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October 13, 2015

Via Email
Original via Mail

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)

Multi-Year Performance Based Ratemaking Plan for 2014 through 2019 approved by British Columbia Utilities Commission (Commission) Order G-139-14 (the PBR Plan) – Annual Review for 2016 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, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO) Information Request (IR) No. 1

On September 11, 2015, FBC filed the Application referenced above. In accordance with Commission Order G-139-15 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCOAPO IR No. 1.

Due to a small number of updates to the forecasts in the Application, FBC will be filing an Evidentiary Update prior to the Annual Review Workshop. The Evidentiary Update will include the items listed below:

- Update to incorporate the forecast 2016 reduction in property taxes (see response to BCUC IR 1.16.3);
- Update to the balance in the Capacity and Energy Purchase and Sale Agreement with Powerex Corp. Application deferred account (see response to BCUC IR 1.21.3); and

- Update to 2015 and 2016 revenue to give effect to certain determinations of the Commission in the Stage IV Decision regarding Celgar's Stand-by Billing Demand (Order G-14-15).

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

Sincerely,

FORTISBC INC.

Original signed by: Joyce Martin

For: Diane Roy

Attachments

cc: Commission Secretary
Registered Parties (email only)

1.0 Reference: Exhibit B-1, page 2

1.1 Footnote #4 indicates that for 2016 "the general rate increase will be applied to all components of residential rates". Please indicate the basis/rationale for FortisBC adopting this approach.

Response:

FBC has historically implemented its rate increases by escalating each component of a rate by the approved percentage. This methodology preserves the allocation of the fixed and variable costs represented by the rate components and as determined in the Cost of Service Analysis.

In Order G-3-12 the Commission directed FBC to apply different rate increases to the components of the Residential Conservation Rate, but the Commission was specific that the direction only applied to rate increases for the years 2012 to 2015. This was discussed in FBC's Residential Conservation Rate Information Report dated November 28, 2014 on page 28 where FBC stated, "Starting in 2016 when the RCR pricing principles expire, FBC plans to apply rate increases to the components of the RCR in the generally accepted manner by which all other rates are adjusted (evenly to all of the rate components), in the absence of any alternate direction."

2.0 Reference: Exhibit B-1, page 10

Exhibit B1, Appendix A2, page 6

2.1 Please provide a breakdown of the June 2015 customer count (130,810) by the customer classes set out in Appendix A2.

Response:

The breakdown of the June 2015 customer count by customer class is provided below.

Customers	Jun-15
Residential	113,475
Commercial	14,585
Wholesale	6
Industrial	49
Lighting	1,600
Irrigation	1,095
Total	130,810

3.0 Reference: Exhibit B-1, page 16

Exhibit B1, Appendix A2, page 6

Exhibit B1, Appendix A3, pages 2-3

3.1 Please provide a schedule that sets out:

a. the weather normalized Residential energy use for the years 2012-2014, the

b. the derivation of each year's "before savings UPC", and

c. the derivation forecast "before savings" energy use for 2015 and 2016.

<u>Response:</u>

Please note for the purpose of calculating before savings UPC for the residential class, 2012 and 2013 actual data were adjusted to account for the integration of the City of Kelowna (CoK) residential customers effective March 31, 2013. The following schedule sets out the calculation used to derive the before-savings UPCs including the adjusted amount for the CoK.

	A	B	C = A+B	D	E =C/D
MWh	**Normalized Residential Energy**	**CoK adjustment**	**Total Residential Energy**	**Average Customer Count**	**Normalized Residential UPC**
2012	1,228,709	147,620	1,376,329	112,069	12.28
2013	1,352,945	45,988	1,398,932	112,079	12.48
2014	1,296,452		1,296,452	112,647	11.51

Before savings UPC forecast =Average of E =12.09 MWh

MWh	F	G	H = F* G
	Before Savings UPC Forecast	**Average Customer Count Forecast**	**Forecast Before Savings Residential Energy**
2015	12.09	113,787	1,375,750
2016	12.09	114,950	1,389,816

4.0 Reference: Exhibit B-1, pages 13-14

Exhibit B1, Appendix A2, page 2 & 8

2015-2016 DSM Plan, Appendix A, Table A6-1

4.1 For each of the customer classes, please provide a schedule that breaks down the difference between the 2016 Before-Savings and After-Savings MWh (as reported in Appendix A2) into each of its contributing components (e.g. DSM, AMI, RCR, CIP and rate-driven impacts).

Response:

A schedule that breaks down the difference between the 2016 Before-Savings and After-Savings MWh (as reported in Appendix A2) into each of its contributing components is provided below.

