FORTIS BC™

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

May 18, 2017

British Columbia Public Interest Advocacy Centre
Suite 208 – 1090 West Pender Street
Vancouver, B.C.
V6E 2N7

Attention: Ms. Kate Feeney

Dear Ms. Feeney:

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 Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, Together Against Poverty Society, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO) Information Request (IR) No. 2

On November 30, 2016, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-197-16 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCOAPO IR No. 2.

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

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

51.0 Reference: Exhibit B-2, BCUC 1.1

51.1 Is there any linkage between FBC's LTERP and its FBC's Self-Generation Policy Stage II Application? If so, please outline.

Response:

FBC's LTERP sets out its long-term resource planning objectives relating to DSM initiatives and the requirements for supply-side resources. These objectives are applicable to potential supply from self-generators, the guidelines for which are set out in the Self-Generation Policy Stage II Application. The LTERP also discusses the cost of alternative sources of supply in the short- to medium-term (i.e. market purchases and PPA Tranche 1 energy and capacity) as well as the LRMC, which are applicable in helping to determine the cost effectiveness of supply from self-generators.

52.0 Reference: Exhibit B-2, BCUC 2.1, page 7, lines 3-7

Exhibit B-1, Volume 2, Section 3

52.1 In BCUC 2.1 reference is made to FBC first determining the "optimal level of DSM". However, the development of the LTDSM Plan only considered four DSM scenarios. Given this limitation on the range of DSM alternatives considered, please explain how the scenario selected (i.e. the High DSM Scenario) can be considered the optimal level of DSM?

<u>Response:</u>

The LT DSM plan explored four DSM Scenarios with increasing savings targets and higher marginal measure costs. Each DSM scenario represents a collection of numerous DSM measures and forms a high-level DSM savings target costed using the FBC CPR results. The optimal portfolio of complementary supply-side resources is dependent on the targeted energy and corresponding capacity savings associated with the DSM scenario. Given the iterative and interactive nature, four reasonable DSM scenarios were created of which High DSM was the preferred option as discussed in the response to BCUC IR 1.48.1.

53.0 Reference: Exhibit B-2, BCUC 2.2

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

Response:

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

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

In terms of cost, the preferred DSM level was determined through an assessment of cost effectiveness based on the Total Resource Cost rather than Utility Cost test, so that the cost impacts to both the utility and customer are taken into account (per the DSM Regulation). The incremental cost of ramping up to the High scenario is $104 per MWh, which is similar to FBC's LRMC of $100 per MWh for B.C. clean or renewable energy. In Section 8.1.3 of the LTERP, FBC discusses how implementing higher levels than the preferred level of DSM would require higher-cost DSM. Marginal costs would average $114 per MWh, well above the DSM cost-effectiveness threshold LRMC of $100 per MWh.

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

53.1.1 If yes, please provide a Table similar to Table 9-2 in Exhibit B-1 that compares the various DSM scenarios against these metrics and indicates that the High DSM scenario is preferable on this basis.

Response:

Please refer to the response to BCOAPO IR 2.53.1.

53.1.2 If not, why were different metrics used to evaluate the DSM scenarios?

Response:

Please refer to the response to BCOAPO IR 2.53.1.

54.0 Reference: Exhibit B-2, BCUC 5.5 and 26.1 to 26.3

54.1 If energy and capacity from expiring BC Hydro EPAs were to become available, what resources in FBC's preferred Portfolio A4 would they potentially replace and under what circumstances?

Response:

Please refer to the response to BCUC IR 2.61.2.1.

55.0 Reference: Exhibit B-2, BCUC 11.3

55.1 Do the same stability concerns apply to larger Self-Generation installations?

Response:

If FBC were to purchase self-generation output from customers as described in Section 8.2.8 of the LTERP, the same stability concerns described in the response to BCUC IR 1.11.3 would apply. In cases where self-generation acts only to offset some or all of a customer's load with no net generation at the meter, the potential for these installations to cause distribution network issues is reduced.

56.0 Reference: Exhibit B-2, BCUC 12.4.2

56.1 Are the referenced purchases just from one customer or are there a number of customers with whom this arrangement currently exists?

Response:

There are a number of customers with whom this arrangement currently exists.

56.2 At what price are such purchases currently made and does it vary depending upon whether FBC is in a surplus situation at the time of delivery?

Response:

The specific pricing, terms and conditions of these individual agreements are confidential. However, these purchases are typically energy only, and do not include any dependable capacity. Therefore the pricing is typically based on the lower of the wholesale market energy rate and the Tranche 1 energy rate under the PPA with BC Hydro.

56.3 Is FBC obligated to purchase the unplanned deliveries to the system?

Response:

FBC is obligated to purchase the unplanned deliveries under bilateral agreements with the customers.

56.4 Are there penalties that can be or are imposed for unplanned deliveries to the FBC system?

Response:

No, not under the current terms of these agreements.

57.0 Reference: Exhibit B-2, BCUC 16.1

Exhibit B-3, BCOAPO 16.3

57.1 With respect to BCUC 16.1, it is noted that with the exception of BCH Kingsgate (which is the smallest wholesale customer) the forecasts as provided by the wholesalers are consistently in excess of actual load. Has FBC investigated whether or not there is a bias in the forecasts it receives through its survey of wholesale customers?

Response:

FBC does review the variance between the wholesale load and the customer forecasts on an annual basis, but has not done any testing to determine whether there is a statistical bias in the forecasts received. FBC has not examined the reasons behind the variances since the three year annual mean absolute percent error (MAPE) for the Wholesale customers is low at only 2.7 percent. MAPE is an accepted and common statistical method of measuring prediction accuracy, which removes the cancellation effect of positive and negative values.

57.1.1 If yes, what were the results and are should any adjustments be made to offset identified bias in the forecasts?

Response:

Please refer to the response to BCOAPO IR 2.57.1.

58.0 Reference: Exhibit B-2, BCUC 23.2.1

Preamble: The response states that "FBC considers DSM savings to be reliable but non-firm resources, and thus are not counted on to defer network system reinforcements that are predicated on peak load requirements".

58.1 When FBC states that it considers DSM savings to be reliable but non-firm resources, is this referring to just forecasted/planned DSM savings to be achieved in future years or also DSM savings that have already been achieved?

