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October 1, 2020

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Marija Tresoglavic, Acting Commission Secretary

Dear Ms. Tresoglavic:

Re: FortisBC Inc. (FBC)

Project No. 1599119

Annual Review for 2020 and 2021 Rates (Application)

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 1

On August 19, 2020, FBC filed the Application referenced above. In accordance with BCUC Order G-211-20 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

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A. LOAD FORECAST AND REVENUE AT EXISTING RATES

1.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Application, Section 3.2, p. 12

Load Forecast Methodology

FortisBC Inc. (FBC) states on page 12 of the Application that the load forecast methodology for 2020 and 2021 is consistent with the forecasting method followed by FBC in previous years.

1.1 Please explain when FBC last conducted a comprehensive review of FBC's current load forecast methodology for the purpose of setting rates.

Response:

FBC last completed a comprehensive review of its forecast methods as part of the Application for 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan (2012-2013 RRA and ISP). The load forecast and methodologies were reviewed by the Load Forecast Technical Committee which included, among others, representatives of FBC, BCUC staff, BCMEU, BCOAPO, and BC Hydro. The review was contained in the Load Forecast Technical Committee Report and filed as part of the 2012-2013 RRA and ISP proceeding.

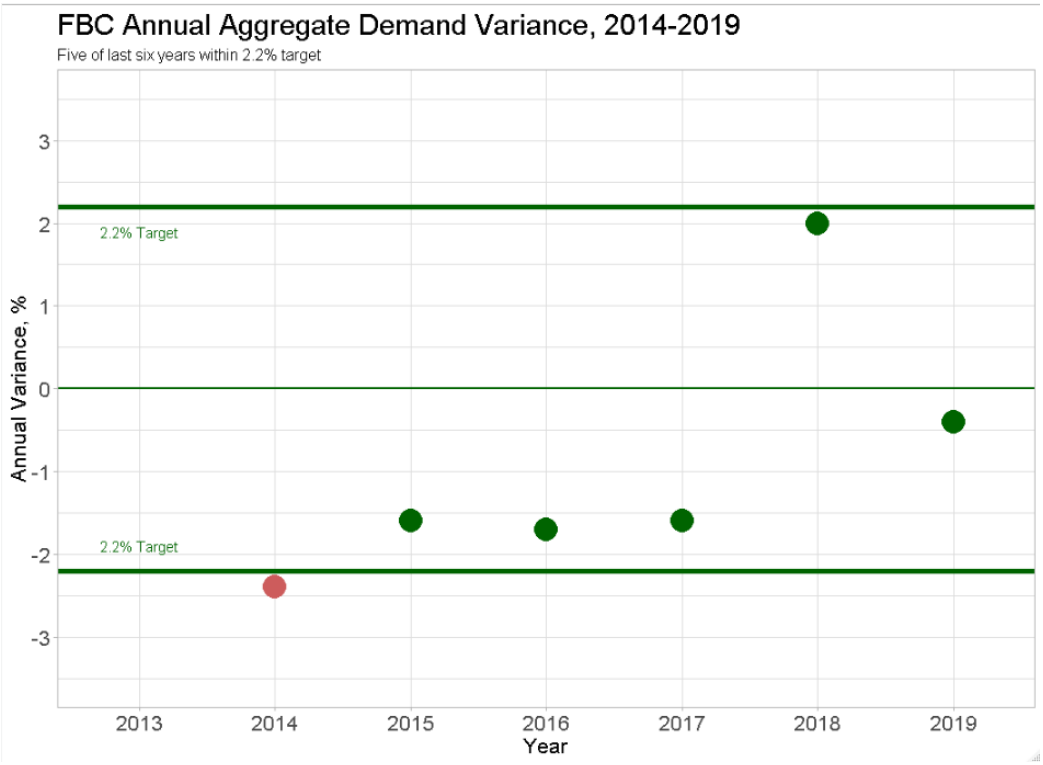
FBC does not frequently undertake comprehensive reviews, as they are costly, resource- and time-intensive, and FBC's forecasting methods have been working well. In FBC's view, unless there is some objective reason to believe that the existing forecast methods need improvement or review, such as a trend of consistently high variances above available benchmarks, such an extensive and costly undertaking is not required.

As stated above, FBC's forecasting methods have been working well. An annual survey of electric utilities from 2014 through 2019 (averaging 67 utilities per year) conducted by ITRON identified an average load variance against forecast of 2.2 percent, which provides a valid and usable benchmark. The ITRON survey results are provided in the following table.

ITRON, Electric*	2014	2015	2016	2017	2018	2019	Average
Respondents	66	71	62	71	74	57	67
Aggregate Load Variance	2.7%	2.1%	2.2%	2.2%	1.7%	1.9%	2.2%

* FBC does not participate in this survey

The annual FBC net load variances are plotted against the above benchmark in the following figure:



As shown above, FBC last exceeded the benchmark in 2014. In five of the last six years, the performance of the FBC load forecast has performed better than the benchmark.

FBC notes its top performing forecast was the forecast submitted for 2019, as the net load variance was just -0.4 percent.

1.1.1 Please discuss whether FBC routinely conducts its load forecast methodology. If yes, please explain the frequency of when a comprehensive review of its load forecast methodology is conducted. If not, please explain why not.

Response:

FBC assumes that the question should read, “Please discuss whether FBC routinely conducts a comprehensive review of its load forecast methodology.” The underlined words have been added.

Please refer to the response to BCUC IR1 1.1.

1.1.2 Please explain the factors that would suggest a need for a comprehensive review of FBC's load forecast methodology.

Response:

Please refer to the response to BCUC IR1 1.1.

2.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Section 3.3, p. 14; Appendix A2, Section 5.3, p. 8; FBC Application for Approval of 2019–2022 Demand Side Management Expenditures Plan dated August 2, 2018, p. 14, Table 5-1

Demand Side Measures (DSM) savings

On page 14 of the Application, FBC provides Table 3-1 showing the breakdown of its DSM savings estimate for 2020 and 2021, respectively:

Table 3-1: Forecast Incremental 2020 and 2021 DSM Savings (GWh)[6]

Line No.	Description	2020	2021
1	Residential	(2)	(7)
2	Commercial	(7)	(20)
3	Wholesale	(2)	(7)
4	Industrial	(5)	(15)
5	Lighting	(0)	(1)
6	Irrigation	(0)	(0)
7	Net Load	(17)	(50)
8	Losses	(2)	(4)
9	Gross Load	(19)	(54)

FBC explains on page 6 of Appendix A3 that "[t]he forecast of DSM savings is consistent with the Company's approved 2019 DSM Plan."

Table 5-1 included in the FBC Application for Approval of 2019–2022 Demand Side Management Expenditures Plan shows the forecast DSM savings from years 2019 to 2022, and is replicated below:

Table 5-1: 2019-2022 DSM Plan Proposed Expenditures (inflation adjusted)

Program Area (Sector)	2018 Plan	Expenditures ($000s)					Energy savings (GWh)					TRC 2019-2022
	Approved	2019	2020	2021	2022	Total	2019	2020	2021	2022	Total	Ratio
Residential	$1,591	$2,086	$2,304	$2,519	$2,795	$9,703	6.0	5.6	6.0	6.5	24.1	1.8
Low Income	$731	$843	$873	$899	$930	$3,545	1.0	1.0	1.0	1.1	4.1	1.5
Commercial	$3,592	$3,178	$3,031	$3,052	$3,047	$12,308	15.5	15.5	15.3	15.5	61.8	1.7
Industrial	$377	$1,762	$1,788	$1,813	$1,815	$7,178	10.0	10.0	10.1	10.1	40.2	1.7
Program sub-total	*$6,291*	*$7,870*	*$7,995*	*$8,284*	*$8,587*	*$32,735*	*32.6*	*32.1*	*32.4*	*33.1*	*130.3*	*1.7*
Education and Outreach	$165	$566	$497	$595	$666	$2,324						
Supporting Initiatives	$742	$1,218	$838	$1,024	$1,044	$4,124						
Portfolio	$743	$776	$913	$1,019	$956	$3,663						
Demand Response		$477	$324	$130	$133	$1,064						
Total	**$7,940**	**$10,900**	**$10,600**	**$11,100**	**$11,400**	**$44,000**	**32.6**	**32.1**	**32.4**	**33.1**	**130.3**	**1.5**
LT DSM Plan	**$7,900**	**$8,100**	**$8,200**	**$9,400**	**$10,600**	**$36,300**	**26.4**	**26.4**	**28.4**	**30.4**	**111.6**	**1.9**

2.1 Please reconcile the DSM savings forecasted for each customer class in 2020 and 2021 in the Application, respectively, with the energy savings estimates

provided in Table 5-1 of FBC's Application for Approval of 2019–2022 Demand Side Management Expenditures Plan.

Response:

The DSM savings forecast for each customer class in 2020 and 2021 in the Application and the energy savings estimates provided in Table 5-1 of FBC's Application for Approval of 2019–2022 Demand Side Management Expenditures Plan (the DSM Plan) are not directly comparable. However, the forecast in the Application is based on, and consistent with, the DSM Plan savings. The difference is a result of the way that the DSM Plan savings are presented, attributed, and disaggregated in the Application's load forecast.

The main reason for the difference is that the load forecast in the Application presents the DSM savings numbers cumulatively, starting in the first year (the prior years' DSM savings are embedded in the consecutive years), whereas the DSM Plan shows the savings for each plan year separately).

The DSM Plan represents annual incremental energy savings for the DSM projects, by customer type, planned for that calendar year. The DSM forecast presented in the Application factors in the timing of DSM projects: a portion of the savings from the DSM projects land in the plan year, with the remainder attributed to the following year. For example, if a project with 12 MWh of savings were completed in December, the DSM Plan shows all of those savings in that year. In contrast, the Application forecast numbers include only 1 MWh (1/12) of the savings with the remaining 11/12 of the project's savings falling into the following year (11 MWh of savings from January to November). As a result of the pro-rating, the savings in the first year of the forecast are approximately one half of the DSM Plan savings for the same year.

Finally, in the Application, FBC disaggregates a number of sub-categories of DSM for forecasting purposes, which are not shown in the DSM Plan savings. For example, "Residential" savings in the DSM Plan includes both FBC direct customers and the residential portion of the "Wholesale" savings (for the City of Penticton and the other municipal utilities), which are presented separately in the Application load forecast. Similarly, the "Commercial" program area of the DSM Plan savings includes: FBC's direct commercial customers; the commercial customers in Wholesale; and the "[Street] Lighting" and "Irrigation" rate class values that are shown separately in the load forecast.

2.1.1 If FBC has adjusted the estimated DSM savings from those included in Table 5-1 referenced above, please explain the basis (including inputs, assumptions and methodology) for any adjustments.

Response:

FBC has not adjusted the estimated DSM savings from those included in Table 5-1 referenced above.

Please refer to the response to BCUC IR1 2.1 for further discussion of the methodological differences between the approved 2019-2022 DSM Plan and the DSM forecasts presented in the Application.

3.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Sections 3.4 and 3.4.7, pp. 14, 24

Losses

On page 24 of the Application, FBC states it conducted a Losses Study in 2019 and, consistent with that study, has assumed a loss rate of 7.6 percent of gross load excluding company use. FBC forecasts the losses to be 276 gigawatt hours (GWh) and 279 GWh in 2020 (2020P) and 2021 (2020F), respectively.

On page 14 of the Application, FBC states that the total load, net of losses, is projected to be 3,273 GWh in 2020P, and 3,355 GWh in 2021F.

3.1 Please show the calculation for the forecast losses at 276 GWh and 279 GWh for year 2020P and 2021F, respectively. Please explain all inputs and assumptions.

3.1.1 If the forecast losses for 2020P and 2021F, respectively, do not equate to 7.6% of gross load excluding company use, please explain any difference.

Response:

To clarify, the loss ratio of 7.6 percent of gross load is calculated on gross load before DSM savings. Therefore, a calculation of the after-savings losses (Figure 3-11) and after-savings gross load (Table 3-2) does not result in a ratio of 7.6 percent.

In preparing the following response, FBC recognized a small discrepancy in the calculation of losses in the Application. Because the impact of this error is immaterial to its revenue requirements and variances will be trued up by way of the Flow-through deferral account, FBC does not propose to update the forecast losses.

The loss ratio of 7.6 percent of gross load is determined using historical data. For forecast purposes, the gross load is unknown (as it is the sum of forecast sales, company use, and the losses themselves) and losses must therefore be calculated based on forecast sales, the formula for which is 0.076 ÷ (1-0.076) = 0.082. As shown in the following table, the loss ratio for net load of 8.2 percent is multiplied by the net load prior to deducting the DSM impact on losses.

Line No.	Year	2020P	2021F	Reference
1	Losses/Gross Load	7.6%	7.6%	
2	Losses/Net Load	8.2%	8.2%	Line 1 ÷ (1- Line 1)
3		GWh		
4	Before Savings Net Load	3,304	3,405	Appendix A2, Table 2-2
5	Before Savings Losses	272	280	Line 2 × Line 4
6	DSM	(2)	(4)	Section 3, Table 3-1
7	After Savings Losses (Calculated)	270	276	Line 5 + Line 6
8	After Savings Losses (Filed)	276	279	Section 3, Figure 3-11
9	Difference	(6)	(3)	Line 7 - Line 8

For 2021F, the discrepancy in losses of 3 GWh represents 0.08 percent of after-savings gross load (that is, the load for determining supply requirements), which would not have a material impact on revenue requirements. For 2020P, the discrepancy is also small, but is not entirely attributable to the calculation error because of the inclusion of actual losses for the January to June period.