	Year 2016 in MWh without losses	Residential	General Service	Wholesale	Industrial	Lighting	Irrigation	Net
A	Before Savings Energy	1,389,816	886,200	587,585	396,384	14,764	39,695	3,314,444
B	DSM	16,162	14,508	7,636	2,544	1,416	807	43,072
C	AMI	(7,329)						(7,329)
D	CIP	4,169						4,169
E	RCR	8,329						8,329
F	Rate Driven	1,807	1,152	764	515	19	52	4,309
G=A-B-C-D-E-F	After Savings Energy	1,366,678	870,539	579,185	393,326	13,329	38,836	3,261,893

4.2 Please reconcile the forecast 2016 DSM savings set out in Table 3-1 with those set out in Table A6-1 of the 2015-2016 DSM Plan.

Response:

Please refer to the response to BCUC IR 1.5.4.

4.3 Please compare/reconcile the AMI savings reported in Appendix A2 for 2016 with those anticipated in the AMI CPCN application/decision.

Response:

Please refer to the response to BCUC IR 1.5.2.1.

4.4 Please provide the derivation of the CIP and RCR savings for 2016.

Response:

Please refer to the response to BCUC IR 1.5.2.1.

4.5 Please provide, by customer class, the derivation of the "Rate-Driven" savings.

Response:

Please refer to the responses to BCUC IR 1.5.2.1 and BCOAPO IR 1.4.1.

5.0 Reference: Exhibit B-1, pages 22-24

Exhibit B-1, Appendix A2, page 8

5.1 Table 3-4 indicates that for 2016 the total impact of AMI on loss reduction is 5.2 GWh. However, Appendix A2 indicates that the increase on load due to increased metered quantities (which were previously part of losses) is 7 GWh. Please reconcile. Wouldn't the impact of AMI on total losses (as reported in Table 3-4) be greater than the portion of the loss reduction that is "transferred" to metered load, with the balance representing a reduction in overall grow-op use?

<u>Response:</u>

The 5.2 GWh in Table 3-4 is the forecast cumulative loss reduction for 2016 related to the theft load <u>reduction</u> impact of FBC's AMI-based revenue protection program. The 7 GWh referenced from Appendix A2 is the forecast cumulative residential AMI load <u>increase</u> for 2016 resulting from the theft deterrence impact of FBC's AMI-based revenue protection program. These two amounts are separate from one another, and offset each other for a net cumulative load increase for 2016 estimated at 2.2 GWh.

FBC's forecasts remain unchanged from the forecasts used in the AMI decision. The AMI impact on total load (incremental sales less loss reductions due to reduced theft) is anticipated to continue to positively impact FBC's load forecast as incremental sales are forecast to exceed loss reductions as assumed in the AMI decision.

6.0 Reference: Exhibit B-1, page 30

6.1 Please provide a revised version of Table 4-2 that shows the GWh contribution associated with each of the rows towards the Approved 2015 total of 3,499 GWh and the Projected 2015 total of 3,438 GWh. In doing so, please include a rows to account for FortisBC's own generation and, if necessary, any external sales.

Response:

The following table shows the GWh contribution of each source to the Approved 2015 and Projected 2015 with the inclusion of FBC Owned Generation and FBC Surplus Sales.

Line No.	Description	Approved 2015	Projected 2015	Difference
1	FBC Owned Generation	1,622	1613	-9
2	Brilliant	920	920	0
3	BC Hydro PPA	760	582	-178
5	Independent Power Producers	4	6	1
6	Market and Contracted Purchases	192	301	109
7	CPA Balancing Pool	0	36	36
8	Loss Recovery	0	8	8
9	Other Adjustments	0	-6	-6
10	FBC Surplus Sales	0	-23	-23
11	Total	3,499	3,438	-61

6.2 Please provide a revised version of Tables 4-3 that shows the GWh contribution associated with each of the rows towards the Forecast 2016 total of 3,540 GWh. In doing so, please include a rows to account for FortisBC's own generation and, if necessary, any external sales.

Response:

The following table shows the GWh contribution of each source in Table 4-3 to the Projected 2015 and Forecast 2016, with the inclusion of FBC Owned Generation and FBC Surplus Sales.