Response:

This statement applies to both forecast and achieved DSM savings.

58.2 When it comes to deferring the need for future generation capacity which is predicated on peak load requirements, please confirm whether FBC considers future DSM savings to be a firm resource that can defer the need to acquire additional generation capacity.

Response:

FBC considers future DSM savings to be a reliable resource that can defer the need to acquire additional generation capacity. However, DSM is neither available on demand nor as reliable as some other supply-side resource options because DSM programs require voluntary participation by customers.

58.2.1 If the answer is yes, please explain why DSM is considered non-firm for purposes of network system reinforcement planning, but firm for purposes of generation capacity planning.

Response:

DSM is considered a reliable resource for purposes of generation capacity planning as a result of diversification. DSM programs cover a variety of cost-effective measures to address key end-uses offered to the major customer sectors across the FBC service territory. The DSM savings realized by any one measure, or in any one location, can be greater than or less than anticipated as a result of factors influencing customer participation such as demographics and socio-economics, or concentrations of customer segments. Therefore, the DSM measure savings realized in any one location is less certain, but when combined in aggregate at the system level are considered reliable.

FBC network planning is based on the actual load growth trajectory for specific lines and substation equipment, which may well have been tempered by DSM activities to date. When there is significant new development in a localized area, the resultant increases in load will generally outpace the impact of DSM savings in that same area. As noted above, the DSM savings in any one location can be greater or less than anticipated, meaning that the impact of future DSM measures on forecast peak load for specific infrastructure is uncertain. Once a planning criteria threshold has been crossed, an upgrade is planned for the infrastructure in question in order to meet mandatory service quality and reliability standard requirements.

Please also refer to the response to BCSEA IR 2.25.2.

59.0 Reference: Exhibit B-2, BCUC 27.2, 27.4 and 30.1.2

59.1 Please confirm that FBC's forecast load-resource balance (Application pages 92-94) does not include any purchases of self-generation from existing customers?

Response:

Not confirmed. As described in the response to BCUC IR 1.10.1 and the LTERP on page 113, "self-generation" refers to power produced by self-generating customers, which, for the purposes of the LTERP, refers to larger, industrial customers that can provide electricity to FBC. For the purposes of the Load Resource Balance (LRB) figures on pages 92-94 of the LTERP, the generation from self-generating customers is included with the IPPs.

59.2 Does FBC's forecast load-resource balance make any provisions for the standby power requirements of existing self-generation customers?

Response:

The standby power requirements of existing self-generation customers are expected to be met on an as needed basis through purchases of short-term market power if the Company does not have sufficient resources at the time to meet the requirements. As such, no provision to supply standby power has been made in the LTERP or included in the Load Resource Balance figures.

59.2.1 If not, why not?

Response:

Please refer to the response to BCOAPO IR 2.59.2.

59.2.2 If yes, how much and in what years?

Response:

Please refer to the response to BCOAPO IR 2.59.2.

60.0 Reference: Exhibit B-2, BCUC 30.2.2

60.1 Please clarify whether the impacts set out in Tables 1 and 2 are based on:

i. Maintaining the level of market purchases assumed in the preferred portfolio but pricing them at the $85/MWh or $100/MWh, or

ii. Assuming market purchases are priced as requested and the portfolio's use of other existing resources (e.g. PPA Purchases) is re-optimized.

<u>Response:</u>

Tables 1 and 2 in the response to BCUC IR 1.30.2.2 were produced by (i) maintaining the level of market purchases assumed in the preferred portfolio but pricing them at the $85 per MWh and $100 per MWh.

60.2 If the impacts are based on approach (i), please re-do the Tables assuming approach (ii).

<u>Response:</u>

If market energy prices were $85 per MWh, and the preferred portfolio A4 was re-optimized, the incremental Revenue Requirements compared to the preferred portfolio A4 with base Mid-C market prices over the years 2018-2025 are estimated as follows:

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

Year	Increase in Revenue Requirements over Preferred Portfolio
2018	$1.0 million
2019	$1.1 million
2020	$0.7 million
2021	$0.4 million
2022	$0.2 million
2023	$0.4 million
2024	$0.4 million
2025	$0.2 million

If market energy prices were $100 per MWh, and the preferred portfolio A4 was re-optimized, the incremental Revenue Requirements compared to the preferred portfolio A4 with base Mid-C market prices over the years 2018-2025 are estimated as follows:

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

Year	Increase in Revenue Requirements over Preferred Portfolio
2018	$1.0 million
2019	$1.2 million
2020	$0.9 million
2021	$0.5 million
2022	$0.4 million
2023	$0.6 million
2024	$0.7 million
2025	$0.6 million

Data presented in Tables 1 and 2 is based on the LTERP resource model, which should be viewed as a high-level planning tool designed to be representative of the full planning horizon. As discussed in the response to BCUC IR 2.63.2, differences can occur between the LTERP market price forecast and shorter-term actual and forward market prices.

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

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

61.1 Please clarify whether the LRMC values presented for the various portfolios on pages 122-125 of the Application (including portfolio B1 – the basis for the LRMC used to evaluate DSM) are average or incremental values (i.e. based on the average cost of all resources used in the portfolio or the incremental cost of the most expensive resources used in the portfolio).

<u>Response:</u>

The LRMC values presented for the various portfolios on pages 122-125 of the LTERP are based on the average incremental costs; therefore, the LRMC is neither based on the average cost of all resources in the portfolio, nor the most expensive resources used in the portfolio.

The following is a simplified example to explain the concept of the Average Incremental Cost (AIC).

Table 1: Example data for simplified Average Incremental Cost example

	Gross Load (Energy)	Total Costs to Serve Load (Energy and Capacity)
Time 0	100 GWh [L0]	$2.00 million [P0]
Time +1	110 GWh [L1]	$2.75 million [P1]

Using the values in Table 1, the AIC calculation is the additional cost divided by the additional load served.

$$AIC = \frac{P1 - P0}{L1 - L0} = \frac{\$2{,}750{,}000 - \$2{,}000{,}000}{110{,}000\ MWh - 100{,}000\ MWh} = \frac{\$750{,}000}{10{,}000\ MWh} = \$75.0\ per\ MWh$$

Expanding on the example to include the Present Value (PV) of a series of cash flows, the equation[1] becomes:

$$AIC = \frac{PV(P1) - PV(P0)}{PV(L1) - PV(L0)}$$

Table 2 below illustrates the AIC approach to estimating the LRMC, which takes the present value of the incremental costs expected to be incurred over the horizon (in this example, four years) and divides the incremental costs by the present value of the incremental load requirements expected to be served within the same period.

