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September 15, 2017

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

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

Dear Mr. Wruck:

Re: FortisBC Inc. (FBC)

Project No. 3698896

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

Errata

On November 30, 2016, FBC filed the LTERP and LT DSM Plan, referenced above. On August 25, 2017, FBC advised the British Columbia Utilities Commission (the Commission) that FBC intended to file Errata to the LTERP and LT DSM Plan as a result of certain errors in the assumptions supporting the British Columbia Conservation Potential Review (CPR) for the FBC service territory.

FBC has determined that two errors exist in the assumptions supporting the CPR for the FBC service territory, the report from which (the CPR Report) was included as Appendix A to the LT DSM Plan. While the net impact of correcting these errors does not change the conclusions reached in the LTERP or LT DSM Plan, the revised assumptions do impact the cost of the Demand Side Management (DSM) scenarios (DSM Scenarios) FBC evaluated. The source of the errors and their impacts are described below.

The first error was the substitution of the real discount rate of 6 percent for the nominal discount rate in the CPR analysis. The CPR analysis should have been performed using a nominal discount rate of 8 percent. Discounting the savings of DSM measures at a higher rate reduces electricity savings over time and increases the costs of the DSM Scenarios.

The second error concerns the treatment of line losses. DSM savings targets are set as a percentage reduction of the growth in gross system load, but the economic potential of DSM measures, which is used to calculate the cost of the DSM Scenarios, was calculated at the customer's meter, without consideration of line losses. In order to determine the impact of the DSM Scenarios on gross load, it is necessary to adjust for line losses (of 8 percent) in the calculation of the DSM Scenario costs. Applying the line loss adjustment both increases energy savings and reduces the costs of the DSM measures.

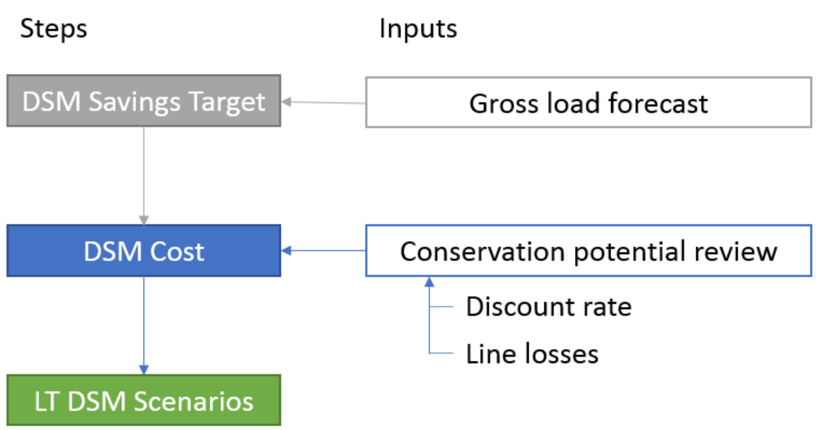
The net impact of the inflation adjustment to the discount rate and the inclusion of line losses is a reduction to the costs of the DSM Scenarios, and accordingly slight reductions to the Long Run Marginal Cost (LRMC) of most of the various resource porfolios evaluated for the LTERP. The LRMC for the purposes of evaluating cost effective DSM pursuant to the DSM Regulation has not changed as this portfolio (B1) did not contain any DSM (per Section 9.3.1 of the LTERP), so the change in the resource cost of DSM does not impact the LRMC of that portfolio.

As noted above, **the changes to the DSM Scenario costs and the portfolio LRMC values are of a relatively small magnitude and do not affect FBC's recommended DSM Scenario, its preferred resource portfolio or its timing**.

Below, FBC summarizes the DSM Scenario development process and the results of the corrections to the LT DSM Plan and the LTERP.

DSM Scenarios Development Process

The development of the DSM Scenarios for the LTERP and LT DSM Plan was a two-step process, as shown in the following figure.



The first step was to establish a DSM savings target. FBC developed four DSM Scenarios: Low, Base, High, and Maximum (Max), with different levels of targeted savings over the planning horizon. These DSM Scenarios are expressed as a percentage reduction of FBC's total gross load growth over the LTERP's 20 year planning horizon. The DSM savings targets used in the portfolio analysis (described in Section 9 of the LTERP) are independent from the cost and therefore unaffected by the corrections noted above.

The second step was to determine the cost to achieve the DSM savings targets. The cost for each of the DSM Scenarios is derived from the collection of measures identified in the CPR. FBC used the lowest cost measures available to meet the savings target for each scenario. The cost of each DSM Scenario increases as marginally higher-cost DSM resources are selected to achieve a higher percentage of load growth offset with DSM. The cost to achieve the DSM savings targets is impacted by the change in discount rate and line losses.

Impact on DSM Scenarios

The impact of these two changes is offsetting, to some extent, and the net effect of the changes is a relatively small reduction to the DSM Scenario costs. The savings targets for each scenario are independent from the cost and therefore unaffected by the errors. Table 3-1 from the 2016 LT DSM Plan has been updated below to show the changes in the incremental costs, including program costs, for the four DSM Scenarios.

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 – As filed	$45	$88	$104	$114
Incremental cost incl. program costs – Correction	$42	$86	$98	$108

These changes result in an increase in Total Resource Cost (TRC) ratios (benefits/costs) due to lower measure costs.

Scenario TRC Benefit/Cost Ratio

Version	DSM Scenario			
	Low	Base	High	Max
As filed	2.6	2.1	1.9	1.7
Correction	3.4	2.6	2.2	2.0

However, the utility cost of the DSM Scenarios remains almost unchanged (less than 1 percent difference between the originally filed and corrected values) because it is calibrated to current expenditure levels. The incremental cost of DSM Max still remains above the $100 per MWh LRMC for the purposes of evaluating cost-effective DSM. Furthermore, the risks associated with higher levels of DSM have not changed. Therefore, the preferred High DSM Scenario as filed in the 2016 LT DSM Plan does not change.

Impact on Resource Portfolios

The changes to the LRMC values of the resource portfolios evaluated for the LTERP are of a small magnitude and do not change FBC's preferred resource portfolio (Portfolio A4; see Section 9.3.6 of the LTERP) or its timing. The various resource portfolios were designed based on particular amounts of load growth offset savings from DSM. It is important to note that, because the amount of load growth offset from the DSM Scenarios is not changing, only the related costs to achieve the savings, the supply-side resources included in the various portfolios, as well as their dispatch and timing, do not change. Only the overall cost of the portfolios changes. The LRMCs of some portfolios did not change after rounding to whole dollars. The tables below show the slight reduction in the LRMC of some of the key portfolios described in Section 9 of the LTERP.

Portfolios Considered for Preferred Portfolio

Portfolio	Description	LRMC ($/MWh) - As filed	LRMC ($/MWh) - Correction
A1	No Self-Sufficiency	$76	$75
C1	93% Clean with CCGT	$91	$90
A4	93% Clean with SCGT	$96	$96
C4	100% Clean	$98	$97

Portfolios with Different DSM Levels

Portfolio	Description	LRMC ($/MWh) - As filed	LRMC ($/MWh) - Correction
B1	No DSM	$100	$100
B2	Base DSM	$92	$92
A4	High DSM	$96	$96
B4	Max DSM	$101	$99

Other Corrections

Unrelated to the issues identified above, FBC has identified a typographical error in Section 2.5 on Page 9 of the LT DSM Plan. Table 2-1 shows the electric energy technical savings potential by end use rather than the electric energy economic potential by end use, as filed.

Finally, the response to BCUC IR 2.77.3 also contained a typographical error which is unrelated to the CPR revisions.

Errata Documents

Attached to this letter are the black-lined versions of the relevant sections of the following documents affected by the Errata:

Description	Revised Pages
LTERP, Executive Summary	Page ES9
LTERP, Section 8	Pages 96, 99, 100, 103, 106
LTERP, Section 9	Pages 119 to 122, 124 to 128
LT DSM Plan, Section 2	Pages 9, 10
LT DSM Plan, Section 3	Pages 13, 14, 15
LT DSM Plan, Appendix A	All Pages
FBC Response to BCUC IR No. 1	Questions 33.1, 34.2, 35.2, 36.3, 38.2, 39.3, 40.2.1, 42.2, 45.1, 46.1.2, 47.1, 48.1, and 49.1
FBC Response to BCUC IR No. 2	Questions 60.1, 62.1.1, 75.3.1, 76.1.1, 76.2, 76.2.2, 77.2, 77.3, and 78.2

Description	Revised Pages
FBC Response to BCOAPO IR No. 1	Questions 4.3, 29.2, 38.2, 39.2, 39.4.1, 39.4.2, 40.2, 41.2, 41.4.1, 41.4.2, 47.1, and 47.5
FBC Response to BCOAPO IR No. 2	Questions 53.1, 61.2.1, 63.1.1, 63.2, 70.2.2, 72.1, 72.2, 72.3, 72.4, 72.5, and 75.2, and Attachment 72.1
FBC Response to BCSEA IR No. 1	Questions 16.2 and 16.4
FBC Response to BCSEA IR No. 2	Question 24.1
FBC Response to CEC IR No. 1	Questions 23.1 and 23.5
FBC Response to Shadrack IR No. 1	Question 10.v
FBC Response to Shadrack IR No. 2	Question 25.i

FBC also notes that it has reviewed the responses to the following IRs and determined that no changes are necessary as a result of the revised CPR at the level of precision (rounding) in the responses:

BCUC IR No. 1, Questions 31.1.1, 35.3, 41.3, 48.1.2, 49.1.1, 49.1.2, 51.2.1
CEC IR No. 1, Question 25.1
BCOAPO No. 2, Question 76.1

Further Review Process

Due to the relatively small magnitude of these errors and no changes in the DSM Scenario FBC selected or the preferred resource portfolio for the LTERP or its timing, FBC submits that no further review process is warranted. Any further process, if deemed necessary, should only address matters raised by the Errata itself and not other general developments in energy policy that have arisen since the evidentiary record was closed.

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

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

cc (email only): Registered Parties

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 $98 per MWh is just below 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.

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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

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

Resource Option	UEC ($/MWh)	UCC ($kW-year)
Base DSM	$86	N/A
High DSM	$98	N/A
Max DSM	$108	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.

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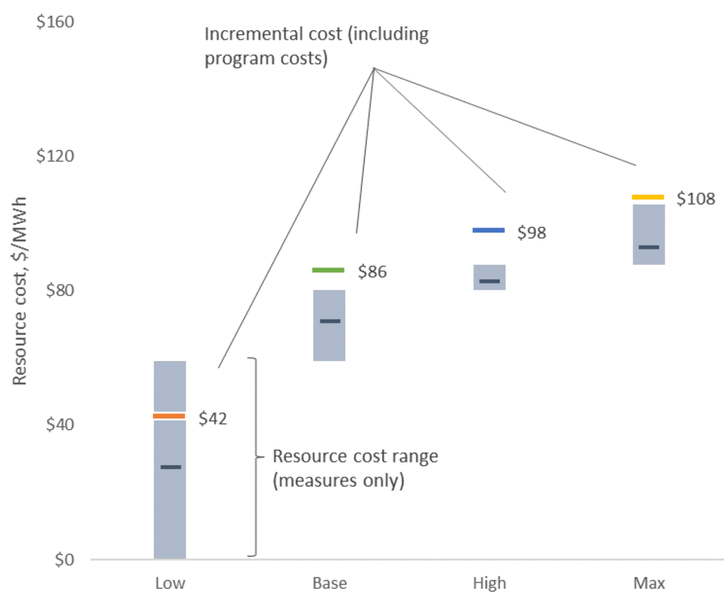
Figure 8-2: Cost of DSM Scenarios



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.

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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	$42	$86	$98	$108

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 $98 per MWh is just below 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.

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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.

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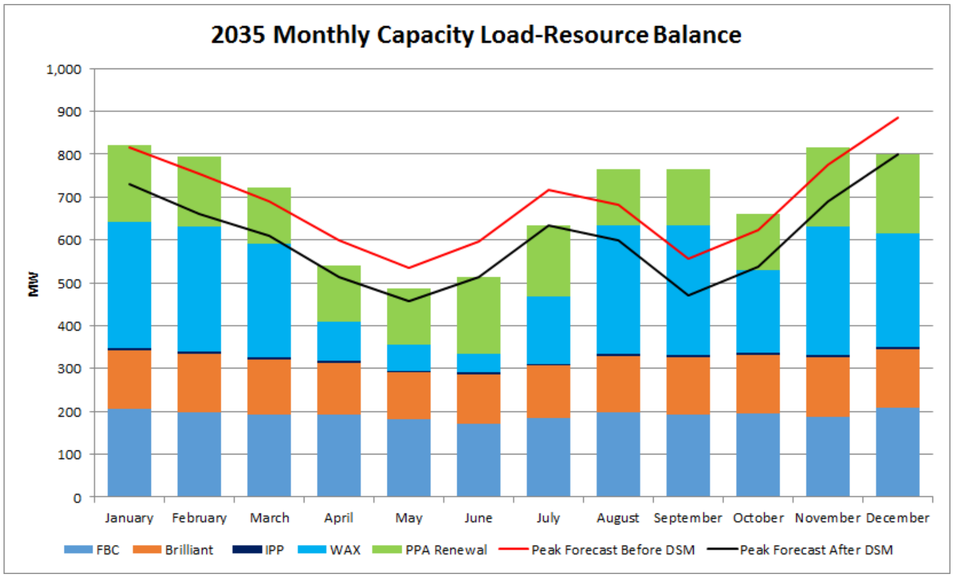
Figure 8-5: Monthly Capacity Load-Resource Balance for 2035, Before and After DSM



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 $98 per MWh, which is just below 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 $108 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.

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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 WACC, per the FBC Annual Review for 2017 Rates Application (Section 8.3.5) filed August 8, 2016.

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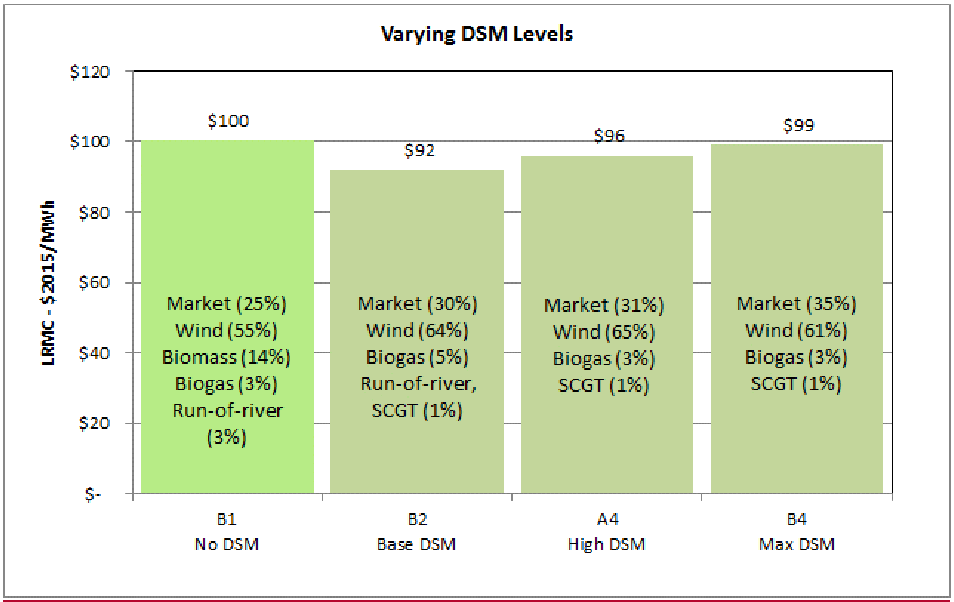
Figure 9-1: Portfolios with Different DSM Levels



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 $99 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.

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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.

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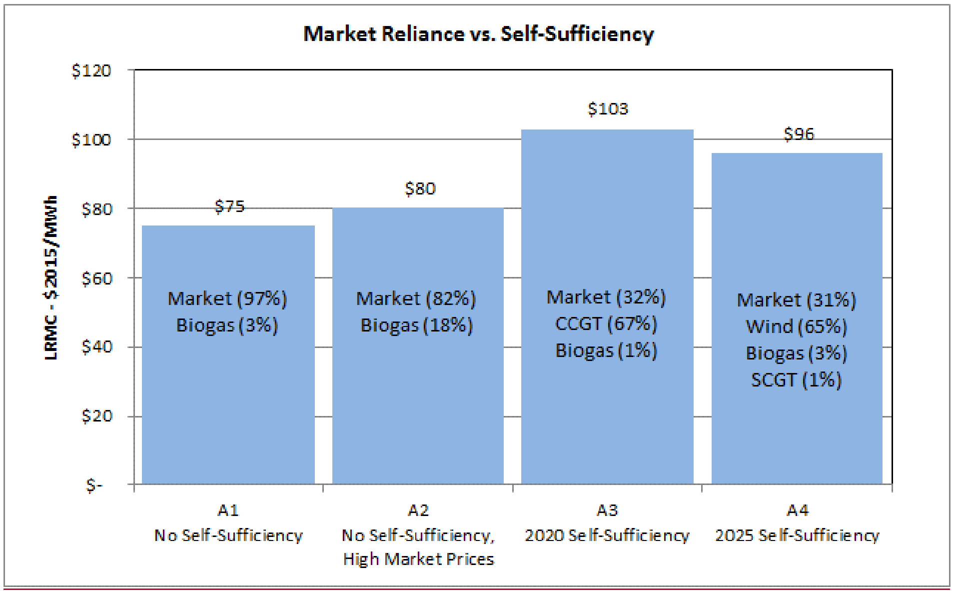
Figure 9-2: Portfolios with Market Access versus Self-Sufficiency



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 $75 per MWh and increases to $80 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 $103 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.

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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*.

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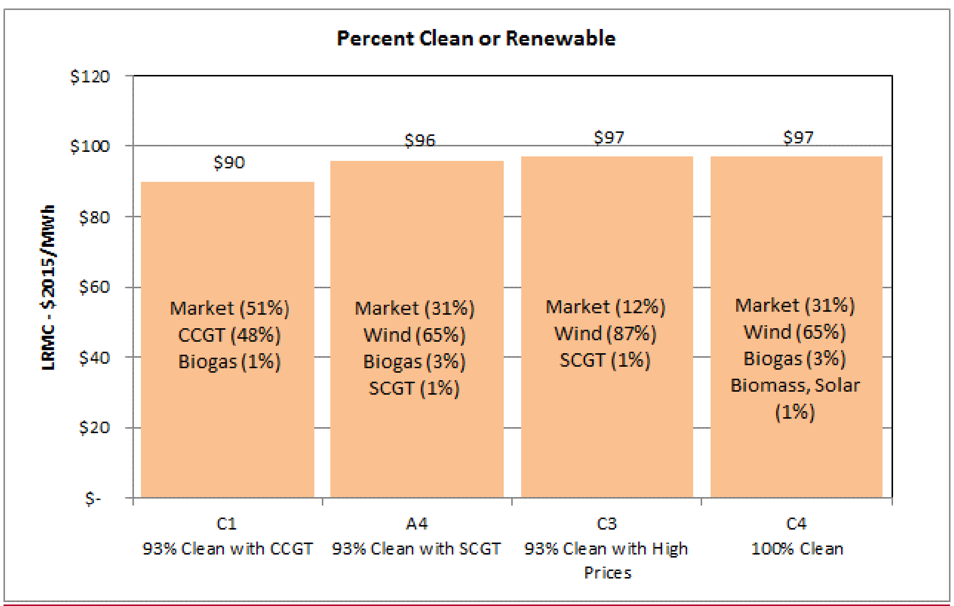
9.3.3 Percentage of Clean or Renewable Energy

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 $90 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

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than the 100 percent clean or renewable portfolio (C4), which has an LRMC of $97 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).

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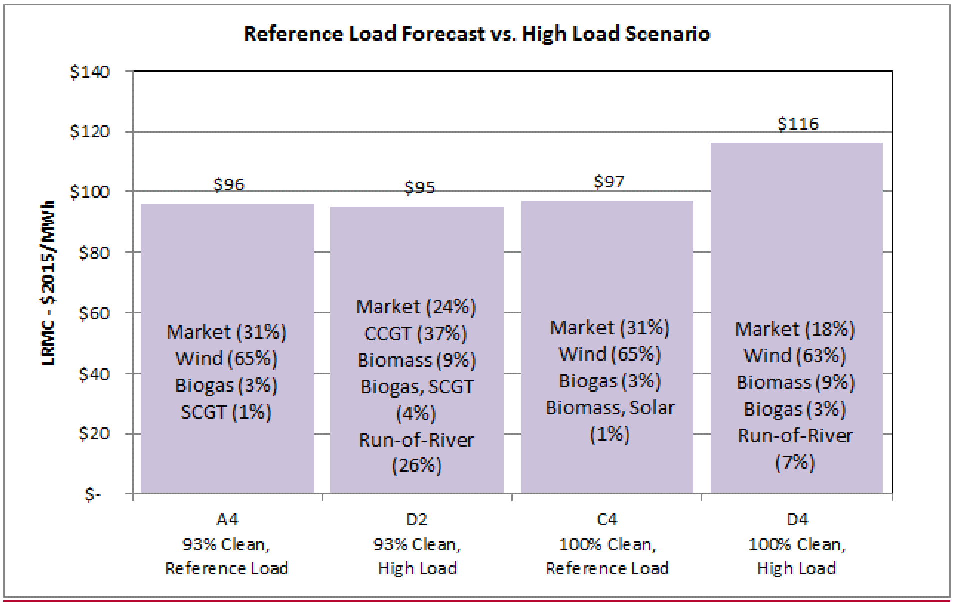
9.3.4 Load Requirements

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

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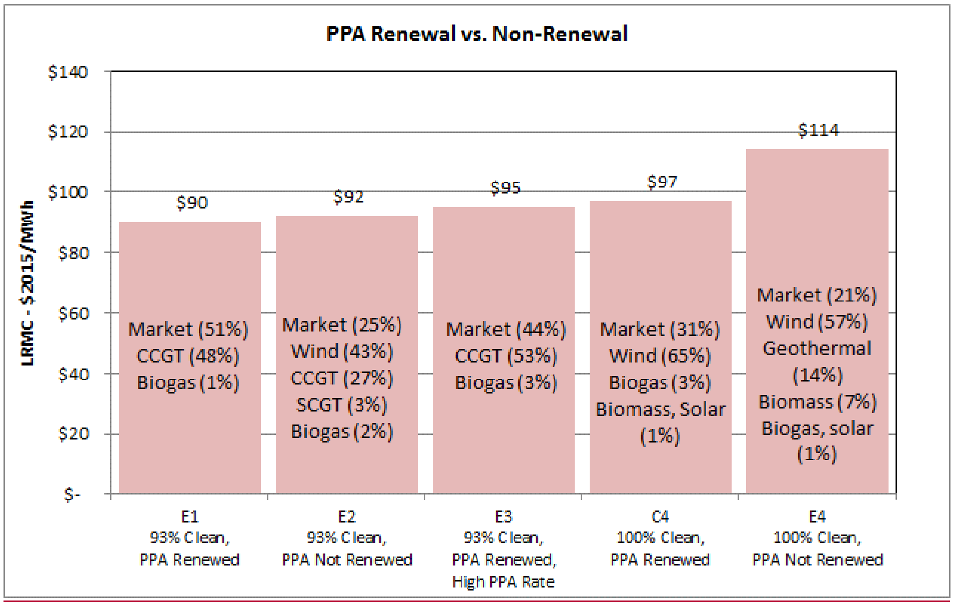
Figure 9-6: Portfolios with and without PPA Renewal



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.

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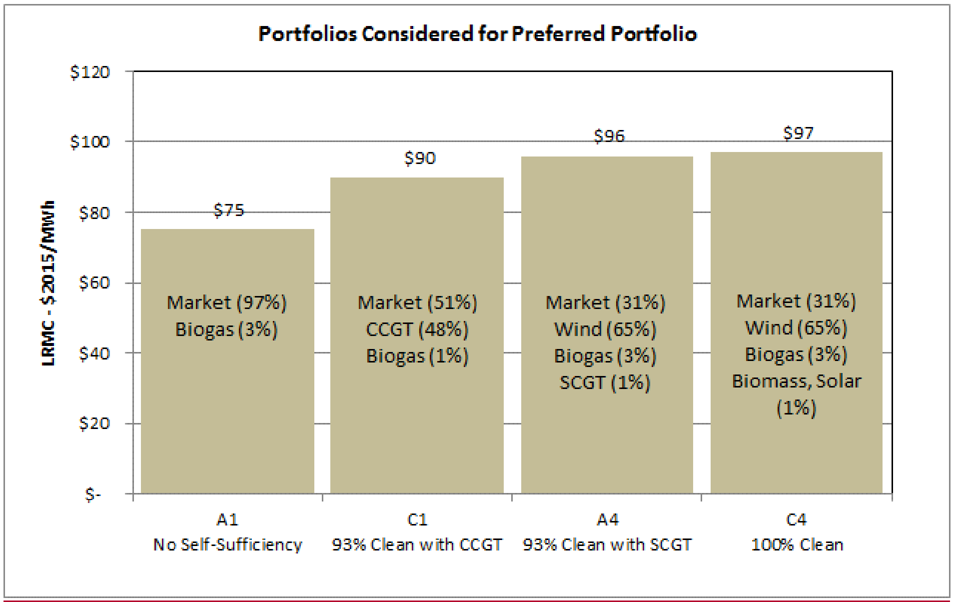
Figure 9-7: Portfolios Considered for Preferred Portfolio



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.

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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%)	$75	0.0%	0	14	Low
C1	93% Clean with CCGT	Market (51%) CCGT (48%) Biogas (1%)	$90	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%)	$97	0.0%	0	216	Medium

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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 $97 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.

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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.

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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 $97 per MWh (C3). With higher market prices, FBC selected more energy from wind generation and less from the market for the portfolio.

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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

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2.5 CPR RESULTS

The following Figure 2-1, taken from the FBC CPR report, shows the technical electric energy potential by end-use, aggregated across customer sectors, for new construction and retrofit combined. The top three technical 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.

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Figure 2-1: Electric Energy Technical Savings Potential by End-Use (GWh/year)

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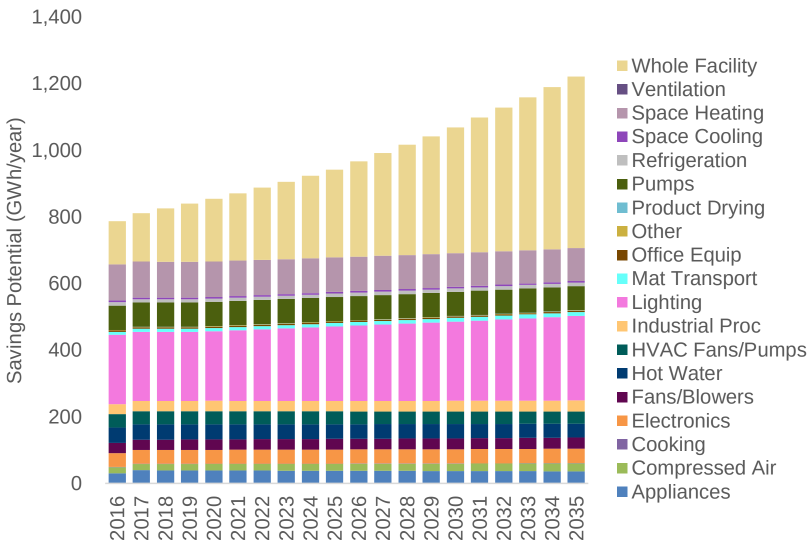

Source: Navigant

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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, 220 GWh per year at a cost up to $100 per MWh and another 160 GWh at a cost up to $150 per MWh. The flattening of the curve at approximately 970 GWh indicates it is approaching the maximum available economic potential, although limited additional potential is available at higher costs.

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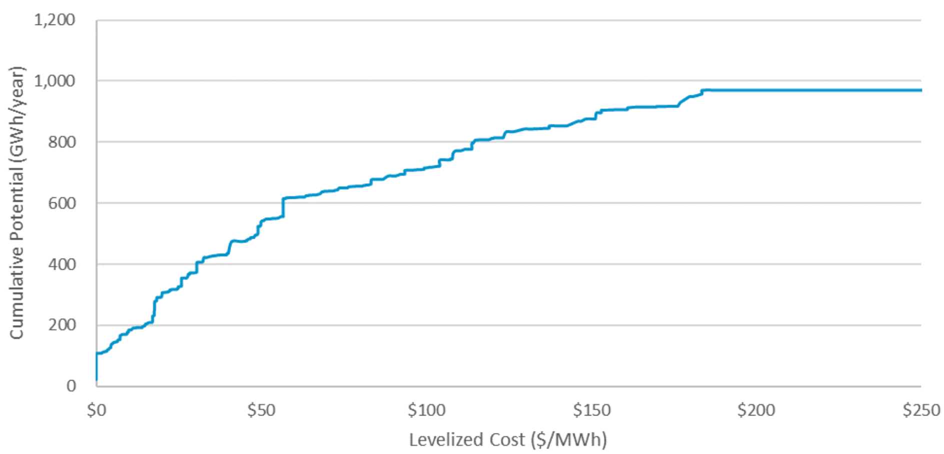
Figure 2-2: Supply Curve of Economic Potential (GWh/year) vs. Levelized Cost ($/MWh)



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.

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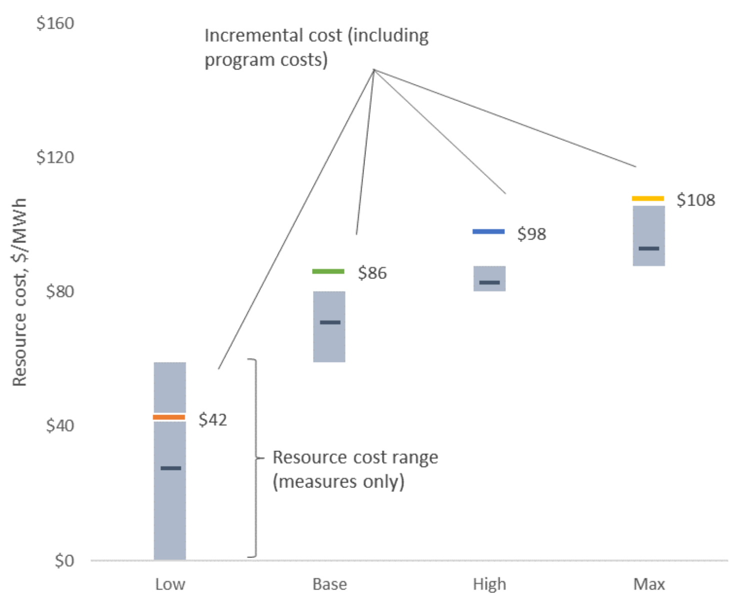
Figure 3-2 illustrates the supply cost curve of the DSM scenarios FBC considered. Each DSM scenario draws from a portfolio of measures, sourced from the FBC CPR results that have a range of resource costs. The incremental cost of each DSM scenario or tranche, increases as higher cost DSM resources are 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



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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	$42	$86	$98	$108

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

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- 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 $98 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.

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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 ($108 per MWh) of the Maximum tranche compared to the LRMC of $100 per MWh.

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REVISED Appendix A

FBC CONSERVATION POTENTIAL REVIEW

British Columbia Conservation Potential Review

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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.

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[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

[2] 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. 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.
[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.

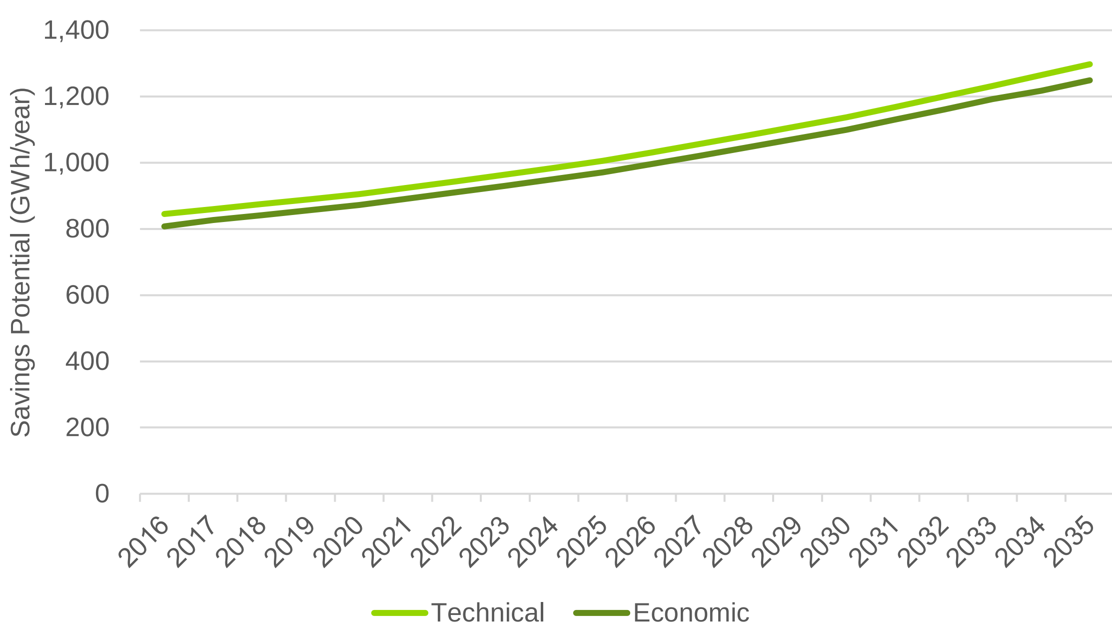
This study defines technical potential as the energy savings that can be achieved assuming that all installed measures can immediately be replaced with the efficient measure, wherever technically feasible, regardless of the cost, market acceptance, or whether a measure has failed (or “burned out”) and 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 half of the total potential by 2035.