Line No.	Description	Projected 2015	Forecast 2016	Difference
1	FBC Owned Generation	1613	1589	-24
2	Brilliant	920	914	-6
3	BC Hydro PPA	582	786	204
4	Waneta Expansion	0	0	0
5	Independent Power Producers	6	4	-2
6	Market and Contracted Purchases	301	247	-54
7	CPA Balancing Pool	36	0	-36
8	Loss Recovery	8	0	-8
9	Special and Accounting Adjustments	-6	0	6
10	FBC Surplus Sales	-23	0	23
11	Total	3,438	3,540	102

7.0 Reference: Exhibit B-1, pages 30-31

7.1 With respect to page 31 (lines 5-7), is all of the increase in Market and Contract purchases (2015 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:

Of the 109 GWh increase in Market and Contracted purchases between 2015 Approved and 2015 Projected (as shown in BCOAPO IR 1.6.1), 104.718 GWh was to replace higher cost PPA purchases that would have otherwise been required. The corresponding reduction to PPA energy purchases is equal to $4.660 million. The remaining increase in Market and Contracted purchases, equal to 4.502 GWh, was required to meet peak demand requirements that could not have been met with PPA purchases, due to the PPA contract demand of 200 MW in any hour.

7.2 How much of the reduction in BC Hydro PPA costs and GWh (as between 2015 Projected vs. Approved) was due to being able to replace the PPA energy purchases with cheaper Market and Contract Purchases?

Response:

Please refer to the response to BCOAPO IR 1.7.1.

7.3 Please confirm that the 2016 forecast of Market and Contract purchases is based on contracts that FortisBC has executed and does not include any allowance for real-time purchases. If not, what is the allowance (dollar and GWh) made for real time purchases?

Response:

Confirmed. However, FBC has included a $1.000 million reduction to the forecast BC Hydro expense to account for potential real-time opportunities to displace PPA purchases with lower cost market purchases in 2016. Real-time opportunities are restricted to a maximum of 25 percent of the PPA nominated energy amount, but depending on system conditions, could be less. For example, if loads were 50 GWh lower in a year than forecast, that must be adjusted for as part of the 25 percent PPA flexibility such that the amount of PPA energy that can be displaced by market purchases is also reduced by 50 GWh.

8.0 Reference: Exhibit B-1, page34-35

8.1 Please provide a schedule that sets out the Other Recoveries for 2013 and 2014. If these values are materially higher (i.e. more than 50%) than the 2016 Forecast, please explain the variance.

<u>Response:</u>

As provided in the table below, Other Recoveries for 2013 and 2014 were not more than 50% higher than the 2016 Forecast.

$ millions	2013 Actual	2014 Actual	2016 Forecast	2013 vs 2016 % Variance	2014 vs 2016 % Variance
Other Recoveries	$0.086 million	$0.201 million	$0.142 million	**(39%)**	**42%**

Although not exceeding the 50% threshold, the higher Other Recoveries in 2014 are due to approximately $0.1 million in fees earned for performing one-time improvements to a substation on behalf of a municipality, which is a non-recurring project that was started in 2014 and was completed in 2015.

9.0 Reference: Exhibit B-1, page 37

9.1 Please explain why Advanced Metering Infrastructure Radio-Off O&M costs are deemed to be "outside the formula".

Response:

Advanced Metering Infrastructure Radio-Off O&M costs are part of the AMI project costs which were determined by the Commission to be outside the formula in its decision approving FBC's PBR plan (the PBR Decision).

The PBR Decision reiterated the Company's position regarding AMI costs on page 188: "O&M expenses related to pension and OPEB, insurance expense and the AMI project are to be tracked outside of the PBR formula. FBC points out that the AMI project will be subject to expenditures and savings which will be highly variable during the implementation phase. By tracking these costs outside of PBR any savings will flow directly to the ratepayer."

The Commission agreed with FBC and stated on page 197: "The Commission Panel accepts the FBC proposal, which allows for pension and OPEB, insurance expense premiums (with the exception of first and third party liability insurance expense), and AMI project costs to be tracked outside of the formula." And the Commission stated on page 210 regarding AMI capital, "The Commission Panel accepts that there is a need to accommodate amounts for Pension/OPEB, PCB Compliance (substations) and the AMI project and these are to be tracked outside of the formula."

For background, Commission Order C-7-13 (the AMI Decision) granted FBC a CPCN for the AMI project, subject to certain conditions, including a requirement that FBC file an application for a provision permitting customers to opt out of accepting a wireless transmitting meter. In compliance with Order C-7-13, FBC filed its Radio-Off AMI Meter Option application on August 30, 2013. Order G-220-13 dated December 19, 2013 set out the tariff terms and conditions for the radio-off option. Because the radio-off option is an integral and necessary component of the AMI project, it is treated in the same manner as other AMI costs and benefits under the terms of the PBR Plan as discussed above.

