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October 13, 2015

Via Email
Original via Mail

British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Inc. (FBC)

Multi-Year Performance Based Ratemaking Plan for 2014 through 2019 approved by British Columbia Utilities Commission (Commission or BCUC) Order G-139-14 (the PBR Plan) – Annual Review for 2016 Rates (the Application)

Response to BCUC 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 files the attached response to BCUC 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: Registered Parties (email only)

A. LOAD FORECAST

1.0 Reference: ANNUAL DEMAND FORECAST

Exhibit B-1, Section 3.5 p, 16, Section 4.5, p. 30, Appendix A2, Sections 4, 5, pp. 8–12

Historical accuracy

FortisBC Inc. (FBC) includes load forecast tables in Appendix A2, and gross load estimates in section 4.5 of the Application (review of 2015 power purchase expense).

1.1 Please confirm that actual data in the tables included in section 4 and 5 of Appendix A2 (pages 8 to 12) is weather normalized. If not confirmed, please reproduce the tables using weather normalized data.

Response:

As discussed in section 1.1 in Appendix A3, FBC only normalizes residential and wholesale rate classes as these are the rate classes that show statistically significant relationships to weather.

The load data for the residential and wholesale rate classes in the tables included in section 4 and 5 of Appendix A2 (pages 8 to 12) are weather normalized, except for the “Actual” section of the table in section 5.2 (p. 10). Table 5.2 is reproduced below using normalized data.

Table 5.2 Normalized - Load Variance[1]

Energy (GWh)	2009	2010	2011	2012	2013	2014
Normalized						
Residential	1,239	1,242	1,249	1,229	1,274	1,296
Commercial	675	660	657	681	725	866
Wholesale	908	895	910	899	904	567
Industrial	216	234	271	291	291	381
Lighting	13	14	13	13	13	16
Irrigation	49	40	40	38	40	40
Net	3,100	3,085	3,140	3,151	3,248	3,166
Gross	3,416	3,369	3,447	3,422	3,526	3,436
Forecast						
Residential	1,222	1,248	1,261	1,264	1,276	1,402
Commercial	678	682	671	696	709	813
Wholesale	921	915	940	926	935	581
Industrial	224	291	233	250	255	389
Lighting	14	15	12	14	14	13
Irrigation	48	50	45	44	43	42
Net	3,107	3,199	3,162	3,193	3,233	3,240
Gross	3,410	3,509	3,472	3,502	3,543	3,519
Variance (GWh)						
Residential	17	(6)	(12)	(35)	(3)	(106)
Commercial	(3)	(22)	(14)	(16)	16	53
Wholesale	(13)	(20)	(30)	(27)	(31)	(14)
Industrial	(8)	(57)	38	41	36	(9)
Lighting	(1)	(1)	1	(0)	(0)	3
Irrigation	1	(10)	(4)	(6)	(3)	(2)
Net	(7)	(114)	(22)	(43)	15	(75)
Gross	6	(140)	(25)	(81)	(17)	(83)
Variance (%)						
Residential	1.4%	-0.5%	-1.0%	-2.9%	-0.2%	-8.2%
Commercial	-0.4%	-3.4%	-2.1%	-2.3%	2.3%	6.1%
Wholesale	-1.4%	-2.2%	-3.4%	-3.0%	-3.4%	-2.5%
Industrial	-3.8%	-24.5%	13.9%	14.1%	12.4%	-2.2%
Lighting	-5.3%	-3.6%	10.4%	-3.5%	-1.5%	18.2%
Irrigation	2.0%	-23.8%	-10.8%	-14.9%	-8.7%	-4.9%
Net	-0.2%	-3.7%	-0.7%	-1.4%	0.5%	-2.4%
Gross	0.2%	-4.2%	-0.7%	-2.4%	-0.5%	-2.4%

[1] Table 5-2 aggregates the individual customers of the former City of Kelowna electric utility, which was integrated with FBC on March 31, 2013, into a single wholesale customer for the entire year 2013. This is necessary in order to compare forecast with actual loads, as the 2013 forecast had been prepared prior to the CoK integration.

1.2 Please explain why 2013 actual total direct customer count in Table 5.1 of Appendix A2 (page 9) does not agree with data in Table 5.3 (page 12).

Response:

The difference between the two tables is limited to 2013 and is the result of timing in the recognition of the integration of the City of Kelowna (CoK) electric utility, which occurred on March 31, 2013. Table 5.3 reports the actual year end direct customers by class, reflecting the migration of customers from the CoK. FBC's direct customer count as of December 31, 2013 was 128,318, compared to 113,766 customers as shown in Table 5.1.

Table 5.1 was created for the purpose of validating the customer count forecast. Since the 2013 forecast was made in late 2011 without any prior knowledge the CoK integration, a comparison of actual to forecast requires the exclusion of individual CoK customers from the 2013 year-end counts. The City of Kelowna is shown as a single wholesale customer in Table 5.1.

1.3 For each customer class and the FBC total (before losses), please complete the following table. Refer to source references in Appendix A2:

Residential	2012	2013	2014	2015S	2016F
Forecast normalized use per customer (calculated using forecast data from Tables 5.1 and 5.2 for 2012-2014, and Table 5.3 for 2015 and 2016)					
Actual normalized use per customer (calculated using actual data from Table 5.1 and 5.2 for 2012 to 2014).					

Response:

Please see the table below. The "Forecast" and "Actual" rows in the table contain the forecast and actual UPC data calculated using the data from Tables 5.1, 5.2, and 5.3, as requested. FBC note that this calculation is arithmetical ($UPC_t = Load_t/(0.5*(Count_{t-1} + Count_t)$ for year t) and does not reflect how the average customer usage is calculated in the existing forecast methodology presented in Section 3.5.1.1 of Exhibit B-1-1 because only residential UPC is forecast directly.

	2012	2013	2014	2015S	2016F
	(MWh per customer)				
Residential					
Forecast	12.76	12.88	13.21	11.98	11.89
Actual	12.41	12.86	12.21		
Commercial					
Forecast	59.67	59.36	61.47	59.43	58.67
Actual	58.33	60.72	65.49		
Wholesale					
Forecast	132,254	133,624	89,424	95,409	96,531
Actual	128,424	129,207	87,250		
Industrial					
Forecast	6,662	6,543	8,851	7,910	8,027
Actual	7,754	7,466	8,657		
Irrigation					
Forecast	40.02	39.44	38.17	35.62	35.21
Actual	34.83	36.29	36.39		
Lighting					
Forecast	7.88	8.09	7.84	8.79	8.23
Actual	7.62	7.98	9.59		
Net Load					
Forecast	28.11	28.40	26.52	24.71	24.61
Actual	27.74	28.53	25.91		

Due to the adjustments in Tables 5.1 and 5.2 for the timing of the CoK integration, the UPC values shown above do not agree to information provided in responses to other IRs.

1.4 Where use-per-customer (UPC) results for any customer class show that FBC's forecasting methodology tends to result in UPC forecasts that are generally higher or lower than actual normalized results, please identify the customer class and explain whether FBC's load forecasting methodology for that customer class should be reviewed/updated.

Response:

The residential load class is the only class where the UPC is forecast and then multiplied with the forecast of customer counts to obtain the load forecast, and for this customer class, for the three years shown, the forecasts have been higher than actual. All other load classes are forecast without using a UPC forecast and therefore FBC is unable to comment on the UPC variances for those rate classes.

FBC does not believe the load forecasting methodology for the residential customer class needs to be reviewed at this time. The methodology to forecast the residential before-savings UPC remains consistent with what has been approved as part of the Load Forecast Technical Committee (LFTC) that took place in 2011[2], which is to take the average of the most recent three years' normalized UPCs. The Company will keep monitoring the 2015 and future load forecast performance for this and all rate classes.

1.5 Please explain the effect on FBC 2016 rates and rates for subsequent years of a +/- 3 percent over / under-forecast in 2016 of the (i) gross load forecast; (ii) winter system peak and (iii) summer system peak.

Response:

There would be no effect on FBC's 2016 rates of an over- or under-forecast in system load, since rates would already have been set using the approved forecast. A change in the actual load/peak from forecast would affect 2017 rates through the impact on power supply costs and on customer revenues which would be captured in the Flow-through deferral account. The effect on FBC's rates in 2017 based on a +/- 3 percent over- or under-forecast of gross load and peak loads in 2016 is estimated to be approximately +/- 1.2 percent.

FBC estimated the rate impacts by assuming the change in forecast to apply equally to all customer classes but notes that an aggregate variance of +/- 3 percent is highly unlikely to be distributed in this manner. While the impact on power supply costs is determined at the aggregate level, revenue is determined at the customer class level, and the accuracy of the revenue calculations is lower than would be the case if the same gross load were to result from logical changes postulated to the inputs of the load forecast methodology by customer class.

1.6 Please state if the 2015 Seed Year (2015S) forecast incorporates any 2015 actual data. If yes, please state the months of 2015 for which actual data is used in the 2015S forecast.

[2] Exhibit B-16, FBC 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan

Response:

No. the 2015 Seed Year (2015S) forecast does not incorporate any 2015 actual data. As defined on page 13 of the Application, the Seed Year forecast is based on the latest actual full year of data available. For the 2016 forecast, the Seed Year is 2015 and the latest available full year of data is for 2014.

1.6.1 If no 2015 actuals are included in the seed year, please update Table 3-3 in the Application to include (i) actual data for 2015 for the months available and (ii) restate 2016 forecast data based on the updated 2015S results.

Response:

FBC has not produced the information as requested because finalized 2015 actual data is not available and will not be available until the end of the first quarter of 2016. Consistent with past practice the FBC load forecast is developed only with finalized year end data. Furthermore, FBC requires the full year of data in order to validate it, including the review of, and potential adjustments to unbilled energy; for this reason mid year data is not used in forecasting.

1.6.2 Please explain whether the use of the most recent actual data could improve the precision of the forecast.

Response:

As noted in the response to BCUC IR 1.1.6.1, partial year data is not validated and cannot be used in forecasting until the full year's data us available.

1.7 Please provide a side by side comparison of (i) the normalized 2015 gross load by customer class approved in the annual review for FBC 2015 rates (totaling 3,499 GWh per Table 4-2 of the Application), (ii) the projected normalized 2015S gross load by customer class (totaling 3,517 GWh per Table 3.3 of the

Application) and (iii) the projected 2015 gross load by customer class (totaling 3,438 GWh per Table 4-2 of the Application). Please explain any significant differences.

Response:

A side by side comparison as per the request is provided below.

	2015 Rates	2016 Rates	
	Table 4-2	Table 3-3	Table 4-2
Energy (GWh)	2015F	2015S	2015P
Residential	1,397	1,363	1,295
Commercial	808	862	857
Wholesale	593	572	574
Industrial	371	388	379
Lighting	13	14	15
Irrigation	40	39	48
Net Load	3,224	3,238	3,168
Losses	275	279	270
Gross Load	3,499	3,517	3,438

On aggregate the 2015 Seed is 0.5% higher than the 2015 Approved forecast. As the forecast methods are purely mathematical any differences are due to differences in the input data used for the two forecasts. When the forecast was prepared for the Annual Review for 2015 Rates, 2014 actual data was not yet available. The 2015 Seed forecast for the Annual Review for 2016 Rates was prepared after the 2014 Actual data became available. At the load class level, the most significant change is in the Commercial forecast, with an approximate 6.7 percent increase. This was largely due to the 2014 Actual load being higher than forecast for the Commercial rate class and an updated higher GDP growth rate for 2015 by the CBOC. Changes in the Wholesale and Industrial class are in accordance with the customers' own forecasts, with the increase in the Industrial rate class offsetting the decrease in the Wholesale rate class. Changes in the Irrigation and Lighting classes are immaterial.

The 2015 Projection value in Table 4-2 contains Actuals to June 2015 which have not been validated or normalized. Validation of load data is performed only after year-end, when the full 2015 load data is available, therefore FBC has not undertaken an analysis of the variances from either the 2015 Forecast or the 2015 Seed.

2.0 Reference: ANNUAL DEMAND FORECAST

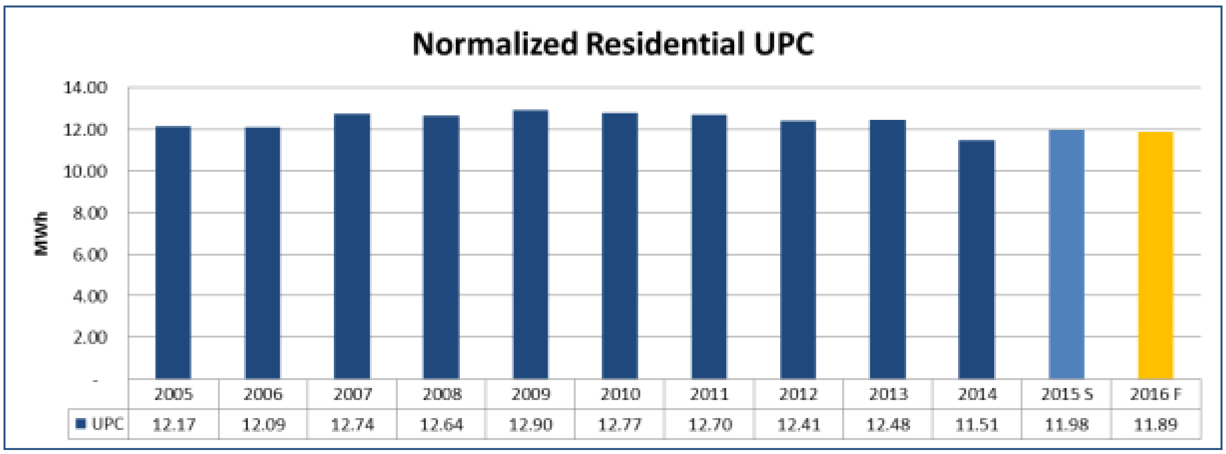
Exhibit B-1, Appendix A2, Section 3, p. 7, Section 5.3, pp. 11, 12

Residential, commercial, industrial

2.1 Please present the data in Table 3 of Appendix A2 (residential normalized UPC) in graphical form and explain the trend over time.

<u>Response:</u>

As a result of major step changes from the Princeton and City of Kelowna integration events (2007 and 2013 respectively), it is not possible to gauge a true trend from the historical data. However as the chart below shows, the residential UPC has been fairly consistent over the time frame.



2.1.1 Please explain the decrease in residential UPC for 2014. Does FBC consider that the 2014 UPC result would be a more accurate starting point for the 2015S and 2016 forecast than the average of the previous three years? Please explain.

<u>Response:</u>

FBC can not definitively explain the 2014 decrease in residential UPC. Any change in residential UPC in a given year is a result of many factors that may be both compounding and offsetting. For example, additional conservation due to RCR might reduce the load but this may be offset by an increase in the number of appliances used in a home. FBC is unable to pinpoint the source of the decrease in the residential UPC in 2014 due to the complexity involved.

For any given year, input data will exhibit some degree of variability. FBC believes the current approach of calculating the three year average of historical UPCs as a proxy for the future before savings UPC is appropriate. By averaging the most recent data, annual fluctuations can be minimized and “smoothed” out. A smoothing technique such as averaging is a common and well established practice to minimize year over year fluctuations. Additionally FBC does not believe it is appropriate or possible to consistently speculate on which recent years may or may not be significant. As a result FBC does not add or remove years from the three year average.

Table 5.3 (Growth Year Over Year) in Appendix A2 shows annual industrial customer growth from 2010 to 2014 (excluding the 21 percent increase in 2013) ranging from 3 percent to 8 percent. The same table also shows that FBC is forecasting annual Industrial customer growth to be 0 percent in both 2015S and 2016F.

2.2 How does FBC’s industrial load forecast methodology identify potential new customers?

Response:

Consistent with past practice, FBC assumes no new industrial customers in the current forecast unless there is a confirmed commitment from an industrial customer. The lead time for new industrial customers is much longer than the lead time for the typical residential and commercial customer, and FBC staff work with industrial customers well in advance of the date they are added to the system.

Given the significant impact and variability in demand from individual customers in the industrial load class, the industrial addition forecast cannot be reliably undertaken through a forecasting process based on historical additions such as that used to forecast commercial customer accounts. If FBC were to forecast the addition of one or more new industrial customers in the absence of confirmed commitments, it would be challenging to predict the load of these individual customers. Furthermore, an error in either the count of new customers or the load associated with those customers could significantly increase the forecast variance for the Industrial class.

2.2.1 Please explain why FBC's assumption of no new industrial customers in 2015S and 2016F is preferable to alternative approaches, such as growth rate in line with historical trends or the provincial GDP estimate.

Response:

Please refer to the response to BCUC IR 1.2.2.

2.2.2 Please provide, by industrial rate class, the number of industrial customers, and change in the number of industrial customers, for each year for the past 10 years.

Response:

The number of industrial customers, and change in the number of industrial customers, for each year for the past 10 years is provided below. Year over year changes are relatively small with the exception of the customer count changes in year 2013 due to the integration of former City of Kelowna customers resulting from FBC's purchase of the City of Kelowna utility assets.

Year	Rate Class ID30	Year to year change	Rate Class ID31	Year to year change	Rate Class ID32	Year to year change	Rate Class ID33	Year to year change	Year end Total	Year to year change
2004	35		5		0		0	0	40	
2005	34	-1	5	0	0	0	0	0	39	-1
2006	32	-2	4	-1	0	0	1	1	37	-2
2007	33	1	4	0	0	0	1	0	38	1
2008	32	-2	3	-1	0	0	1	0	36	-2
2009	29	-3	3	0	0	0	1	0	33	-3
2010	32	3	3	0	0	0	1	0	36	3
2011	35	3	4	1	0	0	0	-1	39	3
2012	35	0	4	0	0	0	0	0	39	0
2013	43	8	4	0	0	0	0	0	47	8
2014	44	1	4	0	1	1	0	0	49	2

Excluding the CoK integration, the net change in industrial customers over ten years is one.

3.0 Reference: ANNUAL DEMAND FORECAST

Exhibit B-1, Appendix A2, Section 5, pp. 9–12

Lighting, irrigation, total net energy before losses

In Table 5.1 and Table 5.2 of Appendix A2 to the Application, FBC shows that in 2014 the number of lighting customers was over-forecast by 7.5 percent, and yet under-forecast by 18.2 percent in GWh.

