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September 28, 2016

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

Attention: Ms. Tannis Braithwaite, Executive Director

Dear Ms. Braithwaite:

Re: FortisBC Inc. (FBC)

Project No. 3698887

Multi-Year Performance Based Ratemaking Plan for 2014 through 2019 approved by British Columbia Utilities Commission (Commission) Order G-139-14 – Annual Review for 2017 Rates (the Application)

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

On August 8, 2016, FBC filed the Application referenced above. In accordance with Commission Order G-123-16 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, page 4

1.1 What were the O&M charges to FBC for the use of the Prince George contact center for the first half of 2016, and what are the forecast O&M charges for all of 2016?

<u>Response:</u>

Please refer to the response to MoveUP IR 1.1.7 which contains the requested information for January to August 2016.

FBC forecasts the O&M charges to be approximately $50,000 for 2016; however, the forecast is subject to change based on actual volumes and actual staffing levels in both operations.

2.0 Reference: Exhibit B-2, page 6

2.1 Were there any staffing impacts due to the SCC assuming management responsibility for the former City of Kelowna distribution system and, if yes, what were they?

Response:

No, there were no staffing impacts. This initiative eliminated the need for a local person in Kelowna to be designated as the Person in Control (PIC) for the former City of Kelowna distribution system. As explained in the response to BCUC IR 1.4.1, this eliminated the need for wage premiums related to PIC responsibilities, but there were no staffing or other labour impacts.

3.0 Reference: Exhibit B-2, pages 12 and 16

3.1 Please provide a schedule that sets out the customer count by customer class for June 2015 and June 2016.

Response:

The requested information is provided in the table below.

Customer Counts by Class

Customers	Jun-15	Jun-16
Residential	113,475	114,321
General Service	14,585	15,062
Industrial	49	50
Wholesale	6	6
Irrigation	1,095	1,099
Lighting	1,600	1,559
Direct Total	130,810	132,097

4.0 Reference: Exhibit B-2, pages 14-16

4.1 Please provide a schedule that for each customer class contrasts the forecast customer count and kWh (net after savings) for 2016 as approved last year for 2016 rates versus those in the current Application.

<u>Response:</u>

The requested table is provided below. Note that the 2016 forecast in the current Application is referred to as the 2016 Seed.

Customer and Load Forecast

	Customer Count			After-Savings Load (KWh)		
	2016 Approved	2016 Seed	Difference	2016 Approved	2016 Seed	Difference
Residential	115,758	115,080	-0.6%	1,366,677,676	1,348,427,975	-1.3%
Commercial	15,042	15,167	0.8%	870,539,441	868,384,264	-0.2%
Wholesale	6	6	0.0%	579,185,465	587,433,672	1.4%
Industrial	49	50	2.0%	393,325,671	393,181,203	0.0%
Lighting	1,620	1,590	-1.9%	13,328,616	15,437,304	15.8%
Irrigation	1,103	1,095	-0.7%	38,836,391	40,515,987	4.3%
Total	133,578	132,988	-0.4%	3,261,893,260	3,253,380,406	-0.3%

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

<u>Response:</u>

The requested table is provided below.

FBC Service Area Population Forecast

Year	Annual Review for 2016 Rates	Annual Review for 2017 Rates	Difference
2016	246,177	247,738	0.6%

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

Response:

The requested table is provided below.

CBOC Provincial GDP Growth Forecast (%)

Year	Annual Review for 2016 Rates	Annual Review for 2017 Rates	Difference
2016	2.70%	2.68%	-0.02%

5.0 Reference: Exhibit B-2, page 16

Exhibit B-2, Appendix A3, page 5

2016 Annual Review, Exhibit B-1-1, page 26

5.1 Please provide a Table similar to Table 3-1 but for 2016 consistent with the 2016S load forecast in the current Application.

<u>Response:</u>

Please refer to the response to CEC IR 1.4.6.

5.2 Please provide the specific cross reference to the 2017 DSM Expenditure Schedule Application that supports the 2017F DSM savings values shown in Table 3-1 and the 2016S DSM savings values provided in response to the previous question.

<u>Response:</u>

FBC provided a discussion of why the DSM Expenditure Schedule is not directly comparable to the forecast of DSM savings in response to BCUC IR 1.5.4 (Exhibit B-2) in the Annual Review for 2016 Rates. FBC has copied that discussion below, with updates to reflect the response for the current filing.