4.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Appendix A2, Section 6, p. 9

Customer Count Variances to Forecast

On page 9 of Appendix A2, FBC provides its customer count variance. The percent variance for commercial customer count for the years 2017, 2018 and 2019 was: -2.7%, -2.8%, -2.8%, respectively.

4.1 Please explain the attributable factors for the negative customer count variance for commercial customers over the 2017 to 2019 period.

4.1.1 Please explain which of the factors explained above are anticipated to persist into 2020 and/or 2021. Please explain why.

4.1.2 For the factors that are expected to persist into 2020 and/or 2021, please explain how they have been accounted for in the 2020P and/or 2021F commercial load forecast.

4.1.2.1 If the factors explained above have not been accounted for in the applicable load forecast, please explain why not.

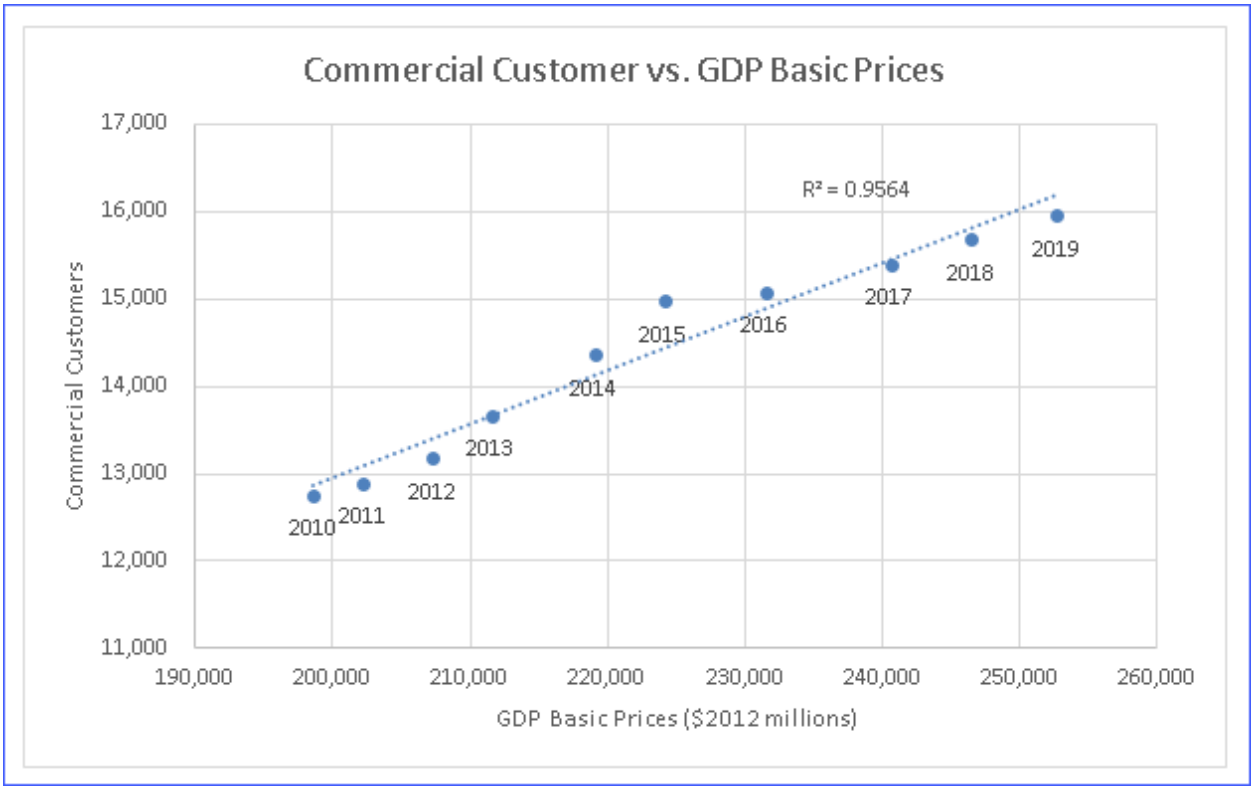
Response:

The commercial customer count is forecast using a regression of actual customer count and actual and projected GDP for the Province of BC from the Conference Board of Canada.

The factors influencing variances in the customer count may include:

- Differences in the composition of the commercial sector in FBC's service territory compared to the provincial economy which is measured by GDP;
- Differences in growth rates of business formation and dissolution versus growth in existing businesses (both of which are components of GDP output) in the FBC service territory compared to the province as a whole; and
- Forecast error for the GDP forecast itself.

The correlation between GDP and FBC commercial customers is very strong, as indicated by a correlation coefficient (r) of 0.98 over the last ten years. While the variances for 2017 to 2019 have been negative, from 2014 through 2019 half of the variances were positive and half were negative, as shown in the graph following (dashed line represents forecast).



The factors identified above will continue to be reflected in the 2020P and 2021F commercial customer forecast and future forecasts using the current method. They are also applicable to the commercial load forecast which is derived from a regression of commercial load on GDP. FBC does not believe that a change in forecast method is warranted given the performance of the overall forecast, as discussed in the response to BCUC IR1 1.1.

Page 9 of Appendix A2 also shows the actual customer count has been below forecast for lighting customers in each of year for 2014 through 2019. FBC explains on page 22 of the Application that the lighting customer count forecast method uses a five-year regression analysis.

4.2 Please explain the attributable factors for the negative customer count variance for lighting customers over the 2014 to 2019 period.

4.2.1 Please explain which of the factors explained above are anticipated to persist into 2020 and/or 2021. Please explain why.

4.2.2 For the factors that are expected to persist into 2020 and/or 2021, please explain how they have been accounted for in the 2020P and/or 2021F lighting load forecast.

4.2.2.1 If the factors explained above have not been accounted for in the applicable load forecast, please explain why not.

Response:

FBC believes the lighting customer count has been declining due to:

- New developments including stratas and gated communities which were developed on old infrastructure and have amalgamated multiple street lights into a single customer account; and
- An effort to save energy by downsizing of lighting in certain areas and communities that were believed to be over-lit.

Both of these factors are likely to continue.

In previous applications, FBC's lighting customer count forecast was set to the previous year-end count, as the customer count had been relatively constant in the past.

For the current forecast, FBC observed a statistically significant trend using a five-year trend method. As a result, FBC used a trend method to forecast the lighting customer count for 2020P and 2021F.

4.3 Please discuss whether FBC considered using an alternative load forecast methodology to improve the forecast accuracy on the customer count forecast for the lighting customer class. If yes, please elaborate on FBC's findings. If not, please explain why not.

Response:

Please refer to the response to BCUC IR1 4.2.

5.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Appendix A2, Section 6.4, p. 12

Residential Use per Account (UPC) Variances to Forecast

On page 12 of Appendix A2 to the Application, FBC provides a table of Residential UPC, Normalized Actual to Forecast in Section 6.4. In the Table, 2019 percent variance is -8.0% actual to forecast.

5.1 Please explain the attributable factors for the forecast variance.

5.2 Please explain which of the factors explained above are anticipated to persist into 2020 and/or 2021. Please explain why.

5.2.1 For the factors that are expected to persist into 2020 and/or 2021, please explain how they have been accounted for in the 2020P and/or 2021F residential load forecast.

5.2.1.1 If the factors explained above have not been accounted for in the applicable load forecast, please explain why not.

Response:

Changes in residential UPC are a result of many factors that may be both compounding and offsetting. For example, use rates for residential customers may go down due to increased efficiencies in lighting and appliances and/or improvements in building envelopes, but this may be offset by an increase in the number of appliances used in a home, a change in how appliances or equipment are used, and/or the number of people in a home. The latter two factors may increase or decrease UPC depending on individual circumstances.

FBC expects that its load will continue to be influenced by many factors that may have affected load variances in the past, including customer behaviour, economic activity, DSM, government policies (such as environmental policy), new technologies such as LED lighting, rooftop solar generation, electric vehicle charging, and changes in the rate of housing formation.

By re-forecasting annually, FBC is able to account for any developing trends in the data in future forecasts. As with all time-series forecast methods, there can be a time lag as trends establish themselves and then exert their influence on the forecast. However, it is not possible to determine whether a fluctuation in any given year is the beginning of one or more trends, or "random noise" that is expected and always present in the actual data.

5.3 Given the forecast variance experienced in 2019, please discuss whether FBC considered using an alternative load forecast methodology to improve the

forecast accuracy on the residential UPC for 2020 and 2021. If yes, please elaborate on FBC's findings. If not, please explain why not.

Response:

FBC did not consider an alternate forecast method based solely on 2019 results.

As explained in the response to BCUC IR1 1.1, new forecast methods are costly to develop and candidates must be evaluated based on their performance over time. Furthermore, the performance of each element of the load forecast is expected to fluctuate from year to year. Just as a single high performing year, such as 2018 where the variance was 1 percent, should not mean the forecast method will never be reviewed, a single lower-performing year like 2019 should not trigger an immediate review.

6.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Appendix A2, Section 6.2, p. 10

Load Forecast Variance in 2019

In Section 6.2 of Appendix A2, FBC presents the normalized actual to forecast load by customer class for each year from 2014 through 2019 and includes the forecast variance in terms of volume and percentage.

6.1 For each customer class that experienced a forecast variance of greater than 3% (in absolute value terms) in 2019, respectively, please explain the attributable factors for the forecast variance.

6.2 For each customer class addressed above, respectively, please explain which of the attributable factors for the forecast variance in 2019 are anticipated to persist into 2020 and/or 2021. Please explain why.

6.2.1 For factors that are expected to persist into 2020 and/or 2021, please explain how they have been accounted for in the applicable load forecast for 2020P and/or 2021F for each customer class, respectively.

6.2.1.1 If the factors explained above have not been accounted for in the applicable load forecast(s) in 2020 and/or 2021, please explain why not.

Response:

The residential variance in 2019 of -6.6 percent was due to the residential UPC being lower than anticipated. FBC cannot definitively explain any UPC variances in a given year, as each is a result of many factors that may be both compounding and offsetting, as explained in the response to BCUC IR1 5.1. For example, use rates for residential customers may go down due to increased appliance efficiency and/or improvements in building envelopes, but this may be offset by an increase in the number of appliances used in a home, a change in how appliances are used and/or the number of people in a home.

Wholesale customers are a mixture of residential, commercial and industrial customers, of which FBC does not have visibility; therefore, FBC cannot explain the 2019 variance of -5.0 percent in this customer class. Wholesale customers are best able to predict their future load requirements and FBC continues to develop its load forecast by gathering and aggregating surveys from 100 percent of all wholesale customers.

The industrial load in 2019 was 22.2 percent higher than forecast in large part because of the timing of the 2019 forecast, which included a very preliminary estimate for the expected load from a new customer.

The variance in the lighting load of -17.8 percent is due to increased savings due to LED lighting and communities removing streetlights in areas that they consider over-lit.

FBC is unable to explain the variance of -16.7 percent in the irrigation load; however, 2019 was cooler and wetter in the spring/summer than in previous years, which may have impacted the load. The total variance in the irrigation class was 6 GWh or 0.2 percent of the forecast net load.

Please refer to the response to BCUC IR1 1.1 which discusses the overall accuracy of FBC's load forecast and which indicates that overall, the variance in net load was very small at -0.4 percent in 2019.

7.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Section 3.4.4, p. 22; Appendix A3, p. 5

Industrial Demand

On page 21 of the Application, FBC describes its method to forecast industrial demand using a customer survey:

> FBC sends all existing industrial customers a load survey that requests the customer's anticipated use for the next 5 years. A survey is used because individual industrial customers have the best understanding of what their future load will be. This year FBC received a response from 80 percent (41 of 51) of the surveys sent out. The responding customers represent approximately 92 percent of the total industrial load.

On page 5 of Appendix A3 to the Application, FBC further describes its load forecast method for industrial customers:

> The before-savings industrial load is the sum of forecasts supplied by those individual customers who responded to the load survey and, for customers who did not respond, escalation of the customer's load in the preceding year by the CBOC forecast GDP growth rates for the industrial sector the customer is in.

7.1 Please compare the response rate and the corresponding load that the respondents represent as a percentage of industrial volume in years 2016 to 2020 in a table format.

7.1.1 Please comment on the trend on the customer survey response rate.

Response:

The following table shows the industrial survey response rate and percentage of total industrial load from the years 2016 to 2021. The response rate as a percent of load has ranged from 88 percent to 92 percent over the time period.

Industrial response rate and percent of total industrial load from 2016 to 2021

Application	Response Rate	Percent of Load
2016	86%	91%
2017	88%	88%
2018	80%	89%
2019	86%	88%
2020/2021	80%	92%

7.1.2 Please explain the measures that FBC has taken to improve the customer survey response rate since 2016.

Response:

In 2016, FBC replaced the older FAX-based survey with a new Excel-based worksheet that is now emailed directly to individual customers. If a customer does not respond, two email reminders are sent. If a customer still does not respond, then FBC directly contacts the individual customer by telephone. Unfortunately, a few customers still choose not to participate and there is no requirement that they do so. Regardless of the level of future improvements, FBC believes a small percentage of customers will still choose not to participate.

FBC evaluates the success of its industrial survey based on the percentage of load represented by respondents. As noted in the response to BCUC IR1 7.1, the response as a percent of load has remained at or above 88 percent since 2016, and was 92 percent for the survey conducted in 2020.

7.2 If possible, please compare the forecast and actual load among non-respondents and respondents, respectively, from 2016 to 2020 in a bar graph and table format.

7.2.1 Based on the response above, please comment on the forecast accuracy among respondents and non-respondents and explain the possible reasons for any difference between the two groups since 2016.