Table 5.3 of Appendix A2 to the Application shows total annual net energy (before losses) in 2014 (3,166 GWh) increasing by 0.8 percent over the previous three years (2011 of 3,140 GWh). This table also shows a forecast increase in total annual net energy (before losses) of 3 percent from 2014 to 2016F (3,166 GWh compared to 3,262 GWh).

3.1 Please provide a table showing actual lighting UPC for each year from 2012 to 2014 and forecast from 2015S to 2016F. Please explain whether the forecast lighting 2016 UPC is reflective of any change in trend over time.

Response:

Lighting UPC has been calculated below to respond to this IR as energy divided by average customers. Based on this calculation, FBC does not see a discernable trend over time.

Lighting	Energy (MWh)	Average Customer	UPC (MWh)
2012	13,487	1,771	7.6
2013	13,479	1,692	8.0
2014	15,633	1,632	9.6
2015S	14,248	1,620	8.8
2016F	13,329	1,620	8.2

UPC is a good proxy to represent an average usage for a rate class that is relatively homogeneous. As such it is typically used for the residential rate class. It is often not representative for load classes having a large degree of heterogeneity like the street lighting class, in which customers differ in the number of lights as well as the types of lights installed.

3.2 Please explain why FBC forecasts a 3 percent increase in net energy from 2014 to 2016F, when the increase in net energy from 2011 to 2014 was only 0.8 percent.

Response:

Each load class uses methods that are appropriate for forecasting demand in that load class. These methods vary, as do the data inputs they rely on. The aggregate forecast is then the sum of the load class forecasts. As a result the average growth from 2011 to 2014 on the total net load may be not reflective of the future growth on the total net load, which is the aggregate from each rate class forecast.

4.0 Reference: ANNUAL DEMAND FORECAST

Exhibit B-1, Section 3.5.7, pp. 23, 24, Appendix A2, Section 5.3, p. 11

Losses, Advanced Metering Infrastructure (AMI)

Table 3-4 of the Application includes before AMI losses as a percentage of gross load. FBC states on page 23 of the Application that the number of theft sites identified annually since 2012 has decreased from 19 to 3 between 2012 and 2014.

4.1 Please explain how FBC arrived at the actual 2012–2014 GWh system losses in Table 3-4 of the Application. For example, does this represent plant gate meter readings less customer meter readings?

Response:

The loss rates in Table 3-4 are calculated as losses (gross load less net load) divided by gross load. The gross load is the sum of FBC generation plus energy purchases and is metered directly at the point of entry into the FBC system. Net Load is the sales load (from customer meter readings) adjusted for unbilled load (consumption used but not read at month end due to the manual meter reading schedule).

4.1.1 How accurate does FBC consider the 2012–2014 system losses as a percentage of gross load provided in Table 3-4 to be (example, within +/- X percent)?

Response:

FBC believes that the current method of estimating losses is reasonably accurate, but cannot quantify the accuracy with certainty. In order to accurately determine losses, both the gross load and billed load need to be measured at the same time. The unbilled load adjustment referred to in the response to BCUC IR 1.4.1 represents FBC's best effort at attaining comparable gross load and consumption. Post-AMI implementation, the timing differences between the gross load and consumption meter readings will be largely eliminated (with the exception of radio-off and meters which for economic reasons are not connected wirelessly). Only after AMI has been in place for at least a full year will FBC be able to determine the relative accuracy of pre- and post-AMI loss estimates.

4.1.1.1 Is this level of accuracy expected to improve significantly as a result of AMI and if so, by how much?

Response:

Please refer to the response to BCUC IR 1.4.1.1.

4.2 Using data in Table 5.3 of Appendix A2 to the Application, please provide in table form normalized losses as a percentage of gross load for each year of 2009 to 2014 (actual), 2015S and 2016F.

Response:

Please see the following table:

Year	After Savings Loss (%)
2009	9.22%
2010	8.43%
2011	8.91%
2012	7.92%
2013	7.95%
2014	7.86%
2015	7.93%
2016	7.85%

4.3 Please provide a table comparing, for 2012 to 2016, (i) normalized system losses as a percentage of gross load as calculated above from Table 5.3 of Appendix A2 to the Application and (ii) the normalized system losses as a percentage of gross load for those years provided in Table 3-4 of the Application. Please explain any differences.

Response:

Table 3-4 is based on Before –Savings Gross load whereas Table 5.3 of Appendix A2 is based on After-Savings Gross load. Any differences arise due to this distinction.

The table requested is provided below for the purpose of answering this IR. Because the customer savings are embedded in historical data, before-savings and after-savings losses are the same in 2012 to 2014.

Loss (%)	**Before Savings**	**After Savings Loss**
	Table 3-4	Table 5.3 of Appendix A2
2012 Actual	7.92%	7.92%
2013 Actual	7.95%	7.95%
2014 Actual	7.86%	7.86%
2015 Seed	8.00%	7.93%
2016 Forecast	8.00%	7.85%

4.3.1 Please explain how FBC arrived at the 8 percent losses estimate for 2015 and 2018 in Table 3-4 of the Application. Is this the most accurate estimate available for FBC?

Response:

The 8 percent system loss rates for 2015 – 2018 are the estimates in the absence of AMI benefits. The AMI loss reductions further reduce the gross rates to be under 8 percent. The use of 8 percent was accepted in the PBR proceeding and, as shown in the following table, exhibits a low variance compared to the actual losses during the last three years. FBC does not believe that the forecast method needs to be changed and continues to monitor actual losses to ensure the appropriateness of its forecast method.

	Forecast	Estimated Actual	Variance
2012	8.50%	7.92%	-0.58%
2013	7.96%	7.95%	-0.01%
2014	7.91%	7.86%	-0.05%

4.4 Please update Table 3-4 of the Application by replacing 'before AMI' normalized forecast losses for 2015S and 2016F with forecast losses for those years from Table 5.3 of Appendix A2 to the Application, and keeping 2017–2019 percentage consistent with the 2016 forecast percentage losses in Table 5.3. If this revised table is used to evaluate AMI performance, does FBC still consider that it will be able to achieve the AMI related losses reduction projected in the AMI Certificate of Public Convenience and Necessity? Please explain.

Response:

FBC clarifies that Table 3-4 is System Losses before savings and that the losses in Table 5.3 are after savings and after AMI loss reduction. Therefore, subtracting the AMI loss reduction benefits in Table 3-4 from the losses in Table 5.3 as requested would result in double counting the AMI loss reduction benefits. Given this clarification, FBC has not provided the requested update to Table 3-4.

4.4.1 Please explain the significant reduction in the number of theft sites identified annually since 2012.

Response:

Although FBC is unable to conclusively explain the reasons behind the significant reduction in the number of theft sites identified for 2012-2014, FBC believes that the reduction is likely due in part to the deterrent impact associated with the deployment of both FBC's and BC Hydro's respective AMI/SMI projects as discussed in section 3.5.7.1 of Exhibit B-1, as well as due to the current uncertainty around what federal regulations will ultimately apply to the production and distribution of medical marijuana. FBC believes there are a number of high load sites active in FBC's service territory that do not possess a valid production license (either under the former *Marihuana Medical Access Regulations* (MMAR) or the current *Marihuana for Medical Purposes Regulations* (MMPR)), yet are not being subject to enforcement activity until further clarity is provided by the Court regarding the manner in which production and distribution of marijuana for medical purposes would be permitted. It is logical to expect that these high load sites who do not possess a valid production license will continue to pay for electricity as long as enforcement activity remains muted.

5.0 Reference: ANNUAL DEMAND FORECAST

Exhibit B-1, Section 3.3, pp. 13–14, Appendix A2, Table 4.3, p. 8

DSM and other customer savings

5.1 Has there been any change in methodology in the calculation of demand side management (DSM) and other customer savings from the Annual Review for 2015 Rates? If yes, please describe.

Response:

The response to BCUC IR 1.5.2 notes a correction to a calculation of the AMI impact, and the RCR forecast has been updated as described in the response to BCUC IR 1.5.2.1. There have been no other changes to the methodologies for these savings.

5.2 For each category of 'DSM and other customer savings' (AMI recovered sales, Customer Information Portal, Residential Conservation Rate, Rate driven, and DSM), please provide in table form the 2015 forecast from the 2015 Performance Based Ratemaking (PBR) Annual Review, and the 2015S and 2016F from this Application. Please explain any differences +/- 10 percent.

Response:

Please note that the "other savings" amount included in the Annual Review for 2015 Rates Appendix A4 is inclusive of losses whereas the other savings amount in Table 4.3 on page 8 in Appendix A2 of the Annual Review for 2016 Rates application is exclusive of losses.

The table provided below as per the request is inclusive of the losses to avoid confusion.

in GWh with losses	2015F in 2015 Annual Review	2015 S in 2016 Annual Review	2016 F in 2016 Annual Review
DSM	(28)	(20)	(47)
AMI	6	1	2
CIP	(2)	(2)	(5)
RCR	(21)	(6)	(9)
Rate Driven	(5)	(5)	(5)

The variances between 2015F and 2015S are discussed below.

The AMI impact provided for the 2015F was updated in the 2015S as a result of a calculation error. Specifically, the initial forecast did not reflect the Commission's determination to lower the assumed annual consumption for high-load sites from 151,200 kWh to 113,400 kWh and also incorrectly calculated the incremental change in the forecast number of high-load sites (both with and without theft).

The RCR was reforecast using the latest information from the study on the control group, which emphasized that most of the RCR saving impacts were already experienced in 2014 and the impacts for subsequent years would then be lowered.

There are no changes in the CIP and rate-driven savings, which account for less than 1% of the residential load.

The differences between 2015F and 2016F can be explained by the cumulative effects of the adjustments. The 2015S values reflect the single year impact (compared to 2014 actuals), while the 2016 values reflect the cumulative 2015 and 2016 impacts (compared to 2014 actuals).

Please refer to the response to BCUC IR 1.5.2.1 explaining the derivation of the 2016 forecast amounts.

5.2.1 For each category, please explain how FBC arrived at the 2016F GWh estimate.

<u>Response:</u>

Advanced Metering Infrastructure (AMI)

The AMI savings are the incremental savings related to the AMI Project compared to the base year of 2014. FBC estimates that approximately 3.5 GWh in incremental sales occurred in 2015 due to an increase in paying marijuana grow operations. FBC is also forecasting further incremental sales of approximately 3.8 GWh in 2016 related to an increase in paying marijuana grow operations. The 2015 savings together with 2016 savings make up the total incremental savings of 7.3 GWh for 2016 related to AMI compared to the base year of 2014. The estimates and forecasts of incremental savings are based on the theft reduction information provided as part of the AMI CPCN Application as adjusted by the Commission determinations provided in Order C-7-13 which included direction to FBC to lower its assumed annual energy consumption per theft site from 151,200 kWh to 113,400 kWh.

Customer Information Portal (CIP)

CIP savings refer to potential savings due to the implementation of the Customer Information Portal, which allows customers to view historical billing and consumption data. The estimated impact, as discussed in the AMI CPCN regulatory process, is in line with the BC Hydro estimate in its Smart Metering & Infrastructure Business Case. The incremental savings due to CIP is estimated to be 4.2 GWh which is approximately 0.3% of Before Savings load in 2016.

Residential Conservation Rate (RCR)

As a result of analysis performed for the most recent RCR Report to the BCUC, the forecast conservation impact due to the RCR was increased to 3.5% 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. In order to realize the incremental savings from the 36.2 GWh to the 46.3 GWh represented by 3.5% of 2017 load, the Company estimates that approximately 8 GWh will occur in 2015-2016 with the remaining 2 GWh being realized in 2017. This is the origin of the 8 GWh found in the table an Appendix A2 Table 4.3.

Rate-driven

Price elasticity savings are given as a percentage of the before-savings loads. 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. This price elasticity, multiplied by the rate increase, produces a saving of around 0.1% of the load.

Demand Side Management (DSM)

Please refer to the response to BCUC IR 1.5.4 which explains the derivation of the 2016 DSM forecast.

5.3 Please explain how FBC monitors actual compared to forecast results for each 'DSM and other customer savings' category.

Response:

Advanced Metering Infrastructure (AMI)

For the AMI-based revenue protection programs, although a portion of savings attributable to reduced theft will be reflected in FBC's overall annual system losses, it is not possible to directly measure the amount of theft detection and deterrence. With respect to the increased sales occurring as a result of the theft deterrence impact of FBC's AMI-based revenue protection program, FBC is unable to directly measure the amount of incremental sales that may be attributed to high-load sites deterred from stealing. Given the Commission's determination in

Order C-7-13 that increased sales to marijuana grow-operations should not be considered a project benefit, FBC believes the appropriate focus to gauge the effectiveness of the AMI-based revenue protection program should be on FBC's annual system loss trends.

Customer Information Portal (CIP)

For the Customer Information Portal (CIP), no impact study has been undertaken nor is one planned at this time. CIP savings will be reflected in lower Use per Customer (UPC).

Residential Conservation Rate (RCR)

For the Residential Conservation Rate (RCR), the conservation impact has been determined through a regression analysis of billing data provided to the Commission on an annual basis. The Company expects that the conservation benefits attributable to the RCR will be fully realized by the end of 2017.

Rate-driven

Actual savings associated with rate driven impacts cannot be separated out from the actual load consumed for a given year. It can only be estimated through an extensive modeling exercise such as the one BC Hydro adopted. FBC's estimate for rate driven savings is consistent with BC Hydro's current elasticity assumption of -0.05. FBC believes the rate driven assumption of -0.05 in line with the BC Hydro's assumption is adequate for the purpose of estimating future rate driven savings at this time.

Demand Side Management (DSM)

Validation of the DSM savings is carried out in accordance with the Company's 2013-2015 Monitoring and Evaluation Plan[3], which was extended to 2016 in the approved 2015-16 DSM Plan, and which includes verification by a third party. DSM results are reported annually in FBC's 2016 Annual DSM Report, which is filed in the 1st Quarter of the following year.

5.4 Please provide a reconciliation of forecast 2016 DSM savings (Table 3-1 of the Application) to the 2016 forecast DSM savings in the 2015/2016 FBC DSM Expenditure Schedule Filing.

Response:

Tables showing the 2016 Forecast DSM Savings from the Application and the 2016 Forecast DSM Savings from the 2015/2016 DSM Plan are reproduced below.

3 http://www.fortisbc.com/About/RegulatoryAffairs/ElecUtility/Documents/130705_FBC_2014-2018_PBR_Plan_Volume_2-Appendices_FF.pdf Appendix H3.

Table 3-1: Forecast 2016 DSM Savings

Line No.	Description	MWh
1	Residential	16,162
2	Commercial	14,508
3	Wholesale	7,636
4	Industrial	2,544
5	Lighting	1,416
6	Irrigation	807
7	Losses	3,745
8	**Total**	46,817

Table A-1: 2015-16 DSM Plan Expenditures & Savings

	Program Area	2015 Plan Savings *MWh*	2015 Plan Cost ($000s)	2015 Plan TRC *B/C ratio*	2016 Plan Savings *MWh*	2016 Plan Cost ($000s)
1	**Programs by Sector**					
2	Residential	12,100	3,160	2.0	12,910	3,350
3	Commercial	12,530	2,530	2.5	12,690	2,560
4	Industrial	1,540	200	5.7	1,590	210
5	**Subtotal Programs**	**26,170**	**5,890**	**2.2**	**27,190**	**6,120**
6	Supporting Initiatives		675	-		675
7	Planning & Evaluation		725	-		735
8	**Total (including Portfolio spend)**		**7,290**	**2.0**		**7,530**
9	Income Tax Impact		(1,823)			(1,883)
10	**Total deferred (net of tax)**		**5,468**			**5,648**

The differences between the two tables occur because the DSM savings are presented differently in the DSM Plan and in the Annual Review forecast.

The main reason for the difference is that the 2016 Forecast presents the DSM savings numbers as cumulative (the savings are cumulative starting in 2015, since DSM savings are embedded in historical data, of which 2014 is the last used in the forecast) whereas the DSM Plan shows the savings as incremental (the savings for each plan year are shown separately).

The 2016 DSM Plan figure of 27,190 MWh represents annualized energy savings for the DSM projects, by major customer sector, planned to be undertaken in that calendar year only. The 2016 forecast DSM savings of 46,817 MWh, set out in Table 3-1, factors in the timing of DSM projects. For forecasting purposes, 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 "Lighting" and "Irrigation" values shown separately in the load forecast. The forecast also isolates the (line) "Losses" associated with the DSM program savings.

6.0 Reference: PEAK DEMAND FORECAST

Exhibit B-1, Section 2.5, p. 16, Appendix A2, Section 5.4, p. 12

General

FBC includes system peak (MW) data in Table 3-3 of the Application. FBC incudes system load factors in Table 5.4, Appendix A2 of the Application.

6.1 Please clarify whether the two tables in the preamble are weather normalized. If not, please update the tables to include weather normalized peak demand and system load factor data.

Response:

Confirmed.

6.2 Please provide a comparison of actual vs. forecast (i) winter peak and (ii) summer peak for each year from 2012 to 2014. Please include in the table the percentage variance.

Response:

Please find the actual (non-normalized) peak values (MW) and the forecasting variances (%) in the table below. Note that the winter peak recorded for a year is the maximum peak value in four consecutive months from November and December of that year to January and February the following year. For example, the peak for the winter 2012/2013 occurred in January 2013, while the actual annual peak for 2012 (737 MW) occurred in January 2012.

Year	Actual		Approved		Variance	
	Winter	Summer	Winter	Summer	Winter	Summer
2012	639	551	721	567	11%	3%
2013	699	581	731	575	4%	-1%
2014	671	601	750	584	11%	-3%

6.3 Please explain why FBC is expecting a lower system load factor in 2015S and 2016F compared to the previous three years as shown in Table 5.4 of Appendix A2.

Response:

FBC is not able to isolate the reason(s) for the higher load factor in 2014. A system-wide load factor analysis would require (at least) monthly data analysis at a disaggregated, perhaps even feeder, level and in any event cannot be performed with the meter reading frequency currently available.

