Diane Roy
Vice President, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

April 6, 2017

British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, B.C.
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)

Response to the British Columbia Utilities Commission (BCUC or the Commission) Information Request (IR) No. 1

On November 30, 2016, FBC filed the Application referenced above. In accordance with Commission Order G-197-16 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCUC IR No. 1.

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

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

Table of Contents **Page No.**

A. CHAPTER 1 – INTRODUCTION

1.0 Reference: PURPOSE OF THE RESOURCE PLAN

FortisBC Energy Utilities (FEU) 2014 Long Term Resource Plan (LTRP) Decision dated December 3, 2014 p. 5 and Order G-189-14; *Utilities Commission Act* (UCA) sections 44.1, 44.2, 45, 71

Long Term Electric Resource Plan guidance for future applications

On page 5 of the British Columbia Utilities Commission (Commission) decision on the FEU 2014 LTRP Application, the Commission describes the purpose of FEU's resource plan as providing strategic direction and insight for future applications, direction on broader policy issues and considering areas where there may be public interest concerns.

1.1 In a format consistent with the three bullets provided on page 5 of the FEU 2014 LTRP Decision, please provide a summary list of the key guidance in this resource plan that FortisBC Inc. (FBC) considers it may rely on in applications to the Commission over the next five years.

Response:

The legislative and strategic linkages between long term resource planning and other applications to the Commission are consistent for FBC and FortisBC Energy Inc. (FEI).

FBC's LTERP will support future applications by:

- Providing strategic direction and insight for applications where the UCA specifically requires consideration of the LTERP: expenditure schedules for demand-side measures (section 44.2), Certificates of Public Convenience and Necessity (CPCN) (section 45), and Energy Supply Contracts (section 71);
- Providing direction on broader policy issues that may arise in other applications such as rate design, extension policy and revenue requirements; and
- Identifying areas of public interest or policy for consideration in all future applications.

2.0 Reference: RESOURCE PLAN OBJECTIVES

Exhibit B-1 (the Application), Volume 1 (2016 LTERP Application), pp. 5, 95; Commission Resource Planning Guidelines[1], p.3; FBC 2012-2013 Revenue Requirement & Review of 2012 Integrated System Plan (2012 RR & ISP), Exhibit B-1-1, p. 11; 2012 RR & ISP Decision dated August 15, 2012, pp. 143,144 and Order G-110-12; Seventh 2016 Northwest Conservation and Electric Power Plan (2016 NW PP)[2], pp. 15-26, 15-43; BC Hydro 2013 Integrated Resource Plan (BCH 2013 IRP)[3], pp. 1-12 – 1-17, 1-19

General

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 95 of the 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 [load resource balance (LRB)] gaps.” FBC 2012 resource planning objectives were described on pages 143 and 144 of the FBC 2012 RR & ISP Decision. FBC stated on page 11 of its 2012 RR & ISP application (Exhibit B-1-1): “Reduction of GHG volumes is a key input in evaluating capacity and energy alternatives in the Company’s 2012 Resource Plan.”

Figure 15-17 on page 15-43 of the 2016 NW PP compares residential bills and rates with and without lower conservation, and figure 15-11 on page 15-26 compares carbon emissions by scenario. BC Hydro described its planning criteria on pages 1-12 to 1-17 of the BCH 2013 IRP which include: achieving electricity self-sufficiency by 2016 and generation and transmission planning criterion. On page 1-19, BC Hydro defines cost-effectiveness.

2.1 In table form, please compare FBC’s 2016 resource planning objectives to those included in the following documents: (i) the Resource Planning guidelines; (ii) FBC’s 2012 RR & ISP; and (iii) BCH’s 2013 IRP. Where objectives are included in the resource plans listed above, but not in FBC’s 2016 LTERP Application, please explain if FBC supports these additional objectives (and if not, why).

[1] http://www.bcuc.com/Documents/Guidelines/RPGuidelines_12-2003.pdf.
[2] https://www.nwcouncil.org/media/7149924/7thplanfinal_chap15_resourcestratanalysis.pdf.
[3] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0001-nov-2013-irp-chap-1.pdf.

Response:

The following table provides a comparison of FBC's LTERP resource planning objectives to those included in the following documents: (i) the Commission's Resource Planning guidelines; (ii) FBC's 2012 LTRP (Volume 1 of the 2012 ISP, filed concurrently with the 2012-2013 RRA); and (iii) BCH's 2013 IRP.

Document	Resource Planning Objectives
FBC 2016 LTERP	• Ensure cost-effective, secure and reliable power for customers; • Provide cost-effective demand-side management, and • Ensure consistency with provincial energy objectives (for example, the applicable *Clean Energy Act (CEA)* objectives).
Commission Resource Planning Guidelines	• Adequate and reliable service; • Economic efficiency; • Preservation of the financial integrity of the utility; • Equal consideration of DSM and supply resources; • Minimization of risks; • Compliance with government regulations and stated policies; and • Consideration of social and environmental impacts.
FBC 2012 LTRP	• Continuing to ensure the availability of cost-effective long-term, reliable power for FBC's customers; • Understanding the uncertainty and risks inherent in the Company's historic, current and proposed market purchase strategy; and obtaining firm power resources over time to achieve 100 percent self-sufficiency, and • Balancing cost effectiveness with the directions and Policy Actions of the *Clean Energy Act*.
BCH 2013 IRP	• Ensure the right balance of proposed cost-effective resource actions to meet customer reliability requirements while addressing environmental concerns and adhering to legislated and B.C. government policy parameters[4].

While there are objectives listed in the documents above that are not included in FBC's LTERP objectives, the LTERP objectives are generally consistent with the objectives in the other documents listed above.

In the Commission's Resource Planning Guidelines, the second objective is "economic efficiency", which FBC interprets as relating to cost effectiveness of resources and reducing waste or stranded resources and assets. FBC considers these in its portfolio analysis and includes cost effectiveness explicitly in its objectives. FBC helps to ensure preservation of the financial integrity of the utility (third objective) by focusing its resource planning on meeting the

[4] BC Hydro 2013 IRP, Page 1-18.

most reasonable load forecast through prudent and cost-effective resource acquisition, market purchases and DSM initiatives.

FBC considers both DSM and supply-side resource options in planning for future customer needs. The amount of DSM resources selected to meet future load growth is first determined by FBC through its LT DSM Plan, rather than within FBC's portfolio analysis. Once the optimal level of DSM is determined, supply-side resource options are then considered to meet any remaining Load-Resource Balance (LRB) gaps.

FBC supports the objective of minimizing risks and includes this consideration in its portfolio analysis and contingency planning. FBC also supports consideration of social and environmental impacts as these were some of the criteria considered in its portfolio analysis in Section 9 of the LTERP.

With regard to the resource planning objectives stated for FBC's 2012 LTRP, FBC continues to support the objective of understanding the uncertainty and risks inherent in the Company's historic, current and proposed market purchase strategy. While FBC has not explicitly stated this objective as part of the LTERP objectives, FBC considers it implicitly under the objective of ensuring cost-effective, secure and reliable supply for customers. FBC discusses its market purchase strategy and potential risks with longer term reliance in Section 8.2.4 of the LTERP. Obtaining firm power resources over time to achieve 100 percent self-sufficiency is incorporated into FBC's portfolio analysis where self-sufficiency is targeted by the end of 2025.

FBC's 2016 LTERP resource planning objectives are generally consistent with those of BC Hydro's 2013 IRP as summarized in the table above.

2.1.1 Does FBC have, as a resource planning objective, giving "equal consideration to DSM and supply resources"? Please explain if this is a change from the 2012 RR &ISP.

Response:

The LTERP does not explicitly have, as a resource planning objective, giving "equal consideration to DSM and supply resources". As discussed in the response to BCUC IR 1.2.1, FBC considers both DSM and supply-side resource options in planning for future customer needs. Once the DSM levels are determined through the DSM scenario development (Section 3 of LT DSM Plan), supply-side resource options were then considered to meet any remaining load resource balance (LRB) gaps. This is not a change from FBC's 2012 LTRP, where both

DSM and supply-side resources were considered and DSM levels were then targeted to meet 50 percent of future load growth.

2.2 Please identify the key metrics that could be used to measure how portfolios perform against each of FBC's objectives. Please specifically comment on whether the following metrics could be appropriate: residential bills, FBC rates, BC greenhouse gas (GHG) emission levels, percentage of load met through energy from BC generators, percentage of load met though clean energy supply, and loss of load expectation (related to network/generator capacity).

Response:

FBC identifies the key metrics or criteria used to measure how the portfolios perform against the objectives in Section 9.3.6 of the LTERP. The results for the portfolios considered for the preferred portfolio are provided in Table 9-2. These criteria include cost (LRMC), geographic diversity of generation resources and consistency with the *CEA* objectives of encouraging socio-economic development and the creation and retention of jobs (employment full-time equivalents (FTEs) per year) and reducing environmental impacts in terms of GHG emissions. The portfolios considered were also subject to FBC's resource adequacy criteria (Planning Reserve Margin requirements) to ensure reliability. The preferred portfolio (A4) best meets the LTERP objectives in terms of balancing cost, reliability and geographic resource diversity with B.C.s energy objectives.

There are other metrics that could be considered to measure how the portfolios perform against the objectives. The impact on FBC rates is one such measure. FBC uses LRMC, as described in Section 9.2 of the LTERP, as its cost metric for the various portfolios rather than rate impacts. Residential bill impact is another metric. However, this metric is less appropriate than the others because, while residential customers may have the same electricity rates, they will have different bills depending on their electricity consumption.

The metrics of B.C. GHG emissions and percentage of load met though clean energy supply are appropriate. FBC uses GHG emissions produced in B.C. and maximum percentage of non-clean B.C. resources in evaluating the portfolios.

Percentage of load met through energy from B.C. generators is a less appropriate metric than the others given that FBC has targeted self-sufficiency by the end of 2025, after which time it is assumed that all of FBC's power supply comes from either its own hydro generation resources or supply from other generators in B.C., including BC Hydro.

Loss of load expectation (LOLE) (related to network/generator capacity) is another appropriate metric for evaluating portfolios. FBC has ensured that the portfolios considered for the preferred portfolio have met the Planning Reserve Margin requirements in terms of LOLE resource adequacy.

3.0 Reference: REGULATORY FRAMEWORK

Exhibit B-1, Volume 1, p. 9

Applicable Clean Energy Act (CEA) objectives relevant to the LTERP

On page 9 of the Application, Table 1-3, FBC states that: "GHG emissions for [the] preferred portfolio including clean or renewable resources and gas-fired generation are minimal".

3.1 Please explain the meaning of "minimal" GHG emissions for the preferred portfolio, measured as emissions per tonne, and provide a comparison of GHG emissions of the preferred portfolio and other considered portfolios in the 2016 LTERP Application.

<u>Response:</u>

Table 9-2 in Section 9.3.6 of the LTERP provides a comparison of the GHG emissions of the preferred portfolio to those of the other portfolios considered. The GHG emissions (produced in B.C.) for the preferred portfolio (A4) are about 3,000 tonnes (CO_2 equivalent) over the planning horizon. The GHG emissions for the portfolio including CCGT (portfolio C1) are about 189,000 tonnes (CO_2 equivalent) over the planning horizon. The other two portfolios, A1 and C4, have zero GHG emissions. FBC considers the GHG emissions of the preferred portfolio to be minimal because they are low on an absolute basis and also less than 2 percent of the GHG emissions of the portfolio including CCGT.

B. CHAPTER 2 – PLANNING ENVIRONMENT

4.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Volume 1, p. 18

Climate Leadership Plan (CLP)

On page 19 of the Application, FBC states that it "has addressed relevant items from the CLP in its load scenarios, market price forecasts and portfolio analysis."

4.1 Please discuss which items in the CLP FBC considers relevant and has addressed in the LTERP.

Response:

There are several items in the CLP that FBC considers relevant and has addressed in the LTERP. These include the following items, discussed on page 19 of Section 2.2.1.4 of the LTERP:

- Increases to the B.C. carbon tax;
- Support for expansion of zero-emission vehicle charging infrastructure and Clean Energy Vehicle program incentives;
- Requirement for 100 percent of BC Hydro electricity supply acquired in B.C. to be from clean or renewable sources;
- Encouragement of the development of net zero buildings;
- Reduction of methane emissions from the oil and gas sector; and
- Increasing the rate of forest replanting and wood fibre recovery in B.C.

FBC discusses the B.C. carbon tax and potential carbon price increases in Section 2.5.3 of the LTERP with the carbon price scenarios. These are then included in FBC's portfolio analysis in Section 9 of the LTERP when determining the potential costs for gas-fired generation and market power purchases. FBC discusses its plans to meet customers' requirements for electric vehicle charging infrastructure in Section 2.3.2 of the LTERP, potential growth in electric vehicle charging requirements and impacts in its load scenarios in Section 4 of the LTERP and potential impacts on its distribution system in Section 6.4.2 of the LTERP.

FBC's portfolio analysis in Section 9 discusses the development of portfolios that include 100 percent clean or renewable B.C. resources as well as meet the requirement for 93 percent clean or renewable resources. The requirement for 100 percent clean and renewable resources is specifically directed to BC Hydro in the CLP.

The encouragement of the development of net zero buildings implies that there is a shift towards less carbon-intensive sources of energy used by residential and commercial customers over time. FBC's load scenarios in Section 4 include the scenario where there are different levels of fuel switching from natural gas to electricity. The portfolio analysis in Section 9 includes a portfolio that meets a high load scenario resulting from greater electrification.

As discussed in Section 2.2.1.4, increased regulation or more standards relating to natural gas extraction or venting could increase the costs for natural gas production and lead to higher natural gas market prices. FBC has provided base, low and high natural gas price forecasts in Section 2.5.1 of the LTERP.

Increasing the rate of forest replanting and wood fiber recovery in B.C. may increase the availability of wood fiber as biomass fuel in the future that could be used for power generation. Biomass is one of the generation sources considered by FBC as a resource option in Section 8.2 of the LTERP and its portfolio analysis.

5.0 Reference: CHANGING SUPPLY ENVIRONMENT

Exhibit B-1, Volume 1, pp. 5, 37, p. 39

Alberta and regional markets

On page 37 of the Application, FBC states that B.C.'s role "in supplying Alberta's future needs is not yet known, but if a significant amount of electricity from B.C. is transported to Alberta, it could reduce the amount of potentially surplus generation available in B.C. to meet FBC requirements."

On page 39 of the Application, FBC states it believes that its strategy of making market purchases to close the gap between its supply and demand has generally been successful. On page 5 of the Application FBC lists its resource planning objectives (cost-effective, secure and reliable power, cost-effective Demand Side Management (DSM), consistency with provincial energy objectives).

5.1 Please discuss the magnitude of the potential impact of BC's role to supply Alberta's electricity needs to FBC.

Response:

Section 8.2.6 of the LTERP explains that there may be surplus IPP power available in B.C. due to expiring BC Hydro IPP contracts that may not be renewed. The magnitude of B.C.'s potential role in supplying Alberta's future needs will depend on many variables, including the availability of transmission to Alberta, regional reliability concerns, regional market developments and B.C. government policy. While FBC has not studied the potential magnitude of B.C. supply to Alberta as it is speculative at this time, it is possible that Alberta purchases would reduce the amount of surplus IPP power available to FBC in B.C. This does not impact the LTERP as FBC does not have any details on specific expiring EPAs, and therefore they were not included as potential resources in the portfolio analysis. However, as discussed in section 8.2.6, FBC will continue to monitor the BC Hydro contract renewals for any resource option opportunities.

5.2 Please explain which metrics FBC uses to establish achievement of its strategy of making market purchases to close the gap between its supply and demand.

Response:

The main metrics FBC uses to establish achievement of its strategy of making market purchases to close the gap between supply and demand are reliability, cost effectiveness and consistency with provincial energy objectives. These metrics are consistent with the stated resource planning objectives on page 5 of the LTERP.

5.3 Please explain how this strategy measures against the stated resource planning objectives.

Response:

Please refer to the response to BCUC IR 1.5.2.

6.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Volume 1, p. 47

Power Purchase Agreement (PPA) rate scenarios for Tranche 1 energy and capacity

On page 47 of the Application, FBC states: "The percentage increases in the PPA Tranche 1 energy and capacity rates are the same as those applicable to BC Hydro's residential customers. … In the low case, rate increases keep up with inflation of about 2 percent per year …. 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."

6.1 Please provide a table showing both the nominal and the real annual percentage increases in BC Hydro's residential rates and the PPA Tranche 1 energy and capacity rates for each year from 2007 through to 2016.

Response:

Please refer to the table below which provides the nominal and real annual percentage increases.

Fiscal Year	F2008	F2009	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017
Rate Change Effective Date	**1-Apr-07**	**1-Apr-08**	**1-Oct-08**	**1-Apr-09**	**1-Apr-10**	**1-Apr-11**	**1-Apr-12**	**1-Apr-13**	**1-Apr-14**	**1-Apr-15**	**1-Apr-16**
BC Hydro RS 1101 - Residential Service Nominal Rate Changes											
Basic Charge per period (per 2 months - April/08 - per day)	2%	2%	0%	2%	6%	8%	4%	1%	9%	6%	4%
All kWh per period	2%	2%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Step 1 - First 1,350 kWh per two months	n/a	n/a	n/a	8%	6%	6%	2%	1%	9%	6%	4%
Step 2 - Additional kWh per two months	n/a	n/a	n/a	15%	6%	10%	6%	1%	9%	6%	4%
BC Hydro RS 1101 - Residential Service CPI Adjusted Real Rate Changes (2006)											
Basic Charge per period (per 2 months - April/08 - per day)	0%	1%	0%	2%	5%	5%	2%	2%	7%	6%	2%
All kWh per period	0%	0%	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Step 1 - First 1,350 kWh per two months	n/a	n/a	n/a	8%	5%	4%	0%	2%	7%	5%	2%
Step 2 - Additional kWh per two months	n/a	n/a	n/a	14%	5%	7%	4%	2%	7%	5%	2%
BC Hydro RS 3808 PPA Tranche 1 - Nominal Rate Changes											
Energy per MWh	2%	2%	0%	9%	6%	8%	4%	1%	9%	6%	4%
Capacity per MW per Month	2%	2%	0%	9%	6%	8%	4%	1%	9%	6%	4%
BC Hydro RS 3808 PPA Tranche 1 CPI Adjusted Real Rate Changes (2006)											
Energy per MWh	0%	0%	0%	9%	5%	5%	2%	2%	7%	5%	2%
Capacity per MW per Month	0%	0%	0%	9%	5%	5%	2%	2%	7%	5%	2%
BC CPI	*1.9%*	*1.7%*	*1.7%*	*0.3%*	*1.0%*	*2.7%*	*1.6%*	*-0.8%*	*1.5%*	*0.5%*	*1.8%*

Notes:

For the fiscal years 2008 to 2012, rates are permanent rates as at April 1 of each year.

Rates are exclusive of the applicable deferral account rate riders.

B.C. CPI based on Statistics Canada CANSIM Tables, April to April of each year where 2006=100.

6.2 Please discuss the likelihood of the PPA Tranche 1 energy and capacity rates having an annual percentage increase of 1 percent in real terms, based on an annual inflation rate of 2 percent. In your discussion please consider the response to the previous question.

Response:

FBC believes that there is a reasonable likelihood that PPA Tranche 1 energy and capacity rates will have annual increases of about 1 percent in real terms, based on an annual inflation rate of 2 percent, at least through to March 31, 2024. As discussed in Section 2.5.4 of the LTERP, BC Hydro rate increases are capped at 3.5 percent effective April 1, 2017 and 3 percent effective April 1, 2018. For the remaining five years of the 10 Year Plan out to F2024 (ending March 31, 2024), the B.C. government has set target annual rate increases of 2.6 percent, subject to Commission review and approval. FBC understands these increases to be in nominal terms, which means, after inflation of about 2 percent, the annual rate increases to March 31, 2024 average close to 1 percent in real terms, assuming the 2.6 percent per year target increases are achieved in the five years leading up to 2024.

There is less certainty in terms of rate increases beyond March 31, 2024 as there has been no target increases set by the B.C. government or BC Hydro of which FBC is aware.

The data presented in the response to the previous BCUC IR 1.6.1 shows that the historical rate increases for BC Hydro and the PPA rates have averaged greater than 1 percent, in real terms, over the past ten years. However, the capped increases will mean annual rate increases in real terms in the order of 1 to 2 percent in the three-year period between April 2016 and March 2019.

6.3 Please explain whether FBC has confirmed with BC Hydro the reasonableness of its low/base/high estimates of Rate Schedule (RS) 3808 T1 increases, and provide BC Hydro's response if available.

Response:

FBC provided its low, base and high BC Hydro PPA Rate Schedule (RS) 3808 T1 scenarios to BC Hydro to confirm their reasonableness. BC Hydro stated that it did not have any feedback on the scenarios.

7.0 Reference: DISRUPTIVE CHALLENGES

Exhibit B-1, Volume 1, p. 69; Edison Electric Institute (EEI), Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business, Jan. 2013, p. 1; Ceres, Practicing Risk-Aware Electricity Regulation, 2014 update, p. 19[5]

General

FBC scenarios on page 69 of the 2016 LTERP Application show that 4 out of 5 of the scenarios modelled show growing peak demand, but only 2 out of the 5 scenarios modelled show growing energy levels. Page 1 of the EEI January 2013 paper states: "The financial risks created by disruptive challenges include declining utility revenues, increasing costs, and lower profitability potential, particularly over the long-term." Page 19 of the Ceres 2014 update paper states: "The U.S. electricity industry has entered what may be the most uncertain, complex and risky period in its history."

7.1 Please describe at a high level the key disruptive challenges faced by FBC and the adjustments made to the LTERP to meet those disruptive challenges.

<u>Response:</u>

The key disruptive challenges which FBC believes that it may face over the longer term include the impacts of electric vehicle (EV) charging and distributed generation (DG) (e.g. roof top solar), which are discussed in Section 4 of the LTERP.

The LTERP discusses the actions or adjustments FBC may have to make in the future to meet these challenges if EV penetration and DG growth become significant. These include continuing to monitor, where possible, these load drivers that may have the most impact on FBC's loads and distribution systems. For example, if EV growth increases significantly or becomes concentrated in certain neighbourhoods, FBC may need to ensure that EV charging occurs outside peak demand times to avoid the potential requirement for increasing transmission and distribution system infrastructure and more peak capacity generating resources.

Section 6.4.2 of the LTERP discusses the potential areas of focus for FBC on the distribution system to meet increased EV growth including mitigating the stresses on the electric grid through asset management, system design practices, and, to some degree, managing the timing of charging electric vehicles to shift the load away from system peak. A proactive FBC approach that includes understanding where EVs are appearing in the system, addressing near-term localized impacts, and developing both customer programs and technologies for managing long-term charging loads will effectively and efficiently support EV adoption.

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[5] https://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation-2014-update/view

FBC discusses potential impacts and actions required to meet the challenge of increased levels of DG in the future in Section 6.4.1 of the LTERP. Rooftop solar generation increases the complexity of managing voltage regulation on circuit feeders due to its intermittent nature. The extent to which DG affects power losses and voltage profiles depends on the type of DG technology, penetration levels, and the location of its connection to the grid. Depending on its location, the integration of DG can reduce power losses on the transmission and distribution network, but as the penetration level increases, the power losses may begin to increase. If DG uptake increases significantly in the near future, FBC transmission and distribution planners will need to have the tools and knowledge for planning and modeling a high penetration of solar PV or other DG technology into the system. Alternative engineering designs, technology solutions, and new and updated planning and operations practices may be needed for the FBC transmission and distribution system to meet this challenge in the future.

In addition to the grid-related challenges, DG also presents rate design challenges. Current electricity rate structures do not fully recover the fixed costs related to having customers connected to the grid. In turn, this means the variable consumption-based charges are higher than they would be on a strict cost-recovery basis. The net result is an economic incentive, greater than it should be on a cost basis, to install DG systems under the current net metering tariff. This increased economic incentive is paid for by customers not participating in the net metering program.

7.2 Please explain to what extent FBC coordinates its long-term planning with BC Hydro and FortisBC Energy Inc. (FEI). Does FBC consider that its coordination in long-term planning should be expanded to also include transportation?

Response:

FBC does coordinate, to a certain degree, its long-term planning with BC Hydro and FEI. As noted in Section 10.1 of the LTERP, BC Hydro is a member of the FBC Resource Planning Advisory Group (RPAG), providing discussion, input and feedback on relevant topics such as the planning environment, load scenarios, resource options, portfolio analysis and long run marginal cost. FBC is also a member of the BC Hydro Integrated Resource Plan Technical Advisory Committee (TAC) which meets periodically to discuss relevant resource planning issues. As noted in Section 8.2.1 of the LTERP, FBC's supply-side resource options as well as the related costs and energy and capacity profiles were developed in collaboration with BC Hydro as it updated its Resource Options Inventory in 2015.

FBC also provides input and feedback for FEI's resource planning as a member of the FEI resource planning steering committee and involvement in various working groups that discuss items such as the planning environment, load scenarios and market and carbon price forecasts. FEI also participated in the FBC steering committee as it developed the LTERP through 2015 and 2016. As discussed in Section 10.2 of the LTERP, FBC and FEI also coordinate presentations and discussions with community stakeholders in the gas and electric shared service area through community workshops each fall.

FBC does coordinate with BC Hydro on transportation planning, and has participated in previous gap analyses used for prioritizing the electrification of BC highways, as well as in identifying potential hosts for electric vehicle charging stations. Although opportunities for coordination are somewhat limited given the relatively small proportion of provincial highways located in FBC's service territory, FBC intends to continue to coordinate with BC Hydro on transportation planning, particularly with respect to the electrification of the Highway 3 and Highway 97 corridors through FBC's service territory.

8.0 Reference: ELECTRIFICATION

Exhibit B-1, Volume 1, p. 24, Appendix B, p. 20, Appendix G, pp. 28, 45; CLP, p. 20; BC Hydro F2017-F2019 Revenue Requirements Application (F2017-F2019 RRA), Exhibit B-9, BCUC IR 7.2, Attachment 1, p. 2

Electric Vehicles (EV)

FBC states on page 24 of the 2016 LTERP Application that it supports electric vehicle adoption by funding charging stations. On page 45 of Appendix G to the FBC 2016 LTERP Application, Navigant states: “Navigant believes that of all eight load drivers, EVs could pose the greatest risk of disruption for FortisBC in the period of analysis.” Page 28 of the Navigant report includes 5 Electric Vehicle (EV) scenarios.

The CLP states on page 20: “… policies that facilitate the adoption of zero emission vehicles like electric cars can make a significant impact in the fight against climate change. A major challenge for adoption of these vehicles is ensuring that owners can access charging stations.” On page 2 of the November 3, 2016 letter from the Minister of Energy to BC Hydro regarding the CLP (Exhibit B-9), the Minister stated that reorienting DSM to promote low-carbon electrification is “expected to be revenue positive….”

8.1 Please describe FBC’s strategy regarding EVs. Specifically, does FBC consider that its strategy is to promote, discourage or be neutral towards EVs?

Response:

FBC’s EV strategy involves supporting customers’ transportation choices by helping to ensure that the necessary charging infrastructure is in place to both meet customer energy demands today, and to help support increased EV market penetration going forward. As such, FBC has established a small annual budget to help support the installation of additional vehicle charging stations in FBC’s service territory. This support primarily consists of financial, logistical, and engineering support for prospective station hosts who are installing charging infrastructure for general public use. To date, FBC has provided support for the federal/provincial DC fast-charging programs, which has resulted in three DC fast-charging stations installed in FBC’s service territory. FBC has also provided support to a City of Kelowna initiative to install two Level 2 EV chargers in the downtown core. Lastly, FBC is currently working with the Columbia Basin Trust, the Community Energy Association, and municipalities located along Highway 3 to complete an East-West charging station route through FBC’s service territory.

8.1.1 Please explain: (i) how much, for each year, FBC has spent on EV charging stations for the last five years and is planned for the next five years; (ii) FBC strategy (if any) to encourage EV customers to charge during off-peak hours; (iii) FBC strategy (if any) regarding grid reinforcements that may be required.

Response:

FBC established an annual budget of $50 thousand in 2015 to help support the installation of public EV charging stations in its service territory. To date, FBC has spent approximately $50 thousand in each of 2015 and 2016 supporting the installation of public EV charging stations. Although total planned expenditures for 2017 – 2021 are forecast at $250 thousand, or $50 thousand annually, FBC notes that it is currently evaluating recent amendments to the *Greenhouse Gas Reduction (Clean Energy) Regulation* to determine if additional investment in EV infrastructure is warranted.

A key benefit to FBC from the support discussed above is an improved understanding of customer uptake and use of public charging resources, as well as insight into the infrastructure requirements/reinforcements necessary to support EV charging stations. FBC expects to use these learnings to help evaluate the potential impact on infrastructure requirements/reinforcements associated with continued EV market penetration, and, if necessary, to inform the development of strategies to promote the use of EV charging infrastructure during off-peak hours.

8.2 Does FBC consider that increased adoption of EVs would provide a net benefit to ratepayers? Please explain.

Response:

It is difficult to determine whether increased adoption of EVs will provide a net benefit to ratepayers, primarily due to the uncertainty around the forecast growth and geographical distribution of EVs and their associated charging stations throughout FBC's service territory. Although the increased load from EV charging has the potential to improve the use of existing electric distribution and transmission infrastructure, realization of this benefit is largely dependent on incenting customers to charge during off-peak hours. This could potentially be accomplished through the use of special "EV-only" rates for separately metered charging stations that encourage off-peak consumption.

8.3 Does FBC consider that EV batteries could be used as a source of grid storage over the term of the LTERP? Please explain.

Response:

Although EV batteries may offer a viable solution for home energy storage/backup, FBC believes that issues such as poor net efficiency and increased battery degradation (currently not covered by manufacturers' warranties) make vehicle-to-grid (V2G) storage an unlikely consideration over the term of the LTERP. While distributed grid-scale storage may become viable at some point, FBC considers it unlikely that V2G, as compared to other currently-available resource options, such as a simple cycle gas turbine, will provide a more cost-effective solution for addressing issues such as buffering renewable generation over the term of the LTERP.

9.0 Reference: ELECTRIFICATION

Exhibit B-1, Volume 1, p. 9, Appendix B, p. 28, Appendix G, p. 46, Volume 2 (2016 LT DSM Plan), Appendix C, p. 3; CLP, p. 28; CEA, Section 2, BC's Energy Objectives; Decision and Order G-186-14 on FBC's application for 2015- 2016 DSM Expenditures, Decision dated December 3, 2014 (FBC 2015-2016 DSM Decision), p. 14; 2016 NW PP, p. 17-5

Natural gas to electricity fuel switching

On page 3 of Appendix C to the 2016 LT DSM Application, Navigant states: "Since there are no economic benefits (only costs) to society resulting from the adoption of these measures, all have a TRC ratio of zero…." On page 46 of Appendix G to the FBC 2016 LTERP Application, Navigant states: "… fuel switching should be monitored simply due to the very substantial unit impacts, the highest of any of the load drivers examined in this study."

BC's energy objectives as stated in the CEA, include: "to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia." The CLP states on page 28: "To advance efficient electrification we are taking action by working with BC Hydro to expand the mandate of its DSM programs to include investments that increase efficiency and reduce GHG emissions."

The Commission stated in the FBC 2015-2016 DSM Decision: "The Commission Panel is concerned that FBC excludes customers from eligibility for FBC DSM incentives where they are switching from gas to electricity. The Panel considers that this approach acts contrary to BC's energy objective …." The 2016 NW PP describes on page 17-5 the model conservation standards for conversion to electric space conditions and water heating and states: "… utilities should take actions through … programs or a combination thereof to achieve electric power savings from such buildings."

9.1 Please describe FBC's strategy regarding natural gas to electricity fuel switching for customer space and water heating needs. Specifically, does FBC consider that its strategy should be to promote, discourage or be neutral to a customer fuel switching from natural gas to electricity?

Response:

FBC's strategy has been neutral to customer fuel switching from natural gas to electricity, however the electricity/natural gas rate difference[6] indicates a customer would not be incented to do so based on the current five-fold differential. If a customer chooses to proceed with

[6] FBC's residential tier 2 rate 15.617 ¢/kWh equates to $43.38/GJ. FEI's residential gas rate is $8.65/GJ, including the BC carbon tax. The electric/gas ratio is $43.38/$8.65 = 5.0

switching to electricity, despite the rate differential, they are likely motivated to do so for non-economic reasons.

9.1.1 Does FBC consider that encouraging natural gas to electricity fuel switching increases risks to its shareholder (either directly, or indirectly via FEI), and if so, how could this disincentive to encourage fuel switching be addressed? Please explain.

Response:

FBC has not completed an analysis of fuel-switching from natural gas to electricity and the potential shareholder impact. The shareholder impact is driven by the relative natural gas versus electric investment in system infrastructure and demand-side management over the long term.

More relevant considerations from a customer perspective, at least in the short term, are the relative price advantage of natural gas and any rate impacts from fuel-switching programs.

9.2 Please explain how Navigant factored in (i) BC GHG reduction benefits and (ii) customers non-energy benefits into its determination that there are no economic benefits (only costs) to society resulting from the adoption of natural gas to electricity fuel switching measures.

Response:

Navigant factored in GHG reduction benefits by incorporating a carbon cost of $30 per tonne (equivalent to $1.50 per GJ) as part of the avoided gas costs used in the analysis. Non-Energy Benefits (NEBs) were not included in the calculation of the TRC.

In Appendix C of the LT DSM Plan, Navigant states that the reason for a fuel-switching TRC of zero is a result of higher commodity costs for electricity compared to natural gas. Therefore, by switching from gas to electricity, the higher electricity costs result in a net cost (rather than a benefit) from the TRC perspective. While the analysis did incorporate GHG reduction emissions into the avoided cost of natural gas, the higher commodity costs of electricity offset the impact of GHG emission reductions from decreased gas consumption.