In order to evaluate the costs associated with the radio-off option and to determine whether the radio-off option fees should be adjusted, FBC was directed in Order G-220-13 to track the costs of the radio-off option separately; therefore, FBC shows the net radio-off costs separately from the remainder of the AMI costs.

9.2 If Advanced Metering Infrastructure Radio-Off costs are to be considered as outside the formula, please explain why they should not be subjected to the "exogenous factor" criteria set out in the Commission's PBR Decision (pages 94-95).

<u>Response:</u>

As explained in the response to BCOAPO IR 1.9.1, the AMI costs, including radio-off costs, are CPCN-related costs that were determined to be outside the formula under the terms of the PBR plan as approved by the Commission. As these costs have already been excluded from the O&M and capital formulas from the outset of PBR, there is no need to apply the exogenous factor criteria.

Regardless, the result of treating these items as exogenous factors or as a CPCN is the same, since the result of exogenous factor treatment is a flow-through of the costs. Given that these costs are the direct result of Commission directions and not reflected in the base costs, it is clear that these are the type of costs that should be subject to flow-through in some manner.

10.0 Reference: Exhibit B-1, page 39

10.1 The Application states that the AMI Radio-Off fees are designed so that customers selecting a Radio-Off meter will cover the associated costs. Where are the additional revenues from Radio-Off fees included in the Application and how much are they forecast to be for 2016?

Response:

The radio-off fees are deducted from the radio-off costs and included in O&M as stated on page 39 of the Application "FBC is recording the radio-off costs net of customer fees." Please refer to the response to BCUC IR 1.12.5 for the amount of the revenues from radio-off meter reading fees.

The per-premise (installation) costs are also reported net of customer fees. Please refer to the response to BCUC IR 1.12.6.

10.2 Given that no cost versus revenue information is available, what is the basis for the statement (lines 29-30) that the approved Radio-Off tariffs are expected to be less than costs.

Response:

There is no actual cost and revenue information available for the per-read radio-off fees because radio-off meter reading services commenced in the last week of July, 2015, but FBC has forecast these to the best of its ability. This information is provided in the response to BCUC IR 1.12.5.

FBC has forecast per-premise radio-off fees and costs based on actual year-to-date information, which is provided in the response to BCUC IR 1.12.6.

11.0 Reference: Exhibit B-1, page 41

11.1 Please describe how the one time and ongoing annual costs described in the first paragraph (lines 1-4) relate to the forecast incremental O&M expenses and capital expenditures for MRS described in the second paragraph (lines 5-8).

Response:

The first paragraph provides FBC's initial estimates for the combined O&M and capital, which was provided to BC Hydro as input to Assessment Report 8 for both one time and ongoing costs. The second paragraph provides more recent (still preliminary) capital and O&M estimates, taking into account the Commission's decision.

12.0 Reference: Exhibit B-1, pages 45-46

12.1 Please explain why Advanced Metering Infrastructure Radio-Off Off capital expenditures are deemed to be "outside the formula".

Response:

Please refer to the response to BCOAPO IR 1.9.1.

12.2 If Advanced Metering Infrastructure Radio-Off capital expenditures are to be considered as outside the formula, please explain why they should not be subjected to the "exogenous factor" criteria set out in the Commission's PBR Decision (pages 94-95).

Response:

Please refer to the response to BCOAPO IR 1.9.2.

13.0 Reference: Exhibit B-1, page 47

13.1 Please provide an update on the status of the transmission and distribution system as impacted by wildfires, in terms of both additional work completed/outstanding and estimated to capital spending.

Response:

The 2015 wildfires affected distribution and transmission assets.

Transmission line 43 Line (Oliver to Princeton) had 6 structures damaged from the Wilson Mountain fire on August 14, 2015. The 6 structures were re-built over 8 days. The line was re-energized on August 22, 2015. Additional cross bracing installation will take place in October 2015.

Distribution line Kettle Valley Feeder 1 had 115 structures damaged from the Rock Creek fire on August 14, 2015. The 115 structures were re-built over 15 days. To minimize the outage time to residents a generator was installed from August 15, 2015 to August 22, 2015 in Beaverdell. The line was fully restored August 28, 2015. Remaining work includes additional brushing for danger trees and final re-connections to homes that were destroyed, if necessary.

Distribution line Pine Street Feeder 2 has a minimum of 12-15 structures damaged by the Testalinden fire near Oliver. As of September 30, 2015 the area is still an active fire zone and FBC has not been allowed into the area to review the damage. Remaining work is to assess, design and rebuild the damaged sections of line. The Company expects to be allowed into the area in October 2015.