B. POWER PURCHASE EXPENSE

7.0 Reference: POWER PURCHASE EXPENSE

Exhibit B-1, Section 4.5, 4.6, p. 30

Overview

7.1 Please provide three tables, based on Table 4-2 in the Application, which compare 2014 actual and 2014 projected (as included in FBC's 2015 Rates Annual Review Filing): (i) power purchase expense ($ millions), (ii) GWh volumes purchased and (iii) energy cost ($/MWh). Please explain any significant differences.

Response:

The 2014 Projected data included in FBC's 2015 Rates Annual Review Filing, filed on February 6, 2015, included power purchase expense actuals through December 31, 2014 and no further adjustments were made. The data is reproduced in the table below:

	Power Purchase Expense ($ millions)		
	Projected 2014	**Actual 2014**	**Difference**
Brilliant	35.742	35.742	0.0
BC Hydro PPA	35.273	35.273	0.0
Independent Power Producers	0.447	0.447	0.0
Market and Contracted Purchases	16.068	16.068	0.0
Sale of Surplus Power	-0.320	-0.320	0.0
CPA Balancing Pool	-1.185	-1.185	0.0
Special and Accounting Adjustments	0.311	0.311	0.0
Total Energy Purchased	**86.337**	**86.337**	**0.0**
	Volume Purchased (GWh)		
	Projected 2014	**Actual 2014**	**Difference**
Brilliant	890.0	890.0	0.0
BC Hydro PPA	599.0	599.0	0.0
Independent Power Producers	13.1	13.1	0.0
Market and Contracted Purchases	378.0	378.0	0.0
Sale of Surplus Power	-13.7	-13.7	0.0
CPA Balancing Pool	-28.0	-28.0	0.0
Special and Accounting Adjustments	0.0	0.0	0.0
Total Energy Purchased	**1838.5**	**1838.5**	**0.0**

	Energy Cost ($/MWh)		
	Projected 2014	**Actual 2014**	**Difference**
Brilliant	$40.16	$40.16	$0.00
BC Hydro PPA	$58.89	$58.89	$0.00
Independent Power Producers	$34.00	$34.00	$0.00
Market and Contracted Purchases	$42.51	$42.51	$0.00
Sale of Surplus Power	$23.39	$23.39	$0.00
CPA Balancing Pool	$42.32	$42.32	$0.00
Special and Accounting Adjustments	N/A	N/A	N/A
Average Cost	**$46.96**	**$46.96**	**$0.00**

7.2 Please provide four tables based on Table 4-2 and Table 4-3 in the Application (excluding Waneta Expansion) which replace '$ millions' with (i) GWh volumes purchased, and (ii) energy cost ($/MWh).

Response:

The following four tables update Table 4-2 and Table 4-3 in the Application with (i) GWh volumes purchased and (ii) energy cost.

Table 4.2 (i) GWh Volumes (GWh)

Line No.	Description	Approved 2015	Projected 2015	Difference
1	Brilliant	920.0	920.0	0.0
2	BC Hydro PPA	760.4	582.0	-178.4
3	Independent Power Producers	4.0	5.5	1.5
4	Market and Contracted Purchases	192.0	301.2	109.2
5	CPA Balancing Pool	0.0	36.4	36.4
6	Total	1876.5	1845.1	-31.4

Table 4.2 (ii) Energy Cost ($/MWh)

Line No.	Description	Approved 2015	Projected 2015	Difference
1	Brilliant	$ 40.29	$ 40.28	-$0.01
2	BC Hydro PPA	$ 59.78	$ 62.29	$2.51
3	Independent Power Producers	$ 40.57	$ 34.10	-$6.47
4	Market and Contracted Purchases	$ 48.85	$ 44.62	-$4.23
5	CPA Balancing Pool	-	$ 43.27	NA
6	Total	$ 49.04	$ 47.97	$ (1.08)

Table 4.3 (i) GWh Volumes (GWh)

Line No.	Description	Projected 2015	Forecast 2016	Difference
1	Brilliant	920.0	914.0	-6.0
2	BC Hydro PPA	582.0	786.0	204.0
3	Independent Power Producers	5.5	4.0	-1.5
4	Market and Contracted Purchases	301.2	247.0	-54.2
5	CPA Balancing Pool	36.4	0.0	-36.4
6	Total	1845.1	1951.0	105.9

Table 4.3 (ii) Energy Cost ($/MWh)

Line No.	Description	Projected 2015	Forecast 2016	Difference
1	Brilliant	$ 40.28	$ 42.43	$ 2.16
2	BC Hydro PPA	$ 62.29	$ 60.49	$ (1.80)
3	Independent Power Producers	$ 34.10	$ 48.85	$ 14.75
4	Market and Contracted Purchases	$ 44.62	$ 40.58	$ (4.04)
5	CPA Balancing Pool	$ 43.27	$ 46.65	$ 3.38
6	Total	$ 47.97	$ 49.49	$ 1.52

7.2.1 How many months of actual data are included in the 2015 projected power purchase costs? If less than four months of actual data are included, please update Table 4-2 and 4-3 in the Application to include all 2015 available months of actual data.

Response:

The Projected 2015 power supply costs include six months of actual data, through June 2015.

8.0 Reference: POWER PURCHASE EXPENSE

Exhibit B-1, Section 4.5, 4.6, pp. 29–31

Brilliant / BC Hydro Power Purchase Agreement (PPA)

FBC states that the reduction in power purchase expense in 2015 is due in part to additional market purchases used to displace BC Hydro PPA energy and capacity purchases at a lower total cost.

8.1 Please provide analysis and show the calculations to support the Brilliant 2016 forecast expense.

Response:

The 2016 Forecast Brilliant expense consists of base energy costs (which include the initial return on capital charge, sustaining capital charges, annual O&M charges, and any true-ups from prior year forecasts), upgrade energy costs, and tailrace capacity charges. Each of these costs is described below.

1. The forecast cost of the BPPA Base Energy is calculated in accordance with the terms set out in the BPPA dated April 4, 1996 as approved by Commission Order E-7-96. The Base Energy rate takes into account several elements such as the original plant return on capital charge related to the initial acquisition costs of the plant by Brilliant, sustaining capital charges related to the return on capital of annual routine capital work, and annual O&M charges for the Brilliant plant which consist of items such as water fees, property taxes and insurance which are charged to and paid by FBC throughout the year. The rate for 2016 is based on an estimate of these totals which is provided by the Brilliant Power Corp. Additionally, since the rate is initially based on an estimate each year, a true up between the estimated cost and the actual cost to FBC is done annually in May of the following year. Any difference between the estimate and actual costs is added to or subtracted from the estimated cost in a future year. As a result, the 2016 base energy costs also include a true-up of the contract costs from 2015, which results in a reduction of 2016 base energy costs by $0.367 million.
2. The forecast cost of the BPPA Upgrade Energy is calculated based on the return on capital of periodic plant capital upgrade work that is in accordance with the terms set out in the BPPA dated April 4, 1996 as approved by Commission Order E-7-96 and the Brilliant Power Purchase Agreement Second Amendment dated March 30, 2000 as approved by Commission Letter L-57-00.
3. The forecast cost of the BPPA Tailrace Capacity is calculated in accordance with the June 7, 2001 Letter Agreement on Tailrace Improvements as accepted by Commission

Order E-17-01. The capacity entitlement is fixed, while the rate is subject to an annual escalation factor linked to the original plant return on capital charge.

The following table shows the calculation of the Brilliant 2016 forecast expense.

BPPA 2016 Costs	
Original Plant Capital Charge ($ millions)	$17.097
Sustaining Capital Charge ($ millions)	$7.592
O&M Charge ($ millions)	$12.296
Previous Years True up ($ millions)	-$0.367
[A] Total Cost for BPPA Base Energy ($ millions)	**$36.618**
Base Energy (GWh)	859.38
Base Rate ($/MWh)	$ 42.61
Upgrade Capital Charge ($ millions)	$1.983
[B] Total Cost for BPPA Upgrade Energy ($ millions)	**$1.983**
Upgrade Energy (GWh)	65.09
Upgrade Rate ($/MWh)	$ 30.47
BRD Capacity Rate ($/MW)	$4,346
Total Capacity (MW)	42.2
[C] BPPA Tailrace Capacity Cost ($ millions)	**$0.183**
[D] Total BPPA Cost ($ millions) = [A] + [B] + [C]	**$38.785**

8.2 Please provide an approximate breakdown between volume related and rate related changes of the difference in BC Hydro PPA power purchase cost for (i) approved 2015 compared to projected 2015 ($9.2 million negative in Table 4-2 of the Application) and (ii) forecast 2016 compared to projected 2015 ($11.3 million positive in Table 4-3 of the Application).

Response:

The following table provides a breakdown of the BC Hydro PPA power purchase costs for 2015 Approved compared to 2015 Projected in $ millions.

BC Hydro PPA Purchases	Approved 2015	Projected 2015	Difference
Energy (GWh)	760	582	-178
Total Energy Expense ($ millions)	$ 33.671	$ 25.919	$ (7.752)
Average Energy Rate ($/MWh)	$ 44.28	$ 44.51	$ 0.23
Total Annual Capacity (MW)	1,685	1,428	-258
Total Capacity Expense ($ millions)	$ 12.789	$ 10.831	$ (1.957)
Average Capacity Rate ($/MW)	$ 7,588	$ 7,586	$ (2)
Forecast Savings ($ millions)	$ (1.000)	$ (0.500)	$ 0.500
Total BC Hydro PPA Expense ($ millions)	$ 45.460	$ 36.250	$ (9.210)

As shown in the table above, the Projected 2015 PPA cost is $36.250 million, which is a decrease of $9.210 million from the Approved 2015 cost of $45.460 million. The decrease in BC Hydro purchase volume accounts for $9.842 million in decreased PPA costs. There was no difference in the BC Hydro rates used in the Approved and Projected 2015; however, due to the rate increase on April 1, 2015 of 6 percent, the average energy rate and average capacity rate has varied slightly, due to the timing of the purchases. As a result of the changes to the average rates, the total BC Hydro PPA expense has increased by $0.132 million. The remaining variance is due to the forecast savings included in the 2015 Projected. The forecast savings of $1.0 million included in the Approved 2015, was applied equally over the twelve months of the year. As the Projected 2015 power purchase expense includes actuals through June 30, 2015, the amount of forecast savings remaining is equal to $0.500 million.

The following table provides a breakdown of the BC Hydro PPA power purchase costs for 2015 Projected compared to 2016 Forecast in $ millions.

BC Hydro PPA Purchases	Projected 2015	Forecast 2016	Difference
Energy (GWh)	582	786	204
Total Energy Expense ($ millions)	$ 25.919	$ 36.447	$ 10.528
Average Energy Rate ($/MWh)	$ 44.51	$ 46.37	$ 1.86
Total Annual Capacity (MW)	1,428	1,524	96
Total Capacity Expense ($ millions)	$ 10.831	$ 12.099	$ 1.267
Average Capacity Rate ($/MW)	$ 7,586	$ 7,938	$ 352
Forecast Savings ($ millions)	$ (0.500)	$ (1.000)	$ (0.500)
Total BC Hydro PPA Expense ($ millions)	$ 36.250	$ 47.545	$ 11.295

As shown in the table above, the Forecast 2016 PPA cost is $47.545 million. This is an increase of $11.295 million from the Projected 2015 cost of $36.250 million.

For 2016, increased BC Hydro rates result in approximately $1.982 million in increased PPA costs further detailed in the response to BCUC IR 1.8.2.1. The increased volumes of energy and capacity increase total PPA cost by $9.813 million.

For 2016 Forecast, consistent with the 2015 Approved, 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. 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.

The remaining variance between Projected 2015 and Forecast 2016 PPA expense is due to the forecast savings included in the 2015 Projected. The forecast savings of $1.0 million included in the Approved 2015 was applied equally over the twelve months of 2015. As the Projected 2015 power purchase expense includes actuals through June 30, 2015, the amount of forecast savings remaining is equal to $0.500 million.

8.2.1 Please provide analysis to support the BC Hydro 2015 and 2016 rate increase component of the BC Hydro PPA cost.

Response:

The BC Hydro PPA expense increase from the Projected 2015 to the Forecast 2016 as a result of BC Hydro rate increases is approximately $1.982 million. This is calculated in the following table:

[A] 2016 PPA Energy Purchase (GWh)		786
[B] Average 2015 Energy Rate ($/MWh)	$	44.53
[C] Average 2016 Energy Rate ($/MWh)	$	46.37
[D] 2016 PPA Capacity Purchase (MW)		1,524
[E] Average 2015 Capacity Rate ($/MW)	$	7,585
[F] Average 2016 Capacity Rate ($/MW)	$	7,939
Energy Cost increase due to BC Hydro Rate Increases [A] x ([C] -[B]) ($ millions)	$	1.443
Capacity Cost increase due to BC Hydro Rate Increases [D] x ([F] -[E]) /1000 ($ millions)	$	0.539
Total PPE Increase due to BC Hydro Rate Increases ($ millions)	$	1.982

8.2.2 For 2015 and 2016 volume related BC Hydro PPA increases/decreases, please identify to what extent this cost is offset by decreased/increased market and contracted purchases.

Response:

As detailed in the response to BCUC IR 1.8.2, the volume-related PPA increase for 2016 is $9.813 million, while as detailed in the response to BCUC IR 1.9.3.1 the volume-related decrease of market and contracted purchases is $2.976 million.

The BC Hydro PPA energy purchases increased from 582 GWh in the Projected 2015 to 786 GWh in 2016 Forecast, an increase of 204 GWh, while Market and Contracted Purchases decreased from 301 GWh in 2015 Projected to 247 GWh in the 2016 Forecast, a decrease of 54 GWh.

Therefore, the PPA volume increase is offset partially by the 54 GWh decrease in market and contracted purchases, at a value of $2.976 million.

9.0 Reference: POWER PURCHASE EXPENSE

Exhibit B-1, Section 4.5, 4.6, pp. 29–31, FBC S. 72 WAX CAPA, Application (August 27, 2010), p. 9

Waneta expansion

FBC states on page 29 of the Application that the reduction in power purchase expense in 2015 is due in part to a reduction in net Waneta Expansion expense due to additional maintenance outages at the WAX plant and increased revenue for WAX surplus sales under the CEPSA.

9.1 Please provide analysis and show the calculations to support the Waneta Expansion 2015 approved, 2015 projected, and 2016 forecast expense (Tables 4-2 and 4-3 of the Application). Please include a breakdown of the cost between WAX CAPA expense, RCA sales revenue and other surplus sales revenue.

Response:

The following table shows the breakdown of the Waneta Expansion costs included in the 2015 Approved, 2015 Projected, and 2016 Forecast power purchase expense.

Waneta Expansion ($ millions)	**Approved 2015**	**Projected 2015**	**Forecast 2016**
WAX CAPA Expense	30.751	29.576	46.658
Surplus Sales Revenue	(4.943)	(6.683)	(9.299)
Waneta Expansion Total	**25.808**	**22.893**	**37.358**
Non WAX Surplus Sales	-	(0.185)	-
Waneta Expansion (Table 4-2 and 4-3)	**25.808**	**22.708**	**37.358**

Please note that the Projected 2015 Waneta Expansion cost included $0.185 million in surplus sales from July 2015 that did not involve Waneta Expansion capacity, and therefore should not be included in the Waneta Expansion line item. The total WAX surplus sales in the Projected 2015 should be equal to $6.683 million, and the total Waneta Expansion cost should be equal to $22.893 million.

The projected July 2015 surplus sales occurred due to a WAX maintenance outage in July that resulted in surplus energy that FBC could not use with WAX CAPA to meet load requirements. In total FBC sold 5.8 GWh of energy in July 2015, at an average rate of $31.89/MWh. This adjustment has no impact to the total Power Supply costs as it only affects the breakdown of surplus sales in the 2015 Projection shown in Tables 4-2 and 4-3 of the Application. The following tables provide an updated Table 4-2 and Table 4-3 from the Application.

Updated Table 4-2 from the Application

Line No.	Description	Approved 2015	Projected 2015	Difference
1	Brilliant	$ 37.069	$ 37.055	$ (0.014)
2	BC Hydro PPA	45.460	36.250	(9.210)
3	Waneta Expansion	25.808	22.893	(2.915)
4	Surplus Energy Sales	-	(0.185)	(0.185)
5	Independent Power Producers	0.164	0.189	0.025
6	Market and Contracted Purchases	9.380	13.441	4.061
7	CPA Balancing Pool	(0.044)	1.573	1.617
8	Special and Accounting Adjustments	-	0.060	0.060
9	Total	$ 117.837	$ 111.277	$ (6.560)
10	Gross Load (GWh)	3,499	3,438	(61)

Updated Table 4-3 from the Application

Line No.	Description	Projected 2015	Forecast 2016	Difference
1	Brilliant	$ 37.055	$ 38.785	$ 1.730
2	BC Hydro PPA	36.250	47.545	11.295
3	Waneta Expansion	22.893	37.358	14.465
4	Surplus Energy Sales	(0.185)	-	0.185
5	Independent Power Producers	0.189	0.195	0.007
6	Market and Contracted Purchases	13.441	10.023	(3.418)
7	CPA Balancing Pool	1.573	-	(1.573)
8	Special and Accounting Adjustments	0.060	-	(0.060)
9	Total	$ 111.277	$ 133.907	$ 22.631
10	Gross Load (GWh)	3,438	3,540	102

The remainder of this response is being filed confidentially as it contains commercially sensitive information on the WAX CAPA, which was determined to remain confidential pursuant to Order E-15-12, and the Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex, which was determined to remain confidential pursuant to Order E-10-15, and if disclosed, could harm the competitive negotiating position of FBC with regard to the sale of surplus capacity, and therefore, cause adverse effects for customers.

9.1.1 Please explain the difference between the 2015 approved and 2015 projected Waneta Expansion cost (Table 4-2 of the Application).

Response:

As discussed in the response to BCUC IR 1.9.1, the 2015 Projected forecast of Waneta Expansion cost included $0.185 million of surplus sales that did not include WAX CAPA, and therefore the difference in Waneta Expansion cost between Approved 2015 and Projected 2015 should be a reduction of $2.915 million, compared to the reduction of $3.100 million shown in Table 4-2 of the Application. This adjustment has no impact to the total Power Supply costs, and only affects the breakdown of surplus sales in the 2015 Projection shown in Tables 4-2 and 4-3 of the Application. An updated Table 4-2 was provided in response to BCUC IR 1.9.1.

