	-5
2029	74	26	25	-135	-35	-67	-18	-21	-6	34	5	-52	-18	-8	-11	-5
2030	81	28	28	-141	-37	-70	-18	-25	-6	56	5	-52	-20	-8	-12	-5
2031	88	31	31	-141	-37	-78	-20	-29	-8	56	5	-65	-21	-9	-13	-6
2032	95	33	33	-145	-38	-81	-21	-34	-9	56	5	-65	-22	-9	-14	-6
2033	100	35	35	-150	-39	-83	-22	-37	-10	56	5	-65	-23	-10	-15	-7
2034	105	37	36	-153	-40	-85	-22	-41	-11	56	5	-65	-25	-10	-16	-7
2035	110	39	38	-151	-39	-94	-24	-45	-12	56	5	-65	-26	-11	-16	-7

Table 8. Scenario 4 - Peak Demand Impacts* (MW/Year)

Peak Demand Impacts* (MW/Year)

Customer Class:	All	All	All	All	All	All	All
Load Driver (Year)	EV	PV	IPSS	IoT	LLST	CHP	Total
2016	0.4	0.0	0.0	-0.3	0.0	0.0	0.1
2017	0.9	0.0	0.0	-0.3	0.0	0.0	0.6
2018	1.7	0.0	0.0	-0.4	0.0	0.0	1.4
2019	2.9	0.0	0.0	-0.5	0.0	-3.0	-0.6
2020	4.3	0.0	0.0	-0.7	3.7	-3.0	4.4
2021	6.2	0.0	0.0	-0.9	3.7	-3.0	6.0
2022	8.4	0.0	0.0	-1.2	3.7	-5.9	4.9
2023	11.0	0.0	0.0	-1.5	3.7	-5.9	7.2
2024	13.8	0.0	0.0	-2.0	3.7	-5.9	9.6
2025	16.8	0.0	0.0	-2.4	4.4	-8.9	10.0
2026	20.0	0.0	0.0	-3.0	4.4	-8.9	12.6
2027	23.2	0.0	0.0	-3.8	4.4	-8.9	15.0
2028	26.8	0.0	0.0	-4.6	4.4	-11.8	14.8
2029	30.2	0.0	0.0	-5.5	4.4	-11.8	17.3
2030	33.3	0.0	0.0	-6.5	7.4	-11.8	22.4
2031	36.2	0.0	0.0	-7.7	7.4	-14.8	21.2
2032	38.8	0.0	0.0	-8.8	7.4	-14.8	22.7
2033	41.2	0.0	0.0	-9.8	7.4	-14.8	24.1
2034	43.3	0.0	0.0	-10.8	7.4	-14.8	25.2
2035	45.1	0.0	0.0	-11.7	7.4	-14.8	26.0

Customer Class:	Residential	Wholesale	Commercial	Residential	Wholesale	Residential	Wholesale	Residential	Wholesale	Commercial	Industrial	Industrial
Load Driver (Year)	EV	EV	EV	PV	PV	IPSS	IPSS	IoT	IoT	LLST	LLST	CHP
2016	0.3	0.1	0.0	0.0	0.0	0.0	0.0	-0.2	-0.1	0.0	0.0	0.0
2017	0.7	0.2	0.0	0.0	0.0	0.0	0.0	-0.2	-0.1	0.0	0.0	0.0
2018	1.3	0.4	0.1	0.0	0.0	0.0	0.0	-0.3	-0.1	0.0	0.0	0.0
2019	2.1	0.6	0.2	0.0	0.0	0.0	0.0	-0.4	-0.1	0.0	0.0	-3.0
2020	3.2	0.9	0.2	0.0	0.0	0.0	0.0	-0.6	-0.1	3.4	0.3	-3.0
2021	4.5	1.3	0.4	0.0	0.0	0.0	0.0	-0.7	-0.2	3.4	0.3	-3.0
2022	6.2	1.7	0.5	0.0	0.0	0.0	0.0	-1.0	-0.3	3.4	0.3	-5.9
2023	8.0	2.3	0.7	0.0	0.0	0.0	0.0	-1.2	-0.3	3.4	0.3	-5.9
2024	10.1	2.9	0.9	0.0	0.0	0.0	0.0	-1.6	-0.4	3.4	0.3	-5.9
2025	12.2	3.5	1.1	0.0	0.0	0.0	0.0	-1.9	-0.5	3.9	0.5	-8.9
2026	14.6	4.1	1.3	0.0	0.0	0.0	0.0	-2.4	-0.6	3.9	0.5	-8.9
2027	16.9	4.8	1.5	0.0	0.0	0.0	0.0	-3.0	-0.8	3.9	0.5	-8.9
2028	19.5	5.5	1.8	0.0	0.0	0.0	0.0	-3.6	-1.0	3.9	0.5	-11.8
2029	22.0	6.3	2.0	0.0	0.0	0.0	0.0	-4.4	-1.1	3.9	0.5	-11.8
2030	24.2	6.9	2.2	0.0	0.0	0.0	0.0	-5.1	-1.3	6.9	0.5	-11.8
2031	26.3	7.5	2.4	0.0	0.0	0.0	0.0	-6.1	-1.6	6.9	0.5	-14.8
2032	28.3	8.0	2.5	0.0	0.0	0.0	0.0	-7.0	-1.8	6.9	0.5	-14.8
2033	30.0	8.5	2.7	0.0	0.0	0.0	0.0	-7.8	-2.0	6.9	0.5	-14.8
2034	31.5	9.0	2.8	0.0	0.0	0.0	0.0	-8.6	-2.2	6.9	0.5	-14.8
2035	32.8	9.3	3.0	0.0	0.0	0.0	0.0	-9.3	-2.4	6.9	0.5	-14.8

*Peak demand defined as demand between 5pm and 6pm on non-holiday January weekdays

6. SCENARIO 5 - COSTLY POWER IN A CONNECTED WORLD

Figure 5. Scenario 5 - System Load

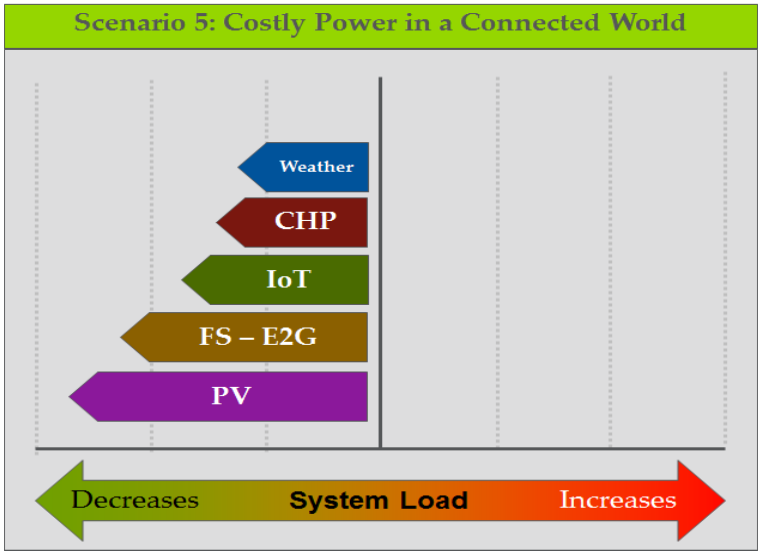

Table 9. Scenario 5 - Energy Impacts (GWh/Year)

Energy Impacts (GWh/Year)

Customer Class:	All	All	All	All	All	All	All
Load Driver (Year)	PV	IPSS	FS - E2G	IoT	CHP	Weather	Total
2016	-31	-2	0	-2	0	-3	-38
2017	-45	-4	-1	-2	0	-6	-59
2018	-62	-8	-2	-3	0	-9	-84
2019	-79	-13	-4	-4	-26	-12	-137
2020	-98	-22	-6	-5	-26	-15	-173
2021	-117	-33	-10	-7	-26	-18	-210
2022	-133	-47	-15	-9	-52	-21	-277
2023	-146	-61	-22	-12	-52	-24	-317
2024	-157	-78	-32	-15	-52	-27	-361
2025	-165	-92	-43	-19	-78	-30	-426
2026	-172	-106	-56	-23	-78	-33	-468
2027	-177	-119	-71	-29	-78	-36	-511
2028	-182	-133	-79	-35	-103	-39	-573
2029	-187	-152	-97	-43	-103	-42	-624
2030	-190	-164	-115	-50	-103	-46	-668
2031	-193	-173	-134	-59	-129	-49	-736
2032	-195	-182	-152	-68	-129	-52	-778
2033	-197	-192	-171	-76	-129	-55	-820
2034	-199	-198	-189	-84	-129	-58	-857
2035	-201	-208	-201	-91	-129	-61	-891

Customer Class:	Residential	Wholesale	Residential	Wholesale	Residential	Wholesale	Residential	Wholesale	Industrial	Residential	Wholesale	Commercial	Industrial
Load Driver (Year)	PV	PV	IPSS	IPSS	FS - E2G	FS - E2G	IoT	IoT	CHP	Weather	Weather	Weather	Weather
2016	-24	-6	-1	0	0	0	-2	0	0	-1	-1	-1	0
2017	-36	-9	-3	-1	-1	0	-2	0	0	-3	-1	-2	-1
2018	-49	-13	-6	-2	-2	0	-2	-1	0	-4	-2	-2	-1
2019	-62	-16	-10	-3	-3	-1	-3	-1	-26	-5	-2	-3	-1
2020	-78	-20	-17	-4	-5	-1	-4	-1	-26	-7	-3	-4	-2
2021	-92	-24	-26	-7	-8	-2	-6	-1	-26	-8	-3	-5	-2
2022	-105	-27	-37	-10	-12	-3	-7	-2	-52	-9	-4	-6	-3
2023	-116	-30	-49	-13	-18	-5	-9	-2	-52	-10	-4	-7	-3
2024	-125	-33	-62	-16	-25	-7	-12	-3	-52	-12	-5	-7	-3
2025	-131	-34	-73	-19	-34	-9	-15	-4	-78	-13	-5	-8	-4
2026	-136	-36	-84	-22	-44	-12	-18	-5	-78	-14	-6	-9	-4
2027	-141	-37	-95	-25	-56	-15	-23	-6	-78	-16	-7	-10	-4
2028	-144	-38	-106	-28	-63	-16	-28	-7	-103	-17	-7	-11	-5
2029	-148	-39	-120	-31	-77	-20	-34	-9	-103	-18	-8	-11	-5
2030	-151	-39	-130	-34	-91	-24	-40	-10	-103	-20	-8	-12	-5
2031	-153	-40	-137	-36	-106	-28	-47	-12	-129	-21	-9	-13	-6
2032	-155	-40	-144	-38	-121	-32	-54	-14	-129	-22	-9	-14	-6
2033	-157	-41	-152	-40	-136	-35	-60	-16	-129	-23	-10	-15	-7
2034	-158	-41	-157	-41	-150	-39	-66	-17	-129	-25	-10	-16	-7
2035	-160	-42	-165	-43	-159	-42	-72	-19	-129	-26	-11	-16	-7

Table 10. Scenario 5 - Peak Demand Impacts* (MW/Year)

Peak Demand Impacts* (MW/Year)															
Customer Class:	All	All	All	All	All	All	Residential	Wholesale	Residential	Wholesale	Residential	Wholesale	Residential	Wholesale	Industrial
Load Driver	PV	IPSS	FS - E2G	IoT	CHP	Total	PV	PV	IPSS	IPSS	FS - E2G	FS - E2G	IoT	IoT	CHP
2016	0.0	0.0	-0.1	-0.5	0.0	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	-0.4	-0.1	0.0
2017	0.0	0.0	-0.2	-0.5	0.0	-0.6	0.0	0.0	0.0	0.0	-0.1	0.0	-0.4	-0.1	0.0
2018	0.0	0.0	-0.4	-0.6	0.0	-1.0	0.0	0.0	0.0	0.0	-0.3	-0.1	-0.5	-0.1	0.0
2019	0.0	0.0	-0.6	-0.8	-5.9	-7.3	0.0	0.0	0.0	0.0	-0.5	-0.1	-0.6	-0.2	-5.9
2020	0.0	0.0	-1.0	-1.1	-5.9	-8.1	0.0	0.0	0.0	0.0	-0.8	-0.2	-0.9	-0.2	-5.9
2021	0.0	0.0	-1.7	-1.4	-5.9	-9.0	0.0	0.0	0.0	0.0	-1.3	-0.3	-1.1	-0.3	-5.9
2022	0.0	0.0	-2.5	-2.0	-11.8	-16.3	0.0	0.0	0.0	0.0	-2.0	-0.5	-1.6	-0.4	-11.8
2023	0.0	0.0	-3.7	-2.5	-11.8	-18.0	0.0	0.0	0.0	0.0	-3.0	-0.8	-2.0	-0.5	-11.8
2024	0.0	0.0	-5.3	-3.2	-11.8	-20.2	0.0	0.0	0.0	0.0	-4.2	-1.1	-2.5	-0.7	-11.8
2025	0.0	0.0	-7.1	-3.9	-17.7	-28.7	0.0	0.0	0.0	0.0	-5.7	-1.5	-3.1	-0.8	-17.7
2026	0.0	0.0	-9.3	-4.8	-17.7	-31.8	0.0	0.0	0.0	0.0	-7.4	-1.9	-3.8	-1.0	-17.7
2027	0.0	0.0	-11.8	-6.1	-17.7	-35.6	0.0	0.0	0.0	0.0	-9.3	-2.4	-4.8	-1.3	-17.7
2028	0.0	0.0	-13.5	-7.4	-23.6	-44.5	0.0	0.0	0.0	0.0	-10.7	-2.8	-5.8	-1.5	-23.6
2029	0.0	0.0	-16.4	-8.9	-23.6	-48.9	0.0	0.0	0.0	0.0	-13.0	-3.4	-7.0	-1.8	-23.6
2030	0.0	0.0	-19.4	-10.4	-23.6	-53.4	0.0	0.0	0.0	0.0	-15.4	-4.0	-8.2	-2.1	-23.6
2031	0.0	0.0	-22.5	-12.3	-29.5	-64.3	0.0	0.0	0.0	0.0	-17.8	-4.6	-9.7	-2.5	-29.5
2032	0.0	0.0	-25.6	-14.1	-29.5	-69.1	0.0	0.0	0.0	0.0	-20.3	-5.3	-11.1	-2.9	-29.5
2033	0.0	0.0	-28.6	-15.7	-29.5	-73.8	0.0	0.0	0.0	0.0	-22.7	-5.9	-12.4	-3.2	-29.5
2034	0.0	0.0	-31.7	-17.3	-29.5	-78.5	0.0	0.0	0.0	0.0	-25.1	-6.6	-13.7	-3.6	-29.5
2035	0.0	0.0	-33.2	-18.8	-29.5	-81.5	0.0	0.0	0.0	0.0	-26.4	-6.9	-14.9	-3.9	-29.5

*Peak demand defined as demand between 5pm and 6pm on non-holiday January weekdays

Appendix J

SUPPLY-SIDE RESOURCE OPTIONS REPORT

FORTIS BC

FORTISBC INC.

Appendix J

2016 Long Term Electric Resource Plan

Supply-Side

Resource Options Report

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List of Tables and Figures

1. INTRODUCTION

This Supply-Side Resource Options Report (ROR) provides information related to the various supply-side energy and capacity resources that are available to FBC to meet any forecast load-resource balance gaps over the 20 year resource planning horizon. These options include resources that could potentially be available either within or outside of FBC's service area. Resources from outside of FBC's service area which would require external transmission arrangements to serve FBC load. The resource options include market purchases as well as the PPA with BC Hydro. The information in this ROR enables FBC to determine the energy and capacity attributes and high-level unit costs for each resource. This enables the development of resource options portfolios so that alternative portfolios can be compared and a preferred portfolio can be selected. The portfolio analysis is provided in Section 9 of the LTERP.

The resource options information is provided at a level appropriate for long term resource planning. If and when particular resources are required in the future, Commission approval will be obtained by way of applications for approval of Certificates of Public Convenience and Necessity (CPCNs) or acceptance of energy supply contracts, as appropriate.

The supply-side resource options costs were developed in collaboration with BC Hydro as it updated its Resource Options Inventory in preparation for its 2015 Integrated Resource Plan (IRP) update, which was to be released in fall 2015 but has now been extended to the end of 2016. As part of this process, consultants and industry experts helped update the potential energy and capacity available from various resource options in B.C., as well as to update resource cost information. By collaborating on updating the resource options, FBC and BC Hydro achieved efficiencies in both time and costs and developed a consistent set of resource options as opposed to assessing resource options in B.C. through separate processes.

Demand-side resource options were not included in the resource option collaboration with BC Hydro as FBC and BC Hydro each have distinct demand side management programs tailored to their specific customer groups. This does not mean, however, that FBC and BC Hydro did not collaborate on determining demand side management potential in B.C. The 2015 CPR process was a collaborative effort by FEI, FBC, Pacific Northern Gas (PNG) and BC Hydro to determine energy conservation potential within the province. This is discussed further in Section 2.4 of the LT DSM Plan.

Numerous supply-side resource options are identified and/or evaluated within this ROR, reflecting the variety and abundance of potential electricity generating resources in the FBC service area or within B.C. While some options are commonly used amongst electrical utilities, such as run-of-river or gas-fired generation, others are considered less mainstream and/or are based on emerging technologies, such as geothermal generation. FBC has pre-screened the resource options for any emerging resource technologies that are not yet viable or cost effective as well as those that are not consistent with the *CEA*. This does not mean that these resource options could not be considered in the future; however, these resources have not been evaluated for the purposes of this ROR. Resources that have not be evaluated for these reasons are identified in the Resource Options Summary Table J3-1. These are discussed in Section 3.9 of this ROR.

Recent declines in costs relating to some renewable resource options, such as solar and wind power, means that these resource options may be more cost-effective than in the past. However, it is important to remember that these types of resources are intermittent and cannot reliably provide dependable capacity on their own. This must be taken into consideration when evaluating these resource options.

FBC has also given consideration to the geographical diversity of its resource base, given that the generation resources owned by FBC are all located in the Kootenay region while most of its load requirements are in the Okanagan region.

2. RESOURCE VALUATION METHODOLOGY

In addition to financial attributes, FBC considers a number of factors when evaluating its resource options. These include consistency with B.C. energy policy and resource attributes, such as operational characteristics and environmental impacts. Geographic diversity of resources is also a consideration given that all of the generation plants FBC owns are located in the Kootenay region whereas most of the load and recent load growth is in the Okanagan region. Locating new generation resources closer to the primary load centres would help mitigate risks relating to transmission disruptions and reliability in the future, and could reduce or delay the need for transmission upgrades in the future. Furthermore, a number of financial assumptions must be made in order to cost the resource options, such as gas and electricity market prices, BC Hydro electricity rates and the cost for carbon emissions. These are discussed in the following sections.

2.1 *ENERGY POLICY ENVIRONMENT*

2.1.1 The B.C. *Clean Energy Act*

As discussed in Section 2.2 of the LTERP, the *Clean Energy Act* (*CEA)* contains the specific energy objectives for the Province of B.C. These energy objectives are an important factor in resource planning and assessing resources options for FBC.

The *CEA* includes a requirement that BC Hydro achieve electricity self-sufficiency by 2016 and section 6(4) states that a public utility, in planning in accordance with section 44.1 of the *UCA*, must consider B.C.'s energy objective to achieve electricity self-sufficiency. Therefore, FBC must consider this objective when assessing its resource options and, in particular, the inclusion of market purchases in its resource portfolio. Market purchases are discussed in Section 3.5 of this ROR.

Section 2 of the *CEA* also includes the objective of generating at least 93 percent of the electricity in B.C. from clean or renewable resources. The *CEA* defines "clean or renewable resource" as meaning biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource. The Clean or Renewable Resource Regulation, B.C. Reg. 291/2010 (as amended) adds biogenic waste, waste heat and waste hydrogen to this list. Natural gas-fired generation is not a prescribed clean or renewable resource. Section 19 of the *CEA* states that the objectives relating to clean or renewable resources apply to BC Hydro and any prescribed public utility. While FBC does not fall into these categories, it takes this energy objective (as well as other relevant objectives) into consideration in its resource planning and resource assessment.

2.1.2 B.C. Climate Leadership Plan

B.C.'s CLP was released in August 2016 and reaffirms the provincial target to reduce annual GHG emissions to 80 percent below 2007 levels by 2050. The CLP requires that, going forward, 100 percent of the supply of electricity acquired by BC Hydro in British Columbia for the integrated grid must be from clean or renewable sources, except where concerns regarding reliability or costs must be addressed. While this requirement is not aimed directly at FBC, FBC considers this in its long term resource planning.

2.1.3 B.C. Carbon Tax

Increasing B.C. carbon taxes, currently set at $30 per tonne until 2018, is not addressed under the current CLP action items. The B.C. government does state in the CLP that it supports the adoption of the Province's $30 per tonne carbon tax as the benchmark price across the country. As any effective price signal on carbon has to go up over time, the B.C. government also supports increasing that price together in an affordable way, once other jurisdictions catch up.

In September 2016, the Canadian government announced a new plan to implement a national price on carbon. It will require the provinces to have a price of at least $10 per tonne of carbon dioxide equivalent emissions starting in 2018. The price would rise by $10 per tonne a year for the next four years, reaching $50 per tonne by 2022. Based on this announcement, it is likely that B.C.'s carbon tax will increase above its current level by 2022.

2.2 *RESOURCE ATTRIBUTES*

FBC considers a number of attributes of the various resource options it evaluates. These attributes include technical, financial, environmental and socio-economic development.

2.2.1 Technical Attributes

Technical attributes describe the energy and capacity characteristics of the resource options. Capacity refers to a resource's ability to meet customers' peak load requirements at a particular point in time and is typically measured in megawatts (MW). Installed capacity, sometimes called nameplate capacity, is the maximum designed output of a power generation plant. Dependable Capacity is defined as the generation capacity available for the peak hours during the each month of the year. For FBC, system peak electrical demand typically occurs in December or January sometime between the hours of 4 pm and 9 pm. Energy, on the other hand, is the amount of electricity generated over a period of time and is usually expressed in gigawatt hours (GWh) per year. Annual Energy is defined as the total energy that can be generated annually on average for the entire expected service life of a particular resource.

Depending on the type of energy conversion technology and fuel source, resources can be grouped into three distinct dispatch categories: base load resources, peaking resources and variable/intermittent resources.

Base load resources provide dependable capacity and are expected to operate at a high capacity utilization factor[1], generating significant amounts of electrical energy over the entire year. Such resources can be reasonably evaluated for both energy and capacity attributes. Examples include:

- Hydro generation with some storage reservoir;
- Combined cycle gas turbine (CCGT) plants;
- Biomass wood-waste thermal generation;
- Geothermal generation; and
- Coal thermal generation.

Peaking resources can be dispatched to provide capacity but are expected to operate at a low utilization factor, generating electricity when it is needed. Peaking resources typically have a low cost to construct per unit of capacity, but high per unit energy costs. These resources can also act as planning reserve margin assets which can be brought into service quickly following a contingency event (e.g. loss of a base load facility), meet sudden changes in customer load requirements or help firm up intermittent resources. Although these resources can produce energy when generating, they are primarily evaluated for their capacity attributes. Examples include:

- Simple cycle gas turbine (SCGT) plants; and
- Pumped storage hydro.

Variable/intermittent resources provide little dependable capacity and typically operate at lower capacity utilization rates than base load resources. Variable/intermittent resources are often renewable resources and generate electricity when their fuel source is available; therefore, generation from these resources cannot be increased on demand in response to changes in customer load. For example, generation from intermittent resources like wind or solar is determined by external environmental factors such as wind speeds and amount of sunshine. Generation from variable resources, like run-of-river, is determined by seasonal flows in rivers, such as the spring freshet. Their generation may not coincide with high system load demand or high market prices. Variable/intermittent resource 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 some variable/intermittent resources can provide at least a small quantity of dependable capacity, they are not considered dispatchable and therefore are primarily valued for their energy attributes. Examples include:

[1] Capacity utilization factor is the ratio of the actual output from a plant over the year to the maximum possible output from it for a year under ideal conditions.

- Wind turbine generation;
- Run-of-river hydro generation; and
- Utility-scale PV solar.

A balanced resource portfolio could include a combination of these supply-side resource types along with demand-side reducing resources to provide a cost effective, diversified, reliable and environmentally-sound portfolio to meet daily and seasonal variations in system load. The analysis of resource options portfolios is discussed in Section 9 of the LTERP.

2.2.2 Financial Attributes

To enable comparisons of the costs of resources that represent a wide range of technologies and fuel sources, capital and operating costs and project lifespans, the financial characteristics of the different resource options are described by two simplified cost metrics: Unit Capacity Cost (UCC) and Unit Energy Cost (UEC). These unit cost comparisons enable an initial ranking of various resources based on cost alone. It should be noted, however, that other resource attributes, such as a resource's ability to respond to changes in demand (i.e. dispatchability), annual energy and dependable capacity and environmental factors, should be considered to fully describe and assess the various resources. The financial as well as other resource attributes, such as the technical, environmental and socio-economic characteristics, are considered in the portfolio analysis in Section 9.

UCC is the annualized cost of providing dependable capacity for each resource option, expressed in $ per kW-year. UEC is the annualized cost of generating a unit of electrical energy using a specific resource option, expressed in $ per MWh. The unit costs include capital, fixed operating and variable operating, including any fuel, costs.

The UCC and UEC values are presented in this ROR on a levelized annual cost basis in order to enable comparison between different resources with different cost structures and energy and capacity values. This means that the UCCs and UECs are calculated by taking the present value of the total annual cost in real dollars of a capacity or energy resource and dividing it by the present value of the resource's dependable capacity or annual energy, respectively. The UECs and UCCs within this ROR are presented in real 2015 dollars.

FBC has made some adjustments to the base unit costs that were developed from the resource option collaboration process with BC Hydro. The base UECs and UCCs include the capital and operating costs for each resource option. The adjusted unit costs include items other than the base costs such as transmission interconnection costs, wheeling charges, intermittent resource integration costs and carbon costs for resources that are not clean or renewable.

It should be noted that while the base cost information, such as capital and operating costs, for the various supply-side resources is the same for FBC and BC Hydro, the base unit costs (i.e. UECs and UCCs) will differ slightly between FBC and BC Hydro. This is because some of the financial assumptions used by FBC are different than those used by BC Hydro. FBC uses different Weighted Average Cost of Capital (WACC) discount rate (DR) assumptions than BC Hydro. This is because FBC's WACC has a different debt and equity ratio and return on equity than BC Hydro's WACC. Furthermore, the adjusted unit costs may also differ due to the differences in the adders to the base unit costs. For example, BCH may have different interconnection or wheeling costs than FBC may incur.

2.2.2.1 Financial Assumptions

A number of assumptions are made in order to determine the base and adjusted UCCs and UECs for the various resource options. These include the WACC discount rate, inflation rate, wheeling, line losses, integration, carbon and interconnection costs. These are discussed in the sections below. Also required to determine resource option costs are electricity, gas and carbon price forecasts, PPA rates and the Canada-US exchange rate forecast. These forecasts are discussed in Section 2.5 of the LTERP regarding FBC's Planning Environment. Within this ROR, base electricity and gas market prices, carbon cost and BC Hydro PPA rate scenario assumptions have been used. In Section 9, the portfolio analysis examines the costs for the various resource portfolios based on different assumptions, including various market prices and PPA rate scenarios.

Weighted Average Cost of Capital

The WACC is the expected cost to finance a resource acquisition and includes both debt and equity components. For this ROR, FBC has rounded this value to 6 percent (in real terms) based on FBC's AFUDC rate for 2017, which is equal to the FBC after-tax WACC, per the FBC Annual Review for 2017 Rates Application (Section 8.3.5), filed August 8, 2016.

Inflation Rate

An inflation rate assumption is required when converting between nominal dollars and real, or inflation-adjusted, dollars. FBC has assumed an annual inflation rate of about 2 percent. The projected inflation factors by year are provided in Section 2.5.5 of the LTERP regarding FBC's Planning Environment.

Wheeling Costs

Wheeling costs include the costs for the transportation of electric power from the generation source or plant to the FBC service area where it can be provided to customers and related losses. These costs can be for transporting electricity from BC Hydro's system to the FBC system or from sources in the U.S., such as the Mid-C electricity market hub, to the FBC system.

Wheeling costs within B.C. are based on the BC Hydro Open Access Transmission Tariff (OATT), effective April 1, 2016. This equates to $8.85 per MWh for wheeling costs and 6.28 percent for line losses, assuming hourly rates.

For FBC market imports from the Mid-C market hub, FBC has assumed the cost for this transmission is based on the Bonneville Power Administration (BPA) transmission and loss rates, effective October 1, 2015[2], escalated based on inflation. These equate to about $7.50 per MWh for wheeling costs and 3 percent for line losses.

Intermittent Resource Options' Integration Costs

Integration costs are those related to integrating an intermittent resource, such as wind or solar, into the FBC transmission system. Because wind or solar power generation is highly variable and unpredictable, highly responsive and flexible generation capacity reserves are required to maintain system reliability and security. The incremental costs for this are captured by adding integration costs to these variable resources.

FBC has assumed $10 per MWh for onshore wind integration costs, based on a previous BC Hydro study. BC Hydro has assumed an onshore wind integration average cost of $10 per MWh.[3] This value was first used in BC Hydro's 2008 Long-Term Acquisition Plan and continued to be used in BC Hydro's 2013 IRP, in the latter instance based on a 2010 wind integration study range of $5 per MWh to $15 per MWh. FBC understands that BC Hydro expects to review this wind integration cost when preparing to update its resource options for its next IRP.

FBC has also assumed $10 per MWh for solar integration costs. FBC and BC Hydro have not conducted any solar integration studies; however, studies done in other jurisdictions have provided some basis for estimating solar integration costs. For example, a recent study by Idaho Power indicates that solar integration costs are in the range of several dollars per MWh, depending on the size of the project[4]. The study notes that solar integration costs are lower than wind integration costs due to less variability and uncertainty with solar generation. However, FBC has assumed $10 per MWh given the relatively small size of the solar projects evaluated within this ROR and lower solar yield than the more southern state of Idaho.

Wind and solar integration studies specific to the FBC system could provide more accurate integration costs for these resources. However, FBC assumes these estimated integration costs are reasonable for the purposes of developing per-unit resource option costs at a high-level for resource planning.

Carbon Costs

For the purposes of this ROR, carbon costs are based on the base forecast for carbon prices in B.C. per Section 2.5 of the LTERP. These carbon costs are applied to the cost of natural gas-fired generation and market purchases in the portfolio analysis in Section 9.

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[2] BPA 2016 Transmission, Ancillary and Control Area Service Rate Summary Effective October 1, 2015, PTP-16 Point-To-Point, Short-Term (firm and non-firm), Hourly (firm and non-firm).
[3] BC Hydro 2013 IRP, Page 3-45.
[4] Idaho Power Solar Integration Study Report, June 2014, page 15.

System Interconnection Costs

Interconnection costs are related to connecting any new generating resources to the FBC or BC Hydro transmission systems. These include the cost of power lines, substation costs and any transmission system upgrades. Power lines costs are determined by the transmission voltage level, which is based on the generating plant output and its distance from the nearest FBC or BC Hydro transmission line. For resource options outside FBC's service area, the interconnection costs to the BC Hydro system have been included. For resource options within the FBC service area, the interconnection costs to the FBC system have been included. The interconnection costs can vary according to the distance from the main transmission system and the size of the resource option.

2.2.3 Environmental Attributes

Environmental considerations are an important objective of the *CEA* and energy policy in B.C. Environmental attributes describe the estimated environmental impact of the various resource options. While DSM resources are assumed to have no negative environmental impacts, some supply-side resources can have impacts on the atmosphere, land and/or water. In the resource options collaboration with BC Hydro, these environmental attributes for the various resource options were not updated from BC Hydro's 2013 IRP. Therefore, for the purposes of this ROR and the portfolio analysis in Section 9, FBC has characterized resource options as either clean or renewable or not according to the *CEA* definition. The *CEA* defines clean or renewable resources as including biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource. FBC also considers energy and capacity under the PPA to be clean and renewable. Based on the regional electricity generation source mix as discussed in Section 2.4, market purchases would include a mix of clean or renewable and non-clean or renewable resources.

2.2.4 Socio-Economic Development Attributes

Social and economic development and job creation are included among B.C.'s energy objectives as set out in the *CEA*. These objectives include contributions to provincial gross domestic product (GDP), employment and government revenue and supporting community and First Nations development. FBC has categorized the economic development attributes for each resource option into low, medium and high impact categories based on employment contributions (full-time equivalent or FTE) per MW of installed capacity for each resource option. A high impact rating means that a particular resource option contributes more to provincial job creation on a per MW basis than a resource option categorized as low impact. Generally speaking, resource options with higher employment contributions per MW will also contribute more to provincial GDP as well as support community and First Nations development. Employment impacts were derived from BC Hydro's 2013 IRP (Appendix 3A-4). Typically, larger-sized plants that take many years to build and require on-going operations will provide higher socio-economic benefits than smaller plants that can be built relatively quickly with minimal operating requirements. The following table shows the FTE per MW rankings for each resource option.

Table J2-1: Resource Options FTE/MW Rankings

Resource Option	Average Construction FTE/MW	Average Operating FTE/MW	Average FTE/MW	Ranking
Municipal Solid Waste	5.0	9.3	14.3	High
Geothermal	2.6	2.2	4.8	High
Biomass	2.0	2.7	4.6	High
Similkameen	3.6	1.2	4.8	High
CCGT	0.5	1.3	1.8	Medium
Biogas	1.6	2.1	3.6	Medium
Run-of-River	1.6	1.2	2.8	Medium
Wind	0.8	0.4	1.1	Medium
SCGT	0.2	0.3	0.5	Low
Pumped Storage Hydro	0.5	0.0	0.6	Low
Solar	0.3	0.0	0.3	Low

3. SUPPLY-SIDE RESOURCE OPTIONS

There is the potential for many types of resource options within the FBC service area and within B.C. over the planning horizon. The summary table below identifies the resource options that were evaluated in this ROR as well as those that were not evaluated due to high cost (e.g. not commercially viable at this time) or due to restrictions on their use arising from the *CEA*. More discussion of the resources options that were not evaluated is provided in Section 3.9 of this ROR.

Table J3-1: Supply-Side Resources Evaluated vs. Not Evaluated

Resource	Status
PPA energy and capacity	Evaluated
Market Purchases	Evaluated
Wood-Based Biomass	Evaluated
Biogas	Evaluated
Municipal Solid Waste (MSW)	Evaluated
Geothermal	Evaluated
Gas-Fired Generation (CCGT)	Evaluated
Similkameen Hydro Project	Evaluated
Gas-Fired Generation (SCGT)	Evaluated
Pumped Hydro Storage	Evaluated
Onshore Wind	Evaluated
Run-of-River Hydro	Evaluated
Solar	Evaluated
Coal	Not Evaluated
Nuclear	Not Evaluated
Battery Storage	Not Evaluated
Offshore Wind	Not Evaluated
Tidal	Not Evaluated
Wave	Not Evaluated

The following table provides a summary of the resource options that were evaluated including their resource type, dependable capacity, annual energy as well as environmental and socio-economic attributes. For those resource options showing a range of capacity and energy, a number of different-sized plants were considered for that particular resource option. For gas-fired generation, FBC has included both Combined Cycle Gas Turbine (CCGT) plants as well as Simple Cycle Gas Turbine (SCGT) plants. The resources are sorted in the table by type with the PPA energy and capacity in green, market purchases in orange and generation resources in blue.

Table J3-2: Resource Options Type, Size, Environmental and Socio-Economic Attributes

Resource Option	Type	Dependable Capacity (MW)	Annual Energy (GWh)	Clean/ Renewable	Socio-Economic Benefits
PPA Tranche 1 Energy	Baseload	N/A	Up to 1,041	Yes	N/A
PPA Tranche 2 Energy	Baseload	N/A	1,042 to 1,752	Yes	N/A
PPA Capacity	Baseload	Up to 200	N/A	Yes	N/A
Market Purchases	Baseload or Peaking	Up to 150	Up to 1,314	Mixed	N/A
Wood-Based Biomass	Baseload	12 – 63	98 - 503	Yes	High
Biogas	Baseload	1 – 2	7 - 18	Yes	Medium
Municipal Solid Waste	Baseload	25	211	No	High
Geothermal	Baseload	8 – 89	57 - 657	Yes	High
Gas-Fired Generation (CCGT)	Baseload	67 – 279	411 – 1,712	No	Medium
Similkameen Hydro Project	Baseload	32	215	Yes	High
Gas-Fired Generation (SCGT)	Peaking	48 – 192	75 - 303	No	Low
Pumped Hydro Storage	Peaking	500	0	Yes	Low
Onshore Wind	Intermittent/Variable	8 – 81	100 – 1,239	Yes	Medium
Run-of-River Hydro	Intermittent/Variable	2 – 13	34 - 314	Yes	Medium
Solar	Intermittent/Variable	1	7	Yes	Low

The following table shows the unit energy and capacity costs for the resource options. The range of unit costs reflects the different plant sizes available for some of the resource options. No UEC is presented for SCGT gas-fired generation or Pumped Hydro Storage because these resources are primarily used for providing capacity and not energy. The UEC and UCC ranges for market purchases and PPA Tranche 1 and 2 energy and PPA capacity reflect the high and low range of market price forecasts and PPA rate scenarios as described in Section 2.5.

Table J3-3: Supply-Side Resource Options Unit Cost Summary

Resource Option	UEC ($/MWh)	UCC ($kW-yr)
PPA Tranche 1 Energy	$47 - $56	N/A
PPA Tranche 2 Energy	$85 - $130	N/A
PPA Capacity	N/A	$96 - $115
Market Purchases	$34 - $64	$169 - $355
Wood-Based Biomass	$118 - $188	$663 - $774
Biogas	$77 - $101	$621 - $838
Municipal Solid Waste	$134	$1,031
Geothermal	$132 - $217	$857 - $1,506
Gas-Fired Generation (CCGT)	$82 - $100	$147 - $279
Similkameen Hydro Project	$202	$1,298
Gas-Fired Generation (SCGT)	N/A	$80 - $143
Pumped Hydro Storage	N/A	$217
Onshore Wind	$111 - $145	$1,219 - $1,618
Run-of-River Hydro	$87 - $150	$1,230 - $1,924
Solar	$169 - $184	$1,399 - $1,413

When looking at the unit costs in the table above, it is important to remember that a resource option with the lowest unit cost may not be the best fit for FBC in terms of meeting customers' load requirements. For example, while pumped storage hydro has one of the lowest UCCs ($217 per kW/year), the size of this resource option, with a capacity of 500 MW and no energy contribution, makes it an impractical option for FBC's requirements. It would provide FBC with too much capacity given the size of the Company's projected capacity gaps, and no energy. The portfolio analysis in Section 9 helps determine the optimal mix of resources based on cost and FBC's monthly energy and capacity requirements.

The following figures graphically show the range of unit costs for the resource options that were considered. Resources are sorted from lowest to highest unit costs. The first figure shows the unit energy costs; the second shows the unit capacity costs. These figures help illustrate the costs of the various resource options relative to each other.

Figure J3-1: Resource Options Unit Energy Costs

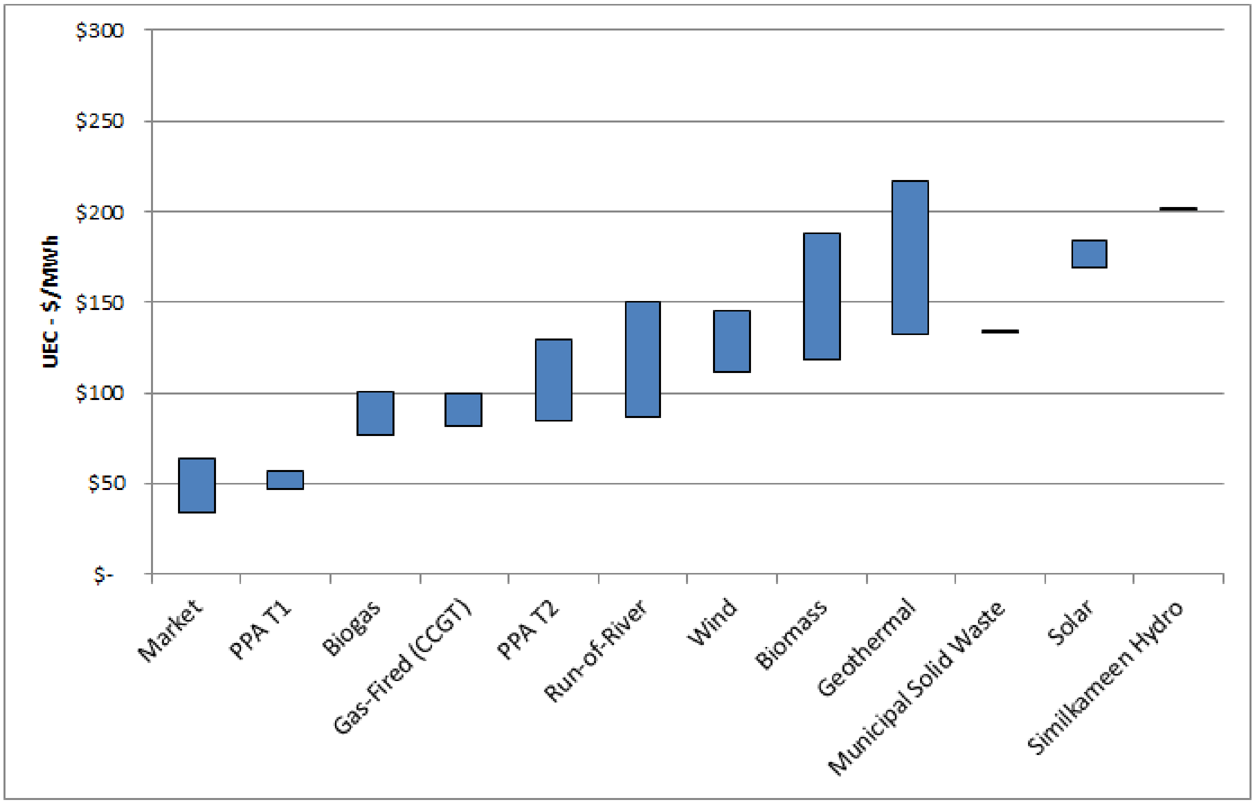
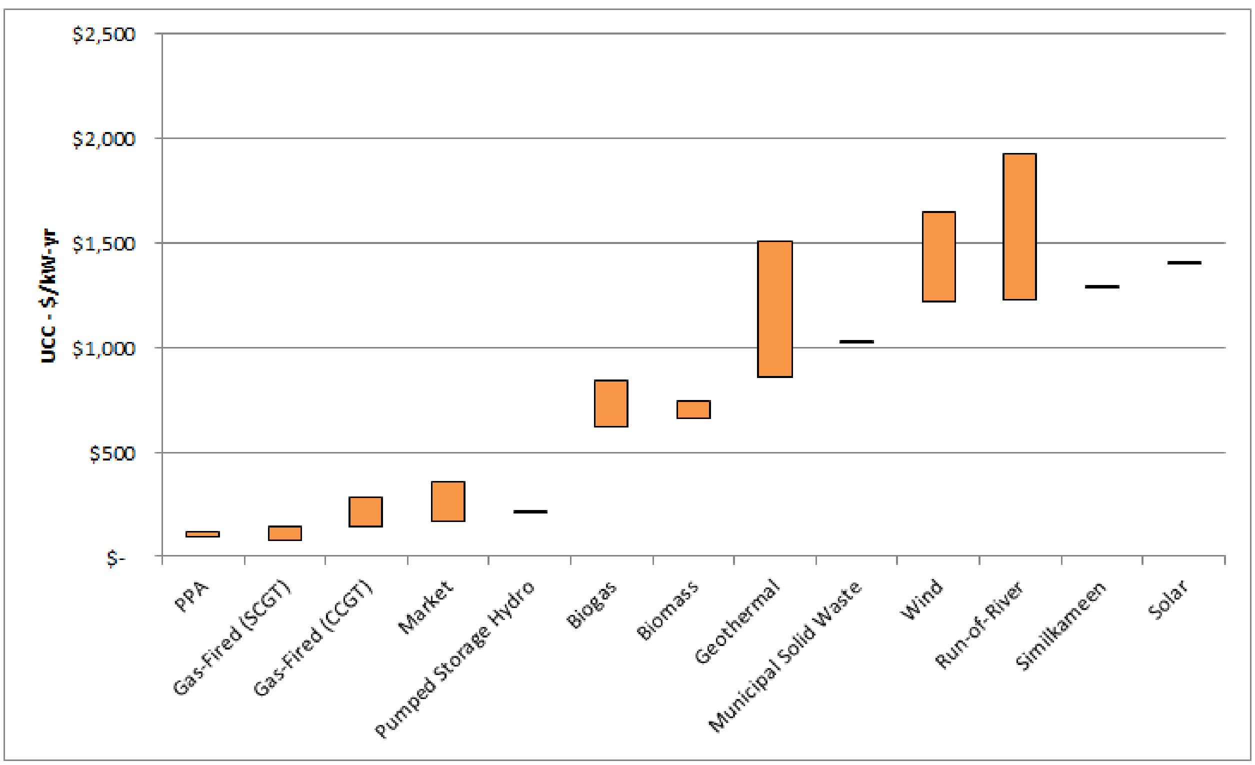


Figure J3-2: Resource Options Unit Capacity Costs



Detailed information for each resource FBC considered is provided in the following sections, organized by resource type. This includes supply curves (which show available supply and associated unit cost), as well as details regarding energy and capacity available from the resources and their environmental and socio-economic attributes.

3.1 BASE LOAD RESOURCES

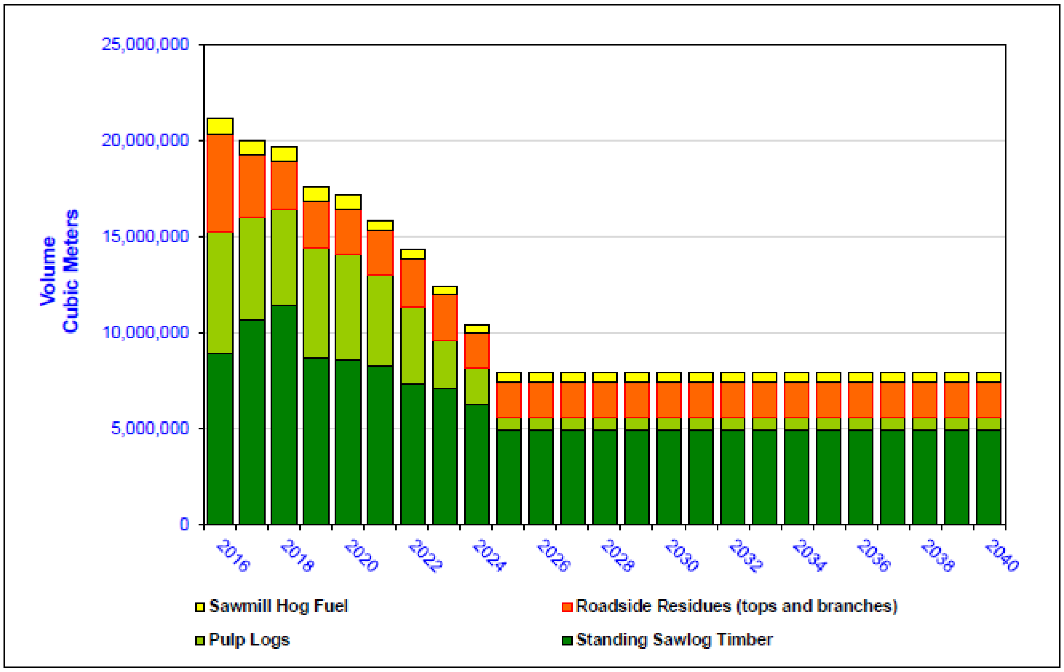
3.1.1 Wood-Based Biomass

Biomass is different from some other renewable energy sources, such as wind and solar, as it is dispatchable. Biomass also produces carbon neutral air emissions from combustion[5]. It requires that a constant supply of fuel be collected and concentrated at a specific location. Therefore, a key factor affecting the sustainability of generation from this resource is biomass availability and transportation to and storage or management at site.

Wood-based biomass energy is electricity generated from the combustion or gasification of organic materials. The four main fibre categories of wood-based biomass are sawmill wood waste (often called "hog fuel"), roadside wood waste from normal tree harvesting operations, standing timber and standing pulp logs from the mountain pine beetle epidemic. The most critical requirement for operating a biomass plant is the assurance of a stable fuel supply. As long as adequate fuel supply is available, biomass-fired steam-cycle plants can be operated as base load systems. Wood-based biomass project costs are largely dependent on capital plant and operation costs as well as the costs to deliver the fuel to the plant. In general, forecasts indicate a declining supply of available biomass in B.C. over the long term.

[5] BC Hydro 2013 IRP, Appendix 3A, page 53.

Figure J3-3: Forecast of Annual Available B.C. Wood-Based Biomass[6]

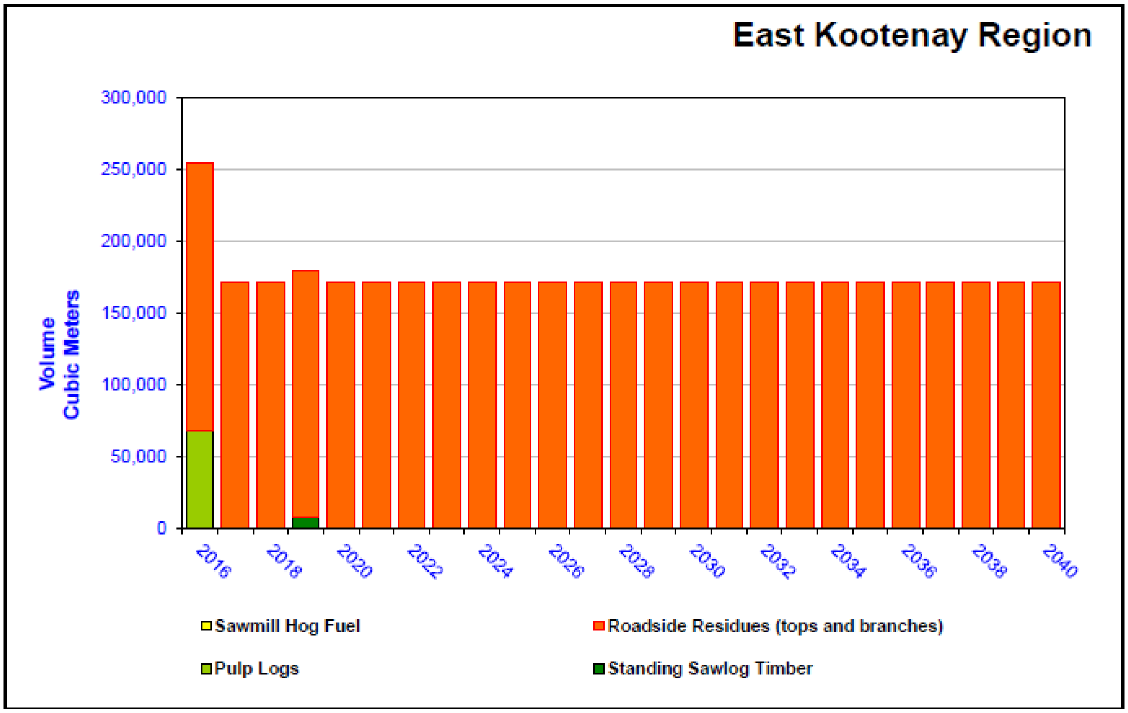


This projected decrease is due to several factors including fewer sawmills, less standing dead biomass as a result of harvesting, fires and trees falling down, reductions in regional Annual Allowable Cuts (AAC) and higher pulp log costs.

The forecasts for annual available wood based biomass within the regions in FBC's service area are provided in the following figures.

[6] Industrial Forestry Services Ltd., Wood Based Biomass in British Columbia and its Potential for New Electricity Generation, July 2015, page ii.

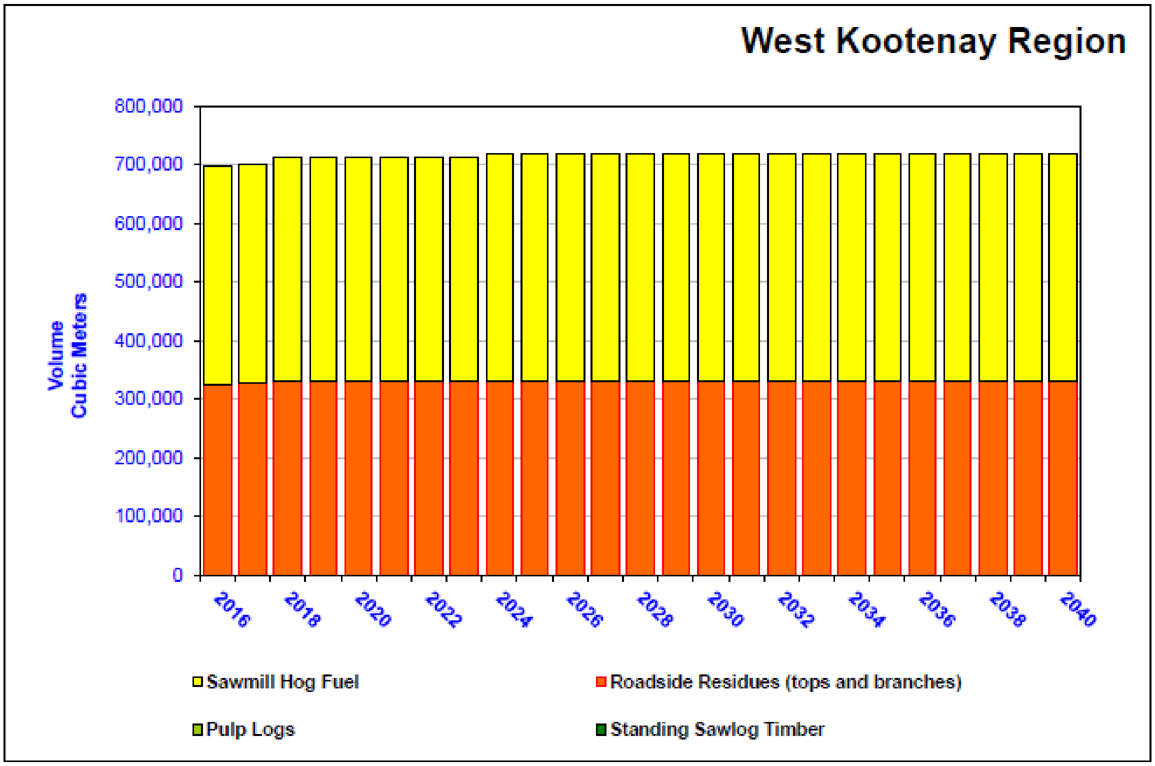
1 **Figure J3-4: Forecast of Annual Available Wood-Based Biomass in the East Kootenay Region**[7]



2

[7] Industrial Forestry Services Ltd., Wood Based Biomass in British Columbia and its Potential for New Electricity Generation, July 2015, page 26.

1 **Figure J3-5: Forecast of Annual Available Wood-Based Biomass in the West Kootenay Region**[8]



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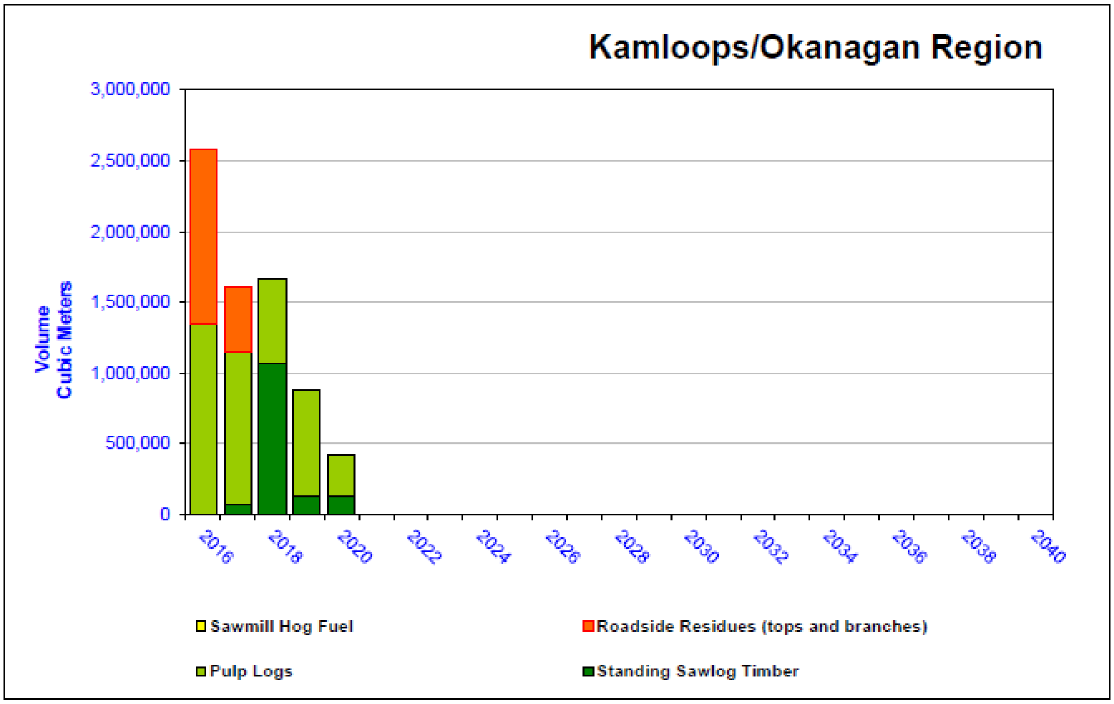
[8] Industrial Forestry Services Ltd., Wood Based Biomass in British Columbia and its Potential for New Electricity Generation, July 2015, page 28.

Figure J3-6: Forecast of Annual Available Wood-Based Biomass in the Kamloops/Okanagan Region[9]



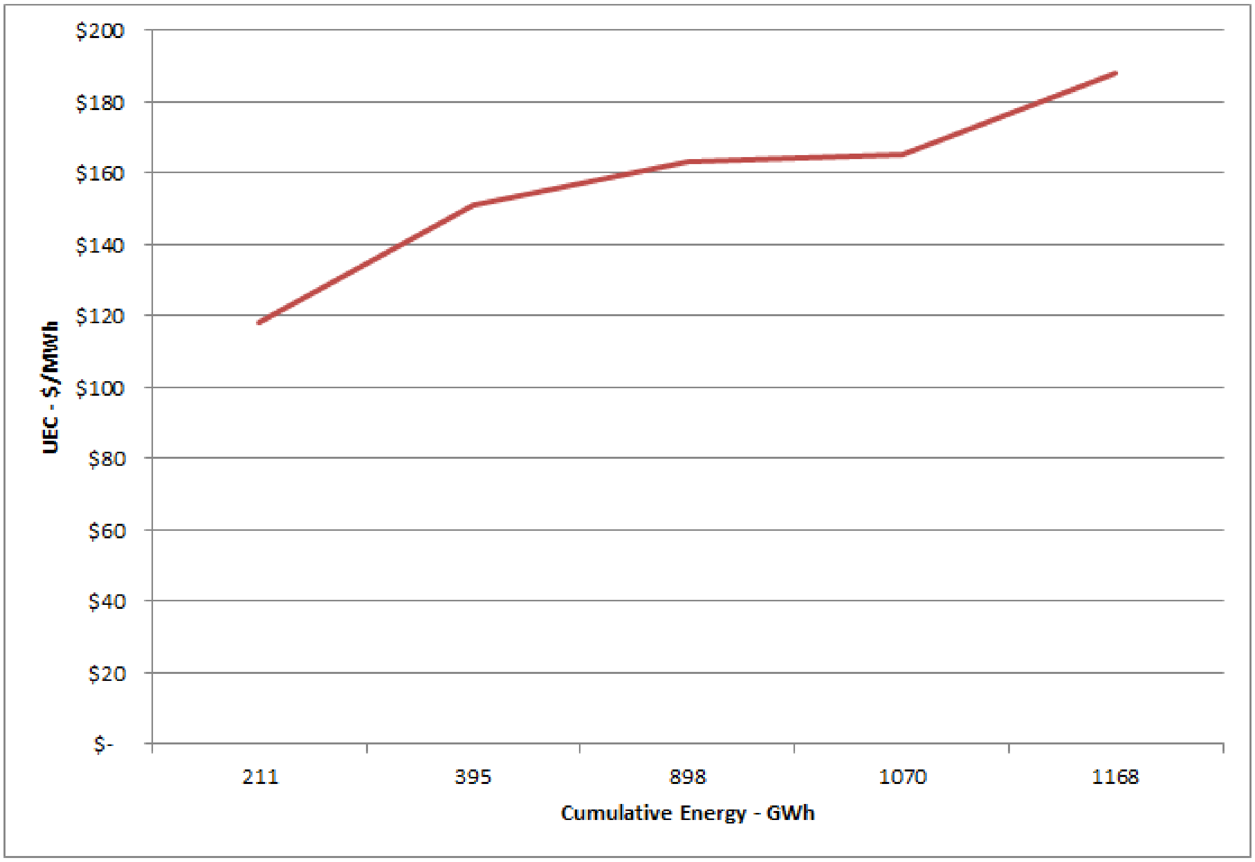
As the figures above show, there is more potential for wood-based biomass in the Kootenay regions than in the Kamloops/Okanagan region of B.C.

FBC notes that the 2016 CLP includes further action to increase the rate of tree replanting and wood fibre recovery[10]. This may help to improve the wood-based biomass potential in the future.

Based on this information and the cost projections from FBC's collaboration with BC Hydro, the wood based biomass supply curve is presented in the following figure.

[9] Industrial Forestry Services Ltd., Wood Based Biomass in British Columbia and its Potential for New Electricity Generation, July 2015, page 31.
[10] BC 2016 Climate Leadership Plan, page 24.

Figure J3-7: Wood Based Biomass Supply Curve

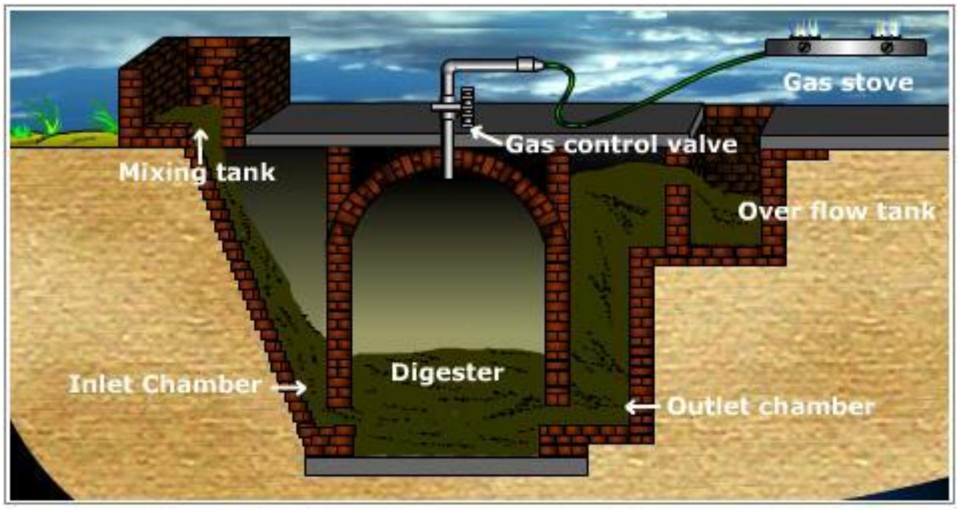


For the environmental attribute, wood-based biomass is a clean and renewable resource per the *CEA*. FBC ranks it as 'high' in terms of socio-economic attributes given the plant construction requirements, on-going plant operations and jobs related to transporting the biomass fuel.

3.1.2 Biogas or Landfill Gas

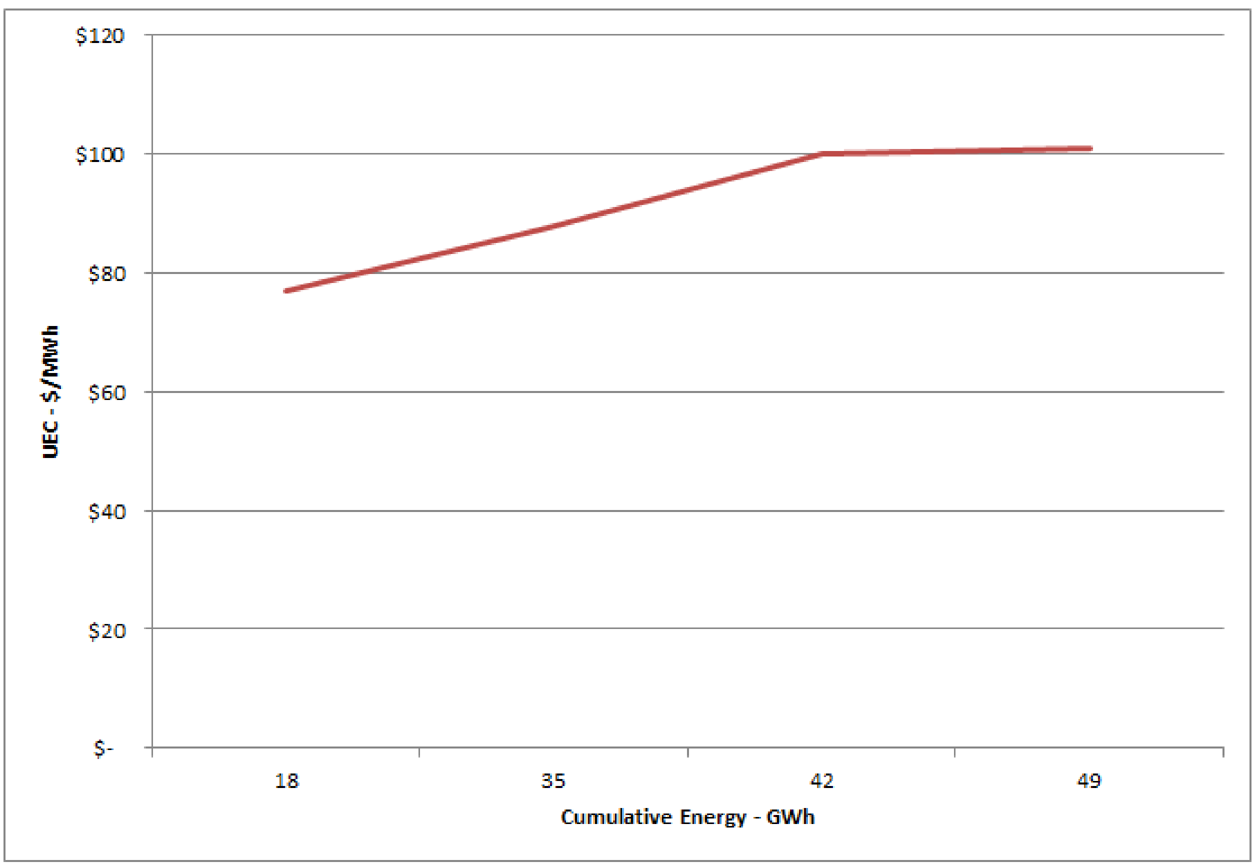
Biogas energy is generated from the decomposition of organic waste with the resulting methane gas captured and used as a fuel source. Sources of biogas energy include landfill sites, sewage treatment plants and anaerobic digestion organic waste processing facilities.

Figure J3-8: Example of Fixed-Dome Biogas Plant



BC Hydro evaluated a dozen potential sites for biogas in B.C., with installed capacity from 1 MW to 3 MW in size. FBC has included four of these project sites as potential resource options based on cost and their proximity to the FBC system. The following figure shows the supply curve for these four biogas options.

Figure J3-9: Biogas Supply Curve

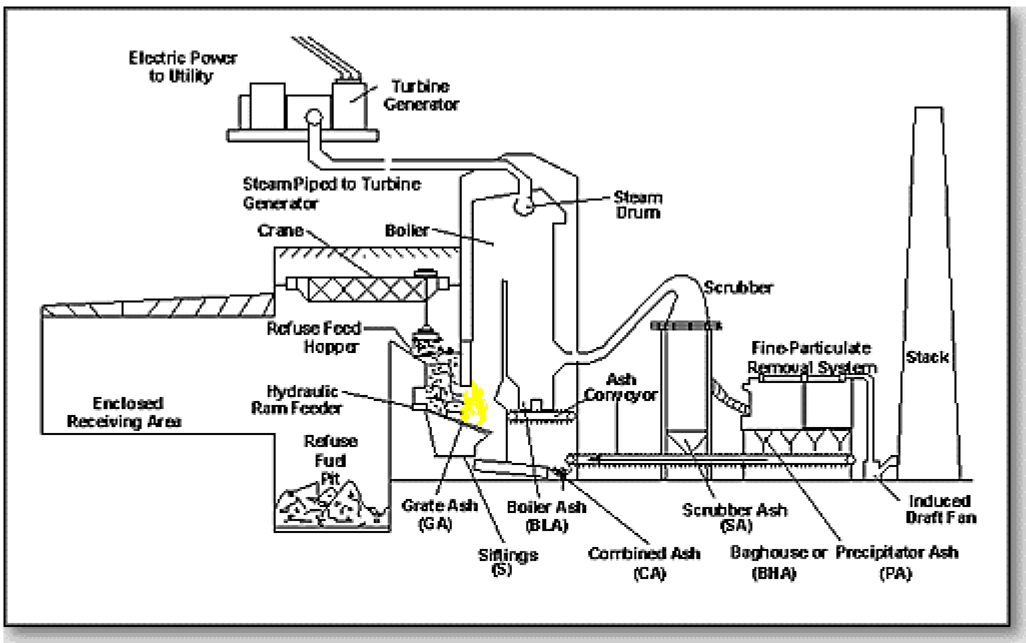


Biogas gas is considered carbon neutral and is included in the definition of "clean or renewable resource" in the *CEA*.[11] On a per MW basis, the socio-economic contribution for biogas plants is be considered 'medium'.

3.1.3 Municipal Solid Waste

Generating electricity from municipal solid waste (MSW) involves the incineration of municipal waste to produce electricity. Essentially, the waste is burned at high temperatures and the resulting heat and gases pass into a boiler area, where they heat tubes filled with water. That water boils to become steam and the steam turns a turbine generator to create electricity.

Figure J3-10: Example of MSW Plant



As part of the resource collaboration process, three potential sites for MSW in B.C. were updated. FBC has included in its evaluation the site BC Hydro determined to be the lowest cost site and excluded the other two more costly sites. The energy cost for this potential site is $137/MWh and it would make 211 GWh of firm energy available.

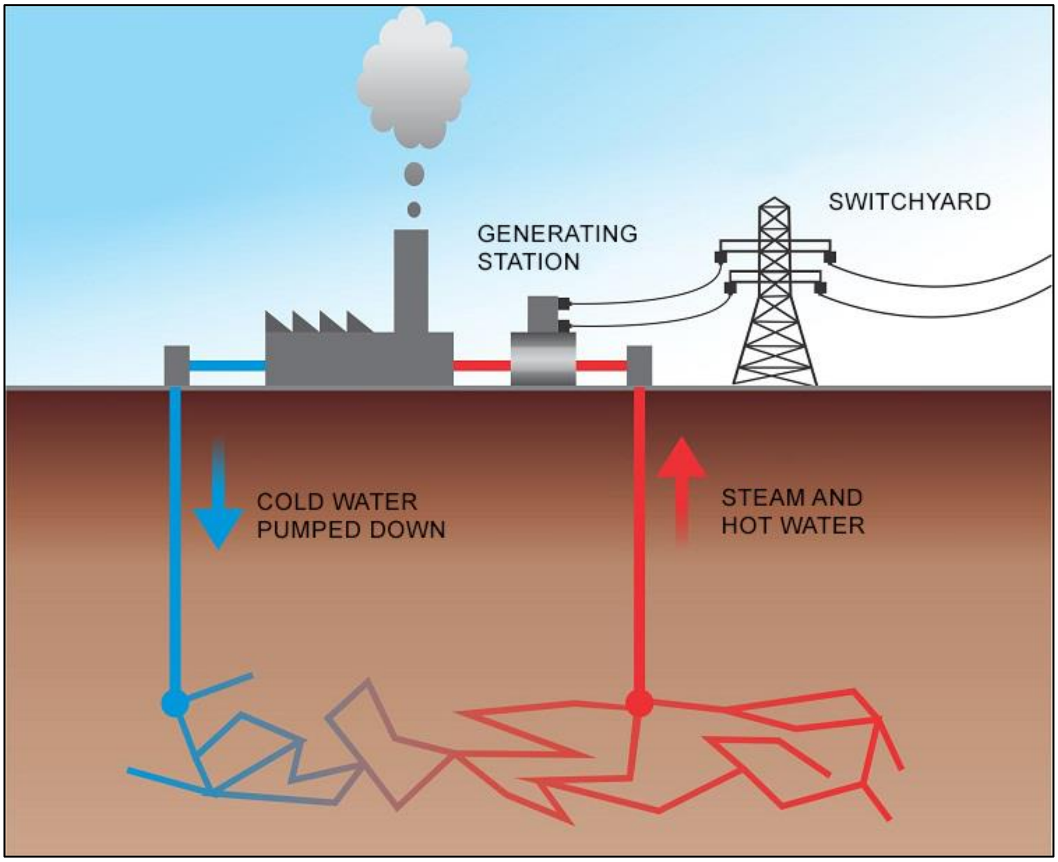
MSW typically produces GHG emissions as well as other air contaminants and so is not considered 100 percent clean or renewable. MSW has significant direct and indirect construction and operating jobs associated with the plant so FBC ranks it as 'high' in terms of socio-economic attributes.

[11] BC Hydro 2013 IRP, Appendix 3A, page 53.

3.1.4 Geothermal

Geothermal energy involves using the earth's naturally occurring and regenerating heat to generate electricity. Drill holes, up to several kilometers deep, are used to access hot fluid and steam below the surface. Turbines then convert the extracted steam to electricity.

Figure J3-11: Geothermal Energy Generation



Geothermal energy generation is a mature technology and has been used for over a hundred years, primarily in areas of high volcanic potential, such as Iceland. Currently, more than 12,600 MW of geothermal power capacity has been installed worldwide and it is expected that by 2020 the installed geothermal capacity will exceed 21,000 MW worldwide[12]. The existence of hot springs within the FBC service area indicates that there is the potential for geothermal energy.

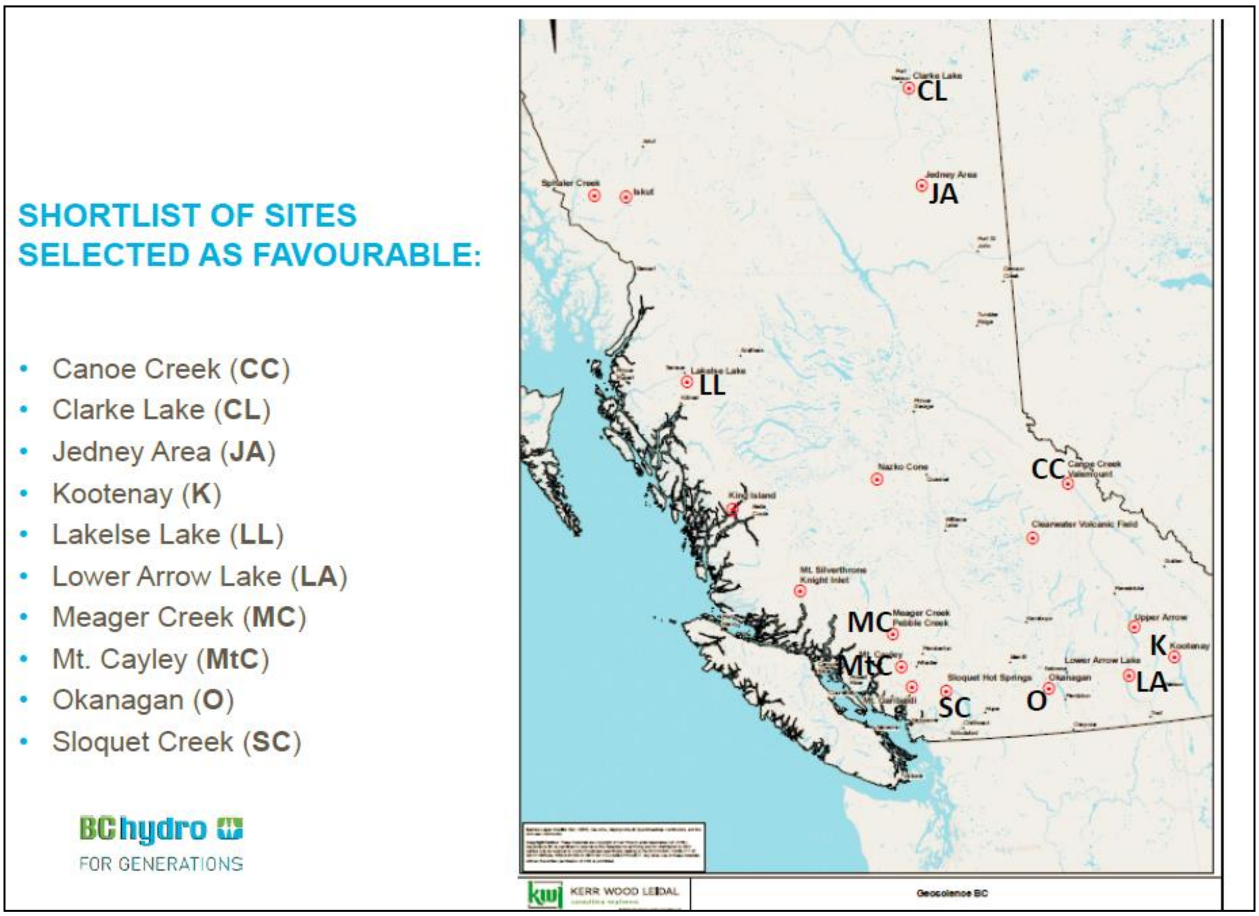
[12] https://pangea.stanford.edu/ERE/db/WGC/papers/WGC/2015/01001.pdf, page 66.

Geothermal resources provide year-round constant energy supply and so are different than some other renewable resources which are intermittent, like wind and solar power.

The feasibility and deployment of geothermal technology is largely dependent on potential improvements in drilling technologies and enhancements in the identification of geothermal resources. The capital costs for geothermal development can be significant due to the high costs related to drilling and well completion.