Completed Work ($000s)

Kettle Valley Feeder 1	$1,668
43 Line	$231

Remaining Work ($000s)

Kettle Valley Feeder 1	$60
43 Line	$20
Pine Street Feeder 2	$1,064

The estimate to completion is $3.043 million.

14.0 Reference: Exhibit B-1, page 48

Exhibit B-1, Section 11, Schedule 2 (line 1)

14.1 Please provide a schedule that contrasts the Approved 2015 Plant In-Service Additions with the current Projected 2015 Plant In-Service Additions by account. Please provide variance explanations for material differences.

<u>Response:</u>

FBC does not have Projected 2015 Plant-In-Service Additions by Account. Under the terms of the PBR Plan, FBC utilizes the 2015 Approved formula capital expenditures that result in the 2015 Plant Additions being added to rate base, which then forms the 2016 opening rate base for ratemaking purposes.

FBC has a 2015 Capital Expenditure Formula and a 2015 Capital Expenditure Projection that it has used to estimate the earnings sharing for 2015, but since the formula amount does not have account level detail, there is no basis to compare the two.

15.0 Reference: Exhibit B-1, page 50

Exhibit B-1, Section 11, Schedule 14

15.1 The Application states that the impact of AMI-Enabled Billing Options on working capital in 2015 will be nil. What is the impact for 2016?

<u>Response:</u>

The impact on working capital in 2016 will depend on the number of customers currently billed on a bi-monthly basis who opt to move to monthly billing. As explained on page 50 of the Application, FBC expects to begin offering the monthly billing option in 2016, but does not have an estimate of the number of customers who may opt for monthly billing.

FBC estimates that a 10 percent increase in the number of residential and commercial customers moving to monthly billing would reduce the working capital requirement by approximately $1 million.

As directed in Order G-169-14, FBC will flow through any working capital benefits to customers as part of the Flow-through deferral account. The benefit will be determined by the change in monthly billed customers at the end of 2016 and included in the true-up of the flow-through deferral account in the subsequent years' revenue requirements calculation.

15.2 What was the split between monthly/bimonthly billing and the associated number of Lag Days attributed to Residential Tariff Revenues:

- Per the Approved 2015 Rates;
- As calculated as of June 2015 (per page 50, lines 8-10); and
- As assumed for purposes of calculating the 2016 Working Capital?

<u>Response:</u>

The information requested is provided in the table below:

Residential Tariff Revenue - Monthly & Bi-Monthly Split & Calculation of Revenue lag	Monthly / Bi-monthly Split		Consumption Lag Monthly	Consumption Lag Bi-monthly	Processing Lag	Clearing Lag Monthly	Clearing Lag Bi-monthly	Total Revenue Lag
	Monthly	Bi-monthly						
	A	B	C	D	E	F	G	A*C+B*D+E+ A*F+B*G
1 Per Approved 2015 Rates	13.4%	86.6%	15.20	30.40	2.00	17.00	22.00	**51.7**
2 Calculated as of June 2015	13.5%	86.5%	15.20	30.40	1.00	17.00	22.00	**50.7**
3 Assumption for calculating 2016 Working Capital	13.5%	86.5%	15.20	30.40	1.00	17.00	22.00	**50.7**

15.3 Does AMI change the proportion of monthly to bimonthly billed commercial customers?

Response:

The AMI implementation itself does not change the frequency of billing for FBC's customers; however, it is expected that the proportion of bi-monthly billed commercial customers will decline once the option of monthly billing is available.

15.4 What was the split between monthly/bimonthly billing and the associated number of Lag Days attributed to Commercial Tariff Revenues:

- Per the Approved 2015 Rates;
- As calculated as of June 2015 (per page 50, lines 8-10); and
- As assumed for purposes of calculating the 2016 Working Capital?

Response:

The information requested is provided in the table below:

Commercial Tariff Revenue - Monthly & Bi-Monthly Split & Calculation of Revenue lag	Monthly / Bi-monthly Split		Consumption Lag Monthly	Consumption Lag Bi-monthly	Processing Lag	Clearing Lag Monthly	Clearing Lag Bi-monthly	Total Revenue Lag
	Monthly	Bi-monthly						
	A	B	C	D	E	F	G	A*C+B*D+E+ A*F+B*G
1 Per Approved 2015 Rates	19.0%	81.0%	15.20	30.40	2.00	17.00	22.00	**50.6**
2 Calculated as of June 2015	18.9%	81.1%	15.20	30.40	1.00	17.00	22.00	**49.6**
3 Assumption for calculating 2016 Working Capital	18.9%	81.1%	15.20	30.40	1.00	17.00	22.00	**49.6**

16.0 Reference: Exhibit B-1, page 52

Preamble: The Application states that the forecasts of Treasury Bills and benchmark Government of Canada Bond interest rates are based on projections made available by Canadian Chartered Banks.