The $2.915 million reduction in the Waneta Expansion cost from Approved 2015 to Projected 2015 is calculated as follows:

- $1.740 million reduction due to increased surplus sales revenue
- $0.961 million reduction due to reduced availability of WAX Capacity due to increased maintenance outages in 2015
- $0.214 million reduction due to changes in the forecast water rental fee adjustments for 2015.

Please refer to the CONFIDENTIAL response to BCUC IR 1.9.1 for a detailed breakdown of the variances between the Waneta Expansion cost in the 2015 Approved and 2015 Projection.

9.1.2 Please explain the difference between the 2015 projected and 2016 forecast Waneta Expansion cost (Table 4-3 of the Application). Please include in this explanation how much of this difference is due to twelve months of capacity being purchased in 2016 instead of nine in 2015, and describe the other factors resulting in the increase in expense.

Response:

As discussed in the response to BCUC IR 1.9.1, the 2015 Projected forecast of Waneta Expansion included $0.185 million of surplus sales that did not include WAX CAPA, and therefore the difference in Waneta Expansion cost between the Projected 2015 and Forecast 2016 should be an increase of $14.465 million, compared to the increase of $14.650 million shown in Table 4-3 of the Application. This adjustment has no impact to the total Power Supply costs, and only affects the breakdown of surplus sales in the 2015 Projection shown in Tables 4-2 and 4-3 of the Application. An updated Table 4-3 was provided in response to BCUC IR 1.9.1.

The $14.465 million increase in the Waneta Expansion cost from Projected 2015 to Forecast 2016 is calculated as follows:

- $16.129 million increase due to the expected increased availability of WAX capacity in 2016. The availability of WAX in the first three months of the year increases the cost by approximately $15.3 million, while the increased availability in 2016 from April through December increases the cost by approximately $0.841 million.
- $0.968 million increase due to annual escalation of WAX CAPA rates.
- $2.617 million decrease due to increased surplus sales revenue due to surplus sales in twelve months, compared to only nine in 2015.
- $0.010 million decrease due to changes in the forecast water rental fee adjustments

Please refer to the CONFIDENTIAL response to BCUC IR 1.9.1 for a detailed breakdown of the variances between Waneta Expansion cost in the 2015 Projection and 2016 Forecast.

9.2 Please provide a comparison between the projected 2015 and forecast 2016 revenues received from the sale of surplus Waneta capacity, and explain any differences. Please also comment on whether the Waneta expansion is able to reduce FBC's other energy purchase costs (for example, market and contracted purchases), and if so, approximately what the size of this benefit would be in 2015 and 2016.

<u>Response:</u>

Please refer to the CONFIDENTIAL response to BCUC IR 1.9.1 for a breakdown of the Waneta Expansion surplus sales revenue included in the Projected 2015 and Forecast 2016.

In addition to the WAX CAPA surplus sales revenue, the capacity purchased by FBC under the WAX CAPA reduces FBC power purchase expense by:

1. Offsetting capacity purchased under the Power Purchase Agreement with BC Hydro (RS 3808).
2. Avoiding Market and Contracted purchases, which includes the early termination of the Powerex Capacity Block contract that would have otherwise expired February 2016 and a small amount of market energy purchases in a few months of the year that would have

been required to meet peak capacity demand that could not have been met with other capacity resources available to FBC.

3. Making beneficial use of energy that previously would have been surplus to FBC's load requirements in the months of May, June and July.

The table below summarizes these benefits and the net impact of WAX CAPA in the 2015 Approved, 2015 Projection and 2016 Forecast.

Waneta Expansion ($ millions)	**Approved 2015**	**Projected 2015**	**Forecast 2016**
WAX CAPA	30.751	29.576	46.658
Surplus Sales Revenue	(4.943)	(6.683)	(9.299)
[A] Total Waneta Expansion	**25.808**	**22.893**	**37.358**
1. RS3808 Displacements	2.254	3.084	5.139
2. Avoided Market and Contracted Purchases	1.462	1.687	2.303
3. Beneficial Use of Surplus Energy	0.293	0.147	0.278
[B] Total Offsets	**4.008**	**4.918**	**7.720**
[C] Net Impact of WAX {[A] - [B]}	**21.800**	**17.975**	**29.638**

9.3 Please identify how much of FBC's 2015 and 2016 actual/expected rate increase is due to the Waneta Expansion cost. Please compare this to the 2015 and 2016 rate increase forecast in FBC's section 71 Application for WAX CAPA (August 27, 2010, p. 9) and explain any differences.

Response:

FBC's rate increase due to the Waneta Expansion cost during 2015 (approved) and 2016 (forecast) are 6.8% and 2.3% respectively (please refer to line 10, in the Table below). These rate increases were forecast at 6.6% and 3.0% for 2015 and 2016 respectively in FBC's section 71 Application for WAX CAPA (August 27, 2010, p. 9).

The difference in rate impacts (please refer to line 12, in the Table below) is mainly attributable to minor variances in available WAX Capacity and surplus sales revenue.

		Approved 2015		Forecast 2016		Reference (2016)
1	Revenue Requirement with WAX	334,531	A	349,949	a	
2	Revenue Deficiency (Surplus)	13,397	A1	6,797	a1	Annual Review 2016, Exhibit-1, Pg 63, Section - 11, Schedule - 1
3	Rate increase with WAX	4.2%	B	1.98%	b	Annual Review 2016, Exhibit-1, Pg 63, Section - 11, Schedule - 1
4	Revenue at Prior Year Rates with WAX	321,134	C	343,152	c	Annual Review 2016, Exhibit-1, Pg 63, Section - 11, Schedule - 1
5	Net Impact of WAX for FBC Customers	21,800	D	29,638	d	
6	Revenue Requirement Pre WAX	312,731	A-D = E	320,311	a-d = e	
7	Revenue at Prior Year Rates Pre WAX	321,134	C	321,352	c-D = f	
8	Revenue Deficiency Pre WAX	(8,403)	E-C = F	- 1,041	e-f = g	
9	Rate increase without WAX	-2.6%	F/C = G	-0.3%	g/f = h	
10	Impact of WAX	6.8%	B-G = J	2.3%	b-h = j	
11	WAX Rate Impact Forecast per Sec. 71 Application	6.6%	K	3.0%	k	Page9, Section 71 Application for WAX CAPA
12	Variance from WAX Rate Forecast per WAX CAPA	0.2%	J-K	-0.7%	j-k	

9.4 Please describe the additional maintenance outages at the WAX plant and their effect on FBC's 2015 power purchase costs.

Response:

Over the period of June 1 to July 15, one unit was offline at Waneta expansion at a time. The work was required to complete the 1,500 hour inspection and for additional work completed by the contractor in order to satisfy the requirements of the owner of the plant.

The impact of reduced capacity availability from the WAX plant due to these maintenance outages is a reduction to power purchase expense equal to $0.461 million, calculated as follows:

- $0.961 million decrease to power purchase expense due to reduced purchases under the WAX CAPA.
- $0.400 million increase to power purchase expense due to reduced surplus sales during this time.
- $0.100 million increase to power purchase expense due to increased market purchases required to meet load.

10.0 Reference: POWER PURCHASE EXPENSE

Exhibit B-1, Section 3.5.7, p. 24, Section 4.5-4.8, pp. 29–33; FBC AMI Certificate of Public Convenience and Necessity Decision dated July 23, 2015 and Order C-7-13, p. 86

Market and contracted purchases, other

Table 4.2 of the Application states that approved 2015 load was 3,499 GWh, while projected 2015 load was 3,438 GWh. FBC states on page 29 that the reduction in power purchase expense in 2015 is due in part to decreased load.

FBC states on pages 32 to 33 that it does not forecast any net use or storage of entitlement energy for 2016 and that it forecasts increase plant entitlement use in 2016.

10.1 Please explain the effect on FBC's projected 2015 power purchases as a result of the lower than approved 2015 load. Specifically, what purchases were displaced and were there additional costs to customers that could have been avoided if the 2015 approved gross load had been set at 3,438 GWh?

Response:

FBC's gross load in the 2015 Projection is 61 GWh less than in the Approved 2015. The impact of this variance is a reduction to power purchase expense of approximately $2.677 million in 2015. The PPA with BC Hydro allows for uncertainty in the load forecast and the PPA flexibility was sufficient to allow the Company to adjust PPA purchases as required. There were no incremental costs to customers that could have been avoided had 2015 approved gross load been set at 3,438 GWh.

The load forecast variance of power purchase expense, as well as the variance in sales revenue associated with changes to gross load, have been recorded in the Flow-through deferral account and are being returned to the customers in 2016 rates.

10.2 Please identify and explain the reason for any changes in methodology to forecast market prices, wheeling expense and water fees from that used for the FBC Annual Review of 2016 Rates.

Response:

There are no changes in the methodology to forecast market prices, wheeling expense and water fees from those used for the FBC Annual Review of 2015 Rates.

10.3 Please explain the difference between the approved 2015 and projected 2015 CPA Balancing Pool cost, and explain why FBC does not forecast any use or storage of entitlement in 2015.

Response:

The CPA balancing pool accounts for year over year timing differences in the volume of entitlement energy stored under the CPA. For forecasting purposes, as was included in the 2015 Approved and the 2016 Forecast, FBC does not include any use or storage of entitlement energy. Storage is not an additional resource that can be used to reduce cost, rather it is used to manage actual fluctuations in load and resources that occur within the year. As such, if energy is stored the cost of the energy is credited to power purchase expense through a balancing pool adjustment. Likewise, when FBC uses this energy to meet its load, it will be deducted from the balancing pool and a cost to power purchase expense will be shown.

The 2015 Projection is based on actual operations and FBC expects to use 36 GWh of energy from the storage account resulting in a $1.573 million cost to power purchase expense. This is equal to an average cost of $43.69/MWh, which is based on the PPA energy rate when the energy is stored or used.

10.4 Please provide analysis to support the Market and Contracted Purchases 2016 forecast expense which includes a breakdown by Commission approved energy purchase agreements.

Response:

This response is being filed confidentially with the Commission as it contains market sensitive information. Since FBC continues to operate within a competitive environment, disclosure of the information contained in this response will prejudice FBC's ability to obtain favourable commercial terms in future contract negotiations or renegotiation of subsequent contracts, which, in turn, will harm the Companies' customers.

10.4.1 Please provide a breakdown of the estimated difference between 2015 (projected) and 2016 (forecast) market and contracted purchases expense between volume related and price related. Please provide an explanation for each.

Response:

The following table provides the breakdown of the average market and contracted purchases cost for 2015 Projected and 2016 Forecast.

Market and Contracted Purchases	Projected 2015	Forecast 2016	Difference
Energy (GWh)	301	247	-54
Total Energy Expense ($ millions)	$ 10.239	$ 8.764	-$ 1.474
Average Energy Rate ($/MWh)	$ 34.00	$ 35.48	$ 1.48
Total Annual Capacity (MW)	574	370	-204
Total Capacity Expense ($ millions)	$ 3.202	$ 1.259	-$ 1.943
Average Capacity Rate ($/MW)	$ 5,577	$ 3,400	-$ 2,177
Total Market And Contracted Expense ($ millions)	$ 13.441	$ 10.023	-$ 3.417

The lower volume of purchases of both energy and capacity reduces power purchase expense by $2.976 million in 2016, while the changes to the average rates decrease power purchase expense by $0.441 million. In total the market and contracted expense decreases by $3.417 million from 2015 to 2016.

The reduction in energy purchases between Projected 2015 and Approved 2016 is mainly because the 2015 Projection includes real-time market purchases that FBC has entered into in 2015. For 2016, all of the market purchases included are based on fixed price contracts executed by the Company, with no forecast of real-time market purchases. The Company has, however, included a $1.000 million reduction to forecast purchases under the BC Hydro PPA to account for potential additional real-time market purchases in 2016.

The volume of capacity purchased has decreased between 2015 and 2016 mainly because the Company terminated the winter Powerex Capacity Block contract in July 2015, as a result of capacity being available from the Waneta Expansion. The termination of the Powerex Capacity block contracts also reduced the average cost of capacity for market and contracted purchases.

10.5 Please provide analysis to show what portion of the 2016 forecast increase in water fees is due to a projected increase in water rates compared to an increase in plant entitlement use.

Response:

The 2nd tier of water rental fees, which for generation is between 160 GWh and 3,000 GWh, is forecast to increase from $6.066/MWh to $6.125/MWh, based on a forecast CPI increase of approximately 1 percent. Plant entitlement use in 2015 compared to 2014 is projected to increase by 80 GWh, as shown in Table 4-5 of the Application.

Therefore, the increase in water fees due to the rate increase is approximately $0.097 million, calculated as follows:

[A] 2016 Plant Entitlement in Previous Year (GWh)	1,649
[B] 2015 2nd Tier Water Fee Rate ($/MWh)	$ 6.066
[C] 2016 2nd Tier Water Fee Rate ($/MWh)	$ 6.125
Water Fee increase due to Rate Increases [A] x ([C] - [B]) ($ millions)	$ 0.097

The increase due to increased plant entitlement in 2015 is approximately $0.487 million, calculated as follows:

[A] 2015 2nd Water Fee Rate ($/MWh)	$ 6.066
[B] 2015 Plant Entitlement in Previous Year (GWh)	1,569
[C] 2016 Plant Entitlement in Previous Year (GWh(	1,649
Water Fee increase due to Volume Increases [A] x ([C] - [B]) ($ millions)	$ 0.487

The total increase in water fees from the 2015 Projection to the 2016 Forecast is $0.585 million.

10.5.1 Please provide documentation to support the change in water fee rates for the projected 2015 and forecast 2016 years.

Response:

The 2015 water fee rates are shown on the BC Provincial government website, located here: http://www.env.gov.bc.ca/wsd/water_rights/water_rental_rates/cabinet/waterpower_rental_rates_may-2015.pdf

Water rental fees are escalated each year by increases in the Provincial Consumer Price index (CPI). For the 2016 water fee rates, FBC has included an estimated 1 percent increase in water fees from 2015 to 2016. The following table shows the 2015 and 2016 water fee rates included in the 2015 Projection and 2016 Forecast of water fees.

Water Fee Rates	2015 Projected	2016 Forecast
1st Tier (First 160 GWh) ($/MWh)	$ 1.301	$ 1.314
2nd Tier (160 to 3,000 GWh) ($/MWh)	$ 6.066	$ 6.125
Capacity ($/MW)	$ 4.334	$ 4.376

Any variance to forecast in water fees is recorded in the Flow-through deferral account and returned to or recovered from customers in the subsequent years.

10.5.2 Please explain why FBC is projecting an increase in plant entitlement use for 2016.

Response:

The water fees are based on plant entitlement use in the previous year, therefore the increase of 80 GWh in plant entitlement use from the 2015 Projection and 2016 Forecast water fees is due to changes in plant entitlement use between 2014 and 2015.

In 2014, FBC stored 28 GWh of energy in the CPA storage account, while FBC is projecting to use 36 GWhs of stored energy in 2015. This creates a variance of 64 GWh of plant entitlement use between 2014 and 2015. 2015 also saw a 9 GWh increase in entitlement compared to 2014 due to lower generator maintenance entitlement losses. Finally, there is a 7 GWh increase in plant entitlement in 2015 due to increases in base energy entitlements and retroactive energy return as a result of the Unit Life Extension (ULE) project that was completed in 2011.

10.6 Please explain what comprised the $60,000 in special and accounting adjustments projected for 2015 in Table 4-2 of the Application.

Response:

The $0.060 million special and accounting adjustments in 2015 was due to year-end timing differences between the December 2014 estimated costs used to book December 2014 costs and the January 2015 adjustment to account for the actual December 2014 costs, adjustments to correct for foreign exchange US dollar based transactions, and accounting adjustments to reverse GST that had been incorrectly charged to power purchase expense.

10.7 Please quantify the amount spent by FBC, for each year from 2012 to 2014, on non-AMI related power theft reduction, compare it to the amount approved by the Commission for those activities and explain any significant differences.

Response:

The Commission has not approved a specific amount for Revenue Protection activities in each of these years.

Actual expenditures for non-AMI Revenue Protection activities for 2012 – 2014 are provided in the following table:

Year	Actuals ($000s)
2012	189
2013	192
2014	168

C. ADVANCED METERING INFRASTRUCTURE (AMI)

11.0 Reference: AMI Project

Exhibit B-1, Section 6.3.3, pp. 38–39

AMI Costs and Savings

11.1 In the last annual review, FBC indicated that the AMI project would be substantially complete in 2015. Please provide a high level status update on the anticipated completion of this project.

Response:

FBC continues to forecast that the AMI project will be substantially complete in 2015, requiring only the following to finalize all aspects of the project in Q2 2016:

- Clean-up deployment of hard-to-exchange and customer refusal meters;
- Final network optimization;
- System acceptance testing; and
- Project completion documentation.

The AMI project includes three primary work streams: Back Office software development and integration, Meter Deployment, and Network Deployment. The following is the status of each of these work streams:

- Back Office: 90 to 95 percent complete. There remains some integration work to complete.
- Meter Deployment: 94 percent complete. Mass meter deployment by FBC's contractor (Itron/Corix) will complete, on schedule, in late October. Meter deployment "clean up" will continue into January 2016.
- Network Deployment: The wide area network backbone is 100 percent complete for all regions. System optimization is complete for Region 1 (Trail/Salmo), 95 percent complete for Region 2 (Kelowna), and underway for Regions 3, 4 and 5. System optimization is scheduled for completion in Q1 2016.

In Table 6-5 on page 39 of the Application, FBC provides a table comparing the cost and savings of the AMI project.

11.2 Please confirm the arithmetic in the second last column with the formula "(j) = (b) +(e) + (h)." Please provide any corrections to the table, if necessary.

Response:

The column heading in the second last column of Table 6-5 should read (j)=(c)+(f)+(h), as shown in the revised table below. The headings in columns (f), (h) and (j) have also been amended for clarification. There are no changes to the values in the table.