The differences between the two tables occur because the DSM savings are presented differently in the DSM Plan and in the Annual Review forecast, hence the savings values are not directly comparable. The difference occurs as a result of the way that the 2017 DSM Plan savings are presented, attributed, and disaggregated in the load forecast.

The main reason for the difference is that the 2017 Forecast presents the DSM savings numbers as cumulative starting in 2016 (2015 and earlier DSM savings are embedded in historical data) whereas the DSM Plan shows the savings as incremental (the savings for each plan year are shown separately).

The 2017 DSM Plan figure of 25,715 MWh represents annualized energy savings for the DSM projects, by major customer sector, planned to be undertaken in that calendar year only. The forecast presented in FBC's Annual Review factors in the timing of DSM projects: some of the DSM project savings are attributed to the year following the project. For example, if a project with 12,000 kWh of savings was planned to be completed in December 2015, the DSM Plan shows all of those savings in 2015. The forecast numbers, however, reflect 1/12 of the savings in 2015 (1,000 kWh of savings in December 2015) and the remaining 11/12 of the project's savings are reflected in 2016 (11,000 kWh of savings from January to November 2016).

Furthermore, for forecasting purposes, FBC disaggregates a number of sub-categories of DSM that are not shown in the DSM Plan savings. For example, "Residential" in the plan savings includes the residential portion of the "Wholesale" savings (for the City of Penticton and the other municipal utilities) presented in the load forecast. Similarly the "Commercial" plan savings contain the "[Street] Lighting" and "Irrigation" values shown separately in the load forecast. The forecast also isolates the (line) "Losses" associated with the DSM program savings.

5.3 Please explain why the CIP savings for 2017 are less than half of those projected in last year's Application for 2016 (per BCOAPO #4.1).

Response:

The CIP savings for 2017 are lower than projected in the Annual Review for 2016 Rates due to the full implementation of CIP being delayed until December 31, 2016. The savings forecast in the Annual Review for 2016 Rates assumed full CIP implementation during 2015 which included 2 GWh of savings in 2015 and full savings of 4 GWh in 2016. Since the project will not be fully implemented until the end of 2016, FBC is now forecasting savings of 2 GWh in 2017 and full savings of 4 GWh in 2018.

5.4 Please provide the derivation of the RCR savings for 2017F.

Response:

As a result of analysis performed for the most recent RCR Report to the BCUC in 2014 and the availability of 2015 load information, the forecast conservation impact due to the RCR was increased to 3.4% relative to the original Residential Inclining Block Rate Application. The 2014 RCR Report also estimated that 36.2 GWh of savings had been realized to the end of 2014 due to the RCR. Another 4.2 GWh of savings are considered to have been realized in 2015, based on residential load data and the RCR annual impact estimates. In order to realize the remaining incremental savings from 40.4 GWh to 46.3 GWh by the end of 2017, the Company estimates that another 4.1 GWh of conservation will occur in 2016 with the remaining 1.8 GWh being realized in 2017.

FBC notes that it has provided a revised version of Table 3-1 in the response to BCUC IR 1.6.1,which corrects the AMI and RCR savings recorded in that table. The RCR impact was revised to a total gross load cumulative impact in 2017 of 7 GWh from 10 GWh.

6.0 Reference: Exhibit B-2, page 17-18

Preamble: It is noted that the Residential UPC has been declining annually since 2013 but that it is forecast to increase for 2016 and then decline again in 2017. It is also noted that the before-savings UPC for 2017 is assumed to remain constant at the 2016S level.

6.1 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 2016S and 2017F.

Response:

The table below shows and contrasts the various adjustments that were made for DSM and other savings to account for the change between the before and after savings Residential UPC values for 2016S and 2017F. The after-savings UPC for 2016S and 2017F in the table below are calculated by taking the before-savings UPC and subtracting the DSM and other-savings.

Before-Savings and After-Savings UPC (KWh)

	Before Savings UPC	DSM	Other Savings				Total DSM and Other-Savings	After-Savings UPC
			AMI	CIP	RCR	Rate-Driven		
2016S	11,801	(28)	33	-	(36)	(10)	(41)	11,764
2017F	11,801	(84)	76	(18)	(61)	(10)	(96)	11,709
Difference	(0)	(55)	43	(18)	(25)	(0)	(55)	(55)

7.0 Reference: Exhibit B-2, pages 23-24

2016 Annual Review, Exhibit B-1-1, page 24

2016 Annual Review, BCOAPO IR #4.1

7.1 Page 23 of the current Application states that the "current forecast loss reductions [from AMI] remain unchanged from those provided as part of the AMI CPCN Application". However the values for the "Incremental AMI Impact" in the current Application's Table 3-4 are materially different from those in last year's Application (Table 3-4). Please reconcile and, in particular, address the change in the 2017 value.