9.3 Does FBC consider that its residential inclining block rate design could discourage customers from fuel switching from natural gas to electricity? Please explain.

Response:

Yes, FBC believes that the electric to gas rate differential is a significant impediment to fuel switching to electricity. Since electric water and space heating will increase the amount of consumption billed at the higher Tier 2 price of the Residential Conservation Rate (RCR), the inclining block rate structure exacerbates this situation. FBC also noted in its response to BCOAPO IR 1.4.3 in its Application for Acceptance of DSM Expenditures for 2017 (2017 DSM Application) that its RCR sends a strong price signal to not build an electrically heated home, impacting the DSM savings achieved in the Residential New Home DSM program in 2016.

Please also refer to the response to BCUC IR 1.9.1.

9.4 Are customers who fuel switch from natural gas to an efficient electric appliance eligible for FBC DSM incentives? If not, does FBC consider that this could discourage customer fuel switching from natural gas to electricity? Please explain.

Response:

No they are not eligible. FBC requires participants of space and water heating DSM programs to be primarily electrically heated. FBC's DSM program is fundamentally a resource acquisition strategy and the benefits in the governing TRC test are predicated on valuing the electricity savings using the LRMC and DCE as avoided costs.

In contrast, fuel switching is inherently a load building program, increasing power purchase costs and (incrementally) transmission and distribution infrastructure needs and costs, thereby negating benefits in the TRC test.

Customers look to FBC as a trusted advisor on energy matters, and offering a fuel-switching incentive (to electricity) would mislead customers into choosing an uneconomic solution that would significantly increase their household utility costs.

9.4.1 Does FEI offer DSM incentives to customers who switch from electricity to natural gas? If yes, please explain.

Response:

The Commission has permitted FEI customers to access hot water and fireplace DSM program incentives, provided the appliances are ENERGY STAR or EnerChoice respectively, and "for customers who, at their own initiative, wish to switch to natural gas"[7]. The Commission has also permitted FEI customers to access "Switch and Shrink" offers for space heating; however, that program was determined to be a load building program and not a demand-side measure, with the result that the costs of the program were allocated to O&M budgets[8].

9.4.2 Does FBC consider that, if a fuel switching customer is not offered a DSM incentive, there is a risk that they could install a less efficient electricity appliance? Please explain.

Response:

FBC believes that a customer who is considering such a fuel switch, despite the five-fold increase in the fuel cost of electricity, would be inclined (and financially motivated) to choose an efficient electricity appliance.

If the equivalent electricity price of $43.38/GJ (refer to the response to BCUC IR 1.9.1) was adjusted, for instance, by the seasonal performance factor of an air-source heat pump, the modified equivalent price drops to about $18/GJ, which is still more than double the natural gas rate of $8.65/GJ. This indicates the customer is choosing to fuel switch to electricity for non-economic reasons, as their operating costs would increase significantly based on the natural gas/electricity rate differential.

7 BCUC Order G-36-09 (2008 EEC Programs) p. 183
8 BCUC Order G-44-12 (FEU 2012-13 RRA) p. 162

10.0 Reference: DISTRIBUTED GENERATION

Exhibit B-1, Volume 1, pp. 8, 21, 26-28, Appendix G, p. 46; CEA, section 2, BC's energy objectives; 2007 BC Energy Plan: A Vision for Clean Energy Leadership (2007 BC Energy Plan), p. 39; FBC 2016 Net Metering Program Tariff Update (FBC 2016 NM), Order G-199-16, Appendix A, Reasons for Decision dated December 29, 2016 (FBC 2016 NM Reasons for Decision), p. 5; BCH 2013 IRP, pp. 8-4, 8-5; FBC 2012 RR & ISP, Exhibit B-1-1, p.9; Arthur D. Little, Distributed Generation [DG]: Policy Framework for Regulators, 1999, pp. iv, 10-12[9]

FBC Strategy

On page 21 of the FBC 2016 LTERP Application, FBC states that the City of Nelson is proposing to build a small solar photovoltaic (PV) array, and that such initiatives, if pursued on a large enough scale, could impact the traditional utility business in which FBC is engaged. On pages 26 to 28, FBC also discusses small-scale distributed generation (DG) and states that it presents some challenges for FBC. On page 46 of Appendix G to the FBC 2016 LTERP Application, Navigant states: "Although likely a lower disruption risk than EVs, rooftop solar PV has the potential to significantly affect the energy consumption of customers in FortisBC territory."

The CEA includes as a BC energy objective: "use and foster…innovative technologies that support…the use of clean and renewable resources." The 2007 BC Energy Plan includes as Policy Action #25: "Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources."

On Page 5 of the FBC 2016 NM Reasons for Decision, the Commission stated: "The Panel feels that these broader issues (for example, whether the Program should be expanded beyond its original intent) are more appropriately addressed following the LTERP and/or [self-generator policy (SGP)] proceedings as these proceedings may provide broader guidance regarding FBC's self-generation strategy."

BC Hydro described its objectives and principles of its Clean Energy Strategy on page 8-4 to 8-5 of the BCH 2013 IRP. These included: "A continual focus on finding the most cost-effective clean energy resources through competitive, or competitively benchmarked, processes" and "Effective participation by First Nations … on clean energy projects in their traditional territories."

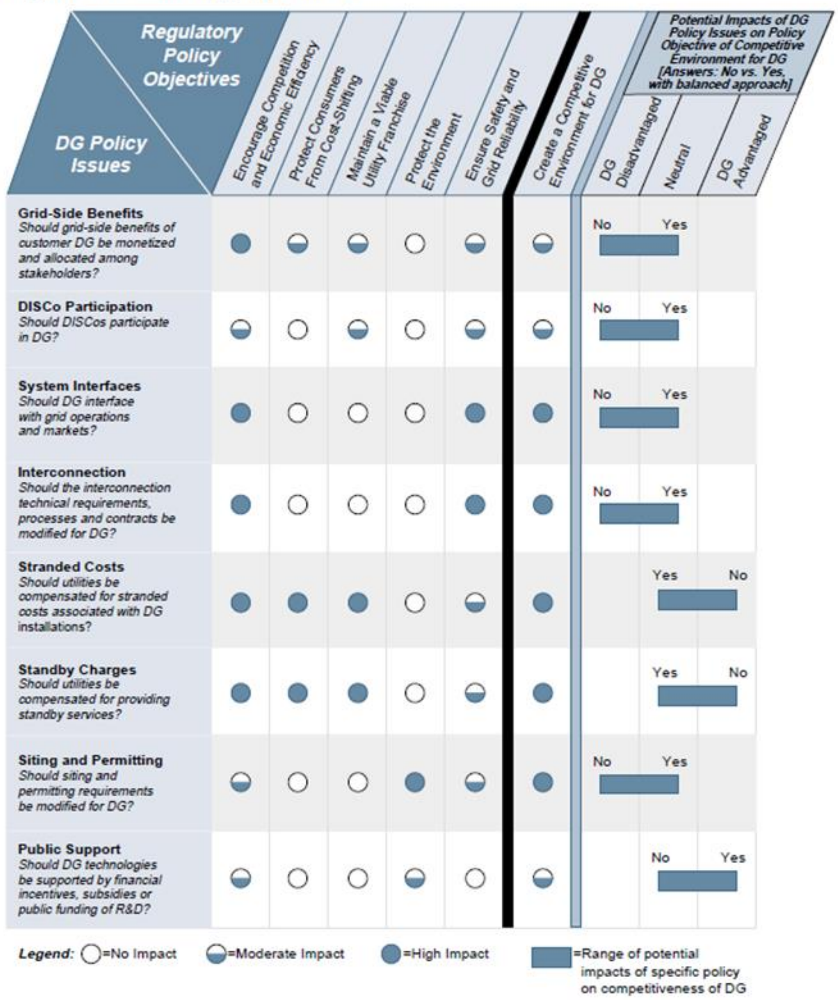
FBC stated on page 9 of its 2012 RR & ISP Application (Exhibit B-1-1): "As BC Hydro proceeds to implement programs such as Feed In Tariffs and continues to operate the various power acquisition activities (Standing Offer Program, Clean Call, Bioenergy

9 http://www.encorp.com/ADLittleWhitePaperPolicyFrameworkForRegulators.pdf

Call), it creates some impetus for FortisBC to consider the implementation of similar programs in its service territory in order to maintain provincial consistency ….”

A 1999 Arthur D. Little White Paper titled “Distributed Generation: Policy Framework for Regulators”, provides the following overview of DG policy issues in Figure E-1, page iv and on page 12 states: “A public policy that prohibits DG interfaces has, at worst, the potential to significantly limit the competitive environment for DG.”

Figure E-1: Issue Mapping Process



10.1 Please define the terms ‘self-generation’, ‘distributed generation’, ‘small-scale distributed generation’, and ‘net metering’ as used in this Application.

<u>Response:</u>

While there is overlap in the meaning of these terms in that self-generation and net metering could both potentially be forms of distributed generation, usage of these terms in the LTERP generally conforms to the following:

Self-Generation: As described in the LTERP on page 113, Self-Generation refers to power produced by self-generating customers, which, for the purposes of this LTERP, refers to larger, industrial customers that can provide electricity to FBC. This is as opposed to smaller, residential or commercial customers that could provide distributed generation to FBC.

Distributed Generation: This term is used as defined in Appendix A to the LTERP. Distributed Generation (DG) is an individual-use generation resource, such as solar or small wind turbines, distributed amongst and utilized by customers. DG typically offsets individual customer power consumption and is connected to the utility system via some form of net metering facility.

The Company uses the terms “distributed generation” and “small-scale distributed generation” interchangeably.

Net Metering is a metering and billing practice that allows for the flow of electricity both to and from a customer, most often through a single, bi-directional meter. Net Metering does not refer to the generation facility itself. Rather, it refers to the billing treatment and infrastructure related to accounting for the energy flows to and from the customer.

10.2 Please describe FBC’s strategy regarding DG. Specifically, for each of the DG Policy Issues described in Figure E-1 of the 1999 Arthur D. Little White paper, does FBC consider that it should advantage, disadvantage or be neutral towards distributed generation compared to other generation? Please also explain whether FBC considers that its strategy should be different depending on the size, type, ownership (e.g. First Nation, community) and location of the generator.

<u>Response:</u>

One statement from the LTERP that summarizes FBC’s current view of self-generation also applies to DG and can be found at page 113:

> FBC is not seeking additional sources of supply at this time and is therefore not actively looking to purchase power from self-generator customers. However, if a self-generator could provide power at a cost lower than FBC’s alternatives,

there may be an opportunity for FBC to purchase the output of the self-generation.

FBC views DG from the same perspective as it does any potential resource that may be considered within the resource planning process. The Company seeks to neither advantage nor disadvantage DG regardless of size, type, or ownership.

In the opinion of the Company, the neutral approach by which FBC evaluates available supply-side resources including DG, is an appropriate approach in light of the situation correctly noted on page 2 in the referenced report that, "Markets and infrastructures vary dramatically across the United States, and DG must be evaluated against local conditions." [10]

The DG Policy issues discussed in the white paper are primarily public or legislative considerations that may potentially impact FBC, and the Company can offer some comment based on its role as a public utility, but not from the perspective of furthering public policy objectives that may be unrelated to how the Company evaluates its options for meeting load. FBC provides such comment, where appropriate, in the table below.

DG Policy Issue	FBC Comments
Should grid-side benefits of customer DG be monetized and allocated among stakeholders?	FBC has a Self-Generation Policy Stage II Application before the Commission in which it proposes to share any net benefits of self-generation on a 50-50 basis between the DG customer and other customers.
Should DISCos participate in DG?	Not Applicable.
Should DG interface with grid operations and markets?	Self-Generating customers in the FBC service area have access to markets utilizing the Company's Open Access Tariff and wheeling related rate schedules.
Should the interconnection technical requirements, processes, and contracts be modified for DG?	FBC has established interconnection guidelines that are applicable to DG customers.
Should utilities be compensated for stranded costs associated with DG installations?	In cases where assets are put in place to serve a load customer who then installs DG, it would generally be appropriate for the utility to be compensated for stranded costs.
Should utilities be compensated for providing standby services?	FBC has an approved standby rate.
Should siting and permitting requirements be modified for DG?	Not a consideration for the utility.
Should DG technologies be supported by financial incentives, subsidies, or public funding of R&D?	Not a consideration for the utility.

[10] FBC believes this applies to Canada as well.

10.3 Does FBC consider that it should have as an objective obtaining all cost-effective clean distributed generation (i.e., 'behind-the-meter' generation) to meet its load? Please explain why/why not.

Response:

A key consideration for FBC resource planning noted in this question is cost-effectiveness. This factor, along with the specific attributes of the resource in question (such as shape, reliability and quality) are all examined when the Company considers the appropriate mix of resources to meet customer load. In the context of resource planning, if clean distributed generation is cost-effective and has favourable characteristics relative to the options being considered, it would be included in a preferred portfolio on its merits alone. FBC does not consider that it requires a specific objective to obtain all cost-effective clean distributed generation.

10.4 Does FBC consider that its DG strategy should aim for provincial consistency with BC Hydro? If no, please explain in which areas FBC's DG strategy should differ.

Response:

FBC considers that provincial consistency is generally a desirable outcome for any DG strategy the Company may put forward. However, FBC operates in a distinct service area, with distinct characteristics and its own cost structure. Differences between the programs and rates it offers will naturally be evident when compared to those of BC Hydro.

BC Hydro has discussed its DG strategy as part of its 2013 Net Metering Evaluation Report #3 and its Clean Energy Strategy as part of its 2013 Integrated Resource Plan. While the Company is not aware of a single statement that defines BC Hydro's overall DG strategy, it considers that the strategy is embodied in the three programs that BC Hydro offers: Net Metering, Micro-SOP for First Nations & Communities, and the Standing Offer Program as discussed in the summary document attached to the 2013 IRP.[11]

[11] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/distributed-generation-programs-lores.pdf

FBC has a net metering program that is generally consistent with that of BC Hydro. The Company may offer to purchase the output of larger generation installations such as those covered by other BC Hydro programs, but only where it makes sense to displace other resources in the preferred resource portfolio, and FBC does not require any specific program in order to do so.

11.0 Reference: DISTRIBUTED GENERATION

Exhibit B-1, Volume 1, pp. 26, 27, 28, 90, 113; FBC 2016 Self Generation Policy (FBC 2016 SGP), Stage I, Decision dated March 4, 2016, p. 17 (FBC 2016 SGP Stage I Decision), and Order G-27-16; 2016 NW PP, p. 1-12; FBC 2016 NM, Exhibit B-12, BCUC IR 13.4

Costs and benefits

On pages 26 and 27 of the FBC 2016 LTERP Application, FBC states that small-scale DG presents some challenges to FBC, including safety, grid stability and cost. FBC also states on page 90: "Intermittent renewable generation creates many new challenges not experienced with conventional distributed generation.… Depending on its location, the integration of DG can reduce power losses on the transmission and distribution network, but as the penetration level increases, the power losses may begin to increase."

FBC states on p. 113 of the 2016 LTERP Application that self-generation supply from larger industrial customers can have the following benefits: self-sufficiency and less reliance on market supply; reduction of transmission losses depending on location on the FBC system; improved reliability depending on location; and complement traditional power generation. FBC also states on pages 27 and 28 of the 2016 LTERP Application that it is considering filing an application for a pilot community solar program.

The FBC 2016 SGP Stage I Decision includes on page 17 a list of potential benefits of self-generation as identified by FBC. The 2016 NW PP states on page 1-12: "… decreasing costs for utility-scale and distributed-scale photovoltaic systems have made them cost-competitive sources of energy supply." FBC stated in the FBC 2016 NM proceeding (Exhibit B-12, BCUC IR 13.4): "The Company does not currently have technical or safety concerns regarding customer investment in small hydro-electric installations that meet the interconnection guidelines."

11.1 Does FBC consider that (i) new small-scale clean self-generation and (ii) new large-scale self-generation provide an overall net benefit to BC? Please explain how FBC estimates the benefits and costs, and arrives at the net benefits.

Response:

FBC does not currently have a Commission-approved methodology in place to estimate the net benefits of self-generation to either the Company, its customers, or the Province.

FBC currently has an Application before the Commission, the *Self-Generation Policy Stage II Application,* in which the recognition of net benefits is discussed for both self-generating customers that would receive service pursuant to some variation of a Generation Baseline (GBL), and self-generating customers that take service utilizing the Company's Stand-By rate (RS37).

However, the Company is not proposing to attempt any sort of detailed determination of net benefits. In the view of FBC, while some net benefits may exist for a DG installation of any size, they are situational, difficult to determine and limited by the fact that an increase in customer-owned, clean self-generation of any scale primarily serves to offset the clean and renewable generation that currently makes up the vast majority of the Company's resource portfolio.

11.2 Please expand on FBC's DG safety concern regarding small-scale DG. Specifically, is FBC able to mitigate this concern through its connection policy?

Response:

The primary safety concern with respect to grid-connected DG is the potential risk to customers, the public, and FBC employees presented by the back-feed of electricity from customer-owned generation into the FBC system. This risk is mitigated by the FBC interconnection requirements, however, that is only the case where a customer advises FBC of the interconnection.

11.3 Please expand on FBC's DG grid stability concern. Specifically, can this concern be addressed through, for example, the planning reserve margin and the connection policy?

Response:

Historically, the power system (and more specifically the distribution network) has been designed with the expectation of unidirectional power flows (i.e. energy flows from the utility substations to end-use customers). Currently, FBC installs devices such as voltage regulators and shunt capacitors on the distribution network to help maintain a uniform voltage profile across its distribution feeders. If a significant amount of new DG is added to the distribution network there is a possibility of undesirable interactions between the utility's control and protection devices and those same devices at the customers' DG installations. These interactions could result in voltage stability issues and/or interference with utility fault protection devices. FBC will need to monitor DG uptake closely and keep abreast of industry practices to anticipate and mitigate any issues before they become a concern.

Planning reserve margin can address potential hour-to-hour variability of supply from DG resources but it is likely that this is at an increased cost. In addition, not all planning reserve margin resources apply to within-the-hour load variability and it is likely that at some increased level of DG, increased frequency and regulating reserve margin will have to be carried on an hourly basis. Finally, distribution stability concerns are localized system issues which cannot be addressed through generation resources that are geographically and electrically distant from the area of concern. As such planning reserve margin is not relevant.

The connection policy, in its current form, is intended for the current low uptake levels of DG and so does not address distribution stability concerns. It would have to be modified to address the highly variable nature of DG; one example of how this could be done would be to require battery back-up to smooth out generation swings.

11.4 Please expand on FBC's DG cost related concern. Specifically: (i) if the concern relates to contribution towards sunk network costs, why is it a problem if an electric heating customer with roof-top solar makes the same or similar contribution, as a customer who is low-use because they have gas space and/or water heating; and (ii) if the concern relates to incremental network costs, can this be addressed in the connection policy?

Response:

On pages 26-27 of the LTERP, the Company lists cost (which should be interpreted as cost recovery) as a challenge, stating that the fixed charges in the current rate structures do not adequately recover the cost of connection to the distribution system.

Currently, for Residential customers, the fixed Customer Charge collects less than 50 percent of the costs allocated to this function in the Company's most recent cost of service analysis (COSA). The balance of these costs is collected through the variable charge portion of the rate.

That means that customers with DG, including net metered customers, pay lower variable consumption charges, and, since some of the Company's fixed costs are collected through the variable (energy and demand) charges, fixed charges are under-recovered. In the case of net metered customers, the compensation for net excess generation during a billing period may reduce the contribution toward fixed costs to zero or negative. While the avoidance of energy charges is fair because the customers did not use the power, it is problematic that they also avoid paying for all of the fixed costs of the grid that delivers power when they need it and/or takes the excess power they sell back to the utility. The costs are ultimately borne by other customers through higher rates.

Customers with low use due to reasons other than customer-owned generation cannot avoid paying fixed charges, although by virtue of low energy charges will contribute less to fixed charges than a customer with higher consumption.

11.5 For each of the benefits identified on page 17 of the FBC 2016 SGP Stage I Decision, please explain: (i) whether FBC considers that they could apply to both large and small distributed generation; and (ii) whether (and if so how) these benefits flow back to the self-generators that provide them.

Response:

Please refer to the response to BCUC IR 1.11.1.

11.6 Please expand on the community solar PV pilot being considered by FBC. Please include in your discussion: (i) how the cost of this investment would be accounted for (would it be in rate base); (ii) whether FBC investment in solar PV would be on a level playing field with self-generators wanting to make the same investment; and (iii) why this was not included in the Action Plan.

Response:

(i) The investment would be included in rate base.

(ii) Self-generators, defined in the LTERP as large commercial customers with behind-load generation capability, are not in a position to make an investment that is analogous to the community solar PV project. The decision to install self-generation is primarily based on the economic considerations related to offsetting load.

With regard to an IPP with no associated load, FBC believes that the concept of a level playing field cannot readily be applied to a comparison between the addition of IPP generation and the addition of an embedded utility resource.

(iii) As described in the Resource Planning Guidelines, the action plan "consists of the detailed acquisition steps for those resources (from the selected resource portfolio) which need to be initiated over the next four years to meet the most likely gross demand forecast." The community solar pilot project is not being relied upon to meet the load forecast and is not included in the recommended resource portfolio.

Nevertheless, FBC's Action Plan includes the following, and FBC considers the community solar pilot project to be consistent with this action item:

> **1. Continue to monitor the energy planning environment**
>
> Being aware of and understanding the many factors that influence FBC's planning environment is critical for long term resource planning and is an ongoing activity for FBC. FBC will continue to monitor energy and environmental policy in Canada and the U.S. as well as regional market developments that may impact market supply, demand and pricing, resource options and costs. In addition, <u>FBC will continue to monitor and examine emerging technologies and changing demand and uses for electricity by its customers. FBC's monitoring activities will ensure that it is aware of and able to respond to relevant changes in the planning environment to meet the LTERP objectives</u>. (emphasis added)

12.0 Reference: DISTRIBUTED GENERATION

Exhibit B-1, Volume 1, p. 113; FBC 2016 SGP Stage I Decision, p. 11; FBC 2016 NM Reasons for Decision, pp. 9, 12

DG market barriers and mitigation approaches

FBC states in its 2016 LTERP Application (p. 113) that it is not actively looking to purchase power from self-generators, but may do so if the cost is lower than FBC alternatives.

The Commission stated in the FBC 2016 SGP Stage I Decision on page 11, that FBC's SGP should identify and mitigate market barriers to cost-effective clean self-generation. The Commission stated in the FBC 2016 NM Reasons for Decision on pages 9 and 12:

> FBC states that the NM Program is not the correct program to set the rate to buy power … However, FBC states that it has no tariff or program in place to purchase IPP power.… The Panel also notes that BC Hydro's net metering program does have such a condition [50kW capacity limit] imposed on participants.

12.1 Please describe the market barriers to customer investment in DG. Please specifically comment on whether they could include: difficulty accessing the market, overly-complex interconnection policy, lack of standby service, and immature state of the industry.

Response:

With respect to the Commission's comment in the FBC 2016 Net Metering Reasons for Decision regarding the purchase of IPP power, the Company notes that the lack of specific program(s) in this regard does not prevent FBC from acquiring the output of either IPPs or self-generators, which it has done in the past, and continues to do if such a purchase is appropriate relative to other available resource options.

The Company's Stage I SGP Application did not contain any discussion of potential barriers to investment in DG. This topic was introduced by the Commission Panel in FBC's 2016 SGP Stage I Decision. In that Decision, the Panel also commented that:

> In the Panel's view, there appears to be some confusion as to what it means to remove a barrier and what constitutes an incentive. The following example may help to clarify the Panel's understanding of the difference. A market barrier that could exist for a customer with self-generation is difficulty accessing the market. An example of removing a barrier would be for the utility to purchase the energy from the self-generator at market prices. On the other hand incenting self-

> generation might be offering the self-generator preferential terms, such as a higher price, than it would offer to an arms-length party.[12]

In accordance with the SGP Stage I Decision, the FBC SGP Stage II Application contains, at Section 5, a discussion centered on removing barriers to self-generation, as the Company understands the Commission's meaning of the phrase. This discussion primarily focusses on the potential purchase by the Company of self-generation output. This is one area where FBC can potentially mitigate a barrier as a direct purchase can eliminate some of the costs associated with the transmission of the power to another party.

FBC acknowledges that the other potential barriers noted by the Commission can exist in a general sense, but that none presents a barrier to self-generation in the specific context of the FBC service area.

12.2 Does FBC consider that a 'neutral' (as opposed to 'discourage') DG strategy requires that FBC identify and mitigate market barriers to distributed generation? Please explain.

Response:

In its Stage I SGP Application, FBC provided its proposed high-level policy with regard to the encouragement/discouragement of self-generation as follows:

> FBC supports the principle that the decision by a customer to install self-generation should be made by the customer based on the merits of the project. In general, it is not the role of the utility to either encourage or discourage the installation of customer-owned generation by any customer. Rather, customers should be free to make strategic investment decisions appropriate to their circumstances which may include consideration of the benefit that the self-generation provides to FBC customers as a whole, including the self-generating customer.

This remains the opinion of the Company. However, in the Stage I Decision the Panel noted:

> The Panel also does not support FortisBC's statement that it is not the role of the utility to either encourage or discourage the installation of customer-owned generation but rather finds that FortisBC's SGP should establish under what circumstances FortisBC would do so.

[12] SGP Stage I Decision G-27-16, page 14

The Company has not put forward any SGP that seeks to discourage self-generation and has discussed in its SGP Stage II Application the potential to mitigate barriers to market entry where self-generated or IPP power is a resource that compares favourably to other available options.

FBC considers this to be a neutral approach that naturally requires an evaluation of the potential purchase of distributed generation (of any size) and would include the cost-effective mitigation of market barriers.

12.3 To what extent does FBC consider that the customers cost of investment in DG is a relevant consideration for FBC in determining what the output is worth? Please explain.

Response:

FBC should consider only the characteristics of the electricity being provided when deciding on the value of any generation source. The producer's cost of providing that power (whether on an incremental basis, an average basis or any other cost calculation basis) cannot and should not be a consideration for FBC.

12.4 BC Hydro has a Standing Offer Program (SOP), micro-SOP and net metering (100kW generator capacity cap, no volume cap). Comparatively, what does FBC have?

Response:

FBC currently has a net metering program with a 50 kW generator capacity cap, limited to a participating customer's annual generation.[13]

Section 10 of the Company's Electric Tariff provides for all customers, regardless of size, to install generation in parallel with the FBC system.

[13] Commission Order G-199-16 provides that a small number of net metering customers have been grandfathered with the right to produce unlimited energy with currently installed generation. New net metering customers are limited, at the time of installation, to generation sized to produce an amount of energy that is typical of their annual consumption. Note that the Company filed an application for reconsideration of Order G-199-16 with the Commission on March 17, 2017.

While FBC does not have a defined program at certain size thresholds (such as BC Hydro's SOP), that would require FBC to acquire the output at set prices, the Company will evaluate such purchases on a case by case basis.

12.4.1 Are new FBC self-generators eligible for BC Hydro's micro-SOP or SOP program?

Response:

Section 2.8 of the BC Hydro Standing Offer Program Rules[14] states:

> Customers taking electrical service from a public utility other than BC Hydro are not eligible to apply under the SOP, with the exception of customers that take only back-up or start-up electricity service from that public utility.

Section 2.15 states:

> Projects located outside the Integrated System Area in another utility's service territory may be eligible for the SOP, but the delivery of energy must be at a specified point of delivery on the Integrated System, and the Developer must bear all costs of transmission and energy losses to that point of delivery.

FBC's understanding is that its self-generating customers are not permitted to apply for the BC Hydro SOP, but an IPP may be eligible.

Section 2.3 of the BC Hydro Micro SOP Rules[15] states:

> Projects must be located within BC Hydro's service area. Projects located within another utility's service territory or jurisdiction, such as the FortisBC service area, are not eligible for the Micro-SOP.

[14] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/standing-offer/standing-offer-program-rules.pdf

[15] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/standing-offer/micro-sop-program-rules.pdf

12.4.2 Does FBC anticipate filing any energy purchase agreements with industrial self-generators in the next four years? Please explain why/why not, and if yes, why it is not included in the four-year Action Plan.

Response:

The Company currently purchases unplanned deliveries to the FBC system during periods when an existing self-generating customer is supplying energy to the FBC system, but does not have an export schedule to a third party in place, and anticipates that it will file an EPA containing the terms of this arrangement. FBC did not include this in the Action Plan because it is not a new resource acquisition.

12.5 Please provide an update on the standby product offerings that FBC has, or plans to develop, for self-generators who are on rates with a demand charge.

Response:

FBC currently has Rate Schedule 37, Large Commercial Service – Standby Service. This rate is available only to customers also taking service on Rate Schedule 31 (Large Commercial Service – Transmission).

FBC has acknowledged in its Stage II SGP Application that in order to provide standby service to a self-generator served at distribution voltage a new tariff rate will be required. The Company expects that this matter will be explored during the regulatory process associated with the SGP Stage II Application.

C. CHAPTER 3 – LONG-TERM LOAD FORECAST

13.0 Reference: LONG-TERM LOAD FORECAST

Exhibit B-1, Volume 1, Appendix E, pp. 6–7

Residential customer count data

13.1 Please use the template below to provide a table which shows historical actual (A) figures for FBC's direct residential customer count for each year from 2006 through to 2015. Please include FBC's 2016 residential customer count forecast (F).

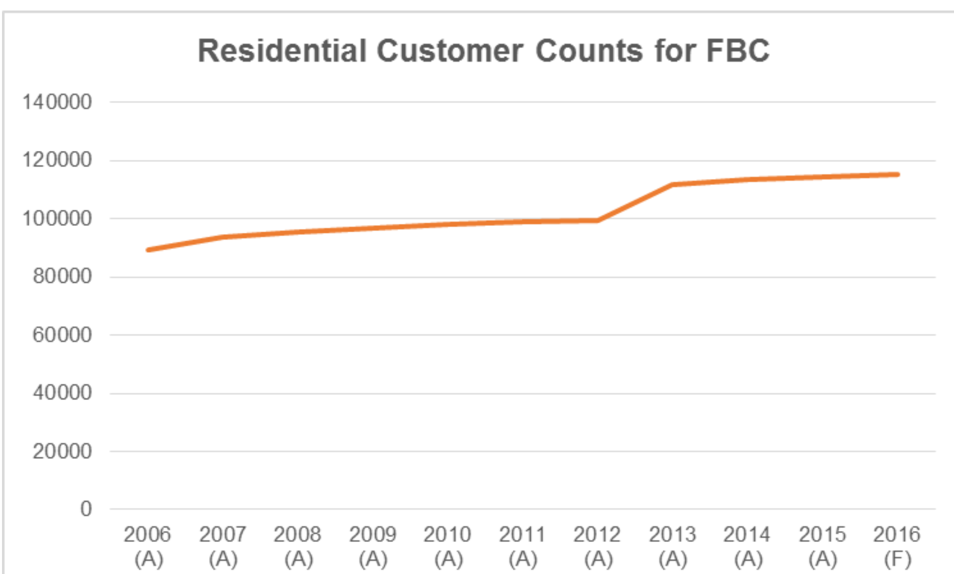
		Column 1	Column 2	...	Column 9	Column 10	Column 11
Row 1		**Residential Customer Count for FBC**					
Row 2		**2006 (A)**	**2007 (A)**	**...**	**2014 (A)**	**2015 (A)**	**2016 (F)**
Row 3	**Residential Customer Count**						

Response:

The requested information is shown in the table and chart below.

Table 1: Residential Customer Count for FBC

	Residential Customer Counts for FBC										
	2006 (A)	**2007 (A)**	**2008 (A)**	**2009 (A)**	**2010 (A)**	**2011 (A)**	**2012 (A)**	**2013 (A)**	**2014 (A)**	**2015 (A)**	**2016 (F)**
Residential Customer Count	89,181	93,647	95,502	96,565	97,883	98,795	99,228	111,862	113,431	114,166	115,080



The increase in direct customers in 2013 was a result of the acquisition of the City of Kelowna electric utility in 2013. These customers had previously been represented by the City of Kelowna as a single direct customer.

13.1.1 Please explain any anomalies in the residential customer count data presented in response to the previous question.

Response:

There are no anomalies in the data. As noted in the response to BCUC IR 1.13.1, the increase in direct customers in 2013 was a result of the acquisition of the City of Kelowna electric utility in 2013.

14.0 Reference: LONG-TERM LOAD FORECAST

Exhibit B-1, Volume 1, Appendix E, pp. 6, 8; Figure E-7, p. 8

Residential UPC data and load forecast methodology

On page 6 of Appendix E of the Application, FBC states: "Residential load growth is driven by the increase in customer count, which itself is determined econometrically as a function of population in the FBC service area. This is then combined with the forecast use per customer (UPC) to determine the residential load forecast."

On page 8 of Appendix E of the Application, FBC states:

> The [residential] UPC is forecast by averaging the most recent three years' normalized historical UPCs (2013, 2014, 2015), and each year after this is assumed to remain constant at the 2016 level of 11.80 MWh. This value was assumed to remain constant since there is no significant long term trend in the UPC at this point in time.
>
> The graph below [Figure E-7: Residential UPC (MWh)] shows the UPC, which was calculated by taking the forecast residential loads and then dividing it by the average customer count. After adjusting for savings, UPC increases slightly over the planning horizon.

14.1 Please use the template below to provide a table which shows historical actual (A) figures for FBC's normalized residential UPC for each year from 2006 through to 2015. Please include FBC's 2016 UPC forecast (F) as shown in the template.