Response:

The following figures compare forecast and actual loads for industrial survey responders and non-responders for the years 2016 to 2019. A full year of 2020 load is not yet available for comparison. FBC notes that a large industrial customer has been excluded from the analysis, as it was not a customer during the time of these surveys.

The average variances from forecast for the years 2016 to 2019 are greater, in percentage terms, for the non-responders (-21%) than the responders (7%). However, because the non-responders make up such a small volume of load, even a relatively small quantitative variance results in a high percentage variance. Moreover, the variance from forecast non-responders load has an immaterial impact because non-responders make up only 8 percent of industrial load. Thus, for the industrial class as a whole, the average variance for the years 2016 to 2019 was -3.1 percent.

Figure 1: Forecast vs Actual Load for Responders to Previous Annual Industrial Load Surveys

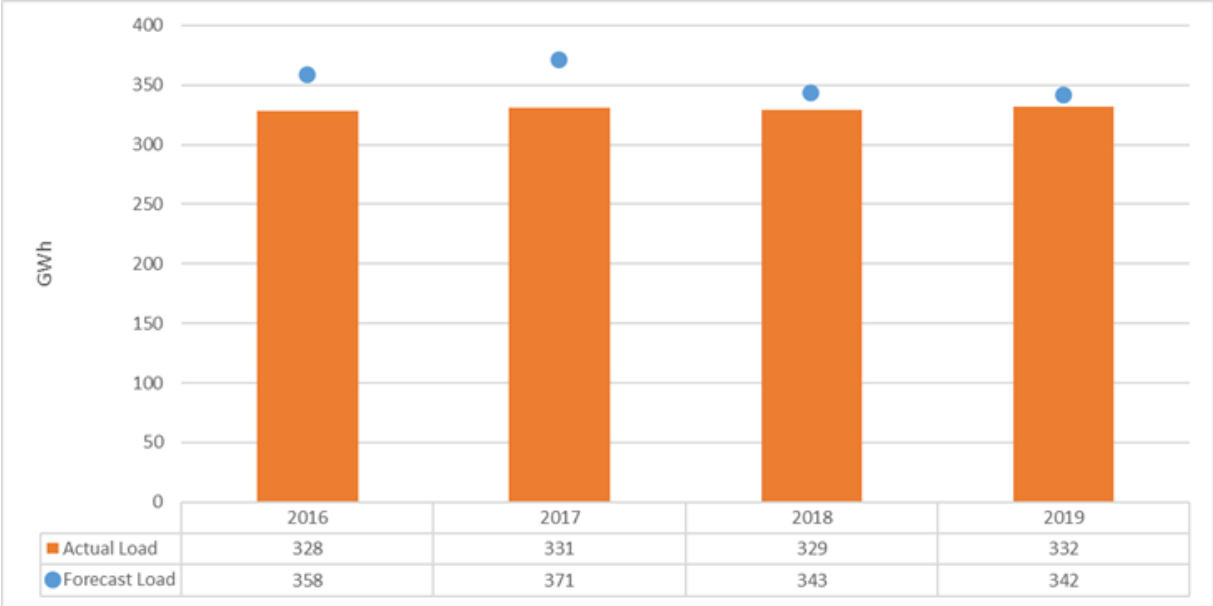
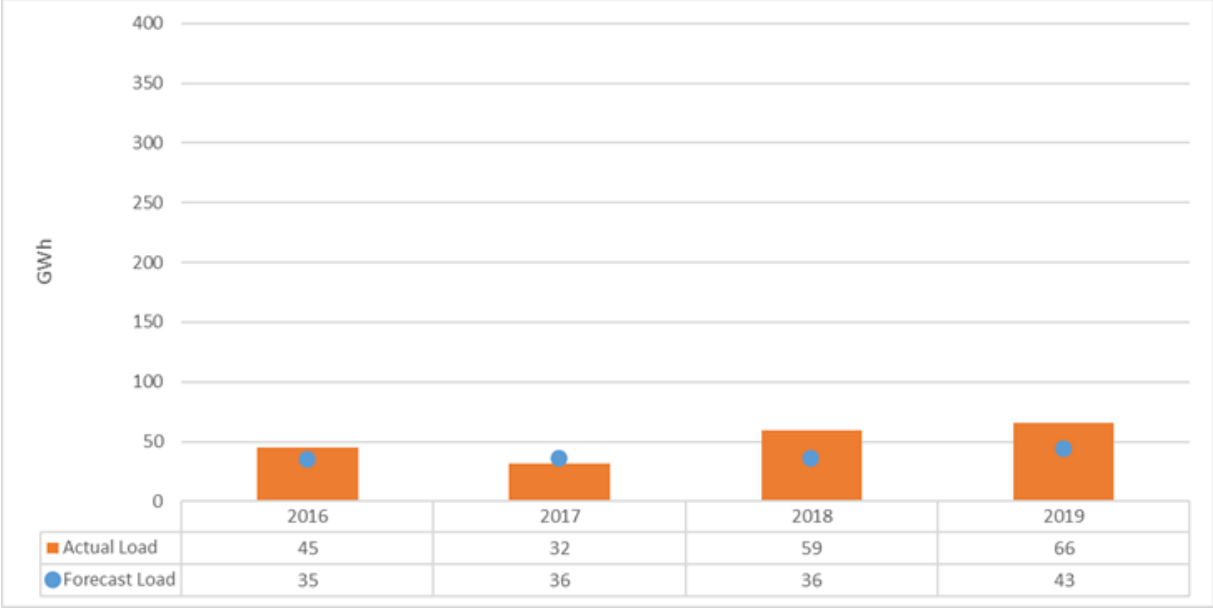


Figure 2: Forecast vs Actual Load for Non-Responders to Previous Annual Industrial Load Surveys



8.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Section 3.4.2.2, p. 19; Appendix A2, Section 2, pp. 2–4

Impact from COVID-19 pandemic

FBC presents the monthly load forecast for each customer class under sections 2.3 through 2.8 in Appendix A2 of the Application. The monthly load forecast shows the normalized loads from January 2010 to December 2019, and actual loads from January 2020 to June 2020.

For the commercial customer class, FBC explains on page 19 of the Application that the 2020P and 2021F fluctuations are due to a Gross Domestic Product (GDP) projection from the Conference Board of Canada (CBOC) that includes COVID-19 impacts and the projected economic recovery.

8.1 Please compare the monthly forecast and actual load for each customer class presented in Section 2.3 through 2.8 of Appendix A2, respectively, for each month from January 2020 to June 2020 (inclusive) in a table format. Please also include the volume and percentage variance between forecast and actual for each month for each customer class, respectively.

Response:

The table below compares the January 2020 to June 2020 actual values to the forecast values using the load forecast methods described in the Application. Note that the actuals from January 2020 to June 2020 are not normalized and therefore variances may also be affected by weather. Overall, sales load for the first half of 2020 is less than 1 percent lower than predicted.

On a June year-to-date basis, increased residential load is largely offset by lower commercial load, while the industrial class is the largest contributor to the variance for the January to June 2020 period. FBC has received indications that industrial loads are increasing in the second half of the year, and therefore expects a reduction in the industrial load variance.

Finally, FBC notes that the variances for the lighting and irrigation classes exhibit volatility, which is caused by the timing of bi-monthly billing cycles.

Actual and Forecast Loads from January 2020 to June 2020

Customer Class	Jan	Feb	Mar	Apr	May	Jun	2020 YTD
Actual Load (GWh)							
Residential	145.7	112.9	119.7	95.4	99.2	84.7	657.5
Commercial	85.8	84.5	79.0	65.6	56.9	66.7	438.4
Wholesale	62.0	54.0	51.2	41.4	36.6	35.7	280.9
Industrial	39.7	40.3	35.8	32.3	31.3	30.7	210.1
Lighting	0.9	1.0	0.9	0.7	0.8	1.1	5.3
Irrigation	0.7	0.7	0.8	1.7	3.4	6.3	13.6
Total	334.8	293.3	287.3	237.1	228.1	225.1	1,605.8
Forecast (GWh)							
Residential	146.8	108.9	116.3	94.7	93.6	83.0	643.2
Commercial	85.4	74.1	77.7	68.9	71.3	71.3	448.7
Wholesale	63.1	50.2	50.5	42.2	38.7	35.4	280.1
Industrial	38.5	39.1	39.6	36.2	37.2	39.0	229.6
Lighting	1.0	0.9	1.0	0.9	0.9	0.9	5.6
Irrigation	0.7	0.6	0.7	1.3	3.9	5.8	12.9
Total	335.4	273.7	285.7	244.2	245.6	235.5	1,620.2
Variance (GWh)							
Residential	-1.1	4.0	3.4	0.7	5.6	1.6	14.3
Commercial	0.4	10.4	1.3	-3.3	-14.4	-4.7	-10.3
Wholesale	-1.1	3.7	0.7	-0.7	-2.1	0.3	0.8
Industrial	1.2	1.2	-3.9	-3.9	-5.9	-8.3	-19.5
Lighting	-0.1	0.1	-0.1	-0.2	-0.2	0.2	-0.3
Irrigation	0.0	0.1	0.2	0.4	-0.5	0.5	0.7
Total	-0.6	19.6	1.6	-7.1	-17.5	-10.3	-14.4
Variance (%)							
Residential	-0.7%	3.6%	2.9%	0.7%	5.6%	1.9%	2.2%
Commercial	0.4%	12.3%	1.7%	-5.1%	-25.3%	-7.0%	-2.3%
Wholesale	-1.7%	6.9%	1.3%	-1.8%	-5.7%	0.9%	0.3%
Industrial	2.9%	3.0%	-10.8%	-12.0%	-18.9%	-26.9%	-9.3%
Lighting	-7.4%	9.1%	-8.3%	-34.9%	-19.8%	16.5%	-5.2%
Irrigation	5.9%	10.9%	18.8%	25.0%	-14.9%	8.0%	5.2%
Total	-0.2%	6.7%	0.6%	-3.0%	-7.7%	-4.6%	-0.9%

8.1.1 For each customer class, please compare the monthly forecast and actual customer count and UPC (if applicable), respectively, between January 2020 and June 2020.

8.1.1.1 If the data requested above is not available, please explain why not.

8.1.1.2 To the extent possible, please discuss the changes between customer count and UPC during the January 2020 and June 2020 period for each customer class, respectively.

Response:

The tables provided by FBC below show the monthly customer count and monthly UPC for each class as compared to forecast. The monthly variance in total customer count is 0.5 percent or less.

Variances in UPC for the residential and commercial classes are consistent with expectations of increasing residential usage and decreasing commercial activity as a result of the COVID-19 pandemic.

Unlike the residential class, for which UPC is forecast directly, the commercial UPC is derived from forecast load and customer count. The lower commercial load is evident in the response to BCUC IR1 8.1, while, as seen below, the commercial customer count has not declined. The result is a downward trend in commercial UPC.

The UPC for lighting and irrigation are also derived from forecast load and customer count. Please refer to the response to BCUC IR1 8.1 regarding the volatility of these loads.

The industrial and wholesale UPCs were not included since both classes are based on a small number of customers of varying sizes and characteristics.

Table 1: Customer Count Forecast and Actual from January to June 2020

Customer Count	Jan	Feb	Mar	Apr	May	Jun
Actual Customer Count						
Residential	122,746	122,924	122,909	123,010	123,166	123,289
Commercial	15,966	15,956	15,978	15,981	16,024	16,071
Wholesale	6	6	6	6	6	6
Industrial	52	52	52	52	52	52
Lighting	1,463	1,469	1,469	1,473	1,452	1,450
Irrigation	1,086	1,086	1,087	1,089	1,084	1,088
Total	141,319	141,493	141,501	141,611	141,784	141,956
Forecast Customer Count						
Residential	122,543	122,622	122,700	122,779	122,857	122,936
Commercial	15,924	15,898	15,872	15,846	15,821	15,795
Wholesale	6	6	6	6	6	6
Industrial	53	53	53	53	53	54
Lighting	1,451	1,454	1,450	1,444	1,441	1,434
Irrigation	1,082	1,082	1,082	1,082	1,082	1,082
Total	141,059	141,115	141,164	141,211	141,260	141,306
Customer Variance						
Residential	203	302	209	231	309	353
Commercial	42	58	106	135	203	276
Wholesale	0	0	0	0	0	0
Industrial	-1	-1	-1	-1	-1	-2
Lighting	12	15	19	29	11	16
Irrigation	4	4	5	7	2	6
Total	260	378	337	400	524	650
Variance (%)						
Residential	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%
Commercial	0.3%	0.4%	0.7%	0.8%	1.3%	1.7%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	-1.9%	-1.9%	-1.9%	-1.9%	-1.9%	-3.8%
Lighting	0.8%	1.0%	1.3%	1.9%	0.8%	1.1%
Irrigation	0.4%	0.4%	0.5%	0.6%	0.2%	0.6%
Total	0.2%	0.3%	0.2%	0.3%	0.4%	0.5%

Table 2: Monthly UPC Forecast and Actual from January to June 2020

UPC (MWh)	Jan	Feb	Mar	Apr	May	Jun	2020 YTD
Actual Monthly UPC (MWh)							
Residential	1.2	0.9	1.0	0.8	0.8	0.7	5.3
Commercial	5.4	5.3	4.9	4.1	3.6	4.1	27.4
Wholesale	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Industrial	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lighting	0.6	0.7	0.6	0.5	0.5	0.7	3.6
Irrigation	0.6	0.6	0.8	1.6	3.1	5.8	12.5
Forecast Monthly UPC (MWh							
Residential	1.2	0.9	0.9	0.8	0.8	0.7	5.2
Commercial	5.4	4.7	4.9	4.4	4.5	4.5	28.3
Wholesale	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Industrial	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lighting	0.7	0.6	0.7	0.7	0.6	0.6	3.9
Irrigation	0.6	0.6	0.6	1.2	3.6	5.4	11.9
Variance							
Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Commercial	0.0	0.6	0.1	-0.2	-1.0	-0.4	-0.9
Wholesale	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Industrial	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lighting	-0.1	0.1	-0.1	-0.2	-0.1	0.1	-0.2
Irrigation	0.0	0.1	0.1	0.4	-0.5	0.4	0.6
Variance (%)							
Residential	-0.9%	3.3%	2.7%	0.5%	5.4%	1.7%	2.0%
Commercial	0.2%	12.0%	1.0%	-6.0%	-26.9%	-8.9%	-3.2%
Wholesale	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Industrial	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Lighting	-8.4%	8.2%	-9.7%	-37.5%	-20.7%	15.6%	-6.4%
Irrigation	5.6%	10.6%	18.5%	24.5%	-15.1%	7.5%	4.7%

8.2 Please discuss how much of the variance between forecast and actual customer count, UPC, and overall load experienced between January 2020 and June 2020 is attributable to the impact of the COVID-19 pandemic.