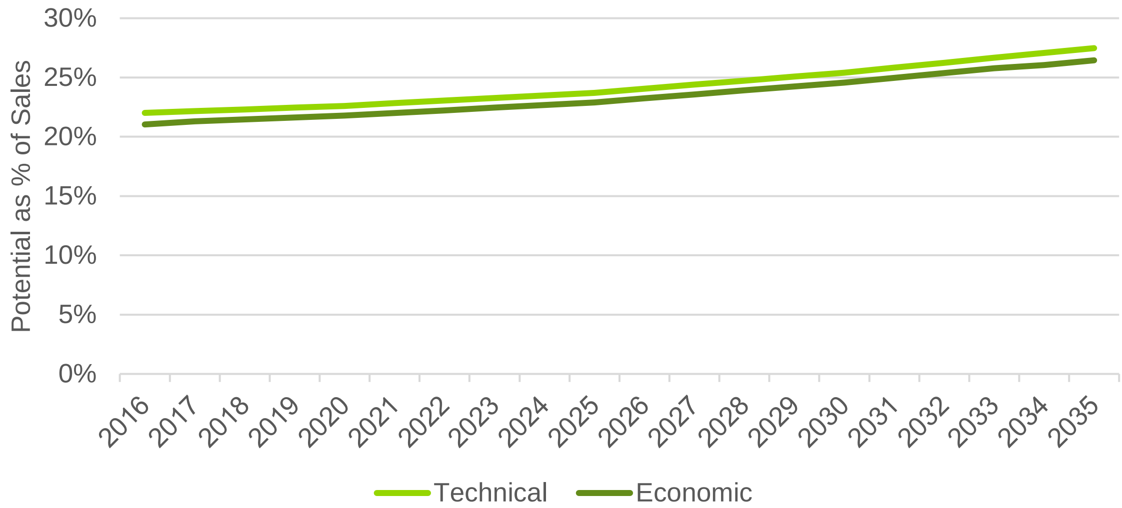
Figure ES-1. Total Electric Energy Savings Potential (GWh/year)



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.

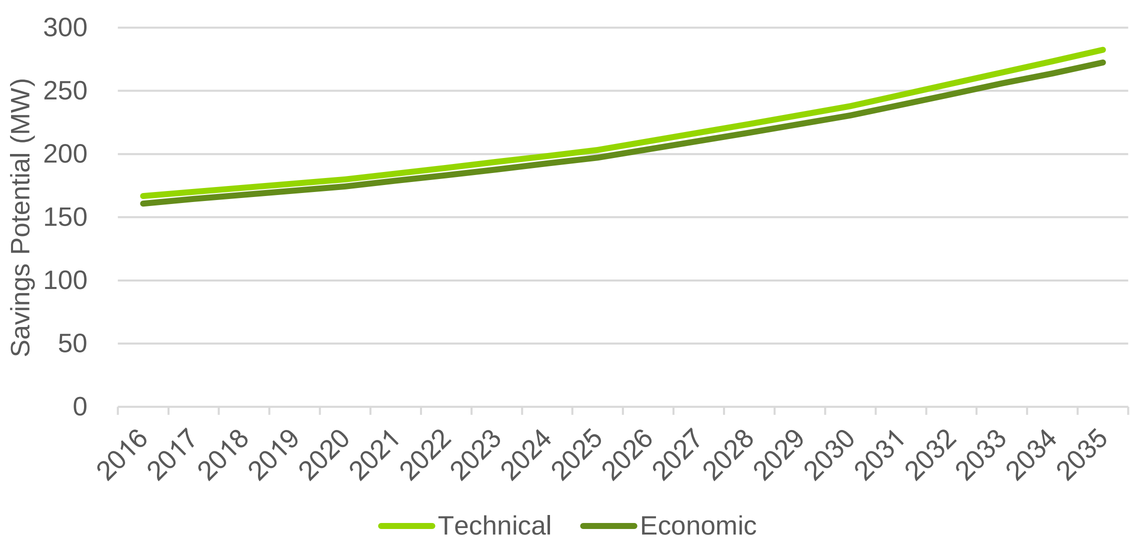
Figure ES-2. Total Electric Energy Savings Potential as a Percent of Total Consumption (%)



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.

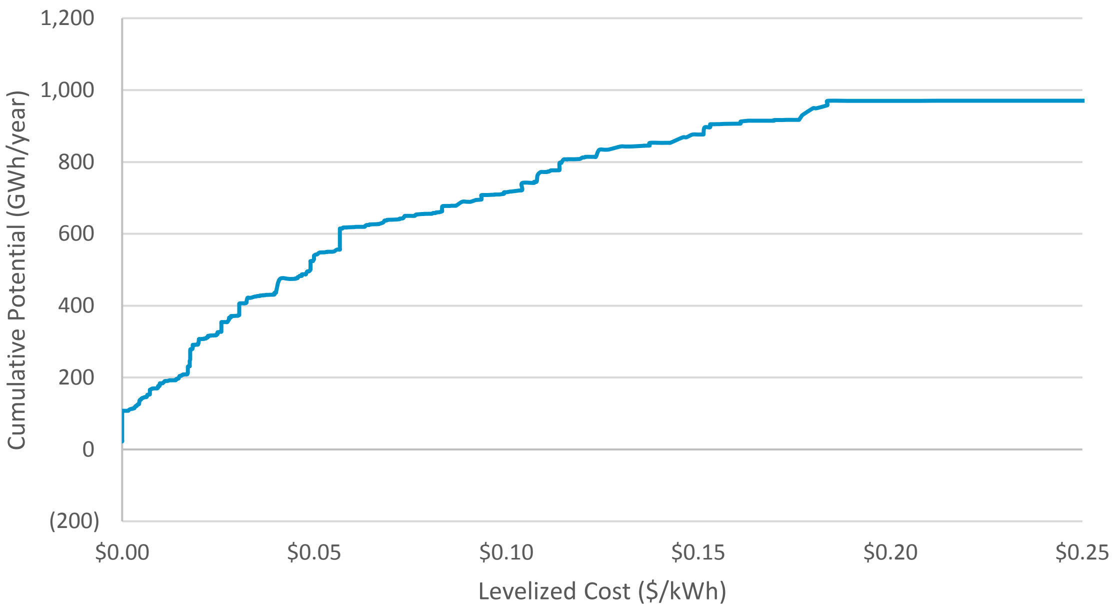
Figure ES-3. Total Electric Demand Savings Potential (MW)



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.

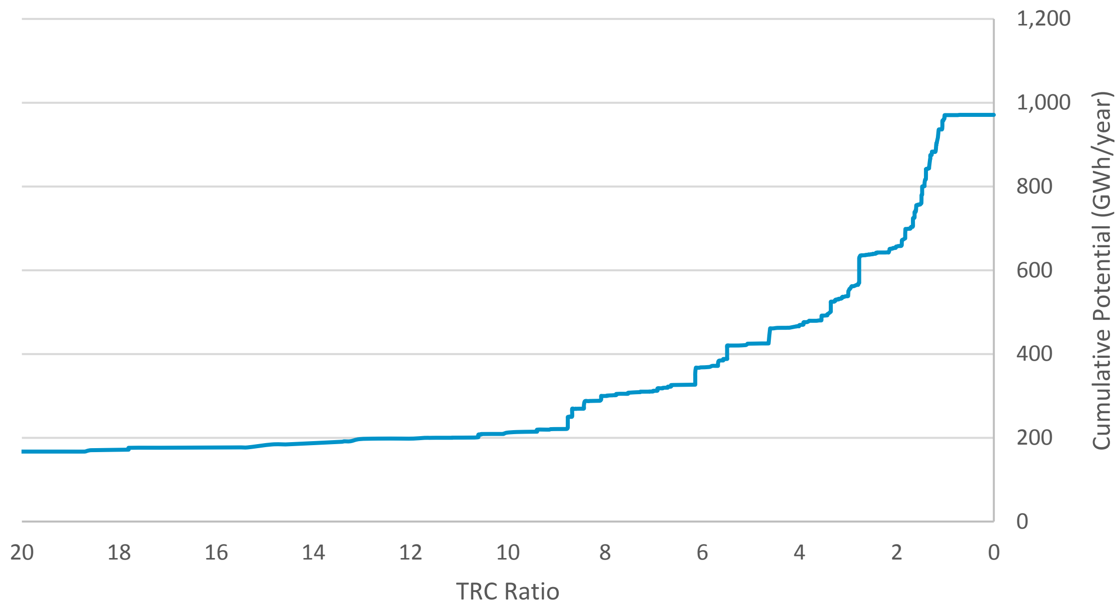
Figure ES-4. Supply Curve of Electric Energy Economic Potential (GWh/year) vs. Levelized Cost of Savings ($/kWh) in 2025



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. Thirty-one percent of the economic energy potential had TRC ratios greater than 8.0. Another 37% fell between TRC ratios of 2.0 and 8.0, while the remaining 32% 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. Additionally, utility staff will receive training in the operation of the model.

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 4.*
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.[4] 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. 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—attributed to apartment buildings—to the residential sector using the analysis of base year 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.

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. While apartment buildings are reported in the residential sector for purposes of the base year analysis and the reference case forecast, they have been moved to the commercial sector for purposes of reporting technical and economic potential savings. Electricity savings from apartment buildings are reported in the commercial sector because FortisBC Electric's conservation programs for apartment buildings are categorized as commercial programs.

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 calibrated iteration required refining of key variables and inputs such as the market share of equipment types, UECs by equipment, and fuel shares.

[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.

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

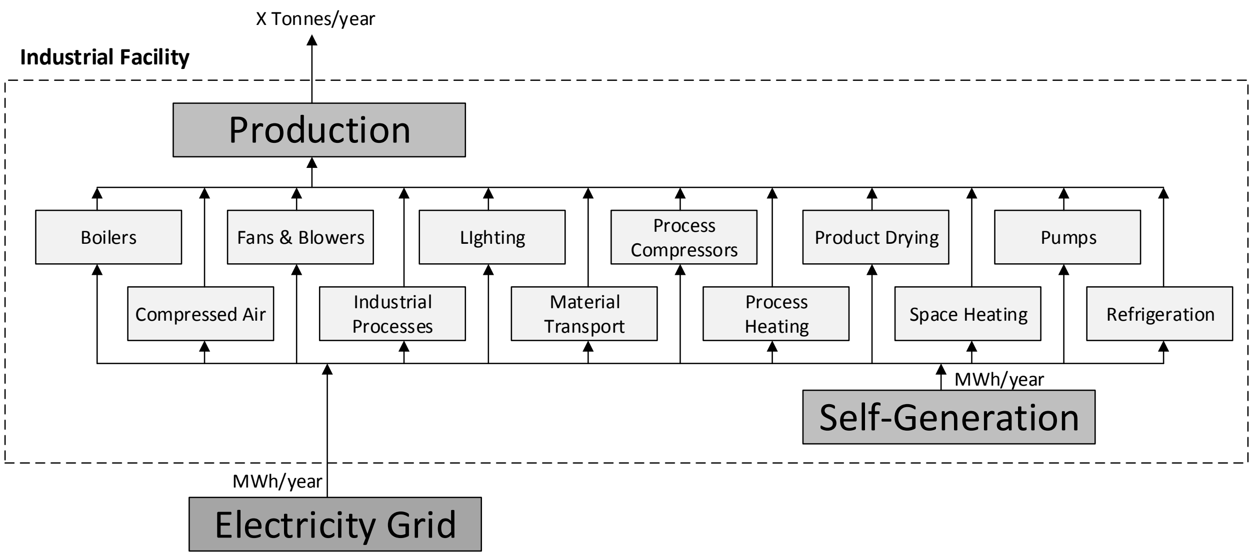
CLEAResult developed estimates of the distribution of energy consumption by end-use for each industrial segment. To calculate the energy consumption by end-use, CLEAResult utilized detailed data on industrial facilities for each of the industrial segments from numerous resources including:

- *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.

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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.

As stated previously, Navigant included apartment buildings in the residential sector for purposes of the base year and reference case analysis. However, in sections 3 and 4, technical and economic savings from apartment buildings are reported in the commercial sector.

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)

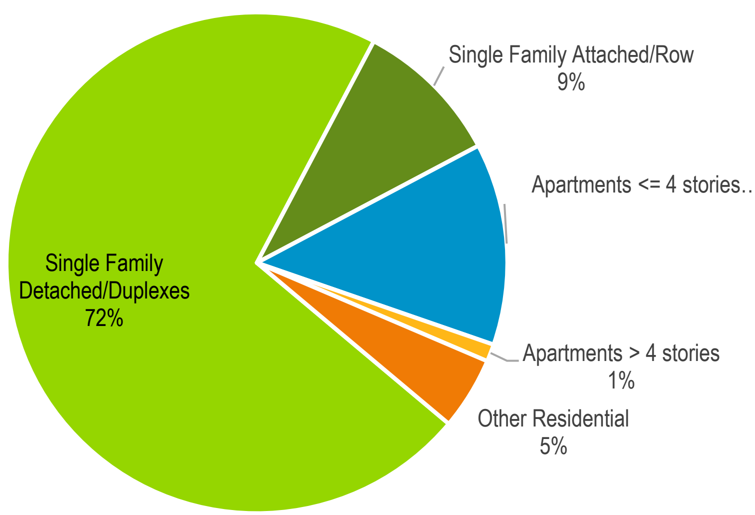
Region	Sector	Actual Consumption (GWh)	Base Year Consumption (GWh)	Difference (%)
Southern Interior	Residential	1,962	1,962	0.0%
	Commercial	924	924	0.0%
	Industrial [9]	874	874	0.0%
	Street Lighting	20	20	0.0%
Total		**3,780**	**3,780**	**0.0%**

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.

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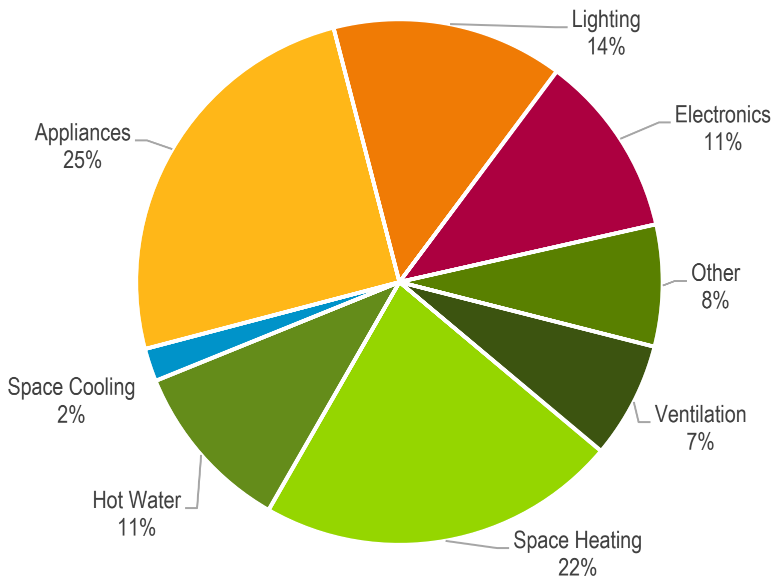
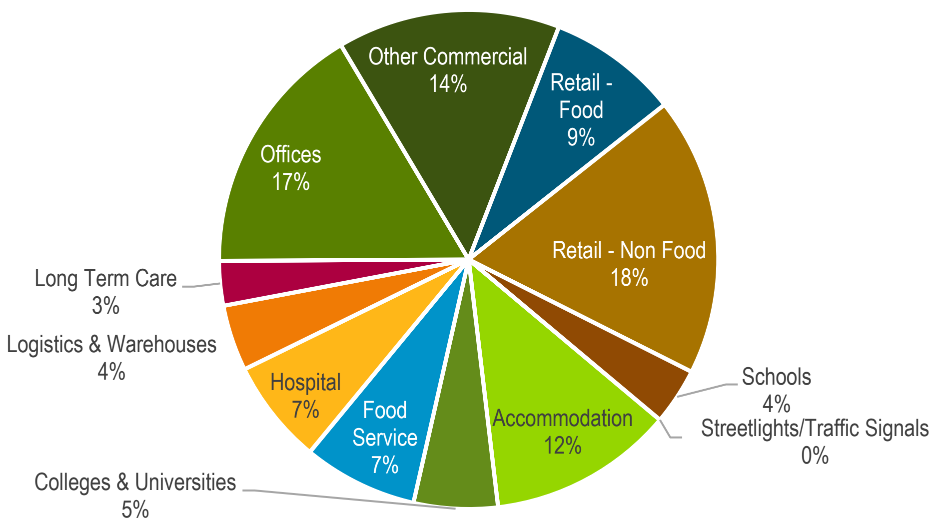
Figure 2-3: Base Year Residential Consumption by End-Use (%)



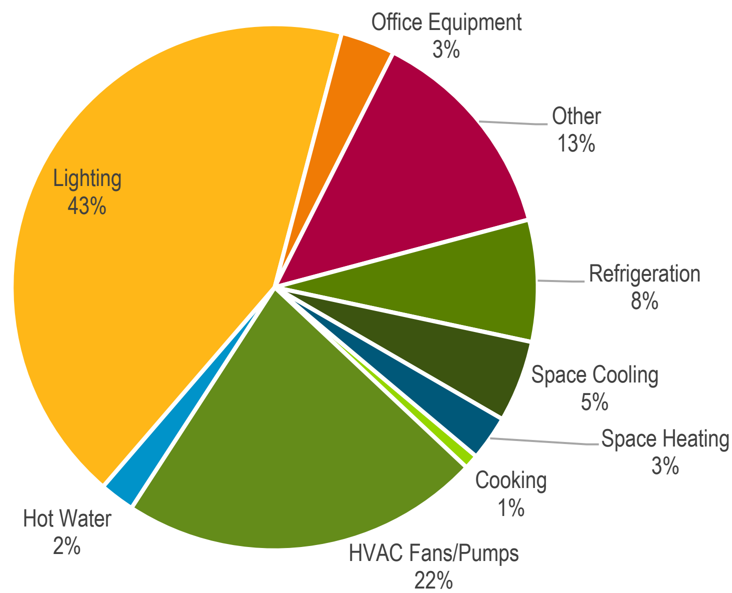
Source: Navigant analysis

Figure 2-4: Base Year Commercial by Segment Consumption (%)



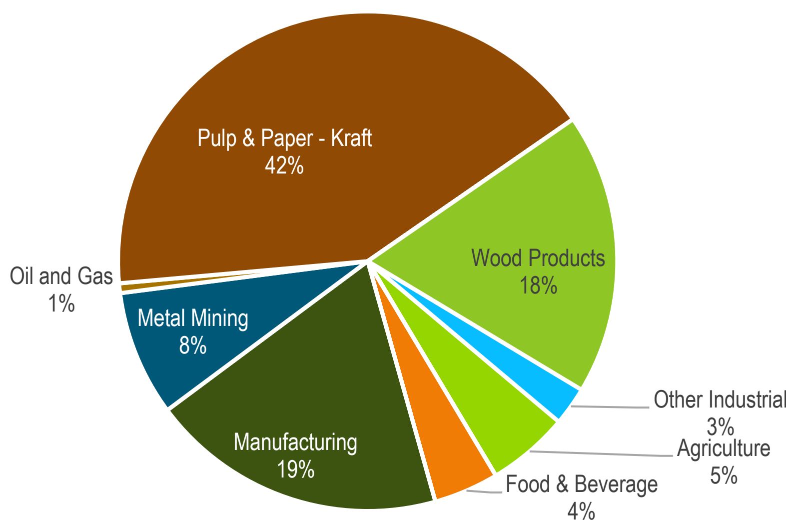
Source: Navigant analysis

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

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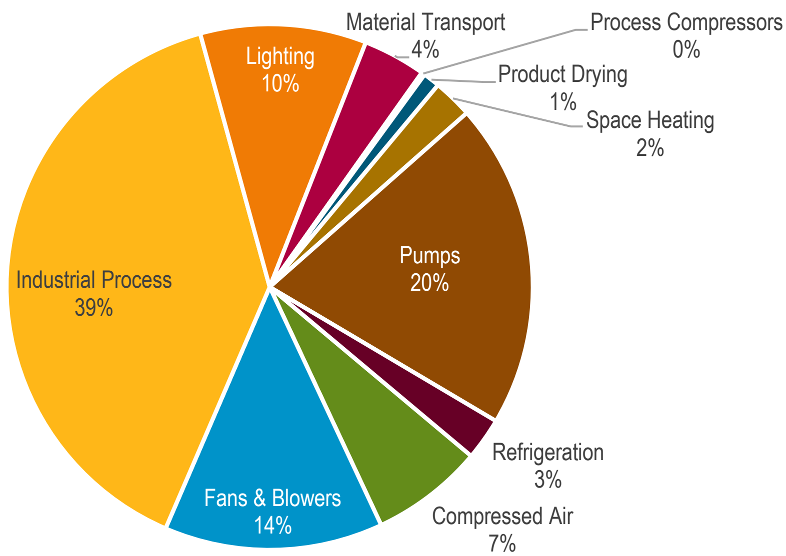
Figure 2-7: Base Year Industrial Consumption by End-Use (%)



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

Errata dated September 15, 2017

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

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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.

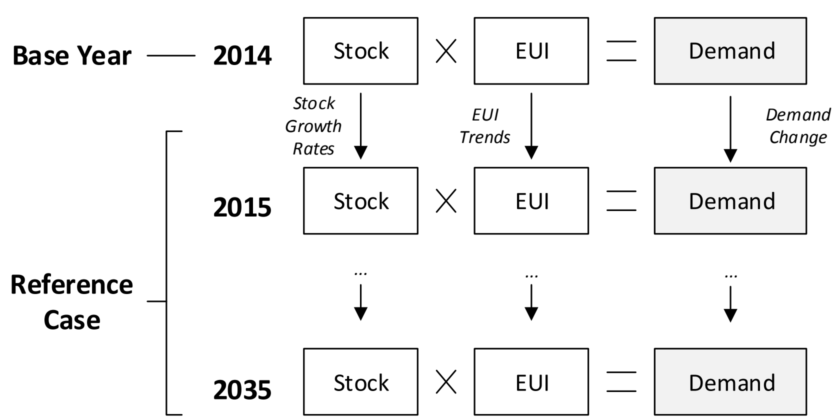
The Reference Case Forecast uses the base year calibration—presented in the previous section—as the foundation for analysis.

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

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- **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] Since apartment buildings are included in the residential sector for the reference case analysis, the following sections shows stock growth rates and EUI trends for apartment units in the residential sector.

[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 Stock Growth Rates

This section describes the approach followed to develop stock growth rates for the residential, commercial and industrial sectors.[11]

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 corresponding to each segment. Most segments show a strong positive correlation with coefficient values

[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.

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.

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[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
		2014-2020	2021-2025	2026-2030	2031-2035	(2015-2035)
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
Table 2-22.

[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: 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

Errata dated September 15, 2017

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.

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.

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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.

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

Errata dated September 15, 2017

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.

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[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

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[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.).

Errata dated September 15, 2017

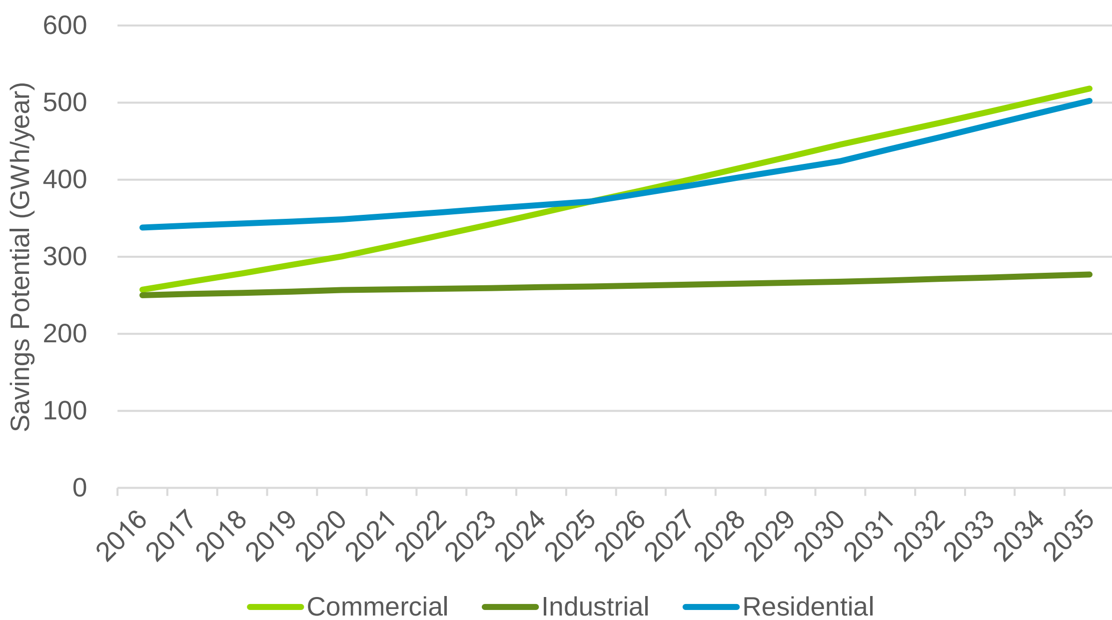
3.2 Technical Potential Results

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.

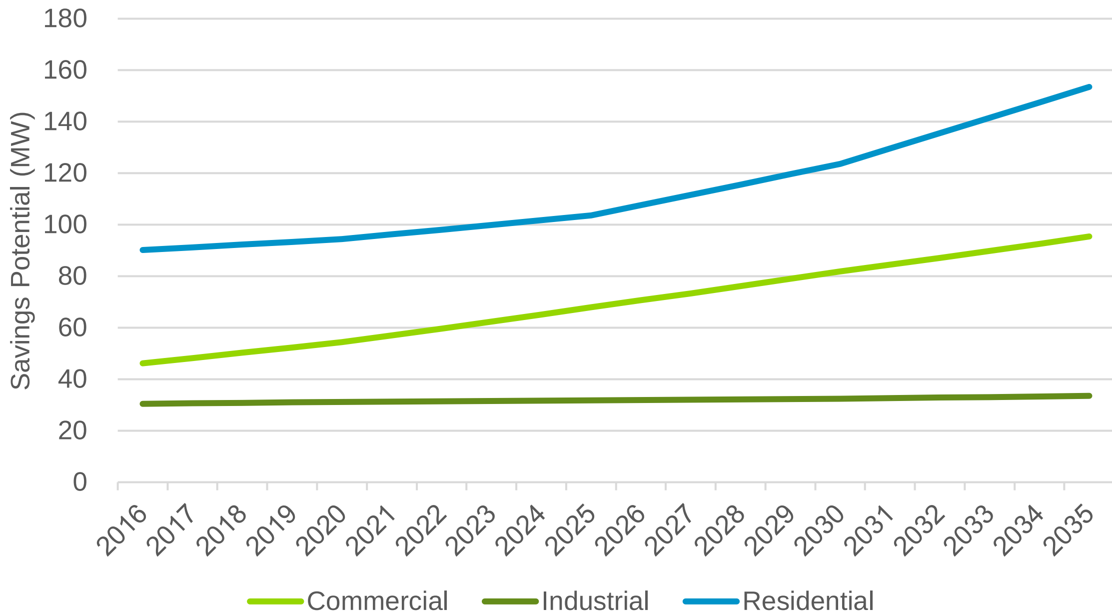
Figure 3-1. Electric Energy Technical Savings Potential by Sector (GWh/year)



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.

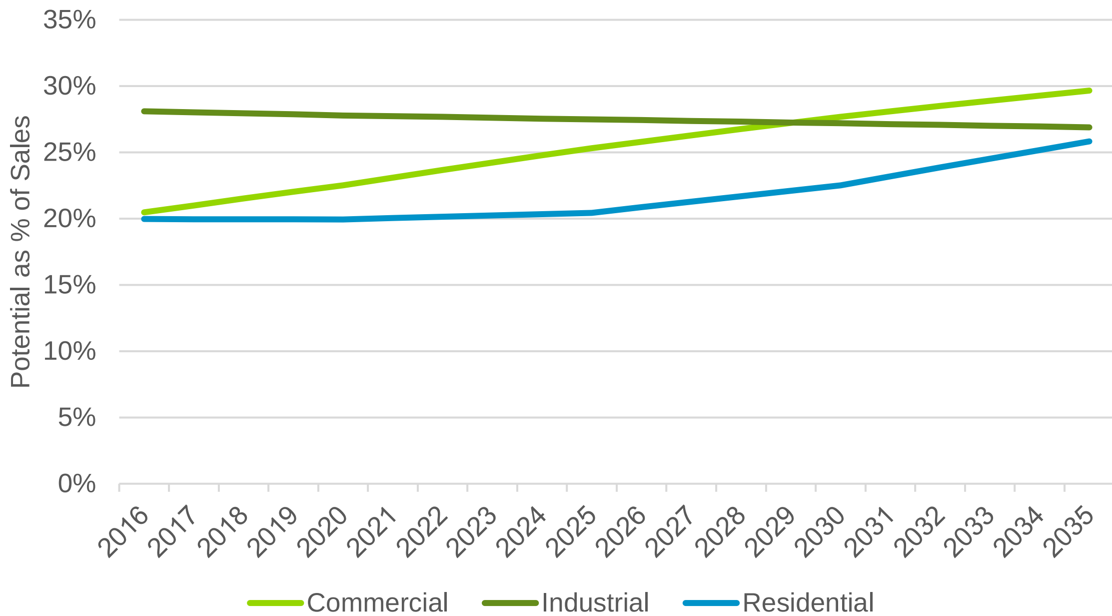
Figure 3-2. Electric Demand Technical Savings Potential by Sector (MW)



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 (%)



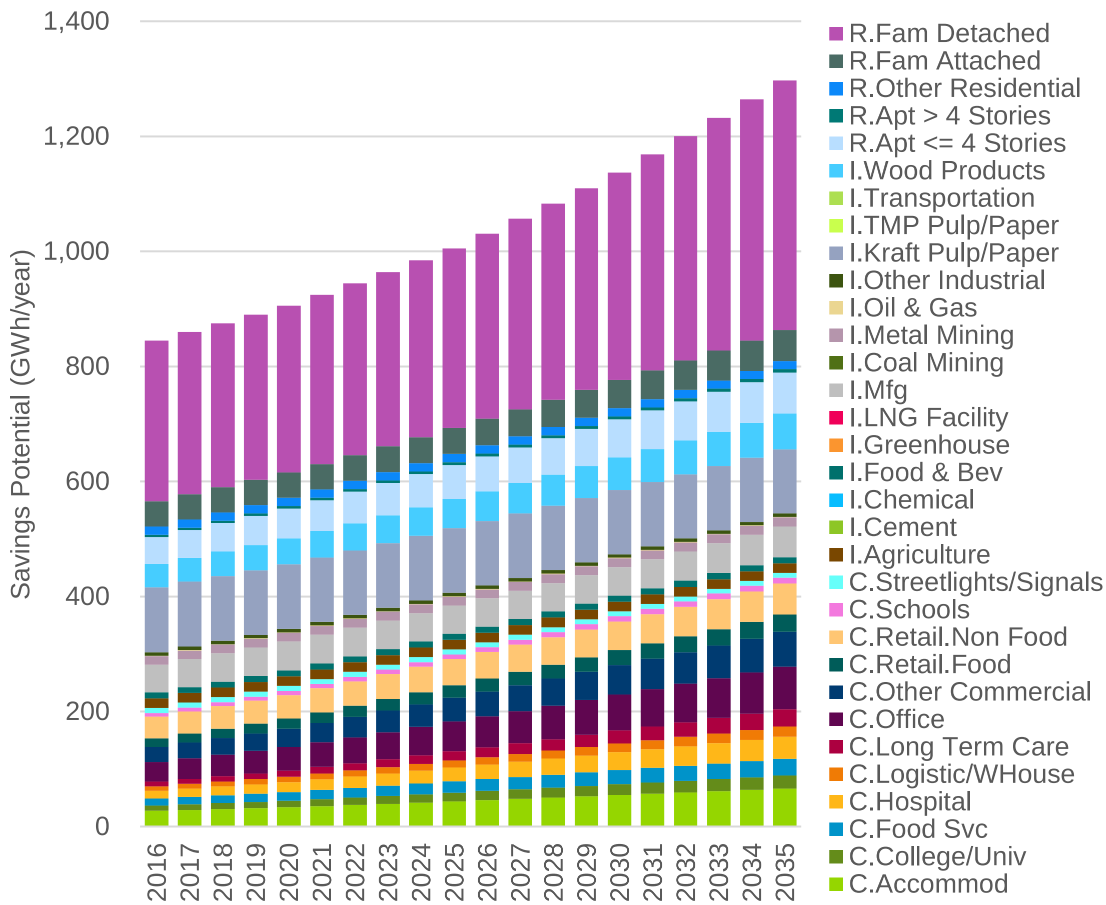
Source: Navigant

Errata dated September 15, 2017

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

Errata dated September 15, 2017

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 14% 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

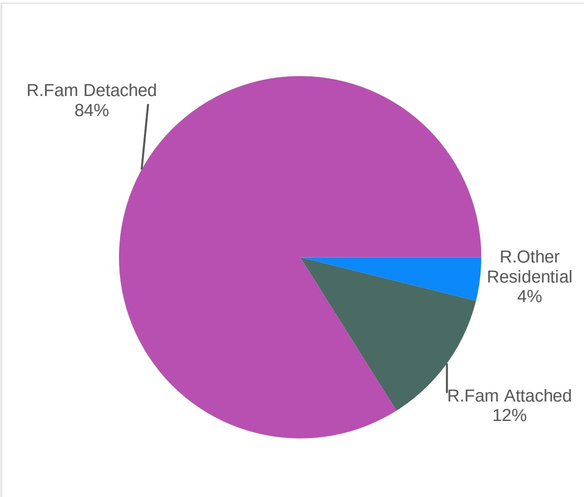


Figure 3-6. Commercial Electric Energy Technical Potential Customer Segment Breakdown in 2025

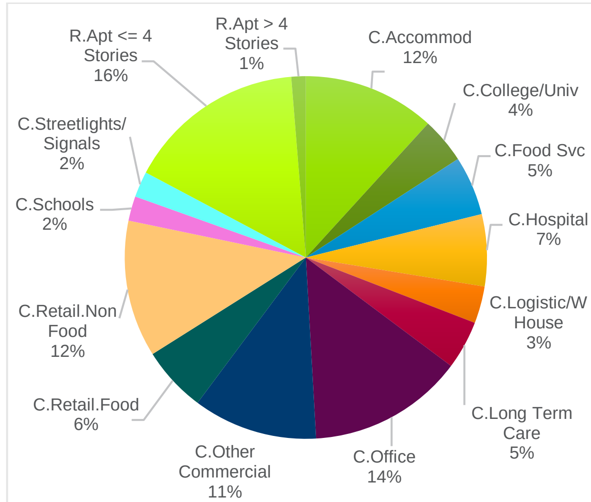
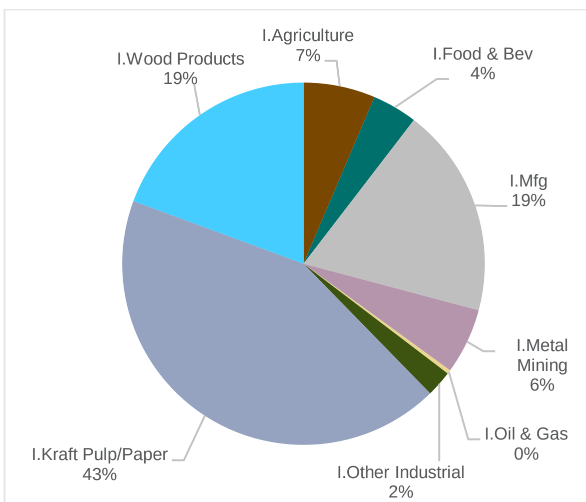


Figure 3-7. Industrial Electric Energy Technical Potential Customer Segment Breakdown in 2025



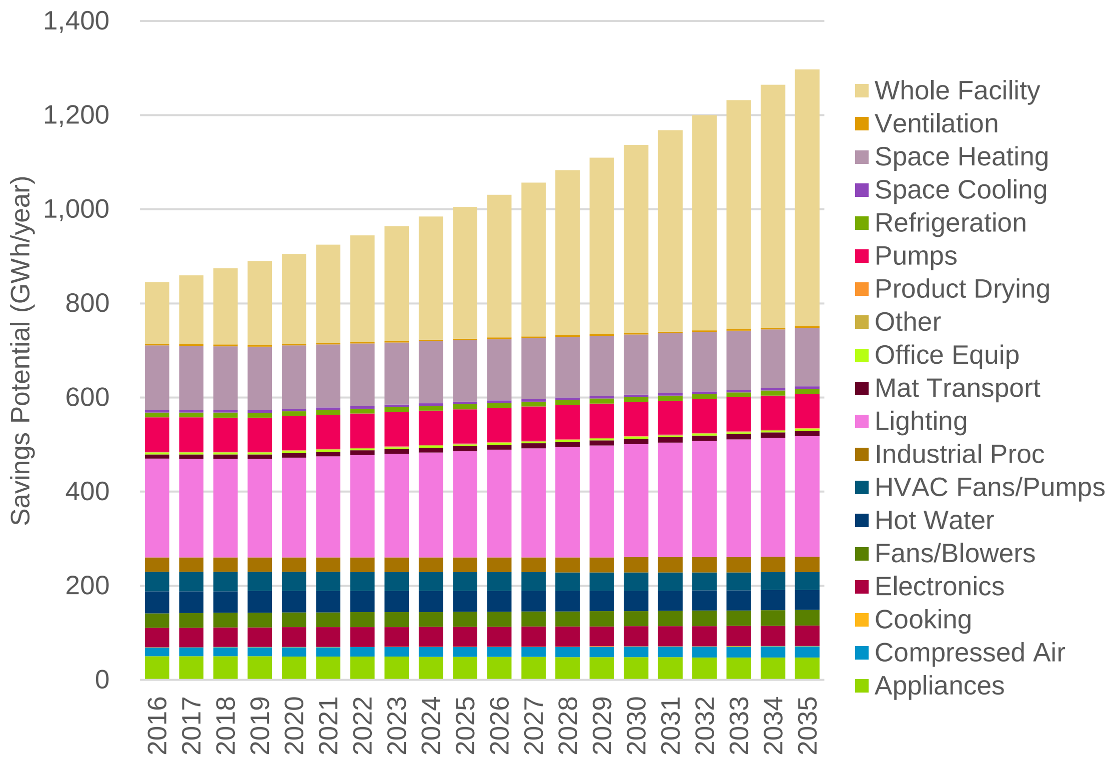
Source: Navigant

Errata dated September 15, 2017

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 29% 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.