		Column 1	Column 2	...	Column 9	Column 10	Column 11
Row 1		**Normalized Residential UPC for FBC**					
Row 2		**2006 (A)**	**2007 (A)**	**...**	**2014 (A)**	**2015 (A)**	**2016 (F)**
Row 3	**Residential UPC (MWh)**						11.80

Response:

Table 1: Normalized Before Savings UPC (MWh)

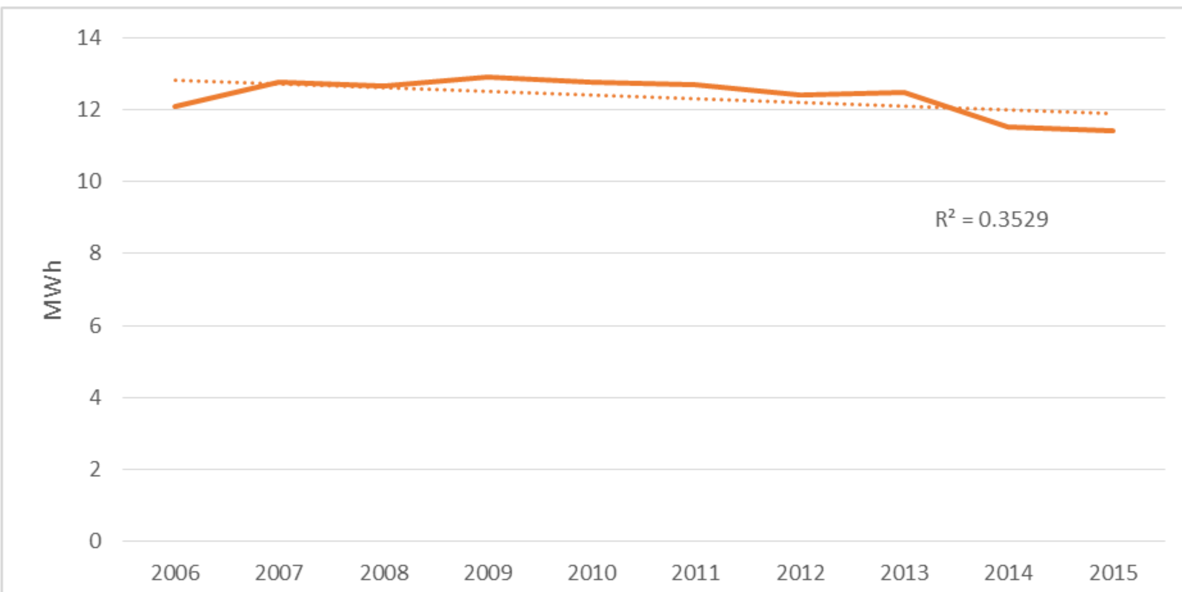
	Normalized UPC and Before Savings Forecast (MWh)										
	2006 (A)	**2007 (A)**	**2008 (A)**	**2009 (A)**	**2010 (A)**	**2011 (A)**	**2012 (A)**	**2013 (A)**	**2014 (A)**	**2015 (A)**	**2016 (F)**
Residential UPC (MWh)	12.09	12.74	12.64	12.90	12.77	12.70	12.41	12.48	11.51	11.41	11.80

14.1.1 Please explain if any trends (increasing/decreasing/constant) are present in FBC's historical normalized residential UPC data from 2006 through to 2015 and include a discussion of any years with an anomalous residential UPC.

Response:

No statistically significant trends are present in FBC's historical normalized residential UPC data from 2006 to 2015. This is demonstrated by the poor R^2 value (indicating low correlation of the UPC data to the trend line) for the before savings UPC trend line of 0.35, shown below.

Figure 1: Normalized Before Savings UPC (MWh)



FBC cannot definitively explain any changes in residential UPC in a given year as it is a result of many factors that may be both compounding and offsetting. For example, additional conservation due to the Residential Conservation Rate (RCR) might have reduced the load but this may have been offset by an increase in the number of appliances used in a home.

Finally, Grubbs test[16] was used to check the historic values for any outliers (anomalous values). None were found at the 95% confidence limit.

[16] https://graphpad.com/quickcalcs/grubbs2/.

14.1.1.1 If an increasing or decreasing trend is present for FBC's historical normalized residential UPC data from 2006 through to 2015, please explain the impact to the reference case load forecast if the trend is used to forecast FBC's residential UPC for the planning period in the Application. Please use calculations to support your response.

Response:

Please refer to the response to BCUC IR 1.14.1.1.

14.2 Please discuss the feasibility of accurately determining the trend for FBC's normalized residential UPC over a twenty year time frame using only the most recent three years of normalized historical UPCs, considering: (i) FBC's actual residential UPC data in response to the previous question; and (ii) recent energy and environmental policy included in B.C.'s CLP released in August 2016.

Response:

As discussed in the response to BCUC IR 1.14.1.1 there is no statistically significant trend in the residential UPC. The R^2 from the trend analysis was only 35 percent. In the absence of a statistically significant trend a different forecast method must be used. In this case a three year average was used and then the average was held constant for the remainder of the forecast period.

None of FBC's forecast methods incorporate any external factors or adjustments, such as the August 2016 CLP. The residential UPC forecast method relies primarily on historical data from FBC customers as captured in the FBC billing system.

FBC's load scenarios, discussed in Section 4 of the LTERP, consider other non-historical load drivers, such as environmental policy that may impact the future load requirements of customers.

14.3 Please confirm, or otherwise explain, that the residential UPC figure for each year in Figure E-7, comprises of a normalized constant residential UPC of 11.80 MWh plus an additional amount attributable to savings.

Response:

The residential after savings UPC in Figure E-7 is comprised of a normalized constant UPC of 11.80 MWh less an amount attributable to load savings.

14.3.1 If confirmed, please provide the forecasted savings figure in MWh for each year in Figure E-7.

Response:

Table 1: Residential UPC Savings Forecast (MWh)

Year	Residential UPC Savings Forecast (MWh)
2016	0.01
2017	0.00
2018	-0.02
2019	-0.04
2020	-0.07
2021	-0.08
2022	-0.09
2023	-0.10
2024	-0.11
2025	-0.11
2026	-0.12
2027	-0.13
2028	-0.14
2029	-0.15
2030	-0.15
2031	-0.16
2032	-0.17
2033	-0.18
2034	-0.19
2035	-0.19

15.0 Reference: LONG-TERM LOAD FORECAST

Exhibit B-1, Volume 1, p. 54; Appendix E, p. 2, p. 11 and p. 16

System losses and Advanced Metering Infrastructure (AMI) impact

On page 54 of the Application, FBC states that: "[l]osses are assumed to be 8 percent of gross load as discussed in Section 4.7 of Appendix E."

On page 16 of Appendix E in the Application, FBC states:

> System losses consist of the following: Losses in the transmission and distribution system; Losses due to wheeling through the BC Hydro system; Company use, and Unaccounted-for energy (meter inaccuracies and theft). Consistent with past practice FBC assumed a loss rate of eight percent of gross load, before the AMI impact. AMI loss reduction is expected to further reduce the losses in the future by reducing theft from the system from illegal marijuana grow operations.

On page 2 of Appendix E in the Application, FBC states: "

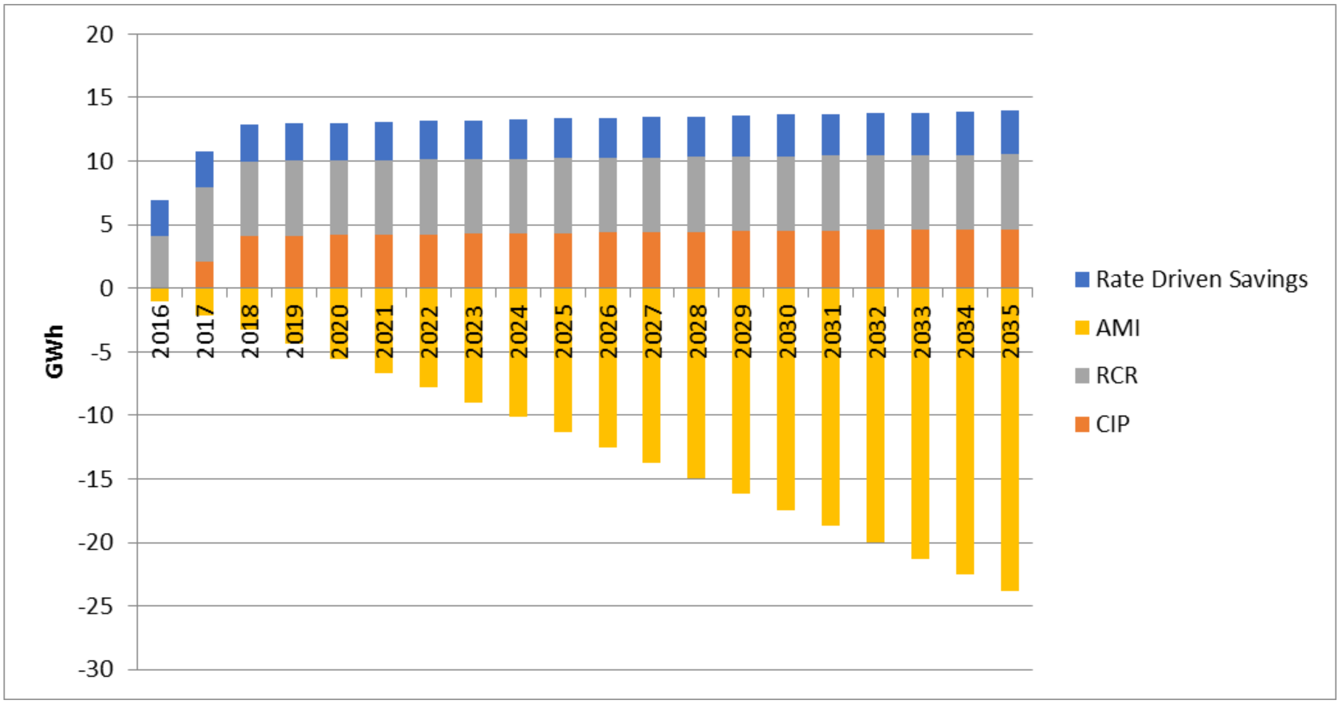
> Load savings include the impacts of the RCR, AMI, and rate-driven reductions in load due to price elasticity … AMI savings are the incremental sales that occur due to deterrence of theft, mainly from marijuana grow operations (as opposed to the closure of illegal unmetered marijuana grow sites, which are reflected in lower system losses)…."

15.1 Please explain, with calculations if necessary, whether the AMI impact is fully accounted for in the system losses forecast or through the load savings forecast described in section 2 of Appendix E of the Application.

<u>Response:</u>

The AMI impact is fully accounted for by combining the AMI system losses savings forecast and the residential AMI savings forecast. Although AMI reduces losses as a result of FBC's AMI-enabled theft detection program, there is also an increase in residential load since some of the previous thefts are converted to billable load, as well as due to a forecast increase in the overall number of marijuana grow operations in FBC's service territory as modeled in the AMI CPCN application. For example, the total AMI savings in 2017 is the AMI system losses savings forecast of 7 GWh in addition to the residential AMI forecast of -9 GWh, making the total 2017 AMI savings -2 GWh.

In the course of responding to this IR, FBC identified that Figure E-1: Load Savings 3 in Section 2 of Appendix E of the LTERP is incorrect. A corrected version of Figure E-1 is shown below. Note that the update affects Figure E-1 only. The correct values were used to prepare the forecast.



15.2 Please complete the table below by populating all the empty cells with corresponding data.

	Column 1	Column 2	Column 3	Column 4
Row 1	**FBC System Losses**			
Row 2 Row 3 Row 4	**Year**	**Normalized Actual System Losses (GWh)**	**Normalized Before-Savings Gross Load (GWh)**	**System Loss* (%)**
Row 5	**2011 Actual**			
Row 6	**2012 Actual**			
Row 7	**2013 Actual**			
Row 8	**2014 Actual**			
Row 9	**2015 Actual**			
Row 10	**2016 Actual**			
	Most recent 5-year average using actual historical data =			
	* - Column 4 = (Column 2 / Column 3) expressed as a %			

Response:

Table 1: FBC System Losses

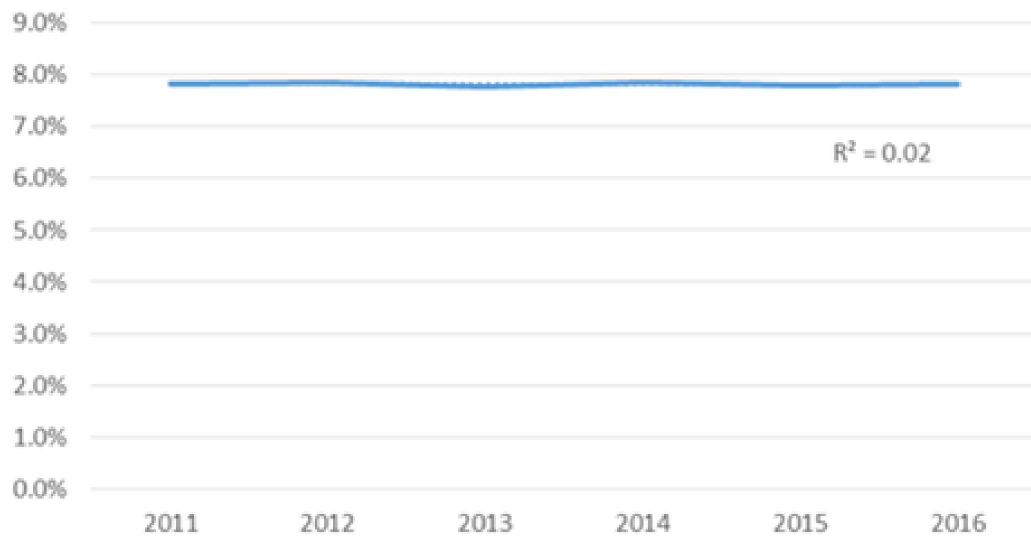
FBC System Losses			
Year	**Normalized Actual System Losses (GWh)**	**Normalized Before-Savings Gross Load (GWh)**	**System Loss (%)**
2011 Actual	307	3,484	8.8%
2012 Actual	271	3,462	7.8%
2013 Actual	278	3,545	7.8%
2014 Actual	270	3,470	7.8%
2015 Actual	272	3,466	7.9%
2016 Actual	274	3,506	7.8%
Most recent 5-year average using actual historical data			7.8%

15.2.1 Please explain if any trends (increasing/decreasing/constant) exist in the percentage figures for system loss presented in response to the previous question.

Response:

No statistically significant increasing or decreasing trends are present in the system losses presented in response to BCUC IR 1.15.2. As shown in the figure below, the losses have been relatively constant since 2011, which is likely due to the transmission system improvements that have been completed since the mid 2000s.

Figure 1: System Losses (%)



15.2.2 Please discuss (i) the feasibility, (ii) the impact to the reference case load forecast, and (iii) the impact to FBC's preferred portfolio and Action Plan of using the average of the percentage system loss for the five most recent years of historical data to forecast system losses for the 20-year planning period.

<u>Response:</u>

Referring to the response to BCUC IR 1.15.2, FBC notes that the 5 year average of losses is consistent with the load forecast of 8.0 percent if 2016 data is excluded. Including 2016 gives 7.8 percent, a difference of 0.2 percent or about a 7 GWh reduction in gross load. While it is possible to change one portion of the load forecast based on updated data, it is inappropriate to do so unless the entire load forecast is being updated. FBC does not expect that there would be any change to the preferred portfolio or action plan due to an updated load forecast.

15.3 Please explain if FBC considers that there will be no improvement in FBC's ability to reduce system losses to a percentage smaller than 8% for the 20-year time period of the Application.

Response:

FBC does expect system losses to be lower than 8 percent over the term of the LTERP.

There are no large-scale transmission reinforcement projects identified within the planning horizon, and FBC does not expect further significant reductions in system losses similar to those achieved through previous major projects. Instead, future system loss reductions from infrastructure upgrades are expected to be incremental and will be associated with ongoing system improvements such as localized distribution conductor replacements or power transformer upgrade projects.

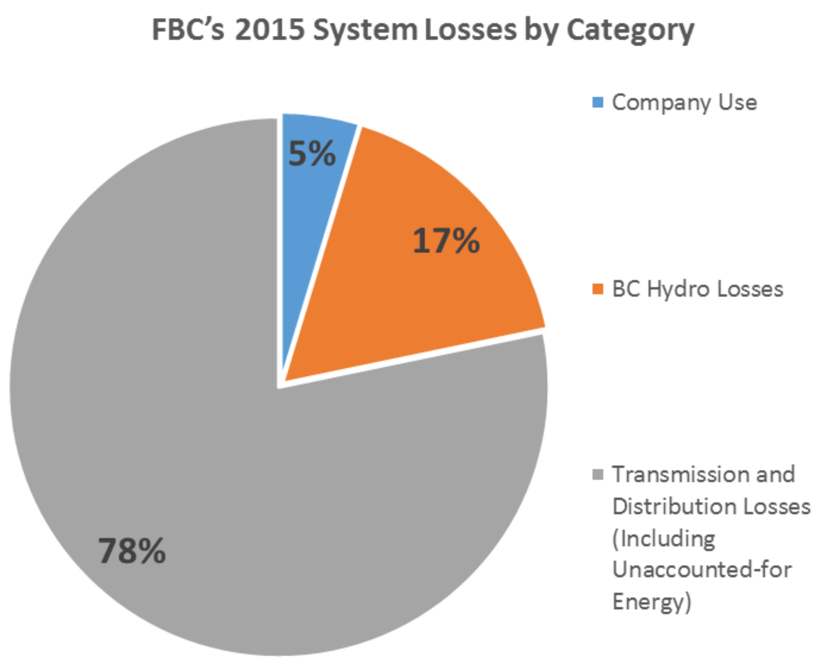
Continued system loss reductions are expected to be realized within the planning horizon from FBC's AMI-enabled theft detection program. As detailed in FBC's Annual Review for 2017 Rates, system losses for 2017 (after accounting for the AMI impact) are forecast at 7.8 percent, declining to 7.64 percent by 2019[17]. Continued improvements in FBC's AMI-enabled theft detection rate are expected out to 2021, after which it is projected that the success rate for theft identification and deterrence will plateau. As stated in section 4.7 of Appendix E in the LTERP, FBC assumed a loss rate of eight percent of gross load <u>before the AMI impact</u>.

15.4 **Please provide, to the best of your ability, a labeled pie chart titled "FBC's 2015 System Losses by Category" that shows the percentage energy losses broken down into each category listed in section 4.7 of Appendix E of the Application. Please include the corresponding energy loss in GWh for each percentage shown.**

Response:

The following chart and table show the percentage energy losses broken down into each category listed in Section 4.7 of Appendix E of the LTERP. Unaccounted-for energy is included in the Transmission and Distribution losses, since it cannot be accurately broken out.

[17] FortisBC Annual Review for 2017 Rates, p. 24, Table 3-4



2015 FBC Losses	MWh	Percent
Company Use	12,576	5%
BC Hydro Losses	45,598	17%
Transmission and Distribution Losses (Including Unaccounted-for Energy)	209,365	78%
Total	267,539	100%

On page 11 of Appendix E, FBC States:

> FBC has six wholesale customers that make up 16.8 percent of the total gross load…. Consistent with past practice the wholesale class is forecast using survey information from each of the individual wholesale customers…. All of the wholesale customers responded to the surveys with their forecast growth projections."

15.5 Please explain if system losses that occur within the wholesale customer's service territory are accounted for exclusively by the wholesale customers through the survey forecasts or exclusively by FBC through FBC's system losses forecast.

Response:

System losses that occur within the wholesale customers' service territory are accounted for exclusively by the wholesale customer surveys. The wholesale customers provide FBC with their forecast energy requirements based on historical energy usage that inherently includes losses.

15.6 Please provide an update of FBC's reduction in theft from the system from illegal marijuana grow operations resulting from the AMI program. Please include in this update a discussion of the strategy used by FBC to detect theft, and the results achieved.

Response:

FBC's strategy with respect to AMI-enabled theft detection involves two primary strategies: 1) the use of the tamper detection functionality of the AMI meters to help generate additional investigative leads, and 2) the use of feeder meters installed at key points on FBC's distribution feeders to measure the total amount of electricity supplied to a specific area and comparing that to the total downstream metered values ("energy balancing").

FBC took delivery of its feeder meters in Q3 2016, and has begun to implement its energy balancing theft detection program as described in the AMI CPCN application. The table provided below details the number of diversions discovered in 2015 and 2016 as compared to the forecast provided in the AMI CPCN application.

Table 1: Forecast and Actual Identified Theft Sites

	Forecast	Actual	Variance
2015	27	9	18
2016	39	11	28

FBC believes the variance between the forecast and actual number of identified theft sites is most strongly linked to the deterrent effect of the AMI meter deployment and the resulting perception that power theft is becoming increasingly difficult to hide. In addition, the delay in the implementation of FBC's energy balancing strategy as compared to the forecast provided in the

AMI CPCN application (originally forecast to commence in 2015), has reduced the number of thefts that could be identified using AMI data.

Based on the reduced number of thefts identified through more traditional means during 2015 and 2016 (prior to the implementation of energy balancing), FBC believes that the theft deterrence impact of the AMI project is increasing at a rate greater than initially forecast in the CPCN application.

16.0 Reference: LONG-TERM LOAD FORECAST

Exhibit B-1, Volume 1, Appendix E, p. 4 and p. 11

Wholesale customer forecast accuracy

On page 4 of Appendix E of the Application, FBC presents a pie chart showing that wholesale customers accounted for 16.8 percent of 2015 gross load consumption. On page 11 of Appendix E in the Application, FBC explains that the wholesale class is forecast using survey information from each of the individual wholesale customers.

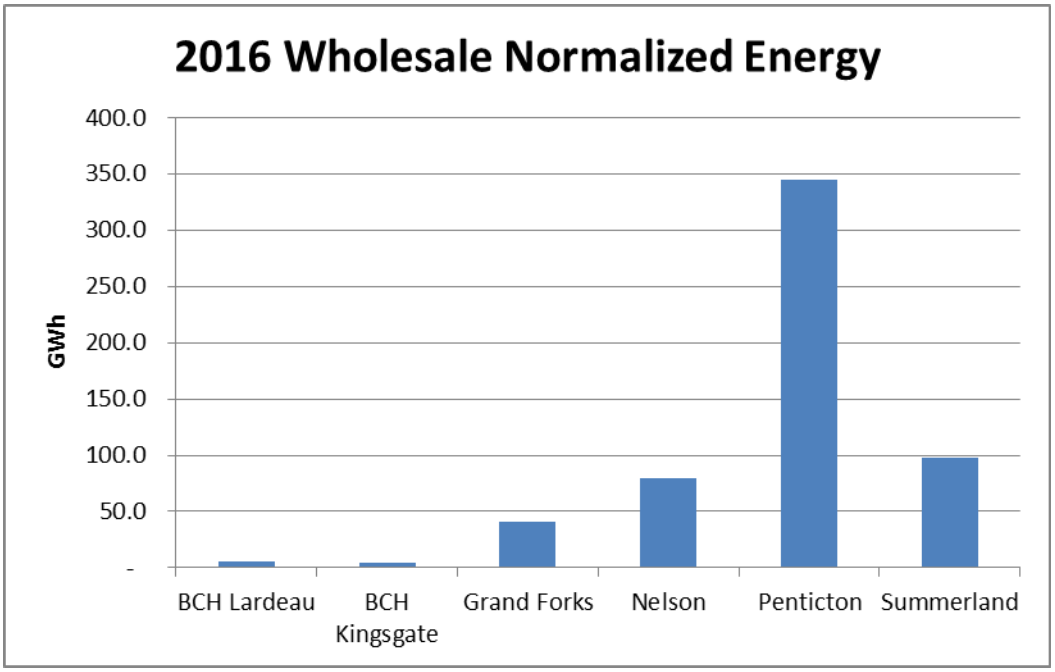
16.1 Please provide a table which shows, for each of the wholesale customers, the three most recent years of data for the (i) forecasted load, (ii) the actual load, (iii) the variance between forecast and actual in units, and (iv) the percentage variance between the forecast load and actual load.

<u>Response:</u>

Actual load is included, below, as requested. However, the variance in this table is calculated by comparing after-DSM 2012 LTRP Forecast load to Normalized Load. FBC believes reporting the variance relative to weather normalized load is more appropriate, and the data is shown in the following table.

Wholesale Customer Actual and Normalized vs. 2012 LTRP Forecast							
	Actual (GWh)						
Year	BCH Lardeau	BCH Kingsgate	Grand Forks	Nelson	Penticton	Summerland	Total
2014	6.3	4.9	40.9	82.2	346.5	97.3	578.1
2015	6.3	4.7	39.8	81.5	344.7	94.8	571.9
2016	6.2	4.7	39.4	80.3	337.1	93.9	561.7
	Normalized (GWh)						
Year	BCH Lardeau	BCH Kingsgate	Grand Forks	Nelson	Penticton	Summerland	Total
2014	6.3	4.6	39.5	80.9	341.9	94.0	567.1
2015	6.5	4.8	40.7	83.0	348.4	97.1	580.5
2016	5.9	4.8	40.5	79.6	345.2	98.2	574.3
	Forecast After-DSM (GWh) (allocated)						
2014	6.7	3.4	43.3	92.1	362.2	100.8	608.4
2015	6.7	3.4	43.4	93.1	366.6	99.9	613.1
2016	6.6	3.4	43.6	93.7	368.5	99.4	615.2
	Variance (GWh) (Forecast to Normalized)						
2014	(0.5)	1.3	(3.8)	(11.2)	(20.3)	(6.7)	(41.2)
2015	(0.2)	1.5	(2.7)	(10.1)	(18.2)	(2.8)	(32.6)
2016	(0.7)	1.5	(3.0)	(14.1)	(23.3)	(1.3)	(40.9)
	Percent Variance (Forecast to Normalized)						
2014	-7%	28%	-10%	-14%	-6%	-7%	-7%
2015	-4%	30%	-7%	-12%	-5%	-3%	-6%
2016	-12%	30%	-7%	-18%	-7%	-1%	-7%

It is important to take into account that the size of each individual wholesaler is not equal as shown in the chart below. A larger wholesale customer such as Penticton makes up a much larger proportion of the total wholesale demand.



16.1.1 Please discuss the accuracy of the forecasts provided in response to the previous question.

<u>Response:</u>

Please refer to the response to BCUC IR 1.16.1.

D. CHAPTER 5 – EXISTING SUPPLY-SIDE RESOURCE

17.0 Reference: MARKET PURCHASES

Exhibit B-1, Volume 1, pp. 32, 36, 108; 2016 NW PP, pp. 1-5, B-15

Attributes – environmental

On page 32 of the FBC 2016 LTERP Application, FBC states: "Regional market electricity prices continue to be highly correlated with regional natural gas prices. This is largely because natural-gas fired power plants are often the marginal generating unit for generating electricity." FBC further states on page 36: "…gas-fired power plants have become a low-cost alternative for power generation … This will further strengthen the interdependency between natural gas and electricity prices in the Pacific Northwest region."

The 2016 NW PP states on page 1-5: "Although the dominant generating resource in the region is hydropower, natural gas-fired plants are often the marginal generating unit for any given hour." Page B-15 includes a graph which shows a linear relationship between the Mid-C electricity price and the natural gas price. On page 108 of the FBC 2016 LTERP Application, FBC describes market energy as 'mixed' under the clean/renewable category.

17.1 Please describe FBC assumptions regarding the environmental attributes of market energy purchases, and explain if assumptions are consistent with those used to forecast market prices.

Response:

FBC has assumed market energy purchases contain 0.19 CO_2e ton/MWh. This assumption is based on historical FBC GHG emission data and is independent from the market price forecast. Please refer to the response to BCUC IR 1.18.3 for the environmental attributes included in the forecast market prices.

17.1.1 Does FBC have the option of purchasing market energy from clean sources? If yes, please estimate the incremental cost.

Response:

FBC believes that the majority of its market purchases are from clean sources, based on the generation mix in the Pacific Northwest, but it is difficult to determine the ultimate source of every market purchase and whether the purchase has all of the clean or renewable energy attributes still associated with it. For example, a wind generator may sell the environmental attributes of its generation to California, and the physical generation to the regional market, which could then be purchased by FBC.

At this time, FBC cannot estimate the cost that it would take to ensure all market purchases come from green resources. FBC would likely have to enter into a bilateral agreement with a clean or renewable generator for all or a portion of the generator’s output, to ensure the energy is secured and has all of the clean and renewable attributes. This means that FBC would likely not pay the wholesale power rate but rather that a negotiated price would have to be agreed upon, likely at a premium to the wholesale market price. However, even if FBC contracts for sufficient clean or renewable generation to meet 100% of market requirements on a planning basis, there is no guarantee that the energy will be available to meet load when required, due to the variable nature of clean or renewable generation and load. The contracted energy simply may not be available when it was counted on or needed, meaning that FBC would have to acquire other market power that may or may not be from clean or renewable generation.

18.0 Reference: MARKET PURCHASES

Exhibit B-1, Volume 1, pp. 45, 111, Appendix J, p. 42; FBC 2012 RR & ISP, Exhibit B-1-2, p. 31

Attributes – price and price risk

FBC provides a graph showing forecast future mid-C prices on page 45 of FBC 2016 LTERP Application, and discusses the range of unit energy costs for market purchases on page 111.

FBC states on page 42 of Appendix J to the 2016 FBC LTERP Application:

> … the base case long term market price for electricity at Mid-C, the levelized unit energy cost for market purchases is about $51 per MWh including transmission costs and losses from Mid-C. … Relying on market purchases for energy or capacity in the long term can be risky for FBC. … regional market power supply, and capacity in particular, may be declining in the future. There may also be new transmission congestion issues as systems are operated differently to integrate renewable resources.

FBC stated on page 31 of the FBC 2012 LTRP that in July 2006 it was required to purchase 1,680 MWh of energy from the market at an average price of $225/MWh during a region-wide hot spell.

18.1 Please describe the attributes of market energy in terms of: term, delivery location and shape.

Response:

Term, delivery, location and shape of market energy will vary depending on each individual transaction and are not set at this time for future transactions. Typically, FBC purchases market energy at the B.C./U.S. border sourced from the United States with the delivery location being FBC's system in the Kootenays. The term will range from one hour to one quarter of a year (e.g. the period from October to December) and the shape will depend on need at the time. The shape can be a single hour, a block of hours, all hours in the term or only the peak hours or off-peak hours.

18.2 Please explain how FBC has included the risk of market price spikes into its price forecast.

Response:

The market price forecast presented in Figure 2-9 of the LTERP does not include the risk of market price spikes since it presents average prices on an annual basis. FBC assumes the risk of price spikes to be minimal over the shorter term as discussed in the response to BCUC IR 1.18.2.1.

18.2.1 Have there been occasions of market price spikes in the last five years, and to what extent does FBC consider this could be a concern in the future?

Response:

There have been market spikes over the last five years, however, FBC believes the risk of market price spikes has been low and will remain low in the future due to five main reasons:

1) Market price spikes have typically been due to short-term imbalances between load and generation, and/or due to transmission congestion, and have not been linked to long-term supply-side shortages. Therefore, they typically do not last long.

2) FBC has sufficient capacity to meet peak demand requirements. FBC may choose to purchase market energy on a specific hour as opposed to increasing PPA capacity, however, the number of hours FBC would be exposed to market rates would be minimal.

3) The majority of FBC's recent market purchases are fixed price transactions entered into in advance, and therefore not subject to market price spikes.

4) For some market purchases that are required only for energy and not capacity, FBC has the ability to delay any purchase by using the flexibility in its CPA Storage Accounts, which can avoid the timing of price spikes.

5) FBC has assumed self-sufficiency, i.e. no market purchases, for the preferred portfolio after 2025. After this time, FBC believes there may be risks with relying upon market capacity and transmission availability, as discussed in Section 2.4.4 of the LTERP.

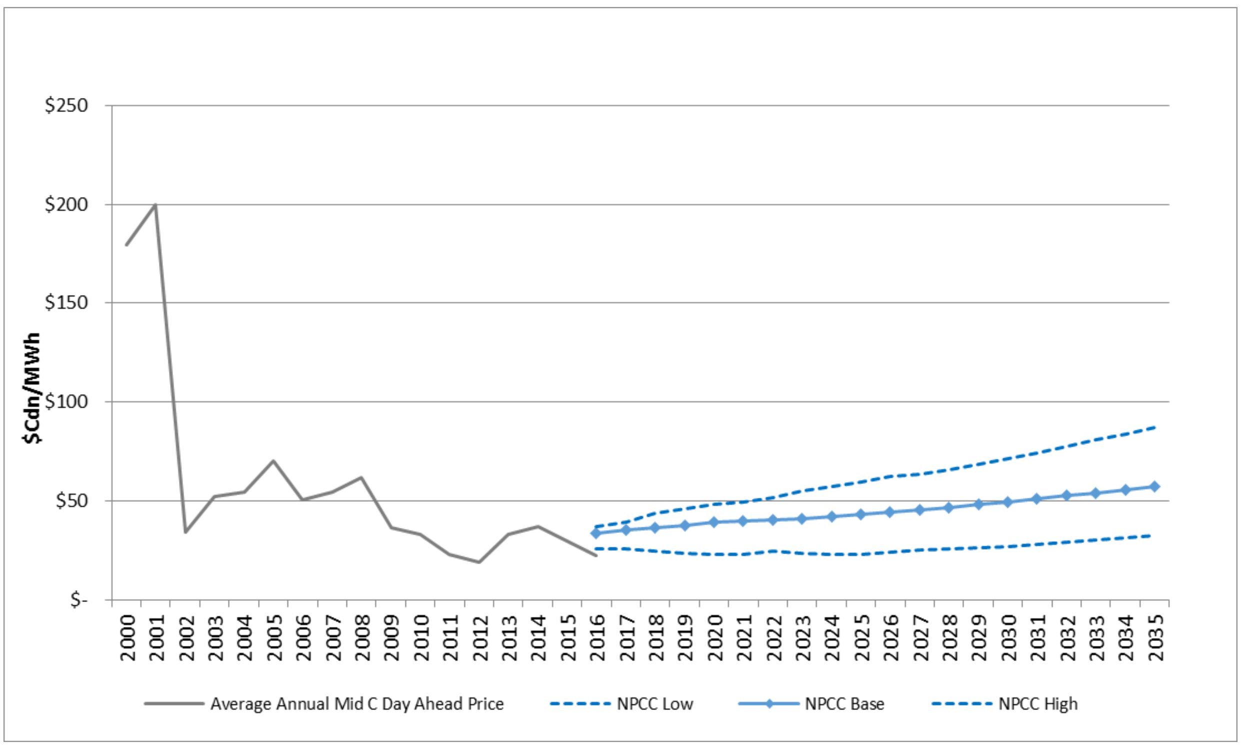
Therefore, FBC believes the risk of market price spikes will remain low in the future.