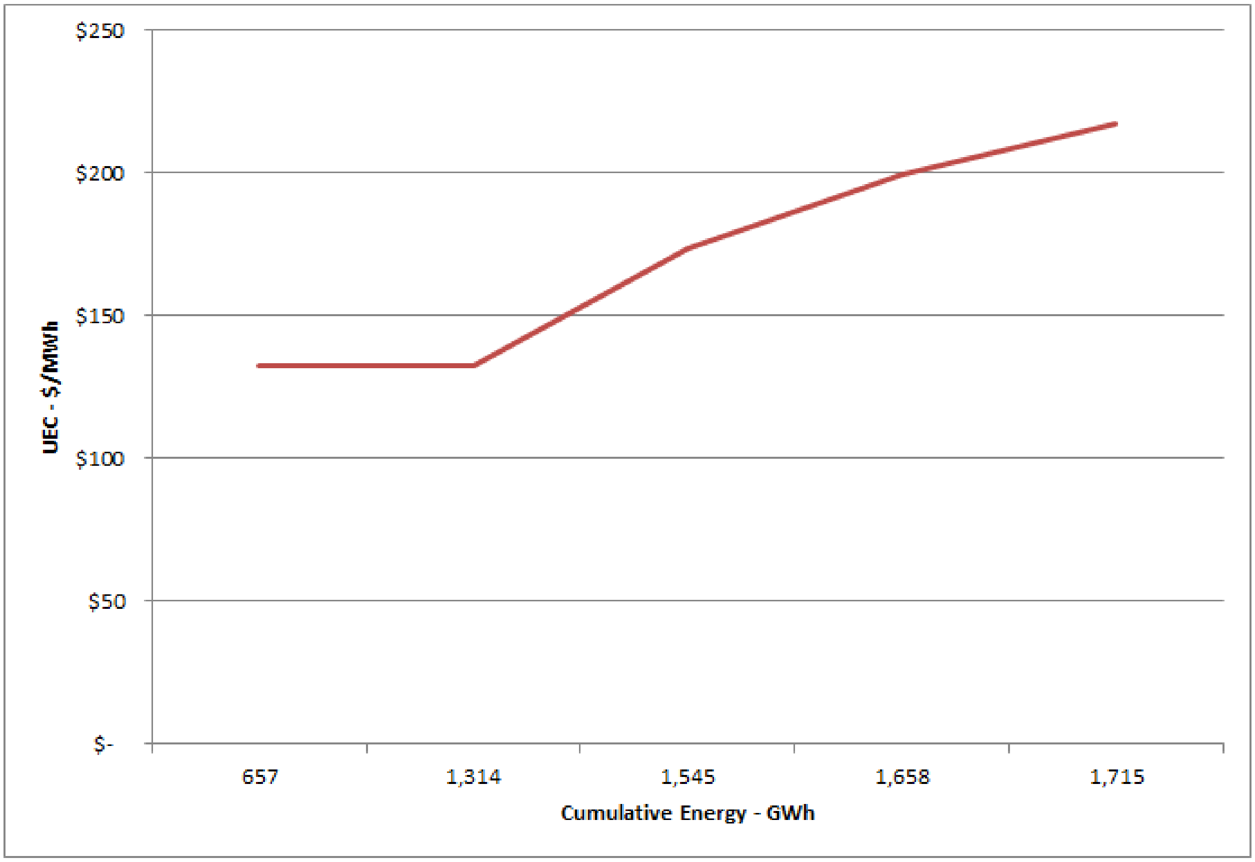
The collaboration process updating of the geothermal resource in B.C. resulted in a shortlist of ten sites that were considered the most favourable for potential development, which are shown in the figure below.

Figure J3-12: Favourable Geothermal Sites in BC



FBC narrowed this list down to the five lowest cost options for consideration in its portfolio analysis. The following figure shows the supply curve for these five potential projects.

Figure J3-13: Geothermal Supply Curve



In terms of environmental attributes, geothermal generation is considered a clean and renewable resource pursuant to the *CEA*. Geothermal has a significant number of direct and indirect construction and operating jobs associated with the plant. FBC ranks it as 'high' in terms of socio-economic attributes.

3.1.5 Natural Gas-Fired Generation - CCGTs

Natural gas-fired generation can include combined cycle gas turbines (CCGTs) and simple cycle gas turbines (SCGTs). CCGTs can be used for both firm base load energy and dependable capacity while SCGTs are a peaking resource. Natural gas-fired generation is dispatchable and plants can respond quickly to changes in demand.

CCGTs couple a combustion turbine with a steam cycle plant. The exhaust gases from the combustion turbine become the heat source for raising water to steam in a steam cycle system. This maximizes the thermal efficiency of the power plant by using the available energy in the combustion turbine's high temperature exhaust gases. CCGTs are available in a variety of sizes. BC Hydro and FBC have considered different sized plants as a result. While CCGTs typically have higher capital costs than SCGT plants, their unit costs can be competitive with other resources due to their high capacity factors.

Combustion turbine technology is well-established and widely used. Because of this there is typically low construction risk and high operational reliability. Furthermore, generation units are available in a range of sizes and can be fit to meet specific load requirements. Plants can be installed with a minimum of site renovation and preparation because they are compact and do not require additional equipment such as cooling towers or elaborate fuel processing subsystems. This enables them to be sited close to system load centres. Furthermore, the natural gas required to fuel the plants is abundant in the PNW region, with plentiful supply from diverse sources and robust gas infrastructure in place. FBC has access to gas supply for its electricity service area via the Spectra T-South system for northern B.C. gas production or via the FEI Southern Crossing Pipeline (SCP) system and Alberta Nova Gas Transmission Limited (NGTL) system and Foothills system for Alberta gas production.

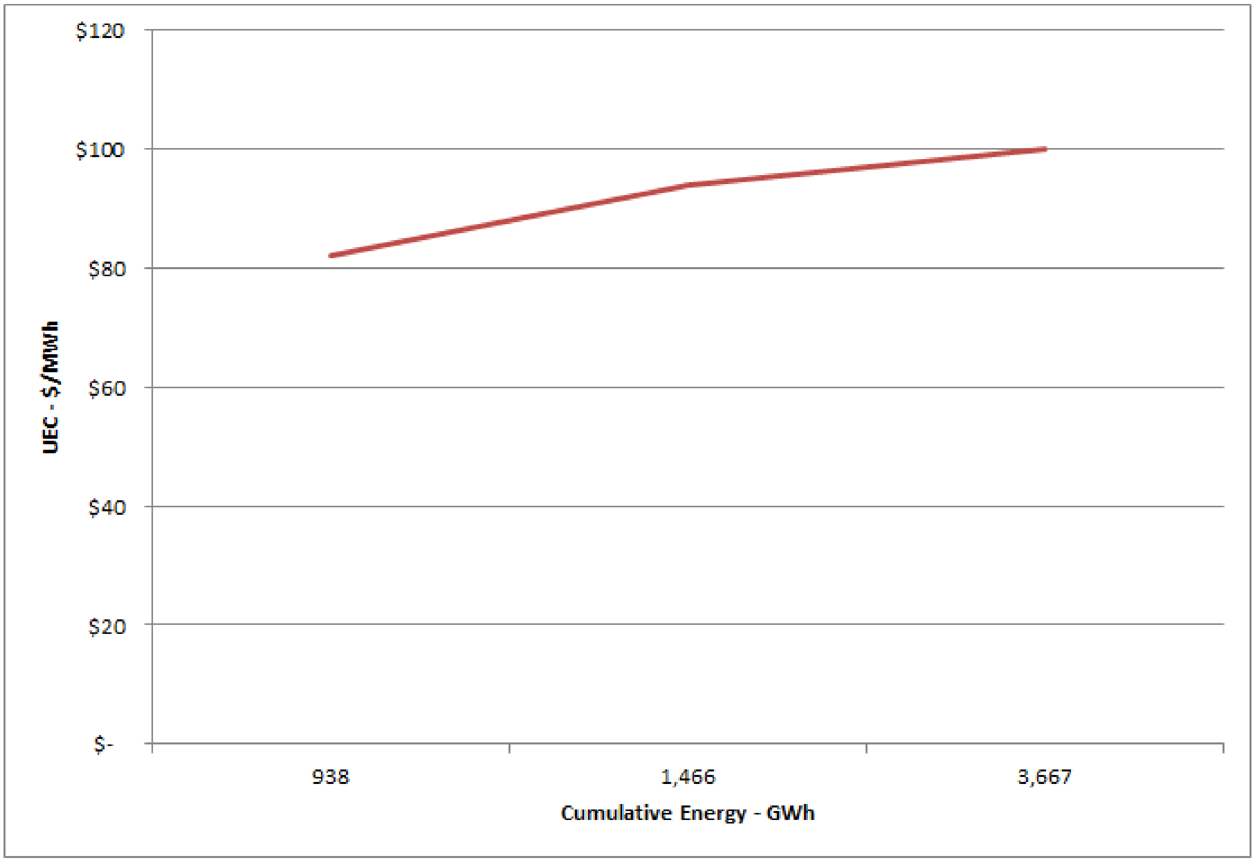
A major consideration for natural gas-fired generation is the fuel cost. While natural gas supply is abundant in North America and available within FBC's service area, natural gas prices can be highly volatile and uncertain. Natural gas prices are currently low relative to recent historical values as strong growth in natural gas production in North America has outweighed demand growth. However, there is no guarantee that this over-supplied situation will continue indefinitely into the future and market price volatility can occur in response to sudden changes in the supply/demand balance, such as during a cold spell in the winter. Market gas price forecast ranges are provided in Section 2.5.

There is also uncertainty regarding future carbon costs. As discussed in Section 2.5, the B.C. carbon tax will likely increase until it reaches $50 per tonne by 2022. However, after this time, it is unknown what future carbon tax increases may be.

Gas-fired generation can complement the use of intermittent renewable resources, providing quick, reliable and cost-effective back-up power when needed.

The collaboration process updated the costs for several sizes of CCGT plants, including 67 MW, 119 MW and 279 MW (installed capacity). The unit costs included in this ROR include the cost of fuel gas (based on the base case gas price forecast plus adders provided in Section 2.5) as well as the base case for carbon pricing (provided in Section 2.5). The following figure shows the supply curve for these three plant sizes.

Figure J3-14: CCGT Supply Curve



Gas-fired generating plants emit greenhouse gases, such as carbon dioxide, and other air pollutants. Therefore, gas-fired generation requires environmental permitting and can raise social licensing issues. While carbon capture technology does exist, it is not yet commercially viable. Section 2 of the *CEA* outlines B.C.'s GHG emission reduction targets and provides that it is a provincial energy objective to generate at least 93 percent of the electricity in B.C. from clean or renewable resources. The *CEA* definition of "clean or renewable resource" does not include natural gas-fired generation. The CLP also commits BC Hydro to acquire 100 percent of its supply of electricity energy from clean or renewable sources going forward, except where there are concerns regarding reliability or costs that must be addressed.

In terms of socio-economic attributes, a CCGT would provide significant construction and operating jobs and revenue for the province of B.C. and so FBC ranks CCGTs as 'medium' in terms of socio-economic attributes.

3.1.6 Large Hydro with Storage (Similkameen Project)

Large hydro with storage includes a dam or reservoir with a hydroelectric generating station. The dam or reservoir provides the ability to store water which can be released when required to meet system load. This storage ability provides capacity whereas run-of-river hydro without storage only provides energy.

As BC Hydro is moving forward with the development of its Site C project and does not require any other large hydro projects for capacity purposes, FBC's resource options collaboration with BC Hydro did not include an update to large hydro with storage resources. Therefore, FBC has used the Similkameen hydro project as an example of a large hydro with storage resource for the purposes of this ROR.

The potential Similkameen Project is a 60 MW (installed capacity) hydroelectric facility located on the Similkameen River approximately 19 km upstream (south) of the Town of Princeton, B.C. The project would provide hydroelectric power generation, flood control, and water management. It would provide approximately 215 GWh of annual firm energy and 32 MW of dependable capacity. FBC contemplated this project as a potential future resource option in the 2012 LTRP. FBC has since updated its analysis of the costs for the project and determined that they are higher than originally estimated. The unit energy cost has now been determined to be $202 per MWh and the unit capacity cost $1,298 per kW-year, putting the project at the higher end of the range, in terms of costs, of resource options FBC has considered in this ROR.

In terms of environmental attributes, the Similkameen hydro project is a clean and renewable resource option. A project of this size would require significant construction and operating resources and so would be considered 'high' in terms of socio-economic benefits.

3.2 *PEAKING RESOURCES*

3.2.1 Natural Gas-Fired Generation - SCGT

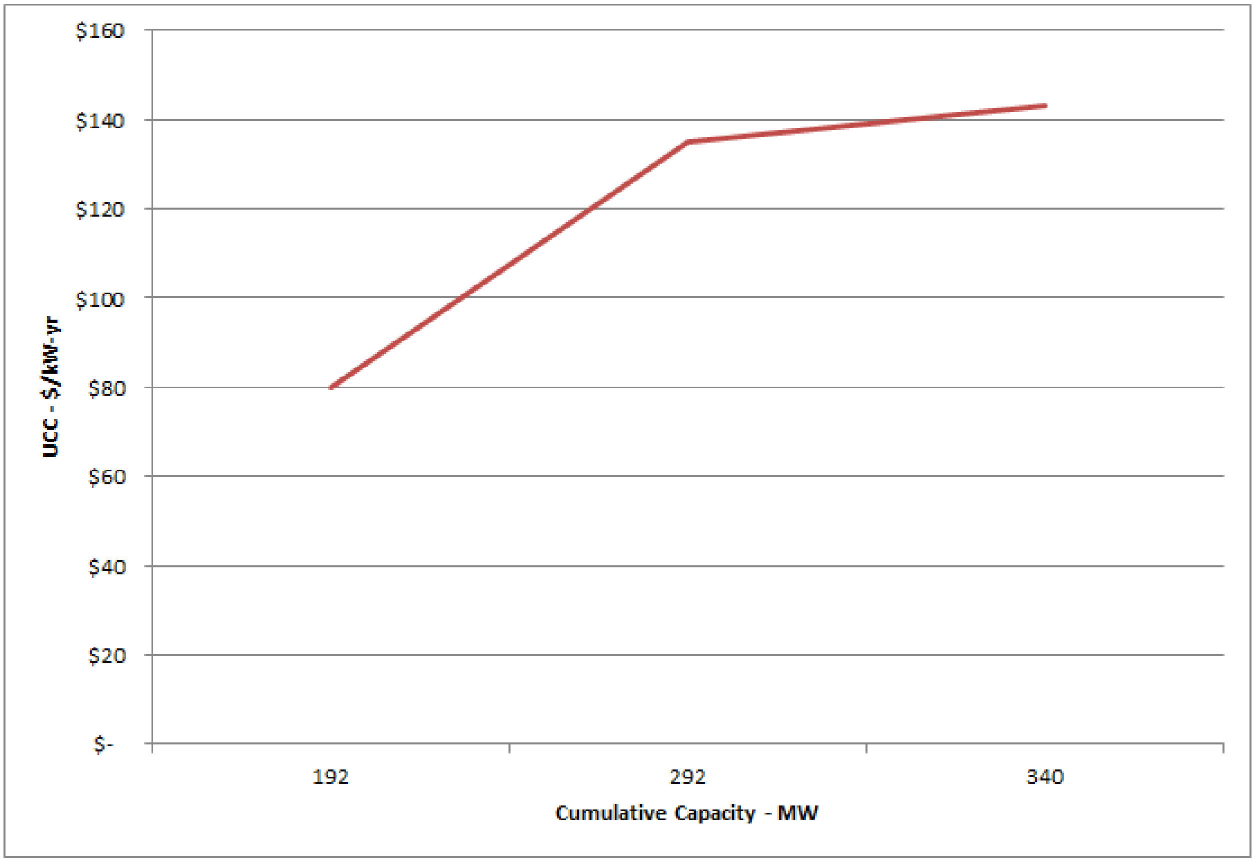
SCGTs can be used for dependable capacity generation and flexibility purposes. Unlike CCGTs, which operate as baseload plants for energy and capacity, SCGTs operate at a much lower utilization rate than CCGTs, providing peaking supply only when it is required to meet the highest loads.

SCGTs operate by propelling hot gas through a turbine, in order to generate electricity. They differ from CCGTs because their waste heat is not supplied to another external heat engine, so they are only used to meet peaking power needs on the electrical grid. SCGTs are typically smaller units than CCGTs, with lower capital costs and shorter construction lead times. SCGTs can ramp up to meet increases in demand faster than CCGT plants and can handle frequent starts and stops to respond to changing system load requirements.

Peaking gas plants have increased their presence in the PNW region in recent years. This is due to the abundant and low-cost natural gas supplies in the region as well as their ability to provide valuable integration (i.e. back-up capability) for intermittent energy resources, such as wind and solar.

As part of the resource options collaboration with BC Hydro, three sizes of SCGT plants were considered – 48 MW, 100 MW and 192 MW (installed capacity). The unit capacity costs are provided in the following supply curve.

Figure J3-15: SCGT Capacity Supply Curve



Because SCGTs operate at a much lower utilization rate than CCGTs, their GHG emissions will typically be much lower than those of a baseload CCGT plant, even though gas-fired generation is not considered 'clean' by the *CEA*. The socio-economic benefits of a SCGT plant would be lower than those for a CCGT plant due to its shorter construction period and lower utilization rate and therefore FBC would characterize this attribute as 'low'.

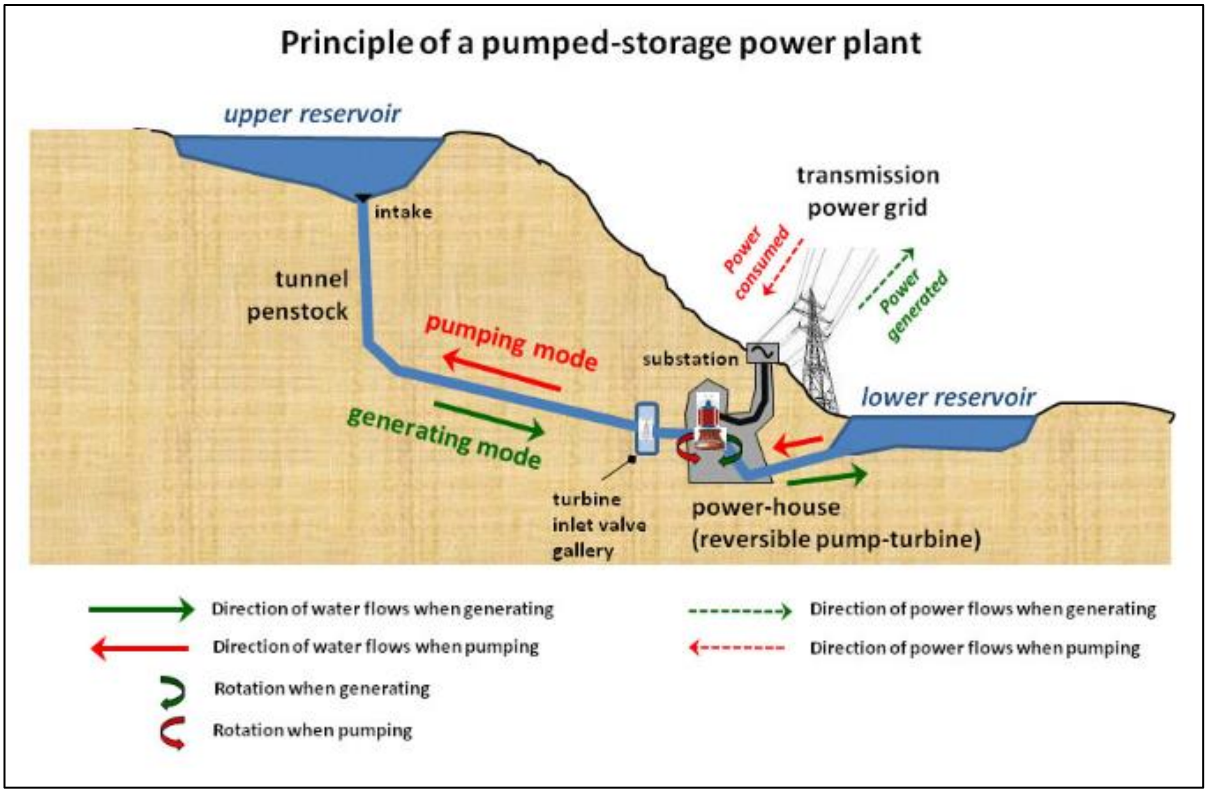
3.2.2 Pumped Storage

Pumped storage hydro (PSH) involves pumping water from a lower elevation to a high elevation so that capacity can be generated when required. The water is pumped to a higher elevation using electricity during light load hours, such as at night when demand is low. When electricity is required, the water in the higher elevation reservoir is released and runs through hydraulic turbines that generate electricity. Pumped storage units require a considerable amount of energy to pump the water to the higher elevation, recovering only about 70 percent of the energy used.[13] Therefore, they are not effective energy resources. However, they are good capacity resources as the pumped water can be stored for a long period of time with virtually no

[13] BC Hydro 2013 IRP, Page 3-65.

energy loss until generation is required. The following figure illustrates how a pumped hydro storage plant works.

Figure J3-16: Pumped Hydro Storage Plant Operation



While pumped storage is used in many countries worldwide, currently there are no commercial pumped storage facilities operating in B.C. and only one facility operating in Canada[14]. This is largely due to the fact that pumped storage facilities require unique geologic formations consisting of two large reservoirs with a sufficient elevation differential between them. Such formations are rare or tend to be found in remote off-grid locations and in mountaineous regions, for example, where construction is difficult.

FBC contemplated pumped storage as a capacity resource in its 2012 LTRP. Siting a pumped storage facility in B.C. would require numerous governmental and regulatory approvals, increasing the uncertainty regarding timing, cost and outcome.

In FBC's collaboration with BC Hydro, two sizes of PSH projects were considered – 500 MW and 1,000 MW (installed capacity). Given the potential size of FBC's capacity gaps over the planning horizon, FBC has only evaluated a single 500 MW-sized plant for the purposes of the present LTERP. The UCC for this resource option is $217 per kW-year.

[14] Sir Adam Beck Pump Generating Station at Niagara Falls in Ontario is the only pumped hydro storage facility operating in Canada. Built in 1957, the station has an output of 174 MW.

FBC considers PSH a clean and renewable resource option as it produces no direct GHG emissions associated with its operations. Given the relatively large size of the potential plant, there would be significant construction and operating costs for this resource option. However, given the power generated by a PSH plant, on a per MW basis the socio-economic attribute rating for this resource option is 'low'.

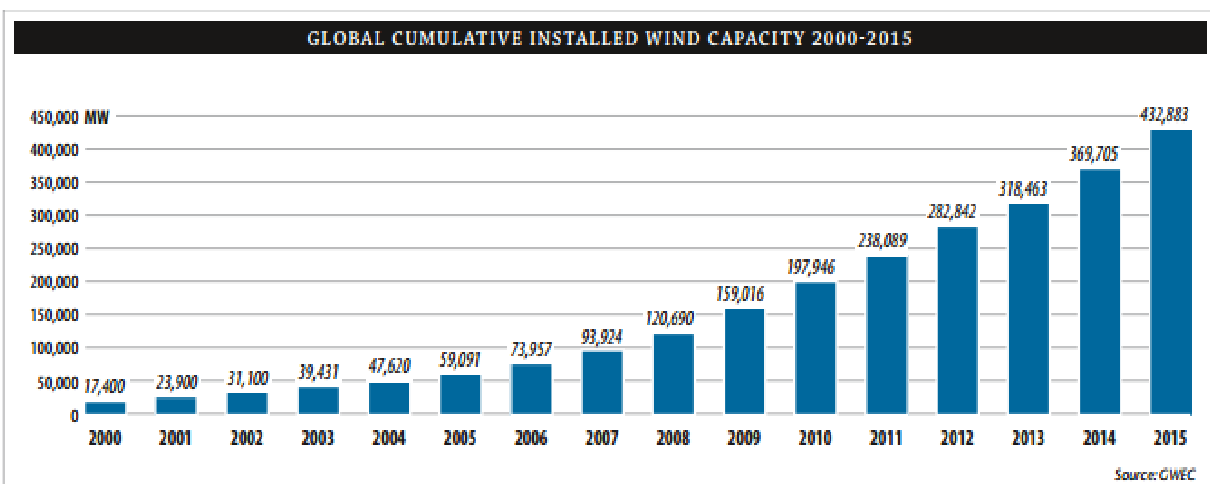
3.3 *INTERMITTENT RESOURCES*

3.3.1 Onshore Wind

Wind power is an intermittent resource and comes from electricity converted from the kinetic energy of the wind. Typical utility-scale wind turbines use rotating blades that drive a generator when the wind blows. Because wind speed is highly variable and difficult to predict, wind power provides energy but cannot be relied upon for capacity. Therefore, greater system flexibility and capacity reserve are required for the integration of wind into a resource portfolio. This means that the cost of wind should include an integration cost adjustment (see Section 2.2.2.1 of this ROR).

The costs for wind generation have fallen significantly in recent years mainly due to two factors: improvements in turbine efficiencies and decreases in turbine costs. Technology improvements have included increased tower heights, blade lengths and rotors designed for lower wind speeds. These have led to improvements in power capacity. Improvements in forecasting wind speeds have also occurred. These improvements, along with the environmental benefits of wind power over non-renewable forms of generation, has led to an increase in the growth of wind power in recent years as shown in the following figure.

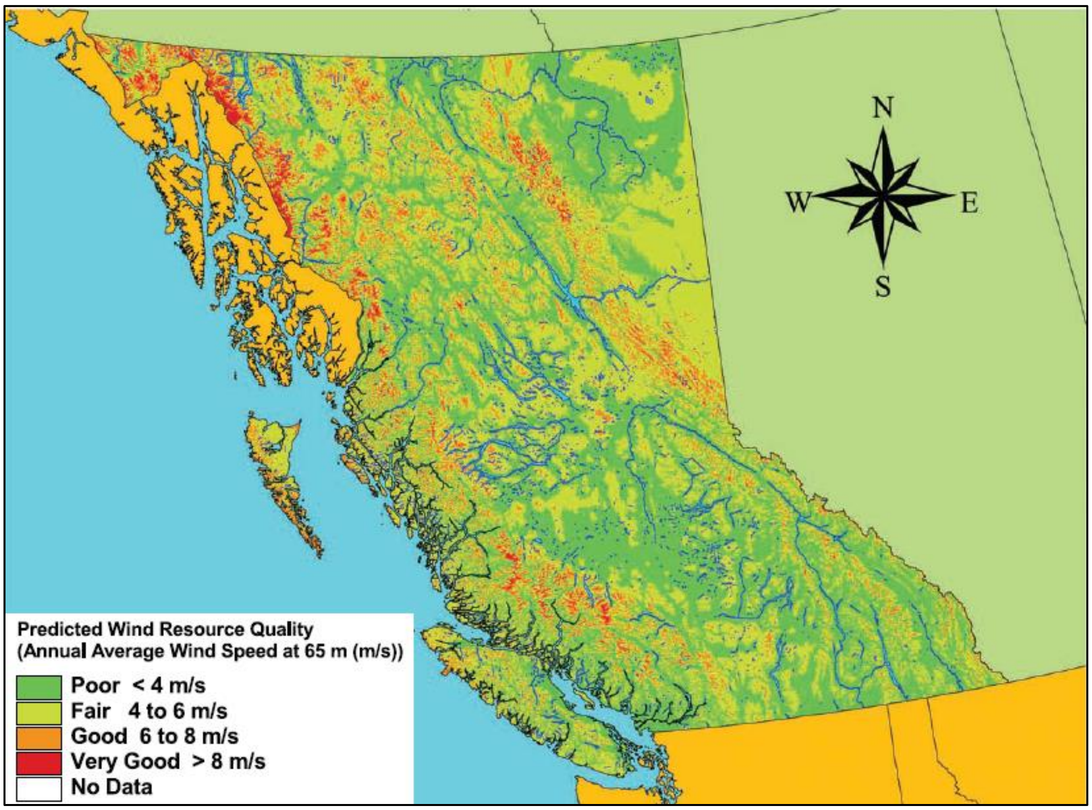
Figure J3-17: Global Cumulative Installed Wind Capacity[15]



[15] http://www.gwec.net/wp-content/uploads/vip/GWEC-Global-Wind-Report_2016.pdf, page 14

The area in B.C. with the most potential for development of onshore wind as a resource option is in the northwestern part of the province, as reflected in the figure below showing the wind speed quality throughout B.C. The figure also indicates there are some areas of fair potential for wind energy within FBC's service area.

Figure J3-18: B.C. Wind Speed Quality[16]

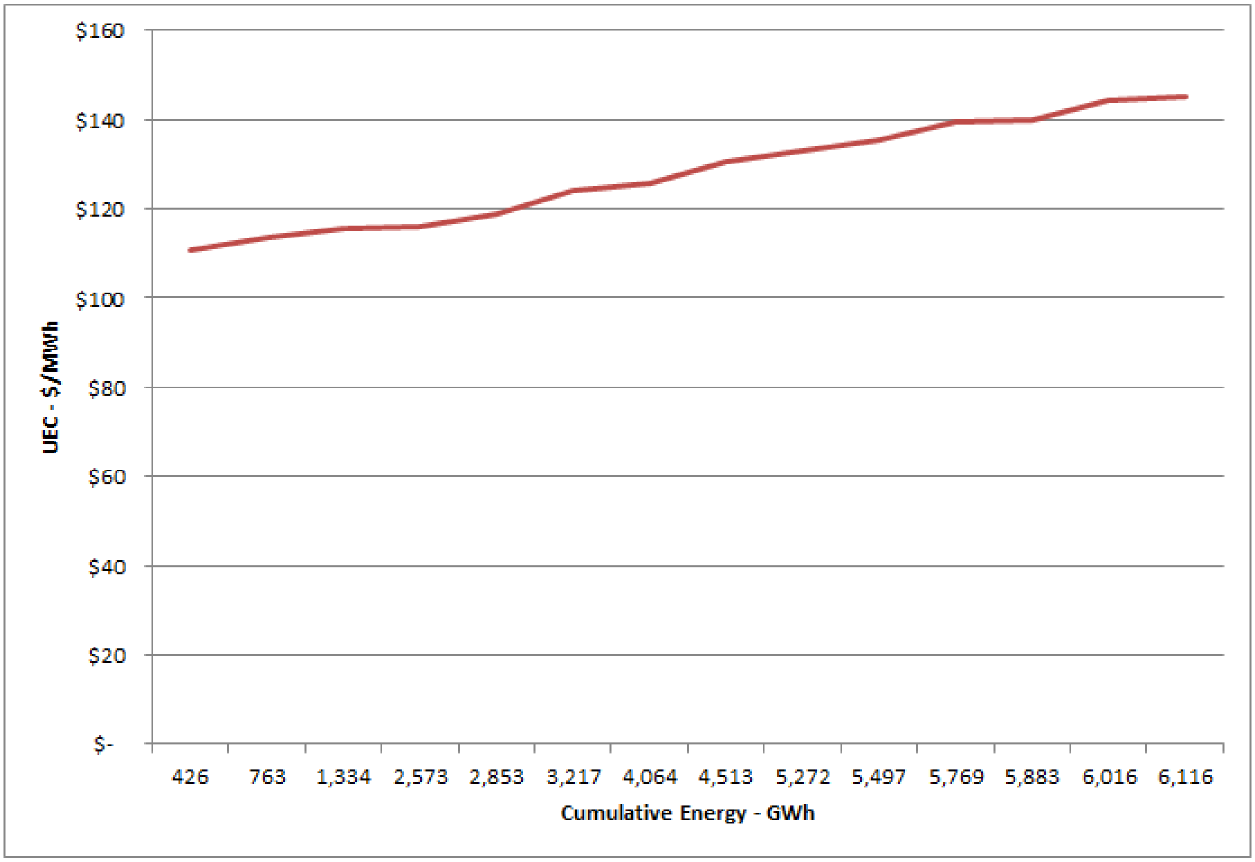


Improvements in the ability to forecast wind more accurately and reductions in costs through design and efficiency improvements are expected to increase the viability of wind energy technologies in the future.

FBC's collaboration with BC Hydro identified over one hundred potential wind projects throughout B.C., with many of them in northern B.C. FBC has evaluated a smaller subset of lower cost sites outside and within its service area for the purposes of this ROR. The supply curve for these lower cost projects is provided in the following figure.

16 Alternative Energy in the Columbia Basis, Columbia Basin Trust, October 2010.

Figure J3-19: Onshore Wind Supply Curve



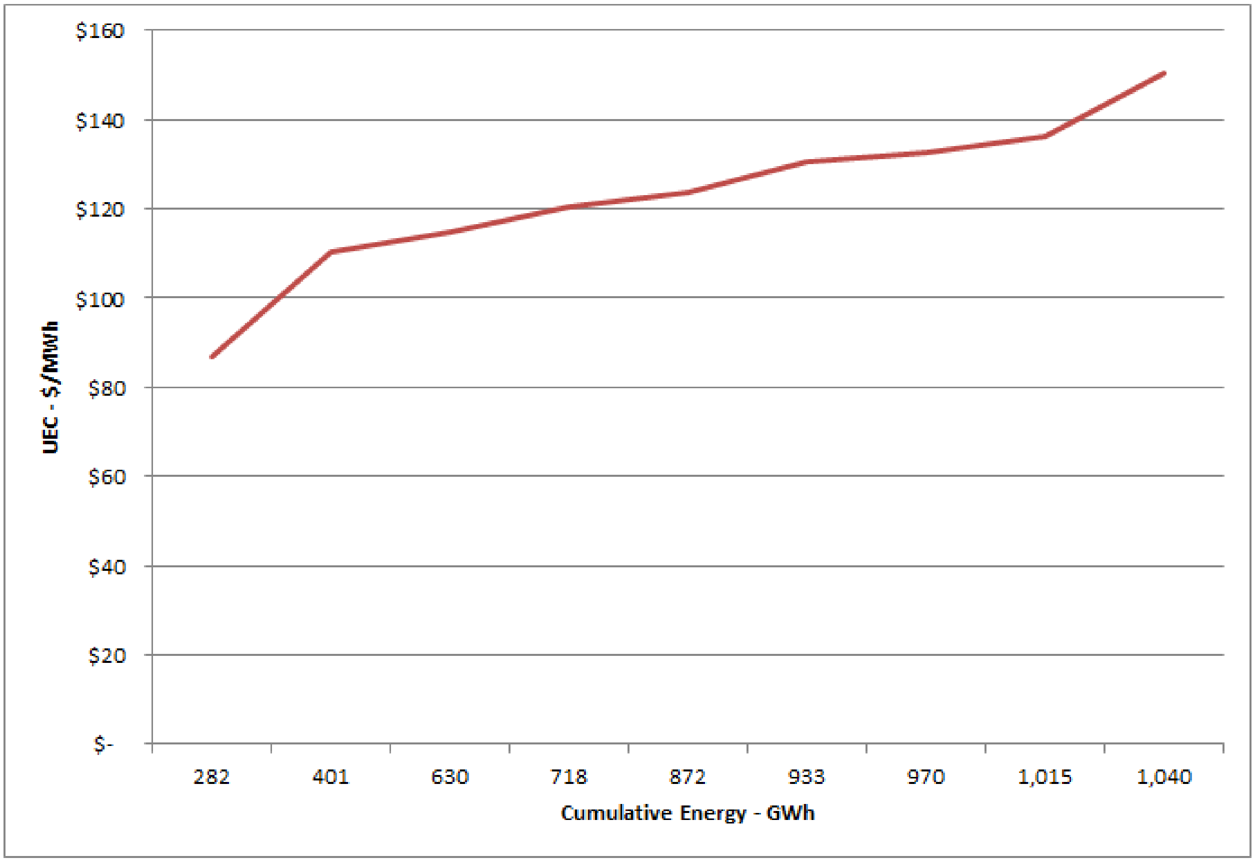
Wind is considered a clean and renewable resource option. FBC ranks this resource option as ‘medium in terms of socio-economic benefits.

3.3.2 Run-of-River Hydroelectricity

Run-of-river hydroelectricity is generated from the potential or kinetic energy of water and is considered a variable resource. Run-of-river generation involves diverting natural stream or river flows and using the drop in elevation to produce electricity. In contrast to hydroelectricity resources with storage, run-of-river projects have no or limited amounts of storage and their output is dependent on seasonal river flows, which peak during the freshet period in late spring/early summer. Run-of-river flows are also subject to annual flow variability, depending on the levels of annual snowpack. As such, run-of-river resources are considered primarily for energy rather than dependable capacity.

There is significant potential for run-of-river generation in B.C. and FBC’s collaboration with BC Hydro identified over seven thousand possible sites. Most of the possible sites would not be considered economic at this time, however. For this ROR, FBC developed a smaller subset of the identified sites by selecting a sampling of cost-effective different-sized sites. The cost curves for these are provided in the following figure.

Figure J3-20: Run-of-River Supply Curve



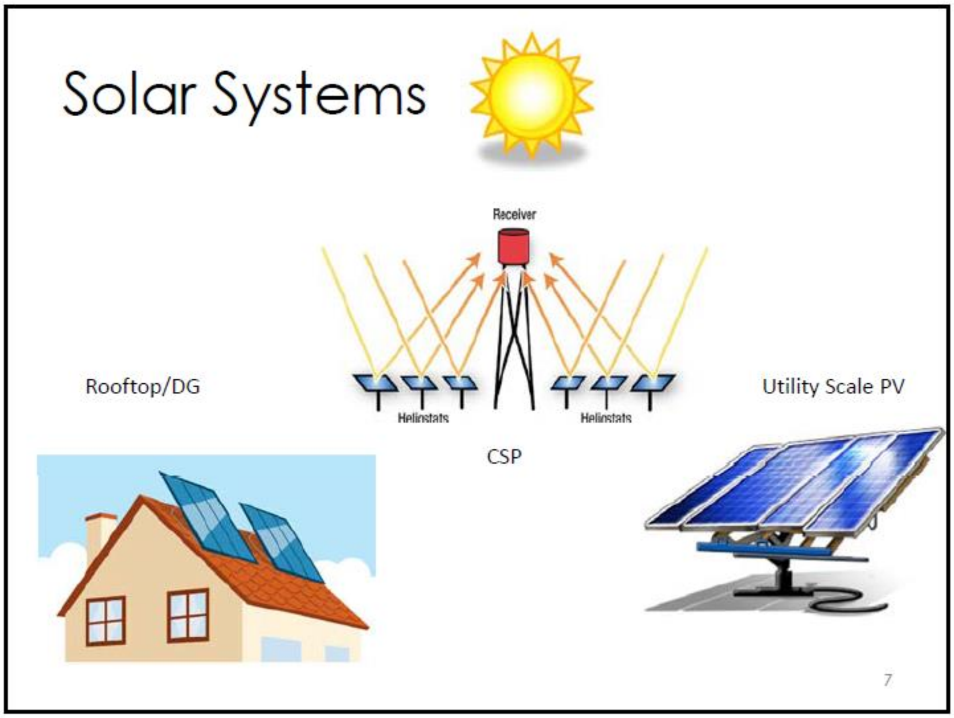
As a variable resource, run-of-river generation is highly dependent on precipitation, snow pack levels and spring runoff. This typically does not correlate well with FBC's peak load requirements during winter hours. In addition, the generation from run-of-river facilities is dependent on annual average water flows and high and low water years may be experienced over a period of time.

Run-of-river generation is considered a clean and renewable resource. FBC considers the socio-economic attribute ranking as 'medium'.

3.3.3 Solar Power

One intermittent resource option that has both grown in popularity and come down in cost significantly during the past few years is solar power. Solar power can be produced directly by individual households or businesses through rooftop solar panels, as part of what is termed distributed generation (DG), or by utilities to generate electricity for customers. Utility-scale solar power generally falls into two main categories – photo-voltaic (PV) and concentrated solar power (CSP). The following figure shows these different types of solar power.

Figure J3-21: Types of Solar Power[17]



Solar PV technologies convert sunlight directly to electric current using semi-conductive materials in solar panels. CSP technologies use mirrors to reflect and concentrate sunlight onto receivers that collect solar energy and convert it to heat. This thermal energy is then used to produce electricity via a turbine or heat engine driving a generator. CSP systems can be designed to store thermal energy and use it to generate power in hours with little or no sunshine. Because CSP technology generally requires good irradiation and clear skies, as compared to solar PV, it is less suited than solar PV to northern hemisphere regions like Canada. While PV can use all incident solar radiation, CSP uses only direct irradiance and is therefore more sensitive to the scattering effects of clouds, haze, and dust. Furthermore, for maximum efficiency and cost effectiveness, CSP systems must be over 100 MW in size[18] due to the high fixed costs of the concentrator technologies.

In general, the use of solar PV has grown much faster than CSP in recent years. Solar PV modules can be fixed or on trackers that follow the sun. Fixed modules are less expensive to install but have lower capacity factors than tracking systems. Dual-axis trackers are most efficient from a kWh per kW perspective, but also are the most costly and require the most ongoing maintenance. Fixed systems are generally less effective at more northern latitudes. The following figure shows the recent growth in solar power in the US, with the largest growth coming from solar PV.

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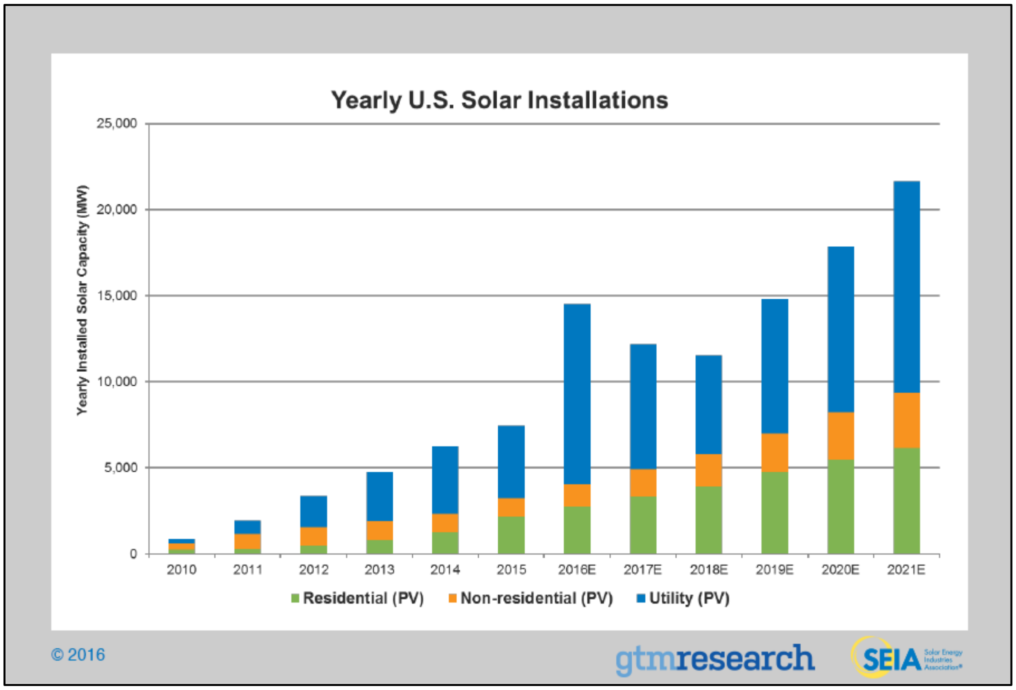
[17] https://www.nwcouncil.org/media/6871479/p1.pdf
[18] https://www.nwcouncil.org/media/6871479/p1.pdf

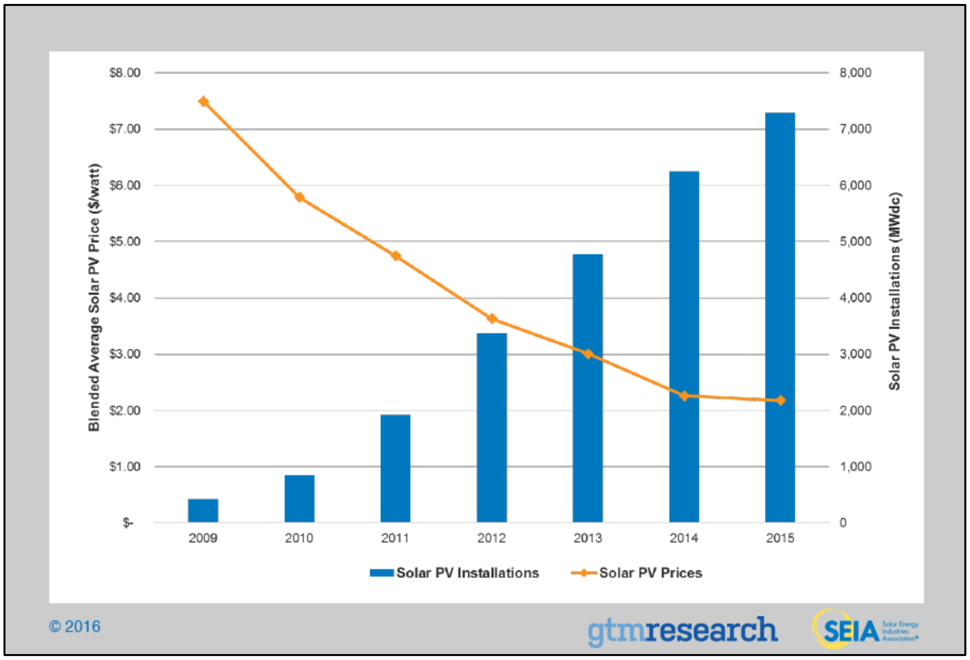
Figure J3-22: Growth in Solar Power in the US[19]



Improvements in technology as well as cost reductions for materials have contributed to the overall decrease in costs for solar PV generation. The following figure shows the decrease in the cost for solar PV since 2009 as installations have risen.

[19] Solar Energy Industries Association, The U.S. Solar Energy Industry – Powering America, June 9, 2016.

1 **Figure J3-23: U.S. Solar PV Installations vs. Prices[20]**

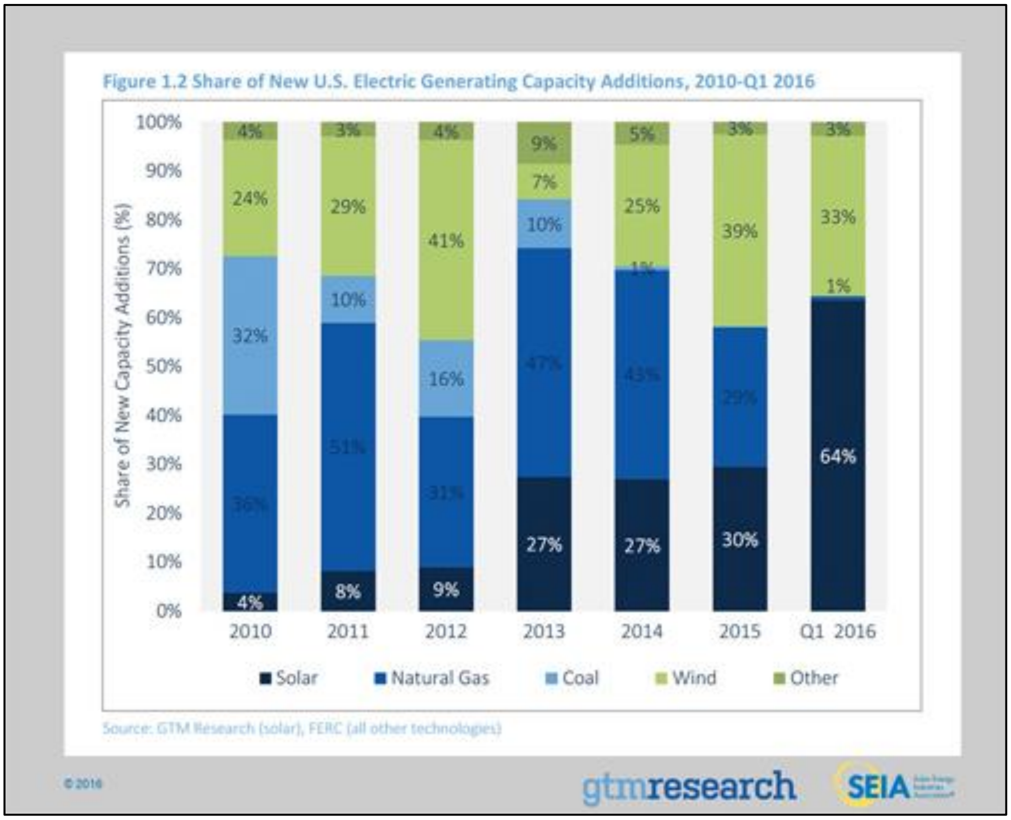


2

3 In many regions throughout Canada and the US, solar PV power generation has increased its
4 share in utility resource portfolios. In some regions, solar power compares favourably to some
5 other supply-side resource options. The following chart shows how solar PV has increased in
6 share as a percentage of new generation capacity additions in the U.S. since 2010.

[20] Solar Energy Industries Association, The U.S. Solar Energy Industry – Powering America, June 9, 2016.

Figure J3-24: New U.S. Generating Capacity by Fuel Type[21]



Although solar power can only be generated during daylight hours, it can still be produced during cloudy conditions. The use of a peaking type of resource, such as natural gas-fired generation or energy storage, can help provide the necessary backup for the intermittency of solar power.

Utility-scale solar PV can require large amounts of land. For projects over 5 MW in size, approximately 5.5 acres of land is required per MW[22]. This would have to be taken into account if FBC considers solar PV as a potential resource in the future.

There is significant potential for solar power generation in southern Canada, including FBC's service area in the southern interior region of B.C., as shown in the following figure.

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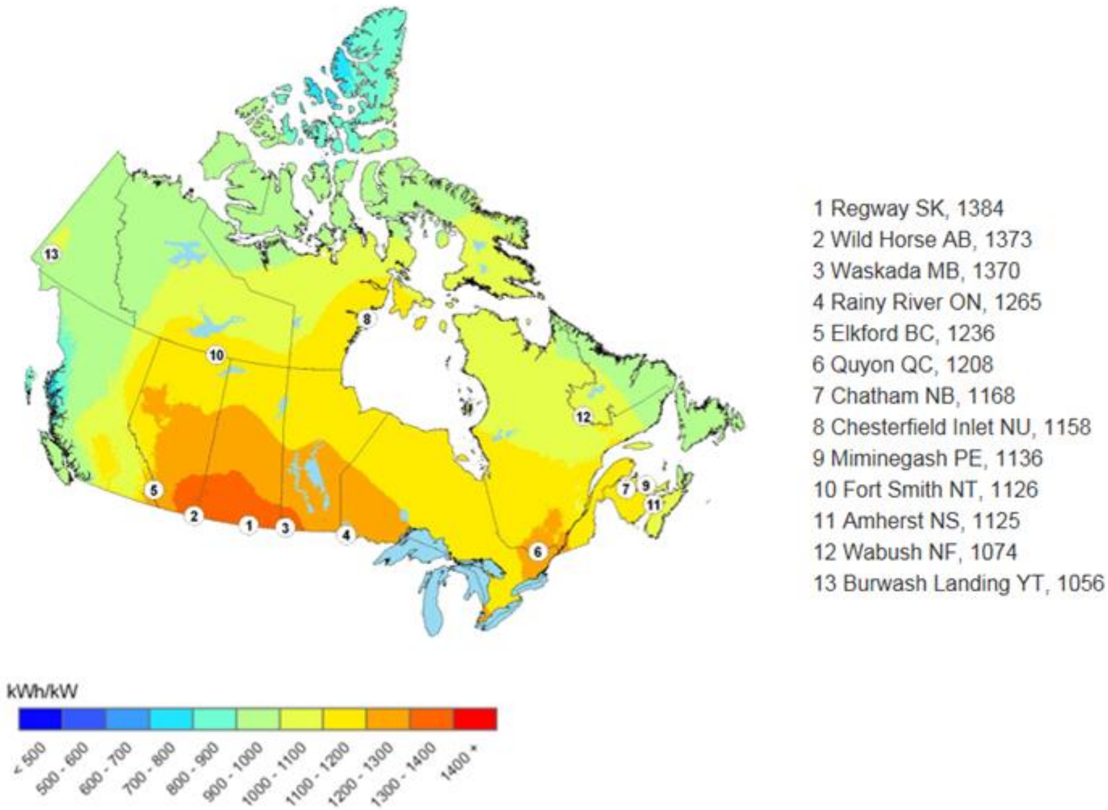
[21] Solar Energy Industries Association, The U.S. Solar Energy Industry – Powering America, June 9, 2016.
[22] NREL Land Use Requirements for Solar Power Plants in the US, June 2013.

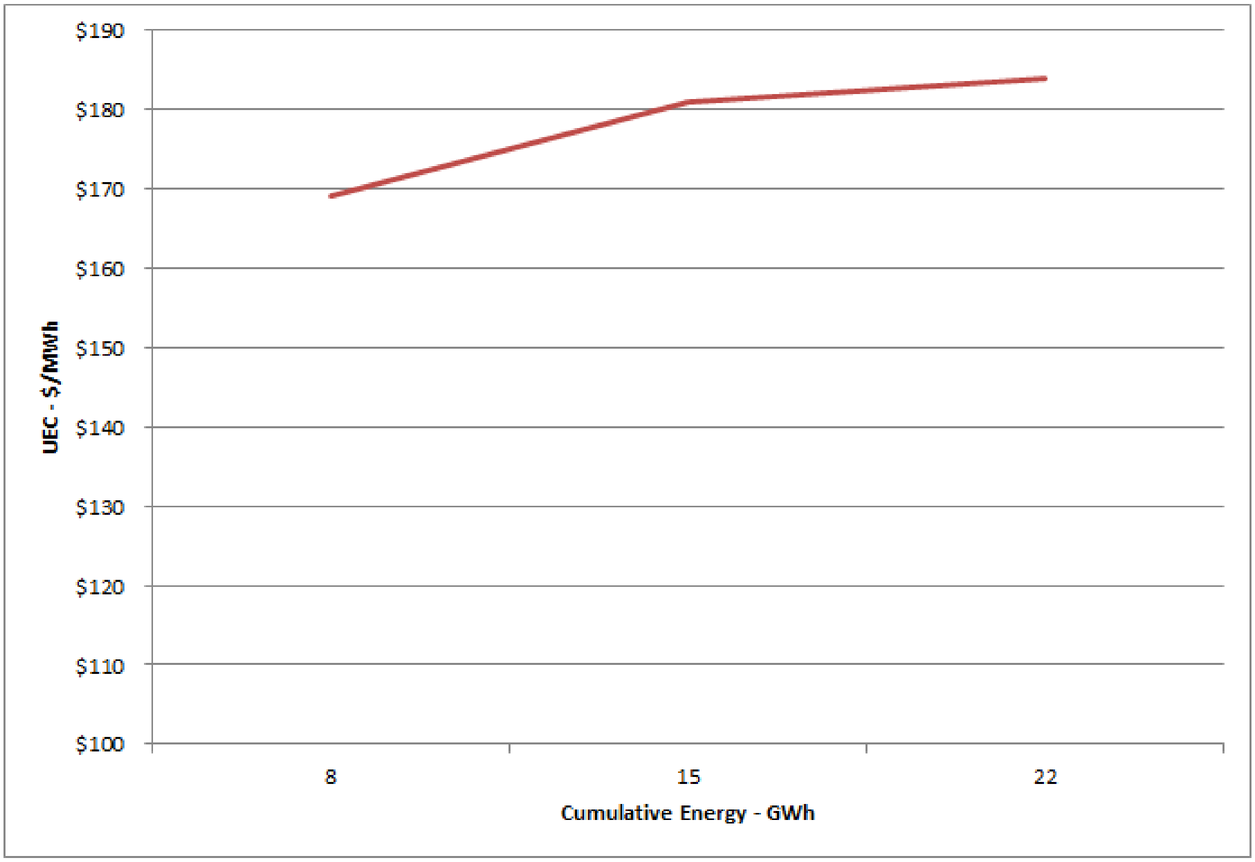
Figure J3-25: Annual Solar PV Yield for Canada



Source: http://pv.nrcan.gc.ca/index.php?m=r

As part of the resource options collaboration with BC Hydro, five potential utility-scale solar PV sites with 5 MW of installed capacity were identified in southern B.C. FBC narrowed this group down to the three lowest cost projects. The supply curve for these options is provided in the following figure.

Figure J3-26: Solar Supply Curve



It is worth noting that FBC's estimated unit costs for solar generation are higher than unit costs in many U.S. jurisdictions, despite solar costs coming down generally over the past few years. This is largely due to the relatively small size of the solar projects FBC considered (5 MW), the lower solar PV yield in Canada compared to the more southerly U.S. states and U.S. government subsidies provided to utilities for solar power.

Solar generation is considered a clean and renewable resource option. In terms of socio-economic benefits, FBC rates utility-scale solar generation as 'low'.

3.4 *ROOFTOP SOLAR POWER (DISTRIBUTED GENERATION)*

Rooftop solar power generation has also increased in popularity in recent years in the U.S. and Canada as individual home owners and businesses have installed solar panels to generate their own electricity and sell excess back into the grid. This form of DG can provide customers with greater energy independence and cost savings through net metering programs. The amount of power generated depends on the amount of available sunlight, the roof angle and orientation of the solar panels and the amount of shading from buildings and trees. In the future, the use of battery technology could improve the effectiveness of rooftop solar by enabling energy generated during daytime to be stored and used later in the evening when load requirements are highest and solar potential drops off.

Shared solar projects, often called community solar, could increase the growth in solar penetration by providing opportunities for those homeowners and businesses that are not able to put solar panels on their own roofs. Shared solar models allow multiple users to own or lease a portion of a solar array. Due to the economies of scale for large projects, this may lower costs required for individuals to benefit from solar power. Utilities can benefit by participating in the design of shared solar programs, as they can help ensure sites are chosen strategically to complement their system requirements rather than having to adapt their systems after the fact to a greater number of smaller rooftop projects in various locations.[23]

If significant in amount, DG can also help utilities avoid transmission and distribution system upgrade costs, reduce line losses and reduce system energy requirements. The increasing popularity of distributed solar can result in more buildings and/or homes reducing their energy consumption. This could lead to oversupply issues for FBC in the spring and summer, while not addressing winter capacity needs.

DG can be considered both a supply-side or demand-side resource. FBC has captured the DG potential for the FBC system within its load scenarios as discussed in Section 4 of the LTERP. While DG's unit cost value can be determined for illustrative purposes, this value should be used with caution for resource planning. This is because DG is not within FBC's control and cannot be considered a reliable resource option. There are no assurances for FBC that the customer-generated electricity will be available on FBC's system when needed or in the appropriate location on the FBC system. As per FBC's Net Metering Update Application, dated April 15, 2016, FBC has proposed to reimburse DG net metering customers based on the BC Hydro PPA Tranche 1 energy rate, currently about $47 per MWh. This is essentially the cost of DG to FBC for the short term.

3.5 *MARKET PURCHASES*

Market purchases of energy and capacity can be a cost-effective and reliable resource within FBC's portfolio. FBC has relied on market electricity purchases in the past and this strategy has proven cost effective in recent years given the decrease in market gas and power prices relative to the costs of other resource options, such as the PPA with BC Hydro. On an annual basis, FBC determines the optimal amount of market purchases within its Annual Electric Contracting Plan (AECP), taking into account its forecast load requirements, the annual PPA energy nomination and the price of market supply compared to the PPA Tranche 1 energy rate. On a long-term planning basis, FBC can compare the forecast price of market purchases to the forecast price of the PPA and other resources to help evaluate market purchases within the resource options portfolio. Based on current base forecasts for market prices (as discussed in

[23] http://energy.gov/eere/articles/nrel-report-shows-big-potential-future-shared-solar

Section 2.5 of the LTERP), some reliance on market purchases of energy and capacity is more cost effective than other resource options, at least over the short to medium term. Based on Figure 2-9 in Section 2.5 of the LTERP, which shows the base case long term market price for electricity at Mid-C, the levelized unit energy cost for market purchases is about $51 per MWh including transmission costs and losses from Mid-C. Overall, this is similar to the base case scenario for the PPA Tranche 1 Energy rate (as provided in Figure 2-11 of Section 2.5), with a levelized value of about $50 per MWh over twenty years. The price for market purchases and PPA Tranche 1 energy is significantly lower than the unit cost of other supply-side resource options, as listed in Figure J3-1 of this ROR, which have levelized energy unit costs ranging of $77 per MWh to $217 per MWh.

Relying on market purchases for energy or capacity in the long term can be risky for FBC. This is because there is no guarantee that market supply will be available when FBC needs it in the future and other generation resources can take time to build. Furthermore, as discussed in Section 2.4 of the LTERP regarding FBC's Planning Environment, regional market power supply, and capacity in particular, may be declining in the future. There may also be new transmission congestion issues as systems are operated differently to integrate renewable resources. Therefore, FBC does not consider market purchases a long-term resource option, even though it has presented a forecast for market prices.

Section 6 of the *CEA* addresses the BC energy objective of electricity self-sufficiency. While the specific requirement mandating self-sufficiency is applicable only to BC Hydro[24], FBC is required to consider the energy objective to achieve electricity self-sufficiency "in planning in accordance with section 44.1 of the UCA" in two circumstances: construction or extension of generation facilities and energy purchases[25]. The addition of WAX capacity into the FBC portfolio in 2015 improves FBC's degree of self-sufficiency from a capacity perspective. However, FBC believes that market purchases, at current price levels, are more cost effective than other supply-side resource options and so should not be ruled out to achieve self-sufficiency, at least in the short to medium term. Self-sufficiency in the long term is discussed in the portfolio analysis in Section 9.

3.6 *BC HYDRO PPA*

The PPA is an existing contracted resource with BC Hydro and provides long-term dependable capacity and energy. FBC has access to up to 200 MW of capacity, up to 1,041 GWh of Tranche 1 Energy and up to 1,752 GWh of Tranche 2 Energy. The cost for this energy and capacity is provided in Section 2.5 and different rate scenarios are also discussed. The PPA is a very flexible resource in the FBC portfolio, enabling FBC to increase or decrease the amount of energy and capacity requirement from year to year, subject to specific limits. Because of this

[24] *CEA*, section 6(2).
[25] *CEA*, section 6(4).

flexibility, FBC has included the PPA in its list of resource options even though it is already an existing contract. More details regarding the PPA are provided in Section 5.4.

3.7 *EXPIRING BC HYDRO ENERGY PURCHASE AGREEMENTS*

In its 2013 IRP, for planning purposes, BC Hydro has assumed that about 50 per cent of the bioenergy Energy Purchase Agreements (EPAs) will be renewed, about 75 per cent of the run-of-river EPAs that are up for renewal in next five years will be renewed, and that all other EPAs will be renewed. It also amended its Standing Offer Program rules to specifically exclude generators with expiring EPAs. The BC Hydro F2017-F2019 Revenue Requirements Application also addresses expiring EPAs. Fourteen of BC Hydro's existing EPAs with IPPs are expiring by the end of fiscal 2019. Consistent with the approved 2013 Integrated Resource Plan, BC Hydro continues to assume renewal of 50 percent of the energy and capacity contributions from biomass EPAs and 75 per cent from the run-of-river hydroelectric EPAs that are due to expire within the remaining years of the 2013 10 Year Rates Plan.

BC Hydro is targeting renewal of contracts for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. However, there may be opportunities for FBC to acquire power from the other facilities on a cost-effective basis. In addition, BC Hydro will need to address expiring EPAs after 2019. FBC will continue to monitor the BC Hydro contract renewals for any resource option opportunities.

3.8 *PURCHASING FROM SELF-GENERATORS*

Electricity purchases from self-generating customers may be a supply option for FBC in the future. Self-generating customers refers to larger, industrial customers that can receive electricity from FBC as opposed to smaller, residential or commercial customers that could provide distributed generation to FBC. Self-generation supply, in addition to benefitting the self-generator, can also have the following benefits for FBC and its customers:

- self-sufficiency and less reliance on market supply;
- reduction of transmission losses depending on location on the FBC system;
- improved reliability depending on location; and
- complimenting traditional power generation.

When assessing the value of self-generation supply, in addition to these benefits, FBC must consider other relevant criteria in terms of its supply requirements and its LTERP objectives, as it does with other supply-side resource options. These include the energy and capacity profile (i.e. when is the electricity provided to FBC during each month of the year), adherence to provincial energy and environmental policy and cost effectiveness. The energy and capacity profile of the self-generation supply needs to meet FBC's customer load requirements, providing energy throughout the year and capacity during peak demand periods. Any self-generation must be consistent with B.C.'s energy and environmental policies, such as meeting requirements in terms of clean or renewable generation. In terms of cost, long-term self-generation supply would need to be at least as cost effective as FBC's other resource options and as indicated by FBC's LRMC values, as discussed in Section 9. If the self-generation supply is short term in nature, the FBC would compare the cost to its short-term resource options, such as market supply or its PPA contract.

At this point in time, FBC does not have any specifics or indications of costs or other attributes such as environmental or socio-economic characteristics. FBC is not seeking additional sources of supply at this time and is therefore not actively looking to purchase power from self-generator customers. However, if a self-generator could provide power at a cost lower than FBC's alternatives, there may be an opportunity for FBC to purchase the output of the self-generation.

3.9 SUPPLY-SIDE RESOURCE OPTIONS EXCLUDED FROM EVALUATION

FBC has pre-screened the supply-side resource options considered in this ROR for any emerging resource technologies that are not yet commercially viable for utility-scale use or those that are not cost effective or consistent with the *CEA*. This does not mean that these resource options could not be considered in the future and in a future resource plan; however, for the purposes of this ROR these resources have been excluded from evaluation as identified in the Resource Options Summary Table J3-1. These non-viable resources include offshore wind, hydrokinetic, battery storage, coal-fired and nuclear generation.

3.9.1 Offshore Wind Power

While offshore wind generation is a viable resource option in certain regions of B.C., it is currently typically less cost effective relative to onshore wind. Offshore wind technology costs are typically higher than those for onshore wind. This is because the higher capital costs for offshore foundation and installation costs typically outweigh the higher energy production for offshore projects. Therefore, FBC has included onshore, but not offshore, wind as a viable resource option within this ROR.

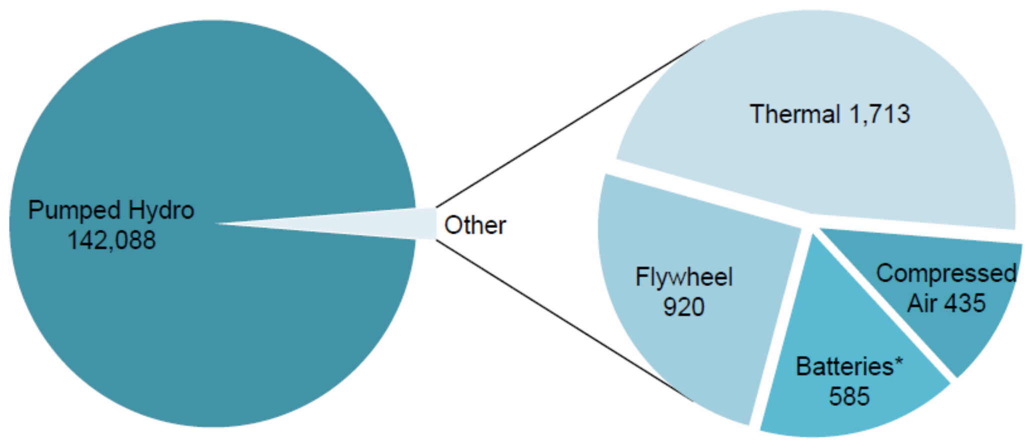
3.9.2 Hydrokinetic Generation

Hydrokinetic technologies include wave and tidal energy. Wave energy is generated by winds blowing over the surface of the ocean. Tidal energy is generated from the kinetic movement of the ocean tides. While there is the potential for significant wave and tidal energy off the coast of BC, these technologies have not yet been proven commercially viable on a utility scale.

3.9.3 Energy Storage

Energy storage consists of three main types: mechanical, chemical and thermal. Mechanical energy storage includes various technologies such as pumped hydro, batteries, flywheels and compressed air. Chemical energy storage includes batteries, capacitors, superconducting coils and fuel cells. Thermal energy storage uses materials that store heat while changing states, perhaps from a solid to liquid form, and includes materials such as rock, concrete, sand, water, and other phase change materials. The following figure shows the recent mix of energy storage in the U.S. Pumped hydro is currently the dominant form of energy storage with other forms comprising about 2.5 percent of the total. FBC has considered pumped hydro storage in its viable resource options as discussed in Section 8.2.

Figure J3-27: Installed Grid-Connected Energy Storage in the U.S. as of August 2015 (MW)[26]



*Batteries include Lithium-ion, Flow, Sodium Sulfur, Nickel Cadmium, Lead Acid, Electrochemical Capacitors and Ultracapacitor Batteries

Energy storage technologies provide a number of benefits including enabling management of the variable supply of intermittent renewable generation sources, providing enhanced power quality (quickly provide power to the grid to stabilize supply voltage), frequency regulation (smoothing cyclic supply), ramping (meet rapid increases in load), shifting the delivery of energy from off-peak to on-peak times and deferring system upgrades (grid improvements and new transmission capacity). While more mature technologies, such as pumped hydro storage, are more common, some emerging technologies, such as battery storage, are experiencing decreasing costs and technical improvements.

[26] Puget Sound Energy 2015 IRP Appendix L, page L-11 - U.S. Department of Energy Global Energy Storage Database (DOE GESDB), August 2015 (http://www.energystorageexchange.org)

Battery storage may become the most viable energy storage technology as the costs of this resource option continue to fall. Some utilities in North America are planning to use battery storage to help make renewable energy more reliable or for outage mitigation, peaking capacity or voltage regulation. Many utilities are beginning battery storage pilot programs with energy storage. For example, Puget Sound Energy (PSE) is planning a 2 MW lithium-ion battery storage pilot project to test outage mitigation, peaking capacity and system flexibility[27]. Avista began testing a 1 MW battery system in 2015 with the goal of demonstrating the ability to provide backup power (outage mitigation), micro-grid operation, peaking capacity, grid flexibility, volt/VAR control, and voltage regulation[28]. On a larger scale, the state of California has mandated its largest utilities to increase their energy storage resources to help fight climate change. Under the rule set by the California Public Utilities Commission, three of California's largest utilities are directed to install 1,300 megawatts of storage capacity (excluding pumped hydro storage) by 2020[29]. Storage will help the state reach its climate goal of having 50 percent of its electricity supplied by renewables by 2030[30].

However, while battery storage is gaining more attention from electricity utilities because of its benefits and decreasing costs, it is still not commercially viable at this point in time. Therefore, FBC has excluded battery storage from its current resource options evaluation. FBC will most likely review the viability of this resource option again in its next LTERP.

3.9.4 Coal-Fired Generation

There is currently no coal-fired electricity generation in B.C. The 2007 BC Energy Plan requires that any coal-fired generation in B.C. must meet a zero GHG emission standard through a combination of 'clean coal' technology, carbon sequestration and offset for any residual GHG emissions[31]. The province has signalled that this will be done by adding coal-fired generation to Schedule A of the *Greenhouse Gas Industrial Reporting and Control Act.* FBC has excluded this resource option from its evaluation due to the potential costs for meeting a zero GHG emission standard and social licensing issues.

3.9.5 Nuclear Power

About 15 percent of Canada's electricity comes from nuclear power, with most of the generators located in Ontario[32]. The 2007 BC Energy Plan made explicitly stated that the government will not allow production of nuclear power in British Columbia. In addition, the *CEA* includes the objective to achieve B.C.'s energy objectives without the use of nuclear power.

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27 Puget Sound Energy 2015 IRP, Appendix L, page L-43.
28 Avista 2015 Electric Integrated Resource Plan Technical Advisory Committee Meeting No. 1 Presentation
29 http://www.prnewswire.com/news-releases/california-adopts-historic-energy-storage-targets-228251181.html
30 http://www.climatecentral.org/news/california-developing-energy-storage-18529
31 http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/bc_energy_plan_2007.pdf, page 13.
32 http://www.world-nuclear.org/information-library/country-profiles/countries-a-f/canada-nuclear-power.aspx

4. SUMMARY

As discussed throughout this ROR, there are many potential supply-side resource options available to FBC to meet its future energy and capacity gaps. These include base load, peaking and intermittent/variable generation resources as well as purchases from the market or self generators. With the decline in natural gas prices over the last few years, natural gas-fired generation is one of the more cost-effective generation options that can provide both energy and capacity for FBC. Of the clean or renewable resources, biogas, biomass, run-of-river and wind are among the lowest cost options. Based on current market price forecasts and PPA rate scenarios, market purchases and the PPA are the least-cost resources available to FBC.

However, it is important to remember that unit cost alone is not the only factor to consider when selecting resources. The size and generation profile of the resource options needs to match the FBC monthly energy and capacity gaps to provide value to FBC. Environmental and socio-economic attributes and geographic resource diversity should also be considered in meeting the LTERP objectives. The portfolio analysis, discussed in Section 9, will help to determine the optimal mix of these various resource options and their attributes, taking into account the resource planning objectives.

Appendix K

LONG RUN MARGINAL COST

FORTISBC INC.

Appendix K
2016 Long Term Electric Resource Plan

Long Run Marginal Cost

Table of Contents

1. INTRODUCTION

Long Run Marginal Cost (LRMC) is a high-level price signal that reflects the cost of prospective future resources required to meet incremental forecast load requirements. In this section, FBC will provide a definition of LRMC, review FBC's previously stated LRMC, review BC Hydro's current LRMC values, and describe the approach used by FBC to determine a LRMC for a specific portfolio.

1.2 *MARGINAL COST DEFINITIONS*

Marginal cost is the change in the total cost of satisfying a permanent increment (or decrement) of demand divided by the magnitude of the increment.[1] The marginal cost can be estimated from either a long-run or a short-run perspective. From a theoretical perspective, the 'Long Run' can be considered a time horizon where all costs are variable. In practice, FBC views the distinguishing differences between the 'short run' and 'long run' as the time horizon considered, specifically the planning horizon of the LTERP.

FBC has previously defined LRMC as "the cost to acquire additional power where existing resources are insufficient to meet load requirements."[2] FBC has updated its definition of Long Run Marginal Cost to be **the incremental cost to build, contract, and/or procure reliable power to meet incremental long term forecast load requirements**. The LRMC is stated in real dollars (2015$)[3] at the point of interconnection to FBC's system. The LRMC includes both an energy and a capacity component.

This definition recognizes FBC's options to build new generation, contract with one or more power providers, further utilize PPA, and/or procure wholesale market power within the planning horizon. The reference to "reliable power" ensures that the power obtained is able to be safely integrated into FBC's system, available at specific times of need, and capable of being scheduled as per industry practices. The use of a portfolio approach recognizes that a combination of existing resources, DSM resources, and incremental supply-side resources will be used to meet the forecast load requirements. It is important to recognize each existing resource contained in the portfolio has a capacity and energy profile. The optimally selected incremental supply-side resources that result in the lowest-cost portfolio will likely complement these existing resource profiles. While a particular resource option may be cost effective relative to a LRMC value, it may not optimally fit the energy or capacity requirements of the portfolio as a whole.

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[1] Market Surveillance Administrator (MSA). A Comparison of the Long-Run Marginal Cost and Price of Electricity in Alberta. December 10, 2012. Section 2.0 Cost in the Long Run. Page 4.
[2] FBC. 2012 – 2013 Revenue Requirements and Review of 2012 Integrated System Plan. Response to BCUC IR 1.242.1.
[3] Costing data related to the resource options contained in the portfolio were collected in 2015. Where applicable, other costs in the portfolio were adjusted to 2015$.

2. FBC'S PREVIOUS LRMC VALUE

The LRMC is used for evaluating DSM resources and serves as a point of reference when evaluating power supply options. On July 10, 2014, the BC Government issued BC Regulation 141/2014 that amended the DSM Regulation under the *UCA*. The amended regulation requires FBC to evaluate DSM opportunities using its LRMC of acquiring electricity generated from clean or renewable resources in B.C.[4]

In the 2012 LTRP, FBC has previously used BC Hydro's Standing Offer Program (SOP)[5] to represent the cost of clean or renewable resources in B.C. The levelized cost to acquire additional power from clean or renewable resources was assessed to be $111.96 per MWh[6]. The $111.96 per MWh levelized value was derived from a 2011-2040 price curve stated in table 5.2-A of Appendix B of the 2012 LTRP.[7] This curve was developed using a base price of $101.39 per MWh (2011$) from BC Hydro's SOP and escalated at 50 percent of CPI annually between 2011 and 2040.

The Commission Panel accepted FBC's LRMC for B.C. clean resources as $112 per MWh (rounded up from the $111.96 per MWh value) for the purposes of the 2015-2016 DSM Plan.[8] Since 2015, FBC has evaluated all DSM programs using a LRMC value of $112 per MWh to represent the cost of clean or renewable resources in B.C. FBC has updated the LRMC for purposes of DSM Regulation in Section 9.3.1 of the LTERP.

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[4] *Utilities Commission Act* Demand-Side Measures Regulation including amendments up to B.C. Reg. 141/2014, July 10, 2014. Section 4: Cost Effectiveness. Point 1.1.b.i

[5] BC Hydro. Standing Offer Program: Report on the SOP 2-Year Review. January 2011.

[6] FBC. Application for Approval of Demand Side Management Expenditures for 2015 and 2016. Response to BCUC IR 1.3.1. September 18, 2014.

[7] FBC. 2012 Integrated System Plan (Vol. 2) & 2012 Long Term Resource Plan. June 30, 2011. Appendix B: 2011 FortisBC Energy & Capacity Market Assessment. Midgard Consulting Inc. May 26, 2011. Pages 26-28 of 54.

[8] Order G-186-14 concerning FBC Application for Approval of Demand Side Management Expenditures for 2015 and 2016. Section 3.2 Long-Run Marginal Cost. Page 5-6.

3. BC HYDRO'S LRMC

FBC and BC Hydro are frequently compared within various regulatory proceedings. The Commission has also previously compared LRMC values between utilities in its decision-making.[9] Although FBC and BC Hydro both operate within B.C., there are several important differences between the two entities. This section reviews BC Hydro's LRMC definition, stated LRMC values, and highlights some of the key differences between BC Hydro's and FBC's LRMC.[10]

BC Hydro defines the LRMC as "the price for acquiring resources to meet incremental customer demand beyond existing and committed resources."[11]

BC Hydro has stated the LRMC in its 2017-2019 Revenue Requirement Application (RRA) (Section 3.4.4.2) at $85 per MWh (2013$) for the years F2022 to F2033 and $100 per MWh (2015$) for years F2034 and beyond.[12] The Energy LRMC value of $85 per MWh (2013$) is an upper price signal for the acquisition of marginal resources, namely DSM programs and EPA renewals with IPPs. The Energy LRMC of $100 per MWh (2015$) for F2034 and beyond is the cost of greenfield, or new, generation from IPPs. Both of the LRMC values are adjusted for delivery to the Lower Mainland.

BC Hydro has stated the LRMC for capacity resources in its 2017-2019 RRA (Section 3.4.4.3) at $50-$55 per kW-year (2013$) for the years F2020 to F2028 and $115 per kW-year (2015$) for years F2029 and beyond.[13] The capacity value of $50-$55 per kW-year (2013$) is based on Revelstoke Unit 6. The Revelstoke Unit 6 UCC, adjusted for both delivery to the Lower Mainland and energy impacts, is estimated to be $57 per KW-year (2015$). For the years 2029 and beyond, BC Hydro considers a SCGT to be the marginal resource, which has an estimated UCC of $115 per kW-Year (F2015$) after adjustments for delivery to the Lower Mainland. It is important to highlight that the addition of Revelstoke Unit 6 is an expansion of an existing resource and therefore an option that is exclusively available to BC Hydro.