Response:

Please refer to the response to BCUC IR1 8.1.1.

8.3 Please explain how the impact of the COVID-19 pandemic has been accounted for in FBC's load forecast for 2020P and 2021F for each customer class, respectively.

Response:

The impact of the COVID-19 pandemic in 2020P and 2021F are reflected in forecast loads for the commercial class and in the portion of the industrial class that did not provide forecast loads, since these load forecasts are based on GDP projections from the CBOC, which reflected the impact of the pandemic. The impact of the pandemic was also reflected in 2020P for all classes, as actual values were used from January to June 2020. FBC has recently seen some recovery in commercial and some industrial loads that were initially impacted by the pandemic.

9.0 Reference: LOAD FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Section 11, pp. 76, 96–98, 107, 127–129

Revenue requirement and rate changes for 2020 and 2021

FBC presents the summary of rate change for 2020 in Schedule 1 in Section 11. FBC provides further details regarding energy volume sold and revenue at existing rates for 2020 in Schedule 17; the revenue at existing and revised rates for the year ending December 31, 2020 in Schedule 18; and the cost of energy for 2020 in Schedule 19.

FBC also provides equivalent financial schedules for year 2021 in Section 11.

9.1 In a table format, please calculate how the load forecast impacts FEI's revenue surplus/deficiency and requested rate change for 2020 and 2021, respectively, if the gross load forecast was -10%, -5%, 0%, +5%, and +10% less/more than the forecast presented in the Application, respectively, assuming all else equal. Please explain all inputs and assumptions made.

Response:

Please refer to the table below for the impact of varying load forecasts on FBC's revenue surplus/deficiency and requested rate changes for 2020 and 2021, respectively.

Revenue adjustments were made on an annual basis and only impacted the energy revenue portion for each class, not fixed costs or demand changes.

Power purchase expense was also adjusted on an annual basis, in order to reflect the varying gross load forecast. The average PPA energy rate for each calendar year was used as a proxy to determine the value of the increase/decrease to power purchase expense.

The analysis also assumed that there is no change to the amount of the 2020 revenue deficiency ($3.587 million, Section 11 – 2020, Schedule 1, Line 35) and the amount of the 2021 revenue deficiency ($23.543 million, Section 11 – 2021, Schedule 1, Line 33). The resulting rate increase/decrease is a function of the revised deficiency/surplus and the revenues at existing rates. However, if the load forecasts were increased from the level included in the Application, FBC could adjust the deferred 2020 revenue deficiency accordingly to maintain the 2020 rate change at 1 percent, which in turn will affect the 2021 revenue deficiency/surplus. If the load forecasts were decreased, FBC could use the remaining balance in the 2018-2019 Revenue Surplus deferral account to help mitigate the corresponding rate increase, which in turn would also affect the 2021 revenue deficiency/surplus.

Finally, FBC notes that variances between the forecast and actual margin are captured in the Flow-through deferral account, and the resulting revenue requirement impacts are returned to or recovered from customers through the amortization of the Flow-through deferral account in subsequent years. In this way, customers are kept whole for any variances from forecast load.

Impacts with Gross Load Adjustments ($ millions)

2020	10% Decrease	5% Decrease	No Change	5% Increase	10% Increase
Revenues at Existing Rates	$ 329.778	$ 344.223	$ 358.668	$ 373.114	$ 387.560
Power Purchase Expense	$ 120.637	$ 129.624	$ 138.612	$ 147.599	$ 156.587
Revised Margin	$ 209.141	$ 214.599	$ 220.056	$ 225.515	$ 230.973
Rate Impact:					
Deficiency at 1% Rate Change	$ 3.587	$ 3.587	$ 3.587	$ 3.587	$ 3.587
Increase (Decrease) in Deficiency	$ 10.915	$ 5.457		$ (5.459)	$ (10.917)
Revised Deficiency (Surplus)	$ 14.502	$ 9.044	$ 3.587	$ (1.872)	$ (7.330)
Revenues at Existing Rates	$ 329.778	$ 344.223	$ 358.668	$ 373.114	$ 387.560
Rate Increase (Decrease)	4.40%	2.63%	1.00%	-0.50%	-1.89%

2021	10% Decrease	5% Decrease	No Change	5% Increase	10% Increase
Revenues at Existing Rates	$ 340.153	$ 354.898	$ 369.643	$ 384.386	$ 399.131
Power Purchase Expense	$ 127.503	$ 136.881	$ 146.260	$ 155.638	$ 165.016
Revised Margin	$ 212.650	$ 218.016	$ 223.383	$ 228.748	$ 234.114
Rate Impact:					
Deficiency at 6.37% Rate Change	$ 23.543	$ 23.543	$ 23.543	$ 23.543	$ 23.543
Increase (Decrease) in Deficiency	$ 10.733	$ 5.367		$ (5.365)	$ (10.731)
Revised Deficiency (Surplus)	$ 34.276	$ 28.910	$ 23.543	$ 18.178	$ 12.812
Revenues at Existing Rates	$ 340.153	$ 354.898	$ 369.643	$ 384.386	$ 399.131
Rate Increase (Decrease)	10.08%	8.15%	6.37%	4.73%	3.21%

9.1.1 Please also provide a revised Schedule 1, and Schedules 17 through 19 for year 2020 and 2021, respectively, in a functional excel spreadsheet with the above sensitivity analysis, if possible.

Response:

Please refer to Attachment 9.1.1 for copies of the functioning Excel spreadsheets that include Schedule 1, and Schedules 17 through 19 for each scenario requested.

B. OTHER REVENUE

10.0 Reference: OTHER REVENUE

Exhibit B-2, Section 5.2, pp. 36–37

Apparatus and Facilities Rental

On pages 36 to 37 of the Application, FBC states "The 2020 Projected [Apparatus and Facilities Rental] is higher than 2019 Approved due to a new pole attachment contract as well as escalations in unit rental rates for continuing contracts. The 2021 Forecast is higher than 2020 Projected due to escalations in unit rental rates."

10.1 Please provide further detail regarding the new pole attachment contract in 2020 (e.g. contract term, number of poles that are contacted, unit rate per pole contact).

Response:

The new pole attachment contract relates to FBC's granting of the right of use for fibre from FBC to a telecommunications company for an annual flat fee of approximately $0.325 million. The transaction was part of a series of agreements executed in 2011. Although these agreements were entered into in 2011, the new pole attachment contract referred to above became effective in early 2019 after certain closing conditions were met.

10.2 Please explain the drivers of unit rental rates and discuss how much rates have gone up for continuing contracts in 2020 and 2021 Forecast.

Response:

FBC has agreements for pole attachments with several different entities, with rate drivers differing between contracts. With the exception of the agreement referenced in the response to BCUC IR1 10.1, which is a flat fee contract, each contract includes formulas that contemplate items such as pole costs, financing and tax costs, maintenance costs (which could include labour, materials, and vehicles), and administration costs. The unit rental rates are calculated each year, instead of prescribed by agreement.

Rates for continuing contracts are forecast to increase by approximately 1.5 percent for both 2020 and 2021.

10.3 Please provide a breakdown of the increases in 2020 Projected Apparatus and Facilities Rental between the new pole attachment contract and "escalations in unit rental rates" for continuing contracts.

Response:

The 2020 Projected Apparatus and Facilities Rental is $0.965 million higher than 2019 Approved. The variance is comprised of the following:

- Approximately $0.220 million related to a higher number of pole contacts compared to 2019 Approved (identified during an audit of unreported contacts finalized in 2019);
- Approximately $0.325 million related to a new pole attachment contract that became effective in early 2019 and was not captured in 2019 Approved; and
- Approximately $0.420 million related to escalations in the estimated unit rental rates, which are calculated annually for each customer.

11.0 Reference: OTHER REVENUE

Exhibit B-2, Section 5.3, p. 37; FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively FortisBC) Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024 Decision and Orders G-165-20 and G-166-20 dated June 22,2020 (MRP Decision), p. 74

Contract Revenues

On page 37 of the Application, FBC states: "The 2020 Projected and 2021 Forecast [Contract Revenues] are expected to be higher than 2019 Approved due to revenues received from a three-year asset refurbishment project for a third party that is beginning in 2020, based on customer requirements."

Table 5-1 shows 2020 Projected and 2021 Forecast Contract Revenues are $2.305 million and $3.088 million, respectively, compared to 2019 Approved of $1.766 million.

On page 74 of the MRP Decision, the British Columbia Utilities Commission (BCUC) states:

> **The Panel approves FortisBC's proposal for forecast variances related to certain controllable Other Revenue components to be subject to the ESM rather than flow-through treatment.** These controllable Other Revenue items approved are listed in Table 20 above. [Emphasis in original]

11.1 Please explain the forecast methodology for 2020 Projected and 2021 Forecast Contract Revenues. Are projected/forecast revenues based on firm contracts with the customer?

Response:

FBC based both 2020 Projected and 2021 Forecast Contract Revenues on continuing contracts in place with third parties. The forecast for contract revenues takes into account average revenues from prior years, as well as work expected to be performed in the forecast year. The amount of work expected to be performed is based on the approved work plan for the year, which is based on customer requirements. However, variances from forecast can arise due to the timing of when work is completed between years, as well as unscheduled work that is carried out when and if needed.

11.2 Please provide a table summarizing the differences between actual and projected/forecast Contract Revenues for the years 2014 through 2019.

Response:

A summary of the difference between Approved and Actual Contract Revenues is provided below.

($ millions)	2014	2015	2016	2017	2018	2019
Approved	1.385	1.544	1.808	1.865	1.769	1.766
Actual	2.076	1.948	1.820	1.915	1.939	2.076
Difference	0.691	0.404	0.012	0.050	0.170	0.310

11.2.1 To the extent that there have been significant differences, please discuss what changes (if any) FBC has made to its forecasting methodology for 2020 and 2021 compared to previous years.

Response:

FBC considers the differences of $0.691 million in 2014, $0.404 million in 2015, and $0.310 million in 2019 significant. The differences for these three years were a result of the following:

- For 2014, the increase was primarily due to higher than forecast capital work completed on a transmission line at Waneta dam and spillgate upgrades and refurbishments at the Brilliant dam due to timing of work between years. Higher than forecast revenue from capital work for the City of Kelowna also contributed to the increase.
- For 2015, the majority of the increase was a result of higher than forecast revenue related to the Waneta Expansion, which was completed in April of 2015. The increased revenue was related to project management during construction through to completion, operating requirements including turbine inspections during the first year of operations, and the implementation of operating plans, administration, treasury and accounting processes.
- For 2019, the increase was primarily due to higher than forecast capital costs at the Brilliant dam related to communication and control systems and dam safety upgrades, as well as higher than forecast revenue from continuing operating and maintenance services provided to Waneta Expansion after its change in ownership in the first quarter of 2019.

As explained above, the causes of the variances in 2014, 2015 and 2019 were generally related to timing differences or unexpected/unplanned additional work being performed. While such events may occur in the future, they are not predictable; therefore, it would not be appropriate to change FBC's forecasting methodology.

C. OPERATIONS & MAINTENANCE EXPENSE

12.0 Reference: OPERATIONS & MAINTENANCE (O&M) EXPENSE

Exhibit B-2, Section 6.3.2, p. 44

Insurance Premiums

On page 44 of the Application, FBC states that the forecast insurance premiums expense for 2021 is $1.916 million. FBC explains:

> The forecast for 2021 is calculated as the amount of the first six months of the known annual insurance premium for July 2020 to June 2021 of $1.734 million and applying a 5 percent increase for the remaining six months, as well as including the annual cost of fire fighting premium of $138,500. FBC has experienced significant increases in insurance expense in the last two renewals as a result of various insurers reducing their capacity and increasing restrictions and retentions.

12.1 Please discuss what actions FBC plans to undertake, or has undertaken, to control increases in insurance expense.

Response:

FBC, as part of the Fortis Inc. Group of Companies, participates in the Corporate insurance program. The insurance groups at Fortis Inc. and FortisBC are very experienced and work together to place the insurance program on a yearly basis with a renewal date of July 1.