Errata dated September 15, 2017

Figure 3-9. Residential Electric Energy Technical Potential End-Use Breakdown in 2025

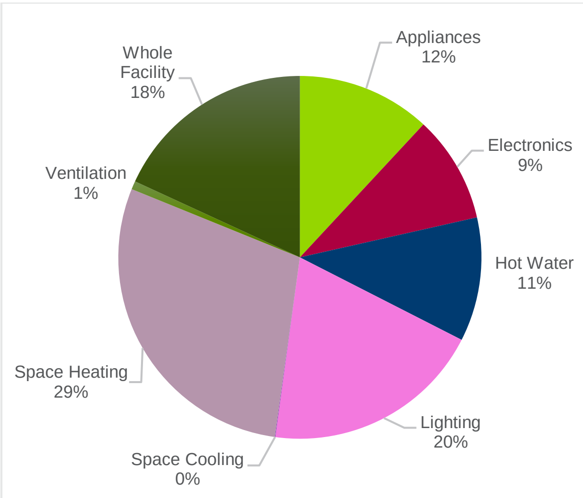


Figure 3-10. Commercial Electric Energy Technical Potential End-Use Breakdown in 2025

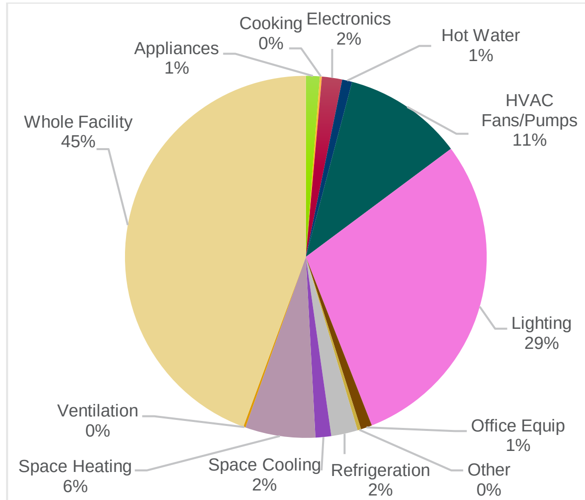
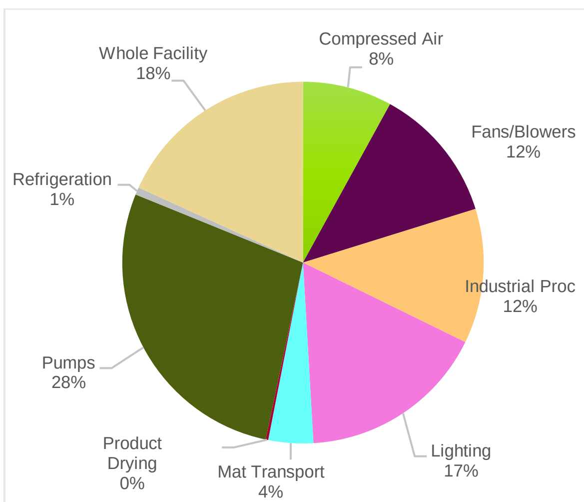


Figure 3-11. Industrial Electric Energy Technical Potential End-Use Breakdown in 2025



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.

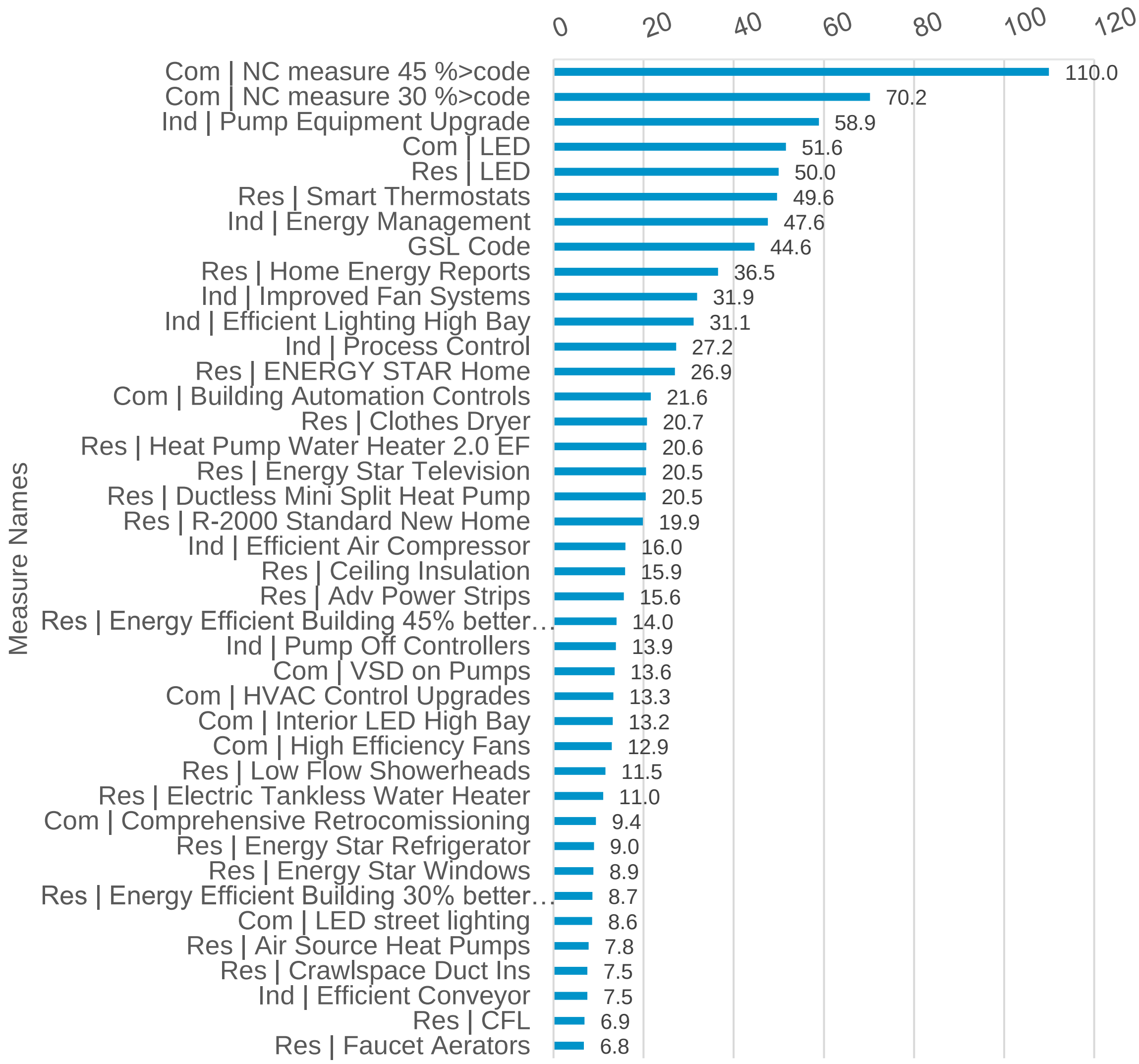
When code-change measures became applicable, they “stole” savings potential from other related measures that may have displayed significant savings in absence of the code. In this way, the sum of the total savings potential between the code and the related energy efficient measure was the same before 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, two additional residential measures are also in the top 10; home energy reports and smart thermostats. Also in the top 10 are two industrial measures; energy management and improved fan systems, and the General Service Lamp (GSL) code measure which includes savings across all customer sectors.

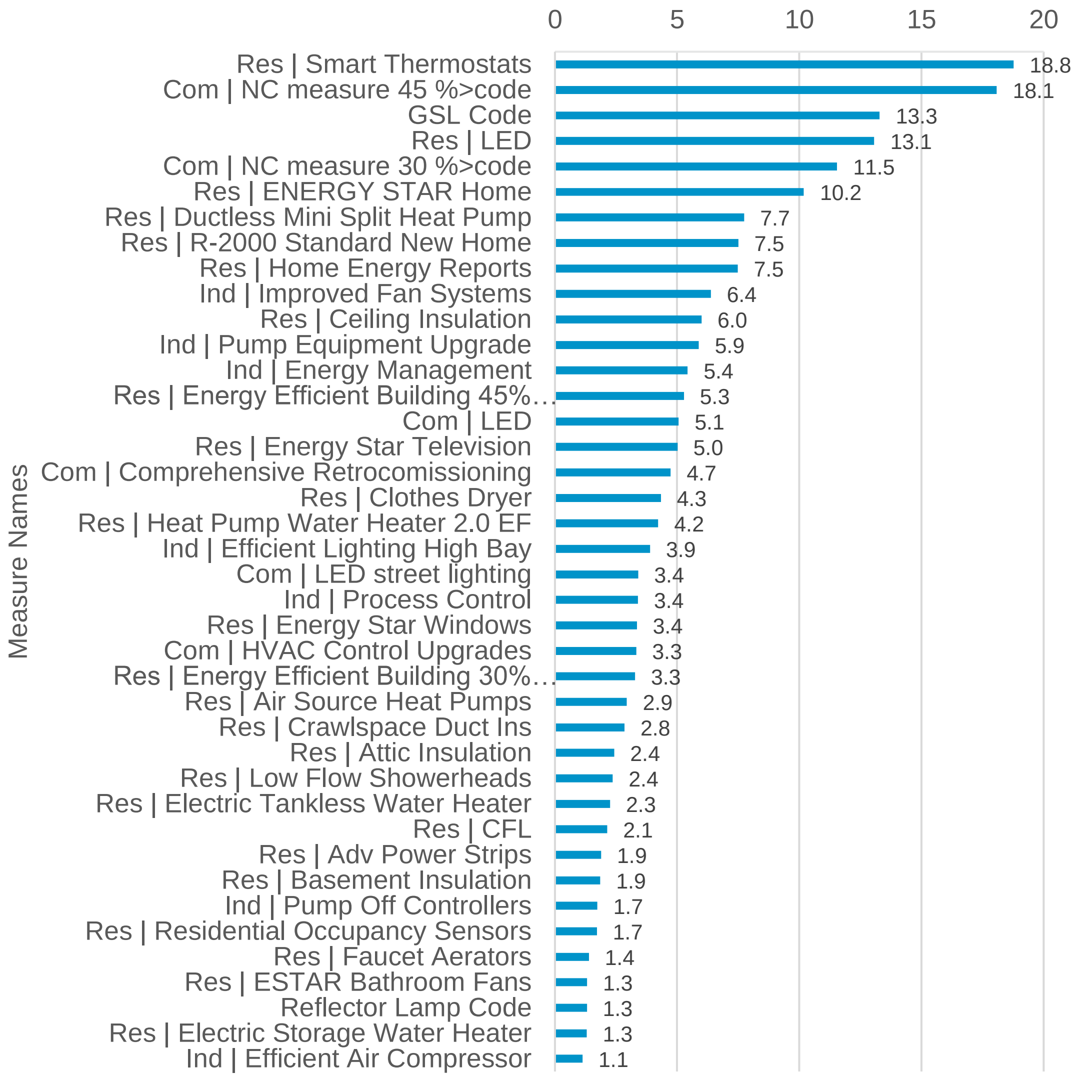
Figure 3-12. Top 40 Measures for Electric Energy Technical Savings Potential in 2025 (GWh/year)



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 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)

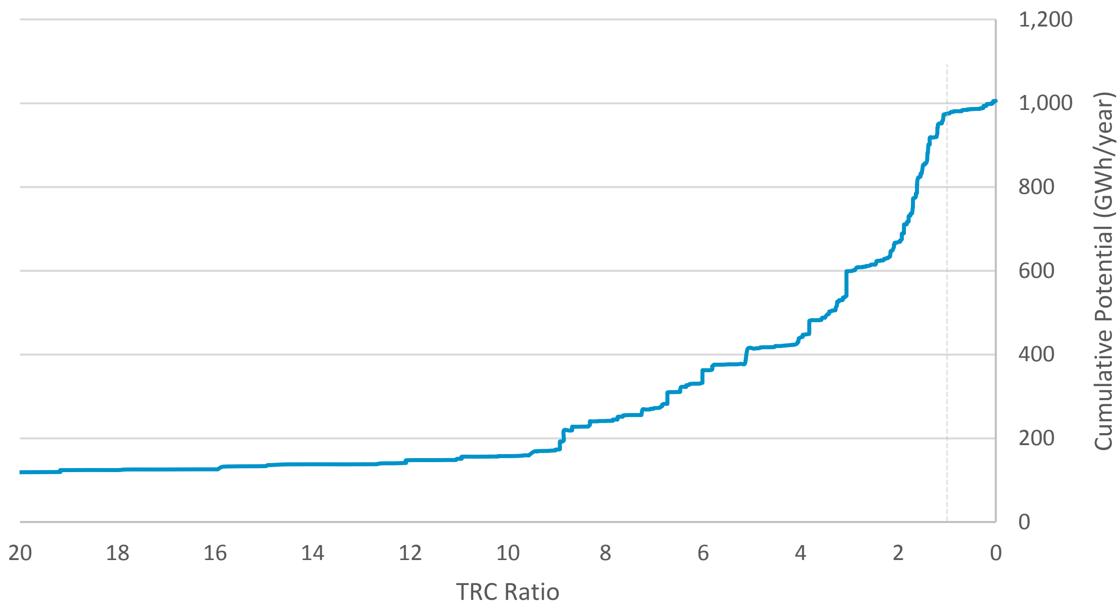


Source: Navigant

Errata dated September 15, 2017

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 9.0, indicating the majority of savings came from measures with TRC ratios less than 9.0. For TRC ratios below 9.0, cumulative potential increased to about 970 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



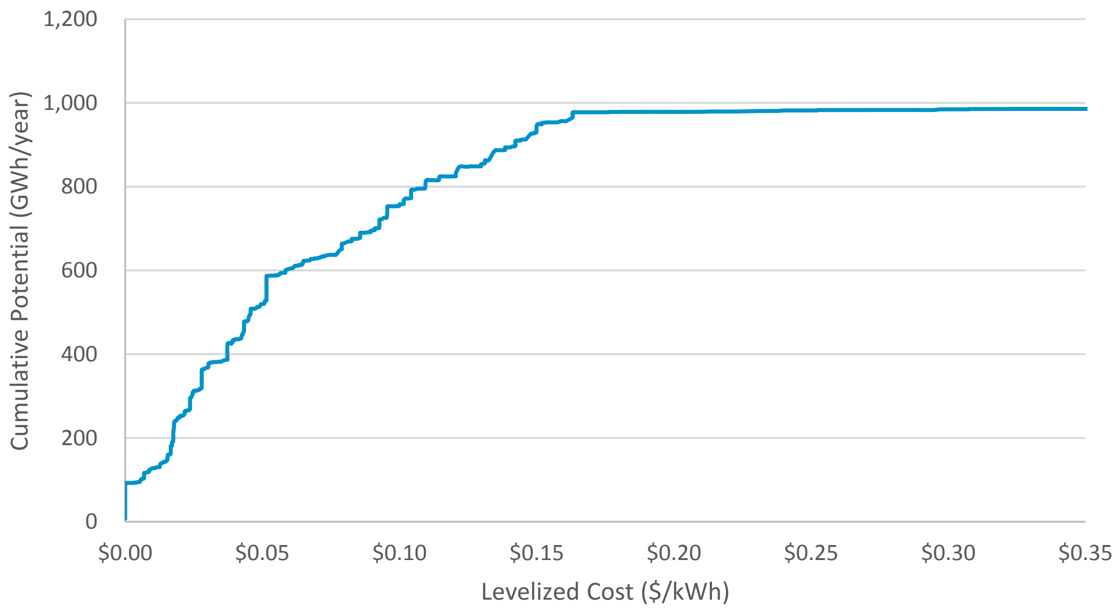
Source: Navigant

[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.

Errata dated September 15, 2017

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 990 GWh/year at a maximum cost of $0.40/kWh, beyond which costlier 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



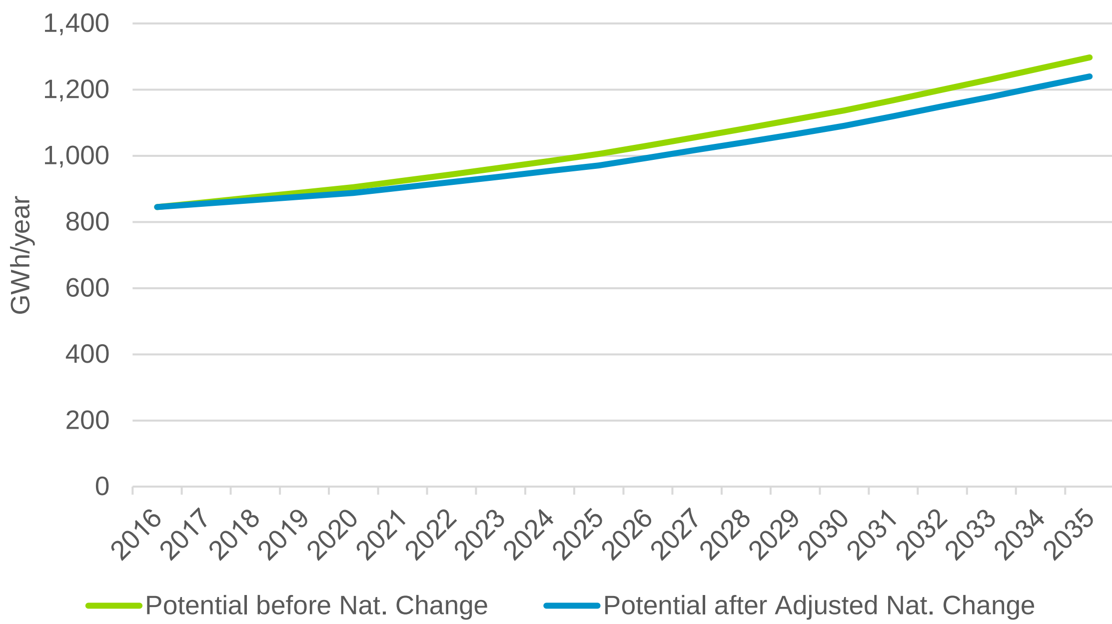
Source: Navigant

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.

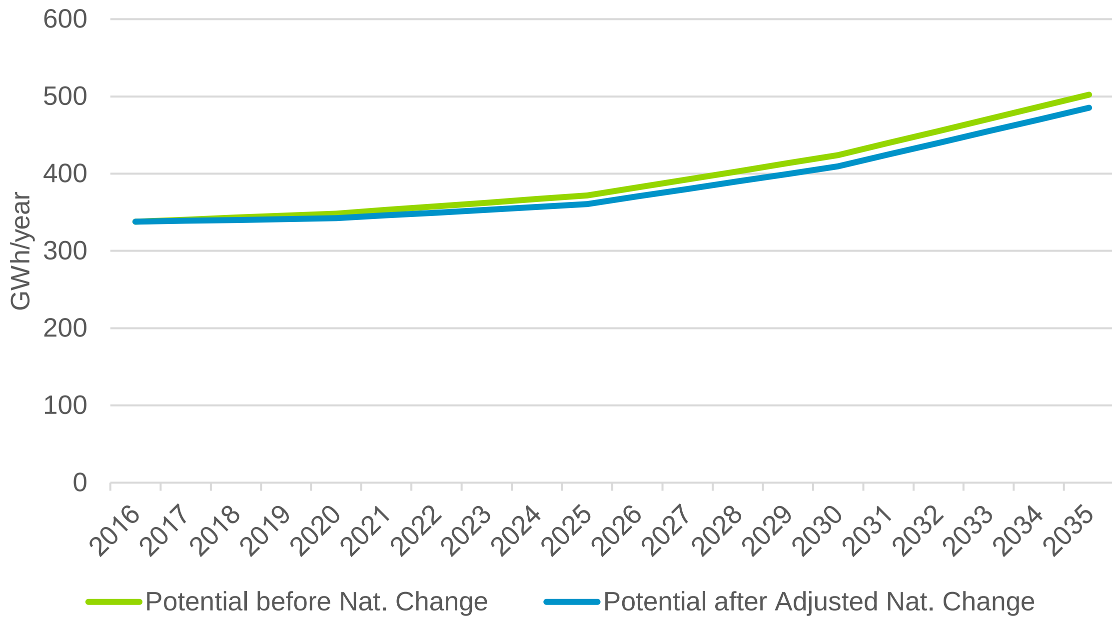
Figure 3-16. Electric Energy Technical Savings Potential with Natural Change (GWh/year)



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 conservation was a larger effect than natural growth, resulting in a lower sector-level technical potential. The adjusted natural change only slightly decreased 2035 technical potential (by 17 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)

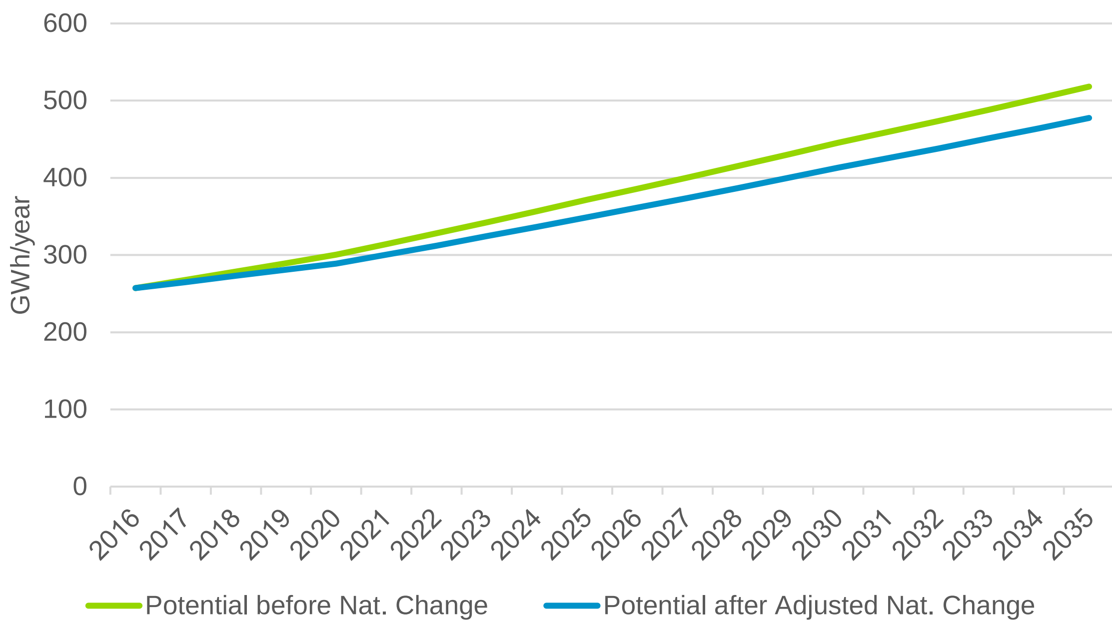


Source: Navigant

Errata dated September 15, 2017

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.

Errata dated September 15, 2017

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.

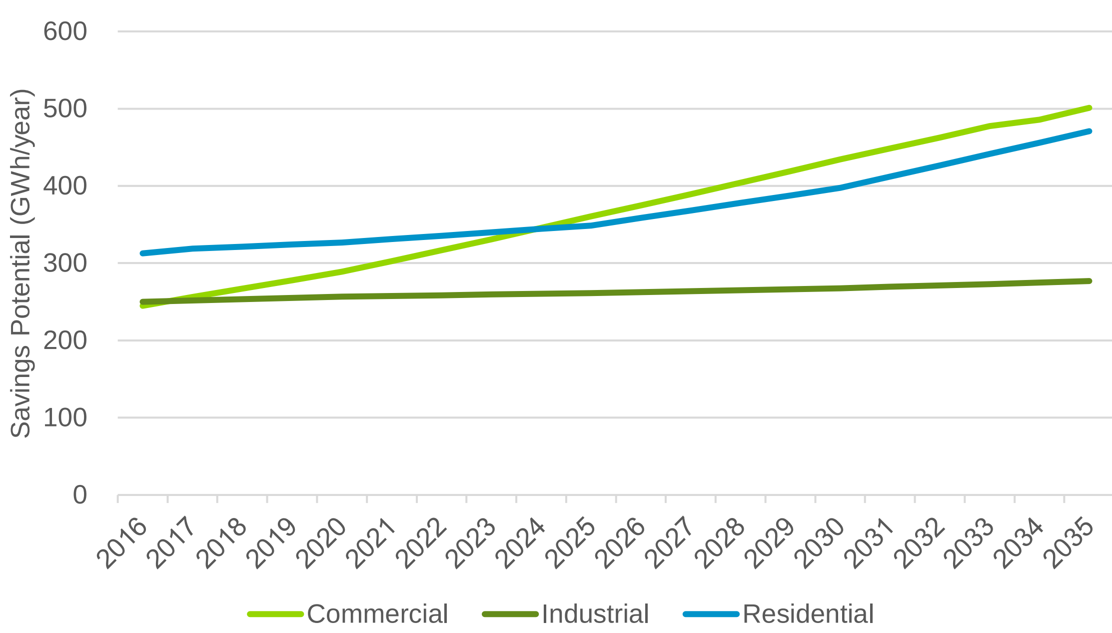
4.2 Economic Potential Results

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

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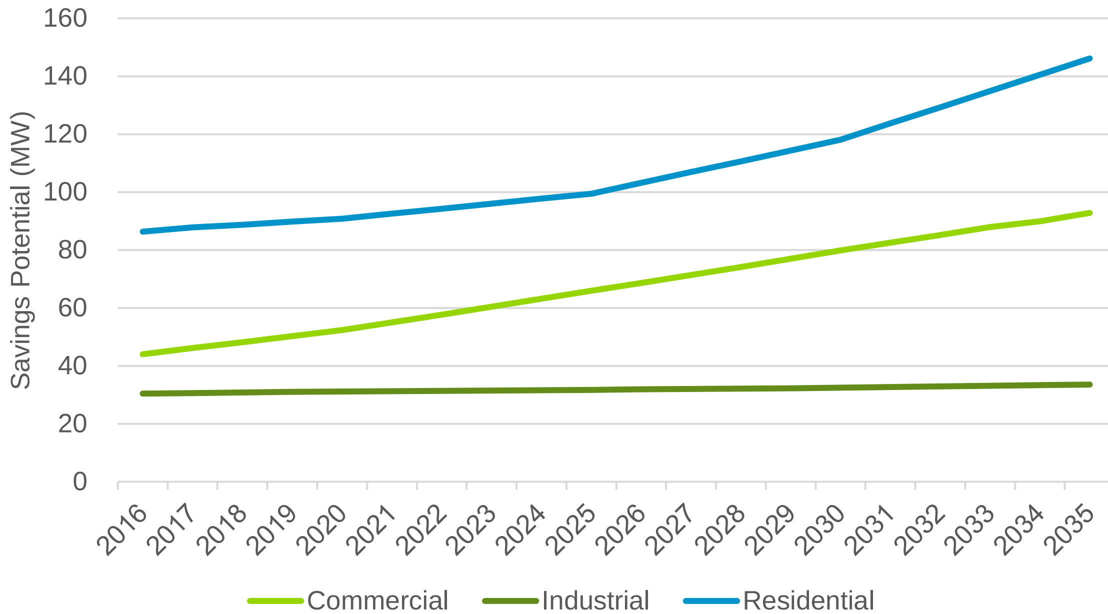
On average across the study period, 94% of residential technical potential was cost-effective. In single-family detached homes, the R-2000 standard new home measure that contributed appreciably to technical potential was not cost-effective. However, with R-2000 standard new homes no longer competing 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, clothes washers caused the greatest reduction in energy potential among the non-cost-effective residential measures.

Commercial economic energy potential was roughly 3% lower than technical potential on average. Commercial new construction practices 30% more efficient than code were non-economic in select customer segments and led to the greatest loss in potential. Commercial LEDs and high-efficiency fans 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, 96% 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 % reduction in economic demand potential relative to technical potential (i.e., 98% 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 2026 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

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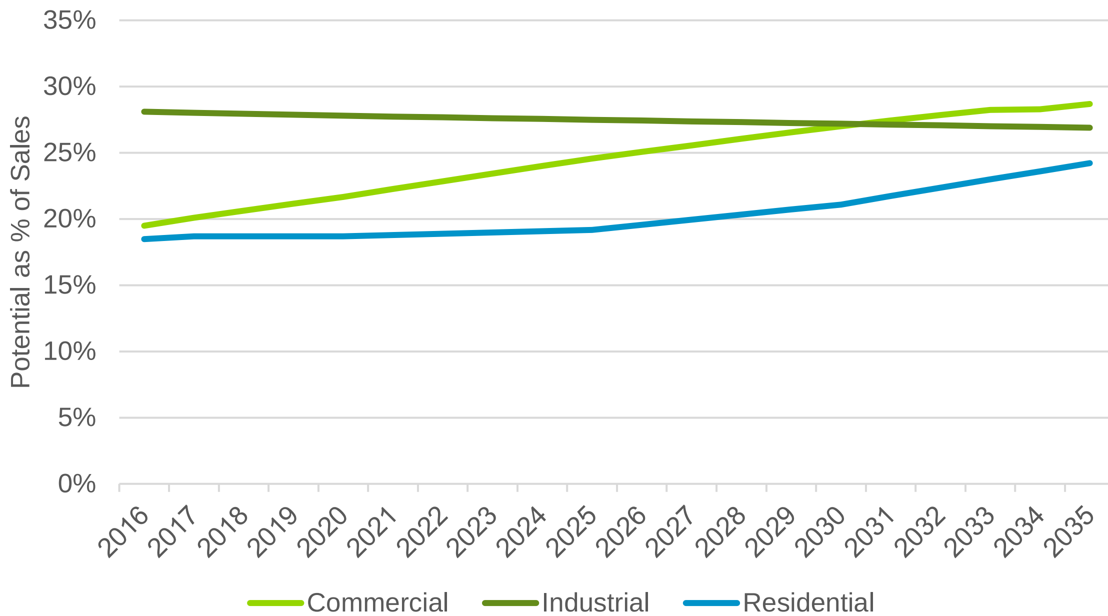
downward. Accordingly, the average industrial savings as a percent of consumption declined as new load became a larger percentage of total industrial load over the study horizon.