<u>Response:</u>

The current forecast loss reductions are unchanged from those provided as part of the AMI CPCN application, adjusted for the Commission's determinations as provided in Order C-7-13.

The Incremental AMI Impact amounts shown in Table 3-4 are the cumulative impacts compared to those embedded in the historical actual load. Since FBC now has actual load data for 2015, there is no need to include an incremental AMI Impact for that year in the 2017 load forecast, and therefore the amount shown for 2017 has declined from the amount reflected in the Annual Review for 2016 Rates.

For example, in the Annual Review for 2016 Rates, the 2017 forecast value was calculated by adding the 2.4 GWh loss reduction forecast for 2015, the 2.7 GWh loss reduction forecast for 2016, and the 3.9 GWh loss reduction forecast for 2017 equaling a cumulative loss reduction impact of 9.1 GWh in 2017. For this year's Application, the 2015 AMI impacts are already embedded in the actual 2015 load data, and the 2.7 GWh loss reduction forecast for 2016 is added to the 3.9 GWh loss reduction forecast for 2017 to equal a total AMI impact of 6.7 GWh (differences due to rounding).

8.0 Reference: Exhibit B-2, page 30

8.1 Please provide a revised version of Table 4-2 that shows the GWh contribution associated with each of the rows towards the Approved 2016 total of 3,540 GWh and the Projected 2016 total of 3,426 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 a revised version of Table 4-2 with the GWh contribution associated with each of the rows, including FBC owned generation. The purchases from Waneta Expansion are for capacity only and do not contribute energy towards the Approved 2016 total of 3,540 GWh or the Projected 2016 total of 3,426 GWh.

2016 Power Purchase Volumes (GWh)

Line No.	Description	Approved 2016	Projected 2016	Difference
1	FBC Generation	1,589	1,599	10
2	Brilliant	914	894	(20)
3	BC Hydro PPA	786	574	(212)
4	Waneta Expansion	-	-	-
5	Independent Power Producers	4	4	-
6	Market and Contracted Purchases	247	337	90
7	CPA Balancing Pool	-	18	18
8	Total	3,540	3,426	(114)

8.2 How much of the reduction in BC Hydro PPA costs and GWh (as between 2016 Projected vs. Approved) was due to being able to replace the PPA energy purchases with cheaper Market and Contract Purchases?

Response:

As shown in the response to BCOAPO IR 1.8.1, BC Hydro PPA energy purchases decreased from 786 GWh to 574 GWh between the 2016 Approved and 2016 Projected Power Purchase Expense, which is a reduction of 212 GWh. The corresponding volume-related decrease in PPA costs is equal to $9.706 million.

Market and Contracted Purchases increased from 247 GWh to 337 GWh between the 2016 Approved and 2016 Projected Power Purchase Expense, which is an increase of 90 GWh.

Expressed as a percentage, the decrease in PPA purchase volume offset by Market and Contracted purchases is 42.5%.[1]

Therefore, of the $9.706 million volume-driven reduction to BC Hydro PPA costs, 42.5% can be attributed to increased market purchases, which is equal to a reduction of $4.12 million.[2]

8.3 Is all of the increase in Market and Contract purchases (2016 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, all of the increase in Market and Contracted purchases between the 2016 Approved and the 2016 Projected Power Purchase Expense was the result of increases to replace more expensive BC Hydro Power Purchase Agreement energy and capacity purchases.

8.4 Please provide a revised version of Tables 4-3 that shows the GWh contribution associated with each of the rows towards the Forecast 2017 total of 3,559 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 a revised version of Table 4-3 with the GWh contribution associated with each of the rows, including FBC owned generation, contributing towards the Forecast 2017 total of 3,559 GWh. The purchases from Waneta Expansion are capacity only and do not contribute energy towards the Forecast 2017 total of 3,559 GWh.

[1] Calculated as 90 GWh divided by 212 GWh (the reduction in BCH energy)
[2] Calculated as 42.5% x $9.706 million.