Each year, the Fortis insurance group works with its brokerage firm Aon Reed Stenhouse Inc. (Aon) to provide professional insurance services to the Fortis Group of Companies. As part of the process, Fortis and Aon assess the insurance market to determine the best course of action to provide Fortis the broadest coverage at the most competitive rates. This is accomplished by continual contact with underwriters capable of insuring the Fortis Group of Companies' risk profile. Fortis and Aon provide underwriters with updated underwriting information (Statement of Values, Loss Control reports etc.) annually for renewal purposes. The Fortis insurance group also attends in person visits with the majority of the markets, in particular, the lead or key markets on the Fortis program, to present the Fortis risk and answer any questions underwriters may have concerning Fortis. The Fortis Insurance group also meets annually with peer organizations and Aon to benchmark the Fortis insurance program.

FBC is therefore comfortable that its current levels of coverage are in line with both its peer group and property and liability exposure faced by it. Regardless of these efforts, insurance costs are very difficult to control as the majority of the impacts to rates are beyond the control of the Fortis Group of Companies.

To manage insurance premiums, FBC (through Fortis Inc.) works each year with its insurance broker Aon to market its insurance program to achieve the lowest premiums and most

favourable terms. Aon provides insurance brokerage services, including insuring property and other risks, to numerous major utilities and organizations globally. Once a year, Aon confirms to FBC's management team and Board of Directors that the coverage and limits provided by the insurance program are consistent in scope and nature with similar types of risks worldwide. Based on Aon's intensive marketing of the FBC insurance program, Aon further confirms that the rates and coverage terms are the best available given the current market conditions. Various insurance markets are approached each year in order to achieve optimal pricing. FBC has and continues to operate and conduct business in a way that represents a healthy and favourable account for insurers.

To manage insurance risk, FBC implements the necessary processes for various aspects of our operations to minimize potential exposures which may result in a loss. Insurance obligations are transferred to contractors and vendors where possible to avoid an impact to FBC's insurance program in the event of a loss.

D. RATE BASE

13.0 Reference: REGULAR CAPITAL EXPENDITURES

Exhibit B-2, Section 7.2, p. 48

2019 Actual Capital Expenditures

On page 48 of the Application, FBC provides Table 7-2:

Table 7-2: Approved Capital Expenditures

Line No.	Description	Approved 2019	Actual 2019	Approved 2020	Approved 2021	Reference
1	Growth Capital	n/a	$ 20.202	$ 27.029	$ 23.042	Section 11, Schedule 4, Line 2
2	Sustainment Capital	n/a	29.481	50.463	49.818	Section 11, Schedule 4, Line 3
3	Other Capital	n/a	11.802	15.752	14.712	Section 11, Schedule 4, Line 4
4	Total	$ 48.474	$ 61.485	$ 93.244	$ 87.572	Section 11, Schedule 4, Line 5

13.1 Please provide reasons for the variance on Line 4 "Total" between the 2019 Approved of $48.474 million and the 2019 Actual of $61.485 million. If possible, please provide separate explanations for each category of capital expenditures (i.e. Growth, Sustainment and Other).

Response:

The variance between the 2019 Approved and 2019 Actual total capital expenditures in Table 7-2 is partly attributable to FBC completing work that was reprioritized from prior years, as described in Appendix B8-3, FBC Capital Directives, in the 2020 – 2024 MRP Application.

In 2019, FBC completed the following work, which includes the re-prioritized work from prior years previously identified:

- Growth Capital:
  - Addition of the Sexsmith Distribution Transformer to accommodate capacity requirements; and
  - System improvements, consisting of projects related to increased capacity, equipment and services upgrades, voltage regulation, feeder ties, and load transfers, which are required to keep pace with normal load growth on the transmission and distribution systems. This also included work to connect new customers and to ensure continuing acceptable standards of service.
- Sustainment Capital:
  - New projects in generation to address compliance with legislation from WorkSafeBC;
  - Unanticipated transmission projects to address safety and reliability issues;

- Additional substation projects to address end-of life equipment replacements; and
- Purchase of fibre from a telecommunications company due to contractual obligations.

- Other Capital:
  - Minor facilities upgrades.

14.0 Reference: MAJOR PROJECTS CAPITAL EXPENDITURES

Exhibit B-2, Section 7.3, pp. 49–50

Certificate of Public Convenience and Necessity (CPCN) Threshold

On page 49 of the Application, FBC explains that the BCUC set the major project financial threshold for CPCN applications at $20 million for FBC for the MRP term.

On page 50 of the Application, FBC states:

> In addition to the three projects described above that have already been approved, FBC is requesting approval under Section 44.2 of the UCA [Utilities Commission Act] for one new capital project, the Playmor Substation Upgrade Project, which is driven by new customer requests received after the preparation of the MRP capital plan…The forecast cost of the Playmor Substation Upgrade Project is $10.922 million, inclusive of AFUDC and cost of removal, with expenditures of $0.490 million, $9.024 million, and $1.408 million in 2020, 2021, and 2022, respectively.

14.1 Please explain why FBC is requesting approval of the Playmor project under Section 44.2 of the UCA when the forecast cost of the project is below the financial threshold of $20 million for a major project filing.

Response:

In the MRP Decision, the BCUC approved a CPCN threshold for FBC of $20 million[1] and, as such, a CPCN is not required for the Playmor Project. The CPCN threshold, however, does not preclude FBC from applying for acceptance of capital expenditures under section 44.2 of the UCA.

As outlined below, in the context of the approved MRP, it is appropriate for FBC to seek acceptance of the Playmor Project under section 44.2 of the UCA, and it is just and reasonable for the capital expenditures to be approved for recovery in rates. In short, FBC could not have reasonably forecast uncertain growth-driven projects like Playmor in the MRP proceeding and FBC explained in the MRP Application (page C-106) that it "may identify new projects and programs that needed to be added over the term of the Proposed MRP". Filing for acceptance under section 44.2 provides a clear and transparent process for FBC to add such projects to the approved forecast.

- First, FBC could not have reasonably forecast the Playmor Project as part of its forecast of Regular capital expenditures in the MRP proceeding. The Playmor Project is a growth-driven project resulting from new customer load requests. The timing and need for such projects are outside of FBC's control and can be difficult to forecast. As listed in Table C3-23 of the MRP Application, FBC included forecast Growth capital expenditures for four transmission Growth capital projects during the MRP term: (i) the Sexsmith

[1] MRP Decision, pp. 132-133.

Second Transformer Addition; (ii) the Summerland Transformer Replacement; (iii) the Beaver Park Substation Upgrade; and (iv) the DG Bell 2nd Transmission Addition. These projects were reasonably expected to occur within the MRP term based on the information FBC had at the time of the MRP proceeding and it was therefore reasonable for FBC to include these capital expenditures in the Growth capital forecasts. At the time of preparing the MRP capital plan, FBC had no reasonable expectation that the Playmor Project would be required, as it had not yet received requests from the two new large customers that drive the project. As a result, FBC did not include a forecast for capital expenditures related to the Playmor Project within its Regular capital forecast.

- Second, it would not have been reasonable for FBC to include uncertain growth projects in its Regular capital forecast. As growth-driven projects are by nature uncertain and unpredictable, FBC was aware that growth-driven projects might materialize during the MRP term. While FBC was aware of such a possibility in general terms when filing the MRP Application and made every effort to ensure the accuracy of its capital expenditure forecasts, it would have been inappropriate to include expenditures related to potential undefined projects within the forecast of Regular Growth capital expenditures. This is because if the loads did not materialize and the projects were therefore not required, FBC would have over-forecast its capital expenditures, which would not have been beneficial for ratepayers. It is for this reason that FBC explained in the MRP Application (page C-106) that it "may identify new projects and programs that needed to be added over the term of the Proposed MRP".

- Third, given the magnitude of the forecast expenditures for the Playmor Project ($10.922 million), it would be impossible for FBC to accommodate the Playmor Project within the approved forecasts. Furthermore, because the Playmor Project is driven by customer load, the timing of the Playmor Project is outside of FBC's control and FBC is unable to defer the Project to future years.

- Fourth, in determining how to add additional projects during the term of the MRP, FBC took guidance from past practice under the 2014-2019 PBR Plan term, during which the BCUC accepted as "Special Projects" capital expenditure schedules under section 44.2 of the UCA for the Upper Bonnington Old Units Refurbishment ($31.783 million) and the Ruckles Substation Rebuild ($8.288 million)[2]. Section 44.2 provides a clear and transparent regulatory path for FBC to seek acceptance of the project expenditures, by which the BCUC can review and accept or deny new capital expenditures that cannot be accommodated within FBC's Regular capital expenditures envelope over the term of the MRP.

Finally, FBC notes that it included the Playmor Project under the heading of "Major Projects" in its Application because FBC is requesting treatment similar to its CPCN projects and those approved as "Special Projects" under the PBR Plan as identified above.

[2] Order G-8-17.

14.1.1 Please compare and contrast the filing requirements of a Section 44.2 capital expenditure schedule filing and a CPCN application.

Response:

The filing requirements for CPCN applications are contained in the 2015 CPCN Guidelines approved by the BCUC pursuant to Order G-20-15.

FBC is unaware of any similar such guidelines or filing requirements for Section 44.2 capital expenditure schedule filings; however, FBC considers it reasonable to provide similar information to what is outlined in the CPCN Guidelines and has done so in the business case for the Playmor Project attached as Appendix B to the Application.

FBC also notes that it has previously applied, and received approval for, capital expenditure schedules as part of the annual review process. In the FBC Annual Review for 2017 Rates, FBC applied for approval pursuant to section 44.2(3) of the UCA for acceptance of capital expenditure schedules for the Ruckles Substation Rebuild Project and the Upper Bonnington Old Units Refurbishment Project. Similar to the Playmor Project in the current Application, FBC submitted business cases for these projects as part of the annual review materials and the projects were reviewed as part of the annual review process. The topics that were explored through the IR process and at the workshop were similar to the topics pursued in a CPCN proceeding. These included examination of the projects' need, alternatives and adequacy of consultation, among others.

The BCUC accepted the capital expenditures for the Ruckles Substation Rebuild and the Upper Bonnington Old Units Refurbishment projects as part of the FBC 2017 Annual Review Decision and Order G-8-17.

In the business case for the Playmor Project attached as Appendix B to the Application, FBC has provided information on the Project need, provided an analysis of the alternatives considered and provided a justification and description of the preferred alternative, including the estimated Project cost and schedule. FBC has also described its consultation activities. Consistent with the Ruckles and Upper Bonnington projects, FBC considers it reasonable to review the Playmor Project as part of this annual review. FBC believes that the regulatory process established for this annual review proceeding should provide sufficient opportunities for the BCUC and interveners to gather the necessary evidence for the Panel to make a determination on the Playmor Project.

14.2 Please explain why FBC is not accounting for the cost of the Playmor project within the Regular Growth Capital expenditures approved in the MRP Decision.

Response:

Please refer to the response to BCUC IR1 14.1.

14.3 Please explain the impacts to the Earning Sharing Mechanism (ESM) if FBC includes or excludes the Playmor project from the Regular Growth Capital expenditures approved in the MRP Decision.

Response:

For the reasons provided in the response to BCUC IR1 14.1, FBC does not consider it reasonable to include the Playmor Project as part of the Regular Growth capital expenditures approved in the MRP Decision; however, FBC provides the following explanation of the ESM impacts as requested in this IR.

If the Playmor Project is excluded from Regular Growth capital expenditures, the expenditures will be treated as flow-through and there will be no impact to the ESM.

If the Playmor Project is included in Regular Growth capital expenditures, all else being equal, there would be a negative impact on the ESM, as FBC has not included a forecast amount for these expenditures as part of the approved Regular capital expenditures. Under the assumption that the Project capital costs enter rate base on January 1, 2022, the ESM impact related to the depreciation, interest and income tax expenses will be experienced in 2022. FBC estimates that the ESM impact would be a reduction to FBC's earned return amount and a recovery from customers of approximately $485 thousand after tax.

In responding to this question, FBC identified an error in the financial analysis in Appendix B. The substation costs are shown entering rate base on January 1, 2023 instead of January 1, 2022. FBC will file an evidentiary update on or before October 12, 2020. This update will not have an impact on FBC's rates for 2021.

14.4 Please explain any other benefits or drawbacks to FBC and/or its ratepayers from requesting a Section 44.2 approval versus accounting for the project under Regular Growth Capital.

Response:

FBC has explained why it is appropriate for capital expenditures associated with the Playmor Project to be accepted under section 44.2 of the UCA in its responses to BCUC IR1 14.1 and 14.1.1. These expenditures were clearly not contemplated during the MRP Application and do not form part of the approved Regular Growth capital. Further, by requesting approval under section 44.2 of the UCA, the BCUC and interveners have the opportunity to review the Project in a more fulsome manner by examining the need, alternatives, scope and other aspects of the Project.

FBC has not identified any other benefits or drawbacks beyond what has been described in response to BCUC IR1 14.1, 14.1.1, 14.2 and 14.3.

15.0 Reference: NEW DEFERRAL ACCOUNTS

Exhibit B-2, Section 7.7.1.1, p. 54

Annual Review for 2020 – 2024 Rates

On page 54 of the Application, FBC states that it requests approval to establish a deferral account to capture costs related to the Annual Reviews for 2020 – 2024 Rates. FBC further states that it forecasts additions of $0.140 million in each of 2020 and 2021 related to the proposed Annual Review for 2020 – 2024 Rates Deferral Account.

15.1 Please explain the basis for the $0.140 million forecast for each of 2020 and 2021related to the annual reviews considering that FBC has filed a joint application for setting 2020 and 2021 permanent rates.

15.2 Please provide Actual costs related to the annual reviews for 2015 through 2019.

Response:

The forecasts for 2020 and 2021 are for different applications. The forecast amount in 2020 is for the costs related to the 2020 and 2021 rates proceeding (i.e., the current Annual Review). During 2021, FBC will incur costs related to the Annual Review for 2022 rates.