Figure 4-3. Electric Energy Economic Savings Potential by Sector as a Percent of Sector Consumption (%)

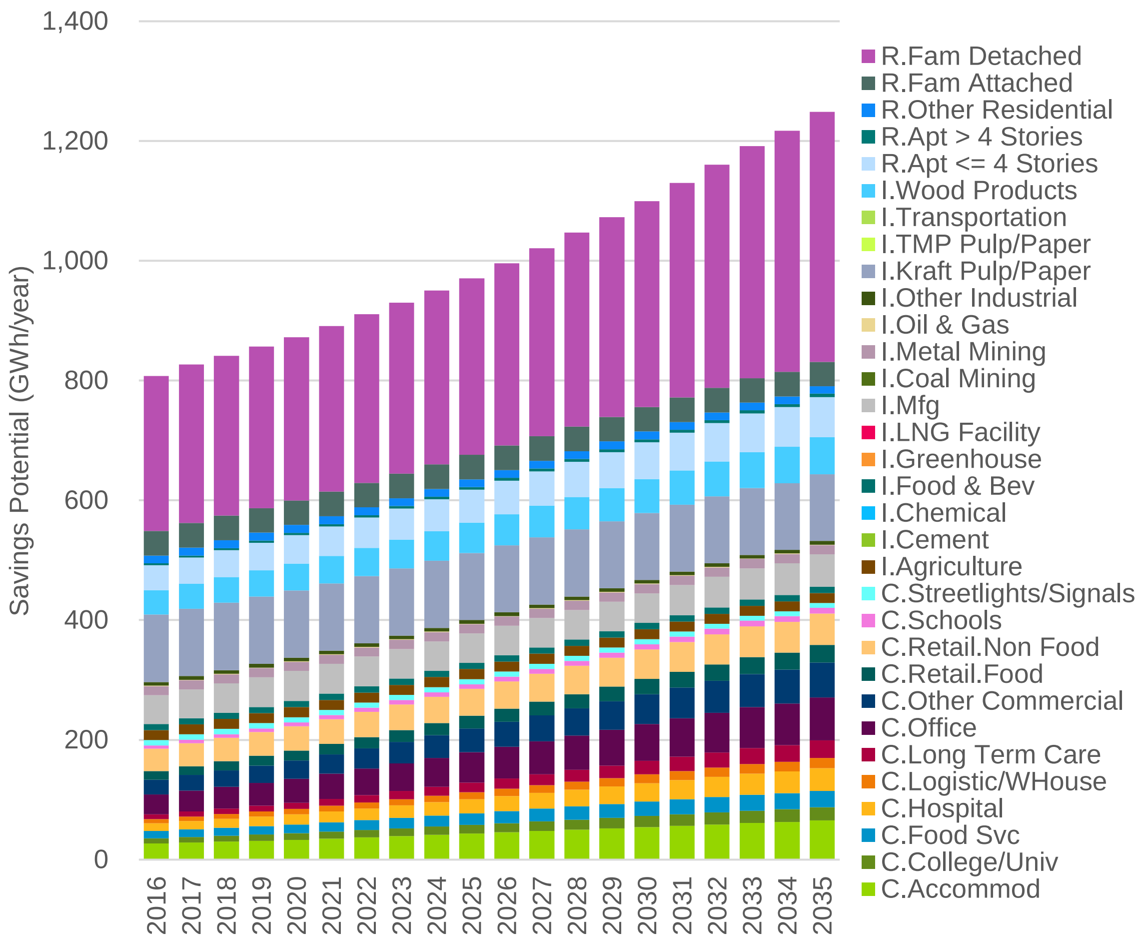


Source: Navigant

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 87% and 95% 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, apartments greater than 4 stories was the least cost-effective, having 92% of the potential pass the TRC screen. The remaining commercial customer segments realized economic potential at levels ranging from 92 to 100% 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.

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Figure 4-5. Residential Electric Energy Economic Potential Customer Segment Breakdown in 2025

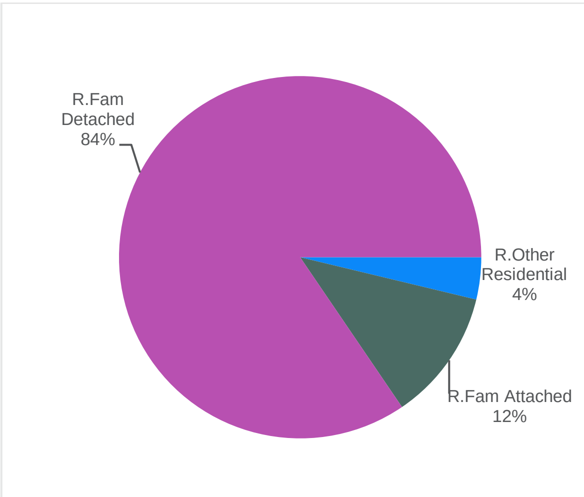


Figure 4-6. Commercial Electric Energy Economic Potential Customer Segment Breakdown in 2025

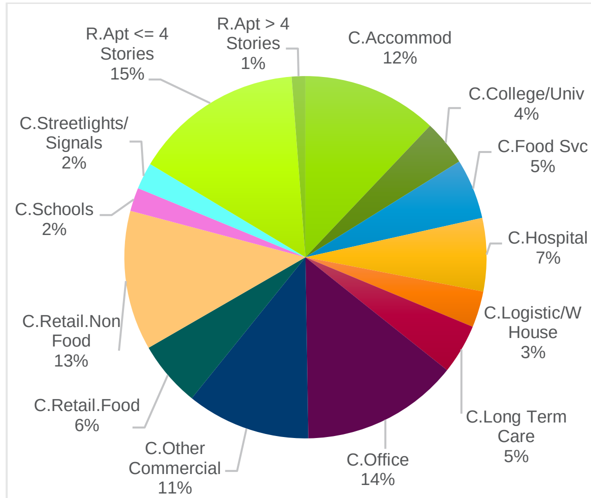
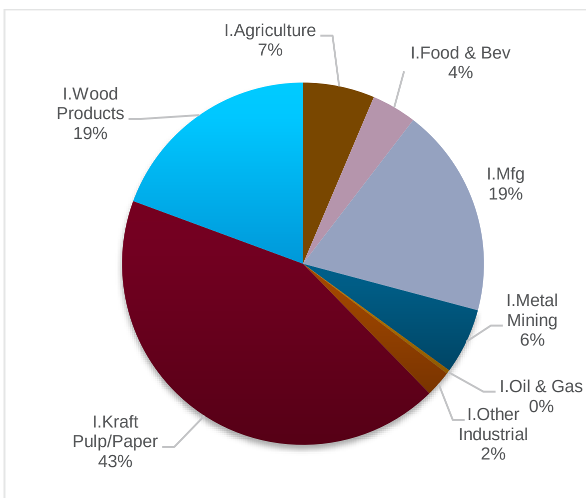


Figure 4-7. Industrial Electric Energy Economic Potential Customer Segment Breakdown in 2025



Source: Navigant

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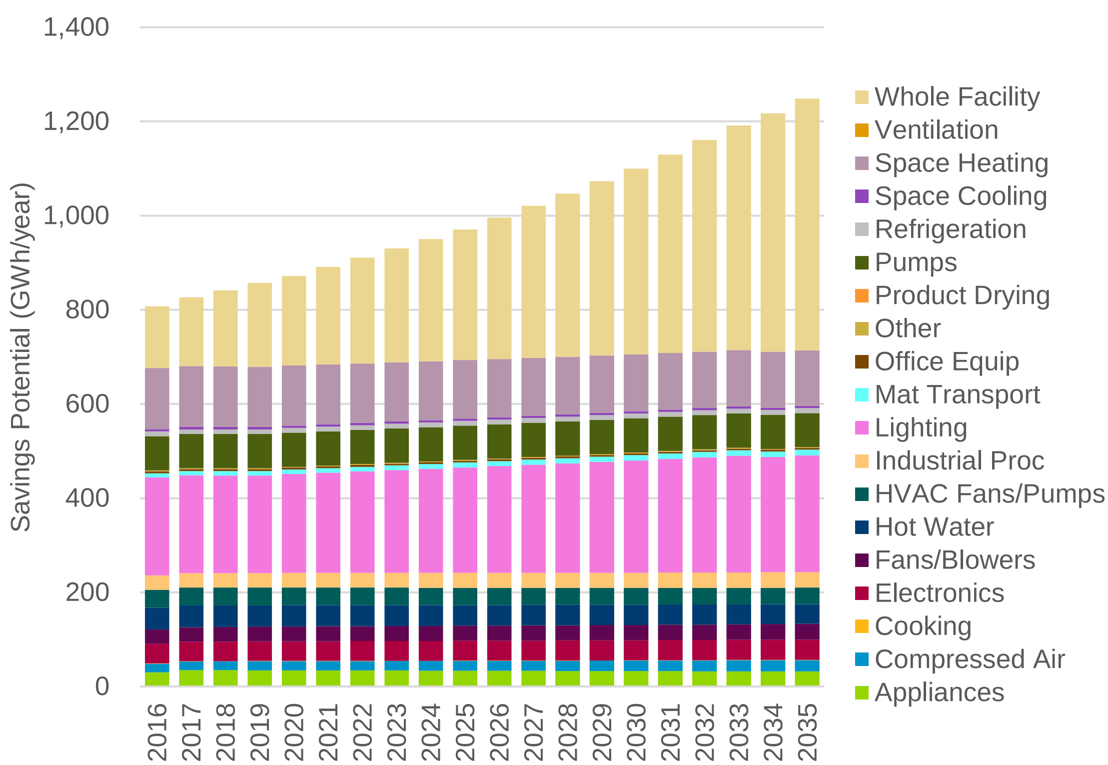
4.2.3 Results by End-use

Depending on the end-use category, between 68% and 100% of the technical energy potential was cost-effective, with ventilation being an exception and having no cost-effective potential. 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%, 99%, and 95% of technical potential, respectively. Space heating 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

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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

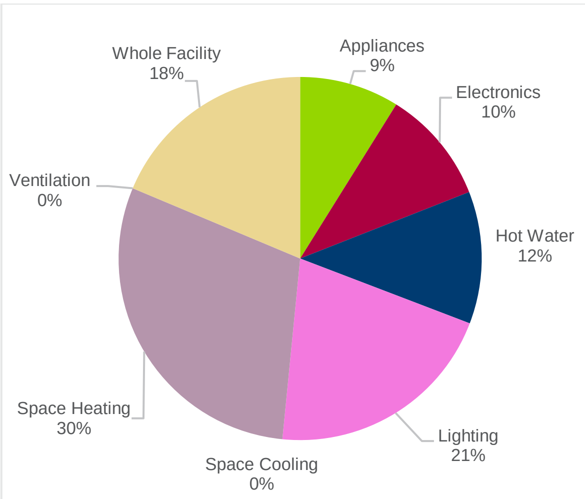


Figure 4-10. Commercial Electric Energy Economic Potential End-Use Breakdown in 2025

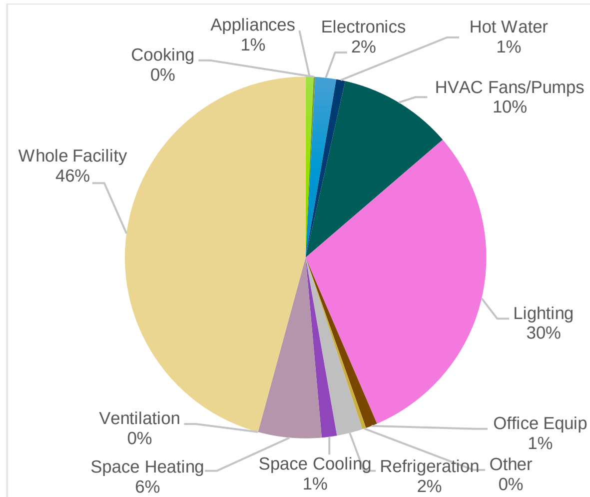
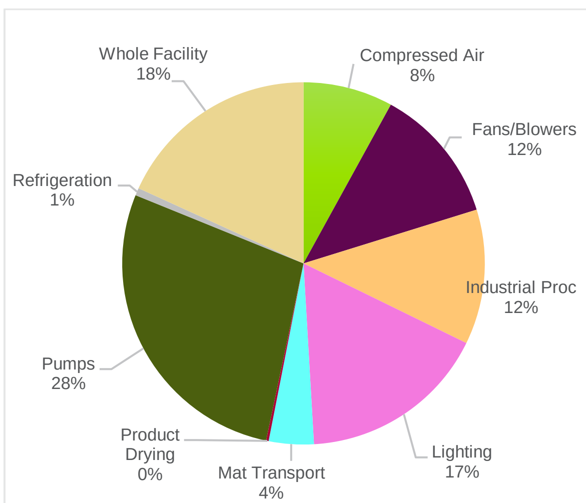


Figure 4-11. Industrial Electric Energy Economic Potential End-Use Breakdown in 2025



Source: Navigant

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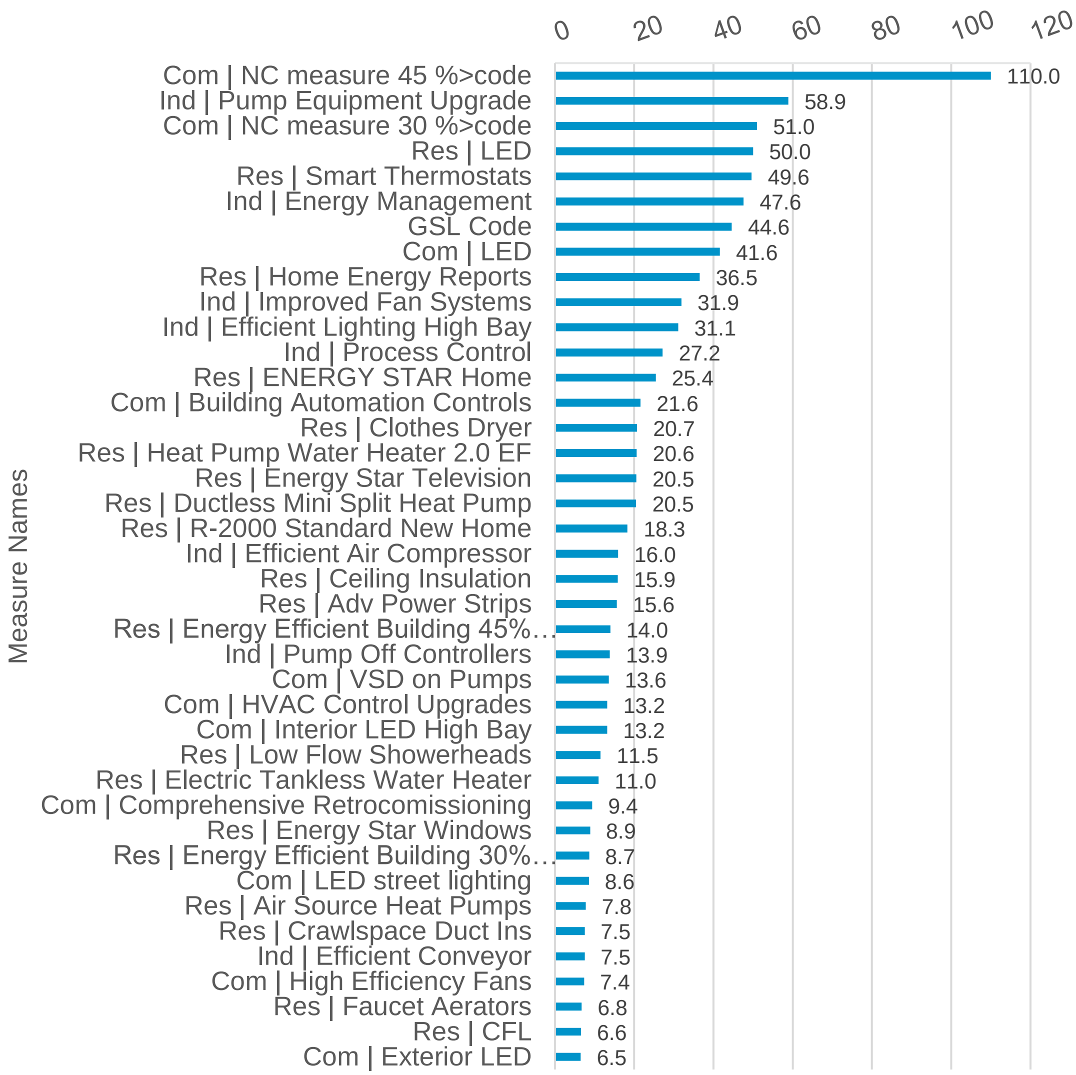
4.2.4 Results by Measure

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 top 10 measures do not change, but their ranks show some movement. For example, commercial LEDs dropped from the 4th rank in technical potential to the 8th rank in economic potential because they were uneconomic for certain, but not all, customer segments.

Figure 4-12. Top 40 Measures for Electric Energy Economic Savings Potential in 2025 (GWh/year)



Source: Navigant

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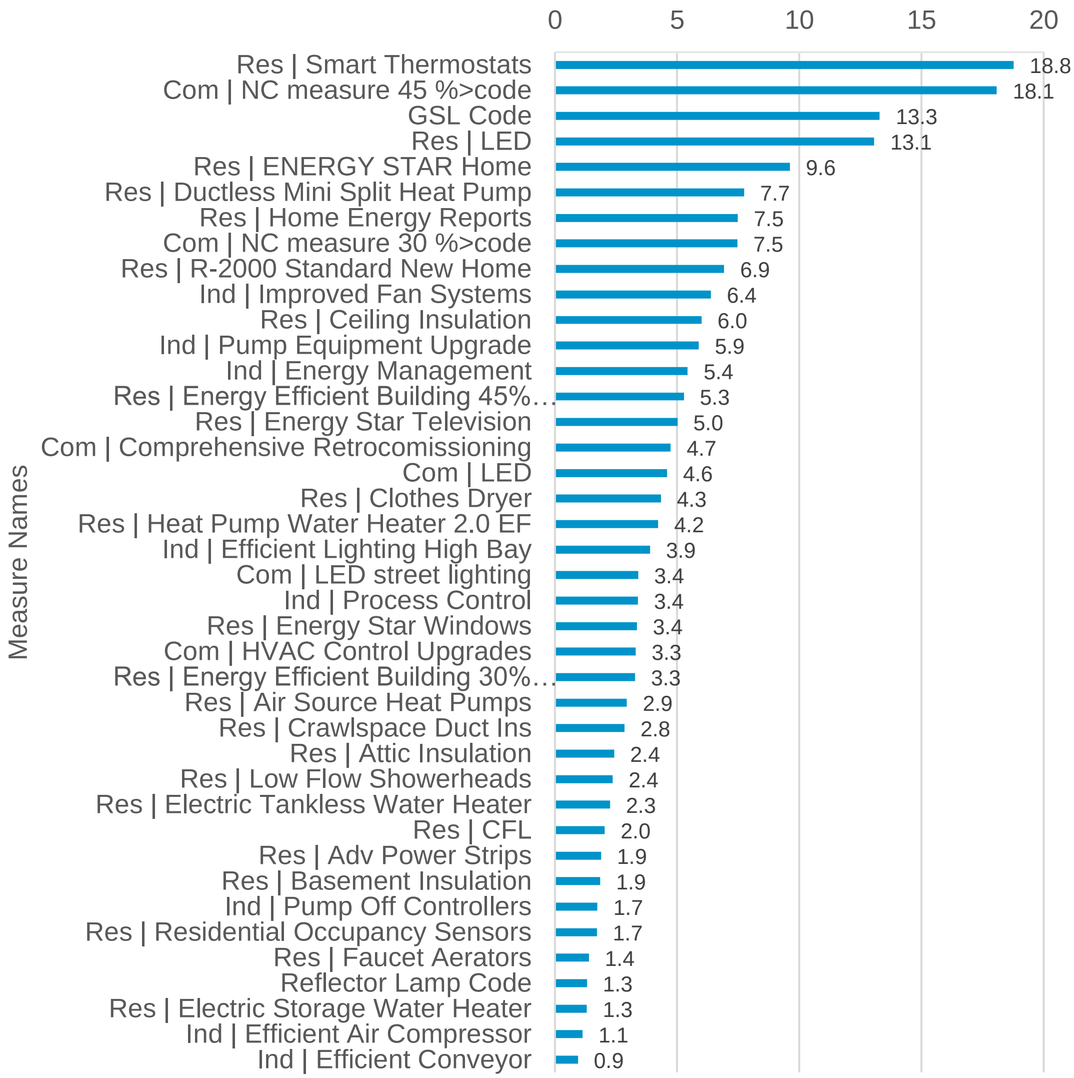
Figure 4-13 provides the 40 highest demand-saving measures regarding economic potential in 2025. Compared with the technical potential results, the whole-building new construction measure 30% better than code fell from the 5th to the 8th rank. Additionally, the R-2000 new home measure fell from the 8th to the 9th position. The position of the four top-ranked measures remained consistent.

Figure 4-13. Top 40 Measures for Electric Demand Economic Savings Potential in 2025 (MW)



Source: Navigant

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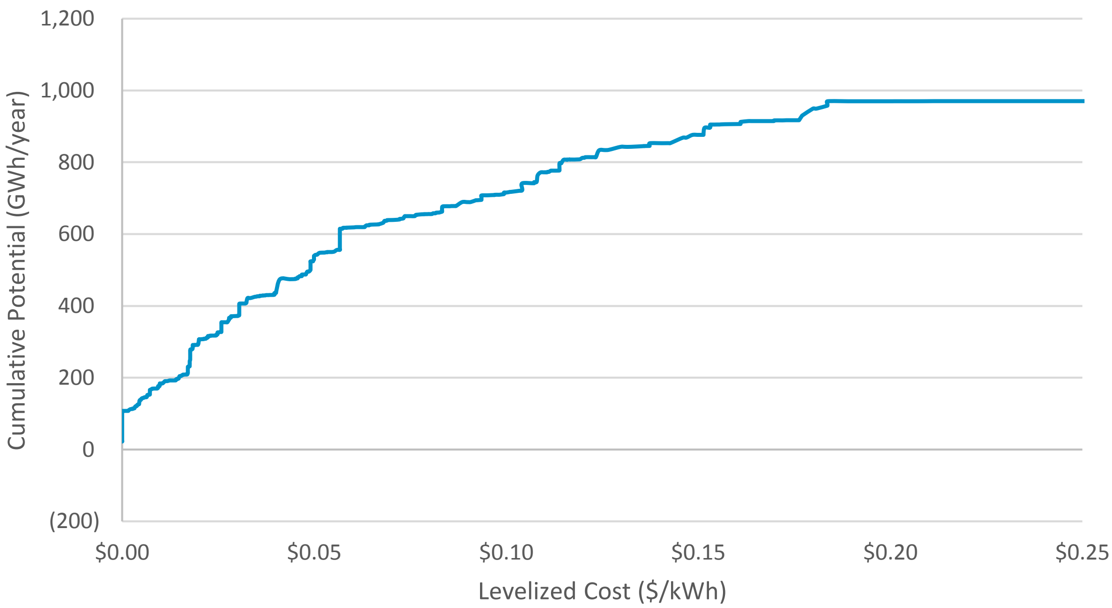
Figure 4-14 provides a supply curve of savings potential versus levelized cost of savings in $/kWh for all measures considered in the study. This curve shows only those measures with a levelized cost less than $0.25/kWh, though the full curve would extend beyond this to measures with costlier savings. 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_2017-08-25.xlsx," for granular results from the DSMSim™ model.

A.2 Measure List and Characterization Assumptions

See attachment, "FortisElectric_Appendix_A2_2017-08-25.xlsx," for granular measure input to the model.

A.3 Other Key Input Assumptions

See attachment, "FortisElectric_Appendix_A3_2017-08-25.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

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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	68%	28%	4%
	Water Heating	64%	33%	3%
Apartments <= 4 Storeys	Space Heating	35%	62%	3%
	Water Heating	64%	36%	0%
Apartments > 4 Storeys	Space Heating	35%	62%	3%
	Water Heating	64%	36%	0%
Other Residential	Space Heating	57%	17%	26%
	Water Heating	25%	65%	9%

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, 55% 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 1% 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	1%	3%	4%	4%	3%
	Gas Furnace 0.8 AFUE	30%	29%	28%	28%	37%
	Gas Furnace 0.9 AFUE	55%	54%	51%	51%	37%
	Gas Boiler 0.7 EF	0%	0%	0%	0%	0%
	Gas Boiler 0.8 EF	8%	9%	11%	11%	15%
	Gas Boiler 0.9 EF	5%	5%	6%	6%	8%
	Gas Fireplace	89%	79%	79%	89%	89%
	Electric Furnace	12%	5%	8%	8%	35%
	Electric Boiler	0%	0%	0%	0%	0%
	Electric Resistance *(Baseboard, ceiling or floor cable, etc.)*	58%	91%	90%	90%	46%
	Air Source Heat Pump	27%	2%	2%	2%	15%
	Ground / Water Source Heat Pump	4%	1%	0%	0%	4%
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.	72%	73%	72%	72%	74%
	Electric DHW High Efficiency	23%	24%	22%	22%	25%
	Electric DHW Tankless	1%	1%	1%	1%	0%
Space Cooling	Air Conditioning (any system)	69%	57%	46%	46%	117%
	Central Air	53%	27%	13%	13%	57%
	Window/ Room AC	21%	25%	24%	24%	51%

^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).

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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 (%)

End Use	Equipment Type	Percentage of Households with Appliance or Equipment Type				
		Single Family Detached/Duplexes	Single Family Attached	Apartments <=4 Storeys	Apartments > 4 Storeys	Other Res
Appliances	Fridge Low Efficiency	54%	54%	54%	54%	54%
	Fridge ENERGY STAR®	46%	46%	46%	46%	46%
	Freezer Low Efficiency	65%	44%	24%	24%	56%
	Freezer ENERGY STAR®	29%	19%	11%	11%	25%
	Dishwasher Low Efficiency	33%	34%	26%	26%	22%
	Dishwasher ENERGY STAR®	49%	50%	40%	40%	34%
	Clothes Washer Low Efficiency	54%	51%	12%	12%	51%
	Clothes Washer ENERGY STAR®/Front load	45%	43%	10%	10%	43%
	C. Dryer Elect. Low Efficiency	63%	63%	18%	18%	56%
	C. Dryer Elect. ENERGY STAR®	34%	34%	37%	37%	30%
	C. Dryer Gas Low Efficiency	7%	7%	4%	4%	7%
	C. Dryer Gas ENERGY STAR®	4%	4%	7%	7%	4%
	Stove Gas	16%	12%	6%	6%	11%
	Stove Elect	84%	88%	94%	94%	89%
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

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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

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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

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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

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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, based on a hypothetical base year EUI of 10 kWh/m2.

In Year 1, the baseline EUI is 10kWh/m2. In Year 2, 6.4% of the space cooling equipment is upgraded, as shown in Table B-10. The EUI of the upgraded equipment is equivalent to 89% of the *baseline*, as shown in Table B-11. Since some of the space cooling equipment has been upgrade, we can expect the average EUI to decrease in Year 2. We can estimate the Year 2 EUI based on the percentage of upgrade space cooling equipment, and the efficiency improvement of the upgraded equipment. This calculation is detailed below. The Year 2 EUI is determined based on the proportion of base and EE equipment; 93.6% and 6.4%, respectively. The proportion of base/EE equipment is then multiplied by the estimate consumption (expressed as a % of the base).

This calculation is shown by the equation below:

Table B-12: Example of EUI Trending Approach – Accommodation, Space Cooling

Parameter	Equipment Consumption (as % of Base)	Year 1	Year 2
Base Space Cooling Equipment	100%	100	93.6%
EE Space Cooling Equipment	89%	0%	6.4%
EUI Multiplier		100% $(100\% * 100\% + 0\% * 89\%)$	98.4% $(93.6\% * 100\% + 6.4\% * 89\%)$
EUI (kWh/m2)	**10.00**	**10.00**	**9.**93

$$EUI_{2015} = EUI_{2014} * (EE\ equipment_{\%} * EE\ consumption_{kWh} + Base\ equipment_{\%} * Base\ consumption_{kWh})$$

$$9.93\frac{kWh}{m2} = 10.00\frac{kWh}{m2} * (6.4\% * 89\% + 93.6\% * 100\%)$$

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

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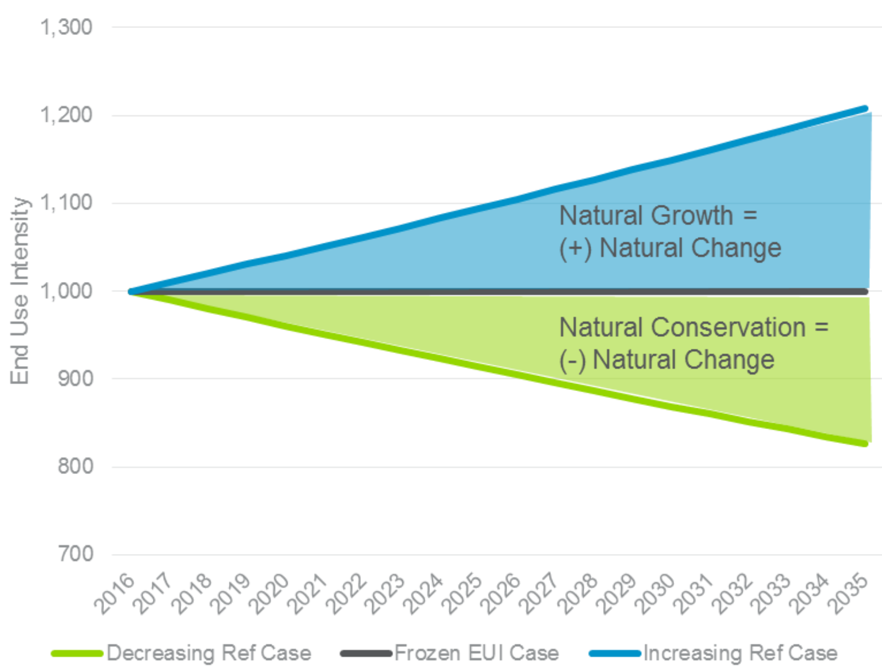
APPENDIX C. EXAMPLE OF NATURAL CHANGE

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

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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 2.3.1, 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

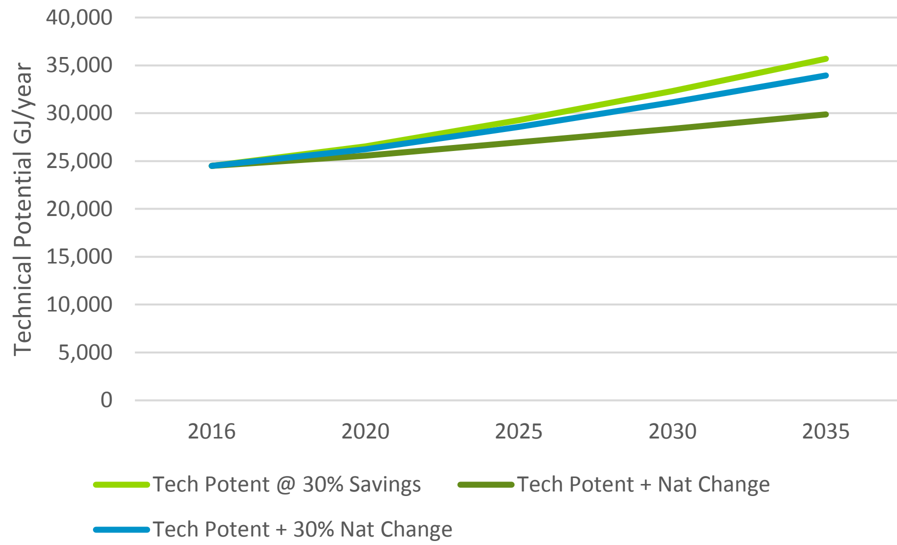
Source: Navigant

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.

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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.

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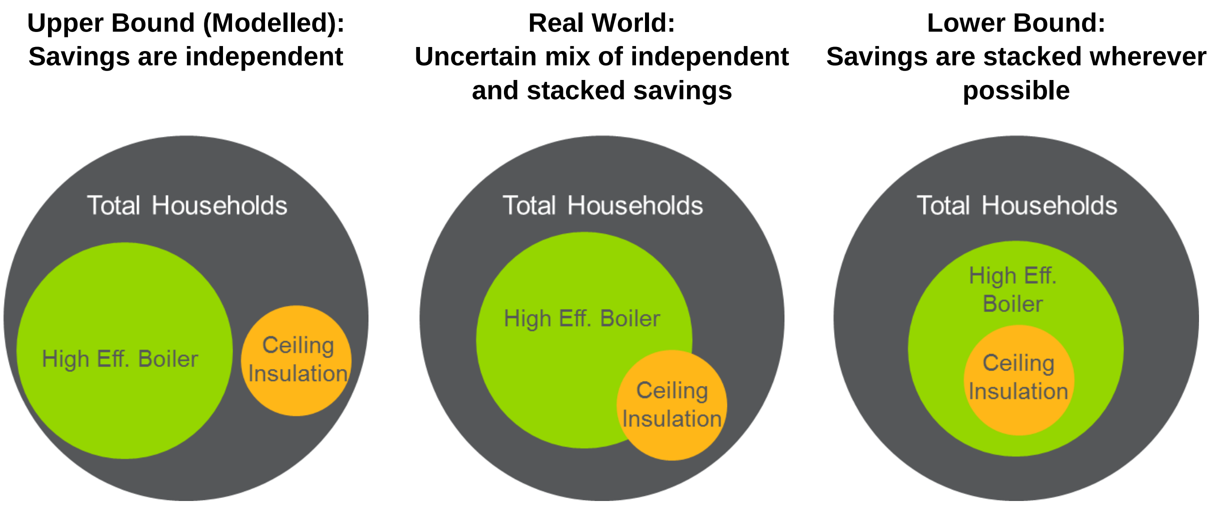
[47] Wherever savings were derived from building energy model simulations evaluating bundled measures, interactive effects of efficiency stacking are included in the savings estimates (e.g., ENERGY STAR New Homes, Net-Zero New Homes, etc.).

