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October 3, 2017

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

Attention: Ms. Leigha Worth, Executive Director

Dear Ms. Worth:

Re: FortisBC Inc (FBC)

Project No. 1598920

Multi-Year Performance Based Ratemaking Plan for 2014 through 2019 approved by British Columbia Utilities Commission (Commission) Order G-139-14 – Annual Review for 2018 Rates (the Application)

Response to the British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO) Information Request (IR) No. 1

On August 10, 2017, FBC filed the Application referenced above. In accordance with the Commission Order G-116-17 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCOAPO IR No. 1.

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

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1.0 Reference: Exhibit B-2, Tab 1, pages 4-6

Preamble: The Application states (page 4):

The 2017 projected O&M savings of $1.2 million have been achieved with the Company's continued broad-based focus on productivity. While some of the savings are one-time in nature, some of the savings are the result of efficiencies which are expected to continue into the future, recognizing that cost pressures in the future may offset such savings. Upcoming costs related to cyber security are an example of such cost pressures.

It is noted that apart from the Sharing of Gas and Electric Contract Centre Staff, the savings from the efficiency and cost savings initiatives outlined on page 5-6 do not appear to start until 2018.

1.1 Please provide examples of the efficiency and cost savings initiatives contributing to the 2017 O&M savings that are: i) one time in nature and ii) expected to continue into the future?

Response:

Please refer to the response to BCUC IR 1.2.1.

1.2 Were there any "new" initiatives that were started in 2017 and contributed to the 2017 O&M savings? If so, what were they and what were the estimated 2017 savings?

Response:

Please refer to the response to BCUC IR 1.2.1.

2.0 Reference: Exhibit B-2, Tab 1, pages 7 - 8

Preamble: The Application states (page 7):

In addition to the formula-related capital pressures noted above, FBC is experiencing capital cost pressures in 2017 due to work that had been re-prioritized from previous years of the PBR term into 2017, to manage unforeseen urgent and higher priority activities in 2017.

The Application also states (page 8):

FBC has been successful in mitigating some of the cost pressures through efficiencies and work prioritization. However, the cost pressures have exceeded the Company's ability to re-prioritize further work within the formula capital spending envelope without incurring more risk to the system. As well, previous work that was delayed is now considered essential or mandatory work and cannot be deferred further. To mitigate this risk exposure, FBC has increased its planned sustainment activities in 2017.

2.1 Please provide a schedule that sets out the projects that had been re-prioritized from previous years of the PBR term into 2017; the 2017 capital spending associated with each and the reasons why they are now considered essential/mandatory?

Response:

Please refer to the response to CEC IR 1.8.1 for a list of projects re-prioritized from previous years including their previously scheduled dates and classifications. These sustainment projects are related to aging infrastructure and equipment unavailability, and are considered essential or mandatory as they relate to the safety and reliability of the electrical system.

3.0 Reference: Exhibit B-2, Tab 1, page 7

Preamble: At page 7, lines 17-25 the Application sets out the main capital spending pressures for 2017.

3.1 In 2017 what is the expected spending on system improvements to accommodate customer growth and how does this compare with the spending in 2015 and 2016?

<u>Response:</u>

Please refer to the response to BCUC IR 1.10.4.

3.2 Is any of the 2017 system improvements spending to accommodate customer growth customer-funded? If yes, how much and from how many customers altogether?

<u>Response:</u>

Yes. FBC projects $11.945 million in CIAC in 2017 related to system improvements representing 1,794 customers.

3.3 Are the expected 2017 capital expenditures on: i) the forced relocation of transmission and distribution infrastructure due to the widening of Highway 97 and ii) the customer driven modifications at RG Anderson Terminal both fully customer funded? If not, please specify the quantum of the "unfunded" expenditures for each (i.e. ratepayer funded)?

<u>Response:</u>

Please refer to the response to BCUC IR 1.10.5.

3.4 What is the basis for the claim that unfavourable exchange rates impacted the cost of equipment and supplies purchased from the United States (i.e., what is the comparison that is being made)?

Response:

The cited comparison is based on an evaluation of historical and anticipated exchange rates used during the PBR application development versus the actual exchange during the PBR term. FBC's Base Capital forecast was set based on an expectation that the CAD/USD exchange rate would be close to par (as shown in the table below), whereas capital expenditures during the PBR term have been incurred at an average annual rate exchange rate closer to 0.81[1]. This causes capital cost pressures as many of FBC's major equipment purchases are from outside Canada and are denominated in USD currency.

FBC's Base Capital for the PBR plan was set at FBC's 2013 Approved levels. FBC's 2013 Approved capital expenditures were based on a CAD/USD exchange rate forecast of 0.97. Over the course of the PBR term, the Base Capital is escalated using the formula described in section 7.2.1 of the Application. A CAD/USD exchange rate forecast is not part of the formula.

However, when FBC filed its Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018, FBC included a forecast of its O&M and capital expenses over the PBR Period for information and reference purposes. Those forecasts were indicative of the future trends, opportunities and challenges that FBC expected during the PBR Period. The following forecast of CAD/USD Exchange Rates was provided in Appendix E1 of the Evidentiary Update to the PBR Application (a 2019 exchange rate is not included in the table below because the initial PBR application was from 2014 to 2018):

2014	2015	2016	2017	2018
0.99	1.01	0.99	0.96	0.95

As of June 2017, FBC's CAD/USD exchange rate forecast for 2018 was 0.76.

For the majority of capital items, the impact of these unfavourable exchange rates cannot be specifically quantified. Apart from the services and materials that FBC sources directly from the United States, there are large volumes of materials that are sourced from Canadian distributors

1 0.81 is the average 2014 through 2017 Bank of Canada annual average daily closing CAD/USD exchange rate per the bank of Canada website. 2017 is based on average available rates up to September 28, 2017. (2014: 0.91, 2015: 0.78, 2016: 0.76, 2017: 0.77).

where the higher cost of goods is passed on to FBC according to the terms of the contract. FBC's vendor contracts can have a negotiated currency clause that governs the treatment of fluctuations in exchange rate between the two parties and the terms of that clause could be different for each vendor. Services and materials for capital projects are also often negotiated specifically based on a detailed scope of work for the project and are therefore subject to the economic conditions and exchange rates in place at that time. The individual contribution of the various drivers on price cannot be isolated, and as a result, FBC is unable to quantify the impact of the unfavourable exchange rate on capital costs from inflationary pressures and other variables that drive service and material costs.

4.0 Reference: Exhibit B-2, Tab 1, page 7 (Table 1-2) and pages 12-13

4.1 Please provide a schedule that sets out the calculation of the 39.08 percent value referenced on page 13 (line 5).

Response:

The calculation of the two-year variance of 39.08 percent is provided below, with reference to Table 10-2, which shows the 2017 Projected earnings sharing.

Line No.	Description	Annual Capital Expenditures 2016	2017	Reference
1	Formula Capital Expenditures	$ 42.874	$ 43.254	Table 10-2, Line 18
2				
3	Total Regular Capital Expenditures	49.512	62.099	Table 10-2, Line 20
4				
5	Less: Capital Expenditures Tracked Outside of Formula			
6	Pension and OPEB	3.674	3.539	Table 10-2, Line 23
7				
8	Actual/Projected Base Capital Expenditures	45.839	58.560	Line 3 - Line 6
9				
10	Actual/Projected Base Capital Expenditure Variance	2.965	15.306	Line 8 - Line 1
11				
12	Single Year Deadband % Variance	6.37%	32.71%	Line 12 / (Line 1 + Line 6)
13	Two Year Cumulative Deadband % Variance		39.08%	Line 12, sum of two years

5.0 Reference: Exhibit B-2, Tab 1, page 13 and Tab 7, page 54

Exhibit B-2, Tab 11, Schedules 2, 6 & 6.1

Preamble: The Application states (page 7):

Accordingly, FBC has added $11.268 million to its opening plant in service for 2018 so that the two-year cumulative capital variance is within the two year dead band of 15 percent.

The Application also states (page 54):

The capital formula dead band adjustment of $11.268 million, discussed in Section 1.4.3, is also included as an opening balance adjustment.

5.1 Please explain how the $11.268 M was apportioned to the individual asset accounts in Schedule 6.1.

Response:

FBC uses an allocation percentage to apportion its allowed formulaic capital each year, which is based on the relative additions to plant accounts in the base year used to determine formula capital. This same allocation methodology was used to apportion the $11.268 million dead band adjustment.

5.2 Please provide a schedule that sets out the derivation of the Net Plant In-Service (Mid-Year) for 2018 per Schedule 2, line 21.

Response:

The table below shows the calculation of Net Plant In-Service (Mid-Year) for 2018.

Calculation of Net Plant in Service (Mid-Year)

Line No.	Particulars	2018 at Revised Rates	Calculation	Total Plant in Service (Mid-year)
1	Plant in Service, Beginning	$ 1,966,584		
2	Opening Balance Adjustment	11,268		
3	Net Additions	73,879		
4	Plant in Service, Ending	2,051,731	**(1,966,584 + 11,268 + 2,051,731) / 2 =**	**2,014,792**
5				
6	Accumulated Depreciation Beginning	$ (591,854)		
7	Opening Balance Adjustment	-		
8	Net Additions	(43,454)		
9	Accumulated Depreciation Ending	(635,308)	**(591,854 + 635,308) / 2 =**	**(613,581)**
10				
11	CIAC, Beginning	$ (187,217)		
12	Opening Balance Adjustment	-		
13	Net Additions	(6,120)		
14	CIAC, Ending	(193,337)	**(187,217 + 193,337) / 2 =**	**(190,277)**
15				
16	Accumulated Amortization Beginning - CIAC	$ 68,323		
17	Opening Balance Adjustment	-		
18	Net Additions	3,913		
19	Accumulated Amortization Ending - CIAC	72,236	**(68,323 + 72,236) / 2 =**	**70,280**
20				
21	Net Plant in Service, Mid-Year	$ 1,281,213	**(2,014,792 + (613,581) + (190,277) + 70,280) =**	**$ 1,281,213**

6.0 Reference: Exhibit B-2, Tab 1, page 15 and Tab 8, page 64

6.1 Does FortisBC still expect to issue $75 M of long-term debt during September 2017 and is the rate still expected to be 3.8%. If not, please update.