FBC reviewed the actual costs of its previous annual reviews in forecasting these costs. Actual costs are shown in the table below, excluding the costs for the regulatory review of compliance filings in 2015, 2016 and 2017 (FBC Generator Outages Report, AIFR Compliance Filing, and FBC Major Projects Capital Treatment, respectively) and the consulting costs associated with the Depreciation Study included in the 2016 rates filing. The average cost for the annual reviews during the PBR term was $0.122 million.

Proceeding	Cost ($millions)
2015 Rates	$ 0.136
2016 Rates	$ 0.111
2017 Rates	$ 0.125
2018 Rates	$ 0.129
2019 Rates	$ 0.111

FBC's 2020 forecast addition to the Annual Review for 2020 – 2024 Rates deferral account of $0.140 million includes a provision for general cost escalation and for possible additional complexity and increased numbers of IRs given that this is the first year under the new MRP and that the Application covers two rate years (2020 and 2021). This amount is consistent with the actual costs incurred for the first annual review during the PBR term ($0.136 million) and FBC considers the forecast to be a reasonable approximation.

When forecasting the 2021 addition to the deferral account, FBC used the same amount as was forecast for 2020; however, FBC acknowledges that this was an oversight as it did not take into account the potential reduction in complexity in the 2022 annual review due to the application only encompassing one rate year, among other differences. Accordingly, FBC proposes to

reduce its 2021 forecast addition to the Annual Review for 2020 – 2024 Rates deferral account to $0.110 million. FBC considers this reduced amount to be reasonable because it is consistent with the actual costs incurred for the 2019 rates filing. FBC will update the financial schedules accordingly in its Compliance Filing following a decision on the Application.

16.0 Reference: NEW DEFERRAL ACCOUNTS

Exhibit B-2, Section 7.7.1.2, p. 54; Section 11 - 2020, Schedule 11

2021 Long-Term Electric Resource Plan

On page 54 of the Application, FBC states that it will file its 2021 Long-term Electric Resource Plan (LTERP) on or before December 1, 2021. FBC seeks a deferral account to capture the costs of external resources required for the 2021 LTERP that are incremental to the costs in FBC's Base O&M. FBC states that annual expenditures are estimated to be $0.260 million, $0.145 million and $0.320 million before tax in 2020, 2021 and 2022, respectively.

In its financial schedules, FBC shows a forecast "Opening Bal/Transfer Adj." of $0.019 million and "Gross Additions" of $0.235 million for 2020 in Schedule 11 related to the proposed 2021 LTERP Deferral Account.

16.1 Please explain the basis for the forecast annual expenditures of $0.260 million, $0.145 million and $0.320 million before tax in 2020, 2021 and 2022, respectively, related to the 2021 LTERP.

Response:

The estimated costs for the 2021 LTERP, consisting primarily of BCUC and PACA costs, external legal and consulting fees, stakeholder consultation, advertising, courier and other miscellaneous costs, are provided in the table below and total $725 thousand. FBC developed its 2021 LTERP estimate primarily by reference to the costs incurred for the 2016 LTERP which are provided in the response to BCUC IR1 16.3.

	2019	2020	2021	2022	Total
			($000s)		
BCUC Fees	$ -	$ -	$ 20	$ 25	$ 45
PACA	-	-	-	240	240
Legal Fees	-	35	110	55	200
Consulting Fees	23	172	10	-	205
Stakeholder Consultation	2	13	5	-	20
Advertising/Other	-	15	-	-	15
Total	$ 25	$ 235	$ 145	$ 320	$ 725

16.2 Please reconcile the 2020 forecast annual expenditures of $0.260 million before tax on page 54 of the Application to the forecast "Opening Bal/Transfer Adj." and "Gross Additions" amounts shown in Schedule 11.

Response:

The reported 2020 gross additions of $0.260 million is the sum of 2019 gross additions of $0.025 million (excluded from regulatory reporting in 2019 prior to approval of the deferral account) and 2020 gross additions of $0.235 million. The 2020 opening balance adjustment at Line 11, Column 3 of Schedule 11 is the net-of-tax value of the 2019 expenditure ($25.4 thousand times (1-27%) = $18.6 thousand, rounded to $19 thousand).

16.3 Please provide the historical cost of FBC's last LTERP.

Response:

The costs for the 2016 LTERP are provided in the following table.

	($000s)
BCUC Fees	$ 41
PACA	205
Legal Fees	188
Consulting Fees	259
Software (Portfolio Evaluation)	24
Stakeholder Consultation	20
Advertising/Other	14
Total	$ 752

17.0 Reference: NEW DEFERRAL ACCOUNTS

Exhibit B-2, Section 7.7.1.3, p. 54

2020 Cost of Service Analysis

On page 54 of the Application, FBC states that it will file a Cost of Service Analysis (2020 COSA) on or before December 31, 2020. FBC further states that it anticipates it will incur $0.080 million of costs in 2020 and an additional $0.020 million in 2021 before tax to manage any regulatory process.

17.1 Please explain the basis for the $0.080 million and $0.020 million forecasts in 2020 and 2021, respectively, related to the 2020 COSA.

Response:

The forecast cost for the 2020 COSA is based on experience with similar filings and anticipation of the nature of the associated regulatory process. The 2020 COSA is being filed for information purposes, and will have no rate design associated with it. FBC therefore expects a limited review process.

The forecast expenditures include external consulting and legal fees, and BCUC costs. FBC anticipates that the bulk of the work will be completed in 2020 and that the regulatory process and costs will extend into 2021.

18.0 Reference: NEW DEFERRAL ACCOUNTS

Exhibit B-2, Section 7.7.1.4, pp. 54–55

BCUC-Initiated Inquiry Costs

On page 54 of the Application, FBC seeks a deferral account to capture costs associated with its participation in BCUC-initiated inquiries and proceedings. FBC states on page 55 that the following proceedings and associated costs will be included in the proposed deferral account:

- BCUC Inquiry into the Regulation of Electric Vehicle Charging Service: FBC incurred $0.066 million ($0.048 after tax) for the Phase 1 and Phase 2 Inquiries.
- BCUC Indigenous Utilities Regulation Inquiry, which concluded in April 2020. To date, FBC has incurred $0.093 million ($0.068 million after tax) and anticipates additional costs of $0.125 million before tax in 2020 related to the issuance of the final report and participant funding costs.
- BCUC Municipal Energy Utilities Inquiry, which is currently adjourned. FBC has incurred $0.006 million ($0.004 million after tax) to date. FBC forecasts further costs, before tax of $0.005 million in 2020 and $0.005 million in 2021.

In its financial schedules, FBC shows a forecast "Opening Bal/Transfer Adj." of $0.087 million and "Gross Additions" of $0.176 million for 2020 in Schedule 11 related to the proposed BCUC-Initiated Inquiry Cost Deferral Account.

18.1 Please reconcile the 2020 incurred and forecast expenditures on page 55 of the Application to the forecast "Opening Bal/Transfer Adj." and "Gross Additions" amounts shown in Schedule 11.

Response:

In responding to this series of questions, FBC recognized that the forecast costs for the Indigenous Utilities Regulation Inquiry had been overstated. The overstatement is related to a misallocation of future PACA costs, which should have been based on the BCUC levy ratio between the four largest utilities, resulting in a smaller allocation to FBC than was included in the Application.

The revised forecast for the BCUC-Initiated Inquiry Costs, by proceeding and year, is provided in the table below and results in a reduction of $0.043 million to amortization expense in 2021. FBC will include this revision in its compliance filing following a decision on the Application.

Inquiry	2019	Jan-Jul 2020	Aug-Dec 2020	Total 2020	2021	Total
	(1)	(2)	(3)	(4)=(2)+(3)	(5)	(6)=(1)+(4)+(5)
			($000s)			
EV Charging Service Regulation	$ 65	$ 1	$ -	$ 1	$ -	$ 66
Indigenous Utilities Regulation	53	40	66	106	-	159
Municipal Energy Utilities	2	4	5	9	5	16
Total	$ 119	$ 46	$ 71	$ 116	$ 5	$ 240
Income Tax	(32)	(12)	(19)	(31)	(1)	(65)
Total, Net of Tax	$ 87	$ 33	$ 52	$ 85	$ 4	$ 176

The costs for each of the proceedings as set out on page 54 of the Application reflect costs at the time of filing (up to July 2020). These costs are shown in columns 1 and 2 of the table above.

The 2020 opening balance adjustment at Line 12, Column 3 of Schedule 11-2020 is the 2019 after-tax expenditure of $0.087 million ($0.119 million times (1-0.27%)). The 2020 Gross Additions at Line 12, Column 4 of Schedule 11-2020 (to be revised) is the pre-tax expenditures in Column 4 of the table above.

18.2 Please provide a breakdown of the 2020 costs incurred to-date and provide the basis for the remaining forecast for 2020 for each BCUC inquiry proceeding.

Response:

The costs incurred to July 2020 (as reflected on page 55 of the Application) for each of the proceedings are provided in the table below.

	EV Charging Service	Indigenous Utilities	Municipal Utilities
		($000s)	
BCUC Fees	$ 1	$ 18	$ -
PACA	31	8	-
Legal Fees	34	67	6
Total	$ 66	$ 93	$ 6

The Inquiry into the Regulation of Electric Vehicle Charging Service has concluded and no further costs are expected.

The forecast of additional costs in 2020 and 2021 for the BCUC Municipal Energy Utilities Inquiry is based on an estimate of external legal and consulting costs for preparation of

evidence in anticipation of the recommencement of the proceeding. FBC's intervention in the proceeding is joined with FEI, and FBC is being allocated 4 percent of the costs incurred, based on the ratio of customers between FEI and FBC.

The revised forecast for the BCUC Indigenous Utilities Inquiry (please refer to the response to BCUC IR1 18.1) is based on the allocation of expected PACA using the BCUC levy ratio between the four largest utilities, and FBC's portion of expected legal fees incurred jointly with FEI.

On page 54, FBC states, "[it] proposes to include the costs of these and future tariff-related applications in a single deferral account, in order to reduce the number of individual deferral account requests."

18.3 For clarity, please confirm whether the proposed BCUC-Initiated Inquiry Costs Deferral Account would be limited to the three proceedings listed on page 55 of the Application (i.e. BCUC Inquiry into the Regulation of Electric Vehicle Charging Service, BCUC Indigenous Utilities Regulation Inquiry, BCUC Municipal Energy Utilities Inquiry) or not.

Response:

The statement on page 54 of the Application is in error and should read: "…proposes to include the costs of these and future BCUC-initiated inquiries in a single deferral account…."

FBC proposes to include in the BCUC-Initiated Inquiry Costs deferral account the costs of the three proceedings listed on page 55 of the Application as well as the costs for any future BCUC-initiated inquiries, such as the recently initiated BCUC Inquiry into the Regulation of Safety.

18.4 Please elaborate on what is meant by "and future tariff-related applications" in the preamble above.

Response:

The reference to "future tariff-related applications" was in error. Please refer to the response to BCUC IR1 18.3.

19.0 Reference: NEW DEFERRAL ACCOUNTS

Exhibit B-2, Section 7.7.1.5, p. 55

Mandatory Reliability Standards (MRS) 2021 Audit

On page 55 of the Application, FBC requests the creation of a new deferral account for the 2021 MRS Audit. FBC states that eligible costs are incremental labour and expenses directly caused by the periodic audit and therefore not included in Formula O&M Expense. FBC states that, based on previous audits, it forecasts cost of $0.350 million before tax in 2021.

19.1 Please confirm, or explain otherwise, that FBC has undertaken triennial MRS audits in the past and that the last audit was performed in 2018.

19.1.1 If confirmed, please explain how these costs were accounted for. If applicable, please explain whether FBC considered extending the same accounting treatment to the 2021 MRS Audit.

Response:

Confirmed. FBC's previous MRS audits were conducted in 2012, 2015 and 2018. The costs of the 2012 compliance audit were recorded in a deferral account as approved by Order G-23-13. The costs of the subsequent compliance audits were included in the 2015 and 2018 revenue requirements in O&M expense, forecast outside of the PBR formula, and variances from forecast were included in the Flow-through deferral account.

FBC believes that deferral treatment for the periodic MRS compliance audits is a more appropriate means of recognizing the costs because it permits recovery over the period between audits and results in a level spending profile, compared to recovering the full costs of the audit in a single year, as would result from expensing the audit costs.

19.2 Please provide the historical actual cost for the last three triennial MRS audits.

Response:

The following table provides the historical actual costs for the last three triennial MRS audits.

	2012	2015	2018
	($000s)		
MRS Complliance Audit Costs	$ 575	$ 375	$ 341

On page 107 of the MRP Decision, the BCUC agreed to use 2018 Actual O&M as the starting point for determining FBC's Base O&M for the MRP.

19.3 Please clarify why the costs of the 2018 MRS Audit are not included in 2018 Actual O&M and therefore are not included in FBC's Formula O&M expense.

Response:

The costs of the 2018 compliance audit are not included in Formula O&M Expense. The basis for setting Formula O&M Expense was actual 2018 Base O&M, as adjusted[3]. As explained in the response to BCUC IR1 19.1, the costs of the compliance audit were outside of formula O&M in 2018 and therefore excluded from the base. The adjustments to the 2018 Base O&M to determine Formula O&M Expense for the MRP term included ongoing costs of MRS compliance which had been recognized as exogenous factors during the PBR term[4], but did not include the costs of the triennial compliance audit.

[3] FEI-FBC MRP Compliance Filing, Table 4.
[4] MRP Application, page C-45.