[1] FBC 2016 LTERP Appendix K. Section 4.3: FBC Average Incremental Cost Calculation. Step 5.

Table 2: Simplified Average Incremental Cost example calculation continued

	Forecast Gross Load (Energy MWh) [L1]	Total Costs to Serve Forecast Load (2015$) [P1]	Gross Load: Year 0 (Energy MWh) [L0]	Total Costs: Year 0 (2015$) [P0]	Incremenal Energy (MWh) [L1]-[L0]	Incremental Costs (2015$) [P1]-[P0]
Year 0	100,000	$ 2,000,000	100,000	$ 2,000,000	-	$ -
Year 1	110,000	$ 2,750,000	100,000	$ 2,000,000	10,000	$ 750,000
Year 2	120,000	$ 3,250,000	100,000	$ 2,000,000	20,000	$ 1,250,000
Year 3	130,000	$ 3,750,000	100,000	$ 2,000,000	30,000	$ 1,750,000
Year 4	140,000	$ 4,250,000	100,000	$ 2,000,000	40,000	$ 2,250,000
NPV @ 6%	530,617	$ 14,001,798	446,511	$ 8,930,211	84,106	$ 5,071,587
	[PV(L1)]	[PV(P1)]	[PV(L0)]	[PV(P0)]	[A] = PV(L1-L0)	[B] = PV(P1-P0)
	AIC = ([PV(P1)] - [PV(P0)]) / ([PV(L1)] - [PV(L0)]) =			**$ 60.30**	AIC = [B] / [A] =	**$ 60.30**

61.2 Which LRMC value (average or incremental) for portfolio B1 does FBC consider to be appropriate for evaluating DSM and establishing the appropriate level of DSM in the LTERP?

Response:

FBC considers the LRMC of portfolio B1, which is $100 per MWh derived using the AIC approach described in Appendix K of the LTERP, to be the appropriate value for evaluating DSM and establishing the appropriate level of DSM in the LTERP.

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

Response:

While these two values are both on an incremental basis, the $104 per MWh represents the incremental **cost** of the energy savings achieved by the measures included in the High DSM scenario, incremental to the Base DSM scenario. In contrast, the $100 per MWh LRMC for clean or renewable resources represents the incremental cost used to value the **benefits** of DSM savings.

61.3 Which LRMC value (incremental or average) does FBC consider to be appropriate for evaluating the cost-effectiveness of resource portfolios and why?

Response:

Portfolio A4 is FBC's preferred portfolio and $96 per MWh is the associated LRMC. It is therefore the appropriate value to use to evaluate the cost-effectiveness of alternative resource portfolios as compared to the A4 portfolio. All LRMC numbers were derived using the AIC approach described in Appendix K of the LTERP.

62.0 Reference: Exhibit B-2, BCUC 51.2.1

62.1 Does FBC consider capacity and energy savings achieved through rate design to be cost effective when the rates charged to customer exceed its LRMC?

Response:

The implementation of rate structures developed through rate design can be a cost effective means of influencing customer behavior to produce energy and capacity savings. A measure that provides energy savings is considered more cost-effective than another viable alternative if it delivers similar results at a lower cost.

The comparison of the rate level to the LRMC is generally considered to provide an indication of economic efficiency (described by Bonbright as price signals that encourage efficient use and discourage inefficient use).

A rate structure, such as an inclining block rate, that is designed to produced energy or capacity savings, may be more cost effective than another DSM initiative that produce the same results, but if the rates (i.e. price signals) charged to customers in the rate structure are greater than an appropriate measure of LRMC it is not an economically efficient approach. As the response to BCUC IR 1.51.2.1 notes, the induced conservation in this situation would cause upward pressure on rates.

62.1.1 If yes, please explain why.

Response:

Please refer to the response to BCOAPO IR 2.62.1.

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

Exhibit B-1, BCUC 35.2

63.1 With respect to BCOAPO 29.2, do the Marginal cost values set out in Table 1 include program costs?

Response:

No, the marginal cost values set out in Table 1 do not include program costs.

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

Response:

FBC has added program costs to the marginal cost values set out in updated Table 1 below, with respect to BCOAPO IR 1.29.2. FBC estimates levelized program costs of $14.50 per MWh for the DSM scenarios.

Category	DSM Scenario			
	Low	Base	High	Max
Resource Cost, 2016 $/MWh				
Marginal cost incl. program costs	$76	$97	$107	$130
Average cost incl. program costs	$45	$54	$61	$67
Incremental cost incl. program costs	$45	$88	$104	$114

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

63.1.2 If not, and program costs cannot be provided for the Marginal cost case, please restate the Average and Incremental costs excluding program costs.

Response:

Please refer to the response to BCUC IR 2.63.1.1.

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

Response:

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

DSM Scenario	Marginal cost incl. program costs	Measure
Low	$76	Com | NC* measure 45 %>code - Electric |South Interior | Other Commercial | NEW
Base	$97	Com | NC measure 45 %>code - Electric |South Int | Colleges & Universities | NEW
High	$107	Com | NC measure 45 %>code - Electric |South Interior | Accommodation | NEW
Max	$130	Com | Exterior LED | Colleges & Universities | RETROFIT

*NC = New Construction

64.0 Reference: Exhibit B-3, BCOAPO 10.2

64.1 Please provide a schedule that compares the 2035 input forecasts used in the 2012 LTRP and current 2016 LTERP for GDP and number of residential customers.

Response:

The following tables show the CBOC GDP forecast values for 2035 as used in both the 2012 LTRP and the 2016 LTERP, in nominal and real dollar values.

Table 1: CBOC GDP Input Forecast (Nominal)

	2012 LTRP	2016 LTERP
Year	CBOC GDP (2002 $Millions)	CBOC GDP (2007 $ Millions)
2035	240,084	321,951

The 2012 LTRP GDP amount in the table above has been converted from 2002 dollars to 2007 dollars below using a Bank of Canada inflation calculator[2] for a better comparison.