[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



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

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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	845	808
2017	860	827
2018	875	842
2019	890	857
2020	905	872
2021	925	891
2022	944	911
2023	964	930
2024	984	950
2025	1,005	971
2026	1,031	996
2027	1,057	1,021
2028	1,083	1,047
2029	1,110	1,073
2030	1,137	1,099
2031	1,168	1,130
2032	1,200	1,161
2033	1,232	1,192
2034	1,264	1,217
2035	1,297	1,249

Source: Navigant

Table E-2. Total Electric Energy Savings Potential as Percent of Total Consumption (%)

	Technical	Economic
2016	22.0%	21.0%
2017	22.2%	21.3%
2018	22.3%	21.5%
2019	22.5%	21.6%
2020	22.6%	21.8%
2021	22.8%	22.0%
2022	23.1%	22.2%
2023	23.3%	22.5%
2024	23.5%	22.7%
2025	23.7%	22.9%
2026	24.1%	23.2%
2027	24.4%	23.6%
2028	24.7%	23.9%
2029	25.1%	24.2%
2030	25.4%	24.6%
2031	25.8%	25.0%
2032	26.2%	25.4%
2033	26.7%	25.8%
2034	27.1%	26.1%
2035	27.5%	26.5%

Source: Navigant

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Table E-3. Total Electric Demand Savings Potential (MW)

	Technical	Economic
2016	167	161
2017	170	165
2018	173	168
2019	177	171
2020	180	174
2021	185	179
2022	189	183
2023	194	188
2024	199	192
2025	203	197
2026	210	204
2027	217	210
2028	224	217
2029	231	224
2030	238	230
2031	247	239
2032	256	247
2033	264	256
2034	273	264
2035	282	272

Source: Navigant

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Table E-4. Electric Energy Technical Savings Potential by Sector (GWh/year)

	Commercial	Industrial	Residential
2016	257	250	338
2017	268	252	340
2018	278	253	343
2019	289	255	346
2020	300	257	348
2021	314	257	353
2022	328	258	358
2023	342	259	362
2024	357	260	367
2025	372	261	372
2026	386	263	382
2027	400	264	393
2028	415	265	403
2029	430	266	414
2030	445	268	424
2031	459	269	440
2032	474	271	455
2033	488	273	471
2034	503	275	486
2035	518	277	502

Source: Navigant

Table E-5. Electric Demand Technical Savings Potential by Sector (MW)

	Commercial	Industrial	Residential
2016	46	30	90
2017	48	31	91
2018	50	31	92
2019	52	31	93
2020	54	31	94
2021	57	31	96
2022	60	31	98
2023	62	32	100
2024	65	32	102
2025	68	32	104
2026	71	32	108
2027	73	32	112
2028	76	32	116
2029	79	32	120
2030	82	32	124
2031	84	33	130
2032	87	33	136
2033	90	33	142
2034	93	33	148
2035	95	34	154

Source: Navigant

Table E-6. Electric Energy Technical Savings Potential by Sector as a Percent of Sector Consumption (%)

	All	Commercial	Industrial	Residential
2016	22.0%	20.5%	28.1%	20.0%
2017	22.2%	21.0%	28.0%	20.0%
2018	22.3%	21.5%	27.9%	20.0%
2019	22.5%	22.0%	27.9%	19.9%
2020	22.6%	22.5%	27.8%	19.9%
2021	22.8%	23.1%	27.7%	20.0%
2022	23.1%	23.7%	27.7%	20.1%
2023	23.3%	24.2%	27.6%	20.2%
2024	23.5%	24.8%	27.5%	20.3%
2025	23.7%	25.3%	27.5%	20.4%
2026	24.1%	25.8%	27.4%	20.9%
2027	24.4%	26.3%	27.4%	21.3%
2028	24.7%	26.8%	27.3%	21.7%
2029	25.1%	27.2%	27.3%	22.1%
2030	25.4%	27.7%	27.2%	22.5%
2031	25.8%	28.1%	27.1%	23.2%
2032	26.2%	28.5%	27.1%	23.9%
2033	26.7%	28.9%	27.0%	24.5%
2034	27.1%	29.3%	26.9%	25.2%
2035	27.5%	29.7%	26.9%	25.8%

Source: Navigant

Table E-7. Electric Energy Technical Potential by Customer Segment (GWh/year)

Customer Segment	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.Cement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I.Chemical	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I.Food & Bev	10	10	10	10	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11	11
I.Greenhouse	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I.LNG Facility	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I.Mfg	48	49	49	50	50	50	50	50	49	49	49	49	49	49	50	50	51	52	53	54
I.Coal Mining	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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.TMP Pulp/Paper	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I.Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	47	48	49	51	52	53	55	56	58	59	61	62	63	65	66	67	68	69	70	72
R.Apt > 4 Stories	4	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	6	6	6	6
R.Other Residential	15	15	15	15	15	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
R.Fam Attached	44	44	44	44	44	44	45	45	45	45	46	47	48	48	49	50	51	52	53	54
R.Fam Detached	280	282	285	287	290	294	299	303	308	312	322	331	341	351	361	375	390	405	419	434
Total	**845**	**860**	**875**	**890**	**905**	**925**	**944**	**964**	**984**	**1,005**	**1,031**	**1,057**	**1,083**	**1,110**	**1,137**	**1,168**	**1,200**	**1,232**	**1,264**	**1,297**

Source: Navigant

Errata dated September 15, 2017

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	137	136	136	135	134	134	133	132	132	131	130	130	129	128	128	127	126	126	125	124
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	**845**	**860**	**875**	**890**	**905**	**925**	**944**	**964**	**984**	**1,005**	**1,031**	**1,057**	**1,083**	**1,110**	**1,137**	**1,168**	**1,200**	**1,232**	**1,264**	**1,297**

Source: Navigant

Table E-9. Electric Energy Economic Savings Potential by Sector (GWh/year)

	Commercial	Industrial	Residential
2016	245	250	313
2017	256	252	319
2018	267	253	321
2019	278	255	324
2020	289	257	327
2021	303	257	331
2022	317	258	335
2023	331	259	340
2024	346	260	344
2025	361	261	349
2026	375	263	358
2027	389	264	368
2028	404	265	378
2029	419	266	388
2030	434	268	397
2031	448	269	412
2032	463	271	427
2033	477	273	441
2034	486	275	456
2035	501	277	471

Source: Navigant

Table E-10. Electric Demand Economic Savings Potential by Sector (MW)

	Commercial	Industrial	Residential
2016	44	30	86
2017	46	31	88
2018	48	31	89
2019	50	31	90
2020	52	31	91
2021	55	31	93
2022	58	31	94
2023	60	32	96
2024	63	32	98
2025	66	32	99
2026	69	32	103
2027	71	32	107
2028	74	32	111
2029	77	32	114
2030	80	32	118
2031	83	33	124
2032	85	33	129
2033	88	33	135
2034	90	33	140
2035	93	34	146

Source: Navigant

Table E-11. Electric Energy Economic Savings Potential by Sector as a Percent of Sector Consumption (%)

	All	Commercial	Industrial	Residential
2016	21.0%	19.5%	28.1%	18.5%
2017	21.3%	20.1%	28.0%	18.7%
2018	21.5%	20.6%	27.9%	18.7%
2019	21.6%	21.1%	27.9%	18.7%
2020	21.8%	21.7%	27.8%	18.7%
2021	22.0%	22.3%	27.7%	18.8%
2022	22.2%	22.8%	27.7%	18.9%
2023	22.5%	23.4%	27.6%	19.0%
2024	22.7%	24.0%	27.5%	19.1%
2025	22.9%	24.6%	27.5%	19.2%
2026	23.2%	25.1%	27.4%	19.6%
2027	23.6%	25.6%	27.4%	20.0%
2028	23.9%	26.1%	27.3%	20.3%
2029	24.2%	26.5%	27.3%	20.7%
2030	24.6%	27.0%	27.2%	21.1%
2031	25.0%	27.4%	27.1%	21.7%
2032	25.4%	27.8%	27.1%	22.4%
2033	25.8%	28.2%	27.0%	23.0%
2034	26.1%	28.3%	26.9%	23.6%
2035	26.5%	28.7%	26.9%	24.2%

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	65
C.College/Univ	9	9	10	10	11	12	12	13	14	15	15	16	17	18	18	19	20	21	21	22
C.Food Svc	12	13	13	14	15	16	17	17	18	19	20	21	22	23	24	25	26	27	27	28
C.Hospital	13	14	15	16	17	18	19	21	22	24	25	26	28	29	31	32	34	35	36	38
C.Logistic/WHouse	7	7	8	8	9	9	10	10	11	12	12	13	13	14	15	15	16	16	16	17
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	69	72
C.Other Commercial	25	26	27	29	30	32	34	36	38	40	42	44	46	48	50	51	53	55	57	59
C.Retail.Food	14	15	15	16	17	18	19	19	20	21	22	23	24	25	25	26	27	28	28	29
C.Retail.Non Food	38	38	39	40	41	41	42	43	44	45	46	47	47	48	49	50	51	52	51	52
C.Schools	6	6	6	6	6	7	7	7	7	8	8	8	8	8	9	9	9	9	9	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.Cement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I.Chemical	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I.Food & Bev	10	10	10	10	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11	11
I.Greenhouse	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I.LNG Facility	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I.Mfg	48	49	49	50	50	50	50	50	49	49	49	49	49	49	50	50	51	52	53	54
I.Coal Mining	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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.TMP Pulp/Paper	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
I.Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	42	44	45	46	47	49	50	52	53	55	56	57	59	60	62	63	64	65	66	67
R.Apt > 4 Stories	3	3	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5
R.Other Residential	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
R.Fam Attached	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41
R.Fam Detached	259	265	267	270	272	277	281	286	290	295	304	314	324	334	344	358	373	388	403	417
Total	**808**	**827**	**842**	**857**	**872**	**891**	**911**	**930**	**950**	**971**	**996**	**1,021**	**1,047**	**1,073**	**1,099**	**1,130**	**1,161**	**1,192**	**1,217**	**1,249**

Source: Navigant

Errata dated September 15, 2017

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	35	35	34	34	34	34	34	34	34	33	33	33	33	33	33	32	32	32	32
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	0	0	0	0	0	0	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	38	38	38	38	38	37	37	37	37	37	37	36	36	36	36	36	35	35	35	35
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	207	207	210	213	215	218	221	224	227	230	233	236	239	242	245	248	245	248
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	130	129	129	128	127	127	126	125	125	124	124	123	122	122	121	121	120	119	119	118
Ventilation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Whole Facility	131	146	162	178	191	208	225	242	260	278	300	323	346	370	394	421	449	478	506	535
Total	**808**	**827**	**842**	**857**	**872**	**891**	**911**	**930**	**950**	**971**	**996**	**1,021**	**1,047**	**1,073**	**1,099**	**1,130**	**1,161**	**1,192**	**1,217**	**1,249**

Source: Navigant

Errata dated September 15, 2017

FBC 2016 LTERP & LT DSM Plan

FBC RESPONSES TO IRS - ERRATA

33.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

Exhibit B-1, Volume 2, pp. 14, 15; 2016 NW PP, p. O-18

Attributes of DSM energy

FBC includes DSM scenario data on page 14 of the FBC 2016 LT DSM Plan Application (Table 3-1). FBC states on page 15 of the 2016 LT DSM Plan Application: "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 2016 NW PP states on page O-18: "Conservation also lacks the economic risk with volatile fuel prices and carbon dioxide emission reduction policies. Its short lead time and availability in small increments also reduce its economic risk."

33.1 For each portfolio option included in Table 3-1 of the FBC LT DSM Plan Application, please provide the following information for each year from 2017-2021, with a five year total: utility annual cost ($'million); annual energy savings (GWh); energy cost (c/kWh), the total resource cost (TRC), Rate Impact Measure (RIM).

Response:

The following tables provide the requested information, including the 100% load growth offset scenario as requested in BCUC IR 1.33.1.1. Table 3-1 of the LT DSM Plan is comprised of portfolio level estimates wherein the savings targets are based on DSM load growth offsets and the estimated costs are prorated based on FBC's 2017 DSM Expenditure Plan Application.

The Company intends to develop, and file later in 2017, a detailed DSM expenditure schedule allocating savings targets to programs and sectors, and thus has not estimated the energy cost, TRC, and RIM on an annual basis, however pro-forma values are presented at the portfolio level for each scenario.

Table 1: Estimated Annual Cost (DSM Budget) in 2016 $000s

Year	Low	Base	High	Max	100% load growth offset
2017	$7,610	$7,610	$7,610	$7,610	$7,610
2018	$5,200	$7,900	$7,900	$7,900	$15,400
2019	$5,200	$7,900	$7,900	$7,900	$15,400
2020	$5,200	$7,900	$7,900	$7,900	$15,400
2021	$5,200	$7,900	$9,000	$9,000	$15,400
Total	**$28,410**	**$39,210**	**$40,310**	**$40,310**	**$69,210**

Table 2: Estimated Annual Savings (GWh)

Year	Low	Base	High	Max	100% load growth offset
2017	25.7	25.7	25.7	25.7	25.7
2018	20.0	26.4	26.4	26.4	40.0
2019	20.0	26.4	26.4	26.4	40.0
2020	20.0	26.4	26.4	26.4	40.0
2021	20.0	26.4	28.4	28.4	40.0
Total	**105.8**	**131.4**	**133.4**	**133.4**	**185.9**

Table 3: Energy Cost, TRC and RIM

Metric	Low	Base	High	Max	100% load growth offset
Average resource cost including program costs (2016 $/MWh)	42.3	51.9	57.9	64.1	71.1
TRC benefit/cost ratio	3.4	2.6	2.2	2.0	1.7
RIM	1.08	0.96	0.91	0.87	0.81

34.0 Reference: LONG-RUN MARGINAL COST

Exhibit B-1, Volume 1, pp. 94, 126, Appendix K, Appendix J, p. 8; BC Hydro F2017-F2019 RRA, Exhibit B-1-1, Appendix X; ACEEE, Everyone Benefits: Practices and Recommendations for Utility System Benefits for Energy Efficiency, June 2015, p. 21[1]; 2016 NW PP, p. G-15

General

FBC describes its proposed portfolio (A4) on page 126 of its 2016 LTERP Application, and its Long-Run Marginal Cost (LRMC) methodology in Appendix K. In Appendix J, page 8, FBC states that it has assumed $10/MWh for solar/wind integration costs. FBC states on page 94 of the FBC 2016 LTERP Application that based on the reference case forecast, minimal capacity gaps start in 2028. BC Hydro provides its avoided capacity costs and generation system reserve margin in Appendix X to its F2017-F2018 RRA.

[1] http://aceee.org/sites/default/files/publications/researchreports/u1505.pdf.

The ACEEE 2015 "Everyone Benefits" states on page 21: "We collected 45 data points for estimates of avoided [transmission and distribution (T&D)] used in efficiency program screening. … The majority of values were between [US] $25 and $50 per kW-year." The 2016 NW PP states on page G-15 that it used data for 8 transmission and distribution utilities to estimate the T&D capacity cost.

34.2 Please calculate the same LRMC estimates, but this time for FBC's proposed portfolio (A4) rather than clean BC energy. Please state all key assumptions made.

Response:

The use of a portfolio approach recognizes that a combination of existing resources, DSM, supply-side resources, and market will be used to meet the forecast gross load requirements. Each portfolio FBC considered, with the exception of portfolio B1, includes DSM valued at the TRC. Qualifications discussed in the response to BCUC IR 1.34.1 are also applicable to FBC's preferred portfolio A4.

For the FBC proposed preferred portfolio A4, the LRMC of both energy and capacity is $96 per MWh, which is the value of energy capable of being delivered to the customer in the peak hour of the winter season. The estimated value of long run energy capable of being delivered in the winter is $83 per MWh and long run peak capacity is $98 per kW-year.

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35.0 Reference: LONG-RUN MARGINAL COST

Exhibit B-1, Volume 2, p. 3; DSM Regulations, s. 4(1.1)(b)(ii); BC Hydro F2017-F2019 RRA, Exhibit B-1-1, p. 3-46, Appendix X, p. 2; FBC SGP Stage II, Exhibit B-1, p. 34

LRMC for DSM

FBC states on page 3 of the LT DSM Plan Application that its LRMC of firm energy (inclusive of generation capacity) is $100.45/MWh (abbreviated as $100/MWh) and the avoided capacity cost of deferred infrastructure is $79.85/kW-year.

Section 4 (1.1)(b)(ii) of the DSM Regulations requires that, in applying the TRC, the avoided electricity cost, in addition to the avoided capacity cost, is "an amount that the commission is satisfied represents the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia."

BC Hydro states on page 3-46 of the F2017-F2019 RRA that the avoided cost of greenfield clean or renewable IPPs is $100/MWh.

35.2 Please compare the average (as opposed to incremental) TRC (in $/MWh) of each DSM portfolio option with the $100 per MWh estimate for BC clean/renewable energy.

Response:

The following table provides the average and incremental TRC (in $/MWh) for each DSM portfolio. Only the incremental costs of the Max DSM portfolio option, including a program cost adder, exceeds the $100 per MWh estimate for BC clean or renewable energy.

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Category	DSM Scenario Low	Base	High	Max
Resource Cost ($2016/MWh)				
Average cost, incl. program costs	$42	$52	$58	$64
Incremental cost, incl. program costs	$42	$86	$98	**$108**

36.0 Reference: LONG-RUN MARGINAL COST

Exhibit B-1, Volume 1, p. 96; FBC 2016 NM Reasons for Decision, pp. 17-19

Energy purchases/DG

FBC states on page 96 of its 2016 LTERP: “The Company does not consider small-scale customer-owned renewable power to be a secure or reliable firm resource”.

The Commission stated on pages 17–19 of the FBC 2016 NM Reasons for Decision:

> BCSEA-SCBC submits that FBC’s long-run marginal cost (LRMC) of clean or renewable resources in BC is the appropriate referent price (11.2 c/kWh). FBC submits that energy generated from a distribution connected customer is short-term in nature as there is no long term-commitment from the customer. However:
>
> - FBC submits the lifetime of distributed generation sources as ranges from 14 years to 38 years.

- FBC states that NM customers do not have the option of selling generation to a third party other than FBC, and that FBC has no tariff or program in place to purchase IPP power other than the NM rate.
- A letter of comment states: "…A system like this can't be just dismantled and moved to an area where its more financially feasible to install."
- Scarlett argues: "The primary reason NM customers don't make a long term commitment is that FBC has not to date given them the opportunity to do so."
- Scarlett also submits that FBC's proposal does not acknowledge the value of aggregated small energy sources, contrary to Policy Action #25 in the BC Energy Plan …"

The Panel reiterates its comments made earlier in this decision that broader issues, such as whether the scope of the Net-Metering (NM) programs should be expanded to include customers who generate Annual (net excess generation [NEG]), and if so what the appropriate price should be, are more appropriately addressed as part of or following the LTERP and/or SGP proceedings

36.3 Please approximate the long-term value of (i) solar PV energy, and (ii) micro-hydro energy using FBC's LRMC of energy estimate as the starting point and adjusting the value for avoided distribution losses, location and shape (if required). Please provide all key assumptions used.

Response:

The LRMC of energy only, which is capable of being delivered in the winter, is estimated in the response to BCUC IR 1.34.2 to be $83 per MWh (FBC's preferred portfolio A4). Assuming the generated power is consumed at the point of generation, then approximately 8 percent less power must be generated at the point of consumption to meet the load than is assumed in portfolio A4 due to loss savings.

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If the resource provides little to no winter energy, such as solar PV, then it will have little to no impact on the LTERP required resources in the preferred portfolio A4, meaning that any energy produced at best only displaces BC Hydro PPA energy costs. A LRMC based on the PPA Tranche 1 energy rate is in the range of $47 - $56 per MWh (per Table 8-4 of the LTERP).

Depending on the seasonal generation profile of a micro-hydro installation, it may be appropriate to apply FBC's estimated energy-only LRMC of $83 per MWh if the owner of the

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project has signed a long-term power supply contract to provide power[2]. If a long-term contract is not in place or if the seasonal generation profile of the micro-hydro installation is weighted heavily to freshet energy, there could be little to no change to the LTERP required resources. If not able to produce in the winter, any energy produced by a micro-hydro installation at best displaces BC Hydro PPA energy costs for LTERP planning purposes. However, on an operational basis, it is more likely this energy will displace short-term portfolio optimized market purchases, especially during freshet when the cost of market energy is traditionally low.

J. VOLUME 2 – LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

38.0 Reference: LONG-TERM DSM PLAN

Exhibit B-1, Volume 2, pp. 14; FBC's 2012 RR & ISP, Exhibit B-1-2 (FBC 2012 LT DSM Plan), p. 11; FBC 2012 RR&ISP, Decision, p. 129 and Order G-110-12; FBC Application for Acceptance of DSM Expenditures for 2017 (FBC 2017 DSM), Order G-9-17, Appendix A, Reasons for Decision dated January 25, 2017 (FBC 2017 DSM Reasons for Decision), p. 5

Funding envelope history

FBC provides in table 3-1, p. 14 of the FBC 2016 LLT DSM Plan Application, key DSM scenario data. On p. 11 (table 2.5) of the FBC 2012 LT DSM plan, FBC provided for the three DSM portfolio options considered: incentive levels as a percentage of TRC and TRC benefit/cost ratio.

On page 129 of the Commission's Decision on the FBC's 2012 RR & ISP (G-110-12), the Commission stated: "The first issue is whether the Plan is in fact a long-term plan or, more accurately, a five-year plan because a placeholder for energy savings has been used for 2017-2030. FortisBC's position is that detailed planning data is only valid for 5 years due to rapidly changing DSM technology and costs."

On page 5 of the FBC 2017 DSM Reasons for Decision, the Commission stated: "In the 2012 LTRP, FBC considered three DSM options (low, medium and high) which resulted in annual funding levels of $5 million, $9 million and $20 million, respectively."

[2] FBC future resource needs are further into the planning horizon after planned DSM savings included in portfolio A4. Therefore, in the short to medium term, any energy generated would only reduce FBC variable resources such as PPA Tranche 1 energy.

38.2 Please provide in table form the following key DSM scenario data (average per annum for the 5 years following the 2012 ISP and 2016 LTERP, respectively) for: (i) the low/medium/high DSM scenarios considered in 2012 and (ii) the low/base/high/max scenarios considered in 2016:

- Annual savings (in GWh, % of load growth, and % of total load)
- Annual DSM funding levels, $ million
- Utility incentive levels as a percentage of the total resource cost
- TRC benefit/cost ratio
- Utility cost of energy savings ($/MWh)

Response:

The following tables provide the requested information. FBC did not develop a detailed DSM expenditure plan, allocating savings by sector, and thus has not estimated the utility incentive levels as a percentage of the TRC, and average utility cost of energy savings on an annual basis. These values are presented for the entire DSM portfolio for each scenario.

Table 1: 2012 LT DSM Plan Annual Savings

Year	Total Load	Load Growth	Annual Savings								
	GWh	GWh	GWh			% of load growth			% of total load		
			Low	Medium	High	Low	Medium	High	Low	Medium	High
2011	3,252	50.8	19.3	27.5	50.5	38%	54%	99%	0.6%	0.8%	1.6%
2012	3,304	52.0	19.3	27.5	50.5	37%	53%	97%	0.6%	0.8%	1.5%
2013	3,357	53.0	19.3	27.5	50.5	36%	52%	95%	0.6%	0.8%	1.5%
2014	3,407	49.2	19.3	27.5	50.5	39%	56%	103%	0.6%	0.8%	1.5%
2015	3,452	45.4	19.3	27.5	50.5	43%	61%	111%	0.6%	0.8%	1.5%

Table 2: 2012 LT DSM Plan Annual DSM Funding

Year	Annual DSM Budget (2016 $000s)		
	Low	Medium	High
2011	$5,000	$9,000	$20,000
2012	$5,000	$9,000	$20,000
2013	$5,000	$9,000	$20,000
2014	$5,000	$9,000	$20,000
2015	$5,000	$9,000	$20,000

Table 3: 2012 LT DSM Plan Other Metrics

Metric	Low	Medium	High
Utility incentive levels as a percentage of the TRC	25%	40%	50%
TRC benefit/cost ratio	> 1.5	> 1.0	> 0.9
First year utility cost of energy savings ($/MWh)	17	35	35

Table 4: 2016 LT DSM Plan Annual Savings

Year	Total Load	Load Growth	Annual Savings											
	GWh	GWh	GWh				% of load growth				% of total load			
			Low	Base	High	Max	Low	Base	High	Max	Low	Base	High	Max
2018	3,644	39.2	20.0	26.4	26.4	26.4	51%	67%	67%	67%	0.5%	0.7%	0.7%	0.7%
2019	3,686	41.4	20.0	26.4	26.4	26.4	48%	64%	64%	64%	0.5%	0.7%	0.7%	0.7%
2020	3,724	38.1	20.0	26.4	26.4	26.4	53%	69%	69%	69%	0.5%	0.7%	0.7%	0.7%
2021	3,758	34.4	20.0	26.4	28.4	28.4	58%	77%	83%	83%	0.5%	0.7%	0.8%	0.8%
2022	3,800	42.3	20.0	26.4	30.4	30.4	47%	63%	72%	72%	0.5%	0.7%	0.8%	0.8%

Table 5: 2016 LT DSM Plan Annual DSM Funding

Year	Annual DSM Budget (2016 $000s)			
	Low	Base	High	Max
2018	$5,200	$7,900	$7,900	$7,900
2019	$5,200	$7,900	$7,900	$7,900
2020	$5,200	$7,900	$7,900	$7,900
2021	$5,200	$7,900	$9,000	$9,000
2022	$5,200	$7,900	$10,000	$10,000

Table 6: 2016 LT DSM Plan Other Metrics

Metric	Low	Base	High	Max
Utility incentive levels as a percentage of the TRC	53%	53%	53%	53%
TRC benefit/cost ratio	3.4	2.6	2.2	2.0
Average utility cost of energy savings ($/MWh)	29	35	38	41

39.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

FBC's 2012 RR & ISP Decision, p. 133; FBC 2014-2018 Multi-Year Performance Based Ratemaking Plan, Decision dated September 15, 2014 (2014-2018 PBR Decision), p. 242; FBC 2015-2016 DSM Decision, pp. 4, 32 and Order G-186-14; FBC Application for Acceptance of Demand Side Management Expenditures for 2017 (FBC 2017 DSM), Reasons for Decision and Order G-9-17, pp. 4, 10,

Guidance from prior Commission Decisions

On page 133 of the Commission's Decision on the FBC's 2012 RR & ISP, the Commission stated:

> The Commission Panel recognizes that this acceptance means that FortisBC may simply maintain current levels of DSM spending over the next five years, subject to future DSM expenditure schedules filed for approval with the Commission. However, … FortisBC received approval to spend approximately twice the amount on DSM in 2011 over 2010 and was unable to spend to the higher approved level. As well, the Commission Panel acknowledges that the Company is implementing new programs that will take time to gain participants.

In the FBC 2014-2018 PBR Decision, the Commission stated on page 242: "The Commission Panel accepts the 2014 DSM schedule filed by FBC … As it is now near the end of 2014, the Panel does not consider that FBC would be able to meaningfully impact its 2014 DSM spend should a higher budget be approved."

In the Commission Decision on FBC 2015-2016 DSM expenditures, the Commission stated on pages 4 and 32:

> Despite the acceptance of the proposed expenditures, the Panel is concerned about the adequacy of expenditures … especially given that FBC's proposed DSM expenditures are less than those accepted in 2013 and those proposed in the 2012 LTRP (in particular for industrial customers). … While the Panel acknowledges FBC's explanation for the 2013 underspend, the issue of utility incentives to undertaken DSM is not new to the Commission.

In the Commission Reasons for Decision on FBC 2017 DSM expenditures, the Commission stated on pages 4, 10:

> Despite the acceptance of the proposed expenditure schedule, the Panel is concerned that it falls short of addressing a range of DSM possibilities that could be pursued in the coming year. …The Panel is further concerned that the extension of existing programming sits on a foundation of recent activity which in

itself can be characterized as having fallen short. In other words, “more of the same” is inherently plagued by underperformance.

39.3 Please identify any key concerns FBC would have with spending that achieves savings that offsets 100% load growth. Please specifically identify whether concerns include: lack of cost-effective DSM opportunities, difficulty in scaling-up DSM programs, timing of Commission approval received, rate impact.

Response:

The Max DSM Scenario presented in the 2016 LT DSM Plan is representative of a 100 percent load growth offset, albeit with an appropriate ramp-up period to escalate customer awareness, expand program offers and build market capacity to achieve the 100 percent offset level. Section 3.2 of the LT DSM Plan explains how FBC chose its preferred High DSM scenario.

The rationale as to why the Company did not choose the Max scenario also applies to the 100 percent load growth offset, as noted in Section 3.2 of the LT DSM Plan:

> 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 ($108 per MWh) of the Maximum tranche compared to the LRMC of $100.

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40.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

Exhibit B-1, Volume 1, p. 95; UCA, s. 44.1; 2007 BC Energy Plan, p. 5; BCH 2013 IRP, p. 9-12; Guide to the DSM Regulation (DSM Guide), p. 8

Definition of cost-effective DSM

FBC states on page 95 of its 2016 LTERP Application: "Demand-side resource options are typically more cost-effective than new supply-side resource options… Accordingly, FBC looks to demand-side resources first to meet any future LRB gaps."

Section 44.1(2)(f) of the UCA states, that a long-term resource plan must include: "(f) an explanation of why the demand for energy … [is] not planned to be replaced by demand-side measures."

The 2007 BC Energy Plan states on page 5: "… the plan supports utilities in [BC] and the [Commission] pursuing all cost-effective and competitive demand side management programs".

BC Hydro states on page 9-12 of its 2013 IRP:

> Cost-Effectiveness: Activities should be cost-effective to ensure BC Hydro's investments in DSM will generally be lower than the LRMC and reduce overall revenue requirements while providing broad opportunities for participation across customer sectors. Cost-effectiveness is measured by the TRC and UC.

Page 8 of the DSM Guide includes illustrative examples of how the 15% non-energy benefit adder can be applied.

40.2.1 Please explain how environmental and non-energy benefits are incorporated into the 'cost effective' DSM definition.

Response:

Environmental and non-energy benefits are not incorporated into the 'cost effective' DSM definition in the 2016 LT DSM Plan. The avoided costs (LRMC, DCE) that are currently being used by FBC result in most DSM measures being cost effective without incorporating environmental and non-energy benefits. For example, 96 percent of the technical potential identified by 2035 in the 2016 CPR is considered economic, or 'cost effective'.

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42.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

Exhibit B-1, Volume 2, Appendix A, 3.2.5, sub-appendix A

CPR: Model results and input assumptions

Appendix A of the 2016 LT DSM Plan Application references three attachments containing additional model results and input assumptions, which are "A.1 Detailed Modeled Results", "A.2 Measure List and characterization Assumptions", and "A.3 Other Key Input Assumptions." Navigant states in the executive summary of the CPR: "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." In section 3.2.5 of Appendix A, Navigant states that it "relied primarily on BC Utility provided program data and TRM data for incremental cost data."

42.2 Please identify the LRMC of energy used in the CPR and discount rate assumption. Please discuss the advantages/disadvantages of using a societal discount rate to calculate the TRC.

Response:

The LRMC of energy used in the FBC 2016 CPR was $100/MWh for BC "clean" resources. The discount rate used in the TRC was the real pre-tax utility cost of capital, equal to 6 percent.

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An advantage of using a societal discount rate (SDR) to calculate the TRC is that if the SDR is lower than the utility cost of capital, then more measures could pass the governing TRC test.

A disadvantage of using the SDR is choosing the appropriate discount rate to apply. Estimating the appropriate value for the SDR is controversial because the SDR has different definitions, depending on the economic perspective taken. Another disadvantage is if the SDR rate is higher than the utility cost of capital, then the discounted benefits will be lower and some measures could fail the TRC test.

The TRC test uses a mix of customer and utility cash flows and the use of the utility cost of capital is the most common practice in the industry for this test.

45.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

Exhibit B-1, Volume 2, Section 3, pp. 14, 16; FBC 2015-2016 DSM Decision, p. 16; BCH 2013 IRP, p. 9-17

Developing alternative DSM portfolios

In the FBC 2015-2016 DSM Decision the Commission stated that, in reviewing the DSM portfolio from the perspective of interests of persons in BC, it would focus on effectiveness (consideration of Utility Cost Test (UCT) results, addressing 'lost opportunities' and maintaining an engagement) and balance (providing broad opportunities for customers to participate, in particular for 'hard to reach' customers).

BC Hydro describes on page 9-17 of its 2013 IRP its principles for developing the DSM portfolio, including consideration of the persistence of savings/short-term energy surplus, lost opportunities, maintaining customer and trade engagement, cost-effectiveness of DSM from a Utility Cost (UC) and TRC perspective, and providing broad opportunities for customers to participate.

On page 14 of the 2016 LT DSM Plan Application, FBC presents four DSM portfolios: low, base, high, max which offsets 50%, 66%, 77%, and 89% of load growth on average from 2018 to 2035, respectively.