E. FINANCING AND RETURN ON EQUITY

20.0 Reference: FINANCING COSTS

Exhibit B-2, Section 8.3.1, p. 67

Long-term Debt

On page 67 of the Application, FBC states that in May 2020, it completed a private placement of $75 million in long-term debt at a rate of 3.12 percent for a term of 30 years. FBC further states that it plans to issue additional long-term debt of approximately $75 million in 2021 in July 2021 at a rate of 3.90 percent.

20.1 Please explain why the forecast interest rate for the debt issuance in July 2021 is higher than the completed debt issuance in May 2020 given that interest rates have been falling.

Response:

To estimate future interest rates on long-term debt issuances, FBC uses 30-year benchmark Government of Canada Bond interest rate forecasts as provided by Canadian Chartered banks with historical indicative credit spreads applied, as well as a liquidity spread due to the smaller forecast issuance size. The past several years have been a period of historically low interest rates in Canada and globally, which is reflected in the interest rate of the recent issuance at FBC. During this period, it has been typical for Canadian Chartered bank projections to include an expectation that long-term benchmark yields will regress back to more historically representative rates in the future, which may provide some explanation for the higher projected rates compared to recent issuances. The forecasts may also incorporate an element of economic uncertainty during the post-COVID-19 pandemic period.

F. TAXES

21.0 Reference: TAXES

Exhibit B-2, Section 9.2, pp. 71–72

Property Taxes

On page 71 of the Application, FBC states that property taxes in 2021 are forecast to increase 7.4 percent compared to 2020 Projects and is primarily driven by increases in rates for transmission and distribution lines. FBC's assumptions for the drivers of the changes, including changes in tax rates, changes in revenues to calculate grants in lieu of taxes and changes in assessed values, are provided on pages 71 to 72.

21.1 Please provide the rationale for the expected increases and decreases to the property tax cost drivers discussed on pages 71 to 72.

Response:

The expected increases and decreases to the 2021 property tax drivers discussed on pages 71 and 72 were based on:

1. Actual data when known;
2. Discussions with BC Assessment and the Ministry of Finance during the three-year pipeline rate review process with pipeline owners; and
3. Discussions with BC Assessment at the time the forecast was being created to identify any trends they may be seeing for the 2021 assessment roll, which has a valuation date of July 1, 2020.

These drivers were applied to the 2020 Projected property taxes to determine the taxes payable in 2021. As stated in the Application, almost 100 percent of 2020 Projected property taxes had already been paid at the time of filing.

21.2 Please provide a breakdown of the forecast increase in property taxes for transmission and attribution lines based on the cost drivers discussed on pages 71 to 72.

Response:

Below is a breakdown of the overall forecast change in property assessment, taxes and rates for transmission and distribution lines based on the cost drivers discussed on pages 71 to 72 of the Application:

2020 Projected Property Tax – Transmission and Distribution Lines ($ millions)

	Net General Assessment	Net School Assessment	General Taxes	School Taxes	Other Taxes	Total Taxes	Average Tax Rate / $1,000 Assessment
Distribution Lines	118.258	172.825	0.549	2.221	1.301	4.071	23.55562
Transmission Lines	90.826	101.112	0.808	1.179	0.698	2.685	26.55471
Total	209.084	273.937	1.357	3.400	1.999	6.756	24.66260

2021 Forecast Property Tax – Transmission and Distribution Lines ($ millions)

	Net General Assessment	Net School Assessment	General Taxes	School Taxes	Other Taxes	Total Taxes	Average Tax Rate / $1,000 Assessment
Distribution Lines	141.896	207.542	0.663	2.534	1.579	4.776	23.01221
Transmission Lines	112.488	125.877	1.017	1.403	0.879	3.299	26.20812
Total	254.384	333.419	1.680	3.937	2.458	8.075	24.21878

As shown in the tables above, tax rates are expected to decrease to partially offset the increased assessments. School tax rate reductions will also apply to other utility classed properties, such as the dams and substations.

G. FINANCIAL SCHEDULES

22.0 Reference: FINANCIAL SCHEDULES

Exhibit B-2, Section 11 – 2020, Schedules 11 and 12

Unamortized Deferred Charges and Amortization

FBC includes in Section 11 of the Application Schedule 11 (Unamortized Deferred Charges and Amortization – Rate Base) and Schedule 12 (Unamortized Deferred Charges and Amortization – Non Rate Base).

22.1 In the same format as is provided in Schedules 11 and 12 in Section 11 of the Application, please provide the previous years' information on unamortized deferred charges by starting with the actual 2018 ending deferral account balances (i.e. 12/31/2018) and including the actual 2019 deferral account additions and the actual 2019 amortization to arrive at the actual ending 12/31/2019 balances.

Response:

Please refer to Attachment 22.1 for an excerpt of Schedules 11, 12 and 12.1 from the FBC 2019 Annual Report to the BCUC, which provides the unamortized deferred charges and amortization for the year ending December 31, 2019.

Schedule 11 includes a $625,000 addition for each of 2020 and 2021 to the Deferred Debt Issue Costs deferral account.

22.2 Please provide a breakdown of the $625,000 additions for each of 2020 and 2021.

Response:

In the table below, FBC provides a breakdown of the $625,000 in additions for each of 2020 and 2021.

FBC issued a long-term debenture of $75 million in May 2020 and forecasts another long-term debenture issuance of $75 million in mid-2021. Total debt issue costs consist of the debt discount, credit rating agency fees, dealers' fees and legal fees, as shown in the table below. A relatively minor debt discount has occurred on various of FBC's past debt issuances, representing the present value of the difference between the issue yield and the coupon, and have historically been approved for inclusion in debt issue costs which are amortized over the life of the debt instrument pursuant to GAAP. FBC expects that the 2021 debt issue costs will generally be consistent with 2020 debt issue costs.

Breakdown of Deferred Debt Issue Costs		
	2020	2021
Debt Discount	$ 102,000	$ 102,000
Rating Agency Fees	134,000	134,000
Dealers' Fees	375,000	375,000
Legal Fees	14,000	14,000
Total	**$ 625,000**	**$ 625,000**

Schedule 11 includes a $650,000 addition for 2020 and $365,000 addition for 2021 to the Preliminary and Investigative Charges deferral account.

22.3 Please provide a breakdown of the $650,000 additions for 2020.

Response:

This account captures costs incurred for preliminary engineering (scope and estimating) or determining the feasibility of projects for utility services, other than CPCN projects.

The $0.650 million is the net additions for 2020, consisting of $1.339 million of gross additions less $0.689 million transferred to capital projects. The majority of the additions are related to:

- Future substation upgrades, including the Salmo station upgrade, Sexsmith 2nd Transformer Addition, and Trout Creek Transformer Replacement projects included in FBC's capital plan filed with the MRP Application, and the Playmor Substation project identified in Section 7.3 (a total of $0.575 million); and
- Transmission line upgrade feasibility studies primarily related to Kootenay area reliability issues ($0.760 million).

The costs in this account are either transferred to the capital project upon commencement of the project, or expensed if the project does not proceed.

In 2020, $0.689 million will be transferred to capital projects underway, including the Salmo, Sexmith and Trout Creek substation projects identified above[5].

22.4 Please provide a breakdown of the $365,000 additions for 2021.

[5] Deferral account additions for these projects preceded the MRP Decision of June 22, 2020.

Response:

Please refer to the response to BCUC IR1 22.3 for an explanation of this deferral account.

The $0.365 million is the net additions for 2021, consisting of $1.044 million of gross additions less $0.680 million transferred to capital projects. The additions are related to:

- Future substation upgrades, including the Fruitvale and Beaver Park Upgrades included in FBC's capital plan filed with the MRP Application and the Playmor Substation project identified in Section 7.3 (a total of $0.541 million);
- Transmission line upgrade feasibility studies primarily related to Kootenay area reliability issues ($0.397 million); and
- Smaller sustainment projects such as distribution line rebuild and underground conductor replacements ($0.105 million).

In 2021, $0.680 million will be transferred to capital projects underway in that year, including the Playmor Substation Upgrade project, and station and distribution sustainment projects.

H. ACCOUNTING MATTERS

23.0 Reference: EXOGENOUS (Z) FACTORS

Exhibit B-2, Sections 1 and 12.2.1, pp. 3, 139

COVID-19 Pandemic

On page 3 of the Application, FBC states that it seeks approval "To record COVID-19 incremental costs and related savings from 2020 and 2021 into the previously approved COVID-Customer Recovery Fund Deferral Account…"

On page 139 of the Application, FBC states that it has incurred incremental O&M expenditures for COVID-19 related items in 2020, including the following:

- Cleaning and disinfecting of facilities;
- Sequestering of system control centre employees from having to return to their homes; and
- Public Affairs Emergency communication activities to keep customers informed of the assistance available.

FBC states that it expects to continue to incur additional expenditures for the remainder of the year but is unable to provide a forecast of the cost for 2020 or for future years. FBC states:

> Due to the uncertainty, FBC is not seeking approval of exogenous factor treatment for incremental impacts related to COVID-19 at this time. Instead, over the coming months, FBC will evaluate the COVID-19 incremental costs and related savings. If the incremental costs and related savings are determined to be significant, FBC proposes to include the amounts in the previously approved COVID-Customer Recovery Fund Deferral Account. The amounts will then be reviewed in 2021 when actual 2020 amounts and forecasts for future years can be ascertained, and an appropriate recovery method can be determined.

23.1 Please confirm that FBC did not seek approval to record the incremental costs and savings to the COVID-19 Customer Recovery Fund Deferral Account in the original FBC COVID-19 Customer Recovery Fund Deferral Account Application.

23.1.1 If confirmed, please explain why FBC is now asking to include these incremental costs and savings, when it did not ask for their inclusion in the original application. Please discuss the changes in factors/circumstances, if any.

Response:

In the preparation of the COVID-19 Customer Recovery Fund Deferral Account Application in May 2020, FBC's focus was on seeking approval of customer relief measures as expeditiously

as possible and not on the potential net incremental impact to FBC's O&M expenses. Additionally, at that time, FBC was uncertain of the impact of COVID-19 on FBC's O&M expenses in 2020. As a result, there was no specific discussion of potential exogenous factor treatment related to net O&M expenses included as part of the COVID-19 Customer Recovery Fund Deferral Account Application.

Further, in FBC's view, the review of any requests related to exogenous factor treatment is best undertaken as part of the Annual Review process. This approach is consistent with the BCUC's determination in the MRP Decision, whereby the BCUC determined that the MRP Annual Review framework should include, among other things, a review of exogenous events that the Company or stakeholders have identified that should be put forward to the BCUC for review.[6]

With the impact of COVID-19 now expected to continue at least over the near term, FBC recognizes the possibility of incremental impacts related to COVID-19 on net O&M expenses, which will eventually require disposition and recovery.

As both the COVID-19 Customer Recovery Fund Deferral Account and the potential exogenous factor treatment for incremental O&M impacts are related to COVID-19, FBC believes it is appropriate to combine the two parts together for review and determine their eventual disposition and recovery. As indicated in the Application, the amounts will be reviewed in 2021 when actual 2020 amounts and forecasts for future years can be ascertained, and an appropriate recovery method can be determined.

23.2 Please provide a breakdown of the incremental O&M expenditures incurred to date in 2020 for COVID-19 related items, broken down by category.

23.2.1 If possible, please provide a forecast for these costs for the remainder of 2020 and for 2021. Please include assumptions and any new costs which are anticipated.

23.3 Please provide a breakdown of incremental savings experienced to date in 2020 related to COVID-19, broken down by category.

23.3.1 If possible, please provide a forecast for these savings for the remainder of 2020 and for 2021. Please include assumptions and any new savings which are anticipated

Response:

Below is a table outlining the approximate incremental O&M costs and offsetting O&M cost reductions related to the COVID-19 pandemic as at the end of August 2020. The incremental

[6] MRP Decision, p. 167.

costs are grouped into categories by department and include a description of the costs incurred by each department/area.

COVID-19 Net Incremental O&M
$ millions

Incremental COVID-19 costs

Categories of Costs	Description	2020 Year to Date
Field Operations	Sequestering of system control centre employees, PP&E and miscellaneous other	$ 0.59
Facilities	Safety supplies, furniture storage, additional cleaning, first aid coverage, signage	$ 0.03
Public Affairs Emergency Team / Communications	Public Affairs Emergency communications activities to keep our customers informed	$ 0.12
Other	Including Information Systems, Customer Service, Human Resources and Regulatory costs	$ 0.06
Subtotal		$ 0.80
Offsetting COVID-19 cost reductions		
Employee expenses	Lower expenses due to activities / travel restrictions in response to COVID-19 pandemic	$ (0.31)
Total COVID-19 Net Incremental O&M		$ 0.49

Considerable uncertainty remains about the duration and impact of COVID-19 on FBC's O&M costs. As indicated in the Application, with the uncertainty regarding COVID-19's expected duration and the timing of the transition to and from Phases 2, 3, and 4 of the Province's BC Restart Plan, FBC at this time is unable to provide a forecast of incremental impacts related to COVID-19 for the remainder of 2020 or for future years.

Year-to-date, the net incremental O&M impact is $0.49 million, with incremental costs totaling approximately $0.80 million and cost reductions consisting of employee expenses totaling approximately ($0.31) million. The temporary lower employee expenditures are primarily the result of restrictions on FBC employees' activities and travel during the COVID-19 pandemic and are not expected to have an impact on the safety and reliability of FBC's distribution system. The expenditures include amounts for course fees, travel, meals, accommodations, employee hiring and relocation expenses.

23.4 If approved, please confirm, or explain otherwise, that the COVID-19 incremental costs and related savings from 2020 and 2021 will be separately tracked in the FBC COVID-19 Customer Recovery Fund Deferral Account. If not, please explain why not.