BC Hydro suggested in its RRA Evidentiary Update that including a generation capacity value with the energy LRMC of $85 per MWh could increase the LRMC from $95 per MWh (based on $85 per MWh in 2013$ adjusted for distribution losses and inflated to 2017$) to $106 per MWh[14]

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[9] BCUC. FBC Self-Generation Policy Application, Stage 1. Decision and Order G-27-16. Section 6.1.3. March 4, 2016

[10] FBC has consulted with BC Hydro and has reviewed BC Hydro's public Commission filings regarding its LRMC. However, the content of this section of the LTERP should not be in any way attributed to BC Hydro; it solely represents FBC's understanding of BC Hydro's LRMC.

[11] BC Hydro. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. July 28, 2016. Section 3.4.4.1. Page 3-45

[12] BC Hydro. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. July 28, 2016. Section 3.4.4.2. Table 3-10 Marginal Energy Resources and Related Costs. Page 3-49

[13] BC Hydro. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. July 28, 2016. Section 3.4.4.3. Table 3-11 Marginal Capacity Resources and Related Costs. Page 3-50

[14] The $106/MWh (2017$) energy with capacity inclusive value is only applicable to BC Hydro's residential load shape.

in 2017$, although this figure is still being explored through the BC Hydro 2017-2019 RRA proceedings at the time of this document publication.[15]

While BC Hydro and FBC both investigate B.C. generation opportunities, it is not possible to draw a direct comparison between BC Hydro and FBC's stated LRMC values. There are notable timing differences for required resources, locational differences in load and generation, volume differences in capacity and energy requirements, and differences in governing policy that can cause BC Hydro and FBC to consider different resource options. BC Hydro has indicated that resources are required in the near to medium term to meet forecast load[16] and has identified specific resources, both demand side and supply side, that will be used to address this requirement. In contrast, FBC's resource needs are further into the future, as identified in the LTERP, Section 9. To identify prospective future resources, FBC developed a collection of resource options and performed portfolio analysis, which is a fundamentally different approach from BC Hydro.

[15] BC Hydro. 2015 Rate Design Application. Evidentiary Update on Load Resource Balance and Long Run Marginal Cost. Conclusion Section. February 18, 2016.

[16] BC Hydro. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. July 28, 2016. Section 2.4.2 BC Hydro's Load-Resource Balances.

4. FBC'S LONG RUN MARGINAL COST APPROACH

Consistent with the BCUC Resource Planning Guidelines[17] and a Commission directive from the 2012 LTRP decision (G-110-12, Directive 54), FBC has adopted a portfolio analysis approach to assessing resource options. FBC investigated a series of scenarios and therefore a series of potential resource portfolios with different characteristics. The LRMC is calculated as a by-product of a given portfolio scenario. Correspondingly, FBC has stated multiple LRMC values with each LRMC being reflective of the optimal combination of resources used to meet the forecast load requirements and PRM requirements of the specific portfolio scenario. The portfolio analysis description and LRMC values are discussed in more detail in the LTERP, Section 9.

There are three standard approaches to determining LRMC values: the Levelized Unit Energy Cost (LUEC) approach, the Perturbation approach (also referred to as the Turvey approach), and the Average Incremental Cost (AIC) approach.

The LUEC approach is a resource-specific calculation and therefore not appropriate for providing a portfolio LRMC. The Perturbation and AIC are the two portfolio approaches that were considered by FBC.[18] Both the Perturbation and AIC approaches involve similar steps, but differ in how they measure the effect of changes in load requirements on future costs. The Perturbation approach considers the impact on cost of a fixed change in load from the forecast load requirements. In contrast, the AIC approach considers the average incremental cost of meeting the forecast load requirements above current load requirements.

In the opinion of FBC, the Perturbation approach, although aligned with the theoretical definition of LRMC, has some significant drawbacks for practical application, namely:

(1) The Perturbation approach requires a demand increment (or perturbation) to be assumed for the analysis. It is difficult to determine the appropriate size and shape of the demand increment. Furthermore, slightly varying the characteristics of this assumption could potentially yield a significantly different LRMC value.

(2) The Perturbation approach does not necessarily reflect the average incremental costs over the full planning horizon, but rather the incremental cost associated with the assumed perturbation in demand.

(3) The Perturbation approach would be more sensitive to the size and type of the resource options considered in the portfolio, which may vary over time.

(4) The nature of the Perturbation approach provides a greater possibility for large variances in the LRMC over time depending on when the LRMC is updated and the supply-demand balance at the start of the analysis.

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[17] BCUC. Resource Planning Guidelines. December 2003. Points 4-6.

[18] Market Surveillance Administrator (MSA). A Comparison of the Long-Run Marginal Cost and Price of Electricity in Alberta. December 10, 2012. Section 2.1 Measures of LRMC. Page 4.

To derive the LRMC value, FBC has selected the AIC approach. FBC's position is that the AIC approach is more intuitive to interpret and better able to reflect the general level and trend of future costs as well as addresses the unique attributes of FBC's resources (e.g. flexibility of the PPA and market access). The AIC approach is more likely to yield a steady price signal and therefore better guide long term decisions.

4.2 AVERAGE INCREMENTAL COST OVERVIEW

The AIC approach to estimating the LRMC takes the present value of the incremental costs expected to be incurred over the planning horizon and divides the incremental costs by the present value of the incremental load requirements expected to be served by marginal resources within the same period. The AIC approach does not directly link a particular increment of load with the resulting change in cost, but rather expresses the LRMC as the average incremental cost of satisfying the forecast load requirements over the planning horizon.

The AIC approach to estimating LRMC can be summarised as follows:[19]

1. Establish a long-run load forecast (e.g. reference case load forecast with a 20 year planning horizon);
2. Gather information regarding the characteristics and costs of resource options considered available to meet demand;
3. Determine the optimal combination of resources given a set of constraints (the levelized least cost capital program plus the change in operating costs), in present value terms, which can satisfy the forecast requirements at each point in the planning horizon and meet reliability standards;
4. Determine the present value of the load that is in excess of the current load requirements, and
5. Calculate the LRMC by dividing the present value (PV) of the cost of servicing the additional demand by the size of that demand increment, where:

$$\mathbf{LRMC}_{AIC} = \frac{PV(cost\ to\ satisfy\ additional\ demand\ over\ planning\ horizon)}{PV(additional\ demand\ served\ over\ planning\ horizon)}$$

[19] Market Surveillance Administrator (MSA). A Comparison of the Long-Run Marginal Cost and Price of Electricity in Alberta. December 10, 2012. Appendix A.2: The average incremental cost approach. Page VI.

4.3 *FBC AVERAGE INCREMENTAL COST CALCULATION*

The following steps were taken by FBC to calculate the LRMC:

1. Established a long-term load forecast *(Labelled* L_1*)*
   - For each month, in each year of the planning horizon
     - Determine the expected peak demand requirement within the month
     - Determine the expected total energy requirements for the month.
2. Create a resource ‘profile’ for each existing resource as well as each potential new resource option considered available to meet future load
   - For each resource:
     - For each month, in each year of the planning horizon, estimate the capacity and energy capabilities as well as define other relevant resource attributes (e.g. environmental attributes such as GHG emissions, etc.)
     - Establish estimates of unit capital costs, incremental operating expenditures, and other relevant costs (e.g. system interconnection costs).
3. Determine an optimal (lowest-cost) portfolio of resources, in present value terms, that can satisfy the current load, assuming no load growth (referred to as the benchmark load), while adhering to the portfolio constraints and variable settings of the given portfolio scenario[20] [*Labelled* P_0]
   - Assume the load is constant at the benchmark level (2016 forecast load) for the full planning horizon [*Labelled* L_0]
   - Set variables and apply constraints to the portfolio optimization routine based on the characteristics of the portfolio scenario
   - Set the DSM to considered minimum (Low DSM)
   - Find the least cost portfolio that meets the benchmark load requirements and adheres to the constraints of the portfolio scenario.
4. Using the same variable settings and same set of constraints used to represent the characteristics of the portfolio scenario, find the optimal combination of resources that satisfies the forecast load requirement for the planning horizon [*Labelled* P_1]
   - Set the DSM to scenario level (e.g. High DSM)

[20] For the purpose of this portfolio, FBC assumes the “Low-DSM” scenario against which the incremental costs associated with higher levels of load growth offset due to DSM are compared in the various other portfolios.

- Using the load forecast from step 1, the same set of resources established in step 2, and the variable setting and portfolio optimization constraints applied in step 3, find the least cost portfolio that meets the forecast load requirements of the planning horizon.

5. The LRMC is calculated by dividing the net change in the present value of the lowest-cost portfolios by the net change in load requirements, in present value terms.

$$\mathbf{LRMC}_{AIC} = \frac{PV(Portfolio_{\text{Forecast Load}}) - PV(Portfolio_{\text{Benchmark Load}})}{PV(Forecast\ Load) - PV(Benchmark\ Load)} \qquad \mathbf{LRMC}_{AIC} = \frac{PV(P_1) - PV(P_0)}{PV(L_1) - PV(L_0)}$$

5. CONSIDERATIONS WHEN APPLYING THE LRMC

The characteristics of each portfolio, and therefore the characteristics of the LRMC, are largely formed by the constraints applied within the optimization routine, the level of DSM, and the variables settings assumed (e.g. high commodity prices versus low commodity prices, varying PPA costs, etc.). For example, within a portfolio including 100 percent clean or renewable B.C. resources, the portfolio optimization routine constrains (i.e. excludes) resource options that are not considered to fit the definition of a B.C. clean or renewable resource in the *CEA*. The result is a different set of resource options considered available when compared to a portfolio scenario that allows gas-fired generation as a potential resource.

DSM is a component of FBC's preferred resource portfolio. The cost of DSM in the portfolio scenarios, and correspondingly the preferred portfolio, is based on the Total Resource Cost (TRC) as discussed in the LTERP, Section 8.1.

The LRMC assumes that all electricity generated is of equal value. This assumption does not hold true in practice. FBC's resource requirements vary at different times of the year and the value of energy in the market varies at different times.

The timing of when resources are required, the selection of resource options, and the optimal operation of the preferred portfolio strategy is contingent on a number of dynamic factors that will change over time including load forecasts, market pricing, changing customer behavior, macro-economic conditions, governing policy, and technological advancement. In future long term resource plans, FBC intends to revisit and update the LRMC with the most current information available at that time.

6. SUMMARY

FBC considers the long run marginal cost to be a price signal and is one of many considerations when assessing the cost-effectiveness of different resource options. FBC does not expect to acquire all available resources up to the LRMC, nor should the LRMC be viewed as a clearing price in isolation from other prudent resource planning considerations, such as energy or capacity profiles or environmental factors. It is important to note that inappropriate applications of the LRMC can lead to negative customer impacts.

FBC has selected the AIC approach to determining the LRMC. Correspondingly, the LRMC is driven by the incremental costs in the portfolio required to supply incremental demand. The AIC approach is easier to understand, reflects changes in cost and demand over the full planning horizon, and is more likely to produce a stable price signal than the alternative Perturbation approach.

FBC has investigated multiple portfolio scenarios, and correspondingly, has stated multiple LRMCs, which are provided with the analysis in the LTERP, Section 9. The characteristics of the LRMC align with the characteristics of the source portfolio. There are considerations associated with applying the LRMC. Examples of these considerations include selecting the correct LRMC value for the intended purpose, and understanding the LRMC is a price signal without reference to when the power will be required.

Appendix L

PLANNING RESERVE MARGINAL REPORT

FORTISBC INC.

Appendix L

2016 Long Term Electric Resource Plan

2016 Planning Reserve Margin Report

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EXECUTIVE SUMMARY

Planning Reserve Margin (PRM) is defined as the dependable capacity above the expected peak demand and is commonly measured as a percentage of the expected peak demand. PRM is required to ensure system resource adequacy. Utilities differ noticeably in their PRM practices, including how to define the dependability of their capacity resources, whether to rely on the external market or not, which reliability metric to target, and how to derive sufficient PRM to meet the resource adequacy requirements suitable for their operating environment. For example, reviewed neighboring utilities of FBC stated their PRM ranging from -28 percent to 22.6 percent, but some of the utilities did not include Operating Reserves (OR) and several of the utilities did not include the market for PRM purposes making direct comparisons difficult. Utilities also differ widely in how PRM studies are conducted. The most widely accepted approach is to examine PRM from probabilistic studies is using the LOLE metric (Loss-Of-Load-Expectation) or the expected number of days in a year the generation capacity fails to meet load. However, other approaches are the LOLP (Loss-Of-Load-Probability or the probability to fail to meet load), using the PRM target set for that utilities region, or a simple deterministic rule. Each utility should consider its own operating environment for PRM purposes since no two utilities are the same and there is really no one-size-fits-all solution.

As part of the 2016 Long Term Electric Resource Plan (LTERP) FBC reviewed all relevant portfolios (in Section 9) to ensure they met PRM requirements. Where necessary, additional capacity requirements were added to the scenario portfolios until the PRM requirements were met.

This appendix gives more detail on the Company's Monte Carlo simulation-based PRM approach. The Company has adopted LOLE as the reliability metric for the assessment of PRM adequacy, and targets a 1 day in 10 years or 0.1 day per year threshold, which is commonly used by other utilities in its evaluation of resource adequacy. The base resource stack to meet load consists of the Company's own resources, its contracted capacity resources such entitlements from Waneta Expansion (WAX) and 200 MW from BC Hydro under the Power Purchase Agreement (PPA), as well as 150 MW of market access. Most portfolio scenarios include incremental resources at some point in the planning horizon. The selected incremental resources and timing of introduction varied with among the scenarios. These incremental resources were also included the PRM model. The optimal portfolios for applicable scenarios were tested for PRM requirements. In the event the portfolio did not meet PRM requirements, additional capacity requirements were added until the resulting resource stack met PRM requirements.

In the sections that follow, Section 1 reviews key concepts related to PRM including Operating Reserves, Planning Margins and resource adequacy metrics, then examines industry practices and explains the pros and cons of different methods to determine PRM for resource adequacy requirements. Section 2 gives an overview of the Company's operating environment. Section 3 describes modeling techniques used to study PRM requirements within the portfolio scenarios and finally, the conclusion is given in Section 4.

1. OVERVIEW OF PLANNING RESERVE MARGIN

1.1 *PLANNING RESERVE MARGIN TERMINOLOGY*

PRM is conceptually the capacity above expected load necessary to maintain a certain resource adequacy level. PRM is calculated as the difference between system dependable generation capacity and peak demand, commonly measured as a percentage of peak demand:

PRM = ((Capacity – Peak Demand)/Peak Demand) *100%

where the peak demand is the expected load while the generation capacity is dependable capacity. The FBC expected load is net of DSM and savings. As described by NERC, PRM is designed to measure the amount of generation capacity available to meet expected demand in the planning horizon[1]. PRM's role is to ensure resource adequacy when dealing with unforeseen increases in demand and forced outages in the system. It serves the utilities' ultimate goal of "keeping the lights on" over the planning horizon. Negative PRM indicates that the system capacity is not sufficient to meet the expected demand. PRM that is positive but falling below some targeted margin signals that additional capacity is needed to meet a resource adequacy target. Note that two other terms, Planning Reserve and Reserve Margin, are still being used quite interchangeably for the term PRM in the power utility industry.

The PRM concept is broader than Operating Reserves (OR) although it includes OR. OR is defined by NERC as "*capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and non-spinning reserves.*"[2] These spinning and non-spinning reserves[3] are used to form two major functional OR components:

- Contingency Reserve: The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard and other NERC and Regional Reliability Organization contingency requirements. It is for control under disturbance conditions and at least half of it must be spinning. It is available for only 60 minutes from the time of any contingency event; and
- Regulating Reserve: An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin. It is for control under normal conditions and consists of spinning reserve only.

[1] "M-1 Reserve Margin." NERC, http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx. Accessed 28 November 2016.
[2] "Glossary of Terms Used in NERC Reliability Standards." NERC, 28 November 2016, p.63 http://www.nerc.com/files/Glossary_of_Terms.pdf. Accessed 28 November 2016.
[3] Ibid, pp. 99, 116

Utilities must hold capacity for OR to meet NERC (BAL-002[4]) and further sub-regional reliability standards (WECC's BAL-002-WECC-2[5] for FBC). Contingency reserve is not available to be used to meet end-use demand unless there is an unplanned outage event.

It is necessary to hold OR to ensure real-time reliable operation of the system. However, the OR requirement is also counted as part of the overall PRM requirement even though it does not directly contribute to PRM's role of ensuring resource adequacy when dealing with unforeseen increases in demand and forced outages in the system. OR ensures hourly operational reliability while PRM must include a sufficient time period to ensure that changes to the resource portfolio can be addressed as needed to ensure system resource adequacy. In other words, PRM includes the resource capacity reserved for OR to address uncertainties caused by hourly load and generation variations as well as any additional capacity needed on a longer term basis. This point is clearly indicated in WECC's Loads and Resources Methods and Assumptions[6] which describe its building block methodology. As outlined in this document, PRM consists of the two obligatory blocks identified above: (1) contingency reserve and (2) regulating reserve, and two optional blocks: (3) reserve for 1-in-10 weather events and (4) reserve for other forced outages that are outside the 60 minute limit for contingency reserve. The first two blocks make up the OR requirement in most utilities' practices.

Caution should be exercised when comparing PRM values stated by different utilities as they may differ in a number of dimensions, and are specific to the type of resources held by each utility and the nature of their loads. Utilities may also use non-firm capacity, and include or exclude market access as a source of capacity. Also, they may use different PRM calculation methods with remarkably different results. Finally, although published PRM values frequently include OR, they may also exclude OR if a utility wants to make a clear differentiation between capacity requirements for OR and longer term planning margin. This is a practice proposed by Pacific Northwest Utilities Conference Committee (PNUCC), and it has been adopted by a number of Pacific Northwest utilities. PNUCC separates PRM into OR and "Planning Margin" (PM), which does not have the "reserved" capacity. Resources for PM might be used to meet end-use demand[7]. PNUCC recommends utilities to report both values of PM and PM with OR in their resource adequacy assessments. Table 1-1 below illustrates differences in PRM as reported by some of FBC's neighboring utilities.

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4 "Standard BAL-002-0 – Disturbance Control Performance." NERC, http://www.nerc.com/files/BAL-002-0.pdf. Accessed 28 November 2016.

5 "WECC Standard BAL-002-WECC-2 – Contingency Reserve." WECC, https://www.wecc.biz/Reliability/BAL-002-WECC-2%20BC.pdf. Accessed 28 November 2016.

6 "Loads and Resources Methods and Assumptions." WECC, November 2015, p.4 https://www.wecc.biz/Reliability/2015LAR_MethodsAssumptions.pdf. Accessed 28 November 2016.

7 "Reserves in Capacity Planning, A Northwest Approach." PNUCC, June 2010, p.2 http://pnucc.org/sites/default/files/ReservesinCapacityPlanningFinal.pdf. Accessed 28 November 2016.

Table 1-1: PRM Stated by Neighbouring Utilities

	Avista	BC Hydro	Idaho Power	NorthWestern Energy	Pacific Corp	Portland General Electric	Puget Sound Energy
PRM	22.6%	14%[8]	>10%[9]	-28%[10]	13%	12%	13.7%
OR Included?	Yes	Yes	Yes	No	Yes	Yes	No
Market Included?	Yes	No	Yes	No	Yes	Yes	Yes
Reference	2015 Electric IRP[11]	2008 LTAP and 2013 IRP	2015 IRP[12]	2015 Resource Procurement Plan[13]	2015 IRP[14]	2013 IRP[15]	2015 IRP[16]

(**IRP**: Integrated Resource Plan)

There are currently no common NERC standards or requirements for PRM. NERC and its regional entities only strongly recommend PRM, but do not mandate it. Resource adequacy metrics and methodologies for PRM by NERC regional reliability councils are summarized in Table 1-2.

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[8] BC Hydro (**BCH**) uses capacity margin, defined as (Capacity-Peak Demand)/Capacity instead of PRM.

[9] "Idaho Power's future resource requirements are not based directly on the need to meet a specified reserve margin.
The company's long-term resource planning is driven instead by the objective to develop resources sufficient to meet higher-than-expected load conditions under lower-than-expected water conditions, which effectively provides a reserve margin."

[10] "2015 Electricity Supply Resource Procurement Plan." Northwestern Energy, p.1-11 http://www.northwesternenergy.com/docs/default-source/documents/defaultsupply/plan15/volume1/chapter1planoverview. Accessed 28 November 2016.

[11] "2015 Electric Integrated Resource Plan." Avista, 31 August 2015, p.6-1 https://user-3golrxp.cld.bz/Avista-s-2015-Electric-IRP#80. Accessed 28 November 2016.

[12] "2015 Integrated Resource Plan." Idaho Power, p.131 https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/2015IRP.pdf. Accessed 28 November 2016.

[13] "2015 Electricity Supply Resource Procurement Plan." Northwestern Energy http://www.northwesternenergy.com/docs/default-source/documents/defaultsupply/plan15/volume1/chapter1planoverview. Accessed 28 November 2016.

[14] "2015 Integrated Resource Plan, Volume 1." PacifiCorp, p.7 http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf. Accessed 28 November 2016.

[15] "2013 Integrated Resource Plan." Portland General Electric, p.35 https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/pge-2013-irp-report.pdf?la=en. Accessed 28 November 2016.

[16] "2015 Integrated Resource Plan." Puget Sound Energy, p.6-15 http://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_Chap6.pdf. Accessed 28 November 2016.

Table 1-2: NERC's Regional Metrics and Methods for PRM

	WECC	MRO	SPP	PJM	ERCOT	MISO	FRCC	NPCC	SERC
Reference Margin Level[17][18]	10.9%-16.6%	11%-15%	13.6%	15.5%	13.75%	14.3%	15%	11.6% -20%	15%
Regional Resource Adequacy Criteria	Not Specified	1 day-in-10 yr LOLE[#]	1 day-in-10 yr LOLE	1 day-in-10 yr LOLE	1 event-in-10 yr LOLP[#]	1 day-in-10 yr LOLE	1 day-in-10 yr LOLP	1 day-in-10 yr LOLE	1 day-in-10 yr LOLE
Methodology	Building Block	Probabilistic LOLE	Probabilistic LOLE	Probabilistic LOLE	Probabilistic LOLP	Probabilistic LOLE	Probabilistic LOLP	Probabilistic LOLE	NERC Reference[&]

Notes:

(#) LOLE and LOLP are discussed below.

(&) NERC's general reference levels are 10% of hydro and 15% for thermal dominant systems.

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[17] "2015 Long-Term Reliability Assessment." NERC, p.97 http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015LTRA%20-%20Final%20Report.pdf. Accessed 28 November 2016.

[18] "Reliability Considerations for Clean Power Plan Development." January 2016, NERC, p.11 http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Reliability%20Considerations%20for%20State%20CPP%20Plan%20Development%20Baseline%20Final.pdf. Accessed 28 November 2016.

WECC, the NERC regional entity monitoring FBC's service area, does not mandate a PRM on its members. However, NERC and WECC strictly require utilities to maintain their reliability standards for OR requirements. Each utility should determine its own PRM requirement based on its own operational needs, including consideration of its resources, load requirements, and access to the market. Nevertheless, all utilities must insure that any PRM must at least cover OR requirements for regulating and contingency reserves. FBC is a member of the North West Power Pool (NWPP) contingency reserve sharing group, and hence is required to hold an amount of capacity equal to 3 percent of load and 3 percent of generation for contingency reserves. Under the Canal Plant Agreement FBC also holds 2 percent of its capacity for regulating reserves. [19]

1.2 *RESOURCE ADEQUACY METRICS*

The utility industry uses a number of metrics (indices) to measure resource adequacy and determine PRM requirements. Most common metrics are described below:

- *Loss of Load Expectation* (LOLE, in days per year): LOLE is the expected number of days in a year when the aggregate resource is insufficient to meet load. It does not matter if there are single or multiple shortfall events in a day of resource inadequacy since the analysis is for the daily peak only. Resource capacity is assumed to remain constant throughout the day. This is the most commonly used metric in the industry. The commonly used LOLE criterion is "1 day in 10 years", or equivalently 0.1 day/year if annual analysis is required.
- *Loss of Load Hours* (LOLH, in hours per year): LOLH is the expected number of hours in a year when the aggregate resource is insufficient to meet load. This metric is very similar to the LOLE, but using hourly load and generation profiles rather than the daily peak and capacity profiles. Conversion between LOLE and LOLH is, however, not straightforward. LOLE does not equal LOLH/24 because a shortfall event typically does not last for the whole day. If outages were to typically last for 8 hours, the LOLE criterion of 0.1 day/year would be closer to a LOLH criterion of (0.1 * 8) or 0.8 hour/year. This uncertainty in the average outage time makes it very difficult to compare LOLE and LOLH numbers.
- *Expected Unserved Energy* (EUE, in MWh): EUE is the expected amount of energy not served per year. This metric gives some information of the aggregated magnitude of shortfalls.
- *Loss of Load Probability* (LOLP, in percent): LOLP is the probability that at least one shortfall event will occur over the time period being evaluated. Common industry standards are 1-in-10 or 10 percent and 1-in-20 or 5 percent. This approach uses an annual measure. This metric does not reflect the frequency of events such as the LOLE

[19] More precisely, FBC is required to hold 6%/1.06 and 2%/1.02 for contingency reserves and regulating reserves, respectfully. This results in a net OR requirement of 7.51%.

or LOLH because it does not matter if there are one or more shortfall events in the bad year.

These resource adequacy metrics are sometimes referred to as reliability indices in the literature. Since cost consideration makes it practically impossible to have a system totally immune to shortage events, a target metric is chosen to reflect a tradeoff between reliability and cost, taking into account a utility's particular situation.

1.3 *METHODS TO DETERMINE PRM*

This section gives an overview of two main approaches to calculate the PRM capacity and the method chosen by FBC.

1.3.1 Simple Rule-Based Approach

This approach can be done in two ways. In the first way, the utility applies PRM as a certain percent of load. This percentage is taken directly from available study results published by its regional coordination organization on regional PRM. For example, a utility member in the Northwest Power and Conservation Council (NPCC) can set its winter PRM at 23 percent and its summer PRM at 24 percent of net demand (inclusive of OR[20]) based on the NWPCC's calculations for its whole area. However, since the regional study's methods typically take into account dispatching capability among all the different load serving entities, whom each have different load and capacity profiles, the regional organization warns utilities that the results should be interpreted for the whole region and should not be directly applied to any single utility.

The second way uses a simple deterministic formula to determine PRM. For example, prior to adopting the building block method described in Section 1.1, WECC used the following formula:

PRM = Most Severe Single Contingency + 5%*Load Responsibility

The analytical methods above are simple to use, but their major disadvantage is that they do not directly address any resource adequacy metrics (LOLE, LOLH, EUE), and hence, the utility cannot know the system risk level and whether the resource adequacy measure is appropriate for its individual situation.

1.3.2 Probabilistic Approach

Unlike methods in the simple rule-based approach, methods in the probabilistic approach directly target resource adequacy metrics. The first method is called the "Capacity Outage Probability Table" and was frequently used in the 1960s - 1980s. In this method, the utility studies its generators' forced outage rate (FOR), then builds up a complex table of capacity

[20] Fazio J.,"A Probabilistic Method to Assess Power Supply Adequacy for the Pacific Northwest." 22 December 2011, NW Power and Conservation Council, p.18 http://www.nwcouncil.org/media/8932/Adequacy_Standard_Background__2008_07a_.pdf. Accessed 28 November 2016.

outage probabilities and compares values in this table to a forecast load duration curve to find LOLE. There are two main disadvantages with this method. First, setting up the capacity outage probability table gets more cumbersome and intractable the more generators there are in the system. Second, this method cannot take into account both load variations and system outages at the same time.

To overcome these disadvantages, most utilities have switched to the stochastic method, which is based on a Monte-Carlo (MC) simulation. In this method, multiple uncertainties in the system are considered simultaneously and the output is obtained after a high number of sampling iterations. The main advantage of this method is to allow utilities to better approximate real operation of the system, which makes planning results more useful.

The resource adequacy metrics mentioned in Section 1.2 are obtained in the MC simulation method as follows. Suppose a MC simulation for a year uses *n* sampling iterations. If there are *m* simulated years ($m \le n$) in which at least one shortfall event occurs (e.g. resource capacity in a day is less than the day's peak demand if the daily load profile is used or resource capacity in an hour is less than this hour's peak demand if the hourly load profile is used), then for this year:

LOLP = m/n, and *LOLE = Total number of days having shortfalls/n,* if the daily load profile is used (day/year), or

LOLH = Total number of hours having shortfalls/n (hour/year) if the hourly load and generation profiles are used.

In the latter case, EUE can also be estimated as *Total hourly capacity shortage/n* (MWh/year). As mentioned earlier, converting LOLH to the more traditional LOLE to compare to the default industry standard LOLE 0.1 day/year is not simple and still a subject of debate.

1.3.3 FBC's Method to Determine PRM

The Company believes a probabilistic approach employing a Monte Carlo simulation of its operating environment to assess the adequacy of its resources to meet a target performance provides the most balanced method. The Company has chosen the LOLE industry practice of 1 day in 10 years, or as it is more commonly expressed, 0.1 day/year as the target resource adequacy index as it is currently the industry standard and it is appropriate for the FBC resources. After the ReliabilityFirst Corporation, a NERC entity, approved this criterion in March 2011[21], WECC remains the only NERC entity that has not endorsed this criterion. The PRM model considers existing and prospective resources contained in a specific portfolio scenario and simulates random forced outages over the planning horizon based on the assumed generator FORs. The daily peak profile is then compared to available portfolio resources after accounting for simulated forced outages to determine if a resource shortfall has occurred.

[21] "Standard BAL-502-RFC-02." NERC, http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RFC-02.pdf. Accessed 28 November 2016.

2. OVERVIEW OF THE FBC OPERATING ENVIRONMENT

The section presents in detail key features of the Company's operating environment as applied to the PRM study for the assessment of the portfolio scenarios. First, FBC's resource stack and expected forced outage rates are discussed. Next, the different types of prospective resource options considered within the portfolio analysis and their assumed forced outage rates are discussed. Third, the characteristics of the peak forecast used to test for PRM adequacy is outlined.

2.1 *FBC EXISTING RESOURCE STACK*

2.1.1 CPA Entitlement

The Company owns four existing hydro plants located on the Kootenay River between Nelson and Castlegar in this order: Corra Linn (three generators), Upper Bonnington (six generators), Lower Bonnington (three generators), and South Slocan (three generators). Since these facilities are operated under the Canal Plant Agreement (CPA), BCH directly dispatches the plants and FBC receives guaranteed entitlement energy and capacity provided the generating units are available to be dispatched. The Company's usage of its plants to meet system requirements is therefore insulated from hydrology risk, but is still subject to plant outages. In addition to its four plants, FBC has a long-term contract to purchase the whole output of the four generating units of the Brilliant Plant (BRD) belonging to the Brilliant Power Corporation (BPC), which are located close to the Company's plants. Because BRD is also a CPA entitlement plant, therefore the BRD output is also hydrology risk free, but subject to outages. FBC has also contracted to purchase entitlement capacity from the WAX project, which is also a CPA entitlement plant that came into service in April 2015.

In order to assess the availability of its generation units, FBC reviewed their historical performance. In 2012, FBC completed its Upgrade and Life Extension Program (ULE), which extended the lives of 11 of the Company's 15 generating units through its course of maintenance and refurbishment programs. Only four small (5 MW) units at the Upper Bonnington plant were not refurbished under the ULE. The majority of ULE work was done in the 1995-2008 period, therefore it is more reasonable to use historical outage data after 2008 to estimate the plants' expected forced outage rates (FOR)[22]. Each generator's average FOR from the 2008-2015 period is then used to set the expected FOR associated with the specific generator in the MC simulation. FBC generators' average outages resulting in loss of entitlement, and therefore assumed FOR in the MC Simulation, are found in Table 2-1. The large majority of FBC's historical forced outages were less than one day in duration.

[22] A forced outage is an unplanned/unexpected shutdown of a generating unit or an unexpected failure to start. Forced outage rate is the proportion of time the unit is on forced outage to its total service time. The PRM assumed forced outage rates are calculated based on unit availability over the years 2008-2015 as determined by entitlement calculation records

Subsequently, for simulation purposes, it was assumed that all CPA entitlement generator forced outages will last for less than one day.

2.1.2 Power Purchase Agreement, Waneta Expansion, and Brilliant Expansion Capacity

In addition to the CPA entitlement capacity, the Company has also entered into a renewed Power Purchase Agreement (PPA) with BCH. The PPA (approved as per the Commission's Order G-60-14 issued on May 6, 2014) allows capacity purchases of up to 200 MW at any time. Given the resources of BCH and the number of interconnection points, the 200 MW of PPA capacity is considered 100 percent available (i.e. FOR=0 percent). In most portfolio scenarios the PPA is assumed to be renewed in 2033. For the scenarios that investigated if the PPA were not to be renewed, the corresponding PRM assessment did not consider the PPA as an available resource after September 2033.

FBC capacity resources also include entitlement capacity with energy from the Brilliant Expansion plant. In the LTERP and the PRM study, the Brilliant Expansion contract is assumed to be renewed until the end of December 2027. The Brilliant Expansion expected FOR was calculated over the same 2008-2015 period.

Furthermore, the Company receives capacity blocks from the WAX project, which came online in the spring of 2015. The Company receives WAX entitlement capacity from two WAX units, each with a capacity of 165 MW. Since WAX is a relatively new unit with little performance record, predicting WAX's FOR is not straightforward. For the purposes of the MC simulation, it is assumed that the WAX unit expected FORs over the planning horizon will not be different from the average historical FOR of the units at the existing Waneta plant (P6).

FBC is also party to the Residual Capacity Agreement (RCA). Under the RCA, FBC sells unit-contingent[23] WAX capacity blocks of up to 50MW for all months (i.e. typically 50 MW except in June where the WAX capacity available to FBC is less than 50 MW) to BC Hydro up until September 2025. As a result, for the purposes of the MC simulation, these monthly blocks are deducted from FBC's WAX entitlement capacity. The remaining FBC WAX entitlement capacity is then considered available to meet the expected monthly load as the marginal (last) resource to dispatch (after FBC's own and contracted resources, including the PPA).

2.1.3 Market Access

FBC's view is that dependence on market capacity to meet expected demand over the long term is not a prudent policy due to the uncertainty associated with both resource availability and market prices. Other utilities, such as Puget Sound, have begun to recognize wholesale market purchases may no longer be 100 percent reliable[24]. However, it is not unreasonable for utilities

[23] Unit contingent sales are sales that require a particular unit to be available to support the sale. .
[24] LTERP Appendix C, page 3

that have access to market supply to consider market access as a supplemental resource to meet system requirements under unexpected conditions. This market capacity would only be called upon in case of contingencies where a utility's own and contracted resources are unexpectedly not sufficient to meet load. Since peak loads only occur for a small number of hours of the month it is expected that any such market usage would be limited even if the shortfall occurred over a longer time frame. In practice, utilities' opinions differ substantially on relying on market imports for resource adequacy purposes as illustrated in Table L-1 with some neighboring utilities counting market capacity as a supplemental resource and others not.

FBC is able to import electricity from the Mid-C market via transmission connected to Teck's Waneta plant (Line 71), as well as through the BC Hydro transmission system. Line 71 has a transmission capacity of 370 MW but Teck has priority over FBC for use of this line. Therefore, the Company only has approximately 150 MW of reliable access to the market over Line 71. It is assumed that the average forced outage rate associated with market capacity is 0.74 percent. This forced outage rate covers the risk of transmission outages and market availability. Transmission forced outages are based on historical operations of Line 71 for the period of 2000-2015. Market availability is harder to evaluate. For example, during a heavy cold snap utilities may be competing for market purchases and there can be both transmission and generation constraints. FBC has included an assumption to represent the risk of competition among utilities for market capacity and hence the small possibility the Company could not be able to purchase on the spot market[25].

Lastly, the company has assumed an additional 75 MW of market capacity would be available during freshet (specifically June) based on the quantity of hydro generation in the region. Capacity would likely be sourced from within B.C. and therefore not subject to potential Line 71 outage risk. In addition, in June, BC Hydro transmission is likely available to import power into the Province at peak load times if it was required to do so and the risk of power not being available to purchase from the Mid-C market is extremely small.

2.1.4 Summary of Existing Resources & Assumed Forced Outage Rates

The following table shows the assumed FOR of FBC's generating units used to evaluate PRM adequacy requirements among the different portfolio scenarios. FBC also included an assumed FOR for each of its contracted resources, which are in the range of 0.00 percent to 3.94 percent.

[25] A presumed FOR of 0.16% shaped for seasonal attributes.

Table 2-1: PRM Assumed Forced Outage Rates for FBC's Generating Units

Plant	Generator	PRM Assumed Forced Outage Rate
P1- Lower Bonnington	LBO-G1-Upgrade	0.17%
	LBO-G2-Upgrade	0.03%
	LBO-G3-Base	0.03%
P2 - Upper Bonnington	UBO-G1-Small	0.17%
	UBO-G2-Small	0.14%
	UBO-G3-Small	0.92%
	UBO-G4-Small	0.36%
	UBO-G5-Upgrade	0.17%
	UBO-G6-Base	0.06%
P3 - South Slocan	SLC-G1-Base	1.21%
	SLC-G2-Base	0.15%
	SLC-G3-Base	0.13%
P4 - Corra Linn	COR-G1-Base	0.06%
	COR-G2-Base	6.50%
	COR-G3-Base	0.04%

2.1.5 Regulating Reserve and Contingency Reserve Obligations

The Company reserves a certain percentage of its capacity for regulating and contingency purposes. This reserved capacity cannot be counted on to meet expected load for planning purposes as discussed in Section 1.1.

FBC and BCH are both members in the Northwest Power Pool (NWPP), which is a contingency reserve sharing group for utilities in the northwest region.[26] The NWPP groups all reserve contributions from its members according to their load and generation attributes. In a situation where a contingency event occurs that is beyond the resources of the utility experiencing the event, reserves are allocated to them from the other members of the NWPP. The biggest advantage of the NWPP is that each individual utility member is not required to hold reserves to deal with its most severe single contingency. This is of great benefit to FBC especially after WAX came online. A single unit WAX outage (165 MW) would represent the most severe single contingency for FBC.

Under the CPA, the Company sets 2 percent of its generation capacity to regulate frequency. In addition, the Company's contingency reserve obligation to the NWPP is equal to 3 percent of load and 3 percent of generation inclusive of BRD, BRX and WAX contracted capacity (see

[26] Members. Northwest PowerPool, http://www.nwpp.org/about-nwpp/our-members. Accessed 28 November 2016.

footnote 19). The first 60 minutes of a contingency can be covered by contingency reserves. After 60 minutes the contingency reserves must be restored. Therefore, forced outages lasting for less than one hour are not included in this analysis. The likelihood of the outage being less than an hour is set for each generator basic on the specific generator's historical percentage of forced outages that lasted for less than one hour. For example, if a generator has a FOR of 0.5 percent and its forced outages have a likelihood of 70 percent of being more than one hour, then it will experience outages lasting for more than one hour about 0.35 percent of the time.

2.2 NEW PORTFOLIO RESOURCES

As discussed in the LTERP, FBC has considered several different potential supply-side resource options to meet the forecast load requirements. These include the following:

- SCGT
- CCGT
- Hydro (with storage)
- Run of River Hydro
- Pumped Storage Hydro
- Solar
- Biomass
- Biogas
- Geothermal
- Wind

Within the resource portfolio model, each of the resource options has a profile that tables the installed capacity, derived dependable capacity, maximum energy, derived reliable energy, and corresponding capacity factor for each month of the year. The monthly dependable capacity of a resource option is the average capacity FBC can expect to be available to meet peak load in the specific month. Operating reserve requirements were applied to the derived dependable capacity and all new resource options were assumed to have OR requirements of 2 percent to regulate frequency, 3 percent of load, and 3 percent of generation (see footnote 19).

When the optimization routine selects a resource option, the monthly dependable capacity is added to the total monthly capacity tabulation in the portfolio scenario. The approach of using resource profiles recognizes that the different resource option types are anticipated to have varying performance during different months of the year. For example, the profile for a wind resource will vary from a solar resource.

The planning reserve model investigates the possibility that the average dependable capacity is not available to service peak load as projected by the performance profile. The various types of resource options available to the portfolio optimization routine were grouped into three broad classifications for purposes of the PRM Monte Carlo Simulation. The following table shows the presumed forced outage rates associated with each resource classification and how the resource option types were grouped into each classification.

Table 2-2: PRM Assumed Forced Outage Rates for New Portfolio Resources

Resource Option Type Classification	Assumed Forced Outage Rate
Thermal Resources (SCGT, CCGT, Biomass, Biogas, Geothermal)	4.0%[27]
Hydro with Storage (includes Pumped Storage Hydro)	3.62%[28]
Intermittent Resources (Wind, Solar, Run of River)	17.00%[29]

For example, the profile for a wind resource in the portfolio model assumes on average 28.6 percent of nameplate capacity will be available to service peak demand in December. The PRM analysis assumes a 17 percent probability that the average expected capacity will not be available due to a prolonged outage, a mechanical failure, or a temperature variance.

Within the PRM analysis, in the same manner as existing resources, new resources contained within the portfolio scenario are simulated as either available or unavailable to service peak demand based on the assumed FOR. Furthermore, for the purposes of evaluating the PRM adequacy of the various portfolio scenarios, FBC expects that a portion of the forced outages associated with the incremental resources will last for more than one hour but less than one day.

2.3 *PEAK FORECAST*

FBC included load sensitivities to test the robustness of the prospective portfolios. For purposes of evaluating PRM requirements for the various portfolio scenarios, FBC used a 1-in-10 year peak demand forecast, after DSM and savings. The basis for the "1 in 10" forecast is the same as the approach taken to generate the "1 in 20" forecast for system planning purposes as discussed in Section 6.2.1, but only includes 10 years and excludes self-generating industrial customers. A 1-in-10 year peak forecast accounts for the possibility of variation in forecast peak demand and/or realized DSM capacity savings over the planning horizon. Furthermore, as

[27] Based on discussions with a Navigant Consultant (Subject Matter Expert)
[28] Approximated based on CEA averages
[29] As the monthly average dependable capacity of intermittent resources options were shaped within the portfolio, it is not clear to FBC how to assign a forced outage rate to the remaining capacity. As such, PRM 'building block' values were used to develop a FOR. Seventh Northwest Conservation and Electric Power Plan. Chapter 11: System Needs Assessment. ARM vs. Planning Reserve Margin. Page 11-26

capacity resources vary on a monthly basis, the PRM study also randomized which months the summer and winter peaks occur based on historical information. This sensitivity randomly assigned the winter peak to happen in November (11.1 percent), December (44.5 percent), and January (44.4 percent) at the probability equal to each month's historical frequency. The same assumption was made for the summer peak in July and August with their probability of occurrence being 63.2 percent and 36.8 percent, respectively. As a result, portfolios that were assessed for PRM requirements met the LOLE target when stress tested to the 1 in 10 year peak demand and were able to accommodate varying timing of the seasonal peak.

For the MC simulation, the peak profile should be on either a daily or hourly basis. The daily peak profile was chosen as it fits the Company's resource profile and is straightforward to compare the resultant LOLE to the industry practice of LOLE 0.1 day/year.

Twelve representative daily load curves for each month (in percentage of the month's peak) were derived based on a study of peaks over the 2006-2015 period. These chronological curves were then assumed for the whole planning horizon. To forecast daily peaks (in MW) for a month, the month's load curve (in percent) is applied to the month's forecast peak (in MW). For example, with a monthly peak of 700 MW and the first day of the month set at 90 percent of the month's peak, the peak on this first day is 630 MW.

3. MONTE-CARLO SIMULATION RESULTS

3.1 MONTE-CARLO SIMULATION AND ASSUMPTIONS FOR A PORTFOLIO SCENARIO

The MC simulation model for PRM was developed in-house using Microsoft Excel and its programming language Visual Basic for Applications (VBA).

In the LTERP the Company considered a number of resource portfolios before determining its preferred portfolio. All portfolios considered were designed to meet forecast monthly capacity and energy requirements for each month of each year in the planning horizon according to the methodology outlined in Section 9.

To assess the robustness of various portfolio scenarios, the company simultaneously investigated a number of factors to represent plausible deviations from the expected operating environment. Each MC simulation consisted of 5,000 iterations for each year. The notable factors considered are variations in load, timing of seasonal peak, and the possibility for multiple outages. These factors were addressed by:

1. utilizing a 1-in-10 year peak demand forecast,
2. assigning at random the months in which the summer and winter peaks occur, and
3. allowing for more than one forced outage to occur. Outages included both existing resources and prospective new resources included in the specific portfolio scenario

A summary of the key assumptions contained in the PRM analysis are as follows:

1. FBC's own and contracted generators' FORs are assumed as explained in Section 2.1.4;
2. Forced outages last for less than one day and an outage on one day does not influence if the following day will have an outage as well;
3. Market access is 150 MW with an average monthly FOR of 0.74 percent. In June there will be an additional 75 MW of capacity available from the local market
4. Prospective new resources deliver dependable capacity as per the assumed performance profile in the resource portfolio model and have an assumed FOR as per Table 2-2; and
5. WAX capacity for unit-contingent sales associated with RCA is not available to meet FBC peak demand.

3.2 PROCESS FOR EVALUATING A PROSPECTIVE PORTFOLIO

The process to find the optimal PRM compliant portfolio for a specific portfolio scenario[30] is as follows:

1. Using the Resource Portfolio model, find an optimal portfolio that meets the forecast load requirements and the constraints of the specific scenario.
2. Test the resulting resource stack for robustness using the planning reserve model and the LOLE target. If the optimal portfolio met the LOLE target in each year of the planning horizon, the portfolio was deeded to meet PRM requirements.
3. If the optimal portfolio did not met the LOLE target, additional capacity requirements were added to the months of January and December in 5 MW increments for PRM purposes starting in the first year of the planning horizon the LOLE target was not met.
4. The Resource Portfolio for the specific scenario was then re-optimized with the additional PRM capacity requirements
5. Steps 2 through 5 were repeated until the optimal portfolio for the specific portfolio scenario met the LOLE target in all years of the planning horizon.

3.3 RESULTS

3.3.1 General Observations

Near the end of the planning horizon, FBC requires the dependable capacity associated with the prospective new resources to meet the LOLE target. The capacity associated with the resources is simulated as either available or unavailable during the peak hour based on the assumed FOR. Many portfolio scenarios include intermittent renewable resources, which, by nature, have a higher assumed forced outage rate than thermal resources or hydro resources with storage. Correspondingly, the PRM model is requiring the optimal portfolio to either add further capacity near the end of the planning horizon to complement the intermittent resources or prefer resources that are less intermittent in nature in order to meet the LOLE target.

PRM calculations limit the overall dispatch of market based power to 150 MW (225 MW in June). This includes both market power required to meet overall resource gaps as well as that used for unexpected requirements (PRM purposes). Given the limited FBC capacity gaps in the LTERP, market reliance to meet capacity gaps is extremely limited. However, if a portfolio was suggested that required significant amounts of market power to meet capacity gaps, it could fail the PRM test. When market access is used for PRM purposes only, the probability of capacity shortages is minimized if market access is not available but the base resources are functioning well. However, if the market is also used as a base resource to meet expected gaps, then if the

[30] Portfolio scenarios that included the boundary high load forecast were not able to be tested for PRM Requirements.

market is not available as a failover resource it is also not available as a base resource and there is a greater probability of capacity shortages. Therefore, reliance on the market as both a base and a backup resource is not a prudent approach in the long run.

3.3.2 Preferred Portfolio

As discussed in LTERP Section 9.4.6, the Company ultimately selected portfolio A4 as its preferred portfolio. This preferred portfolio includes wind, biogas and SCGT as supply side resources. Table 3-1 below shows the LOLE of the preferred portfolio (A4) over the planning horizon, and demonstrates that the PRM requirement of LOLE equal to or less than 0.1 days per year has been met over the planning horizon. There are noticeable variations in the LOLE value among the years in the planning horizon that can be explained. The WAX RCA agreement expires September 2025, effectively adding 50 MW of available capacity to FBC in all months. The introduction of a wind resource in 2026, primarily for energy purposes, provides a degree of capacity value. These two changes in capacity significantly reduced the annual LOLE in 2026. In both the Resource Portfolio and the PRM Model, the BRX agreement is assumed to be extended to December 2027. After the year 2027, BRX is assumed not to be a part of FBC's resource stack. Correspondingly, in 2028 the LOLE value increases. Later in the planning horizon, the LOLE again decreases when the supporting capacity of the SCGT is brought into service.

Table 3-1: LOLE in the Preferred Portfolio (0.1 day per year as the target)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	LOLE
2016	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01
2017	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.02
2018	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.02
2019	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.02
2020	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.03
2021	0.01	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.02	0.04
2022	0.02	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.02	0.06
2023	0.02	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.03	0.07
2024	0.03	0.00	0.00	0.00	0.00	0.01	0.02	0.00	0.00	0.00	0.01	0.03	0.09
2025	0.04	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.07
2026	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01
2027	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
2028	0.00	0.00	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.05	0.08
2029	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.04	0.07
2030	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.04	0.08
2031	0.01	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.05	0.08
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02

4. CONCLUSION

The main objective of the LTERP is to ensure reliable, secure and cost effective power supply for its customers. In line with this objective, PRM resource adequacy requirements need to be met. FBC has determined that a Monte Carlo probabilistic approach to assessing PRM requirements is the best approach. The most common metric to assess PRM requirements is the LOLE with a 1 day per 10 years or 0.1 day per year target, which is an industry standard for resource adequacy and has been adopted by FBC as well.

FBC has investigated a series of portfolio scenarios within the LTERP. Noting FBC will likely require energy resources earlier in the horizon before capacity resources, the portfolio optimization routine selects intermittent renewable resources as the most cost-effective way to fill a large portion of the forecast energy requirements within a number of the portfolio scenarios. In the later years of the planning horizon, the intermittent renewable resources warrant the need for either additional capacity to complement the intermittent resources or the optimal portfolio for the specific scenario needs to be adjusted to include resources that are less intermittent in nature to meet the 1-in-10 year target.

FBC has confirmed the preferred portfolio (A4) meets resource adequacy with respect to the LOLE target of 1 day in 10 years using a MC simulation. To ensure robustness, multiple aspects of the operating environment were randomly deviated from the expected conditions.

Appendix M

DRAFT ORDERS

Appendix M-1

DRAFT PROCEDURAL ORDER

British Columbia Utilities Commission

Sixth floor, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
TEL: (604) 660-4700
BC Toll Free: 1-800-663-1385
FAX: (604) 660-1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
2016 Long Term Electric Resource Plan and 2016 Long Term Demand Side Management Plan

BEFORE:
Panel Chair/Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On November 30, 2016, FortisBC Inc. (FBC) filed its 2016 Long Term Electric Resource Plan (2016 LTERP) including its 2016 Long Term Demand Side Management (DSM) Plan (2016 LT DSM Plan), as Volumes 1 and 2, respectively, for acceptance by the British Columbia Utilities Commission (Commission) under section 44.1(6) of the *Utilities Commission Act* (UCA);

B. The 2016 LTERP presents a long term plan for meeting the forecast peak and energy requirements of FBC customers with demand-side and supply-side resources at the lowest reasonable cost to customers over the next 20 years;

C. The 2016 LTERP analyzes the external regulatory, policy and planning environment within which FBC operates, compares energy and capacity forecasts against current resource capabilities and evaluates the potential for load reduction with DSM initiatives and portfolios of resource options to meet forecast customer needs under different scenarios. The 2016 LTERP includes a preferred portfolio to meet the long term requirements of FBC's customers. The LTERP also includes an action plan that identifies activities that FBC expects to take during the first four years of the 20-year planning horizon;

D. The 2016 LT DSM Plan includes an assessment of the energy efficiency and conservation potential for FBC customers. The 2016 LT DSM Plan provides FBC with different levels of demand-side resource options to assess along with supply-side resource options in order to address the forecast load-resource balance gaps identified in the 2016 LTERP over the 20-year planning horizon. The 2016 LT DSM Plan also identifies FBC's preferred DSM scenario for long term planning purposes;

E. FBC proposes to provide the terms and conditions regarding its DSM measures pursuant to its DSM program offerings and to rescind Rate Schedule 90 Demand Side Management Services from its Electric Tariff;

F. Section 44.1(5) of the UCA provides that the Commission may establish a process to review a long-term resource plan;

.../2

G. The Commission has determined that a written public hearing is appropriate to review the 2016 LTERP and 2016 LT DSM Plan and considers that the establishment of a regulatory timetable is warranted.

NOW THEREFORE the British Columbia Utilities Commission orders as follows:

1. The Regulatory Timetable for the review of the FortisBC Inc. (FBC) 2016 Long Term Electric Resource Plan (2016 LTERP) and 2016 Long Term Demand Side Management Plan (2016 LT DSM Plan) is set out in Appendix A to this order.

2. FBC is to publish, as soon as possible, the Public Notice, attached as Appendix B to this Order, in such local and community newspapers as to provide adequate notice to those parties who may be affected by the plans outlined in FBC's 2016 LTERP and 2016 LT DSM Plan.

3. FBC must provide a copy of this Order to the key parties consulted in FBC's Stakeholder and First Nation Engagement outlined in Section 10 of FBC's 2016 LTERP.

4. The 2016 LTERP and 2016 LT DSM Plan, together with any supporting materials, will be available for inspection at FBC Office, Suite 100, 1975 Springfield Road, Kelowna, BC, V1Y 7V7. The 2016 LTERP and 2016 LT DSM Plan and supporting materials will also be available on the FortisBC website at www.fortisbc.com.

5. Interveners who wish to participate in the regulatory proceeding are to register with the Commission by completing a Request to Intervene Form, available on the Commission's website at http://www.bcuc.com/Registration-Intervener-1.aspx, by the date established in the Regulatory Timetable attached as Appendix A to this order and in accordance with the Commission's Rules of Practice and Procedure.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

FortisBC Inc.
2016 Long Term Electric Resource Plan and 2016 Long Term Demand-Side Management Plan

REGULATORY TIMETABLE

ACTION		DATE (2017)
Intervener and Interested Party Registration		Thursday, January 12
Commission Information Request No. 1		Thursday, January 19
Intervener Information Requests No. 1		Thursday, January 26
FBC Responses to Information Requests No. 1		Thursday, March 2
Commission and Intervener Information Requests No. 2		Thursday, March 23
Notification by Interveners of Intent to file Evidence		Thursday, April 13
FBC Responses to Information Requests No. 2		Thursday, April 20
	No Intervener Evidence	**If Intervener Evidence**
Intervener Evidence	n/a	Thursday, May 4
Commission and Intervener Information Request No. 1 on Intervener Evidence	n/a	Thursday, May 18
Intervener Responses to Information Requests No. 1 on Intervener Evidence	n/a	Thursday, June 15
FBC Final Written Submission	Thursday, May 4	Thursday, June 29
Intervener Final Written Submissions	Thursday, May 18	Thursday, July 13
FBC Reply Submission	Thursday, June 1	Thursday, July 27

British Columbia Utilities Commission

Public Notice of Commission Review of FortisBC Inc.'s 2016 Long Term Electric Resource Plan and 2016 Long Term Demand-Side Management Plan

On November 30, 2016, FortisBC Inc. (FBC) filed its 2016 Long Term Electric Resource Plan (2016 LTERP) and 2016 Long Term Demand Side Management Plan (LT DSM Plan) for acceptance by the British Columbia Utilities Commission (Commission), pursuant to section 44.1(6) of the *Utilities Commission Act.*

The 2016 LTERP presents a long term plan for meeting the forecast peak and energy requirements of FBC customers with demand-side and supply-side resources at the lowest reasonable cost to customers over the next 20 years.

The 2016 LTERP analyzes the external regulatory, policy and planning environment within which FBC operates, compares energy and capacity forecasts against current resource capabilities and evaluates the potential for load reduction with demand-side management initiatives and portfolios of resource options to meet forecasted customer needs under different scenarios. The 2016 LTERP also includes an action plan that identifies activities that FBC expects to take during the first four years of the 20 year planning horizon.

The 2016 LT DSM Plan includes an assessment of the energy efficiency and conservation potential for FBC customers. The 2016 LT DSM Plan provides FBC with different levels of demand-side resource options to assess along with supply-side resource options in meeting the forecast load-resource balance gaps over the planning horizon identified within the 2016 LTERP.

How to get involved

Persons who are directly or sufficiently affected by the Commission's decision or have relevant information, or expertise and who wish to actively participate in the proceeding can request intervener status by submitting a completed Request to Intervene Form by Thursday, January 12, 2017. Forms are available on the Commission's website at www.bcuc.com. Interveners will receive notification of all non-confidential correspondence and filed documentation, and should provide an email address if available.

Persons not expecting to participate, but who have an interest in the proceeding, should register as interested parties through the Commission's website. Interested parties receive electronic notice of submissions and the decision when it is released.

Letters of comment may also be submitted using the Letter of Comment Form found online at www.bcuc.com. By participating and/or providing comment on the application, you agree to your comments being placed on the public record and posted on the Commission's website. All submissions and/or correspondence received, including letters of comment are placed on the public record, posted on the Commission's website, and provided to the Panel and all participants in the proceeding.

For more information about participating in a Commission proceeding please see the Rules of Practice and Procedure available at www.bcuc.com. Alternatively, persons can request a copy of the Rules of Practice and Procedure in writing. All forms are available on the Commission's website or can be requested in writing.

View the FBC 2016 LTERP and 2016 LT DSM Plan

The FBC 2016 LTERP and 2016 LT DSM Plan and all supporting documentation are available on the Commission's website on the "Current Applications" page. If you would like to review the material in hard copy, it is available to be viewed at the locations below:

British Columbia Utilities Commission Sixth Floor, 900 Howe Street Vancouver, BC V6Z 2N3 Commission.Secretary@bcuc.com Telephone: 604-660-4700 Toll Free: 1-800-663-1385	**FortisBC Inc.** Suite 100, 1975 Springfield Road Kelowna, BC V1Y 7V7

For more information please contact Laurel Ross, Acting Commission Secretary using the contact information above.

Appendix M-2

DRAFT FINAL ORDER

British Columbia Utilities Commission

Sixth floor, 900 Howe Street
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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
2016 Long Term Electric Resource Plan and 2016 Long Term Demand Side Management Plan

BEFORE:
Panel Chair/Commissioner
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On November 30, 2016, FortisBC Inc. (FBC) filed its 2016 Long Term Electric Resource Plan (2016 LTERP) including its 2016 Long Term Demand-Side Management (DSM) Plan (2016 LT DSM Plan), as Volumes 1 and 2, respectively, for acceptance by the British Columbia Utilities Commission (Commission) under section 44.1(6) of the *Utilities Commission Act* (UCA);

B. The 2016 LTERP presents a long term plan for meeting the forecast peak and energy requirements of FBC customers with demand-side and supply-side resources at the lowest reasonable cost to customers over the next 20 years;

C. The 2016 LTERP analyzes the external regulatory, policy and planning environment within which FBC operates, compares energy and capacity forecasts against current resource capabilities and evaluates the potential for load reduction with DSM initiatives and portfolios of resource options to meet forecast customer needs under different scenarios. The 2016 LTERP includes a preferred portfolio to meet the long term requirements of FBC's customers. The LTERP also includes an action plan that identifies activities that FBC expects to take during the first four years of the 20-year planning horizon;

D. The 2016 LT DSM Plan includes an assessment of the energy efficiency and conservation potential for FBC customers. The 2016 LT DSM Plan provides FBC with different levels of demand-side resource options to assess, along with supply-side resource options, in order to address the forecast load-resource balance gaps identified in the 2016 LTERP over the 20-year planning horizon. The 2016 LT DSM Plan also identifies FBC's preferred DSM scenario for long term planning purposes;

E. FBC proposes to provide the terms and conditions regarding its DSM measures pursuant to its DSM program offerings and to rescind Rate Schedule 90 Demand Side Management Services from its Electric Tariff;

F. Section 44.1(5) of the UCA provides that the Commission may establish a process to review a long-term resource plan;

.../2

G. The Commission has reviewed and considered the 2016 LTERP including the 2016 LT DSM Plan and the evidence submitted through the review process.

NOW THEREFORE the Commission, for the reasons set out in the decision, orders as follows:

1. The Commission accepts the FortisBC Inc. (FBC) 2016 Long Term Electric Resource Plan, including the 2016 Long Term Demand-Side Management Plan, to be in the public interest pursuant to section 44.1(6) of the *Utilities Commission Act* (UCA).

2. The proposal to rescind Rate Schedule 90 from FBC's Electric Tariff is approved. FBC is directed to submit revised tariff pages in respect of Rate Schedule 90.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

FortisBC Inc.

2016 Long-Term Electric Resource Plan

Volume 2

2016 Long-Term Demand-Side Management Plan

November 30, 2016

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1. OVERVIEW

FortisBC Inc. (FBC or the Company)'s 2016 Long Term Demand-Side Management Plan (LT DSM Plan), part of the 2016 Long-term Electric Resource Plan (LTERP), is filed pursuant to section 44.1(2)(b) of the *Utilities Commission Act* (*UCA*). The Company is *not* seeking approval of the pro-forma DSM expenditures listed in section 3.3 of the LT DSM Plan.

The BC Energy Plan and the *Clean Energy Act* (*CEA*) emphasize the deployment of demand side measures to meet growing electricity demand in British Columbia. The *UCA* and the Demand Side Measures Regulation (DSM Regulation) enacted under the *UCA* set out more specific requirements for a public utility in developing a plan of how it intends to reduce customer demand for energy by taking cost-effective DSM measures and to include certain programs in the public utility's DSM plan portfolio.

The Company's objective for DSM activities 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 for each major customer sector.

The key objective for LT DSM Plan is to determine the appropriate level of cost-effective DSM resource acquisition to match the Company's resource needs over the LTERP's planning horizon. The proposed DSM savings target is to offset 77 percent of load growth over this 20 year period. The savings target for the first three years of the LT DSM Plan (2018-2020) are largely an extension of the approved 2016 DSM Plan and 2017 DSM Plan, as filed, (approximately 26 GWh/yr). Thereafter the savings target is escalated to 32 GWh/yr and held there to the end of the LTERP planning horizon.

1.1 *THE UCA AND DSM REGULATION*

Table 1-1 in Section 1.4.1 of the LTERP lists the relevant sections of the *UCA* for resource planning requirements. The following requirements for a long term resource plan in s. 44.1(2) of the UCA are specifically relevant to the LT DSM 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;

(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.

In addition, s. 44.1(8) of the *UCA* requires the BC Utilities Commission (BCUC or the Commission), in determining whether to accept a long term resource plan, to consider "(c) whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures".

The DSM Regulation, enacted pursuant to the *UCA*, defines what DSM measures must be included in the public utility's DSM plan for it to be "adequate" within the meaning of s. 44.1(8)(c) of the UCA. A public utility's DSM plan portfolio is only adequate for the purposes of section 44.1 (8)(c) of the *UCA* if it includes all of the following:

Table 1-1: Requisite Contents for a Long Term DSM Plan

Section of the *DSM Regulation*	Adequacy Requirement	Section of LT DSM Plan Addressing Requirement
3(a)	a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption	4.1.7
3(b)	a demand-side measure intended specifically to improve the energy efficiency of rental accommodations	4.1.8
3(c)	an education program for students enrolled in schools in the public utility's service area	4.4.4
3(d)	an education program for students enrolled in post-secondary institutions in the public utility's service area	4.4.4

The DSM Regulation, in section 4, also defines the basis for FBC's marginal electricity costs and sets out the test the Commission must use in making determinations of cost effectiveness.

These provisions, and where they are addressed in the LTERP and/or LT DSM Plan, are as follows:

Table 1-2: Commission Considerations for Accepting a Long Term DSM Plan

Section of the *DSM Regulation*	Cost-effectiveness Requirement	References Addressing Requirement
4(1.1)	The commission must make determinations of cost effectiveness by applying the total resource cost test as follows …	LT DSM Plan Section 2.4
4(1.1)(b)	subject to subsection (1.3), the avoided electricity cost, if any, respecting a demand-side measure, in addition to the avoided capacity cost, is (i) in the case of a demand-side measure of FortisBC Inc., an amount that the commission is satisfied represents FortisBC Inc.'s long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia	LTERP Section 9.4 and LT DSM Plan Section 2.4

Accordingly, the Company has developed a long-run marginal cost (LRMC) for DSM purposes, based on BC clean and renewable resources, of $100.45/MWh (abbreviated as $100/MWh), which reflects the cost of firm energy i.e. inclusive of generation capacity. FBC is using a Deferred Capital Expenditure (DCE) value of $79.85/kW-yr[1], consistent with the updated DCE value filed in the Company's 2017 DSM Expenditure Plan (2017 DSM Plan), as its avoided capacity cost of deferred infrastructure.

In conclusion, the Company believes the LT DSM Plan meets the applicable requirements of the DSM Regulation, as amended July 10, 2014.

1.2 *THE CLEAN ENERGY ACT*

The *UCA*, s. 44.1(8)(a) also requires the Commission to consider the applicable of British Columbia's energy objectives in determining whether to accept the LTERP for filing.

Relevant energy objectives under the *CEA* are discussed in Section 1.1 of the LTERP, and include the objective "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 Company's current level of DSM plan savings approximates 66% DSM offset, which has been used as the base DSM Scenario in the LT DSM Plan.

The *CEA* defines a "demand-side measure" to mean a rate, measure, action or program undertaken:

[1] FBC 2017 DSM Expenditure Plan, Exhibit B-1, Appendix C.

(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.

FBC has prepared the LT DSM Plan taking into consideration "the applicable of British Columbia's energy objectives" set out in the *CEA*[2]. Table 1-3 below lists the objectives set out in the *CEA* that FBC believes are directly relevant to the Company's LT DSM Plan.

Table 1-3: Relevant *Clean Energy Act* Objectives

***Clean Energy Act* Objectives**	**2016 LT DSM Plan Satisfies Objective**	
(b) to take demand-side measures and to conserve electricity…	✓	FBC proposes to adopt its High DSM Scenario to be implemented over the LTERP planning horizon
(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia	X	Section 5.1 of LT DSM Plan
(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiency;	✓	Supporting Initiatives includes Community Energy Planning (Section 4.4.2)

1.3 *BCUC DIRECTIVES*

The following Directives from Order G-186-14 have been addressed in previous filings (Annual Reports or the 2017 DSM Plan) and are reproduced here as they are relevant to the LT DSM Plan.

[2] British Columbia's energy objectives as defined in the *CEA* are fully identified in Table 1-3 of the LTERP.

1 **Table 1-4: Order G-186-14 Commission Directives**

Directive:		Notes:
3	The Panel directs FBC to include in the next DSM expenditure request a description of the assumptions used to develop the updated avoided capacity and LRMC estimate, and to explain how avoided transmission and distribution energy losses are incorporated into DSM cost/benefit tests.	Section 2.4 of LT DSM Plan Updated LRMC in Section 9.3 of LTERP Deferred Capital Expenditure Study filed as Appendix C to the 2017 DSM Plan
5	The Panel therefore directs FBC to review the TRC discount rate assumptions in the next DSM expenditure request, including identification of potential additional DSM measures that would pass both the TRC and the UCT if a societal discount rate was used for the TRC. FBC is also directed to identify in the next DSM expenditure request any DSM measures (in addition to those proposed) that fail the TRC but would pass the mTRC.	Section 2.4 of LT DSM Plan Updated Discount Rate (DR) in 2017 DSM Plan (Section 5.1.2)
9	As a result, the Panel directs FBC to include in the next DSM expenditure request: • an update on FBC’s investigation into potential fuel switching programs, including those targeting vehicles and propane/oil heating; and • a cost-benefit analysis (including supporting assumptions) showing whether FBC can allow customers with gas as their primary heating source to access FBC’s DSM programs and still be compliant with the DSM Regulations.	Section 5.1 in LT DSM Plan

2. DSM PLAN DEVELOPMENT

2.1 *PLANNING PRINCIPLES*

Through the LTERP process, FBC used the following guiding principles to develop a LT DSM Plan that:

1. is customer focused by offering a range of measure choices within programs that address the key end uses of the principal customer rate classes;
2. is cost effective by including only those measures, with the exception of adequacy measures, that have a Total Resource Cost (TRC) Benefit/Cost (B/C) ratio greater than unity on a portfolio basis (see Section 2.4); and
3. is compliant with the applicable sections of the *UCA*, the *CEA*, and the DSM Regulation.

The objective of the LT DSM Plan is to determine the total quantity of DSM savings that are appropriate to fulfill FBC's resource needs over the planning horizon of the LTERP. It is not a detailed DSM Plan allocating savings to sector levels, nor is FBC seeking acceptance of the DSM program cost estimates presented in the LT DSM Plan.

The Company expects to file its next DSM expenditure schedule in mid-2017.

2.2 *PLANNING STEPS*

The LT DSM Plan was developed using the following steps:

1. Quantify the technical and economic energy savings potential available (see Section 2.3);
2. Develop DSM scenarios including low, base, high, and maximum options modeled as part of the resource portfolios analyzed in the LTERP process;
3. Present these scenarios in a series of public consultations through the LTERP process; and
4. Select the DSM scenario that is the preferred option for the LT DSM Plan and the LTERP.

The following sections explain the above steps.

2.3 CONSERVATION POTENTIAL REVIEW (CPR)

FBC partnered with three other BC utilities[3] to perform a provincial, dual-fuel conservation potential review (BC CPR). Navigant Consulting (Navigant) was engaged to determine the energy efficiency potential for electricity and natural gas across British Columbia in the residential, commercial, and industrial sectors over the planning horizon of 2016 to 2035.

Although the BC CPR was developed collaboratively, each of the participating BC Utilities, including FBC, received its own CPR Results and Report based on its specific inputs, (e.g. avoided costs and discount rate). A provincial level report, summarizing the economic potential across all participating utilities, will be compiled for other users such as the BC Ministry of Energy and Mines (MEM).

The scope of the FBC CPR Results and Report (FBC CPR[4]) included assessing the conservation potential of the total loads in its service territory, including those partially supplied by self-generating customers. In the case of Nelson Hydro, its self-generation was allocated to the Residential & Commercial sectors, and for the Industrial sector its self-generation was allocated to the relevant segments (e.g. Pulp & Paper).

The BC CPR used three distinct steps to estimate potential: generating a reference case forecast, characterizing energy savings measures, and estimating the economic savings potential.

For the first step, Navigant developed a base year and a reference case forecast of energy consumption. The base year establishes a profile of energy consumption for the utility based on an assessment of energy consumption by customer sector and segment, end-use, fuel, and types of equipment used.

Primary inputs to the base year were the Company's 2012 Residential and 2015 Commercial End-Use Surveys (R/CEUS). The key objectives of the R/CEUS are 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. Additionally the surveys solicit customer opinions, attitudes and behaviours related to electricity and conservation. This information was a key input to the BC CPR and is further used to develop programs and communications strategies that are suited to the needs of FBC's customers.

Navigant also used selected data from the FEI and BC Hydro R/CEUS where finer granularity (e.g. market segmentation) was available and secondary sources such as Statistics Canada (StatCan) and Natural Resources Canada (NRCan).

After calibrating the 2014 base year to actual utility energy sales, Navigant generated a reference case forecast that estimates the electricity demand over the CPR period absent incremental DSM activities. The technical and economic potential scenarios were then

[3] British Columbia Hydro and Power Authority (BC Hydro), FortisBC Energy Inc. (FEI) and Pacific Northern Gas (PNG) (collectively, the BC Utilities)

[4] The FBC CPR Technical and Economic report can be found in Appendix A of the LT DSM Plan.

calculated against the reference case forecast. Navigant used two key inputs to construct the Reference Case forecast for each customer sector: stock growth rates and energy use intensity trends.

The next step was to develop a comprehensive list of energy efficiency measures that will provide the bulk of economic potential. Over 200 energy savings measures were included from the residential, commercial, and industrial sectors, covering electric and natural gas fuel types. Navigant prioritized measures with high impact, data availability, and most likely to be cost-effective as criteria for inclusion in the study.

Finally, once the reference case forecast and list of measures were established, Navigant estimated the technical and economic savings potential for electric energy and electric demand across FBC's service territory. Technical potential includes energy savings that could be achieved if all installed measures were immediately replaced with the efficient measure, wherever technically feasible, regardless of the cost, market acceptance, or whether a measure has failed.

Economic potential is a subset of the technical potential, using the same assumptions as the technical potential, but includes only measures that have passed the TRC test.

2.4 *THE TRC AND FBC AVOIDED COSTS*

The TRC is the governing test used to determine the cost-effectiveness of a utility's DSM portfolio. It comprises of benefits (the present value of the measures' energy savings, over their effective measure life, valued at the utility's avoided costs) divided by the costs[5] (incremental cost of the measures plus program administration costs). The TRC can be expressed on an individual measure basis, for a program (group of measures), on a sector level and/or at the portfolio level.

The TRC test was done at the measure level in the DSMSim™ modelling tool[6]. The benefits are FBC's "avoided costs", calculated as the present value over the effective measure life of:

- the measures' energy savings, valued at the LRMC of $100.45 per MWh; and
- the measures' demand savings, valued at the DCE of $79.85 per kW-yr.

The measures' energy and demand savings are grossed-up by the avoided transmission and distribution energy losses (line losses) value of 8%, before the benefits are calculated. A 6% discount rate was used to calculate the present value of the benefits.

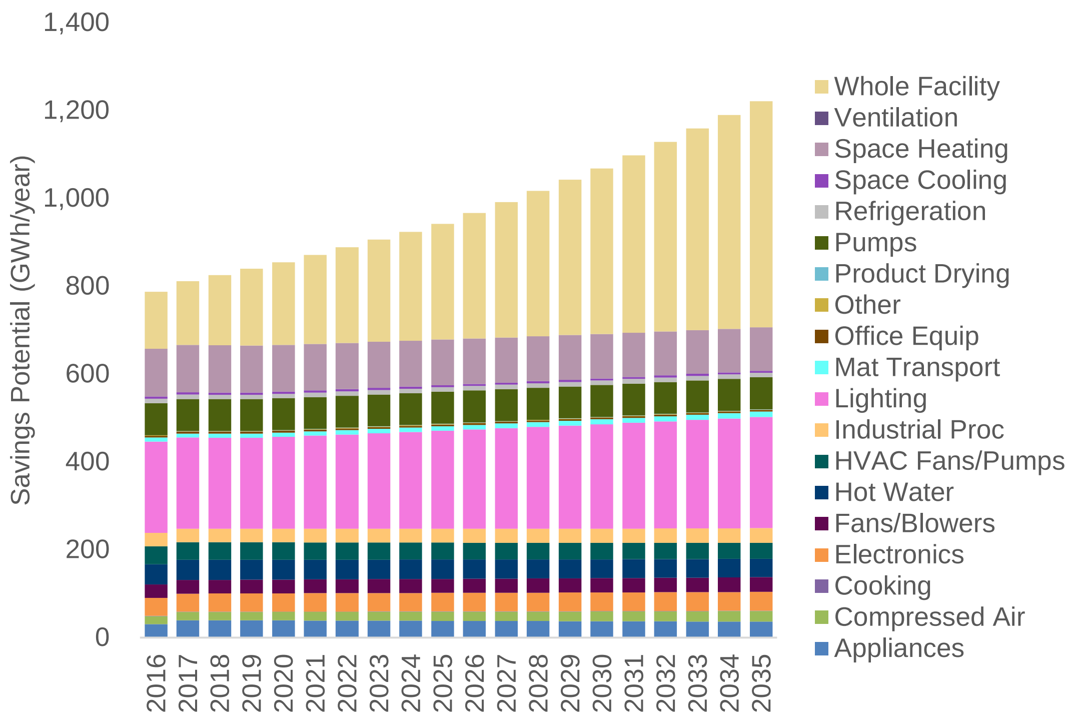
5 TRC costs are already expressed in present value, since the measure cost and program administration cost are in current dollars.

6 Navigant uses DSMSim™ a proprietary bottom-up technology diffusion and stock tracking model implemented using a System Dynamics framework.

2.5 *CPR RESULTS*

The following Figure 2-1, taken from the FBC CPR report, shows the economic electric energy potential by end-use, aggregated across customer sectors, for new construction and retrofit combined. The top three economic potential categories include: whole-facility that includes new efficient building construction as well as behavioural energy management programs; lighting; and space heating that includes both building envelope (insulation etc.) improvements and equipment such as heat pumps.

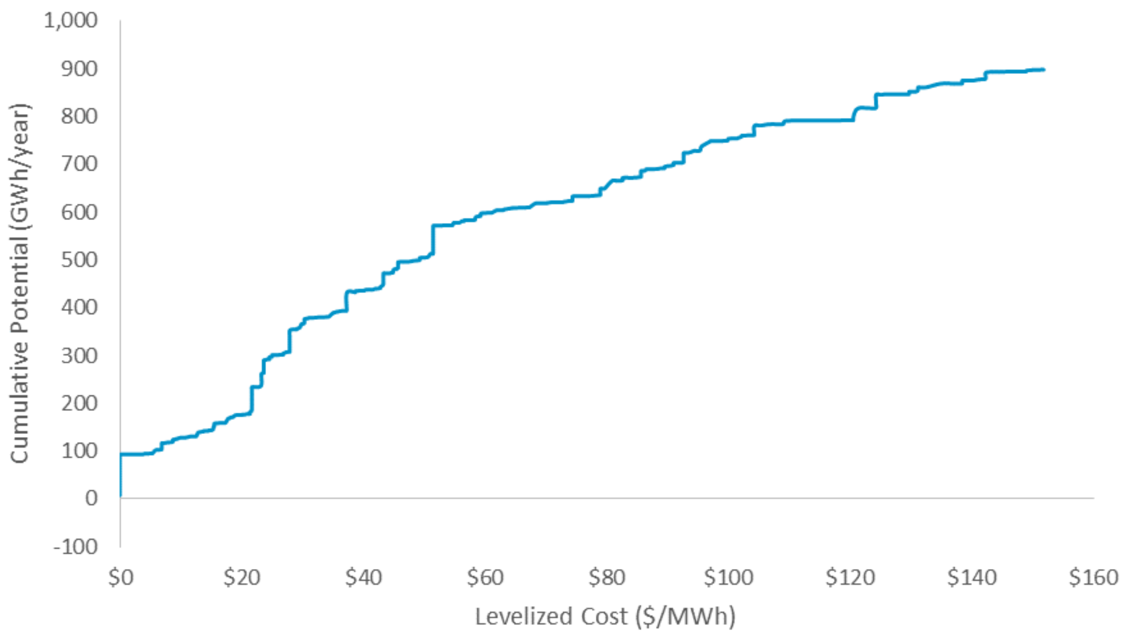
Figure 2-1: Electric Energy Economic Savings Potential by End-Use (GWh/year)



Source: Navigant

The following Figure 2-2 shows the supply curve of economic energy savings versus the levelized cost of savings in $/MWh. The curve illustrates that roughly 500 GWh of savings are available at a cost less than $50 per MWh, 250 GWh per year at a cost up to $100 per MWh and another 150 GWh at a cost up to $150 per MWh. The flattening of the curve at approximately 900 GWh indicates it is approaching the maximum available economic potential, although limited additional potential is available at higher costs.