Response:

Currently, FBC expects to issue between $50 and $110 million of long-term debt in the 4th quarter of 2017. FBC's updated forecast assumptions suggest that the new issuance yield may be between 3.80 percent and 3.90 percent, but is contingent on investor demand and debt capital market conditions at the time of issuance. If FBC has concluded its debt issuance prior to a compliance filing for 2018 Rates, it will update the yield and timing at that time

7.0 Reference: Exhibit B-2, Tab 1, page 15 and Tab 8, page 58

Exhibit B-2, Tab 11, Schedule 7

Preamble: The Application states (page 58):

Depreciation is calculated beginning January 1 of the year after the assets are placed in service, which is the treatment approved in Commission Order G-139-14.

7.1 Given the statement on page 58, please explain why, per Schedules 6.1 & 7, 2018, plant additions related to CPCNs are included in the Gross Plant for Depreciation (Schedule 7, Column 3 – cross reference).

<u>Response:</u>

The CPCN-related additions to plant in service and depreciable plant in schedules 6 and 7 (Kootenay Operations Centre and Unit 3 of the UBO Refurbishment project) have been added to rate base on January 1, 2018 and are for projects that were in service in 2017. Therefore, the depreciation is calculated consistent with the referenced statement, beginning January 1 of 2018 (the year after they are placed in service).

8.0 Reference: Exhibit B-2, Tab 3, pages 22-23

Exhibit B-2, Appendix A2, Table 5.3

Preamble: The Application states (page 22):

DSM savings and other savings are forecast on an incremental basis (to savings embedded in historical loads to 2016).

8.1 Please provide the equivalent of Table 3-1 that shows both 2018 and 2017 – the Seed Year - values.

Response:

Exhibit B-2, Appendix A2, Table 5.3 showed actual DSM savings for 2016 of 11 GWh and a forecast of 23 GWH for DSM in 2017S. The correct values are 23 GWh for 2016 and 13 GWh for 2017S. These typographical errors do not affect the load forecast in any way. Table 5.3 has been corrected below.

Revised Table 5.3: DSM and Other Savings (GWh) without Losses

	2012	2013	2014	2015	2016	2017S	2018F
DSM	(30)	(28)	(14)	(12)	(23)	(13)	(37)
AMI	-	2	3	4	4	5	9
CIP	-	-	-	-	-	(2)	(4)
RCR	(8)	(14)	(14)	(4)	(4)	(4)	(4)
Rate-driven	-	-	(5)	(5)	(3)	(3)	(3)
Total Net	(38)	(40)	(30)	(17)	(26)	(17)	(38)

The requested tables equivalent to Table 3-1 that show both 2017 and 2018 are provided below.

Table 1: 2017S DSM Savings and Other Savings (GWh)

Line		2017					
No.	**Description**	**DSM**	**AMI**	**CIP**	**RCR**	**Rate-Driven**	**Total**
1	Residential	(5)	5	(2)	(4)	(1)	(7)
2	Commercial	(6)				(1)	(7)
3	Wholesale	(1)				(1)	(2)
4	Industrial	(1)					(1)
5	Lighting	(0)					(0)
6	Irrigation	(0)					
7	Net	(13)	5	(2)	(4)	(3)	(17)
8	Losses	(1)	(4)				(5)
9	Gross Load	(14)	1	(2)	(4)	(3)	(21)

Table 2: Forecast 2018 DSM Savings and Other Savings (GWh)

Line		2018					
No.	**Description**	**DSM**	**AMI**	**CIP**	**RCR**	**Rate-Driven**	**Total**
1	Residential	(14)	9	(4)	(4)	(1)	(13)
2	Commercial	(17)				(1)	(18)
3	Wholesale	(2)				(1)	(2)
4	Industrial	(2)					(2)
5	Lighting	(1)					(1)
6	Irrigation	(0)					
7	Net	(37)	9	(4)	(4)	(3)	(38)
8	Losses	(3)	(7)				(10)
9	Gross Load	(40)	2	(4)	(4)	(3)	(48)

8.2 It is noted that the 2018 values in Table 5.3 are the same as those in Table 3-1. Please confirm that the 2018 values in Table 5.3 represent incremental savings over those embedded in 2016 loads.

Response:

Confirmed.

8.3 What is the basis for the 2017 values set out in Table 5.3, e.g., are they also incremental to those embedded in 2016 loads?

Response:

Yes, the saving values for 2017 in Table 5.3 are incremental savings and do not include savings embedded in the actual data through 2016.

8.4 What is the basis for the 2012-2016 values set out in Table 5.3 (e.g., are each of the values incremental to the savings embedded in the previous historical year)?

Response:

As confirmed in the response to BCOAPO IR 1.8.3, the savings shown in Exhibit B-2, Appendix A2, Table 5.3 are incremental to the savings embedded in the previous years. It is not possible to directly measure avoided energy use or increased load due to reduced theft as forecast for Demand Side Management (DSM), Advanced Metering Infrastructure (AMI), Customer Information Portal (CIP), Residential Conservation Rate (RCR) and Rate-Driven savings. The manner in which these impacts are estimated is explained below.

DSM results are validated through a number of due diligence steps. DSM planning utilizes unit measure savings obtained from regional Technical Resource Manual, or other reputable sources. Custom projects are subject to Measurement & Verification using International Performance Measurement and Verification Protocols. All programs are periodically subjected to third-party Monitoring & Evaluation reviews, which include a savings realization assessment as well as free-rider and spillover determinations. Results are reported annually in FBC's DSM Reports.

In the case of AMI, the impact of revenue protection is expected to be validated using the number of discovered electricity thefts as a proxy.

Where expenditures and savings are small (as for CIP), studies or estimates from other utilities or organizations are used. In the case of the CIP savings, FBC used numbers from a meta-study it commissioned and from BC Hydro estimates provided in its Smart Meter Initiative business case. Subsequent estimates of impact are not considered cost-effective.

FBC's statistically based estimates of savings from the RCR were developed by an external consultant as input to the most recent RCR Report, which was filed in November 2014. The analysis was conducted by comparing the usage characteristics of a control group of customers that have remained on a flat rate against customers taking service on the RCR.

Price elasticity savings are given as a percentage of the before-saving load. The current price elasticity estimate of -0.05 is consistent with BC Hydro's estimate of price elasticity. Based on the assessment of similarities between the two utilities, FBC believes that the BC Hydro estimate provides a good proxy for the price elasticity-driven savings for FBC.

8.5 Please provide a revised version of Table 5.3 where all of the values are incremental to the savings embedded in historical 2011 loads.

Response:

The values in Table 5.3 are the incremental estimated annual savings. FBC has not provided the requested table, because it does not have the capability to quantify the actual savings embedded in the historical loads. Therefore, the cumulative values that would result from using the incremental estimated savings cannot be verified.

9.0 Reference: Exhibit B-2, Tab 3, page 23 (Table 3-1) and pages 31-32

9.1 Please confirm that:

i) the 9 GWh in increased Residential load due to AMI is due to an increase in "paying" illegal grow operations (load that was previously part of losses), and

ii) The 7 GWh in reduced losses is due to a reduction in theft by illegal grow operations (i.e., they cease operation)

Response:

Confirmed. It should be noted that the estimated increase in billable load and decrease in losses is comprised of both high-load sites converted from theft to paying, and the assumed 1 percent annual growth rate in the number of high-load sites as modeled in the AMI CPCN application.

9.2 Please explain why the conversion of illegal grow operations previously "stealing" power to paying operations is not considered to contribute to a reduction in losses (i.e., losses are reduced and revenue generating load is increased by an equivalent amount)?

Response:

Please refer to the response to BCOAPO IR 1.9.1. The 2 GWh difference between the increase in billable load and the decrease is due to the assumed 1 percent annual growth rate in the number of high-load sites as modeled in the AMI CPCN application.

9.2.1 If it is viewed as contributing to reduced losses, then why isn't the impact of AMI on losses greater less than the impact of AMI on residential loads?

Response:

Only a portion of the increase (7 GWh) in paying high-load sites is related to the conversion of sites from theft to paying (as a result of theft deterrence or detection), with the remainder (2 GWh) related to the assumed 1 percent annual growth rate in the number of high load sites as modeled in the AMI CPCN application. Please also refer to the response to BCOAPO IR 1.9.1.

10.0 Reference: Exhibit B-2, Tab 3, page 23 (Table 3-1) and pages 31-32

Preamble: The Application states (page 31):

The projected GWh theft reduction for the test year and subsequent years is unchanged from the estimated GWh theft reduction assumed in the AMI decision

10.1 Please provide a schedule that sets out the AMI savings that were assumed would occur from theft reduction in the AMI Decision and reconcile with the savings assumed in the current Application.

Response:

Please refer to the response to BCUC IR 1.17.4.

10.2 Please provide the basis for the 9 GWh of increased Residential load in 2018 (incremental to 2016) due to AMI as forecast in Table 3-1.

Response:

Please refer to the response to BCOAPO IR 1.9.2.1.

11.0 Reference: Exhibit B-2, page 23, Table 3-1

Exhibit B-2, Appendix A-2, Table 5.3

11.1 Please provide the basis for the 2017 and 2018 DSM savings forecast in Table 5.3 (and Table 3-1 for 2018).

Response:

The basis for the DSM savings forecast is the approved 2017 DSM Expenditure Schedule, which is assumed to be the same in 2018. Please refer to the response to BCUC IR 1.17.3 which explains the differences between the DSM savings in the DSM Expenditure Schedules and the annual load forecasts.

