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October 5, 2016

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Inc. (FBC)

Project No. 3698889

Application for Acceptance of Demand Side Management (DSM) Expenditures for 2017 (the Application)

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 1

On August 8, 2016, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-135-16 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to CEC IR No. 1.

If further information is required, please contact Joyce Martin, Manager Regulatory Affairs at (250) 368-0319.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1. Reference: Exhibit B-1, Page 1

> The Company intends to include a new Long Term DSM Plan (2016 LT DSM Plan) as part of the 2016 Long Term Electric Resource Plan (LTERP) which will be filed on or before November 30, 2016. The provincial dual-fuel Conservation Potential Review (BC CPR) is currently underway jointly by FortisBC Energy Inc. (FEI), British Columbia Hydro and Power Authority (BC Hydro) and FBC, and will inform the new Long-Term DSM Plan. Since the BC CPR report is not final, and FBC is seeking acceptance of the DSM expenditure schedule for 2017 only as suggested by the Commission, no BC CPR results have been incorporated in this filing.

1.1 What years will the new Long Term DSM Plan cover?

Response:

The Long Term DSM Plan (LT DSM Plan) period will align with the Long Term Electric Resource Plan (LTERP) 20-year planning horizon of 2016-2035.

1.2 What steps need to occur for the BC CPR report to be finalized?

Response:

The final draft of FBC's CPR Base Services report, including updated numerical results, is expected by mid-October. The next major step is to disseminate the final draft reports of all participating BC Utilities, to the Technical Advisory Committee (TAC) stakeholders and meet with them to discuss any further input or feedback for the final reports.

FBC expects to file its CPR Base Services report of the Economic potential in its service area in its LT DSM Plan to be filed as part of the LTERP on or before November 30, 2016.

The BC CPR Additional Services, including Market, Fuel Switching and Demand Response, has not yet been contracted for, but its results and report(s) are expected by year-end.

1.3 When does FBC expect the BC CPR report to be final?

Response:

Please refer to the response to CEC IR 1.1.2.

2. Reference: Exhibit B-1, Pages 1 and 2; Appendix C, Table 4

> For the purposes of calculating the cost-effectiveness of the DSM programs, this filing uses a Long-Run Marginal Cost (LRMC) of $112 per MWh from FBC's 2012 Long Term Resource Plan (2012 LTRP)[1], as accepted in the 2015-16 DSM Plan Decision. The LRMC will be updated in the Company's 2016 LTERP.
>
> Also for the calculation of benefits, the Company has updated the Deferred Capital Expenditure (DCE) factor, and the study supporting the new DCE factor is included as Appendix C. As described further in section 5.1.2, the 2017 DSM Plan uses a DCE of $79.85 per kW-year.

Table 4
Estimated Capital Deferred Value

	Transmission	Distribution	T&D
Avoided Investment ($/kW-Yr)	$686.08	$131.30	$817.38
Annualized DCE			
Avoided Annual Return (6.00%)[20]	$41.16 per kW	$7.88 per kW	$49.04 per kW
Avoided Depreciation (2.54%)[21]	$17.44 per kW	$3.34 per kW	$20.78 per kW
Avoided Taxes (1.23%)[22]	$8.42 per kW	$1.61 per kW	$10.03 per kW
Avoided O&M (0.00%)[23]	$0.00 per kW	$0.00 per kW	$0.00 per kW
Total DCE	$67.03 per kW	$12.83 per kW	$79.85 per kW

2.1 Please confirm that in crediting capacity savings, the $79.85 per KW-year includes both Transmission and Distribution deferred capital values as shown in Appendix C Table 4.

Response:

Confirmed.

2.2 Recognizing that the LRMC is yet to be updated, does FBC have any expectations with respect to the value or range that the LRMC will likely be established at?

Response:

An updated Long Run Marginal Cost (LRMC) for DSM purposes will be provided in the LTERP to be filed with the Commission on or before November 30, 2016.

2.2.1 If yes, please provide.

Response:

Please refer to the response to CEC IR 1.2.2.

2.3 In reviewing the LRMC, the CEC is interested in the methodology that has been used, and has the following questions with regard to the existing LRMC:

a) Please confirm or not confirm that Transmission and Distribution is included in the Generation Capacity LRMC.

Response:

Not confirmed. FBC does not have a Generation Capacity LRMC. The $112 is inclusive of both energy and any corresponding capacity benefits. The LRMC is representative of the cost of energy delivered to the system at the plant gate. The $112 LRMC does not include any adjustment for transmission or distribution losses nor for required reserves.

The $112 is a levelized number that was developed from the BC Hydro Standing Offer Program (SOP) as described in FBC's 2012 Long-Term Resource Plan (Appendix B)[1] and a previous BCUC IR response[2]. It represents the cost of clean or renewable BC resources as required under the DSM Regulation. Although it is possible to argue the SOP best represents an energy product, it is inclusive of any associated capacity[3]. This capacity component does not include any benefits on the Transmission and Distribution system. Details regarding BC Hydro's SOP

[1] FBC. 2012 Integrated System Plan (Vol. 2) & 2012 Long Term Resource Plan. June 30, 2011. Appendix B: 2011 FortisBC Energy & Capacity Market Assessment. Midgard Consulting Inc. May 26, 2011. Pages 26-28 of 54.

[2] FBC. Application for Approval of Demand Side Management Expenditures for 2015 and 2016. Response to BCUC Information Request (IR) No. 1.3.1. September 18, 2014. Page 12-13.

[3] At the time of publication [Jan 2011], BC Hydro assumed that 70% of delivered energy from SOP projects would be physically firm as stated in the SOP 2-year review (citation below)

can be found on BC Hydro's website and in the report on the SOP two year program review[4]. Because the SOP is an average, the price for any individual project may be higher or lower, but taken as a whole, it is a reasonable representation of BC New Resources for planning purposes.

The LRMC value of $112 at plant gate used in the Application is the same value the BCUC approved for the purposes of the 2015-2016 DSM Expenditure Plan[5] (2015-16 DSM Plan). The capital expenditure component has been updated from $35.60 to $79.85 with the supporting study included as Appendix C to the Application (Exhibit B-1). FBC remains committed to updating the $112 LRMC value in the Company's LTERP.

b) To what point is the Energy value used delivered in the FBC service territory?

Response:

Please refer to the response to CEC IR 1.2.3(a).

c) Please provide the % distribution losses included in the Energy LRMC value.

Response:

Please refer to the response to CEC IR 1.2.3(a).

d) Please provide the % transmission losses included in the Energy LRMC value.

[4] BC Hydro. Standing Offer Program: Report on the SOP 2-Year Review. January 2011. URL: https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/acquiring_power/2012q2/20110125_bc_hydro.pdf

[5] BCUC Decision and Order G-186-14, p. 5-6.

Response:

Please refer to the response to CEC IR 1.2.3(a).

e) Please provide the average % losses for transmission and distribution.

Response:

FBC's average system loss rate between 2012 and 2015 is 7.91%. The Company estimates that the transmission and distribution portion of the losses is 6.1%.

f) Please provide the % losses for transmission and distribution at system peak.

Response:

FBC estimates that transmission and distribution losses at the time of peak load can range from 8%-10% of peak load.

g) What is the % of generation capacity FBC requires to be held as spinning reserve?