	2014			2015			2016		Total		
	Estimated Actual	Approved	CPCN(1)	Projected	Approved	CPCN(1)	Forecast	CPCN(1)	Actual / Forecast	CPCN(1)	Change
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)=(a)+(d)+(g)	(j)=(c)+(f)+(h)	(k)=(i)-(j)
AMI Costs	531	750	1,116	1,591	1,591	1,859	1,738	1,892	3,860	4,867	(1,007)
AMI Savings	(100)	(150)	(516)	(1,139)	(1,139)	(1,977)	(3,538)	(3,976)	(4,777)	(6,469)	1,692
Net AMI Costs	431	600	600	452	452	(118)	(1,800)	(2,084)	(917)	(1,602)	685

(1) CPCN estimates adjusted to include reclassification of software from capital pursuant to Order G-13-14

12.0 Reference: AMI Radio-Off

Exhibit B-1, Section 6.3.4, pp. 39, 46; FBC Radio-off AMI Meter Option Decision dated December 19, 2013, pp. 17, 24

Net customer costs

FBC states that it is tracking the actual number of radio-off participants and the actual annual radio-off costs separately from other costs, pursuant to Order G-222-13.

In paragraph 54 of FBC's final submission in the AMI Radio-off proceeding, it stated that it would track actual meter costs directly related to the activities of the contact center and meter analyst time, starting on November 1, 2013 and until the AMI project is complete.

12.1 Please clarify when FBC commenced the collecting this data.

Response:

FBC started tracking the number of concerned AMI customer interactions when the AMI CPCN was originally filed in 2012. Contact centre costs related to these interactions will be calculated using an estimated cost per interaction multiplied by the number of those concerned customers that have since chosen a radio-off meter.

There was no other significant radio-off activity aside from the concerned customer interactions discussed above until April 2014, at which point FBC started tracking radio-off costs for information systems, contact centre and meter analysts.

In the AMI Radio-off proceeding, FBC proposed to track the actual number of Radio-off AMI Meter Option participants and actual manual meter reading costs and to suggest revisions, if appropriate, in the next Cost of Service/Rate Design Application. Accordingly, on page 24 the Commission directed a reporting on these items by September 30, 2016.

FBC also acknowledges on page 39 that the "AMI Radio-off fees are designed so that those customers selecting a Radio-off AMI meter will cover the associated costs so as not to reduce the AMI benefits accruing to all other customers."

12.2 Please clarify whether the intent of the Radio-off tariff fees were designed to cover the total costs of the program from the customers who elect this option.

Response:

FBC's intent when filing the radio-off application was that the tariff fees would recover the total cost of the radio-off program from those customers electing the radio-off option and FBC believes that it is clear that the Commission's intent when it approved the tariff fees was to recover the total costs of the program from those customers. At page 11 of the Decision accompanying Order G-220-13, the Commission states:

> "Charges should recover only the incremental costs that should be properly attributed to the customers electing to use this optional service in order to ensure there is not a cross-subsidy by the customers not opting out."

However, the per-premise radio-off tariff fees were set based on estimates of the costs of the program and these estimates were acknowledged to be uncertain. For this reason, FBC proposed a mechanism that would adjust the fees if they were not recovering the program costs. At page 19 of the Decision accompanying Order G-220-13, the Commission made the following determination on FBC's proposed adjustment mechanism:

> "The Panel does not consider it reasonable to retroactively adjust or refund the Per-premises Setup Fee charged. To do so would create rate uncertainty for those customers making a decision as to whether or not to participate in the Radio-off AMI Meter Option. Removing rate uncertainty is consistent with the Commission's approach to setting rates based on evidence provided in a rate proceeding. Accordingly, the Panel sets the Per-premises Setup Fee as permanent. …
>
> After full implementation of the AMI project FortisBC may bring forward an application for review of future Radio-off AMI Meter Option rates, following its normal practice."

The Commission therefore considered the possibility that the per-premise radio-off tariff fees might not recover the costs of the program and determined that regardless of this possibility it was not just and reasonable to have an adjustment mechanism in place with respect to per-premise fees.

The per-read meter fees were also set on a permanent basis. An adjustment to per-read fees is possible after the September 30, 2016 cost report is filed, as further discussed in the response to BCUC IR 1.12.3.

> In this Application, FBC indicates that the approved tariff fees are expected to be less than the associated costs with providing the Radio-off service and proposes that the "net

[O&M] costs to all customers of $0.168 million and $0.392 million expected in 2015 and 2016 respectively" be flowed through outside the O&M formula.

On page 46, FBC also proposes to flow through (outside of the capital formula) Radio-off capital-related costs of $0.498 million in 2015 and $0.073 million in 2016.

12.3 Given that FBC's proposed mechanism would flow through the net incremental costs to all customers (regardless of whether or not they have elected the Radio-off option), please discuss whether this proposal meets the intended matching of cost and causation for this program?

Response:

FBC does not expect the approved radio-off per-premise and per-read fees to fully recover costs both because the cost estimates on which the fees were based appear to be too low and because the fees were reduced from those which FBC requested. However, as discussed in response to BCUC IR 1.12.2, the potential for the fees to not recover the costs of the program was considered at the time the rates were set and Order G-220-13 prohibits per-premise radio-off fee adjustments and made those fees permanent. As indicated by the Commission, after full implementation of the AMI project, FBC may bring forward an application for review of future Radio-off AMI Meter Option rates, following its normal practice. Further, pursuant to Order G-220-13, FBC will report by September 30, 2016 on whether or not a revision to the radio-off meter reading fee is required to restore matching of cost and causation for manual reading of radio-off meters.

12.4 Is there another mechanism to treat these net costs? For example, would FBC be amenable to placing these costs in a deferral account for future determination, following the filing of the Radio-off report and the Commission's review of that report. Please discuss.

Response:

Although FBC is amenable to placing the net manual meter reading costs in a deferral account for future determination, the Company assumes that a potential outcome of creating this deferral account would be to recover the deferred amounts through radio-off fees following a revision to the tariff fees, in order to ensure that the costs of manually reading meters is fully borne by the radio-off customers.

FBC provides the following additional information to assist the Commission in determining if this would be an appropriate course of action.

The amounts that would be deferred in 2015 and 2016 are estimated at $0.168 million and $0.392 million respectively, for a total of $0.560 million which could be recovered through future meter read fees from radio-off customers. As shown in the response to BCUC 1.12.5, 2016 tariff revenue for radio-off meter reading for a forecast 1,965 customers is estimated to be $0.212 million. The implication is that recovery of these deferred amounts from future radio-off customers would result in a significant increase to their fees (potentially tripling them). FBC's preferred approach is to recover these costs from all customers until such time as the radio-off fees are reset.

12.5 Please provide a breakdown and details of the net O&M costs of $0.168 million and $0.392 million expected in 2015 and 2016, respectively. Show calculations where possible.

Response:

The following table is based on an assumption that reading 1,965 Radio-Off meters will require 3.3 full time equivalent (FTE) employees. This assumption, along with the actual number of Radio-Off customers, will be validated in FBC's September 2016 report to be filed with Commission pursuant to Order G-220-13.

FEE REVENUE			
Radio-Off Customers	(a)	1,965	
Bi-Monthly Fee	(b)	$18	
Equivalent Monthly Fee	(c) = (b) /2	$9	
Number of months in 2015	(d)	5	
Number of months in 2016	(e)	12	
2015 Revenue	(a) * (c) * (d)	$88,425	
2016 Revenue	(a) * (c) * (e)	$212,220	
RADIO-OFF O&M COSTS			
Labour + vehicle rate	(f)	$88	per hour
Hours per month per FTE	(g)	173	hours
FTE requirement	(h)	3.3	
Radio-Off training	(i)	$5,000	

2015 Costs	(f) * (g) * (h) * (d) + (i)	$256,680
2016 Costs	(f) * (g) * (h) * (e)	$604,032

NET COSTS (Revenue less Costs)	
2015 Net Costs	($168,255)
2016 Net Costs	($391,812)
Total 2015 – 2016 Net Costs	($560,067)

In the Radio-off proceeding, FBC assumed 2.1 additional RF range extenders will be required, with capital and installation costs of $187 and $520 per unit, respectively. FBC also proposed to recover the total incremental capital and installation costs through the one-time per-premise setup fee.

12.6 Please provide a breakdown of the Radio-off capital costs of $0.498 million in 2015 and $0.073 million in 2016, showing the calculation and derivation of the proposed costs.

Response:

Capital costs associated with the radio-off option are being recorded net of the per-premise fees.

PER-PREMISE FEE REVENUES		
2015 Radio-Off Customers	(a)	1,636
2016 Radio-Off Customers	(b)	329
Per-Premise Fee	(b)	$60
2015 Revenue	(a) * (b)	$98,160
2016 Revenue	(a) * (c)	$19,740

RADIO-OFF CAPITAL COSTS	2015	2016
Radio-Off Application	$215,238	$ -
Software Development	$58,266	$ -
Misc Hardware	$6,940	$1,850
Contact Centre	$44,965	$15,610
Radio-Off Meter Installation	$247,056	$66,000
Radio-Off Handheld Readers	$23,260	$10,043
Total Capital Costs	$595,725	$93,503
NET COSTS (Revenue less Capital Costs)		
2015 Net Costs	($497,565)	
2016 Net Costs	($73,763)	
Total 2015-2016 Net Costs	($571,328)	

12.7 Please explain why the incremental O&M portion of the Radio-off costs are proposed to be treated as a Z-factor item while the capital portion of the Radio-off costs are not?

Response:

FBC has not identified the O&M portion of the radio-off costs as a Z-factor. The AMI radio-off costs are excluded from the O&M formula because they are CPCN-related, as explained in the responses to BCOAPO IRs 1.9.1 and 1.9.2.

D. MANDATORY RELIABILITY STANDARD

13.0 Reference: 2016 MRS Incremental Operating Expense

Exhibit B-1, Section 6.3.6, p. 40

MRS costs and Z-factor treatment

"By letter to the Commission dated June 11, 2015, FBC identified that its preliminary estimates of the one-time costs to achieve compliance are in the range of $0.780 million to $1.230 million, and preliminary estimates of its ongoing (annual) costs to maintain compliance are in the range of $0.395 million to $0.525 million."

Further, FBC is forecasting incremental O&M expenses of $0.445 million in 2016, approximately $0.500 million in 2017 and $0.425 million in 2018 and beyond, which it has included in its O&M forecast outside the formula.

13.1 Please clarify which portion of the above amounts represent the "one-time costs" associated with MRS compliance, otherwise are they all related to ongoing (annual) costs?

Response:

Please refer to the response to BCUC IR 1.13.5.

FBC states that the Commission accepted BC Hydro's recommendation of adoption of certain MRS standards and by Order R-38-15, the Commission confirmed adoption of 34 reliability standards.

13.2 Please confirm that not all of the 34 reliability standards are applicable to FBC.

Response:

FBC confirms that 29 of the 34 adopted reliability standards apply to FBC.

13.3 Please also confirm that FBC has previously indicated to the Commission that the adoption of some standards do not incur any incremental costs for FBC.

Response:

Confirmed. Of the 29 standards that apply to FBC, 13 have no associated incremental costs to the Company.

13.4 Please confirm that not all standards require immediate adoption and that FBC could delay the adoption of certain standards.

Response:

The Commission has adopted the relevant standards in Order R-38-15 and Order R-38-15 sets out the effective date by which FBC is required to be compliant with each standard. FBC cannot delay adoption of the standards beyond the effective date, nor would FBC consider it prudent to do so from a reliability perspective.

As indicated in Order R-38-15, not all standards are effective immediately after the Commission's adoption, as some provide time for the utility to transition to the new standard. FBC must begin preparing in advance in order to be able to meet the requirements of the new standards on the dates they are effective.

13.5 Please provide a table listing all relevant standards applicable to FBC, the costs forecast broken down by one-time costs and on-going costs as provided by FBC during the MRS Assessment Report No.8, then compare to the current cost forecast for each standard for each of 2016 to 2018. Please also include the effective date of adoption for each standard. Please clearly show the breakdown of costs for each applicable standard and how this reconciles to the proposed costs for 2016 in this Application.

Response:

Table 1 below provides the cost forecast by standard.[4] Each CIP standard exists as part of a suite of CIP Standards related to cyber security and this suite of CIP Standards is referred to as

[4] In this and other MRS-Related IRs, the following standard abbreviations apply:
CIP – Critical Infrastructure Protection
EOP – Emergency Preparedness and Operations

the Version 5 CIP Cyber Security Standards. Because the CIP standards are complex and highly interdependent, it is necessary to treat the effort to implement and maintain compliance to them as a single group.

As discussed in the response to BCUC IR 1.13.4, adoption of the new/revised standards occurred when the Commission issued Order R-38-15. Table 1 shows the effective dates pursuant to Order R-38-15. FBC's preliminary cost estimates were identified as ranges in the initial input to Assessment Report 8 and are provided as a summary in Table 2 (one-time costs include one-time O&M plus capital) along with a comparison to the estimates in the same format.

FBC is requesting approval for only the 2016 expenditures at this time. The effort in 2016 will define the scope, evaluate options, and determine the solutions required to be compliant with the standards in Assessment Report 8. 2017 and 2018 are preliminary cost estimates which will be refined as part of the effort in 2016 with updated estimates to be submitted in future annual reviews.

In addition, any variances to the amounts included in 2016 rates will be treated as flow-through and will be trued up in the subsequent year's revenue requirements.

Table 1: Incremental Costs Associated with Assessment Report No. 8

Adoption Date	Effective Date	Standards	2016			2017			2018
			One-Time O&M	Ongoing O&M	One-Time Capital	One-Time O&M	Ongoing O&M	One-Time Capital	Ongoing O&M
24-Jul-15	1-Oct-18	CIP Version 5 Standards	$ 320,000	$ -	$ -	$ 430,000	$ -	$ 445,000	$ 397,000
24-Jul-15	1-Oct-16	EOP-010-1 (New)	$ 20,000	$ -	$ -	$ -	$ 3,000	$ -	$ 3,000
24-Jul-15	1-Oct-16	FAC-001-2	$ 25,000	$ -	$ -	$ -	$ -	$ -	$ -
24-Jul-15	1-Oct-16	PER-005-2	$ 35,000	$ -	$ -	$ 40,000	$ 25,000	$ -	$ 25,000
24-Jul-15	1-Oct-17	PRC-005-2	$ 20,000	$ -	$ -	$ -	$ -	$ -	$ -
24-Jul-15	1-Oct-16	VAR-001-4 & VAR-002-3	$ 25,000	$ -	$ -	$ -	$ -	$ -	$ -
		Total	$ 445,000	$ -	$ -	$ 470,000	$ 28,000	$ 445,000	$ 425,000

FAC – Facilities Design, Connections and Maintenance
PER – Personnel Performance, Training and Qualifications
PRC – Protection and Control
VAR – Voltage and Reactive
TPL – Transmission Planning

Table 2: Comparison of Incremental Costs to Assessment Report No. 8 Input

Standards	Estimates		Assessment Report No. 8 Input			
	One Time Costs	Ongoing Costs	One Time Costs		Ongoing Costs	
			Low	High	Low	High
CIP Version 5 Standards	$ 1,195,000	$ 397,000	$ 645,000	$ 1,025,000	$ 362,000	$ 475,000
EOP-010-1	$ 20,000	$ 3,000	$ 20,000	$ 30,000	$ 3,000	$ 5,000
FAC-001-2	$ 25,000	$ -	$ 15,000	$ 25,000	$ -	$ -
PER-005-2	$ 75,000	$ 25,000	$ 60,000	$ 80,000	$ 20,000	$ 30,000
PRC-005-2	$ 20,000	$ -	$ -	$ 15,000		
VAR-001-4 & VAR-002-3	$ 25,000	$ -	$ 20,000	$ 25,000	$ -	$ -
TLP-001-4	$ -	$ -	$ 20,000	$ 30,000	$ 10,000	$ 15,000
Total	$ 1,360,000	$ 425,000	$ 780,000	$ 1,230,000	$ 395,000	$ 525,000

13.6 For each of the applicable standards listed in the previous question, please clearly identify the capital related costs and the O&M related costs. Please also identify the relationship between the one-time costs / ongoing costs to capital or O&M related costs.

<u>Response:</u>

Please refer to the response BCUC IR 1.13.5, which shows the estimated one-time and ongoing O&M expenditures. All capital expenditures are one-time expenditures.

On page 143 of the PBR Application, FBC provides descriptions of the Engineering Services and Project Management O&M departments and states that:

> The Mandatory Reliability Standards department is responsible for ensuring corporate compliance with the BC Mandatory Reliability Standards. On-going effort is required to ensure auditable compliance with all applicable standards and to evaluate the impacts of and implement changes to existing and new

standards as well as processes and procedures (internal and external) to support the MRS program in British Columbia.

On page 238 of the PBR Decision, the Commission acknowledged that "In its 2012–2013 FBC RRA Decision, the Commission approved O&M expenses related to MRS totaling $1.2 million in 2012 and $1.2 million in 2013…" The Commission then dealt with the incremental MRS O&M costs through deferral treatment.

13.7 It appears that at least $1.2 million for MRS are already included in FBC's 2013 base O&M. Please provide further justification on why any incremental O&M costs should be treated outside of the O&M formula capital.

Response:

The amount included in the 2013 Base O&M for MRS was $2.150 million[5]. These are the ongoing O&M costs required to maintain compliance with the MRS standards that were applicable to FBC in 2013 and continue to be applicable today.

The costs for which FBC requests approval in this application are incremental costs required to achieve and maintain compliance with the standards newly adopted by Order R-38-15. These incremental costs should be treated outside of the formula O&M and formula capital amounts because they meet the criteria for exogenous factor treatment under the terms of the PBR Plan.

In Section 12.2.2 of the Application, FBC explains that the costs required as a result of the adoption of the reliability standards meet the exogenous factor criteria because:

- The costs are entirely attributed to complying with the changes to BC's MRS program approved by Order R-38-15, which is an event outside the control of FBC. These changes were developed by regulatory bodies in the U.S., assessed for adoption by BC Hydro and then adopted by the BCUC. FBC is legally obligated to comply with the new reliability standards.
- As described in section 6.3.6, the costs are directly and solely attributable to complying with the changes to the BC MRS program approved on July 24, 2015. These costs have not been previously incurred and were not known at the time the 2013 base O&M was determined and therefore were not included in the 2013 base O&M used to determine the O&M expense included in the PBR formula.
- The costs to comply with the reliability standards that were approved by Order R-38-15 could not have been foreseen at the time the 2013 base was set as the new standards were either non-existent or under preliminary development at the time.

[5] 2014 – 2018 PBR Application, page 145.