FBC presents its DSM portfolio scenarios in section 3 of the 2016 LT DSM Plan Application. Table 3-2 on page 16 shows the High DSM scenario rollout of target savings and pro-forma costs over the LTERP planning horizon

45.1 Please replicate Table 3-2 for all of the DSM portfolio scenarios, and for a hypothetical scenario if DSM spending offsets 100% of load growth.

Response:

The revised table is provided below. The 2016 LT DSM Plan is not an expenditure schedule, thus the portfolio level costs for the various scenarios, including the 100 percent load growth offset, are high-level estimates. FBC anticipates filing a new DSM expenditure schedule, for 2018 onwards, later this year.

Although the 100 percent load growth projections are seen to fluctuate, the corresponding budget estimate is portrayed as a constant, based on the average of 40 GWh per year load growth over the planning horizon.

Description	Year	Annual DSM Budget (2016 $000s)					Annual DSM Savings (MWh)				
		Low	Base	High	Max	100% load growth offset	Low	Base	High	Max	100% load growth offset
Plan	2017		$7,610					25.7			
Forecast	2018	$5,100	$7,900	$7,900	$7,900	$15,400	20.0	26.4	26.4	26.4	39.2
Forecast	2019	$5,100	$7,900	$7,900	$7,900	$15,400	20.0	26.4	26.4	26.4	41.4
Forecast	2020	$5,100	$7,900	$7,900	$7,900	$15,400	20.0	26.4	26.4	26.4	38.1
Forecast	2021	$5,100	$7,900	$9,000	$9,000	$15,400	20.0	26.4	28.4	28.4	34.4
Forecast	2022	$5,100	$7,900	$10,000	$10,000	$15,400	20.0	26.4	30.4	30.4	42.3
Forecast	2023	$5,100	$7,900	$10,900	$11,100	$15,400	20.0	26.4	32.0	32.4	44.5
Forecast	2024	$5,100	$7,900	$10,900	$12,300	$15,400	20.0	26.4	32.0	34.4	39.9
Forecast	2025	$5,100	$7,900	$10,900	$13,400	$15,400	20.0	26.4	32.0	36.4	41.1
Forecast	2026	$5,100	$7,900	$10,900	$14,600	$15,400	20.0	26.4	32.0	38.4	41.2
Forecast	2027	$5,100	$7,900	$10,900	$15,400	$15,400	20.0	26.4	32.0	40.0	39.4
Forecast	2028	$5,100	$7,900	$10,900	$15,400	$15,400	20.0	26.4	32.0	40.0	40.1
Forecast	2029	$5,100	$7,900	$10,900	$15,400	$15,400	20.0	26.4	32.0	40.0	40.4
Forecast	2030	$5,100	$7,900	$10,900	$15,400	$15,400	20.0	26.4	32.0	40.0	36.7
Forecast	2031	$5,100	$7,900	$10,900	$15,400	$15,400	20.0	26.4	32.0	40.0	38.5
Forecast	2032	$5,100	$7,900	$10,900	$15,400	$15,400	20.0	26.4	32.0	40.0	40.5
Forecast	2033	$5,100	$7,900	$10,900	$15,400	$15,400	20.0	26.4	32.0	40.0	41.2
Forecast	2034	$5,100	$7,900	$10,900	$15,400	$15,400	20.0	26.4	32.0	40.0	40.7
Forecast	2035	$5,100	$7,900	$10,900	$15,400	$15,400	20.0	26.4	32.0	40.0	41.2

46.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

Exhibit B-1, Volume 2, p. 11; BC Hydro F2017-F2019 RRA, Exhibit B-1-1, p. 10-23, Exhibit C1-8, p. 8; FBC 2015-2016 DSM Decision, p. 11

DSM portfolios - load growth target

FBC states on page 11 of the 2016 LT DSM Plan Application: "The DSM scenarios FBC considered are based on offsetting FBC's forecast growth, which is included in section 3 of the LTERP." The Commission stated on page 11 of the FBC 2015-2016 DSM Decision: "… the Panel considers that this load reduction target should act as a floor rather than a cap on the level of cost effective DSM funding."

BCSEA state in their intervener evidence on the BC Hydro F2017-F2019 RRA (Exhibit C1-8): "The uneven nature of load growth can lead to rising and falling energy efficiency and conservation investments as growth fluctuates due to external forces." BC Hydro states on page 10-23 of their F2017-F2019 revenue requirements application: "However, this metric [66 percent target] can be highly variable given changes in the load forecast …"

46.1.2 Does FBC consider that the 77 percent load reduction target in the proposed DSM portfolio should act as a floor rather than a cap on the level of cost-effective DSM? Please explain why/why not.

Response:

It is a target, first and foremost, and to some extent has the effect of a cap since the High scenario uses measures up to an incremental cost of $98 per MWh, which approximates the LRMC of $100 per MWh.

Deleted: the LRMC value of $100 per MWh

47.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

BC Hydro F2017-F2019 RRA, Exhibit B-9, BCUC IR 176.2; FBC PBR 2014-2018, Exhibit B-43, Appendix C, p. 35, Exhibit C10-7, Appendix A, pp. 2, 10-18, 30-33

Benchmarking

In the BC Hydro F2017-F2019 RRA (Exhibit B-9, BCUC IR 176.2), BC Hydro provides a comparison of its DSM energy savings as a percentage of energy sales to other jurisdictions.

FBC includes a January 2013 Public Utilities Fortnight article titled "DSM in the Rate Case: a regulatory model for resource parity between supply and demand," as Appendix C to its 2014-2018 PBR Application Rebuttal Evidence to the Industrial Customer's Group (ICG). The article states on page 35: "Recently the U.S. Energy Information Administration (EIA) indicated that $5.5 billion was spent on electric DSM programs in 2011, representing 1.5 percent of total electric retail revenues."

ICG submitted a 2006 report prepared for the Canadian Association of Members of Public Utility Tribunals (CAMPUT) titled "Demand-Side Management: Determining Appropriate Spending Levels and Cost-Effectiveness Testing" in the FBC PBR 2014-2018 Application (Exhibit C10-7). This report discusses on pages 2, 10-18, 30-33 setting appropriate targets for the amount of DSM activity. The executive summary of this report provides recommendations which include: "A minimum expenditure of 1.5% of annual electric revenues might be appropriate with a ramping up to a level near 3%."

47.1 Please calculate, for each DSM portfolio considered, (i) DSM spend as a percentage of FBC revenues and (ii) DSM energy savings as a percentage of energy sold.

Response:

(i) DSM spend as a percentage of estimated FBC revenues

	% of revenues		
Year	**Base**	**High**	**Max**
2017	2.1%	2.1%	2.1%
2018	2.1%	2.1%	2.1%
2019	2.1%	2.1%	2.1%
2020	2.0%	2.0%	2.0%
2021	2.0%	2.3%	2.3%
2022	2.0%	2.5%	2.5%
2023	1.9%	2.7%	2.7%

	% of revenues		
Year	Base	High	Max
2024	1.9%	2.6%	2.9%
2025	1.9%	2.6%	3.2%
2026	1.8%	2.5%	3.3%
2027	1.7%	2.3%	3.3%
2028	1.6%	2.2%	3.2%
2029	1.6%	2.2%	3.1%
2030	1.6%	2.2%	3.1%
2031	1.5%	2.1%	3.0%
2032	1.5%	2.1%	3.0%
2033	1.5%	2.0%	2.9%
2034	1.4%	2.0%	2.9%
2035	1.4%	2.0%	2.8%

(ii) DSM energy savings as a percentage of estimated energy sold

	% of total load		
Year	Base	High	Max
2017	0.7%	0.7%	0.7%
2018	0.7%	0.7%	0.7%
2019	0.7%	0.7%	0.7%
2020	0.7%	0.7%	0.7%
2021	0.7%	0.8%	0.8%
2022	0.7%	0.8%	0.8%
2023	0.7%	0.8%	0.8%
2024	0.7%	0.8%	0.9%
2025	0.7%	0.8%	0.9%
2026	0.7%	0.8%	1.0%
2027	0.7%	0.8%	1.0%
2028	0.7%	0.8%	1.0%
2029	0.6%	0.8%	1.0%
2030	0.6%	0.8%	1.0%
2031	0.6%	0.8%	1.0%
2032	0.6%	0.8%	1.0%
2033	0.6%	0.8%	0.9%
2034	0.6%	0.7%	0.9%
2035	0.6%	0.7%	0.9%

48.0 Reference: LONG TERM DEMAND-SIDE MANAGEMENT PLAN

Exhibit B-1, Volume 1, p. 5, Volume 2, p. 11; 2016 NW PP, p. 17-3; FBC 2015-2016 DSM Decision, p. 17; BCH2013 IRP, pp. 4-21, 4-22, 6-153

Evaluation of DSM vs. supply side: objectives

FBC describes its resource planning objectives on page 5 of the 2016 LTERP Application. The Commission describes resource planning objectives on page 3 of the Resource Planning Guidelines, which include 'equal consideration of DSM and supply resources'. FBC states on page 11 of the 2016 LT DSM Plan Application that the High DSM scenario was designed to optimize use of RS 3808 Tranche 1 energy and minimize the rate impact.

Page 17-3 of the 2016 NW PP describes conservation program standards. The Commission stated in the FBC 2015-2016 DSM Decision, p. 17: "The Panel also considers that concerns regarding the overall rate impacts from the DSM portfolio are best addressed in a LTRP …."

Figure 6-21 (p. 6-153) in BC Hydro's 2013 IRP show the differential rate impact related to alternative DSM portfolios over time. BC Hydro includes the following comparators on page 4-21 of the BCH 2013 IRP: rate impact, cost-effectiveness (TRC and UC), bill reductions and risk/flexibility. BC Hydro also states on page 4-22: "Over the long-term, a negligible difference between the average rate impacts of the different alternative means is expected."

48.1 Please describe the key factors FBC considered in comparing DSM portfolios against supply side portfolios. Please specifically address the four criteria used by BC Hydro in its 2013 IRP.

Response:

As noted in the response to BCUC IR 1.2.1.1, FBC considers both demand-side and supply-side resource options in planning for future customer needs. Section 3 of the LT DSM Plan explored four DSM Scenarios with increasing savings targets and higher marginal measure costs. Once the preferred DSM level was determined, bundles of supply-side resource options were then evaluated in combination with DSM through the portfolio analysis process.

The preferred DSM level was determined through an assessment of cost effectiveness based on the TRC rather than UC, so that the cost impacts to both the utility and customer are taken into account (per the DSM regulations). The LRMC of each portfolio includes the TRC costs of the associated DSM level. In Section 8.1.3 of the LTERP, FBC discusses how implementing higher levels than the preferred level of DSM would require higher-cost DSM. Marginal costs would average $108 per MWh, well above the DSM cost-effectiveness threshold LRMC of $100 per MWh, increasing rates for customers. In terms of risk/flexibility, DSM levels higher than the preferred level create risks in terms of managing the load resource balance (LRB). DSM is neither available on demand nor as reliable as a portfolio of supply-side resources 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.

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Once the preferred level of DSM is determined, FBC's portfolio analysis determined the optimal supply-side resources in combination with DSM and existing resources to meet the remaining forecast load requirements. As discussed in Section 9.3.6 of the LTERP, FBC primarily considered the LRMC, rather than specific rate or bill impacts, to assess the cost effectiveness of the various portfolios. Other criteria used to evaluate the portfolios include GHG emissions, percentage of clean and renewable resources, and job creation (i.e. FTE per year). Geographic resource diversity criteria help to assess risk as geographic diversity reduces risk versus a concentration of generation resources in a single area on the FBC system. FBC also assesses risk through its Planning Reserve Margin, ensuring portfolios considered for the preferred portfolio pass the requirements for resource adequacy.

49.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

Exhibit B-1, Volume 1, pp. 29, 127, Volume 2, p, 14; 2016 NW PP, pp. 15-42, 15-26, O-17; 2016 PSE IRP, p. 1-18

Evaluation of DSM vs. supply side: results

FBC states on page 29 of its 2016 LTERP Application: "With increasing federal, provincial and local government interest and development of new regulatory frameworks to reduce GHG emissions, FBC anticipated that there will be a greater requirement for DSM programming." FBC includes DSM scenario data on page 14 of the FBC 2016 LT DSM Plan Application (Table 3-1). FBC states on page 127 of the 2016 LTERP Application that the LRMC of its preferred portfolio is $96/MWh.

Figure 15-17 (p. 15-42) of the 2016 NW PP compares the effect over time on rates and average regional residential bills of different levels of energy efficiency spending, and figure 15-11 (p. 15-26) compares CO2 emissions. The plan states on page O-17 that the highest priority new resource is conservation, and that the Lower Conservation scenario (which still offsets regional load growth through 2030) had significantly higher ($14 billion) average system cost and exposed the region to much larger ($19 billion) economic risk that the Existing Policy scenario.

Page 1-18 of the 2016 PSE IRP states: “This plan - like prior plans – includes acquiring conservation to levels such that much of what is available will be acquired. … PSE’s analysis indicates that although current market power prices are low, accelerating acquisition of [demand side resources] continues to be a least-cost strategy.”

49.1 Please estimate for each of FBC’s DSM portfolio options the effect (in year 5, 10 and 20) on (i) residential customer bills and (ii) FBC rates. Please assume that the avoided cost of energy is equal to the long-run marginal cost of FBC’s preferred portfolio.

Response:

The assumption of the avoided cost of energy being equal to the long-run marginal cost of FBC’s preferred portfolio is not applicable in this case as each of the DSM portfolios investigates a specific DSM program scenario. The avoided cost of energy used within the DSM program scenarios is portfolio B1 and is described in Section 9.3.1 of the LTERP.

For the purpose of responding to this IR, the forecast years of rate impacts are considered 2018-2035, since FBC customer rates have already been approved by the Commission until 2017. Cumulative rate impacts, therefore, start from 2017.

The annual bill impact figures are based on 11.8 MWh using FBC Rate Schedule 3A Exempt Residential Service, which is the equivalent flat rate schedule to RS 01 (Residential Inclining Block Rate) in order to simplify calculations. The bill impact figures exclude GST.

Table 1: Portfolio B2: Base DSM

Year in Planning Horizon	Incremental Rate Impact in Year	Cumulative Rate Impact starting 2018	Residential Customer Annual Bill Impact
5th year (2020)	1.2%	4.6%	$ 73.46
10th year (2025)	1.6%	11.5%	$ 185.88
20th year (2035)	1.3%	40.2%	$ 647.00

Table 2: Portfolio A4: High DSM

Year in Planning Horizon	Incremental Rate Impact in Year	Cumulative Rate Impact starting 2018	Residential Customer Annual Bill Impact
5th year (2020)	1.2%	4.6%	$ 73.46
10th year (2025)	1.8%	12.2%	$ 197.10
20th year (2035)	0.9%	41.7%	$ 672.23

1 **Table 3: Portfolio B4: Max DSM**

Year in Planning Horizon	Incremental Rate Impact in Year	Cumulative Rate Impact starting 2018	Residential Customer Annual Bill Impact
5th year (2020)	1.2%	4.6%	$ 73.46
10th year (2025)	1.9%	12.4%	$ 199.63
20th year (2035)	1.1%	43.6%	$ 702.75

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D. CHAPTER 8 – RESOURCE OPTIONS

60.0 Reference: RESOURCE OPTIONS

Exhibit B-1, Volume 1, Table 8-3, p. 108; Table 8-4, p. 109; p. 127

Wood-Based Biomass

The following information was extracted from Tables 8-3 and 8-4 in the Application.

Resource Option	Wood-Based Biomass	Biogas
Type	Baseload	Baseload
Dependable Capacity (MW)	12 - 63	1 - 2
Annual Energy (GWh)	98 - 503	7 - 18
Clean/Renewable	Yes	Yes
Socio-Economic Benefits	High	Medium
Unit Energy Cost ($/MWh)	$118 - $188	$77 - $101
Unit Capacity Cost ($kW-year)	$663 - $774	$621 - $838

On page 127 of the Application, FBC explained that portfolio A4 best meets the LTERP objectives and is FBC's preferred portfolio. The incremental resources in portfolio A4 comprise of market (31%), wind (65%), biogas (3%) and simple cycle gas turbine (SCGT) (1%). Portfolio A4 has a LRMC of $96 per MWh.

60.1 Please explain and quantify the impact to the LRMC for portfolio A4, of using wood-based biomass to replace biogas.

Response:

Replacing biogas with wood-based biomass increases the LRMC from $96 per MWh to $100 per MWh. To respond to this question, FBC included the wood-based biomass resource in the preferred resource portfolio in the year 2031. The particular wood-based biomass resource selected has a UEC of $118 per MWh (the lowest UEC among the wood-based biomass resource options evaluated by FBC in its Resource Options Report in Appendix J of the LTERP) and an installed capacity of 26 MW. The year 2031 was selected to introduce the resource into the portfolio as this is the same year the two biogas resources are optimally dispatched in portfolio A4. The UECs of the two biogas resources in portfolio A4 are $77 per MWh and $88 per MWh. The increase in both fixed capital costs and variable energy costs associated with the wood-based biomass resource leads to an increase in the LRMC of the portfolio. The incremental energy resources included in this portfolio are wood-based biomass (13 percent), wind (59 percent) and market (28 percent).

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E. CHAPTER 9 – PORTFOLIO ANALYSIS AND LONG RUN MARGINAL COST

62.0 Reference: PORTFOLIO ANALYSIS

Exhibit B-1, Volume 1, p. 47; Table 9-2, p. 126;

Exhibit B-2, BCUC IR 6.1, pp. 15-16

Tranche 1 Power Purchase Agreement (PPA) high rate scenario

On page 47 of the Application, FBC states:

> 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. … 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 … 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.

Table 9-2 on page 126 of the Application shows the attributes of portfolios that FBC considered for the preferred portfolio.

62.1.1 If the LRMC figures in Table 9-2 are based on the base case PPA rate scenario, please present an updated version of Table 9-2 based on the high PPA rate scenario.

Response:

The following figure includes the portfolios listed in Table 9-2 of the LTERP, updated to include the high PPA rate scenario instead of the base case rate scenario.

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	Comments
A1	No Self-Sufficiency	Market (98%) Biogas (2%)	$83	0.0%	0	7	Low	LT market supply access and price risks
C1	93% Clean with CCGT	Market (44%) CCGT (53%) Biogas (3%)	$95	7.0%	339k	164	Medium	Gas and carbon price risks
A4	93% Clean with SCGT	Market (39%) Wind (57%) Biogas (3%) SCGT (1%)	$99	0.2%	3k	145	High	Minimal gas and carbon price risks
C4	100% Clean BC Resources	Market (35%) Wind (53%) Biomass (12%)	$102	0.0%	0	249	High	Higher cost, lower reliability than with CCGT or SCGT

75.0 Reference: INFORMING DG/SG RELATED FILINGS

2007 BC Energy Plan: A Vision for Clean Energy Leadership (2007 BC Energy Plan), Policy Action # 25; Exhibit B-2, BCUC IR 36.1, 36.3; BC Hydro, SOP Standard Form Electricity - Purchase Agreement, March 2016, Appendix 3

Avoided cost

The 2007 BC Energy Plan includes as Policy Action #25: "Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources."

FBC states in BCUC IR 36.1: "… the primarily residential nature of the premises on which the [small-scale customer-owned generation] facilities are installed are subject to the ability of the original project owner to relocate. Small-scale customer-owned generation of the size typified by net metering installations is highly variable both in terms of generation and the associated load. For these reasons, as well as the timing of the generation, the Company cannot consider it to be long term in nature."

FBC states in BCUC IR 36.3: "If the resource provides little to no winter energy, such as solar PV, then it will have little to no impact on the LTERP required resources in the preferred portfolio A4, meaning that any energy produced at best only displaces BC

Hydro PPA energy costs. A LRMC based on the PPA Tranche 1 energy rate is in the range of $47 - $56 per MWh (per Table 8-4 of the LTERP)."

Appendix 3 of BC Hydro's March 2016 standard form electricity purchase agreement for its SOP program includes a table showing time of delivery factor adjustments (monthly and within day).

75.3.1 Using the monthly delivery factor adjustments included in BC Hydro's SOP program, please provide an estimate of the seasonal adjusted LRMC for energy with a shape similar to that produced by (i) solar PV installation, and (ii) micro-hydro generation.

Response:

FBC does not believe it is correct to apply the BC Hydro SOP adjustments to FBC, as explained in the response to BCUC IR 2.67.4. As shown in Table 1 and Table 2, the portion of the annual energy generated by these resource types in the winter season is comparatively low and therefore their value is quite low as they will not displace required new resources to provide the winter energy needed. However, for purposes of this question, FBC has applied BC Hydro's SOP delivery factor adjustments[1] to FBC's $83 per MWh LRMC of acquiring energy[2]. The annual energy shape of a solar PV installation is estimated as the average of the solar resource options included in the FBC resource portfolio. The annual energy shape of a micro-hydro generator is estimated as the average of the three smallest run-of-river hydro resource options included in the FBC resource portfolio.

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[1] As FBC does not have hourly delivery shapes for the resource options included in the LTERP, FBC weighted the time of delivery factors.

[2] Please refer to the response to BCUC IR 1.34.2.

Table 1: Solar PV seasonal adjusted LRMC for energy using BC Hydro SOP monthly delivery factor adjustments

	Weighted BC Hydro SOP	FBC Adjusted LRMC	Assumed Delivery Profile Solar PV	Monthly LRMC Weight
Jan	117%	$ 98	4%	$ 4
Feb	110%	$ 91	6%	$ 5
Mar	108%	$ 90	9%	$ 8
Apr	92%	$ 76	10%	$ 8
May	78%	$ 65	11%	$ 7
Jun	77%	$ 64	11%	$ 7
Jul	89%	$ 74	12%	$ 9
Aug	96%	$ 80	11%	$ 9
Sep	101%	$ 84	10%	$ 9
Oct	106%	$ 88	8%	$ 7
Nov	108%	$ 90	5%	$ 4
Dec	116%	$ 96	3%	$ 3
			100%	$ 80

Table 2: Micro-Hydro seasonal adjusted LRMC for energy using BC Hydro SOP monthly delivery factor adjustments

	Weighted BC Hydro SOP	FBC Adjusted LRMC	Assumed Delivery Profile Micro Hydro	Monthly LRMC Weight
Jan	117%	$ 98	5%	$ 4
Feb	110%	$ 91	4%	$ 4
Mar	108%	$ 90	5%	$ 5
Apr	92%	$ 76	10%	$ 8
May	78%	$ 65	17%	$ 11
Jun	77%	$ 64	17%	$ 11
Jul	89%	$ 74	13%	$ 9
Aug	96%	$ 80	7%	$ 6
Sep	101%	$ 84	5%	$ 4
Oct	106%	$ 88	6%	$ 5
Nov	108%	$ 90	6%	$ 6
Dec	116%	$ 96	6%	$ 5
			100%	$ 78

76.0 Reference: LONG RUN MARGINAL COST

Exhibit B-1, Volume 2, 2016 Long-term (LT) DSM Plan, p. 3; Exhibit B-2, BCUC IR 35.1

Guidance for future applications

FBC states on page 3 of the 2016 LT DSM Plan Application that its LRMC of firm energy (inclusive of generation capacity) is $100.45/MWh (abbreviated as $100/MWh) and the avoided capacity cost of deferred infrastructure is $79.85/kW-year.

FBC states in BCUC IR 35.1: "The LRMC includes line losses, therefore includes delivery to the customer. If a generation resource were to be located in the FBC system at the distribution level, it can be expected that transmission losses would be reduced by 2 to 3 percent."

76.1.1 Please provide a side by side comparison of the following components FBC's LRMC estimate with that of BC Hydro: generation (energy), generation (capacity), network (capacity), and explain any significant differences.

Response:

	BC Hydro[3] Avoided Costs	FBC Avoided Costs Portfolio B1 (2015$)	FBC Preferred Portfolio Portfolio A4 (2015$)
Energy	$87 per MWh (2016$) – 2022-2033 $102 per MWh (2016$) - 2034 onward	$86 per MWh	$83 per MWh
Capacity	$37 per kW-year (2016$) - 2016-2019 $58 per kW-year (2016$) - 2020-2028 $118 per kW-year (2016$) -2029 onward	$115 per kW-Year	$98 per kW-Year
Network Capacity	Bulk transmission capacity: $0 per kW-year (2011$) Regional transmission and substation capacity: $11 per kW-year (2011$) Distribution capacity $1 per kW-year (2011$)	$80 per kW-Year[4]	$80 per kW-Year

[3] BC Hydro. F2017-F2019 Revenue Requirements Application. Revision 1 – August 17, 2016. Appendix X: Demand-Side Management Assumptions. Table X-1: Portfolio Wide Assumptions.

[4] Represented by FBC's Deferred Capital Expenditure (DCE) value of $79.85 per kW-Year rounded to the nearest dollar

As stated in Appendix K of the LTERP, FBC and BC Hydro have taken different approaches to calculating the LRMC. Despite the different methodologies, overall the FBC energy LRMC numbers are similar to those used by BC Hydro. BC Hydro has identified specific resources to address forecast load requirements, such as Revelstoke Unit 6[5] for capacity, which is exclusively available to BC Hydro.

FBC has developed a portfolio of resources and presented a LRMC that reflects the incremental costs of serving incremental load requirements over the planning horizon. Other factors that result in differences include the size and scale of resource options, the timing of resource requirements and locational attributes. For further discussion regarding FBC's Deferred Capital Expenditure (DCE) value compared to other utilities including BC Hydro, please refer to the response to BCUC IR 1.34.3.

76.2 Please provide a description of the key portfolio components making up FBC's portfolio LRMC estimate (including cost and weighting).

Response:

The key components that make up FBC's LRMC estimate include incremental DSM[6], PPA, new resources, market purchases, and surplus sales[7]. Only incremental costs and incremental energy within the planning horizon is considered within the LRMC calculation (please refer to the response to BCOAPO 2.61.1 for a simplified numerical example). The portfolio composition, and therefore the cost and weighting of each component, change depending on the portfolio characteristics such as the level of DSM activity, the restriction to include only clean resources, the load scenario, the assumed cost of market energy, the assumed cost of PPA, or inclusion of a self-sufficiency target. Correspondingly, the LRMC for each portfolio scenario changes as the weighting and costs of the key components contained in the portfolio change.

This variability between the various portfolios leads to non-intuitive results such as the cost of new resources on a per MWh basis being lower if DSM is not undertaken as compared to where a high level of DSM is achieved. This is due to the economies of scale wherein a much larger generation plant achieves a lower unit cost compared to the relatively small plants required

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[5] BC Hydro. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. July 28th, 2016. Section 3.4.4.3.

[6] 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 portfolios.

[7] Incremental surplus sales by FBC vary from portfolio to portfolio as the portfolio model optimizes the use of resources. Since surplus sales impact the total portfolio cost, they also impact the LRMC.

under the high DSM A4 portfolio. For portfolio B1, the LRMC is $100 per MWh. Table 1 provides a breakdown of the key components of portfolio B1, including the weights and costs

Table 1: Portfolio B1 Components

	Weighting	$ per MWh	Weighted Average Cost ($ per MWh)
DSM	0.00%	$0.00	$0.00
PPA	29.98%	$58.72	$17.60
New Resources	57.51%	$126.17[8]	$72.56
Market	12.63%	$60.13	$7.59
Surplus Sales	0.44%	N/A[9]	$2.69
		LRMC	**$100.45**

For FBC's preferred portfolio A4, the LRMC is $96 per MWh. Table 2 provides a breakdown of the key components of portfolio A4, including the weights and costs.

Table 2: Portfolio A4 Components

	Weighting	$ per MWh	Weighted Average Cost ($ per MWh)
DSM	20.16%[10]	$103.03	$20.77
PPA	38.09%	$61.08	$23.26
New Resources	34.93%	$133.57	$46.65
Market	3.38%	$57.70	$1.95
Surplus Sales	3.40%	N/A	$2.88
		LRMC	**$95.52**

[8] The values for New Resources in both Tables 1 and 2 tend to be higher than would be expected from the Unit Energy Costs (UECs) of the available New Resources. The model is just an approximation of actual operations that does not dispatch a resource in cases where the power is not needed to meet load and this can lead to higher than expected costs on a $ per MWh basis. In addition, if capacity-only resources are included in the total (as in Table 2 for the A4 portfolio), this will also increase the cost on a $ per MWh basis. The appropriate method to evaluate a new resource alternative is to include it in the portfolio model to see if it is selected for dispatch to meet load requirements. UECs are based on total resource costs divided by total available energy and do not account for the timing of energy requirements in the planning horizon or energy requirements less than total available from the resource.

[9] Surplus sales are a combination of energy and capacity sales which makes representation on a $ per MWh basis inappropriate.

[10] Under portfolio A4, low DSM of about 55 percent is assumed to occur and not considered incremental and therefore it is not part of the weighting. In addition, since all cost values are net present value (NPV), load values must also have NPV applied to them to calculate the appropriate weightings. Since the DSM performance is greater in the later part of the planning horizon, the overall weighting on a NPV basis is much lower than on an actual basis. On an actual basis, all DSM is meeting about 77 percent of total load growth throughout the planning horizon as per Section 8.1.1 of the LTERP.

76.2.2 Please show the effect on the LRMC portfolio under the following scenarios: (i) DSM is excluded; (ii) market purchases are excluded; (iii) non-BC clean energy is excluded; (iv) DSM and market purchases are excluded; and (ii) DSM and non-BC clean energy is excluded.

Response:

Table 1 shows the impact on the LRMC of Portfolio B1 and Portfolio A4 with various portfolio components removed from the LRMC calculation. To derive the adjusted LRMC both the incremental costs and incremental energy of the components being removed from the portfolio were excluded from the portfolio LRMC calculation.

Table 1: Effect on the LRMC portfolio with components excluded

	Portfolio B1 (2015$)	Portfolio A4 (2015$)
Portfolio LRMC per LTERP	**$100**	**$96**
(i) DSM is excluded	N/A	$94
(ii.a) Market Purchases are Excluded	$106	$97
(ii.b) Market Purchases and Surplus Sales are excluded	$104	$97
(iv.a) DSM and Market Purchases are Excluded	N/A	$95
(iv.b) DSM, Market Purchases and Surplus Sales are excluded	N/A	$96

Note that for question item (iii) FBC does not have any non-BC clean energy other than potential market sources and therefore the response is the same as for question (ii).

F. VOLUME 2 – LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

77.0 Reference: LT DSM PLAN

Exhibit B-2, BCUC IR 33.1; FBC Long Term DSM Plan (2012), p.11; FBC Application for Acceptance of DSM expenditures for 2017 Reasons for Decision to Order G-9-17 dated January 25, 2017, pp. 4, 10; 2017 RIB Rate Report, p. 27

DSM portfolio options

FBC provides the 2017-2021 DSM budget for the four DSM portfolio options modelled in the FBC LTERP in BCUC IR 33.1:

Table 1: Estimated Annual Cost (DSM Budget) i

Year	Low	Base	High	Max
2017	$7,610	$7,610	$7,610	$7,610
2018	$5,200	$7,900	$7,900	$7,900
2019	$5,200	$7,900	$7,900	$7,900
2020	$5,200	$7,900	$7,900	$7,900
2021	$5,200	$7,900	$9,000	$9,000
Total	**$28,410**	**$39,210**	**$40,310**	**$40,310**

On page 11 of the FBC 2012 long-term DSM Plan, FBC provided an overview of its three DSM options (Low: $5 million/year; Medium: $9 million/year and High: $20 million/year).

The Commission stated in its January 25, 2017 Reasons for Decision to Order G-9-17 on an FBC Application for Acceptance of DSM expenditures for 2017 (pp. 4, 10):

> The Panel accepts FBC's DSM requested expenditure schedule of $7.6 million for 2017, and considers that making the expenditures referred to in the schedule is in the public interest. Despite the acceptance of the proposed expenditure schedule, the Panel is concerned that it falls short of addressing a range of DSM possibilities that could be pursued in the coming year. ...
>
> The Panel is further concerned that the extension of existing programming sits on a foundation of recent activity which in itself can be characterized as having fallen short. In other words, "more of the same" is inherently plagued by underperformance. FBC has provided responses/justifications for many of the challenges laid down by the

interveners in terms of past performance shortfalls, but the Panel finds some of these explanations unpersuasive.

The 2017 RIB Rate Report states on page 27: "For FortisBC, the current environment would support an expansion of DSM funding to accommodate new programs."

77.2 Please provide in table form: the annual DSM funding assumed for the low, base, high and max DSM options for each year from 2018 to 2022 (with a total row); additional rows showing average annual DSM funding (2018-2022); accepted 2017 DSM funding; average annual DSM funding (2018-2022) as a percentage of the accepted 2017 DSM funding.

Response:

Please refer to the table which provides high-level estimates of annual DSM expenditures for the four DSM scenarios presented in the LT DSM Plan filing. 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. The 2016 LT DSM Plan is not an expenditure schedule, so funding levels by sector or by program were not determined. FBC anticipates filing its next DSM expenditure schedule, for 2018 onwards, later this year.

Annual DSM funding, accepted 2017 and LTERP forecast 2018 to 2022

Year	Annual DSM Funding (2016 $000s)			
	Low	Base	High	Max
2018	$5,100	$7,900	$7,900	$7,900
2019	$5,100	$7,900	$7,900	$7,900
2020	$5,100	$7,900	$7,900	$7,900
2021	$5,100	$7,900	$9,000	$9,000
2022	$5,100	$7,900	$10,000	$10,000
Total	$25,500	$39,500	$42,700	$42,700
Average	$5,100	$7,900	$8,540	$8,540
2017 Accepted	$7,610	$7,610	$7,610	$7,610
2018-2022 avg as % of 2017	68%	104%	112%	112%

77.3 Does FBC consider that the size of the DSM funding envelope for 2018-2021 could reasonably be increased by 50% compared to that proposed by FBC, while ensuring that the DSM portfolio (on a total basis) passes the TRC and UCT? If no, please explain why not.

Response:

FBC's preferred DSM scenario (detailed in Table 3.2 of the LT DSM Plan) escalates the DSM funding envelope to $10.9 million in 2025, which is timed to make full use of the BC Hydro PPA Tier 1. FBC does not believe it is reasonable to escalate the DSM funding envelope before maximizing use of cost-effective PPA Tier 1.