11.2 Please provide the derivation of the CIP savings for 2017 and 2018 as set out in Table 5.3 (and Table 3-1 for 2018). In doing so, please explain why there is no increase in savings for 2018 relative to 2017.

Response:

Please refer to the response to BCUC IR 1.17.7.

11.3 Please provide the derivation of the RCR savings for 2017 and 2018 as set out in Table 5.3 (and Table 3-1 for 2018). In doing so, please explain why there is no increase in savings for 2018 relative to 2017.

Response:

RCR savings estimates were developed by an external consultant as an input to the most recent RCR Report, which was filed in November 2014. The analysis was conducted by comparing the usage characteristics of a control group of customers that have remained on a flat rate against customers taking service on the RCR. Savings do not increase in 2018 since conservation resulting from the RCR is fully realized by the end of 2017 while the 2018 savings are the cumulative savings. RCR values are incorporated into the forecast as a cumulative target that is multiplied by the before-savings residential load and is shown in the table below.

Both the 2017 and 2018 values in the table below are incremental to the savings embedded in 2016 actuals. Therefore, the incremental savings in 2018 compared to 2017 is nil. It has been assumed since the original RIB Rate Application in 2012 that RCR related savings would be fully realized over a 5 year period.

	Before- Savings Residential Load (GWh)	RCR Cumulative Target (%)	RCR Savings (GWh)
2017	1,296	0.28%	4
2018	1,293	0.28%	4

11.4 Please provide the derivation of the Rate-Driven savings for 2017 and 2018 as set out in Table 5.3 (and Table 3-1 for 2018). In doing so, please explain why there is no increase in savings for 2018 relative to 2017.

Response:

Rate driven savings are calculated by taking the real rate increase before savings from the model and multiplying it by the rate driven savings assumption of -0.05. That percentage is then multiplied by the before-savings load. A rate increase of 1.76 percent, equal to the 2017 rate increase, was assumed for 2018. The 3 GWh is calculated as follows based on the 2018 before-savings load of 3,251 GWh:

$$3\ GWh = 0.05 \times 1.76\% \times 3{,}251\ GWh$$

FBC used the 2017 rate increase of 1.76 percent as a proxy for the forecast year because it is impractical to undertake multiple iterations of the load forecast as various components of annual revenue requirements are in flux until very shortly prior to the filing, and the magnitude of the rate-driven savings is very small.

11.5 Is there no reduction in losses associated with the CIP, RCR and Rate-Driven savings or are there no values shown because they are negligible?

Response:

The loss reduction associated with the CIP, RCR and Rate-Driven savings are all below 0.5 GWh and therefore do not show in Table 3-1 on page 23 of the Application, due to rounding.

12.0 Reference: Exhibit B-2, Tab 3, page 23 and Appendices A-1 & A-3

Preamble: The Application states (page 23):

Forecast residential customer counts are determined by a regression of the year-end customer accounts against population in the FBC direct service area. The population forecast for the FBC service area is provided by a BC Statistics report produced for FBC.

12.1 Please provide a schedule that for each customer class contrasts the forecast customer count for 2017 as approved last year for 2017 rates versus those in the current Application.

Response:

The requested information is provided in the table below.

	2017 AR	2018 AR
Customer Class	**2017F**	**2017S**
Residential	116,031	116,657
Commercial	15,813	15,748
Wholesale	6	6
Industrial	50	50
Lighting	1,590	1,559
Irrigation	1,095	1,090

12.2 Please provide a schedule that contrasts the population forecast for the FBC service area for 2016 and 2017 as used last year for 2017 rates versus that used in the current Application for the same years.

Response:

The requested information is provided below.

Year	Annual Review for 2017 Rates	Annual Review for 2018 Rates
2016	247,738	247,738
2017	250,637	250,637

FBC received a forecast from BC Stats in April of 2017 for each of the forecast years and notes that the FBC service area population forecasts were unchanged from 2016. BC Stats has confirmed that the current population forecast is correct.

12.3 Please provide a schedule that contrasts the provincial GDP forecast for the FBC service area for 2016 and 2017 as used last year for 2017 rates versus that used in the current Application.

Response:

The requested schedule is provided below.

Year	Annual Review for 2017 Rates	Annual Review for 2018 Rates	Difference
2016	2.68%	4.61%	1.94%
2017	3.43%	2.45%	-0.98%

12.4 It is noted that, unlike the information provided for the Residential forecast (Appendix A-3, Table A3-4), Appendix A-3 does not contain information regarding the regression model used to forecast the Commercial customer count. Please provide the equivalent of Table A3-4 for the Commercial class.

Response:

FBC did not include the Commercial customer regression analysis output in Appendix A-3 because, unlike the Residential forecast, the Commercial load forecast does not use the customer count as an input. Section 1.2.2 of Appendix A-3 discusses the methods used to calculate the commercial energy forecast.

Please see below the Commercial customer count and GDP regression results.

Regression	Commercial
Start year	2007
End year	2016
R^2	0.96
Adjusted R^2	0.95
df	9
Intercept	-1,740.91
Slope	0.09

12.5 Please provide a schedule that sets out the customer count by customer class for June 30, 2016 and June 30, 2017.

Response:

The requested schedule is provided below.

Customers	June-16	June-17
Residential	114,321	116,083
Commercial	15,062	15,398
Industrial	50	50
Wholesale	6	6
Irrigation	1,099	1,088
Lighting	1,559	1,529
Total	132,097	134,154

Exhibit B-2, Table 2-2 incorrectly showed a June customer count of 134,152. The corrected value is shown above. This addition of two customers does not impact the customer growth rate used in the O&M and capital formulas or the 2018 O&M or capital amounts.

13.0 Reference: Exhibit B-2, Tab 3, page 25

Preamble: The Application states (page 25):

The decline in residential after-savings load is due to a decreasing UPC, and to DSM and other savings, which account for a 3 GWh and a 13 GWh decline in load, respectively.

13.1 Please provide a schedule that shows and contrasts the various adjustments that were for DSM and Other Savings to account for the change between the before and after savings Residential UPC values for 2017 and 2018.

<u>Response:</u>

The after-savings residential UPC is forecast by taking the after-savings load and then dividing it by the average annual customer count. To show how DSM and Other Savings impact the UPC, the MWh savings must also be divided by the annual average customer count which is shown in Table 1. Savings on a per-customer basis are subtracted from the before-savings UPC to give after-savings UPC in Table 2.

Table 1: Residential UPC Adjustments

	DSM and Other Savings (MWh)		Average Annual Customer Count		UPC Adjustments (MWh)	
	2017	2018	2017	2018	2017	2018
DSM	4,889	13,935	115,813	117,216	0.04	0.12
AMI	- 5,025	- 9,177	115,813	117,216	- 0.04	- 0.08
CPI	1,945	3,880	115,813	117,216	0.02	0.03
RCR	3,632	3,632	115,813	117,216	0.03	0.03
Price Elasticity	1,141	1,138	115,813	117,216	0.01	0.01

Table 2: Before and After Residential UPC Adjustments (MWh)

	Before Savings UPC	DSM	AMI	CPI	RCR	Price Elasticity	After - Savings UPC
2017	11.16	0.04	(0.04)	0.02	0.03	0.01	11.10
2018	11.04	0.12	(0.08)	0.03	0.03	0.01	10.92

14.0 Reference: Exhibit B-2, Tab 3, page 25 and Appendix A-3, page 4

14.1 With respect to Table A3-3, is the slope UPC value of -0.12 (statistically) significantly different (i.e., statistically) from zero? What is the t-value for the slope coefficient?

<u>Response:</u>

The slope is statistically different from zero at the 90 percent confidence level. The absolute value for the t statistic for the slope coefficient is 11.27. The sample size, n, is 3 so the degrees of freedom, df, is (n-2) = 1. Using a p value of 0.05, the critical value of t is 6.31. At 11.27 the t statistic for the UPC slope is greater than 6.31, which is statistically significant at the 90 percent confidence level.

14.2 Please confirm that the 2014-2016 Residential UPC values used in the trend analysis are the actual after-savings (weather normalized) UPC values for each year.

<u>Response:</u>

Confirmed.

14.2.1 If yes, please confirm that part of the downward trend observed in the values for the three years is due to incremental savings achieved each year from the various factors noted in Table 3-1.

<u>Response:</u>

Confirmed.

14.3 Please provide a schedule that sets out:

i) The impact on the 2015 UPC of the savings incremental to those embedded in the 2014 UPC value.

ii) The impact on the 2016 UPC of the savings incremental to those embedded in the 2014 UPC value.

iii) The 2014, 2015 and 2016 UPC values where all three only include savings embedded in the historic 2014 loads

Response:

FBC does not have the ability to remove embedded savings from the after-saving historical loads. The embedded savings include changes in customer behaviours, technologies adopted by customers and a number of other factors that FBC does not have the capability to monitor.

14.4 Based on the results from part 14.3 (iii), please re-estimate the trend equation per Table A3-3 and provide the resulting forecast for the 2017 and 2018 (before savings) UPCs, including the t-value for the slope coefficient.

Response:

Please refer to the response to BCOPAO IR 1.14.3.

14.5 Please provide a schedule that sets out for 2017 and 2018 the forecast savings incremental to those embedded in historic loads to 2014.

Response:

Please refer to the response to BCOPAO IR 1.14.3.

14.6 Based on the results from parts 14.4 and 14.5 please provide a schedule that calculates the after savings Residential UPC values for 2017 and 2018.

Response:

Please refer to the response to BCOPAO IR 1.14.3.

14.7 What is the impact on the Residential 2018 load forecast of using the UPC value derived from the regression/trend analysis as opposed to using the three year historical averages as was done for 2017 Rates?

Response:

Using an average when a downward trend exists will always result in a higher forecast. As shown in the table below, in this case the forecast from the average method is 42 GWh higher than the forecast developed from the trend method.