Figure 2-2: Supply Curve of Economic Potential (GWh/year) vs. Levelized Cost ($/MWh)



Source: Navigant

The economic results of the FBC CPR are a key input for the LT DSM plan, as they indicate the availability of energy savings potential and provide measure costing as inputs for the various DSM scenario options considered.

2.5.1 CPR Phases

The FBC CPR results and report completed to-date are for technical and economic potential in FBC's service area. The next phase of the BC CPR project, expected in 2017, includes assessing the market potential that is a subset of economic potential and carving out non-programmatic potential (e.g. Codes & Standards savings that are achieved through federal/provincial equipment regulation). The market potential identified in the next phase of the BC CPR is expected to inform FBC's next DSM expenditure schedule.

3. DSM SCENARIO DEVELOPMENT

The following section describes how FBC developed and analyzed DSM scenarios to plan for its long term resource needs. FBC developed four different DSM scenarios including Low, Base, High, and Maximum (Max) cases that were subsequently tested with various supply-side resource options in the Resource Planning portfolio analyses (Section 9 of the LTERP).

The DSM scenarios FBC considered are based on offsetting FBC's forecast load growth, which is included in section 3 of the LTERP.

Both the BC Energy Plan and the *CEA* express DSM targets as a load growth offset (DSM offset). The DSM targets in the Energy Plan (50% of load growth) and the *CEA* (at least 66% of load growth) only apply to BC Hydro. However, FBC adopted a 50% DSM offset target in its 2012 LTRP and is using the 66% DSM offset target as its Base DSM scenario in the LT DSM Plan, since it reflects approximately the same level of target savings (26 GWh/yr) that is included in FBC's approved 2016 DSM Plan and its 2017 DSM Plan filing. The Base scenario could therefore be characterized as a continuation of the current DSM plan.

The DSM offset is best used as a long run average (i.e. over the LTERP planning horizon) to smooth the short-term fluctuations shown in the load forecast, and reflected in annual sales.

The High scenario originates from the final LTERP Resource Planning Advisory Group (RPAG) meeting in October 2016 (see LTERP Section 10.2), where a midpoint scenario (between Base and Max) was requested by meeting participants and subsequently modelled by FBC in response. FBC ramped the High scenario, beginning in 2021, from the 66% Base case to an 80% load growth offset, to optimize utilization of tranche 1 energy from the Power Purchase Agreement with BC Hydro under Rate Schedule 3808 (BC Hydro PPA) and thus minimize rate impact. Over the planning horizon the High case averages a 77% load growth offset.

The Max DSM scenario exhibits a similar ramp-up to 100% average load growth offset, resulting in a DSM offset of 89% over the planning horizon.

Figure 3-1 shows the proposed roll-out of the four DSM scenarios considered, against the backdrop of the FBC's gross load forecast after "other" savings.

Figure 3-1: Low, Base, High and Max DSM Scenarios

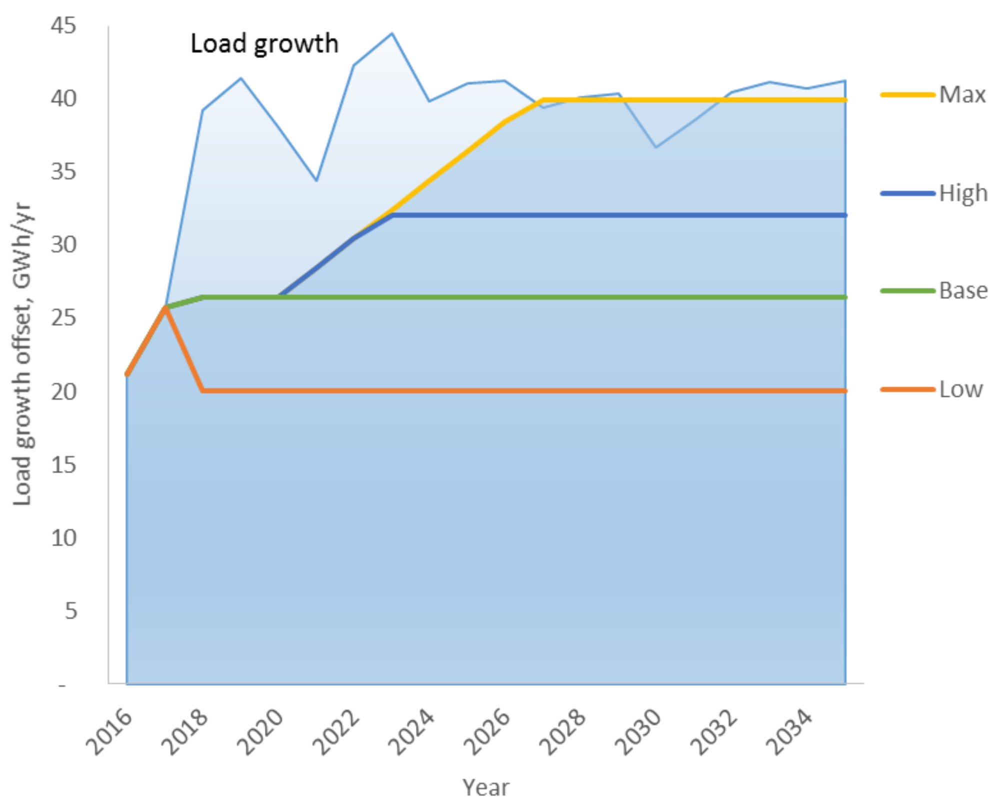
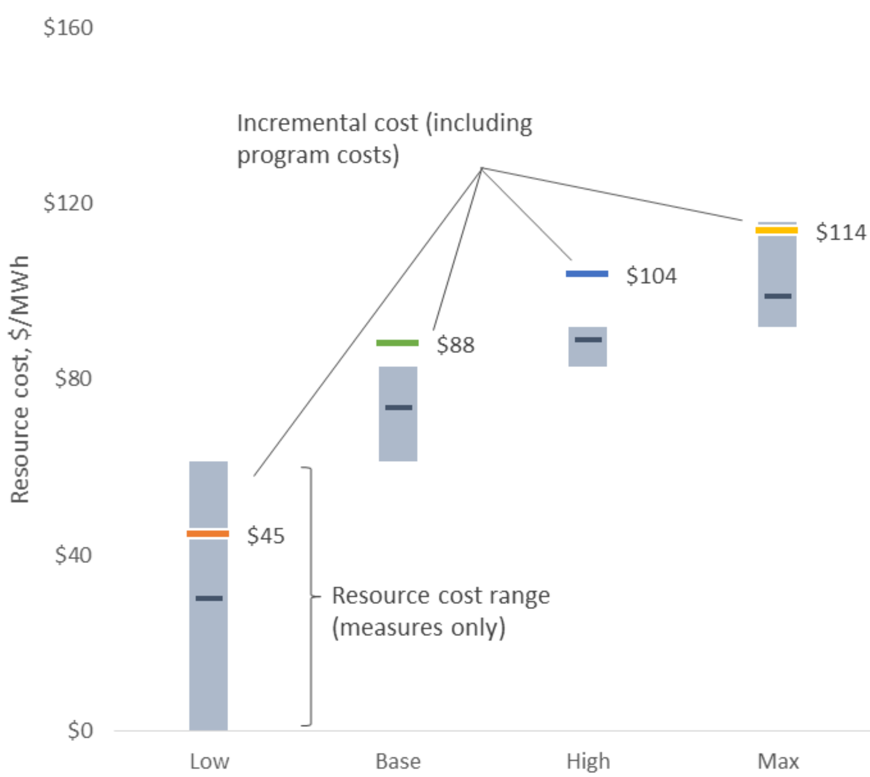


Figure 3-2 illustrates the supply cost curve of the DSM scenarios FBC considered. Each DSM scenario draws from a portfolio of measures, sourced from the FBC CPR results that have a range of resource costs. The incremental cost of each DSM scenario or tranche, increases as higher cost DSM resources are selected to achieve a higher percentage of load growth offset with DSM. A proxy for DSM program implementation costs is added to the average incremental measure (i.e. tranche) costs to estimate the total cost of acquiring DSM as a resource for each of the scenarios.

Figure 3-2: Costs of DSM Scenarios



The following Table 3-1 shows key DSM scenario data, including the percentage of forecast load growth to be offset by DSM and the sum total of DSM savings to be targeted over the planning horizon. For context, of the total (2016 to 2035) annual savings, FBC has booked 511 GWh of DSM program savings from program inception in 1989 to 2015 inclusive.

Table 3-1: Key DSM Scenario Data

Category	DSM Scenario			
	Low	Base	High	Max
Annual Savings, GWh				
Average per annum ('18-'35)	20	26	31	36
% of load growth ('18-'35)	50%	66%	77%	89%
Total (2016 to 2035)	407	523	602	686
Resource Cost, 2016 $/MWh				
Incremental cost incl. program costs	$45	$88	$104	$114

3.1 *DSM SCENARIO CONSULTATION*

The FBC CPR Economic results along with the Low, Base and Max DSM scenarios were presented during the stakeholder consultation process undertaken in the Fall of 2016. The results of the community consultation process, including the RPAG, can be found in section 10 of the LTERP.

Customer feedback to key aspects of the LT DSM Plan was sought through an online “bulletin board” approach delivered by Sentis Research (Sentis). Sentis recruited both residential and commercial participants and hosted and moderated four sets of bulletin board discussion groups. Three groups engaged residential customers (in the regions of Central Okanagan, South Okanagan and Kootenay/Boundary) and one group engaged commercial customers (for the entire FBC service area). The consultation findings are reported in Appendix B of the LT DSM Plan.

Key research topics and summary findings were as follows:

- LTERP priorities: Cost-effective, secure and reliable power was the customers’ top priority, with half as many votes for cost-effective energy conservation programs;
- Meeting growth in electricity demand: Reducing demand through energy conservation was the preferred choice, with only about a quarter as many votes for building additional generating facilities. Buying from other generators was the last place choice;
- Preferences for setting future DSM offsets:
    - About a quarter of participants indicated the “Base” or 66% offset, as it was the current level targeted;
    - Four out of ten preferred the “High” or 80% offset level as a happy medium and more reasonable goal or that the 100% offset was unrealistic; and

  - About one third indicated the 100% offset as the most environmentally-friendly or ideal option and one they were not sure would be affordable.

3.2 *PREFERRED DSM SCENARIO*

FBC has selected the High DSM scenario as its preferred scenario in the LT DSM Plan. The incremental cost of ramping up to the High scenario is $104 per MWh, which is similar to FBC's LRMC of $100 per MWh for clean or renewable energy in BC. Thus, it includes the majority of cost effective DSM from an LRMC perspective.

The High scenario maintains a consistent target of approximately 26 GWh/yr from 2018 to 2020 and then ramps up from 2021 to 2023 to a load offset of 80%, or 32 GWh/yr for the period 2023 to 2035 – when the load growth averages 40 GWh/yr. As shown in Figure 3-1 above, the High scenario offsets 77% of forecast load growth over the entire LTERP planning horizon. Ramping up DSM starting in 2021 will mitigate the "opportunity cost" of offsetting the relatively inexpensive BC Hydro PPA in the near term.

Section 8.1.2 of the LTERP discusses the High DSM scenario in terms of meeting the forecast Load-Resource Balance (LRB) energy gaps, which are deferred until 2025 using the High DSM scenario. Starting the ramp up in 2021 will allow sufficient time to plan and implement the programs needed to achieve the increased goals while delivering a robust, cost-effective DSM portfolio.

The Max scenario was not chosen for a number of reasons including the voluntary nature of DSM participation and the inherently non-dispatchable nature of DSM savings compared to supply-side resources. The Max scenario presents:

- higher risks of:
  - insufficient customer participation; or
  - incurring higher costs if load growth falls short of expectations;
- gaps in DSM monthly savings profile vs. load resource needs (see section 8.1.3 of the LTERP); and
- a higher cost ($114/MWh) of the Maximum tranche compared to the LRMC of $100.

3.3 *HIGH DSM SCENARIO*

The following Table 3-2 shows the High DSM scenario rollout of target savings and pro-forma costs over the LTERP planning horizon. The estimated DSM savings ramp up from 26.4 to 32.0 GWh/yr, and the estimated program costs escalate respectively from $7.6 million (as filed in the 2017 DSM Plan) to a projected $10.9 million, in constant ($2016) dollars, by 2023 and thereafter. The figures, including the DSM savings targets and notably the pro-forma DSM budget cost estimates, are intended to be illustrative and FBC is not seeking approval as part of the LT DSM Plan as it is not a DSM expenditure schedule.

Table 3-2: Pro-forma DSM Savings Targets

Description	Year	Annual DSM Budget ($000s)	Annual DSM Savings (GWh)
Plan	2017	$7,610	25.7
Forecast	2018	$7,900	26.4
Forecast	2019	$7,900	26.4
Forecast	2020	$7,900	26.4
Forecast	2021	$9,000	28.4
Forecast	2022	$10,000	30.4
Forecast	2023	$10,900	32.0
Forecast	2024	$10,900	32.0
Forecast	2025	$10,900	32.0
Forecast	2026	$10,900	32.0
Forecast	2027	$10,900	32.0
Forecast	2028	$10,900	32.0
Forecast	2029	$10,900	32.0
Forecast	2030	$10,900	32.0
Forecast	2031	$10,900	32.0
Forecast	2032	$10,900	32.0
Forecast	2033	$10,900	32.0
Forecast	2034	$10,900	32.0
Forecast	2035	$10,900	32.0

4. DEMAND-SIDE MANAGEMENT PROGRAMS

DSM programs have been offered to qualified FBC customers since 1989 and are available to all direct customers as well as indirect customers served by FBC's municipal electricity Wholesale customers of Grand Forks, Nelson, Penticton, and Summerland.

The LT DSM Plan portfolio includes programs for the Residential, Commercial (including Irrigation and Lighting), and Industrial customer classes and is intended to capture economic potential savings over the long term, as identified in the FBC CPR report. There are also portfolio-level supporting initiatives, and planning and evaluation activities required to support the DSM Plan.

The LT DSM Plan was developed in compliance with the provincial DSM Regulation, including program measures mandated to meet the regulation's adequacy provisions[7], namely measures for rental and low income customers, education (elementary and secondary) and post-secondary schools.

The following sections and sub-sections largely describe the current program offerings in each customer sector that target key end-uses with cost-effective measures identified in the FBC CPR report. Over the LTERP's planning horizon the various program offers and names, including the list of eligible measures, will likely change to suit the evolving marketplace, legislative requirements (DSM Regulation amendments) and FBC customer needs.

4.1 *RESIDENTIAL SECTOR PROGRAMS*

The DSM Plan focuses on the opportunities in residential energy retrofits, addressing major end-uses (space heating, hot water and lighting), and new home construction where the majority of economic potential was identified in the FBC CPR report. A general description of each program and the primary delivery mechanisms follows.

4.1.1 Home Improvement

The main components of the Home Improvement Program (HIP) are building envelope improvements (insulation and air sealing). Program delivery will be primarily through the Home Energy Renovation Rebate (HRR), in partnership with FEI and BC Hydro. The program encourages customers to focus on the appropriate measure sequence up to obtaining a "whole house" EnerGuide rating. Heating/cooling systems, (for example, heat pumps) are promoted where applicable but tabulated under a separate plan line item. ENERGY STAR® appliances and lighting are marketed separately, as described below.

[7] Section 3 of the DSM Regulation 326/2008 as amended July 10, 2014.

4.1.2 Heat Pumps

With its temperate winters and hot summers, the FBC service area is an ideal climate for energy efficient heat pumps. Further, the Company's market research shows that 38 percent of FBC customers have electric heat, indicating a large potential market for the program. The program will continue with incentives for owners to upgrade electric heating systems to either central split (forced-air) or (for customers with electric baseboard heating) ductless mini-split air source heat pumps. Both configurations are currently eligible for the HRR bonus offer to attract more comprehensive retrofits.

As an alternative to direct financial incentives, FBC will also continue to offer heat pump loans for qualifying customers at a below market interest rate. To ensure customers continue to attain high efficiencies from their heat pump technology, a heat pump tune-up rebate and promotion will be continued.

4.1.3 Residential Lighting

Approximately 14 percent of all residential electrical use within the FBC service area is attributed to lighting. To help build market transformation and improve customer participation in lighting incentive programs, FBC will continue its collaboration with BC Hydro and retailers to provide "instant rebates" at the point of purchase for limited time periods over the course of the year. Rebates will be provided for qualified ENERGY STAR® specialized Light Emitting Diode (LED) lamps, controls and hard-wired luminaires.

4.1.4 New Home

FBC will provide incentives to encourage a higher level of whole home energy efficiency via a performance path (i.e. ENERGY STAR® for New Homes (ESNH)) to exceed the baseline requirements of the BC building code. ENERGY STAR® rated appliances and lighting products are integral requirements to qualifying for ESNH designation.

To enable ESNH, FBC offers incentives for pre-construction plan review, and mid-construction blower door testing to ensure enrolled homes meet qualifying criteria.

4.1.5 Water Heating

Approximately 50 percent of FBC customers' water heaters are heated with electricity. To encourage efficient water heating, FBC will continue to offer rebates for the installation of heat pump water heaters for customers with electrically heated hot water.

The results of the Heat Pump Water Heater pilot project will inform the tiers FBC will support going forward, as well as confirm the unit savings of this measure. FBC will also continue efforts to improve product availability and customer awareness. Low flow showerheads will be distributed via Energy Saving Kits (ESK) and other channels.

4.1.6 Appliances

FBC will continue to provide rebate offers for top tier ENERGY STAR® clothes washers and dryers and refrigerators in collaboration with BC Hydro, appliance manufacturers and retailers.

4.1.7 Low-Income Households Program

FBC will continue to provide low income households with ESKs and distribute them directly to qualified customers, primarily through low-income service providers like food banks and via direct mail.

The Energy Conservation Assistance Program (ECAP) is modelled on the BC Hydro/ FEI program. The FBC ECAP program, which is offered in partnership with FEI, will provide a Basic level of service to all qualifying single- and multi-family home participants. The Basic level of service includes direct installation of basic measures (ENERGY STAR® lighting and low-flow products, i.e. showerheads), limited draft-proofing installation, energy coaching to occupants, and an energy assessment, which identifies single-family homes for extended energy conservation measures like insulation of ceilings and basements and additional draft-proofing, and/or ENERGY STAR® refrigerators.

A "top-up" rebate program for multi-unit residential buildings (MURBs) will be continued for common area lighting, Heating, Ventilation and Air Conditioning (HVAC), and basic building envelope improvements.

4.1.8 Rental Accommodation

In collaboration with FEI, the Rental Apartment Program (RAP) will continue to be offered. This program includes the direct installation of ESK measures for rental MURB suites. The program also provides no-cost whole-building energy audits to identify additional measures (common area lighting, central space heating and hot water boilers) that could be undertaken by the building owners and provides two years of technical support and access to the FBC commercial rebate programs.

4.1.9 Residential Behavioural

FBC messaging to encourage residential customers to adopt energy-efficient behaviours (for example, the use of clotheslines) will continue using a variety of communication channels, including the distribution of product samples at community events.

An in-home display (IHD) incentive will enable participants to view real-time energy usage of their residential and small commercial (single phase) AMI meters. Either stand-alone devices, or a gateway modem – to enable smart phone apps – will allow customers to better understand and manage their energy usage.

In collaboration with FEI, FBC plans to implement a Customer Engagement Tool (CET). The CET will promote energy literacy and residential conservation and efficiency behaviour changes.

Customers will be able to complete an on-line energy assessment, set savings goals, create a personalized savings plan, track their progress, and receive tailored conservation and efficiency messaging and rebate offers. CET and behaviour programs improve customer service and satisfaction, and enable substantial savings.

4.2 COMMERCIAL SECTOR PROGRAMS

Program offers for the Commercial sector, including the Irrigation and Lighting class customers, will be focused on the economic opportunities in Lighting and Building Improvements (non-lighting systems such as HVAC, Compressed Air, etc.) through a number of program offers/channels namely Custom Business Efficiency (CBEP), Commercial Product Rebates (CPR) and Business Direct Install (BDI) Programs.

4.2.1 Commercial Lighting Program – New and Retrofit

Program assistance and financial incentives to install high efficiency lighting will continue to be offered for existing and new commercial and multi-unit residential customers. Program assistance will include a free walkthrough energy assessment of the customer's premises. FBC will also subsidize the cost of a more detailed assessment, as requested.

New in 2016 was the introduction of the Business Direct Install (BDI) program. BDI utilizes a third-party implementer to engage contractors to perform lighting and other energy efficiency retrofits. Targeting small- and medium-sized enterprises and using proven energy assessment tools and energy efficiency sales training, the BDI offer will continue to be offered in 2017 and renewed as indicated.

Lighting incentives for retrofit and new construction projects will be available through multiple channels including:

- point-of-purchase product rebates at authorized lighting wholesalers;
- point-of-installation rebates from local electrical contractors through the BDI program;
- prescriptive retrofit through the Demand-side Management Central (DSMC) online portal; and
- custom rebates for larger, more complex new construction or retrofits through the Custom Business Efficiency program.

4.2.2 Building Improvement – New and Retrofit

Program assistance and financial incentives will continue to be offered for existing and new commercial and multi-unit residential customers to install energy efficiency measures. Program assistance will include a free walkthrough energy assessment of the customer's premises. FBC will also subsidize the cost of a more detailed assessment, as requested.

FBC will offer rebates to support energy efficiency for various end-uses, including, but not limited to: heating, ventilation, air conditioning measures, pumps, motors, commercial kitchen equipment, compressed air, and refrigeration technologies. Energy efficiency retrofit rebates will be available through multiple channels including:

- point-of-purchase product rebates at authorized distributors;
- point-of-installation rebates from local contractors through the BDI program;
- prescriptive rebates through the DSMC online portal; and
- custom rebates for larger, more complex projects through the Custom Business Efficiency offer.

FBC will also offer new construction rebates to encourage efficient construction practices for new commercial and multi-unit residential buildings. Incentives will be offered to offset the incremental cost of energy efficiency construction compared to standard "baseline" construction. The baseline for new construction rebates will continue to be ASHRAE 90.1 as adopted by the provincial building code.

4.2.3 Partners in Efficiency

FBC will continue to offer a "Partners in Efficiency" initiative for local governments and larger key account customers. In addition to the incentives offered in the form of rebates and energy assessments, FBC representatives work closely with qualifying customers to help determine the economics for energy efficiency upgrades for new and existing facilities and street lighting.

FBC will also co-sponsor in-house energy specialists to help build institutional capacity to complete energy efficiency retrofit projects within their organizations.

4.2.4 Irrigation

Program assistance and financial incentives will continue to be offered for irrigation customers to install energy efficiency measures and promote energy efficient irrigation. Free walk-through audits will be available to qualifying irrigation customers.

Product rebate incentives on energy-efficient irrigation system components (variable-speed drives, high-efficiency pumps, low pressure irrigation systems, etc.) will be offered through the DSMC online rebate portal. A custom option approach will also be offered for comprehensive system retrofits for qualified customers through the Custom Business Efficiency Program.

4.3 *INDUSTRIAL SECTOR PROGRAMS*

4.3.1 Industrial Efficiency

FBC will continue to offer program assistance and financial incentives for industrial customers to achieve increased efficiency in their processes, buildings and/or systems. Program assistance will include a free walkthrough energy assessment of the customer's premises. New in 2016 was the offer of subsidized facility-wide energy efficiency assessments and detailed feasibility studies to qualifying industrial customers. The facility energy efficiency assessments will continue to be offered in 2017.

FBC will offer custom rebates through the Custom Business Efficiency program to support energy efficiency for various industrial end-uses, including, but not limited to: industrial process optimization, lighting, pumps and fans, compressed air, hydraulics and other motor systems. Prescriptive product rebates (for example, variable-speed air compressors) will also be offered through the DSMC online rebate portal.

4.4 *SUPPORTING INITIATIVES*

Supporting initiatives are important for the implementation of the DSM portfolio because they provide the program support, education for customers and students, build trade ally capacity and promote market transformation, all of which are necessary to enable the identified potential savings. The supporting initiatives, which complement the incentive-based programs listed previously, are characterized as portfolio level spending as they do not result in direct DSM savings.

4.4.1 Public Awareness

This component seeks to increase public awareness of energy efficiency and conservation matters, and informs customers about 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 are required. Collateral and promotional items will be distributed to residential customers at trade shows and community events and provided to trade allies (electrical contractors, equipment wholesalers/distributors, 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 that sell energy efficiency equipment.

Targeted information campaigns with specific messaging about programs and energy efficiency may be purchased for trade magazines, newsletters and other industry focused information pieces. Mass market advertising (on-line, radio and print) and the CET will also be used to promote general conservation messaging and residential rebate programs.

4.4.2 Community Energy Planning

This element of Supporting Initiatives provides financial assistance to local governments and qualified institutions to facilitate energy efficiency planning activities like the development of community energy efficient strategic plans, energy efficient design practices and organizational policies like energy efficiency building code bylaws. The planning must be aimed at specifically reducing electricity usage and demand.

4.4.3 Trades Training

FBC provides sponsorships for training and support for a number of initiatives from the building trades and electrical non-profit trade organizations,[8] as well as support for energy management planning training like NRCan's "Spot the Savings" workshops. Committed to growing the energy efficiency knowledge among the trades, FBC will continue to provide this support.

4.4.4 Education Programs

FBC, in collaboration with the FEI, is developing an online education program that supports the development of energy education in BC classrooms. It will provide high quality, engaging, curriculum-connected resources and programs that highlight the BC energy story and encourages a bias-balanced development of energy literacy in classrooms for kindergarten through to Grade 12.

In addition, FBC will provide funding support for several external third party non-profit educational organizations to deliver conservation messaging.

FBC also provides financial and in-kind support for post-secondary initiatives for curriculum-based class-room instruction and broader campus-wide behaviour change programs.

4.4.5 Codes and Standards

A number of international and national organizations such as the Consortium for Energy Efficiency and the Canadian Standards Association work to set new efficiency standards for consumer electronics, appliances, and lighting products among other equipment and technologies. Similarly local, provincial and federal governments are setting policy and regulations to increase energy efficiency equipment and/or as-built building performance level including raising awareness (e.g. EnerGuide building ratings). FBC supports codes and standards policy development and research, through in-kind and financial co-funding arrangements.

[8] TECA (Thermal Environmental Comfort Association), SICA (Southern Interior Construction Association), CHBC (Canadian Home builders Association), GeoExchangeBC, etc.

5. OTHER MATTERS

5.1 *FUEL-SWITCHING*

Directive 9 in the 2015-16 DSM Plan Decision (Order G-186-14) required:

> a cost-benefit analysis (including supporting assumptions) showing whether FBC can allow customers with gas as their primary heating source to access FBC's DSM programs and still be compliant with the DSM Regulations.

The B/C analysis was completed by the BC CPR consultants and is attached as Appendix C of the LT DSM Plan. The finding was that the fuel switching measure failed, on a TRC basis, which is the governing test under the DSM Regulation. Since the measure is uneconomic the Company will not propose a gas to electric fuel switching measure or program.

5.2 *SELF-GENERATORS ELIGIBILITY FOR DSM SERVICES*

The benefits of DSM measures and programs are valued on energy savings priced at the LRMC and DCE, over the effective measure lives, and evidenced through reduced utility sales to participating customers. In turn, the DSM financial incentives that are made available to qualified customers, under DSM programs, are predicated on reduced electricity consumption or demand to the Company.

Customers that normally supply a portion of their load through self-generation may be eligible for DSM programs and financial incentives in proportion to the share of potential energy savings to the Company. Qualifying DSM projects will be subject to DSM program terms and conditions, including Measurement & Verification of the DSM project savings and satisfactory evidence of reduced FBC sales to the participating self-generation customer for the duration of the effective measure life. The prorating of DSM incentives would be on a sliding scale ranging from 100% for customers who procure their entire electricity load requirements from the Company on an on-going basis, to zero percent for customers that normally supply their entire load from self-generation.

5.3 *RATE SCHEDULE 90 (ENERGY MANAGEMENT)*

FBC's Electric Tariff No. 2 Schedule 90, Energy Management Services (RS90), was introduced in 1990, pursuant to BCUC Order G-47-89. At that time, the purpose of RS90 was to describe each of the Company's specific programs, including the associated offers and financial incentives, and the overall program terms and conditions. Any revisions or extensions to a specific DSM program required an application to and order from the Commission. In 2010 a major revision to RS90 removed much of the program specific pages and reduced RS90 to a generic high-level outline of program attributes.

Since RS90 was first introduced, the energy efficiency landscape in British Columbia has evolved considerably, including the enactment of and revisions to the DSM Regulation issued under the *UCA*, the enactment of the *CEA*, and increasing opportunities and expectations for collaboration and integration of DSM programs among utilities in BC.

Over time, the DSM (or Energy Management as it was then known) services offered under RS90 have been essentially made redundant by the specific DSM programs in FBC's approved DSM Plan portfolios, and thus the original purpose of RS 90 – to present individual program incentive offers – is no longer relevant. Similarly, the financial Terms & Conditions (T&Cs) presented in RS90 are supplanted by the T&Cs of individual programs where they have increased customer visibility and mandatory sign-off by participants. In the case of RS90's Repayment of Energy Management Incentives, the key RS90 T&Cs are replicated in the general terms and condition of the Electric Tariff (on pp.TC29-30).

In addition to the redundancy aspects, other parts of RS90 are in conflict with the Company's offers or practices. For example, Low-Income program offers include an ESK or direct-install measures in which the Company is paying all of the measure costs, despite the RS90 monetary caps. Also, in providing point-of-sale rebates, that reduce process and increase customer participation (e.g. residential lighting campaigns), the relevant programs are notionally in conflict with the provision in RS90 that the customer must receive prior approval by the Company.

Another rule under RS90 limits FBC to paying half of the incentive upon completion of larger projects, with the remainder paid up to a year later subject to confirmation measurement and verification (M&V) of project savings. Customer feedback indicates a larger first payment will enhance their projects' cash flow, and hence increase participation rates. The necessary M&V requirements are built into the project agreement signed by the customer, and will still ensure the total incentive paid by the Company is commensurate to the project savings realized.

The consulting or study subsidy offered under RS90 is limited to a $1,500 contribution by the Company. Any additional study contribution is to be taken back in the form of reduced project incentive payments under RS90. In order to identify all potential DSM projects, and hence garner more program participation, the Company currently pays up to 75% of the cost of plant-wide audits or the more detailed process energy assessments. DSM best practice would be to *not* claw-back the energy assessment contribution as that policy impinges on the DSM projects' economics (i.e. the customer's internal business case) and therefore reduces program participation.

Of note, FBC is the only utility in BC with a DSM tariff schedule and such a tariff is virtually unknown in other North American jurisdictions.

In conclusion, FBC is proposing to rescind RS 90 from its Electric Tariff to increase the Company's flexibility in DSM program design, to allow the Company to respond to market trends and new technologies more quickly and effectively, and to better align FBC's DSM programs with similar DSM programs and best practices from other utilities, including BC Hydro and FEI. The terms and conditions contained in RS90 are already set out in the individual program-specific terms and conditions, providing customers with better visibility of program obligations. Subject to Commission approval of FBC's request to remove RS 90 from the Company's Electric Tariff, FBC will file updated tariff sheets for endorsement.

Appendix A

FBC CONSERVATION POTENTIAL REVIEW

British Columbia Conservation Potential Review

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DISCLAIMER

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EXECUTIVE SUMMARY

FortisBC Inc. (FortisBC Electric) and the other BC Utilities —namely BC Hydro, FortisBC Energy Inc. (FortisBC Gas), and Pacific Northern Gas Ltd. (PNG)— engaged Navigant Consulting, Inc. (Navigant or the team) to prepare a conservation potential review (CPR) for electricity and natural gas across all of British Columbia over a 20-year forecast horizon from 2016 to 2035. The CPR's objective is to assess the energy efficiency potential in the residential, commercial, and industrial sectors by analyzing energy efficiency measures, defining operational and maintenance activities to keep existing devices or equipment in good working order, and improving end-user behaviors to reduce energy consumption. These analysis efforts provide input data to Navigant's Demand Side Management Simulator (DSMSim™) model, which calculates technical and economic savings potential across FortisBC Electric's service territory. FortisBC Electric may use these results to inform its long-term conservation goals, energy efficiency program design, integrated resource planning (IRP), and load forecasting models.

Approach

This section provides an overview of the methods Navigant employed for conducting the 2016 CPR for British Columbia.

Base Year and Reference Case Forecast

Navigant developed the Base Year Calibration (2014) based on an assessment of energy consumption in each utility's service territory, by customer sector and segment, end-use, fuel, and types of equipment used. The objective of the base year is to establish a profile of energy consumption by utility which is consistent with the total energy demand (gas and electricity) reported by each utility. The team then used the base year as the foundation to develop the Reference Case Forecast of energy demand through 2035.

The Reference Case Forecast estimates the expected level of electricity demand over the CPR period from 2016-2035 absent incremental demand-side management (DSM) activities or demand impacts from rates. The significance of the Reference Case in the context of this CPR study is that it acts as the point of comparison (i.e., the reference) for the calculation of the technical and economic potential scenarios.

The Reference Case Forecast uses the base year calibration as the foundation for analysis. Navigant used two key inputs to construct the Reference Case forecast for each customer sector; stock growth rates, and EUI[1] trends. Applying stock growth rates to the base year stocks of each customer segment results in a forecast of stocks through 2035. Similarly, applying the EUI trends to the base year EUIs results in a forecast of EUIs through 2035. The final step of this process involves multiplying the stock forecast with the corresponding EUI forecast in order to obtain a consumption forecast.

[1] End-Use Intensities (EUI) typically expressed as kWh/yr per widget or end-use for Residential (see Table B-6), and kWh/m2 (see Table B-9) for Commercial customers.

To construct the Reference Case forecast, Navigant developed growth projections of residential building stock, commercial floor area, and industrial energy consumption. The team then modeled the potential for energy efficiency based on the resulting stock projections of each sector and the changing proportion of new and existing stock. The team applied EUI trends to the Base Year EUIs for each customer segment, and also used these trends to represent natural change in end-use consumption over time.

Navigant compared the forecasts developed as part of the Reference Case for the residential, commercial, and industrial sectors with the long-term load forecast developed by each utility. The team performed this comparison to ensure that the Reference Case forecast is consistent with each utility's current expectations for load growth over the 2015 to 2035 period.

Measure Characterization

Navigant fully characterized over 200 measures across the BC Utilities' residential, commercial, and industrial sectors, covering electric and natural gas fuel types. The team prioritized measures with high impact, data availability, and most likely to be cost-effective as criteria for inclusion into DSMSim™.

The team reviewed a number of sources to identify which energy efficient measures to include in the study. These sources include current BC program offerings, previous CPR and other Canadian programs, and potential model measure lists from other jurisdictions. The team supplemented the measure list using the Pennsylvania, Illinois, Mid-Atlantic, and Massachusetts technical resource manuals (TRMs), and partnered with CLEAResult to inform the list of industrial measures. CLEAResult specializes in energy programs and demand-side management strategies for electric and gas utilities, and has considerable expertise with BC industrial customers and the BC Utilities. CLEAResult provided input to the development of the industrial measures, as well as to the development of the base year and Reference Case forecast.

Navigant worked with the BC Utilities to finalize the measure list and ensure it contained technologies viable for future BC program planning activities. Appendix A.2 provides the references to the final measure list and assumptions.

Estimation of Potential

Navigant employed its proprietary DSMSim™ potential model to estimate the technical and economic savings potential for electric energy and electric demand across FortisBC Electric's service territory.[2] DSMSim™ is a bottom-up technology diffusion and stock tracking model implemented using a System Dynamics[3] framework. The model explicitly accounts for different types of efficient measures such as retrofit (RET), replace-on-burnout (ROB), and new construction (NEW) and the impacts these measures have on savings potential. The model then reports the technical and economic potential savings in

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[2] The electric demand savings referenced in this report are those commensurate to energy saving measures. Demand-only measures such as Demand Response (DR) are part of the Additional Services phase of the BC CPR study.
The study also identified the impacts on gas consumption caused by electric measures with either dual-fuel savings or cross-fuel interactive effects. Since the gas impacts are negligible, they are included in Appendix A.1, but not within the body of the report.

[3] See Sterman, John D. *Business Dynamics: Systems Thinking and Modeling for a Complex World*. Irwin McGraw-Hill. 2000 for detail on System Dynamics modelling. Also see http://en.wikipedia.org/wiki/System_dynamics for a high-level overview.

aggregate by service territory, sector, customer segment, end-use category, and highest-impact measures.

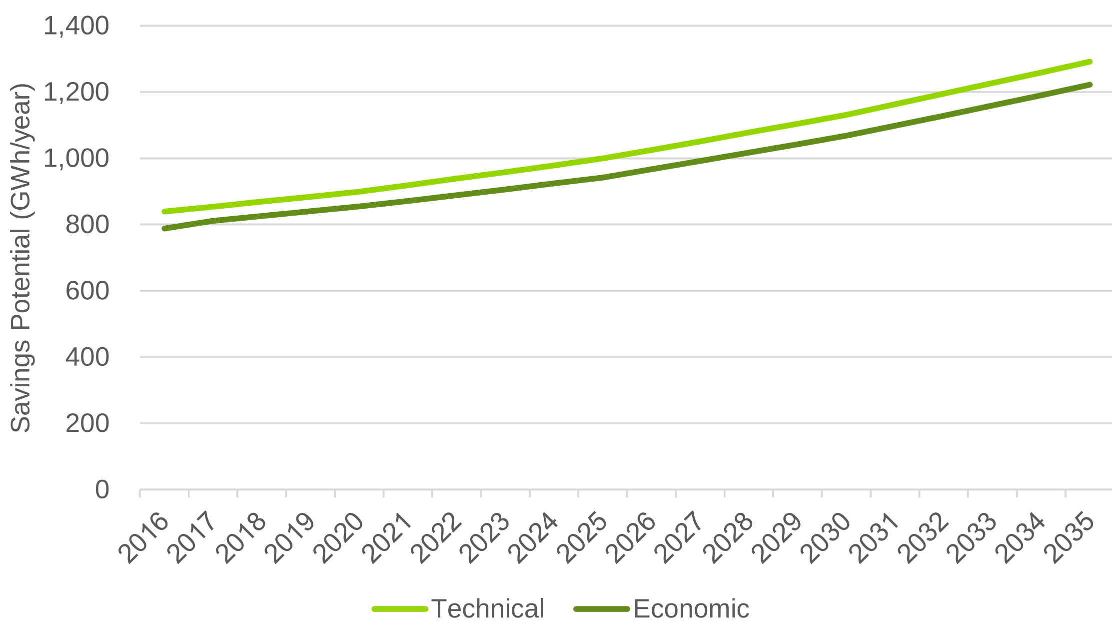
This study defines technical potential as the energy savings that can be achieved assuming that all installed measures can immediately be replaced with the efficient measure, wherever technically feasible, regardless of the cost, market acceptance, or whether a measure has failed (or “burned out”) and is in need of being replaced. Economic potential is a subset of technical potential, using the same assumptions regarding immediate replacement as in technical potential, but limiting the calculation only to those measures that have passed the benefit-cost test chosen for measure screening, in this case the Total Resource Cost (TRC) test.

Savings reported in this study are “gross”, rather than “net,” meaning they do not include the effects of natural change (as described in Section 2.3.2). The technical results section concludes with a comparison of aggregate potential before consideration of natural change, and after the inclusion of natural change. Providing gross potential is advantageous because it permits a reviewer to more easily calculate net potential when new information about net-to-gross ratios or changing end use intensities become available.

Findings

Figure ES-1 and Table E-1 in Appendix E provide the technical and economic electric energy savings potential in FortisBC Electric’s service territory. Both technical and economic potential grew about 55% over the twenty-year study horizon. The majority of growth came from high-impact whole-facility measures directed toward new construction, though measures influencing existing construction still accounted for roughly 60% of the total potential by 2035.

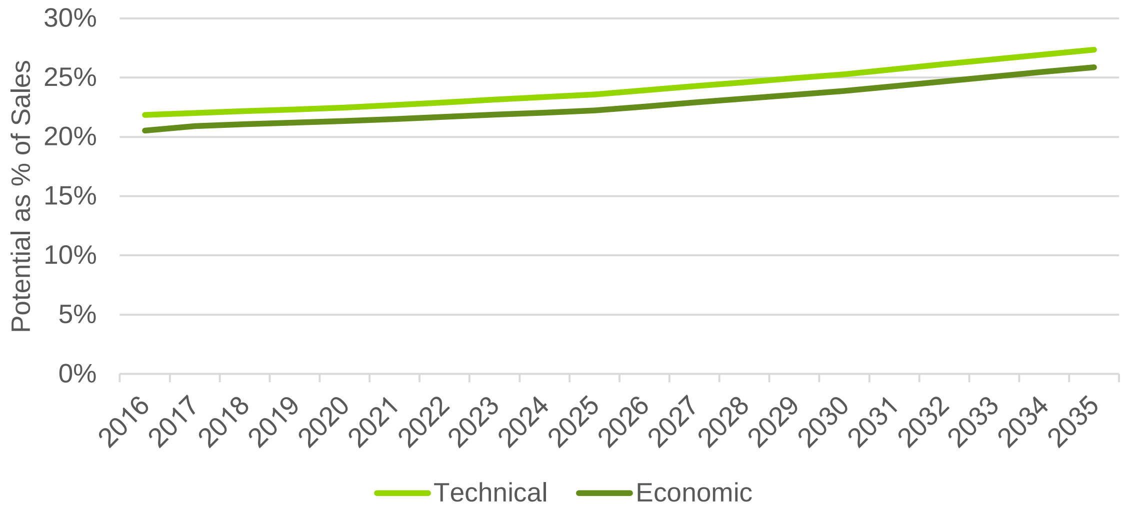
Figure ES-1. Total Electric Energy Savings Potential (GWh/year)



Source: Navigant

Figure ES-2 and Table E-2 in Appendix E represent the technical and economic energy savings potential as a percentage of customers' total electricity consumption. The upward trends indicate the savings potential grew at a faster rate than the expected rate of growth in electricity consumption.

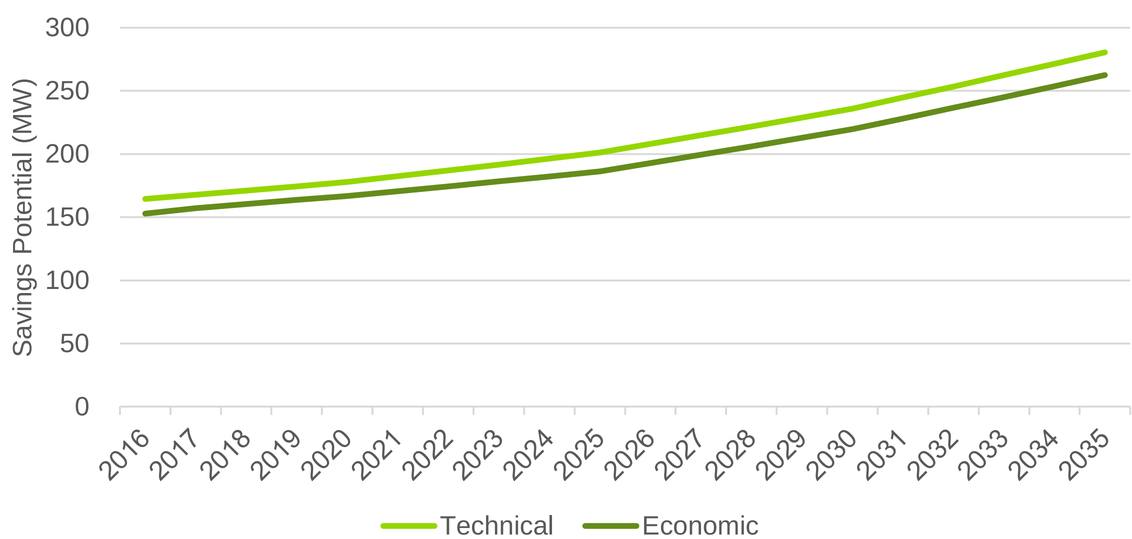
Figure ES-2. Total Electric Energy Savings Potential as a Percent of Total Consumption (%)



Source: Navigant

The total technical and economic demand savings potential appear in Figure ES-3, and Table E-3 in Appendix E. Both of the demand savings projections grew by about 83% over the simulation period. The growth reflects the impact of new construction measures—particularly whole-facility measures—which were most effective at reducing electric demand.

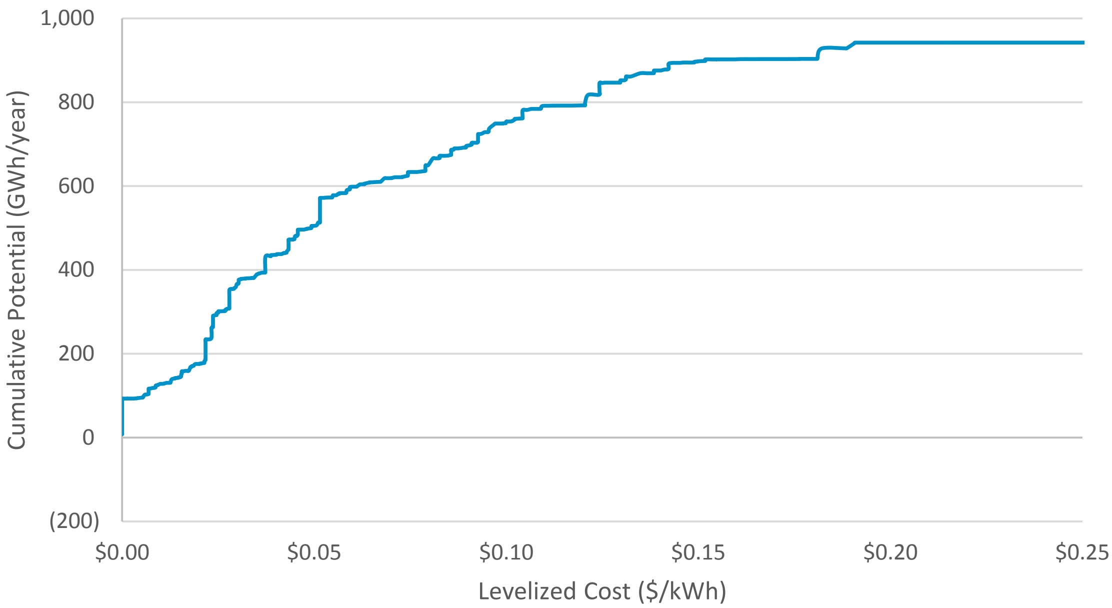
Figure ES-3. Total Electric Demand Savings Potential (MW)



Source: Navigant

A supply curve of 2025 economic energy savings versus the levelized cost of savings is shown in Figure ES-4. The curve illustrates that roughly 500 GWh/year of savings are available at a cost less than $0.05 per kilowatt-hour, with another 400 GWh/year at a cost between $0.05 and $0.15/kWh.

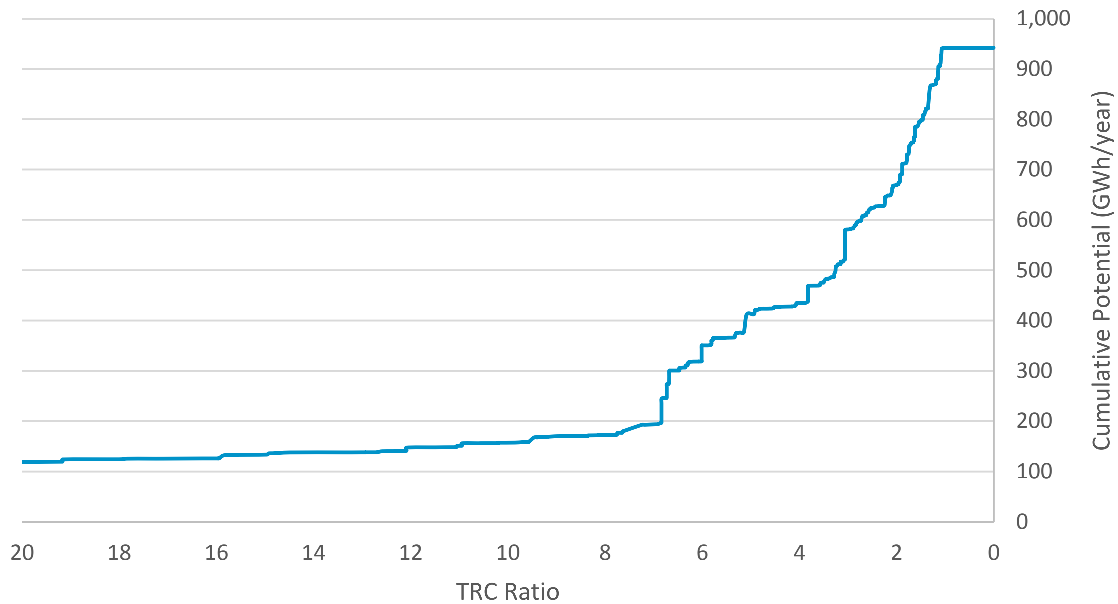
Figure ES-4. Supply Curve of Electric Energy Economic Potential (GWh/year) vs. Levelized Cost of Savings ($/kWh) in 2025



Source: Navigant

Figure ES-5 provides a TRC-focused perspective of the 2025 economic energy savings supply curve, whereby economic measure savings are plotted against their associated TRC benefit-to-cost ratios. Eighteen percent of the economic energy potential had TRC ratios greater than 8.0. Another 53% fell between TRC ratios of 2.0 and 8.0, while the remaining 29% ranged between 1.0 and 2.0. The curve flattens at TRC ratios below 1.0 because this study considers all measures not meeting or exceeding the 1.0 threshold as non-economic.

Figure ES-5. Supply Curve of Electric Energy Economic Potential (GWh/year) vs. TRC Ratio (ratio) in 2025



Source: Navigant

Next Steps

This report contains the Technical and Economic potential savings results, which comprise the initial and fundamental phase of the broader BC CPR. The next, and final, phase of the BC CPR includes additional scope services, namely Market potential, Fuel Switching potential, Demand Response (DR) and the requisite supporting calculations including total thermal demand as well as customization and enhancements to Navigant's DSMSim model specific to BC, and utility staff training.

1. INTRODUCTION

1.1 Conservation Potential Review Background and Goals

The BC Utilities—defined in this report as BC Hydro, FortisBC Inc., FortisBC Energy Inc., and Pacific Northern Gas Ltd.—engaged Navigant Consulting, Inc. (Navigant or the team) to prepare a conservation potential review (CPR) for electricity and natural gas across all of British Columbia over a 20-year forecast horizon from 2016 to 2035. The CPR's objective is to assess the energy efficiency potential in the residential, commercial, and industrial sectors by analyzing energy efficiency measures, defining operational and maintenance activities to keep existing devises or equipment in good working order, and improving end-user behaviors to reduce energy consumption. These analysis efforts provide input data to Navigant's Demand Side Management Simulator (DSMSim™) model, which calculates technical and economic savings potential across the BC Utility's service territories. The BC Utilities may use these results as input to their own DSM planning and long term conservation goals, energy efficiency program design, integrated resource planning (IRP), and load forecasting models.

1.2 Organization of Report

This report is organized as follows:

Section 2 describes the methodologies and approaches Navigant used for estimating energy efficiency and demand reduction potential, including discussion of base year calibration, Reference Case forecast, the frozen end-use intensity case, and measure characterization.

Section 3 offers the technical potential savings forecast for FortisBC Electric, including the methods for estimating technical potential and the modeling results by customer segment and end-use.

Section 4 offers the economic potential savings forecast for FortisBC Electric, including the methods for estimating economic potential and the modeling results by customer segment and end-use.

Accompanying Appendices provide detailed model results and additional context around modeling assumptions.

1.3 Caveats and Limitations

There are several caveats and limitations associated with the results of this study, as detailed below.

1.3.1 Forecasting Limitations

Navigant obtained future energy sales forecasts from each BC Utility. Each of these forecasts contain assumptions, methodologies, and exclusions that could differ by utility. Navigant has leveraged the assumptions underlying these forecasts, as much as possible, as inputs into the development of the Reference Case stock and energy demand projections. Where sufficient and detailed information could not be extracted—due to the granularity of the information available or customer data protection requirements—Navigant developed independent projections of stock for each utility. These independent projections were developed based on secondary data resources and in collaboration with the utilities. These secondary resources and any underlying assumptions are referenced throughout this report.

1.3.2 Program Design

The results of this study provide a high-level account of savings potential results across the BC Utilities' service territories. However, this study is not considered to be a detailed program design tool, as it does not consider incentive, marketing, advertising and budget levels, nor customers' willingness to adopt efficient measures. As such, the magnitude of the results should not be interpreted as the savings potential that could be realistically achieved by utility-sponsored energy conservation programs.

1.3.3 Measure Characterization

Efficiency potential studies may employ a variety of primary data collection techniques (e.g., customer surveys, on-site equipment saturation studies, and telephone interviews), which can enhance the accuracy of the results, though not without associated cost and time requirements. The scope of this study did not include primary data collection, but rather relied on data from the BC Utilities, other regional efficiency programs, Natural Resources Canada (NRCan), and technical reference manuals (TRMs) from Pennsylvania, Illinois, Mid-Atlantic, and Massachusetts to inform inputs to DSMSim™.

Furthermore, the team considers the measure list used in this study to appropriately focus on those technologies likely to have the highest impact on savings potential over the potential study horizon. However, there is always the possibility that emerging technologies may arise that could increase savings opportunities over the forecast horizon, and broader societal changes may impact levels of energy use in ways not anticipated in the study.

1.3.4 Measure Interactions

This study models energy efficiency measures independently. As a result, the total aggregated energy efficiency potential estimates may be different from the actual potential available if a customer installs multiple measures in their home or business. Multiple measure installations at a single site generate two types of interactions: within-end-use interactions, and cross-end-use interactions. An example of a within-end-use interaction is when a customer implements an operational program to review and maintain steam traps, but also installs a more efficient boiler. To the extent that the steam trap program reduces heating requirements at the boiler, the savings from the efficient boiler would be reduced. An example of a cross-end-use interaction is when a homeowner replaces a number of heat producing incandescent light bulbs with efficient LEDs. This impacts the cooling and heating load of the space—however slightly—by increasing the amount of heat, and decreasing the amount of cooling generated by the Heating Ventilation and Air Conditioning (HVAC) system.

Navigant employed the following methods to account for interactive effects:

- Where measures clearly compete for the same application (e.g., CFL and LED), the team created competition groups to eliminate the potential for double-count savings
- For measures with significant interactions (e.g., industrial process and boilers), the team adjusted applicability percentages to reflect varying degrees of interaction
- Wherever cross-end-use interactions were appreciable (e.g., lighting and HVAC), the team characterized those interactions for both same-fuel (e.g., lighting and electric heating) and cross-

fuel (e.g., lighting and gas heating) applications. A small number of measures accounted for interactions among multiple efficient measures. For measures whose characterization was based on building energy model simulations evaluating bundled measures, interactive effects among those measures were included in the savings estimates (e.g., ENERGY STAR New Homes, Net-Zero New Homes, etc.).

Appendix D provides further discussion of the challenges involved with accurately determining interactive effects.

1.3.5 Measure-Level Results

This report includes a high-level account of savings potential results across the BC Utility's service territories and focuses largely on aggregated forms of savings potential. However, Appendix A.1 provides results at the finest level of granularity, which is at the measure-level within each customer segment. The measure-level data is mapped to the various regions, customer segments and end-use categories to permit a reviewer to easily create custom aggregations

1.3.6 Gross Savings Study

Navigant and the BC Utilities agreed to show savings from this study at the gross level, whereby natural change (either natural conservation or natural growth in consumption) is not included in the savings estimates but rather is estimated separately. Providing gross potential is advantageous because it permits a reviewer to more easily calculate net potential when new information about changing end use intensities or net-to-gross ratios become available. However, the team calculated natural change at end-use level and included those results in Appendix A.1. Additionally, the technical potential section concludes with a comparison of aggregate potential before consideration of natural change and after including natural change.

2. APPROACH TO ESTIMATING ENERGY AND DEMAND SAVINGS POTENTIAL

This section describes the methodologies Navigant employed for estimating energy and demand savings across the BC Utility's service territories including base year calibration, reference case forecast, the frozen end-use intensity case, and measure characterization.

2.1 Base Year Calibration

Navigant developed the Base Year Calibration (2014) based on an assessment of energy consumption in each utility's service territory, by customer sector and segment, end-use, fuel, and types of equipment used. The objective of the base year is to define a detailed profile of energy consumption by utility which matches the total energy demand (gas and electricity) reported by each utility. The team will then use the base year as the foundation to develop the Reference Case Forecast of energy demand through 2035. Section 2.2 discusses the development of the Reference Case.

Navigant developed the Base Year analysis for the province as a whole based on data provided by the BC Utilities. The data presented in this report is specific to FortisBC Electric, supplemented by BC Hydro data for the contiguous South Interior region. The data sources provided included the following:

- Historical consumption, demand, and self-generation data;
- Residential accounts data;
- Residential (2012) and commercial (2015) end-use surveys;
- Program evaluation reports, conditional demand analyses, and end-use intensity studies; and
- Previous CPR reports (conducted in 2010, and 2013 Update)

Where utility- or BC-specific information was not available, Navigant utilized data from publicly available sources such as BC Statistics (BC Stats), Statistics Canada (StatsCan), and Natural Resources Canada (NRCan) and the Office of Energy Efficiency (OEE) in addition to internal Navigant data sources. Navigant's review of these resources was generally used to support the data sources provided by FortisBC Electric and to ensure consistency among FortisBC Electric's data, Navigant's estimates, and publicly available resources. In order to develop the final estimates of energy consumption, Navigant compared and calibrated preliminary estimates with actual sales data obtained from FortisBC Electric.

Navigant focused the calibration analysis on volumetric energy (e.g., MWh or GJ) consumed in each region by customer segment, end-use, and equipment type in order to develop the base year energy profile for each utility. Navigant chose not to perform calibration based on peak demand (e.g., MW or GJ/hr.) for several reasons. First, each utility reports sales and self-generation amounts exclusively by volumetric energy, and utilities rarely aggregate and report peak demand data other than for billing purposes. Second, each utility reports load forecasts in volumetric terms, and not by peak demand. Third, each utility had readily available and granular volumetric energy data.

2.1.1 Segmentation of Customer Sectors

Navigant disaggregated FortisBC Electric's base year electricity consumption by region in the province, sector, and customer segment. Navigant worked with the BC utilities to determine an appropriate level of segmentation for each sector and an acceptable geographic representation resulting in four regions consistent with regional definitions used by BC Hydro.

Table 2-1 indicates the relationship between the four utilities' service territories and the regions considered in the CPR.

Table 2-1: Mapping of Utility Service Territories to CPR Regions

	Vancouver Island	Lower Mainland	Southern Interior	Northern BC
BC Hydro (Electric)	✓	✓	✓	✓
FortisBC (Electric)			✓	
FortisBC Energy (Gas)	✓	✓	✓	✓
PNG (Gas)				✓

Source: Navigant

The first major task to develop the base year electricity calibration involved the disaggregation of the three main sectors—the residential, commercial, and industrial sectors—into specific customer segments. Each sector was segmented based on several factors including the availability and level of detail of the data provided by each utility, supporting information from secondary resources, level of consumption within segments, and consistency with previous CPRs.

The segmentation also reflects Navigant's modeling approach for representing efficiency measures within the DSMSim™ model. DSMSim™ models energy efficiency measures at the segment level, and tracks building and equipment stocks for each segment within each region and utility. Differences in fuel choices (i.e., space and water heating market shares), types of equipment used (i.e., use of a furnace or boiler for space heating), and equipment and system efficiency levels are all represented within the model for each segment, region, and utility, as required.

This modeling approach represents all measures separately within each customer segment, and does not require the duplication of segments using different space heating sources or different industrial processes. For example, the model represents space conditioning measures separately by fuel type (e.g., characterizing thermal envelope measures for homes with electric or gas heat) eliminating the need to define a customer segment with electric heat versus a segment with gas heat.

Table 2-2 shows the segmentation used for the residential, commercial, and industrial sectors, with additional detail provided for each sector in the following sections. Although the streetlights/traffic signals segment is included in the commercial sector in Table 2-2, it has been analyzed and referenced separately elsewhere this report.

Table 2-2: Customer Segments by Sector

Residential	Commercial	Industrial
Single Family Detached/Duplexes	Accommodation	Agriculture
Single Family Attached/Row	Colleges/Universities	Cement
Apartments <= 4 stories	Food Service	Chemical
Apartments > 4 stories	Hospital	Food & Beverage
Other Residential	Logistics/Warehouses	Greenhouses
	Long Term Care	Mining - Coal
	Office	Mining - Metal
	Other Commercial	LNG Facilities
	Retail - Food	Oil and Gas
	Retail - Non Food	Manufacturing
	Schools	Pulp & Paper - Kraft
	Streetlights/Traffic Signals*	Pulp & Paper - TMP
		Wood Products
		Other Industrial
		Transportation

**see footnote 5.*
Source: Navigant

2.1.1.1 FortisBC Electric Sales

FortisBC Electric supplies electricity to residential, commercial and industrial customers in the Southern Interior region of BC. FortisBC Electric also supplies electricity to *indirect* customers through local municipal utilities (e.g., embedded utilities), reporting sales to these embedded utilities under the wholesale category.[4] Navigant allocated sales from the categories by which FortisBC Electric reports sales to the three CPR sectors in two steps:

1. Allocation of the entire Wholesale category into the three CPR sectors—residential, commercial and industrial. FortisBC Electric obtained sales data from embedded utilities that represent close to 80% of the Wholesale load[5]. The team allocated the remaining 20% of the Wholesale category across the three CPR sectors according to the breakdown of 2014 direct sales to the residential, commercial and industrial sectors.
2. Allocation of multi-unit residential buildings (MURBs)—including apartment or condo strata buildings. This CPR categorizes apartment buildings in the residential sector even though FortisBC Electric includes common area of apartment buildings in the commercial sector for billing purposes. The team therefore re-allocated a fraction of the commercial sector sales—

[4] FortisBC Electric reports an additional two categories; Street Lighting and Irrigation. These two categories were allocated directly to the other sectors. Street Lighting was allocated to the commercial sector, and Irrigation to the Agriculture segment (within the industrial sector).
[5] Nelson Hydro, the City of Penticton, and the City of Grand Forks Hydro provided FortisBC Electric with a breakdown of their electricity sales by customer sector. These three municipal utilities account for roughly 80% of all Wholesale sales.

attributed to apartment buildings—to the residential sector using the analysis of base year sales and the stock of apartment units and apartment EUIs. This raised the residential and lowered the commercial sales relative to the initial allocation of direct and indirect sales.

FortisBC Electric also utilizes this segmentation in its load forecast as discussed in the Reference Case Forecast section 2.2. Navigant performed the same two-step process for allocating the Wholesale load to the three CPR sectors for the Reference Case.

2.1.1.2 Utility Owned Self-Generation

One of the municipal utilities supplied by FortisBC Electric, Nelson Hydro, owns and operates a hydroelectric facility whose generation during the base year (2014) was included in FortisBC Electric's base year consumption. Navigant allocated the electricity generated by Nelson Hydro to the residential and commercial sectors in proportion to the breakdown of sales provided by Nelson Hydro.

2.1.1.3 Residential Sector

Navigant divided residential customers into five segments based on the type of residential building they occupied, as shown in Table 2-3.

Table 2-3: Description of Residential Segments

Segment	Description
Single Family Detached/Duplexes	Detached and duplex residential dwellings
Single Family Attached/Row	Attached, row and/or townhouses
Apartments <= 4 stories	Apartment units located in low-rise apartment buildings made up of four stories or fewer
Apartments > 4 stories	Apartment units located in high-rise apartment buildings made up of more than four stories
Other Residential	Manufactured, mobiles or other types of residential dwellings

Source: Navigant

This segmentation is largely consistent with the dwelling types employed in FortisBC Electric's 2013 CPR, with the following two exceptions:

- **Manufactured Homes:** The 2013 CPR included "manufactured homes" as one of four residential segments. However, manufactured homes pertain to both Single Family Detached/Duplexes units and single family attached/row units, two of the segments considered in the present study. Navigant allocated manufactured homes to these two segments to avoid potential issues with overlapping building stock across customer segments, rather than tracking manufactured homes in a segment of their own.
- **Apartments:** The 2013 CPR included only one segment for apartment buildings, regardless of their size. However, the size of the apartment building (e.g., whether low-rise or high-rise) directly impacts the electricity consumption of the building tenants. Moreover, high- and low-rise buildings differ in terms of the fuel type used for space heating and the prevalence of the equipment used for space conditioning and water heating. To capture these key differences,

Navigant chose to break apartment buildings into two separate customer segments: low-rise buildings (i.e., less than or equal to 4 stories) and high-rise buildings (i.e., more than 4 stories).

Navigant developed the breakdown of the residential sector into dwelling types based on FortisBC Electric customer data and based on StatsCan data. Table 2-4 shows the stock numbers by housing type and Appendix B.1 describes the methodology used to develop them.

Table 2-4: Base Year Housing Stocks (Residential units)

Housing Type	Southern Interior
Single Family Detached/Duplexes	106,926
Single Family Attached/Row	20,077
Apartments <= 4 stories	33,033
Apartments > 4 stories	2,632
Other Residential	8,850
Total	**171,518**

Source: Navigant analysis based on FortisBC Electric and StatsCan data

2.1.1.4 Commercial Sector

Navigant divided the BC commercial sector into 12 segments, including streetlights and traffic signals. Table 2-5 provides a list and description for the commercial segments.

Table 2-5: Description of Residential Segments

Segment	Description
Accommodation	Short-term lodging including related services such as restaurants and recreational facilities
Colleges/Universities	Post-secondary education facilities such as colleges, universities and related training centers
Food Service	Establishments engaged in preparation of meals, snacks and beverages for immediate consumption including restaurants, taverns, and bars.
Hospital	Diagnostic and medical treatment services such as hospitals and clinics
Logistics/Warehouses	Warehousing/storage facilities for general merchandise, refrigerated goods, and other wholesale distribution
Long Term Care	Residential care, nursing, or other types of long term care
Office	Administration, clerical services, consulting, professional, or bureaucratic work but not including retail sales.
Other Commercial	Establishments, not categorized under any other sector, including but not limited to recreational, entertainment and other miscellaneous activities
Retail - Food	Engaged in retailing general or specialized food and beverage products
Retail - Non Food	Engaged in retailing services and distribution of merchandise but not including food and beverage products
Schools	Primary and secondary schools (K to 12)
Streetlights/Traffic Signals	Roadway lighting and traffic signal loads

Source: Navigant

Navigant selected the commercial segments with the goal that the building types within those segments be reasonably similar in terms of gas and electricity use, operating and mechanical systems, and annual operating hours. This approach allowed for consistency in building characteristics within each segment as required by the measure characterization and modeling processes.

The selection of these commercial segments is similar to those for previous CPRs with the exception that this CPR does not distinguish commercial segments based on the size of facilities (e.g., large vs. medium). Navigant normalized the analysis of the commercial sector based on the stock of commercial floor space in FortisBC Electric’s territory using electricity sales data provided by FortisBC Electric and applied the end-use intensities (EUIs) derived through the calibration process. Appendix B.3 describes the methodology used to estimate the commercial sector EUIs in greater detail. Based on these initial floor estimates, the team performed multiple iterations by adjusting the applied fuel shares, equipment shares, and EUIs in order to approximate the sales target of each commercial segment. Table summarizes the resulting floor space estimates developed for each commercial segment.

Table 2-6: Base Year Commercial Floor Area (million m2)

Segment	Floor Area (million m2)	Floor Area (%)
Accommodation	1.01	14%
Colleges/Universities	0.27	4%
Food Service	0.24	3%
Hospital	0.29	4%
Logistics/Warehouses	0.48	7%
Long Term Care	0.23	3%
Office	1.20	17%
Other Commercial	1.37	19%
Retail - Food	0.20	3%
Retail - Non Food	1.39	20%
Schools	0.41	6%
Total	**7.09**	**100%**

Source: Navigant analysis

2.1.1.5 Industrial Sector

Navigant divided the BC industrial sector into 15 segments as shown in Table 2-7.

Table 2-7: Description of Industrial Segments

Segment	Description
Agriculture	Engaged in growing crops, raising animals, harvesting timber, fish and other animals, including farms, irrigation, ranches, or hatcheries.
Cement	Cement manufacturers and related operations including asphalt and concrete
Chemical	Industrial facilities that produce industrial and consumer chemicals including paints, synthetic materials, pesticides, and pharmaceuticals
Food & Beverage	Food and beverage industrial facilities including breweries, tobacco, meat/dairy and animal food manufacturers
Greenhouses	Engaged in growing nursery stock and flowers, including greenhouses, nurseries and orchards.
Mining - Coal	Thermal and metallurgical coal mines
Mining - Metal	Copper, gold and other metal mines
LNG Facilities	Natural gas liquids processing facilities
Oil and Gas	Industries that explore, operate or develop oil and gas resources including the production of petroleum, mining and extraction of shale oil and oil sands.
Manufacturing	Industrial facilities that engage in light and heavy manufacturing processes including fabricated metal, metal manufacturing, machinery, and textiles.
Pulp & Paper - Kraft	Pulp and Paper industrial facilities dedicated specifically to the chemical kraft process
Pulp & Paper - TMP	Pulp and Paper industrial facilities dedicated to the thermo-mechanical pulp (TMP) process
Wood Products	Industrial facilities that manufacture wood products including lumber, plywood, veneer, boards, panel boards and pellets.
Other Industrial	Other industrial facilities and related production operations not categorized under any other industrial segment, including construction, contracting services, waste management and municipal water.
Transportation	Facilities providing transportation of passengers/cargo/resources and support activities related to common modes of transportation including air, rail, water, road, and pipeline.

Source: Navigant

Navigant selected these industrial segments to group industries with similar manufacturing processes, operations, outputs, and patterns of electricity and gas use. The selection of these segments allowed differences in processes or patterns of energy use for each segment to be characterized more accurately than if they were combined into one segment. While this approach attempts to better characterize and analyze energy consumption in certain industrial segments, the proposed segmentation is not intended to accurately represent energy consumption at individual industrial facilities. The team also notes that, in general, the industrial sector exhibits much greater diversity regarding energy usage compared to the commercial or residential sectors.

2.1.2 End-Use Definitions

The next step in the base year calibration analysis involved the establishment of specific end-uses for each customer sector. This CPR defines end-uses as a specific activity or customer need that requires energy, such as space heating or domestic water heating, without specifying the particular type of equipment used to satisfy that need.

Table 2-8 presents the list of end-uses by sector used in the CPR, with end-use definitions provided in Appendix B.1. These end-use categories have significant impact on the base year calibration since Navigant calculated the energy consumption for a given baseline measure based on the electricity intensity of the end-use to which that measure is assigned. These end-uses also allow Navigant's DSMSim™ model to incorporate changes in electric and gas end-use intensity over time.

Table 2-8: End-Uses by Sector[6]

Residential	Commercial	Industrial
Appliances	Cooking	Boilers
Electronics	HVAC Fans/Pumps	Compressed Air
Water Heating	Hot Water	Fans & Blowers
Lighting	Lighting	Industrial Process
Other	Office Equipment	Lighting
Space Cooling	Other	Material Transport
Space Heating	Refrigeration	Process Compressors
Ventilation	Space Cooling	Process Heating
Whole Building	Space Heating	Product Drying
	Whole Building	Space Heating
		Pumps
		Refrigeration
		Whole Building

Source: Navigant

2.1.3 Fuel Share and Equipment Data

Navigant developed fuel share and equipment data for each end-use based on the segmentations defined in the previous sections. The team followed two approaches, depending on sector, as described below:

- **Residential and Commercial Sectors**

  Navigant developed estimates of the distribution of fuel shares for each end-use and the types of equipment that contribute to energy consumption within each end-use based on available data from prior FortisBC and BC Hydro end use surveys. Navigant analyzed FortisBC's *2012 Residential End-Use Survey* (2012 REUS) and *2015 Commercial End-Use Survey* (2015 CEUS) and consulted BC Hydro's *2014 Residential End-Use Survey* (2014 REUS) and *2014 Commercial End-Use Survey* (2014 CEUS) to support analysis where applicable. Navigant also relied on program evaluation reports, conditional demand analysis (CDA) studies, and monitoring surveys

[6] Street lighting is reflected under the commercial lighting end-use, and irrigation is categorized under the industrial pumps end-use.

provided by both utilities[7]. Appendix B.2 and Appendix B.3 summarize the fuel shares and equipment shares used for the residential and commercial sectors, respectively.

- **Industrial Sector**

  Navigant subcontracted CLEAResult, who has considerable expertise in the industrial sector in BC, to develop an estimate of the distribution of energy consumption by each end-use for each industrial customer segment. CLEAResult determined these estimates based on a detailed database of industrial equipment such as pumps, fans, blowers, motors, compressed air equipment, etc. This database contains information on equipment types, key equipment characteristics including system efficiency and/or equipment efficiency levels, and equipment market shares. CLEAResult developed this database based on *Power Smart* industrial reviews, industrial energy assessments, equipment inventories, and ongoing audit and market assessment work with BC Hydro and FortisBC.

The information developed for each sector and the resulting estimates of energy intensity are described in Appendix B.2 and Appendix B.3.

2.1.4 Calibration Process

This section describes the calibration process used for the residential, commercial, and industrial sectors.

2.1.4.1 Residential and Commercial Sectors

For the residential and commercial sectors, Navigant developed a base year calibration model to analyze electricity consumption at an equipment level, at an end-use level, and at a segment level. The team developed this calibration model to accurately calibrate the estimated electricity consumption of each sector to the FortisBC Electric electricity sales.

The calibration process began at an equipment level for each of the energy-intensive end-uses—the primary end-uses—and at an end-use level for the less energy-intensive end-uses—the secondary end-uses. Navigant determined the primary end-uses as those that make up more than 15% of electricity consumption and for which the availability of equipment data provided enabled a detailed analysis of equipment data. The calibration model for primary end-uses involved a complete bottom-up buildup of detailed equipment information including various efficiency levels, Unit Energy Consumption (UEC) for each efficiency level, equipment market shares, and fuel types for different equipment. The team extracted these inputs primarily from FortisBC Gas 2012 REUS, and residential and commercial end-use surveys provided by both FortisBC and BC Hydro. For the secondary end-uses, calibration focused primarily on analyzing and establishing end-use intensities based on previous CPR studies (i.e., FortisBC Electric's 2013 CPR and FortisBC Gas 2010 CPR), CDA reports, and other secondary resources. This process ensured that the segment-level EUIs approximated the sales targets with reasonable precision.

The calibration model used these inputs to aggregate electricity consumption by end-uses and by customer segment, and compared the results to the FortisBC Electric electricity sales at the lowest level of disaggregation available. The calibration of the base year was an iterative process to estimate energy consumption from the lowest level of granularity (i.e., equipment types) to the sector level. Each

[7] We note that some of the data sources provided by the BC Utilities were provided on a confidential basis and are not publically available.

calibrated iteration required refining of key variables and inputs such as the market share of equipment types, UECs by equipment, and fuel shares.

Table 2-9 shows an example of the calibration process for appliances in Single Family Detached/Duplexes in the Southern Interior region. The process used to calibrate the estimate of energy use builds on an estimate of the percentage of homes with a particular end-use and fuel type, using a particular type of equipment and efficiency within an end-use. The fuel shares (column B), equipment shares (column E), and an estimated level of energy use for each equipment type (column F) are multiplied to obtain an estimated UEC (column G). In the example below, column H sums the total consumption across major and small appliances. The team summed the resulting UECs across end-uses to obtain the segment-level intensity in kWh per year (column H), and then calibrated (or pro-rated) this initial estimate to match the actual target intensity stemming from FortisBC Electric sales data (column I). In this example, the total uncalibrated annual consumption results in a very close match (93%) to the target consumption. The final step of this process is to scale the EUIs proportionally to achieve a 100% match. Navigant repeated this same process across all residential and commercial segments in each region.

Table 2-9: Example of Calibration Process (Single Family Detached/Duplexes – Southern Interior)

A	B	C	D	E	F	G	H	I
End Use	Fuel Share (%)	Equipment	Efficiency	Equipment Share (%)	Annual Energy Use (kWh)	End-Use Weighted Avg. Use (kWh)	Total Uncalibrated Consumption (kWh)	Total Calibrated Consumption (kWh)
Space Heating	25%	…	…	…	…	…	2781	2988
Water Heating	39%	…	…	…	…	…	1122	1206
Cooling	100%	…	…	…	…	…	240	258
Appliances	100%	Fridge Low E	Low E	54%	555	2403	3123	3355
		Fridge Estar	Estar	46%	444			
		Freezer Low E	Low E	65%	522			
		Freezer Estar	Estar	29%	470			
		Dishwasher Low E	Low E	33%	289			
		Dishwasher Estar	Estar	49%	263			
		Clothes Washer Low E	Low E	54%	174			
		Clothes Washer Estar or Front lo	Estar	45%	89			
		C. Dryer Elect. Low E	Low E	63%	938			
		C. Dryer Elect. Estar	Estar	34%	641			
		C. Dryer Gas Low E	Low E	7%	0			
		C. Dryer Gas Estar	Estar	4%	0			
		Stove Gas	Average	16%	0			
		Stove Elect	Average	84%	305			
		Other Appliances	n/a	n/a	n/a	Deemed to be equivalent to 30% of major appliances		
Lighting	100%	…	…	…	…	…	1817	1952
Electronics	100%	…	…	…	…	…	1405	1510
Other	100%	…	…	…	…	…	937	1007
Ventilation	25%	…	…	…	…	…	859	923
Estimated Consumption (kWh per year)							12285	**13198**
Target Consumption (kWh per year)		- Determined based on Fortis Electric 2014 Usage per Customer (UPC) data					13198	**13198**
	Uncalibrated vs. Target						**93%**	**100%**

Source: Navigant

Navigant developed the calibration process to operate across all of the dimensions of the model. The following sections present the key estimates of energy use by end-use, sector, and region. Most inputs to the calibration process, including efficiency levels and shares, equipment types, equipment shares, fuel shares, and EUIs by end-use, segment, and region, are presented in Appendix B.2 for the residential sector and Appendix B.3 for the commercial sector.

Table 2-10: Base Year Calibration Dimensions (Residential and Commercial Sectors)

Element	No. of Dimensions	Dimensions	
Energy Types	2	**Electricity**	**Natural Gas**
Sectors	2	Residential, Commercial	
Regions	4	Lower Mainland Southern Interior Vancouver Island Northern BC	Lower Mainland Southern Interior Vancouver Island Northern BC
Utilities	4	BC Hydro FortisBC Inc.	FortisBC Energy Inc. Pacific Northern Gas
Segments	17	Five residential segments, 12 commercial segments	
End-Uses	17	Residential (8), commercial (9)	
Equipment Types	<5	Varies by end-use—generally less than five	
Efficiency Levels	>2	Generally two for each equipment type	

Source: Navigant

Streetlights/Traffic Signals

Street lighting did not require calibration. Navigant characterized the segment by one end-use (i.e., Lighting) based on a single set of inputs; a baseline measure and an energy efficient measure.