- FBC will manage its costs to comply with the reliability standards in a prudent manner and the Commission will have the opportunity to review the costs in subsequent annual reviews.
- The forecast O&M costs of $0.445 million in 2016, $0.500 million in 2017, and $0.425 million in 2018 and beyond, and the forecast capital expenditures of $0.445 million in 2017 exceed the materiality threshold of $0.301 million.

13.8 For each applicable standard, outlined in Order R-38-15, and for which FBC has indicated an incremental O&M costs (as requested in previous questions) please explain why the adoption of the standard is not already performed by personnel and O&M budget already included in the base O&M.

Response:

The following table summarizes the activities that will be required to achieve and maintain compliance with the standards adopted by Order G-38-15. Since the activities were not performed, or required to be performed, prior to the adoption of these standards, the costs are not included in Base O&M Expense.

<table>
<tr><td>CIP Version 5 Standards
(as these standards are interdependent, the activities are more easily explained by aggregating)</td><td>FBC will need to
• Create, implement and maintain new or significantly modified processes and procedures. This will include development and maintenance of:
  o new cyber systems lists; and
  o new in-scope assets.
• Evaluate, develop and implement:
  o additional training and awareness;
  o stringent controls regarding vendor (external) relations and access management;
  o additional security measures; and
  o technical solutions for additional assets being brought into scope.
• Analyse, select, acquire and implement effective solutions for modified and new procedures.
• Increase the frequency of monitoring and maintenance of cyber systems and supporting tools
• Address recovery exercises conducted on cyber systems, all within the required time periods/cycles.</td></tr>
</table>

EOP-010-1 (New)	FBC will need to create and implement a new internal operating procedure to respond to Geomagnetic Disturbances, which will also require review and approval by Peak Reliability.
FAC-001-2	FBC will need to complete a major review and update to several publicly available procedures.
PER-005-2	A higher level of annual review and tracking will require development of a reporting mechanism to track annual reviews and updates of reliability related tasks. FBC will be required to develop and deliver an annual training program to operations support personnel.
PRC-005-2	Changes in this version of the standard include required testing for generator station service and exciter relays. Additional testing for auxiliary tripping relays may be required
VAR-001-4 & VAR-002-3	FBC will need to review, update, approve and implement internal operating procedures.

E. WILDFIRE DAMAGE

14.0 Reference: 2015 Wildfire Damage

Exhibit B-1, p.47, pp. 94–95

Wildfire Damage and Z-Factor Treatment

FBC discusses the 2015 wildfire damage. Pertaining to the Rock Creek wildfire, FBC states on page 47 that the distribution line feeding repeaters at the peak of Kobau Mountain is yet to be rebuilt as of September 8, 2015, as crews have not been allowed to access the line.

14.1 When does FBC anticipate re-entry into the affected area? What are FBC's best estimated costs to repair/rebuild this line?

Response:

The area is still an active fire zone. FBC anticipates accessing the Pine Street 2 feeder (Kobau Mountain) in October 2015. A high level estimate to repair/rebuild the line is approximately $1 million based on an aerial survey of the line.

14.2 How does FBC propose to treat these 2015 incremental capital costs subsequent to the Commission's decision of this annual review proceeding?

Response:

FBC proposes that the actual costs will be included as part of FBC's compliance filing following the decision, and actual expenditures will be included in rate base for setting 2016 rates. FBC expects that the remaining fire-related capital work will be completed in October and that final expenditures will be known before a decision is issued in regards to the Application.

FBC explains on pages 94 and 95 that the costs of the magnitude of the experience in 2015 were not included in the 2013 base capital and that no measures could have been taken to prevent the damage. FBC also states that all of the costs to repair on an emergency basis have been or will be prudently incurred.

14.3 Please discuss whether FBC could have made an insurance claim for any damages related to the 2015 wildfires.

Response:

An insurance claim for damages related to the 2015 wildfires was not possible as the assets damaged were not covered by FBC Property insurance policies. The FBC insurance program excludes transmission and distribution line assets, as full insurance coverage remains either unavailable and/or uneconomical due to extremely low market capacity for this class of risk exposure. Only transmission and distribution lines which are within 1,000 feet of an insured generation plant or substation are covered by FBC Property insurance policies.

In the PBR Decision on page 28, FBC characterizes exogenous factors as "non-controllable and unforeseen costs/revenues…"

14.4 Please provide historical evidence for the occurrence wildfires in FBC's service area in the past 10 years. Please also provide the capital spending on these events for each of the past 10 years.

Response:

FBC has no records of wildfires causing damage to company assets in the past 10 years. Although the Application at page 95 states that wildfires "in recent years" have generally resulted in damage to approximately three or four structures, FBC has investigated further in responding to this IR and concluded that in fact these instances occurred outside of the ten-year timeframe and were not recent. Therefore, there were no fire-related capital expenditures in FBC's 2013 capital expenditures, upon which the PBR formula amount is based.

The last wildfire known to cause damage to FBC assets was in 2003, during which the Okanagan Mountain Fire caused $2.4 million in damages to the transmission and distribution systems.

F. FINANCING

15.0 Reference: Financing

Exhibit B-1, pp. 51–52

Long-term debt costs

FBC states that it anticipates to issue "long-term debt of $100 million during October 2016, at a rate of 4.6 percent…The proceeds of this issuance are expected to be used to repay unfunded debt, as well as to repay the $25 million Series H debenture with a coupon rate of 8.77 percent maturing in February 2016."

15.1 Please confirm that the long-term debt issuance of $100 million is anticipated in October 2015, not October 2016.

Response:

Not confirmed. The projected long-term debt issuance is anticipated in October 2016 as stated.

The unfunded debt, also referred to as credit facilities or short term debt, will be used to repay the $25 million Series H debenture maturity in February 2016. The aggregate draws on the credit facilities, including those used to repay the Series H debenture, are expected to approach $100 million by October 2016, at which time a long-term $100 million debenture is forecast to be issued in order to pay down the draws on the credit facilities.

15.2 Please explain the "unfunded debt" as referred to in the preamble.

Response:

Unfunded debt, as referred to in the preamble, is also referred to as Short term Debt. Short-term Debt is described on page 52 of the Application "FBC obtains short-term funding primarily through the issuance of Bankers' Acceptances and prime lending rate margin loans, both drawn on its $150 million operating credit facility…". Conversely, funded debt is synonymous with long-term debt.

15.3 Please clarify whether the intent of the repayment of the Series H debenture is to retire high cost debt with lower cost financing. If not, please explain.

Response:

The Series H debenture matures in February 2016, which means that FBC is required to repay the principal balance of $25 million back to the debtholders pursuant to the 1996 trust indenture. The primary intent of the new debt issue is to ensure that there is adequate funding and liquidity as described in response to BCUC IR 1.15.1. While there is a benefit to customers of the Series H higher cost debt being replaced with lower cost financing through unfunded debt and a long-term debt issuance in October 2016, this is a result of the current market conditions. There could be instances where lower cost debt is maturing and is required to be re-financed with higher cost financing as a result of the market conditions at that point in time. In such situations, the primary intent will still be to ensure adequate funding and liquidity to make the repayment when the debt matures.

15.4 Was the Series H debenture originally established as a callable debenture? If not, what is the penalty to repay this debenture as proposed by FBC?

Response:

Similar to many long-term debentures, Series H was originally established with a callable feature provision that would permit early redemption, also known as repaying the debt earlier than its original maturity date. However, the economics of early redemption provisions generally deter prepayment of the debt, as shown in the response to BCUC IR 1.15.5.

15.5 What is the net benefit (net savings) for customers by repaying the Series H debenture for the period of October 2015 to February 2016? Show calculations.

Response:

There would be a net cost, rather than a net benefit, to customers of approximately $500 thousand by repaying the Series H debenture for the period of October 2015 to February 2016. The calculations are as follows:

	Series H ($000s)	
Coupon	8.77%	(a)
Face Value	25,000	(b)
Maturity Date	01-02-2016	
Semi Annual Periods to maturity (rounded up)	1.0	(c)
Government of Canada Yield	0.492%	(d)
Prepayment Spread	0.35%	(e)
Yield To Market rate	0.84%	(f)=(d)+(e)
Redemption Cost on October 1, 2015	25,987	(g)=present value of [(f)/2, '(c'), (a)x(b)/2, (b)]
Excess to Par Price (Face Value)	987	(h)=(g)-(b)
Refinancing Rate	4.21%	(i)
Interest on new debt issuance	526	(j)=(b)x(c')/2x(i)
Interest cost of debt to maturity	1,096	(k)=(b)x(c')/2x(a)
Excess cost (savings) of debt to refinance with early redemption	**461**	(h)-(j)

For Series H, the early redemption price is the greater of the face value of the debenture ($25 million) and Canada Yield Price, as well as unpaid interest. The Canada Yield Price requires a yield to maturity compounded semi-annual calculation. The yield to maturity calculation assumes that all semi-annual coupon interest payments are reinvested at the same rate as the Series H current yield of 8.77 percent and takes into account the debenture's current market price, face value, coupon interest rate and term to maturity. The yield to maturity calculation utilizes a discount rate equal to the Government of Canada Yield (estimated to be 0.492% as at October 1, 2015), plus 0.35% pursuant to the Series H redemption provision.

The above calculation has been prepared on a simplified and hypothetical basis as it assumes that FBC would theoretically be able to refinance a new public debt tranche for $25 million at the current 30 year coupon rate of 4.21%. However there is a low probability that a $25 million debt tranche would be readily accepted by the capital market without demanding a liquidity premium which would be dependent on the market demand and the number of investors participating at that time. Previously, $100 million debt tranches were viewed by the market as the minimum debt tranche sizes, however the market is beginning to require larger deals in excess of $100 million to provide sufficient liquidity for the secondary market trading. Series H was originally issued as a private placement debt and its coupon rate of 8.77% reflects the lack of liquidity and limited number of investors. Accordingly the excess costs to customers required to refinance Series H would actually be higher than in the above calculation.

15.6 Given that the Series H debenture was first issued in January 1992, please explain why FBC did not previously consider repaying this debenture and/or replacing it with lower cost financing in earlier years.

Response:

FBC notes that the Series H debenture was first issued in February 1996 (rather than January 1992 as referenced in the question). Due to the existence of early redemption provisions which generally deter early repayment, the pricing of the Government of Canada yield during this period, and the lack of market demand for a relatively smaller debt tranche of $25 million, as explained in the responses to BCUC IRs 1.15.4 and 1.15.5, FBC would have incurred an increased cost of debt for customers if it were to have refinanced the Series H debenture earlier than February 2016 as required pursuant to the trust indenture.

15.7 According to FBC's Schedule 27, FBC currently has several higher cost debt instruments with high embedded financing costs. Given the current market lending rates and FBC's current credit ratings, please provide a discussion and analysis (including calculations, where appropriate) on whether any other debentures / debt instruments listed are callable and can be repaid/refinanced with lower cost debt (in particular, Series G, Series I, and MTN-09). Please also include a discussion on any repayment penalties.

Response:

Series G, I and MTN-09 are redeemable prior to the date of maturity, but these debt instruments are subject to redemption terms that limit the ability of the borrower to take advantage of lower borrowing rates and refinance with lower cost debt prior to maturity. Under the applicable redemption terms for Series G, I and MTN-09, the applicable redemption price would be equal to the price of the applicable debenture to be redeemed calculated to provide a yield to maturity compounded semi-annually equal to the Government of Canada Yield plus a spread of 25-40 basis points. Based on current rates, the cost to redeem and refinance early would exceed the cost of refinancing upon maturity.

A detailed discussion on the increased cost of debt resulting from early redemption, along with a calculation example on Series H, is provided in the response to BCUC IR 1.15.5. To further supplement the response, an estimate of the cost to redeem Series G in October 2015 is shown as follows:

	Series G ($000s)	
Coupon	8.80%	(a)
Face Value	25,000	(b)
Maturity Date	28-08-2023	
Semi Annual Periods to maturity (rounded up)	15.0	(c)
Government of Canada Yield	1.24%	(d)
Prepayment Spread	0.40%	(e)
Yield To Market rate	1.64%	(f)=(d)+(e)
Redemption Cost on October 1, 2015	37,591	(g)=present value of [(f)/2, '(c'), (a)x(b)/2, (b)]
Excess to Par Price (Face Value)	12,591	(h)=(g)-(b)
Refinancing Rate	4.21%	(i)
Interest on new debt issuance	7,894	(j)=(b)x(c')/2x(i)
Interest cost of debt to maturity	16,500	(k)=(b)x(c')/2x(a)
Excess cost (savings) of debt to refinance with early redemption	**4,697**	(h)-(j)

Table 8-1 on page 53 of the Application shows FBC's short-term interest rate forecast.

15.8 Please provide a table showing the proportion (in dollars) of Banker's Acceptance loans and Prime Lending Rate Margin Loans.

Response:

The table below shows the forecasted proportion (in thousands of dollars) of Banker's Acceptance loans and Prime Lending Rate Margin Loans.

	Balance	Allocation
Banker's Acceptance loans	79,272	90%
Prime Lending Rate Margin Loans	8,808	10%
Total Short Term Debt	88,080	100%

G. TAXES

16.0 Reference: Taxes

Exhibit B-1, p. 55–56

Property taxes

FBC states that property taxes in 2016 are forecast to increase 13 percent from 2015, which is partly due to changes in revenues used to calculate the grant-in-lieu of taxes to municipalities. FBC states that the revenues reported to municipalities are expected to increase by <u>10.6 percent</u> based on actual revenues to be reported.

16.1 Please clarify whether the grant-in-lieu of taxes are similar to municipal franchise fees.

<u>Response:</u>

Grants-in-lieu of taxes are separate and distinct from municipal franchise or operating fees.

FBC does not collect and remit municipal franchise fees. FEI does collect franchise (operating) fees, which are based on an agreement between the Company and a municipality for the use of public spaces within the municipality. In exchange for 3% of gross revenues, excluding gas for resale to the municipality, the company is granted access to these public places. These fees are collected from customers and paid to the municipality

The grant-in-lieu of taxes is a legislated requirement under the Local Government Act that applies to a utility company doing business in the municipality, which includes both FBC and FEI. For certain improvements other than buildings that are used solely in the municipality for local purposes, the company pays 1% of gross revenues on gas consumed within the municipality excluding gas for resale. This is paid in lieu of general municipal taxes that are levied directly by the municipality which would otherwise be calculated by multiplying the taxable assessment by the general municipal rate set annually by Council.

16.2 On schedule 19 of the Financial Schedules, the forecast 2016 Wholesale revenues is less than a 1 percent increase over 2015 and the overall revenue increase of all rate classes is 4.6 percent over 2015. Please show the calculation supporting the 10.6 percent increase of revenues anticipated to be reported to municipalities, as referenced in the preamble.

<u>Response:</u>

Revenues forecasts in Schedule 19 reflect total revenues in the year earned, whereas revenues used to calculate the grant-in-lieu of taxes are based on gross sales of electricity within the municipality, excluding electricity sold for resale, from the second preceding year. With the acquisition of the City of Kelowna distribution system on March 31, 2013, only 9 months of revenue was included in 2015. 2014 revenues used to calculate the 2016 grant in lieu payment will be the first year the grant-in-lieu is based on a full 12 months.

2016 Grant in Lieu Payment Compared to 2015 Grant in Lieu Payment

Municipality	Type	2016 Taxes Payable	2015 Taxes Payable	$ Change	% Change
Castlegar	City of	139,160.68	133,253.94	5,906.74	4.4%
Creston	Town of	57,463.95	56,895.20	568.75	1.0%
Fruitvale	Village of	15,589.13	15,681.49	(92.36)	(0.6%)
Grand Forks	City of	62,470.03	57,405.37	5,064.66	8.8%
Greenwood	City of	6,876.37	7,275.55	(399.18)	(5.5%)
Kaslo	Village of	14,361.55	13,071.30	1,290.25	9.9%
Kelowna	City of	1,259,475.04	1,100,476.10	158,998.94	14.4%
Keremeos	Village of	16,082.95	15,829.46	253.49	1.6%
Lake Country	District of	4,133.20	3,727.02	406.18	10.9%
Midway	Village of	14,870.07	13,701.86	1,168.21	8.5%
Montrose	Village of	6,980.17	6,641.05	339.12	5.1%
Oliver	Town of	48,646.13	49,578.79	(932.66)	(1.9%)
Osoyoos	Town of	66,062.44	61,310.88	4,751.56	7.7%
Penticton	City of	2,219.23	2,587.23	(368.00)	(14.2%)
Princeton	Town of	50,520.40	48,390.44	2,129.96	4.4%
Rossland	City of	32,401.16	32,410.41	(9.25)	(0.0%)
Salmo	Village of	10,730.26	10,660.92	69.34	0.7%
Slocan	Village of	4,313.56	4,332.50	(18.94)	(0.4%)
Summerland	District of	4,984.78	4,820.21	164.57	3.4%
Trail	City of	86,037.95	82,583.65	3,454.30	4.2%
Warfield	Village of	11,888.66	11,537.19	351.47	3.0%
		1,915,267.71	**1,732,170.56**	**183,097.15**	**10.6%**

FBC also explains that a portion of the property taxes increase in 2016 is related to changes in the assessed values by BC Assessment.

16.3 Please provide a discussion and further evidence for the 45.9 percent increase in assessed values for distribution lines and the 13.5 percent increase in assessed values for transmission lines.

Response:

Recently, BC Assessment has been reviewing various legislated rates that have historically been subject to an annual update using numerous negotiated approaches. Since the original rates that were subject to he annual update were established around 1986 there has been no comprehensive review. BC Assessment advised FBC in late 2014 that it intended to undertake a comprehensive review of the legislated rates used for valuing electric distribution lines and transmission lines. At that time, BC Assessment stated its intention to have the review completed for implementation in the 2016 assessment roll.

At the start of 2015, both FBC and BC Hydro began discussions with BC Assessment to determine an appropriate methodology for establishing rates set out in legislation, given that BC Assessment had no information on how the original rates were established in the mid to late 1980s. After agreeing to a basic model for the valuation of distribution and transmission lines, both FBC and BC Hydro provided current cost information as required by legislation.