18.2.2 Please update the graph on page 45 of the Application to also show historical Mid-C prices from the year 2000.

Response:

Figure 2-9 on page 45 of the LTERP shows forecast annual Mid-C prices on an inflation-adjusted basis in 2015 Canadian dollars per megawatt-hour (MWh). Figure 2-9 has been updated as Figure 1 below to include average annual Mid-C day-ahead prices from 2000 through 2016 in Canadian dollars per MWh. The historical Mid-C prices are actual prices in nominal terms and therefore have not been adjusted for inflation.

Figure 1: Mid-C Electricity Actual Prices and Annual Price Forecast



18.3 Please compare the methodology used by FBC in developing its market price forecast and the attributes assumed (i.e., firmness, environmental) with that assumed by BC Hydro in its 2013 IRP. Please explain any significant differences.

Response:

The FBC Mid-C electricity market price forecasts are based on the Northwest Power and Conservation Council (NPCC) Seventh Power Plan (Power Plan) released in February 2016. FBC converted the Power Plan price forecasts from 2012 real U.S. dollar units to 2015 real Canadian dollar units. The Power Plan electricity price forecasts represent the future price of electricity traded on the wholesale spot market at the Mid-C trading hub. The NPCC makes no reference to the firmness attributes assumed for the spot market prices. The NPCC uses an Electricity Market Model to develop the electricity price forecasts. The model is an hourly dispatch model which calculates an electricity price based on the variable cost of the marginal generating unit[18]. Therefore, the electricity price forecasts are highly influenced by the Sumas market gas price forecast since natural gas is most often the marginal generation resource in the region. The key price drivers include electricity load, fuel price delivered to generation, existing and new generation capabilities and costs, Renewable Portfolio Standards (RPS), which drive new resource builds, and carbon emission pricing policies. The carbon emission pricing policies impact electricity prices by attaching an emission cost to fossil fuel generation. A carbon price curve for the California cap and trade program was implemented in the model as a cost in terms of dollar per ton of carbon emitted while the carbon price of $30 per tonne was attached to carbon-emitting resources that reside within B.C.

BC Hydro's 2013 IRP electricity market price forecasts were developed based on gas market price, carbon price and renewable energy credit (REC) price forecasts produced by Ventyx[19]. The electricity price forecasts were modelled under a computer simulation of the hourly supply-demand balance for the WECC regional market. The dispatch cost of the marginal resource at the point where supply and demand are in equilibrium determines the market price for that hour. Monthly and yearly average prices are obtained by aggregating the computed hourly prices. BC Hydro does not make any reference to the firmness attributes assumed for the electricity market prices.

Ventyx developed five market scenarios based on different assumptions, such as gas and electricity supply and demand, resource options and carbon emission policies. The natural gas and carbon price forecasts inform the cost of natural gas-fired generation in B.C. BC Hydro notes that given the increased role of natural gas-fired generation in the U.S. portion of the Western Electricity Coordinating Council (WECC) region, natural gas prices have become a critical determinant in establishing spot market electricity prices. Regulation of carbon emissions

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[18] NPCC Seventh Power Plan, Appendix B.
[19] BC Hydro 2013 IRP, Chapter 5.

and RPS result in both costs and benefits for resource options that can influence market prices.[20]

The BC Hydro carbon price forecasts are used as inputs to the electricity price forecasts and are applied to all carbon-emitting resources in the WECC under a national cap-and-trade scenario and only to Alberta, B.C. and California carbon-emitting resources in the regional scenarios. This has the effect of uplifting electricity prices[21]. The carbon price forecasts are also used as adders to B.C. carbon-emitting resources (natural gas-fired generation). BC Hydro's analysis assumes that natural gas-fired generation in B.C. would incur the maximum of either the B.C. carbon tax ($30 per tonne) or the developed carbon price forecasts.

Based on FBC's understanding of the NPCC and BC Hydro price forecast methodologies, it does not see any significant differences.

[20] BC Hydro 2013 IRP, Chapter 5, page 5-2.
[21] BC Hydro 2013 IRP, Chapter 5, page 5-25.

19.0 Reference: MARKET PURCHASES

Exhibit B-1, Volume 1, pp. 39, 40, 79; Appendix L, pp. 9, 10; BCH 2013 IRP, p. 9-54; FBC 2012 RR & ISP, Exhibit B-1-2, p. 31

Attributes – firmness

FBC states on pages 39 and 40 of the FBC 2016 LTERP: "… under critical water conditions the region faces the probability of a peak capacity shortfall … transmission interconnections often operate at their maximum available transfer limits …" FBC also states on page 79: "Additional firm transmission cannot be reliably obtained on the U.S. side of the border and as such … it cannot be considered a long-term resource to meet capacity requirements." FBC provides on pages 9 and 10 of Appendix L to the FBC 2016 LTERP (2016 Planning Reserve Margin (PRM) report) the forced outage rate assumed for market availability.

BC Hydro states on page 9-54 of its 2013 IRP "The spot market provides non-firm energy and no capacity, and generally has a term of one hour." On page 31 of the FBC 2012 LTRP FBC stated that during a regional cold spell in 2010, FBC attempted to purchase an additional 10MW in the real time market and there was no supply available at any price and that a similar situation occurred the following week.

19.1 Please provide the forced outage rate assumed related to (1) transmission forced outages and (2) market availability in both the 2014 Planning Reserve Margin Studies report and the 2016 Planning Reserve Margin Report. Please explain how these estimates were derived, and any changes in assumptions between the 2014 and 2016 estimates.

Response:

In the Planning Reserve Margin (PRM) Study, FBC treats the market as a resource that can be drawn upon to support deviations from the expected operating environment. The following table states the assumptions around market access contained in the PRM study.

Table 1: Market Access & Planning Reserve Margin Assumptions

	2014 PRM Study	2016 PRM Study
Probability of transmission forced outage	0.74 percent	0.55 percent
Probability of market NOT available	Zero (0) percent	0.16 percent

The assumed probability of a transmission forced outage resulting in the loss of market access is based on the historic availability of 71 Line. For the 2014 PRM study, FBC considered forced outage data for the years 2000-2011. For the 2016 PRM study, FBC considered forced outage data for the years 2000-2015. As there were no significant outages to 71 Line that occurred in the years 2012-2015, the assumed transmission forced outage rate effectively decreased.

In the 2016 PRM study, the probability of the market not being available to serve peak load was updated to 0.16 percent, which equates to an estimate of three times in five years and shaped for seasonal attributes. FBC will continue to monitor and refine the approach to quantifying the risk of market availability in the future.

The Market Availability assumption was updated to recognize that the probability of the market not being available for purposes of meeting peak load in the future is no longer equal to zero. This change in assumption reflects the potential for increasing competition for market capacity among utilities and the changing regional resource mix. Other utilities are also beginning to recognize the market contains some level of reliability risk.[22] FBC did assume an additional 75 MW of fully reliable market capacity during Freshet (specifically June) given the large quantity of hydro generation in the region and that capacity would likely be sourced from within B.C.

19.1.1 Does FBC consider that these reliability estimates reflect future (rather than historic) risks of market reliability? Please explain.

Response:

FBC has used historic market risk in an attempt to estimate future market reliability. FBC believes that in the long term, the market risk is likely greater than these estimates, but has not attempted to include that in the risk estimate. Please also refer to the response to BCUC IR 1.19.1.

19.1.2 To what extent, if any, does FBC consider market energy to be ‘firm’ energy.

[22] Puget Sound Energy. 2015 IRP. Chapter 6: Electric Analysis. Incorporating Wholesale Market Reliability Risk.

Response:

FBC's market purchases are all designated firm energy using industry standard scheduling practices. At this time, FBC does not purchase non-firm market energy. However, this should not be confused with an assurance that market energy is available to be purchased on any given hour, only that if it is purchased, it is firm. Please also refer to BCUC IR 1.19.2.

19.2 Please explain why FBC considers market purchases to be a reliable and secure source of energy supply in the short to medium term.

Response:

The LTERP in Sections 5.5 and 8.2.4 differentiates between market energy and capacity. The reliability of market capacity may decrease in the future such that it cannot be considered a long-term resource to meet capacity requirements. However, in the short to medium term FBC expects that it will be reliable enough to cover any small gaps, if needed. No resource can be counted on 100 percent and therefore no resource is risk free, including market capacity. FBC examines the overall reliability of a portfolio through a Planning Reserve Margin analysis as described in the LTERP Section 9.3.6.1.

Regarding market energy, FBC is confident in its continued ability, as demonstrated by current and past operating experience, to utilize system operating flexibility to allow market energy to be purchased on a reliable and secure basis in sufficient volume to meet the relatively small energy gaps through 2035. However, as explained in the Section 9.3.2 of the LTERP, FBC believes that self-sufficiency at some point in the planning horizon is a more prudent approach to resource planning.

20.0 Reference: FBC-OWNED GENERATION ENTITLEMENTS

Exhibit B-1, Volume 1, pp. 76, 78

Generation Capital Expenditures/contract extension

On page 76 of the FBC 2016 LTERP Application, FBC states that, subject to Commission approval, it intends to refurbish four generating units at the Upper Bonnington Plant in the 2017-2020 timeframe. FBC also states on page 78 that it is in discussions to extend the purchase of unused CPA entitlements from the Brilliant and Brilliant Expansion Plants.

20.1 Please explain why FBC has not included a potential filing of an extension of the Brilliant power purchase agreement or the Upper Bonnington Plant refurbishment in the four-year Action Plan.

Response:

As described in the Resource Planning Guidelines, the action plan "consists of the detailed acquisition steps for those resources (from the selected resource portfolio) which need to be initiated over the next four years to meet the most likely gross demand forecast." FBC does not consider the extension of the existing contract, which is assumed in the preferred portfolio, or the refurbishment of its existing generating plants, to represent new resource acquisitions, and therefore did not include them in the action plan.

FBC applied for approval of the Upper Bonnington Old Units Refurbishment Project in its Annual Review for 2017 rates, and the project was approved by Order G-8-17. As noted on page 78 of the LTERP, FBC will file any extension of the Brilliant agreement for Commission acceptance.

20.2 Please discuss if there are other generation capital expenditures expected in the next four years that FBC intends to construct or extend to serve the estimated demand.

Response:

FBC confirms that there are no other generation capital expenditures expected in the next four years that FBC intends to construct or extend to serve the estimated demand.

E. CHAPTER 6 – TRANSMISSION AND DISTRIBUTION SYSTEM

21.0 Reference: RECENT SYSTEM UPGRADES AND EXPENDITURES

Exhibit B-1, Volume 1, Section 6.1.3, pp. 83–84; FBC 2012 RR & ISP, Exhibit B-1, Tab 6 2012-2013 Capital Expenditure Plan, Index of Tables and Figures, pp. vi–vii-

Capital Expenditures

On page 83 of the Application, FBC states that "To ensure ongoing safe and reliable operation of the electric system, FBC undertakes both growth and sustainment capital investments in the transmission and distribution system on an annual basis." Under Table 6-2 on page 84 of the Application, FBC provides the following actual expenditures from 2011 – 2015 and planned expenditure for 2016:

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

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

21.1 Please expand the above table to provide the total transmission and distribution capital expenditures planned for the next four years.

<u>Response:</u>

The following is an expansion of the above table containing the current plan for capital expenditures. FBC has extended the table to cover five years in response to the information requested in Gabana IR 1.19.

Expenditure Categories	2017	2018	2019	2020	2021
Transmission, Stations, Protection & Control, Telecommunications	15,123	17,513	19,339	35,160	30,622
Distribution	30,405	29,513	28,726	34,921	33,445

21.1.1 Please provide:

- A breakdown of the transmission and distribution facilities that FBC intends to construct or extend in order to serve the estimated demand in the next four years,

- A brief description of the facilities that FBC intends to construct or extend in order to serve the estimated demand,
- An explanation of why the demand for the energy to be served by the facilities FBC intends to construct or extend are not planned to be replaced by demand-side measures.

Response:

FBC interprets the term “facilities to serve the estimated demand in the next four years” as meaning only the non-routine projects that will serve growth over the requested time frame, of which there are three:

1. Sexsmith Second Distribution Transformer Addition – Due to growth in north Kelowna, a second distribution transformer at the Sexsmith Substation will be required in order to continue to meet planning criteria. This project will include the addition of a substation transformer, associated breaker(s) and switches, instrument metering, and protection and control devices.
2. DG Bell Distribution Transformer Addition – Due to growth in south Kelowna, a second distribution transformer at the DG Bell Terminal will be required in order to continue to meet planning criteria. This project will include addition of a substation transformer, associated breaker(s) and switches, instrument metering, and protection and control devices.
3. DG Bell Feeder 4 Addition – Due to growth in south Kelowna, an additional distribution feeder will be required in order to continue to meet planning criteria. The construction of the first phase of this new distribution feeder supplied from the DG Bell Terminal is tentatively planned to coincide with City of Kelowna new road construction in order to minimize construction cost.

Please refer to the response to BCUC IR 1.23.2.1 regarding targeted demand-side management measures.

In FBC’s 2012-2013 RR & ISP Application (Exhibit B-1), under the 2012-2013 Capital Expenditure Plan, FBC requested Commission approval of projects and associated expenditures under: ‘Generation’, ‘Transmission’, ‘Distribution’, ‘Telecommunications, SCADA and Protection and Control’, ‘General Plant’ and ‘Demand Side Management’, all listed from Table 2 to Table 7.

21.2 From all projects listed in Table 2 to Table 7, please identify any significant changes to the facilities planned to be built or extended from the 2012-2013 Capital Expenditure Plan.

Response:

There were significant changes to the following projects listed in Table 2 to Table 7 from the 2012-2013 Capital Expenditure Plan. These are shown in the table below.

Table	Project	Comments
Table 2.0 - Generation Projects	All Plants Safety and Security	Optimization resulted in a substantial reduction in scope. Completion of required scope is ongoing.
Table 3.0 - Transmission and Stations Projects	Grand Forks Transformer Addition/ High Capacity Communications	As indicated in Table 6-3 of the LTERP, this project is now planned for the 2018-2020 Time Frame. FBC is currently evaluating alternatives to satisfy system requirements and minimize project costs.
	Kelowna Bulk Transformer Capacity Addition	As indicated in Table 6-3 of the LTERP, this project is now planned for 2019-2020 Time Frame.
Table 4.0 - Distribution Projects	Glenmerry Feeder 2-Glenmerry Feeder 1 Tie Line	There was a decrease in commercial load in this area. This growth project was deferred and is still on hold.
Table 6.0 - General Plant Projects	Kootenay Long Term Facilities Strategy	Change to project timing. Kootenay Operations Centre construction began in 2016 and will be complete in 2017.

22.0 Reference: ANTICIPATED SYSTEM REINFORCEMENTS

Exhibit B-1, Volume 1, pp. 87, 164–166

Transmission Project CPCNs/Long Term Capital Plan

On page 87 of the Application, FBC indicated that it "filed a [LT CP] Plan in June 2011, which identified short term (2012-2013), medium term (2014-2016) and long term (2017 onward) transmission projects."

FBC further states: "At the present time, only two transmission reinforcement projects have been identified within the 20-year planning horizon; in both cases these projects were intended to be the subject of future CPCN applications." Table 6-3 in the Application shows these projects:

Table 6-3: Transmission Reinforcement Projects

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

FBC includes its Action Plan on pages 164 to 166 of the Application.

22.1 Please confirm that FBC will not be filing a new Long Term Capital Plan (LT CP) under this proceeding. If not confirmed, please discuss and specifically indicate when FBC anticipates filing a LT CP.

<u>Response:</u>

FBC confirms that it is not filing a long term capital plan under this proceeding. FBC is currently reviewing the timing for filing of future capital plans and does not have a specific filing date at this time.

22.2 If the two transmission reinforcement projects are Certificates of Public Convenience and Necessity (CPCNs) expected within the next four years, please discuss why these have not been included in the action plan.

Response:

As described in the Resource Planning Guidelines, the action plan "consists of the detailed acquisition steps for those resources (from the selected resource portfolio) which need to be initiated over the next four years to meet the most likely gross demand forecast."

FBC therefore included in its Action Plan only activities and actions specific to the acquisition of new energy and capacity resources, which are reflected in the selected portfolio, to meet the requirements of its customers. FBC will seek Commission approval of these projects prior to their commencement.

22.3 Please provide more details on why the two transmission reinforcement projects are needed to serve the estimated demand.

Response:

Grand Forks Terminal (GFT) Transformer Addition:

In the event of a single contingency outage of the existing GFT T1 161/63 kV transformer, the loads in the Grand Forks and Christina Lake areas must be supplied via two existing 63 kV transmission lines. In this operating configuration, these lines must be operated in parallel to keep voltages in the area within acceptable limits during winter peak. Based on the current condition of these lines, FBC does not believe that this operating configuration provides adequate reliability. Additionally, as load in the area increases, this configuration may not be an option to maintain voltages within acceptable limits.

Kelowna Bulk Transformer Capacity addition:

Bulk transformation capacity addition is needed to adequately serve Kelowna area load in a single contingency. In the case of an outage of either the LEE T3 or T4 transformers, the remaining transformer is overloaded both during winter and summer peak periods. Initially the overloading can be mitigated by reconfiguring the 138 kV network in Kelowna and transferring load from Lee Terminal station to DG Bell Terminal station. However, the ability to transfer load is limited by transmission line limitations. In addition, as per FBC Facility Ratings Operating Order, facilities can only be operated at the emergency limits for a maximum of six hours. If emergency operating conditions are expected to last longer than six hours, plans to reduce the facility loadings must be developed and implemented within the six hours. Without additional bulk transformation capacity, this may require load shedding as Kelowna load increases.

23.0 Reference: NETWORK INVESTMENTS

Exhibit B-1, Volume 1, pp. 87, 89; FBC 2012 RR & ISP, Exhibit B-1-1, FBC 2012 Long-Term Capital Plan (FBC 2012 LT CP), p. 8; 2016 NW PP, pp. 12-41, G-52; Puget Sound Energy 2015 Integrated Resource Plan (PSE 2015 IRP)[23], p. 6-27; Idaho Power 2015 Integrated Resources Plan[24], p. 48

DSM and DG alternatives

FBC states on page 87 of the 2016 LTERP Application: that the lack of dynamic reactive support in the Okanagan (due to absence of generation resources which can respond to load changes in real-time) can lead to low voltages or voltage collapse during contingency conditions.

FBC states on page 89 of the 2016 LTERP Application that the integration of a new large-scale generation resource, such as a gas-fired generation plant, could defer the requirement for the proposed third bulk transformer.

FBC stated on page 8 of its 2012 LT CP that it was evaluating Voltage and Var Optimization. The 2016 NW Power Plan describes on page 12-41 its program to regulate voltage on distribution lines to minimize system and end-use losses, and on page G-52 describes its distribution system efficiency measure bundles. The PSE 2015 IRP includes on page 6-27 voltage reduction and phase balancing as a demand-side resource. Idaho Power 2015 IRP includes on page 48 conservation voltage reduction.

23.1 Please provide an update of FBC's evaluation of voltage and Var optimization discussed in FBC's 2012 LT CP. Does FBC have Voltage and Var optimization programs similar to those described in the 2016 NW PP, PSE 2015 IRP and Idaho Power 2015 IRP? Please explain why/why not.

<u>Response:</u>

FBC continues to study voltage and Var optimization (VVO). The most recent evaluation of a potential VVO program indicated that it would not result in an overall financial benefit to customers. As such, FBC is not actively pursuing a VVO program at this time.

[23] https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_Chap6.pdf
[24] https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/2015IRP.pdf

23.2 Please explain whether small-scale or larger clean DG could (i) defer the requirement for the anticipated network system reinforcements, and (ii) provide dynamic reactive support.

Response:

It is possible that small-scale or larger clean DG resources could (i) defer the requirement for the anticipated network system reinforcements, and (ii) provide dynamic reactive support. In order to have this impact, the clean DG resources would collectively need to have availability factor, capacity factor, and dynamic reactive capability characteristics similar to a gas-fired generation plant. They will also need to be located in areas where the anticipated network system reinforcements are planned to occur.

23.2.1 Please explain whether targeted regional DSM programs could defer the requirement for the anticipated network system reinforcements.

Response:

DSM programs incorporate a broad range of measures, targeted at major end-uses in each customer sector, and offers are made available to all eligible customers across the FBC service area. Targeted regional offers introduce disparate incentive offers, which are inequitable to customers outside of the target region.

FBC considers DSM savings to be reliable but non-firm resources, and thus cannot be counted on to defer network system reinforcements that are predicated on peak load requirements.

F. CHAPTER 7 – LOAD RESOURCE BALANCE

24.0 Reference: LOAD RESOURCE BALANCE

Exhibit B-1, Volume 1, pp. 92-93, p. 49; BC Hydro 2014 Application for Approval of Rates between BC Hydro and FBC with regards to Rate Schedule 3808 (2014 BC Hydro RS 3808), Decision dated May 6, 2014, p. 54, and Order G-6-14

BC Hydro PPA Tranche 2 Energy and FBC's Load-Resource Balance

Figure 7-1 on page 92 of the Application shows FBC's annual energy load-resource balance (in GWh) from 2016 through to 2035. On page 93 of the Application, FBC states that:

> PPA Tranche 2 Energy is also available to FBC but at a much higher cost…FBC expects that it would be able to build or contract for new energy resources at a lower cost than the PPA Tranche 2 Energy cost. For this reason, the energy LRB is presented here with only the PPA Tranche 1 Energy amount.

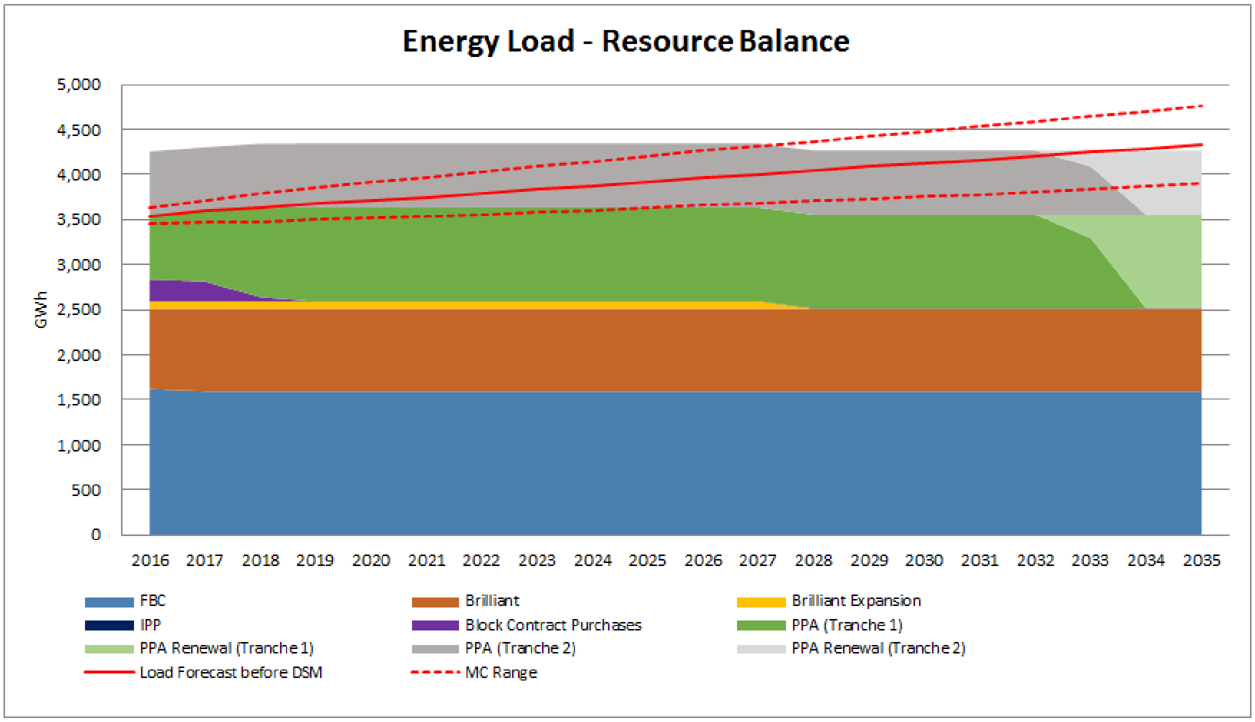
FBC state on page 49 of the Application that PPA Tranche 2 energy rate ($129.70/MWh) is tied to BC Hydro's long run marginal cost (LRMC), and BC Hydro's LRMC was recently updated to $85/MWh. The Commission stated on page 54 of the 2014 BC Hydro RS 3808 Decision: "… both FortisBC and BC Hydro have stated that there is no forecast intention to use any Tranche 2 energy …."

24.1 Please provide an updated version of Figure 7-1: "Annual Energy Load-Resource Balance (GWh)", which includes PPA (Tranche 2) energy in a new colour. Please assume that the PPA Tranche 2 energy price is $85/MWh, as described in the preamble, from the beginning of 2019.

<u>Response:</u>

The following figure is an updated version of Figure 7-1 in Section 7.1 of the LTERP with PPA Tranche 2 energy added to the resources.

Figure 1: Annual Energy Load-Resource Balance with PPA Tranche 2



The PPA Tranche 2 energy is shown in the figure in grey, with the PPA Tranche 2 renewal beyond 2033 shown in lighter grey. FBC has included the maximum PPA Tranche 2 energy for the entire planning horizon in this figure because this figure merely reflects FBC's existing resources compared to forecast customer load requirements, before DSM, but does not determine the optimal mix of resources based on their costs and other attributes. The portfolio analysis optimizes the resources to meet load requirements based on the LTERP objectives. FBC's portfolio analysis indicates that, even if the PPA Tranche 2 energy price was $85 per MWh, only minimal amounts of PPA Tranche 2 energy would be required based on the forecast costs and load profile attributes of the other DSM and supply-side resource options.

24.2 Please describe the attributes (in terms of shape) of BC Hydro RS 3808 Tranche 2 energy. Does FBC intend to use any Tranche 2 energy over the proposed term of the New PPA?

Response:

BC Hydro RS 3808 Tranche 2 energy has the same attributes as BC Hydro RS 3808 Tranche 1 energy. The PPA provides FBC with access to a total of 1,752 GWh of energy per contract year[25]. FBC pays the Tranche 1 energy price for the first 1,041 GWh of energy in the contract year, and the Tranche 2 energy price for any energy taken over 1,041 GWh.

The PPA provides a bundled product, meaning FBC must schedule PPA capacity to receive PPA energy. FBC cannot take delivery of energy without capacity, nor can it take delivery of capacity without energy. FBC has access to a maximum of 200 MW of capacity in any hour, which creates a physical limitation on the amount of energy that can be scheduled in any month, regardless of the energy rate or remaining available energy in the contract year. The following table shows the maximum PPA energy available in each month of the year.

Table 1: Monthly Maximum PPA Energy

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Hours in Month [A]	744	672	744	720	744	720	744	744	720	744	720	744	8760
Max PPA (MW) [B]	200	200	200	200	200	200	200	200	200	200	200	200	200
Max Energy Available (GWh) [A*B]/1000	148.8	134.4	148.8	144.0	148.8	144.0	148.8	148.8	144.0	148.8	144.0	148.8	1752

FBC forecast energy gaps after ‘High DSM’ planned savings are predominately in the winter months (November, December, January, and February). Table 2 below shows the forecast energy gaps for the years 2026-2035 for the reference case load forecast, after ‘High DSM’ planned savings, and after all available PPA energy in each month is fully utilized. This table is applicable for all the portfolios considered for the preferred portfolio in Figure 9-7 of the LTERP.

Table 2: Forecast Energy gaps after "High DSM" and after all monthly available PPA energy

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Monthly Gaps (GWh)
2026	7.7											17.6	25.3
2027	9.0											19.0	28.0
2028	22.1	10.8										35.5	68.5
2029	23.5	11.8									0.7	37.0	73.0
2030	24.6	12.3									1.2	38.1	76.3

[25] Calculated as follows: 200 MW * 8760 hours per year / 1,000 MWh per GWh = 1,752 GWh. A contract year is October to September.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Monthly Gaps (GWh)
2031	25.8	13.1									1.9	39.4	80.2
2032	27.2	14.0									2.7	40.9	84.8
2033	28.6	15.0									3.5	42.5	89.6
2034	30.0	15.9									4.3	43.9	94.2
2035	31.5	16.9									5.2	45.5	99.0

When looking at resources available to meet the energy gaps in the winter there is insufficient PPA energy available on a monthly basis regardless of the Tranche 1 or Tranche 2 price. With a self-sufficiency target of 2026, a new resource that is able to meet the winter monthly energy gaps is required. As a new resource is a lumpy investment, once the resource is acquired, energy from the incremental resource is utilized rather than further utilizing PPA energy at the Tranche 2 rates. For a portfolio with no self-sufficiency target in 2026 the winter energy gaps are filled with market energy.

On an annual basis it appears FBC has sufficient energy to meet the gaps of the reference case forecast using Tranche 2 energy as the total PPA energy available in the contract year is not being fully utilized (this is shown in the LRB provided in the response to BCUC IR 1.24.1). However, on a monthly basis there are remaining energy gaps in the winter months due to the bundled nature of the PPA product.

At this time, FBC is not forecasting to use any PPA Tranche 2 energy over the term of the new PPA.

24.3 Please confirm that energy purchases under RS 3808 are 'BC clean' and that FBC retains the environmental attributes of this energy.

Response:

FBC considers that purchases under RS3808 are 98 percent clean, as per the value for BC Hydro resources discussed in Table 1-3 of the LTERP. FBC retains the environmental attributes of energy purchased under the PPA.

G. CHAPTER 8 – RESOURCE OPTIONS

25.0 Reference: SUPPLY SIDE GENERATION

Exhibit B-1, Volume 1, pp. 96, 109, 128, Appendix J, p.8; BCH 2013 IRP, pp. 4-56, 4-68; GE Energy Consulting, Pan-Canadian Wind Integration Study, 2016, pp. 36, 37[26]; 2016 NW PP pp. 13-9, 13-11

Unit cost and wind integration

FBC summarizes the cost of its supply-side resource options on page 109 of the 2016 LTERP Application. The 2016 NW PP includes at page 13-9 and 13-11 an estimate of the cost of natural gas generating resources and renewable resources.

FBC estimates on page 96 of the 2016 LTERP Application the onshore wind cost at $111 - $145/MWh, and stated on page 128 that portfolio C4 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 Appendix J, page 8 of the FBC 2016 LTERP Application, FBC states that it has assumed $10/MWh for solar/wind integration costs.

BC Hydro includes in its 2013 IRP) a $10/MWh wind integration cost. The GE Energy Consulting 2016 Wind Integration report states on page 36 that hydro generation provides a valuable complement to wind generation, and estimated the wind-levelized cost of energy as about $40.5/MWh - $43.4/MWh. On page 37 the report states that regulation reserve requirements to mitigate wind variability appear to be a small fraction of the additional installed wind capacity.

25.1 Please compare the FBC estimated cost of its supply-side resource options with the estimated cost included in the 2016 NW PP and explain any significant differences.

Response:

The Seventh Northwest Power Plan (NW PP) was developed for the four northwest states in the U.S., Idaho, Montana, Oregon, and Washington. Generation resource options identified in the NW PP are commercially available and deployable in those states over the 20 year planning period, and will be used to inform the Regional Portfolio Model.

The NW PP divides generating resources into three categories: primary, secondary and long-term. Primary resources are defined as "significant resources that are deemed proven, commercially available, and deployable on a large scale in the Pacific Northwest at the start of the power planning period. These resources have the potential to play a major role in the future

[26] http://canwea.ca/wp-content/uploads/2016/07/pcwis-fullreport.pdf

regional power system."[27] The primary generation resources include: natural gas-fired simple cycle and combined cycle turbines and reciprocating engines, solar photovoltaic, onshore wind, and conventional geothermal[28]. Only primary resources are included in the Regional Portfolio Model.

The following tables compare primary generation costs in the NW PP to the resource costs for the same generation types in the FBC LTERP (see Table 8-1 in Section 8).

Table 1: NW PP Primary Resource Cost Summary (2012 US Dollars)

	Levelized Cost of Energy (LCOE) ($/MWh)	Levelized Fixed Cost ($/kW-yr)
SCGT[29]	$120-$154	$148-$214
CCGT[30]	$71-$74	$182-$204
Onshore Wind[31]	$94-$110	$303-$375
PV Solar[32]	$91-$121	$204-$292
Geothermal[33]	$85	$633

Table 2: FBC Resource Cost Summary (2015 Canadian Dollars)

	FBC UEC ($/MWh)	FBC UCC ($/kW-yr)
SCGT	N/A	$80-$143
CCGT	$82-$100	$147-$279
Onshore Wind	$111-$145	$1,219-$1,618
PV Solar	$169-$184	$1,399-$1,413
Geothermal	$132-$217	$857-$1,506

Although some of the costs are similar once adjusted for base year and exchange rate, like the UEC versus LCOE for a CCGT and onshore wind, many of them are significantly different. There are many reasons why the costs are different. These could include, but are not limited to:

- Project locations (e.g. B.C. versus 4 US states);
- Project size assumptions (economies of scale);

[27] Seventh NW PP, Chapter 13, 13-5
[28] Seventh NW PP, Chapter 13, page 3, pp 2.
[29] Seventh NW PP, Chapter 13, page 9, Table 13-2
[30] Seventh NW PP, Chapter 13, page 9, Table 13-2
[31] Seventh NW PP, Chapter 13, page 11, Table 13-3
[32] Seventh NW PP, Chapter 13, page 11, Table 13-3
[33] Seventh NW PP, Chapter 13, page 11, Table 13-3

- Solar or wind intensities and heat rate assumptions;
- Fuel cost forecasts;
- Technologies assumed (e.g. PV fixed tilt vs single axis trackers);
- Assumed capacity factors;
- Capital cost assumptions;
- Operating cost assumptions;
- Discount rates;
- Tax regimes (e.g. U.S. tax subsidies for renewables);
- Project debt-equity ratio assumptions (e.g. levered vs unlevered);
- Project debt costs assumptions;
- Return on equity assumptions; and
- Definitions (e.g. dependable capacity vs nameplate capacity).