2017 Forecast Power Purchase Volumes (GWh)

Line No.	Description	Forecast 2017
1	FBC Generation	1,593
2	Brilliant	917
3	BC Hydro PPA	750
4	Waneta Expansion	-
5	Independent Power Producers	3
6	Market and Contracted Purchases	296
7	CPA Balancing Pool	-
8	Total	3,559

9.0 Reference: Exhibit B-2, pages 34-35

Exhibit B-2, page 16

9.1 Which customer classes are subject to "connection charges"?

Response:

All customer classes are subject to connection charges as set out in FBC's Rate Schedule 80.

10.0 Reference: Exhibit B-2, page 37

2016 Annual Review, Exhibit B-1-1, page 39

10.1 With respect to Table 6-3 please provide the approved and actual values for 2015 for each of the first three line items.

Response:

The approved and actual values for 2015 are provided below.

Line No.	Description	Approved 2015	Actual 2015
1	Pension/OPEB (O&M Portion)	$ 3.925	$ 3.925
2	Insurance Premiums	1.380	1.334
3	Advanced Metering Infrastructure Project	0.452	0.272

10.2 Please explain why there are no entries for 2016 or 2017 for Advanced Metering Infrastructure Radio-Off O&M costs in Table 6-3.

Response:

In the Annual Review for 2016 Rates, FBC indicated that the approved tariff fees for radio-off customers were not sufficient to recover the forecast costs associated with providing installation and manually meter reading services to these customers. FBC proposed to track and recover the shortfall (the net costs after fees collected) outside of formula O&M expense. The Commission denied this request in its Decision and directed that the shortfall be recorded in a deferral account for future determination.[3] Therefore, there are no O&M expenses forecast for radio-off customers in 2016 or 2017 in Table 6-3. Instead, the net costs associated with manually reading the radio-off meters are captured in the AMI Radio-Off Shortfall deferral account in Section 11, Schedule 12.2, Line 14.

[3] Decision accompanying Order G-202-15, Appendix A, page 21.

11.0 Reference: Exhibit B-2, page 39

11.1 Please confirm that FortisBC continues to collect revenues from Meter Connection fees in certain instances and, if so, indicate how these revenues are treated (i.e., as offset to costs or as a component of Other Revenues).

<u>Response:</u>

FBC confirms that it continues to collect revenues associated with the connection and reconnection of a service in certain instances.

All revenues related to the connection or reconnection of service, including the charge for the setup or transfer of the account, are treated as an offset to costs in Other Revenue.

11.2 Is this practice consistent with how revenues from Meter Connection fees were treated in the past (i.e., prior to Letter L-1-16)?

<u>Response:</u>

The treatment of recognizing meter connection fees revenue in Other Revenue is consistent with past practice.

12.0 Reference: Exhibit B-2, page 41

12.1 What is the basis for the $0.04 M savings associated with not needing to carry out the annual inspection of Upper Bonnington Unit 3 (i.e., how was it established)?

Response:

The basis for the $0.04 million in savings consists of the avoided cost of not performing an annual inspection on Unit 3 during the refurbishment. These annual costs have historically been in the range of $0.03 million, and FBC has added some minor savings in operations and maintenance expense due to not running the unit during the refurbishment period.

12.2 Please explain the difference between the $0.04 M savings associated with avoiding the inspection of Upper Bonnington Unit 3 and the projected $0.3 M cost of inspecting Lower Bonnington Unit 1.

Response:

The $0.04 million savings is the avoided cost associated with not performing the annual inspection and other annual maintenance for UBO Unit 3, as explained in the response to BCOAPO IR 1.12.1.

The $0.3 million cost is the projected cost of the major unit inspection planned for Lower Bonnington Unit 1.

The annual inspections occur each year on each unit and the major inspections occur approximately every 80,000 run hours. The major unit inspection is larger in scope and consists of a comprehensive mechanical and electrical inspection, hence the difference in cost.

13.0 Reference: Exhibit B-2, page 44

13.1 Was the need for ongoing AMI Sustainment Capital identified in the AMI CPCN Application and, if so, please indicate the relevant reference(s).

<u>Response:</u>

Yes, the need for AMI Sustainment Capital was identified in Table 5.1.b of the AMI CPCN application (Exhibit B-1, section 5.1, Project Costs). At page 71 of the AMI CPCN application, FBC made it clear that the costs and benefits presented in Table 5.1.b were not included in the capital expenditure approval being sought under the requested CPCN, but would be included in future revenue requirement and capital expenditure applications.

The costs included in Table 5.1.b of the AMI CPCN application were subsequently impacted by the Addendum to the CPCN application (Exhibit B-1-3), which factored in the additional City of Kelowna acquisition-related costs and benefits, and by Order G-139-14, which reclassified certain software costs from capital to O&M.