Response:

FBC is currently required to hold 3% of its generating capacity as spinning reserve, and 3% of its generating capacity as non-spinning reserve. Additionally, FBC is required to hold 2% of its generating capacity as a regulating and frequency reserve margin. In total, this is equivalent to 7.51% of generating capacity.[6]

[6] Calculated as follows: Spinning and non-spinning reserve is equal to 6%/1.06 of generation = 5.66%. Regulating and frequency reserve margin is equal to 2%/1.02 of 94.34% generation [equal to generation less 5.66% spinning and non-spinning reserve] = 1.85%. Total reserve is equal to 5.66% + 1.85% = 7.51%.

h) Do the FBC calculations for Generation Capacity LRMC include allowance for the total cost of spinning reserves? Please explain why or why not and provide quantification if available.

Response:

Please refer to the response to CEC IR 1.2.3(a).

i) Do the FBC calculations for Generation Capacity LRMC include generation capacity costs required to deliver energy for the losses in the FBC system? Please explain why or why not and provide quantification if available.

Response:

Please refer to the response to CEC IR 1.2.3(a).

j) Do the FBC calculations for Transmission Capacity LRMC include transmission capacity costs required to deliver energy for the losses in the FBC system? Please explain why or why not, and provide quantification if available.

Response:

Please refer to the response to CEC IR 1.2.3(a).

k) Does the FBC LRMC for Energy include, in addition to direct costs, all indirect and soft costs (paid by FBC) such as costs related to regulatory,

First Nations consultation, environment, public engagement etc.? Please explain why or why not, and provide quantification if available.

Response:

Please refer to the response to CEC IR 1.2.3(a).

l) Do the FBC LRMCs for Capacity (Generation, Transmission and Distribution) include, in addition to direct costs, all indirect and soft costs (paid by FBC) such as costs related to regulatory, First Nations consultation, environment, public engagement etc.? Please explain why or why not.

Response:

Please refer to the response to CEC IR 1.2.3(a).

m) Does the FBC LRMC for Energy include, beyond direct and indirect and soft costs, all externalities (i.e. costs which are not incurred by FBC but may be transferred to others or the general public such as costs related to environmental impacts, socioeconomic impacts, First Nations impacts), etc.? Please explain why or why not and provide quantification if available.

Response:

Please refer to the response to CEC IR 1.2.3(a).

n) Do the FBC LRMCs for Capacity (Generation, Transmission and Distribution) include, beyond direct and indirect and soft costs, all externalities (i.e. costs which are not incurred by FBC but may be transferred to others or the general public such as costs related to

environmental impacts, socioeconomic impacts, First Nations impacts), etc.? Please explain why or why not, and provide quantification if available.

Response:

Please refer to the response to CEC IR 1.2.3(a).

o) Are the FBC LRMCs for Energy and Capacity based on average expected future costs for energy and capacity or on the highest marginal cost expected? Please explain and provide quantification.

Response:

Please refer to the response to CEC IR 1.2.3(a).

p) Are the FBC LRMCs for Energy and Capacity based on a single point estimate, or on a future stream of costs estimate? Please explain and provide the relevant time frames.

Response:

Please refer to the response to CEC IR 1.2.3(a).

2.4 In reviewing the LRMC, the CEC is interested in uncertainties that arise in providing an estimate for the LRMC and has the following questions:

a) Please confirm or otherwise explain that in making an estimate for the LRMC there is uncertainty with respect to the final sources from which supply will be acquired, which can influence the final estimate of the LRMC.

Response:

Please refer to the response to CEC IR 1.2.3(a).

b) Please confirm or otherwise explain that in making an estimate for the LRMC there is uncertainty with respect to the prices that may be finally established for the supply which can influence the final estimate of the LRMC.

Response:

Please refer to the response to CEC IR 1.2.3(a).

c) Please confirm or otherwise explain that in making an estimate for the LRMC there is uncertainty with respect to elements of the market environment such as inflation, interest rates, exchange rates, GDP, which can influence the final estimate of the LRMC.

Response:

FBC confirms there is some degree of uncertainty associated with elements of the market environment. The LRMC was levelized over a 30 year period using an assumed inflation rate of 2% and a discount rate of 8%.

d) Please confirm or otherwise explain that in making an estimate for the LRMC there is uncertainty with respect to the final prices that will be established with BC Hydro under both the current and future Power Purchase Agreements or other agreements, which can influence the final estimate of the LRMC.

Response:

The Power Purchase Agreement with BC Hydro was not a factor in the current FBC LRMC of $112. Please refer to the response to CEC IR 1.2.3(a).

e) Please confirm or otherwise explain that in making an estimate for the LRMC there is uncertainty with respect to the basic load forecast which can influence the timing of the supply requirements and therefore the estimate of the LRMC.

Response:

The load forecast was not a factor in the current FBC LRMC of $112. Please refer to the response to CEC IR 1.2.3(a).

f) Please confirm or otherwise explain that in making an estimate for the LRMC there is uncertainty with respect to future energy efficiency trends and capabilities and DSM impacts which can influence the load forecasts and timing of the supply requirements and therefore the estimate of the LRMC.

Response:

Please refer to the response to CEC IR 1.2.3(a).

g) Please confirm that or otherwise explain in making an estimate for the LRMC there is uncertainty with respect to government policy which can influence the supply options, the price of energy, and the load forecast and therefore the estimate of the LRMC.

Response:

Please refer to the response to CEC IR 1.2.3(a).

h) Please confirm or otherwise explain that in making an estimate for the LRMC there is uncertainty with respect to the impacts of future rate increases which can influence the load forecast and therefore the timing of the supply requirements and the estimate of the LRMC.

Response:

Please refer to the response to CEC IR 1.2.3(a).

i) Please confirm or otherwise explain that in making an estimate for the LRMC there is uncertainty with respect to changes in technology which can influence electricity supply options, supply prices and load forecasts and therefore the estimate of the LRMC.

Response:

Please refer to the response to CEC IR 1.2.3(a).

j) Please confirm or otherwise explain that in making an estimate for the LRMC there is uncertainty with respect to all levels of regulation which can influence the load forecast, supply option and energy prices and the estimate of the LRMC.

Response:

Please refer to the response to CEC IR 1.2.3(a).

k) Please confirm or otherwise explain that in making an estimate for the LRMC there is uncertainty with respect to indirect and soft costs which can influence the price of electricity and the load forecast and therefore the LRMC.

Response:

Please refer to the response to CEC IR 1.2.3(a).

l) Please confirm or otherwise explain that in making an estimate for the LRMC there may be uncertainty in many other areas that influence the supply options, prices and load forecast and therefore the LRMC.

Response:

Please refer to the response to CEC IR 1.2.3(a).

2.5 Please confirm that given the uncertainties listed above, and/or any other uncertainties with respect to the factors influencing the LRMC, it is reasonable to consider the LRMC as a range, rather than as a single point estimate, particularly for assessing DSM plans and measures.

Response:

Not confirmed. FBC believes a single point estimate of the LRMC for DSM purposes is more in line with the requirements of the Demand-Side Measures Regulation under the *Utilities Commission Act*. FBC recognizes there is always some degree of uncertainty associated with the future, and therefore, the LRMC should be viewed as a price signal. For purposes of practicality and consistent application, FBC believes a single point LRMC estimate is appropriate for assessing DSM plans and measures, along with other qualitative criteria.

2.5.1 If not confirmed, please explain why not.

Response:

Please refer to the response to IR CEC 1.2.5.