Significant differences include the following:

FBC did not calculate a UEC for the SSGT because it was considered strictly a capacity plant, and the UEC would depend on actual dispatch. The NW PP assumed a capacity factor of 25 percent for its SCGT.

The studies show a significant difference is the Levelized Fixed Cost vs LCOE for renewables. This is because the FBC-BC Hydro collaboration studies used dependable capacity as the input in the calculation, while it is assumed that the NW PP utilized nameplate capacity.

The geothermal plants are also showing a significant difference. Geothermal plants are capital intensive and capital costs and energy production are site specific. The NW PP looked at one site in Central Oregon with existing transmission. FBC-BC Hydro looked at 10 sites each with significant transmission costs.

Solar UEC is different because smaller plants were evaluated in B.C., so they were not able to realize the same economies of scale. In addition, it is likely that the solar intensities of good sites were greater in the U.S. as they are closer to the equator. Renewables in the U.S. also are able to access a federal tax credit which does not have an equivalent in Canada.

25.2 Please explain the difference between the estimated onshore wind cost used by FBC and the 2016 GE Energy Consulting report.

Response:

The FBC analysis uses an estimate of the wind cost of production based on project cash flow considering both capital and operating costs whereas the model discussed in the 2016 GE Energy Consulting report calculates an avoided cost value for wind based on the variable cost of other types of generation.[34] The study acknowledges it has a limited focus on economic analysis. It states:

> The production cost simulations quantify variable operating costs only. These are the costs which determine which units, of the ones available to the system operator, should be utilized to serve the load in a least cost manner. These costs include fuel consumption, variable operations and maintenance, and unit startup. The production cost analysis does not include costs related to new capital expenditures required for new wind additions or fixed operations and maintenance or power purchase agreements for new generation resources.[35]

25.3 Please explain the assumptions made by FBC regarding the approach and cost of integrating wind energy into its portfolio options.

Response:

The resource portfolio optimization model assumes a flat cost of $10 per MWh for the integration of onshore wind resources. This is a simplifying assumption, but is also the integration cost assumed by BC Hydro in its 2013 IRP analysis [36]. For example, a wind resource that provides 100 GWh of energy annually would result in an annual variable integration cost of about $1 million per year (100 GWh x $10 per MWh).

BC Hydro's more detailed wind integration study shows wind integration costs range from $5.39 per MWh to $15.63 per MWh (F2011), depending on the penetration of wind within the resource portfolio, the geographic diversity of the wind resources, the electric system characteristics, and the assumed market conditions.[37] The main wind integration costs considered by BC Hydro were operating reserve requirements and day-ahead power trading opportunity costs.

[34] 2016 PCWIS, Key Finding 5, Page 36-37
[35] 2016 PCWIS, Limited Focus of the Economic Analysis, Page 84.
[36] BC Hydro. 2013 IRP. Chapter 3 – Resource Options. Page 3-45. November 2013.
[37] BC Hydro. 2013 IRP. Appendix 3E - Wind Integration Study Phase II. November 2010.

25.3.1 Please provide a comparison in $/MWh of the cost of integrating wind into the portfolio using (i) clean energy or demand-side alternatives, and (ii) non-clean energy.

Response:

In the event a wind resource is required in the future and FBC investigates costs and resource attributes in greater detail, additional analysis would be conducted around integration costs, including various integration approaches. Given the number of factors that could influence integration costs, this level of detail would likely be captured within a CPCN Application when more data regarding the attributes of the specific resource were gathered and presented.

Please also refer to the response to BCUC IR 1.25.3.

25.4 For the preferred portfolio (A4), please explain which resources (market, biogas, single cycle gas turbine [SCGT]) are primarily being relied on to provide wind integration, and why.

Response:

In the preferred portfolio (A4), FBC expects to use the CPA Entitlement Capacity from its owned generation, Brilliant Power Purchase Agreement and the Waneta Expansion Capacity Purchase Agreement (WAX CAPA) to integrate a wind resource on an hourly basis. These CPA resources are hydro facilities that can ramp up or down as required to support the integration of intermittent renewable energy resources.

26.0 Reference: RESOURCE OPTIONS

Exhibit B-1, Volume 1, p. 112; BC Hydro 2017-2019 RRA, Exhibit B-1-1, p. 4-18

Expiring Energy Purchase Agreements

BC Hydro states on page 4-18 of its 2017-2019 RRA that "Over the last three years, 14 Electricity Purchase Agreements have been terminated."

On page 112 of the Application, FBC states:

> Fourteen of BC Hydro's existing EPAs with IPPs are expiring by the end of fiscal 2019. Consistent with the approved 2013 Integrated Resource Plan (IRP), BC Hydro continues to assume renewal of 50 percent of the energy and capacity contributions from biomass EPAs and 75 percent from the run-of-river hydroelectric EPAs that are due to expire within the remaining years of the 10-Year Rates Plan the BC government announced in 2013. BC Hydro is targeting renewal of contracts for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. However, there may be opportunities for FBC to acquire power from the other facilities on a cost-effective basis.

26.1 Please estimate the total quantities of energy and capacity that will become available for a potential energy supply contract with parties other than BC Hydro if BC Hydro executes its plan as described in the preamble. Please provide supporting explanations and/or calculations.

<u>Response:</u>

Terminated EPAs

The preamble states that over the last three years BC Hydro has terminated 14 EPAs. To further clarify the context, BC Hydro's 2017-2019 RRA also states:

> Since 2013, BC Hydro has implemented a number of actions to optimize the portfolio of IPP resources. BC Hydro has executed agreements with IPPs to terminate 14 Electricity Purchase Agreements, downsize and defer two Electricity Purchase Agreements, and defer the delivery of energy to BC Hydro from an additional 11 Electricity Purchase Agreements. As a result of these actions, BC Hydro has reduced electricity purchase commitments by $2.1 billion through ongoing reductions representing 435 MW in nameplate capacity and

approximately 1,890 GWh per year contracted energy through Electricity Purchase Agreement downsizing and terminations.[38]

BC Hydro also noted that "*In each case, the contracts were terminated by mutual agreement with the IPPs as a result of project challenges encountered by the IPP related to the project costs, financing and permitting, as well as actions identified in BC Hydro's approved 2013 Integrated Resource Plan*."[39] FBC understands that energy was not being actively supplied to BC Hydro under these EPAs, thus their termination does not free up any existing energy or capacity to the market.

Expiring EPAs

It is difficult for FBC to estimate the amount of energy and capacity that will be freed up to the market as a result of BC Hydro not renewing active EPAs for the following reasons:

- BC Hydro is making these assumptions on a planning basis, and it is unknown if and how that target will be implemented on an operational basis.
- The 14 expiring IPP contracts are confidential and FBC does not have access to the individual terms including contracted energy and capacity and the EPA expiry dates.
- These renewal assumptions are on an aggregate basis and do not reflect the particular circumstances for individual EPAs.[40]
- BC Hydro has not publically identified which EPAs will expire by 2019, although most of the run-of-river EPAs were likely procured under the BC Hydro 1998 Greater than 5 MW Call and the BC Hydro 1989 Less Than 5 MW Call.

In addition, these renewal targets have changed, making the use of past public information on these EPAs unreliable:

- Prior to the 2013 IRP, BC Hydro assumed that no existing bioenergy EPAs would be renewed upon expiry due to pricing and fuel supply risks, and that all other existing EPAs would be renewed for the remainder of the planning horizon.[41]
- In the 2013 IRP, BC Hydro assumed "*about 75 percent of the small hydroelectric EPAs that are up for the renewal in the next five years will be renewed, and all remaining EPAs will be renewed*".[42]

[38] BC Hydro 2017-2019 RRA, page 3-42, lines 13-23.
[39] BC Hydro 2017-2019 RRA, page 4-18, lines 26-27 to page 4-19, lines 1-2.
[40] BC Hydro 2017-2019 RRA, page 4-22, lines 19-25.
[41] BC Hydro 2013 IRP Final, Table 4-7, page 4-15, lines 15-17.
[42] BC Hydro 2013 IRP Final, Table 4-7, page 4-16, lines 1-3.

- Currently, BC Hydro is planning to renew 50 percent of the energy and capacity contributions from the biomass EPAs and 75 percent from the run-of-river hydroelectric EPAs that are due to expire within the remaining years of the 2013 Ten Year Rates Plan[43] (F2015-F2024).

To develop an estimate of the total quantities of energy and capacity that may become available from the expiring BC Hydro EPAs, FBC utilized information on IPP energy and capacity renewal forecasts from BC Hydro's 2017-2019 RRA, as shown in the following table.

Table 1: BC Hydro Cumulative Energy and Capacity Forecast From Planned IPP Renewals:

	F2017	F2018	F2019	F2020	F2021	F2022	F2023	F2024
Energy (GWh)[44]	61	234	569	647	779	936	1,114	**1,349**
Peak Capacity (MW)[45]	9	23	55	79	120	135	419	**441**

The tables illustrate that from F2017 to F2024, BC Hydro forecasts it will acquire 1,349 GWh of energy from 441 MW of capacity from IPP EPA renewals. Given that the RRA tables do not distinguish between run-of-river and biomass, the amount of energy and capacity from biomass EPA renewals is unknown. Therefore, FBC made the simplifying assumption that this is 75 percent of the IPP power available from the renewals (as opposed to the planned 50 percent for biomass).

The amounts of expiring EPA energy and capacity available to the market by the end of F2024 is estimated to be:

Energy = (1,349 / 75 percent) x 25 percent = **450 GWh**

Peak Capacity = (441 / 75 percent) x 25 percent = **147 MW.**

26.2 Please quantify and explain what would be a cost-effective price for FBC to acquire the additional power from the expired BC Hydro Electricity Purchase Agreements (EPAs).

[43] BC Hydro 2017-2019 RRA, page 1-26, lines 21-26.
[44] BC Hydro 2017-2019 RRA, Table 3-8, page 3-31
[45] BC Hydro 2017-2019 RRA, Table 3-9, page 3-32

Response:

FBC cannot identify a fixed price at which any individual resource is cost-effective as the characteristics of any resource are unique and must be evaluated as part of a group of resource options. It is not the purpose of the LTERP to provide a price point whereby a supply-side resource alternative is cost-effective if it meets a fixed number. Rather, the LRMC should be used as a general guideline to help determine if potential projects may be economically viable if they provide power that meets resource requirements. As the Company is not looking to acquire any power at this time, it is not likely that any contracts will be entered into in the near future unless they can displace other variable sources of power, such as the PPA Tranche 1, in the current resource portfolio. Furthermore, any discussion between FBC and a project owner around the appropriate price to pay must take many factors into consideration and is not simply a determination of the price at which the power becomes "cost-effective" to the utility.

26.3 Please provide an analysis of the energy and capacity resource options that will become available if BC Hydro executes its plan described in the preamble by analyzing the (i) technical, (ii) financial, (iii) environmental, and (iv) socio-economic attributes.

Response:

These resources are existing plants currently connected to and supplying the BC Hydro grid.

(i) Technical:

- The run-of-river plants are approximately 20 years old, and would likely need a major maintenance investment to ensure reliable operation. In addition, given the uncertainty in the renewal of the BC Hydro EPAs, the operators would likely have held off non-critical planned maintenance to avoid stranding the investment, and would need to do that immediately.
- The biomass plants are likely 10-15 years old and will likely be inefficient compared to today's standards. Some would likely need a major maintenance investment to ensure reliable operation. Fibre supply may also be an issue as it is likely the existing fibre supply contracts were tied to the term of the original EPA.

(ii) Financial

- BC Hydro is targeting renewal of contracts for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. BC Hydro expects to negotiate a lower energy price than the initial EPAs. In its EPA renewal negotiations, BC Hydro will consider the IPPs' opportunity cost, the electricity spot market, the cost of service for the IPPs (including fibre supply costs for biomass facilities) and other factors such as the attributes of the energy produced and other non-energy benefits.[46] In its 2016 RDA, BC Hydro noted that the costs for service for IPPs can vary significantly and that it expects cost differences for biomass renewals and run-of-river renewals, with biomass having greater ongoing costs for operations. However, BC Hydro also estimated that the renewal volumes in the plan could be acquired at or below the LRMC of $85 per MWh. [47]

- The non-renewed EPAs will likely be higher cost resources.

(iii) Environmental

- The plants are existing plants and would have all of their environmental approvals. FBC does not know if any of the current permits need to be renewed.

(iv) Socio-economic attributes.

- Socio-economic attributes are less than greenfield plants as there is no construction phase. Jobs benefits will be limited to major maintenance investment and existing operating jobs. There may be issues of loss of existing jobs as well as of tax revenues for regional districts and municipalities if the plant cannot find another market for its power and is forced to shut down.

26.4 Please explain the feasibility of FBC securing energy and/or capacity from the expired energy purchase agreements if BC Hydro executes its plan described in the preamble.

[46] BC Hydro 2017-2019 RRA, page 3-43, lines 6-17.
[47] BC Hydro 2015 RDA, Exhibit B-17, page 7.

Response:

FBC could consider procuring expired BC Hydro EPA facilities' output when it becomes available. These expired EPA opportunities would be evaluated the same as any other energy procurement opportunity. Considerations would need to include, but are not limited to:

- Timing of when the energy or capacity became available;
- Term;
- FBC need for energy or capacity at that time;
- Cost competitiveness of the energy or capacity compared to other resource options;
- Costs of integration of renewables;
- Cost of wheeling and losses to the FBC service territory;
- Provincial legislation (e.g. *Clean Energy Act* requirements); and
- Regulatory approval.

26.4.1 If FBC was satisfied with the price for BC Hydro non-renewed Independent Power Producer (IPP) energy and FBC required the energy, please describe some options on how FBC may acquire it from BC Hydro or the IPP. Could FBC purchase it directly from the IPP and wheel it through BC Hydro? Could FBC negotiate a special contract or tariff with BC Hydro where BC Hydro purchases the power from the IPP and BC Hydro delivers it to FBC transmission system? Please elaborate.

Response:

FBC expects that it would be purchased directly from the IPP and wheeled through the BC Hydro system to the FBC system. In concept, it would be no different than the IPP power that BC Hydro currently purchases from within the FBC system that is delivered to the BC Hydro system.

Several other approaches such as BC Hydro flowing the IPP contract through to FBC or netting FBC and BC Hydro IPP purchases from the other's service area against each other may also be possible but should not be relied upon.

27.0 Reference: RESOURCE OPTIONS

Exhibit B-1, Volume 1, p. 113; FBC SGP Stage II, Exhibit B-1 (FBC SGP Stage II Application), p. 13, Appendix A; FBC 2014 Stepped and Stand-By Rates for Transmission Voltage Customers (FBC 2014 Stepped and Stand-By), Decision dated May 26, 2014, p. 48

Purchases from eligible self-generation customers

On page 13 of the FBC SGP Stage II Application, FBC explains that it currently has three customers with self-generation above the thresholds eligible for the policy. On page 113 of the Application, FBC states: "… if a self-generator could provide power at a cost lower than FBC's alternatives, there may be an opportunity for FBC to purchase the output of the self-generation."

The Commission stated on page 48 of the FBC 2014 Stepped and Stand-Bby Decision:

> The Panel is concerned that FortisBC conducts transmission planning based on the expected [Celgar] 45 MW firm customer load … if the costs are the same based on either load then there seems to be little harm in using 45 MW. However, in the event that there are cost savings to FortisBC of using an amount less than that the Commission would fully expect FortisBC to only use that amount required for its customer's firm needs.

27.1 Please quantify the cost, or range of costs, that would be lower than FBC's alternatives for power. Please state the assumptions.

<u>Response:</u>

Please refer to the response to BCUC IR 1.26.2.

27.2 Considering the three customers and their potential generation quantities, please explain the potential impact on FBC's (i) annual energy load-resource balance presented in section 7.1 of the Application, (ii) the capacity-resource balance presented in section 7.2 of the Application, and (iii) FBC's preferred portfolio (93% clean with SCGT) presented in section 9.3.6 of the Application, if:

i. The Commission approves the FBC SGP Stage II Application as submitted by FBC; or

ii. The Commission denies the FBC SGP Stage II Application as submitted by FBC.

Response:

The approval or denial of the policies contained in the FBC SGP II Application will not, in isolation, have an impact on the preferred portfolio contained in the LTERP. The portfolio reflects a continuation of the current situation with regard to self-generation customers. In the event that the Commission denies the FBC SGP Stage II Application, as submitted by FBC, and the existing situation is maintained, then there is no change to the load-resource balance.

The key element of the proposed SGP with the potential to alter FBC's load-resource balance is the ability gained by a self-generating customer to use a portion of its below-load generation for a purpose other than supplying its own plant load. However, gaining such an ability is different than actually incorporating it into its operations. While electing to increase purchases from FBC would increase the requirement for resources, the amount of this increase would depend on the election of the customer. The approval of the SGP in no way obligates FBC to purchase the available output from the self-generating customer, which would be done only if the purchase of the power was the preferred resource alternative.

At the current time, FBC is of the opinion that, even if the ability to increase the amount of load placed on FBC were gained by the eligible customers, there is likely no opportunity to dispose of the self-generated power, made available, that would provide an economic benefit greater to the customer than that achieved by using the output to serve load. However, if such an opportunity should arise, and the self-generating customer chooses to take advantage of it, then FBC must examine the alternatives at that time. Given that the self-generating customer's election could be for a time-period as short as five years, it is unlikely that FBC would seek a long-term resource to supply the required load. FBC expects that the two most likely options would be to either buy the output of the self-generator directly at a market-based rate, or to supply any requirement, after existing surplus power was used, directly from the market. In either case, there would be little net impact to the existing load-resource balance and as such the preferred portfolio is expected to remain the same.

27.3 Please explain if FBC would purchase a portion or all of the output of the self-generation from its eligible customers if power could be provided to FBC at a cost below $96 per MWh, which is the LRMC for FBC's preferred portfolio. In your response, please consider the technical, environmental and socio-economic attributes of the self-generation customers.

Response:

Please refer to the response to BCUC IR 1.26.2.

27.4 Please explain how Celgar's energy and demand consumption levels have been reflected in FBC's energy and demand forecast.

Response:

This response is being filed confidentially with the Commission, pursuant to section 18 of the Commission's Rules of Practice and Procedure, established by Order G-1-16, regarding the filing of documents containing confidential information. FBC requests that the response be kept confidential as it contains confidential customer information which FBC does not have the authority or permission to disclose.

A redacted version of the response is provided below. FBC is of the view that only the Commission and the customer should have access to the unredacted confidential version.

Celgar's energy consumption level has been forecast individually at [redacted] until 2021 after which the industrial class is forecast as a whole based on the CBOC industrial GDP. Celgar's demand is forecast at [redacted] for the entire forecast period.

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

28.0 Reference: PLANNING OBJECTIVES

Exhibit B-1, Volume 1, p. 5; FBC 2012 RR & ISP, Exhibit B-1-1, p. 11, Exhibit B-1-2, pp. 73, 74; FBC 2016/2017 Annual Electric Contracting Plan (AECP), Letter L-8-16 dated April 21, 2016

Energy supply options

FBC describes its resource planning objectives on page 5 of the 2016 FBC LTERP as: ensure cost-effective, secure and reliable power for customers; provide cost-effective DSM; and ensure consistency with provincial energy objectives.

FBC described its resource options ranking and evaluation criteria on page 73 and 74 of its 2012 LTRP as: appropriate size; environmental impact and adherence to the Directives of the CEA; appropriate energy shape; and comparative resource economics test (targeting the least cost solution conditional upon fidelity with the other criteria). FBC stated on page 11 of its 2012 ISP:“ Reduction of GHG volumes is a key input in evaluating capacity and energy alternatives in the Company’s 2012 Resource Plan.”

FBC described its objectives in the 2016/2017 AECP: To ensure a firm supply of resources to meet expected annual energy and peak capacity requirements and to maintain an appropriate balance of:

a. cost minimization for FBC customers through optimization of FBC resources and market purchases;

b. reliability and security, to ensure that cost effective power is available when needed to meet load;

c. flexibility, to minimize the risk of changes to load forecast, generation and transmission availability, wholesale power market and BC Hydro rates; and

d. operational efficiency, in order to be able to supply load requirements while maintaining contractual compliance.

28.1 Does FBC consider that, when evaluating alternative supply side options: (i) the objectives articulated in the 2016/2017 AECP define FBC’s LTERP objective to ensure cost-effective, secure and reliable power for customers; and (ii) preference should be given to options that support BC energy objectives? Please explain why/why not.

Response:

The objectives articulated in the 2016/17 AECP are based on the LTERP objective to ensure cost-effective, secure and reliable power for customers. The AECP objectives are more short-term in nature, as compared to the LTERP. However, the 2016/17 AECP, which was accepted by the Commission on April 21, 2016 by way of Letter L-8-16, is consistent with the 2012 LTRP and 2016 LTERP objectives.

For similar-cost resources that meet FBC's requirements, including the objectives of being secure and reliable, FBC believes preference should be given to supply-side resource options that support B.C. energy objectives.

28.2 Does FBC consider that resource options ranking and evaluation criteria described on pages 73 and 74 of the FBC 2012 LTRP, and the GHG related statement on page 1 of the FBC 2012 ISP, also apply to the FBC 2016 LTERP Application resource option evaluation criteria? If no, please explain.

Response:

Generally speaking, the evaluation criteria for the resource options in the 2012 LTRP and for the 2016 LTERP portfolios are consistent.

in the 2012 LTRP, FBC evaluated individual resource options based on the criteria described in the preamble. The 2016 LTERP, however, evaluates resource options on a portfolio basis, as directed by the Commission in its decision regarding the 2012 LTRP. FBC provides the unit cost, type, size, environmental and socio-economic attributes of the resource options considered in Tables 8-1 and 8-3 of the 2016 LTERP. These attributes are then used in the portfolio analysis to determine the preferred portfolio. The evaluation criteria for the portfolios considered are based on the 2016 LTERP objectives and include cost (i.e. LRMC), percent clean or renewable, GHG emissions, socio-economic development in terms of job creation and geographic diversity as described in Section 9.3.6 and Table 9-2 of the 2016 LTERP.

29.0 Reference: PLANNING RESERVE MARGIN

Exhibit B-1, Volume 1, p. 128, Appendix L, p. 7; PSE 2015 IRP, p. 1-3; BCH 2013 IRP, pp. 1-16, 4-9

General

FBC states on page 128 of its 2016 LTERP Application that it has adopted Loss-Of-Load-Expectation (LOLE) as the reliability metric for Planning Reserve Margin (PRM), and targeted '1 day in 10 years'. FBC states on page 7 of Appendix L to the 2016 LTERP Application: "[Western Electricity Coordinating Council (WECC)] remains the only [North American Electric Reliability Corporation (NERC)] entity that has not endorsed this criterion."

The PSE 2015 IRP states on page 1-3:

> Translating the MWh lost into the Customer Value of Lost Load allows us to quantify the value associated with different levels of reliability … moving to the 2015 Optimal Planning Standard reduces the expected value of lost load to customer by $130 million per year. The cost to achieve that expected savings is $63 million per year ….

BC Hydro states on page 1-16 of the BCH 2013 IRP: "An `adequate` generation system is defined as one that has an annual expectation of being unable to serve the daily peak demand of less than one day in 10 years. The one day in 10 years LOLE methodology has widespread use in the industry" and on page 4-9 "… once the planning criteria are met, reliability can be traded off against other objectives."

29.1 Please provide FBC's actual generation capacity related loss of load over the past 10 years.

<u>Response:</u>

There were no occasions in the last 10 years when FBC had to shed load due to resource insufficiency. The LOLE target (1 day in 10 years) should be viewed as a planning tool to test for robustness rather than as an operational metric. The LOLE target as a planning tool provides a level of confidence based on probability that sufficient resources will be available to meet load given a variety of possible deviations from the expected operating environment.

29.2 Did FBC quantify the cost/value to customers associated with different levels of reliability? If yes, please provide. If no, please explain why not.

Response:

FBC did not quantify the cost to customers associated with different levels of reliability. The Planning Reserve Margin study assesses resource adequacy to meet load with considerations for plausible deviations from the expected operating environment and does not explicitly consider cost as a factor. The Company has chosen the LOLE industry practice of 1 day in 10 years as the target resource adequacy index. The 1 day in 10 years, or 0.1 day/year target is currently a widely adopted industry standard[48], appropriate for FBC resources, and consistent with BC Hydro methodology[49] for its evaluation of capacity reliability.

29.3 Please explain why WECC has not endorsed the probabilistic approach, and whether there would be any effect on FBC's costs over the next five years of using a WECC endorsed approach.

Response:

NERC does not require a specific method for calculating the necessary reserve margin for maintaining reliability. Unlike other NERC entities, WECC does not use a 1 day in 10 year LOLE/LOLP method but instead uses a building block methodology for their internal assessments. FBC is not aware of why WECC has not endorsed the probabilistic approach. FBC expects that using the WECC building block approach may increase costs.

As reported by WECC, members are not precluded from using a probabilistic approach:

> Regional and subregional Target Reserve Margins are calculated using a building block methodology created by WECC's Reliability Assessment Work Group. As such, they do not reflect a criteria- based margin- determination process and do not reflect any BA- or Load- Serving Entity (LSE)- level requirements that may have been established through other processes (e.g., state regulatory authorities). Moreover, they are not intended to supplant any of those requirements. [50]

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48 NERC. Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning. March 2011.

49 BC Hydro. 2013 IRP. 1.2.2.2 Generation Capacity Planning Criterion. p. 1-16. November 2013.

50 WECC. Loads and Resources Methods and Assumptions. December 2016. https://www.wecc.biz/Reliability/2016LAR_MethodsAssumptions%20(002).pdf

For example, the California Independent System Operator (CAISO) has been shifting to a probabilistic method, largely to ensure that the reliability issues associated with renewable integration are being fully considered.[51]

29.4 Please explain the assumptions FBC has made regarding the dependability of market power purchases over the planning period in developing its Planning Reserve Margin estimate, and whether this is consistent with the assumptions made by BC Hydro in its 2013 IRP.

Response:

The response to BCUC IR 1.19.1 sets out FBC's assumptions related to the market. The Company is uncertain what market-related assumptions were made by BC Hydro in its PRM estimate in the 2013 IRP.

[51] California ISO. 2016 Summer Loads & Resource Assessment. https://www.caiso.com/Documents/2016SummerAssessment.pdf.

30.0 Reference: SUPPORT FOR BC SELF-SUFFICIENCY OBJECTIVE

Exhibit B-1, Volume 1, pp. 36, 111, 116, 117, Appendix L, p. 9; PSE 2015 IRP p. 1-2

FBC proposal

FBC states on page 111 of its 2016 LTERP Application: "… FBC believes that market purchases, at current price levels, are more cost effective than other supply-side resource options and so should not be ruled out in favour of self-sufficiency, at least in the short to medium term." FBC states on page 116, that the base portfolio characteristics included self-sufficiency by 2025. FBC states on page 117 that, its base case assumption is that it will be able to access low-cost and reliable market supply for the next ten years, out to 2025.

FBC states on page 9 of Appendix L of its 2016 LTERP Application: "FBC's view is that dependence on market capacity to meet expected demand over the long term is not a prudent policy due to the uncertainly associated with both resource availability and market prices. This view is common among utilities." FBC states on page 36 of the 2016 LTERP Application: "In the next decade, the Pacific Northwest is forced to face a capacity deficit due to load growth, coal plant retirements, and increasing growth of intermittent resources such as solar and wind generation."

The PSE 2015 IRP states on page 1-2:

> The surplus conditions the Pacific Northwest electric markets have experienced for a decade are forecast to change significantly with the scheduled retirement of two coal plants in 2020 … During the decade of surplus capacity, relying on short-term wholesale market purchases to meet a significant portion of peak customer need has been a low cost/low risk strategy, but now that supplies are tightening, continuing this level of market purchases would expose PSE and its customers to unreasonable levels of physical and financial risk.

30.1 Please calculate, for each year over the past 10 years, and for each year to 2025 under FBC's proposed portfolio (A4), the percentage of total energy (in terms of energy volume) that FBC has or expects to acquire from (i) the market, (ii) Canadian Entitlement energy generated from generators not located in BC, and (iii) energy that FBC considers meets the CEA definition of electricity self-sufficiency.

Response:

For purposes of this response, FBC-owned generation, long term contracted resources in B.C. (e.g. Brilliant Power Purchase Agreement) purchases from the Brilliant Expansion (consistent with the assumption of renewal), and Independent Power Producer generation are considered "electricity self-sufficiency" resources. BC Hydro PPA energy is considered "electricity self-sufficiency" through association with BC Hydro. "Canadian Entitlement energy generated from generators not located in BC" is interpreted as energy associated with the Columbia River Treaty. These entitlements are provided to BC Hydro. Table 1 shows as a proportion of load the percentage of total energy after planned DSM served by self-sufficient resources.

Table 1: Percentage of Total Energy After Planned DSM Served by Self-Sufficient Resources

Year	(i) the market	ii) Canadian Entitlement energy generated from generators not located in BC	(iii) energy that FBC considers meets the CEA definition of electricity self-sufficiency
2007	1.0%	0.0%	99.0%
2008	1.3%	0.0%	98.7%
2009	3.4%	0.0%	96.6%
2010	8.4%	0.0%	91.6%
2011	14.1%	0.0%	85.9%
2012	14.4%	0.0%	85.6%
2013	15.1%	0.0%	84.9%
2014	8.6%	0.0%	91.4%
2015	7.8%	0.0%	92.2%
2016	7.9%	0.0%	92.1%
2017*	9.2%	0.0%	90.8%
2018*	8.4%	0.0%	91.6%
2019	7.0%	0.0%	93.0%
2020	6.3%	0.0%	93.7%
2021	5.1%	0.0%	94.9%
2022	1.6%	0.0%	98.4%
2023	1.6%	0.0%	98.4%
2024	1.7%	0.0%	98.3%
2025	3.2%	0.0%	96.8%
2026	Self-Sufficiency	0.0%	100.0%

*Note: 2017 and 2018 values are the model-determined utilization of the market for the portfolio scenario A4 as opposed to actual planned 2017/2018 market purchases as discussed in the AECP

30.1.1 If FBC has assumed market price energy will displace RS 3808 T1 energy over the next 10 years, please provide an updated analysis assuming no displacement of T1 energy.

Response:

Table 1 below shows the percentage of total energy after planned DSM (High DSM, the preferred level of DSM resources) served by self-sufficient resources, if FBC were to make no further market purchases. FBC assumes market contracts already executed through 2018 remain as a firm resource in the portfolio, but no incremental market purchases are made to displace PPA energy.

Table 1: Percentage of Total Energy After Planned DSM Served by Self-Sufficient Resources with no Incremental Market Purchases

Year	(i) the market	(ii) Canadian Entitlement energy generated from generators not located in BC	(iii) energy that FBC considers meets the CEA definition of electricity self-sufficiency
2016	7.93%	0.00%	92.07%
2017	6.08%	0.00%	93.92%
2018	2.06%	0.00%	97.94%
2019	0.00%	0.00%	100.00%
2020	0.00%	0.00%	100.00%
2021	0.00%	0.00%	100.00%
2022	0.00%	0.00%	100.00%
2023	0.00%	0.00%	100.00%
2024	0.00%	0.00%	100.00%
2025	0.00%	0.00%	100.00%
2026	0.00%*	0.00%	100.00%

*Assuming the new resource of the preferred portfolio A4 is available.

30.2 Please describe the options that could be used by FBC to increase energy purchases from BC generators. Please specifically address the following: additional T1 purchases under RS 3808; EPAs with BC Hydro; IPPs; self-generators; standing offer programs (similar to BC Hydro's SOP and micro-SOP); expansion of the net metering program; expansion of DSM programs.

Response:

FBC has access up to 200 MW of PPA capacity, and up to 1,041 GWh of Tranche 1 Energy. The PPA is a very flexible resource in the FBC portfolio, enabling FBC to increase or decrease the amount of energy and capacity requirement from year to year, subject to specific limits. Those limits are discussed in Section 5.4 of the LTERP. The limits include an annual nomination and a restriction on how much the nomination can change year to year. It should be noted that FBC still has access to the full energy amount, but there are cost implications to not following the nomination process. The PPA would include capacity.

FBC could try to negotiate an additional energy EPA with BC Hydro. FBC understands that BC Hydro currently is in an energy surplus and sells that surplus into the market. FBC should be able to acquire cost-effective energy from BC Hydro at a market-based rate, until such time as BC Hydro is not in energy surplus. This power would likely have no associated long-term capacity.

FBC could procure IPP energy. The source could be expiring BC Hydro EPAs that are not renewed or greenfield resources. Table 8.1 of the LTERP demonstrates the potential cost of the greenfield resources. Some of those resources, like geothermal, biomass and gas generators will include capacity. If required this could either be done through a call for power or a standing offer program. Timing of this energy would depend on how advanced the IPP has developed the project.

FBC has not included power supply from self-generators within FBC's service area in the demand side and supply side resource options. 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.