14.0 Reference: Exhibit B-2, pages 45-46

14.1 Please provide a break down by project of the $16.485 M for Change in Special Projects and CPCN Work in Progress (Table 7-4, line 14).

<u>Response:</u>

A continuity schedule is provided below.

Continuity of Construction Work in Progress, CPCN and Special Projects ($millions)

	CWIP Balance 12-31-16	Expenditures	Additions to Plant in Service	CWIP Balance 12-31-17	Change in CWIP
	(1)	(2)	(3)	(4)	(4)-(1)
Project					
Advanced Metering Infrastructure	$ 5.973	$ -	$ (5.973)	$ -	$ (5.973)
Kootenay Operations Centre	6.717	14.416	-	21.133	14.416
Upper Bonnington Old Units Refurbishment	-	5.898	-	5.898	5.898
Ruckles Substation Upgrade		2.143	-	2.143	2.143
Total	$ 12.690	$ 22.457	$ (5.973)	$ 29.174	$ 16.485

14.2 At page 45 (lines 10-13) the Application states that none of these projects is forecast to be included in rate base or affect rates for 2017. However, Table 7-4 indicates that Special and CPCN Projects have an impact on in-service plant used for rate base of $5.973 M. Please reconcile.

<u>Response:</u>

CPCN and Special Projects enter rate base on January 1 of the year after entering into service. No portion of the projects listed on page 45 (the Kootenay Operations Centre, Ruckles Substation Rebuild and UBO Old Units Refurbishment projects) enter service during 2016 and therefore none of them enter rate base or affect rates in 2017. The $5.973 million shown in Table 7-4 is the value of final transfers to Plant in Service during 2016 for the AMI and AMI Radio-Off projects, which do enter rate base on January 1, 2017.

15.0 Reference: Exhibit B-2, pages 47 and 62

15.1 Please explain the 47% increase in Working Capital as between 2016 Approved and 2017 Forecast.

Response:

The increase in Working Capital from $0.697 million in the 2016 Approved to $1.520 million for the 2017 Forecast is primarily due to an increase in the forecast of uncollectible accounts. FBC forecasts this value to be $1.520 million in 2017, based on the 2015 actual value of $1.504 million.

16.0 Reference: Exhibit B-2, page 48

16.1 What was the proportion of customers billed monthly and bi-monthly as of June 2015?

Response:

At the end of June 2015 there were 18,896 monthly billed customers, which is approximately 14% of customers. There were 111,914 bi-monthly customers at that time, which is approximately 86% of customers.

16.2 What was this proportion as of June 2016?

Response:

At the end of June 2016 there were 19,797 monthly billed customers, which is approximately 15% of customers. There were 112,300 bi-monthly customers at that time, which is approximately 85% of customers.

17.0 Reference: Exhibit B-2, page 51

17.1 Please provide the detail derivation of the 2.14% value for 2017 Standby Fee on Undrawn Credit (Table 8-1, lines 12) and explain the increase over the approved 2016 value of 0.16%.

Response:

FBC notes that the 2016 value of 0.16% is the Projected stand-by rate, not the Approved stand-by rate.

There are two factors that are increasing the stand-by rate.

The first is an increase in the amount of the stand-by fee being charged. The stand-by fee is charged on the undrawn portion of FBC's operating credit facility balance at a rate of 0.2%. Since FBC is forecasting an increase in its undrawn operating credit facility balance from $63 million to $118 million, this results in a $127 thousand increase in the stand-by fee from $115 thousand in 2016 to $237 thousand in 2017.

The second is that the stand-by rate is calculated as a percentage of FBC's credit facility balance. FBC's credit facility balance is forecast to decrease from $81.869 million to $11.062 million, which, although not changing the amount of the stand-by fee significantly, does change the percentage from 0.16%[4] to 2.14%[5].

17.2 Please provide the detail derivation of the 3.41% value for 2017 Financing Fees (Table 8-1, lines 14) and explain the increase over the approved 2016 value of 0.43%.

Response:

FBC notes that the 2016 value of 0.43% is the Projected financing fee rate, not the Approved financing fee rate.

The derivation of the 2016 Projected and 2017 Forecast financing fees (Table 8-1, lines 14) are shown in the table below.

[4] $127 thousand divided by $82 million, variance due to rounding.
[5] $237 thousand divided by $11 million, variance due to rounding.