2.1.4.2 Industrial Sector

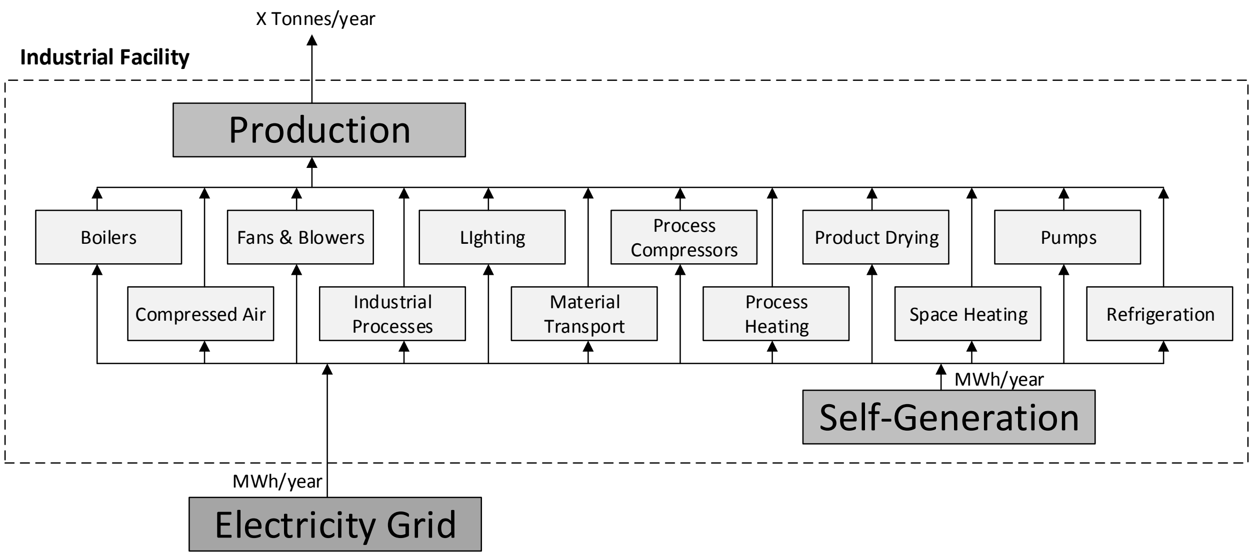
CLEAResult developed estimates of the distribution of energy consumption by end-use for each industrial segment. To calculate the energy consumption by end-use, CLEAResult utilized detailed data on industrial facilities for each of the industrial segments from numerous resources including:

- *Power Smart* Industrial Electricity Analysis Reviews of industrial customers;
- Prior industrial energy assessments performed for BC Hydro and FortisBC;
- Detailed energy audits of large industrial facilities in BC;
- Inventories of industrial equipment; and
- CLEAResult professional experience and literature review.

Over many years of data collection, CLEAResult has used these resources to build a detailed database of industrial equipment such as pumps, fans, blowers, motors, compressed air equipment, etc. For each equipment type, CLEAResult determined key equipment characteristics including overall system efficiency and/or equipment efficiency levels and equipment market shares, and developed industrial models for BC Hydro and FortisBC. CLEAResult has used these models on a continuous basis to assist BC Hydro and FortisBC with market assessments and DSM program business case developments. For this CPR, Navigant and CLEAResult aligned the industrial models with up-to-date billing account information broken down into the various industrial segments, and developed end-use allocation factors used to estimate the proportion of energy use attributed to each end use.

CLEAResult Industrial Models are broken down into separate sub-models for the major industrial energy end use categories. Figure 2-1 shows a schematic example of one of these industrial models.

Figure 2-1: Schematic of Industrial Model



Source: Navigant schematic of CLEAResult model

The production occurring in each particular segment drives the models for the major energy use industrial segments. A given amount of production requires a certain amount of electricity or natural gas consumption, and this energy can be broken down into each of the end-uses based on the installed equipment.

This detailed modeling approach is not appropriate for certain diverse segments such as food and beverage, manufacturing, and “other” industrial. These three segments involve such a large variety of processes and equipment types that it is not practical to set up an energy model for them. For these industrial segments, the team used end-use information from over 200 facility audits—sponsored by BC Hydro, and including industry groups such as the *BC Food Processors Association* and *Canadian Manufacturers & Exporters*—to estimate the end-use breakdown of each segment. For each of these audits, CLEAResult developed a breakdown of equipment and energy end-use, which Navigant used to develop the end-use breakdown of the food and beverage, manufacturing, and “other” industrial segments.

Table 2-11 shows the resulting end-use consumption percentages developed by CLEAResult, as a distribution of electricity demand by end-use for each industrial segment.

Table 2-11: Industrial Electricity End-use Allocation Factors (%)

Segment	Boilers	Compressed Air	Fans & Blowers	Industrial Process	Lighting	Material Transport	Process Compressors	Process Heating	Product Drying	Space Heating	Pumps	Refrigeration	Total
Agriculture	0%	10%	16%	3%	31%	2%	0%	0%	0%	1%	22%	15%	**100%**
Cement	0%	3%	15%	41%	4%	23%	0%	0%	0%	0%	13%	0%	**100%**
Chemical	0%	0%	1%	95%	0%	0%	0%	0%	0%	0%	3%	1%	**100%**
Coal Mining	0%	2%	10%	51%	2%	15%	0%	0%	0%	0%	20%	0%	**100%**
Food & Beverage	0%	7%	7%	19%	21%	1%	0%	0%	0%	3%	8%	34%	**100%**
Greenhouses	0%	4%	28%	0%	64%	0%	0%	0%	0%	0%	4%	0%	**100%**
LNG Facilities	0%	0%	1%	5%	0%	0%	79%	0%	0%	0%	3%	12%	**100%**
Manufacturing	0%	9%	13%	35%	25%	3%	0%	0%	0%	9%	6%	1%	**100%**
Metal Mining	0%	0%	1%	86%	5%	1%	0%	0%	0%	0%	6%	0%	**100%**
Oil and Gas	0%	8%	19%	17%	1%	0%	33%	0%	0%	1%	14%	8%	**100%**
Pulp & Paper - Kraft	0%	4%	15%	37%	2%	2%	0%	0%	0%	0%	40%	0%	**100%**
Pulp & Paper - TMP	0%	1%	2%	85%	1%	3%	0%	0%	0%	0%	8%	0%	**100%**
Transportation	0%	0%	19%	11%	22%	0%	0%	0%	0%	1%	4%	43%	**100%**
Wood Products	0%	13%	17%	44%	6%	12%	0%	0%	6%	2%	0%	0%	**100%**
Other Industrial	0%	9%	13%	35%	25%	3%	0%	0%	0%	9%	6%	1%	**100%**

Source: CLEAResult

The next step of the industrial sector analysis was to determine the total electricity consumption by each segment. Navigant worked with FortisBC Electric to determine the total sales to each industrial segment. Self-generated electricity estimates were also determined for each industrial segment and were added to FortisBC Electric sales. The combined total of sales and self-generation established the base year electricity consumption. Table 2-12 shows the total electricity consumption of each industrial segment region in the base year (2014).

The final step of this analysis was the application of the end-use consumption percentages to the electricity consumption corresponding to each industrial segment. Table 2-12 shows the resulting distribution of electricity consumption by end-use and by industrial segment.

Table 2-12: Base Year Industrial Consumption by End-use (GWh)

Segment	Boilers	Compressed Air	Fans & Blowers	Industrial Process	Lighting	Material Transport	Process Compressors	Process Heating	Product Drying	Space Heating	Pumps	Refrigeration	Total
Agriculture	-	5	7	1	14	1	-	-	-	0	10	7	**46**
Cement	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Chemical	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Coal Mining	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Food & Beverage	-	3	3	7	8	0	-	-	-	1	3	13	**37**
Greenhouses	-	-	-	-	-	-	-	-	-	-	-	-	**-**
LNG Facilities	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Manufacturing	-	16	21	58	41	5	-	-	-	14	10	2	**168**
Metal Mining	-	0	1	61	4	1	-	-	-	-	4	-	**71**
Oil and Gas	-	0	1	1	0	-	2	-	-	0	1	0	**6**
Pulp & Paper - Kraft	-	15	55	136	7	7	-	-	-	0	146	0	**365**
Pulp & Paper - TMP	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Transportation	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Wood Products	-	20	27	71	10	19	-	-	9	3	0	1	**159**
Other Industrial	-	2	3	8	5	1	-	-	-	2	1	0	**22**
Totals -	**-**	**61**	**118**	**343**	**89**	**34**	**2**	**-**	**9**	**21**	**175**	**23**	**874**

Source: Navigant analysis of FortisBC Electric sales data and CLEAResult data

2.1.5 Base Year Consumption

Each of the BC utilities provided Navigant with information on actual sales and customer numbers for the base year (2014), as well as information on self-generated electricity by segment where appropriate. Table 2-13 shows the total electricity consumption by sector in 2014 (the "actual consumption"). This table includes electricity sales from FortisBC Electric and self-generated electricity by certain customers. Although street lighting is commercial segment, it is reported separately to highlight that calibration was not required, in contrast with all other commercial segments.

Table 2-13: FortisBC Actual Consumption in 2014 (GWh) - Include Self-Generation

Segment	Southern Interior
Residential	1,962
Commercial	924
Industrial	874
Streetlights/Traffic Signals	20
Total	**3,780**

Source: Navigant analysis

2.1.6 Comparison between Base Year and Actual Consumption

Navigant used the calibration process—described in previous sections—along with the actual consumption targets to develop calibrated estimates of electricity consumption (the "base year consumption").

- **Residential and commercial sectors** required fine-tuning of key input assumptions—through multiple iterations—until the base year consumption matched the actual consumption targets.
- For the **industrial sector**, the team applied the end-use percentages determined in the previous section to the actual consumption targets for each segment. Based on this approach, base year consumption aligns fully with actual consumption.
- **Street lighting** did not require any changes or calibration given that the street lighting load is treated as an individual sector to recognize that the drivers for that segment differ from the rest of the sectors.[8]

Table 2-14 shows the result of the base year calibration by sector and region. Table 2-14 compares the actual consumption targets (based on FortisBC Electric sales and self-generation) with the base year consumption (determined through the calibration process). The base year consumption in each sector matches the actual consumption.

[8] Navigant characterized street lighting consumption based on total energy use for the segment. In comparison, the team characterized energy use for the commercial sector based on customer segment or end-use consumption and equivalent quantity of a given measure in a square meter of floor area.

Table 2-14: FortisBC 2014 Actual Consumption vs. Base Year Consumption (GWh)

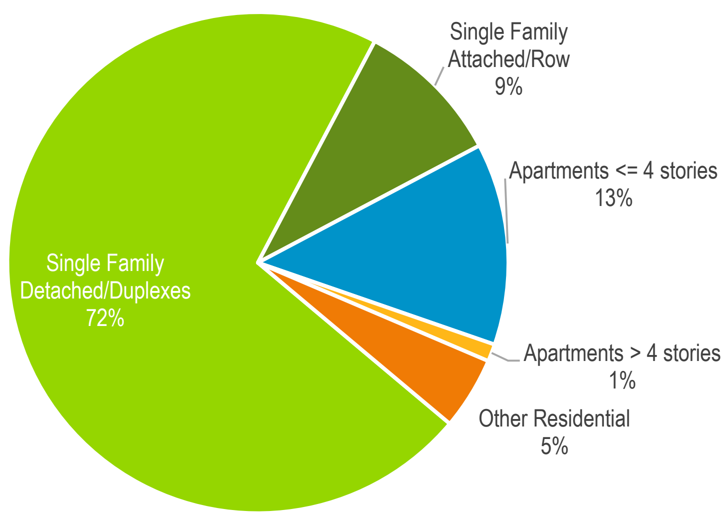
Region	Sector	Actual Consumption (GWh)	Base Year Consumption (GWh)	Difference (%)
Southern Interior	Residential	1,962	1,962	0.0%
	Commercial	924	924	0.0%
	Industrial [9]	874	874	0.0%
	Street Lighting	20	20	0.0%
Total		**3,780**	**3,780**	**0.0%**

Source: Navigant analysis

As part of the development of the base year, Navigant determined the electricity consumption for each segment within the residential, commercial, and industrial sectors. The distribution of electricity consumption by segment and end-use for each sector is shown by Figure 2-2 through Figure 2-7, and the tabulated results are shown by Table 2-15 (residential) and Table 2-16 (commercial). The industrial results were shown by Table 2-12 in Section 2.1.4.2.

Additional information relating to each segment can be found in Appendix B.2 (for the residential sector), Appendix B.3 (for the commercial sector).

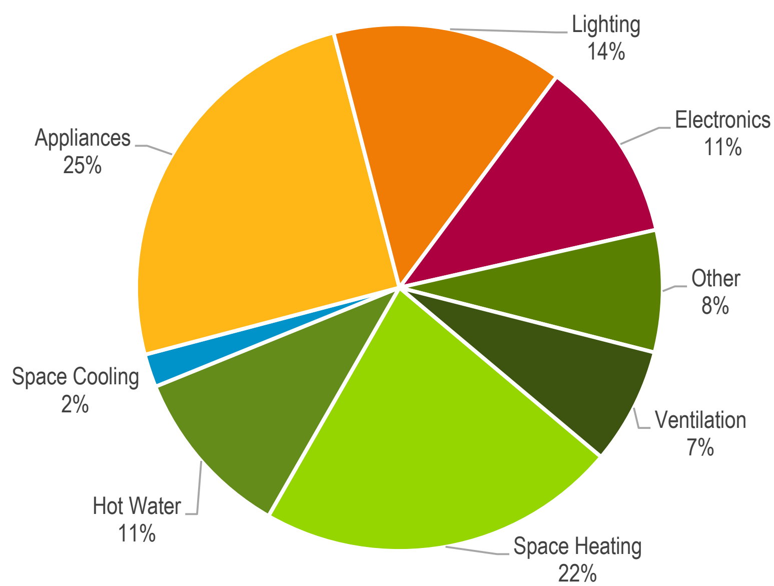
Figure 2-2: Base Year Residential Consumption by Segment (%)



Source: Navigant analysis

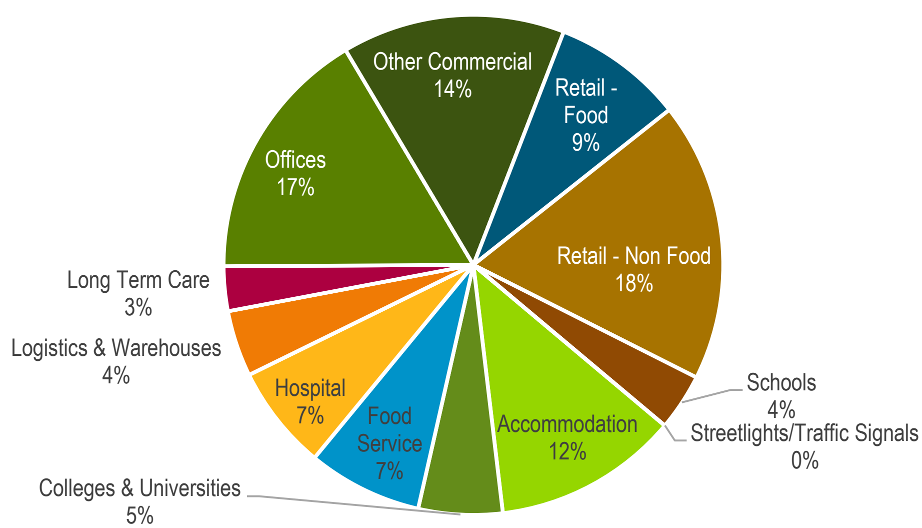
[9] The 2014 industrial self-generation consumption accounts for 44% of the total industrial load, equivalent to 385 GWh.

Figure 2-3: Base Year Residential Consumption by End-Use (%)



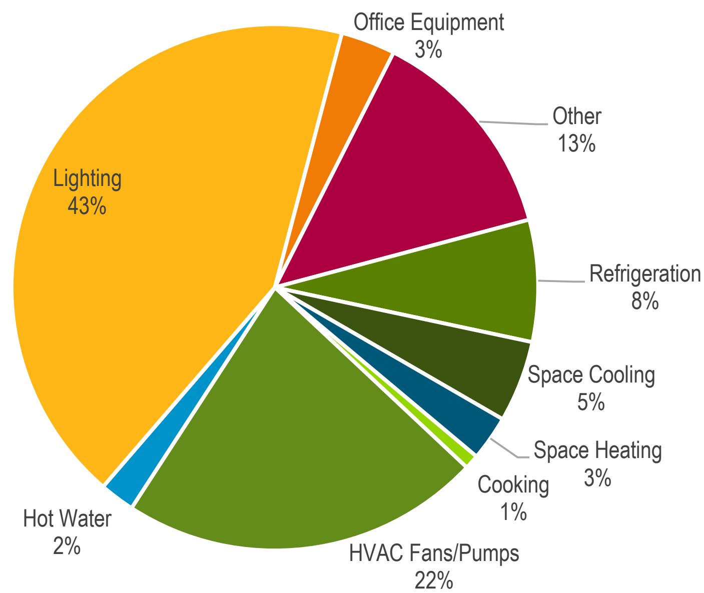
Source: Navigant analysis

Figure 2-4: Base Year Commercial by Segment Consumption (%)



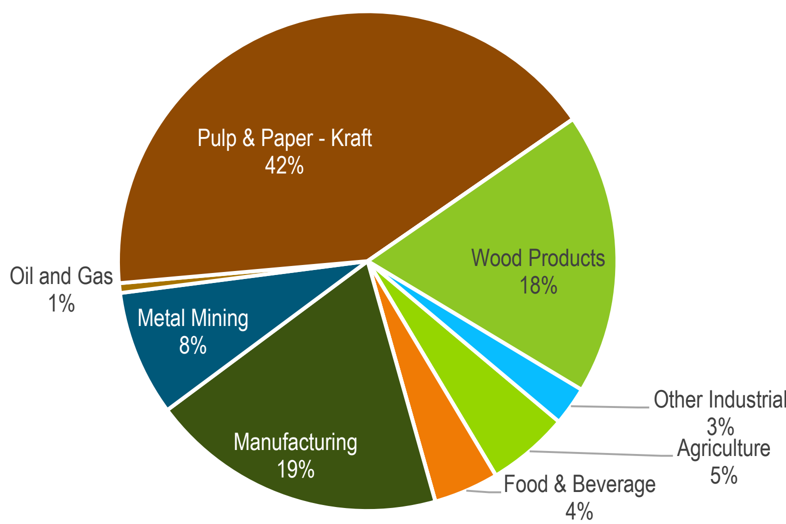
Source: Navigant analysis

Figure 2-5: Base Year Commercial by Segment End-Use (%)



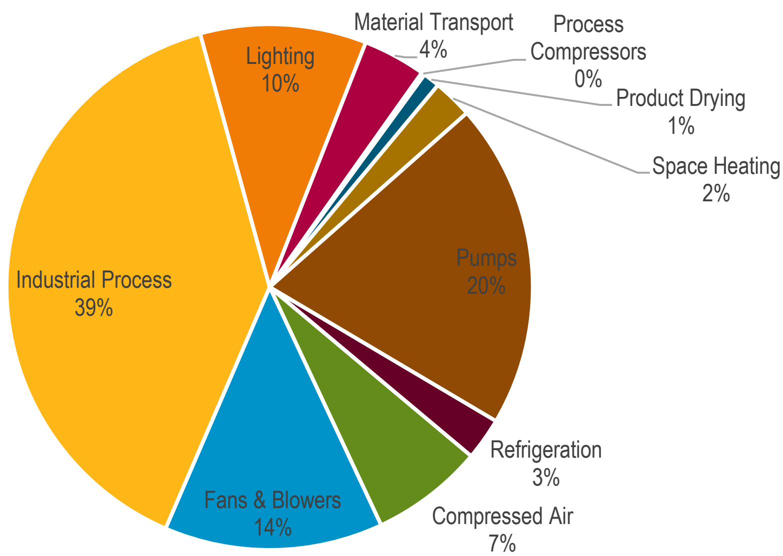
Source: Navigant analysis

Figure 2-6: Base Year Industrial Consumption by Segment (%)



Source: Navigant analysis

Figure 2-7: Base Year Industrial Consumption by End-Use (%)



Source: Navigant analysis

Table 2-15: Base Year Residential Consumption by Segment and End-use (GWh)

Segment	Space Heating	Hot Water	Space Cooling	Appliances	Lighting	Electronics	Other	Ventilation	Total
Single Family Detached/Duplexes	320	129	28	359	209	161	108	99	**1,411**
Single Family Attached/Row	35	19	3	45	27	16	9	16	**170**
Apartments <= 4 stories	58	39	5	61	31	34	24	20	**273**
Apartments > 4 stories	5	3	0	5	2	3	1	2	**22**
Other Residential	18	17	3	22	10	8	4	3	**86**
Totals -	**435**	**208**	**40**	**492**	**279**	**221**	**147**	**140**	**1,962**

Source: Navigant analysis

Table 2-16: Base Year Commercial Consumption by Segment and End-use (GWh)

Segment	Cooking	NVAC Fans/Pumps	Hot Water	Lighting	Office Equipment	Other	Refrigeration	Space Cooling	Space Hating	Total
Accommodation	1	24	3	53	9	8	2	6	4	**111**
Colleges/Universities	0	18	1	21	3	3	0	1	1	**50**
Food Service	3	11	6	24	0	12	3	8	2	**69**
Hospital	1	17	0	21	1	16	1	3	3	**63**
Logistics/Warehouses	0	5	1	19	1	8	3	1	1	**40**
Long Term Care	1	7	1	11	1	2	1	1	3	**27**
Office	1	38	2	70	11	18	0	10	3	**153**
Other Commercial	0	48	3	44	1	12	17	5	3	**133**
Retail - Food	0	7	1	23	0	5	41	1	0	**78**
Retail - Non Food	1	23	1	94	3	33	1	8	3	**167**
Schools	0	8	0	15	1	7	0	1	1	**34**
Totals -	**8**	**205**	**20**	**395**	**31**	**124**	**69**	**46**	**25**	**924**

Source: Navigant analysis

2.2 Reference Case Forecast

This section presents the Reference Case for the CPR study period from 2015 to 2035. The Reference Case estimates the expected level of electricity consumption over the CPR period, absent incremental demand-side management (DSM) activities or load impacts from rates. The Reference Case is significant in the context of this CPR study because it acts as the point of comparison (i.e., the reference) for the calculation of the technical and economic potential scenarios.

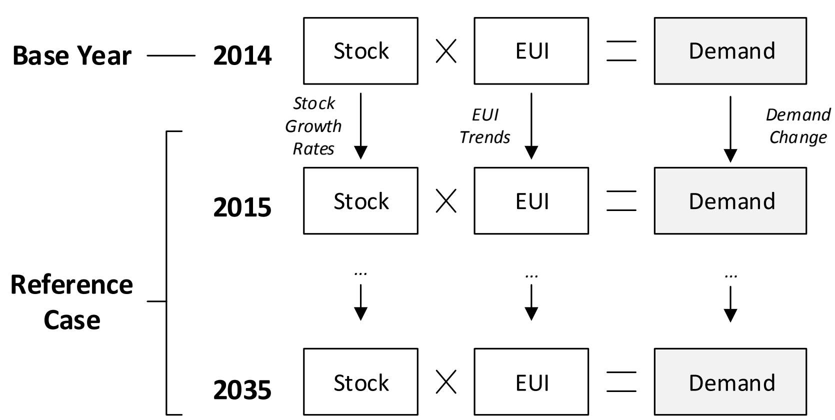
The Reference Case Forecast uses the base year calibration—presented in the previous section—as the foundation for analysis.

Navigant constructed the Reference Case forecast based on two different approaches.

- **Residential and commercial sectors:** For the residential and commercial sectors, Navigant used two key inputs: stock growth rates and EUI trends. Navigant developed stock growth projections of residential households and commercial floor area. The team then modeled the potential for energy efficiency based on the resulting stock projections of each customer segment. The team applied EUI trends to the base year EUIs for each customer segment, and used these trends to represent natural change in end-use consumption over time.

  Figure 2-8 illustrates the process used the develop the Reference Case for the residential and commercial sectors. This figure illustrates that applying stock growth rates to the base year stocks of each customer segment results in a forecast of stocks through 2035. Similarly, applying the EUI trends to the base year EUIs results in a forecast of EUIs through 2035. The final step of this process involves multiplying the stock forecast with the corresponding EUI forecast in order to obtain a load forecast.

Figure 2-8: Schematic of Reference Case Development



Source: Navigant

- **Industrial sector:** The Reference Case for the Industrial sector assumed frozen EUIs over the Reference Case forecast (e.g., frozen EUIs assume that EUIs do not change and are static over time). A more detailed discussion supporting this assumption is presented in Section 2.2.3.3. Based on the frozen-EUI approach, the Industrial Reference Case was established solely by developing energy demand growth assumptions for each industrial segment.

Navigant compared the forecasts developed for the Reference Case for the residential, commercial, and industrial sectors with the long-term load forecast developed by each utility. This comparison ensured that the Reference Case forecast is consistent with each utility's current expectations for load growth over the 2015 to 2035 period.

2.2.1 Approach

This section provides a brief introduction to the overall process for developing the residential and commercial Reference Case. As noted earlier, the Reference Case approach for the industrial sector differed from the residential and commercial sectors.

Navigant's Reference Case started with the base year estimate of stocks and electricity consumption for 2014. Two key inputs were the basis for projected change in electricity consumption through the CPR study period:

- Stock growth rates
- Electricity EUI trends

To develop the Reference Case for each sector, Navigant first developed the stock growth rates based on the CPR segmentation for each sector and region. The second step established appropriate EUI trends that the team applied to each segment and region. Finally, the team applied these two inputs to the base year estimates of stock and EUIs, and projected the results through 2035 to construct the Reference Case.

Navigant developed the growth rates for stock and the EUI trends based primarily on information provided by FortisBC Electric and supported by BC Hydro data specific to the Southern Interior region. Secondary sources supported any gaps in these data.

The following two sections provide detailed descriptions of the approach followed to establish the stock growth rates and the electric EUI trends of each sector.[10]

2.2.2 Stock Growth Rates

This section describes the approach followed to develop stock growth rates for the residential, commercial and industrial sectors. [11]

[10] For the industrial sector, the stock growth rate section (Section 2.2.2.3) presents the demand forecast established for each industrial customer segment, and the EUI trends section (Section 0) describes the reasoning for a frozen EUI approach.

2.2.2.1 Residential Sector

The first step in developing the residential Reference Case involved the development and application of growth rates for each residential segment over the CPR study period. Navigant derived the stock growth rates from the sector-level, residential stock forecast provided by FortisBC Electric. To disaggregate this sector-level stock forecast down to individual segments, the team analyzed BC Hydro's residential stock forecast for the Southern Interior region. Navigant used BC Hydro's segment-level stock forecast to determine the proportion of residential growth attributed to each residential segment. The team then applied these percentages to the overall, sector-level stock projections for FortisBC Electric to develop segment-level stock projections from 2015 through 2045. Based on this residential household forecast, average annual growth rates were established for each five-year period in the forecast (e.g., 2015 to 2019, 2020 to 2024, etc.). The team applied these five-year growth rates over the same periods through the end of the CPR study period for each residential segment.

Table 2-17 shows the growth rates employed in the CPR study. The growth of single family detached and other residential households is expected to be higher than any other segment.

Table 2-17: Annual Growth Rates by Residential Segment (%)

Region	Segment	CPR Period				Cumulative (2015-2035)
		2014-2020	2021-2025	2026-2030	2031-2035	
Southern Interior	Single Family Detached/Duplexes	0.8%	0.8%	0.7%	0.7%	18%
	Single Family Attached/Row	0.4%	0.5%	0.4%	0.3%	9%
	Apartments <= 4 stories	0.6%	0.8%	0.7%	0.5%	14%
	Apartments > 4 stories	0.6%	0.8%	0.7%	0.5%	14%
	Other Residential	1.3%	0.8%	0.7%	0.5%	19%

Source: Navigant analysis of FortisBC Electric and BC Hydro residential forecasts

Table 2-18 presents the Reference Case forecast of households by segment and region over time. The team initially based the number of residential dwellings presented in Table 2-18 on the base year residential stock determined for 2014, but adjusted these numbers applying the growth rates presented above in Table 2-17.

[11] In relation to the natural turnover of commercial floor stock, Navigant's DSMSim™ model assumes a stock demolition rate of 0.5% per year for commercial and residential segments and 0% for industrial segments. These demolition rates apply to the existing stock in each year of the analysis. A demolition rate of 0.5% is a conservative assumption used to avoid over-estimation of new construction building stock which is driven more largely by new buildings than demolition of old buildings.

Table 2-18: Number of Residential Dwellings by Segment

Region	Segment	CPR Period				
		2014	2020	2025	2030	2035
Southern Interior	Single Family Detached/Duplexes	106,926	112,315	117,134	121,540	125,719
	Single Family Attached/Row	20,077	20,557	21,052	21,500	21,792
	Apartments <= 4 stories	33,033	34,260	35,571	36,755	37,621
	Apartments > 4 stories	2,632	2,730	2,835	2,929	2,998
	Other Residential	8,850	9,563	9,947	10,313	10,564
Total		**171,518**	**179,426**	**186,539**	**193,037**	**198,694**

Source: Navigant analysis of base year residential stock and 2013 CPR

2.2.2.2 Commercial Sector

The first step in developing the commercial Reference Case involved the selection of floor area as the most appropriate driver for electricity consumption in the commercial sector. This section describes the development and application of floor space growth rates for each commercial segment and region over the CPR study period. To develop projections of commercial floor area growth by segment, the team relied on three key resources:

- StatsCan's Labour Force Statistics for British Columbia (*BC Labour Force Statistics*)[12]
- NRCan-Office of Energy Efficiency (OEE) Comprehensive Energy Consumption Database
- FortisBC Electric's 20 Year Load Forecast

The primary resource employed to develop stock growth rates was the BC Labour Force Statistics, which tracks labour force levels for 11 commercial segments and 36 commercial sub-segments across seven economic regions in British Columbia. Two of these seven regions cover the Southern Interior—Thompson/Okanagan and Kootenay. BC Stats uses these statistics to report employment statistics represents the most granular publicly available resource reporting commercial sector trends since 2000. In fact, employment levels can be a stronger predictor of electricity demand than commercial floor space.[13]

Navigant calculated the statistical relationship between labour force levels and commercial floor space to determine the appropriateness of using labour as a proxy for floor space. Commercial floor stock was based on the OEE database, which tracks commercial floor space for 10 commercial segments. Since the OEE reports data at a provincial level and not disaggregated across regions, employment levels were summed across all regions. The team analyzed floor space and labour force levels for the period between 2000 and 2012 for each OEE commercial segment. The table below shows the correlation coefficient

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[12] *CANSIM Labor Force Survey Estimates (LFS) (March 2001 to December 2015)* – Table 282-026

[13] For example, vacant floor space can misrepresent the actual stock of floor space in use. As a result, projections of floor space which account for vacant floor space can skew electricity demand upwards. In Ontario, the Independent Electricity System Operator (IESO) employs a forecasting approach based on employment levels. The IESO utilizes employment figures as an indicator to forecast electricity demand in the near term (i.e., 18-Month Outlook forecasts) and in the long term (i.e., Long Term Energy Plan). The IESO employs non-manufacturing employment levels to forecast demand in the commercial sector, and manufacturing employment for the industrial sector.

corresponding to each segment. Most segments show a strong positive correlation with coefficient values ranging between 0.80 and 0.97.

Table 2-19: Correlation Coefficient (Floor Space vs. Labor Force) – Commercial Sector

OEE Commercial Segment	Correlation Coefficient (2000 – 2012)
Wholesale Trade	0.80
Retail Trade	0.90
Transportation and Warehousing	(0.27)
Information and Cultural Industries	(0.62)
Offices	0.80
Educational Services	0.87
Health Care and Social Assistance	0.95
Arts, Entertainment and Recreation	0.83
Accommodation and Food Services	0.89
Other Services	0.13

Source: Navigant analysis of OEE and StatsCan data

Three of the commercial OEE segments—Transportation and Warehousing, Information and Cultural Industries, and Other Services—are exceptions with a negative correlation or close to no correlation at all. Two of the commercial segments in this CPR—Logistics and Warehousing and Other Commercial— use employment levels derived from these three OEE segments to establish stock growth rates. To avoid the use of poorly correlated variables, the team adjusted the growth rates for these two segments to follow the average growth in electricity consumption across the commercial sector. Navigant mapped the BC Labour Force Statistics to each of the CPR commercial segments and regions in the Reference Case. The team then analyzed labour force growth rates over the 15-year period from 2000 to 2014 to use as a proxy to establish commercial floor space growth rates.

Finally, Navigant analyzed FortisBC Electric's 20 Year Load Forecast—which uses Conference Board of Canada's GDP forecast as its primary driver—to ensure that the stock growth rates applied in the Reference Case aligned with the overall trends in commercial demand projected by FortisBC Electric. The growth rates derived from the BC Labour Force Statistics have only been applied to the first five years of the CPR forecast through 2020. For each subsequent five-year period in the forecast, the team applied an adjustment multiplier to the stock growth rates to align with the 20 Year Load Forecast. For example, the load forecast projects commercial consumption to grow rapidly from 2015 through 2035. The load forecast projects growth rates to peak during the 2020 to 2025 period, decreasing slightly through 2035. The team adjusted the Reference Case growth rates every five-year period to align with these trends in consumption

Table 2-20 presents the growth rates employed in the CPR study for each segment and across time. In general, commercial floor space in colleges/universities, long term care, and hospitals is expected to growth at levels relatively higher than the regional average. These trends in the Southern Interior region are relatively consistent with overall trends in the Lower Mainland, Vancouver Island, and Northern BC. The following paragraphs provide additional information in relation to these three segments:

- **Colleges/Universities:** Historical post-secondary enrollment data from StatsCan shows an average annual growth rate of 3.3% across the province.[14] Enrolment in 2000/2001 was reported at 183,000, growing to approximately 278,000 by 2013/2014. BC Labour Force Statistics show that employment growth rates are highest in the Lower Mainland, and more paced in the Southern Interior, Vancouver Island, and Northern BC.
- **Long Term Care:** BC is experiencing the fastest growth rate of senior citizens across Canada.[15] In absolute numbers, much of this growth is expected in Lower Mainland and Vancouver Island where retirement homes clusters are most predominant. However, in relative terms, growth rates in the Southern Interior and Northern BC will be higher.[16] BC's Ministry of Health forecasts that demand for long-term care facilities will more than double by 2036 as a result projected growth in the senior population over the next 20 years.[17] Based on BC Labour Force Statistics, employment in nursing and residential care facilities more than doubled in the Southern Interior from 3,700 in 2000 to 9,200 in 2014, at an average annual growth rate of 4.8%. Growth in the Long Term Care segment in the Southern Interior is expected to be the highest across all other regions.
- **Hospitals:** The Ministry of Health has identified the province's aging hospital infrastructure and current hospital capacity as critical challenges to meet projected provincial demand over the next two decades.[18] Following hospital closures across the province between 2002 and 2004, employment in healthcare has grown from 69,000 in 2005 to 91,700 in 2014, at an annual growth rate of 3.2%.[19] The Ministry of Health forecasts significant increases in demand in all health services through 2036. Hospital floor space is projected to grow at rates much higher than each regional commercial average, however the growth rate in the Southern Interior is expected to be the lowest across all regions.

Based on the growth rate presented in Table 2-20, the estimated stock of commercial floor space over time is shown in Table 2-21. The stock of commercial floor space presented in Table 2-21 is initially based on the base year commercial stock determined for 2014, and has been adjusted in future years by applying the growth rates identified in Table 2-20.

[14] Statistic Canada. Table 477-0019. Postsecondary enrolments from 2000/2001 to 2013/2014.
[15] British Columbia. Ministry of Health. (2014). Setting priorities for the B.C. health system. Retrieved from http://www.health.gov.bc.ca/library/publications/year/2014/Setting-priorities-BC-Health-Feb14.pdf
[16] Office of the Senior's Advocate. May 2015. *"Senior's Housing in BC"*. Available: https://www.seniorsadvocatebc.ca/wp-content/uploads/sites/4/2015/05/Seniors-Housing-in-B.C.-Affordable-Appropriate-Available.pdf
[17] Marowitz, Ross. June 2015. The Canadian Press. *"Canada's Next Boom Industry? Retirement Homes, Developer Says"*. Available: http://www.huffingtonpost.ca/2015/06/17/quebec-developer-forecast_n_7603704.html
[18] Ministry of Health (2014)
[19] Cohen, March. July 2012. BC Health Coalition. *"Caring for BC's Aging Population".* Available: https://www.policyalternatives.ca/sites/default/files/uploads/publications/BC%20Office/2012/07/CCPABC-Caring-BC-Aging-Pop.pdf

Table 2-20: Annual Growth Rates by Commercial Floor Space Segment (%)

Region	Segment	CPR Period				Cumulative (2015-2035)
		2014-2020	2021-2025	2026-2030	2031-2035	
Southern Interior	Accommodation	2.4%	3.1%	2.8%	2.5%	75%
	Colleges/Universities	1.9%	2.4%	2.2%	2.0%	56%
	Food Service	1.8%	2.2%	2.0%	1.8%	49%
	Hospital	2.8%	3.5%	3.2%	2.9%	89%
	Logistics/Warehouses	1.9%	2.4%	2.2%	1.9%	54%
	Long Term Care	4.7%	5.9%	5.4%	4.8%	188%
	Office	1.9%	2.4%	2.2%	2.0%	56%
	Other Commercial	1.9%	2.4%	2.2%	1.9%	54%
	Retail - Food	1.4%	1.8%	1.6%	1.4%	38%
	Retail - Non Food	0.7%	0.9%	0.8%	0.7%	17%
	Schools	0.9%	1.1%	1.0%	0.9%	22%

Source: Navigant analysis of StatsCan Labour Market Statistics (CANSIM Table 282-026)

Table 2-21: Commercial Floor Space by Segment by Region (million m^2)

Region	Segment	CPR Period				
		2014	2020	2025	2030	2035
Southern Interior	Accommodation	1.01	1.16	1.35	1.55	1.76
	Colleges/Universities	0.27	0.30	0.34	0.38	0.42
	Food Service	0.24	0.26	0.29	0.33	0.36
	Hospital	0.29	0.34	0.40	0.47	0.55
	Logistics/Warehouses	0.48	0.53	0.60	0.67	0.74
	Long Term Care	0.23	0.30	0.40	0.52	0.66
	Office	1.20	1.35	1.52	1.70	1.87
	Other Commercial	1.37	1.54	1.73	1.92	2.12
	Retail - Food	0.20	0.22	0.24	0.26	0.28
	Retail - Non Food	1.39	1.45	1.52	1.58	1.63
	Schools	0.41	0.43	0.46	0.48	0.50
Total		**7.09**	**7.90**	**8.85**	**9.86**	**10.88**

Source: Navigant analysis of StatsCan Labour Market Statistics and FortisBC Electric Load Forecast

2.2.2.3 Industrial Sector

The first step in developing the industrial Reference Case involved the development and application of growth rates of electricity demand for each industrial segment and region over the CPR study period. The team derived the demand growth rates employed in the CPR based on two resources provided by FortisBC Electric:

- The 20-Year Load Forecast (which contains a sector-level forecast through 2035)
- A short-term, segment-level forecast through 2021 (the “Short Term” forecast)[20]

The team determined segment-specific demand growth rates up to 2021 using the Short Term. Navigant used the Short Term forecast growth rates and projected them forward through 2035 by applying an adjustment multiplier to the Short Term forecast growth rates over each subsequent five-year period. The resulting forecast shows a decrease in the growth of industrial demand over time. Specifically, an adjustment multiplier of 75% was applied for 2021-2025; a multiplier of 50% for 2026-2030; and 25% for 2031-2035.[21]

Table 2-22 presents the demand growth rates employed in the CPR study. Broadly speaking, the demand growth rates for the industrial sector exhibit much greater fluctuation across segments and over time than the commercial and residential sectors. The primary reason is that industrial segments are tightly dependent on global commodity markets and demand-supply conditions beyond the Canadian context. As a result, the price of natural gas, oil, coal, and wood/lumber can significantly affect the economic output of certain industrial sectors. There are three general trends in relation to the projected growth rates within the industrial sector:

- **Resource-dependent industries** such as the mining and energy sectors are much more sensitive to primary cost drivers (timber prices, labour costs) and are influenced by macroeconomic conditions, imports/exports, and global markets. These segments include coal and metal mining, oil and gas, and LNG facilities. In the near term, resource-dependent industries are expected to experience substantial growth. The majority of this growth will take place in Northern BC, driven primarily by gold, copper, and nickel mining and LNG export facilities. FortisBC Electric serves industrial customers in the metal mining segment, however little growth is projected over time. Further, these segments represent less than 10% of total industrial demand, as shown by Table 2-23.
- **Non-resource-dependent industries** are less influenced by commodity prices. These industries include food & beverage, manufacturing, and “other” industrial. Combined, these segments represent about 25% of total industrial demand.
- The **pulp & paper and wood products** industries in BC have been struggling over the last decade as a result of lower prices and reduced global demand. Adoption of cogeneration contributed to the historical decline in electricity demand. However, since self-generation is reflected in this study, any decrease in sales from FortisBC Electric as a result of cogeneration adoption would be accounted for by increased self-generation loads. In the Southern Interior, some of the recent decline in wood products is a result of closures of two sizeable sawmills. FortisBC Electric’s forecast does not project any major changes in pulp & paper moving forward, however the wood products segment is projected to grow significantly. The agriculture segment is expected to decline steadily through 2035.

The growth rates presented in Table 2-22 lead to the estimated industrial consumption shown in Table 2-23. The industrial demand in Table 2-23 is initially based on the base year consumption, and has been adjusted in future years by applying the growth rates identified in

[20] FortisBC Electric’s *Short Term* industrial forecast is based on a customer survey of large power customers supplied by FortisBC Electric.
[21] Consistent with the approach for BC Hydro, Navigant developed a forecast of self-generated by applying the growth rates of electricity consumption corresponding to the industrial segment where electricity was self-generated

Table 2-22.

Table 2-22: Annual Growth Rates by Industrial Segment (%)

Region	Segment	CPR Period				Cumulative (2015-2035)
		2014-2020	2021-2025	2026-2030	2031-2035	
Southern Interior	Agriculture	0.3%	0.0%	0.0%	0.0%	2%
	Cement	-	-	-	-	-
	Chemical	-	-	-	-	-
	Mining - Coal	-	-	-	-	-
	Food & Beverage	0.1%	0.5%	0.2%	0.2%	5%
	Greenhouses	-	-	-	-	-
	LNG Facilities	-	-	-	-	-
	Manufacturing	1.5%	-0.6%	0.3%	1.8%	18%
	Mining - Metal	0.2%	0.5%	0.2%	0.2%	6%
	Oil and Gas	-1.6%	-0.7%	-1.0%	-0.9%	-20%
	Pulp & Paper - Kraft	-0.2%	0.0%	-0.1%	-0.1%	-2%
	Pulp & Paper - TMP	-	-	-	-	-
	Transportation	-	-	-	-	-
	Wood Products	3.5%	2.8%	2.6%	2.2%	79%
	Other Industrial	-0.2%	0.3%	0.0%	0.0%	0%

Source: Navigant analysis of FortisBC Electric load forecast

Table 2-23: Industrial Electricity Demand by Segment (GWh)

Region	Segment	CPR Period				
		2014	2020	2025	2030	2035
Southern Interior	Agriculture	46	47	47	47	47
	Cement	-	-	-	-	-
	Chemical	-	-	-	-	-
	Mining - Coal	-	-	-	-	-
	Food & Beverage	37	37	38	38	39
	Greenhouses	-	-	-	-	-
	LNG Facilities	-	-	-	-	-
	Manufacturing	168	183	178	181	197
	Mining - Metal	71	72	74	75	75
	Oil and Gas	6	5	5	5	4
	Pulp & Paper - Kraft	365	361	362	360	359
	Pulp & Paper - TMP	-	-	-	-	-
	Transportation	-	-	-	-	-
	Wood Products	159	196	225	256	286
	Other Industrial	22	22	22	22	22
Total		**874**	**923**	**951**	**984**	**1,030**

Source: Navigant analysis of FortisBC Electric load forecast

2.2.3 EUI Trends

This section discusses the EUI trends across the residential, commercial, and industrial sectors.

2.2.3.1 Residential Sector

The next step in building the residential sector Reference Case involved the development and application of EUI trends over the CPR study period. The main resource informing the change in EUIs over time was the BC Hydro 2014 REUS study, which included fuel and equipment shares for 2002, 2005, 2007 and 2014. Navigant used this data to calculate an average annual rate of change for each EUI.[22]

To determine the change in EUI trends over time, the team analyzed FortisBC Electric's load forecast. The analysis of the load forecast ensured that the Reference Case residential consumption, determined based on the growing residential stock and the EUI trends, aligned with the forecast of residential consumption, reported in FortisBC Electric's load forecast. Navigant made these adjustments to the EUI trends across every five-year period of the CPR analysis horizon.

Based on this analysis, the team applied the EUI trends from the REUS analysis to the first five years of the CPR period, and systematically decreased the magnitude of EUI trends over the subsequent five-year periods in order for the Reference Case forecast to match the load forecast in 2035. Specifically, the EUI trends decrease by a factor of 40% every five-year period. [23]

Table 2-24 shows the EUI trends determined for each residential segment and end-use over time, and Table 2-25 provides the resulting EUIs for each five-year period. Navigant based the EUIs presented in Table 2-25 on the base year EUIs (for 2014) and adjusted them with the EUI trends identified in Table 2-24.

As Table 2-24 indicates, expected electricity consumption for most end-uses will increase over the CPR period. Current trends suggest the most significant EUI changes will come from space heating, space cooling, water heating, appliances and lighting. Trends show electricity intensity from space heating, space cooling, and water heating increasing at relatively higher rates than other end-uses. In contrast, electricity intensity from appliances and lighting are likely to decrease. In general, the magnitude of the expected annual change in EUIs is greater in the near term and will decrease over time.

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[22] A limitation of this approach is that the REUS data reflects, among other factors, the impact of provincial and federal DSM programs while the objective of this analysis is to trend natural change in EUIs in the absence of DSM impacts. The impact of this limitation on the study is that the EUI trends established for each residential end-use may be overstated, which may affect the overall results of this study. Additionally, this EUI trending approach inherently reflects both new and existing buildings because the residential customers surveyed as part of the 2014 REUS would include both existing and new residential buildings.

[23] For example, if the EUI trend determined from the REUS was a 1.0% decrease in EUI per year, the team applied 1.0% per year from 2015 through 2020, 0.6% per year from 2021 through 2025, 0.36% per year from 2026 through 2030, and 0.22% per year from 2031 through 2035.

- **Space heating** – The use of natural gas for space heating has continued a small downward trend over the past decade—primarily in single detached homes and apartment units—resulting in an increase in the electric space heating EUI.
- **Water Heating** – Electricity consumption from water heating is expected to increase across most segments as a result of increased penetration of electric water heaters. The trend is most prevalent in single detached and attached homes.
- **Space cooling** –. Electricity consumption in space cooling is expected to increase: it is the fastest growing end-use and similar in growth to electronics.
- **Appliances** – Forecasts indicate appliance electricity consumption will continue to decrease over time. Codes and standards have targeted large, energy-intensive appliances such as clothes washers and refrigerators. However, an increase in the number of minor appliances will continue to offset some of these savings.
- **Lighting** – Electricity consumption from lighting loads has decreased steadily as the market share of more energy efficient lighting products has grown over time. Declining household sizes, partly due to the growth of high-rise apartment buildings, has also decreased lighting consumption on average. Forecasts show codes and standards will continue to drive this trend.

As noted for some of these end-uses, the change in electricity consumption over time is also reflective of changing fuel shares for individual residential segments.

Table 2-24: Residential Electricity Intensity Trends (%)

Residential Segment	End-Use	CPR Period			
		2014-2020	2021-2025	2026-2030	2031-2035
Single Family Detached/Duplexes	Space Heating	1.0%	0.6%	0.4%	0.2%
	Water Heating	1.1%	0.6%	0.4%	0.2%
	Cooling	1.4%	0.8%	0.5%	0.3%
	Appliances	-1.2%	-0.7%	-0.4%	-0.2%
	Lighting	-1.5%	-0.9%	-0.6%	-0.3%
	Electronics	1.3%	0.8%	0.5%	0.3%
	Other	-1.1%	-0.7%	-0.4%	-0.2%
	Ventilation	1.0%	0.6%	0.4%	0.2%
Single Family Attached/Row	Space Heating	0.4%	0.2%	0.1%	0.1%
	Water Heating	0.5%	0.3%	0.2%	0.1%
	Cooling	1.3%	0.8%	0.5%	0.3%
	Appliances	-0.8%	-0.5%	-0.3%	-0.2%
	Lighting	-1.7%	-1.0%	-0.6%	-0.4%
	Electronics	1.3%	0.8%	0.5%	0.3%
	Other	-1.1%	-0.7%	-0.4%	-0.2%
	Ventilation	0.4%	0.2%	0.1%	0.1%
Apartments <= 4 stories	Space Heating	0.8%	0.5%	0.3%	0.2%
	Water Heating	0.3%	0.2%	0.1%	0.1%
	Cooling	1.4%	0.8%	0.5%	0.3%
	Appliances	-0.4%	-0.3%	-0.2%	-0.1%
	Lighting	-2.2%	-1.3%	-0.8%	-0.5%
	Electronics	1.3%	0.8%	0.5%	0.3%
	Other	-1.1%	-0.7%	-0.4%	-0.2%
	Ventilation	0.8%	0.5%	0.3%	0.2%
Apartments > 4 stories	Space Heating	0.8%	0.5%	0.3%	0.2%
	Water Heating	0.3%	0.2%	0.1%	0.1%
	Cooling	1.4%	0.8%	0.5%	0.3%
	Appliances	-0.4%	-0.3%	-0.2%	-0.1%
	Lighting	-2.2%	-1.3%	-0.8%	-0.5%
	Electronics	1.3%	0.8%	0.5%	0.3%
	Other	-1.1%	-0.7%	-0.4%	-0.2%
	Ventilation	0.8%	0.5%	0.3%	0.2%
Other Residential	Space Heating	1.3%	0.8%	0.5%	0.3%
	Water Heating	-0.2%	-0.1%	-0.1%	0.0%
	Cooling	0.8%	0.5%	0.3%	0.2%
	Appliances	-1.0%	-0.6%	-0.4%	-0.2%
	Lighting	-1.8%	-1.1%	-0.6%	-0.4%
	Electronics	1.3%	0.8%	0.5%	0.3%
	Other	-1.1%	-0.7%	-0.4%	-0.2%
	Ventilation	1.4%	0.8%	0.5%	0.3%

Source: Navigant analysis of BC Hydro's 2014 REUS, FortisBC Electric Residential Load Forecast

Table 2-25: Residential Electricity Intensity (kWh/household) – Southern Interior

Residential Segment	End-Use	CPR Period				
		2014	2020	2025	2030	2035
Single Family Detached/Duplexes	Space Heating	2,988	3,167	3,261	3,319	3,354
	Hot Water	1,206	1,285	1,326	1,352	1,368
	Cooling/Refrigeration	258	280	292	300	304
	Appliances	3,355	3,130	3,023	2,961	2,924
	Lighting	1,952	1,779	1,698	1,652	1,625
	Electronics	1,510	1,627	1,689	1,728	1,751
	Other	1,007	943	912	894	884
	Ventilation	923	982	1,013	1,032	1,044
	Total	**13,198**	**13,193**	**13,216**	**13,238**	**13,254**
Single Family Attached/Row	Space Heating	1,747	1,785	1,804	1,816	1,823
	Hot Water	940	971	987	997	1,003
	Cooling/Refrigeration	172	186	194	199	201
	Appliances	2,234	2,126	2,074	2,044	2,026
	Lighting	1,323	1,191	1,130	1,095	1,075
	Electronics	782	843	875	895	907
	Other	447	418	405	397	392
	Ventilation	810	829	839	844	848
	Total	**8,455**	**8,350**	**8,308**	**8,287**	**8,275**
Apartments <= 4 stories	Space Heating	1,749	1,832	1,875	1,902	1,918
	Hot Water	1,191	1,214	1,226	1,233	1,237
	Cooling/Refrigeration	157	171	178	183	186
	Appliances	1,852	1,806	1,784	1,770	1,762
	Lighting	941	821	767	736	719
	Electronics	1,019	1,098	1,140	1,166	1,182
	Other	741	694	671	658	651
	Ventilation	607	637	653	663	669
	Total	**8,257**	**8,273**	**8,294**	**8,311**	**8,323**
Apartments > 4 stories	Space Heating	1,935	2,027	2,074	2,103	2,121
	Hot Water	1,105	1,126	1,137	1,144	1,148
	Cooling/Refrigeration	146	159	165	170	172
	Appliances	1,868	1,822	1,799	1,785	1,777
	Lighting	873	762	712	683	667
	Electronics	1,028	1,107	1,150	1,176	1,192
	Other	560	525	508	498	492
	Ventilation	768	807	827	839	847
	Total	**8,282**	**8,333**	**8,371**	**8,398**	**8,416**
Other Residential	Space Heating	1,988	2,145	2,228	2,280	2,311
	Hot Water	1,975	1,953	1,942	1,936	1,932
	Cooling/Refrigeration	378	397	407	413	416
	Appliances	2,499	2,353	2,284	2,243	2,219
	Lighting	1,172	1,053	998	967	948
	Electronics	875	943	979	1,001	1,014
	Other	500	468	453	444	439
	Ventilation	372	403	420	431	437
	Total	**9,759**	**9,715**	**9,711**	**9,714**	**9,718**

Source: Navigant analysis of base year EUIs, BC Hydro's 2014 REUS, and FortisBC Electric load forecast

2.2.3.2 Commercial Sector

The next step in building the commercial sector Reference Case involved the development and application of EUI trends over the CPR study period. To develop EUI trends for the commercial sector Reference Case, Navigant analyzed BC Hydro's 2014 CEUS study. The 2014 CEUS surveyed commercial customers in relation to upgrades made to end-use equipment in the past 5 years.[24] Based on the incidence of equipment upgrades made to specific end-uses (e.g., space cooling vs. space heating), Navigant estimated the potential reduction in energy consumption from higher efficiency equipment. This approach is described in more detail in Appendix B.3. [25]

This analysis resulted in EUI trends for all the end-uses for which equipment upgrade information was reported in 2014 CEUS. [26] This included the following end-uses:

- Lighting
- Water heating
- Space cooling
- HVAC fans/pumps
- Space heating

Similar to the residential sector, Navigant analyzed FortisBC Electric's load forecast to determine the commercial EUI trends. This ensured that the Reference Case commercial consumption—determined based on the commercial floor space stock and the EUI trends—aligned with the total forecast of regional commercial consumption reported in FortisBC Electric's load forecast.

Based on this analysis, the commercial EUI trends determined from the CEUS analysis are applied to the first five years of the analysis, and decrease over the subsequent five-year periods. Specifically, the EUI trends decrease by a factor of 50% every five-year period. This 50% reduction in EUI trends enables the Reference Case commercial consumption to match the regional total load forecast consumption in 2035.

Table 2-26 shows the EUI trends for each commercial segment and end-use, and Table 2-27 shows the resulting EUIs over five-year intervals. The EUIs presented in Table 2-27 were initially based on the base year EUIs (for 2014) and have been adjusted by applying the EUI trends identified in Table 2-26.

As seen in Table 2-26, electricity consumption from five end-uses is projected to decrease over the CPR period, and the remainder stay constant. Current trends indicate the most significant EUI changes are expected to involve HVAC fans/pumps, lighting and space heating. Hot water and space cooling EUIs are also expected to decline over time, however, at lower rates.

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[24] For example, the incidence of space cooling equipment upgrades within the past 5 years was 28% across the commercial sector. The incidence of space cooling upgrades varied across commercial segments (e.g., 32% in Offices, 7% in Long Term Care).

[25] As with the residential sector, a limitation of this approach is that the CEUS data reflects, among other factors, the impact of provincial and federal commercial DSM programs while the objective of this analysis is to trend natural change in EUIs in the absence of DSM impacts. The impact of this limitation on the study is that the EUI trends established for these commercial end-uses may be overstated, which may affect the overall results of this study. Additionally, this EUI trending approach inherently reflects both new and existing buildings because commercial customers surveyed as part of the 2014 CEUS would include both existing and new buildings.

[26] The 2014 CEUS did not report equipment upgrade information for the cooking, refrigeration, and office equipment end-uses.

These changes in EUIs over time implicitly reflect natural changes in electricity end-use consumption caused by naturally occurring improvements in end-use equipment efficiency and saturation levels, fuel switching, and retrofit initiatives.

Natural changes in electricity end-use consumption in the commercial sector are generally different than most trends in the residential sector. Electricity consumption across all commercial end-uses is projected to decrease on a kWh/m2-basis, compared to consumption in the residential sector, where most end-uses are projected to increase consumption on a kWh/household-basis. Additionally, compared with the wide variation in EUI trends observed across residential segments, EUI trends across all commercial segments varied only slightly. Energy efficient improvements driven by initiatives like ENERGY STAR and government and corporate environmental and sustainability initiatives will influence EUI trends. While the impact of these two energy performance initiatives remains limited, they are likely to increase adoption of commercial envelope measures and higher efficiency space heating, lighting, and space cooling equipment.

Table 2-26: Commercial Electricity Intensity Trends (%)

Commercial Segment	End-Use	CPR Period			
		2014-2020	2021-2025	2026-2030	2031-2035
Accommodation	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-0.5%	-0.2%	-0.1%	-0.1%
	Hot Water	-0.4%	-0.2%	-0.1%	0.0%
	Lighting	-1.7%	-0.8%	-0.4%	-0.2%
	Office Equipment	0.0%	0.0%	0.0%	0.0%
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	0.0%	0.0%	0.0%	0.0%
	Space Cooling	-0.3%	-0.2%	-0.1%	0.0%
	Space Heating	-1.0%	-0.5%	-0.3%	-0.1%
Colleges/ Universities	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-1.3%	-0.6%	-0.3%	-0.2%
	Hot Water	-0.5%	-0.3%	-0.1%	-0.1%
	Lighting	-1.3%	-0.7%	-0.3%	-0.2%
	Office Equipment	0.0%	0.0%	0.0%	0.0%
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	0.0%	0.0%	0.0%	0.0%
	Space Cooling	-0.3%	-0.1%	-0.1%	0.0%
	Space Heating	-1.1%	-0.6%	-0.3%	-0.1%
Food Service	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-0.9%	-0.4%	-0.2%	-0.1%
	Hot Water	-0.5%	-0.2%	-0.1%	-0.1%
	Lighting	-1.8%	-0.9%	-0.5%	-0.2%
	Office Equipment	0.0%	0.0%	0.0%	0.0%
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	0.0%	0.0%	0.0%	0.0%
	Space Cooling	-0.5%	-0.2%	-0.1%	-0.1%
	Space Heating	-1.2%	-0.6%	-0.3%	-0.2%
Hospital	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-1.2%	-0.6%	-0.3%	-0.1%
	Hot Water	-0.3%	-0.2%	-0.1%	0.0%
	Lighting	-1.6%	-0.8%	-0.4%	-0.2%
	Office Equipment	0.0%	0.0%	0.0%	0.0%
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	0.0%	0.0%	0.0%	0.0%
	Space Cooling	-0.6%	-0.3%	-0.2%	-0.1%
	Space Heating	-1.1%	-0.5%	-0.3%	-0.1%
Logistics/ Warehouses	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-0.7%	-0.3%	-0.2%	-0.1%
	Hot Water	-0.3%	-0.2%	-0.1%	0.0%
	Lighting	-1.6%	-0.8%	-0.4%	-0.2%
	Office Equipment	0.0%	0.0%	0.0%	0.0%
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	0.0%	0.0%	0.0%	0.0%
	Space Cooling	-0.5%	-0.3%	-0.1%	-0.1%
	Space Heating	-0.8%	-0.4%	-0.2%	-0.1%
Long Term Care	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-0.4%	-0.2%	-0.1%	0.0%
	Hot Water	-0.4%	-0.2%	-0.1%	-0.1%
	Lighting	-1.2%	-0.6%	-0.3%	-0.2%
	Office Equipment	0.0%	0.0%	0.0%	0.0%
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	0.0%	0.0%	0.0%	0.0%
	Space Cooling	-0.1%	-0.1%	0.0%	0.0%
	Space Heating	-1.1%	-0.6%	-0.3%	-0.1%
Office	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-1.1%	-0.6%	-0.3%	-0.1%
	Hot Water	-0.2%	-0.1%	0.0%	0.0%
	Lighting	-1.7%	-0.8%	-0.4%	-0.2%
	Office Equipment	0.0%	0.0%	0.0%	0.0%
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	0.0%	0.0%	0.0%	0.0%

Commercial Segment	End-Use	CPR Period			
		2014-2020	2021-2025	2026-2030	2031-2035
	Space Cooling	-0.7%	-0.3%	-0.2%	-0.1%
	Space Heating	-1.1%	-0.5%	-0.3%	-0.1%
Other Commercial	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-1.1%	-0.6%	-0.3%	-0.1%
	Hot Water	-0.2%	-0.1%	0.0%	0.0%
	Lighting	-1.7%	-0.8%	-0.4%	-0.2%
	Office Equipment	0.0%	0.0%	0.0%	0.0%
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	0.0%	0.0%	0.0%	0.0%
	Space Cooling	-0.7%	-0.3%	-0.2%	-0.1%
	Space Heating	-1.1%	-0.5%	-0.3%	-0.1%
Retail - Food	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-1.1%	-0.5%	-0.3%	-0.1%
	Hot Water	-0.4%	-0.2%	-0.1%	-0.1%
	Lighting	-2.0%	-1.0%	-0.5%	-0.2%
	Office Equipment	0.0%	0.0%	0.0%	0.0%
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	0.0%	0.0%	0.0%	0.0%
	Space Cooling	-0.7%	-0.3%	-0.2%	-0.1%
	Space Heating	-1.3%	-0.7%	-0.3%	-0.2%
Retail – Non Food	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-1.1%	-0.5%	-0.3%	-0.1%
	Hot Water	-0.4%	-0.2%	-0.1%	-0.1%
	Lighting	-2.0%	-1.0%	-0.5%	-0.2%
	Office Equipment	0.0%	0.0%	0.0%	0.0%
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	0.0%	0.0%	0.0%	0.0%
	Space Cooling	-0.7%	-0.3%	-0.2%	-0.1%
	Space Heating	-1.3%	-0.7%	-0.3%	-0.2%
Schools	Cooking	0.0%	0.0%	0.0%	0.0%
	HVAC Fans/Pumps	-0.7%	-0.4%	-0.2%	-0.1%
	Hot Water	-0.3%	-0.1%	-0.1%	0.0%
	Lighting	-2.2%	-1.1%	-0.5%	-0.3%
	Office Equipment	0.0%	0.0%	0.0%	0.0%
	Other	0.0%	0.0%	0.0%	0.0%
	Refrigeration	0.0%	0.0%	0.0%	0.0%
	Space Cooling	-0.2%	-0.1%	-0.1%	0.0%
	Space Heating	-1.1%	-0.5%	-0.3%	-0.1%

Source: Navigant analysis of NRCan-OEE and FortisBC Electric 2015 Load Forecast

Table 2-27: Commercial Electricity Intensity (kWh/m2) – Southern Interior

Commercial Segment	End-Use	CPR Period				
		2014	2020	2025	2030	2035
Accommodation	Cooking	1	1	1	1	1
	HVAC Fans/Pumps	24	23	23	23	23
	Hot Water	3	3	3	3	3
	Lighting	53	47	45	44	44
	Office Equipment	9	9	9	9	9
	Other	8	8	8	8	8
	Refrigeration	2	2	2	2	2
	Space Cooling	6	6	6	6	6
	Space Heating	4	4	4	4	4
	Total	**110**	**104**	**102**	**100**	**100**
Colleges/ Universities	Cooking	1	1	1	1	1
	HVAC Fans/Pumps	66	61	59	58	58
	Hot Water	4	4	4	4	4
	Lighting	80	74	71	70	70
	Office Equipment	13	13	13	13	13
	Other	12	12	12	12	12
	Refrigeration	1	1	1	1	1
	Space Cooling	5	5	5	5	5
	Space Heating	5	5	5	5	5
	Total	**187**	**175**	**171**	**169**	**168**
Food Service	Cooking	13	13	13	13	13
	HVAC Fans/Pumps	44	42	41	41	41
	Hot Water	26	26	25	25	25
	Lighting	102	91	87	85	84
	Office Equipment	1	1	1	1	1
	Other	49	49	49	49	49
	Refrigeration	12	12	12	12	12
	Space Cooling	35	34	34	33	33
	Space Heating	7	6	6	6	6
	Total	**288**	**273**	**267**	**264**	**263**
Hospitals	Cooking	3	3	3	3	3
	HVAC Fans/Pumps	57	54	52	51	51
	Hot Water	0	0	0	0	0
	Lighting	73	66	64	62	62
	Office Equipment	4	4	4	4	4
	Other	54	54	54	54	54
	Refrigeration	3	3	3	3	3
	Space Cooling	12	12	11	11	11
	Space Heating	11	10	10	10	10
	Total	**217**	**205**	**201**	**198**	**197**
Logistics/ Warehouses	Cooking	0	0	0	0	0
	HVAC Fans/Pumps	11	10	10	10	10
	Hot Water	1	1	1	1	1
	Lighting	40	36	35	34	34
	Office Equipment	2	2	2	2	2
	Other	17	17	17	17	17
	Refrigeration	7	7	7	7	7
	Space Cooling	3	3	3	3	3
	Space Heating	3	3	3	2	2
	Total	**83**	**79**	**77**	**76**	**76**
Long Term Care	Cooking	3	3	3	3	3
	HVAC Fans/Pumps	29	28	28	28	28
	Hot Water	4	4	3	3	3
	Lighting	49	46	44	43	43
	Office Equipment	2	2	2	2	2
	Other	11	11	11	11	11
	Refrigeration	2	2	2	2	2
	Space Cooling	5	4	4	4	4
	Space Heating	13	12	12	12	12
	Total	**117**	**112**	**110**	**109**	**108**
Office	Cooking	0	0	0	0	0

Commercial Segment	End-Use	CPR Period				
		2014	2020	2025	2030	2035
	HVAC Fans/Pumps	32	30	29	28	28
	Hot Water	2	2	2	2	2
	Lighting	58	52	50	49	49
	Office Equipment	9	9	9	9	9
	Other	15	15	15	15	15
	Refrigeration	0	0	0	0	0
	Space Cooling	8	8	8	8	8
	Space Heating	2	2	2	2	2
	Total	**127**	**119**	**116**	**114**	**113**
Other Commercial	Cooking	0	0	0	0	0
	HVAC Fans/Pumps	35	33	32	31	31
	Hot Water	2	2	2	2	2
	Lighting	32	29	27	27	27
	Office Equipment	1	1	1	1	1
	Other	9	9	9	9	9
	Refrigeration	12	12	12	12	12
	Space Cooling	4	3	3	3	3
	Space Heating	2	2	2	2	2
	Total	**97**	**92**	**89**	**88**	**88**
Retail - Food	Cooking	2	2	2	2	2
	HVAC Fans/Pumps	33	31	30	30	30
	Hot Water	4	3	3	3	3
	Lighting	113	100	95	93	91
	Office Equipment	0	0	0	0	0
	Other	26	26	26	26	26
	Refrigeration	204	204	204	204	204
	Space Cooling	5	4	4	4	4
	Space Heating	1	1	1	1	1
	Total	**387**	**371**	**365**	**363**	**361**
Retail – Non Food	Cooking	0	0	0	0	0
	HVAC Fans/Pumps	17	16	15	15	15
	Hot Water	1	1	1	1	1
	Lighting	67	60	57	55	55
	Office Equipment	2	2	2	2	2
	Other	24	24	24	24	24
	Refrigeration	1	1	1	1	1
	Space Cooling	6	5	5	5	5
	Space Heating	2	2	2	2	2
	Total	**120**	**111**	**107**	**105**	**105**
Schools	Cooking	1	1	1	1	1
	HVAC Fans/Pumps	21	20	19	19	19
	Hot Water	1	1	1	1	1
	Lighting	37	33	31	30	30
	Office Equipment	2	2	2	2	2
	Other	16	16	16	16	16
	Refrigeration	0	0	0	0	0
	Space Cooling	2	2	2	2	2
	Space Heating	3	3	3	3	3
	Total	**83**	**77**	**75**	**74**	**73**

Source: Navigant analysis of NRCan-OEE and FortisBC Electric 2015 Load Forecast

2.2.3.3 Industrial Sector

Discussions between Navigant and CLEAResult concluded "natural" change in industrial energy efficiency would be minimal over the study horizon. This assumption is consistent with past CPRs, which forecasted very small changes in industrial EUIs over a 20-year forecast horizon (typically only a few percent over 20 years)[27]. Given the expected small magnitude of natural change in industrial EUIs, inherent EUI forecasting uncertainty and limited historical data availability for industrial EUIs, this study assumes that EUIs in the industrial sector will remain constant in the absence of conservation programs.

The outline below details key considerations for the industrial consumption forecast.

- **Resource-extraction industries** are much more sensitive to primary cost drivers (timber prices, labour costs), suggesting their consumption is not strongly dependent on electricity prices. The prime reason for upgrading equipment is for increasing production, market expansion, or new product lines, rather than to increase energy efficiency.
- **Non-resource-extraction industries** are unlikely to experience significant changes in EUIs. Many of these customers, particularly food & beverage and manufacturing customers, operate smaller facilities and the tendency is not to invest capital upgrading older facilities but rather in expanding or building new plants.
- The **pulp & paper and wood products** consumption has been declining steadily over the past decade. These industrial segments are projected to continue declining through 2020, particularly in other regions where much of the industry is concentrated. Capital constraints in this segment limit the opportunities for energy efficiency. These industries, in addition to the chemical and cement sector, consist mainly of older plants and for several years customers have shown reluctance to upgrade to more efficient equipment because of uncertain market conditions.

Although industrial EUIs are assumed to remain consistent, this study represents industrial energy demand (analogous to production levels) as an index that begins at 1.0 in 2014 and grows or declines in accordance with expected trends in demand, or production. These production levels are analogous to building stocks and are multiplied by EUIs to determine consumption in a given year.

2.2.4 Reference Case Forecast and Comparison with Utility Forecast

This section provides the final Reference Case forecast and compares the sector-level results of the Reference Case forecast with FortisBC Electric's load forecast.

2.2.4.1 Reference Case Forecast

Table 2-28 summarizes the results of the Reference Case for each sector and customer segment. Navigant computed these results by applying the stock growth rates and the EUI trends established in previous sections for each customer segment to the base year results. This table includes both FortisBC Electric sales and self-generated electricity.

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[27] The base year analysis did not characterize industrial consumption on a per-unit basis, as was done for the residential sector (kWh or GJ *per* household) and commercial sector (kWh or GJ *per* m2). As a result, Industrial EUIs are expressed directly in units of MWh.

Table 2-28: Reference Case Forecast by Segment (TWh) – Include Self-Generation

Sector	Segment	CPR Period				
		2014	2020	2025	2030	2035
Residential	Single Family Detached	1.41	1.48	1.55	1.61	1.67
	Single Family Attached/Row	0.17	0.17	0.17	0.18	0.18
	Apartments <= 4 stories	0.27	0.28	0.30	0.31	0.31
	Apartments > 4 stories	0.02	0.02	0.02	0.02	0.03
	Other Residential	0.09	0.09	0.10	0.10	0.10
	Total	**1.96**	**2.05**	**2.14**	**2.22**	**2.29**
Commercial	Accommodation	0.11	0.12	0.14	0.16	0.18
	Colleges/Universities	0.05	0.05	0.06	0.06	0.07
	Food Service	0.07	0.07	0.08	0.09	0.09
	Hospital	0.06	0.07	0.08	0.09	0.11
	Logistics/Warehouses	0.04	0.04	0.05	0.05	0.06
	Long Term Care	0.03	0.03	0.04	0.06	0.07
	Office	0.15	0.16	0.18	0.19	0.21
	Other Commercial	0.13	0.14	0.15	0.17	0.19
	Retail - Food	0.08	0.08	0.09	0.09	0.10
	Retail - Non Food	0.17	0.16	0.16	0.17	0.17
	Schools	0.03	0.03	0.03	0.04	0.04
	Street Lights	0.02	0.02	0.02	0.02	0.02
	Total	**0.94**	**0.99**	**1.08**	**1.19**	**1.30**
Industrial	Agriculture	0.05	0.05	0.05	0.05	0.05
	Cement	-	-	-	-	-
	Chemical	-	-	-	-	-
	Mining - Coal	-	-	-	-	-
	Food & Beverage	0.04	0.04	0.04	0.04	0.04
	Greenhouses	-	-	-	-	-
	LNG Facilities	-	-	-	-	-
	Manufacturing	0.17	0.18	0.18	0.18	0.20
	Mining - Metal	0.07	0.07	0.07	0.07	0.08
	Oil and Gas	0.01	0.01	0.00	0.00	0.00
	Pulp & Paper - Kraft	0.37	0.36	0.36	0.36	0.36
	Pulp & Paper - TMP	-	-	-	-	-
	Transportation	-	-	-	-	-
	Wood Products	0.16	0.20	0.23	0.26	0.29
	Other Industrial	0.02	0.02	0.02	0.02	0.02
	Total	**0.87**	**0.92**	**0.95**	**0.98**	**1.03**
Total		**3.78**	**3.96**	**4.17**	**4.39**	**4.62**

Source: Navigant analysis

2.2.4.2 Comparison between Reference Case and Utility Forecast

In this section, we compare the Reference Case forecast with FortisBC Electric's 20 Year Load Forecast. Nelson Hydro's self-generated electricity was incorporated into the FortisBC Electric's forecast based on extrapolating FortisBC Electric's growth model. Since most of the demand growth assumptions underlying the load forecast were used as inputs to develop the stock growth rates in the Reference Case, the two forecasts are largely consistent.

Table 2-29 compares the projected electricity sales in 2035 between the Reference Case and the Load Forecast.

Table 2-29: Reference Case Forecast – Include Self-Generation

Class/Sector	Growth Rate (%)		2035 Sales (GWh)		Difference (%)
	Reference Forecast	FortisBC Electric Forecast	Reference Forecast	FortisBC Electric Forecast	
Residential	0.8%	0.8%	2,288	2,288	0.0%
Commercial	1.4%	1.4%	1,301	1,301	0.0%
Industrial	0.8%	0.8%	1,030	1,030	0.0%
Total	**1.0%**	**1.0%**	**4,619**	**4,619**	**0.0%**

Source: Navigant analysis

2.3 Frozen End-use Intensity Case and Natural Change

Navigant's DSMSim™ model uses the building stock projections from the reference case forecast to calculate technical and economic potential, but does not use the reference case's time-changing end-use intensities (EUIs). Rather, it freezes the end-use intensities from the reference case forecast at 2016 levels and holds them fixed over time. This section describes the reasons for this approach and the method by which the team links the frozen EUI case back to the reference case using "natural change."

2.3.1 Frozen EUI Case

The Reference Case includes many embedded assumptions derived from observed trends in the market and forward-looking expectations. The Reference Case allows for end-use intensities to change over time as a function of:

- Changing mix of efficient versus inefficient equipment
- Changing use of building space (e.g., open plan office spaces)
- Changing mix of commercial activities (e.g., decrease in manufacturing and increase in service industries)
- New trends in consumption (e.g., increase in use of home electronics)
- Fuel switching (e.g., switching from gas appliances to electric appliances, or vice versa)

Modelling these considerations at the *measure* level would require a detailed adoption forecast for every measure in each customer segment. Typically, potential studies forecast measure-level adoption when looking at achievable market potential in the context of utility-sponsored energy efficiency programs. The achievable market potential hinges on expected levels of incentives, program budgets, and marketing/advertising levels, and there is adequate industry experience to provide substance to these forecasts. Conversely, it is difficult to estimate retrospectively what would have happened with measure adoption in the absence of energy efficiency programs (typically estimated through "net-to-gross" ratio studies), and it is even more difficult and uncertain to *forecast* such "natural" behavior at the measure level. Since program design is outside the scope of this study, and considering the inherent uncertainty in forecasting natural adoption at the measure level, Navigant did not pursue and create detailed measure adoption forecasts for technical and economic potential. Rather, the study uses a "frozen EUI" approach to estimate technical and economic potential combined with an estimation of aggregate end use intensity trends to calculate the natural change expected at the end use level.

Navigant calculated technical and economic potential assuming that EUIs are frozen at 2016 levels, ensuring consistency between modelled energy sales and measure characterization. For example, measure characterization assumes a fixed mix of efficient and inefficient measures over time—absent any energy efficiency programs—implying that end-use intensities do not change over time when calculating technical and economic potential. However, building stock changes (e.g., growth in the residential customer count or commercial floor space) can increase overall energy sales and assumed total equipment counts, which would impact the estimates for technical and economic potential.

If end-use intensities are changing in the Reference Case, Navigant calculates what this study refers to as the "natural change"—defined in section 2.3.2—of EUIs over time. The team then applies this natural change to the technical and economic potential results using the frozen EUI to estimate the shift in potential savings.

2.3.2 Natural Change

Navigant's definition of "natural change" stems from two related concepts: natural conservation and natural growth. Natural *conservation* is a well-established concept in DSM programs, and typically refers to actions taken by utility customers—in absence of utility-sponsored programs—to improve energy efficiency and reduce consumption. These actions are occurring naturally, with no influence from utilities or program administrators. Natural *growth* refers to actions taken by utility customers to *increase consumption* without the involvement of utility-guided programs. An example of natural growth is home electronics, where customers may be increasing their electric consumption (e.g., through addition of more televisions, computers, etc.) and causing an increase in the electronics end-use intensity.

This study captures the effects of natural conservation as well as natural growth within the end-use intensities, and defines these effects as "natural change." When natural change is positive for an end-use category, it reflects growth. When natural change is negative, it reflects conservation. The technical and economic results sections conclude with a comparison of potential before and after accounting for natural change.

2.4 Measure Characterization

Navigant fully characterized over 200 measures across the BC Utility's residential, commercial, and industrial sectors, covering electric and natural gas fuel types. The team prioritized measures with high impact, data availability, and most likely to be cost-effective as thresholds for inclusion into DSMSim™.