	Before Savings UPC (MWh)	After-Savings UPC (MWh)	After-Savings Load Forecast (GWh)
Three Year Average	11.40	11.28	1,322
Trend Analysis	11.04	10.92	1,280

15.0 Reference: Exhibit B-2, Tab 3, pages 23 & 28-29

Exhibit B-2, Appendix A-3, page 6

15.1 Please clarify whether the trend analysis undertaken for Lighting load was based on total load (as suggested on page 28) or the UPC (as indicated in Appendix A-3).

<u>Response:</u>

Please refer to the response to BCUC IR 1.16.1.

15.2 It is noted that the number of Lighting customers is forecast to decline. What is the basis for this forecast?

<u>Response:</u>

The number of lighting customers is forecast to remain constant at the 2016 level of 1,559 customers for the forecast period. Exhibit B-2, Tab 3, pages 28-29 and Exhibit B-2, Appendix A-3, page 6 both refer to the load forecast and not the customer count. The lighting load is forecast to decline slightly over the forecast period due to DSM savings.

16.0 Reference: Exhibit B-2, Tab 4, pages 37-38

Preamble: The Application states (page 35):

The reduction in 2017 projected power purchase expense is primarily due to additional market purchases used to displace BC Hydro PPA energy and capacity purchases at a lower total cost, reduced Waneta Expansion costs resulting from increased mitigation revenue, as well as reduced load.

16.1 Please provide a revised version of Table 4-2 that shows the GWh contribution associated with each of the rows towards the Approved 2017 total of 3,559 GWh and the Projected 2017 total of 3,542 GWh. In doing so, please include rows to account for FortisBC's own generation and, if necessary, any external sales.

Response:

The following table shows the energy volumes associated with the expense presented in Table 4-2, including FBC owned generation. The purchases from Waneta Expansion are for capacity only and do not contribute energy towards the Approved 2017 total of 3,559 GWh or the Projected 2017 total of 3,542 GWh. The Independent Power Producers and Self Generators have been aggregated in the table for confidentiality reasons.

Line No.	Description	Approved 2017	Projected 2017	Difference
1	FBC Generation	1,593	1,568	(26)
2	Brilliant	917	891	(26)
3	BC Hydro PPA	750	577	(173)
4	Waneta Expansion	-	-	-
5	Market and Contracted Purchases	296	496	200
6	Independent Power Producers and Self Generators	3	3	(0)
7	Loss Recovery		7	7
8	Special and Accounting Adjustments			-
9	Total	3,559	3,542	(17)

16.2 How much of the reduction in BC Hydro PPA costs and GWh (as between 2017 Projected vs. Approved) was due to being able to replace the PPA energy purchases with cheaper Market and Contract Purchases?

Response:

BC Hydro PPA energy purchases decreased from 750 GWh to 577 GWh between the 2017 Approved and the 2017 Projected Power Purchase Expense, which is a reduction of 173 GWh. The corresponding volume-related decrease in PPA costs is equal to $10.045 million.

Market and Contracted Purchases increased from 296 GWh to 496 GWh between the 2017 Approved and 2017 Projected Power Purchase Expense, which is an increase of 200 GWh. Because the increase in market purchases exceeded the reduction to PPA purchases, 100% of the volume-related decrease in PPA costs (173 GWh and $10.045 million) can be attributed to increased market purchases. Additionally, if FBC had not entered into the market purchases, FBC's 2017 Projected BC Hydro Cost would have increased by the additional 27 GWh (200 GWh less 173 GWh) at a cost of $1.313 million[2]. In other words, all of the 200 GWh of market purchases would have had to be replaced by higher cost PPA energy and capacity if not supplied from the market.

16.3 Is all of the increase in Market and Contract purchases (2017 Projected vs. Approved) the result of increases to replace more expensive PPA energy purchases? If not, how much of the increase (in both dollar and GWh terms) was for this reason?

Response:

Yes, the increased market purchases replaced more expensive PPA energy and PPA capacity purchases.

16.4 Please provide a revised version of Tables 4-3 that shows the GWh contribution associated with each of the rows towards the Forecast 2018 total of 3,542 GWh. In doing so, please include rows to account for FortisBC's own generation and, if necessary, any external sales.

2 Calculated as 27 GWh times the PPA Tranche 1 Energy rate of $48.63 as of April 1, 2017.

Response:

The 2018 Forecast gross load is 3,485 GWh and not 3,542 GWh as stated in the question.

The following table shows the GWh contribution associated with each of the line items in Table 4-3, including FBC owned generation. The purchases from Waneta Expansion are for capacity only and do not contribute energy towards the Forecast 2018 total of 3,485 GWh. The Independent Power Producers and Self Generators have been aggregated in the table for confidentiality reasons.

Line No.	Description	Forecast 2018
1	FBC Generation	1,587
2	Brilliant	918
3	BC Hydro PPA	662
4	Waneta Expansion	-
5	Market and Contracted Purchases	315
6	Independent Power Producers and Self Generators	3
7	Loss Recovery	-
8	Special and Accounting Adjustments	
9	Total	3,485

17.0 Reference: Exhibit B-2, Tab 4, pages 38-39

Preamble: The Application states (page 38):

The forecast increase from $130.437 million in 2017 to $133.071 million in 2018 is a result of a reduction in market and contracted purchases and correspondingly a greater reliance on relatively higher cost energy supplied by BC Hydro, as well as increases to BC Hydro, Waneta Expansion, and Brilliant contract rates.

17.1 How much of the increase is due to "a reduction in market and contracted purchases and correspondingly a greater reliance on relatively higher cost energy supplied by BC Hydro"?

Response:

BC Hydro PPA purchases increased from 577 GWh to 662 GWh between the 2017 Projected and the 2018 Forecast Power Purchases Expense, which is an increase of 85 GWh. The corresponding volume related increase in BC Hydro PPA expense is $6.488 million. The corresponding rate related increase in BC Hydro PPA expense is $1.612 million. The remaining variance is due to the $2.0 million reduction due to potential market savings as discussed in the response to BCOAPO IR 1.17.3.

Market and Contracted purchases decreased from 496 GWh to 315 GWh between the 2017 Projected and the 2018 Forecast Power Purchases Expense, which is a reduction of -181 GWh. The corresponding volume related decrease in Market and Contracted expense is -$5.343 million. The corresponding rate related increase in Market and Contracted expense is $0.282 million. Therefore, the volume related decrease in Market and Contracted purchases that is a result of increased BC Hydro PPA purchases can be calculated as 85 GWh/181 GWh or 47 percent of -$5.343 million, which is -$2.511 million.

Therefore, the total increase in Power Purchase expense that is due to a greater reliance on higher cost energy supplied by BC Hydro is $3.977 million, calculated as the sum of the volume related increase to BC Hydro PPA costs of $6.488 million and 47 percent of the volume related reduction in Market and Contract purchases of -$2.511 million.

17.2 Why does the forecast for 2018 assume a reduction in market and contracted purchases and a greater reliance on higher cost energy supplied by BC Hydro?

Response:

The 2018 Forecast only directly includes those market purchases for 2018 that FBC was able to execute prior to filing. To account for additional market opportunities that may occur over the course of the year, an additional $2 million reduction in Power Purchase Expense for 2018 is also included as discussed in Section 4.6 of the Application. This amount may be more or less than FBC is actually able to achieve and any variance will be flowed through as part of the power purchase expense variance via the Flow-through Deferral account.

17.3 Based on historical experience (i.e., 2016 and 2017) is the $2 M reduction in expected purchases under the BC Hydro PPA in order to account for additional real-time market opportunities reasonable?

Response:

FBC believes that the $2.0 million reduction to BC Hydro PPA expense, in addition to the market contracts already executed and included in the forecast of PPE, is a reasonable forecast for PPE in 2018 based on current load and market estimates for the year. Actual incremental market savings may be more or less than the forecast $2.0 million and will ultimately depend upon system and market conditions.

While FBC was able to achieve incremental savings above the planned $1.0 million in 2016 and $2.0 million in 2017, individual past years are not a good indicator of expected future results. In both 2016 and 2017 market prices were lower than anticipated which resulted in greater than expected market opportunities. In 2016 low market prices were the result of low natural gas prices combined with mild weather throughout the early winter months. In 2017 low market prices mainly resulted from a well above average[3] water year.

[3] 115% of Normal as per data from: Water Year Precipitation Table. September 22 2017. Retrieved from URL: https://www.nwrfc.noaa.gov/water_supply/wy_summary/wy_summary.php?tab=4.

18.0 Reference: Exhibit B-2, Tab 5, page 42

Preamble: The Application states (page 42)

Rent is charged at a unit rate per pole contact multiplied by the number of poles that are contacted. The 2017 Projected is expected to be in line with 2017 Approved. 2018 revenue is forecast to be higher than 2017 Approved due to escalations in unit rental rates.

18.1 How are the unit rental rates established and what is the basis for the 2018 escalation in unit rental rates?

Response:

Unit rental rates and escalation factors are established with contracts between FBC and each third party Joint Use Customer.

Generally, the rental rates include consideration of:

- pole occupancy (the proportion of the pole being used by each party); and
- FBC support costs required to maintain its infrastructure.

Escalation factors are tied in part to changes in the Consumer Price Index (CPI).

19.0 Reference: Exhibit B-2, Tab 6, page 48

Preamble: The Application states (page 48):

The AMI project was substantially completed during 2016, such that 2017 will be the first year of fully realized costs and savings for the AMI project.

19.1 Do the CPCN values for AMI Costs and Savings as set out in Table 6-5 for 2017 and 2018 reflect the values for first and second year of full implementation as per the CPCN Application and Order G-13-14? If not, what are the relevant values?

<u>Response:</u>

Yes, the 2017 Projected and 2018 Forecast values in Table 6-5 represent the first and second year of full implementation, respectively. In the CPCN, the first and second years of full implementation were 2016 and 2017.