3. Reference: Exhibit B-1, Pages 5 and 14

Recent BC Hydro proceedings[8] indicate its LRMC is $106/MWh which is similar in magnitude to the $112/MWh that FBC is using for the 2017 DSM Plan.

[8] BC Hydro 2015 Rate Design Application, Evidentiary Update on Load Resource Balance and Long Run Marginal Cost. Conclusion Section. Page 9. February 18, 2016.

5.1.3 Avoided Cost Sensitivity

As stated in the previous section, the 2017 DSM Plan uses the LRMC of $112 per MWh from the 2012 LTRP to determine the avoided energy cost benefits of DSM program measures. The LRMC utilized is considered "firm" energy, i.e. inclusive of generation capacity benefits. The Company also includes a DCE value of $79.85 per kW per year to represent the incremental capacity savings of deferred infrastructure. The estimated Benefit/Cost ratios, using the two figures, are shown at the sector and portfolio levels in Table 4-1 above.

Based on a recent submission,[17] BC Hydro's LRMC is approximately $106/MWh, including energy and capacity, which approximates the $112/MWh value for firm energy (inclusive of capacity) that FBC is utilizing, so no sensitivity runs were undertaken.

3.1 Please confirm the following segments in the BC Hydro Evidentiary Update of Load Resource Balance and Long Run Marginal Cost, of pages 6, 7, 8 and 9, February 18, 2016 read:

Pages 6 and 7

Since the DSM and IPP renewal resource supply curves (price and volume relationship) are not easily visible until the actions have been undertaken and as their prices are expected to overlap, BC Hydro used a LRMC of $85/MWh to establish that there would be sufficient supply available from planned DSM initiatives and IPP EPA renewals. BC Hydro's current outlook on the LRMC has shifted towards $85/MWh because the need for new resources has reduced and the price outlook for marginal resources has dropped since the 2013 IRP.

Page 8

DSM

The $85/MWh LRMC upper limit was used to inform the development of the DSM plan including by ensuring that all DSM initiatives were cost effective in a Total Resource Cost (TRC) test against the $85/MWh threshold. Details of BC Hydro's DSM plan for F2017 to F2019 will be included in the revenue requirements application. The DSM savings shown in the LRB beyond F2019 are an outlook

for DSM activities, which will be further explored in the next IRP due in November 2018.

Pages 8 and 9

Conclusion (bold in original)
Consistent with the 2013 IRP, over the next ten years the marginal need for new energy resources is expected to be met by DSM and IPP EPA renewals. Given the LRB outlook, BC Hydro's current outlook on the energy LRMC has shifted towards $85/MWh because the need for new resources has reduced and the price outlook for marginal resources has dropped since the 2013 IRP.

The price signal provided to set the upper limit on those acquisitions is $85/MWh ($F2013) and BC Hydro expects it will be able to acquire sufficient resources to meet its need at or below the LRMC.

Page 9

Updating the energy LRMC to $85/MWh may result in questions about what if any changes should be made to the Residential Inclining Block rate design. BC Hydro notes that a steady price signal is beneficial for encouraging a conservation culture. Additionally, as there is a continued need for capacity resources in the system, there may be merit in exploring the inclusion of a generation capacity value in the energy LRMC for the purpose of the Residential Inclining Block Step 2 rate. The addition of a generation capacity value to the energy LRMC could increase the LRMC for Residential Inclining Block from $95/MWh (based on $85/MWh in $F2013 adjusted for distribution losses and inflated to $2017) to $106/MWh in $F2017. BC Hydro proposes that these matters be explored further through this proceeding.

Response:

Confirmed.

3.2 Please confirm that BC Hydro has not yet updated its LRMC to include a generation capacity value, but proposed to explore the matter further during the Rate Design Application.

Response:

That is FBC's current understanding.

3.2.1 If not confirmed, please identify what other source indicates that BC Hydro has made a determination to include a generation capacity value in its LRMC.

Response:

Please refer to the response to CEC IR 1.3.2.

3.3 Please confirm that BC Hydro used $85 as the LRMC in its Total Resource Cost Test for DSM.

Response:

Please refer to BC Hydro's F2017-F2019 Rate and Revenue Requirements Application dated July 28, 2016, section 3.4.4.2, pages 3-46 to 3-49.

3.3.1 If not, please provide the figure that BC Hydro used and cite the evidence for that figure.

Response:

Please refer to the response to CEC IR 1.3.3.

3.4 Please provide FBC's LRMC without the inclusion of a capacity value.

Response:

FBC is not able to separate the energy and capacity components of BC Hydro's SOP that is the basis for FBC's LRMC. Please refer to the response to CEC IR 1.2.3(a).

3.5 Please confirm that the use of a firm LRMC (inclusive of capacity) provides a better representation of the actual savings delivered by DSM than that suggested by an LRMC without the generation capacity costs included.

Response:

To clarify, FBC interprets this question to be about the value (i.e. benefits) of the DSM savings, as the magnitude of DSM savings are not modified by the LRMC.

Confirmed, in principle, that the use of a firm LRMC provides a better representation of the value of the actual DSM savings. For a DSM program to realize a capacity benefit associated with the energy savings, the given DSM measure(s) should have a reasonable probability that energy savings will occur at times of peak FBC resource need.

4. Reference: Exhibit B-1, Page 6

> **2.4.3 Education Programs**
>
> FBC, in collaboration with FEI, is developing an online education program that supports the development of energy education in BC classrooms. It will provide high quality, engaging, curriculum-connected resources and programs that highlight the BC energy environment and encourage a bias-balanced development of energy literacy in classrooms for kindergarten to grade 9 students. FBC plans to implement the initial pilot phase in 2016 and expects to expand the education program to grades 10-12 in 2017. In addition, FBC will provide funding support for several third party non-profit educational organizations to deliver conservation messaging.
>
> FBC also provides financial and in-kind support for post-secondary initiatives for curriculum-based classroom instruction and broader campus-wide behaviour change programs.

4.1 When will FEI and FBC complete development of the online education program?

Response:

The grade one to nine online education portal program is being pilot tested with teachers across BC this November 2016 through May 2017. Tweaks and improvements will be made, as necessary, and the full program is anticipated to be launched in September 2017. The grade ten to twelve program will be developed after the new curriculum is available in mid 2017 and launched for testing in September 2017.

4.2 Has FBC commenced implementing the initial pilot phase as of yet?

Response:

The pilot project is being launched in November 2016.

4.2.1 If not, does FBC still expect to implement the pilot phase in 2016, or has this been deferred? Please explain.

Response:

Please refer to the response to CEC IR 1.4.2.

5. Reference: Exhibit B-1, Pages 9 and 13

Table 4-1: FBC DSM Expenditures & Savings – 2016 Approved/Projected and 2017 Plan

	Program Area	2016 Approved Savings MWh	2016 Approved Cost ($000s)	2016 Projected Savings MWh	2016 Projected Cost ($000s)	2017 Plan Savings MWh	2017 Plan Cost ($000s)	2017 Plan TRC B/C ratio
1	**Programs by Sector**							
2	Residential	12,909	3,349	7,098	2,607	10,493	2,718	2.5
3	Commercial	12,695	2,564	11,734	2,547	13,666	3,131	2.2
4	Industrial	1,585	209	2,327	330	1,556	309	1.9
5	**Subtotal Programs**	**27,189**	**6,122**	**21,160**	**5,484**	**25,715**	**6,158**	**2.3**
6	Supporting Initiatives		675		678		674	
7	Planning & Evaluation		737		675		777	
8	**Total (including Portfolio spend)**		**7,534**		**6,838**		**7,610**	**2.0**

The governing TRC test is generally expressed as a ratio of the benefits of a DSM measure divided by the measure's cost, including the utility's program costs. The benefits are the "avoided costs", calculated as the present value over the effective measure life of:

i. the measure's energy savings, valued at the LRMC; and
ii. the measure's demand savings, valued at the DCE.