2.4.1 Measure List

Navigant developed a comprehensive measure list of energy efficiency measures likely to contribute to economic potential. The team reviewed current BC program offerings, previous CPR and other Canadian programs, and potential model measure lists from other jurisdictions to identify EE measures with the highest expected economic impact. The team supplemented the measure list using the Pennsylvania, Illinois, Mid-Atlantic, and Massachusetts technical resource manuals (TRMs), and partnered with CLEAResult to inform the list of industrial measures. Navigant worked with the BC Utilities to finalize the measure list and ensure it contained technologies viable for future BC program planning activities. Appendix A.2 provides the final measure list and assumptions.

Working sessions with the BC Utilities revealed topics of note regarding the following measures:

- **Multi-Unit Residential Building (MURB) measures –** Navigant characterized both in-suite and common area measures for MURBs. In-suite measures are similar to other residential measures such as LED light bulbs, power strips, and televisions. Common area measures include space heating and hot water heating measures such as make-up air units, HVAC controls, central boilers, and roof deck insulation
- **Tankless water heaters (electric) –** This study includes technical potential from electric tankless water heaters, however BC Utilities currently have no plans to incentivize this measure due to its impact to peak demand.
- **Showerheads for MURBs –** The model currently uses material and labor costs for showerheads assuming the customer installs the measure themselves. However, BC Utilities offer a direct install program for showerheads in the MURB customer segment and may purchase showerheads at a wholesale price. Since the measure is already cost-effective without the direct install cost adjustments, this issue does not impact the technical and economic potential results.

This issue would impact any further analysis of achievable potential, but that is outside of the scope of this study.

2.4.2 Measure Characterization Key Parameters

The measure characterization effort consisted of defining nearly 50 individual parameters for each of the 200 measures included in this study. This section defines the top 10 key parameters and how they impact technical and economic potential savings estimates.

1. **Measure Definition**: The team used the following variables to qualitatively define each characterized measure:
   - ***Replacement Type****:* Replacing the baseline technology with the efficient technology can occur in three variations:
     i. Retrofit (RET): where the model considers the baseline to be the existing equipment, and uses the energy and demand savings between the existing equipment and the efficient technology during technical potential calculations. RET also applies the full installed cost of the efficient equipment during the economic screening.
     ii. Replace On Burnout (ROB): where the model considers the baseline to be the code-compliant technology option, and uses the energy and demand savings between the current code option and the efficient technology during technical potential calculations. ROB also applies the incremental cost between the efficient and code-compliant equipment during the economic screening.
     iii. New Construction (NEW): where the model considers the baseline to be the least cost, code-compliant option, and uses the energy and demand savings between this specific current code option and the efficient technology during technical potential calculations. NEW also applies the incremental cost between the efficient and code-compliant equipment during the economic screening.
   - ***Baseline Definition***: Describes the baseline technology.
   - ***EE Definition***: Describes the efficient technology set to replace the baseline technology.
   - ***Unit Basis***: The normalizing unit for energy, demand, cost, and density estimates.
2. **Regional, Sector, and End-use Mapping:** The team mapped each measure to the appropriate end-uses, customer segments, sectors, and climate regions across the BC Utility's service territory. Section 2.1 describes the breakdown of customer segments with each sector. Navigant characterized weather dependent measures into four regions: Lower Mainland, Southern Interior, Vancouver Island, and Northern BC to account for changes in climate that impact energy savings.
3. **Annual Energy Consumption:** The annual energy consumption in kilowatt-hours (kWh) or mega joules (MJ) for each of the base and energy-efficient technologies
4. **Coincident Electric Demand**: The peak coincident demand in kilowatts (kW) for each of the base and energy-efficient technologies
5. **Fuel Type Applicability Multipliers**: Assigns the percentage of electric fuel type to measures with electric fuel type such as water heaters and space heating equipment
6. **Measure Lifetime:** The lifetime in years for the base and energy-efficient technologies. The Base and EE lifetime only differ in instances where the two cases represent inherently different technologies, such as light-emitting diodes (LEDs) or compact fluorescent lamp (CFL) bulbs compared to a baseline incandescent bulb.

7. **Incremental Costs:** The incremental cost between the assumed baseline and efficient technology, using the following variables:
    - ***Base Costs***: The cost of the base equipment, including both material and labor costs
    - ***EE Costs:*** The cost of the energy-efficient equipment
8. **Technology Densities**: This study defines "density" as the penetration or saturation of the baseline and efficient technologies across the BC Utility's territory. For residential, these saturations are on a per home basis, for commercial they are per 1,000 square feet of building space, and for industrial they are based on energy consumption.[28]
    - ***Base Initial Saturation***: The saturation of the baseline equipment in a territory for a given customer segment
    - ***EE Initial Saturation:*** The saturation of the efficient equipment in a territory for a given customer segment
    - ***Total Maximum Density***: The total number of both the baseline and efficient units in a territory for a given technology
9. **Technology Applicability:** The percentage of the base technology that can be reasonably and practically replaced with the specified efficient technology. For instance, occupancy sensors are only practical for certain interior lighting fixtures (an applicability less than 1.0), while all existing incandescent exit signs can be replaced with efficient LED signs (an applicability of 1.0).
10. **Competition Group**: The team combined efficient measures competing for the same baseline technology density into a single competition group to avoid the double-counting of savings. (Section 3.1.3 provides further explanation on competition groups.)

2.4.3 Measure Characterization Approaches and Sources

This section provides approaches and sources for the main measure characterization variables. The BC Utilities and Technical Advisory Committee reviewed Navigant's measure assumptions for each sector and provided inputs to refine measure assumptions. Navigant also worked with CLEAResult to further customize industrial measures.

2.4.3.1 Energy and Demand Savings

Navigant took three general bottom-up approaches to analyzing residential and commercial measure energy and demand savings:

1. **TRM Standard Algorithms:** Navigant used TRM standard algorithms for unit energy savings and demand savings calculations for the majority of measures. BC Hydro provided energy-to-demand factors for the residential sector.
2. **Program Evaluation Data:** Where available, Navigant used measure specific program evaluation data from the BC Utilities to inform energy savings.
3. **Engineering Analysis:** Navigant used appropriate engineering algorithms to calculate energy savings for any measures not included in BC Utility programs or available TRMs.

[28] Navigant sourced density estimates from the residential end-use survey (REUS), commercial end-use survey (CEUS), BC Utility program data, and other related secondary resources.

2.4.3.2 Incremental Costs

Navigant relied primarily on BC Utility provided program data and TRM data for incremental cost data. Navigant conducted secondary research and used other publicly available cost data sources such as the Database for Energy Efficient Resources (DEER), ENERGY STAR®, and the Michigan Energy Measures Database (MEMD) for all other cost data.

2.4.3.3 Building Stock and Densities

The residential end-use survey (REUS) and commercial end-use survey (CEUS) provided building stock data for the BC Utility's service territory, enabling Navigant to characterize residential and commercial measures. The measure characterization workbooks include full documentation of assumptions applied to each measure. Navigant also used the REUS and CEUS reports to develop measure densities by customer segment. For measures not included in REUS and CEUS, Navigant reviewed other data sources such as NRCan for estimates.

2.4.3.4 Industrial Measures

The industrial sector measure characterization deploys a high-level approach, which differs from the residential and commercial sectors. Navigant characterized industrial measures as a percentage reduction of the customer segment and end-use consumption. CLEAResult evaluated past project data from the BC Utilities to estimate the energy savings and incremental cost for all industrial measures.

2.4.4 Codes and Standards Adjustments

Natural Resources Canada publishes all federal energy efficiency regulations. Amendment 14[29] states that the intent of the amendment is to "align with energy efficiency standards in force or soon to be in force in the U.S." The BC Government sets all provincial regulations pertaining to energy efficiency standards in the province[30]. The U.S. Department of Energy (DOE) Technical Support Documents (TSD)[31] contains information on energy and cost impact of each appliance standard. Engineering analysis is available in Chapter 5 of the TSD; energy use analysis is available in Chapter 7, and cost impact is available in Chapter 8.

As these codes and standards take effect, the energy savings from existing measures impacted by these codes and standards declines, and the reduction is transferred to the code measures' savings potential. In this way, the study maintains the same level of overall savings potential before and after the code and standards compliance years. Navigant accounts for the impact of codes and standards through baseline energy and cost multipliers—sourced from the DOE's analysis—which reduce the baseline equipment consumption starting from the year a particular code or standard takes effect. The baseline cost of an efficient measure impacted by codes and standards will often increase upon implementation of the code. Technical and economic savings potential presented in the model results includes savings potential from codes and standards, and measure-level results show their contribution to overall potential.

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[29] Natural Resources Canada Amendment 14 to the Energy Efficiency Regulations. Access at: http://www.nrcan.gc.ca/energy/regulations-codes-standards/18437

[30] http://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/energy-efficiency-conservation/policy-regulations/standards

[31] Appliance standards rulemaking notices and Technical Support Documents can be found at: http://energy.gov/eere/buildings/current-rulemakings-and-notices

3. TECHNICAL POTENTIAL FORECAST

This section describes Navigant's approach to calculating technical potential and presents the results for FortisBC Electric's service territory.

3.1 Approach to Estimating Technical Potential

This study defines technical potential as the total energy savings available assuming that all installed measures can *immediately* be replaced with the "efficient" measure/technology—wherever technically feasible—regardless of the cost, market acceptance, or whether a measure has failed and must be replaced.

Navigant used its DSMSim™ model to estimate the technical potential for demand side resources in the regions considered for this study. DSMSim™ is a bottom-up technology-diffusion and stock-tracking model implemented using a System Dynamics framework.[32]

Navigant's modelling approach considers an energy-efficient measure to be any change made to a building, piece of equipment, process, or behaviour that could save energy.[33] The savings can be defined in numerous ways, depending on which method is most appropriate for a given measure. Measures like condensing water heaters are best characterized as some fixed amount of savings per water heater; savings for measures like commercial automated building controls are typically characterized as a percentage of customer segment consumption; and measures like industrial ventilation heat recovery are characterized as a percentage of end-use consumption. The model can appropriately handle savings characterizations for all three methods.

The calculation of technical potential in this study differs depending on the assumed measure replacement type. Technical potential is calculated on a per-measure basis and includes estimates of savings per unit, measure density (e.g., quantity of measures per home) and total building stock in each service territory. The study accounts for three replacement types, where potential from retrofit and replace-on-burnout measures are calculated differently from potential for new measures. The formulae used to calculate technical potential by replacement type are shown below.

[32] See Sterman, John D. *Business Dynamics: Systems Thinking and Modeling for a Complex World*. Irwin McGraw-Hill. 2000 for detail on System Dynamics modelling. Also see http://en.wikipedia.org/wiki/System_dynamics for a high-level overview.

[33] This study does not examine the impact of end-user electricity rates on consumption, nor energy efficiency's impact on electricity rates.

3.1.1 New Construction Measures

The cost of implementing new construction (NEW) measures is incremental to the cost of a baseline (and less efficient) measure. However, new construction technical potential is driven by equipment installations in new building stock rather than by equipment in existing building stock.[34] New building stock is added to keep up with forecast growth in total building stock and to replace existing stock that is demolished each year. Demolished (sometimes called replacement) stock is calculated as a percentage of existing stock in each year, and this study uses a demolition rate of 0.5% per year for residential and commercial stock and 0% for industrial stock. New building stock (the sum of growth in building stock and replacement of demolished stock) determines the incremental annual addition to technical potential which is then added to totals from previous years to calculate the total potential in any given year. The equations used to calculate technical potential for new construction measures are provided below.

Equation 1. Annual Incremental NEW Technical Potential (AITP)

$AITP_{YEAR}$ = New $Buildings_{YEAR}$ (e.g., buildings/year[35]) X Measure Density (e.g., widgets/building) X $Savings_{YEAR}$ (e.g., kWh/widget) X Technical Suitability (dimensionless)

Equation 2. Total NEW Technical Potential (TTP)

$$TTP = \sum_{YEAR=2016}^{YEAR=2035} AITP_{YEAR}$$

3.1.2 Retrofit and Replace-on-Burnout Measures

Retrofit (RET) measures, commonly referred to as advancement or early-retirement measures, are replacements of existing equipment before the equipment fails. Retrofit measures can also be efficient processes that are not currently in place and that are not required for operational purposes. Retrofit measures incur the full cost of implementation rather than incremental costs to some other baseline technology or process because the customer could choose not to replace the measure and would therefore incur no costs. In contrast, replace-on-burnout (ROB) measures, sometimes referred to as lost-opportunity measures, are replacements of existing equipment that have failed and must be replaced, or they are existing processes that must be renewed. Because the failure of the existing measure requires a capital investment by the customer, the cost of implementing replace-on-burnout measures is always incremental to the cost of a baseline (and less efficient) measure.

Retrofit and replace-on-burnout measures have a different meaning for technical potential compared with new construction measures. In any given year, the model uses the existing building stock for the calculation of technical potential.[36] This method does not limit the calculated technical potential to any pre-assumed rate of adoption of retrofit measures. Existing building stock is reduced each year by the

[34] In some cases, customer-segment-level and end-use-level consumption are used as proxies for building stock. These consumption figures are treated like building stock in that they are subject to demolition rates and stock-tracking dynamics.
[35] Units for new building stock and measure densities may vary by measure and customer segment (e.g., 1,000 square meters of building space, number of residential homes, customer-segment consumption, etc.)
[36] In some cases, customer-segment-level and end-use-level consumption are used as proxies for building stock. These consumption figures are treated like building stock in that they are subject to demolition rates and stock-tracking dynamics.

quantity of demolished building stock in that year and does not include new building stock that is added throughout the simulation. For retrofit and replace-on-burnout measures, annual potential is equal to total potential, thus offering an *instantaneous* view of technical potential. The equation used to calculate technical potential for retrofit and replace-on-burnout measures is provided below.

Equation 3. Annual/Total RET/ROB Technical Savings Potential

Total Potential = Existing Building Stock$_{YEAR}$ (e.g., buildings[37]) X Measure Density (e.g., widgets/building) X Savings$_{YEAR}$ (e.g., kWh/widget) X Technical Suitability (dimensionless)

3.1.3 Competition Groups

Navigant's modelling approach recognizes that some efficient technologies will compete against each other in the calculation of potential. The study defines "competition" as an efficient measure competing for the same installation as another efficient measure. For instance, a consumer has the choice to install a compact fluorescent or LED lamp, but not both. These efficient technologies compete for the same installation.

General characteristics of competing technologies used to define competition groups in this study include the following:

- Competing efficient technologies share the same baseline technology characteristics, including baseline technology densities, costs, and consumption
- The total (baseline plus efficient) measure densities of competing efficient technologies are the same
- Installation of competing technologies is mutually exclusive (i.e., installing one precludes installation of the others for that application)
- Competing technologies share the same replacement type (RET, ROB, or NEW)

To address the overlapping nature of measures within a competition group, Navigant's analysis only selects one measure per competition group to include in the *summation* of technical potential across measures (e.g., at the end-use, customer segment, sector, service territory, or total level). The measure with the largest energy savings potential in a given competition group is used for calculating total technical potential of that competition group. This approach ensures that the aggregated technical potential does not double-count savings. The model does still, however, calculate the technical potential for each individual measure outside of the summations.

[37] Units for building stock and measure densities may vary by measure and customer segment (e.g., 1,000 square meters of building space, number of residential homes, customer-segment consumption/sales, etc.).

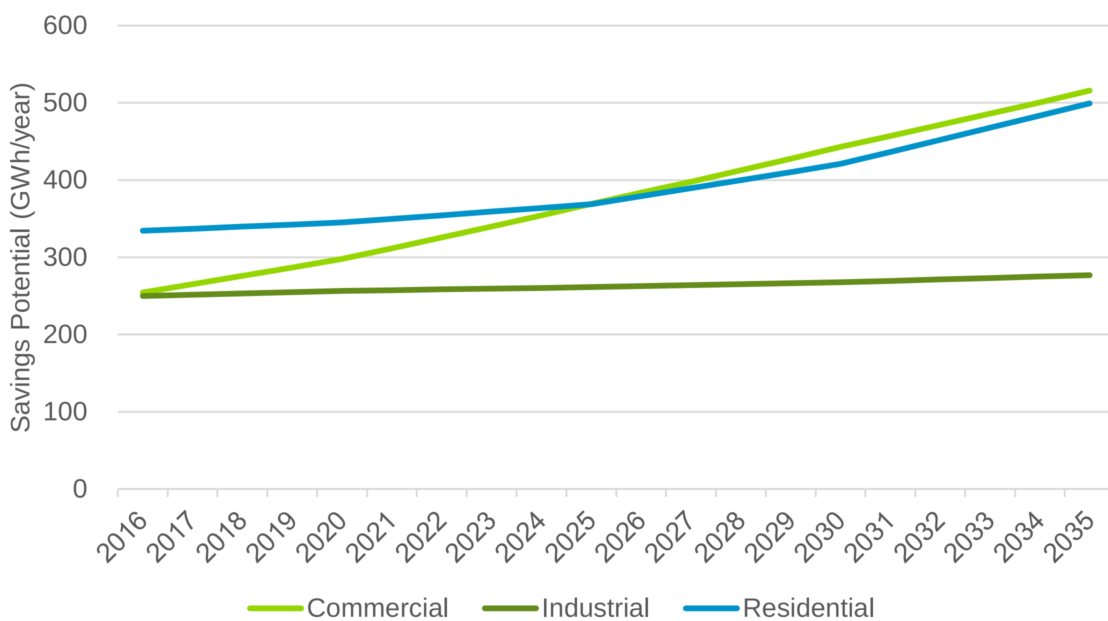
3.2 Technical Potential Results

This sub-section provides DSMSim™ results pertaining to total technical savings potential at different forms of aggregation. Results are shown by sector, customer segment, end-use category and highest-impact measures. The sub-section concludes with a review of natural change and its impacts on technical potential.

3.2.1 Results by Sector

Figure 3-1 shows the total electric energy technical savings potential for each sector, and Table E-4 in Appendix E provides the associated data. The increased rate of growth in residential technical potential beginning around 2025 was due to highly efficient building practices that save energy for the whole building in single-family detached homes. The upward trend in the commercial sector stemmed largely from high-impact whole-building new construction measures and appreciable growth in forecasted new commercial construction. Industrial savings increased slightly due to savings from the "whole facility" end-use, which included savings from new energy management measures and efficient whole-facility new construction practices.

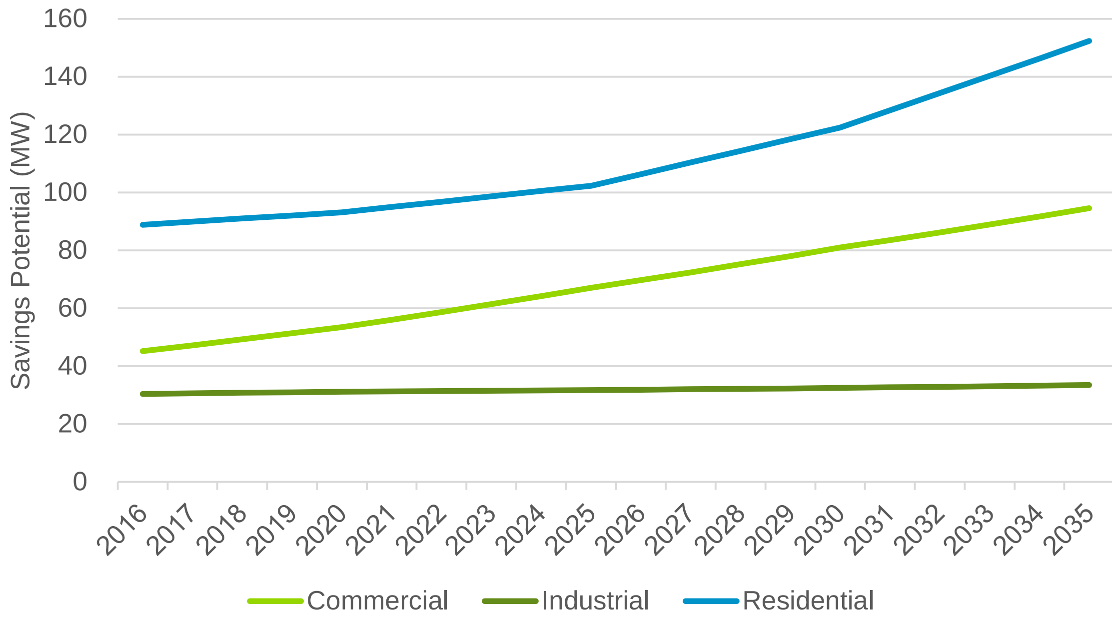
Figure 3-1. Electric Energy Technical Savings Potential by Sector (GWh/year)



Source: Navigant

Figure 3-2 shows the electric demand savings potential for all sectors, and Table E-5 in Appendix E provides the associated data. The residential sector exhibited a significant increase in potential over time—driven largely by whole-building savings from passive and net-zero home construction. Growth in commercial demand savings potential resulted from new construction building practices that were 45% more efficient than code. Electric demand savings in the industrial sector increased very slightly and came from a variety measures without being dominated by any particular measure.

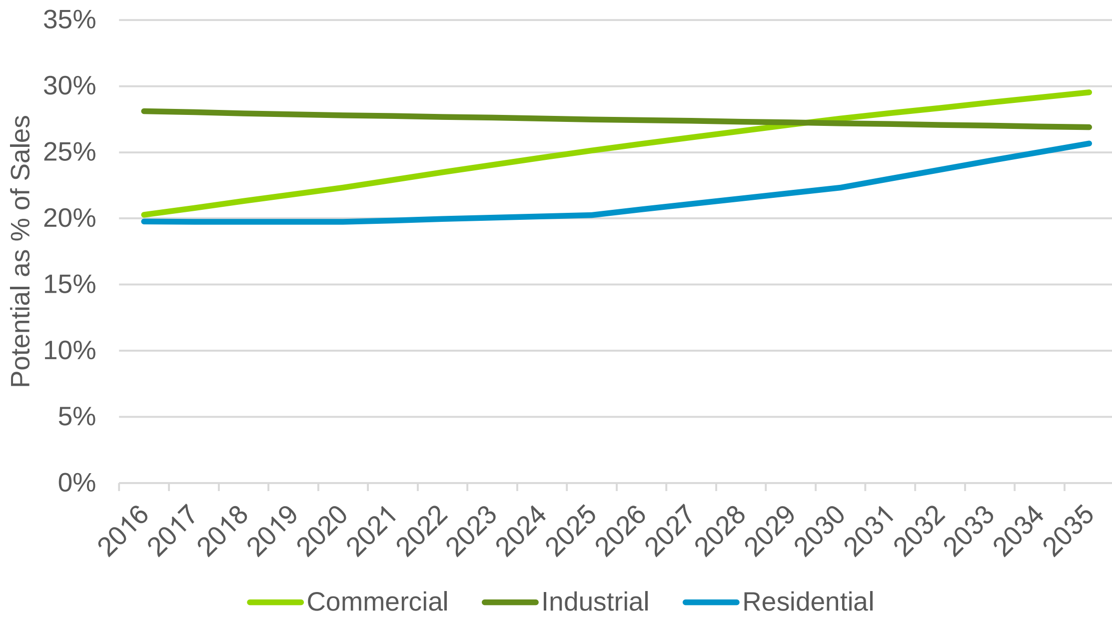
Figure 3-2. Electric Demand Technical Savings Potential by Sector (MW)



Source: Navigant

Figure 3-3 shows the electric energy technical savings potential for each sector as a percentage of that sector's total forecasted consumption, and Table E-6 in Appendix E provides the associated data. The percentages reflect a weighted average savings among measures applicable to existing building stock and new building stock constructed during the study period. As such, upward-sloping sectors indicated that savings opportunities—on a percentage of consumption basis—were larger in new construction than existing construction. While the residential sector provided the largest amount of absolute electric energy technical savings potential in GWh/year, the commercial sector provided the largest amount of savings potential as a percent of total sector consumption. The savings potential as a percent of total sector consumption increased over time for both the residential and commercial sectors. Conversely, despite relatively stable absolute technical savings potential over the next twenty years, the industrial savings potential as a percent of total consumption declined steadily due to forecasted changes in how different industrial customer segments will contribute to overall sector consumption.

Figure 3-3. Electric Energy Technical Savings Potential by Sector as a Percent of Sector Consumption (%)

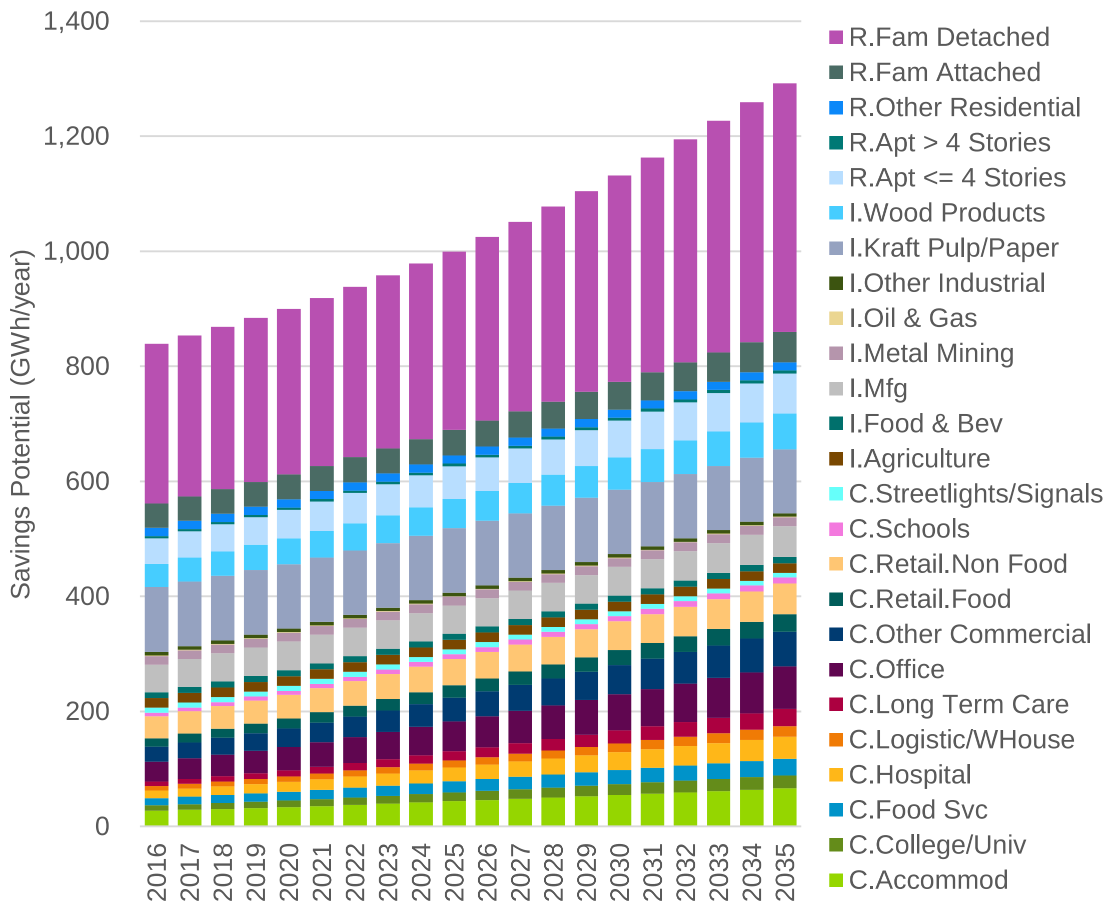


Source: Navigant

3.2.2 Results by Customer Segment

Figure 3-4 shows the electric energy technical savings potential across all customer segments and Table E-7 in Appendix E provides the associated data. This figure highlights the large savings potential of the residential detached single family home customer segment relative to other customer segments across all sectors. The growth in potential for the detached single family home segment contributed largely to the increase in savings potential in the last ten years of the study, when efficient home construction practices had reached maturity and were able to impact the sizable growth in residential sector consumption. The office and accommodation commercial customer segments also exhibited significant growth in savings potential due to a corresponding forecasted growth in these segments' consumption over time.

Figure 3-4. Electric Energy Technical Savings Potential by Customer Segment (GWh/year)



Source: Navigant

Figure 3-5, Figure 3-6, and Figure 3-7 break out the electric energy technical savings potential for each sector by customer segment. For the residential sector, detached single family homes/duplexes represented the largest savings potential of any customer segment by far, accounting for 84% of the total savings potential. Attached (row/town) homes' contribution to total potential was 12%, and other residential contributed the remaining 4%.

The savings potential for the commercial sector was distributed more evenly across a broad range of customer segments. Low rise apartment buildings and office buildings were the two customer segments with the largest savings potential, accounting for 16% and 15% of the overall potential for the sector, respectively. Accommodation, "other" commercial segments, and non-food retail accounted for an additional one-third of total savings potential. Note that, though prefixed with the letter "R" in the figures, apartment buildings were considered part of the commercial sector for FortisBC Electric.

For the industrial sector, more than 80% of the overall electric energy savings potential was concentrated within three customer segments: kraft pulp and paper, manufacturing and wood products. Agriculture and metal mining accounted for 7% and 6% of total potential, respectively, and the remainder was distributed in smaller proportions across the remaining industrial customer segments.

Figure 3-5. Residential Electric Energy Technical Potential Customer Segment Breakdown in 2025

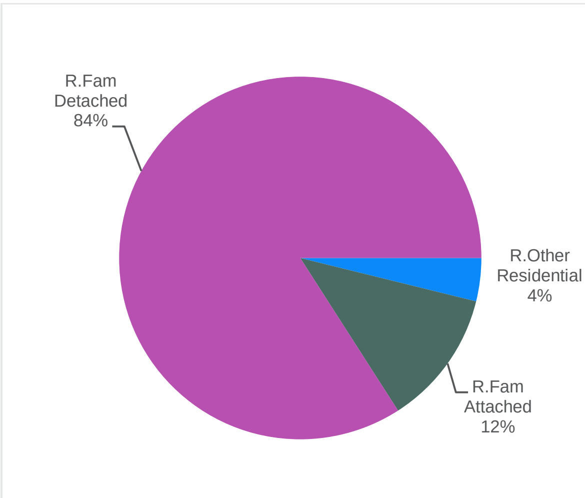


Figure 3-6. Commercial Electric Energy Technical Potential Customer Segment Breakdown in 2025

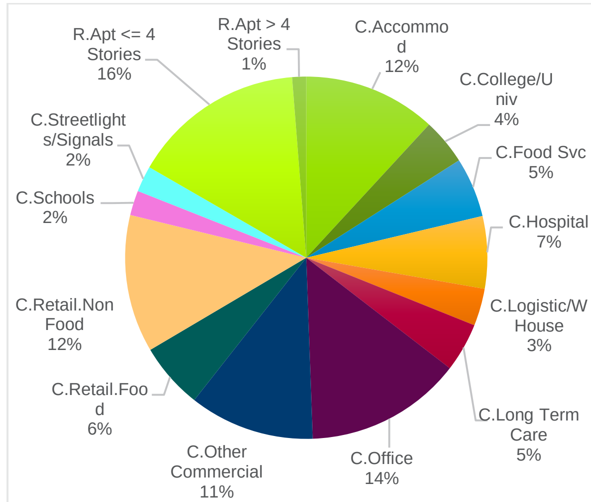
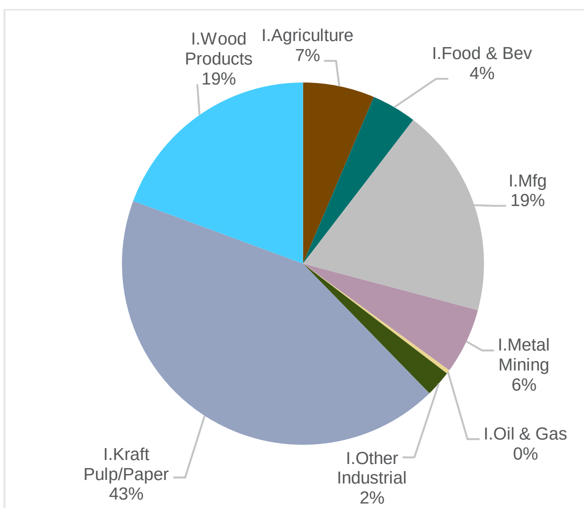


Figure 3-7. Industrial Electric Energy Technical Potential Customer Segment Breakdown in 2025

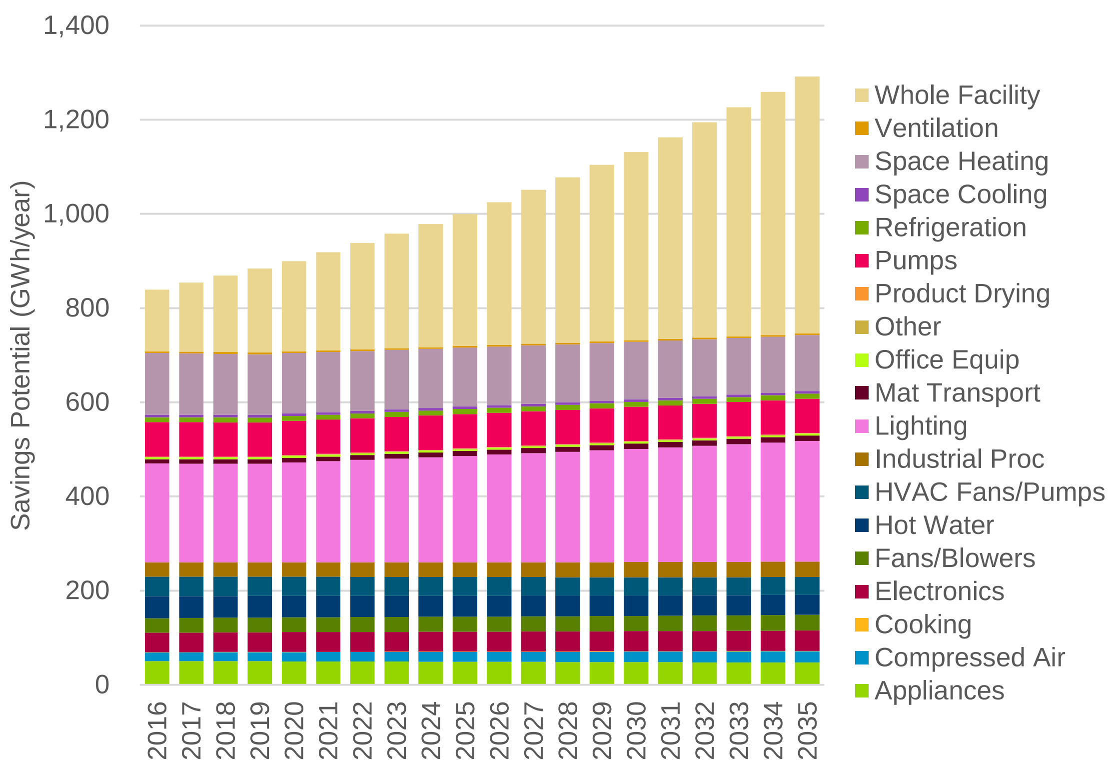


Source: Navigant

3.2.3 Results by End-use

Figure 3-8 shows the electric energy technical savings potential across all end-uses and sectors. The data used to generate the figure are in Table E-8 in Appendix E. The dominant end-uses were lighting and whole facility. The bulk of savings potential in the lighting end-use came from LEDs, lighting code changes, and efficient high-bay lighting. Lighting code changes accounted for about a third of the lighting savings. The whole facility end-use primarily consisted of savings from comprehensive whole-facility new construction practices. As such, these whole-facility savings implicitly included savings from multiple end-uses.

Figure 3-8. Electric Energy Technical Savings Potential by End-Use (GWh/year)



Source: Navigant

Figure 3-9, Figure 3-10, and Figure 3-11 break out the electric energy technical savings potential for each sector. The lighting, space heating, and whole facility end-uses dominated the residential sector, together accounting for just under 70% of the total savings potential. The whole facility end-use encompassed efficient whole-facility construction practices as well as behavioral energy management programs. Notably, there is very little potential for electric energy savings from residential space cooling because of the temperate summer climate in this service territory. In the commercial sector, the lighting and whole facility end uses accounted for 30% and 45% of the total technical savings potential, respectively, with HVAC fans/pumps contributing another 11% and the remaining end-uses making up the balance. Although the whole facility end use played a large role in industrial savings potential (as in the residential and commercial sectors), the industrial sector showed a more distributed spread across end-uses including industrial processes, lighting, and pumps.

Figure 3-9. Residential Electric Energy Technical Potential End-Use Breakdown in 2025

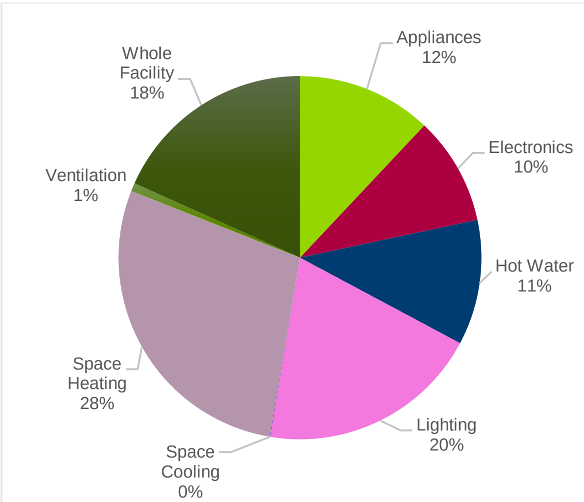


Figure 3-10. Commercial Electric Energy Technical Potential End-Use Breakdown in 2025

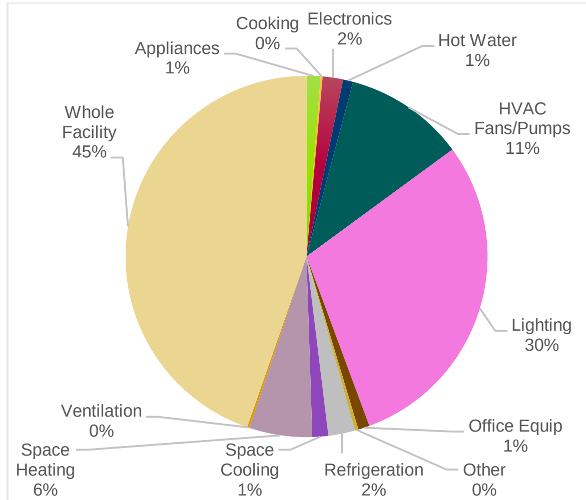
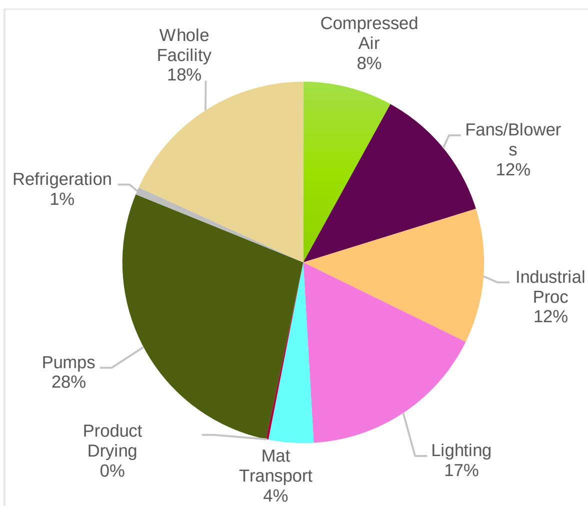


Figure 3-11. Industrial Electric Energy Technical Potential End-Use Breakdown in 2025



Source: Navigant

3.2.4 Results by Measure

The measure-level savings potential shown in Figure 3-12 is prior to adjustments made to competition groups. Some of the measures shown here are not included in the customer segment, end-use, sector and portfolio totals because they were not the measures with the greatest savings potential for their respective competition group.

The figure presents the top forty measures ranked by their electric energy technical savings potential in 2025. Wherever a group of measures were similar in nature, their potential was consolidated into a representative measure name to produce a more succinct view at the measure level. For example, the LED potential in the figure represents the technical savings potential for several different types of LEDs: general service LEDs, reflector LEDs, troffer LEDs, exterior LEDs, interior recessed LED down-lighting, etc.

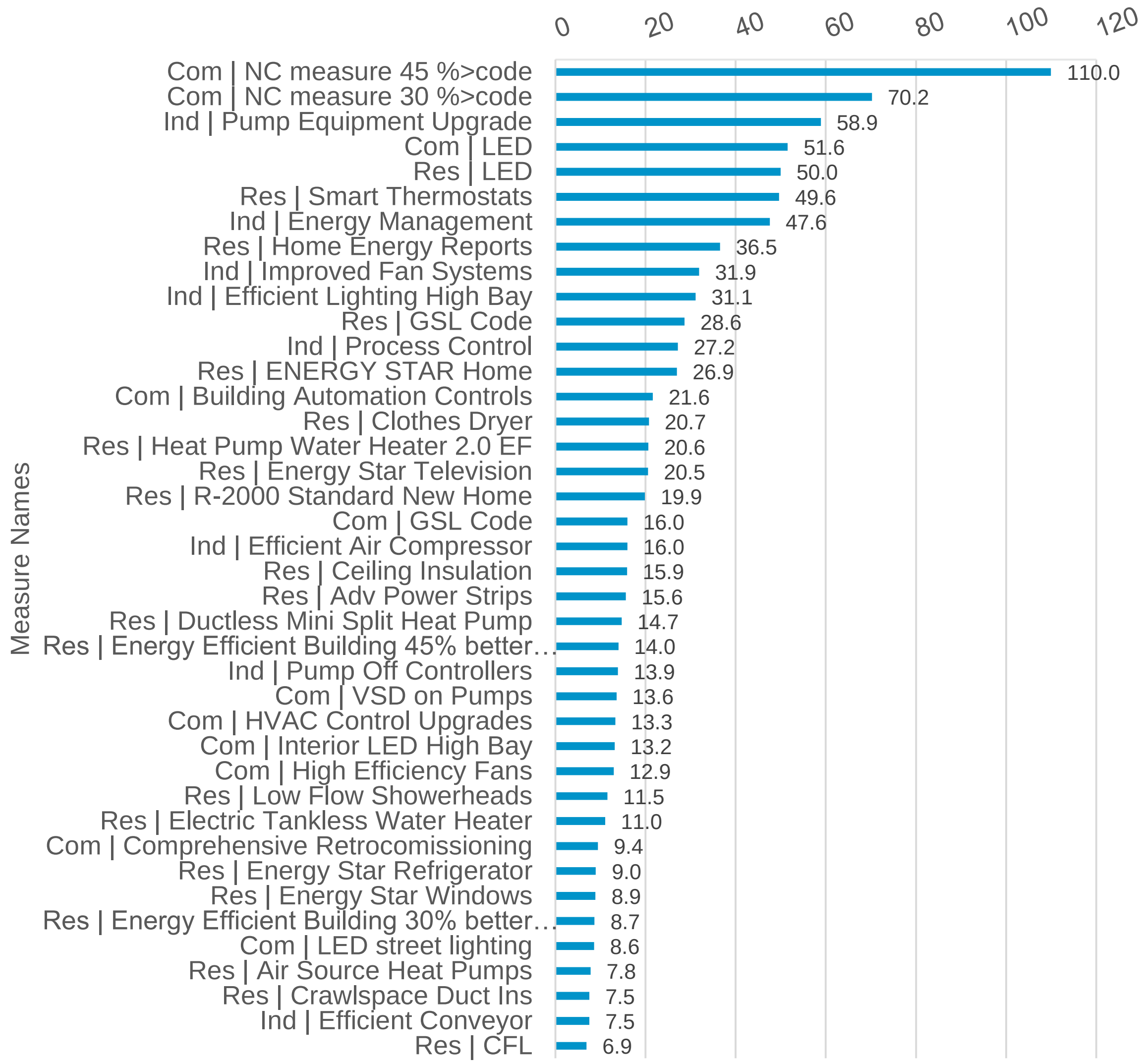
When code-change measures became applicable, they “stole” savings potential from other related measures that may have displayed significant savings in absence of the code. In this way, the sum of the total savings potential between the code and the related energy efficient measure was the same before and after a code took effect. This ensured there was no double counting of savings from codes and the energy efficient measures impacted by the code.

The figure shows that the top two measure categories by electric energy technical savings potential were related to the commercial, whole-facility end-use. The top two-ranked measures were related to commercial, whole-building new construction practices that were at least 45% and 30% more efficient than code. However, the savings of the commercial 30% more efficient than code measure did not contribute to aggregate potential results because they were in competition with the 45% more efficient than code measure. In reality not all new construction will be built to 45% more efficient, and over time the BC Building Code requirements will raise the baseline. Thus, the market potential, to be estimated in the next phase of the BC CPR project, will be less than the 110 GWh of technical savings indicated.

The third-ranked measure is the industrial pump equipment upgrade measure, and the fourth and fifth-ranked measures are a collection of residential and commercial LED lighting measures.

Moving further down the list, three additional industrial measures are also in the top 10; energy management, improved fan systems and efficient high-bay lighting. Also in the top 10 are residential home energy reports and smart thermostats.

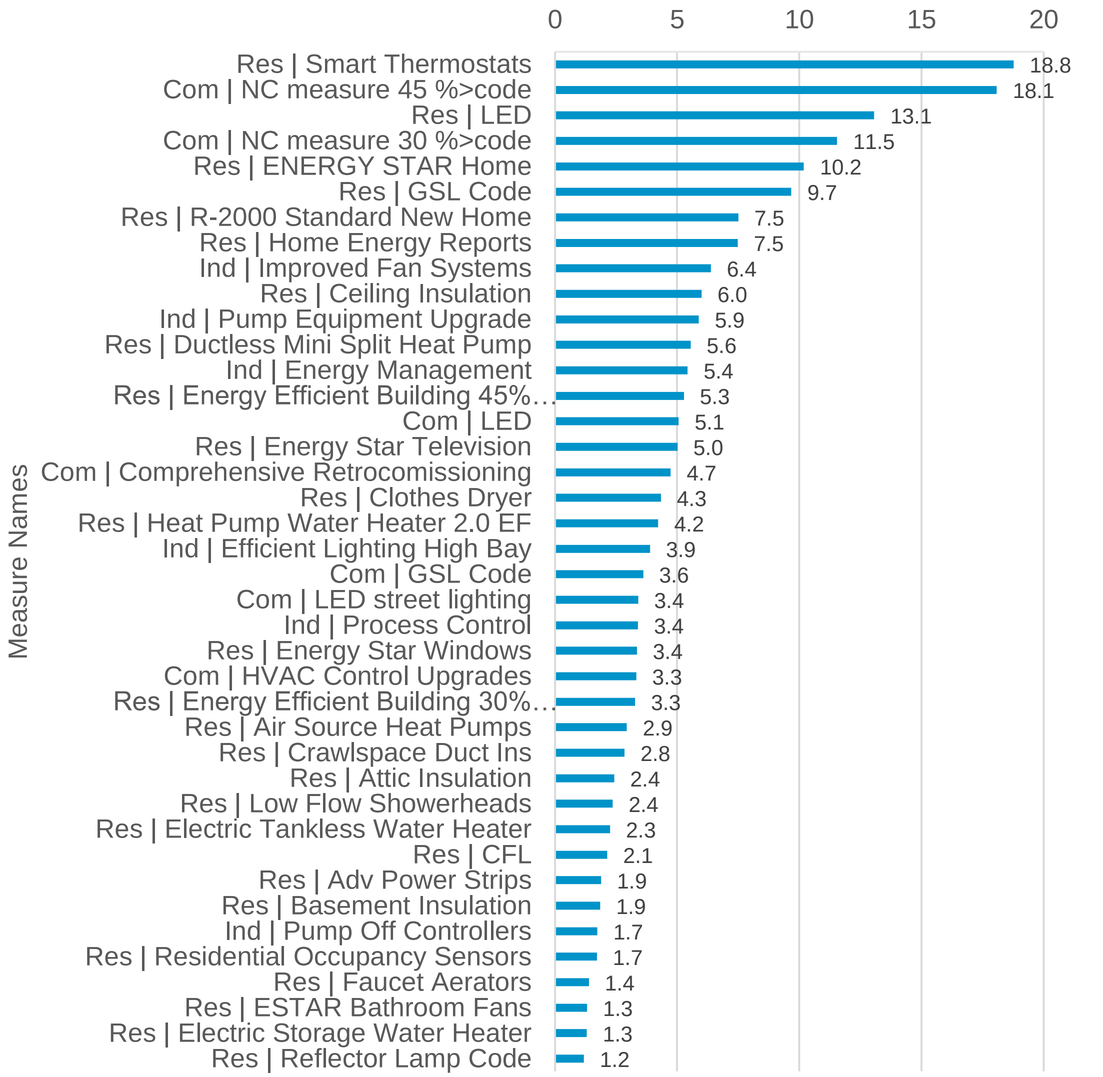
Figure 3-12. Top 40 Measures for Electric Energy Technical Savings Potential in 2025 (GWh/year)



Source: Navigant

Figure 3-13 presents the top forty measures ranked by their electric demand technical savings potential in 2025. Compared with the rank of measures by electric energy potential, many of the residential measures ranked higher. Residential whole-building measures such as ENERGY STAR homes, and R-2000 homes are ranked in the top ten based on demand savings. Residential smart thermostats and lighting measures such as LED and General Service Lamp (GSL) code also ranked higher. In general, residential measures were more effective at reducing electric demand because of their higher coincidence with peak demand.

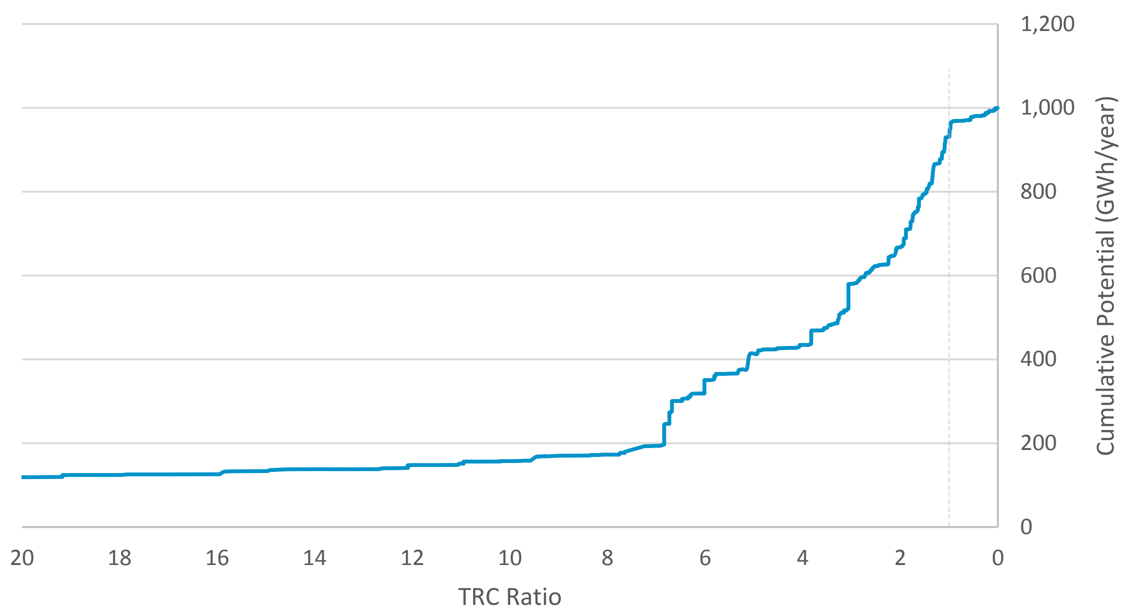
Figure 3-13. Top 40 Measures for Electric Demand Technical Savings Potential in 2025 (MW)



Source: Navigant

Figure 3-14 provides a supply curve of technical savings potential versus the TRC ratio for all measures considered in the study. Navigant truncated this curve only to show TRC ratios below 20, although the full curve would extend well beyond this ratio. Much of the potential with TRC ratios larger than 20 came from new codes and standards measures, which the team modelled as having zero costs and infinite TRC ratios.[38] There was a distinct "elbow" in the supply curve at a TRC ratio of about 7.0, indicating the majority of savings came from measures with TRC ratios less than 7.0. For TRC ratios below 7.0, cumulative potential increased to about 930 GWh/year at a ratio of 1.0. Measures with TRC ratios less than 1.0 were non-cost-effective and did not appear in the economic potential.

Figure 3-14. Supply Curve of Electric Energy Technical Potential (GWh/year) vs. TRC Ratio (ratio) in 2025

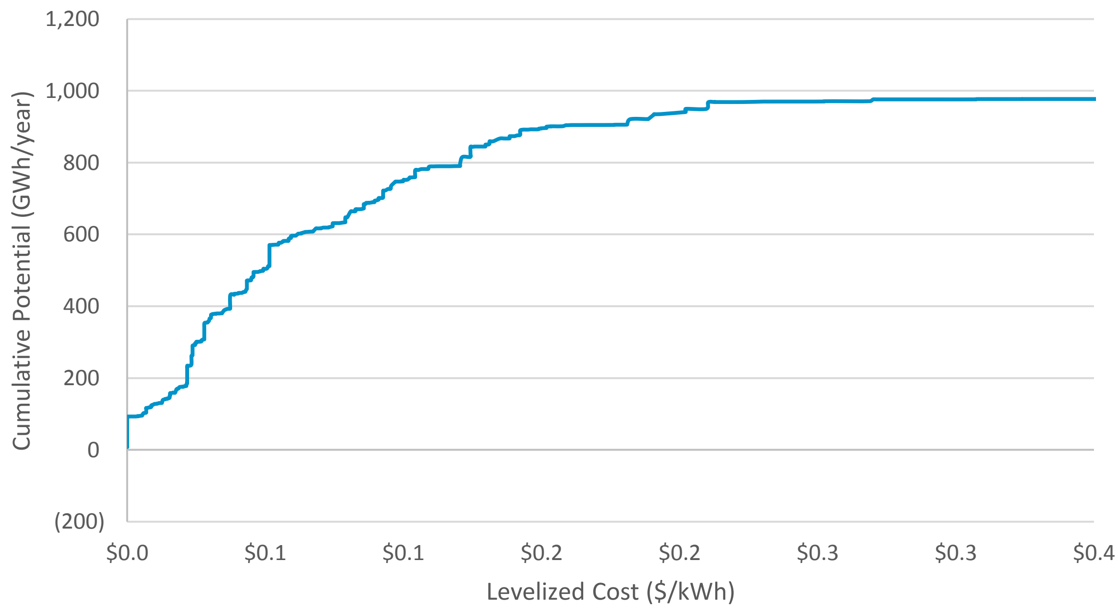


Source: Navigant

[38] The team expects that regulators will implement all of the codes and standards included in the study. Thus, Navigant did not consider the costs of code and standards because the team wanted to ensure the codes and standards would appear in economic potential. Additionally, the codes and standards appearing in this study have already been reviewed by regulatory bodies, and those reviews often include considerations for cost-effectiveness.

Figure 3-15 provides a supply curve of savings potential versus levelized cost of savings in $/kWh for all measures considered in the study. Navigant truncated this curve to show only those measures with a levelized cost less than $0.40/kWh, though the full curve would extend beyond this to measures with more costly savings. The savings potential having a cost of $0/kWh was due to code-change measures, which Navigant modelled as having zero costs. Total cumulative savings potential increased steadily to just under 980 GWh/year at a maximum cost of $0.40/kWh, beyond which more costly modes of savings added little additional cumulative potential.

Figure 3-15. Supply Curve of Electric Energy Technical Potential (GWh/year) vs. Levelized Cost ($/kWh) in 2025



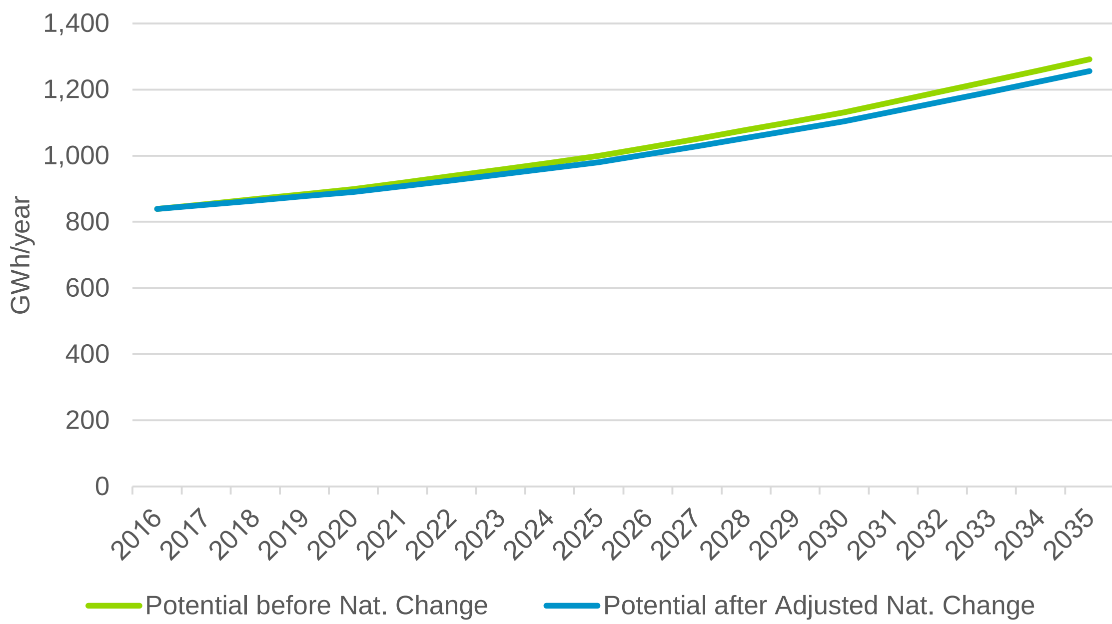
Source: Navigant

3.2.5 Adjustments for Natural Change

As discussed in section 2.3.2, Navigant estimated natural change to account for differences in end-use consumption in the Reference Case compared to the frozen EUI case. Natural change accounts for changes in consumption that are naturally occurring and are not the result of utility-sponsored programs or incentives. Adding natural change to the frozen EUI case required adjusting the technical potential forecasts accordingly.

Figure 3-16 shows the total technical potential across all sectors before and after adjusting for natural change. The total natural change was negative in all years, indicating an overall natural tendency toward increased energy conservation rather than consumption. The adjusted natural change is computed by accounting for the percentage of the gross natural change that could reasonably be attributed to energy savings for each end use.

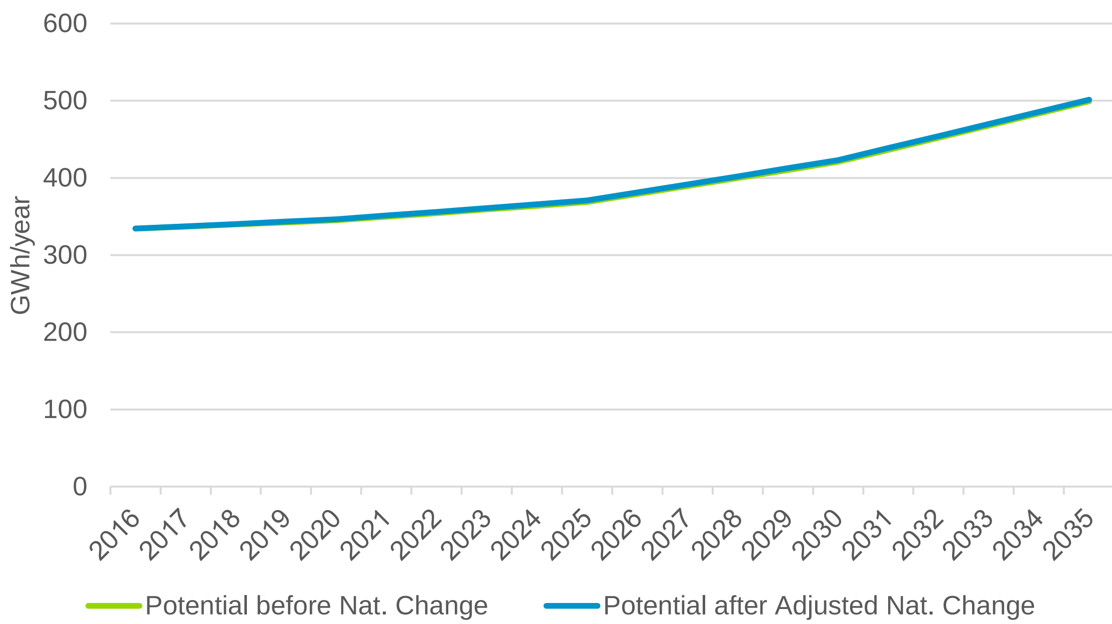
Figure 3-16. Electric Energy Technical Savings Potential with Natural Change (GWh/year)



Source: Navigant

Figure 3-17 shows the effect of adjustments for natural change in the residential sector. Space heating, electronics, and hot water end-uses accounted for significant natural growth. In contrast, appliances and lighting end-uses accounted for natural conservation. When aggregated to the sector level, natural growth was a larger effect than natural conservation, resulting in a higher sector-level technical potential. The adjusted natural change only slightly increased technical potential (by 2 GWh/year) relative to the potential before accounting for natural change, indicating that the frozen EUI case did not materially underestimate technical potential.

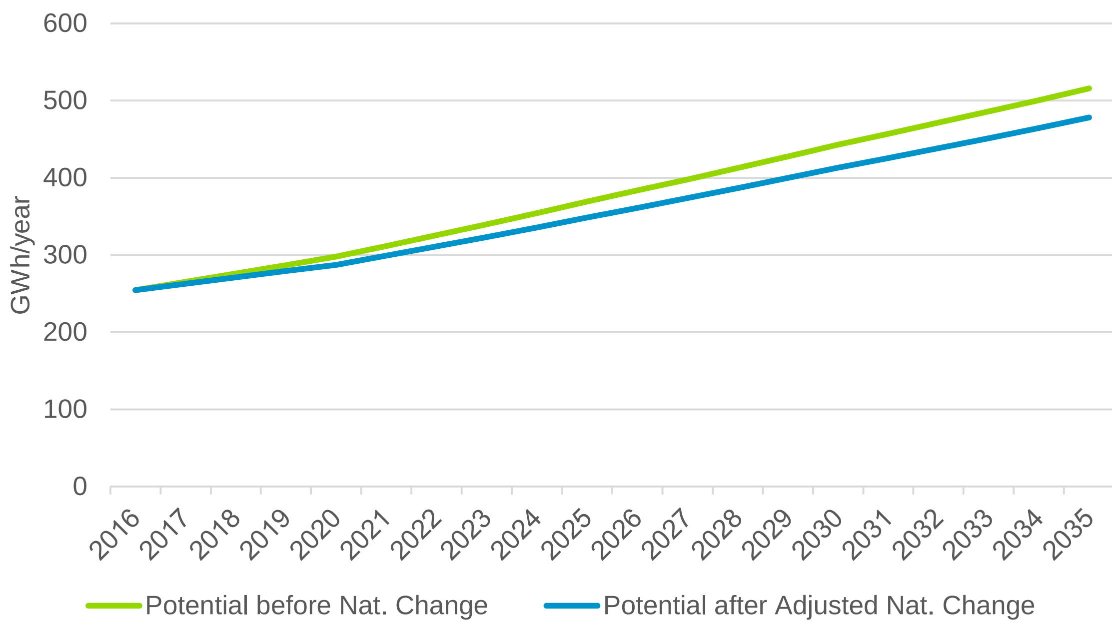
Figure 3-17. Residential Electric Energy Technical Savings Potential with Natural Change (GWh/year)



Source: Navigant

The effect of adjustments for natural change on the commercial sector's technical potential were more significant than for the residential sector, as seen in Figure 3-18. After adjusting for savings percentages in each end-use, the reduction in technical savings potential due to the adjusted natural change was 8% of the total savings potential before natural change in 2035.

Figure 3-18. Commercial Electric Energy Technical Savings Potential with Natural Change (GWh/year)



Source: Navigant

For the industrial sector, there was no forecasted natural change, so adjustments to the technical potential results presented in previous sections were not necessary.

4. ECONOMIC POTENTIAL FORECAST

This section describes the economic savings potential, which is potential that meets a prescribed level of cost effectiveness, available in the utility's service territories. The section begins by explaining Navigant's approach to calculating economic potential. It then presents the results for economic potential.

4.1 Approach to Estimating Economic Potential

Economic potential is a subset of technical potential, using the same assumptions regarding immediate replacement as in technical potential, but including only those measures that have passed the benefit-cost test chosen for measure screening (in this case the Total Resource Cost (TRC) test, per the utility's guidance). The TRC ratio for each measure is calculated each year and compared against the measure-level TRC ratio screening threshold of 1.0. A measure with a TRC ratio greater than or equal to 1.0 is a measure that provides monetary benefits greater than or equal to its costs. If a measure's TRC meets or exceeds the threshold, it is included in the economic potential.

The TRC test is a cost-benefit metric that measures the net benefits of energy efficiency measures from combined stakeholder viewpoint of the utility (or program administrator) and the customers. The TRC benefit-cost ratio is calculated in the model using the following equation:

Equation 4. Benefit-Cost Ratio for Total Resource Cost Test

$$TRC = \frac{PV(Avoided\ Costs + O\&M\ Savings)}{PV(Technology\ Cost + Admin\ Costs)}$$

Where:

- *PV( )* is the present value calculation that discounts cost streams over time;
- *Avoided Costs* are the monetary benefits resulting from electric energy and capacity savings (e.g., avoided costs of infrastructure investments, as well as avoided LRMC (commodity costs) due to electric energy conserved by efficient measures);
- *O&M Savings* are the non-energy benefits such as operation and maintenance cost savings;
- *Technology Cost* is the incremental equipment cost to the customer;
- *Admin Costs* are the administrative costs incurred by the utility or program administrator.

Navigant calculated TRC ratios for each measure based on the present value of benefits and costs (as defined above) over each measure's life. Avoided costs, discount rates, and other key data inputs used in the TRC calculation are presented in Appendix A.3, while measure-specific inputs are provided in Appendix A.2. As agreed upon with the utility, effects of free ridership are not present in the results from this study, so no net-to-gross (NTG) factor was applied. Providing gross savings results will allow the utility to easily apply updated NTG assumptions in the future, as well as allow for variations in NTG assumptions by reviewers.

Although the TRC equation includes administrative costs, the study does not consider these costs during the economic screening process because the study is concerned with an individual measure's cost effectiveness "on the margin." The model also excluded administrative costs from this analysis because those costs are largely driven by program design, which is outside of the scope of this evaluation.

Similar to technical potential, only one "economic" measure (meaning that its TRC ratio meets the threshold) from each competition group is included in the summation of economic potential across measures (e.g., at the end-use category, customer segment, sector, service territory or total level). If a competition group is composed of more than one measure that passes the TRC test, then the economic measure that provides the greatest electric savings potential is included in the summation of economic potential. This approach ensures that double-counting is not present in the reported economic potential, though economic potential for each individual measure is still calculated and reported outside of the summation.

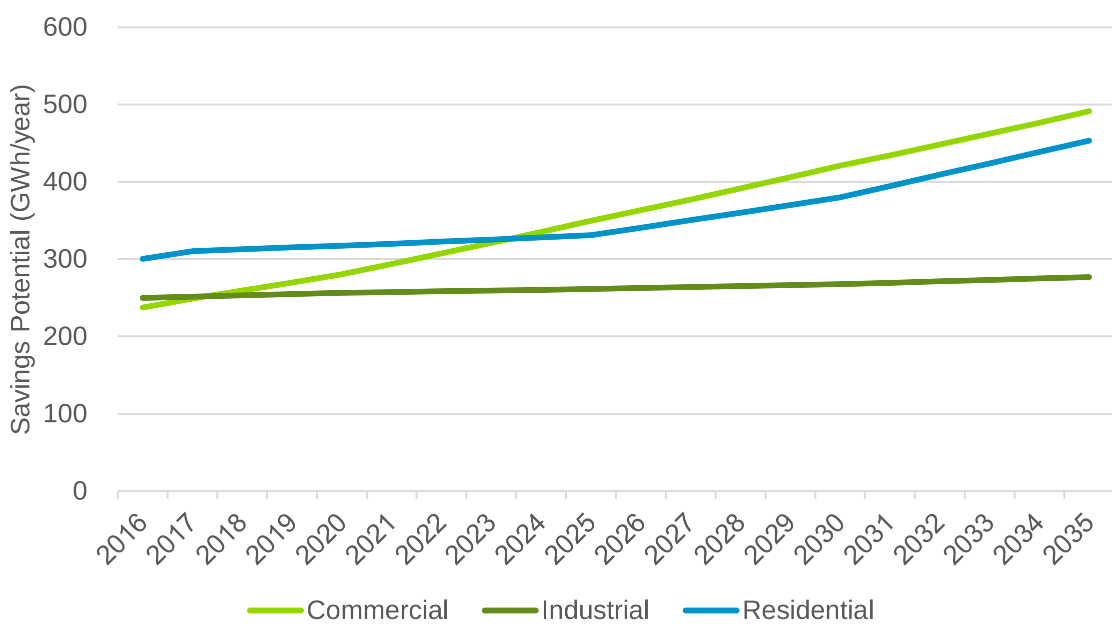
4.2 Economic Potential Results

This sub-section provides DSMSim™ results pertaining to economic savings potential at different forms of aggregation. Results are shown by sector, customer segment, end-use category and highest-impact measures.

4.2.1 Results by Sector

Figure 4-1 shows economic energy savings potential across all sectors. The data used to generate the figure are in Table E-9 in Appendix E. The residential and commercial economic savings potential grew at a relatively similar rate as the technical potential. In the industrial sector, economic potential is equal to technical potential.

Figure 4-1. Electric Energy Economic Savings Potential by Sector (GWh/year)



Source: Navigant

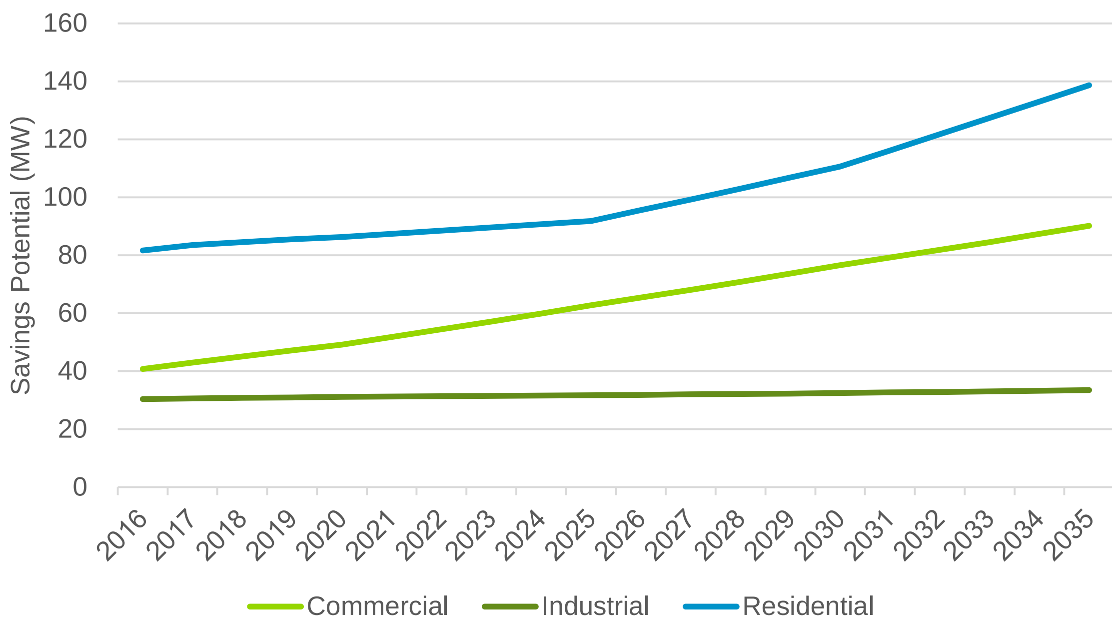
On average across the study period, 91% of residential technical potential was cost-effective. In single-family detached homes, the R-2000 standard new home measure that contributed appreciably to technical potential was not cost-effective. However, with R-2000 standard new homes no longer competing in economic potential, the ENERGY STAR new home was able to contribute to economic potential and supplant much of the potential lost from the R-2000 standard new home. In addition to the R-2000 standard new home measure, and clothes washers caused the greatest reduction in energy potential among the non-cost-effective residential measures.

Commercial economic energy potential was roughly 5% lower than technical potential on average. Whole-building new construction practices that were 45% more efficient than code were non-economic in select customer segments and led to the greatest loss in potential. High-efficiency fans, interior T5 lighting, and wall insulation were additional non-cost-effective commercial measures that contributed significantly to the reduction in economic potential relative to technical potential.

Technical and economic energy potential were identical in the industrial sector because all measures passed the TRC screening threshold. The industrial measures included in the study were selected according to data availability, which often results from pilot demonstrations or measurable industry adoption. Since adoption and pilot demonstrations are correlated with a measure's likelihood of achieving reasonable payback times, it is not unexpected that the industrial measures characterized in this study were cost-effective.

Figure 4-2 presents the economic demand potential in each of the sectors, with supporting data provided in Table E-10 in Appendix E. Demand potential in the residential and commercial sectors grew at similar rate as the technical demand potential, though they were of smaller magnitude. In the industrial sector, economic potential is equal to technical potential.

Figure 4-2. Electric Demand Economic Savings Potential by Sector (MW)



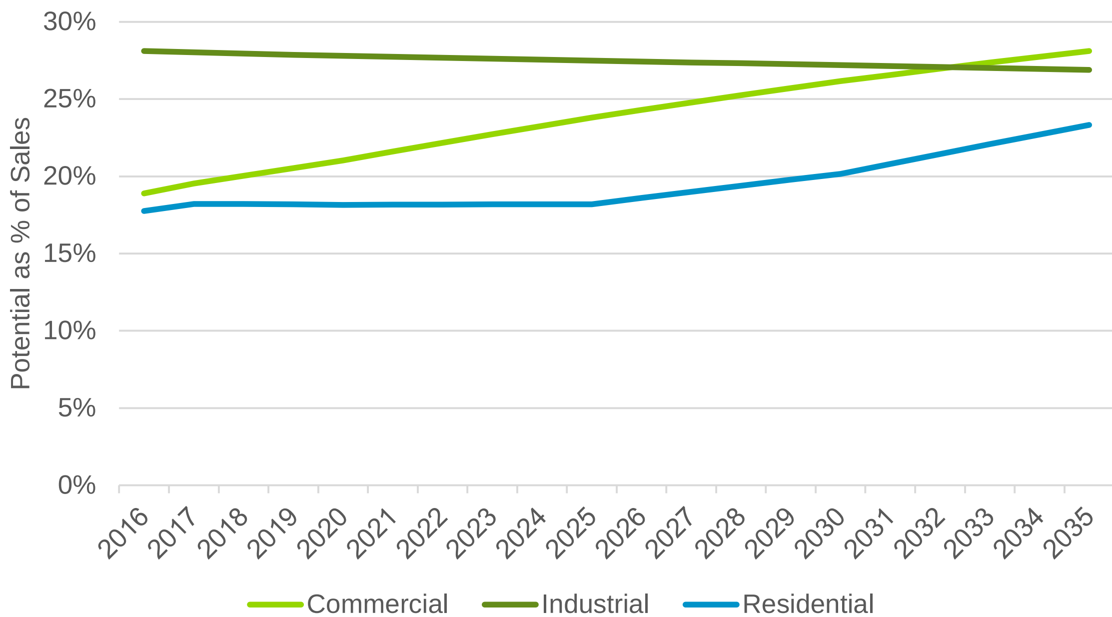
Source: Navigant

For residential demand savings, 91% of technical potential met or exceeded a TRC of 1.0. The R-2000 standard new home measure and clothes washers caused the greatest reduction in demand potential among the non-cost-effective residential measures.

The commercial sector experienced a 5% reduction in economic demand potential relative to technical potential (i.e., 95% of technical potential passed the economic screening threshold).

Figure 4-3 shows the economic energy potential as a percentage of consumption, with associated data presented in Table E-11 in Appendix E. In the residential sector, economic potential as a percent of consumption stayed below 20% and increased after 2030 due to an increase in savings potential from single family detached homes. The growth in economic potential as a percentage of consumption within the commercial sector exhibited a similar pattern as technical potential, though the economic potential was smaller in magnitude. In the industrial sector, both the economic and technical savings potential as a percent of industrial consumption decrease over time. This decrease resulted from lower percentage savings opportunities in new load that pulled the sector's weighted average savings percentage downward. Accordingly, the average industrial savings as a percent of consumption declined as new load became a larger percentage of total industrial load over the study horizon.

Figure 4-3. Electric Energy Economic Savings Potential by Sector as a Percent of Sector Consumption (%)

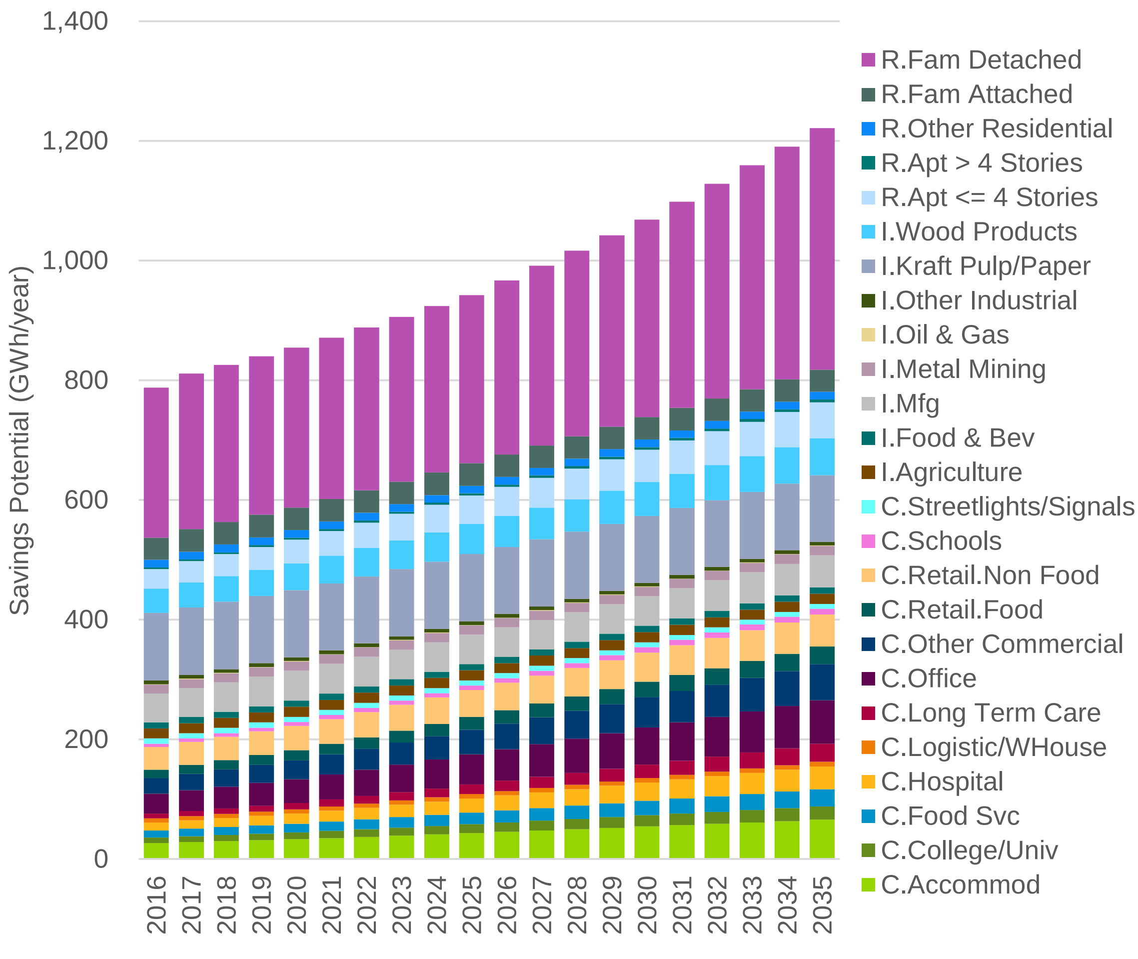


Source: Navigant

4.2.2 Results by Customer Segment

Figure 4-4 depicts the economic energy savings potential for all customer segments, and Table E-12 in Appendix E provides the corresponding data values. Depending on the customer segment, between 81% and 92% of the technical energy potential passed the economic screening threshold within the residential sectors. Economic potential in single-family attached homes showed the greatest deviation (on a percentage basis) from technical potential, while the smallest deviation occurred in the single-family detached homes. Of the commercial customer segments, logistics and warehouses was the least cost-effective, having 57% of the potential pass the TRC screen. However, the remaining commercial customer segments realized economic potential at levels ranging from 93 to 99% of technical potential.