The Assessment Act requires that the valuation of electric distribution and transmission lines:

1. must be based on the average current cost of the existing improvements, and
2. “average current cost” means the cost to construct or install the existing improvements
    a. Including all materials, labour, overhead and indirect costs,
    b. Assuming improvements were constructed or installed
        i. On July 1 of the previous year to the assessment roll, and
        ii. At a location that has average construction and installation difficulty.

After reviewing the cost information provided, it became apparent that there were some differences of opinion on whether the cost information provided was adequate. The rates used to establish the 45.9 percent increase for distribution lines and the 13.5 percent increases in the assessed values were based on the information provided by both FBC and BC Hydro. These increases assumed the total rate increase would be phased in over 3 years, as permitted by legislation.

By September 2015, it became apparent that BC Assessment had a different opinion on what the legislation mandated to be included compared to FBC and it was unlikely that these differences could be resolved prior to the date 2016 rates needed to be approved for establishing 2016 values. On September 10, 2015 BC Assessment advised that it would be delaying the implementation of new rates until the 2017 assessment roll, and the update of the rates for 2016 would be based on the same methodology used in prior years. For 2016, the increase put forward by BC Assessment was 0 (zero) percent. Based on this change, FBC provides below a revised Table 9-1 including a decrease in the 2016 estimate from $17.320 million to $15.407 million.

Revised Table 9-1: Property Taxes ($ millions)

	Approved 2015	Projected 2015	Revised Forecast 2016
Generating Plant	2.982	2.918	2.995
Transmission and Distribution	6.278	6.123	6.139
Substation Equipment	3.600	3.584	3.651
Land and Buildings	0.705	0.684	0.707
1% of Revenue	1.766	1.732	1.915
Total Property Tax	**15.331**	**15.041**	**15.407**

The forecast 2016 reduction of $1.913 million in property taxes will be incorporated into an evidentiary update to be filed by FBC prior to the Annual Review Workshop.

16.3.1 Is the assessment for right-of-ways where FBC's distribution and transmission lines are located or is it for the physical lines themselves?

Response:

Rights of way for FBC's distribution and transmission lines are assessed separately from the physical lines, but only when they are located on Crown land. Under the Assessment Act occupiers of Crown land are treated for assessment purposes as the owner. Rights of way over private land or in a road allowance are not assessed.

16.3.2 Does FBC agree that these assessments are reasonable? Has FBC made any attempts to appeal these assessments? Please discuss.

Response:

Please refer to the response to BCUC IR 1.16.3 for background on the increases and the process that FBC has been involved in with BC Assessment. The expected rate increase has been delayed and FBC's 2016 property taxes have been reduced.

16.3.3 Has FBC observed similar increases to other areas in British Columbia? Please discuss.

Response:

Although the tax increase has now been delayed, as explained in the response to BCUC IR 1.16.3, FBC confirms that the rates used to value distribution and transmission lines apply equally throughout British Columbia.

BC Assessment has indicated that other linear utilities have or will be experiencing similar or larger increases resulting from their rate reviews.

17.0 Reference: Taxes

Exhibit B-1, p. 56

Income taxes

FBC states that income tax is forecast to increase in 2016 by $0.836 million or 12.5 percent primarily due to an increase in overall revenues, a decrease in lower deductible temporary tax timing differences associated with CCA, a decrease in pension and OPEB contributions and an increase in the amortization of deferral credits and flow-throughs.

17.1 Please provide a table showing the percentage and income tax dollar impact for each of the items listed in the preamble.

<u>Response:</u>

The table below shows the percentage and income tax dollar impact for each of the items listed in the preamble.

	Income Tax Impact ('000)	Precentage
Revenue Less Expenses before Timing Differences	642	9.62%
Timing Differences		
Difference between CCA & Depreciation	197	2.93%
Net Pension & OPEB Contributions and Expenses	388	5.78%
Amortization of Deferral Credits & Flow-throughs	(528)	-7.88%
Other Timing Differences	137	2.04%
	836	12.50%

H. EARNING SHARING

18.0 Reference: Earnings Sharing

Exhibit B-1, p. 60

Calculation of earnings sharing to be returned in 2016, Table 10-2

FBC states that the earnings sharing is calculated each year as one-half of the pre-tax earnings impact of the variances in the formula driven gross O&M and cumulative capital expenditures.

18.1 Please clarify whether the cumulative nature of the capital sharing formula is the same as in previous PBRs (pre-2013).

Response:

The cumulative nature of the capital sharing formula is not the same as in previous PBRs.

FBC's previous PBR (2007 – 2011) did not set capital expenditures by formula and its earnings sharing was based on the variance between allowed and actual earnings.

FEI's previous PBR (2004 – 2009) did set capital expenditures by formula, but its earnings sharing was also based on the variance between allowed and actual earnings. In this way, the cumulative variances in capital expenditures impacted the rate base and that in turn impacted the earnings and the earnings sharing calculation.

18.2 Please provide a breakout of the capital portion of Table 10-2 showing 2014 and 2015 separately.

Response:

A restated Table 10-2 showing the 2014 and 2015 components of capital is provided below.

Table 10-2 Restated: Calculation of Earnings Sharing to be Returned in 2016 ($ millions)

Line No.	Description				Reference
1	Approved Formula O&M	$ 52.984			G-139-14
2					
3	Actual/Projected Gross O&M	58.230			
4					
5	Less: O&M Tracked Outside of Formula				
6	Pension/OPEB (O&M Portion)	3.925			
7	Insurance Premiums	1.334			
8	Advanced Metering/Infrastructure Costs/Savings	0.452			
9	Advanced Metering/Infrastructure Radio-Off	0.168			
10	2015 MRS Audit	0.350			
11	Total	6.229			Sum of Lines 6 - 10
12					
13	Actual/Projected Base O&M	52.001			Line 3 - Line 11
14					
15	O&M Subject to Sharing	(0.983)			Line 13 - Line 1
			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	99.229	49.379	49.850	
21					
22	Less: Capital Expenditures Tracked Outside of Formula				
23	Cumulative Pension and OPEB	10.649	6.396	4.253	
24					
25	Actual/Projected Base Capital Expenditures	88.580	42.983	45.597	Line 20 - Line 23
26					
27	Actual Base Capital Expenditure Variance	4.003	0.790	3.213	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	0.147	0.029	0.118	Product of Lines 27, 28 & 29
31					
32	Tax Rate	26.00%	26.00%	26.00%	G-139-14
33					
34	Before Tax Capital Expenditures Subject to Sharing	0.198	0.039	0.159	Line 30 ÷ (1 - Line 32)
35					
36	Total Before Tax Sharing Account	(0.785)			Line 15 + Line 34
37	Sharing Percentage	50.00%			G-139-14
38					
39	Earnings Sharing Before Adjustments	(0.393)			Line 36 x Line 37
40	Actual Customer Growth Adjustment	0.001			Table 10-1, Line 17
41	2015 Earnings Sharing	(0.392)			Line 39 + Line 40
42					
43	2014 Pre-Tax Earnings Sharing True-Up	-			
44	2016 Pre-Tax Amortization	(0.392)			Line 41 + Line 43
45	2016 After-Tax Amortization	(0.290)			Sch 12 Line 21 Col 6

18.3 For ease of reference and transparency, would FBC be amendable to showing separate years in the cumulative capital expenditures and calculations going forward?

Response:

Yes, FBC will show annual and cumulative expenditures and calculations in future applications.

I. ACCOUNTING MATTERS

19.0 Reference: Depreciation Study and Rates

Exhibit B-1, p. 98

Depreciation rates

FBC states that Gannet Fleming has estimated the depreciation rates using various statistical methods, operating interviews with FBC staff and informed judgement based on their experience in the electricity industry.

19.1 Please explain whether Gannet Fleming has included any jurisdictional studies and comparisons in his analysis. For example, when reviewing the useful life of the asset classes, were considerations given to results of observed useful lives in other comparable utilities? Please generally discuss the results of any comparable utilities, at minimum, for the 5 asset classes identified on pages 99 to 100 of the Application.

<u>Response:</u>

Gannett Fleming did consider useful life estimates from other Canadian electric utilities, including AltaLink, ATCO Electric, FortisAlberta, Manitoba Hydro, and BC Hydro. The useful life estimates in years for the five asset classes identified on pages 99 to 100 of the Application for these five utilities, are summarized in the table below that was provided by Gannett Fleming.

In general, a lower life estimate, in years, would result in a higher depreciation rate. However, the ultimate rate derived from the depreciation study also takes into account differences between the actual reserve booked (i.e. accumulated depreciation) compared to the calculated reserve. These differences can arise as a result of changes in the asset class' estimated life over time and the recovery of gains/losses on retirement of assets recorded in the reserve account.

As indicated in the table below, the life estimates used by other Canadian electric utilities are, for the most part, comparable to those used by FBC. Due to the individual circumstances of each utility (life of system, asset maintenance practices, etc.), FBC cannot comment on why there are differences for each specific utility.

Asset Class	AltaLink	ATCO Electric	FortisAlberta	Manitoba Hydro	BC Hydro	FBC
Transmission Substation Equipment (353)	47	53	n/a	n/a	45	50

Asset Class	AltaLink	ATCO Electric	FortisAlberta	Manitoba Hydro	BC Hydro	FBC
Distribution Conductors and Devices (365)	65	n/a	45 / 58	60	45	49
Distribution Line Transformers (368)	n/a	51	27	50	35	45
Structures-Masonry (390.1.2)	45	40	25 / 40	45 / 100	60	40 / 41
Transportation Equipment (392.1.2)	8	8 / 18	3 / 14	11 / 19	8 / 13	10 / 15

FBC provides a discussion on the asset categories that account for the majority of the forecast change in depreciation expense: Transmission Substation Equipment (353), Distribution Conductors and Devices (365), Distribution Line Transformers (368), Structures-Masonry (390.1.2) and Transportation Equipment (392.1.2).

19.2 Please provide a similar discussion on the drivers of the changes to the depreciation rates for the other asset classes listed on Table 12-2 which is greater than $0.5 million.

Response:

The asset classes in Table 12-2 with variances greater than $0.5 million that were not explained in the application are Transmission Poles, Towers and Fixtures with a decrease of $0.787 million (355.00), Distribution Substation Equipment with a decrease of $0.791 million (362.00), Distribution Poles, Towers and Fixtures with a decrease of $0.575 million (364.00), and Communication Structures and Equipment with a decrease of $0.743 million (397.00). Variance explanations for each of these asset classes are provided below.

For Transmission Poles, Towers and Fixtures (355.00), Gannett Fleming recommends a 50 year life, which is the same as the service life recommended in the previous study. A recent review of retirements, additions and other plant transactions for the period 1950 to 2014 suggests that an average service life of 50 years is still reflective of the historical retirement activity and falls within the typical range of lives used for this account. As a result of an accumulated depreciation deficiency that existed in this asset class as of the date of the previous study of December 31, 2009, a higher rate was incorporated at that time to make up for the historical under depreciation. Therefore, even though the average service life for

Transmission Poles, Towers and Fixtures remains at 50 years, the decrease of approximately 0.75 percent in the depreciation rate for this category is primarily a result of no longer having an accumulated depreciation deficiency that existed at the date of the previous depreciation study.

For Distribution Station Equipment (362.00) Gannett Fleming recommends a 50 year life, a decrease from the 55 year service life recommended in the previous study. Review of retirement transactions suggests that an average service life of 50 years is more reflective of the historical retirement activity and falls within the typical range of lives used for this account. The decrease of the average service life results in an increase to the depreciation rate. However, as a result of an accumulated depreciation deficiency that existed in this asset class as of the date of the previous study of December 31, 2009, a higher rate was incorporated at that time to make up for the accumulated depreciation deficiency, which has been caught up by December 31, 2014, the date of the latest depreciation study. Therefore the decreased rate is the result of no longer having an accumulated depreciation deficiency, partially offset by the reduced service life of the assets.

For Distribution Poles, Towers and Fixtures (364.00), Gannett Fleming recommends a 50 year life, which is the same as the service life recommended in the previous study. A recent review of retirements, additions and other plant transactions for the period 1940 to 2014 suggests that an average service life of 50 years is still reflective of the historical retirement activity and falls within the typical range of lives used for this account. As a result of an accumulated depreciation deficiency that existed in this asset class as of the date of the previous study of December 31, 2009, a higher rate was incorporated at that time to make up for the historical under depreciation. Therefore, even though the average service life for Distribution Poles, Towers and Fixtures remains at 50 years, the decrease of approximately 0.29 percent in the depreciation rate for this category is primarily a result of no longer having an accumulated depreciation deficiency that existed at the date of the previous depreciation study.

For Communication Structures and Equipment (397.00), Gannett Fleming recommends a 15 year life, which is the same as the service life recommended in the previous study. As a result of an accumulated depreciation deficiency that existed in this asset class as of the date of the previous study, a higher rate was incorporated at that time to make up for the accumulated depreciation deficiency. Therefore, even though the average service life for Communication Structures and Equipment remains at 15 years, the decrease of approximately 2.56 percent in the depreciation rate for this category is primarily a result of no longer having an accumulated depreciation deficiency that existed at the date of the previous depreciation study.

There appears to be 2 variables impacting the recommended change in depreciation rates: (i) a recommended longer asset life and (ii) adjustment to the current rate to true-up any historical over/under accumulated depreciation.

19.3 To the extent that the future actual asset retirement is longer than or shorter than the current forecast asset life, please generally discuss the necessary adjustments to accumulated depreciation at that time.

Response:

Gannett Fleming indicates that when actual retirement activity varies from the expected life, it will show up as an outlier in the statistical life curve expectation. When enough retirement activity varies in one direction, for instance being shorter than the expected life, then the estimated remaining service life may be shortened to take into account the historical experience. Depending on the magnitude of the retirement experience, this may result in an increase in the depreciation rate the next time a depreciation study is performed. Conversely, if the retirement activity ends up being longer than the expected life, then the estimated remaining service life is extended to take into account the historical experience and this can result in a decrease in the depreciation rate the next time a depreciation study is performed.

Variances from expected life are one of the primary reasons depreciation studies are recommended to be performed periodically. This allows an opportunity to evaluate the actual retirement activity that has occurred, as well as consider the useful life estimates since the last depreciation study.

20.0 Reference: Net Salvage

Exhibit B-1, pp. 101–103

Net salvage

On page 102 of the Application, Table 12-3 lists asset classes where net salvage is recommended by Gannet Fleming. FBC explains that the estimates of net salvage were based on the professional judgement of Gannet Fleming, primarily through historical data and through a comparison to peer companies.

20.1 Please provide reference to the peer companies used in Gannet Fleming's comparison. Please also generally discuss why these companies are considered comparable peers.

Response:

Gannett Fleming considered AltaLink, ATCO Electric, FortisAlberta, Manitoba Hydro, and BC Hydro in determining estimates of net salvage. Manitoba Hydro and BC Hydro were considered comparable to FBC in terms of being vertically integrated utilities (generation, transmission, and distribution) and including generation facilities which are primarily hydro powered. AltaLink, being primarily transmission, and FortisAlberta, being primarily distribution, have more specific types of assets but provide a good representative sample of a large volume of those assets and therefore were considered relevant to draw salvage estimates from. ATCO Electric is primarily transmission and distribution and therefore also provides a good representative sample of a large volume of those assets to draw salvage estimates from.

20.2 Please confirm that both the net salvage and depreciation rates are calculated on an asset pool basis.

Response:

Confirmed.

20.3 Please explain why Gannet Fleming recommends net salvage on some assets classes and not all asset classes applicable to FBC. Is it because only certain asset classes have traditionally incurred significant removal costs? If so, is there an assumption that other asset classes do not incur any net salvage at all?

Response:

Only those asset classes that are anticipated to incur costs of removal have been recommended by Gannett Fleming for collection of net salvage over the lives of the assets. The determination of which accounts will incur future costs of removal is based on a review of the historical retirement transactions and on the assessment of the probability of the future retirements requiring a cost of removal. In the case of some accounts, such as land rights or software accounts, there is no expectation that the retirement of the asset will result in a cost of removal expenditure. While other asset classes may incur removal costs, they are not experienced routinely from year to year, or are not reliably estimable (in terms of amount of cost and/or period when the removal work would take place) and therefore net salvage treatment for these assets classes is not recommended at this time.

20.4 Please explain how these net salvage rates will be applied to the asset classes. Will they be applied to legacy assets or only to new assets?

Response:

The net salvage rates are applied to the gross cost of plant in service, so they will be applied to both legacy assets and newly constructed assets. In other words, the net salvage being collected through the rates will be applied to the total asset balance in the asset class at the beginning of each year. This will serve to allocate the costs of removal for the assets in use today (in rate base) to those customers that are utilizing them.

FBC defines net salvage as "removal costs less salvage proceeds."

20.5 To the extent that some future salvage proceeds may exceed removal costs collected in the depreciation rates, please discuss the treatment for this potential over-collection of net salvage.

Response:

FBC cannot envision a scenario where future salvage proceeds will be higher than removal costs for those asset classes that net salvage rates are recommended for.

However, variances in removal costs (net of any salvage proceeds) are one of the primary reasons depreciation studies are recommended to be performed periodically. This allows for an opportunity to review how much net salvage is being collected. If the unlikely event that future salvage proceeds were to exceed removal costs for an asset class that is subject to net salvage rates, this would result in an over-collection of net salvage which would result in a decrease (all else being equal) in the net salvage rate when the next depreciation study is performed.

20.6 Please confirm that the proposed transition to the inclusion of the provision for estimated net value in depreciation rates will have a one-time rate impact for customers, during the year of transition. If not confirmed, please explain and provide numerical examples for illustration.

Response:

Confirmed. In the absence of implementing the net salvage rates, the proposed depreciation rates would be lower resulting in a lower customer rate increase for 2016. Once net salvage rates have been implemented, they are subject to changes every three to five years from updated depreciation studies.

20.7 Please clarify that the proposed change to the net salvage method and resulting $10 million impact shown in Table 12-3 is a reasonable estimate of the ongoing annual net salvage expected in each future year? If not, please explain.

Response:

The estimated annual net salvage amount of $10 million to be collected in customer rates is not intended to be representative of the actual net salvage costs (or costs of removal) to be incurred each year, although that could be the result in certain years. The net salvage accruals accumulate in a reserve within accumulated depreciation, and the reserve is drawn down (debited) when actual net salvage costs (or costs of removal) are incurred.