Table 2: CBOC GDP Input Forecast (Real)

	2012 LTRP	2016 LTERP
Year	CBOC GDP (2007 $Millions)	CBOC GDP (2007 $Millions)
2035	269,700	321,951

Inputs to the residential customer forecast are shown in Table 3 below. Note that in the 2012 LTRP the residential customer forecast was developed by using the CBOC Housing Starts forecast for the Province of BC. FBC now uses a service territory specific population forecast prepared by BC STATS. The two forecasts are different and not directly comparable.

Table 3: Residential Customer Forecast Inputs - Housing Starts and Population

	2012 LTRP	2016 LTERP
Year	CBOC Housing Starts	BC Stats - FBC Service Territory Population
2035	29,176	298,214

[2] http://www.bankofcanada.ca/rates/related/inflation-calculator/

65.0 Reference: Exhibit B-3, BCOAPO 12.5, 14.2 and 14.3

Exhibit B-1, BCUC 14.1

65.1 With respect to BCUC 14.1 and BCOAPO 14.3, please confirm that the historical "before savings" normalized UPC values are based on the actual weather normalized UPC values and therefore represent "after DSM values" (i.e. they have not been adjusted for historical DSM savings).

Response:

Confirmed. The historical values presented in the response to BCUC IR 1.14.1 from 2006 to 2015 are the normalized UPC values and are not adjusted for DSM. The before-savings UPC forecast value in the response to BCUC IR 1.14.1 for 2016 does not include DSM. The response to BCOAPO IR 1.14.3 refers to the after-savings UPC forecast which also does not include DSM.

65.2 BCOAPO 12.5 states that there is no trend in the residential UPC. If the historical UPC values used in calculating the 3-year average are based on actual values (which include the effects of DSM programs during those years), why is it appropriate to use these values to conclude there will be no trend in the future UPC value – prior to additional DSM?

Response:

It is appropriate to use the historical UPC values to test for the presence of a trend in the UPC data because customer usage and behavior patterns, which include the impacts of DSM embedded in the historical data, are assumed to continue. For example, if a customer has installed an LED light the savings are not limited only to the year the LED was installed, but continue into the future.

The DSM forecast is based on newly installed or adopted measures and are therefore incremental to, and independent of, the DSM impacts embedded in the historical values.

66.0 Reference: Exhibit B-3, BCOAPO 14.1

Preamble: The coefficient in the equation applicable to population has increased materially (from 0.06 to 0.33) in the most equation used to forecast the number of residential customers. It is also noted that the current equation was estimated using only 5 years of data versus the 20 years of data used for the 2012 LTRP.

66.1 Why was the current equation estimated using only 5 years of data?

Response:

FBC reviews its forecasting methods annually along with the most current external information to provide the best forecast possible. FBC tested the residential customer regression using 10 and 20 years of data in addition to the 5 years used in the LTERP forecast. The results using 10 and 20 years of data are higher than FBC considers to be reasonable, given the rates of population growth forecast by BC STATS for the service territory over the planning horizon. The forecast results using 10 and 20 years of data can be found in the response to BCOAPO IR 2.66.3.

66.2 Does FBC have any concerns regarding the material change in the equation?

Response:

The 2012 LTRP used the CBOC Provincial Housing Starts forecast while the 2016 LTERP used the BC STATS Service Area Population forecast. The coefficients related to different input variables are not expected to be the same.

The 2016 LTERP forecast prepared using the BC STATS data showed a strong and statistically significant trend which is demonstrated by an R^2 of 0.87.

66.3 What would be the result if 10 or 20 years of data were used – in terms of the equation the coefficient applicable to population and the resulting residential customer forecast?

Response:

Year-end customers are forecast with the following equation (reprinted from Appendix E, page 6)

$$Year - end\ Customers_t = b_0 + b_1 \times Population_t$$

The regression results for 5, 10 and 20 years are shown below:

Length	b_0	b_1
5 Years	33,787	0.32814
10 Years	(174,218)	1.19490
20 Years	(210,911)	1.34906

Applying the coefficients above to the BC STATS population forecast results in the three year-end customer forecasts shown in Table 1, below:

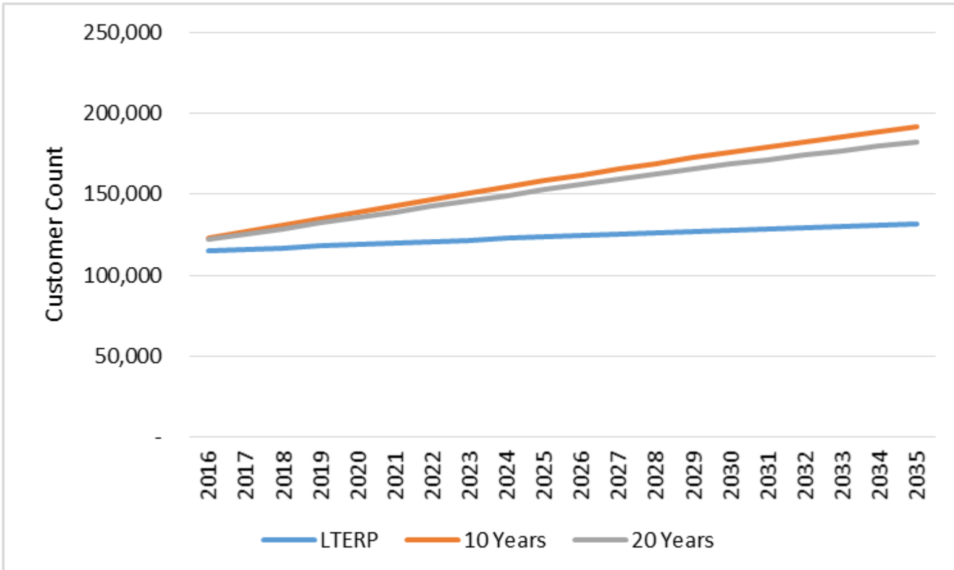
Table 1: Residential Customer Forecast using 5 (LTERP), 10 and 20 years of data (rounded data)