Figure 4-4. Electric Energy Economic Savings Potential by Customer Segment (GWh/year)



Source: Navigant

In general, the mix of economic energy savings from various customer segments within a given sector were similar between economic and technical potential. Detached single-family homes had the highest occurrence of economic savings, and they provided the largest share of economic savings potential within the residential sector. The mix of economic potential from the commercial segments did not change appreciably relative to the technical potential. Figure 4-5, Figure 4-6 and Figure 4-7 provide a breakdown of economic energy potential by customer segment and sector.

Figure 4-5. Residential Electric Energy Economic Potential Customer Segment Breakdown in 2025

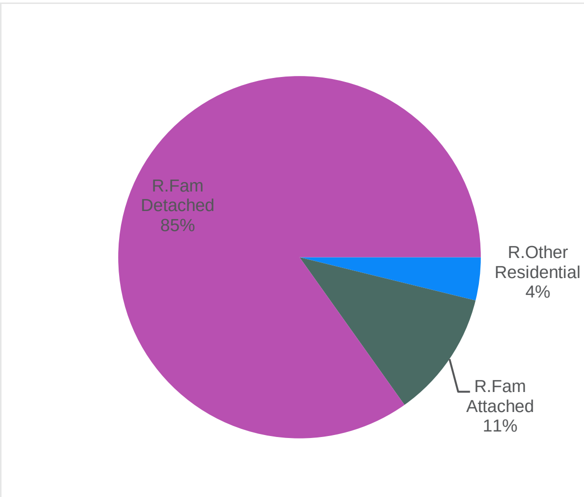


Figure 4-6. Commercial Electric Energy Economic Potential Customer Segment Breakdown in 2025

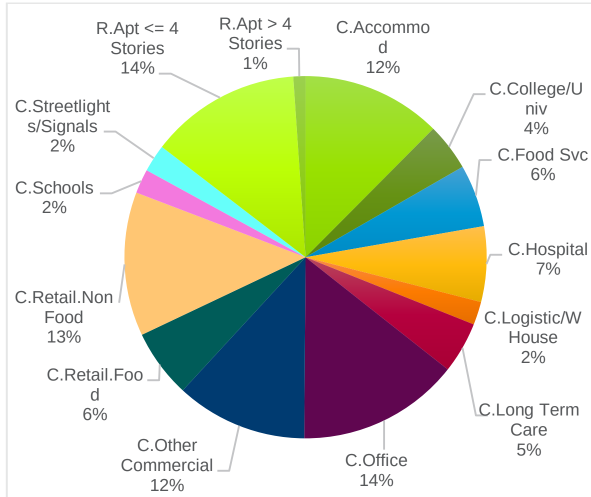
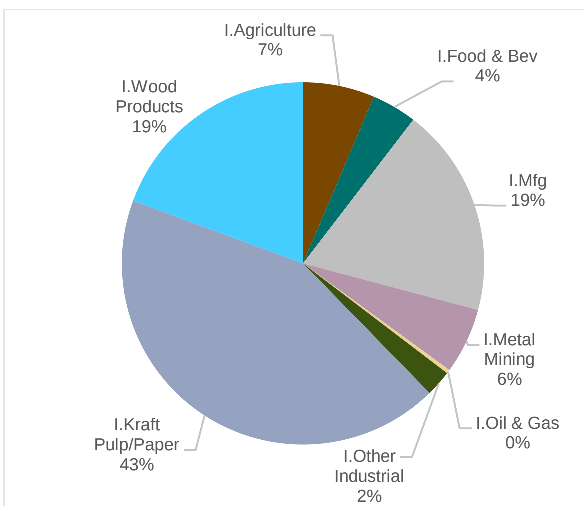


Figure 4-7. Industrial Electric Energy Economic Potential Customer Segment Breakdown in 2025

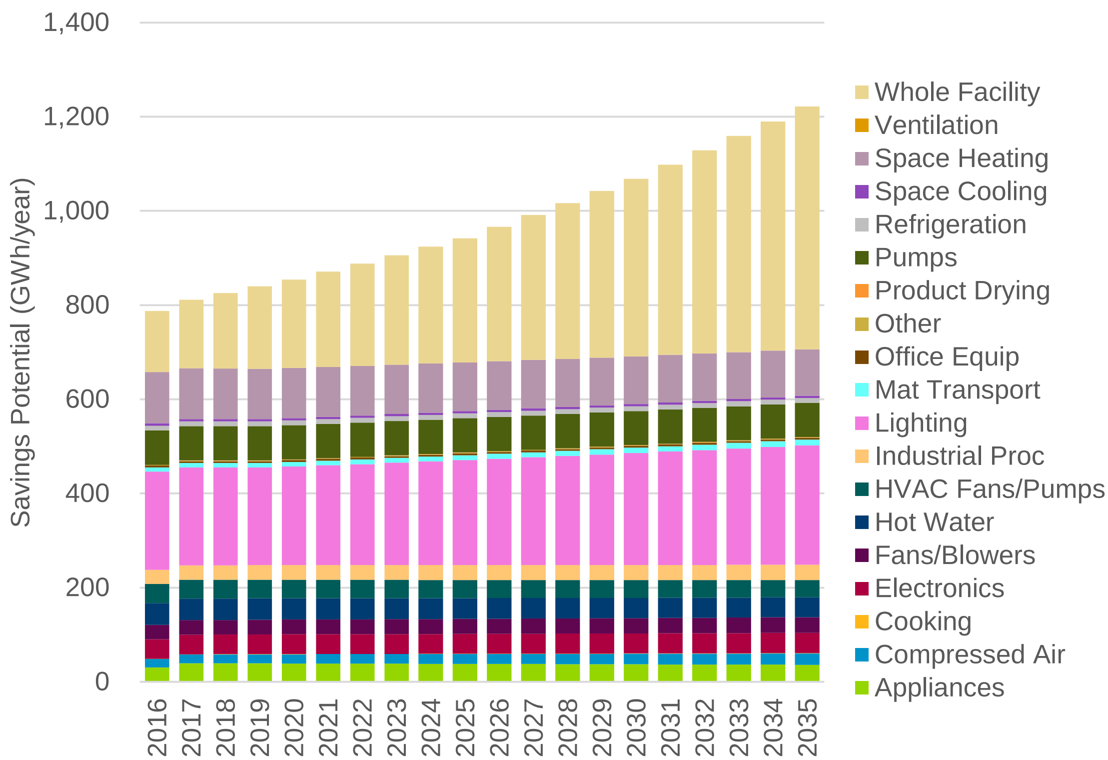


Source: Navigant

4.2.3 Results by End-use

Depending on the end-use category, between 77% and 100% of the technical energy potential was cost-effective. Lighting, whole facility, and space heating were the three highest-impact end-use categories in technical potential that also had high economic potential of 99%, 95%, and 83% of technical potential, respectively. Whole facility potential dropped slightly due to non-cost effectiveness of certain measures in specific customer segments, yet overall economic potential continued to grow along with housing stock and introduction of whole-facility new construction practices in 2026 and 2031. Figure 4-8 shows the economic electric energy potential by end-use, with associated data in Table E-13 in Appendix E.

Figure 4-8. Electric Energy Economic Savings Potential by End-Use (GWh/year)



Source: Navigant

Figure 4-9, Figure 4-10 and Figure 4-11 provide the breakdown of economic energy potential by end-use categories within each sector. The 2025 breakdowns of economic potential were quite similar to the technical potential.

Figure 4-9. Residential Electric Energy Economic Potential End-Use Breakdown in 2025

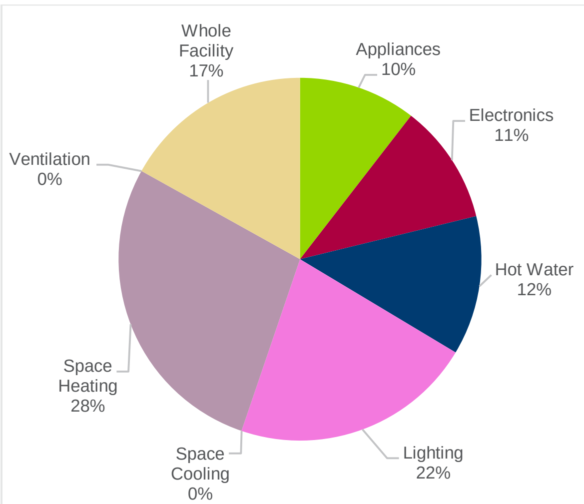


Figure 4-10. Commercial Electric Energy Economic Potential End-Use Breakdown in 2025

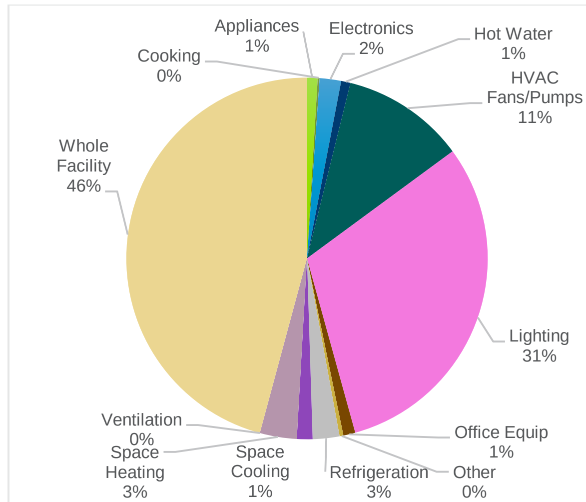
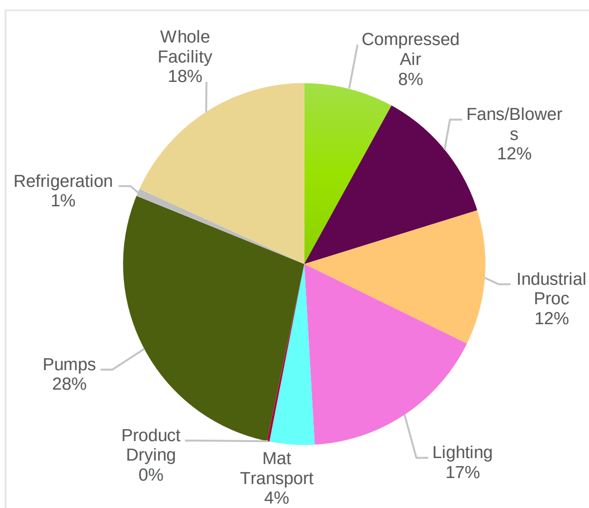


Figure 4-11. Industrial Electric Energy Economic Potential End-Use Breakdown in 2025

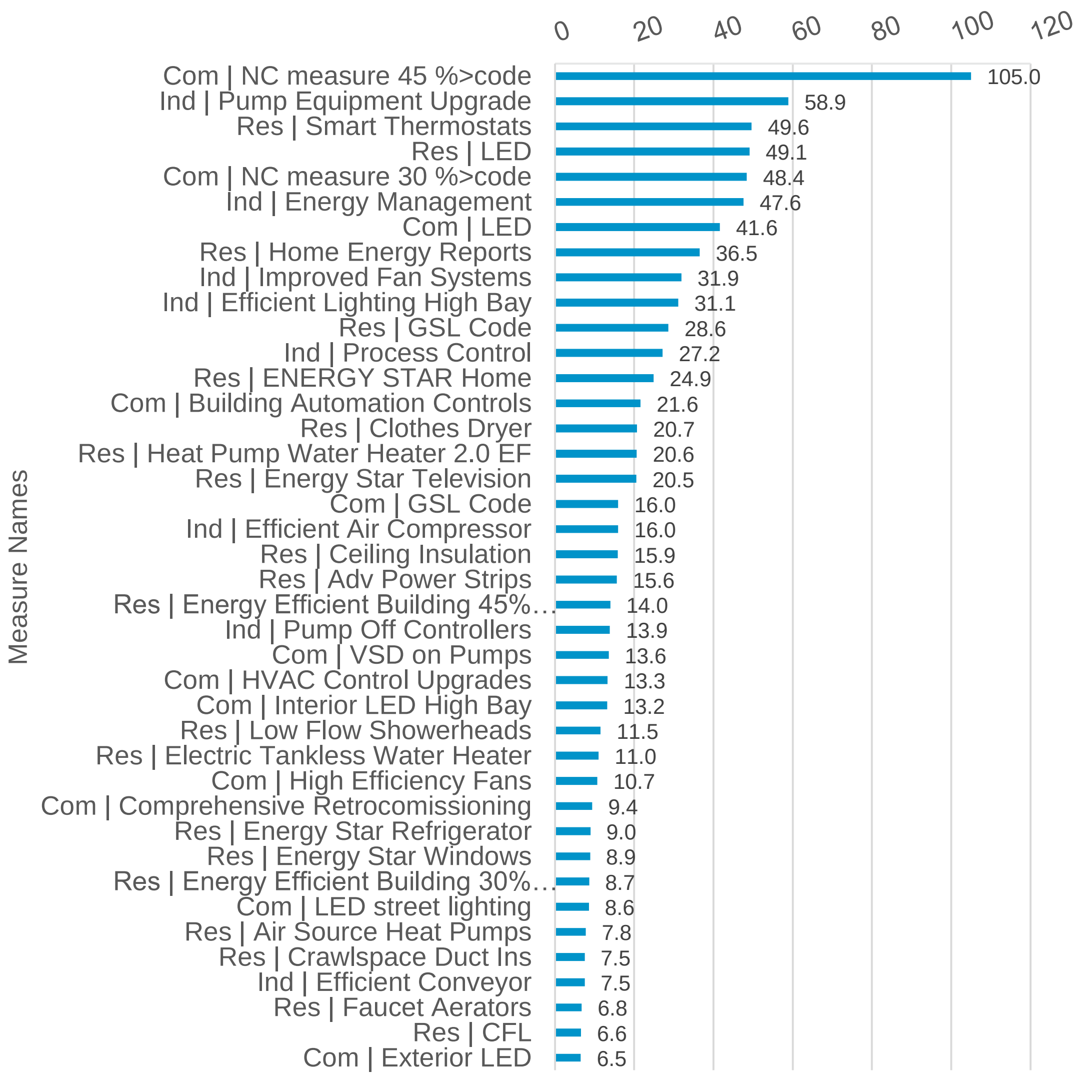


Source: Navigant

4.2.4 Results by Measure

The measure-level economic energy savings potential shown in Figure 4-12 is prior to adjustments made to competition groups as detailed in Section 3.2.4. The figure highlights the economic potential from the top 40 highest energy-savings measures. When compared with technical potential, the commercial whole-building new construction practices that are 30% above code fell from the 2nd to the 5th position, and the collection of commercial LED measure fell from the 4th to the 7th position. These measures lost savings potential because they were uneconomic for certain, but not all, customer segments. Otherwise, the position of the highest ranking measures for both economic and technical potential were generally consistent.

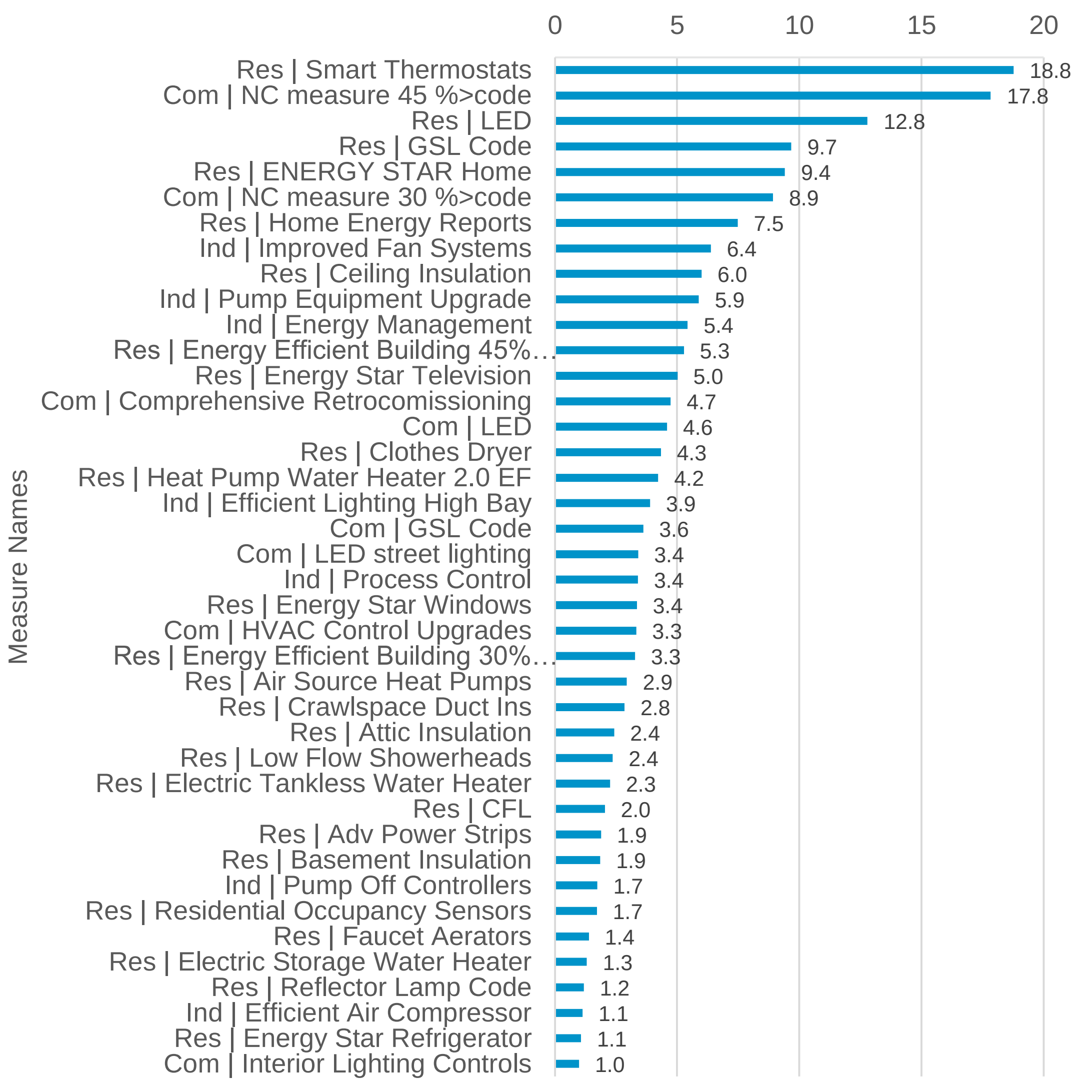
Figure 4-12. Top 40 Measures for Electric Energy Economic Savings Potential in 2025 (GWh/year)



Source: Navigant

Figure 4-13 provides the 40 highest demand-saving measures regarding economic potential in 2025. Compared with the technical potential results, the commercial whole-building new construction practices that are 30% above code fell from the 4th to the 6th position. The R-2000 standard new home measure which ranked 7th in technical potential was not economic and no longer appears in the top 40 list. The position of most other top-ranked measure remained relatively consistent.

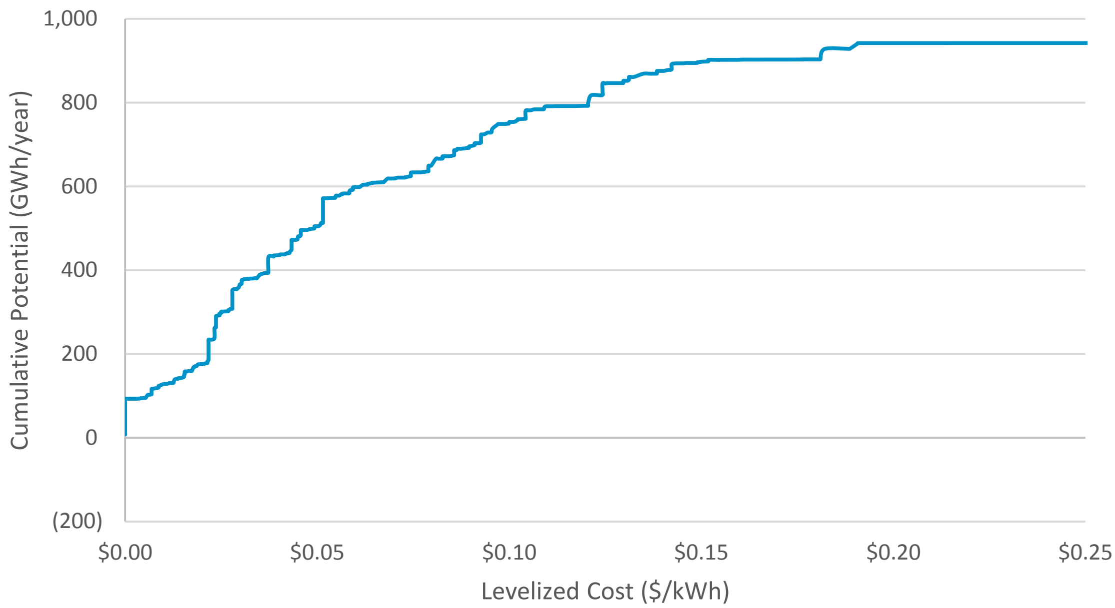
Figure 4-13. Top 40 Measures for Electric Demand Economic Savings Potential in 2025 (MW)



Source: Navigant

Figure 4-14 provides a supply curve of savings potential versus levelized cost of savings in $/kWh for all measures considered in the study. This curve shows only those measures with a levelized cost less than $0.25/kWh, though the full curve would extend beyond this to measures with more costly savings. The savings potential seen at a cost of $0/kWh was due to code-change measures, which have zero costs in the model.

Figure 4-14. Supply Curve of Electric Energy Economic Potential (GWh/year) vs. Levelized Cost ($/kWh) in 2025



Source: Navigant

APPENDIX A. ADDITIONAL MODEL RESULTS AND INPUT ASSUMPTIONS

A.1 Detailed Model Results

See attachment, "FortisElectric_Appendix_A1_2016-10-31.xlsx," for granular results from the DSMSim™ model.

A.2 Measure List and Characterization Assumptions

See attachment, "FortisElectric_Appendix_A2_2016-10-31.xlsx," for granular measure input to the model.

A.3 Other Key Input Assumptions

See attachment, "FortisElectric_Appendix_A3_2016-10-31.xlsx," for key assumptions about building stocks, end-use intensities, avoided costs, discount rates, etc. used by the model.

APPENDIX B. APPROACH TO BASELINE CALIBRATION

B.1 End Use Definitions

Table B-1. Description of End-Uses

Segment	End-Use	Definition
Residential	Appliances	Large/small appliances including ovens, refrigerators, freezers, clothes washers, etc.
	Electronics	Televisions, computers and related peripherals, and other electronic systems
	Water Heating	Heating of water for domestic hot water use
	Lighting	Interior, exterior and holiday/seasonal lighting
	Other	Miscellaneous loads
	Space Cooling	All space cooling, including both central AC and room or portable AC
	Space Heating	All space heating, including both primary heating and supplementary heating
	Ventilation	Ventilation requirements for space heating/cooling including furnace fans
	Whole Building	The whole building end-use reflects the total customer load. The residential whole building end-use is used to characterize measures that impact overall energy consumption such as home energy reports, and new construction home/building measures such as ENERGY STAR and Net Zero homes.
Commercial	Cooking	Food preparation equipment including ranges, broilers, ovens, and griddles
	HVAC Fans/Pumps	HVAC auxiliaries including fans, pumps, and cooling towers
	Hot Water	Hot water boilers, tank heaters, and others
	Lighting	Interior, exterior and holiday/seasonal lighting for main building areas and secondary areas
	Office Equipment	Computers, monitors, servers, printers, copiers and related peripherals
	Other	Miscellaneous loads including elevators, gym equipment, and other plug loads
	Refrigeration	Refrigeration equipment including fridges, coolers, and display cases
	Space Cooling	All space cooling equipment, including chillers, and DX cooling.
	Space Heating	All space heating equipment, including boilers, furnaces, unit heaters, and baseboard units
	Whole Building	The whole building end-use reflects the total customer load. The commercial whole building end-use is used to characterize measures that impact overall energy consumption such as building automation controls, new construction measures, occupant behavior, and retro-commissioning.
Industrial	Boilers	Boilers for industrial applications
	Compressed Air	Air compressors and related equipment
	Fans & Blowers	Fans and blowers for ventilation, combustion and pneumatic conveyance
	Industrial Process	Industrial processes for various applications including mechanical, electrical, and chemical processes
	Lighting	Interior, exterior, and seasonal lighting loads
	Material Transport	Feedstock and product movement by conveyance or stackers
	Process Compressors	Process compressors
	Process Heating	Process heating including heat treatment and industrial ovens
	Product Drying	Industrial drying equipment and systems
	Space Heating	All non-process space heating equipment (e.g., comfort heating)
	Pumps	Process pump systems
	Refrigeration	Industrial refrigeration
	Whole Building	The whole building end-use reflects the total customer load. The commercial whole building end-use is used to characterize measures that impact overall energy consumption such as energy management, and new plant measures.

Source: Navigant

B.2 Residential Sector – Additional Detail

In order to characterize the Residential sector energy usage, Navigant developed a bottom-up analysis based on the mix of fuel shares and the types of equipment used for each end-use. Navigant developed these estimates for FortisBC Electric based on a review of FortisBC' 2012 REUS and BC Hydro's 2014 REUS, with survey results for the Southern Interior region. In general, Navigant consistently used the 2014 REUS as the main resource for the calibration of the residential sector. This end-use survey provides detailed residential household data as well as detailed information in relation to each of the end-uses, existing equipment, main and secondary fuel systems, and saturation levels for common energy efficiency measures.

The following sections summarized the approach for developing the following:

- **Residential Stock** for each residential segment
- **Fuel shares** and **equipment shares** for each residential segment in each region
- **End use intensities (EUIs)** for each residential segment in each region

Residential Stock

To develop the housing stock of FortisBC Electric residential customers, Navigant used the 2013 CPR and StatsCan census data for the FortisBC Electric territory. The housing stock for the non-apartment residential segments (e.g., Single Family Detached/Duplexes, single family attached, and other residential) and for the apartment segments (less than 4 stories, and greater than 4 stories) were developed independently.

- **Non-Apartment Residential Segments** - To develop estimates for the non-apartment segments, Navigant translated the non-apartment residential stock from the 2013 CPR to the CPR non-apartment segments. Since the definitions of the non-apartment segments in this CPR are different relative to the 2013 CPR, Navigant used the distribution of non-apartment stock employed by StatsCan[39]. The StatsCan segments are consistent with this CPR's residential segments which allowed for the use of the StatsCan data.
- **Apartment Residential Segments** - To develop estimates for the apartment segments, Navigant also relied on the StatsCan data. StatsCan disaggregates apartments into low-rise and high-rise apartment units. The StatsCan data, however, is only representative of communities that are part of the census-defined CA or CMAs. In the FortisBC Electric context, this means that the StatsCan data only incorporates survey data from two CAs, which account for approximately 62% of all FortisBC Electric residential customers[40]. For the balance of the service territory which is primarily

[39] The StatsCan data provides census results for the number of residential households in BC's Conglomerated Areas (CA) and Census Metropolitan Area (CMA). This data was particularly important given that the StatsCan residential segmentation is largely consistent with the Navigant-proposed segmentation.

[40] For the FortisBC Electric service territory, Navigant used data for two census areas (Kelowna and Penticton) in developing the housing splits. The Kelowna and Penticton CAs, combined, account for approximately 62% of the estimated residential stock in FortisBC Electric territory.

composed of smaller communities, Navigant assumed that the proportion of apartment units would be 50% lower than the proportion in the CA/CMAs reported by StatsCan.[41]

Fuel Shares and Equipment Shares

Using the data provided by BC Hydro's 2014 REUS study and FortisBC's 2012 REUS, Navigant developed specific fuel share and equipment estimates for each residential segment in each region. The translation of data from both REUS studies to the CPR analysis was straightforward given the granularity of the results. For example, the residential survey reports most information aggregated based on four types of dwellings (House/Duplex, Row/Townhouse, Apartment/Condo, and Mobile Home/Other), which are largely consistent with the residential segments employed for this CPR. The only adjustment made by Navigant, as shown by the tables below, is that the results for the "Apartment/Condo" category are used for both apartment segments.

- Table B-1 shows the mix of fuel shares for each residential segment by region
- Table B-3 shows the types of equipment used for the **Space Heating**, **Space Cooling**, and **Water Heating** end-uses by residential segment and region
- Table B-4 shows the types of **Lighting** and **Appliance** equipment by residential segment and region

Table B-2. FortisBC Electric Residential Fuel Shares (Percentage of Homes Using Each Energy Type)

Building Type	End-use	Southern Interior		
		Gas	Electric	Other
Single Family Detached/Duplexes	Space Heating	72%	27%	1%
	Water Heating	69%	29%	2%
Single Family Attached	Space Heating	67%	31%	2%
	Water Heating	58%	41%	2%
Apartments <= 4 Storeys	Space Heating	28%	69%	3%
	Water Heating	60%	40%	0%
Apartments > 4 Storeys	Space Heating	28%	69%	3%
	Water Heating	60%	40%	0%
Other Residential	Space Heating	52%	22%	26%
	Water Heating	62%	38%	0%

Source: Navigant analysis of FortisBC Gas 2012 REUS and BC Hydro 2014 REUS

[41] It is worth noting that the apartment estimates developed by Navigant are approximately double the apartment stock used by the 2013 CPR. Although the magnitude of the difference is substantial, the Navigant estimates are consistent with the StatsCan CA/CMA data. Navigant considers that the StatsCan data represent the most accurate source of information to estimate the housing stock of apartment units.

For the **Space Heating** end-use, the team calculated the electricity consumption based on the distribution of equipment types such as furnaces, boilers, and heat pumps across efficiency levels and on the electricity consumption at each of these efficiency levels. Navigant used the 2014 REUS to determine the distribution of equipment across fuel types (e.g., gas furnace and electric furnace). Since this study does not estimate the distribution of equipment across efficiency types, Navigant estimated the equipment distribution based on its past CPR experience. In relation to the overall electricity consumption from space heating, the team applied these equipment shares to the average unit energy consumption (UEC) by household type and region estimated in BC Hydro's *2010 Residential Conditional Demand Analysis* (CDA) study.[42]

The space heating equipment shown in the table below includes both gas and electric equipment. For each fuel, the percentages shown represent the fraction of households using each type of equipment. The gas equipment values (excluding gas fireplaces) add up to 100%, and the electric equipment values also add up to 100%. For example, 54% of all Single Family Detached/Duplexes homes with gas as their primary space heating use 0.9 AFUE furnaces. Similarly, 30% of gas-space heating homes use 0.8 AFUE furnaces, and 2% use 0.6 AFUE furnaces. A similar logic applies for the electric equipment. For gas fireplaces, the values shown represent the fraction of homes with gas fireplaces.

For the **Water Heating** end-use, Navigant followed the same approach used for Space Heating, using the 2014 REUS to determine the distribution of equipment across fuel types, and estimating the distribution of water heating equipment by efficiency levels. The team used the measure characterization inputs to establish the water heating equipment UEC by household type and region.

For the **Space Cooling** end-use, the team used the 2014 REUS to determine the distribution of space cooling equipment across equipment types. Navigant used the measure characterization inputs to establish the space cooling equipment UEC by household type and region. In relation to the 2014 REUS study, it is worth noting that the Southern Interior region has a much higher uptake of space cooling equipment. As a result, the space cooling EUI is higher in the Southern Interior relative to other regions.

[42] BC Hydro's 2010 CDA was used over FortisBC Electric's 2013 CDA given the increased granularity provided for primary and secondary space heating equipment, as well as based on regional differences.

Table B-3. Residential Equipment Shares (%)

End-use	Equipment Type	Fraction of Households Using Equipment Type (%)				
		Single Family Detached/Duplexes	Single Family Attached	Apartments <=4 Storeys	Apartments >4 Storeys	Other Residential
Space Heating	Gas Furnace 0.6 AFUE	2%	5%	4%	4%	3%
	Gas Furnace 0.8 AFUE	30%	26%	30%	30%	44%
	Gas Furnace 0.9 AFUE	54%	48%	54%	54%	44%
	Gas Boiler 0.7 EF	0%	0%	0%	0%	0%
	Gas Boiler 0.8 EF	10%	13%	7%	7%	4%
	Gas Boiler 0.9 EF	5%	7%	4%	4%	4%
	Gas Fireplace	98%	79%	79%	79%	79%
	Electric Furnace	10%	5%	12%	12%	10%
	Electric Boiler	0%	0%	0%	0%	0%
	Electric Resistance *(Baseboard, ceiling or floor cable, etc.)*	58%	90%	85%	84%	66%
	Air Source Heat Pump	28%	4%	2%	2%	20%
	Ground / Water Source Heat Pump	3%	1%	0%	1%	3%
Water Heating	Gas Water Heater Conventional	0%	0%	0%	0%	0%
	Gas Water Heater Condensing	0%	0%	0%	0%	0%
	Gas DHW Tankless	0%	0%	0%	0%	0%
	Electric DHW Std.	75%	75%	75%	75%	75%
	Electric DHW High Efficiency	24%	25%	23%	23%	25%
	Electric DHW Tankless	1%	1%	1%	1%	0%
Space Cooling	Air Conditioning (any system)	62%	62%	62%	62%	62%
	Central Air	40%	40%	40%	40%	40%
	Window/ Room AC	25%	25%	25%	25%	25%

^Note - Equipment types using same energy type add to percentage of homes with end use. Space heating system may add to >100% if secondary systems included (i.e. fireplaces).

For the **Appliances** end-use, Navigant calculated the electricity consumption based on the distribution of appliance types such as refrigerators and freezers across efficiency levels and on the electricity consumption at each efficiency level. Regional differences based on the average number of appliances per household in each region are not reflected in Table B-4. Appliances and Lighting Equipment (%)Table B-4; they are, however, reflected in the electricity consumption estimates. The team used the 2014 REUS to determine the efficiency levels and the average number of appliances by household type and region.

For the **Lighting** end-use, the team calculated electricity consumption based on an estimate of the number of hours of lighting for each lighting type, as shown in Table B-4. These estimates have been derived based on the average number of bulb types found across different household types. For example, apartment units have a slightly higher penetration of LED bulbs than other residential segments. However, in general, variations across segments are relatively minor. In addition to the estimates of lighting-hours, Navigant also employed differences in the average number of bulbs found across regions to provide a more accurate representation of lighting energy use across regions and household types. For example, households in Vancouver Island and Southern Interior have the highest penetration of bulbs, whereas Northern BC homes have the lowest penetration. The team used the 2014 REUS to determine the differences in lighting types across regions and household types.

Table B-4. Appliances and Lighting Equipment (%)

		Percentage of Households with Appliance or Equipment Type				
End Use	Equipment Type	Single Family Detached/Duplexes	Single Family Attached	Apartments <=4 Storeys	Apartments > 4 Storeys	Other Res
Appliances	Fridge Low Efficiency	87%	67%	54%	54%	55%
	Fridge ENERGY STAR®	10%	30%	41%	41%	33%
	Freezer Low Efficiency	52%	31%	12%	12%	46%
	Freezer ENERGY STAR®	23%	13%	6%	6%	21%
	Dishwasher Low Efficiency	8%	8%	8%	8%	7%
	Dishwasher ENERGY STAR®	74%	76%	58%	58%	49%
	Clothes Washer Low Efficiency	54%	53%	34%	34%	49%
	Clothes Washer ENERGY STAR®/Front load	46%	45%	28%	28%	42%
	C. Dryer Elect. Low Efficiency	60%	60%	18%	18%	56%
	C. Dryer Elect. ENERGY STAR®	32%	32%	37%	37%	30%
	C. Dryer Gas Low Efficiency	2%	1%	0%	0%	1%
	C. Dryer Gas ENERGY STAR®	1%	0%	0%	0%	0%
	Stove Gas	21%	13%	9%	9%	12%
	Stove Elect	86%	87%	94%	94%	85%
Lighting	Lighting Type	Percentage of Lighting Hours Using Lighting Type				
Lighting	Incandescent	38%	37%	35%	35%	34%
	CFL	17%	17%	15%	15%	20%
	LED	19%	21%	24%	24%	20%
	Strip T12	4%	8%	3%	3%	6%
	Strip T5/T8	4%	8%	3%	3%	6%
	Other lighting	18%	22%	13%	13%	18%

Source: Navigant analysis of BC Hydro 2014 REUS

End-Use Intensities (EUIs)

The next step of the residential calibration process required the roll up of the fuel share and equipment share estimates in order to establish EUIs for each residential segment in each region. Based on this approach, Navigant developed bottom-up EUI estimates for Space Heating, Water Heating, Space Cooling, Appliances, and Lighting. The EUIs for the Electronics and Other End-Uses were each derived as a proportion of the Appliances EUI.

Table B-5 shows an example of the calibration process followed for Single Family Detached/Duplexes in the Southern Interior region. The process used to calibrate the estimate of energy use builds on an estimate of the percentage of homes with a particular end-use and fuel type, using a particular type of equipment and efficiency within an end-use. The fuel shares (column A), equipment shares (column E), and an estimated level of energy use for each equipment type (column F) are multiplied to obtain an estimated UEC (column G). In the example below, the total consumption across major and small appliances is summed (column H).   The resulting EUCs are summed across end-uses to obtain a segment-level intensity (kWh per year), which is then calibrated to the match the actual target intensity determined from FortisBC Electric sales data.

This same process is repeated across all residential and commercial segments in each region. Ultimately, EUIs that matched the segment-level sales targets in the base year were determined for each end-use and segment, and across all regions.

With the base year EUIs established, the Reference Case EUIs were determined based on the residential and commercial sector EUI trends. The approach for developing the EUI trends is described in the body of the report.

Table B-6 shows the residential EUIs by residential segment for the base year. With the base year EUIs established, the Reference Case EUIs were determined based on residential sector EUI trends. The approach for developing the EUI trends is described in the body of the report.

Table B-5. Example of Calibration Process (Single Family Detached/Duplexes – Southern Interior)

A	B	C	D	E	F	G	H	I
End Use	Fuel Share (%)	Equipment	Efficiency	Equipment Share (%)	Annual Energy Use (kWh)	End-Use Weighted Avg. Use (kWh)	Total Uncalibrated Consumption (kWh)	Total Calibrated Consumption (kWh)
Space Heating	25%	…	…	…	…	…	2781	2988
Water Heating	39%	…	…	…	…	…	1122	1206
Cooling	100%	…	…	…	…	…	240	258
Appliances	100%	Fridge Low E	Low E	54%	555	2403	3123	3355
		Fridge Estar	Estar	46%	444			
		Freezer Low E	Low E	65%	522			
		Freezer Estar	Estar	29%	470			
		Dishwasher Low E	Low E	33%	289			
		Dishwasher Estar	Estar	49%	263			
		Clothes Washer Low E	Low E	54%	174			
		Clothes Washer Estar or Front lo	Estar	45%	89			
		C. Dryer Elect. Low E	Low E	63%	938			
		C. Dryer Elect. Estar	Estar	34%	641			
		C. Dryer Gas Low E	Low E	7%	0			
		C. Dryer Gas Estar	Estar	4%	0			
		Stove Gas	Average	16%	0			
		Stove Elect	Average	84%	305			
		Other Appliances	n/a	n/a	n/a	Deemed to be equivalent to 30% of major appliances		
Lighting	100%	…	…	…	…	…	1817	1952
Electronics	100%	…	…	…	…	…	1405	1510
Other	100%	…	…	…	…	…	937	1007
Ventilation	25%	…	…	…	…	…	859	923
Estimated Consumption (kWh per year)							12285	**13198**
Target Consumption (kWh per year)		- Determined based on Fortis Electric 2014 Usage per Customer (UPC) data					13198	**13198**
	Uncalibrated vs. Target						**93%**	**100%**

Source: Navigant

Table B-6. Base Year Residential EUIs (kWh/household)

Building Type	End-Use	Average Use per Household (kWh)
		Southern Interior
Single Family Detached/Duplexes	Space Heating	2,988
	Water Heating	1,206
	Cooling	258
	Appliances	3,355
	Lighting	1,952
	Electronics	1,510
	Other	1,007
	Ventilation	923
	Total	**13,198**
Single Family Attached	Space Heating	1,747
	Water Heating	940
	Cooling	172
	Appliances	2,234
	Lighting	1,323
	Electronics	782
	Other	447
	Ventilation	810
	Total	**8,455**
Apartments <= 4 Storeys	Space Heating	1,749
	Water Heating	1,191
	Cooling	157
	Appliances	1,852
	Lighting	941
	Electronics	1,019
	Other	741
	Ventilation	607
	Total	**8,257**
Apartments > 4 Storeys	Space Heating	1,935
	Water Heating	1,105
	Cooling	146
	Appliances	1,868
	Lighting	873
	Electronics	1,028
	Other	560
	Ventilation	768
	Total	**8,282**
Other Residential	Space Heating	1,988
	Water Heating	1,975
	Cooling	378
	Appliances	2,499
	Lighting	1,172
	Electronics	875
	Other	500
	Ventilation	372
	Total	**9,759**

Source: Navigant analysis

B.3 Commercial Sector – Additional Detail

To characterize the Commercial sector, Navigant developed a bottom-up analysis based on the mix of fuel shares and the types of equipment used for each end-use. To analyze the commercial sector, Navigant reviewed FortisBC's *2015 Commercial End-use Survey,* FortisBC Gas's 2010 CPR, the FortisBC Electric's 2013 CPR, and BC Hydro's *2009 Commercial End-use Survey.*

The following sections summarized the approach for developing the following:

- **Fuel Shares** and **Equipment Shares** for each commercial segment
- **End use intensities (EUIs)** for each commercial segment
- **Commercial Floor Space Stock** for each commercial segment

Fuel Shares and Equipment Shares

Fuel share estimates were developed for end-uses that generally show a split across gas and electricity supply: Cooking, Hot Water, and Space Heating. All other end-uses were treated as electric-only end-uses. Similarly, equipment shares were estimated for end-uses for which the available information enabled a detailed assessment of equipment types and equipment efficiencies. These included Space Heating, Space Cooling, and Lighting. The EUIs for the other end-uses were estimated at an end-use level.

Navigant developed the fuel share estimates for the commercial sector based on a review of BC Hydro's 2014 CEUS, and FortisBC Electric's 2013 CPR. Navigant found that the fuel shares estimates used in the 2013 CPR, which were based on surveys results from 2009, were not as granular as those developed in BC Hydro's 2014 CEUS. Using the data provided by 2014 CEUS, Navigant developed fuel share and equipment estimates for each commercial **segment**. The 2014 CEUS results were disaggregated across each region and reported for each commercial segment.[43]

To develop the equipment shares estimated, Navigant reviewed FortisBC's 2015 CEUS study and the Southern Interior results of BC Hydro's 2014 CEUS. Both of these end-use surveys provide detailed commercial building characteristics, and detailed information in relation to end-uses, existing equipment, main and secondary fuel systems, and saturation levels for common energy efficiency measures. The use of the FortisBC 2015 CEUS was secondary to the BC Hydro 2014 CEUS as a result of the increased level of granularity offered by the BC Hydro study. BC Hydro's 2014 CEUS provided detailed end-use results at a commercial-segment level, whereas the FortisBC 2015 CEUS was limited to sector-level results.

[43] Given the granularity of the 2014 CEUS results, the sample of commercial customers in certain regions and segments was limited. In this cases, the fuel share estimates were determined based on the province-wide results.

Table B-7 and Table B-8 summarize the results of this analysis. These tables show the estimated fuel shares and equipment shares for each commercial segment and climate region.

Table B-7. Commercial Fuel Shares (Percentage of Segment Using Each Energy Type)

Building Type	End-use	Southern Interior	
		Gas	Electric
Accommodation	Cooking	74%	26%
	Hot Water	78%	22%
	Space Heating	67%	33%
Colleges/ Universities	Cooking	52%	48%
	Hot Water	63%	32%
	Space Heating	53%	42%
Food Service	Cooking	79%	21%
	Hot Water	44%	56%
	Space Heating	47%	41%
Hospitals	Cooking	52%	48%
	Hot Water	93%	7%
	Space Heating	93%	7%
Logistics/ Warehouses	Cooking	0%	100%
	Hot Water	8%	67%
	Space Heating	42%	33%
Long Term Care	Cooking	52%	48%
	Hot Water	50%	38%
	Space Heating	50%	50%
Offices	Cooking	6%	94%
	Hot Water	37%	63%
	Space Heating	59%	39%
Other	Cooking	22%	78%
	Hot Water	44%	48%
	Space Heating	52%	41%
Retail - Food	Cooking	26%	74%
	Hot Water	33%	56%
	Space Heating	63%	25%
Retail - Non Food	Cooking	9%	91%
	Hot Water	36%	64%
	Space Heating	55%	41%
Schools	Cooking	17%	83%
	Hot Water	67%	17%
	Space Heating	80%	20%

Source: Navigant analysis of FortisBC Gas 2010 CPR and BC Hydro 2014 CEUS

Table B-8. Commercial Equipment Shares (%)

End-use	Equipment Type	Percentage of Equip in End-use within Fuel Type^										
		Accommodation	Colleges/ Universities	Food Service	Hospital	Logistics/ Warehouses	Long Term Care	Office	Other Commercial	Retail - Food	Retail - Non Food	Schools
Space Heating	Gas Boiler Low E	35%	40%	6%	73%	4%	34%	8%	10%	1%	1%	40%
	Gas Boiler High E	9%	0%	2%	19%	1%	10%	2%	4%	0%	0%	11%
	Gas Rooftop or Other Forced Air (Low E)	45%	60%	64%	6%	60%	44%	64%	53%	72%	65%	35%
	Gas Rooftop or Other Forced Air (High E)	11%	0%	18%	2%	11%	12%	17%	21%	20%	25%	9%
	Gas Unit Heater (Conventional.)	0%	0%	8%	0%	20%	0%	7%	8%	5%	6%	5%
	Gas Unit Heater (Condensing)	0%	0%	2%	0%	4%	0%	2%	3%	1%	2%	1%
	Electric Heat Resistance (Low E)	62%	50%	32%	79%	46%	68%	48%	40%	38%	44%	2%
	Electric Heat Resistance (High E)	16%	0%	9%	21%	9%	19%	13%	15%	11%	17%	1%
	Electric Forced Air System (Low E)	18%	50%	46%	0%	38%	10%	31%	33%	40%	28%	77%
	Electric Forced Air System (High E)	5%	0%	13%	0%	7%	3%	8%	12%	11%	11%	20%
Space Cooling	Chiller Low E	7%	20%	1%	37%	2%	5%	1%	2%	2%	1%	4%
	Chiller High E	1%	3%	0%	15%	1%	0%	0%	1%	1%	0%	1%
	Packaged Terminal AC Low E	45%	59%	70%	34%	54%	46%	52%	37%	38%	46%	55%
	Packaged Terminal AC High E	8%	8%	10%	14%	18%	3%	24%	20%	18%	20%	7%
	Ventilation Cooling	31%	11%	17%	0%	22%	33%	20%	35%	36%	30%	27%
Lighting	VSD Ventilation	8%	0%	1%	0%	3%	12%	3%	6%	5%	3%	6%
	Strip Lighting T12	5%	22%	8%	0%	15%	4%	26%	18%	22%	24%	19%
	Strip Lighting T8 /T5	9%	58%	31%	71%	57%	23%	40%	40%	47%	43%	68%
	HID (MV / HPS / MH)	1%	4%	0%	2%	13%	0%	1%	4%	2%	3%	3%
	Gen Service Incandescent	15%	3%	26%	4%	8%	7%	13%	15%	11%	12%	4%
	Gen Service CFL or LED	69%	14%	35%	23%	6%	66%	20%	23%	18%	19%	6%

Source: Navigant analysis of FortisBC Gas 2010 CPR and BC Hydro 2014 CEUS

End-Use Intensities (EUIs)

The next step of the commercial calibration process required the roll up of the fuel share and equipment share estimates in order to establish EUIs for each commercial segment in each region. Based on this approach, Navigant developed bottom-up EUI estimates for Space Heating, Space Cooling, and Lighting. EUIs were developed for each commercial segment according to the calibration process. Based on the use of BC Hydro's 2014 CEUS, the EUIs established for FortisBC Electric's commercial customers are consistent with those applied to BC Hydro's commercial customers in the Southern Interior region. These EUIs have been applied for the base year analysis. Table B-9 presents the EUIs established for each end-use, and commercial segment. With the EUIs established for the base year, the Reference Case EUIs were determined based on the commercial EUI trends. The approach for developing the commercial EUI trends is described in the body of the report.

Table B-9. Base Year Commercial EUIs (kWh/m2) by Segment

Segment	End-Use	Southern Interior
Accommodation	Cooking	1
	HVAC Fans/Pumps	24
	Hot Water	3
	Lighting	53
	Office Equipment	9
	Other	8
	Refrigeration	2
	Space Cooling	6
	Space Heating	4
	Total	**110**
Colleges/ Universities	Cooking	1
	HVAC Fans/Pumps	66
	Hot Water	4
	Lighting	80
	Office Equipment	13
	Other	12
	Refrigeration	1
	Space Cooling	5
	Space Heating	5
	Total	**187**
Food Service	Cooking	13
	HVAC Fans/Pumps	44
	Hot Water	26
	Lighting	102
	Office Equipment	1
	Other	49
	Refrigeration	12
	Space Cooling	35
	Space Heating	7
	Total	**288**
Hospitals	Cooking	3
	HVAC Fans/Pumps	57
	Hot Water	0
	Lighting	73
	Office Equipment	4
	Other	54
	Refrigeration	3
	Space Cooling	12
	Space Heating	11
	Total	**217**
Logistics/ Warehouses	Cooking	0

Segment	End-Use	Southern Interior
	HVAC Fans/Pumps	11
	Hot Water	1
	Lighting	40
	Office Equipment	2
	Other	17
	Refrigeration	7
	Space Cooling	3
	Space Heating	3
	Total	**83**
Long Term Care	Cooking	3
	HVAC Fans/Pumps	29
	Hot Water	4
	Lighting	49
	Office Equipment	2
	Other	11
	Refrigeration	2
	Space Cooling	5
	Space Heating	13
	Total	**117**
Offices	Cooking	0
	HVAC Fans/Pumps	32
	Hot Water	2
	Lighting	58
	Office Equipment	9
	Other	15
	Refrigeration	0
	Space Cooling	8
	Space Heating	2
	Total	**127**
Other Commercial	Cooking	0
	HVAC Fans/Pumps	35
	Hot Water	2
	Lighting	32
	Office Equipment	1
	Other	9
	Refrigeration	12
	Space Cooling	4
	Space Heating	2
	Total	**97**
Retail – Food	Cooking	2
	HVAC Fans/Pumps	33
	Hot Water	4
	Lighting	113
	Office Equipment	0
	Other	26
	Refrigeration	204
	Space Cooling	5
	Space Heating	1
	Total	**387**
Retail – Non Food	Cooking	0
	HVAC Fans/Pumps	17
	Hot Water	1
	Lighting	67
	Office Equipment	2
	Other	24
	Refrigeration	1
	Space Cooling	6

Segment	End-Use	Southern Interior
	Space Heating	2
	Total	**120**
Schools	Cooking	1
	HVAC Fans/Pumps	21
	Hot Water	1
	Lighting	37
	Office Equipment	2
	Other	16
	Refrigeration	0
	Space Cooling	2
	Space Heating	3
	Total	**83**

Source: Navigant analysis

Description of EUI Trending Approach

BC Hydro's 2014 CEUS surveyed commercial customers across each commercial segment in relation to upgrades made to end-use equipment in the past 5 years. The annual incidence of end-use equipment upgrades is then used to estimate the reduction in energy consumption from the adoption of higher efficiency equipment.

Table B-10 summarizes the incidence of space cooling equipment upgrades.

Table B-10: Incidence of Space Cooling Commercial Equipment Upgrades (2014 CEUS)

Segment	Equipment Upgrades	
	Past 5 years (%)	Estimate per year (%)
Accommodation	15.0%	3.0%
Colleges & Universities	12.0%	2.4%
Food Service	22.0%	4.4%
Hospital	29.0%	5.8%
Logistics & Warehouses	25.0%	5.0%
Long Term Care	7.0%	1.4%
Offices	32.0%	6.4%
Other	32.0%	6.4%
Retail - Food	31.0%	6.2%
Retail - Non Food	31.0%	6.2%
Schools	11.0%	2.2%

Source: Navigant analysis of BC Hydro's 2014 CEUS

Although the BC Hydro 2014 CEUS did not survey the type of equipment or the efficiency of the upgrades, Navigant has estimated the potential reduction in consumption by analyzing the inputs used to characterize conservation measures corresponding to each end-use.[44] For example, to estimate the

[44] Navigant analyzed the energy efficiency measures corresponding to each end-use, comparing the base energy consumption against the efficient energy consumption.

improvement in space cooling equipment upgrades, Navigant analyzed the following space cooling measures:

- PTAC/PTHP Equipment
- Unitary and Split System AC/HP Equipment
- Heat Pump, Geothermal or Water Source
- CAC Tune-up
- Electric chiller
- Economizer controls

Based on its review of these measures, Navigant estimated the average improvement in space cooling measure efficiency at approximately 25%. This means that the efficient consumption of space cooling measures is estimated to be 75% of the base consumption (equivalent to a 25% improvement).

Navigant followed this process across all commercial segments for end-uses for which equipment upgrade information is reported in the BC Hydro 2014 CEUS. This includes the following end-uses:

- Lighting;
- Water Heating;
- Space Cooling;
- HVAC Fans/Pump; and
- Space Heating

Table B-11 summarizes the results for each end-use. As explained above and shown in this table, the improvement in space cooling consumption was estimated at 25%. The lowest improvement in consumption is estimated to be for water heating measures at 8%, and the highest improvement is 36% for the HVAC Fans/Pumps end-use.

Table B-11: Commercial Measure Efficiency – Base vs. EE

End Use	Improvement in End-Use Efficiency (%)	EE as % of Base consumption (%)
Lighting	33%	67%
Water Heating	8%	92%
Space Cooling	11%	89%
HVAC Fans/Pump	36%	64%
Space Heating	25%	75%

Source: Navigant analysis of measure characterization

The average change in EUI can be calculated using two factors; (1) the incidence of equipment upgrades (for each end-use) and (2) the estimate improvement in consumption (also for each end-use). The following example estimates the space cooling EUI change (or the *EUI trend)* for the Accommodation sector, assuming a base year EUI of 10kWh/m2.

In Year 1 of this example, all of the space cooling equipment is assumed to be the *base* measure. By Year 2, 6.4% of the space cooling equipment is upgrade and is assumed to be the *energy efficient* measure. This 6.4% is determined as the fraction of space cooling equipment that is upgraded each year, as shown in Table B-10. The space cooling *energy efficient* equipment is assumed to have an annual electricity consumption equivalent to 75% of the *base* measure consumption, as determined in Table B-11. As show below, the impact of equipment upgrades and an assumed EUI of 10kWh/m2, the change in EUI is estimated as a decrease of 1.6%, or 1.6kWh/m2.

This calculation is shown by the equation below:

Table B-12: Commercial Measure Efficiency – Base vs. EE

Parameter	Equipment Consumption (as % of Base)	Year 1	Year 2
Base Space Cooling Equipment	100%	100	93.6%
EE Space Cooling Equipment	75%	0%	6.4%
EUI Multiplier		100% $(100\% * 100\% + 0\% * 75\%)$	98.4% $(93.6\% * 100\% + 6.4\% * 75\%)$
EUI (kWh/m2)	**10.00**	**10.00**	**9.**84

$$EUI_{2015} = EUI_{2014} * (EE\ equipment_{\%} * EE\ consumption_{kWh} + Base\ equipment_{\%} * Base\ consumption_{kWh})$$

$$9.84 \frac{kWh}{m2} = 10.00 \frac{kWh}{m2} * (6.4\% * 75\% + 93.6\% * 100\%)$$

A limitation of this approach is that the estimated decrease in EUI inherently reflects the impact of DSM programs. Navigant has not attempted to extract the impact of DSM participation from the EUI trends.

Table 2-26 in the main body of this report, shows the EUI trends determined for each end-use and commercial segment.

Commercial Floor Space Stock

To determine the floor space of each commercial segment, Navigant first estimated commercial segment EUIs. To develop those intensity values, Navigant referenced the EUIs developed for BC Hydro's commercial customers in the Southern Interior region. The next step required to estimate the distribution of commercial sector sales across each segment. To determine electricity sales for each segment, the distribution of electricity sales in BC Hydro's Southern Interior region was analyzed. The FortisBC Electric commercial sales were estimated using the same allocation of sales across each segment. Navigant then applied the electric EUIs to the sales estimates by segment and calculated the resulting floor space for each commercial segment.

The FortisBC Electric floor space stocks by commercial segment is shown by the first column in Table B-13. The second and third columns shows the EUI and the resulting estimated sales by segment.

Table B-13. Base Year Floor Space, EUIs, and Sales by Segment

Segment	Floor Space (million m2)	EUI (kWh/m2)	Sales (GWh)
Accommodation	1.01	110	111
Colleges/Universities	0.27	187	50
Food Service	0.24	288	69
Hospital	0.29	217	63
Logistics/Warehouses	0.48	83	40
Long Term Care	0.23	117	27
Office	1.20	127	153
Other Commercial	1.37	97	133
Retail - Food	0.20	387	78
Retail - Non Food	1.39	120	167
Schools	0.41	83	34
Total	**7.09**	**130**	**924**

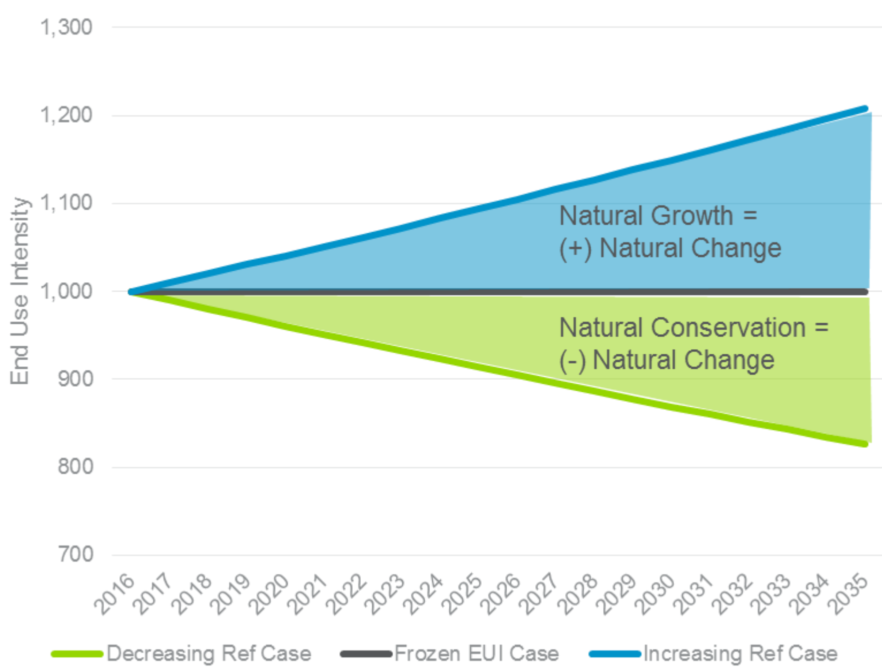
Source: Navigant analysis of FortisBC Electric stock, and EUIs

APPENDIX C. EXAMPLE OF NATURAL CHANGE

Navigant's definition of "natural change" stems from two related concepts: natural conservation and natural growth. Natural *conservation* is a well-established concept in demand side management programs, and typically refers to actions taken by utility customers—in absence of utility-sponsored programs—to improve energy efficiency and reduce consumption. These actions are occurring naturally, with no influence from utilities or program administrators. Natural *growth* refers to actions taken by utility customers to *increase consumption* without the involvement of utility-guided programs. An example of natural growth is home electronics, where customers may be increasing their electric consumption (e.g., through addition of more televisions, computers, etc.) and causing an increase in the electronics end-use intensity.

This study captures the effects of natural conservation as well as natural growth within the end-use intensities, and defines these effects as "natural change." When natural change is positive for an end-use category, it reflects growth. When natural change is negative, it reflects conservation. Figure C-1 illustrates this concept of natural change as it relates to the Reference Case end-use intensities as compared with the frozen EUI case.

Figure C-1. Natural Change in Context of End-use Intensity



Source: Navigant

Navigant calculated natural change by subtracting the energy consumption in the frozen EUI case from the energy consumption in the Reference Case (see Table C-1). Positive natural change results indicate a quantity of consumption missing from the frozen EUI case, whereas negative natural change indicates an overestimate of consumption in the frozen EUI case. Since Navigant estimates technical and economic potential based on the frozen EUI case, any missing consumption (i.e., positive natural change) is not included in the technical and economic results. Conversely, the model overestimates technical and economic potential when natural change is negative. Natural change helps provide a bound for the technical and economic potential forecasts, as it reflects one component of the uncertainty in energy savings from end-uses with expected changes to intensities over time.

Table C-1. Illustrative Calculation of Natural Change

Year	Building Stock (homes)	Reference Case EUI (GJ/year-home)	Frozen Case EUI (GJ/year-home)	Reference Case Consumption (GJ/year)	Frozen EUI Case Consumption (GJ/year)	Natural Change (GJ/year)
	A	B	C	D = A x B	E = A x C	F = D - E
2016	1,000	70	70	70,000	70,000	0
2020	1,082	69	70	74,808	75,770	-962
2025	1,195	68	70	81,351	83,656	-2,305
2030	1,319	67	70	88,412	92,364	-3,952
2035	1,457	66	70	96,162	101,977	-5,815

Source: Navigant

Calculating technical and economic potential that includes natural change at the measure level would require measure-level adoption forecasts. As mentioned in section 0, Navigant's calculation of technical and economic potential does not involve forecasting adoption at the measure level. However, the team does estimate upper and lower bounds on the technical and economic potential inclusive of natural change at the end-use level.[45]

Navigant refined the frozen EUI technical potential by estimating savings potential percentages for natural change. The team calculated the technical potential as a percentage of consumption within a given end-use category, and applied that percentage to the natural change occurring within that end-use. For example, if the model concludes that technical potential for lighting is 30% of the total consumption from lighting, Navigant can apply that 30% to the natural change occurring within the lighting end-use to find a midway estimate between the technical potential and the upper or lower bound.

[45] Adding consumption from natural change directly to savings potential—instead of adding the expected savings from the natural change—typically exaggerates the upper or lower bound results.

Table C-2 builds off the example in Table C-1 by estimating adjusted technical potential for the frozen EUI case by applying the example of 30% savings to the natural change estimates.

Table C-2. Illustrative Calculation of Bounds on Technical Potential (GJ/year)

Year	Frozen EUI Case Consumption	Natural Change	Tech Potent @ 30% Savings	Tech Potent + Nat Change	Tech Potent + 30% Nat Change
	A	B	C = A x 30%	D = B + C	E = B x 30% + C
2016	70,000	0	24,500	24,500	24,500
2020	75,770	-962	26,520	25,558	26,231
2025	83,656	-2,305	29,280	26,975	28,588
2030	92,364	-3,952	32,327	28,375	31,142
2035	101,977	-5,815	35,692	29,877	33,948

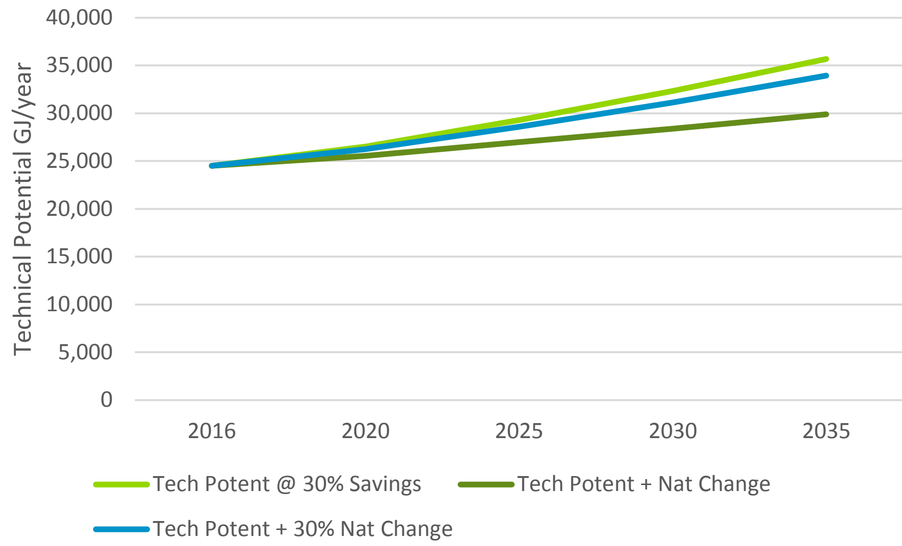
Source: Navigant

Where:

- **Frozen EUI Case Consumption** – the consumption forecast from the frozen EUI case
- **Natural Change** – the natural change between the frozen EUI case and the Reference Case
- **Tech Potent @ 30% Savings** – the technical potential assuming that efficient measures, in aggregate, lead to 30% savings as a percentage of the frozen EUI case's consumption
- **Tech Potent + Nat Change** – the sum of technical potential and natural change. Because natural change is negative, it reduces the total technical potential and indicates an extreme lower bound. This lower bound is overly conservative because it reduces the technical potential by the total natural change, rather than reducing potential by the overestimation of savings from natural change.
- **Tech Potent + 30% Nat Change** – the sum of technical potential and 30% of the natural change. Instead of reducing the technical potential by the total natural change, we reduce the potential by an estimate of the savings from natural change. The savings from natural change is a rough estimate based on the same 30% savings as a percentage of consumption used to estimate the technical potential. In reality, the percentage savings from natural change could be different from the 30% aggregate technical savings for the end-use.

Figure C-2 plots the illustrative results from Table C-2.

Figure C-2. Illustrative Example of Technical Potential and Bounds Derived from Natural Change



Source: Navigant

At the end-use level, the technical potential plus the adjusted natural change (i.e., "Tech Potential + 30% Nat Change") will always fall between the technical potential and the bound created by adding natural change directly to the potential. At the sector level, however, this may not always be the case due to the aggregation of various end-use categories that may have positive or negative natural change. The natural change and estimated savings from natural change can be positive or negative and will cancel each other out, which leads to aggregate natural change and aggregate savings from natural change that can be in different proportions than was calculated at the end-use level. After aggregation, the technical potential plus the adjusted natural change may or may not fall between the technical potential and the bound. This phenomenon is apparent in the sector-level charts shown in the result sections.[46]

[46] The effects of natural change by end-use category and customer segment are available in Appendix A.1.

APPENDIX D. INTERACTIVE EFFECTS OF EFFICIENCY STACKING

The results shown throughout the body of this report assume that measures are implemented in isolation from other efficient measures and do not include adjustments for interactive effects of efficiency stacking (with some exceptions).[47] Interactive effects from efficiency stacking are different from cross-end-use interactive effects (e.g., efficient lighting impacts heating/cooling loads), which are present regardless of stacking assumptions and are included in the reported savings estimates. This appendix describes the challenges related to accurately determining the impacts of efficiency stacking, and why Navigant has modelled savings as though measures are implemented independently from others. Although the examples in this appendix focus on gas measures, the concepts are dually applicable to electric measures.

D.1 Background on Efficiency Stacking

When two or more measures that impact the same end-use energy consumption are installed in the same building, the total savings that can be achieved are less than the sum of the savings from those measures independently. For example, in isolation, the installation of a high efficiency boiler might save 11% of gas consumption relative to a baseline (lower efficiency) boiler, while ceiling insulation might save 71% of gas consumption relative to a baseline insulation level. However, if both the boiler and the insulation are installed in the same facility, the savings from the high efficiency boiler decrease due to the reduced need for space heating caused by better insulation.

To generalize this concept Navigant refers to measures that actually convert energy as *engines* (boilers, light bulbs, motors, etc.). We refer to measures that impact the amount of energy that engines must convert as *drivers* (insulation, thermostats, lighting controls, etc.). Anytime an engine and driver are implemented in the same building, the expectation is that savings from the engine measure will decrease.[48]

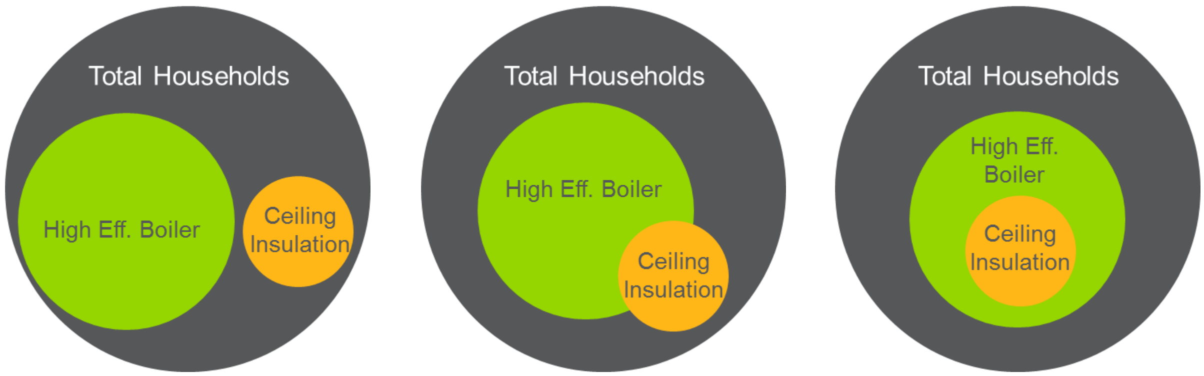
Figure D-1 provides an illustration of three different efficiency stacking approaches. The modelled approach assumes no overlap in measure implementation and no efficiency stacking, which leads to an upper bound on savings potential. The opposite of the modelled approach is to assume all measures are stacked wherever possible, which provides a lower bound on savings. Lastly, there is the real-world approach where some measures are implemented in isolation and others are stacked. Unfortunately, the data is simply not available to accurately estimate the savings from the real-world approach.

[47] Wherever savings were derived from building energy model simulations evaluating bundled measures, interactive effects of efficiency stacking are included in the savings estimates (e.g., ENERGY STAR New Homes, Net-Zero New Homes, etc.).

[48] In practice it does not matter whether one assumes the engine's savings decrease or the driver's savings decrease, as the final savings result is the same. In this discussion, the team has chosen to always reduce the savings from the engine measures, while holding the savings from the driver measures fixed.

Figure D-1. Venn Diagrams for Various Efficiency Stacking Situations

Upper Bound (Modelled): Savings are independent	Real World: Uncertain mix of independent and stacked savings	Lower Bound: Savings are stacked wherever possible



Area of colored circle represents the number of households with a given savings opportunity. Overlapping circles indicate a household has implemented both measures.

D.2 Illustrative Calculation of Savings after Efficiency Stacking

For a very simplistic scenario looking at only two measures, it is possible to determine the stacked savings from the lower bound approach, which assumes efficiencies are stacked wherever possible. To find the high efficiency boiler's savings relative to the baseline after stacking, we must perform several steps:

1. Find the complement of the insulation's savings percentage:

   Insulation Savings Complement = 100% - Insulation Savings
   Insulation Savings Complement = 100% - 71% = 29%

2. Reduce the boiler's unstacked savings by the complement of the insulation's savings:

   Stacked Boiler Savings = Unstacked Boiler Savings x Insulation Savings Complement
   Stacked Boiler Savings =11% x 29% = 3.2%

3. Find the greatest percentage of homes where boiler and insulation stacking is possible:

   % of Homes with Stacking = Homes with Insulation / Homes with Boilers x 100%
   % of Homes with Stacking = 145,300 / 720,200 x 100% = 20.2%

4. Calculate the boiler's weighted average savings across all homes with boilers:

   Weighted Boiler Savings = Stacked Boiler Savings x % of Homes with Stacking + Unstacked Boiler Savings x (100% - % of Homes with Stacking)
   Weighted Boiler Savings = 3.2% x 20.2% + 11% x (100% - 20.2%) = 9.4%

Table D-1 provides an example of the technical potential from the boiler and insulation before and after stacking. As expected, the combined savings from the measures treated independently exceeds the combined savings after stacking.

Table D-1. Comparison of Savings Before and After Stacking

	High Efficiency Boiler	Ceiling Insulation	Combined Technical Potential
Applicable Households (households)	720,200	145,300	
Savings treated independently (no stacking)			
Savings Relative to Baseline (%)	11%	71%	
Total Technical Potential in Region (TJ/year)	2,540	1,860	4,400
Savings treated interactively (stacking)			
Savings Relative to Baseline (%)	9.4%	71%	
Total Technical Potential in Region (TJ/year)	2,176	1,860	4,036

D.3 Impetus for Treating Measure Savings Independently

Although it is possible to find the lower bound on savings with just one driver and one engine measure, the process quickly becomes intractable when multiple drivers and engines can be installed in the same facility. Table D-2 lists all of the engine and driver measures included in this study that could have interactive effects within the gas residential space heating end-use (which is just one of many end-uses across multiple sectors where stacking could occur).

Table D-2. Measures with Opportunity for Stacking in Residential Gas Space Heating End-use

Engine Measures	Driver Measures
Boiler Tune Up	Air Infiltration
Central High Eff Boiler Replace	Attic Duct Insulation
Combination System	Attic Insulation
Direct Vent Heaters	Basement Insulation
Efficient Fireplaces	Ceiling Insulation
Furnace Early Retirement	Crawlspace Duct Insulation
High Eff Boiler Replace	Energy Star Windows
High Eff Furnace Replace	Fireplace Timers
Vertical Direct Vent Fireplaces	Heat Reflectors
	Smart Thermostats
	Wall Insulation
	Window Film

Determining the appropriate stacking and correctly weighting the savings percentages from each of the engine measures requires:

- Case-by-case expert judgment about the combinations of driver and engine measures that might realistically be found in the same building, given historic and future construction practices;
- The conditional probability that a building has an inefficient driver “A” and an inefficient engine “B” for all drivers and engines relevant to a given end-use;
- In-depth knowledge of program design and how managers are considering pursuing participants and bundling measure offerings.

Answering the bullets above is beyond the scope of this study.

Lastly, at low levels of customer participation, it is clear that assuming savings are independent is the best representation of what actual measure stacking would be. When customer participation is high, the “real-world” scenario is the best representation of actual measure stacking. Thus, under the plausible ranges of customer participation, the modelled (upper bound) scenario is likely to be a better representation of actual measure stacking than the lower bound scenario.

Although this report does not rigorously attempt to quantify the impact from efficiency stacking within the modelled service territories, Navigant’s experience indicates that stacking can lead to a 5-10% reduction in savings potential at high levels of technology adoption. This estimate is applicable to the residential and commercial sectors, but less applicable for the industrial sector because of reduced opportunity for stacking among the industrial measures considered in this study. Additionally, the 5-10% reduction is highly uncertain and very much dependent upon the characteristics of any given building and bundling of measures.