Line #	Description	2016 Projected	2017 Approved	REF
(in Million Dollars)				
1	Financing fee	0.358	0.377	
2	Credit facility balances drawn to finance rate base	82	11	
3	Financing fee rate	0.43%	3.41%	Line 1 / Line 2

While the financing fees costs have not increased significantly from the 2016 Projected of $358 thousand to the 2017 Forecast of $377 thousand, there is an increase in the rate once these fees are converted into a short-term rate. This short-term rate increase is primarily due to lower draws on credit facilities of $11.062 million (a lower denominator) in 2017 as compared to the 2016 projected of $81.869 million.

18.0 Reference: Exhibit B-2, pages 12 and 58

18.1 Please provide schedules setting out the derivation of the Average Customers for 2015 and 2014 (Table 10-3, lines 1 & 2).

<u>Response:</u>

The monthly and average customer counts for 2014 and 2015 are provided below.

	Customer Count	12 Month Average Customers
Jan-14	128,768	
Feb-14	128,786	
Mar-14	129,123	
Apr-14	128,955	
May-14	129,430	
Jun-14	129,328	
Jul-14	129,514	
Aug-14	129,537	
Sep-14	129,547	
Oct-14	130,244	
Nov-14	130,500	
Dec-14	130,572	129,525
Jan-15	130,676	
Feb-15	130,729	
Mar-15	130,830	
Apr-15	130,765	
May-15	130,769	
Jun-15	130,810	
Jul-15	130,846	
Aug-15	130,795	
Sep-15	131,131	
Oct-15	131,209	
Nov-15	131,754	
Dec-15	131,883	131,016

18.2 Please provide a copy of FBC's 2015 Annual Report to the Commission (or reference to a link where it can be found).

Response:

FBC's 2015 Annual Report is filed with the Commission on a confidential basis because it contains information subject to FortisBC's privacy policy and applicable privacy legislation, as well as commercially and financially sensitive information that is not publicly disclosed.

This question references pages 12 and 58 of the Application which relate to customer counts and the calculation of the earnings sharing. FBC has provided the relevant pages from the FBC 2015 Annual Report to the Commission in Attachment 18.2 as these pages do not contain confidential or sensitive information.

19.0 Reference: Exhibit B-2, page 91

19.1 Does FortisBC have a multi-year plan (and associated budget) for complying with the changes to BC's MRS program? If so, please provide.

<u>Response:</u>

FBC has developed a plan in 2016 to complete the transition to the standards adopted in Assessment Report 8 to meet the approved effective dates. Please see FBC's responses to the BCUC IR 1.17 series of questions for cost estimates associated with transitioning to these standards for 2017 and the response to ICG IR 1.5.1 for forecast costs in 2018 and beyond.

20.0 Reference: Exhibit B-2, pages 73-74 and 95

20.1 Please reconcile the reported $5.038 M debit balance for mid-year 2017 for unamortized non-rate base deferred charges (page 95) with the values reported in Schedule 12 (page 74).

<u>Response:</u>

The $5.038 million debit balance for mid-year 2017 non-rate base deferred charges includes the accounts listed in Schedule 12 financed at short term interest (STI) rates, in addition to those accounts listed in Schedule 12.1 that are financed at FBC's Weighted Average Cost of Debt (WACD) or AFUDC or that are non-interest bearing, all as shown below:

	($ millions)	Reference
Deferral Accounts at STI	$ (3.629)	Section 11, Schedule 12, Line 33, Column 8
Financing Costs at STI	(0.115)	Section 11, Schedule 12, Line 35, Column 8
Deferral Accounts at WACD	8.389	Section 11, Schedule 12.1, Line 21, Column 8
Financing Costs at WACD	0.333	Section 11, Schedule 12.1, Line 23, Column 8
Deferral Accounts at AFUDC	0.010	Section 11, Schedule 12.1, Line 28, Column 8
Financing Costs at AFUDC	0.001	Section 11, Schedule 12.1, Line 30, Column 8
Deferral Accounts, Non-Interest Bearing	0.050	Section 11, Schedule 12.1, Line 34, Column 8
Total Non-Rate Base Deferral Accounts	$ 5.038	Section 11, Schedule 12.1, Line 36, Column 8

20.2 Does FortisBC have any approved rate base or non-rate base deferral accounts in addition to those noted in Schedules 11 and 12? If so, please indicate what they are and their current status.

<u>Response:</u>

No, FBC does not have any approved rate base or non-rate base deferral accounts other than those identified in Schedules 11, 12 and 12.1.