FBC could also expand the net metering program, but does not expect that such a supply would significantly change LTERP requirements due to the timing of when the energy is expected to be delivered. This power would likely be acquired at a cost between the PPA Tranche 1 and Tranche 2 rate.

FBC selected the preferred High DSM scenario for the LTERP. The company believes that DSM resources are reliable but non-firm and thus does not believe it is prudent to expand DSM beyond that.

30.2.1 To what extent does FBC estimate it would be able to replace (a) 100% and (b) 50% of its market energy purchases with energy purchased from generators located in BC if the market price offered to the BC generators was: (i) the levelized Mid-C market price, (ii) $85/kWh, or (iii) $100/kWh? Please explain.

Response:

Through 2025, FBC can replace up to 100 percent of market supply by increasing BC Hydro PPA purchases. From 2026 forward all requirements are assumed to be met with B.C.-based supply under the preferred portfolio.

30.2.2 Please estimate the (i) annual cost to FBC and (ii) rate impact if FBC replaced 100% of market price purchases with energy purchased for (a) $85/kWh or (b) $100/kWh.

Response:

The units in the question should read $ per MWh, not $ per kWh. Specified market prices are assumed to be $85 per MWh and $100 per MWh, in 2015$, inclusive of all transmission adjustments, and constant among all months of the year. "Annual costs to FBC" is assumed to be the Total Revenue Requirements for FBC.

If market energy prices were $85 per MWh the average annual Revenue Requirements, compared to the preferred portfolio, over the years 2018 to 2025 are estimated as follows:

Table 1: Estimated Revenue Requirements with Market Power Priced at $85 per MWh

Year	Increase in Revenue Requirements over Preferred Portfolio
2018	$9.7 million
2019	$9.4 million
2020	$8.0 million
2021	$7.1 million
2022	$2.2 million
2023	$2.2 million
2024	$2.3 million
2025	$4.2 million

The cumulative rate impact by 2025 is estimated to be 1.1 percent higher than the preferred portfolio).

If market energy prices were $100 per MWh the average annual Revenue Requirements, compared to the preferred portfolio, over the years 2018 to 2025 are estimated as follows:

Table 2: Estimated Revenue Requirements with Market Power Priced at $100 per MWh

Year	Increase in Revenue Requirements over Preferred Portfolio
2018	$13.4 million
2019	$13.2 million
2020	$11.5 million
2021	$10.2 million
2022	$3.1 million
2023	$3.3 million
2024	$3.3 million
2025	$6.3 million

The cumulative rate impact by 2025 is estimated to be 1.7 percent higher than the preferred portfolio).

Note that if market energy prices were $85 per MWh or $100 per MWh, the optimal market energy purchases within the preferred portfolio (A4) would likely decrease and be replaced with additional PPA purchases, which is currently occurring starting in the year 2022.

30.3 Does FBC agree with the statement on page 1-2 of the PSE 2015 IRP that relying on the market is no longer a low cost/low risk strategy? Please explain.

Response:

FBC agrees with the statement that relying on the market is no longer a low cost/low risk strategy in the long term. As FBC states on page 117 of the LTERP, its base case assumption is that it will be able to access low-cost and reliable market supply for the short to medium term (i.e. the next ten years), out to 2025. After this time, FBC has assumed it will become self-sufficient to reduce the risks with market reliance in the long term.

30.3.1 Please explain how FBC has incorporated the physical and financial risk of reliance on the Mid-C market into its portfolio analysis.

Response:

FBC evaluated the portfolios considered for the preferred portfolio to confirm they meet the Planning Reserve Margin (PRM) requirements. The physical risk associated with the market has been captured within the PRM study and is considered acceptable given the selected LOLE target.

As is shown in the response to BCUC IR 1.30.2.2, over the short to medium term, FBC has sufficient flexibility to increase the BC Hydro PPA purchases to cover market purchases should market prices rise above the PPA rates. Any actual remaining market requirements that occur should be small in size and therefore have a reduced financial risk.

30.4 Please explain to what extent FBC's proposed strategy is to rely on market purchase to meet (i) energy needs under the expected load forecast, (ii) energy needs where the load forecast is higher than expected, and (ii) generation capacity needs.

Response:

i) Market purchases are included in the preferred portfolio A4 as discussed in Section 9.3.6 of the LTERP and the response to BCUC IR 1.30.1. FBC does have the alternative to take additional PPA energy at additional cost in the years 2016 to 2025 as discussed in the response to BCUC IR 1.30.1.1.

ii) In the event energy needs are significantly greater than anticipated, FBC's contingency plan is presented in Section 9.3.6.2 of the LTERP application. In general, increased requirements will require an increase in resources. If the changes are gradual, FBC anticipates that either increased PPA use or market purchases could provide the required resources in the short to medium term. However, if the increased load is significant, then to the extent that PPA use cannot be increased in a specific month, market purchases for energy would likely be required. The next long term resource plan is the appropriate time to consider how to meet the increased load on a longer term basis.

iii) FBC’s preferred portfolio A4 includes market capacity in the month of June and minimally in July for the years 2016-2020 to optimize PPA use. Given the reference case load forecast, and assuming anticipated DSM savings, FBC can alternatively opt to increase the use of PPA capacity at an increased cost.

31.0 Reference: SUPPORT FOR BC ENERGY OBJECTIVES

Exhibit B-1, Volume 1, pp. 8-10, Appendix B, p. 28; CLP, p. 28

FBC proposal

FBC describes BC's Energy objectives on pages 8 to10 of its 2016 LTERP Application. The CLP states on page 28: "Going forward, 100 per cent of the supply of electricity acquired by BC Hydro in British Columbia for the integrated grid must be from clean or renewable sources, except where concerns regarding reliability or costs must be addressed."

31.1 Please calculate, for each year over the past 10 years, the percentage of energy volume used to serve load that meets the CEA definition of clean/renewable. Please also calculate this percentage for each year to 2025 under FBC's proposed portfolio (A4). Please describe all key assumptions.

Response:

For the purpose of this response, FBC owned generation, long term contracted resources in B.C. (e.g. Brilliant Power Purchase Agreement), purchases from the Brilliant Expansion (consistent with the assumption of renewal), and Independent Power Producer generation are considered 100 percent clean/renewable. BC Hydro PPA energy is considered 98 percent clean/renewable.[52] Market purchases are considered 50 percent clean. Percentages are proportion of load after planned DSM savings. Table 1 shows the percentage of total energy after planned DSM served by clean and renewable resources.

Table 1: Percentage of Forecast Load, After Planned DSM, Served by Clean and Renewable Resources

Year	Clean/Renewable	Non-Clean
2007	98.9%	1.1%
2008	98.9%	1.1%
2009	97.8%	2.2%
2010	95.4%	4.6%
2011	92.6%	7.4%
2012	92.5%	7.5%
2013	92.2%	7.8%
2014	95.3%	4.7%
2015	95.8%	4.2%
2016	95.8%	4.2%
2017*	95.0%	5.0%
2018*	95.4%	4.6%

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

Year	Clean/Renewable	Non-Clean
2019	96.1%	3.9%
2020	96.4%	3.6%
2021	97.0%	3.0%
2022	98.7%	1.3%
2023	98.7%	1.3%
2024	98.6%	1.4%
2025	97.9%	2.1%
*Note: 2017 and 2018 values are the model determined utilization of resources for the portfolio scenario A4.		

31.1.1 Please estimate the (i) annual cost to FBC and (ii) rate impact if FBC was to ensure that a minimum of (A) 93% of its energy (by volume) or (B) 100% of its energy (by volume) was sourced using clean or renewable sources. Please include all assumptions.

Response:

The responses to the two scenarios (A) and (B) are provided below.

(A) FBC's preferred portfolio A4 assumes at least 93 percent of its energy generated in B.C. is sourced using clean or renewable sources as described in Section 9.3.6 of the LTERP. In the last year of the planning horizon (2035) for preferred portfolio A4, total revenue requirements are estimated to be $178 million higher than in 2017, and the cumulative rate impact is estimated to be 41.7 percent, a compound average growth rate of 1.96 percent, after accounting for load growth[53]. Note that portfolio A4 includes some market purchases until the end of 2025.

(B) FBC portfolio C4 assumes 100 percent of its energy generated in B.C. is sourced using clean or renewable sources as described in Section 9.3.6 of the LTERP. Although the BC Hydro PPA is only 98 percent clean, it is assumed for purposes of portfolio C4 to be 100 percent clean to allow the BC Hydro PPA to be used to meet load. In the last year of the planning horizon (2035) for portfolio C4, total revenue requirements are estimated to be $186 million higher than in 2017, and the cumulative rate impact is estimated to be 43.9 percent, a compound average growth rate of 2.04

[53] For both scenarios (A) and (B), the rate increases shown are net of load growth, which reduces the rate increases by approximately 0.28 percent on a compound growth basis. The value of this rate reduction is approximately $30 million in total over the period of the planning horizon.

percent, after accounting for load growth. Please note that portfolio C4 includes some market purchases until the end of 2025.

31.2 Please estimate the (i) annual cost to FBC and (ii) rate impact if FBC replaced its market energy purchases with market purchases from clean sources. Please state all assumptions.

Response:

Please refer to the response to BCUC IR 1.17.1.1.

31.3 Please explain whether (and if so how) FBC's proposed supply side energy acquisition strategy specifically supports each of the following BC energy objectives: innovative technologies, waste heat/biogas/biomass, and the development of clean or renewable resources by First Nation and rural communities. If FBC does not have specific strategies, please explain why.

Response:

FBC's proposed short- to medium-term acquisition strategy does not specifically support the listed objectives because, as discussed in Section 9.4 of the LTERP, FBC does not have any new resource requirements until after 2025. FBC's short- and medium-term resource strategy includes optimization of the low-cost and reliable PPA Tranche 1 energy and market purchases.

However, for the longer term, FBC's resource acquisition strategy potentially supports some of the listed objectives. Longer term resource options FBC has considered include biogas and other clean and renewable resources such as wind generation. The assessment of resource options involving innovative technologies, such as battery storage, have not been included in FBC's current resource options but will likely be included in the next long term electric resource plan, as discussed in Section 3.9.3 of Appendix J of the LTERP. As noted in Section 8.2.9 of the LTERP, if new supply-side resources are needed in the future, FBC would consider generation projects that promote First Nations and community development if they are competitive with the cost of alternative resources and meet the LTERP objectives.

32.0 Reference: MARKET PURCHASES

Exhibit B-1, Volume 1, p. 79

Displacement of RS 3808 -short vs. long term

FBC states on page 79 of its 2016 LTERP Application: "FBC purchases energy and capacity from the wholesale market when it is more competitively priced than purchases under the PPA, or when FBC does not have sufficient resources to meet peak demand requirements. In 2015, market and contracted purchases accounted for 10 percent of FBC's annual energy requirements."

32.1 Please explain how FBC takes into account (i) BC self-sufficiency objectives; (ii) environmental objectives; and (ii) reduced level of reliability/increased planning reserve margin, in determining whether BC Hydro PPA (RS 3808) power should be displaced with market purchases.

Response:

FBC's LTERP objectives relating to B.C. electricity self-sufficiency and the environment are long-term planning objectives that FBC balances with its primary objective of cost-effective, secure and reliable power for customers. In determining whether PPA power should be displaced with market purchases, FBC considers this primary objective first to provide cost savings for customers (if market purchases are more cost-effective than the PPA Tranche 1 energy). Self-sufficiency is targeted after 2025 as discussed in Section 9.3.6 of the LTERP. Environmental considerations are taken into account later in the planning horizon when new resources are required within the preferred portfolio. Please also see the response to Shadrack IR 1.6.ii.

FBC notes that its Annual Electric Contracting Plan (AECP) discusses its annual strategy of displacing PPA purchase with market purchases and how that strategy is consistent with its most recently accepted long term resource plan. Most recently, Section 1.4.2 of FBC's 2016/17 AECP discussed how its strategy is consistent with FBC's 2012 LTRP. The 2016/17 AECP was accepted by the Commission on April 21, 2016, by way of Letter L-8-16.

The reduced level of reliability/increased planning reserve margin, if any, is a small and manageable risk when relying on market purchases to displace BC Hydro PPA purchases to meet peak demand. When FBC is displacing PPA purchases used to meet peak demand, the PPA capacity is not lost, and remains available to use if it is needed. For example, if FBC was dispatching the maximum amount of 200 MW from the PPA to meet capacity needs and then 25 MW of FBC owned generation was lost, it would likely have to be replaced on short notice from the market for the duration of the outage. Alternatively, if FBC were relying on 175 MW of PPA and 25 MW of market energy, FBC would have the option of increasing the PPA purchases to 200 MW if market energy cannot be found on short notice.

On a day ahead basis, the PPA can always be increased up to the 200 MW maximum demand limit. In the real-time/hourly market, FBC has the ability to increase the PPA schedule by 25 MW. Therefore, if FBC is relying on more than 25 MW of market to displace PPA, the risk would only be for a few peak hours of a day, before FBC is able to increase the PPA schedule to the maximum of 200 MW. Even during this period, the risk is mitigated by being able to increase the PPA by 25 MW in any hour, prior to the hour. As FBC retains access to the full 200 MW PPA hourly limit, the strategy of using market purchase to reduce PPA purchases has no impact on FBC's Planning Reserve Margin studies.

There is a potential reliability and planning reserve margin issue in using market power to meet capacity needs if it is planned to use the full 200 MW of PPA capacity at the same time. Such a plan may not meet planning reserve margin requirements on a long-term basis since any loss of the planned market supply may also mean that no replacement power is available on an hourly basis either. However, at this time FBC has sufficient capacity resources that such a scenario is only expected to occur in the short to medium term if there are significant outages to FBC owned generation or an unforeseen major increase in load.

32.1.1 Does FBC consider that the increased flexibility of the new BC Hydro PPA RS 3808 has resulted in an increase in FBC's reliance on market purchases compared to that accepted in the FBC 2012 RR & ISP? Please explain.

Response:

No, taken as a whole, the new BC Hydro PPA did not increase FBC's flexibility. The new BC Hydro PPA has restrictions that were not in the old PPA, including an annual nomination of energy and a 75 percent minimum take, as discussed in Section 5.4 of the LTERP. It is likely that FBC's reliance on market purchases has decreased as compared to that accepted in FBC's 2012 LTRP.

32.2 Please describe FBC's strategy regarding the proportion of its energy needs that should be met through hourly market purchases compared to (i) 1 – 3 year market contracts and (ii) long-term contracts. Please also comment on whether the disruption risks identified in this LTERP have resulted in an increase or decrease in the proposed level of reliance on short-term vs. long-term energy purchase contracts compared to the FBC 2012 IRP.

Response:

FBC believes that it is good practice to have sufficient power secured on a long term basis to meet its load provided it can be secured on appropriate terms. For example, referring to Figure 7-1 in the LTERP it is seen that after accounting for existing long term contracts (i.e. the BC Hydro PPA, Brilliant Power Purchase Agreement and the WAX CAPA) as well as FBC owned generation, by far the majority of the load is met through these long-term resources. In addition, FBC expects to renew the agreement for surplus Brilliant Expansion power through 2027, further reducing FBC's reliance on short term purchase contracts. To the extent that additional long-term opportunities that meet FBC's needs become available at a cost-effective price, the Company expects that it would bring forward additional long-term resources for Commission approval.

As is described in the response to CEC IR 1.26.2, the Company believes that additional generation resources can be secured, if needed, with up to 5 years notice. Therefore, as long as the Company's existing resources do not result in a shortfall based on expected load until beyond the 5 year time frame, there is no immediate need to take action to obtain resources to fill that gap. However, if a long-term resource did become available in advance of it being fully required, the Company would consider obtaining that resource early provided it was economic to do so. Resources tend to be lumpy in size and it may not be possible to always exactly match the Company's needs.

On a shorter time frame that may be measured from hourly to several years in advance, the Company will optimize its portfolio to ensure that power is obtained at the lowest reasonable cost in accordance with the objectives as laid out in the AECP. This optimization process will rely heavily on market power but not because there was no other source of the power, but because it is cost effective to do so.

Within any contract year, considered the hourly market for this response, FBC is limited in the amount of market energy it can purchase on an hourly basis due to the BC Hydro PPA annual nomination and the 25 percent flexibility. Prior to each contract year, which is from October 1 to September 30, FBC ensures it has either fixed price market purchases or a PPA nomination that is available to meet forecast load. Within the contract year, FBC has 25 percent flexibility to reduce its PPA take. FBC will make use of the 25 percent flexibility in the PPA nomination by ensuring that it is available to address reductions to load from forecast. However, if actual load is close to forecast load, FBC has the ability to use the 25 percent variability to displace PPA purchases with market purchases if it is economical to do so. Therefore, FBC is typically limited in the amount of hourly market purchases that it can enter into, under its current strategy.

For advanced market contracts entered into prior to the contract year, contracts typically ranging from 3 months to 5 years, FBC will carefully consider its obligations under the BC Hydro PPA and its need for energy. The majority of FBC's energy requirements are in the winter. Therefore, annual market contracts may not make sense, as they could provide energy at times when it is not needed. The majority of FBC's market purchases are currently based on quarterly contracts, typically over the fourth quarter (October to December) and first quarter (January to March) during off-peak hours. Market liquidity dictates how far in advance these contracts can be entered into. Typically, trading of quarterly contracts becomes more difficult outside of 18 months in advance, and extremely difficult outside of 36 months. FBC will continue to attempt to enter into advance market contracts, limited by restrictions in the PPA and operating strategy[54] as well as market liquidity.

FBC considers the "disruption risks" to be the transmission risk identified in lines 9-20 of page 79 of the LTERP. The transmission risk identified on page 79 has not resulted in an increase or decrease of reliance on short-term and long-term contracts. As discussed above, the reliance on short-term versus long-term market contracts is restricted by reasons other than transmission risk.

[54] This strategy was discussed in Section 5 of FBC's 2106-2017 Annual Electric Contracting Plan, which was filed in confidence and accepted by Letter L-8-16 dated April 21, 2016.

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) in2016 $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	$14,600
2019	$5,200	$7,900	$7,900	$7,900	$14,600
2020	$5,200	$7,900	$7,900	$7,900	$14,600
2021	$5,200	$7,900	$9,000	$9,000	$14,600
Total	**$28,410**	**$39,210**	**$40,310**	**$40,310**	**$66,010**

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)	44.7	54.2	60.7	67.3	71.5
TRC benefit/cost ratio	2.6	2.1	1.9	1.7	1.6
RIM	0.89	0.85	0.82	0.80	0.79

33.1.1 Please provide an estimate of the above metrics for a DSM portfolio option that achieves energy savings that offsets 100% of load growth.

Response:

Please refer to the response to BCUC IR 1.33.1 for the requested scenario.

33.2 For the proposed DSM portfolio, please describe the following attributes of the 'DSM energy' saved as a result (i.e. the energy that displaces supply side alternatives). Please also indicate if the responses would be significantly different for any of the alternative DSM portfolios:

- The level of confidence FBC has on the annual volume of energy generated/conserved
- The level of confidence FBC has on what the cost of the energy will be

- Energy shape (i.e., what is the seasonal/within-day shape of energy saved through DSM)
- Environmental attributes (i.e., is DSM energy clean)
- Firmness (generation capacity) – to what extent is the energy saved through DSM coincident with the generation system peak
- Firmness (network capacity) - to what extent is the energy saved through DSM coincident with the (i) transmission, and (ii) distribution system peak
- Other benefits related to the DSM portfolio, such as economic development, social etc.

Response:

In terms of the confidence in the amount and cost of energy conserved (items 1 and 2, above), FBC has confidence that it will achieve its DSM savings targets, at the approved budget levels, but notes that ultimately the decision to proceed with a DSM measure or project is determined by its customers, who pay their portion of the measure costs.

In terms of energy shape and firmness (items 3, 5, and 6), FBC believes DSM to be a reliable non-firm energy resource on an annualized basis. 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). The DSM energy savings are forecast and incorporated into the Company's load forecast on a monthly basis, not on a seasonal or daily basis. Likewise the capacity savings associated with the energy savings are forecast on a monthly basis.

In terms of other benefits related to the DSM portfolio (items 4 and 7), the governing DSM test in B.C. is the TRC test, albeit measure benefits can be increased for non-energy benefits under the modified TRC in the DSM Regulation. The societal cost test that incorporates externalities such as environmental and social-economic benefits does not apply, and hence FBC does not attempt to estimate their value.

33.3 Please compare in table form the attributes (as listed above) of the conserved energy through DSM to (i) market energy purchases, (ii) onshore wind generation, and (iii) FBC's preferred energy supply portfolio (portfolio A4). For each attribute, please comment on whether the DSM portfolio performs better or worse than the supply side option

Response:

To respond to this IR, FBC ranks the options relative to each other with 1 being most favorable and 4 being least favorable. Rankings were determined through a qualitative approach as opposed to quantitative analysis. Please note FBC's preferred portfolio A4 has integrated 'High DSM' into the resource stack.

Table 1: Comparison of Select Portfolio A4 Components

Attribute	DSM Portfolio	Market Energy	Onshore Wind Generation	Portfolio A4
Confidence on the annual volume of energy generated/conserved	3	2	3	1
Confidence on the cost of the energy	3	4	2	1
Energy shape (i.e., what is the seasonal/within-day shape of energy produced/saved)	3	1	2	1
Environmental attributes (i.e. is DSM energy clean)	1	3	2	2
Generation capacity: to what extent is the energy saved/generated coincident with the generation system peak	2	3	3	1
Network capacity: to the extent the energy saved/ generated is coincident with the (i) transmission, and (ii) distribution system peak	2	3	3	1
Other benefits (e.g. socio-economic development.)	1	4	3	2

33.4 Please discuss the level of confidence FBC has in its energy savings estimate from the alternative DSM portfolios. Specifically, does FBC consider that its DSM programs have been effective in achieving forecast energy/capacity savings in the past?

Response:

Please refer to the response to BCUC IR 1.33.2.

33.5 Please identify DSM programs that meet the following criteria and identify the level of funding for these programs over the next five years under FBC's preferred DSM portfolio:

- Have a utility cost lower than the LRMC of market purchases;
- Address 'lost opportunities' (energy savings that would be more expensive to obtain later); and
- Required to meet the adequacy requirements of the DSM Regulations.

Response:

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.

Please refer to the response to BCUC IR 1.45.4.1 for a discussion on lost opportunities.

Section 4 of the LT DSM Plan contains descriptions of programs that the Company intends to undertake, and/or continue to promulgate, including those required to meet the adequacy requirements of the DSM Regulation, namely for rental and low income customers and education (elementary, secondary and post-secondary schools).

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[55]; 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.

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.

34.1 Please provide FBC's LRMC of acquiring electricity generated from clean or renewable resources in BC at the transmission voltage level for: (i) energy - non-firm ($/MWh), (ii) energy – firm ($/MWh) and (iii) generation capacity ($/kW-year).

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. The LRMC including both capacity and energy components is $100 per MWh, which is the value of energy capable of being delivered to the customer in the peak hour of the winter season with resources connected to the FBC system at the transmission voltage level[56].

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55 http://aceee.org/sites/default/files/publications/researchreports/u1505.pdf.

56 FBC used the Gross Load forecast, which includes adjustments for line losses, therefore LRMC is stated at delivery to the customer. LRMC is a measure of cost per unit of energy required and therefore doesn't change much, if at all with respect to where on the system the energy is generated. However, FBC recognizes that if losses are reduced, then overall costs are reduced as well. For example, if a generation project was able to avoid all losses of approximately 8%, then, all other things being equal, it is more cost effective than a generation project that must also supply those losses. In Appendix K of the LTERP FBC stated the LRMC at the point of interconnection. This was intended to communicate that the costs of new resource options included both the generator and the infrastructure to connect the generator to FBC's system.

FBC forecasts energy gaps in the winter months later in the planning horizon after DSM savings that cannot be addressed with existing resources (refer to the response to BCUC 1.24.2). Therefore, new incremental resources that provide both capacity and energy are dispatched to meet the monthly energy only requirements with a self-sufficiency target at the end of 2025. As portfolio B1 requires new resources (capacity) to deliver winter energy, only an estimate of the LRMC for energy only[57] and an estimate of the LRMC for capacity can be given.

For portfolio B1, FBC estimates the value of long run energy capable of being delivered in the winter months to be $86 per MWh and long run peak generation capacity to be $115 per kW-year. For energy outside of the winter season, the value to FBC would be substantially less, more closely resembling the lower of the wholesale market and PPA Tranche 1 energy rate. In the event a net energy surplus to FBC's existing resources occurs in a month, the value could be even lower. These estimated LRMC price components are based on the portfolio as a whole, therefore may not be applicable for individual projects.

34.1.1 Does FBC consider that the $10/MWh wind/solar integration cost is a reasonable proxy for the cost of generation capacity, which would result in an LRMC of non-firm clean generation of being $10/MWh less than the cost of firm generation? Please explain.

<u>Response:</u>

FBC does not consider $10 per MWh a proxy for generation capacity. As discussed in the response to BCUC IR 1.25.3, FBC assumed a $10 per MWh integration cost based on a BC Hydro study. Please also refer to the response to BCUC IR 1.34.2 for a discussion of FBC's estimated cost of energy-only generation as compared to firm energy (energy with capacity).

[57] FBC considers 'firm energy' as received energy that can be relied upon to meet capacity needs. In the context of market power this implies that a firm schedule can be used to meet load without a backup resource in place. This is as opposed to a non-firm market schedule for which full operating reserve must be held. In the context of a variable resource such as wind, an appropriate derating factor is applied to the name-plate rating to arrive at what is considered the firm portion of the resource. As such, FBC considers that it only plans to use firm resources and has used the term "energy only" to indicate a firm resource that provides only energy for planning purposes. However, as the resource is firm, the associated capacity may also assist in meeting capacity needs and therefore it can be difficult to identify a true energy-only LRMC.

34.1.2 For the energy LRMC estimates above, please provide the adjustments to the LRMC for network losses and ancillary services that would be required to for delivery at the (i) distribution – primary, and (ii) distribution – secondary voltage level.

Response:

The LRMC is the incremental cost of meeting FBC's incremental forecast gross load requirements. Distribution losses are already included in FBC's forecast gross load, therefore no further adjustments for additional losses need to be made. The LRMC includes the costs of interconnecting new generation resources to the system, fixed operating costs, variable energy costs, and losses to the end customer.

For resource related ancillary services, such as operating reserves, these requirements are included in the attributes of each potential resource and therefore included in the LRMC. For system administration related ancillary services, such as scheduling and dispatching of the resource, there may be additional costs related to controlling and optimizing new resources, however these costs would likely not have a material impact.

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 $84 per MWh and long run peak capacity is $98 per kW-year.

34.3 Please compare FBC's estimate of transmission and distribution capacity LRMC with the ACEEE and NW PP benchmarking findings and explain any significant differences.

Response:

FBC uses a Deferred Capital Expenditure (DCE) value of $79.85/kW-year, as filed in FBC's 2017 DSM Expenditure Plan (2017 DSM Plan), for its avoided capacity value of deferred transmission and distribution (T&D) infrastructure.

FBC's DCE of $61.90 (USD, using the DCE report's exchange rate of 1.29) is within the range of the avoided costs compiled by the ACEEE, similar to the $57.00 used in the 2016 NW PP, and the average compiled in the sample filed in Appendix C of the 2017 DSM Plan (reproduced below). The table also illustrates the considerable DCE range across utilities, as shown in the magnitude of standard deviations.

		U.S. $			Canadian $[24]			
Company	Year $	Trans. $/kW-yr.	Dist. $/kW-yr.	Total T&D $/kW-yr.	Trans. $/kW-yr	Dist. $/kW-yr	Total T&D $/kW-yr.	Methodology
BC Hydro	2011				$11.00	$1.00	$12.00	
OPA	2014				$3.83	$4.73	$8.56	Marginal Cost
Hydro One	2007				$3.40	$4.20	$7.60	Marginal Cost
Northwest Power Council	2012	$26.00	$31.00	$57.00	$33.54	$39.99	$73.53	Benchmarking
Snohomish PUD	2013	N/A	$42.00	$42.00	N/A	$54.18	$54.18	Marginal Cost
PGE	2012	$22.56	$9.87	$32.43	$29.10	$12.73	$41.83	Unknown
PSE	2012	$10.71	N/A	$10.71	$13.82	N/A	$13.82	Unknown
PSI	2012	$6.43	N/A	$6.43	$8.29	N/A	$8.29	Unknown
PacifiCorp	2012	$29.42	$84.35	$113.77	$37.95	$108.81	$146.76	Unknown
Pacific Northwest Average		**$19.02**	**$41.81**	**$43.72**	**$17.62**	**$53.93**	**$40.73**	
Standard Deviation		**$8.91**	**$27.14**	**$35.81**	**$11.49**	**$35.01**	**$46.19**	
Standard Deviation (%)		**47%**	**65%**	**82%**	**65%**	**65%**	**113%**	
CL&P	2015	$1.25	$32.19	$33.44	$1.61	$41.53	$43.14	ICF Tool
WMECO	2011	$22.27	$76.08	$98.35	$28.73	$98.14	$126.87	ICF Tool
NSTAR	2011	$21.00	$68.79	$89.79	$27.09	$88.74	$115.83	ICF Tool
National Grid MA	2015	$23.01	$124.28	$147.29	$29.68	$160.32	$190.00	ICF Tool
National Grid RI	2015	$37.86	$162.47	$200.33	$48.84	$209.59	$258.43	ICF Tool
PSNH	2013	$16.70	$53.35	$70.05	$21.54	$68.82	$90.36	ICF Tool
United Illuminating	2015	$2.74	$49.75	$52.49	$3.53	$64.18	$67.71	B&V Report
Unitil MA	2013	N/A	$171.15	$171.15	N/A	$220.78	$220.78	ICF Tool
Unitil NH	2013	$73.03	$29.26	$102.29	$94.21	$37.75	$131.95	ICF Tool
Efficiency Maine	2015	N/A	N/A	$81.67	N/A	N/A	$105.35	Unknown
Vermont (Statewide)	2012	$50.45	$113.51	$163.96	$65.08	$146.43	$211.51	Historical
Ameren Illinois Company (AIC)	2014	$6.00	$17.00	$23.00	$7.74	$21.93	$29.67	Marginal Cost
Burlington Electric Dept.	2012	$48.00	N/A	$48.00	$61.92	N/A	$61.92	Historical
Consumers Energy (MI)	2011	N/A	N/A	$5.00	N/A	N/A	$6.45	Proxy
CPL	2012	$49.02	N/A	$49.02	$63.24	N/A	$63.24	Unknown
KCP&L	2012	$8.28	N/A	$8.28	$10.68	N/A	$10.68	Unknown
NV Energy	2011	N/A	N/A	$12.23	N/A	N/A	$15.78	Marginal Cost
SCE	2011	$23.39	$30.10	$53.49	$30.17	$38.83	$69.00	Marginal Cost

[24] Exchange rate used:1 US Dollar equal 1.29 Canadian Dollar (07/05/2016)

		U.S. $			Canadian $[24]			
Company	Year $	Trans. $/kW-yr.	Dist. $/kW-yr.	Total T&D $/kW-yr.	Trans. $/kW-yr	Dist. $/kW-yr	Total T&D $/kW-yr.	Methodology
SDG&E	2011	$21.08	$52.24	$73.32	$27.19	$67.39	$94.58	Marginal Cost
PG&E	2011	$18.77	$55.85	$74.62	$24.21	$72.05	$96.26	Marginal Cost
Average		**$24.67**	**$66.85**	**$70.00**	**$28.60**	**$74.39**	**$81.93**	
Standard Deviation		**$17.60**	**$45.81**	**$52.11**	**$22.71**	**$60.58**	**$67.85**	
Standard Deviation (%)		**71%**	**69%**	**74%**	**79%**	**81%**	**83%**	

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.

35.1 Please describe the energy resources used to arrive at the estimate of $100 per MWh for clean or renewable firm energy in BC. Please explain whether adjustments to these LRMC estimates would be required to reflect the delivery location and shape of DSM.

Response:

As discussed in Section 9.3.1 of the LTERP, portfolio B1 is the portfolio of clean or renewable resources without any DSM activity. Portfolio B1 includes wind, biomass, biogas, and run-of-river resources as well as market purchases out to 2025.

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. Distribution losses would remain unless the generation source was located right at the load source. FBC's future anticipated energy requirements in the winter and capacity requirements in the winter and summer influence the LRMC for DSM purposes.

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 High and Max DSM portfolio options, including a program cost adder, exceed the $100 per MWh estimate for BC clean or renewable energy.

	DSM Scenario			
Category	**Low**	**Base**	**High**	**Max**
Resource Cost ($2016/MWh)				
Average cost, incl. program costs	$45	$54	$61	$67
Incremental cost, incl. program costs	$45	$88	**$104**	**$114**

35.2.1 Please explain the difference between comparing each DSM portfolio options against the average TRC as opposed to incremental changes on FBC's preferred DSM portfolio option.

Response:

FBC believes presenting the incremental costs of each DSM portfolio clearly illustrates the increased cost, i.e. declining economics, of obtaining higher load growth offsets. Use of average TRC has the effect of blending lower and higher cost resources and thereby obscuring the marginal measures that likely should not be pursued.

BC Hydro provides its avoided energy cost (electricity and natural gas) assumptions in Appendix X to the F2017-F2019 RRA , and estimates avoided electric energy costs at $85 per MWh (F2013 $) for F2015-F2033.

FBC states on page 34 of its SGP Stage II Application: "… any rates to be based on a LRMC value must value DSM measures based on the Utility Cost (UC) for DSM rather than on the TRC as the UC only considers costs the utility incurs to achieve the DSM results."

35.3 Does FBC consider that the LRMC of Portfolio Option A4 ($96/MWh on page 125 of the Application) is the appropriate utility cost to estimate the effect of alternative DSM portfolios on residential bills and rates? Please explain why/why not.