The measures' energy & demand savings are grossed-up by the avoided transmission and distribution energy losses (AKA "line losses") before the benefits are calculated.

5.1 Please provide the calculations for the Total Resource Cost tests for each sector for 2017.

Response:

The Total Resource Cost (TRC) test Benefit/Cost (B/C) ratio for each program and sector is provided in the Application, Appendix A, Table A6-1: Summary Table of 2017 DSM Plan (Exhibit B-1).

The TRC test is calculated for each sector using the following formula:

$$\text{TRC B/C ratio} = \frac{\textit{(net energy savings X avoided long run marginal cost + net demand savings X deferred capital expenditure cost)}}{\textit{(incremental cost of measures + program administration costs)}}$$

The TRC calculated benefits and costs for each sector are provided in the table below:

Sector	Benefits ($)	Costs ($)	B/C Ratio
Residential	11,171,303	4,390,919	2.5
Commercial	11,261,462	5,089,298	2.2
Industrial	1,122,841	583,916	1.9
Total Programs	**23,555,606**	**10,064,133**	**2.3**

5.2 Please provide the TRCs for each sector and for the portfolio as a whole for the 2016 Approved and 2016 Projected.

Response:

The TRC test Benefit/Cost ratio for 2016 Approved (as filed in the 2015-2016 DSM Plan) is provided for each sector and the portfolio in the table below.

	Program Area	2016 Approved TRC *B/C ratio*
1	**Programs by Sector**	
2	Residential	2.0
3	Commercial	2.5
4	Industrial	3.4
5	**Subtotal Programs**	**2.2**
6	Supporting Initiatives	-
7	Planning & Evaluation	-
8	**Total (including Portfolio spend)**	**2.0**

FBC is unable to provide the 2016 Projected TRC ratios due to uncertainties in the commercial and industrial project types and actual project costs that will be realized in 2016. The actual cost of each project is the most uncertain variable in calculating the TRC and the measure lifetime also varies by measure type further influencing the TRC.

The 2016 actual TRCs will be reported in the 2016 Annual DSM Report that will be filed in the first quarter of 2017. In the interim a proxy for the 2016 TRC ratios are the 2015 Actual TRC ratios.

5.3 Please describe how DSM under and overspending is accounted for under PBR.

Response:

Through the Annual Rate Review process under FBC's Performance Based Ratemaking (PBR) Plan, the actual DSM expenditure is updated for previous years and the forecasts for the current and upcoming years are also reviewed and updated.

This process continuously tracks and moderates the bottom-line mid-year rate base deviations due to DSM spend and any consequent impact on revenue requirements.

As noted in the response to BCUC IR 1.3.1, the impact to the revenue requirements and customer rates due to any reasonable deviation between actual and approved DSM spend is expected to be negligible.

5.4 Please describe the impact of DSM underspending on ratepayers and shareholders.

Response:

Please refer to the response to BCUC IR 1.3.1.

6. Reference: Exhibit B-1, Pages 9 and A-13

Table 4-1: FBC DSM Expenditures & Savings – 2016 Approved/Projected and 2017 Plan

	Program Area	2016 Approved Savings MWh	2016 Approved Cost ($000s)	2016 Projected Savings MWh	2016 Projected Cost ($000s)	2017 Plan Savings MWh	2017 Plan Cost ($000s)	2017 Plan TRC B/C ratio
1	**Programs by Sector**							
2	Residential	12,909	3,349	7,098	2,607	10,493	2,718	2.5
3	Commercial	12,695	2,564	11,734	2,547	13,666	3,131	2.2
4	Industrial	1,585	209	2,327	330	1,556	309	1.9
5	**Subtotal Programs**	**27,189**	**6,122**	**21,160**	**5,484**	**25,715**	**6,158**	**2.3**
6	Supporting Initiatives		675		678		674	
7	Planning & Evaluation		737		675		777	
8	**Total (including Portfolio spend)**		**7,534**		**6,838**		**7,610**	**2.0**

Table A5-1: Planning and Evaluation Expenditures

	Component	2016 Approved	2017 Plan
1	Staffing, incl training costs	395	440
2	Office Expenses	50	55
3	Consulting Fees	90	96
4	M&E Reports	200	186
5	**TOTAL**	**735**	**777**

6.1 Why are Planning and Evaluation costs for 2017 proposed to increase by over $100 thousand versus the 2016 Projected?

Response:

Table A5-1: Planning and Evaluation Expenditures ($000s)

Program	2017 Plan	2016 Projected	Variance
Salaries	440	395	45
Office Expense	55	50	5
Consulting Fees	96	80	16
M&E Reports	186	150	36
Total	**777**	**675**	**102**

As shown in the table above, the $100,000 variance between the 2017 Plan and the 2016 Projected for Planning and Evaluation expenditures is mainly attributable to Salaries and Monitoring and Evaluation (M&E) Reports. Please refer to the response to BCUC IR 1.13.1 and 1.13.3 for an explanation of the salary variances between 2017 Plan and 2016 Projected.

The 2017 Plan budget for M&E Reports is $36,000 higher than the 2016 Projected budget primarily as a result of not requiring the Building Improvement Program study and a reduction in

the cost of undertaking the remaining M&E reports. The $186,000 budget for the 2017 Plan M&E Reports is detailed in Table A5-2 on p. A14 of Appendix A to the Application (Exhibit B-1).

6.2 Please provide a breakdown of the Planning and Evaluation expense for 2016 Projected.

Response:

The approximate breakdown of the Planning and Evaluation expense for 2016 Projected is provided in the table below:

Planning and Evaluation Expenditures ($000s)

Program	2016 Projected
Salaries	395
Office Expense	50
Consulting Fees	80
M&E Reports	150
Total	**675**

7. Reference: Exhibit B-1, Page 9; Appendix B, 2015 Year-End DSM Report, Page 3 (page 53 of 121)

Table 4-1: FBC DSM Expenditures & Savings – 2016 Approved/Projected and 2017 Plan

	Program Area	2016 Approved Savings MWh	2016 Approved Cost ($000s)	2016 Projected Savings MWh	2016 Projected Cost ($000s)	2017 Plan Savings MWh	2017 Plan Cost ($000s)	2017 Plan TRC B/C ratio
1	**Programs by Sector**							
2	Residential	12,909	3,349	7,098	2,607	10,493	2,718	2.5
3	Commercial	12,695	2,564	11,734	2,547	13,666	3,131	2.2
4	Industrial	1,585	209	2,327	330	1,556	309	1.9
5	**Subtotal Programs**	**27,189**	**6,122**	**21,160**	**5,484**	**25,715**	**6,158**	**2.3**
6	Supporting Initiatives		675		678		674	
7	Planning & Evaluation		737		675		777	
8	**Total (including Portfolio spend)**		**7,534**		**6,838**		**7,610**	**2.0**

The Company has a long record of successfully meeting or exceeding its savings targets, while keeping expenditures within approved plans and 2015 results were not in line with past performance. A number of factors contributed to the 2015 outcome:

Given that 2015 was a transition year from 2014's scaled-back programs and considerable development work was undertaken for new and relaunched programs, the Company believes it now has the necessary resources and a fulsome complement of programs in place going forward to achieve budget and target performance in 2016.