20.0 Reference: Exhibit B-2, Tab 6, page 51

20.1 What was the cost of the last MRS audit?

Response:

The actual cost for the 2015 MRS Audit was $0.375 million.

21.0 Reference: Exhibit B-2, Tab 7, page 58

21.1 With respect to Table 7-5 (line 15), please provide a breakdown of the $25.287 M Special Projects and CPCN Additions to Plant by project.

Response:

The Special Projects and CPCN Additions to Plant consists of $19.875 million related to the Kootenay Operations Centre, which will be completed in 2017, plus $5.412 million related to Unit 3 of the Upper Bonnington Old Units Refurbishment project, which will be both completed and returned to service during 2017. The remainder of the refurbished units will also enter rate base on January 1 of the year following their return to service.

21.2 Please provide a break down by project of the ($5.391 M) Change in Special Projects and CPCN Work in Progress (Table 7-5, line 14).

Response:

The change in construction work in progress between December 31, 2017 and December 31, 2018, which is deducted from current year expenditures to calculate additions to plant in Table 7-5, is provided by project in the table below.

	Change in CWIP ($ millions)
Kootenay Operations Centre	$ (19.875)
Corra Linn Spillway Gate Replacement	21.119
Ruckles Substation Rebuild	2.348
UBO Refurbishment	1.799
Total -	$ 5.391

22.0 Reference: Exhibit B-2, Tab 7, page 60

22.1 What was the proportion of customers (by customer class) billed monthly and bi-monthly as of June 2017?

Response:

Please see the breakdown of customer billed monthly and bi monthly broken down by customer class.

Rate Class	Monthly	Bi monthly
Residential	16%	84%
Commercial	22%	78%
Industrial	100%	0%
Lighting	42%	58%
Irrigation	17%	83%
Wholesale	100%	0%

23.0 Reference: Exhibit B-2, Tab 10, page 74

23.1 Assuming they do not contain confidential or commercially sensitive information, please provide the pages from the 2016 Annual Report to BCUC that document the 2016 Actual Earning Sharing Account Ending Balance referenced in Table 10-4.

<u>Response:</u>

Please refer to Attachment 23.1, which includes the continuity of the deferred charge account with the referenced ending balance (page 12) and the calculation of the 2016 additions to the deferred account.

24.0 Reference: Exhibit B-2, Tab 12, page 108

Annual Review for 2017 Rates, ICG 1.5.1

24.1 In response to ICG 1.5.1 from last year's review, FortisBC forecast that the incremental MRS O&M cost for 2018 would be $0.55 M and that there would be no capital costs for 2018. Please explain the reason for the higher costs forecast for 2018 in the current Application ($0.72 M in O&M and $0.05 M in capital).

<u>Response:</u>

With respect to the forecast provided in the Annual Review for 2017 Rates, an Errata dated October 5, 2016 was issued (Exhibit B-2-1) correcting the table to include the $0.050 million in capital expenditures for 2018.

The 2018 increase in forecast O&M to $0.720 million is the result of Assessment Report 10 standards that were not known at the time of the forecast, but were adopted via Commission Order R-39-17.

25.0 Reference: Exhibit B-2, Tab 12, page 112

25.1 Please provide a copy of the Regulatory Account Filing Checklist as issued by the Commission on May 3, 2017.

Response:

Please refer to Attachment 25.1.

26.0 Reference: Exhibit B-2, Tab 12, pages 2 & 119-121

26.1 Why isn't FortisBC proposing to recover the regulatory proceedings costs of the Community Solar Pilot Project in the rates to be charged to the customers participating in the pilot project?

Response:

The treatment of regulatory proceeding costs for the Community Solar Pilot Project (CSPP) is consistent with the treatment of the regulatory proceeding costs for every other FBC program or rate-specific process that comes before the Commission. Examples of other such processes are DSM, Net Metering, general Self-Generation policy issues, and rates specific to Stand-by customers. All of these programs or rates will only be adopted by a small percentage of FBC customers; however, they are generally available to customers on a wider basis and are part of the suite of offerings of the Company and it is appropriate that the regulatory proceeding costs are shared across the customer base.

26.2 Why isn't the cost of the Joint Use Pole Audit recoverable from the users themselves?

Response:

The costs of the Joint Use Pole Audit are fairly allocated amongst each third party Joint Use Customer (of which FBC is one) on the following basis:

- each party to the Audit pays for its own personnel and equipment.
- each party to the Audit pays a proportion of the general and administrative Audit costs equivalent to their share of total contacts.

FBC's portion of the costs related to the joint use pole audit are appropriately recovered from all customers as the revenue derived from the rental agreements benefits those customers; as shown in Table 5-1, 2018 Forecast revenue from Apparatus and Facilities Rental, which is comprised primarily of pole contact revenue from third parties, is $4.736 million.

26.2.1 In the setting of the unit rental rates was any allowance made to recover the cost of the periodic joint use pole audit? If not, why not?

Response:

No, the costs of the periodic joint use pole audits are not included in the annual rental rates. The audits occur only once every five years and costs vary from audit to audit and among the parties. Attempting to incorporate the audit costs into the annual rental fees at the time of contract negotiation is not a feasible solution. Please see the response to BCOAPO IR 1.26.2 for a discussion of the method of recovering the audit costs, which FBC submits is the most appropriate means of recovery.

26.3 With respect to page 120 (lines 14-20), has FortisBC provided the Commission with the results of its consultations with parties? If so, please provide a copy of the "report". If not, when does FortisBC expect to provide the required report to the Commission?

Response:

On August 29, 2017, FEI and FBC jointly sent an email to the stakeholders that participated in the benchmarking study, with a copy to Commission staff, providing a progress update on the benchmarking study (refer to a copy of the email provided below). The update included a summary reporting on the stakeholder consultation efforts and documenting stakeholders' feedback provided on "Suggestions for Benchmarking Consultant" and "Terms of Reference and Parameters for the Benchmarking Study" along with other comments stakeholders provided on the Benchmarking Study.

In its update, FEI and FBC also outlined the suggested next steps for the Benchmarking Study initiative. FEI and FBC provided a list of potential consultants along with information about the consultants' background, qualifications and experience in preparing benchmarking studies. Stakeholders were asked to review the list and advise which consultants they would object to using for the benchmarking study. Additionally, FEI and FBC provided a draft set of high level metrics for stakeholders to consider as part of the benchmarking study.

Once stakeholders have provided their input and comments on the choice of a mutually acceptable consultant and the terms of reference for the study, FEI and FBC intend to initiate an RFP process and select the benchmarking consultant to perform the study.

A copy of the Summary of Stakeholder Comments Regarding the Benchmarking Study that was circulated to stakeholders is included as Attachment 26.3

Email sent to stakeholders

From: Wong, James

Sent: Tuesday, August 29, 2017 11:06 AM

To: 'Chris F. Weafer (cweafer@owenbird.com)' <cweafer@owenbird.com>; 'David Craig (dwcraig@allstream.net)' <dwcraig@allstream.net>; 'Janet Rhodes (jlrhodescmc@gmail.com)' <jlrhodescmc@gmail.com>; 'Thomas Hackney (thackney@shaw.ca)' <thackney@shaw.ca>; 'William J. Andrews (wjandrews@shaw.ca)' <wjandrews@shaw.ca>; 'Leigha Worth' <LWorth@bcpiac.com>; Russ Bell <russ@russbell.ca>; 'Jim Quail' <jquail@aqwlaw.ca>; Iain Reeve (IReeve@moveuptogether.ca) <IReeve@moveuptogether.ca>; Cindy A. Lee <clee@moveuptogether.ca>; 'Fred Weisberg' <fredweislaw@gmail.com>; 'Robert Hobbs' <rhhobbs@shaw.ca>; 'alove@nelson.ca' <alove@nelson.ca>; 'dgeissler@nelson.ca' <dgeissler@nelson.ca>; 'mcraig@nelson.ca' <mcraig@nelson.ca>
Cc: 'Domingo, Yolanda BCUC:EX' <Yolanda.Domingo@bcuc.com>; Roy, Diane <Diane.Roy@fortisbc.com>; Martin, Joyce (FortisBC Electric) (joyce.martin@fortisbc.com) <joyce.martin@fortisbc.com>; Perttula, Dave <Dave.Perttula@fortisbc.com>; Mehrazma, Rouzbeh <Rouzbeh.Mehrazma@fortisbc.com>
Subject: Benchmarking Study - next steps

Hi everyone

Further to our recent meetings on the required Benchmarking Study as outlined in the BCUC directive, attached is a summary of the stakeholder comments received. Please recall each stakeholder's comments were circulated back to the stakeholder for edit and confirmation before including their comments in this overall summary.

<u>Next Steps</u>

Following are the suggested next steps to finalize the Terms of Reference and narrow down the list of potential consultants to include in a proposed Request for Proposal (RFP) process regarding the benchmarking study.

1. Attached is a document titled "Benchmarking Study Terms of Reference" which outlines some key considerations to include in the Study. Based on a review of prior benchmarking studies undertaken, FortisBC has drafted a set of high level metrics to consider. Measures include those that cover costs (i.e. OM&A) and service levels. Included in the document are suggestions provided by stakeholders for inclusion in the Terms of Reference. Please review the document and provide any suggestions you may have.

2. Attached is a document titled "List of Benchmarking Consultants" which outlines potential consultants for the benchmarking study. Included for your consideration is information about their background, qualifications and experience in preparing benchmarking studies including listing of some of their previous clients. The list of potential consultants was developed based on suggestions provided by stakeholders and consultants which FortisBC has identified. Please review the list and advise which consultants stakeholders **"would object to using"** for the benchmarking study.

3. In deciding which consultant to select for the benchmarking study, FortisBC proposes the following selection criteria:

   - Consultant's prior experience in preparing similar benchmarking studies for electric and natural gas distribution companies;

   - Consultant's approach to normalizing the data to ensure an "apples to apples" comparison; and

   - Cost of the benchmarking studies (FortisBC Energy Inc. and FortisBC Inc.).