Response:

No. The LRMC of Portfolio Option A4 ($96/MWh) represents the TRC for the DSM portion of the portfolio, and therefore it does not reflect the costs applied to bill and rate impacts since the utility cost is lower.

The utility cost for the DSM portion of the portfolio is used for the residential bill and rate impact calculations for the alternative DSM portfolios presented in BCUC IR 1.49.1.

35.3.1 Please explain whether adjustments to this LRMC estimate would be required to reflect the delivery location, firmness, shape and environmental attributes of DSM.

Response:

For purposes of practicality and consistent application, FBC has applied a single point LRMC estimate for assessing DSM plans and measures. Other criteria such as delivery location, firmness, shape and environmental attributes are examples of qualitative factors considered.

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

36.1 Does FBC consider generation from small-scale customer-owned generation to be long-term in nature? If no, please explain why and specifically address each of the five bullets included in the FBC 2016 NM Reasons for Decision extract above.

Response:

There is a difference between whether small-scale customer-owned generation is long-term in nature (as alluded to by bullet 1 above), and whether a net metering customer is either able or willing to make a long term commitment for the disposition of the generation output. While, as indicated by bullet 3, the installation itself may be difficult to dismantle and move, the primarily residential nature of the premises on which the 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.

With respect to bullet 2, FBC does not have a specific program under which to purchase IPP power. However, the Company would consider the purchase of any interconnected generation that met its needs in the context of the LTERP.

With respect to the first comment of Mr. Scarlett, the Company notes that the net metering program is an established and Commission-approved tariff rate and that once a customer is enrolled in the program and remains eligible, for practical purposes, the customer can remain in the program in perpetuity. Any cancellation of or amendments to the rate must be approved by the Commission. FBC is not aware of any reason why the customer would believe that the program will not be offered in the long term.

FBC disagrees with the last point. The Company has an established net metering program in support of small-scale customer-owned generation, which at the current compensation rates values the DG output delivered to FBC in excess of its value.

36.2 Please provide a break-down of FBC's long-term avoided cost of energy between (i) generation –energy; (ii) generation – capacity; and (iii) network – capacity.

Response:

Please refer to the response to BCUC IR 1.34.2. FBC's LRMC does not include a network capacity component. FBC's long-term avoided capacity value of deferred transmission and distribution infrastructure is discussed in the response to BCUC IR 1.34.3.

36.2.1 Please describe the attributes of the generation assumed for FBC's long-term avoided cost (for example, is it a flat or shaped block of power, location, clean, delivery voltage (distribution/transmission).

Response:

The attributes of the LRMC are inherited from the source portfolio, which is composed of a number of different resource alternatives. The attributes and cleanliness of Portfolio A4 (FBC's preferred portfolio) are discussed on pages 126-127 of the LTERP but in general it is low-carbon emitting with resources shaped to meet FBC's primary requirement for winter energy. Resources are generally connected to the transmission system but include all FBC system losses. The majority of the generation would likely be physically located within the service area.

Considerations regarding application of the LRMC are discussed in Section 5 of Appendix K of the LTERP. Each portfolio presented as a whole is shaped to meet the forecast gross load requirements (energy and capacity) of each month of each year in the planning horizon using a collection of resources including existing resources, DSM, PPA, new resources, and market. The composition of the portfolios is influenced by FBC's forecast winter energy requirements later in the planning horizon.

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 $84 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.

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 $84 per MWh if the owner of the project has signed a long-term power supply contract to provide power[58]. 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.

36.3.1 Please estimate the additional value (in terms of avoided generation and network capacity costs) that could accrue to firm long-term distributed generation.

Response:

In the response to BCUC IR 1.23.2, the required characteristics that distributed generation must have, such that there would be avoided network capacity costs, are provided. FBC believes that it is unlikely that distributed generation can meet these requirements and, as such, there are generally no network capacity cost benefits. Please refer to the response to BCUC 1.36.3 for an estimate of the ability of distributed generation to avoid generation costs.

36.4 When does FBC next plan to review/update the NM rate (RS 95)? Please explain.

Response:

FBC will review its current net metering program as part of its next Rate Design Application, which will be filed with the Commission in late 2017.

58 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.

I. CHAPTER 10 – STAKEHOLDER AND FIRST NATIONS ENGAGEMENT

37.0 Reference: STAKEHOLDERS AND FIRST NATIONS ENGAGEMENT

Exhibit B-1, Volume 1, pp. 135, 136

Community consultation workshops

On page 135 of the Application, FBC states that seven community workshops were held between 2014 and 2016 in communities within the FBC service area. FBC notes that the workshops included interactive sessions with stakeholders to promote discussion about potential electricity demand and scenarios and resource options. FBC further states on page 136 that workshop discussions were robust and customer-focused and they demonstrated that FBC's long-term planning considerations align well with stakeholders expectations.

37.1 Please discuss the content and amount of information provided to stakeholders with respect to tradeoffs of considered demand scenarios and resource options, for example: cost/emissions trade off; cost/energy security trade off; cost/reliability trade off; short-term costs vs. long-term benefit; rate impacts; bill impacts.

<u>Response:</u>

In the community workshops held between 2014 and 2016, FBC presented to stakeholders the load-resource balance for energy and capacity before and after base levels of DSM.

FBC presented the load scenarios discussed in Section 4 of the LTERP to stakeholders in the fall 2016 community workshops (the load scenarios were not developed until after the 2014 or 2015 workshops). Specifically, Figures 4-1 and 4-2 of the LTERP were presented to stakeholders and the potential for various load drivers, such as rooftop solar and electric vehicles, were discussed.

FBC also presented the unit energy and capacity costs, Figures 8-6 and 8-7 of the LTERP, as discussed in Section 8.2.3. This helped stakeholders understand which resource options were being considered in the portfolio analysis, and how market purchases and PPA Tranche 1 energy are more cost effective than other supply-side resources in the short to medium term and other additional resources are required in the long term. FBC then provided preliminary portfolio analysis results to stakeholders (as the final results of the portfolio modelling were not completed at the time of the workshops). At this point, FBC discussed the portfolio trade-offs between cost and carbon emissions and cost and reliability, such as for a portfolio with gas-fired generation versus one without.

FBC did not provide rate forecasts or potential bill impacts in the workshops, instead focusing on the high-level portfolio costs relative to one another and potential trade-offs between portfolios with different attributes (for example, 100% clean and renewable versus least cost) to gather feedback on the portfolios considered for the preferred portfolio.

37.2 Please discuss results of the feedback you received from the stakeholders, including customer preferences regarding alternative scenarios considered.

Response:

Stakeholders that participated in the workshop discussions indicated that their primary concerns relating to resource planning included cost, reliability, reducing energy usage and reducing carbon emissions. One stakeholder stated that they did not think FBC should be considering a portfolio with gas-fired generation as their preference was for electricity from clean and renewable sources only, even if this came at a higher cost, given government policies and their own community carbon emission targets. Other stakeholders, however, preferred gas-fired generation due to the current low cost of natural gas relative to other resource options and reliability of gas-fired plants to meet peak customer demand. One stakeholder indicated that cost and reliability of electricity supply should be the first priority, with clean and renewable sources as a secondary priority.

In terms of the demand scenarios FBC presented, stakeholders noted that, while there was a lot of interest in and discussion about electric vehicles in their communities, electric vehicle uptake currently remains low. Stakeholders also noted that rooftop solar penetration was low, likely due to the long payback period of the investment. However, stakeholders did not disagree that these load drivers could potentially be significant in the longer term as rooftop solar costs decline and electric vehicle range and infrastructure improves over time.

37.2.1 Please discuss were the results of customer feedback considered? If yes, in which areas?

Response:

FBC has considered the results of the customer feedback relating to the portfolio analysis. While there was no consensus among stakeholders, as shown in the response to BCUC IR 1.37.2, FBC's preferred portfolio does generally provide a balance between stated preferences. For example, with regard to the utilization of gas-fired generation, the preferred portfolio includes a small amount of energy and capacity required from a gas-fired SCGT plant, providing cost-effectiveness and reliability while being almost 100 percent clean and renewable.

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."

38.1 Please confirm, or otherwise explain, that the FBC 2012 LT DSM plan was a five-year plan only, ending in 2016.

<u>Response:</u>

Not confirmed. The FBC 2012 LT DSM plan had a twenty year planning horizon, even though the LT DSM Plan is updated in conjunction with the Company's long term resource plan that is updated at approximately five year planning intervals. Updates are necessary to incorporate changes in market conditions, legislative framework, avoided costs, and other changes. The 2017 DSM expenditure schedule filing was also based on the 2012 LT DSM plan. The 2012 LT DSM has effectively endured for six years, which demonstrates that it was not solely a five-year plan.

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)

<u>Response:</u>

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	49%	49%	49%	49%
TRC benefit/cost ratio	2.6	2.1	1.9	1.7
Average utility cost of energy savings ($/MWh)	29	34	37	40

38.2.1 Please also provide the key DSM data (see bullets above) for the past 10 years of historical actual and historical forecasted (as approved under s. 44.1) DSM, and 5 years of projected DSM based on the proposed DSM portfolio in the 2017 LT DSM Plan.

Response:

The table below contains 10 years of historical DSM data.

Year	Actual Energy Savings	Approved Savings	Actual (% of Load Growth)	Actual (% of Sales)	Actual Expenditure	Approved Expenditure	Incentive (% of TRC)	TRC B/C ratio	Actual Levelized Cost	Plan Levelized Cost[1]
	(GWh)				($000s)				($/MWh)	
2006	23.1	20.4	40%	0.7%	2,242	2,234	24%	1.8	15	-
2007	27.9	21.8	556%	0.8%	2,549	2,474	22%	1.9	21	-
2008	27.3	19.5	-297%	0.8%	2,683	2,355	26%	1.8	22	-
2009	28.4	25.3	37%	0.8%	3,464	3,667	28%	1.7	23	-
2010	29.3	27.5	-19%	0.9%	3,712	3,951	30%	2.0	23	-
2011	36.3	39.7	28%	1.1%	5,918	7,842	30%	1.6	34	-
2012	31.6	32.0	-82%	0.9%	7,300	7,731	33%	1.6	51	-
2013	29.5	31.5	40%	0.8%	6,855	7,878	26%	1.7	67	-
2014	14.6	12.8	-38%	0.4%	3,473	3,001	32%	1.7	55	21
2015	12.6	26.2	-19%	0.4%	3,531	7,292	16%	2.0	60	34

[1] Plan levelized costs were not filed in the DSM expenditure schedules prior to 2014.

Please refer to the response to BCUC IR 1.38.2 for the projected DSM portfolio data.

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.

39.1 Please provide in table form a comparison, for each year from 2010 to 2016: (i) DSM expenditure levels accepted in the appropriate LTRP; (ii) accepted DSM funding levels under s.44.2 of the UCA; (iii) actual FBC DSM expenditures.

Response:

Please refer to the following table for the responses to (ii) and (iii).

	2010	2011	2012	2013	2014	2015	2016
	($ millions)						
DSM expenditure levels:							
Accepted DSM funding levels under s.44.2 of the UCA;	4.0	7.8	7.7	7.9	3.0	7.3	7.5
Actual FBC DSM expenditures	3.7	5.9	7.3	6.9	3.5	3.5	6.5

In regard to the information requested in (i) above, the DSM expenditure levels accepted in the appropriate LTRP, the Company notes that its previous LT DSM Plans did not contain expenditures by year, however the preferred Medium Option in the 2012 LT DSM Plan included a high-level estimate of $9 million, that was not broken down by year over the planning horizon.

39.2 For each of the four examples of FBC's explanation for DSM underspend that the Commission considered unpersuasive on page 10 of the FBC 2017 DSM Reasons for Decision, please explain whether (and if so how) they were also an FBC consideration in the selection of the proposed 2016 LT DSM Plan.

Response:

Please refer to Section 3.2 of the LT DSM Plan for the Company's rationale for choosing the preferred High DSM scenario. FBC's explanations for DSM underspend, provided in the 2017 DSM Plan proceedings, were not a consideration in selecting the preferred scenario.

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 ($114/MWh) of the Maximum tranche compared to the LRMC of $100.

39.4 Does FBC consider that it is conflicted in any way in its motivation to identify and achieve cost-effective DSM savings? Please explain why/why not.

Response:

No, FBC is not conflicted in its motivation to identify and achieve cost-effective DSM savings.

The 2016 FBC CPR study identified a broad economic savings potential, and the Company's preferred DSM scenario escalates the proposed DSM savings targets to offset 77 percent of FBC's load growth with cost-effective DSM savings over the LTERP planning horizon.

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.

40.1 Does FBC consider that, in order to meet the requirement of s. 44.1(2)(f) of the UCA, it should include in its list of DSM portfolios an option that attempts to capture all cost-effective DSM? If no, please explain why not.

Response:

No, FBC does not consider that it should include in its list of DSM portfolios an option that attempts to capture all cost-effective DSM.

In compliance with section 44.1(2)(f) of the UCA, Section 8.1.3 of the LTERP provides an explanation of why the demand for energy to be served by supply side resources is not planned to be replaced by demand-side measures (i.e. the "Max DSM Scenario").

FBC notes that section 3 of the LT DSM Plan includes a "Max" DSM Scenario that ramps up to 100 percent load growth offset, effectively resulting in a cumulative load growth offset of 89% over the LTERP planning horizon.

40.2 Is FBC's definition of 'cost-effective' DSM is the same as that used by BC Hydro in its 2013 IRP? Please explain.

Response:

FBC is in general agreement with BC Hydro's definition of cost-effective DSM, but notes that the TRC, as modified by the DSM Regulation, is the governing test under the BC legislative framework, whereas the Utility Cost (UC) test is informative.

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, 95 percent of the technical potential identified by 2035 in the 2016 CPR is considered economic, or 'cost effective'.

41.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

Exhibit B-1, Volume 2, pp. 6, 10, 14; FBC 2017 DSM Reasons for Decision, p. 10; FBC 2012 RR & ISP, Exhibit B-1-2, LT DSM Plan, p. 14; 2016 NW PP, pp. 12-10, 12-16

Conservation Potential Review (CPR): linkage to DSM portfolio options

Table 3-1 on page 14 of FBC's 2016 LT DSM Plan, shows the four DSM portfolio options, including their respective resource cost.

FBC describes on page 6 of the 2016 LT DSM Plan the steps used to develop the plan. FBC further states on page 10 "roughly 500 GWh of savings are available at a cost less than $50 per MWh … The economic results of the FBC CPR are a key input for the LT DSM plan …."

FBC states on page 10 of the 2016 LT DSM Plan: "

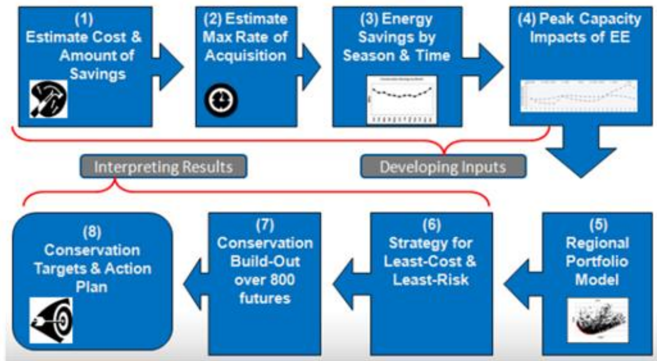
> The next phase of the BC CPR project, expected in 2017, includes assessing the market potential that is a subset of economic potential and carving out non programmatic potential (e.g. Codes & Standards …). The market potential identified in the next phase of the BC CPR is expected to inform FBC's next DSM expenditure schedule.

The FBC 2017 DSM Reasons for Decision stated on page 10: "FBC submits that any attempt to increase 2017 DSM spending on the basis of the draft BC CPR would have been imprecise guess work."

FBC stated on page 14 of the 2012 LT DSM Plan: "In this plan, FortisBC has included all programs identified in the [CPR] reports in which the program TRC ratio is above unity, which supports the objective of pursuing all cost-effective DSM."

The 2016 NW PP includes the following chart on p. 12-10, and conservation ramp rates on p. 12-16.

Figure 12 - 5: Approach to Setting Conservation Targets



41.1 Please explain FBC's action plan item to complete the final phase of the BC CPR (identifying the market potential and non-program potential). Would regulatory efficiency be enhanced if the 2016 LT DSM plan was filed after the CPR had been finished?

<u>Response:</u>

The contract for the Additional Services portion of the BC CPR scope, which includes the market potential, has recently been awarded and is anticipated to be completed mid-year. The market potential will inform the next DSM expenditure plan (for 2018 onwards) that the Company expects to file later this year.

No, delaying the LT DSM plan would not enhance regulatory efficiency. The 2016 FBC CPR report filed as Appendix A of the LT DSM Plan provides the economic potential and measure data needed to create the long-run DSM scenarios and to inform the preferred DSM portfolio the Company is proposing.

41.1.1 Does FBC consider that the development of the DSM portfolio's prior to the completion of the CPR is 'imprecise guess work'? Please explain.

<u>Response:</u>

The referenced quotation is from FBC's Reply Argument in the 2017 DSM Plan proceeding. The phrase was used by counsel in the context of submitting why it was not reasonable for preliminary draft results from the BC CPR, that were still subject to change at the time, to be used as a basis to significantly increase a DSM expenditure schedule that had been planned well in advance of the completion of the initial phase of the BC CPR. The initial phase of the BC

CPR and Navigant's report for FBC regarding technical and economic potential results for its service area (which Navigant described as the "initial and fundamental phase of the broader BC CPR"; please refer to Appendix A of the LT DSM Plan) had both been completed prior to the LT DSM Plan being finalized and filed.

41.2 Please explain how the 2016 CPR results have informed the development of the DSM scenarios.

Response:

The energy savings and measures costs estimated in the 2016 CPR results are the basis of the DSM scenarios. FBC developed four load growth offset scenarios for DSM including Low, Base, High, and Maximum (Max), over the planning horizon. The supply cost curve for each of these DSM scenarios included a portfolio of measures from the FBC CPR results that have a range of resource costs. FBC used a portfolio of the most cost effective measures available for each scenario. The cost of each DSM scenario increases as higher cost DSM resources are selected to achieve a higher percentage of load growth offset with DSM. DSM program implementation costs are added to the measure costs to estimate the total cost of acquiring DSM as a resource for each of the scenarios.

41.2.1 Please explain the key differences between the approach used in the FBC's 2016 LT DSM Plan to develop alternative DSM portfolios and the approach used in (i) FBC's 2012 LT DSM Plan, and (ii) the 2016 NW PP.

Response:

FBC provides below a review of the high level similarities (including principles and processes) between the 2012 and 2016 LT DSM Plans, identifies the key differences in relation to these similarities, and then compares FBC's methodology to the 2016 NW PP. In summary, the approach used in these three plans is similar: identify the conservation potential starting with a list of measures and apply various assumptions to estimate a market/achievable potential.

For both the 2012 and 2016 LT DSM Plans FBC has submitted a plan that: offers a range of measure choices within programs that address the key end uses of the principal customer rate classes; is cost effective by including only those measures (with the exception of adequacy measures) that have a TRC Benefit/Cost (B/C) ratio greater than unity on a portfolio basis; and is compliant with the applicable legislation including the *UCA*, the *CEA*, and the DSM Regulation. In terms of principles, the key difference between these two plans are the avoided costs used to calculate the TRC.

In addition, both the 2012 and 2016 LT DSM Plans follow a similar process including: quantify the technical and economic energy savings potential available; develop DSM scenarios and present these scenarios in a series of public consultations; and identify the DSM scenario that is the preferred option. In terms of process, one key difference is the source used to estimate the technical and economic energy savings. The 2012 LT DSM Plan relied on the 2010 CPR study that was undertaken by EES Consulting for FBC only. For the 2016 LT DSM plan, FBC in partnership with FEI and BC Hydro, engaged Navigant Consulting to undertake the BC CPR study, the results of which included FBC's 2016 CPR report filed as Appendix A of the LT DSM Plan. This study included generating a new reference case forecast, characterizing energy savings measures, and estimating the economic savings potential from 2016 onwards. Included in this study is an update of all of the key inputs including updated end-use studies, load forecasts, measure lists and assumptions, discount rate and avoided costs.

FBC has limited understanding of the process used to develop the 2016 NW PP but believes that the approach may be similar with a few key differences. Similarly, the 2016 NW PP creates a list of energy efficiency measures and then evaluates the technical feasibility, similar to the 2016 LT DSM Plan. However, the 2016 FBC CPR examined the technical potential and then screened for economic potential, whereas the 2016 NW PP assesses technical achievability (identifying market adoption barriers) of DSM before economic potential. As part of this achievable potential, the 2016 NW PP applies ramp rates to each measure to establish the upper limit of annual conservation resource development annually. FBC has not (yet) estimated the achievable potential for each measure in the 2016 LT DSM Plan, which is an anticipated result of the market potential in the next phase of the BC CPR. The 2016 LT DSM Plan relies upon the economic lowest-cost resource portfolios for each of the scenarios.

41.3 Please show in table form the annual DSM savings under each of FBC's DSM portfolio options and the Navigant CPR findings of 500 GWh/year savings available at a cost less than 5c/kWh. Please calculate the DSM portfolio savings as a percentage of the 500 GWh/year savings.

Response:

The following table shows the average and total GWh estimated savings for each DSM scenario over the planning horizon, and the percentage of the identified 500 GWh per year CPR tranche utilized under each scenario.

Table 1: Average and total DSM scenario savings (GWh/yr):

	Low	Base	High	Max	100% load growth offset
Average GWh/yr (2018-2035):	20.0	26.4	30.8	35.5	40.0
Sum of GWh/yr (2018-2035):	360.4	475.7	554.8	639.4	720.7
Percent (of 500 GWh):	72%	95%	100%	100%	100%

41.4 Please explain how FBC calculates the resource cost of each DSM portfolio in the absence of a complete CPR. Please state all assumptions and data sources.

Response:

In the absence of a completed CPR, FBC developed an interim estimate of market potential to calculate the resource cost of each DSM portfolio. The major assumptions include:

- 2035 is used as the end year (i.e. maximum potential);
- 85 percent of economic potential identified in the CPR is achievable, consistent with assumptions from the NPCC (2007)[59];
- A utility incentive rate of half the measure cost; and
- Energy savings are calibrated to historical results.

Using this interim estimate of market potential ensures that there is sufficient achievable potential to feasibly deliver all of the scenarios included in the LTERP scenarios and provides a more realistic resource cost for each DSM scenario considered.

[59] Northwest Power and Conservation Council (NPCC) (2007). A Retrospective Look at the Northwest Power and Conservation Council's Conservation Planning Assumptions. https://www.nwcouncil.org/reports /2007/2007-13.

41.5 Please explain when FBC considers it should file the next LTERP.

Response:

As discussed in action item 6 in Section 11 of the LTERP, FBC expects that it would submit its next long term electric resource plan and long term DSM plan in approximately five years from the submission date of this LTERP (November 30, 2016). This would provide FBC with enough lead time to assess the updated LRB and available resource options and costs before any new resources may be required by 2026.

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."

42.1 Please provide the referenced excel attachments in Appendix A of the CPR.

Response:

Please refer to Attachments 42.1a, 42.1b, and 42.1c.

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 after tax utility cost of capital, equal to 6 percent.

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.

42.3 Please provide a summary of which area of the CPR relied on the TRMs as an input, and explain whether the TRMs is an appropriate proxy that is applicable in FBC's geographical and operating environment.

Response:

Navigant used Technical Reference Manuals (TRMs) to supplement missing information for purposes of characterizing energy efficiency measures. For various measures, data required to complete measure characterization was not available from secondary data provided by the BC Utilities. Navigant leveraged TRM data to complete the measure characterization process including algorithms for the calculation of energy savings, space heating equipment full load hours, data on frequency of usage of appliances and electronics, among other inputs. All TRM data was adjusted based on FBC's geographical and operating environment (such as temperature regions) to ensure the information used was appropriate for FBC's customer base.

42.3.1 Please explain whether Navigant adjusted the TRM values due to geographic differences. If yes, please explain how FBC determines when an adjustment is necessary and the appropriate magnitude and methodology of the adjustment(s). If not, why not?

Response:

Navigant leveraged TRM data to close any measure characterization data gaps after using the data provided by the BC Utilities. The team used TRM data from utilities and jurisdictions closest in nature to FBC's climate zone in order to develop appropriate measure characteristics and parameters. Navigant worked with FBC and the BC Utilities to refine these assumptions and discuss their applicability to the regions across the province. For certain weather sensitive measures, the team used data from similar climactic region TRMs, and adjusted the data based on FBC regional temperature and heating/cooling degree days. This approach provides the most accurate estimate of electric consumption for weather-sensitive end-use equipment and measures.

43.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

Exhibit B-1, Volume 2, Appendix A, sections 1.3.4, 2.4.3, sub-Appendix D

CPR: modeling measures independently

Navigant states in section 1.3.4 of Appendix A that:

> 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.

Navigant states in sub-appendix D of Appendix A that: "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" Navigant states in section 2.4.3 of Appendix A that it "used measure specific program evaluation data from the BC Utilities to inform energy savings."

43.1 Please explain whether the use of evaluation data offsets the potential overstatement of the estimated energy savings from modeling measures independently.

<u>Response:</u>

Navigant Consulting Inc. provided the following response to BCUC IR 1.43.1.

Navigant does not believe that reliance on evaluation data materially offsets the potential overstatement of estimated energy savings. Navigant provides three justifications for this conclusion:

1. Evaluation data was not available or applicable to all measures considered in the CPR, and consequently many measures rely on other data sources for energy savings estimates.
2. Though some evaluations will consider interactive effects from multiple efficient measures, they rarely seek to attribute the total savings to individual measures, preferring instead to treat the efficient measures as a bundle. Since evaluation studies are more likely to focus on single measure offerings rather than combinations, the evaluation data, upon which the team relied, are more likely to represent savings prior to considerations for multiple efficient measure installations at a single site.

3. In cases where the team used evaluation studies for bundled measures (e.g., ENERGY STAR homes), the energy savings estimates would account for efficiency stacking and thus offset the potential overstatement of savings. However, these cases are less common and are likely to represent a small percentage of total savings reported.

44.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

Exhibit B-1, Volume 2, p. 7; 2016 NW PP, pp. G-33, G-39, G-47; FBC 2012 RR & ISP, Exhibit B-1-2, LT DSM Plan, pp. 18, 29;

CRP: Other

Page G-33, G-39, and G-47 of the 2016 NW PP include residential, commercial and industrial measures bundles by end use respectively. Page 18 to 29 of the FBC 2012 LT DSM Plan includes a list of DSM programs. FBC states on page 7 of the 2016 LT DSM Plan Application that, primary inputs in the base year were the 2012 Residential and 2015 Commercial End-Use Surveys.

44.1 Are there any residential, commercial or industrial measures that were listed on pages G-33, G-39, and G-47 of the 2016 NW PP which were not included in the 2016 FBC CPR? If yes, please identify and explain why.

Response:

Table 1, below, lists measures that are in the 2016 NW PP but not included in the 2016 FBC CPR. Conversely there are measures included in the 2016 FBC CPR that are not included in the 2016 NW PP.

For the purposes of the BC CPR, Navigant prioritized measures with high impact, data availability, and most likely to be cost-effective as criteria for inclusion in the study.

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Table 1: Measures included in 2016 NW PP, but not included in the 2016 FBC CPR

Sector	End Use	Measure
Residential	Electronics	Laptop
Residential	HVAC	Ground-source heat pump
Residential	Water Heating	Dishwasher
Residential	Water Heating	Solar water heater
Residential	Whole Bldg/Meter Level	Electric vehicle supply equipment
Commercial	Electronics	Laptop
Commercial	Electronics	Monitor
Commercial	Electronics	Smart Plug Power Strips
Commercial	HVAC	DCV Parking Garage
Commercial	HVAC	DCV Buildings
Commercial	HVAC	Premium Fume Hood
Commercial	HVAC	Secondary Glazing Systems
Commercial	Lighting	Bi-Level Stairwell Lighting

Sector	End Use	Measure
Commercial	Lighting	Parking Garage Lighting
Commercial	Motors/Drives	Motors Rewind
Commercial	Process Loads	Municipal Sewage Treatment
Commercial	Process Loads	Municipal Water Supply
Commercial	Refrigeration	Water Cooler Controls
Commercial	Water Heating	Clothes Washer
Industrial		CA Retrofit - CO2 Scrub
Industrial		CA Retrofit - Membrane
Industrial		Clean Room: Change Filter Strategy
Industrial		Clean Room
Industrial		Elec Chip Fab
Industrial		Kraft: Efficient Agitator
Industrial		Metal: New Arc Furnace
Industrial		Motors: Rewind
Industrial		Panel: Hydraulic Press

44.2 Please identify any DSM programs that FBC described on page 18 to 29 of the FBC 2012 LT DSM Plan that were either not included in the 2016 LT DSM Plan Application, or were proposed 2017 funding levels are more than 25% lower than those proposed for 2016 in the 2016 LT DSM Plan Application.

Response:

The majority of the programs included in the FBC 2012 LT DSM Plan are included in the 2016 LT DSM Plan. However, various program offers have been modified and updated as necessary. The 2016 LT DSM Plan is not an expenditure schedule, so funding levels by sector or by program were not provided. The Company intends to file such an expenditure schedule for 2018 onwards, in the latter part of 2017.

In the Residential sector FBC no longer offers incentives for geo-exchange systems, or for a refrigerator and freezer pick-up program. For the Commercial sector, FBC no longer has a Building Optimization Program (BoP), however a retro-commissioning program is under consideration. Finally, FBC continues to support the Energy Management Information Systems (EMIS) program, however the program has been rolled up into the Industrial program.

44.2.1 For these identified programs, please provide the estimated TRC ratio and utility cost (in $/MWh) explain why they have been eliminated/funding reduced.

Response:

TRC and utility cost are not available for the measures that were not included in the study.

44.3 Please explain why the residential end-use survey was not updated for the CPR.

Response:

FBC updates its Residential End-Use Survey (REUS) at approximately five year intervals, therefore a more recent update was not available.

Although the FBC 2012 REUS was the primary input to the 2016 FBC CPR, Navigant supplemented the FBC data with BC Hydro's 2014 REUS data for their adjoining southern-interior region, where more current or granular data was available.

44.4 Please explain how behaviour based DSM opportunities have been captured in the 2016 CPR.

Response:

The scope of the BC CPR Technical/Economic study included behaviour based DSM opportunities. The 2016 FBC CPR included the following behavioural measures:

- Residential Home Energy Reports;
- Commercial Comprehensive Retrocommissioning;
- Commercial Occupant Behavior; and
- Industrial Energy Management.

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.

<u>Response:</u>

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	Estimated Annual DSM Budget (2016 $000s)					Annual DSM Savings (GWh)				
		Low	Base	High	Max	100% load growth offset	Low	Base	High	Max	100% load growth offset
Plan	2017		$7,610					25.7			
Forecast	2018	$5,200	$7,900	$7,900	$7,900	$15,500	20.0	26.4	26.4	26.4	39.2
Forecast	2019	$5,200	$7,900	$7,900	$7,900	$15,500	20.0	26.4	26.4	26.4	41.4
Forecast	2020	$5,200	$7,900	$7,900	$7,900	$15,500	20.0	26.4	26.4	26.4	38.1
Forecast	2021	$5,200	$7,900	$9,000	$9,000	$15,500	20.0	26.4	28.4	28.4	34.4
Forecast	2022	$5,200	$7,900	$10,000	$10,000	$15,500	20.0	26.4	30.4	30.4	42.3
Forecast	2023	$5,200	$7,900	$10,900	$11,100	$15,500	20.0	26.4	32.0	32.4	44.5
Forecast	2024	$5,200	$7,900	$10,900	$12,300	$15,500	20.0	26.4	32.0	34.4	39.9
Forecast	2025	$5,200	$7,900	$10,900	$13,400	$15,500	20.0	26.4	32.0	36.4	41.1
Forecast	2026	$5,200	$7,900	$10,900	$14,600	$15,500	20.0	26.4	32.0	38.4	41.2
Forecast	2027	$5,200	$7,900	$10,900	$15,500	$15,500	20.0	26.4	32.0	40.0	39.4
Forecast	2028	$5,200	$7,900	$10,900	$15,500	$15,500	20.0	26.4	32.0	40.0	40.1
Forecast	2029	$5,200	$7,900	$10,900	$15,500	$15,500	20.0	26.4	32.0	40.0	40.4
Forecast	2030	$5,200	$7,900	$10,900	$15,500	$15,500	20.0	26.4	32.0	40.0	36.7
Forecast	2031	$5,200	$7,900	$10,900	$15,500	$15,500	20.0	26.4	32.0	40.0	38.5
Forecast	2032	$5,200	$7,900	$10,900	$15,500	$15,500	20.0	26.4	32.0	40.0	40.5
Forecast	2033	$5,200	$7,900	$10,900	$15,500	$15,500	20.0	26.4	32.0	40.0	41.2
Forecast	2034	$5,200	$7,900	$10,900	$15,500	$15,500	20.0	26.4	32.0	40.0	40.7
Forecast	2035	$5,200	$7,900	$10,900	$15,500	$15,500	20.0	26.4	32.0	40.0	41.2

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45.2 Please articulate the key principles FBC used when grouping together different DSM programs/incentive levels to develop alternative DSM portfolios.

Response:

Please refer to the response to BCUC IR 1.41.2 that sets out the method, and key principles, that FBC used to develop the alternative DSM portfolios.

45.3 For each portfolio options included in Table 3-1 of the FBC 2016 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), TRC, Rate Impact Measure (RIM).

Response:

Please refer to the response to BCUC IR 1.33.1.

45.3.1 Please provide an estimate of the above metrics for a DSM portfolio option that is 50% higher than the annual DSM budget compared to the 'High DSM' scenario.

Response:

FBC is unable to complete this request as the budget estimates shown in Table 3-2 are founded on savings targets based on load growth offset; hence the budget follows, not vice-versa.

FBC has prepared an additional 100 percent load offset scenario in the response to BCUC IR 1.33.1.