The annual net salvage accrual amount will be dependent on future additions to plant in service and retirements, since the proposed rate will be applied to the gross cost of plant in service at the beginning of the year. The $10 million amount is the result when the recommended rates are applied to FBC's forecast 2016 opening gross plant in service.

The actual net salvage costs (or costs of removal) will vary each year depending on which assets are removed and the costs that are incurred for their removal.

When FBC next updates its depreciation study, the net salvage rates will be adjusted to account for any changes in circumstance since this depreciation study was undertaken, and these revised rates, once approved, will then be applied to the gross plant in service in subsequent years to determine future net salvage accrual amounts.

20.8 Please clarify whether this change in accounting policy will require a retroactive restatement for FBC.

Response:

There will be no retroactive restatement required for FBC for accounting purposes. Since FBC has no history of collecting a provision for net salvage in its revenue requirements, and since these rates are being proposed to be implemented effective January 1, 2016 on a prospective basis, there is no retroactive restatement that could be booked.

20.8.1 Please clarify, or explain otherwise, that the retained earnings restatement adjustments are reflected in the current period charge.

Response:

Please refer to the response to BCUC IR 1.20.8. As there will be no retroactive restatement there are no retained earnings entries.

21.0 Reference: New Deferral Accounts

Exhibit B-1, pp. 101–103

Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex Corp.

FBC explains that CEPSA was accepted by Order E-10-15 as an energy supply contract and that FBC incurred $0.163 million in costs which are primarily legal fees, Commission expenses and intervener funding.

21.1 Please confirm that the proposed method of seeking approval for cost recovery after the fact removes any forecast risk that FBC may have otherwise incurred.

Response:

Not confirmed. The practice of recording the external costs associated with regulatory applications in deferral accounts ensures that only the actual costs are recovered through rates. As only actual costs are recovered, there is no forecast risk and the timing of the request for approval of the account, whether "before" or "after the fact", is not a factor in the recovery of costs.

The costs associated with regulatory proceedings, which include Commission costs and PACA funding, legal and consulting fees and miscellaneous external costs such as facility rentals, supplies and postage, are dependent on the nature of the application, the process determined by the Commission for its review, and the degree of participation by interveners. The costs of regulatory proceedings are outside of the Company's control and vary from year to year; hence these costs can not be accurately forecast for rate setting purposes and the consistent practice approved by the Commission is to recover these costs through the amortization of deferral accounts.

21.2 Please explain the meaning of "primarily" in the above preamble. What other expenses are included in the $0.163 million in 2015.

Response:

FBC clarifies that no expenses other than legal fees, Commission expenses and intervener funding are included in the $0.163 million in 2015.

21.3 Please provide a breakdown of the $0.163 million into legal fees, Commission expenses and intervener funding.

Response:

At the time of filing, FBC had forecast expenditures of $163 thousand. The final total of costs incurred for this process is now known and it is $147.328 thousand, a breakdown of which is provided below. FBC will revise the balance in the deferred account in its Evidentiary Update to be filed prior to the Annual Review Workshop.

	(thousands)
Commission expenses	$ 4.629
Intervener funding	1.117
Legal fees	141.582
Total	$ 147.328

21.4 Please provide a list of all applications and proceeding costs for 2016 in which FBC anticipates filing or plans to participate in. Please also provide FBC's best estimate of such costs (aside from regulatory O&M costs) during 2016.

Response:

FBC expects to incur external costs for the preparation and/or review of the applications listed below. At this time, the Company does not expect to incur external costs for its participation in other utilities' applications.

Application	2016 Costs (Before Tax, $000s)	Reference
Annual Review for 2017 Rates	$ 100	Section 11, Schedule 12, Line 17
2016 Long Term Electric Resource Plan	261	Section 11, Schedule 12.1, Line 9
2017 Rate Design Application	250	Section 11, Schedule 12.1, Line 10

In addition, the Company anticipates filing CPCN applications for the Upper Bonnington Old Unit Refurbishment Project and the Corra Linn Concrete Rehabilitation Project during 2016. For these projects, project development and approval costs, including the costs of regulatory reviews, are captured in the CPCN Projects Preliminary Engineering deferral account approved by Order G-139-14, and are transferred to the capital project following Commission approval. At this time, the Company estimates approximately $150 thousand in external costs for the review of each CPCN application.

21.5 Does FBC agree that another method of recovering costs which were not otherwise included in base O&M is to provide the best available forecast at the beginning of each annual review for any upcoming application / proceeding costs.

Response:

FBC agrees that another method of recovering costs of regulatory applications which are not otherwise included in base O&M would be to forecast the costs outside of the PBR O&M formula and then true up the costs to actual through the Flow-through deferral account. However, FBC believes that establishing a deferral account for these types of expenditures is the most appropriate means of capturing and recovering the regulatory costs for a number of reasons.

First, it is consistent with FBC's past practice and it is accepted regulatory practice to defer these costs for review and recovery following the regulatory review of the application, and for the recovery term of such deferral accounts to align with the periods to which the applications relate. This is consistent with the principle that the amortization period for a deferral account should consider the timing of associated benefits.

Further, capturing the costs in a deferral account allows for more transparency as the history of the costs is simpler to track and report on. Including costs in the larger O&M and Flow-through accounts would reduce visibility and introduce a source of variability into the Company's O&M costs.

Finally, since the Flow-through deferral account is only in existence for the term of the PBR, FBC believes it is more straight forward to continue with a regulatory practice that works whether it is in PBR or not.

21.5.1 Using this method, would true-up to actual costs require additional approval from the Commission?

Response:

Using the method described in the response to BCUC IR 1.21.5, the true-up to actual costs would be accomplished by the true-up of the variances being recorded in the Flow-through deferral account, rather than the specific deferral account for the regulatory proceeding as FBC has proposed, which already is subject to Commission approval and so would require no additional Commission approval. Any review of the actual costs incurred in subsequent revenue requirements, no matter which deferral account is used, would be the same in either case, but as indicated in the response to BCUC IR 1.21.5, the separate deferral account allows for greater transparency.

21.5.2 Would FBC be amendable to this alternative method? Please discuss.

Response:

No, FBC believes the current method is preferable. Please refer to the response to BCUC IR 1.21.5.

22.0 Reference: New Deferral Accounts

Exhibit B-1, p. 101–103

2017 Rate Design Application

FBC states that it plans to file a Rate Design Application on or before December 31, 2017, but anticipates commencing work in 2016 for this application. FBC expects the additions to the proposed deferral account of $0.250 million in 2016 and an additional $0.350 million to $0.450 million in 2017.

22.1 If actual 2016 costs vary from the forecast of $0.250 million, please explain FBC's anticipated method of treating those variances.

Response:

FBC has not requested the disposition of any costs associated with the 2017 Rate Design Application. The actual costs incurred during 2016 will be recorded in the deferral account and recovery of the costs will be requested in a future application.

In general, if actual costs vary from forecast costs, the variances will be trued up through amortization expense in a subsequent application, so that only the actual amount of expenditures is collected in rates.

22.2 Please explain the meaning of "primarily" in the above preamble. What other expenses are included in the $0.250 million for 2016?

Response:

For clarity, FBC provides the referenced text from the Application below.

> *FBC will be filing a Rate Design Application on or before December 31, 2017. In order to meet this filing date, work on the application will commence in 2016. As such FBC is requesting approval for a deferral account to capture costs related to the application. Based on historical experience, the December 31, 2017 balance in this deferral account is expected to be in the range of $0.600 million to $0.700 million, with the majority of the costs expected to be incurred in 2017. Additions to the deferral account in 2016 are forecast to be $0.250 million ($0.185 million after tax) and are primarily related to consultant costs and participant funding associated with stakeholder workshops.*

The Company states that 2016 costs will be "primarily" associated with consultant costs and participant funding because, while it expects that most costs will fall into these categories, there may be additional costs for other items such as public notification, facility rentals, and miscellaneous incremental expenses such as production and distribution of consultation materials. 2017 costs will also include external legal fees, Commission fees and participant funding.

22.3 Please provide a breakdown of the $0.250 million into consultant costs and intervener funding?

Response:

FBC provides the requested breakdown below, but notes that the amounts below are estimates only, and that only the actual costs incurred will be recorded in the deferral account.

Consultant Costs	$200,000
Participant funding	$35,000
Other costs	$15,000
Total	$250,000

22.3.1 Please clarify whether the intervener funding includes intervener participation in stakeholder workshops?

Response:

The Company has made an allowance for funding for intervener participation in stakeholder workshops.

22.3.2 When does FBC plan to commence stakeholder workshops?

Response:

A consultation plan has not yet been developed; however, the Company expects that workshops will not commence until late 2016 or early 2017, after initial data collection and analysis has been completed.

J. SERVICE QUALITY INDICATORS

23.0 Reference: Service Quality Indicators
Exhibit B-1, pp. 111–114
Billing Index and All Injury Frequency Rate (AIFR)

For the Billing Index indicator, FBC explains that the June 2015 year-to-date performance is 0.29.

23.1 Given that the previous year's results were 2.34, please clarify whether the June performance should not be transcribed as 2.9 instead of 0.29?

Response:

The result for the billing index is confirmed to be 0.29.

In FBC's past efforts to maintain the Certificate of Recognition through annual audits and providing validation of the effectiveness of the Company's safety programs, there appears to be a continued increased in the AIFR. FBC's last year's result was 2.58 while this year's forecast result is even higher, at 2.86.

23.2 Please explain whether FBC has analyzed the past safety incidents to determine whether there are any commonalities in terms of the type of injuries, location of injuries, age and training of the injured workers, language barriers or any other possible causes.

Response:

FBC investigates all injury-resulting safety incidents to determine root causes and implements corrective measures to prevent recurrence. Additionally, all injuries are reviewed to determine if any trends are evident, including but not limited to job classification, injury type, age range, employee affiliation and geographic location.

All findings from investigations are shared and made available throughout the Company. Recent trending is toward ergonomic related injuries with improper body positioning and failure to identify/recognize hazards during routine work as leading causes. These injuries are occurring within all age and length of service ranges.

FBC continues to provide ongoing training in Site Safe Work Planning for hazard recognition and control in addition to the MoveSafe ergonomic program to assist workers in preparing their bodies to safely perform work.

With the launch of FBC's Target Zero safety program in January 2016, FBC includes, on page 112, "development and implementation of a new voluntary employee based safety program."

23.3 Please explain why such a program will be voluntary as opposed to mandatory.

Response:

The employee based safety program is intended to enhance FBC's safety management system, and is an element of the Target Zero safety program. The main goal is to engage employees in the safety process through a program they can develop and have ownership of.

Key elements of the program are:

- it is discipline free
- participation is voluntary
- it concentrates on positive reinforcement
- all participants can remain anonymous
- it is simple with immediate and frequent feedback

Participation rates in voluntary employee safety programs assist in understanding employee engagement and involvement around safety. Affinity, affiliation, and autonomy have been identified as key attributes in employee engagement; a voluntary safety program supports the growth of these attributes. The Company believes that over time, this approach will foster a stronger safety culture and improve safety performance through implementation of a program employees can more closely identify with and choose to be a part of rather than being mandated.

24.0 Reference: Service Quality Indicators

Exhibit B-1, p. 121

Generator Forced Outage (GFOR)

In its discussion on whether the GFOR should be moved from an informational SQI to a measurable SQI, FBC performed investigations into the two fires at South Slocan Unit 1 and Corra Linn Unit 2 which revealed that the most likely cause was an installation issue and not due to "less robust inspection programs or lower maintenance standards." FBC therefore took steps to implement additional quality assurance standards as well as measures for new and existing cable installations.

24.1 Please clarify what additional quality assurance standards were implemented. What were the new measures for new and existing cable installations?

Response:

On June 23, 2015, the Commission issued its Decision and Order G-107-15 in the FBC Annual Review for 2015 Rates Application. Directive 8 of G-107-15 directed FBC to prepare a report on the two fires that occurred with and provided a list of items to include in that report. On August 6, 2015, FBC filed the requested report with the Commission. That report included a summary of short-term and long-term corrective actions, and a preventative maintenance plan and operating activity changes[6].

The report identified additional quality assurance standards that will be implemented:

i. Implementation of new and revised maintenance practices and frequency. All cables will be tested on a five year cycle with special attention paid to the armoured cables.

ii. Pilot projects were implemented on SLC G3 and COR G2 to monitor the flow of any undesired circulating current in the cable armour as well as measure the cable temperature. Due to the success of the pilot project, COR U1, COR U3 and SLC G1 are planned to have cable monitoring systems implemented by end of 2016.

The cable monitoring pilot projects installed on SLC G3 and COR G2 currently report into the FBC Data Historian system and are set up to automatically notify personnel at certain thresholds. Once a level of comfort is reached with the cable monitoring systems, the data that is currently used for monitoring purposes only could be used as part of a protection scheme. This could allow the cable temperature monitoring system to automatically shut down or reduce the Unit output to risk the risk of cable over-temperature damage.

[6] Pages 11 – 13 of the Generator Outages Report Compliance filing.

iii. Where practicable, addition of infrared viewing ports to simplify the inspection process will be conducted.

iv. A generator protection settings review and updates will be conducted as required for all units.

v. FBC will continue to review and monitor the health of the generator cables; replacement with more suitable (un-armoured) cable may be conducted in future.

vi. As an interim measure, until the necessary long term actions have been implemented, all generating units which have TECK cable have had their unit dispatch modified (generators that are not equipped with the TECK cables are started and run preferentially) to reduce exposure.

The new maintenance practices now require a comprehensive cable test every five years. On top of the annual visual inspection and IR scan, five year testing will include:

i. Generator cable Hi-Pot test;

ii. Generator cable Tangent Delta test; and

iii. Generator cable DC Insulation (Megger) test.

FBC states that "should the Commission be persuaded to make GFOR a measurable index, FBC's performance should not be held to a standard that is much higher than other industry participants. Rather, the target should be based on the CEA average."

24.2 Please provide evidence on the most recent available CEA average for GFOR. Please also compare this to FBC's historical results for the past 5 years.

Response:

FBC provided the Canadian Electricity Association (CEA) data in Table 13-12 on page 119 of the Application. The CEA data presented for 2014 was based on preliminary results, which CEA has now updated to final. An updated version of Table 13-12 with the 2014 final CEA data is presented below.

	2010	2011	2012	2013	2014
FBC	0.1%	0.1%	0.5%	5.2%	1.7%
CEA	3.9%	5.0%	4.9%	4.9%	6.3%

K. OTHER

25.0 Reference: Financial Schedules

Exhibit B-1, p.63

Schedule 1

25.1 Schedule 1 of Section 11 appears to show a different format of the Summary of Rate Change than previous years. Please reproduce the same schedule showing additional columns for 2015 Approved, 2015 Forecast/Actual, and the variance between the two.

Response:

The requested format is provided below.

Line No.	Particulars	Approved 2015	Projected 2015	Forecast 2016	Change from Approved	Cross Reference: Section 11
	(1)	(2)	(3)	(4)	(5)	(6)
1	Sales Volume (GWh)	3,224	3,154	3,262	38	Schedule 18, Line 7
2	Rate Base ($ thousands)	1,248,978	1,247,853	1,286,868	37,890	Schedule 2, Line 30
3	Return on Rate Base	6.83%	6.82%	6.68%	-0.15%	Schedule 16, Line 22
4						
5						
6	**POWER SUPPLY**					
7	Power Purchases	$ 117,837	$ 111,277	$ 133,907	$ 16,070	Schedule 17, Line 11
8	Water Fees	9,796	9,706	10,291	495	Schedule 17, Line 16
9	Wheeling	4,734	4,723	4,764	30	Schedule 17, Line 27
10		132,367	125,706	148,962	16,595	
11	**OPERATING**					
12	O&M Expense	59,091	58,230	57,371	(1,720)	Schedule 21, Line 23
13	Capitalized Overhead	(8,864)	(8,864)	(8,606)	258	Schedule 21, Line 25
14	Other Revenue	(8,272)	(8,391)	(8,177)	95	Schedule 20, Line 8
15		41,955	40,975	40,588	(1,367)	
16	**TAXES**					
17	Property Taxes	15,331	15,041	17,320	1,989	Schedule 23, Line 7
18	Income Taxes	6,684	7,317	7,520	836	Schedule 24, Line 14
19		22,015	22,358	24,840	2,825	
20	**FINANCING**					
21	Cost of Debt	39,648	39,261	38,918	(730)	Schedule 26, Lines 1+2
22	Cost of Equity	45,713	45,864	47,099	1,386	Schedule 26, Line 3
23	Depreciation Expense	55,359	54,967	54,380	(979)	Schedule 22, Line 2
24	Amortization Expense	(2,527)	(2,905)	(4,838)	(2,311)	Schedule 22, Line 9
25		138,193	137,187	135,559	(2,634)	
26						
27	**2015 Flow-through and ESM Adjustments**		1,928			
28						
29	**TOTAL REVENUE REQUIREMENT**	$ 334,531	$ 328,154	$ 349,949	$ 15,419	
30						
31	LESS: REVENUE AT PRIOR YEAR RATES	321,134		343,152	22,018	Schedule 18, Line 15
32	REVENUE DEFICIENCY	$ 13,397		$ 6,797	$ (6,600)	
33						
34	**RATE INCREASE**	**4.20%**		**1.98%**	**-2.22%**	

26.0 Reference: Financial Schedules

Exhibit B-1, p.65

Schedule 3

26.1 Line 9 of Schedule 3 shows a net inflation factor for 2015 of 0.271 percent. However, in FBC's 2015 Annual Review application, this figure was shown as 0.273 percent. Please clarify the difference and provide any corrections, if necessary.

<u>Response:</u>

As noted in response to BCUC IR 1.1.1 of FBC's Annual Review for 2015 Rates, the initial CPI calculation was not rounded to three decimal places correctly. In the FBC 2015 2015 Rates G-107-15 Compliance Filing dated July 8, 2015 (Schedule 5) this was corrected, resulting in a 0.002 percent decrease to the net inflation factor. The recalculation is outlined below.

	Original Filing 2015 Formula	Compliance Filing 2015 Formula
CPI	0.884%	0.879%
AWE	1.646%	1.646%
Labour Split		
	45.000%	45.000%
	55.000%	55.000%
CPI/AWE	1.303%	1.301%
Productivity Factor	-1.030%	-1.030%
Net Inflation Factor	0.273%	0.271%