	A	B	C	D
Year	**BC Stats - Population**	**LTERP**	**10 Years**	**20 Years**
2016	247,738	115,080	123,302	121,804
2017	250,637	116,031	127,213	125,268
2018	253,515	116,975	131,095	128,707
2019	256,399	117,922	134,986	132,153
2020	259,309	118,877	138,912	135,630
2021	262,229	119,835	142,851	139,119
2022	265,167	120,799	146,814	142,630
2023	268,050	121,745	150,704	146,075
2024	270,867	122,669	154,504	149,441
2025	273,671	123,589	158,287	152,791
2026	276,425	124,493	162,002	156,082
2027	279,116	125,376	165,632	159,298
2028	281,749	126,240	169,184	162,444
2029	284,311	127,081	172,641	165,505
2030	286,791	127,895	175,986	168,468
2031	289,213	128,689	179,254	171,362
2032	291,573	129,464	182,438	174,182
2033	293,862	130,215	185,526	176,917
2034	296,083	130,944	188,522	179,571
2035	298,214	131,643	191,397	182,118

As an example of how the calculation works, in Table 1 above the 2016 LTERP forecast is 115,080, which equals 33,787 + (0.32814 x 247,738)

The results from Table 1 are plotted in Figure 1 below.

Figure 1: Customer Count Regression Comparison



The BC STATS forecast annual average population growth rate for the service area is one percent over the planning horizon. The FBC LTERP forecast increase of 0.7 percent aligns more favorably than would a forecast based on 10 years of data (2.3 percent increase) or 20 years of data (2.1 percent increase).

It is not reasonable to compare the coefficients from the 2012 LTRP to the 2016 LTERP since the 2012 LTRP was based on CBOC housing starts data while the 2016 LTERP was based on BC Stats population data for the service area.

67.0 Reference: Exhibit B-3, BCOAPO 15.1

Preamble: The coefficient in the equation applicable to GDP has increased materially (from 0.06 to 3.52) in the most equation used to forecast the number of commercial energy.

67.1 Does FBC have any concerns regarding the material change in the equation?

Response:

No, FBC does not have any concerns because the most up to date CBOC GDP forecast was used and the regression showed a very strong statistically significant trend with an R^2 of 98 percent.

68.0 Reference: Exhibit B-3, BCOAPO 38 to 41

68.1 For each of the portfolios A1, C1, A4 and C4 please provide a schedule that sets out by year the energy (MWh) provided by each resource in the same level of detail at the tables provided in the responses to BCOAPO 38 through 41.

Response:

The following tables show the schedule of total energy for each incremental resource by calendar year. Note that the PPA contract year is October to September, therefore, while PPA Tranche 1 Energy does not exceed 1,041 GWh in a contract year, it can exceed this amount in a calendar year. In addition, the DSM amounts are cumulative.

Table 1: Schedule of Energy for Portfolio A1 (GWh)

A1 Schedule							
Year	DSM (TRC)	PPA T1 Energy	PPA T2 Energy	SCGT2	Biogas1	Biogas3	Market
2016	21.2	619.8	0.0	0.0	0.0	0.0	105.1
2017	46.9	649.0	0.0	0.0	0.0	0.0	113.2
2018	73.3	687.1	0.0	0.0	0.0	0.0	254.9
2019	99.7	749.3	0.0	0.0	0.0	0.0	253.1
2020	126.2	786.5	0.0	0.0	0.0	0.0	227.3
2021	154.6	819.9	0.0	0.0	0.0	0.0	183.3
2022	185.0	959.4	0.0	0.0	0.0	0.0	56.7
2023	217.1	970.8	0.0	0.0	0.0	0.0	58.9
2024	249.1	978.5	0.0	0.0	0.0	0.0	60.1
2025	281.2	955.8	0.0	0.0	0.0	0.0	93.0
2026	313.2	944.1	0.0	0.0	0.0	0.0	115.0
2027	345.3	928.4	0.0	0.0	0.0	0.0	139.1
2028	377.3	1010.7	0.0	0.0	0.0	0.0	144.6
2029	409.3	1037.9	0.0	0.0	0.0	0.0	126.8
2030	441.4	1034.6	0.0	0.0	0.0	0.0	136.1
2031	473.4	1028.5	0.0	0.0	0.0	0.0	149.8
2032	505.5	1072.3	0.0	0.0	0.0	0.0	115.6
2033	537.5	1013.7	0.0	0.0	18.3	0.0	166.3
2034	569.6	1042.4	0.0	0.0	18.3	0.0	149.1
2035	601.6	1076.2	0.0	0.0	18.3	16.7	109.8

Table 2: Schedule of Energy for Portfolio C1 (GWh)

C1 Schedule						
Year	DSM (TRC)	PPA T1 Energy	PPA T2 Energy	CCGT1	Biogas1	Market
2016	21.2	619.8	0.0	0.0	0.0	105.1
2017	46.9	649.0	0.0	0.0	0.0	113.2
2018	73.3	687.1	0.0	0.0	0.0	254.9
2019	99.7	749.3	0.0	0.0	0.0	253.1
2020	126.2	786.5	0.0	0.0	0.0	227.3
2021	154.6	819.9	0.0	0.0	0.0	183.3
2022	185.0	959.4	0.0	0.0	0.0	56.7
2023	217.1	970.8	0.0	0.0	0.0	58.9
2024	249.1	978.5	0.0	0.0	0.0	60.1
2025	281.2	949.4	0.0	0.0	0.0	99.4
2026	313.2	938.9	0.0	120.1	0.0	0.0
2027	345.3	971.0	0.0	96.5	0.0	0.0
2028	377.3	1025.2	0.0	130.1	0.0	0.0
2029	409.3	1044.4	0.0	120.3	0.0	0.0
2030	441.4	1043.5	0.0	127.2	0.0	0.0
2031	473.4	1039.2	0.0	139.1	0.0	0.0
2032	505.5	1033.3	0.0	154.6	0.0	0.0
2033	537.5	1033.4	0.0	164.8	0.0	0.0
2034	569.6	1043.8	0.0	164.4	0.0	0.0
2035	601.6	1069.5	0.0	130.7	18.3	0.0