   Additionally, the consultant is expected to provide commentary as required on the study's results, explaining any differences and contributing factors.

4. Please provide your suggestions and feedback to Steps 1 – 3 above **by Tuesday September 12.**

   On receipt of your suggestions and feedback, FortisBC will initiate the RFP process and select the benchmarking consultant.

Thanks

James

27.0 Reference: Exhibit B-2, Tab 12, page 121

Exhibit B-2, Appendix E, Table 2-1

27.1 With respect to Table 2-1, please explain why the monthly fees received in the last two months of 2015 and the first four months of 2016 are less than those in the 2016 months of April through August when there were more Radio-Off customers in the earlier period.

Response:

The lower revenue (meter read fees) during the period identified is due to the fact that not all Radio-Off meters were read on schedule during the early period of AMI deployment. Radio-off meters are widely dispersed throughout the service territory, which created logistical challenges to complete the meter reading routes, including travel distance between meters, winter road conditions, typically more difficult access for this customer group, and the need to coordinate work crews to be in proximity of the radio-off meters during the reading cycles. Manual meter reading procedures have since been optimized to address these logistical challenges.

27.2 At page 121, the Application states that since the completion of the Radio-Off Report the "shortfall" has grown to an estimated $0.120 M on an annual basis.

27.2.1 Please provide an updated version of Table 2-1 that substantiates this statement.

Response:

The expanded table below shows the shortfall to June 30, 2017 to be $0.061 million, which is approximately equivalent to an annual shortfall of $0.120 million.

Year	Month	RO Count	RO Read Costs ($000)	RO Read Fee ($000)	Net: Costs - Fees ($000)
2014	September	259	$0.0	$0.0	$0.00
	October	358	$0.0	$0.0	$0.00
	November	449	$0.0	$0.0	$0.00
	December	541	$0.0	$0.0	$0.00
	2014 Total		**$0.0**	**$0.0**	**$0.0**
2015	January	648	$0.0	$0.0	$0.0
	February	762	$0.0	$0.0	$0.0
	March	896	$0.0	$0.0	$0.0
	April	1,072	$0.0	$0.0	$0.0
	May	1,116	$0.0	$0.0	$0.0
	June	1,238	$0.0	$0.0	$0.0
	July	1,566	$0.0	$0.1	- $0.1
	August	1,694	$0.0	$3.4	- $3.4
	September	1,868	$15.3	$8.6	$6.7
	October	2,112	$8.1	$9.2	- $1.1
	November	3,080	$7.9	$6.7	$1.2
	December	2,968	$9.0	$14.0	- $5.0
	2015 Total		**$40.3**	**$42.0**	**- $1.7**
2016	January	2,994	$27.9	$16.9	$11.0
	February	2,991	$29.8	$12.4	$17.4
	March	2,862	$32.0	$15.9	$16.1
	April	2,865	$30.1	$37.5	- $7.4
	May	2,857	$22.4	$22.8	- $0.4
	June	2,835	$26.2	$26.9	- $0.7
	July	2,827	$25.5	$23.0	$2.5
	August	2,828	$25.8	$25.0	$0.8
	September	2,814	$25.3	$24.9	$0.4
	October	2,789	$19.8	$22.4	- $2.6
	November	2,774	$30.3	$21.3	$9.0
	December	2,759	$31.3	$22.7	$8.6
	2016 Total		**$326.6**	**$271.6**	**$55.0**
2017	January	2,750	$34.8	$21.5	$13.3
	February	2,739	$31.8	$18.7	$13.1
	March	2,724	$33.7	$22.8	$10.9
	April	2,707	$30.9	$21.3	$9.6
	May	2,700	$35.2	$21.6	$13.6
	June	2,690	$23.4	$22.9	$0.5
	2017 Total		**$189.8**	**$128.8**	**$61.0**

27.2.2 It is noted that in the last four months covered by the Report (Appendix E, Table 2-1) fees roughly cover costs. If not evident in the response to the previous question, please indicate what has changed to create the shortfall.

Response:

As shown in the response to BCOAPO IR 1.27.2.1, the shortfall for the first half of 2017 is higher than the 2016 shortfall. FBC attributes this, in part, to a decrease in the number of radio-off accounts, which has the effect of increasing costs on a per-read basis.

As noted on page 121 of the Application, FBC intends to address the appropriateness of the read fees in its upcoming Rate Design Application.

28.0 Reference: Exhibit B-2, Tab 13, pages 132-134

28.1 How are calls answered via the new call back option treated in the determination of the Telephone Service Factor (i.e., are they included in the calculation and is the time required to answer them measured from when the call was first received until the call back occurs?)?

Response:

The Telephone Service Factor is calculated as the number of non-emergency calls answered within thirty seconds or less divided by the total (non-emergency) calls received. Call-backs are included in the denominator as part of the total calls received. Once the Customer selects a call back, the wait time is measured by the system from the time when the customer selected the call back option to when the call back occurs. As the call-back typically takes longer than 30 seconds to complete, the majority of call-back calls would be considered outside the service level and therefore would not be part of the numerator of the TSF calculation.

28.2 Please confirm that callers requesting the call back option are treated as "unabandoned calls" in the calculation of the Telephone Abandon Rate. If not, how are they treated?

Response:

The Telephone Abandon Rate is calculated as the number of calls abandoned by the customer before speaking to a customer service representative divided by total calls received. All calls from customers requesting the call back option are answered and as such, not accounted for as abandoned calls or included in the numerator when calculating the Telephone Abandon Rate. Call-backs are included in the denominator (i.e. total calls).

28.3 Is it reasonable to expect the introduction of the "call back" option to have a favourable effect on the Telephone Abandon Rate (i.e., possibly reduce it)?

Response:

A reduction or increase in the Telephone Abandon Rate is not necessarily favourable or unfavourable, particularly when considering the impact on customer satisfaction and service quality. For example, the Telephone Abandon Rate may increase due to IVR messaging that provides customers with the information that they were looking for.

FBC anticipates that the call-back option will reduce abandoned calls due to waiting times and will provide a better overall customer experience. However, since FBC typically has an average speed of answer less than one minute, customers typically do not experience significant wait times and as such, there may be limited overall reduction in the Telephone Abandon Rate as a result of this feature.

28.4 It is noted that the Telephone Abandon Rate was 3.3% for the first half of 2016 (See Annual Review for 2017 Rates, page 112) but increases to 3.9% for 2016 overall and to 4.4% for 2017 year to date. To what does FortisBC attribute this recent increase in the Telephone Abandon Rate over the past 12 months?

Response:

FBC is not able to determine with certainty the reasons that a customer may abandon a specific call; however, the abandon rate can vary depending on the frequency and nature of large outages often caused by storms.

As noted in the Annual Review for 2017 Rates, FBC did not experience any major events during the first six months of 2016[4]. This compares to the first six months of 2017 in which FBC experienced two major outages as described in Section 13 of Exhibit B-2. As such, it is reasonable to attribute some of the increase to the June 2017 year-to-date abandon rate (as compared to the June 2016 year-to-date abandon rate) to the two major outage events that have occurred in 2017.

4 Annual Review for 2017 Rates, Exhibit B-2, Page 113, Line 25.

29.0 Reference: Exhibit B-2, Appendix C, pages 1 and 7

Preamble: The Application states (Appendix C, page 1):

FBC does not anticipate any significant delays to the project and plans to advance some work from 2018 into 2017.

29.1 By how much has the capital spending on the project for 2017 increased as a result of advancing this work?

Response:

FBC has advanced $3.3 million into 2017 for a total forecast spend of approximately $5.4 million in 2017. This compares to 2017 forecast spending in the Annual Review for 2017 Rates of $2.1 million.

29.2 With respect to Table C-2 (page 7), please explain:

29.2.1 Why the contingency has increased given that a portion of the work has already been completed (see page 1)?

Response:

FBC is currently holding a risk contingency of 12 percent for the project. During the development of the updated forecast, the contingency allowance was inadvertently increased by $19 thousand. The contingency and project estimates have been corrected in the table below.

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percentage Budget Spent
	(1)	(2)	(3)	(4)=(2)+(3)	(5)=((4)-(1))/(1)	(6)=(2)/(1)
	($000s)				(%)	
Line Work	241	115	150	264	10%	48%
Civil & Site	1,688	27	1,611	1,638	-3%	2%
Buildings	191	1	190	191	-%	1%
Structures & Buswork	427	-	427	427	-%	-%

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance	Percentage Budget Spent
	(1)	(2)	(3)	(4)=(2)+(3)	(5)=((4)-(1))/(1)	(6)=(2)/(1)
	($000s)				(%)	
Station Equipment & Apparatus	2,602	87	2,315	2,402	-8%	3%
Communications & SCADA	32	14	18	32	-%	44%
Protection, Control & Metering	270	92	178	270	-%	34%
Design	627	383	226	609	-3%	61%
Commissioning	132	-	132	132	-%	-%
Project Management	544	51	380	431	-21%	9%
Subtotal - Construction	**6,754**	**770**	**5,625**	**6,395**	**-5%**	**11%**
Cost of Removal	301	-	301	301	-%	-%
Project Contingency	805	-	805	805	-%	-%
Subtotal- Construction & Removal	**7,860**	**770**	**6,731**	**7,501**	**-5%**	**10%**
AFUDC	428	9	509	518	21%	2%
Total Project Cost	**8,288**	**779**	**7,240**	**8,019**	**-3%**	**9%**

29.2.2 Where in the Project Cost Summary are the contributions to CoGF and Interfor included?

Response:

FBC's contributions to the 13 kV system voltage conversion of the City of Grand Forks and Interfor are included in the value of "Station Equipment and Apparatus".

30.0 Reference: Exhibit B-2, Appendix D, page 1

Preamble: The Application states (Appendix D, page 1):

FBC does not anticipate any significant delays to the project and plans to advance some engineering and procurement work from 2018 into 2017.