7.1 Please explain why total 2016 Projected savings were only about 77% (line 5 Subtotal Programs) of the 2016 Approved; and please provide an explanation for each Sector with quantification.

Response:

Please refer to the response to BCSEA IR 1.4.3.

7.2 Please explain why the 2016 Projected spending for Residential was only about 78% of Approved.

Response:

Please refer to the response to BCSEA IR 1.4.5.

8. Reference: Exhibit B-1, Page 10

> The 2016 Projected expenditures of $6.8 million represent slightly over 90% of the annual approved spending under the 2015-2016 DSM Plan, a substantial increase over 2015 results due to the Company's efforts to rebuild customer and trade ally awareness, additional staffing capacity and the successful launch of new offers such as the Business Direct Install (BDI) program, that replaced the successful FLIP (Fortis LiveSmartBC Lighting Installation program) that ended in March 2013.

8.1 How does FBC evaluate the success of its DSM programs? Please explain and provide quantification of any measures and thresholds that FBC uses to evaluate the success of its DSM activities and spending.

Response:

FBC tracks and evaluates the success of its DSM programs in its year end DSM Reports that are filed with the Commission on an annual basis.

The annual DSM Reports provide key program metrics, namely DSM savings and costs, both plan and actual, by program, sector, program total and portfolio level. The TRC B/C ratios and other reference tests of interest are also reported at the program, sector, and portfolio level.

8.2 Please provide the relevant measures for the total DSM program and for each of the sectors for 2011 through to 2016.

Response:

Historical DSM program results (including from 2011-2015) are provided in FBC's 2015 Annual DSM Report filed as Appendix B to the Application.

The 2016 Plan and Projected results (expenditure and savings) are provided in Table 4.1 of the Application (Exhibit B-1).

9. Reference: Exhibit B-1, Page 13

> In response to Directive 3 of the 2015-16 DSM Plan Decision (see Table 2.5 above), the Company reviewed the assumptions underlying the previous DCE value ($35.60 per kW-year), and commissioned a study to update it. The updated DCE study, which is filed as Appendix C, reviewed the methodologies and best practices to determine a utility specific DCE value and determined a new value based on the present value of the anticipated growth related transmission and distribution capital upgrades over the planning horizon. The study determined a DCE value of $79.85[15] per kW-yr, which is used for this Application.
>
> As required by the 2015-16 DSM Plan decision (Directive 5), the Company reviewed the 8% discount rate (DR) used in the 2012 LTRP and recent DSM filings, and has updated it to use a 6% DR in the current filing. Since all measures passed at the 6% DR, there are no additional measures available if a "societal" discount rate is used.

9.1 Please provide an explanation for how FBC arrived at the 6% Discount Rate.

Response:

Please refer to the responses to ICG IR 1.1.1 and CEC IR 1.9.2.

9.2 Please provide FBC's Weighted Average Cost of Capital calculation

Response:

The Weighted Average Cost of Capital (WACC) for FBC is calculated as follows:

Financial Parameters	**Relation**	**WACC Calculation (2017)**	
		Pre Tax	**Post Tax**
Proportion of Debt	A	60.00%	60.00%
Weighted Average Cost of Debt	B	5.21%	5.21%
Income Tax Rate	C	0.00%	26.00%
Tax-Effected Debt Component	D = A B (1-C)	**3.13%**	**2.31%**
Proportion of Equity	E	40.00%	40.00%
Return on Equity	F	9.15%	9.15%
	C	26.00%	0.00%
Equity Component	G = E F /(1-C)	**4.95%**	**3.66%**
Weighted Average Cost of Capital	H = D + G	**8.07%**	**5.97%**

Note: Post Tax WACC is analogous to FBC's AFUDC Rate.

Please note that FBC's WACC is generally used as a proxy to Discount Rate (DR) for financial analysis. The pre-tax and post-tax DR for FBC is forecast at approximately 8% and 6% respectively for 2017. The post-tax DR is also analogous to its AFUDC Rate.

Please also refer to the response to ICG IR 1.1.1.

10. Reference: Exhibit B-1, Page A-5

> An in-home display (IHD) incentive will enable participants to view real-time energy usage of their residential and small commercial (single phase) AMI meters. Either stand-alone devices, or a gateway modem – to enable smart phone apps- will allow customers to better manage their energy usage.
>
> In collaboration with FEI, FBC plans to select a service provider to implement a customer engagement program (CEP). CEP will promote energy literacy and residential conservation and efficiency improvements through behaviour modifications. Customers will be able to set savings goals, create a personalized savings plan, track their progress, and receive tailored conservation and efficiency messaging and rebate offers. CEP and behaviour programs improve customer service and satisfaction, and enable energy savings.

10.1 Please provide further details of the IHD incentive.

Response:

FBC has allocated funding in the 2017 DSM expenditure to provide a $50 incentive to support the purchase, configuration, and installation of in-home displays (IHD) for 250 customers in 2017. The Company has undertaken preliminary testing on IHDs and anticipates offering two or three different options (such as an IHD device and/or a home internet gateway to enable smart phone apps) for those customers interested in this technology.

10.2 Will the IHD incentive be available to all residential customers?

Response:

As per the response to CEC IR 1.10.1, the IHD incentive will be available for 250 customers in 2017. All FBC direct customers who are not enrolled in the Company's Radio-off AMI Meter Option Rate Schedule 81 will be eligible. Indirect residential customers (i.e. those served by FBC municipal Wholesale customers) will not be eligible for an IHD incentive because their meters are not compatible.

10.2.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.10.2.

10.3 Will the IHD incentive also be available to Commercial customers?

Response:

The incentive will be available to small commercial customers with single-phase AMI meters.

10.3.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.10.3.

10.3.2 If not, please outline any costs and savings that would be associated with making the IHD program available to Commercial customers.

Response:

Please refer to the response to CEC IR 1.10.3.

11. Reference: Exhibit B-1, Page A-6

> New in 2016 was the introduction of the Business Direct Install (BDI) program. BDI utilizes a third-party implementer to engage contractors to perform lighting and other energy efficiency retrofits targeting small- and medium-sized enterprises, using proven energy assessment tools and energy efficiency sales training. The BDI offer will continue to be offered in 2017.

11.1 What are the parameters that determine the 'small and medium-sized' enterprises to be targeted?

Response:

For the purposes of the Business Direct Install program, small and medium-sized enterprises are defined as:

- Commercial customers with average monthly billing demand below 200 kVA and an annual consumption exceeding 12,000 kWh/yr located in the FBC service area; and
- Commercial customers with the above profile served by FBC's Wholesale customers Grand Forks, Nelson Hydro, Penticton, and Summerland.

11.2 Could the BDI program be expanded to include larger enterprises as well? Please explain why or why not.

Response:

No, the BDI program was developed to specifically target a segment of customers, i.e. small and medium enterprises (SME). The BDI program provides a turn-key solution to SME customers, who generally have less knowledge and/or resources to complete energy efficiency upgrades, by equipping local contractors with the tools to assess the energy efficiency opportunities, and provides point-of-sale incentives to offset the proposed DSM project costs.