16.1 Which banks forecasts are relied on and what was the date of publication for each of the forecasts used?

Response:

FBC obtained rate forecasts from the following banks: Canadian Imperial Bank of Commerce (CIBC), Royal Bank of Canada (RBC) and Bank of Montreal (BMO). The dates of publication for each of the 3 sources used are as follows:

1) CIBC Interest and Exchange Rate Forecast – June 30, 2015;
2) RBC Financial Market Forecasts – July 8, 2015; and
3) BMO Rates Scenario – July 16, 2015.

For forecast updates, FBC uses the most recent forecasts at the time the Application is prepared with the applicable information from three or more of these sources, and takes an arithmetic average.

16.2 Please provide the each Bank's forecast of the 30 Year GOC and 3-Month T-Bill rates.

Response:

Bank forecast rates from BMO, CIBC, and RBC are provided below:

	2015				2015
30 Year	Q1[1]	Q2[1]	Q3	Q4	Average
BMO	2.15	2.15	2.29	2.41	2.25
CIBC	2.15	2.15	2.50	2.60	2.35
RBC	2.15	2.15	2.50	2.75	2.39

	2016				2016
30 Year	Q1	Q2	Q3	Q4	Average
BMO	2.51	2.56	2.62	2.70	2.60
CIBC	2.50	2.65	2.85	3.05	2.76
RBC	2.95	3.10	3.20	3.30	3.14

1 - Rates reflect actual GOC 30 Year Bond Rates for 1H 2015 as obtained from Bloomberg.

	2015				2015
3 Month T-Bill Rates	Q1[2]	Q2[2]	Q3	Q4	Average
BMO	0.63	0.63	0.44	0.42	0.53
CIBC	0.63	0.63	0.45	0.45	0.54
RBC	0.63	0.63	0.50	0.50	0.56

	2016				2016
3 Month T-Bill Rates	Q1	Q2	Q3	Q4	Average
BMO	0.42	0.42	0.66	0.90	0.60
CIBC	0.45	0.45	0.70	1.00	0.65
RBC	0.55	0.60	0.85	1.40	0.85

2 - Rates reflect actual 3 Month T-Bill Rates for 1H 2015 as obtained from Bloomberg.

16.3 Are more recent forecasts available from any of the Canadian Chartered Banks? If so, please update the response to the previous question.

Response:

The most recent forecasts from the same banks are provided below:

	2015				2015
30 Year	Q1[1]	Q2[1]	Q3[3]	Q4	Average
BMO	2.15	2.15	2.20	2.30	2.20
CIBC	2.15	2.15	2.26	2.35	2.23
RBC	2.15	2.15	2.25	2.45	2.25

	2016				2016
30 Year	Q1	Q2	Q3	Q4	Average
BMO	2.39	2.44	2.51	2.59	2.48
CIBC	2.30	2.30	2.55	2.75	2.48
RBC	2.55	2.65	2.90	3.25	2.84

	2015				2015
3 Month T-Bill Rates	Q1[2]	Q2[2]	Q3[3]	Q4	Average
BMO	0.63	0.63	0.41	0.39	0.52
CIBC	0.63	0.63	0.39	0.45	0.53
RBC	0.63	0.63	0.40	0.40	0.52

	2016				2016
3 Month T-Bill Rates	Q1	Q2	Q3	Q4	Average
BMO	0.39	0.39	0.39	0.39	0.39
CIBC	0.45	0.45	0.55	0.70	0.54
RBC	0.50	0.55	0.60	1.10	0.69

1 - Rates reflect actual GOC 30 Year Bond Rates for 1H 2015 as obtained from Bloomberg.
2 - Rates reflect actual 3 Month T-Bill Rates for 1H 2015 as obtained from Bloomberg.
3 - Where actual rates were available for Q3 we have incorporated them into the average rate.