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78.0 Reference: LT DSM PLAN

Exhibit B-2, BCUC IR 45.3.1, 48.1; Exhibit B-1, Volume 1, p. 95

Bottom up vs. top down portfolio planning

FBC states in BCUC IR 45.3.1 that it is unable to estimate DSM savings from a DSM portfolio option that is 50% higher than the annual 'High DSM' scenario as the starting point is energy savings targets rather than alternative DSM budgets. FBC states in BCUC IR 48.1: "FBC primarily considered the LRMC, rather than specific rate or bill impacts, to assess the cost effectiveness of the various portfolios."

FBC states on page 95 of the 2016 LTERP Application: "… FBC looks to demand-side resources first to meet any future [load resource balance] gaps."

78.2 Please explain why FBC used LRMC in assessing the cost effectiveness of the various portfolios. Specifically, how did this approach inform FBC as to the appropriate level of DSM incentives to offer, whether funding levels for existing programs should be increased and/or whether new programs should be offered?

Response:

FBC's LRMC of acquiring electricity generated from clean or renewable resources, for purposes of evaluating DSM programs, is represented by Portfolio B1 in Section 9.3.1 of the LTERP: FBC valued the measures' energy savings at the LRMC of $100.45 per MWh.

Section 3.2 of the LT DSM Plan explains how FBC chose its preferred High DSM scenario. The LRMC was used to calculate a TRC benefit cost ratio (2.2) to inform the selection of this scenario. This TRC indicates that the LRMC was not a limiting factor on selecting the preferred scenario.

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In terms of funding levels, the 2016 LT DSM Plan is not an expenditure schedule, so funding levels by sector or by program were not estimated. FBC anticipates filing its next DSM expenditure schedule, for 2018 onwards, later this year.

4.0 Reference: Exhibit B-1, Volume 1, page ES9 and pages 97-100

Preamble: The Application states (page ES9) that the High DSM Scenario "includes the majority of cost effective DSM from an LRMC perspective". The Application also states that the incremental cost of the High Scenario is $104 / MWh (page 100).

4.3 Given that the $104 LRMC for High DSM scenario exceeds the LRMC used to evaluate potential DSM programs ($100 per Exhibit B-1, Volume 2, page 8) why doesn't the High DSM scenario include all cost effective DSM from an LRMC perspective?

Response:

The updated incremental resource cost of the High Scenario is $98 per MWh and does not exceed the LRMC of $100 per MWh used to evaluate cost effective DSM. For this IR, FBC now refers to the Max Scenario which exceeds the LRMC.

FBC uses the LRMC and the DCE to calculate cost effectiveness as provided by the Demand-Side Measures Regulation. DSM programs can have a cost of energy above the LRMC of $100 per MWh and still be considered cost effective on a TRC basis. For example, the Max Scenario can have an incremental cost of $108 per MWh and still not include all of the cost effective DSM measures – because the benefits of the DCE are also included. Note that the $108 per MWh figure also includes program administration costs.

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29.0 Reference: Exhibit B-1, Volume 1, pages 97-100

Exhibit B-1, Volume 2, pages 12-14

29.2 For Resource Cost attributed to each of the scenarios set out in Volume 1, Table 8-2, does the value represent the average (or overall) cost of the DSM Scenario or the cost of the most expensive DSM measure in the portfolio?

Response:

The Resource Cost attributed to each of the scenarios set out in LTERP, Table 8-2, represents the incremental cost of the additional DSM measures included in each scenario: incremental to the next lowest DSM scenario (Low < Base < High < Max).

The following table provides the information requested in BCOAPO IRs 1.29.2.1 to 1.29.2.3 where: the marginal cost is the cost of the highest cost measure included in the scenario; the average cost including program costs is the average resource cost of each scenario; and the incremental cost including program costs represents the incremental cost of the additional DSM measures included in each scenario.

Table 1: DSM Scenario Costs

Category	DSM Scenario			
	Low	Base	High	Max
Resource Cost, 2016 $/MWh				
Marginal cost	$59	$80	$88	$106
Average cost incl. program costs	$42	$52	$58	$64
Incremental cost incl. program costs	$42	$86	$98	$108

38.0 Reference: Exhibit B-1, Volume 1, page 119

38.2 For each of the four Portfolios, please provide a schedule setting out the cost for each incremental resource (including BCH PPA Tranche 2 energy) included.

Response:

The following tables show the schedule of total annual costs for each increment resource. Costs include levelized fixed and variable energy costs.

Portfolio B1 is unchanged as it contains no DSM.

Table 1: Schedule of Costs for Portfolio B1 ('000s 2015$)

B1 Schedule														
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	Biomass1	Biogas1	Wind4	Wind6	RoR2	RoR4	Biomass3	Biogas4	Biogas3	Market
2016	$0	$10,707	$29,167	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,174
2017	$0	$11,274	$31,963	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,952
2018	$0	$12,048	$35,096	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,776
2019	$0	$12,781	$39,767	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$14,000
2020	$0	$13,497	$43,312	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,063
2021	$0	$14,920	$46,247	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,309
2022	$0	$16,205	$51,392	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,318
2023	$0	$16,304	$51,823	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$14,894
2024	$0	$16,591	$52,163	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,624
2025	$0	$16,682	$51,908	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$23,151
2026	$0	$16,272	$48,044	$0	$0	$0	$47,190	$0	$0	$0	$0	$0	$0	$0
2027	$0	$16,696	$50,594	$0	$0	$0	$47,190	$0	$0	$0	$0	$0	$0	$0
2028	$0	$17,498	$50,730	$0	$22,703	$0	$47,015	$0	$0	$0	$0	$0	$0	$0
2029	$0	$17,776	$51,471	$0	$22,637	$1,408	$47,024	$0	$0	$0	$0	$684	$1,436	$0
2030	$0	$17,679	$49,701	$0	$22,499	$1,408	$47,060	$14,043	$0	$0	$0	$684	$1,436	$0
2031	$0	$17,670	$50,799	$0	$22,420	$1,408	$47,100	$13,876	$0	$5,919	$0	$684	$1,436	$0
2032	$0	$18,144	$52,789	$0	$22,571	$1,408	$47,128	$13,977	$0	$5,939	$0	$685	$1,455	$0
2033	$0	$18,513	$54,424	$0	$22,582	$1,408	$47,151	$13,948	$3,602	$5,965	$0	$693	$1,455	$0
2034	$0	$18,754	$56,279	$0	$22,582	$1,408	$47,174	$14,071	$3,609	$6,001	$9,734	$693	$1,455	$0
2035	$0	$19,015	$58,312	$0	$22,667	$1,408	$47,190	$14,136	$3,609	$6,038	$10,323	$693	$1,466	$0

Table 2: Schedule of Costs for Portfolio B2 ('000s 2015$)

B2 Schedule												
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT1	Biogas1	Wind3	RoR2	Biogas2	Biogas4	Biogas3	Market
2016	$10,065	$10,502	$28,379	$0	$0	$0	$0	$0	$0	$0	$0	$5,020
2017	$11,202	$10,834	$30,183	$0	$0	$0	$0	$0	$0	$0	$0	$5,607
2018	$11,629	$11,306	$32,295	$0	$0	$0	$0	$0	$0	$0	$0	$13,136
2019	$11,629	$11,730	$35,548	$0	$0	$0	$0	$0	$0	$0	$0	$13,475
2020	$11,629	$12,130	$37,669	$0	$0	$0	$0	$0	$0	$0	$0	$12,646
2021	$11,629	$13,791	$39,730	$0	$0	$0	$0	$0	$0	$0	$0	$10,593
2022	$11,629	$16,035	$47,090	$0	$0	$0	$0	$0	$0	$0	$0	$3,457
2023	$11,629	$16,391	$48,377	$0	$0	$0	$0	$0	$0	$0	$0	$3,644
2024	$11,629	$16,687	$49,449	$0	$0	$0	$0	$0	$0	$0	$0	$3,971
2025	$11,629	$16,507	$48,702	$0	$0	$0	$0	$0	$0	$0	$0	$6,883
2026	$11,629	$14,616	$38,464	$0	$0	$0	$38,202	$0	$0	$0	$0	$0
2027	$11,629	$14,557	$39,498	$0	$0	$0	$38,215	$0	$0	$0	$0	$0
2028	$11,629	$16,337	$46,944	$0	$0	$0	$37,785	$0	$0	$0	$0	$0
2029	$11,629	$17,327	$47,773	$0	$0	$0	$37,819	$0	$0	$668	$0	$0
2030	$11,629	$17,559	$48,060	$0	$0	$1,408	$37,785	$0	$0	$668	$0	$0
2031	$11,629	$17,701	$48,228	$0	$0	$1,408	$37,792	$0	$728	$668	$1,398	$0
2032	$11,629	$17,510	$48,988	$0	$7,422	$1,408	$37,827	$0	$728	$668	$1,398	$0
2033	$11,629	$17,438	$50,137	$0	$7,433	$1,408	$37,864	$0	$728	$668	$1,398	$0
2034	$11,629	$17,847	$51,281	$0	$7,445	$1,408	$37,900	$0	$728	$668	$1,398	$0
2035	$11,629	$18,182	$51,840	$0	$7,389	$1,408	$37,937	$3,497	$728	$668	$1,398	$0

Table 3: Schedule of Costs for Portfolio A4 ('000s 2015$)

A4 Schedule									
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	Wind3	Biogas1	Biogas3	SCGT1	Market
2016	$10,059	$10,502	$28,379	$0	$0	$0	$0	$0	$5,020
2017	$11,194	$10,834	$30,183	$0	$0	$0	$0	$0	$5,607
2018	$11,622	$11,306	$32,295	$0	$0	$0	$0	$0	$13,136
2019	$11,622	$11,730	$35,548	$0	$0	$0	$0	$0	$13,475
2020	$11,622	$12,130	$37,669	$0	$0	$0	$0	$0	$12,646
2021	$13,324	$13,775	$39,658	$0	$0	$0	$0	$0	$10,565
2022	$15,026	$15,985	$46,831	$0	$0	$0	$0	$0	$3,416
2023	$16,404	$16,283	$47,852	$0	$0	$0	$0	$0	$3,585
2024	$16,404	$16,555	$48,703	$0	$0	$0	$0	$0	$3,718
2025	$16,404	$16,206	$46,900	$0	$0	$0	$0	$0	$7,377
2026	$16,404	$14,401	$37,132	$0	$38,180	$0	$0	$0	$0
2027	$16,404	$14,218	$37,870	$0	$38,192	$0	$0	$0	$0
2028	$16,404	$15,873	$45,190	$0	$37,727	$0	$0	$0	$0
2029	$16,404	$16,877	$45,999	$0	$37,752	$0	$0	$0	$0
2030	$16,404	$17,184	$46,662	$0	$37,770	$0	$0	$0	$0
2031	$16,404	$17,316	$46,172	$0	$37,730	$1,408	$1,398	$0	$0
2032	$16,404	$17,274	$46,662	$0	$37,756	$1,408	$1,398	$7,422	$0
2033	$16,404	$16,879	$47,535	$0	$37,783	$1,408	$1,398	$7,433	$0
2034	$16,404	$17,220	$48,401	$0	$37,809	$1,408	$1,398	$7,445	$0
2035	$16,404	$17,623	$49,554	$0	$37,836	$1,408	$1,398	$7,003	$0

Table 4: Schedule of Costs for Portfolio B4 ('000s 2015$)

Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT2	Biogas1	Wind2	Market
2016	$10,059	$10,502	$28,379	$0	$0	$0	$0	$5,020
2017	$11,194	$10,834	$30,183	$0	$0	$0	$0	$5,607
2018	$11,622	$11,306	$32,295	$0	$0	$0	$0	$13,136
2019	$11,622	$11,730	$35,548	$0	$0	$0	$0	$13,475
2020	$11,622	$12,130	$37,669	$0	$0	$0	$0	$12,646
2021	$13,324	$13,775	$39,658	$0	$0	$0	$0	$10,565
2022	$15,026	$15,985	$46,831	$0	$0	$0	$0	$3,416
2023	$16,759	$16,280	$47,836	$0	$0	$0	$0	$3,581
2024	$18,624	$16,534	$48,586	$0	$0	$0	$0	$3,693
2025	$20,489	$16,443	$47,893	$0	$0	$0	$0	$5,647
2026	$22,354	$14,773	$39,169	$0	$0	$0	$33,221	$0
2027	$23,776	$14,775	$39,564	$0	$0	$0	$33,224	$0
2028	$23,776	$16,253	$46,057	$0	$0	$0	$32,843	$0
2029	$23,776	$17,202	$46,520	$0	$0	$0	$32,856	$0
2030	$23,776	$17,321	$46,187	$0	$0	$1,408	$32,814	$0
2031	$23,776	$17,438	$46,572	$0	$0	$1,408	$32,819	$0
2032	$23,776	$17,410	$46,702	$0	$7,422	$1,408	$32,830	$0
2033	$23,776	$17,188	$47,209	$0	$7,433	$1,408	$32,842	$0
2034	$23,776	$17,445	$47,702	$0	$7,445	$1,408	$32,856	$0
2035	$23,776	$17,749	$48,424	$0	$7,096	$1,408	$32,871	$0

39.0 Reference: Exhibit B-1, Volume 1, page 120

39.2 For each of these three Portfolios, please provide a schedule setting out the cost for each incremental resource (including BCH PPA Tranche 2 energy) included.

Response:

The following tables show the schedule of total annual costs for each increment resource. Costs include levelized fixed and variable energy costs.

Table 1: Schedule of Costs for Portfolio A1 ('000s 2015$)

A1 Schedule								
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT2	Biogas1	Biogas3	Market
2016	$10,059	$10,502	$28,379	$0	$0	$0	$0	$5,020
2017	$11,194	$10,834	$30,183	$0	$0	$0	$0	$5,607
2018	$11,622	$11,306	$32,295	$0	$0	$0	$0	$13,136
2019	$11,622	$11,730	$35,548	$0	$0	$0	$0	$13,475
2020	$11,622	$12,130	$37,669	$0	$0	$0	$0	$12,646
2021	$13,324	$13,775	$39,658	$0	$0	$0	$0	$10,565
2022	$15,026	$15,985	$46,831	$0	$0	$0	$0	$3,416
2023	$16,404	$16,283	$47,852	$0	$0	$0	$0	$3,585
2024	$16,404	$16,555	$48,703	$0	$0	$0	$0	$3,718
2025	$16,404	$16,464	$48,034	$0	$0	$0	$0	$5,928
2026	$16,404	$14,916	$47,920	$0	$0	$0	$0	$7,494
2027	$16,404	$14,311	$47,595	$0	$0	$0	$0	$9,154
2028	$16,404	$16,506	$52,320	$0	$0	$0	$0	$9,773
2029	$16,404	$17,392	$54,247	$0	$0	$0	$0	$8,738
2030	$16,404	$17,541	$54,600	$0	$0	$0	$0	$9,593
2031	$16,404	$16,715	$54,808	$0	$6,822	$0	$0	$10,858
2032	$16,404	$17,874	$57,706	$0	$6,822	$0	$0	$8,594
2033	$16,404	$17,510	$55,091	$0	$6,822	$1,408	$0	$12,627
2034	$16,404	$18,090	$57,197	$0	$6,822	$1,408	$0	$12,144
2035	$16,404	$18,780	$59,636	$0	$6,822	$1,408	$1,474	$9,575

Table 2: Schedule of Costs for Portfolio A2 ('000s 2015$)

A2 Schedule										
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT2	Biogas1	Biogas2	Biogas4	Biogas3	Market
2016	$10,059	$10,620	$30,246	$0	$0	$0	$0	$0	$0	$3,396
2017	$11,194	$11,113	$32,348	$0	$0	$0	$0	$0	$0	$3,525
2018	$11,622	$12,647	$40,295	$0	$0	$0	$0	$0	$0	$5,055
2019	$11,622	$14,124	$43,727	$0	$0	$0	$0	$0	$0	$4,493
2020	$11,622	$15,478	$46,247	$0	$0	$0	$0	$0	$0	$2,038
2021	$13,324	$16,160	$47,781	$0	$0	$0	$0	$0	$0	$1,038
2022	$15,026	$16,482	$48,755	$0	$0	$0	$0	$0	$0	$1,294
2023	$16,404	$16,791	$49,812	$0	$0	$0	$0	$0	$0	$1,520
2024	$16,404	$17,056	$50,681	$0	$0	$0	$0	$0	$0	$1,707
2025	$16,404	$17,329	$51,578	$0	$0	$0	$0	$0	$0	$1,975
2026	$16,404	$17,027	$52,459	$0	$0	$0	$0	$0	$0	$2,355
2027	$16,404	$17,154	$52,931	$0	$0	$0	$0	$0	$0	$3,297
2028	$16,404	$17,484	$53,976	$0	$0	$1,408	$0	$0	$0	$9,297
2029	$16,404	$17,516	$54,587	$0	$0	$1,408	$0	$0	$0	$10,453
2030	$16,404	$17,759	$54,823	$0	$0	$1,408	$0	$0	$1,460	$10,472
2031	$16,404	$17,906	$55,374	$0	$0	$1,408	$0	$0	$1,466	$11,669
2032	$16,404	$17,358	$56,007	$0	$6,822	$1,408	$0	$0	$1,474	$13,097
2033	$16,404	$17,527	$56,658	$0	$6,822	$1,408	$0	$701	$1,474	$13,760
2034	$16,404	$17,827	$57,343	$0	$6,822	$1,408	$728	$700	$1,474	$14,251
2035	$16,404	$18,381	$58,505	$0	$6,822	$1,408	$728	$701	$1,474	$14,384

Table 3: Schedule of Costs for Portfolio A3 ('000s 2015$)

A3 Schedule

Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	CCGT1	Biogas1	Market
2016	$10,059	$10,502	$28,379	$0	$0	$0	$5,020
2017	$11,194	$10,834	$30,183	$0	$0	$0	$5,607
2018	$11,622	$11,306	$32,295	$0	$0	$0	$13,136
2019	$11,622	$11,730	$35,548	$0	$0	$0	$13,475
2020	$11,622	$11,956	$37,450	$0	$0	$0	$13,165
2021	$13,324	$11,817	$39,000	$0	$30,194	$0	$0
2022	$15,026	$13,086	$44,212	$0	$25,639	$0	$0
2023	$16,404	$13,449	$45,409	$0	$25,632	$0	$0
2024	$16,404	$13,772	$46,400	$0	$25,615	$0	$0
2025	$16,404	$14,072	$47,418	$0	$25,662	$0	$0
2026	$16,404	$14,230	$48,467	$0	$25,697	$0	$0
2027	$16,404	$14,620	$49,771	$0	$25,287	$0	$0
2028	$16,404	$15,584	$53,063	$0	$27,698	$0	$0
2029	$16,404	$16,758	$54,588	$0	$27,158	$0	$0
2030	$16,404	$16,974	$55,074	$0	$27,768	$0	$0
2031	$16,404	$17,124	$55,389	$0	$28,800	$0	$0
2032	$16,404	$17,248	$55,614	$0	$30,133	$0	$0
2033	$16,404	$17,454	$56,165	$0	$31,118	$0	$0
2034	$16,404	$17,802	$57,283	$0	$31,314	$0	$0
2035	$16,404	$18,491	$59,277	$0	$28,915	$1,408	$0

39.4.1 How would the response to parts 1-3 of this question change if the cost of PPA Tranche 2 energy was $100 / MWh (real 2015 $)?

<u>Response:</u>

FBC re-ran portfolios A1, A2, and A3 using a Tranche 2 PPA Energy price of $100 per MWh. There was no resulting change in the optimal selected resources or LRMC for portfolio A1 and A3.

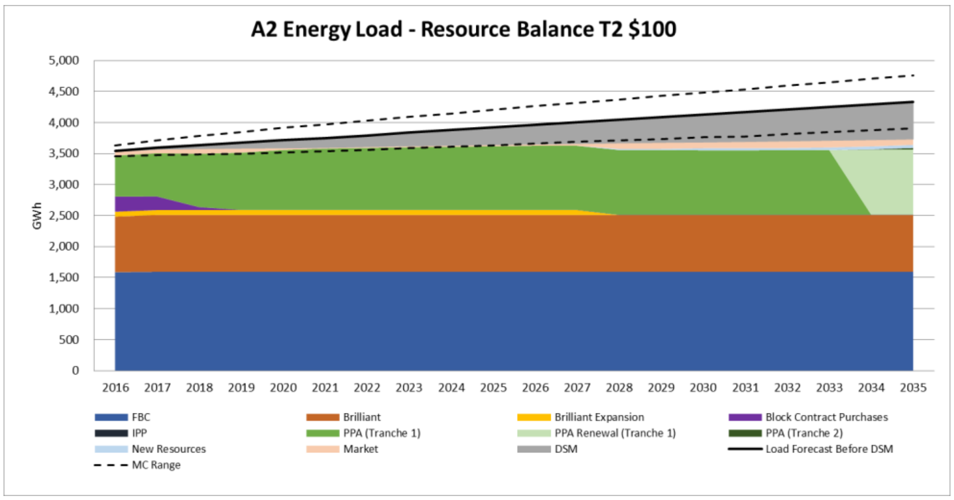
In regards to portfolio A2, PPA Tranche 2 energy at $100 per MWh is used minimally in the last two years of the planning horizon. The LRMC of portfolio A2 decreased by $0.03 per MWh

Table 1: Schedule of Costs for Portfolio A2 ('000s 2015$) with PPA Tranche 2 Energy at $100 per MWh

A2 Schedule T2 $100

Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT2	Biogas1	Biogas2	Biogas4	Biogas3	Market
2016	$10,059	$10,620	$30,246	$0	$0	$0	$0	$0	$0	$3,396
2017	$11,194	$11,113	$32,348	$0	$0	$0	$0	$0	$0	$3,525
2018	$11,622	$12,647	$40,295	$0	$0	$0	$0	$0	$0	$5,055
2019	$11,622	$14,124	$43,727	$0	$0	$0	$0	$0	$0	$4,493
2020	$11,622	$15,478	$46,247	$0	$0	$0	$0	$0	$0	$2,038
2021	$13,324	$16,160	$47,781	$0	$0	$0	$0	$0	$0	$1,038
2022	$15,026	$16,482	$48,755	$0	$0	$0	$0	$0	$0	$1,294
2023	$16,404	$16,791	$49,812	$0	$0	$0	$0	$0	$0	$1,520
2024	$16,404	$17,056	$50,681	$0	$0	$0	$0	$0	$0	$1,707
2025	$16,404	$17,329	$51,578	$0	$0	$0	$0	$0	$0	$1,975
2026	$16,404	$17,027	$52,459	$0	$0	$0	$0	$0	$0	$2,355
2027	$16,404	$17,154	$52,931	$0	$0	$0	$0	$0	$0	$3,297
2028	$16,404	$17,484	$53,976	$0	$0	$1,408	$0	$0	$0	$9,297
2029	$16,404	$17,516	$54,587	$0	$0	$1,408	$0	$0	$0	$10,453
2030	$16,404	$17,759	$54,823	$0	$0	$1,408	$0	$0	$1,460	$10,472
2031	$16,404	$17,906	$55,374	$0	$0	$1,408	$0	$0	$1,466	$11,669
2032	$16,404	$17,358	$56,007	$0	$6,822	$1,408	$0	$0	$1,474	$13,097
2033	$16,404	$17,527	$56,658	$0	$6,822	$1,408	$0	$701	$1,474	$13,760
2034	$16,404	$17,881	$57,575	$384	$6,822	$1,408	$728	$700	$1,474	$13,332
2035	$16,404	$18,557	$58,269	$2,511	$6,822	$1,408	$728	$701	$1,474	$12,097

Figure 1: Energy Load-Resource Balance (LRB) for Portfolio A2 with PPA Tranche 2 Energy at $100 per MWh



39.4.2 How would the LRMC for each Portfolio change if the cost of PPA Tranche 2 energy was $85 / MWh (real 2015 $)?

<u>Response:</u>

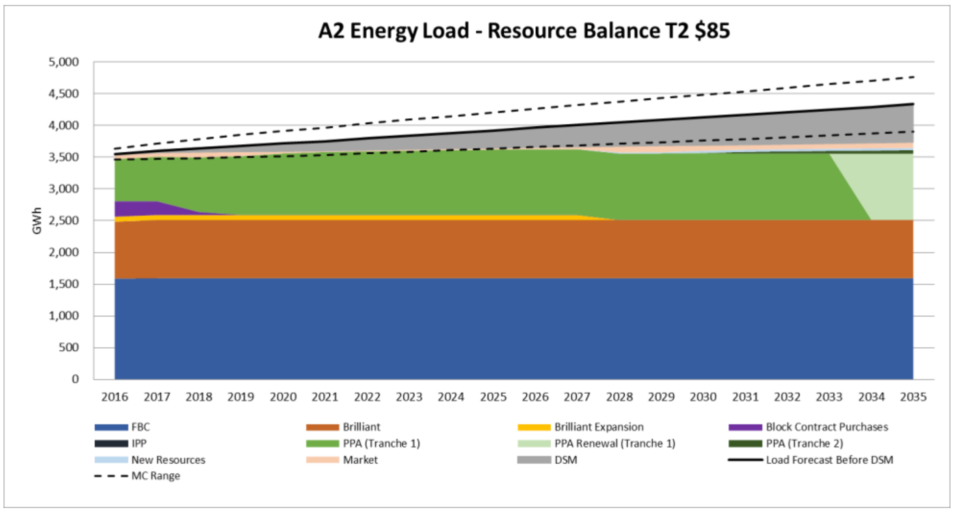
FBC re-ran portfolios A1, A2, and A3 using a Tranche 2 PPA Energy price of $85 per MWh. There was no resulting change in the optimal selected resources or LRMC for portfolio A1 and A3.

In regards to portfolio A2, PPA Tranche 2 energy at $85 per MWh is used starting in the year 2031 of the planning horizon. Portfolio A2 does not include a self-sufficiency target and investigates the impact of high commodity prices, including market prices. As shown in the tables in Appendix D of the LTERP, the Market prices associated with the high price scenario are greater than $85 per MWh in later years of the planning horizon. Correspondingly, the portfolio uses additional PPA energy, including PPA Tranche 2 energy, rather than the comparatively more expensive Market energy. The LRMC of portfolio A2 decreased by $0.57 per MWh.

Table 1: Schedule of Costs for Portfolio A2 ('000s 2015$) with PPA Tranche 2 Energy at $85 per MWh

A2 Schedule T2 $85										
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT2	Biogas1	Biogas2	Biogas4	Biogas3	Market
2016	$10,059	$10,620	$30,246	$0	$0	$0	$0	$0	$0	$3,396
2017	$11,194	$11,113	$32,348	$0	$0	$0	$0	$0	$0	$3,525
2018	$11,622	$12,647	$40,295	$0	$0	$0	$0	$0	$0	$5,055
2019	$11,622	$14,124	$43,727	$0	$0	$0	$0	$0	$0	$4,493
2020	$11,622	$15,478	$46,247	$0	$0	$0	$0	$0	$0	$2,038
2021	$13,324	$16,160	$47,781	$0	$0	$0	$0	$0	$0	$1,038
2022	$15,026	$16,482	$48,755	$0	$0	$0	$0	$0	$0	$1,294
2023	$16,404	$16,791	$49,812	$0	$0	$0	$0	$0	$0	$1,520
2024	$16,404	$17,056	$50,681	$0	$0	$0	$0	$0	$0	$1,707
2025	$16,404	$17,329	$51,578	$0	$0	$0	$0	$0	$0	$1,975
2026	$16,404	$17,027	$52,459	$0	$0	$0	$0	$0	$0	$2,355
2027	$16,404	$17,154	$52,931	$0	$0	$0	$0	$0	$0	$3,297
2028	$16,404	$17,484	$53,976	$0	$0	$1,408	$0	$0	$0	$9,297
2029	$16,404	$17,516	$54,587	$0	$0	$1,408	$0	$0	$0	$10,453
2030	$16,404	$17,930	$55,557	$0	$0	$1,408	$0	$0	$1,460	$8,983
2031	$16,404	$18,617	$55,554	$2,317	$0	$1,408	$0	$0	$1,466	$8,262
2032	$16,404	$18,372	$56,135	$2,904	$6,822	$1,408	$0	$0	$1,474	$8,836
2033	$16,404	$18,658	$56,599	$3,691	$6,822	$1,408	$0	$0	$1,474	$9,485
2034	$16,404	$18,851	$57,140	$4,159	$6,822	$1,408	$0	$0	$1,474	$10,441
2035	$16,404	$19,046	$57,702	$4,633	$6,822	$1,408	$0	$0	$1,474	$11,450

Figure 1: Energy Load-Resource Balance (LRB) for Portfolio A2 with PPA Tranche 2 Energy at $85 per MWh



40.0 Reference: Exhibit B-1, Volume 1, page 121

40.2 For each of these three Portfolios, please provide a schedule setting out the cost for each incremental resource (including BCH PPA Tranche 2 energy) included.

Response:

The following tables show the schedule of total annual costs for each incremental resource. Costs include levelized fixed and variable energy costs.

Table 1: Schedule of Costs for Portfolio C1 ('000s 2015$)

C1 Schedule							
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	CCGT1	Biogas1	Market
2016	$10,059	$10,502	$28,379	$0	$0	$0	$5,020
2017	$11,194	$10,834	$30,183	$0	$0	$0	$5,607
2018	$11,622	$11,306	$32,295	$0	$0	$0	$13,136
2019	$11,622	$11,730	$35,548	$0	$0	$0	$13,475
2020	$11,622	$12,130	$37,669	$0	$0	$0	$12,646
2021	$13,324	$13,775	$39,658	$0	$0	$0	$10,565
2022	$15,026	$15,985	$46,831	$0	$0	$0	$3,416
2023	$16,404	$16,283	$47,852	$0	$0	$0	$3,585
2024	$16,404	$16,555	$48,703	$0	$0	$0	$3,718
2025	$16,404	$16,391	$47,712	$0	$0	$0	$6,344
2026	$16,404	$14,305	$47,664	$0	$26,753	$0	$0
2027	$16,404	$14,620	$49,771	$0	$25,287	$0	$0
2028	$16,404	$15,584	$53,063	$0	$27,698	$0	$0
2029	$16,404	$16,758	$54,588	$0	$27,158	$0	$0
2030	$16,404	$16,974	$55,074	$0	$27,768	$0	$0
2031	$16,404	$17,124	$55,389	$0	$28,800	$0	$0
2032	$16,404	$17,248	$55,614	$0	$30,133	$0	$0
2033	$16,404	$17,454	$56,165	$0	$31,118	$0	$0
2034	$16,404	$17,802	$57,283	$0	$31,314	$0	$0
2035	$16,404	$18,491	$59,277	$0	$28,915	$1,408	$0

1 **Table 2: Schedule of Costs for Portfolio C3 ('000s 2015$)**

2

C3 Schedule							
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT2	Wind3	Market
2016	$10,059	$10,620	$30,246	$0	$0	$0	$3,396
2017	$11,194	$11,113	$32,348	$0	$0	$0	$3,525
2018	$11,622	$12,647	$40,295	$0	$0	$0	$5,055
2019	$11,622	$14,124	$43,727	$0	$0	$0	$4,493
2020	$11,622	$15,478	$46,247	$0	$0	$0	$2,038
2021	$13,324	$16,160	$47,781	$0	$0	$0	$1,038
2022	$15,026	$16,482	$48,755	$0	$0	$0	$1,294
2023	$16,404	$16,791	$49,812	$0	$0	$0	$1,520
2024	$16,404	$17,047	$50,639	$0	$0	$0	$1,778
2025	$16,404	$17,278	$51,449	$0	$0	$0	$2,198
2026	$16,404	$15,703	$37,132	$0	$0	$38,180	$0
2027	$16,404	$14,218	$37,870	$0	$0	$38,192	$0
2028	$16,404	$15,873	$45,190	$0	$0	$37,727	$0
2029	$16,404	$16,877	$45,999	$0	$0	$37,752	$0
2030	$16,404	$17,184	$46,662	$0	$0	$37,770	$0
2031	$16,404	$17,490	$47,413	$0	$0	$37,792	$0
2032	$16,404	$17,460	$48,245	$0	$6,861	$37,817	$0
2033	$16,404	$17,766	$49,051	$0	$7,113	$37,844	$0
2034	$16,404	$17,981	$49,849	$0	$7,374	$37,870	$0
2035	$16,404	$18,200	$50,679	$0	$7,661	$37,897	$0

Table 3: Schedule of Costs for Portfolio C4 ('000s 2015$)

C4 Schedule

Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	Solar1	Solar2	Solar3	Biogas1	Biogas2	Biogas3	Biogas4	Wind3	Biomass3	Market
2016	$10,059	$10,502	$28,379	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,020
2017	$11,194	$10,834	$30,183	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,607
2018	$11,622	$11,306	$32,295	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,136
2019	$11,622	$11,730	$35,548	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,475
2020	$11,622	$12,130	$37,669	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,646
2021	$13,324	$13,775	$39,658	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,565
2022	$15,026	$15,985	$46,831	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,416
2023	$16,404	$16,283	$47,852	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,585
2024	$16,404	$16,555	$48,703	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,718
2025	$16,404	$16,206	$46,900	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,377
2026	$16,404	$14,401	$37,132	$0	$0	$0	$0	$0	$0	$0	$0	$38,180	$0	$0
2027	$16,404	$14,218	$37,870	$0	$0	$0	$0	$0	$0	$0	$0	$38,192	$0	$0
2028	$16,404	$15,873	$45,190	$0	$0	$0	$0	$0	$0	$0	$0	$37,727	$0	$0
2029	$16,404	$16,877	$45,999	$0	$0	$0	$0	$0	$0	$0	$0	$37,752	$0	$0
2030	$16,404	$17,184	$46,662	$0	$0	$0	$0	$0	$0	$0	$0	$37,770	$0	$0
2031	$16,404	$17,316	$46,172	$0	$0	$0	$0	$1,408	$0	$1,398	$0	$37,730	$0	$0
2032	$16,404	$17,429	$46,811	$0	$0	$0	$0	$1,408	$0	$1,398	$0	$37,756	$9,276	$0
2033	$16,404	$17,346	$47,750	$0	$0	$0	$0	$1,408	$0	$1,398	$0	$37,783	$9,163	$0
2034	$16,404	$17,775	$48,684	$0	$0	$0	$0	$1,408	$0	$1,398	$0	$37,809	$9,046	$0
2035	$16,404	$18,032	$48,457	$0	$1,277	$1,265	$1,259	$1,408	$728	$1,398	$668	$37,719	$8,926	$0

41.0 Reference: Exhibit B-1, Volume 1, page 122

41.2 For each of these two Portfolios, please provide a schedule setting out the cost for each incremental resources (including BCH PPA Tranche 2 energy) included.