21.0 Reference: Exhibit B-2, pages 95-97

21.1 With respect to the Self-Generation Policy Stage II account, please indicate what types of costs related to public consultation will be posted to the account.

<u>Response:</u>

FBC had intended the description of the costs to be for consultation costs with interveners and interested parties, and not general public consultation. To date, FBC has incurred facility rental costs for a workshop on the Self-Generation Policy, which was held on May 25, 2016.

21.2 With respect to the RIB Rate Report account, please indicate what types of costs FortisBC expects will be posted to the account.

<u>Response:</u>

The RIB Rate Report deferral account will include consultant costs for research and COSA analysis, PACA funding, and Commission costs including any applicable BCUC-directed public consultation activities.

22.0 Reference: Exhibit B-2, page 103

22.1 Please provide a revised version of Table 13-1 that includes a column with the "2015 June YTD Results".

Response:

The table below has been revised to include 2015 June YTD Results. These results were previously included in the 2016 Annual Review on pages 109 and 110.

Table 13-1: Approved SQI, Benchmarks and Actual Performance

Performance Measure	Description	Benchmark	Threshold	2015 Results	2015 June YTD Results	2016 June YTD Results
	Safety SQIs					
Emergency Response Time	Percent of calls responded to within two hours	93%	90.6%	92%	91%	98%
All Injury frequency rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	1.64	2.39	2.52	2.86	1.88
	Responsiveness to the Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	78%	72%	76%	75%	77%
Billing Index	Measure of customer bills produced meeting performance criteria	5.0	≤5.0	0.39	0.29	0.48
Meter Reading Accuracy	Number of scheduled meters that were read	97%	94%	96%	97%	98%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	68%	71%	71%	70%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.1	8.1	8.2
Telephone Abandon Rate	Informational indicator – percent of calls abandoned by the customer before speaking to a customer service representative	-	-	2.7%	2.9%	3.3%

Performance Measure	Description	Benchmark	Threshold	2015 Results	2015 June YTD Results	2016 June YTD Results
	Reliability SQIs					
System Average Interruption Duration Index (SAIDI) - Normalized	3 year average of SAIDI (average of cumulative customer outage time)	2.22	2.62	2.15	2.20	2.12
System Average Interruption Frequency Index (SAIFI) - Normalized	3 year average of SAIFI (average customer outage)	1.64	2.50	1.49	1.49	1.52
Generator Forced Outage Rate	Informational indicator – Percent of time a generating unit is removed from service due to component failure or other events.	-	-	0.1%	0.2%	1.6%

23.0 Reference: Exhibit B-2, Appendix D, pages 23-25

23.1 Please confirm that the capital costs included in the evaluation of Option 3 include those forecast to be required in 20-years' time in order to extend the life for 40 years in total.

Response:

FBC confirms that the evaluation of Option 3 for both the NPV and rate impact compared to Options 1 and 2 included the additional capital expenditures that will be required in 20 years in order to extend the life for 40 years. Please refer to Appendix D, page 25, lines 15 to 19 and page 26, footnote 11 where it is stated that the additional capital required is estimated to be approximately $24.444 million in total between 2037 and 2057.

24.0 Reference: Order G-107-15, Reasons for Decision

24.1 With respect to pages 7-9, please provide the current status of FortisBC's 2016 LTERP.

<u>Response:</u>

At the time of the Commission Order G-107-15, FBC was expecting to file its 2016 LTERP by June 30, 2016. FBC requested an extension to this filing date to November 30, 2016 in a letter to the Commission on March 2, 2016. The Commission approved this request on April 1, 2016 pursuant to Order G-43-16. Therefore, FBC is planning to file the 2016 LTERP by November 30, 2016.

24.2 With respect to page 15 and the BCUC's direction as to the information to be provided in future filings on the reduction of theft related losses:

24.2.1 Please indicate where in the current Application this information can be found.

<u>Response:</u>

The information can be found in section 3.5.7.1 of the Application (pages 23-24).

24.2.2 If not included, please address as a part of the information request responses.

<u>Response:</u>

Please refer to the response to BCOAPO IR 1.24.2.1.

24.3 At page 23, FortisBC was directed to "include in its next Annual Review Application a discussion on whether GFOR should be moved from an informational SQI and added to the list of measurable SQIs".