Updated Report Dates

RBC Financial Market Forecasts - September 22, 2015
BMO Rates Scenario - September 25, 2015
CIBC Interest and Exchange Rate - September 23, 2015

Using the latest forecasts from Canadian Banks would result in an estimated 30 year new issue rate of 4.0% for 2015, and 4.3% for 2016. This results in a decrease in expected issuance rate of 0.10% for 2015, and 0.30% in 2016 from the previous forecast. These changes are within the typical range of 30-year yield variance in a given month, and do not represent a significant change in market outlook. This change in the underlying Government of Canada yield would result in a decrease to the forecast 2016 interest on long-term debt of approximately $63 thousand from the forecast of $36.587 million, as shown on line 1, page 93, Schedule 26, Section 11 of the 2016 Rate Filing, to an updated 2016 long-term debt interest forecast of $36.524 million.

Based on the latest 3-month T-bill forecasts, short term interest rates in 2015 would remain unchanged while 2016 rates would decrease by 0.20%. This change is also within the range of expected variance in a given month, and does not represent a significant change in market outlook. This change in the underlying 3-month T-bill forecasts would result in a decrease to the forecast 2016 interest on short-term debt of approximately $176 thousand from the forecast of $2.331 million, as shown on line 2, page 93, Schedule 26, Section 11 of the 2016 Rate Filing, to an updated 2016 short-term debt interest forecast of $2.155 million.

Combined, the decrease in interest expense of $239 thousand would reduce the rate increase by less than 0.1 percent. Given the rate impact, the fact that any variances will be captured in the Flow-through deferral account, and that the forecasts will continue to change, FBC does not propose to update its financial schedules.

17.0 Reference: Exhibit B-1, pages 55-56

17.1 Please explain the significant increases in assessed values for distribution (45.9%) and transmission (13.5%) lines.

<u>Response:</u>

Please refer to the response to BCUC IR 1.16.3.

17.2 Please provide greater details regarding the increase in legislated transmission and distribution line (tax) rates per page 55, lines 17-19.

<u>Response:</u>

Please refer to the response to BCUC IR 1.16.3.

18.0 Reference: Exhibit B-1, page 95

18.1 Were all of the projected costs associated with repairing the damage cause by wildfires treated as capital expenditures?

Response:

Yes.

19.0 Reference: Exhibit B-1, page 101-102

19.1 In FortisBC circumstance, when assets reach the end of life do net salvage costs typically arise because:

a. The existing assets are being retired and the site will no longer be used by FortisBC, or

b. The existing assets are being removed and replaced by new assets which will continue to serve customers?

Response:

When assets reach the end of life, the net salvage costs arise primarily from existing assets being retired or removed and replaced by new assets which will continue to serve customers, as outlined in scenario (b).

19.2 If the response to the previous question is (b), why shouldn't net salvage costs be viewed as part of the cost of the new/replacement facilities and be depreciated accordingly?

Response:

The question describes a way to treat net salvage costs that is similar to how costs of removal are treated currently by FBC through to the end of 2015. However, this method pushes the recovery of net salvage costs out to future periods and theoretically results in tomorrow's customers paying for part of the cost of service of the asset being used to serve today's customers.

The way net salvage costs are being proposed to be collected in this Application is better suited to matching the cost of service for existing customers, where the costs of building an asset as well as the cost of removing that asset are collected over its estimated useful life from the customers who receive the benefit of that asset. In other words, this method recognizes that net salvage is a cost of providing service and should be recovered from customers over the useful life of the asset. The inclusion of a provision for net salvage value in depreciation rates is also consistent with the BCUC Uniform System of Accounts (Account 303).

19.3 The application states that the proposed approach is the one recommended by Gannet Fleming. Please indicate any other Canadian electric utilities that Gannet Fleming has completed Depreciation Studies for in the last three years and, in each case where applicable, indicate what advice/recommendations Gannet Fleming provided regarding the treatment of net salvage costs?

Response:

Gannett Fleming's recommended approach to collecting costs of removal is to collect net salvage over the lives of the assets through depreciation rates. However, there are circumstances where utility or regulator specific requirements would necessitate a change from that recommendation. Examples of such requirements could be the utility's interpretation of their relevant accounting standards, whether asset retirement obligations are recognized, or whether it is cost prohibitive to include the recovery in rates at the point in time of recommendation.

The following table provides a list of other Canadian electric utilities that Gannett Fleming has completed depreciation studies for in the last three years, and the recommendation provided regarding the treatment of net salvage costs.