1 **Table 3: Schedule of Energy for Portfolio A4 (GWh)**

A4 Schedule								
Year	DSM (TRC)	PPA T1 Energy	PPA T2 Energy	Wind3	Biogas1	Biogas3	SCGT1	Market
2016	21.2	619.8	0.0	0.0	0.0	0.0	0.0	105.1
2017	46.9	649.0	0.0	0.0	0.0	0.0	0.0	113.2
2018	73.3	687.1	0.0	0.0	0.0	0.0	0.0	254.9
2019	99.7	749.3	0.0	0.0	0.0	0.0	0.0	253.1
2020	126.2	786.5	0.0	0.0	0.0	0.0	0.0	227.3
2021	154.6	819.9	0.0	0.0	0.0	0.0	0.0	183.3
2022	185.0	959.4	0.0	0.0	0.0	0.0	0.0	56.7
2023	217.1	970.8	0.0	0.0	0.0	0.0	0.0	58.9
2024	249.1	978.5	0.0	0.0	0.0	0.0	0.0	60.1
2025	281.2	933.1	0.0	0.0	0.0	0.0	0.0	115.7
2026	313.2	731.7	0.0	327.3	0.0	0.0	0.0	0.0
2027	345.3	739.0	0.0	328.5	0.0	0.0	0.0	0.0
2028	377.3	873.3	0.0	282.0	0.0	0.0	0.0	0.0
2029	409.3	880.3	0.0	284.5	0.0	0.0	0.0	0.0
2030	441.4	884.3	0.0	286.3	0.0	0.0	0.0	0.0
2031	473.4	866.5	0.0	282.4	18.3	11.1	0.0	0.0
2032	505.5	867.3	0.0	284.9	18.3	11.1	6.4	0.0
2033	537.5	874.9	0.0	287.6	18.3	11.1	6.4	0.0
2034	569.6	882.2	0.0	290.2	18.3	11.1	6.4	0.0
2035	601.6	894.4	0.0	292.9	18.3	11.1	1.8	0.0

2

Table 4: Schedule of Energy for Portfolio C4 (GWh)

C4 Schedule

Year	DSM (TRC)	PPA T1 Energy	PPA T2 Energy	Solar1	Solar2	Solar3	Biogas1	Biogas2	Biogas3	Biogas4	Wind3	Biomass3	Market
2016	21.2	619.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	105.1
2017	46.9	649.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	113.2
2018	73.3	687.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	254.9
2019	99.7	749.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	253.1
2020	126.2	786.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	227.3
2021	154.6	819.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	183.3
2022	185.0	959.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	56.7
2023	217.1	970.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	58.9
2024	249.1	978.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	60.1
2025	281.2	933.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	115.7
2026	313.2	731.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	327.3	0.0	0.0
2027	345.3	739.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	328.5	0.0	0.0
2028	377.3	873.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	282.0	0.0	0.0
2029	409.3	880.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	284.5	0.0	0.0
2030	441.4	884.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	286.3	0.0	0.0
2031	473.4	866.5	0.0	0.0	0.0	0.0	18.3	0.0	11.1	0.0	282.4	0.0	0.0
2032	505.5	870.0	0.0	0.0	0.0	0.0	18.3	0.0	11.1	0.0	284.9	3.6	0.0
2033	537.5	878.8	0.0	0.0	0.0	0.0	18.3	0.0	11.1	0.0	287.6	2.4	0.0
2034	569.6	887.3	0.0	0.0	0.0	0.0	18.3	0.0	11.1	0.0	290.2	1.2	0.0
2035	601.6	874.6	0.0	7.5	6.9	7.0	18.3	7.2	11.1	4.6	281.3	0.0	0.0

69.0 Reference: Exhibit B-3, BCOPAO 43.2

69.1 It is noted (BCOAPO 38.2) that portfolio A4 relies on Biogas #1 and Biogas #3 as resource options but not Biogas #2. In light of the lower cost of Biogas #2 (CEC 23.1), please explain more fully why Biogas #2 was not used in the portfolio in lieu of a portion of the Wind Energy.

<u>Response:</u>

The wind resource is selected into the portfolio as the most cost-effective resource option to meet the energy gaps after self-sufficiency is met in 2026. The biogas resources do not provide sufficient amounts of energy to displace the need for the wind resource. Once the wind resource is acquired into portfolio A4, variable energy costs are assumed to be a flat $10 per MWh for integration as discussed in the response to BCUC IR 1.25.3. It is more cost effective to further utilize the wind resource as opposed to additionally constructing Biogas #2. Later in the planning horizon, the two least-cost biogas resources, Biogas #1 and Biogas #3, are selected to meet incremental smaller amounts of energy required starting in 2031.

70.0 Reference: Exhibit B-3, BCOAPO 47.1

70.1 The BCUC Resource Planning Guidelines state (page 1): "Resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run". Furthermore, FBC's LTDSM Plan (page 1) states: "The key objective for LTDSM Plan is to determine the appropriate level of cost-effective DSM resource acquisition to match the Company's resource needs over the LTERP's planning horizon". Given this focus on cost-effectiveness, wouldn't it be more appropriate to prepares DSM scenarios based on LRMC?

Response:

No. Provincial policy that favours setting DSM targets based on offsetting load growth – not on an LRMC basis – informed FBC's approach. The LT DSM Plan considered four DSM Scenarios with increasing savings targets (load growth offset) by deploying cost-effective measures with higher marginal costs.

Please also refer to the response to BCOAPO IR 1.47.1.

70.2 Please clarify whether, in concluding that a DSM scenario with only measures whose LRMC was less than or equal to $100 / MWh would "land between the High and Max cases", FBC assumed the $100 also included program costs.

Response:

FBC's response to BCOAPO IR 1.47.1, indicating that the requested $100/MWh scenario would land between the High and Max case, did not include program costs.

70.2.1 If the answer is yes, please reconcile this response with BCOAPO 29.2 which indicates that for the High DSM scenario the additional DSM included (vis-à-vis the Base Scenario) had an incremental cost of $104 when program costs are included.

Response:

Please refer to the response to BCOAPO IR 2.70.2.

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

Response:

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

However, FBC believes that using the Base scenario as a proxy for the requested scenario would be useful to the BCOAPO. As indicated in the response to BCOAPO IR 2.63.1.1, the marginal cost including program costs for the Base DSM Scenario is $97, similar to the requested $100 scenario.