30.1 By how much has the capital spending on the project for 2017 increased as a result of advancing this work?

<u>Response:</u>

Capital spending for the project in 2017 has increased approximately $0.9 million due to Unit 4 engineering and procurement work being advanced from 2018 into 2017. This includes, but is not limited to:

- Unit 4 Generator Rewind
- Unit 4 Turbine Assessment
- Unit 4 High Pressure Governor System
- Unit 4 Excitation System
- Unit 4 Control System
- Unit 4 Switchgear

Attachment 23.1

FORTISBC INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	Dec. 31 2015	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Dec. 31 2016	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Short Term Interest Rate**								
2									
3									
4	Revenue and Power Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Note 1
5									
6	Flow-Through Accounts	$ 2,412	$ -	$ 2,191	$ -	$ 561	$ 5,165	$ 3,788	
7									
8	Non-Controllable Items								
9	Pension & Other Post Retirement Benefits (OPEB) Variance	$ (1,124)	$ -	$ (125)	$ -	$ (1,243)	$ (2,492)	$ (1,808)	
10		$ (1,124)	$ -	$ (125)	$ -	$ (1,243)	$ (2,492)	$ (1,808)	
11									
12	Regulatory Compliance								
13	2014-2019 Performance Based Ratemaking Application	$ 994	$ -	$ 6	$ (2)	$ (260)	$ 739	$ 866	
14	Annual Review for 2015 Rates	102	-	19	(5)	(71)	46	74	
15	Annual Review for 2016 Rates	122	-	53	(14)	(167)	(5)	59	
16	Annual Review for 2017 Rates	-	-	131	(34)	-	97	48	
17	Self-Generation Policy Application, Stage II	-	-	11	(3)	-	8	4	
18	Net Metering Program Tariff Update	-	-	43	(11)	-	32	16	
19	BCUC Residential Inclining Block Rate Report	-	-	54	(14)	-	40	20	
20	2017 Demand Side Management Expenditure Schedule Application	-	-	108	(28)	-	80	40	
21		$ 1,218	$ -	$ 426	$ (111)	$ (497)	$ 1,037	$ 1,128	
22									
23	Other								
24	2014-2019 Earnings Sharing Account	$ (356)	$ -	$ (727)	$ 189	$ 284	$ (610)	$ (483)	
25	2014 Interim Rate Variance	(17,547)	-	-	-	5,000	(12,547)	(15,047)	
26		$ (17,904)	$ -	$ (727)	$ 189	$ 5,284	$ (13,157)	$ (15,530)	
27									
28	Residual								
29	BC Hydro Application for Power Purchase Agreement with FBC	$ 103	$ -	$ 51	$ (13)	$ (76)	$ 64	$ 84	
30	2015-2016 DSM Plan Application	(1)	-	-	-	1	-	-	
31	Residual Capacity Agreement Application	4	-	-	-	(4)	-	2	
32	Capacity and Energy Sale and Purchase Agreement with Powerex	109	-	-	-	(109)	-	55	
33	City of Kelowna Acquisition Legal & Regulatory Costs, Phase I	2	(2)	-	-	-	-	-	
34		$ 217	$ (2)	$ 51	$ (13)	$ (188)	$ 64	$ 140	
35									
36									
37	**Total Deferral Accounts at Short Term Interest**	$ (15,180)	$ (2)	$ 1,817	$ 65	$ 3,917	$ (9,383)	$ (12,282)	
38									
39	Financing Costs at STI	$ (371)	$ (91)	$ (258)	$ -	$ 360	$ (360)	$ (411)	
40									
41	Note 1: Revenue and Power Supply Variances are included in the Flow-Through Accounts during the PBR Term.								

EARNINGS SHARING CALCULATION BEFORE TAX
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

No.	Particulars					Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Approved Formula O&M	$ 53,596				G-139-14
2						
3	Actual Gross O&M	55,609				Page 21, Line 22, Column 5
4						
5	Less: O&M Tracked Outside of Formula					
6	Pension/OPEB (O&M Portion)	3,391				Page 21, Line 16, Column 5
7	Insurance Premiums	1,306				Page 21, Line 17, Column 5
8	Advanced Metering/Infrastructure Costs/Savings	(1,391)				Page 21, Line 18, Column 5
9	Mandatory Reliability Standards	464				Page 21, Line 19, Column 5
10	Total	3,771				Sum of Lines 6 - 9
11						
12	Actual/Projected Base O&M	51,839				Line 3 - Line 10
13						
14	O&M Subject to Sharing	$ (1,757)				Line 12 - Line 1
15				Annual Capital Expenditures		
16			2014	2015	2016	
17						
18	Cumulative Formula Capital Expenditures	$ 127,451	$ 42,193	$ 42,384	$ 42,874	G-139-14
19						
20	Cumulative Total Regular Capital Expenditures	147,616	49,061	49,043	49,512	Page 4, Line 11 + Line 15, Column 5
21						
22	Less: Cumulative Pension and OPEB					
23	Tracked Outside of Formula	14,323	6,396	4,253	3,674	Page 4, Line 15, Column 5
24						
25	Actual/Projected Base Capital Expenditures	133,293	42,665	44,791	45,838	Line 20 - Line 23
26	Dead Band Adjustment	-			-	Adjustment to stay within deadband
27	Actual Base Capital Expenditure for ESM Calculation	133,293	42,665	44,791	45,838	
28						
29	Actual Base Capital Expenditure Variance	5,842	472	2,407	2,964	Line 25 - Line 18
30						
31	Single Year Deadband % Variance (after adjustment)		0.97%	5.16%	6.37%	Line 29 ÷ (Line 18 + Line 23)
32	Two year Cumlative Deadband % Variance (after adjustment)			6.13%	11.53%	
33						
34						
35						
36	Equity Component of Rate Base	40.00%				G-139-14
37	Approved Return on Equity	9.15%				G-75-13/G-47-14
38	After Tax Capital Expenditures Subject to Sharing	$ 214				Product of Lines 29, 36 & 37
39						
40	Tax Rate	26.00%				
41						
42	Before Tax Capital Expenditures Subject to Sharing	$ 289				Line 38 ÷ (1 - Line 40)
43						
44	Total Before Tax Sharing Account	(1,468)				Line 14 + Line 42
45	Sharing Percentage	50.00%				G-139-14
46						
47	Earnings Sharing Before Adjustments	(734)				Line 44 x Line 45
48	Actual Customer Growth Adjustment	7				Table 10-3, Line 17 of Annual Review for 2017 Rates
49	Total Earnings Sharing Returned to Customers	$ (727)				Line 47 + Line 48

Attachment 25.1

British Columbia Utilities Commission

Appendix B

REGULATORY ACCOUNT FILING CHECKLIST

Clean Version

May 3, 2017

British Columbia Utilities Commission

REGULATORY ACCOUNT FILING CHECKLIST

Purpose and scope of this filing checklist

The purpose of this Regulatory Account Filing Checklist is to assist regulated entities in the preparation of an application requesting deferral or regulatory account treatment (both referred to as regulatory account treatment for the purpose of this checklist) in order to facilitate an efficient review of these applications by the British Columbia Utilities Commission (Commission).

The Regulatory Account Filing Checklist is intended to provide guidance regarding the information a regulated entity is expected to provide when applying for regulatory account treatment. Applications for regulatory account treatment filed either as a standalone application or as part of a larger application should be prepared in accordance with this checklist.

This checklist is applicable to regulated entities that are requesting approval to either establish a <u>new</u> regulatory account or to <u>modify or change the scope</u> of a previously approved regulatory account.

Regulatory account application filing considerations

I. Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.

   a) If the request is for a modification or change in scope to an <u>existing</u> regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).

   b) If the request is for approval of a <u>new</u> regulatory account, state the purpose of the regulatory account and explain its intended use.

II. Propose a term (i.e. length of time) that the regulatory account should be approved for and explain why that term is appropriate.

III. Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.

IV. Address the following:

   a) whether, or to what extent, the item is outside of management's control;

   b) the degree of forecast uncertainty associated with the item;

   c) the materiality of the costs; and

   d) any impact on intergenerational equity (note that this item is linked to the proposed timeline for recovery which is further outlined in item IX below).

V. Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other.[4]

VI. Identify if the regulatory account is a cash or non-cash account.

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[4] See "Regulatory Account Types" on pages 2 and 3 for further details on the classification of regulatory accounts.

VII. Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.

VIII. Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.[5]

IX. Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.[6]

X. Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.

XI. Outline a recommended regulatory process for the Commission's review of the application.

Regulatory account types

(f) Forecast variance account

- A forecast variance account captures the variance between forecast costs or revenues and actual costs or revenues.

(g) Rate smoothing account

- A rate smoothing account can mitigate rate shock resulting from the impact of large forecast one-time items, mitigate rate shock resulting from forecast overall general rate increases, or reduce rate volatility.
- A rate smoothing account should generally capture forecast, as opposed to actual, costs and revenues and therefore should not change the total cost being recovered in rates (other than the carrying costs), rather it only impacts the timing of when those costs are recovered.
- In the event that actual costs <u>are</u> proposed to be captured in a rate smoothing account, the request should include a rationale for why this treatment is appropriate.

(h) Benefit matching (capital-like) account

- A benefit matching account defers recovery of costs that under Generally Accepted Accounting Principles (GAAP) would otherwise be required to be expensed in the current accounting period to a future period (when the benefits of those costs are realized) if they provide long-term benefits to current and future ratepayers.
- A benefit matching account should generally capture forecast, as opposed to actual, costs and therefore should not change the total costs being recovered in rates (other than the carrying costs), rather it only impacts the timing of when those costs are recovered.
- In the event that actual costs <u>are</u> proposed to be captured in a benefit matching account, the request should include a rationale for why this treatment is appropriate.

(i) Retroactive expense account

- A retroactive expense account applies only to an uncontrollable cost or revenue that occurs in a period where rates have already been approved and set by the Commission.