Electric Utility	Year of Study	Gannett Fleming Recommendation
ENMAX Power Corporation	2012	Recover on a traditional basis (collect a net salvage provision through rates).
ATCO Electric	2014	Recover on a traditional basis (collect a net salvage provision through rates).
Manitoba Hydro Inc.	2014	Not to recover net salvage. This was a change in recommendation from the previously employed traditional approach due to Manitoba Hydro's decision to adopt IFRS which was interpreted as not allowing the recovery of a net salvage provision in depreciation rates.
Newfoundland Power	2015	Recover on a traditional basis (collect a net salvage provision through rates).
New Brunswick Power	2012	Not to recover net salvage.

19.4 The text on page 101 states that FBC's existing practice (re net salvage costs) is widely used and accepted. Then on page 102 the text states that the proposed practice is generally followed by other utilities across Canada. Please reconcile these two statements and provide a summary of the practices of other Canadian electric utilities (particularly integrated utilities with hydro generation).

Response:

There is varying practice in collecting net salvage.

In addition to the list of utilities discussed in response to BCOAPO 1.19.3, AltaLink and Maritime Electric collect net salvage over the useful lives of the assets, while SaskPower and Ontario Power Generation do not. The method proposed by FBC is followed by other utilities in Canada; however FBC's past practice is still widely used and accepted. In other words, both methodologies are utilized throughout Canada.

Although there are several ways to manage the collection of costs of removal, and evidence of each being used by other utilities in Canada, the reasons why FBC is proposing to collect net salvage over the useful lives of the assets are outlined below:

- When an asset is placed in service, there is an associated cost of removal and that cost should be collected over the life of the asset, similar to the recovery of the capital cost. This method appropriately allows for the full cost of service of an asset to be collected from the customers who receive the benefit of that asset.
- Delaying collection until removal costs are incurred at the end of an asset's useful life results in a charge to customers for assets from which they did not receive service and, as a result of the delay in recovery, also results in higher revenue requirements related to net salvage.
- Allocating net salvage costs over the life of the related asset is in accordance with authoritative texts and most Uniform Systems of Accounting including those published in BC, Alberta, Ontario, the National Energy Board of Canada and the Federal Energy Regulatory Commission (FERC).
- The FERC Uniform System of Accounts specifically requires service value to be recovered through depreciation, and goes on to define service value as "the difference between the original cost and the net salvage value of the utility plant". In other words, the service value of an asset must be accrued during the life of the asset and since net salvage is a part of the service value, it must also be accrued during the life of the related asset in order to comply with the FERC Uniform System of Accounts.

- Other methods, such as expensing costs of removal when incurred or including costs of removal of retired plant as part of future capital costs of replacement plant, may be required for certain circumstances where utility or regulator specific requirements would necessitate a change from the recommended approach, however they are in contrast to the FERC published and long-followed net salvage concepts from regulatory jurisdictions throughout North America.
- Collecting net salvage over the lives of the assets aligns with FEI's policy for collecting costs of removal.

20.0 Reference: Exhibit B-1, page 110-111

20.1 Is there more recent information available that would indicate the Emergency Response Time for 2015 that includes the summer period when the wildfires were occurring? If so, please update Table 13-2.

<u>Response:</u>

The updated Table 13-2 below indicates the Emergency Response Time including July and August when the wildfires were occurring. During June through August, there were higher than normal levels of trouble calls to respond to, which did have an impact on Emergency Response Time. However, in September the number of trouble calls was at annual average levels and FBC's monthly response time was 95% within 2 hours of the call. Overall results up to September 2015 YTD are 91% for Emergency Response Time.

Table 13-2: Historical Emergency Response Time

2009	2010	2011	2012	2013	2014	2015 Sept YTD
92%	95%	92%	91%	94%	91%	91%

21.0 Reference: Exhibit B-1, page 114

21.1 Based on the results of each of the Billing Sub-Measures please provide the calculation of the 0.29 result for the 1st half of 2015.

<u>Response:</u>

The table below illustrates the YTD Billing Index sub-measures calculation for the first half of 2015.

Billing sub-measure	**Precent Achieved (PA)**	**Formula**		**Result**
Billing accuracy (percent of bills without a production issue based on input data).	100%	IF [PA ≥ 99.9%, 5000 * (1 - PA), 100 * (1.05 - PA)]	=5000*(1-1)	0
Billing timeliness (percent of invoices delivered to Canada Post within two days of file creation); and	100%	(100%-PA)*100	=(100%-100%)*100	0
Billing completion (percent of accounts billed within two days of the billing due date);	99.10%	(100%-PA)*100	=(100%-99.1%)*100	0.87
Billing Service Quality Indicator		(Accuracy PA + Timeliness PA + Completion PA) / 3	=(0 + 0 + 0.87) / 3	0.29