<u>Response:</u>

The following tables show the schedule of total annual costs for each incremental resource. Costs include levelized fixed and variable energy costs.

Table 1: Schedule of Costs for Portfolio D2 ('000s 2015$)

D2 Schedule													
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT1	CCGT2	Biomass1	Biogas1	Biogas2	Biogas3	Biogas4	RoR10	Market
2016	$10,059	$10,589	$28,629	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,035
2017	$11,194	$11,006	$30,720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,624
2018	$11,622	$11,642	$33,289	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,155
2019	$11,622	$12,318	$37,371	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,355
2020	$11,622	$13,114	$40,831	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,366
2021	$13,324	$14,766	$43,937	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,859
2022	$15,026	$16,545	$50,930	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,831
2023	$16,759	$16,566	$51,520	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,074
2024	$18,624	$16,722	$52,029	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,850
2025	$20,489	$17,129	$46,484	$0	$0	$0	$0	$1,408	$0	$0	$0	$0	$34,143
2026	$22,354	$15,604	$54,649	$0	$0	$46,297	$0	$1,408	$0	$0	$0	$0	$0
2027	$23,776	$14,022	$57,607	$0	$0	$47,183	$0	$1,408	$0	$0	$0	$0	$0
2028	$23,776	$14,863	$52,368	$0	$0	$45,585	$0	$1,408	$0	$0	$0	$24,222	$0
2029	$23,776	$15,288	$53,439	$0	$0	$48,789	$0	$1,408	$0	$0	$0	$24,330	$0
2030	$23,776	$15,969	$56,543	$0	$0	$49,766	$0	$1,408	$0	$1,455	$0	$24,417	$0
2031	$23,776	$17,081	$58,702	$0	$0	$50,482	$0	$1,408	$728	$1,474	$698	$24,434	$0
2032	$23,776	$17,110	$53,479	$0	$0	$49,355	$23,945	$1,408	$728	$1,474	$701	$24,434	$0
2033	$23,776	$16,854	$56,092	$0	$7,433	$49,548	$24,261	$1,408	$728	$1,474	$701	$24,434	$0
2034	$23,776	$16,156	$56,564	$0	$7,459	$53,074	$24,493	$1,408	$728	$1,474	$701	$24,434	$0
2035	$23,776	$17,481	$61,252	$0	$6,822	$50,524	$24,663	$1,408	$728	$1,474	$701	$24,434	$0

Table 2: Schedule of Costs for Portfolio D4 ('000s 2015$)

D4 Schedule																	
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	Biomass1	Biomass2	Biogas1	Biogas2	Biogas3	Biogas4	Wind1	Wind3	Wind4	RoR7	Biomass3	Biomass4	Market
2016	$10,059	$10,589	$28,629	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,035
2017	$11,194	$11,006	$30,720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,624
2018	$11,622	$11,642	$33,289	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,155
2019	$11,622	$12,318	$37,371	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,355
2020	$11,622	$13,114	$40,831	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,366
2021	$13,324	$14,766	$43,937	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,859
2022	$15,026	$16,545	$50,930	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,831
2023	$16,759	$16,566	$51,520	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,074
2024	$18,624	$16,722	$52,029	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,850
2025	$20,489	$17,106	$51,939	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,147	$0	$0	$14,478
2026	$22,354	$16,136	$45,602	$0	$0	$0	$0	$0	$0	$0	$0	$0	$47,190	$12,457	$0	$0	$0
2027	$23,776	$16,669	$48,202	$0	$0	$0	$0	$0	$0	$0	$0	$0	$47,190	$12,621	$0	$0	$0
2028	$23,776	$17,401	$48,105	$0	$22,138	$0	$1,408	$728	$1,455	$693	$0	$0	$47,117	$12,185	$0	$0	$0
2029	$23,776	$17,615	$50,124	$0	$22,363	$0	$1,408	$728	$1,455	$693	$0	$0	$47,157	$12,359	$0	$15,564	$0
2030	$23,776	$16,728	$43,168	$0	$21,043	$0	$1,408	$728	$1,398	$668	$0	$38,161	$46,847	$12,071	$0	$14,950	$0
2031	$23,776	$17,015	$45,147	$0	$21,358	$0	$1,408	$728	$1,414	$668	$0	$38,219	$46,917	$12,071	$0	$14,950	$0
2032	$23,776	$17,678	$47,149	$0	$21,675	$0	$1,408	$728	$1,417	$676	$0	$38,050	$47,190	$12,113	$8,926	$14,950	$0
2033	$23,776	$17,903	$45,735	$0	$21,279	$0	$1,408	$728	$1,417	$676	$15,720	$38,163	$47,092	$12,075	$8,926	$14,950	$0
2034	$23,776	$17,693	$46,920	$0	$21,552	$16,667	$1,408	$728	$1,417	$676	$15,666	$38,208	$47,190	$12,122	$8,926	$14,950	$0
2035	$23,776	$17,540	$47,590	$0	$21,784	$17,565	$1,408	$728	$1,417	$676	$15,776	$38,216	$47,147	$12,164	$8,926	$14,950	$0

41.4.1 How would the response to parts 1-3 of this question change if the cost of PPA Tranche 2 energy was $100 / MWh (real 2015 $)?

Response:

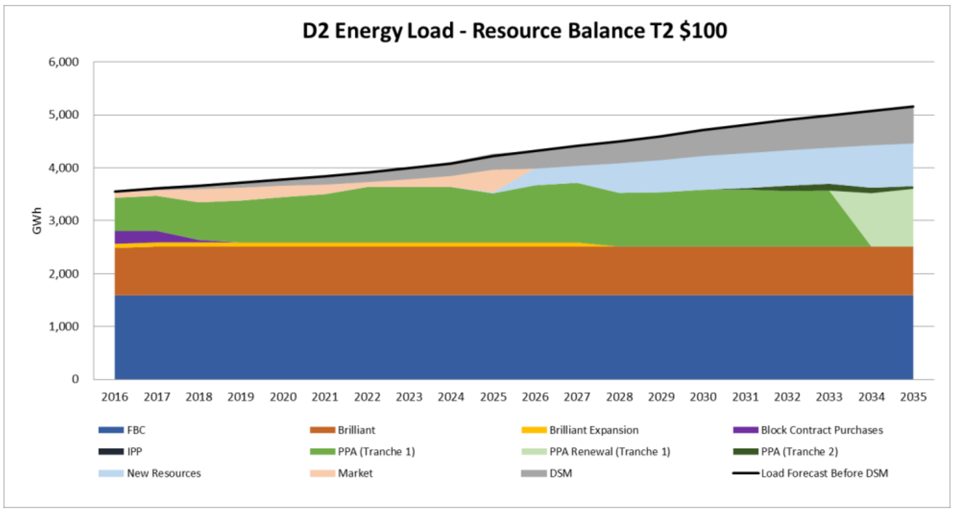
FBC re-ran portfolios D2 and D4 using a Tranche 2 PPA Energy price of $100 per MWh. There was no resulting change in the optimal selected resources or LRMC for portfolio D4.

In regards to portfolio D2, PPA Tranche 2 energy at $100 per MWh is used in the later years of the planning horizon. The LRMC of portfolio D2 decreased by $0.08 per MWh.

Table 1: Schedule of Costs for Portfolio D2 ('000s 2015$) with PPA Tranche 2 Energy at $100 per MWh

D2 Schedule T2 $100														
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT2	CCGT2	Solar1	Biogas1	Wind1	Biogas2	RoR10	Biogas4	Biogas3	Market
2016	$10,059	$10,589	$28,629	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,035
2017	$11,194	$11,006	$30,720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,624
2018	$11,622	$11,642	$33,289	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,155
2019	$11,622	$12,318	$37,371	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,355
2020	$11,622	$13,114	$40,831	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,366
2021	$13,324	$14,766	$43,937	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,859
2022	$15,026	$16,545	$50,930	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,831
2023	$16,759	$16,566	$51,520	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,074
2024	$18,624	$16,722	$52,029	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,850
2025	$20,489	$17,129	$46,484	$0	$0	$0	$0	$1,408	$0	$0	$0	$0	$0	$34,143
2026	$22,354	$15,604	$54,649	$0	$0	$46,297	$0	$1,408	$0	$0	$0	$0	$0	$0
2027	$23,776	$14,022	$57,607	$0	$0	$47,183	$0	$1,408	$0	$0	$0	$0	$0	$0
2028	$23,776	$14,857	$52,342	$0	$0	$45,618	$0	$1,408	$0	$0	$24,222	$0	$0	$0
2029	$23,776	$15,304	$53,439	$0	$0	$48,788	$0	$1,408	$0	$0	$24,330	$0	$0	$0
2030	$23,776	$15,969	$56,543	$0	$0	$49,767	$0	$1,408	$0	$0	$24,417	$0	$1,455	$0
2031	$23,776	$16,720	$57,206	$2,798	$0	$50,667	$0	$1,408	$0	$728	$24,434	$698	$1,474	$0
2032	$23,776	$17,630	$56,358	$10,005	$7,422	$51,165	$0	$1,408	$0	$728	$24,434	$701	$1,474	$0
2033	$23,776	$17,733	$57,340	$12,813	$7,451	$52,079	$1,277	$1,408	$0	$728	$24,434	$701	$1,474	$0
2034	$23,776	$17,705	$55,206	$10,321	$7,445	$53,037	$1,277	$1,408	$15,880	$728	$24,434	$701	$1,474	$0
2035	$23,776	$17,925	$60,316	$5,082	$6,985	$54,059	$1,277	$1,408	$15,880	$728	$24,434	$701	$1,474	$0

Figure 1: Energy Load-Resource Balance (LRB) for Portfolio D2 with PPA Tranche 2 Energy at $100 per MWh



41.4.2 How would the LRMC for each Portfolio change if the cost of PPA Tranche 2 energy was $85 / MWh (real 2015 $)?

Response:

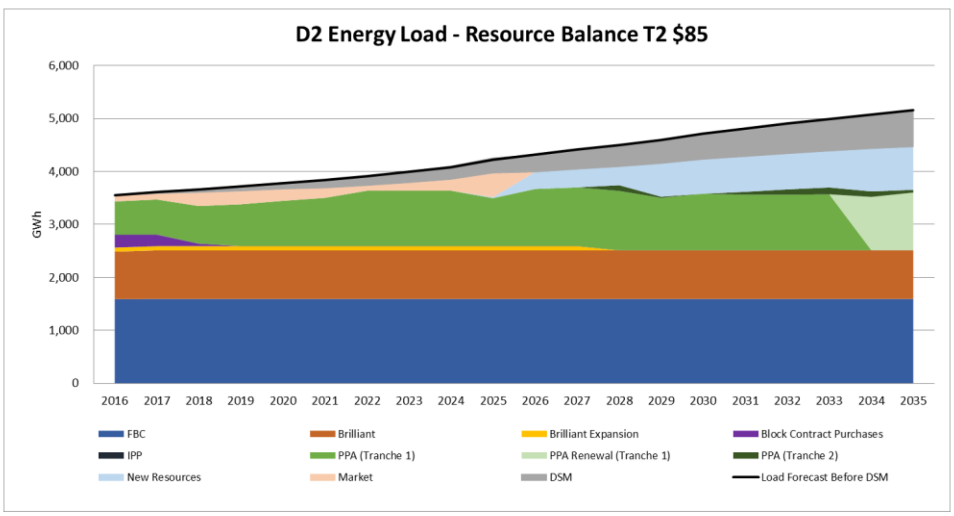
FBC re-ran portfolios D2 and D4 using a Tranche 2 PPA Energy price of $85 per MWh. There was no resulting change in the optimal selected resources or LRMC for portfolio D4.

In regards to portfolio D2, PPA Tranche 2 energy at $85 per MWh is used in the portfolio. Portfolio D2 investigates the High Load scenario. The LRMC of portfolio D2 decrease by $0.44 per MWh.

Table 1: Schedule of Costs for Portfolio D2 ('000s 2015$)
with PPA Tranche 2 Energy at $85 per MWh

D2 Schedule T2 $85														
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT1	CCGT2	Solar1	Biogas1	Wind1	Biogas2	RoR10	Biogas4	Biogas3	Market
2016	$10,059	$10,589	$28,629	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,035
2017	$11,194	$11,006	$30,720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,624
2018	$11,622	$11,642	$33,289	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,155
2019	$11,622	$12,318	$37,371	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,355
2020	$11,622	$13,114	$40,831	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,366
2021	$13,324	$14,766	$43,937	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,859
2022	$15,026	$16,545	$50,930	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,831
2023	$16,759	$16,566	$51,520	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,074
2024	$18,624	$16,722	$52,029	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,850
2025	$20,489	$17,129	$45,379	$0	$0	$0	$0	$1,408	$0	$0	$0	$0	$0	$35,565
2026	$22,354	$15,858	$54,638	$0	$0	$46,298	$0	$1,408	$0	$0	$0	$0	$0	$0
2027	$23,776	$13,917	$56,734	$0	$0	$47,139	$0	$1,408	$0	$0	$0	$0	$1,474	$0
2028	$23,776	$16,165	$57,949	$9,120	$0	$47,950	$0	$1,408	$0	$0	$0	$0	$1,474	$0
2029	$23,776	$15,891	$51,577	$1,872	$0	$48,795	$0	$1,408	$0	$0	$24,330	$0	$1,436	$0
2030	$23,776	$15,869	$56,220	$0	$0	$49,720	$0	$1,408	$0	$0	$24,417	$693	$1,455	$0
2031	$23,776	$16,688	$55,790	$4,629	$0	$50,667	$0	$1,408	$0	$728	$24,434	$698	$1,474	$0
2032	$23,776	$17,630	$56,334	$8,542	$7,422	$51,165	$0	$1,408	$0	$728	$24,434	$701	$1,474	$0
2033	$23,776	$17,733	$57,340	$10,891	$7,451	$52,079	$1,277	$1,408	$0	$728	$24,434	$701	$1,474	$0
2034	$23,776	$17,705	$55,206	$8,772	$7,445	$53,037	$1,277	$1,408	$15,880	$728	$24,434	$701	$1,474	$0
2035	$23,776	$17,925	$60,316	$4,320	$6,985	$54,059	$1,277	$1,408	$15,880	$728	$24,434	$701	$1,474	$0

Figure 1: Energy Load-Resource Balance (LRB) for Portfolio A2
with PPA Tranche 2 Energy at $85 per MWh



47.0 Reference: Exhibit B-1, Volume 2, pages 11-15

47.1 What would be the effect (per Figure 3-1 and Table 3-1) of a DSM scenario that only included DSM measures with an LRMC of $100/MWh or less? As with the High and Max scenarios please assume any required ramp up starts in 2021.

Response:

Please refer to the response to BCOAPO IR 1.4.3.

If applied to the marginal measure cost (please refer to the response to BCOAPO IR 1.29.2 for definitions), the requested $100 per MWh scenario would land between the High and Max case, achieving 99 percent of the savings potential of the Max scenario.

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FBC prepared the DSM scenarios based on load growth offset targets, not on an LRMC basis. This additional scenario would thus be inconsistent with the methodology used in the LTERP and is not recommended. The results are close enough to use the Max scenario as a proxy for the requested $100 per MWh scenario.

47.5 Does the High Scenario include all DSM measures identified by the CPR with a cost of $100/MWh or less? If not, which ones are excluded and why?

Response:

No, the High scenario included only measures with a marginal cost of up to $88 per MWh. The $98 per MWh incremental cost shown for the High DSM scenario in Figure 3-2 and Table 3-1 at pages 13-14 of the LT DSM Plan includes an adder for program administration costs.

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The 2016 LT DSM Plan is not an expenditure schedule, so funding levels by sector or by program were not estimated. Similarly, FBC did not include an analysis of the individual measures included within each scenario.

53.0 Reference: Exhibit B-2, BCUC 2.2

53.1 Were the same metrics that were used to measure how portfolios perform against one another also used to establish the preferred DSM Scenario?

Response:

No, the same metrics that were used to measure how portfolios perform against one another were not used to establish the preferred DSM Scenario, although cost and risk/flexibility was used for both.

The DSM Scenarios were based on load growth offset, consistent with provincial policy and the CEA objectives, and the preferred DSM Scenario was then selected based on two key metrics: resource cost and risk/flexibility. The other metrics used to evaluate the portfolios are not as appropriate for evaluating DSM options. As discussed in Section 9.3.6 of the LTERP, the portfolios, including supply-side resources and DSM, were evaluated using the metrics relating to cost, percentage of clean and renewable resources, GHG emissions, FTEs per year and geographic resource diversity, consistent with the LTERP objectives. FBC also discussed risk and flexibility for the preferred portfolio in terms of contingency plans (discussed in Section 9.3.6.2 of the LTERP).

In terms of cost, the preferred DSM level was determined through an assessment of cost effectiveness based on the Total Resource Cost rather than Utility Cost test, so that the cost impacts to both the utility and customer are taken into account (per the DSM Regulation). The incremental cost of ramping up to the High scenario is $98 per MWh, which is similar to FBC's LRMC of $100 per MWh for B.C. clean or renewable energy. In Section 8.1.3 of the LTERP, FBC discusses how implementing higher levels than the preferred level of DSM would require higher-cost DSM. Marginal costs would average $108 per MWh, well above the DSM cost-effectiveness threshold LRMC of $100 per MWh.

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In terms of risk/flexibility, DSM levels higher than the preferred level create risks in terms of managing the load resource balance (LRB). FBC believes DSM to be a reliable non-firm energy resource. DSM energy savings are non-firm in that they are not dispatchable and cannot be shifted (i.e. transferred from the measures' inherent load shapes).

61.0 Reference: Exhibit B-2, BCUC 35.1 – 35.3

Exhibit B-1, Volume 1, pages 122-125 & Volume 2, page 15

61.2.1 When, in Volume 2 (page 15), FBC compares the $104/MWh incremental cost for the High DSM scenario to the $100/MWh LRMC for clean or renewable resources, are the two values being compared calculated on the same basis (i.e., incremental)?

Response:

While these two values are both on an incremental basis, the $98 per MWh represents the incremental **cost** of the energy savings achieved by the measures included in the High DSM scenario, incremental to the Base DSM scenario. In contrast, the $100 per MWh LRMC for clean or renewable resources represents the incremental cost used to value the **benefits** of DSM savings.

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63.0 Reference: Exhibit B-3, BCOAPO 4.1, 29.2 and 29.2.1

Exhibit B-1, BCUC 35.2

63.1.1 If not please re-state, including program costs – so as to be comparable to the other values included in the Table.

Response:

FBC has added program costs to the marginal cost values set out in updated Table 1 below, with respect to BCOAPO IR 1.29.2. FBC estimates levelized program costs of $14.80 per MWh for the DSM scenarios.

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Category	DSM Scenario			
	Low	Base	High	Max
Resource Cost, 2016 $/MWh				
Marginal cost incl. program costs	$74	$95	$102	$120
Average cost incl. program costs	$42	$52	$58	$64
Incremental cost incl. program costs	$42	$86	$98	$108

As explained in the response to BCOAPO IR 1.29.2, the marginal cost is the cost of the highest cost measure included in the scenario; the average cost including program costs is the average resource cost of each scenario; and the incremental cost including program costs represents the incremental cost of the additional DSM measures included in each scenario.

63.2 FBC has not responded fully to BCOAPO 29.2.1 which also requested that FBC identify what the highest cost measure in each DSM scenario was. Please do so.

Response:

The highest cost measure in each DSM scenario is shown in the table below.

DSM Scenario	Marginal cost incl. program costs	Measure
Low	$59	Res | LED (Reflector) | R_Single Family Detached | ROB
Base	$80	Res | Clothes Dryer Elec | R_Single Family Detached | ROB
High	$88	Res | Heat Pump Water Heater 2.0 EF | R_Single Family Attached/Row | ROB
Max	$106	Res | Air Source Heat Pumps-SI | R_Single Family Detached | ROB

*NC = New Construction

70.0 Reference: Exhibit B-3, BCOAPO 47.1

70.2.2 If no, please provide responses to BCOAPO 47.1 through 47.4 assuming the $100 includes program costs.

Response:

FBC prepared the DSM scenarios based on load growth offset targets and not on an LRMC basis. The requested scenario is inconsistent with the methodology used in the LTERP, which, as described in the response to BCOAPO IR 2.70.1, is based on provincial policy that favours DSM targets based on offsetting load growth.

However, FBC believes that using the High scenario as a proxy for the requested scenario would be useful to the BCOAPO. As indicated in the response to BCOAPO IR 2.63.1.1, the marginal cost including program costs for the High DSM Scenario is $102, similar to the requested $100 scenario.

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72.0 Reference: Exhibit B-3, BCOAPO 49.1

2016 LTDSM Plan, pages 8-10

Preamble: The response states that DSM measures (programs) were not defined in the DSM scenarios. However the 2016 LTDSM Plan (page 13) states that each DSM scenario draws on a portfolio of measures sourced from the FBC CPR results.

72.1 Please provide a schedule that sets out the DSM measures included in the High DSM scenario. In the same schedule, please include the LRMC for each measure (including an allowance for program costs).

Response:

Please refer to the Excel spreadsheet in Revised Attachment 72.1, which provides the requested information for BCOAPO IRs 1.72.1 through 1.72.5. The attachment includes the measure name, levelized cost of electricity, total resource cost, and the applicable DSM scenario (all measures in the High scenario were included in the Max DSM scenario). FBC interprets the request for the LRMC as a request for the cost of the measure (the levelized cost of electricity) because the same LRMC is used for each measure ($100 per MWh).

FBC does not apply program costs at the measure level but at the scenario level. Please refer to the response to BCOAPO IR 2.63.1.1 for an accounting of the cost of each DSM scenario including program costs.

72.2 Please indicate in this schedule those "measures" for which FBC's 2017 DSM Plan has programs that address/target the savings opportunity presented by the measure.

Response:

Please refer to the response to BCOAPO IR 2.72.1 and to the Excel spreadsheet in Revised Attachment 72.1.

72.3 Please provide a schedule that sets out the TRC test (ratio) results for each DSM measure included in the High DSM scenario, where: i) benefits include both the LRMC and DCE and ii) DSM measure costs also include program costs.

Response:

Please refer to the response to BCOAPO IR 2.72.1 and to the Excel spreadsheet in Revised Attachment 72.1.

72.4 Please provide another schedule that sets out the DSM measures included in the Max DSM scenario. In the same schedule, please include the LRMC for each measure (with and without an allowance for program costs).

Response:

Please refer to the response to BCOAPO IR 2.72.1 and to the Excel spreadsheet in Revised Attachment 72.1.

72.5 Please provide a schedule that set out the TRC test (ratio) results for each DSM measure included in the Max DSM scenario, where: i) benefits include both the LRMC and DCE and ii) DSM measure costs also include program costs.

Response:

Please refer to the response to BCOAPO IR 2.72.1 and to the Excel spreadsheet in Revised Attachment 72.1.

75.0 Reference: Exhibit B-1, Volume 1, page 119 and pages 124-127

75.2 Please re-do Table 9-2 to include Portfolio B2.

Response:

The following table includes the addition of Portfolio B2 (in the last row) to Table 9-2 from page 126 of the LTERP.

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	Comments
A1	No Self-Sufficiency	Market (97%) Biogas (3%)	$75	0.0%	0	14	Low	LT market supply access and price risks
C1	93% Clean with CCGT	Market (51%) CCGT (48%) Biogas (1%)	$90	3.9%	189k	164	Medium	Gas and carbon price risks
A4	93% Clean with SCGT	Market (31%) Wind (65%) Biogas (3%) SCGT (1%)	$96	0.2%	3k	145	High	Minimal gas and carbon price risks
C4	100% Clean BC Resources	Market (31%) Wind (65%) Biogas (3% Biomass, Solar (1%)	$97	0.0%	0	216	Medium	Higher cost, lower reliability than with CCGT or SCGT
B2	Base DSM	Market (30%) Wind (64%) Biogas (5%) Run-of-river, SGCT (1%)	$92	0.2%	4k	186	High	

REVISED Attachment 72.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

E. VOLUME 2 – LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

16.0 Topic: Long-Term DSM Plan

Reference: Exhibit B-1, Volume 2, 2016 Long-Term DSM Plan, 3.2 Preferred DSM Scenario, p.14 (pdf p.501)

FBC says that the High DSM scenario "includes the majority of cost effective DSM from an LRMC perspective."

16.2 Please provide a table showing the percentage of cost-effective DSM from an LRMC perspective included in each of the four DSM scenarios, or for each of the scenarios for which this data is available.

Response:

The following table shows DSM savings as a percentage of the interim estimate of market potential from 2018 to 2035. FBC has engaged Navigant to prepare a market potential study in 2017, based on the 2016 FBC CPR, which will update these values, and will be filed with FBC's next DSM expenditure schedule. The figures in the table below coincide with the load growth offset targets over the planning horizon; the interim estimate of market potential is comparable to the total estimated load growth from 2018 to 2035.

Table 1: DSM Savings as a Percentage of Interim Estimate of Market Potential from 2018 to 2035

Metric	DSM Scenario			
	Low	Base	High	Max
Percent of interim estimate of market potential	46%	60%	70%	81%

16.4 Please describe and provide anticipated costs and savings values for a scenario that includes all the cost-effective DSM from an LRMC perspective.

Response:

Please refer to the response to BCUC IR 1.33.1 for a hypothetical scenario where DSM activities offset 100 percent of load growth, which is approximately 92 percent of the total interim estimate of market potential.

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24.0 Topic: Long Term DSM Plan

Reference: Exhibit B-2, FBC Response to BCSEA-SCBC IR 1.16.4

BCSEA-SCBC IR 1.16.4 asks FBC to "describe and provide anticipated costs and savings values for a scenario that includes all the cost-effective DSM from an LRMC perspective."

FBC's response is: "Please refer to the response to BCUC IR 1.33.1 for a hypothetical scenario where DSM activities offset 100 percent of load growth, which is approximately equivalent to the total interim estimate of market potential." [underline added]

24.1 Is it a coincidence that "100 percent of load growth" is approximately equivalent to the "total interim estimate of market potential"? If not, please explain the linkage.

Response:

The total interim estimate of market potential and the forecast load growth are not linked. Based on the revisions to the CPR and DSM scenarios, FBC's forecast load growth is approximately 92 percent of the total interim estimate of market potential..

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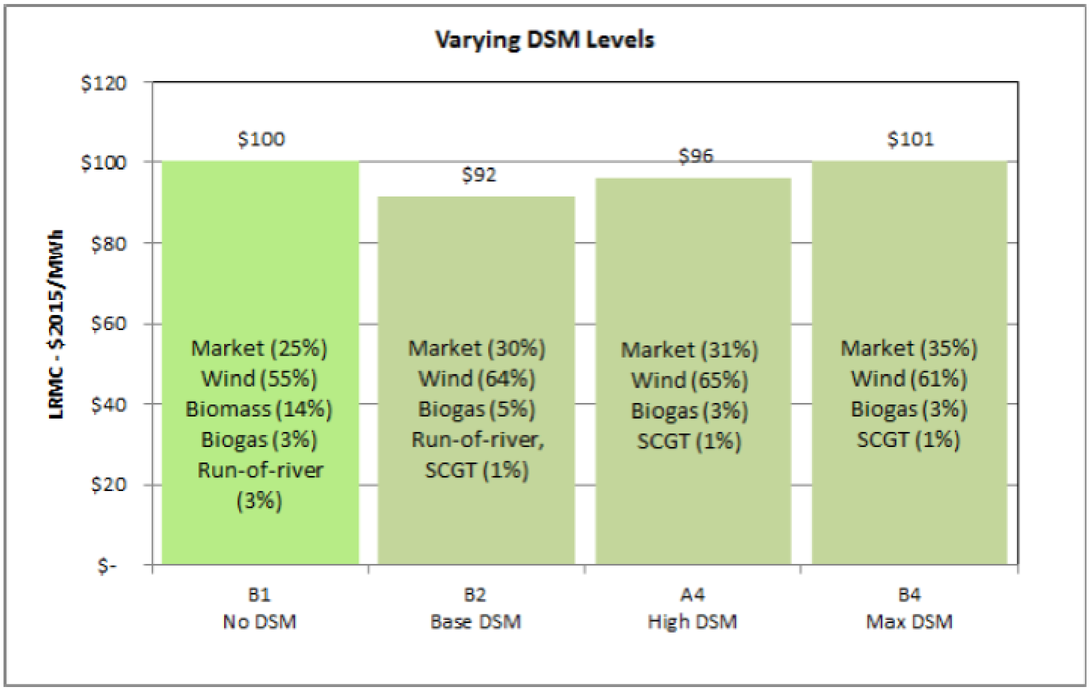
1 **23. Reference: Exhibit B-1, page 119**

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.

2

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.

3

4 23.1 Please provide the expected costs of each of the energy resources included in
5 this analysis on a $/MWh basis.
6

Response:

The following are the UECs[1] ($ per MWh) of the resources contained in portfolios B1, B2, A4, and B4.

		Portfolio			
Resource Type	**Resource Name**	**B1**	**B2**	**A4**	**B4**
DSM	Base DSM		$86		
	High DSM			$98	
	Max DSM				$108
PPA	PPA Tranche 1[2]	$50	$50	$50	$50
New Resources	Biogas1	$77	$77	$77	$77
	Biogas2		$101		
	Biogas3	$88	$88	$88	
	Biogas4	$100	$100		
	Wind2				$119
	Wind3		$113	$113	
	Wind4	$111			
	Wind6	$145			
	RoR2	$150	$150		
	RoR4	$136			
	Biomass1	$118			
	Biomass3	$188			
	SCGT1		N/A	N/A	
	SCGT2				N/A
Market	Market	$50	$50	$50	$50

[1] UECs were derived using a 6 percent discount rate, are stated in 2015$, and are based on the reliable energy each specific resource is presumed capable of producing on an annual basis. For additional details, please refer to the Resource Options Report in Appendix J of the LTERP.

[2] PPA energy only.

23.5 Please provide an estimate of the total costs and benefits for each of the Base DSM, High DSM and Max DSM maximizing the use of market purchases.

Response:

The LRMC can be used as a metric to compare the costs and benefits of varying DSM levels. FBC has interpreted 'maximizing the use of market purchases' as removing the self-sufficiency target in 2026. The following table shows the LRMC of portfolios with varying levels of DSM and without a self-sufficiency target in the planning horizon.

Table 1: No Self-Sufficiency, Varying Levels of DSM

Portfolio	LRMC
Base DSM, No Self-Sufficiency	$72 per MWh
High DSM, No Self-Sufficiency (Portfolio A1)	$75 per MWh
Max DSM, No Self-Sufficiency	$78 per MWh

10. Recently it was reported that:

"The U.S. Energy Department's National Renewable Energy Lab expects [solar] costs of about $1.20 a watt now declining to $1 by 2020"

(https://www.bloomberg.com/news/articles/2017-01-03/for-cheapest-power-on-earth-look-skyward-as-coal-falls-to-solar)

v. FBC provides three different Unit Energy Cost estimates in Table 8-1 for DSM. For comparison purposes, please provide the average DSM UEC MWh expenditures for each of the last five years.

Response:

The Unit Energy Cost (UEC) estimates in Table 8-1 (LTERP, page 96) for DSM represent the unit costs of the incremental cost for the Base, High and Maximum scenarios, including program administration. The derivation of the numbers is shown in Table 3-1 in the LT DSM Plan and values are presented in $2016.

The comparable average UECs for the three scenarios of the LT DSM Plan, along with the UEC for Actual DSM expenditures over the last five years are as follows:

Year/Scenario	UEC Incremental 2016 $/MWh	UEC Average 2016 $/MWh	UEC Average $/MWh
2016 LT DSM Plan - Base	86	52	
2016 LT DSM Plan - High	98	58	
2016 LT DSM Plan - Max	108	64	
DSM Actual 2016			47
DSM Actual 2015			60
DSM Actual 2014			59
DSM Actual 2013			67
DSM Actual 2012			51

25. With reference to FBC's response to Shadrack IR#1.10.v. in Exh. B-9, FBC stated three different UEC values for DSM: Incremental, Average, and Actual Average.

i. With reference to FBC's response to Shadrack IR#1.11.iv. in Exh. B-9, is the difference between the Actual DSM cost in 2016 of $47, the Base Incremental value of $88, and the UEC Average value of $54, due to uptake of the program by customers?

Response:

The updated Base Incremental value is $86 and the updated UEC Average value is $52.

The differences between the Actual DSM cost in 2016 of $47, the Base Incremental value of $86 and UEC Average value of $52 are as follows:

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- The Actual DSM cost in 2016 of $47 is the levelized cost of DSM programs in 2016;
- The Base Incremental value of $86 is the net present value (NPV) of the incremental costs of DSM programs over the LTERP planning horizon from 2018 to 2035 that is required to achieve the Base scenario level of DSM. 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 approved 2017 DSM Plan. 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[1];

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- The UEC Average value of $52 represents the NPV of all DSM programs, both existing and incremental, to achieve the Base level scenario, so it includes existing DSM programs as well as incremental costs, discounted over the planning horizon.

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It should also be noted that the Actual UEC is based on the total resource costs, which includes incremental customer incurred costs, whereas the Plan UECs are based on utility resource costs only.

[1] FBC 2016 LT DSM Plan, page 13.