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[5] For example, recover through amortization expense in the revenue requirements or through a rate rider.
[6] Recovery timelines may be short term (1 year or less), medium term (1-3 years), or long term (3+ years).

- Used only in exceptional circumstances to recover (or refund) certain uncontrollable costs or revenues that materialize after the occurrence of an unforeseeable event. This would apply in a situation where the cost or revenue was neither forecast (expected) in the test period or where actual costs are considerably greater than forecast.

(j) Other

- While it is expected that the majority of regulatory account requests would fall within the four categories described above, there may be others which the Commission would consider on a case-by-case basis.
- Example: In certain situations, a regulated entity may recognize a non-cash GAAP provision which results in a request for a Commission-approved regulatory asset account to offset the liability (provision) recorded under GAAP.
  - This regulatory asset account would be amortized as the corresponding GAAP provision is drawn down (i.e. paid in cash). The application may include a request to record changes to the account balance due to accretion and the discount rate as required by GAAP.
  - Recovery of the balance would require additional review and approval by the Commission.

Attachment 26.3

Summary of Stakeholders Comments Regarding the Benchmarking Study – June 12, 2017 (updated)

	BC Sustainable Energy Association (BCSEA)	BC Pensioners' and Seniors' Organization (BCOAPO)	Commercial Energy Consumer Association of BC (CEC)	MoveUP	Irrigation Ratepayers Group (IRG)	Industrial Customer Group (ICG)	British Columbia Municipal Electrical Utilities (BCMEU)
Represented by:	Bill Andrews, Thomas Hackney	Leigha Worth, Russ Bell	David Craig, Chris Weafer, Janet Rhodes	Jim Quail, Iain Reeve, Cindy Lee	Fred Weisberg	Robert Hobbs	Alex Love, Dan Geissler, Marg Craig
Considerations for the Benchmarking Study							
Suggestions for Benchmarking Consultant	No suggestions provided at the time of the meeting. It is important that there was consensus amongst stakeholders on the selection of the consultant.	BCOAPO did not have a specific consultant in mind for the benchmarking initiative. BCOAPO notes that they do not know what parties the benchmarking consultants typically work for (utilities versus customers or other interests) but if most of their work is on behalf of utilities, then that would raise some red flags because benchmarking is an art, not a science and the results tend to be heavily influenced by the study's sponsor.	The company should be determined by the Commission and should include an opportunity for a follow on project to identify improvements that could be made by prudent management.	5. As for who should be engaged as consultant, of the options presented we prefer Elenchus/John Todd, largely because of their extensive history and expertise in the field. We strongly oppose engaging a "vanilla" large accounting firm.	No suggestions provided at the time of the meeting but current retainer of Elenchus Research by BCUC indicates competence.	No suggestions provided at the time of the meeting.	No suggestions provided at the time of the meeting.

	BC Sustainable Energy Association (BCSEA)	BC Pensioners' and Seniors' Organization (BCOAPO)	Commercial Energy Consumer Association of BC (CEC)	MoveUP	Irrigation Ratepayers Group (IRG)	Industrial Customer Group (ICG)	British Columbia Municipal Electrical Utilities (BCMEU)
Represented by:	Bill Andrews, Thomas Hackney	Leigha Worth, Russ Bell	David Craig, Chris Weafer, Janet Rhodes	Jim Quail, Iain Reeve, Cindy Lee	Fred Weisberg	Robert Hobbs	Alex Love, Dan Geissler, Marg Craig
Terms of References and Parameters for the Benchmarking study	Suggested that the benchmarking study address any changes in O&M and Capital work prioritization, whether we are accounting for the activities differently (i.e. accounting policy changes) and whether we are moving activities/costs between the allowed formulaic amounts and the amounts outside of the PBR Plan.	BCOAPO's preference is that the study benchmark the utility as against others, not itself. Every utility resists suggestions that they be benchmarked against others with the claim that their specific characteristics make them unique and therefor difficult to benchmark. BCOAPO suggested that if the Benchmarker were to use an amalgamation, perhaps using the two largely rural and largely urban distribution utilities in Alberta, it would effectively mimic Fortis' diverse characteristics. Together, these utilities provide comparable size, topography, etc. to make them a useful benchmarking tool. There may be other utilities that can be	The benchmarking study should include an external review of relevant OPEX and CAPEX to identify improvements that prudent management should be able to achieve. A jurisdictional review should not be required. Benchmarking study should be primarily against 'self'. The benchmarking company should identify potential references for alternative design for FEI processes or cost efficiencies that are able to be achieved.	3. Benchmarks that are limited to measuring how well the utilities are doing at "business-as-usual" are inadequate and will tend to distort and limit the trajectory of their development. 4. Among other things, the utilities should want to be evaluated for their success in adapting to the evolving context and societal needs. 6. Interveners should have meaningful input into the design of the benchmarks and related issues.	Should include utilities in the Pacific Northwest (Washington State) as part of the study OR provide rationale for excluding those comparators. Where possible, there should be consideration of metrics relevant to irrigation customers, the nature of how these types of customers use the power and the costs.	Indicated that defining the terms of reference (scope) for the benchmarking study was more important than selecting the consultant. The stakeholders should agree on what the metrics should be first. Some high level metrics to consider include comparison of customer rates and employees per customer. Additionally, FortisBC's performance would be compared to other utilities for a suggested period of ten years. Commented that ICG was more interested in metrics that focused on costs (i.e. $ per unit of activity) instead of service oriented metrics. Suggested a "phased-in"	Measures related to reliability, safety and operational efficiency should be part of the study. The benchmarking study to include inter-utility comparisons. The benchmarking study should compare FortisBC's capital spending against other utilities in order to assess whether FortisBC's capital spending was appropriate.

	BC Sustainable Energy Association (BCSEA)	BC Pensioners' and Seniors' Organization (BCOAPO)	Commercial Energy Consumer Association of BC (CEC)	MoveUP	Irrigation Ratepayers Group (IRG)	Industrial Customer Group (ICG)	British Columbia Municipal Electrical Utilities (BCMEU)
Represented by:	Bill Andrews, Thomas Hackney	Leigha Worth, Russ Bell	David Craig, Chris Weafer, Janet Rhodes	Jim Quail, Iain Reeve, Cindy Lee	Fred Weisberg	Robert Hobbs	Alex Love, Dan Geissler, Marg Craig
		grouped to provide additional benchmarks. BCOAPO suggested that Customers should have input regarding the Terms of Reference and the choice of FEI's Benchmarker. BCOAPO does not suggest anything as extreme as a veto but instead an opportunity to make suggestions and have meaningful input in a context where those comments and the Utility's response would be recorded or reported on where appropriate. BCOAPO supports more detailed benchmarks, perhaps at the USA functional level, such as (but not limited to) customer accounting, distribution, A&G etc.				approach to the benchmarking study. To determine what metrics to include in the study, indicated we should benchmark some high level metrics first (i.e. O&M per customer, etc). Depending on the results, the next phase of the study would focus on the high level metrics which warranted further investigation. Mentioned that depending on the result of the first phase, there may be only a limited need for a consultant. Noted that ICG was not in favour of TFP studies for benchmarking or for setting the X-factor as part of the PBR proceeding as these studies are difficult to understand.	

	BC Sustainable Energy Association (BCSEA)	BC Pensioners' and Seniors' Organization (BCOAPO)	Commercial Energy Consumer Association of BC (CEC)	MoveUP	Irrigation Ratepayers Group (IRG)	Industrial Customer Group (ICG)	British Columbia Municipal Electrical Utilities (BCMEU)
Represented by:	Bill Andrews, Thomas Hackney	Leigha Worth, Russ Bell	David Craig, Chris Weafer, Janet Rhodes	Jim Quail, Iain Reeve, Cindy Lee	Fred Weisberg	Robert Hobbs	Alex Love, Dan Geissler, Marg Craig
Other Comments provided			A benchmarking study is necessary.	1. What gets measured by the regulator tends to determine where and how the company evolves. 2. On the strategic level, the most pressing need for Fortis utilities and their customers is the ability to continue to adapt to changing imperatives and demands in the context of a rapidly-evolving energy sector. 7. This should not be taken as necessarily constituting an endorsement by MoveUP of any proposal to continue under a PBR regime after the expiry of the current one.	Confirmed that consultant selection process and choice of benchmarking methodology for FEI and FBC will not necessarily be the same if the "same mold doesn't seem to fit" for both electric and gas utilities.	Commented that for the benchmarking study, it should be an iterative consultation process, instead of just an initial discussion in the early stages of the study.	

	BC Sustainable Energy Association (BCSEA)	BC Pensioners' and Seniors' Organization (BCOAPO)	Commercial Energy Consumer Association of BC (CEC)	MoveUP	Irrigation Ratepayers Group (IRG)	Industrial Customer Group (ICG)	British Columbia Municipal Electrical Utilities (BCMEU)
Represented by:	Bill Andrews, Thomas Hackney	Leigha Worth, Russ Bell	David Craig, Chris Weafer, Janet Rhodes	Jim Quail, Iain Reeve, Cindy Lee	Fred Weisberg	Robert Hobbs	Alex Love, Dan Geissler, Marg Craig
Comments confirmed by stakeholder	Confirmed on June 1.	Confirmed on June 8.	Comments provided on May 29.	*We ask that these comments be incorporated into your report as they are stated and not re-cast or summarized.* Comments provided June 8.	Confirmed on June 1.	Confirmed on June 1.	Waiting to receive confirmation.

Benchmarking Consultation Process and Study Timeline

The stakeholder consultation process is expected to be complete by the end of May / early June. In June, FortisBC will provide the highlights of the stakeholder feedback received regarding the benchmarking study with further discussions required to finalize the selection of the consultant and a broad terms of reference.

The study would likely begin late in 2017 or early in 2018 with the target to file the completed study with the Commission in Q3/Q4 of 2018.