71.0 Reference: Exhibit B-3, BCOAPO 48.1 and BCOAPO 2.2

71.1 The response provided did not address the request for cumulative DSM savings. Please confirm that since FBC assumes there is no loss in the persistence of DSM savings over time (BCOAPO 2.2) that the cumulative savings in any year will simply be the sum of the DSM savings in that year and all preceding years.

Response:

Confirmed.

71.2 Has FBC undertaken any evaluations of past programs that confirm its assumption that there will be no loss in the persistence of DSM savings over time?

Response:

Please refer to the response to BCOAPO IR 1.2.3.

While FBC has not undertaken a specific evaluation to confirm its assumption, a significant effort to quantify DSM savings persistence by determining technical degradation factors (TDF) for common end uses was undertaken in California. The study found:

> For more than 95% of typical efficiency measures, the TDF studies in California found no statistically significant net change in measure energy performance compared to standard measures (California Energy Efficiency Evaluation Protocols 2006). Based in part upon this work, efficiency industry practitioners have tended to conclude that efficient measures do not degrade significantly faster than existing inefficient measures. For this reason, California eventually dispensed with TDFs.[3]

[3] Energy Savings Lifetimes and Persistence: Practices, Issues and Data. Lawrence Berkeley National Laboratory Electricity Markets and Policy Group. May 2015. p.14. https://emp.lbl.gov/sites/all/files/savings-lifetime-persistence-brief.pdf

72.0 Reference: Exhibit B-3, BCOAPO 49.1

2016 LTDSM Plan, pages 8-10

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

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

<u>Response:</u>

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

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

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

<u>Response:</u>

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

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

Response:

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

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

Response:

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

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

Response:

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

73.0 Reference: Exhibit B-4, BCSEA 16.1 and 16.2

73.1 Please confirm that the "market potential" used to establish the percentages in BCSEA 16.2 was the "economic market potential".

Response:

Confirmed. The "market potential" used to establish the percentages in the response to BCSEA 16.2 was estimated from the economic potential identified in the 2016 BC CPR.

73.1.1 If not, what definition of market potential was used and why?

Response:

Please refer to the response to BCOAPO IR 2.73.1.

73.2 In making the referenced statement (see preamble to question) did the LRMC used to determine "cost-effective" DSM measures (as compared to FBC's LRMC of $100.45 / MWh and DCE of $79.85 / kW / year per 2016 LTDSM Plan, page 8) include any allowance for program costs?

Response:

FBC interprets this question to be asking if the interim estimate of market potential presented in the response to BCSEA IR 1.16.2 included an estimate of program costs in the LRMC used to determine "cost-effective" DSM measures.

No, FBC included only the LRMC and DCE to determine the cost effectiveness of each measure. If the measure was deemed to be cost effective based on these metrics it was included for consideration in the interim estimate of market potential.

The LRMC and DCE are used to value the benefits of energy savings from DSM measures in the total resource cost calculation. Program costs represent a cost in the total resource cost calculation and are thus not additive to the benefits attributed to the LRMC and DCE. The program costs are reported along with the resource cost to assess the $/kWh of achieving the energy savings. Please see the response to BCOAPO IR 2.63.1.1 for an accounting of the cost of each DSM scenario including program costs.

73.2.1 If not, please re-do the response to BCSEA 16.2 where the cost-effective DSM from an LRMC perspective is DSM measures whose costs (including program costs) are less than FBC's LRMC.

Response:

Please refer to the response to BCOAPO IR 2.73.2.

74.0 Reference: Exhibit B-4, CEC 23.1

74.1 It is noted that Portfolio B1 (the no DSM portfolio used to evaluate the cost effectiveness of DSM) includes resources with costs up to $188 / MWh. Doesn't this suggest that, to some degree, DSM measures with costs in excess of the $100 / MWh value used by FBC for evaluation purposes would be a cost-effective alternative?

Response:

No. The portfolio needs to be considered as a whole since the resources within the portfolio are interdependent and complementary. The portfolio as a whole is able to meet the forecast energy and capacity requirements on a monthly basis. For a DSM measure to be a perfect substitute for Biomass3 (the resource with a UEC of $188 per MWh in Portfolio B1), that particular DSM measure would require an equivalent performance profile in terms of dependable capacity and reliable energy on a monthly basis. If a DSM measure with costs in excess of $100 per MWh is not a perfect substitute, then the DSM measure could have an impact on the optimal dispatch of other resources. This could change the composition of the portfolio, but without necessarily displacing specific supply side resources. Additionally, the timing of when Biomass3 is introduced into the portfolio is an important consideration. Biomass3 is dispatched in the year 2033 of the planning horizon. On a Present Value basis, Biomass3 likely represents a small portion of the costs.

74.2 It is noted that the preferred Portfolio A4 includes resource options (i.e. wind) with costs in excess of $100 / MWh. Does mean that the use of the $100 / MWh to evaluate the cost effectiveness of DSM screens out measures that would be cost-effective in terms of a preferred portfolio?

Response:

No, the use of the $100 per MWh to evaluate the cost effectiveness of DSM does not screen out measures that would be cost-effective in terms of a preferred portfolio. The wind resource within preferred portfolio A4 primarily addresses the winter energy gaps discussed in the response to BCUC IR 1.24.2. As discussed in the response to BCOAPO IR 2.74.1, the portfolio as a whole is used to meet forecast load requirements, therefore the performance profiles of resources, both existing and incremental, as well as the timing of incremental resources within the portfolio need to be considered.

For additional levels of DSM to be cost effective relative to the wind resource, the DSM measure would need to completely cover the winter energy gaps discussed in the response to BCUC IR 1.24.2, otherwise, the need for an incremental resource would remain. Additional DSM savings that were outside the winter season would lead to higher cost DSM resources offsetting lower variable cost resources (i.e. PPA). Additionally, if DSM measures were not able to fully cover the winter energy requirements, the new resource would be limited in its ability to achieve economies of scale.

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

75.1 Please explain why Portfolio B2, which meets the CEA's 93% clean or renewable resource objective and has a lower cost than the Preferred Portfolio (A4), was not included as one of the portfolios considered for preferred portfolio.

<u>Response:</u>

Portfolio B2 was not included as one of the portfolios considered for the preferred portfolio because it includes the Base DSM level rather than the High DSM level, which is the preferred DSM option for the LT DSM Plan as discussed in Section 8.1.1 of the LTERP.