Larger enterprises tend to have staff partially or entirely dedicated to improving energy efficiency at their facilities. In addition, larger enterprises often have project management and technical resources to implement energy efficiency retrofits internally, relying less on contractors.

From an FBC DSM program perspective, larger enterprises are already actively served by FBC Technical Advisors and other incentive programs. Large enterprises also have access to the

walkthrough energy assessments from FBC Technical Advisors and may be eligible for other energy assessment funding.

Expanding the BDI program to larger enterprise customers would result in duplication of program administration and higher implementation costs, with no additional benefit to the larger enterprise customer.

11.2.1 If yes, does FBC intend to expand the program to target larger enterprises as well? Please explain.

Response:

Please refer to the response to CEC IR 1.11.2.

11.2.2 If no, why not?

Response:

Please refer to the response to CEC IR 1.11.2.

12. Reference: Exhibit B-1, Appendix A, DSM Cost and Savings Summary Report, Page 1; Appendix B, Historical DSM Costs and Energy Savings 2010-2014

Table A-1: FBC DSM Summary Report for Year Ended December 31, 2015

Program Area	2015 Approved Plan Savings (MWh)	2015 Actual Energy Savings (MWh)	Lifetime savings (MWh)[2]	Incentive Expenditure ($000)	Non-Incentive Expenditure ($000)	2015 Actual Spend ($000s)	2015 Approved Plan ($000s)	Benefit/Cost Tests			Levelized cost (¢/kWh)
								TRC	UCT	RIM	
Residential											
Home Improvement	3,106	231.2	6,326	62.0	136.8	198.7	884	1.7	1.7	0.7	7.1
Behavioural	888	0.0				-	85				
Watersavers	850	4.6	64	0.3	1.8	2.2	387	1.5	3.2	1.0	10.8
Appliances	288	51.9	865	23.3	47.7	71.0	96	1.2	1.5	0.9	17.9
Lighting	1,569	4,144.4	50,893	167.9	30.1	198.0	193	5.3	26.5	1.1	2.1
Heat Pumps	1,618	569.0	17,561	138.4	44.1	182.5	302	1.5	4.3	0.9	7.9
New Home Program	1,179	356.2	12,366	37.6	73.2	110.8	390	1.1	5.1	0.9	10.2
Low Income Housing	2,598	281.8	1,827	97.5	189.9	287.3	824	1.3	0.9	0.6	9.7
Residential Total	**12,096**	**5,639.0**	**89,903**	**526.9**	**523.5**	**1,050.4**	**3,160**	**2.9**	**7.0**	**1.00**	**4.0**
Commercial											
Lighting	7,445	4,089.3	71,188	404.4	331.0	735.4	1,485	2.0	5.7	1.0	6.0
Building Improvement	3,454	1,605.9	41,841	175.8	367.3	543.0	842	1.6	4.3	1.0	8.3
Computers	378	0.0		-	-	-	55				
Municipal (WWTP)	759	186.6	4,900	24.5	11.7	36.2	79	2.3	5.5	0.9	5.0
Irrigation	490	0.0		-	9.0	9.0	69				
Commercial Total	**12,526**	**5,881.8**	**117,929**	**604.7**	**719.0**	**1,323.7**	**2,530**	**1.8**	**5.2**	**1.0**	**6.7**
Industrial											
Industrial Efficiency	1,537	1,086.8	27,937	146.2	79.8	226.0	202	2.0	6.2	1.0	5.7
Industrial Total	**1,537**	**1,086.8**	**27,937**	**146.2**	**79.8**	**226.0**	**202**	**2.0**	**6.2**	**1.0**	**5.7**
Total Programs	**26,159**	**12,607.6**	**235,769**	**1,277.8**	**1,322.3**	**2,600.1**	**5,892**	**2.2**	**6.0**	**1.0**	**5.3**
Portfolio Level Activities											
Planning & Evaluation	-	-		-	584.9	584.9	725				
Supporting Initiatives	-	-		-	346.3	346.3	675				
Total Portfolio	**26,159**	**12,607.6**[1]	**235,769**	**1,277.8**	**2,253.5**	**3,531.3**	**7,292**	**2.0**	**4.4**	**0.9**	**6.0**

[1] Commensurate Demand Savings are 2.6 MW

[2] Lifetime savings are energy savings over the lifetime of the measure

Table B-1: Historical FBC DSM Costs and Energy Savings 2010-2014

		2010 (Actual)							2011 (Actual)						
		Spend ($000s)			Energy Savings (MWh)			TRC[3]	Spend ($000s)			Energy Savings (MWh)			TRC[3]
		Planned	Actual	Variance	Planned	Actual	Variance	(B/C)	Planned	Actual	Variance	Planned	Actual	Variance	(B/C)
1	**Residential**														
2	Home Improvements	294	434	(140)	953	4,948	3,995	3.1	2,145	479	1,666	8,960	3,692	(5,268)	1.6
3	Building Envelope[4]														
4	Heat Pumps	624	749	(125)	6,377	3,239	(3,138)	1.2	694	532	162	3,397	2,257	(1,140)	1.0
5	Residential Lighting	243	278	(35)	2,383	2,589	206	2.4	438	239	199	3,420	3,308	(112)	2.2
6	New Home Program	254	247	7	1,392	477	(915)	1.1	54	205	(151)	105	689	584	1.0
7	Appliances[4]														
8	Electronics[4]														
9	Water Heating[4]														
10	Low Income[4]	100	131	(31)	1,000	385	615	0.7	305	245	60	540	1,447	(907)	1.0
11	Behavioural[4]														
12	*Residential Total*	**1,515**	**1,838**	**(323)**	**12,105**	**11,638**	**764**	**1.9**	**3,636**	**1,700**	**1,936**	**16,422**	**11,393**	**(6,843)**	**1.3**
13	**Commercial**														
14	Lighting	722	526	196	5,304	7,971	2,667	3.5	1,114	1,995	(881)	7,370	20,577	13,207	2.3
15	Building and Process Improvements	658	597	61	6,751	6,685	(67)	1.5	572	606	(34)	3,010	1,386	(1,624)	0.7
16	Computers														
17	Municipal (Water Handling)[2]								432	231	201	3,560	2,199	(1,361)	1.6
18	Irrigation[2]														
19	*Commercial Total*	**1,380**	**1,123**	**257**	**12,055**	**14,655**	**2,600**	**2.1**	**2,118**	**2,832**	**(714)**	**13,940**	**24,162**	**10,222**	**1.9**
20	**Industrial**														
21	Compressed Air	87	25	62	938	114	(823)	0.7							
23	EMIS								10	9	1	80	-	(80)	-
22	Industrial Efficiencies	302	216	86	2,412	2,853	441	2.1	603	128	475	9,280	794	(8,486)	2.5
24	*Industrial Total*	**389**	**241**	**148**	**3,350**	**2,967**	**(383)**	**2.0**	**613**	**137**	**476**	**9,360**	**794**	**(8,566)**	**2.4**
25	**Programs Total**	**3,284**	**3,203**	**81**	**27,510**	**29,261**	**2,981**	**2.1**	**6,367**	**4,669**	**1,698**	**39,722**	**36,349**	**(5,187)**	**1.8**
26	Supporting Initiatives	148	155	(7)	-	-	-		725	658	67	-	-	-	-
27	Planning & Evaluation	519	354	165	-	-	-	-	750	590	160	-	-	-	-
28	**Total**	**3,951**	**3,712**	**239**	**27,510**	**29,261**	**2,981**	**2.0**	**7,842**	**5,918**	**1,924**	**39,722**	**36,349**	**(5,187)**	**1.6**

12.1 Please confirm that there are no programs that have not historically met the TRC test either individually or within the DSM program as a whole.