45.4 Please identity the key differences in programs offered between each portfolio option. Specifically, do differences primarily relate to the level of incentives provided or are there differences in the measures targeted (and if so, which ones)?

Response:

The 2016 LT DSM Plan is not an expenditure schedule, so funding levels by sector or by program were not estimated. Specifically, the incentive for each measure was set to half of the measure cost to develop the DSM portfolio level cost estimates.

Please refer to the response to BCUC IR 1.41.2, that sets out the method FBC used to develop the alternative DSM portfolios. FBC used a portfolio of the most cost effective measures available for each scenario. The cost of each DSM scenario increases as higher cost DSM resources are selected to achieve a higher percentage of load growth offset with DSM. Thus, the measures "targeted" in each scenario are included as a function of their cost of energy.

45.4.1 Please identify the differences between FBC's presented DSM portfolio options in terms of: (i) the range of measures targeted; (ii) the incentive levels offered; (iii) the extent to which 'lost-opportunities' are addressed; and (iv) the extent to which broad opportunities are provided for customers to participate.

Response:

Please refer to the response to BCUC IR 1.45.4.

The FBC 2016 CPR captures the economic potential for a broad range of measures that target key end-uses for each customer sector, including "lost opportunities" such as bundled residential new construction measures, namely ENERGY STAR, R2000, Passive House, and Net Zero which shows the higher performance and more costly packages becoming cost-effective over the planning horizon.

45.5 Please explain to what extent the different DSM portfolios focus on targeting customer behaviour as opposed to promoting investments in efficient appliances.

Response:

Please refer to the response to BCUC 1.44.4.

The 2016 LT DSM Plan is not an expenditure schedule, so funding levels by sector or by program (including behavioural measures) were not estimated. The Company anticipates filing its next DSM expenditure schedule, for 2018 onwards, later this year.

45.6 Please describe the key assumptions used to determine the utility cost (in $/MWh) of alternative DSM portfolios, including assumptions regarding the discount rate, free-rider/spillover rates and persistence of savings.

Response:

The key assumptions include:

- A utility incentive rate of half the measure cost;
- program administration costs, including supporting initiatives, were based on the approved 2017 DSM Expenditure plan;
- the measures' energy savings, valued at the LRMC of $100.45 per MWh;
- the measures' demand savings, valued at the DCE of $79.85 per kW-yr;
- measures' energy and demand savings are grossed-up by the avoided transmission and distribution energy losses (line losses) value of eight percent;
- a six percent discount rate was used to calculate the present value of the benefits;
- free-rider/spillover rates of zero percent; and
- measure persistence as identified in the 2016 CPR.

45.7 Please identify any measures identified in the 2016 CPR that pass the TRC which FBC is not targeting in its DSM portfolio options.

Response:

The lowest cost energy measures available are used in each of the DSM scenarios. For example, the Base scenario will include all the measures in the Low scenario, plus additional measures with a higher cost of energy until the load growth offset target is met.

All measures that pass the TRC are included, to some extent, in the 100 percent of load growth offset scenario shown in the response to BCUC IR 1.33.1.

45.8 Please identify DSM programs that meet the following criteria and identify the level of funding for these programs over the next five years under FBC's preferred DSM portfolio:

- have a utility cost lower than the LRMC of market purchases;
- address 'lost opportunities' (energy savings that would be more expensive to obtain later);
- required to meet the adequacy requirements of the DSM Regulations

Response:

The 2016 LT DSM Plan is not an expenditure schedule, so funding levels by sector or by program were not estimated. Similarly the savings targets for the DSM scenarios were not divided or allocated to specific sectors/programs or to address specific "lost opportunities" or adequacy requirements.

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 Please explain why FBC has based its portfolio options on a percentage of load growth. Please include in your response whether this could result in FBC purchasing energy for a higher cost than could be obtained through DSM.

Response:

The Company adopted the B.C. provincial policy framework, as indicated in the Energy Plan and the *CEA*, that expresses DSM targets in terms of load growth offset.

It is unlikely that this could result in FBC purchasing energy at a higher cost since FBC’s preferred High DSM scenario incorporates measures up to the LRMC ($100 per MWh) that FBC uses to screen DSM measures, whereas the current market price of energy is approximately half the LRMC.

46.1.1 Does FBC consider that it should only offer DSM programs when it is experiencing load growth? Please explain why/why not.

Response:

No. Please refer to the response to BCUC IR 1.38.2.1, which demonstrates (DSM actual savings as a percent of load growth) that FBC continued to offer DSM programs even though five years of the ten year span from 2006 to 2015 experienced negative load growth.

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 the LRMC value of $100 per MWh.

46.1.3 Please provide FBC's (i) plan and (ii) actual DSM energy savings as a percentage of load growth for each year from 2010 to 2016.

Response:

The requested information is provided in the table below.

Table 1: FBC Approved Plan and Actual DSM as a Percent of Normalized Gross Load Growth

Year	DSM Approved Plan (GWh)	DSM Actual Energy Savings (GWh)	Normalized Gross Load Growth (GWh)	DSM Forecast Percent of Load Growth	DSM Actual Percent of Load Growth
2010	27.5	29.3	-47.1	-58%	-62%
2011	39.7	36.3	78.6	51%	46%
2012	32.0	31.6	-25.6	-125%	-123%
2013	31.5	29.5	78.3	40%	38%
2014	12.8	14.6	-63.5	-20%	-23%
2015	26.2	12.6	9.3	281%	135%
2016	27.2	22.8	30.7	89%	74%

46.2 Does FBC consider that its proposed 'percentage of load growth' approach to the development of DSM portfolios is consistent with general industry practice? Please explain and provide references.

Response:

Please refer to the response to BCUC IR 1.46.1.

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.

<u>Response:</u>

(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%	2.0%	2.0%
2020	2.0%	2.0%	2.0%
2021	2.0%	2.2%	2.2%
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	1.6%	2.3%	3.2%
2028	1.6%	2.2%	3.2%
2029	1.6%	2.2%	3.1%
2030	1.6%	2.1%	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%	2.8%
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%

47.1.1 Please compare the above DSM metrics to those of BC Hydro and other utilities and explain any significant differences.

Response:

The BC Hydro reference provided states that "*The American Council for an Energy-Efficient Economy report shows the industry average at 0.7 per cent and median at 0.6 per cent*." The same reference shows BC Hydro's program savings, as a percent of retail sales, is 0.7 percent (F2014-16) and 0.6 percent (F2017-19).

FBC's metrics, in terms of energy savings, are comparable to industry average, including those of BC Hydro.

Table 13 of the same ACEEE report (in the BC Hydro reference) shows the median expenditure by state for electric utilities is 1.28 percent of revenues. FBC's preferred High DSM Scenario indicates an estimated DSM expenditure of 2.0 percent or higher, as a percentage of estimated revenues, over the planning horizon.

However, there are many challenges with comparing data across jurisdictions. These include:

- Inconsistencies in the quality and quantity of reported costs and savings data;
- Inconsistencies in the definition of different types of costs and savings;
- Differences in market opportunities; and
- Differences in the over-arching policy drivers for demand-side management activities.

As a result, developing conclusions based on jurisdiction comparisons should be approached with caution.

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.

<u>**Response:**</u>

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 $114 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.

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.

48.1.1 Does FBC consider that the principles used to evaluate DSM with supply side options are consistent with that used to compare alternative supply side options? Please explain.

Response:

Please refer to the responses to BCUC IRs 1.2.1 and 1.48.1.

48.1.2 Please explain why FBC used RS 3808 Tranche 1 energy as an input into the development of the High DSM scenario, rather than FBC's long-term avoided cost.

Response:

FBC did not use RS 3808 Tranche 1 energy as an input into the development of the High DSM scenario. FBC used the LRMC ($100 per MWh) to calculate the resource cost of all DSM scenarios.

The Load-Resource Balance gaps and utilization of RS 3808 Tranche 1 energy were considerations in the ramping of the High DSM scenario.

48.2 Does FBC consider that the size of the DSM portfolio should be constrained to address rate impact concerns? If yes, please describe and justify any rate limit proposed.

Response:

While rate impacts are not a primary determinant, FBC does consider rate impacts to balance the cost impacts of marginal DSM measures, and the implementation of those measures, while optimizing the use of available low-cost resources such as the BC Hydro PPA Tranche 1.

48.2.1 Please discuss the advantages/disadvantages of alternative options to mitigate the effect of DSM related rate impacts. Please include: DSM programs to target hard-to-reach vulnerable customers (such as low-income); ensuring a reasonable balance of DSM programs between customer classes; reducing the level of cost-effective DSM.

Response:

FBC interprets this question to mean “what is the expected impact on rates of the following options”.

Programs that target hard-to-reach vulnerable customers tend to rely on direct install measures and pay for the entire measure cost with an incentive. Direct install programs tend to cost more per unit energy savings than other programs. Thus, acquiring more energy savings from programs that target hard-to-reach vulnerable customers may increase DSM related rate impacts.

There is a range in costs of measures available to each customer. Ensuring a reasonable balance of DSM programs between customer classes may, or may not, increase DSM related rate impacts.

It is unclear what is meant by "reducing the level of cost-effective DSM". If FBC interprets this to be "what is the impact on rates of acquiring less cost-effective DSM" then FBC suggests that, absent any other considerations, acquiring less cost effective DSM may increase DSM related rate impacts.

48.2.2 Does FBC consider that DSM related rate impact considerations are short-term in nature only? Please explain.

<u>Response:</u>

No. DSM involves reducing electricity usage through activities and programs that promote a combination of energy efficiency, conservation and efficient management of electricity loads and consequently is a sustained practice in electricity utilities. Therefore, DSM's (rate) impact on customers is also sustained, or long term in nature. Additionally, the DSM amortization period is presently set at 10 years and therefore also has a longer term impact on customer rates.

Please refer to the response to BCUC 1.49.1 for estimated yearly and cumulative rate impacts.

48.3 Does FBC consider that DSM can be preferable to new generation build as a result of the flexibility to ramp up/down DSM spending levels? Please explain, and discuss how any such benefit is recognized in the evaluation of all presented DSM portfolio options.

<u>Response:</u>

FBC has significant existing system flexibility to adjust to lower than expected loads by decreasing BC Hydro Tranche 1 PPA purchases. Higher than expected loads can also be accommodated through increasing BCH PPA purchases, but Tranche 2 may be required, or through the market if cost-effective energy is available. The potential ability to treat DSM as a dispatch resource over many years' time is simply too slow in responding to meaningfully add value to FBC's power supply portfolio.

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%	$ 73.33
10th year (2025)	1.8%	12.2%	$ 196.85
20th year (2035)	0.9%	41.7%	$ 672.11

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%	$ 73.33
10th year (2025)	1.9%	12.4%	$ 199.39
20th year (2035)	1.1%	43.6%	$ 702.97

49.1.1 Please provide the same metrics for a DSM portfolio option that is 50% higher than the utility DSM funding compared to the 'High DSM' portfolio. Please state all assumptions used.

Response:

The estimated annual DSM budget required to achieve DSM portfolio B4 (Max DSM) escalates to 142 percent of portfolio A4 (High DSM); which the Company considers to approximate the 50% higher expenditure requested in this IR.

The associated rate impacts are provided in response to BCUC IR 1.49.1. Also please refer to the response to BCUC IR 1.38.2 for the estimated funding levels.

49.1.2 Please estimate how much of the effect on rates in the first five years is due to (i) the cost of DSM spend; and (ii) the effect on consumption levels.

Response:

The effect on rates for the first 5 years solely for DSM was evaluated to be the difference between portfolio B1 (No DSM) and FBC preferred portfolio A4 (High DSM). For purposes of this IR response, the "first five years" is assumed to refer to the first five forecast years (2018-2022). DSM investment increases rates by approximately 2.8 percent on a cumulative basis during the years 2018-2022, while saving approximately 470.5 GWh of energy by year 2022. (Note that DSM savings realized in these 5 years will continue to have impacts beyond 2022.)

49.2 Please explain the level of weight FBC considers should be placed on the following metrics in evaluating the DSM portfolios: residential bills, FBC rates, GHG emissions. If the level of weight placed on any one of these metrics has changed since the 2012 IRP, please explain why.

Response:

The Company created its DSM Scenarios based on four levels of load growth offset, informing the cost of each DSM portfolio with the cost-effective measures provided in the economic potential results of the 2016 FBC CPR.

FBC did not create or evaluate the DSM portfolios based on the listed metrics, however the Company is mindful of residential bills and rate impacts. The Company notes that the GHG emissions, or reduction thereof, are minimal due to the small GHG factor associated with FBC electricity energy savings.

50.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

FBC's 2012 RR & ISP, Exhibit B-1-2, LT DSM Plan, pp. 14, 15; BC Hydro F2017-F2019 RRA, Exhibit B-9, BCUC IR 176.1; 2016 NW PP, p. 17-4

Adequacy and balance

On page 14 and 15 of FBC's 2012 LT DSM Plan Application, FBC provides energy savings targets by sector and cost benefit ratios by sector. In Exhibit B-9 (BCUC IR 176.1) of the F2017-F2019 RRA proceeding, BCH provides DSM expenditures as a percentage of retail revenue by sector.

The 2016 NW PP states on page 17-4:

> Although low-income customers are often an underserved segment, other hard-to-reach (HTR) segments may include: mid-income customers, customers in rural regions, small business owners, commercial tenants, multifamily tenants, manufactured home dwellers, and industrial customers if they are unable or unwilling to participate in conservation programs.

50.1 Please provide an estimate of the annual break down by customer class over the next five years of DSM spend as a percentage of revenues. Please (i) explain any significant variation in these percentages between customer classes and (ii) comment on any significant differences between DSM spend as a percentage of customer class revenue and that is proposed by BC Hydro.

Response:

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

50.2 Please identify the 2012-2016 (actual) and 2017-2021 (proposed) DSM funding to meet each of the four adequacy requirements in Section 3(a) of the DSM Regulations, and describe the programs offered. Please explain any significant difference in the programs offered or funding allocated between these two periods.

Response:

The programs required to meet the adequacy requirements are described in the following sections of the LT DSM Plan: 4.1.7 (Low Income Households Program), 4.1.8 (Rental Accommodation), and 4.4.4 (Education Programs). The 2012-2016 (actual) DSM funding and 2017 Plan funding levels are provided in the table below.

	Low income	Rental	Education in schools & Post-secondary
2012 Actual	308	-	-
2013 Actual	235	179	22
2014 Actual	396	106	20
2015 Actual	253	35	83
2016 Actual	885	67	157
2017 Plan	1221	146	150

The 2016 LT DSM Plan is not an expenditure schedule so funding levels by sector or by program, including adequacy requirements, have not been determined for the years 2018 and beyond.

The Company anticipates filing its next DSM Expenditure Schedule, for 2018 onwards, later this year.

50.3 Please identify any low-income DSM programs offered by BC Hydro that are not offered by FBC, and explain why FBC does not offer similar programs to its customers.

Response:

FBC offers the same low-income programs as BC Hydro. Wherever possible, the Energy Conservation Assistance Program and the Energy Savings Kit Program have identical eligibility and measure criteria, measure installations and offers, and service levels. FBC and BC Hydro use the same implementation and quality assurance contractors for both programs to ensure consistent service across the province.

50.4 Please explain whether (and if so how) FBC has given specific consideration to other potentially 'hard to reach' customers. Please specifically address: First Nation communities, rural communities without access to natural gas, low-income/high use residential customers, and high use customers in rental accommodation who are direct customers of FBC.

Response:

The 2016 LT DSM Plan is not an expenditure schedule, so funding levels by sector or by program were not estimated for years 2018 and beyond.

FBC has given consideration to hard-to-reach customers. The following outlines the efforts made to-date for each of the identified customer segments:

First Nations communities:

- FBC worked closely with all First Nations in its territory to encourage participation in its direct installation Energy Conservation Assistance Program (ECAP). The Osoyoos and Penticton Indian Bands have realized 100 percent participation, the Lower Similkameen and Ktunaxa Indian Bands realized 80+ percent participation and the Upper Similkameen Indian Band slightly less;
- Provided heat pumps to 50 plus First Nations homes with the Ministry of Energy and Mines (MEM) co-funding;
- Provided rebates, advice and project management support for the Penticton Indian Band Super-Efficient Sage homes, and helped secure Ministry of Energy and Mines funding; and
- Provided rebates for new construction projects (schools, new homes, health and wellness centres, administration buildings) for the Penticton, Osoyoos and Lower Similkameen Indian Bands.

Rural communities:

- FBC focused its ECAP marketing efforts on rural communities, some of which do not have access to natural gas;
    - Partnered with MLA Linda Larson to deliver personal presentations to all rural communities in the South Okanagan/Similkameen;

- Met with 40 plus social service organizations in the Kootenays and South Okanagan to encourage referrals and face-to-face promotion of the program;
- Made presentations to the majority of municipal government councils and staff;
- Provided ECAP collateral to all local government and social service organization offices;
- Direct mailed all Ministry of Social Development and Social Innovation clients;
- Sent bill inserts to all customers;
- Conducted community presentations and open houses; and
- Provided information displays, Energy Savings Kits (ESKs) and ECAP marketing at food banks

Low Income/High Users:

- FBC has not been able to identify low income/high users per se. However, high users have been identified and FBC has sent two direct mail pieces marketing its rebate programs.

Rental accommodation:

- FBC offers its Rental Apartment Program which provides direct installation of in-suite energy efficiency measures; an ASHRAE[60] level one energy (gas/electric) evaluation of common areas and subsequent support to implement energy efficiency measures for common areas
- Incentive offers include prescribed and custom rebates for common area efficiency upgrades

50.5 Please explain the approach used by FBC to identify energy savings from industrial customers.

Response:

FBC Technical Advisor staff conduct annual site visits with industrial customers with consumption over one GWh/yr, and generally conduct bi-annual site visits with most of FBC's

[60] American Society of Heating, Refrigerating and Air-Conditioning Engineers.

smaller industrial customers. During site visits, FBC Technical Advisors meet with operations and maintenance staff to discuss energy savings opportunities, answer billing queries and assist with individual process metering using FBC energy monitoring equipment. Industrial customers regularly contact FBC Technical Advisors on an as-and-when needed basis to discuss capital plans and how their facility can save energy and secure incentive funding to complete energy efficiency projects.

In 2016, FBC partnered with FEI to provide industrial customers with two levels of energy assessment offers as a part of the Industrial Optimization Program: the Plant Wide Audit and Feasibility Study. The study offers are up to 75% of the total study cost and must be conducted by an approved third party consultant with experience in providing energy efficiency evaluations for industrial customers.

The Plant Wide Audit is a high-level, whole facility audit that identifies a range of opportunities to use electricity and/or natural gas more efficiently. Energy conservation measures identified in the audit are presented in a report with cost and savings estimates at a +/- 50 percent uncertainty level.

The Feasibility Study looks at a specific process or system within the customer's facility to fully investigate an opportunity to use electricity and/or natural gas more efficiently. Energy conservation measures identified in the study are presented in a report with cost and savings estimates at a +/- 10 percent uncertainty level.

51.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

2007 BC Energy Plan p. 5; City of New Westminster report, Partnership with BC Hydro-Power Smart, April 12, 2007[61]

Co-ordination

The 2007 BC Energy Plan states on page 5: "Ensure a coordinated approach to conservation and efficiency is actively pursed in British Columbia." A City of New Westminster report dated April 12, 2007, states that the City has signed a Memorandum of Agreement with BC Hydro PowerSmart, allowing City of New Westminster electrical customers to participate in all BC Hydro PowerSmart programs.

51.1 Please explain how FBC, in the development and implementation of its DSM programs, ensures that it actively coordinates with Livesmart, FEI and BC Hydro.

Response:

To seek program efficiencies, share resources and have consistent program offers and messaging, FBC continually seeks to collaborate with its BC utility partners (FEI and BC Hydro) and the Ministry of Energy and Mines (MEM).

For example, FBC worked closely with MEM throughout the development and implementation of LiveSmart. FBC's contributions included incentives, rebate processing and customer service support, marketing support, and funding for evaluation measures. until the LiveSmart program ended in March 2014.

FBC has integrated its DSM programs with FEI wherever feasible. Residential and low-income programs are presented to customers through one-stop-shop offers, with one set of eligibility criteria, application forms, legal terms and conditions, and program offers. All the elements of program development, implementation, marketing, and evaluation are shared. Costs are separated and paid based on a customer per capita and/or savings basis. The commercial/industrial programs are also progressing towards full integration.

FBC and FEI have signed an MOU with BC Hydro to work collaboratively whenever possible. Research, evaluation and marketing efforts are commonly shared and/or co-funded. The residential Retail, Appliance, Home Retrofit, New Home and Low-Income programs were jointly developed and implemented to ensure consistent offers and messaging across the province. When feasible, those programs are also jointly marketed and evaluated. Although there is less joint program development and implementation for commercial and industrial programs, research and program information is shared among the BC utilities.

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[61] http://www.newwestcity.ca/council_minutes/0416_07/CW/Reports/CW13.pdf.

51.1.1 Does FBC consider that it should increase the standardization of its DSM programs with BC Hydro? Please explain why/why not.

Response:

No. Despite the high level of collaboration, and standardized offers where feasible, each BC Utility manages its own programs to achieve its own goals (expenditures & savings). FBC's preferred DSM Scenario was selected based on the Company's LTERP requirements and informed by the 2016 FBC CPR results.

Please also refer to the response to BCUC IR 1.51.1.

51.1.2 Does FBC consider that there could be a net benefit from BC Hydro extending some or all of its DSM programs into FBC's service areas in a similar manner that the City of New Westminster has done with BC Hydro? Please explain.

Response:

No. FBC is an autonomous integrated electrical utility that is responsible for its own resource planning, including this LTERP application currently under consideration, and determining its appropriate level of DSM activity.

FBC notes it has a similar arrangement to that of BC Hydro and the City of New Westminster by providing its DSM programs to all indirect customers served by its wholesale customers, namely Nelson Hydro, Cities of Grand Forks and Penticton, and the District of Summerland.

51.2 Please identify FBC's DSM budget for 2012-2016 and 2017-2021 for (i) rate design and (ii) codes and standards.

Response:

(i) The Company manages rate design within its regulatory department, and hence there is no budget allocation for this function in its DSM budgets.

(ii) The budget for codes and standards was set at approximately $25,000 per year over the period 2012-2016. The 2016 LT DSM Plan is not an expenditure filing, therefore FBC has not determined the specific DSM program costs going forward. The Company anticipates filing its next DSM expenditure schedule, for 2018 onwards, later in 2017.

51.2.1 Does FBC consider that it can obtain cost effective energy/capacity savings through rate design? Please explain why/why not. In your response, please compare the incremental energy charges of FBC's main rate classes with FBC's LRMC of portfolio A4.

Response:

Yes, FBC can utilize rate design to obtain energy/capacity savings. The conservation provided by the Residential Conservation Rate, as provided to the Commission in the Company's 2014 RCR Report, is evidence that energy savings can be provided by rate design initiatives. FBC is not in a position to comment on the cost-effectiveness of such measures relative to other means but notes that, as both tiers of the RCR are above the LRMC and current average embedded cost of power, such conservation decreases the customers' contribution to fixed costs and places upward pressure on rates.

The chart below contains the LRMC of Portfolio A4 in comparison to the energy rates of the Company's main rate schedules. For the stepped rates (RS01 and RS21), the rates cited are those in the second tier.

	Rate	$ / MWh
LRMC - Portfolio A4	n/a	96.00
Residential Service	RS01	156.17
Small Commercial Service	RS20	101.95
Commercial Service	RS21	71.91
Large Commercial Service - Primary	RS30	55.71
Large Commercial Service - Primary	RS31	55.16
Wholesale - Primary	RS40	54.41
Wholesale - Transmission	RS41	45.01

51.2.2 Please explain the approach undertaken by FBC to identify cost effective codes & standards energy savings.

Response:

At present, FBC does not independently identify energy savings from codes and standards.

The BC CPR study model incorporated known codes and standards implementation dates, so the 2016 FBC CPR Economic potential results reflect those items.

51.3 Please discuss the make-up and role of FBC's DSM advisory committee. If FBC no longer has an active DSM advisory committee, please explain why not.

Response:

The DSM Advisory Committee (DSMAC) is made up of a cross-section of customers representing key customer sectors (and rate classes) including residential, commercial, industrial, institutional and wholesale. Additionally, ex-officio participants have included representation from MEM and the BCUC staff. The DSMAC's original role was overseeing a DSM Regulatory Incentive, which ended with FBC's PBR plan in December 2011, after which its role became advisory.

Although the DSMAC as a whole has been relatively dormant for several years, certain members of the DSMAC participated in key DSM planning activities, namely by serving on the LTERP advisory group and the BC CPR Technical Advisory Committee.

The Company anticipates reconvening the DSMAC to review its upcoming DSM expenditure schedule that is anticipated to be filed later in 2017.

52.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

Exhibit B-1, Volume 2, p. 24

Self-generator eligibility

FBC states on page 24 of the 2016 LT DSM Plan Application: “Customers that normally supply a portion of their load through self-generation may be eligible for DSM programs and financial incentives in proportion to the share of potential energy savings to the Company.”

52.1 Please explain which customer classes FBC considers could be subject to prorating of DSM incentives, and identify existing FBC industrial or wholesale customers that could be affected.

Response:

Self-generators within the context of the reference are potentially those customers served under the Company’s Large General Service rate schedules, specifically 30 and 31. Wholesale customers, while able to extend the benefit of FBC’s DSM programs to their end-use customers, are not themselves eligible for DSM incentives. Currently, only Zellstoff-Celgar and Tolko Industries are served under the affected rate schedules and have self-generation.

52.2 Please explain to what extent the (i) TRC and (ii) UCT is affected depending on whether the customer purchases their energy from the utility, a third party, or self-supplies generation.

Response:

The more energy a customer purchases from a third party, or self-supplies, the lower the benefits a utility can claim for energy efficiency measure(s). The TRC and UCT both use the present value of the avoided costs from a measure: the energy savings of the measure at the LRMC plus the deferred infrastructure costs using the DCE.

From the utility perspective, the less energy that the customer purchases from the utility the less of the energy savings from the measure the utility realizes, which lowers the benefits of the TRC and UCT. For example, if a customer self-supplies 50% of their electricity from self-generation, or a third party, and the remaining 50% from the utility then only 50% of the electricity savings from the energy efficiency measure(s) incented by the utility are realized by the utility.

52.2.1 Please explain whether (i) FEI reduces the DSM incentives available to its customers depending on whether they purchase gas from FEI or an alternative supplier and (ii) BC Hydro reduces a self-generators eligibility to participate in DSM programs.

Response:

(i) FEI provides incentives to customers who take natural gas delivered by FEI regardless of who they have contracted with for the commodity. These customers are entitled to participate in DSM programs because the cost of DSM programs is recovered through the delivery charges that they pay and any reduction in their load reduces the load on FEI's system.

(ii) FBC understands that BC Hydro does not reduce DSM incentives for self-generators as long as the customer continuously imports power from the utility (i.e. the project does not result in full load displacement). BC Hydro does not provide DSM incentives to customers who self-generate the entirety of their load or where a DSM project would result in the customer self-generating the entirety of their load. For example, independent power generating facilities are not eligible for BC Hydro DSM incentives for efficiency projects conducted within their facilities.

52.3 Did FBC consider an alternative option of determining eligibility to DSM programs based on the contribution the self-generator makes towards the sunk cost of the network (for example, if a self-generator pays 50% of network charge compared to a full service customers, they would be eligible for 50% of the DSM funding)? Please explain why/why not and the results.

Response:

FBC assumes that the network charge to which the question refers is the Demand Charge assessed to Large Commercial customers on a monthly basis. FBC has not considered determining DSM eligibility on this basis. Depending on whether or not the customer takes full service or partial service from FBC using the Stand-By Rate, it may or may not be subject to full demand charges. The demand charge is intended to contribute to the fixed costs of providing service which do not vary appreciably despite the intermittent nature of such load since facilities to serve the full load of the customer are still required.

The Company considers linking the demand charge/fixed cost recovery to DSM is not appropriate since DSM activities are primarily related to the reduction in energy usage by the customer, and by extension, a reduction in the energy requirement of FBC. In addition, Demand Charges can vary greatly by month and it would be difficult to assess the degree to which these charges cover network costs during a prospective period and how this variability would or should impact DSM eligibility.

52.4 Please explain why FBC considers that the DSM incentive levels for self-generators would be adjusted downwards, rather than the total DSM funding level (i.e. no reduction in the incentive level provided, but fewer DSM programs funded). Specifically, to the extent the incentive level is set at the minimum level required to incent the customer to undertake the efficiency measure, would a reduction in the incentive mean the customer would not participate in the program?

Response:

The Company considers that customers have their own investment criteria (i.e. business case) to determine whether to proceed with a project that includes energy-efficiency measure(s). The available DSM incentive is not the sole criterion upon which the project hinges. The project's business case likely includes non-energy benefits, such as process improvements, reductions in other inputs (raw materials, labour), and reduced O&M costs, in addition to energy usage (utility cost savings) and the available DSM incentive.

Reducing the number of DSM programs offered would be difficult to administer and since two of the three known self-generation customers are Industrial and FBC offers a single industrial program, it would be impractical to adjust the number of DSM programs funded downwards.

53.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

FBC 2012 RR & ISP Decision, p. 134; National Action Plan for Energy Efficiency (2007). Model Energy Efficiency Program Impact Evaluation Guide. Prepared by Steven R. Schiller, Schiller Consulting, Inc.,[62] p. 7-2

Evaluation, Measurement and Verification (EM&V)

On page 134 of the Commission's Decision on FBC's 2012 RR & ISP, the Commission rejected FBC's proposed monitoring and evaluation plan as it failed to ensure that all programs are evaluated.

Figure 1 on page 7-2 of The Model Energy Efficiency Program Impact Evaluation Guide (2007) outlines the Program Implementation Cycle with High-Level Evaluation Activities. The report states on page 7-2 that "When a program is first envisioned, often as part of a portfolio of programs, is when both program goals and evaluation goals should be considered."

53.1 Please explain whether FBC has an EM&V plan that includes proposed evaluation methods and timing that will be used to conduct both process and impact evaluations on its DSM programs. If yes, please provide. If not, why not?

Response:

FBC last filed its formal EM&V Plan in the FBC 2014-2018 PBR Plan Application[63] for the three-year period 2013 to 2015, which was accepted pursuant to Order G-139-14. The EM&V Plan describes the methods used to conduct both process and impact evaluations. Evaluation activities, as filed for the 2016 and 2017 DSM expenditure schedules, are a continuation of that plan.

FBC anticipates filing its next DSM expenditure schedule, for 2018 onwards, later this year and that it will include an EM&V schedule for the filing period.

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62 https://www.epa.gov/sites/production/files/2015-08/documents/evaluation_guide.pdf.

63 Volume 2 Appendix H, Attachment H3, DSM Monitoring and Evaluation Plan 2013 to 2015.

54.0 Reference: LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

Exhibit B-1, Volume 2, pp. 25, 26; FBC 2017 DSM proceeding, Exhibit B-2, BCUC IR 9.1

RS 90 / RS 91

On page 25 of the FBC 2016 LT DSM Plan Application, FBC states "FBC is proposing to rescind RS 90 from its Electric Tariff…." On page 26, FBC requests approval to remove RS 90 from FBC's tariff sheet. FBC stated in Exhibit B-2 of the FBC 2017 DSM Expenditures proceeding (BCUC IR 9.1) that it intends to apply to formally close RS 91 to new entrants, as part of its 2016 LT DSM Plan Application.

54.1 Please explain why FBC has not applied to close RS 91 to new entrants.

Response:

Section 13 of FBC's Terms and Conditions and RS 91 set out the term of November 1, 2012 to January 1, 2015 for the On-Bill Financing Program and, therefore, RS 91 is already effectively not available (closed) to new entrants. FBC intends to file to formally request cancellation of RS 91 once all customer agreements under that rate schedule expire.

54.2 Please explain the difference between to cancel, rescind, and close a rate schedule.

Response:

To rescind a rate schedule is to remove it from FBC's Electric Tariff completely. The rate schedule will no longer be available to existing customers taking service under the rate schedule or to new entrants. By definition, cancel means rescind, however the language under the UCA specifically states "rescind".

To close a rate schedule will leave the schedule in the Tariff, but new entrants will not be able to take service under the rate. The rate schedule will remain in the Tariff and existing customers taking service under the rate schedule before it was closed will continue to be served under that rate schedule.

54.3 Please confirm, or otherwise explain, that FBC is requesting in this proceeding to cancel RS 90 from FBC's tariff sheet under section 58 to 61 of the UCA.

Response:

Please refer to the response to BCUC IR 1.54.2. FBC is requesting in this proceeding to rescind (or cancel, which has the same meaning) RS 90 from FBC's Electric Tariff, pursuant to section 61 of the UCA.

54.3.1 Would FBC customers be affected by FBC's request to rescind RS 90, and if so, how?

Response:

No, FBC's customers will not be impacted by FBC's request to rescind RS 90. As stated in Section 5.3 of the LT DSM Plan, the Terms and Conditions (T&Cs) contained in RS 90 are already set out in the individual program-specific terms and conditions where they have increased customer visibility and mandatory sign-off by participants. Among other benefits, removing RS 90 will eliminate the redundancy of having T&Cs in multiple places.

54.4 Please explain whether (and if so how) RS 90 has been used in the past five years, for example to determine the level of incentives offered under a DSM program or as part of a dispute resolution.

Response:

RS 90 has been used on an ongoing basis to provide a high-level check on the incentive amount by limiting the portion of incremental cost paid on a participant's payback period. With few exceptions, the incentives paid were based on the program offer's incentive rates ($/kWh), and not the limiting clauses in RS 90.

While there has been a dispute related to the application of RS 90 to an individual customer with respect to a single potential project, to FBC's knowledge RS 90 has not been used as part of a dispute resolution.

Attachment 42.1

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)