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

<u>Response:</u>

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

Portfolio		Incremental Resources	LRMC ($/MWh)	Max % Non-Clean BC Resources (based on energy)	GHG emissions produced in BC (tonnes CO2e)	Full-Time Equivalents per year	Geographic Resource Diversity
A1	No Self-Sufficiency	Market (97%) Biogas (3%)	$76	0.0%	0	14	Low
C1	93% Clean with CCGT	Market (51%) CCGT (48%) Biogas (1%)	$91	3.9%	189k	164	Medium
A4	93% Clean with SCGT	Market (31%) Wind (65%) Biogas (3%) SCGT (1%)	$96	0.2%	3k	145	High
C4	100% Clean BC Resources	Market (31%) Wind (65%) Biogas (3% Biomass, Solar (1%)	$98	0.0%	0	216	Medium
B2	Base DSM	Market (30%) Wind (64%) Biogas (5%) Run-of-river, SGCT (1%)	$92	0.2%	4k	186	High

76.0 Reference: Exhibit B-4, CEC 25.1

76.1 Would a portfolio similar to A1 but incorporating the Low DSM scenario (per Volume 2, page 3) have a LRMC lower than $72 per MWh?

Response:

FBC expects that this portfolio would likely have a similar or slightly higher LRMC than $72 per MWh. While the cost of incremental supply-side resources, primarily market purchases, to offset the decrease in DSM energy savings may reduce the LRMC, resources to support planning reserve requirements for this scenario would increase the LRMC. As discussed in the response to BCUC IR 1.48.1, FBC's preferred level of DSM is the High DSM scenario.

76.2 Would a portfolio that incorporated the Low DSM scenario but also met the 93% clean criteria and the self-sufficiency criteria have a lower LRMC than Portfolio B2?

Response:

FBC expects that a portfolio that incorporates the Low DSM scenario would likely have a similar or slightly higher LRMC than portfolio B2. As indicated in the response to BCUC IR 1.48.1, FBC's preferred level of DSM is the High DSM scenario.

76.2.1 If yes, why was it not included as one of the portfolios to be considered for preferred portfolio?

Response:

A portfolio with Low DSM was not included as one of the portfolios considered for the preferred portfolio because High DSM is FBC's preferred DSM option for the LT DSM Plan as discussed in Section 8.1.1 of the LTERP.

77.0 Reference: Exhibit B-4, CEC 29, 30 and 31

77.1 For each of the tables provided, please add a column indicating the annual MWh expected from each site.

<u>Response:</u>

The following tables have been updated to include expected annual firm energy in GWh (the same units as FBC's energy load forecast and energy Load-Resource Balance).

Table 1: Wind

Name	Service Territory	Nameplate Capacity (MW)	Annual Firm Energy (GWh)	UEC ($/MWh)[4]	UCC ($/kW-yr)[5]	Earliest Availability
Wind1	FBC	48	113.7	$140	$1,308	2021
Wind2	FBC	102	280.4	$119	$1,272	2021
Wind3	FBC	117	337.5	$113	$1,270	2021
Wind4	FBC	150	425.7	$111	$1,219	2021
Wind5	FBC	144	363.7	$124	$1,225	2021
Wind6	BC Hydro	32	100.2	$145	$1,564	2021
Wind8	BC Hydro	41	133.4	$144	$1,618	2021
Wind10	BC Hydro	74	224.6	$136	$1,413	2021
Wind11	BC Hydro	95	272.2	$139	$1,379	2021
Wind13	BC Hydro	150	449.7	$131	$1,333	2021
Wind14	BC Hydro	165	570.5	$115	$1,333	2021
Wind15	BC Hydro	240	758.7	$133	$1,436	2021
Wind16	BC Hydro	272	846.7	$126	$1,325	2021
Wind17	BC Hydro	344	1239.2	$116	$1,393	2021

4 Assumes a 6 percent discount rate.
5 Assumes a 6 percent discount rate.

Table 2: Run of River Hydro

Name	Service Territory	Nameplate Capacity (MW)	Annual Firm Energy (GWh)	UEC ($/MWh)[6]	UCC ($/kW-year)[7]	Earliest Availability
RoR2	BC Hydro	10.7	24.7	$150	$1,695	2021
RoR3	BC Hydro	13.9	37.0	$132	$1,592	2021
RoR4	BC Hydro	16.8	44.8	$136	$1,743	2021
RoR5	BC Hydro	22.3	60.6	$131	$1,567	2021
RoR6	BC Hydro	28.6	87.7	$120	$1,674	2021
RoR7	BC Hydro	45.5	119.0	$110	$1,230	2021
RoR8	BC Hydro	52.7	154.4	$124	$1,611	2021
RoR9	BC Hydro	66.3	229.6	$115	$1,924	2021
RoR10	BC Hydro	73.4	281.6	$87	$1,586	2021

Table 3: Solar PV

Name	Service Territory	Nameplate Capacity (MW)	Annual Firm Energy (GWh)	UEC ($/MWh)[8]	UCC ($/kW-year)[9]	Earliest Availability
Solar1	FBC	5	7.6	$169	$1,413	2020
Solar2	FBC	5	6.9	$184	$1,407	2020
Solar3	FBC	5	7.0	$181	$1,399	2020

77.2 Please provide a comparable table for the Biomass projects identified by FBC and considered in the 2016 LTERP Application.

[6] Assumes a 6 percent discount rate.
[7] Assumes a 6 percent discount rate.
[8] Assumes a 6 percent discount rate.
[9] Assumes a 6 percent discount rate.

Response:

Name	Service Territory	Nameplate Capacity (MW)	Annual Firm Energy (GWh)	UEC ($/MWh)[10]	UCC ($/kW-year)[11]	Earliest Availability
Biomass 1	FBC	26	211.0	$118	$695	2020
Biomass 2	FBC	23	184.0	$151	$692	2020
Biomass 3	BC Hydro	12	98.0	$188	$744	2020
Biomass 4	BC Hydro	22	172.0	$165	$680	2020
Biomass 5	BC Hydro	63	503.0	$163	$663	2020

[10] Assumes a 6 percent discount rate.
[11] Assumes a 6 percent discount rate.

Attachment 72.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

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