Response:

On occasion, DSM programs do not pass the TRC test either in actual results and/or program plans. As identified in Table B-1: Historical FBC DSM Costs and Energy Savings 2010-2014' from Appendix B to the Application (Exhibit B-1), actual results from the residential 'Low income' and the industrial 'Compressed air' programs each had a TRC of 0.7 in 2010. However, the reported results also show that the portfolio level TRC was 2.0 in 2010.

FBC will sometimes support individual programs that do not pass the TRC, provided the programs pass the modified TRC (mTRC) test and as long as no more than 10% of the DSM portfolio expenditures are directed towards these programs.

12.1.1 If not confirmed, please identify those programs that have historically not met the TRC test individually.

Response:

Please refer to the response to CEC IR 1.12.1.

13. Reference: Exhibit B-1, Page A-16

Table A6-1: Summary Table of 2017 DSM Plan

Program/ Portfolio areas	Savings (MWh)	Cost ($000s)	Benefit/Cost Tests TRC	UCT	PCT	RIM	Levelised Cost ($/MWh)
Residential							
Home Improvement	364	348	1.7	2.6	7.3	0.8	44.5
Heat Pumps	781	298	1.5	2.6	4.6	0.8	53.1
New Home	126	151	1.4	3.3	2.8	0.8	42.1
Lighting	2,735	190	2.2	21.3	2.8	0.9	5.6
Appliances	126	133	1.3	1.6	9.2	0.6	74.8
Water Heating	17	30	1.5	1.1	0.0	0.5	110.3
Low Income & Rentals	3,247	1,367	3.4	3.3	0	0.7	54.5
Behavioural	3,097	200	3.7	3.7	0	0.7	29.9
Subtotal	**10,493**	**2,718**	**2.5**	**4.4**	**6.6**	**0.8**	**32.3**
Commercial							
Com Lighting	10,592	2,322	2.2	3.6	4.9	1.0	37.9
Building Improvement	2,931	784	2.3	6.4	2.9	1.1	20.8
Irrigation	144	25	3.6	3.1	0	0.9	36.3
Subtotal	**13,666**	**3,131**	**2.2**	**4.0**	**4.3**	**1.1**	**34.1**
Industrial							
Industrial	1,556	309	1.9	5.1	2.6	1.1	22.0
Subtotal	**1,556**	**309**	**1.9**	**5.1**	**2.6**	**1.1**	**22.0**
Program Total	**25,715**	**6,158**	**2.3**	**4.2**	**5.1**	**0.9**	**32.6**
Portfolio							
Supporting Initiatives		674					
Planning & Evaluation		777					
Total (including Portfolio area)		**7,610**	**2.0**	**3.1**	**3.6**	**0.8**	**43.8**

13.1 Please provide the calculations for the Utility Cost Test (UCT) and the Participant Cost Test (PCT) and the Ratepayer Impact Measure (RIM) test.

Response:

Calculations for the Utility Cost Test (UCT), Participant Cost Test (PCT), and the Ratepayer Impact Measure (RIM) test Benefit/Cost (B/C) ratio are provided below.

The UCT is calculated using the following formula:

$$\text{UCT B/C ratio} = \frac{(net\ energy\ savings \times avoided\ long\ run\ marginal\ cost + net\ demand\ savings \times deferred\ capital\ expenditure\ cost)}{(utility\ program\ incentive\ and\ administration\ costs)}$$

The PCT is calculated using the following formula:

$$\text{PCT B/C ratio} = \frac{(net\ energy\ savings \times customer\ energy\ cost + net\ demand\ savings \times customer\ demand\ cost)}{(customer\ portion\ of\ measure\ cost)}$$

1 The RIM test is calculated using the following formula:

$$\text{RIM B/C ratio} = \frac{(net\ energy\ savings \times avoided\ long\ run\ marginal\ cost + net\ demand\ savings \times deferred\ capital\ expenditure\ cost)}{(utility\ program\ incentive\ and\ administration\ costs + net\ energy\ savings \times customer\ energy\ cost + net\ demand\ savings \times customer\ demand\ cost)}$$

2

3

14. Reference: Exhibit B-1, Appendix C, Deferred Capital Expenditure Study, Pages 1, 19 and 20

implementation. Based on FortisBC's forecast growth-related capital T&D expenditure schedules and annualizing factors obtained from FortisBC, this study found the levelized T&D DCE values to be $67.03 and $12.83 respectively in 2015 dollars.

Figure 5 summarizes the estimated deferred T&D costs from the studies cited in this section in 2015 Canadian dollars. Appendix A containing a summary table of all the estimated DCE. The average, high and low DCE by function are provided in Table 3 below for the full survey and for utilities in WECC.

Table 3
Survey Results (CA$)

	Transmission	Distribution	Total T&D
Average			
All Utilities	$28.60	$74.39	$81.93
WECC	$20.23	$40.39	$52.20
High			
All Utilities	$94.21	$220.78	$258.43
WECC	$37.95	$108.81	$146.76
Low			
All Utilities	$1.61	$1.00	$7.60
WECC	$5.13	$1.00	$6.45

- Calculate separate estimates for Transmission and Distribution.
- Results differs by region and utility. Therefore, the best option for FortisBC is to estimate T&D DCE based on FortisBC data.
- While benchmarking may be indicative, benchmarking DCE results for FortisBC outside WECC does not appear to be appropriate.
- Using a marginal costing approach appears to be the most common calculation methodology.

14.1 Please provide the units of measurement for Figure 5.

Response:

The values shown are in Canadian dollars per kilowatt-year ($/kW-yr).

14.2 Why is the average FortisBC Transmission costs so much higher than the average WECC transmission figures?

Response:

The first best practice (see page 3 of Appendix C to the Application) listed by the DCE study authors is as follows:

- Use methodology based on specific utility data available. Estimated deferred T&D investments can vary considerably depending on the region and the utility system. Therefore, the best option for FortisBC is to estimate T&D DCE based on FortisBC data.

The FBC DCE value of $67.03/kW-yr developed in this study was based on FBC's anticipated schedule and estimated costs of Transmission projects related to serving system load growth over the next twenty years. It may be that the WECC utilities face different load growth prospects or patterns, and/or anticipate fewer Transmission projects to serve their anticipated load growth, hence their average Transmission DCE value is lower.

14.3 Why are the average FortisBC Distribution costs so much lower than the average WECC distribution figures?

Response:

Please refer to the response to CEC IR 1.14.2.

The FBC DCE value of $12.83/kW-yr developed in this study was based on FBC's anticipated schedule and estimated costs of Distribution projects related to serving system load growth over the next twenty years. It may be that the WECC utilities face different load growth prospects or patterns, and/or anticipate more and costlier projects to serve their anticipated load growth, hence their average Distribution DCE value is higher.