24.3.1 Please indicate where, in the current Application, this direction is addressed.

Response:

The Commission direction referred to in the question was from the Commission's Decision on FBC's Annual Review for 2015 Rates Application, and directed FBC to include the discussion "in its next Annual Review Application." FBC addressed the direction by providing the requested discussion in its Annual Review for 2016 Rates, at pages 120 and 121. As discussed in the referenced portion of FBC's Annual Review for 2016 Rates, FBC's view was that the GFOR should be remain as an informational indicator.

24.3.2 If not included, please address as a part of the information request responses.

Response:

Please refer to the response to BCOAPO IR 1.24.3.1.

Attachment 18.2

FORTISBC INC.

CUSTOMERS, VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 Normalized	2015 Actual	2015 Normalized	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**CUSTOMERS**					
2	Residential	113,431	114,166	114,166	735	
3	Commercial	14,363	14,976	14,976	613	
4	Wholesale	6	6	6	-	
5	Industrial	49	50	50	1	
6	Lighting & Irrigation	2,723	2,685	2,685	(38)	
7	Total	130,572	131,883	131,883	1,311	
8						
9	**ENERGY VOLUME (GWh)**					
10	Residential	1,302	1,252	1,299	(3)	
11	Commercial	864	848	842	(23)	
12	Wholesale	569	581	599	30	
13	Industrial	377	375	370	(7)	
14	Lighting & Irrigation	56	61	62	7	
15	Sales Load	3,166	3,116	3,172	4	
16	Losses	268	268	273	4	
17	Gross Load	3,436	3,384	3,445	9	
18						
19	**REVENUE**					
20	Residential	$ 160,535	$ 163,258	$ 169,417	$ 8,882	
21	Commercial	76,267	79,354	78,772	2,505	
22	Wholesale	42,968	43,959	45,334	2,366	
23	Industrial	30,059	29,837	29,436	(623)	
24	Lighting & Irrigation	6,176	6,968	7,205	1,029	
25	Total	$ 316,005	$ 323,375	$ 330,164	$ 14,159	

FORTISBC INC.

CALCULATION OF EARNINGS SHARING MECHANISM
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

No.	Particulars				Reference
	(1)	(2)	(3)	(4)	(5)
1	Approved Formula O&M	$ 52,984			G-139-14
2					
3	Actual Gross O&M	57,785			Page 21, Line 19, Column 5
4					
5	Less: O&M Tracked Outside of Formula				
6	Pension/OPEB (O&M Portion)	3,925			Page 21, Line 13, Column 5
7	Insurance Premiums	1,334			Page 21, Line 14, Column 5
8	Advanced Metering/Infrastructure Costs/Savings	272			Page 21, Line 15, Column 5
9	2015 MRS Audit	375			Page 21, Line 16, Column 5
10	Total	5,905			Sum of Lines 6 - 9
11					
12	Actual/Projected Base O&M	51,880			Line 3 - Line 10
13					
14	O&M Subject to Sharing	$ (1,104)			Line 12 - Line 1
15			Annual Capital Expenditures		
16			2014	2015	
17					
18	Cumulative Formula Capital Expenditures	$ 84,577	$ 42,193	$ 42,384	G-139-14
19					
20	Cumulative Total Regular Capital Expenditures	98,104	49,061	49,043	Page 4.1, Line 8 Column 2
21					
22	Less: Cumulative Pension and OPEB				
23	Tracked Outside of Formula	10,649	6,396	4,253	Page 4.1, Line 7, Column 3
24					
25	Actual/Projected Base Capital Expenditures	87,456	42,665	44,791	Line 20 - Line 23
26					
27	Actual Base Capital Expenditure Variance	2,879	472	2,407	Line 25 - Line 18
28	Equity Component of Rate Base	40.00%	40.00%	40.00%	G-139-14
29	Approved Return on Equity	9.15%	9.15%	9.15%	G-75-13/G-47-14
30	After Tax Capital Expenditures Subject to Sharing	$ 105	$ 17	$ 88	Product of Lines 27, 28 & 29
31					
32	Tax Rate	26.00%	26.00%	26.00%	
33					
34	Before Tax Capital Expenditures Subject to Sharing	$ 142	$ 23	$ 119	Line 30 ÷ (1 - Line 32)
35					
36	Total Before Tax Sharing Account	(961)			Line 14 + Line 34
37	Sharing Percentage	50.00%			G-139-14
38					
39	Earnings Sharing Before Adjustments	(481)			Line 36 x Line 37
40	Actual Customer Growth Adjustment	1			Table 10-1, Line 17 of Annual Review for 2016 Rates Application
41	Total Earnings Sharing Returned to Customers	$ (481)			Line 39 + Line 40