APPENDIX E. SUPPORTING DATA FOR CHARTS

Table E-1. Total Electric Energy Savings Potential (GWh/year)

	Technical	Economic
2016	839	788
2017	854	811
2018	869	825
2019	884	840
2020	899	854
2021	919	871
2022	938	888
2023	958	906
2024	979	924
2025	999	942
2026	1,025	967
2027	1,051	991
2028	1,077	1,017
2029	1,104	1,042
2030	1,131	1,068
2031	1,163	1,098
2032	1,194	1,128
2033	1,227	1,159
2034	1,259	1,190
2035	1,292	1,221

Source: Navigant

Table E-2. Total Electric Energy Savings Potential as Percent of Total Consumption (%)

	Technical	Economic
2016	21.9%	20.5%
2017	22.0%	20.9%
2018	22.2%	21.1%
2019	22.3%	21.2%
2020	22.5%	21.3%
2021	22.7%	21.5%
2022	22.9%	21.7%
2023	23.1%	21.9%
2024	23.4%	22.0%
2025	23.6%	22.2%
2026	23.9%	22.6%
2027	24.3%	22.9%
2028	24.6%	23.2%
2029	24.9%	23.5%
2030	25.3%	23.9%
2031	25.7%	24.3%
2032	26.1%	24.7%
2033	26.5%	25.1%
2034	27.0%	25.5%
2035	27.4%	25.9%

Source: Navigant

Table E-3. Total Electric Demand Savings Potential (MW)

	Technical	Economic
2016	164	153
2017	168	157
2018	171	160
2019	174	164
2020	178	167
2021	182	171
2022	187	174
2023	192	178
2024	196	182
2025	201	186
2026	208	193
2027	215	199
2028	222	206
2029	229	213
2030	236	220
2031	245	228
2032	253	236
2033	262	245
2034	271	254
2035	280	262

Source: Navigant

Table E-4. Electric Energy Technical Savings Potential by Sector (GWh/year)

	Commercial	Industrial	Residential
2016	255	250	334
2017	265	252	337
2018	276	253	340
2019	287	255	342
2020	298	257	345
2021	312	257	350
2022	326	258	354
2023	340	259	359
2024	354	260	364
2025	369	261	369
2026	383	263	379
2027	398	264	389
2028	413	265	400
2029	428	266	410
2030	443	268	421
2031	457	269	436
2032	471	271	452
2033	486	273	468
2034	501	275	483
2035	516	277	499

Source: Navigant

Table E-5. Electric Demand Technical Savings Potential by Sector (MW)

	Commercial	Industrial	Residential
2016	45	30	89
2017	47	31	90
2018	49	31	91
2019	51	31	92
2020	53	31	93
2021	56	31	95
2022	59	31	97
2023	61	32	99
2024	64	32	100
2025	67	32	102
2026	70	32	106
2027	72	32	110
2028	75	32	114
2029	78	32	118
2030	81	32	122
2031	84	33	128
2032	86	33	134
2033	89	33	140
2034	92	33	146
2035	95	34	152

Source: Navigant

Table E-6. Electric Energy Technical Savings Potential by Sector as a Percent of Sector Consumption (%)

	All	Commercial	Industrial	Residential
2016	21.9%	20.3%	28.1%	19.8%
2017	22.0%	20.8%	28.0%	19.8%
2018	22.2%	21.3%	27.9%	19.8%
2019	22.3%	21.8%	27.9%	19.7%
2020	22.5%	22.3%	27.8%	19.7%
2021	22.7%	22.9%	27.7%	19.9%
2022	22.9%	23.5%	27.7%	20.0%
2023	23.1%	24.0%	27.6%	20.1%
2024	23.4%	24.6%	27.5%	20.2%
2025	23.6%	25.1%	27.5%	20.3%
2026	23.9%	25.6%	27.4%	20.7%
2027	24.3%	26.1%	27.4%	21.1%
2028	24.6%	26.6%	27.3%	21.5%
2029	24.9%	27.1%	27.3%	21.9%
2030	25.3%	27.5%	27.2%	22.3%
2031	25.7%	28.0%	27.1%	23.0%
2032	26.1%	28.4%	27.1%	23.7%
2033	26.5%	28.8%	27.0%	24.4%
2034	27.0%	29.1%	26.9%	25.0%
2035	27.4%	29.5%	26.9%	25.7%

Source: Navigant

Table E-7. Electric Energy Technical Potential by Customer Segment (GWh/year)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
C.Accommod	27	29	30	32	33	35	37	39	42	44	46	48	50	52	55	57	59	61	64	66
C.College/Univ	9	10	10	11	12	12	13	14	14	15	16	17	17	18	19	20	20	21	22	23
C.Food Svc	12	13	14	14	15	16	17	18	19	20	21	22	22	23	24	25	26	27	28	29
C.Hospital	13	14	15	16	17	18	20	21	22	24	25	27	28	29	31	32	34	35	37	38
C.Logistic/WHouse	8	8	9	9	9	10	11	11	12	12	13	13	14	15	15	16	16	17	17	18
C.Long Term Care	8	9	9	10	11	12	13	14	15	16	17	19	20	21	23	24	25	27	28	30
C.Office	34	36	38	39	41	43	45	47	49	52	54	56	58	60	63	65	67	69	72	74
C.Other Commercial	26	28	29	30	32	34	36	37	39	41	43	45	47	49	51	53	55	57	59	61
C.Retail.Food	15	15	16	17	17	18	19	20	21	22	23	23	24	25	26	27	28	29	29	30
C.Retail.Non Food	38	39	40	40	41	42	43	44	44	45	46	47	48	49	50	50	51	52	53	54
C.Schools	6	6	7	7	7	7	7	8	8	8	8	9	9	9	9	10	10	10	10	10
C.Streetlights/Signals	9	9	9	9	9	9	9	9	9	9	9	8	8	8	8	8	8	8	8	8
I.Agriculture	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
I.Food & Bev	10	10	10	10	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11	11
I.Mfg	48	49	49	50	50	50	50	50	49	49	49	49	49	49	50	50	51	52	53	54
I.Metal Mining	15	15	15	15	15	15	15	15	15	15	15	15	15	16	16	16	16	16	16	16
I.Oil & Gas	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
I.Other Industrial	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
I.Kraft Pulp/Paper	113	113	112	112	112	112	112	112	112	112	112	112	112	112	112	112	112	111	111	111
I.Wood Products	40	41	43	44	45	46	47	48	49	51	52	53	54	55	56	58	59	60	61	62
R.Apt <= 4 Stories	45	46	47	48	50	51	53	54	55	57	58	60	61	62	64	65	66	67	68	69
R.Apt > 4 Stories	4	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	6	6
R.Other Residential	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
R.Fam Attached	43	43	43	43	43	43	44	44	44	44	45	46	47	48	48	49	50	51	52	53
R.Fam Detached	277	280	283	285	288	292	296	301	305	310	320	329	339	349	359	373	388	403	417	432
Total	**839**	**854**	**869**	**884**	**899**	**919**	**938**	**958**	**979**	**999**	**1,025**	**1,051**	**1,077**	**1,104**	**1,131**	**1,163**	**1,194**	**1,227**	**1,259**	**1,292**

Source: Navigant

Table E-8. Electric Energy Technical Potential by End-use (GWh/year)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Appliances	50	50	50	50	50	50	49	49	49	49	49	49	48	48	48	48	48	47	47	47
Compressed Air	18	19	19	19	20	20	20	20	21	21	21	21	22	22	22	23	23	23	24	24
Cooking	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Electronics	41	41	42	42	42	42	42	42	42	42	42	42	43	43	43	43	43	43	43	43
Fans/Blowers	31	31	31	31	31	31	32	32	32	32	32	32	32	32	33	33	33	33	33	33
Hot Water	46	46	46	46	46	45	45	45	45	44	44	44	44	44	43	43	43	43	42	42
HVAC Fans/Pumps	42	41	41	41	41	41	40	40	40	40	40	39	39	39	39	39	38	38	38	38
Industrial Proc	30	31	31	31	31	31	31	31	31	31	32	32	32	32	32	32	32	33	33	33
Lighting	210	210	209	209	212	214	217	220	223	226	229	231	234	237	240	243	246	250	253	256
Mat Transport	9	9	9	10	10	10	10	10	10	10	11	11	11	11	11	11	12	12	12	12
Office Equip	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Other	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Product Drying	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pumps	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Refrigeration	10	10	10	10	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11	11
Space Cooling	6	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	5	5	5
Space Heating	131	130	130	129	128	128	127	126	126	125	124	124	123	123	122	121	121	120	120	119
Ventilation	4	4	4	4	4	4	4	4	3	3	3	3	3	3	3	3	3	3	3	3
Whole Facility	131	146	162	178	191	209	226	244	262	280	303	327	351	375	400	429	457	487	516	546
Total	**839**	**854**	**869**	**884**	**899**	**919**	**938**	**958**	**979**	**999**	**1,025**	**1,051**	**1,077**	**1,104**	**1,131**	**1,163**	**1,194**	**1,227**	**1,259**	**1,292**

Source: Navigant

Table E-9. Electric Energy Economic Savings Potential by Sector (GWh/year)

	Commercial	Industrial	Residential
2016	237	250	300
2017	249	252	311
2018	259	253	313
2019	270	255	315
2020	280	257	317
2021	294	257	320
2022	307	258	323
2023	321	259	325
2024	335	260	328
2025	350	261	331
2026	363	263	341
2027	377	264	350
2028	391	265	360
2029	406	266	370
2030	421	268	380
2031	434	269	394
2032	448	271	409
2033	462	273	424
2034	477	275	439
2035	491	277	453

Source: Navigant

Table E-10. Electric Demand Economic Savings Potential by Sector (MW)

	Commercial	Industrial	Residential
2016	41	30	82
2017	43	31	84
2018	45	31	85
2019	47	31	86
2020	49	31	86
2021	52	31	87
2022	54	31	89
2023	57	32	90
2024	60	32	91
2025	63	32	92
2026	65	32	96
2027	68	32	99
2028	71	32	103
2029	74	32	107
2030	77	32	111
2031	79	33	116
2032	82	33	122
2033	85	33	127
2034	87	33	133
2035	90	34	139

Source: Navigant

Table E-11. Electric Energy Economic Savings Potential by Sector as a Percent of Sector Consumption (%)

	All	Commercial	Industrial	Residential
2016	20.5%	18.9%	28.1%	17.7%
2017	20.9%	19.5%	28.0%	18.2%
2018	21.1%	20.0%	27.9%	18.2%
2019	21.2%	20.5%	27.9%	18.2%
2020	21.3%	21.0%	27.8%	18.2%
2021	21.5%	21.6%	27.7%	18.2%
2022	21.7%	22.2%	27.7%	18.2%
2023	21.9%	22.7%	27.6%	18.2%
2024	22.0%	23.3%	27.5%	18.2%
2025	22.2%	23.8%	27.5%	18.2%
2026	22.6%	24.3%	27.4%	18.6%
2027	22.9%	24.8%	27.4%	19.0%
2028	23.2%	25.2%	27.3%	19.4%
2029	23.5%	25.7%	27.3%	19.8%
2030	23.9%	26.2%	27.2%	20.2%
2031	24.3%	26.6%	27.1%	20.8%
2032	24.7%	27.0%	27.1%	21.4%
2033	25.1%	27.4%	27.0%	22.1%
2034	25.5%	27.7%	26.9%	22.7%
2035	25.9%	28.1%	26.9%	23.3%

Source: Navigant

Table E-12. Electric Energy Economic Savings Potential by Customer Segment (GWh/year)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
C.Accommod	27	29	30	32	33	35	37	39	41	44	46	48	50	52	55	57	59	61	63	66
C.College/Univ	9	9	10	11	11	12	13	13	14	15	16	16	17	18	19	19	20	21	22	22
C.Food Svc	12	13	13	14	15	16	17	18	18	19	20	21	22	23	24	25	26	27	28	29
C.Hospital	13	14	15	16	17	18	19	21	22	24	25	26	28	29	31	32	34	35	37	38
C.Logistic/WHouse	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8
C.Long Term Care	8	8	9	10	11	12	13	14	15	16	17	18	20	21	23	24	25	27	28	30
C.Office	33	35	36	38	40	42	44	46	48	51	53	55	57	59	62	64	66	68	71	73
C.Other Commercial	26	27	29	30	32	33	35	37	39	41	43	45	47	49	51	53	54	56	58	60
C.Retail.Food	14	15	16	16	17	18	19	20	20	21	22	23	24	25	26	26	27	28	29	30
C.Retail.Non Food	38	38	39	40	41	41	42	43	44	45	46	47	47	48	49	50	51	52	52	53
C.Schools	6	6	6	6	6	7	7	7	7	8	8	8	8	8	9	9	9	9	10	10
C.Streetlights/Signals	9	9	9	9	9	9	9	9	9	9	9	8	8	8	8	8	8	8	8	8
I.Agriculture	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
I.Food & Bev	10	10	10	10	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11	11
I.Mfg	48	49	49	50	50	50	50	50	49	49	49	49	49	49	50	50	51	52	53	54
I.Metal Mining	15	15	15	15	15	15	15	15	15	15	15	15	15	16	16	16	16	16	16	16
I.Oil & Gas	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
I.Other Industrial	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
I.Kraft Pulp/Paper	113	113	112	112	112	112	112	112	112	112	112	112	112	112	112	112	112	111	111	111
I.Wood Products	40	41	43	44	45	46	47	48	49	51	52	53	54	55	56	58	59	60	61	62
R.Apt <= 4 Stories	33	36	37	38	40	41	43	44	46	47	49	50	51	53	54	55	56	58	59	60
R.Apt > 4 Stories	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4	4	5	5	5	5
R.Other Residential	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	12	12	12	12
R.Fam Attached	37	38	38	38	37	37	37	37	37	38	38	38	37	37	37	37	37	37	37	37
R.Fam Detached	251	260	262	265	267	270	272	275	278	281	291	300	310	320	330	344	359	374	389	404
Total	**788**	**811**	**825**	**840**	**854**	**871**	**888**	**906**	**924**	**942**	**967**	**991**	**1,017**	**1,042**	**1,068**	**1,098**	**1,128**	**1,159**	**1,190**	**1,221**

Source: Navigant

Table E-13. Electric Energy Economic Savings Potential by End-Use (GWh/year)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Appliances	30	39	39	39	39	39	39	38	38	38	38	38	37	37	37	37	37	37	36	36
Compressed Air	18	19	19	19	20	20	20	20	21	21	21	21	22	22	22	23	23	23	24	24
Cooking	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Electronics	41	41	41	42	42	42	42	42	42	42	42	42	42	43	43	43	43	43	43	43
Fans/Blowers	31	31	31	31	31	31	32	32	32	32	32	32	32	32	33	33	33	33	33	33
Hot Water	46	46	46	45	45	45	45	44	44	44	44	44	43	43	43	43	42	42	42	42
HVAC Fans/Pumps	40	40	40	40	40	39	39	39	39	39	38	38	38	38	38	37	37	37	37	37
Industrial Proc	30	31	31	31	31	31	31	31	31	31	32	32	32	32	32	32	32	33	33	33
Lighting	208	208	208	207	209	212	215	217	220	223	226	229	232	235	238	241	244	247	250	254
Mat Transport	9	9	9	10	10	10	10	10	10	10	11	11	11	11	11	11	12	12	12	12
Office Equip	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Other	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Product Drying	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pumps	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73
Refrigeration	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Space Cooling	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Space Heating	109	108	107	107	106	106	105	105	104	104	103	103	102	102	101	101	100	100	99	99
Ventilation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Whole Facility	130	145	160	175	188	203	217	233	248	264	286	308	331	354	377	404	431	459	487	515
Total	**788**	**811**	**825**	**840**	**854**	**871**	**888**	**906**	**924**	**942**	**967**	**991**	**1,017**	**1,042**	**1,068**	**1,098**	**1,128**	**1,159**	**1,190**	**1,221**

Source: Navigant

Appendix B

LT DSM PLAN CONSULTATION FINDINGS

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FortisBC Inc. Long-Term DSM Plan and Long Term Electric Resource Plan Customer Consultation

Final Report

Prepared For:

FortisBC Inc.

November 25, 2016

FORTIS BC™

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Contents

Background and Methodology

Background & Objectives

- The 2016 Long Term Electric Resource Plan (LTERP) presents a long-term plan for meeting the energy and capacity needs of FortisBC Inc. (FortisBC) customers. The LTERP is intended to meet the objectives of ensuring cost-effective, secure and reliable power for customers, providing cost-effective demand side management, and ensuring consistency with provincial energy objectives.
- The BC Energy Plan supports utilities to pursue all cost-effective and competitive demand side management (DSM) programs. DSM programs consist of the planning, implementation and monitoring of activities designed to modify consumers' levels and patterns of energy consumption. The BC Energy Plan specifies that DSM programs should:
  - Continue to remove barriers that prevent customers from reducing their consumption
  - Build upon efforts to educate customers about the choices they make today with respect to the amount of electricity they consume
- FortisBC consults with the public for input to assist in maximizing the success of its DSM activities and to support its long-term energy planning. In the past, public consultation usually took the form of "open houses". These events are generally poorly attended and do not represented the diverse customer base that FortisBC serves. As such, FortisBC selected an online discussion approach for this research to produce better quality feedback that will inform DSM decision-making.
- The objectives of the research are to effectively consult and engage both the residential and business community on energy conservation, conservation targets, and the pros and cons of conservation targets based on various budget levels and marginal costs and how to best meet future load growth and long term resource planning objectives.

Methodology

- Four qualitative discussion boards were conducted online using QualBoard, provided by 20|20 Research. The project was in field from Nov 15-18, 2016, and each discussion was open for two days.

Group	Customer Type	Region	Field Dates	Completed Participants
Group 1	Residential	Kelowna	Nov 15-16	12/20 (60%)
Group 2	Residential	Central Okanagan/ Similkameen	Nov 15-16	12/19 (63%)
Group 3	Residential	Boundary/ Kootenays	Nov 17-18	12/20 (60%)
Group 4	Commercial	Central Okanagan (incl. Kelowna)/ Similkameen, Boundary/ Kootenays	Nov 17-18	13/20 (65%)

- Residential customers were recruited by Research Now via online panels from October 31 - November 13, 2016. Each participant who fully completed the discussion was awarded panel points equivalent to a value of $90.
- Commercial customers were recruited by Sentis via phone from November 7 - 8, 2016. Those who completed the discussion received a $120 cash incentive.
- Sentis Market Research Inc. is a full service research and consulting company located in Vancouver, BC. The consultations were directed by Adam DiPaula, Managing Partner. Adam was assisted by Emily Larsen, Research Manager, in moderating the consultations and preparing the report.

Executive Summary

Executive Summary

- **Both residential and commercial customers regularly take steps to conserve energy in their home or office.**
  - Some are larger steps, such as investing in high-efficiency appliances and hot water tanks.
  - Many are smaller steps, such as ensuring lights are turned off in unused rooms, and unplugging computers and appliances when not in use.
- **The main motivation to conserve energy is cost savings, particularly among commercial customers.**
  - The perception that conservation has a positive impact on the environment is another important motivator.
  - Consumers also feel a sense of pride and personal achievement from making an effort to reduce their consumption.
- **The most common barriers to participating in the energy conservation programs offered by FortisBC are:**
  - Lack of awareness of the programs or qualifications;
  - Prohibitive costs; and,
  - Too much effort being required to receive the benefits.
- **Attitudes toward rate increases for renewable energy are polarized.**
  - Some are more responsive than others, though they may require more information or proof of the rationale behind the increase.
  - Conversely, there are some who are adamantly opposed to further increases, regardless of energy source, believing that they already pay too much now.
- **A challenge exists in communicating about hydro as a source of electricity.**
  - There is a lack of clarity around whether hydro is a renewable or non-renewable resource.

Executive Summary

- With respect to long-term planning priorities, **both residential and commercial customers place priority on ensuring a cost-effective, secure, and reliable supply of power.**
  - Among both customer groups, there tends to be a focus on affordability and maintaining reasonable costs for consumers.
- When it comes to managing future demand in growth, **residents find reducing demand through energy conservation to be the most appealing method, while commercial customers are split between energy conservation and building new facilities**.
  - Support for reduction of demand through energy conservation comes from the desire to encourage consumers to be more energy efficient, as well as openness to adopting use of renewable energy sources through rebate programs.
  - Those who place priority on building additional facilities feel energy conservation is not sufficient for ensuring that capacity can keep pace with growing demand.
- **Most residential and commercial customers are in favour of increasing the level of demand offset through energy conservation from the current target of 66%.**
  - The 100% level is viewed as an ideal state, but is generally not considered to be a realistic target.
  - 80% is perceived as a happy medium and a more attainable goal, and one which will make customers more proactive in conserving energy and acting on incentives.

Residential Customers

Ways Residential Customers are Conserving Electricity

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- Residential customers report multiple measures that they take to conserve electricity. Most were very quickly able to list five to six things that they currently do to conserve electricity, and some listed more than ten. These are the main ways they conserve:

- **Replacing Lower-Efficiency with Higher-Efficiency**
  - Switching to LED lightbulbs
  - Switching to low-flow shower heads and toilets
  - Installing Energy Star appliances
  - Replacing hot water tanks

- **Reducing Electricity Use**
  - Turning down the thermostat (and using sweaters and blankets)
  - Not turning on the fireplace
  - Hanging clothes to dry
  - Turning the hot water temperature down
  - Reducing shower time

- **Right-Sizing Use**
  - Turn lights off/closing vents when rooms are not occupied
  - Only running appliances like dishwashers and washing machines on full loads
  - Installing a programmable thermostat
  - Using motion sensor lighting outdoors
  - Unplugging appliances/shutting down computers when not in use
  - Using smaller appliances when possible (e.g., countertop oven instead of stove)

- **Insulating**
  - Sealing drafts
  - Installing extra insulation
  - Weather stripping on doors
  - Putting plastic storm windows over single pane windows

- The number and range of measures that customers take to conserve electricity indicate that they are generally in the mindset that even relatively small changes will have an incremental benefit.

Benefits of Conserving Electricity

- Residential customers cited a number of shorter term and longer term benefits that they experience (or expect to experience) as a result conserving electricity:

Shorter-Term Benefits

- **Saving on Electricity Bills**
  - Savings on electricity bills is front and center for most customers. They either have experienced lower electricity bills as a result of their conservation efforts or “hope that it reduces” their bill. Customers commonly cite dual benefits, one personal/financial (“saving money”), and one social (“reducing my carbon footprint.”)
- **Helping the Environment**
  - Customers do feel a sense of responsibility to the “collective good” to act in ways that will conserve natural resources and reduce their environmental impact. They talk about “doing our part” for the environment or “doing my part for the whole” so that it is “less damaged for our children.”
  - Consistent with this, customers feel that the best results can be achieved when more people change their behaviour in small ways.

> *“Knowing that although not a huge impact I am doing a little bit to help the environment. If everyone made a few changes I think we would be better off.”*
> - Fia A., Group 1

- **Feeling Pride and a Sense of Accomplishment**
  - Customers feel a sense of pride that they are taking actions toward the greater good and teaching their children (and neighbours) to act in ways that promote energy conservation.
  - They also feel a sense of accomplishment because they view conservation as a challenge to come up with smart, creative ways to reduce costs.

> *“I also enjoy the thrill of finding something else that can lower my costs. The cost of electricity is only going to go up so I like to think that I’m ahead of the game.”*
> - Karen C., Group 1

Longer-Term Benefits

- Several longer-term benefits of conservation were cited by customers, including:
  - Broader economic improvements (because consumers will have more disposable income due to energy savings).
  - Less reliance on non-renewable energy sources.
  - Less infrastructure required to build to keep up with population growth.

Awareness and Participation of FortisBC Energy Conservation Programs

Awareness of FBC Energy Conservation Programs

- Unaided awareness of FBC energy conservation programs is moderate; customers either indicate a lack of awareness, mention that they do have some energy efficiency measures currently in their home (e.g., "I have the energy saver shower head"), or mention that they have heard of "rebate programs for buying energy efficient appliances".
- When prompted, most customers are aware of the EnergyStar Appliance Rebates; some are aware of the Home Renovation Rebate Program and Energy Efficient Lighting Rebates.

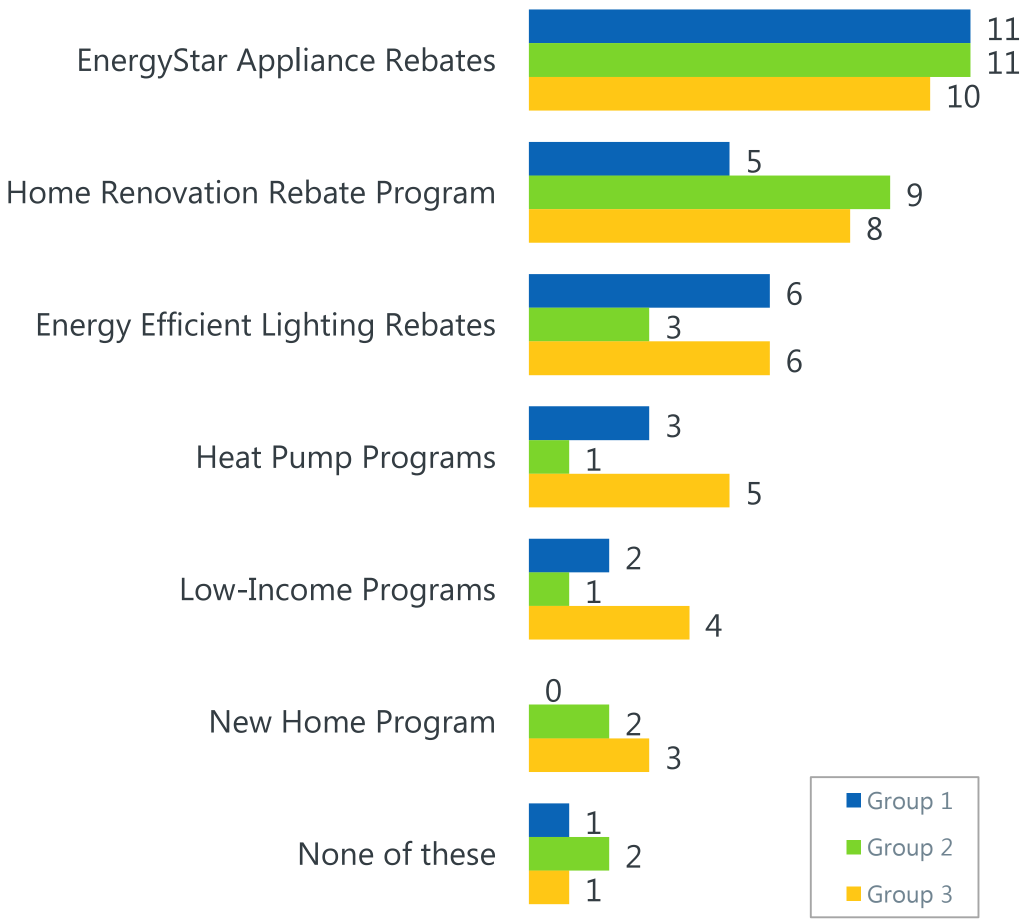
Participation in FBC Energy Conservation Programs

- Few have actually participated in these programs, mainly due to not having enough information (i.e., timing of the offer, how to qualify) as well as the effort involved in going through the process.

"I don't feel these other programs are being published enough to the end consumer. A friend did participate in a new furnace rebate and quote… it was like jumping through rings of fire to obtain the rebate."
- Adrian S., Group 3

- It follows that customers indicate that they would be more likely to participate in these programs if information about these programs was easy to find. Even sophisticated energy consumers indicated that it has been challenging to find useful information.
- Furthermore, anything that can be done to "reduce the work" that customers need to do to receive rebates (e.g., rebates at point of sale) would increase uptake of these programs.

Total (Aided) Awareness



Note: Data displayed in counts.

S3Q2. Here is a list of some of FortisBC's energy conservation programs. From the list below, please select the ones you area aware of, including any you may have mentioned before.

Assumptions Regarding Why FBC Offers These Programs

- Customers believe FBC offers energy conservation programs for several reasons:

Encouraging Energy Conservation

- First and foremost, customers view these programs as a way to motivate consumers to conserve energy. Customers do not consider feelings of responsibility to the collective or appeals based on what is best long-term for the environment to be sufficient to motivate conservation among the broader population.

"As an incentive to get people who need to see personal gain for doing the responsible thing to change their habits."
- Scott A., Group 1

Reducing Load at Peak Times

- Customers see these programs as a way FBC can reduce the load on the system during peak times which customers do link to financial benefits (e.g., "do not have to buy more at peak times") and reliability benefits (e.g., "reduce surges", "brown outs", "put less pressure on the power grid.")

"Encouraging conservation puts less stress on the system. This makes it less costly to operate. The decrease in individual demand means less issues from population and industrial growth supply."
- Robert B., Group 1

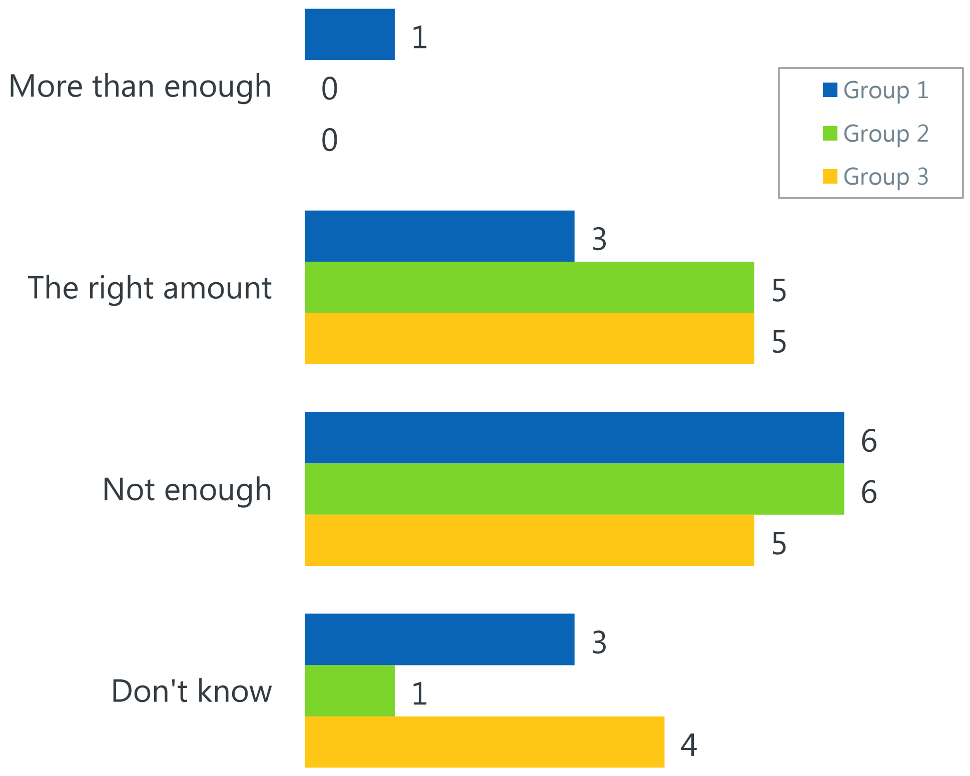
Lowering Investment in Infrastructure

- Customers also see FBC's involvement in energy conservation programs as a way to reduce the investment it needs to make in maintenance and new facilities.

"To reduce the need to build new generating facilities."
- Larry K., Group 2

- Some feel that FortisBC could provide more information about its energy conservation programs. Residential customers suggest a combination of direct mail and online advertising to direct consumers to the FortisBC website.
- Others concede that they receive information from FortisBC about programs (through bill inserts and emails), but do not read them.

Information Provided by FortisBC



Note: Data displayed in counts.

S3Q9. Does FortisBC provide enough information, programs, and offers toward encouraging energy conservation?

"Lately I have seen a pack that could be sent to low income families. It seems you're only focusing on new appliance purchases and low income users and leaving the majority of the consumers alone."
- Adrian S., Group 3

Awareness and Perceptions of Renewable Energy

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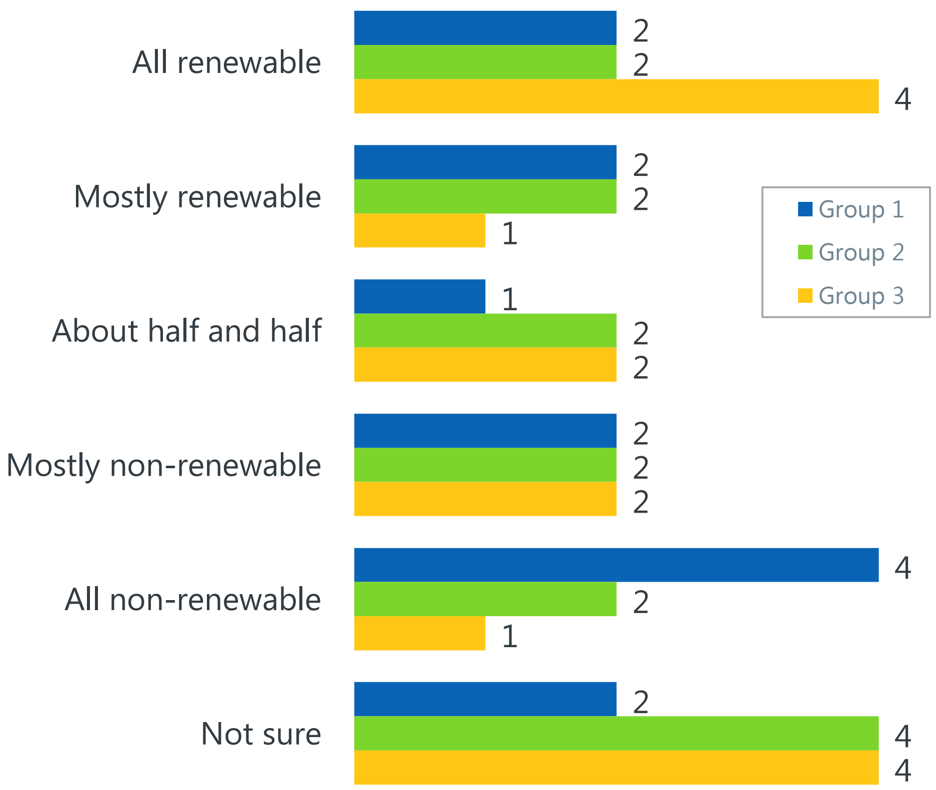
Awareness of Renewable and Non-Renewable Energy Sources

- Customers defined non-renewable energy as “finite”, “cannot be reused”, and “when it’s used it’s gone”. The most common non-renewable sources mentioned were coal, oil and gas. Some customers mentioned natural gas as non-renewable, some mentioned it as renewable.
- Renewable energy was defined by customers as “self-generating“, “replenishes itself”, “doesn’t run out” and “offering a continuous supply”. The most common renewable sources mentioned were solar and wind, followed by geothermal and tidal.
- Few customers mentioned hydro as a source of renewable energy and there is clearly confusion among customers on whether or not hydro is renewable or non-renewable. A few customers did mention that “in some instances” hydro is renewable.
- The confusion is evident when customers estimate how much of their home’s electricity supply comes from renewable versus non-renewable sources. Some customers – even if electricity is their primary or only source – indicate either that most or none of their electricity supply is non-renewable. Other customers assume that because their home is entirely powered by electricity that the supply is all renewable.

> *“It’s all renewable. My entire house is electric.”*
> - Mary G., Group 1

Energy Type in the Home



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S4Q5. How much of your home’s current electricity supply is renewable vs. non-renewable?

Willingness to Pay More for Renewable Energy

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- Customers were asked if they would be willing to pay more (5% or 10%) on their electricity bill for renewable energy. Their answers illustrate two kinds of sentiment:

Cautious Willingness

- A number of customers are open to paying more but they want information and/or assurances regarding the benefits and impacts of the increase. Common questions/comments were:
  - "Want absolute clarity on what is being achieved through higher payments."
  - "Need to know the rationale for the increase – does it truly cost more or is Fortis making a hefty profit under the guise of providing renewable energy?"
  - "I am willing to pay more for renewable energy if it equates to 3 to 5% in savings using renewable energy."

Resistance Due to Current Perceptions of Rates

- Some customers are opposed to a bill increase for renewable energy because they believe current rates are too high already. While not the majority opinion, these customers are adamant in their resistance.

> *"We pay enough already. Unless you are offering me a way to save and reduce my bill, I have had enough. "*
>
> - Donalie S., Group 1

> *"Absolutely not. We get slammed with increases all the time. The majority of us have to budget our money and increases are not welcome."*
>
> - Antony K., Group 2

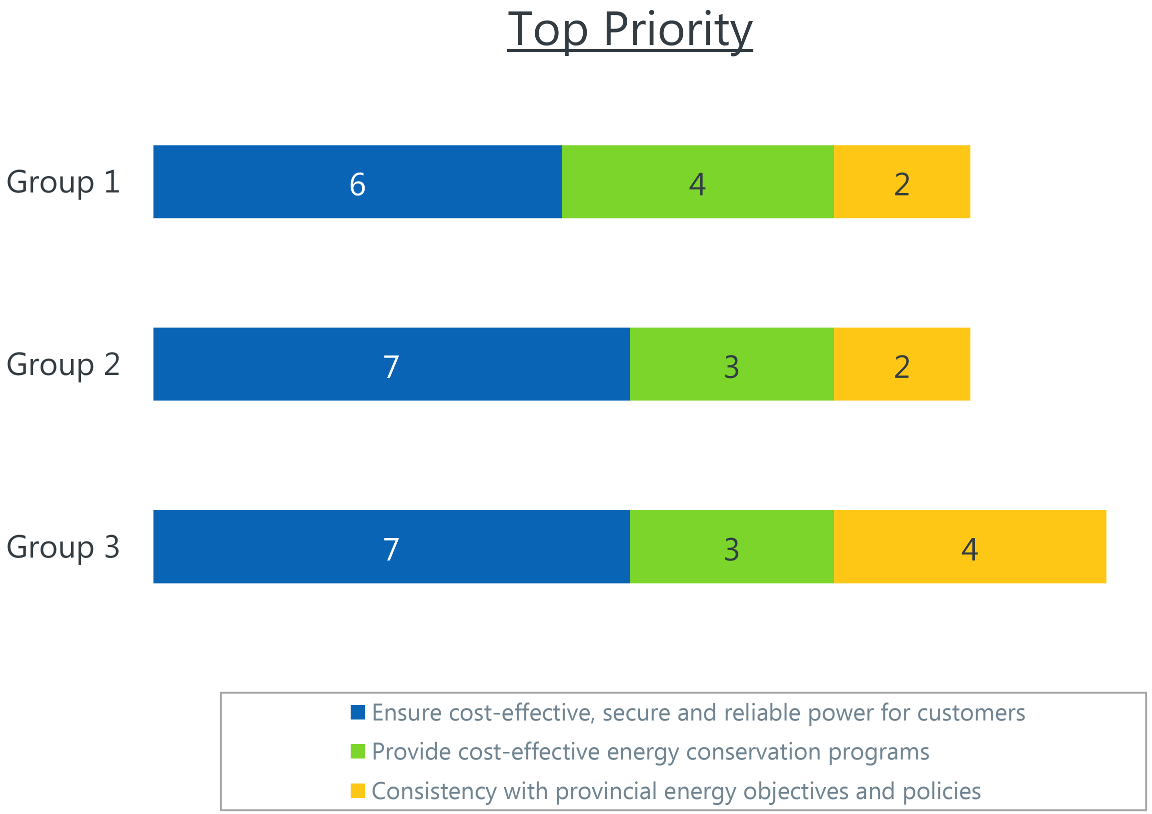
Reactions to Long-Term Resource Planning Priorities

Critical Objectives for Long-Term Resource Planning

- Customers were presented with the three long-term resource planning objectives and asked if there was one that stood out that was particularly critical.
- As can be see in the chart, most customers in each group thought it was most important to ensure cost-effective, secure and reliable power for customers.
- **Why Ensuring Cost-Effective Secure and Reliable Power is Most Critical**
  - Customers who view this objective as critical tend to focus on the importance of maintaining reasonable costs for the everyday customer. They either believe that current costs are already too high or that, given that costs will inevitably increase in the future, the focus has to be on affordability.

> *"With rising living costs we must be wary of keeping things affordable for customers while having a solid eye on being environmentally wary."*
> \- Mark L., Group 1

- **Why Cost-Effective Energy Conservation Programs are Most Critical**
  - Customers who place top priority on energy conservation programs tend to place more emphasis on collective action now as a way to ensure successful long-term planning. They view these programs as what will "help consumers make the required changes", "promote the development of all communities", and "create more energy efficient people."
- **Why Consistency with Provincial Energy Objectives and Policies is Most Critical**
  - Customers who place top priority on maintaining consistency with provincial energy objectives and policies see benefit in all stakeholders "having the same agenda" with respect to energy conservation and as a way to ensure that the entire province benefits from conservation initiatives.



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S5Q3. Is there one objective in this list which stands out as particularly critical or more important than the others?

FortisBC's Future Investment in Energy Conservation Activities

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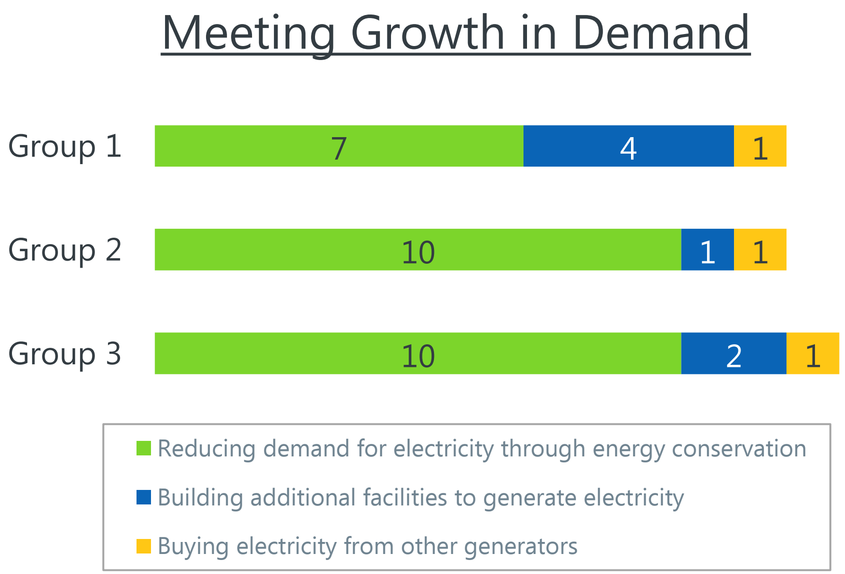
Meeting Future Growth in Demand for Electricity

- Residential customers were presented with three options for how FBC could meet the future growth in demand for electricity. As illustrated in the chart below, customers across all three groups favour FBC reducing demand through energy conservation over buying electricity from other generators or building additional generation facilities.



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S6Q1. Which of these options appeals most to you, and why?

Why Customers Favour Demand Reduction Through Energy Conservation

- Customers who favour reducing demand reduction through energy conservation tend to view this as the most prudent course in the short-term, and they do so for several reasons:
  - Giving customers incentives that reduce demand will begin to change their behaviour which will minimize the need for additional facilities.

"I think that this is the place to start. If you give customers the incentives then further down the road you could start to build additional facilities. I think it's always a good idea to get the customer on board with trying to be more energy efficient."
- Craig M., Group 1

  - Customers point to the renewable energy sources that could be adopted more widely through energy conservation rebate programs.

"There is an abundance of energy available from the sun and wind. Making it affordable to switch and share our resource with the grid would help both issues."
- Bette A., Group 1

  - The fact that residential customers favour energy conservation over building additional facilities does necessarily mean that they oppose future facility generation. They note that it can take a long time for additional facilities to be approved and built – and some mentioned Site C as a good example of this. These customers see conservation as a way of pushing back the timeline for building new facilities.

FortisBC's Future Investment in Energy Conservation Activities

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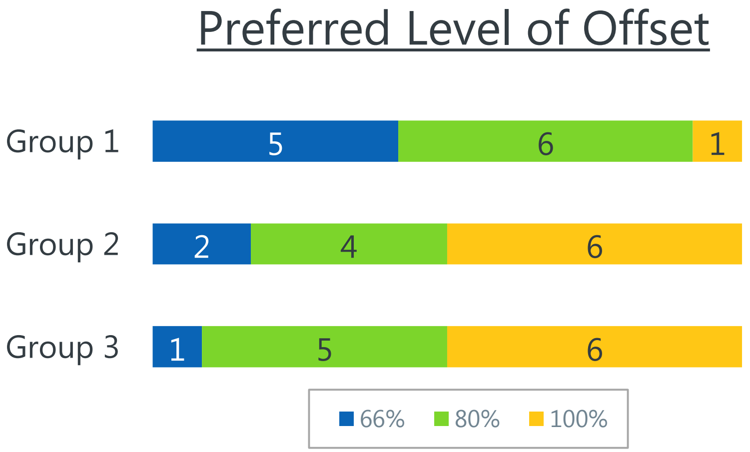
Preferences Regarding Future Offset Levels

- Residential customers were presented with three options for future offset levels and asked which they find most appealing:
  - **Option 1**: Continue to meet **66%** of future demand growth through energy conservation (this is the current level). The remaining 34% could be met through a combination of buying electricity from other generators as well as building new facilities.
  - **Option 2**: Increase to meeting **80%** of future electricity demand growth through energy conservation. The remaining 20% could be met through a combination of buying electricity from other generators as well as building new facilities.
  - **Option 3**: Increase to meeting **100%** of future electricity demand growth through energy conservation. This means that FortisBC could not purchase any electricity from other generators or build any new facilities, and will provide for any increase in electricity demand through energy conservation.



- Customers are broadly in favour of increasing the level of offset from 66%. However, there is no clear agreement on whether the target should be 80% or 100%.
- **Why Customers Prefer 66% Offset**
  - Customers who prefer the current offset level point out that it is already above the current level mandated in the BC Energy Plan.
  - These customers are also wary that higher offset levels may increase the cost of electricity for consumers (e.g., "we cannot afford to price customers out of the marketplace.")
- **Why Customers Prefer 80% Offset**
  - Customers in favour of the 80% level feel it is a happy medium and is a more reasonable goal, or that the 100% offset level is "unrealistic".

> *"I wanted to choose 100% offset because that is how I try to live but 80% is more realistic. There should always be more than one way to solve your problem. That way you have options for the future."*
> - Craig M., Group 1

- **Why Customers Prefer 100% Offset**
  - Customers view this as the most environmentally-friendly option which is why they choose it. They do view it as "an ideal option", and one that they are not sure will be affordable. Some customers accept that it "may be the most expensive, but it has less impact on the environment."
  - Some believe that the 100% offset does not necessarily have to mean higher costs for the consumer because increased conservation should reduce energy bills – even though the per-unit electricity cost is higher.

Commercial Customers

Ways Commercial Customers are Conserving Electricity

- Like residential customers, commercial customers report multiple measures that they take to conserve electricity. These are the main ways they conserve:

- **Replacing Low-Efficiency with Higher-Efficiency**
  - Switching to LED lightbulbs
  - Using heat pumps instead of base board heating
  - Using photo-electric/solar cells to light walkways and signage

- **Reducing Electricity Use**
  - Turning down the thermostat
  - Not turning on the fireplace
  - Hanging clothes to dry
  - Turning the hot water temperature down
  - Reducing shower time

- **Right-Sizing Use**
  - Turn lights off/closing doors when rooms are not occupied
  - Installing a programmable thermostat
  - Using motion sensor lighting for washrooms and outside buildings
  - Shutting down computers when not in use
  - Using smaller, more energy efficient heaters
  - Unplugging equipment when not in use

- Commercial customers were more likely than residential customers to mention regularly servicing equipment as a way to conserve energy, but less likely to mention insulation measures.

Benefits of Conserving Electricity for Commercial Customers

- While commercial customers do mention that they “feel good” knowing that they are “making a difference” by conserving, they are more likely than residential customers to focus more squarely on the financial benefits of conservation.

Shorter-Term Benefits

- **Saving on Electricity Bills/ Mitigating Increases**
  - While some commercial customers have yet to experience savings on their electricity bills (but they hope to), some have experienced significant savings as a result of their conservation efforts. One participant who had switched from baseboard heating to a heat pump, and also switched to all LED lighting offered:

> *“I have reduced my power bill from around $500 per month to less than half that amount.”*
> - Orison W., Group 4

  - Commercial customers also noted that savings does not necessarily come in the form of lower bills, but in bills that are less than what they would be if the customer didn’t conserve.

> *“We have managed to maintain our energy costs at or near where they were 15 years ago so our efforts have offset the increase in energy prices that have been experienced over the same period.”*
> - Suzanne C., Group 4

Longer-Term Benefits

- As with discussing the shorter-term benefits, commercial customers tended to focus on financial benefits they expect, or hope to realize, over the long-term through conservation. These include:
  - Savings that can be re-invested in the business.
  - Reduced electricity bills.
  - Minimizing future increases in energy costs for the business.
- Commercial customers also cite reduced environmental impacts, reduced need for additional generation facilities and job creation as long-term benefits.

> *“The less energy we use, the less we need to create, the less we need to build dams, develop natural gas plants and spend energy on plants to create energy. I realize that the building of these creates jobs and economical aid to our province, country, etc., but there are also great jobs to be had in conservation & developing/building/maintaining alternatives like biomass, landfill gas and wind.”*
> - Suzanne C., Group 4

Awareness and Participation of FortisBC Energy Conservation Programs

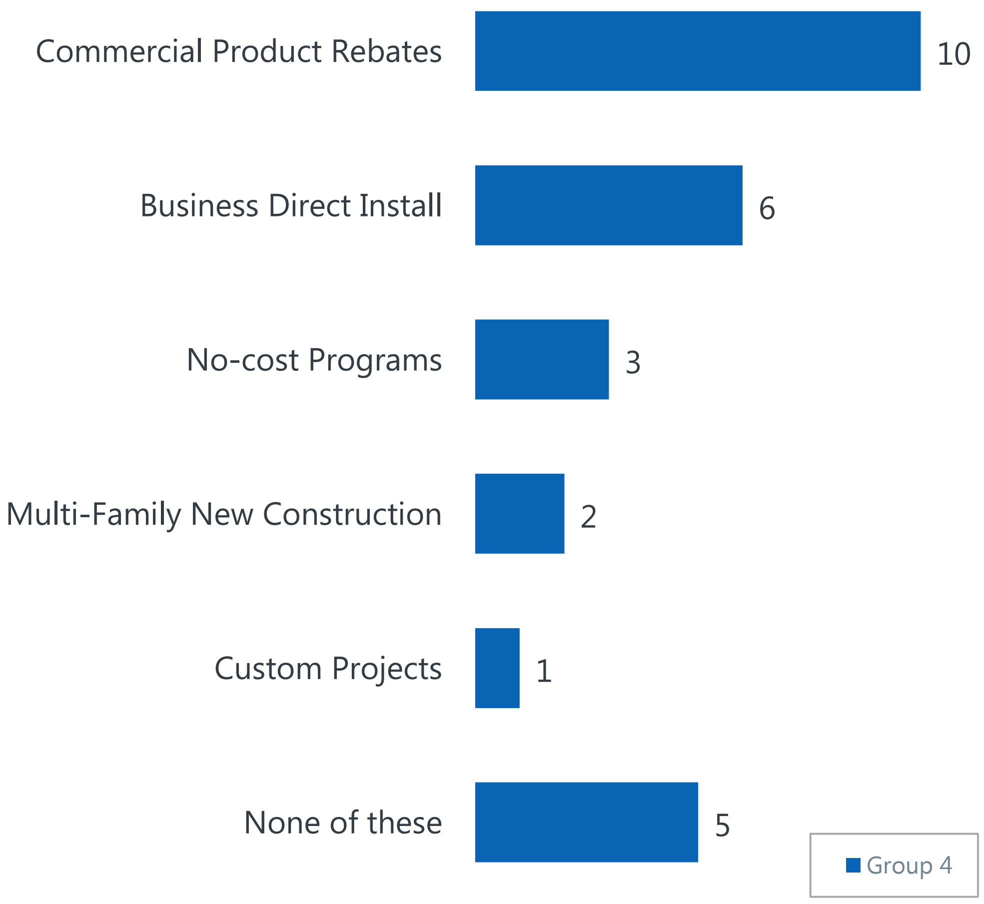
Awareness of FBC Energy Conservation Programs

- As is the case among residential customers, unaided awareness of FBC energy conservation programs among commercial customers is moderate: customers indicate either a lack of awareness, or that they are aware of rebates for heating, lighting and appliance upgrades.
- When prompted, most commercial customers indicate that they are aware of commercial product rebates.

Participation in FBC Energy Conservation Programs

- Commercial customers are more likely to report participating in FBC programs than residential customers are. The programs that they have participated in include:
  - Commercial product rebates
  - Light bulb upgrades
  - Business direct install
  - Furnace and heat pump replacement
  - Appliance upgrades
- Commercial customers participated in these programs largely for the financial benefits, but the ease of the application process and conservation benefits were also mentioned by a few participants.
- Those who participated in the programs generally received the benefits they expected with respect to cost savings and cost mitigation. However, there were some unanticipated benefits, including gaining knowledge of energy use and efficiency, and reducing the use of physical resources, like the number of light bulbs needed to light a space.

Total (Aided) Awareness



Note: Data displayed in counts.

S3Q2. Here is a list of some of FortisBC's energy conservation programs. From the list below, please select the ones you area aware of, including any you may have mentioned before.

Assumptions Regarding Why FBC Offers These Programs

- Like residential customers, commercial customers believe FBC offers energy conservation programs to motivate customers to conserve and to minimize the need for future infrastructure investment. They also believe that savings through conservation will allow FBC to invest more in future conservation projects.
- **Encouraging energy conservation**

> *"To bring awareness to the individuals and families; make them aware of what they can do to. It is the person's choice whether they want to go that route or not, but at least Fortis is making them aware of that is there for them to help conserve."*
> - Kelly M., Group 4

- **Lowering Investment in Infrastructure**

> *"I think that if Fortis helps us to be efficient, they may not have to upgrade some of their electric distribution systems. This in turn saves them money."*
> - Doug E., Group 4

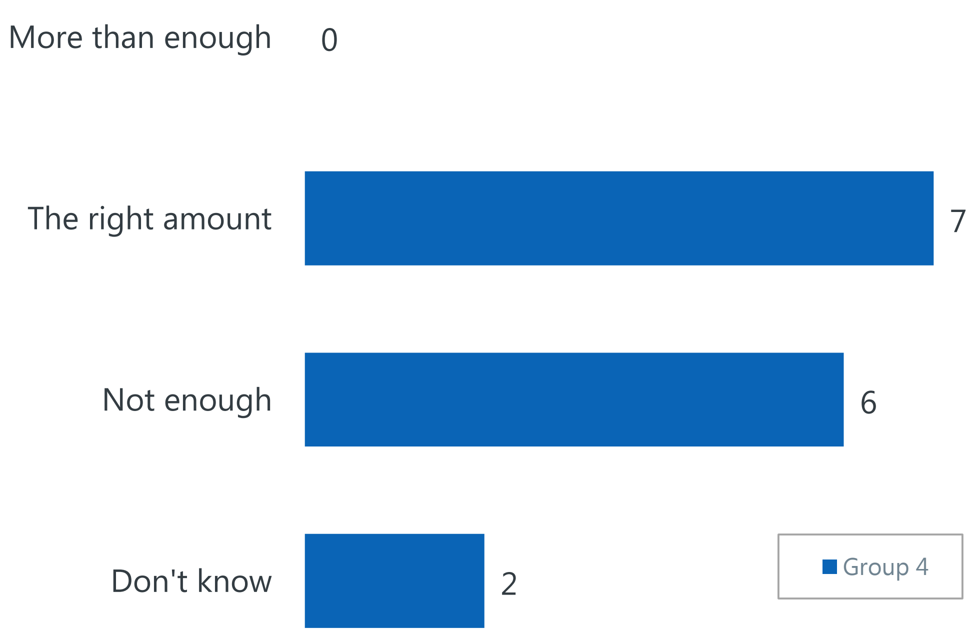
- **Investing in Future Conservation Projects**

> *"I believe that Fortis is planning for the future in order to keep costs in check and ensure future supply; every avenue of conservation must be investigated and utilized. The more savings that are realized, the more Fortis can invest into future conservation projects."*
> - Leigh S., Group 4

- Commercial customers are divided on whether or not FortisBC provides enough information about its conservation programs. Like residential customers, commercial customers receive information from FortisBC about energy conservation programs, but do not necessarily attend to it.

> *"We get so much junk mail now days that I would guess that we do not pay attention to what we do get sent to us. So I would say that the money Fortis spends on encouraging conservation with ads and flyers which are ultimately paid for by the targeted customers is not 100 percent effective and has room for improvement."*
> - Doug P., Group 4

Information Provided by FortisBC



Note: Data displayed in counts.

S3Q9. Does FortisBC provide enough information, programs, and offers toward encouraging energy conservation?

Awareness and Perceptions of Renewable Energy

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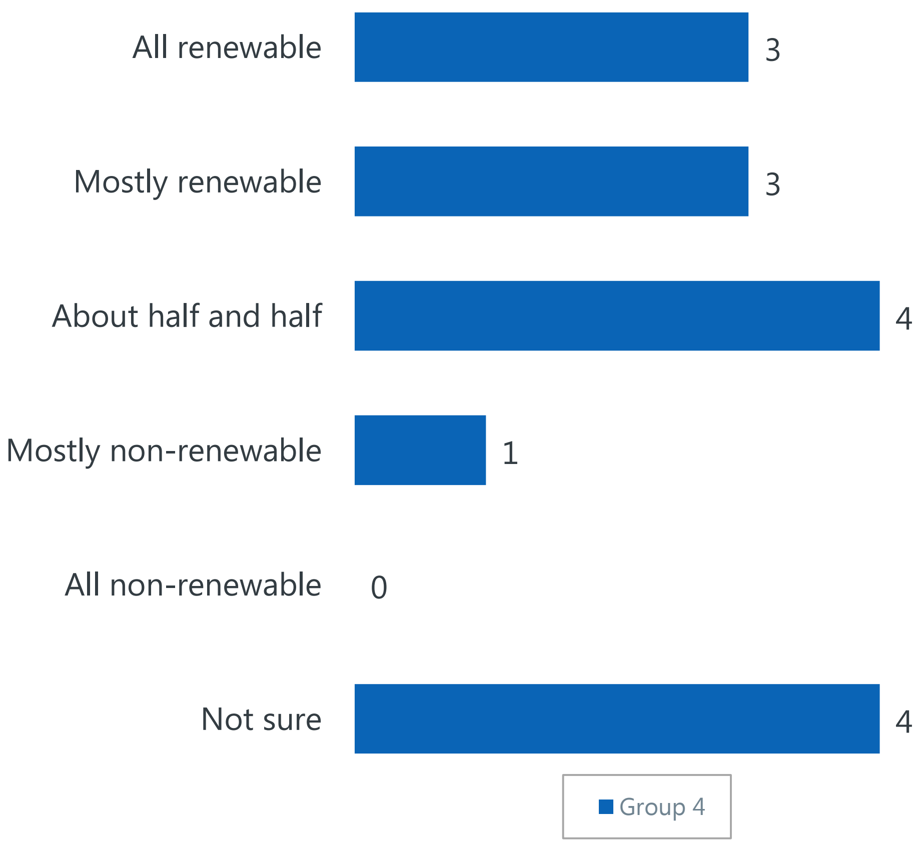
Awareness of Renewable and Non-Renewable Energy Sources

- Commercial customers referred to non-renewable energy as “finite”, “single use”, and “requiring extraction and leaving nothing behind.” The most common non-renewable sources mentioned were coal, oil, and gas. Commercial customers were more likely to mention natural gas as non-renewable, as well “gas-fired facilities”, nuclear energy, and petroleum products, compared to residential customers.
- Commercial customers described renewable energy as “unlimited” and as “energy that “does not run out.” The most common renewable sources mentioned were solar and wind. Biomass and landfill gases were also mentioned.
- Hydro was mentioned as a renewable by a number of customers. However, some customers expressed a nuanced view of hydro’s status – e.g., “renewables include wind, solar and hydro to a lesser extent as the environmental impact is not renewable”. Others were not clear on hydro’s current status:

> *“These days though, renewable does not include hydro electric. It would be solar and wind. Am I right?”*
> - Doug E., Group 4

- As is the case with residential customers, the varying assumptions regarding hydro’s status as a renewable impacts the assumptions commercial customers make regarding how much of their businesses’ electricity comes from renewable sources. Those who believe that most or all of their electricity come from renewable sources tend to assume that hydro is renewable.

Energy Type at the Business



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S4Q5. How much of your business’s current electricity supply is renewable vs. non-renewable?

Willingness to Pay More for Renewable Energy

- Commercial customers expressed the full range of intent when asked if they would consider paying more on their electricity bills for renewable energy. Some are adamantly opposed, some were in favour, and some needed proof.

Adamantly Opposed

- In line with their focus on cost containment, some commercial customers are strongly opposed to paying an additional percentage on their bills for renewable energy.

> *"Are you kidding? Bills are way too high now."*
> \- Al T., Group 4

In Favour

- Some commercial customers are very supportive of paying an additional percentage, particularly if it will help the environment:

> *"Absolutely! Again, I believe we need to all be more responsible in our role in conservation and the planet's health. Yes we do our part at this end, but we also need to let the suppliers know what we want in order to make educated decisions and choices."*
> \- Suzanne C., Group 4

Need Proof

- Some commercial customers want proof before they commit to paying an additional percentage for renewable energy. Some want proof that the energy is in fact renewable:

> *"The problem is that we cannot with 100% certainty know if the energy we receive is renewable or not. We have to trust that what we are told is true."*
> \- Al T., Group 4

- Others want proof that the use of renewable energy will have a "positive impact" or "make a difference."

> *"Why is it always paying more money, we try and conserve energy yet our bills still keep going up and up. We have renewable energy in place. No am not willing to pay more until you can prove to me that what you will do will make a difference."*
> \- Simone L., Group 4

- Some commercial customers are conflicted based on financial pressures.

> *"This is really a tough one for me. I would pay 5% more on my personal bill, but in my business the bottom line always wins."*
> \- Jill B., Group 4

Reactions to Long-Term Resource Planning Priorities

- Like residential customers, most commercial customers feel that the most important objective is ensuring cost-effective, secure, and reliable power for customers. Providing cost-effective energy conservation programs is of secondary importance, while consistency with provincial energy objectives and policies is not seen to be as important.

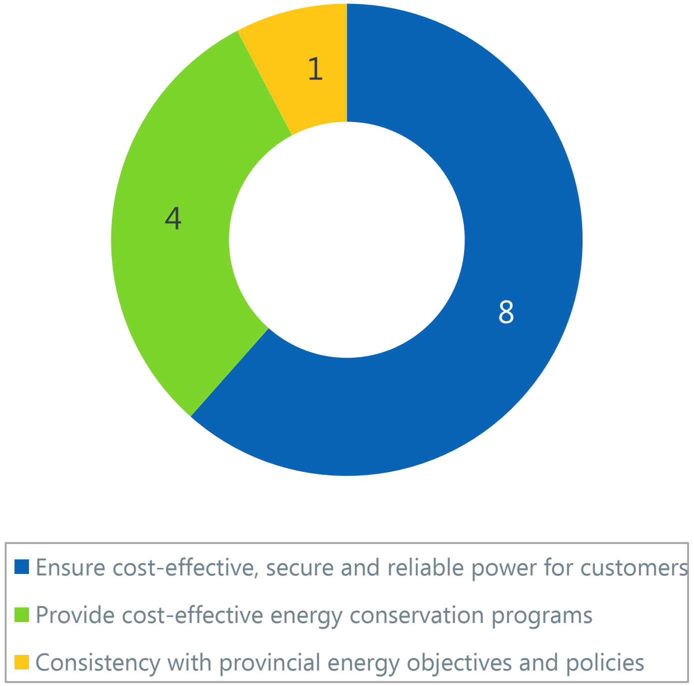
Why Ensuring Cost-Effective Secure and Reliable Power is Most Critical

- Customers who view this objective as critical cite the central role of electricity in everyday life – "everything revolves around electricity" – and the need to contain costs so that electricity can be an affordable option.

"Cost is increasing at an alarming rate, customers on a fixed income will have trouble paying their bill. Do I pay my electric bill or buy groceries?"
- Al T., Group 4

"Many people have trouble paying the high power bills now, so cost is important. Secure and reliable power is definitely a priority."
- Sandy T., Group 4

Top Priority



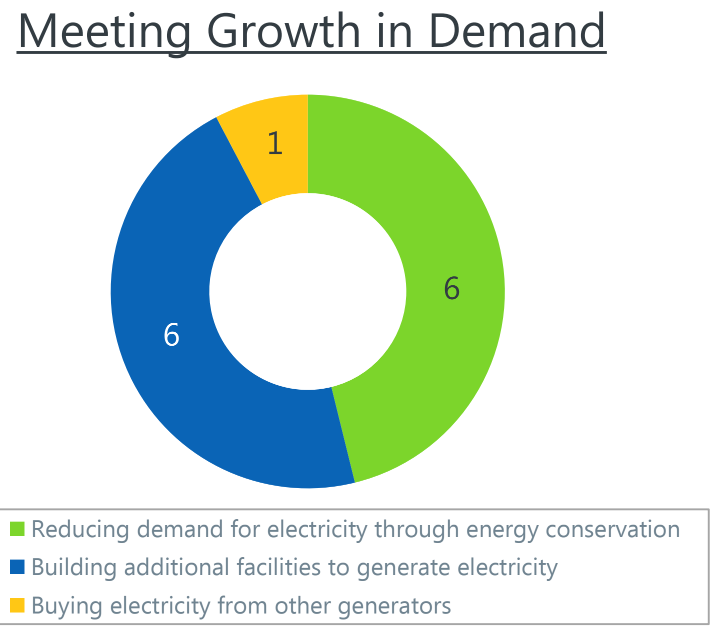
Note: Data displayed in counts.

S5Q3. Is there one objective in this list which stands out as particularly critical or more important than the others?

FortisBC's Future Investment in Energy Conservation Activities

Meeting Future Growth in Demand for Electricity

- Unlike residential customers who tend to place priority on demand reduction through energy conservation, commercial customers are split between the conservation option and the option to build additional facilities.
- Buying electricity from other generators is not seen to be as appealing of a method for meeting growth in demand – largely because costs may be difficult to predict.



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S6Q1. Which of these options appeals most to you, and why?

Why Customers Favour Building Additional Facilities

- In explaining why they place higher priority on building additional generation facilities, commercial clients refer to the limits of conservation as a way to manage demand given our future energy needs.

> *"I don't believe we can conserve enough energy to meet the needs of an ever-expanding marketplace."*
> - Bob K., Group 4

> *"Although I believe in energy conservation and think efforts towards that should continue, I also believe that demand will still increase and that we should plan for that."*
> - Jill B., Group 4

- Customers also note that conservation has limits due to the fact that many people are not financially able to participate in conservation programs.

> *"Rebates sound very good and appealing but I don't believe it's the answer to the problem. Today people live on fixed income (baby boomers) or very low income families… There is no money left to go out and buy new appliances, never mind applying for rebates."*
> - Simone L., Group 4

FortisBC's Future Investment in Energy Conservation Activities

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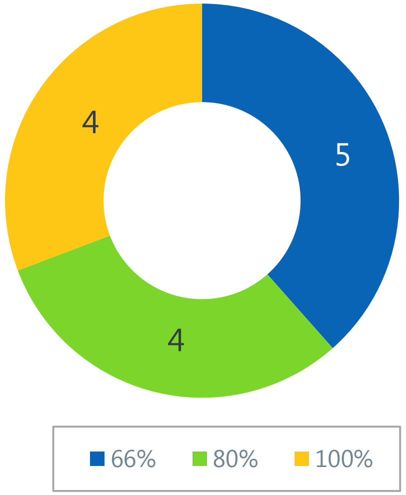
Preferences Regarding Future Offset Levels

- Preferences are divided among commercial customers when it comes to the preferred level of offset. Most favour of increasing the level of offset from 66%. However, there is no clear consensus on which of the 80% or 100% levels is optimal.

Preferred Level of Offset



- **Why Customers Prefer 66% Offset**
  - Commercial customers who prefer the current offset level point the fact that energy costs are already making them struggle financially, and that the 66% option "is the best option to keep costs in check." They also indicate that with this option they will continue to engage in the energy conservation activities that they already engage in.

- **Why Customers Prefer 80% Offset**
  - Commercial customers see the 80% level as a "balance" between the two other options. They don't see the 100% level as "sustainable" and they see the 66% option as "risky" (given the reliance on other generators.) They see the 80% option as one that will make them proactive in reducing energy and acting on incentives.

- **Why Customers Prefer 100% Offset**
  - Commercial customers view this option as the "ideal" option that would have the biggest impact on consumer conservation behaviour.

> *"I am choosing this option with the hopes that our full demand can be met this way."*
> \- Kelly M., Group 4

> *"Of course this is the sound good option and the dream."*
> \- Simone L., Group 4

  - However, they note that this option is "realistically difficult" and would take a very significant public information campaign by FBC in order to approach this level.

Respondent Profile

Appendix

Respondent Profile: Residential Customers

	Group 1	Group 2	Group 3
Base	*12*	*12*	*12*
Gender			
Male	6	9	7
Female	6	3	5
Age			
25-34	-	-	1
35-44	-	1	3
45-54	8	5	2
55+	4	6	6
Region			
Kelowna	12	-	-
Central OK/Similkameen	-	12	-
Boundary/Kootenays	-	-	12
Education			
Completed high school	4	1	-
Some college	1	1	4
Completed college	2	3	3
Some university	1	-	-
University degree	3	7	2
Post-graduate degree	1	-	3

	Group 1	Group 2	Group 3
Base	*12*	*12*	*12*
Employment			
Full-time	10	10	9
Part-time	1	-	1
Student/Unemployed	1	1	-
Retired	-	1	2
Home Ownership			
Own	12	11	11
Rent	-	1	1
Home Type			
Single detached	8	10	11
Townhouse	1	-	-
Apartment/condo	2	1	1
Other	1	1	-

Note: Data displayed in counts.

Respondent Profile: Commercial Customers

	Group 4
Base	*13*
Gender	
Male	6
Female	7
Age	
25-34	-
35-44	1
45-54	2
55+	10
Region	
Kelowna	5
Central OK/Similkameen	4
Boundary/Kootenays	4
Education	
Some high school	1
Completed high school	1
Some college	1
Completed college	-
Some university	2
University degree	7
Post-graduate degree	1

	Group 4
Base	*13*
Title	
Owner/Co-owner/CEO	10
Manager	3
Office Ownership	
Own	11
Rent/Lease	2
Industry	
Retail (non-food)	2
Manufacturing	1
Agriculture/ Greenhouses	1
Office	2
Public Institution	2
Lodgings	3
Residential	2

Note: Data displayed in counts.

Appendix C

FUEL SWITCHING ANALYSIS

NAVIGANT

Memorandum

To: Keith Veerman (FortisBC Inc.)

From: Navigant Consulting, Inc.

Date: November 28, 2016

Re: Cost Effectiveness of Selected Fuel Switching Measures

Introduction

As part of the development of the 2016 Conservation Potential Review (CPR), FortisBC Inc. ("FortisBC Electric") retained Navigant to identify and assess the financial and economic attractiveness of selected fuel switching measures for the Residential and Commercial sectors. Specifically, Navigant assessed the economics of switching from gas to electricity.

The purpose of this memo is to summarize the results of this analysis, which are presented in the following sections:

- Methodology;
- Description of Fuel-Switching Measures; and
- Cost-Effectiveness Results.

Methodology

This section describes the overall methodology Navigant applied to determine the cost-effectiveness of fuel-switching measures.

Navigant and FortisBC Electric selected the fuel-switching measures based on commercially available electric and gas space heating technologies that were characterized as part of the broader BC CPR study. These electric and gas heating technologies are potential fuel-switching alternatives, but may or may not be economic. The characterization of these fuel switching measures relied on the assumptions and underlying engineering calculations performed for the CPR study. These assumptions include the baseline and measure technology costs, and the annual gas and electric energy consumption.

Navigant calculated the cost-effectiveness of the selected fuel-switching measures using the Total Resource Cost (TRC) test and the Rate Impact Measure (RIM) test. The team calculated cost-

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effectiveness based on FortisBC Electric's avoided cost of electricity and retail prices of electricity, and FortisBC Energy's (or FortisBC Gas) avoided cost of natural gas and retail prices of gas.

Consistent with the segmentation of customer sectors defined in the CPR, Navigant calculated results for each of the five residential segments and eleven commercial segments. The complete list of residential and commercial segments in presented in the following section.

Description of Fuel-Switching Measures

This section provides a brief description of the fuel-switching measures and technologies included in this analysis.

The analysis includes one residential and one commercial fuel switching measure. The fuel-switching measure for each customer sector was selected to illustrate a hypothetical residential or commercial FortisBC Electric customer opting to switch from natural gas space heating to electric space heating.

The residential fuel-switching measure consists of installing an electric air source heat pump to replace a gas furnace. **Table** 1 shows the characteristics of the residential fuel-switching measure.

Table 1: *Residential Fuel-Switching Measure*[1]

	Gas Technology	Electric Technology
Space Heating Measure	Residential Gas Furnace	Residential Air Source Heat Pump (ASHP)
Target Segments	• Single Family Detached • Single Family Attached/Row • Apartments =< 4 stories • Apartments > 4 stories • Other Residential	
Measure Type	Replace-On-Burnout (ROB)	
Useful Life	18 years	16 years

Source: Navigant

The commercial fuel-switching measure consists of installing a rooftop unit heat pump to replace a rooftop unit gas furnace. **Table** 2 shows the characteristics of the commercial fuel-switching measure.

[1] Although apartments are classified as residential segments in the CPR study, FortisBC considers them commercial customers.

Table 2: *Commercial Fuel-Switching Measure*

	Gas Technology	Electric Technology
Space Heating Measure	Commercial Gas Rooftop Unit Furnace	Commercial Rooftop Unit (RTU) Heat Pump
Target Segments	• Accommodation • Colleges & Universities • Food Service • Hospital • Logistics & Warehouses • Long Term Care	• Office • Other Commercial • Retail - Food • Retail - Non Food • Schools
Measure Type	Replace-On-Burnout (ROB)	
Useful Life	18 years	15 years

Source: Navigant

Cost-Effectiveness Results

Fuel switching for all measures results in increased system costs as well as incremental measure costs. Since there are no economic benefits (only costs) to society resulting from the adoption of these measures, all have a TRC ratio of zero and a RIM ratio close to 1.0. The following paragraphs explain these results.

Figure 1, below, presents the TRC equation. As Figure 1 illustrates, the TRC benefits are calculated as the total of the avoided electric costs and the avoided gas costs divided by the incremental cost to the consumer of fuel-switching. Most demand side management (DSM) measures rely on a single-fuel measure where the energy efficiency (EE) alternative has a lower energy consumption and lower demand than the baseline technology, resulting in a positive numerator. With gas-to-electric fuel-switching measures, however, the baseline and EE technologies use different fuels. The baseline is a gas technology (e.g., a gas furnace) and the EE alternative is an electric technology (e.g., an electric air source heat pump). As a result of the dual-fuel nature of fuel-switching measures, the total avoided costs are calculated as the sum of the avoided gas costs and the incremental electricity supply costs (or *negative* avoided costs). Given the higher commodity cost of electricity relative to gas for space heating purposes, the total avoided costs result in a *negative* cash flow, or a net cost. These negative avoided costs are no longer benefits and are moved to the denominator of the TRC equation to be accounted for as a net-cost, as shown by Figure 2. Consequently, the total benefits are zero and the TRC ratios are also zero.[2]

Figure 1: *Standard TRC Equation*

$$TRC = \frac{Benefits}{Costs} = \frac{PV(Avoided\ Electric\ and\ Gas\ Costs)}{PV(Incremental\ Equipment\ Cost)}$$

Source: Navigant

[2] The California 2001 Standard Practice Manual (2001) notes that most cash flows can be either positive or negative and as such they need to be accounted for appropriately as costs or benefits. California Public Utility Commission - CPUC (2001). *California Standard Practice Manual: Economic Analysis of Demand-Side Programs*. Website: http://www.cpuc.ca.gov/General.aspx?id=5267

Figure 2: *Modified TRC Equation*

$$TRC = \frac{Benefits}{Costs} = \frac{0.0}{PV(Avoided\ Electric\ and\ Gas\ Costs) + PV(Incremental\ Equipment\ Cost)}$$

Source: Navigant

Table 3, below, illustrates this point. For example, consider a residential customer that installs an air source heat pump (4,300 kWh of annual consumption) in place of a gas furnace (43,000 MJ of annual consumption)[3]. The avoided gas cost, as a result of opting not to install a new gas furnace, is $215 per year (=43,000MJ x $0.005/MJ). The avoided electric cost from installing the air source heat pump is $-430 per year (4,300kWh x $0.10/kWh), or $430 of incremental supply costs per year[4]. The avoided gas cost is a benefit, while the avoided electric cost (normally a benefit) is, (in this case) a cost. The total avoided cost (gas + electric) is equivalent to $-215 per year, or a net-cost of $215. As a negative cash flow, the avoided costs are moved to the denominator of the equation for the calculation of the TRC. Ultimately, the benefits are zero and the costs are equivalent to the total of the incremental equipment costs and the avoided fuel costs.

Table 3: *Illustrative Calculation of Negative Avoided Costs for TRC Test*[5]

	Base technology	EE technology	Cost/Benefit
Fuel	Gas	Electricity	
Equipment	Gas Furnace	Air Source Heat Pump	
Capital Costs	$4,500	$6,000	*Incremental Product Equipment Cost =* **$1,500**
Annual Consumption	43,000 MJ	4,300 kWh	
Avoided Costs	$0.005/MJ	$0.10/kWh	
Calculation of Avoided Gas and Electric Costs			*Avoided Gas + Electric Cost*
Year 1	$215	($430)	**($215)**
Year 2	$215	($430)	**($215)**
Year 3	…	...	**…**

Source: Navigant

A similar logic applies to the RIM results. Figure 3 presents the RIM equation. The benefits —or the avoided electric and gas costs— are net-negative and are moved to the denominator to be accounted for as costs. Similarly, the costs —or the lost electric and gas revenues— result in a net-positive cash flow, and are moved to the numerator to be accounted for as benefits. Figure 4 illustrates the modified RIM equation.

Figure 3: *Standard RIM Equation*

$$RIM = \frac{Benefits}{Costs} = \frac{PV(Avoided\ Electric\ and\ Gas\ Costs)}{PV(Lost\ Electric\ and\ Gas\ Revenue)}$$

Source: Navigant

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[3] Assumes an 8.69 HSPF air source heat pump with, and a 92% AFUE gas furnace.
[4] Avoided electric demand costs ($/kW) are not included in this example o**r** Table 3, however they are accounted for in the final TRC results.
[5] Table 3 assumes that avoided costs of electricity and gas are fixed in Year 1 and Year 2.

Figure 4: *Modified RIM Equation*

$$RIM = \frac{Benefits}{Costs} = \frac{PV(Lost\ Electric\ and\ Gas\ Revenue)}{PV(Avoided\ Electric\ and\ Gas\ Costs)}$$

Source: Navigant

Table 4, below, shows an example calculation of the RIM test. The total avoided cost (electric and gas) is calculated as $-215 per year —or a $215 net-cost—, and the total lost revenue (electric and gas) is $212 per year —or a $212 net-benefit. As a result, the avoided costs are accounted for as costs (and not benefits) and the lost revenues are accounted for as benefits (and not as costs), as illustrated by Figure 4.

Table 4: *Illustrative Calculation of Negative Avoided Costs and Positive Lost Revenue for RIM Test*[6]

	Base technology	EE technology	Cost/Benefit
Fuel	Gas	Electricity	
Annual Consumption	43,000 MJ	4,300 kWh	
Avoided Costs	$0.005/MJ	$0.10/kWh	
Retail Rates	$0.009/MJ	$0.14/kWh	
Calculation of Avoided Gas and Electric Costs			*Avoided Gas + Electric Cost*
Year 1	$215	($430)	**($215)**
Year 2	$215	($430)	**($215)**
Year 3	…	…	**…**
Calculation of Lost Gas and Electric Revenue			*Lost Gas + Electric Revenue*
Year 1	($390)	$602	**$212**
Year 2	($390)	$602	**$212**
Year 3	…	…	…

Source: Navigant

Table 5 presents the TRC and RIM results of the fuel-switching measures for each of the residential and commercial segments analyzed. All measures have a TRC ratio of zero because there are no economic benefits and only costs. All residential and most commercial segments have a RIM ratio higher than 1.0.

[6] Avoided electric demand costs ($/kW) are not included in Table 4, however they are accounted for in the final TRC results.

Table 5: *Cost-Effectiveness Results (2016)*

Sector	Segment	TRC (B/C ratio) *Modified*	RIM (B/C ratio) *Modified*
Residential	Single Family Detached	0.00	1.02
	Single Family Attached/Row	0.00	1.02
	Apartments =< 4 stories	0.00	1.08
	Apartments > 4 stories	0.00	1.08
	Other Residential	0.00	1.02
Commercial	Accommodation	0.00	1.17
	Colleges & Universities	0.00	1.17
	Food Service	0.00	1.17
	Hospital	0.00	1.02
	Logistics & Warehouses	0.00	1.02
	Long Term Care	0.00	1.09
	Office	0.00	1.05
	Other Commercial	0.00	1.09
	Retail - Food	0.00	1.04
	Retail - Non Food	0.00	1.07
	Schools	0.00	0.99

Source: Navigant