15. Reference: Exhibit B-1, Appendix C, Pages 22 and 23

Distribution Avoided Costs

- Determine analysis period
- Determine expected peak growth over the analysis period
- Determine the forecasted distribution system investments due to growth over the analysis period
  - Exclude capital investments needed to support current load
  - Exclude capital investments needed to repair or replace current equipment
  - Exclude new connection capital costs
- Calculate the annualized $/kW-yr avoided distribution cost as the avoided investment divided by load growth times a real carrying charge
- If applicable add avoidable general plant and O&M adders

Table 4
Estimated Capital Deferred Value

	Transmission	Distribution	T&D
Avoided Investment ($/kW-Yr)	$686.08	$131.30	$817.38
Annualized DCE			
Avoided Annual Return (6.00%)[20]	$41.16 per kW	$7.88 per kW	$49.04 per kW
Avoided Depreciation (2.54%)[21]	$17.44 per kW	$3.34 per kW	$20.78 per kW
Avoided Taxes (1.23%)[22]	$8.42 per kW	$1.61 per kW	$10.03 per kW
Avoided O&M (0.00%)[23]	$0.00 per kW	$0.00 per kW	$0.00 per kW
Total DCE	$67.03 per kW	$12.83 per kW	$79.85 per kW

15.1 What was the analysis period that FBC used in calculating the Distribution avoided costs? Please provide and explain why this period was selected.

Response:

FBC used a 20-year analysis period (2016-2035) to match the LTERP planning horizon, since the DCE avoided costs will also be used in the LT DSM Plan that will be filed as part of the LTERP.

15.2 How did FBC determine the peak growth over the analysis period? Please explain and provide details of the calculations.

Response:

The winter and summer peaks are calculated by taking the ten year average of the monthly max peaks escalated by the gross load growth for the winter months of November to February in the case of the winter peak, and the summer months of July to August in the case of the summer peak. Once the summer and winter peaks are calculated, 16 MW is added to account for a self-generating customer that was removed from the historical load data since the underlying trends that impact other loads do not apply. The peak growth rate is then calculated by taking a peak value peak and dividing it by the previous year's peak value, subtracting one and multiplying by 100.

The following tables and calculations demonstrate how the 2017 summer peak and growth rate were calculated. (Note that the winter peak uses the same calculations except the monthly peaks from November to February are used.)

First, the monthly July and August peaks are determined by escalating the peaks by the gross load growth rate and taking the ten year average.

2017 July Peak Calculation

Year	Gross Load Growth	Jul-06	Jul-07	Jul-08	Jul-09	Jul-10	Jul-11	Jul-12	Jul-13	Jul-14	Jul-15	Average
2006		560										
2007	0.1%	561	569									
2008	-0.3%	560	567	533								
2009	2.3%	572	580	545	570							
2010	-4.4%	547	555	521	545	560						
2011	3.8%	568	576	541	566	582	503					
2012	-1.1%	562	570	535	559	575	497	510				
2013	2.2%	574	582	547	572	588	508	521	579			
2014	-1.1%	568	576	541	565	581	503	515	573	596		
2015	-1.9%	557	565	530	555	570	493	506	562	585	597	
2016	3.0%	574	582	547	572	587	508	521	579	602	615	569
2017	1.5%	582	591	555	580	596	516	529	588	612	625	577

2017 August Peak Calculation

Year	Gross Load Growth	Aug-06	Aug-07	Aug-08	Aug-09	Aug-10	Aug-11	Aug-12	Aug-13	Aug-14	Aug-15	Average
2006		443										
2007	0.1%	443	529									
2008	-0.3%	442	528	542								
2009	2.3%	452	540	554	535							
2010	-4.4%	432	516	530	511	545						
2011	3.8%	449	536	550	531	566	519					
2012	-1.1%	444	530	544	525	560	513	540				
2013	2.2%	453	541	556	537	572	524	552	556			
2014	-1.1%	448	535	550	531	566	519	546	550	580		
2015	-1.9%	440	525	539	521	555	509	535	539	569	581	
2016	3.0%	453	541	556	536	572	524	552	556	586	599	547
2017	1.5%	460	549	564	545	580	532	560	564	595	608	556

Once the July and August monthly escalated peaks are determined, the summer peak is calculated the same way as the monthly peak except the maximum value of either July or August peak is used.

2017 Summer Peak Calculation

Year	Gross Load Growth	Summer 2006	Summer 2007	Summer 2008	Summer 2009	Summer 2010	Summer 2011	Summer 2012	Summer 2013	Summer 2014	Summer 2015	Average
2006		560										
2007	0.1%	561	569									
2008	-0.3%	560	567	542								
2009	2.3%	572	580	554	570							
2010	-4.4%	547	555	530	545	560						
2011	3.8%	568	576	550	566	582	519					
2012	-1.1%	562	570	544	559	575	513	540				
2013	2.2%	574	582	556	572	588	524	552	579			
2014	-1.1%	568	576	550	565	581	519	546	573	596		
2015	-1.9%	557	565	539	555	570	509	535	562	585	597	
2016	3.0%	574	582	556	572	587	524	552	579	602	615	574
2017	1.5%	582	591	564	580	596	532	560	588	612	625	583

Once the summer peak is determined, 16 MW is added to account for self-generating customers as follows:

2016 summer peak = 574 + 16 = 590

2017 summer peak = 583 + 16 = 599

The before-savings summer peak growth rate is then calculated by taking the 2017 summer peak and dividing it by the 2016 summer peak, subtracting one and multiplying by 100.

2017 summer peak growth rate = (599/590)-1 *100 = 1.5%

15.3 Why did FBC determine that there would be no additional avoided O&M or general plant?

Response:

The O&M factor is set to zero because the O&M budget does not change under PBR, except for inflationary/productivity adjustments that are not a function of capital expenditures.

In addition, General Plant, which primarily consists of office infrastructure and Information Systems, is not expected to incur any material incremental costs due to Transmission and Distribution capital expenditures.

16. Reference: Exhibit B-1, Appendix C, Pages 22 and 23

Transmission Avoided Costs

- Determine analysis period
- Determine expected peak growth over the analysis period
- Determine the forecasted transmission system investments due to growth over the analysis period
  - Exclude capital investments needed to support current load
  - Exclude capital investments needed to repair or replace current equipment
  - Exclude new connection capital costs
- Calculate the annualized $/kW-yr avoided transmission cost as the avoided investment divided by load growth times a real carrying charge
- Review the proposed programs and determine if a de-ration factor needs to be applied

Table 4
Estimated Capital Deferred Value

	Transmission	Distribution	T&D
Avoided Investment ($/kW-Yr)	$686.08	$131.30	$817.38
Annualized DCE			
Avoided Annual Return (6.00%)[20]	$41.16 per kW	$7.88 per kW	$49.04 per kW
Avoided Depreciation (2.54%)[21]	$17.44 per kW	$3.34 per kW	$20.78 per kW
Avoided Taxes (1.23%)[22]	$8.42 per kW	$1.61 per kW	$10.03 per kW
Avoided O&M (0.00%)[23]	$0.00 per kW	$0.00 per kW	$0.00 per kW
Total DCE	$67.03 per kW	$12.83 per kW	$79.85 per kW

16.1 What was the analysis period that FBC used in calculating the Transmission avoided costs? Please provide and explain why this period was selected.

Response:

FBC used a 20-year analysis period 2016-2035 to match the LTERP planning horizon, since the DCE avoided costs will also be used in the LT DSM Plan that will be filed as part of the LTERP.

16.2 How did FBC determine the peak growth over the analysis period? Please explain.

Response:

Please refer to the response to CEC 1.15.2.

16.3 Why did FBC determine that there would be no additional avoided O&M or general plant?

Response:

Please refer to the response to CEC IR 1.15.3.