Response:

Confirmed.

The COVID-19 incremental costs and related savings from 2020 and 2021 will be separately tracked in the FBC COVID-19 Customer Recovery Fund Deferral Account.

23.5 If approved, please confirm, or explain otherwise, that the recovery of any amounts included in the COVID-19 Customer Recovery Fund Deferral Account related to this approval (i.e. COVID-19 incremental costs and related savings from 2020 and 2021) will remain subject to future BCUC determination based on the established exogenous factor criteria, including the materiality threshold.

Response:

Confirmed.

In this Application, FBC is only seeking approval to include the COVID-19 incremental costs and related savings in the COVID-19 Customer Recovery Fund Deferral Account.

If approved, the recovery from customers of the net incremental O&M impact included in the COVID-19 Customer Recovery Fund Deferral Account will remain the subject of a future BCUC determination based on the established exogenous factor criteria, including the materiality threshold.

24.0 Reference: EXISTING DEFERRAL ACCOUNTS

Exhibit B-2, Section 12.4.1.3, p. 145

2020 Flow-through Deferral Account Balance

On page 145 of the Application, FBC states:

> FBC is not projecting a Flow-through balance for 2020. This is because FBC has included actual amounts up until June 30, 2020 within its Projected 2020 revenue requirement throughout this Application and is not projecting any further variances for the remainder of the year from the amounts included in this Application. Therefore, there are no amounts to include within the 2020 Flow-through projection.

On page 7 of the Application, FBC states that amortization expense in 2021 increases by $7.759 million primarily from the elimination of the credit flow-through variance embedded in 2020 rates.

24.1 Please provide a summary of the historical projected flow-through deferral account balances embedded in rates for the years 2014 through 2019. Please specify whether the amounts were credits to be distributed to customers or amounts to be recovered from customers.

Response:

The requested information is provided in the table below. All of the variances were credits to be returned to customers, with the exception of the 2016 Flow-through variance, which was recovered from customers in 2017.

Line No.	Particulars	Variance 2019	Variance 2018	Variance 2017	Variance 2016	Variance 2015
	(1)	(2)	(3)	(4)	(5)	(6)
1	Revenue	$ 2.885	$ (9.844)	$ 1.736	$ 13.310	$ 7.257
2						
3	Power Purchase Expense	(6.063)	(2.824)	(5.779)	(9.043)	(6.560)
4						
5	Water Fees	(0.069)	0.079	0.001	(0.104)	(0.090)
6						
7	Wheeling	0.660	0.110	0.089	0.015	(0.012)
8						
9	O&M Tracked Outside of Formula					
10	Insurance Premiums	0.098	(0.019)	(0.060)	(0.042)	(0.046)
11	Advanced Metering Infrastructure Project	(0.134)	-	-	0.465	-
12	Mandatory Reliability Standards	(0.049)	(0.030)	-	0.010	-
13	Upper Bonnington Unit 3 Annual Inspection	-	-	-	-	-
14	MSP Premium Reduction	(0.012)	(0.168)	-	-	-
15	Employer Health Tax	(0.020)	-	-	-	-
16	2015 Mandatory Reliability Standards Audit	-	-	-	-	-
17						
18	Property Tax	(0.049)	(0.541)	(0.164)	0.167	(0.289)
19						
20	Depreciation and Amortization	0.818	0.328	0.062	(0.371)	(0.771)
21						
22	Other Revenue	(1.359)	(1.193)	(0.924)	0.196	(0.119)
23						
24	Interest Expense	(0.491)	-	(1.739)	(0.409)	(0.390)
25						
26	Income Tax	(2.436)	3.592	1.455	(1.117)	0.459
27						
28	Working Capital Adjustment for AMI	(0.131)	(0.024)	(0.006)	-	-
29						
30	After-Tax Flow-Through Addition to Deferral Account	$ (6.352)	$ (10.534)	$ (5.329)	$ 3.077	$ (0.561)
31						
32	Prior Year Ending Deferral Account Balance True-Up	$ (1.122)	$ (2.254)	$ (0.886)	$ 2.973	
33	After-Tax Amortization	$ (7.475)	$ (12.788)	$ (6.216)	$ 6.051	
34						
35	True-up Double-Counted in Deferred Schedule[1]			(0.886)		
36						
37	Balance per Schedule 12	$ (7.475)	$ (12.788)	$ (7.102)	$ 6.051	$ (0.561)
38						
39	Reference	Annual Review for 2020 Rates Aug 19 2020	2019 Compliance Filing Mar. 15 2018	2018 Compliance Filing Jun. 25 2018	2017 Evidentiary Update Oct. 5 2016	2016 Compliance Filing Dec 16. 2015

[1] In its Annual Review for 2018 Rates, FBC inadvertently duplicated the true-up of the 2016 Flow-through account ($0.886 million). The correction is reflected in the true-up for the 2017 Flow-through account in the Annual Review for 2019 Rates, as set out in the response to BCUC IR1 37.1 for 2019.

24.2 Please discuss whether it would be appropriate to determine a projected flow-through deferral account balance to be amortized in rates for 2021 based on either prior years' projected or actual flow-through deferral account balances. Please explain why or why not.

Response:

FBC's July 2020 to December 2020 projected amounts are based on the most recent information available to FBC at the time of preparing the Application and are FBC's best estimate of the expected results over that same period. While there will inevitably be a variance between actual and approved amounts, FBC does not have any information at this time on which to quantify any such variance, or to determine whether it will be positive or negative. Any variance that materializes between the actual and approved amounts over the remainder of the year will be captured in the Flow-through deferral account, and either recovered from or returned to customers in future rates.

It would be unreasonable to forecast 2020 flow-through additions based on FBC's projected or actual flow-through deferral additions from prior years, since the amounts from prior years are not indicative of the actual activity expected to be recorded in the Flow-through deferral account in the last six months of 2020. Further, flow-through deferral additions in past years are based on FBC's 2014-2019 PBR Plan, whereas 2020 flow-through deferral additions will be based on FBC's 2020-2024 MRP. Finally, such an approach may also cause unintended rate consequences in the future. For example, forecasting a hypothetical Flow-through deferral account refund now, when the actual 2020 deferral addition is ultimately an amount recoverable from customers, would result in additional rate pressure in future years.

I. SERVICE QUALITY INDICATORS

25.0 Reference: SERVICE QUALITY INDICATORS
Exhibit B-2, Section 13.2.2, p. 153
Customer Satisfaction Index

On page 153 of the Application, FBC discusses the Customer Satisfaction Index:

> The average index score for June 2020 year-to-date is 8.4… Of the five measures that make up the overall customer satisfaction score, the results for June 2020 year-to-date were lower in three, higher in one, and static in another category compared to June 2019 year-to-date performance. Customer attitudes about the Company's contact centre decreased by two points from 8.5 to 8.3. There are small decreases in scores for both accuracy of meter reading and energy conservation information metrics, with the former decreasing from 8.3 to 8.2, and the latter from 7.7 to 7.6. Satisfaction with field services increased from 8.9 to 9.0, while overall satisfaction remained static at 8.4.

25.1 Please discuss the factors that contributed to the decrease in customer attitudes about the Company's contact centre.

25.2 Please discuss the factors that contributed to the decrease in scores for the accuracy of meter reading metric.

25.3 Please discuss the factors that contributed to the decrease in scores for the energy conservation metric.

25.4 Please discuss the factors that contributed to the increase in satisfaction with field services.

Response:

The differences observed in the scores between June 2019 YTD and June 2020 YTD for the four Customer Satisfaction Index measures – contact centre, meter reading accuracy, energy conservation information, and field services – are statistically insignificant. Rather than actual changes in customer attitudes, statistical testing suggests the differences observed are due to sampling variability.

The Customer Satisfaction Index survey tracks and identifies long-term trends in customer attitudes. It does not determine why there are small shifts in scores from one iteration to the next. However, if trends in customer attitudes sustain over a longer time frame, the factors influencing the trends may be identified and investigated.

26.0 Reference: SERVICE QUALITY INDICATORS

Exhibit B-2, Section 13.2.3, pp. 154-157; Exhibit A2-1,FortisBC 2020-2024 MRP compliance filing dated July 20, 2020 (MRP Compliance Filing), p. 3

Reliability Service Quality Indicators

On page 3 of Exhibit A2-1, FBC states:

> For the benchmarks, and as outlined in the Application, FBC proposed to update the existing SAIDI [System Average Interruption Duration Index] and SAIFI [System Average Interruption Frequency Index] three year rolling average benchmark using the most recent three full years of results 2017, 2018 and 2019, which incorporate the impact of the OMS [Outage Management System]. For the thresholds... Similar to the approach used to determine the thresholds for the prior PBR term, the proposed thresholds are based on statistical analysis (i.e., standard deviation) of the SAIDI and SAIFI historical results from 2010 to 2019.
>
> Using the annual results from 2010 to 2019, the volatility as measured by two standard deviations are 1.30 for SAIDI and 0.62 for SAIFI. The proposed thresholds are then determined by adding the volatility calculated to the proposed benchmarks.

The annual results from 2010 to 2019 and proposed benchmarks and thresholds are shown in the following table:

Table 2: FBC Proposed Benchmarks and Thresholds for SAIDI and SAIFI

Service Quality Indicator	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	Proposed Benchmark	Proposed Threshold
System Average Interruption Duration Index - Normalized	2.84	1.86	1.95	2.01	2.32	2.13	2.10	4.05	3.15	2.45	3.22	4.52
System Average Interruption Frequency Index - Normalized	2.27	1.38	1.27	1.27	1.64	1.56	1.34	1.78	1.73	1.21	1.57	2.19

26.1 Considering that 2010 through 2016 Actual results are each before the implementation of the OMS, please explain why reported values for 2011 Actual SAIDI results were lower than the other years in this time period.

Response:

The 2011 Actual SAIDI results were lower than the other years from 2010 through 2016 mainly due to strong transmission system performance, while the distribution system performance was consistent with historical levels at the time. Generally, transmission system performance is strongly correlated to weather conditions such as snow, windstorms and lightning. The distribution system is exposed to the same weather conditions, but also to other factors such as animals and motor vehicles.

26.1.1 Please discuss whether FBC considers 2011 Actual results to be an outlier. Please explain why or why not.

Response:

No, FBC does not consider the 2011 result to be an outlier. An outlier is a data point that differs significantly from other values in the same dataset. The 2011 result is not far from the other 2010 through 2016 results and, in FBC's view, does not meet the definition of an outlier.

26.2 Considering that 2017 through 2019 Actual results are each after the implementation of the OMS, please explain why reported values for 2017 Actual SAIDI results were higher than 2018 and 2019 Actual.

Response:

While the actual SAIDI results from 2017 through 2019 were impacted by the improved accuracy in outage reporting associated with the implementation of the OMS, the 2017 SAIDI results were also heavily impacted by motor vehicle accidents, wind, snowstorms and wildfires. Specifically, wildfires in the Princeton and Joe Rich areas of the Okanagan accounted for approximately 15 percent of the annual SAIDI. None of the wildfires in 2017 met the threshold for normalization (i.e., none qualified as a major event such that they would be excluded from the normalized SAIDI calculation).

26.2.1 Please discuss whether FBC considers 2017 Actual results to be an outlier. Please explain why or why not.

Response:

No, FBC does not consider the 2017 result to be an outlier. As discussed in the response to BCUC IR1 26.1.1, an outlier is a data point that differs significantly from other values in the same dataset. Although the 2017 SAIDI is somewhat higher than other years, FBC does not believe the difference is large enough to warrant excluding 2017 from the benchmark calculation. While there is still limited data available since deployment of the OMS, if similar environmental conditions such as wildfires, windstorms or snowstorms were to occur in the future, a comparable result could be expected.

26.2.2 Please explain why reported values for SAIDI have been decreasing since the OMS was first implemented in 2017. Does FBC expect this trend to continue? Please explain why or why not.

Response:

No, the three data points from 2017 to 2019 are not indicative of a downward trend and FBC does not expect SAIDI results to be lower in 2020 and future years. This is already evident from the 2020 YTD results, which are higher than the results in 2018 and 2019, although lower than in 2017. Moreover, as discussed in response to BCUC IR1 26.2, FBC's SAIDI results were higher in 2017 because of the impact of the OMS, but also because FBC experienced significant challenges in 2017 from environmental factors such as wildfires and wind and snowstorms that did not qualify as major events.

The reported values for SAIDI in 2018 and 2019 are lower than in 2017 because FBC was not as challenged in those years by environmental factors or other factors such as foreign interference. Going forward, FBC expects the SAIDI results will continue to fluctuate due to adverse weather, wildfires, foreign interference and other factors. As the OMS system is more accurate than FBC's previous manual reporting system, and thus more sensitive to weather and other factors, there may also be more volatility in the SAIDI results than experienced pre-2017 as indicated by the variation in results from 2017 to 2019.

26.3 Considering that 2010 through 2016 Actual results are each before the implementation of the OMS, please explain why reported values for 2010 Actual SAIFI results were higher than the other years in this time period.

Response:

The 2010 Actual SAIFI results were severely impacted by a small number of outages affecting a large number of customers. These outages included:

- A significant forced outage to the 230 kV lines that supplied Kelowna to allow for the removal of a fabric meshing that blew onto the lines from a nursery. The outage impacted almost 13,000 customers;
- A lightning storm in the South Okanagan that impacted 16,600 customers; and
- An equipment failure in Creston that impacted 9,400 customers.

The three outages listed above represent approximately 0.73 SAIFI or 32 percent of the total SAIFI for the year.

26.3.1 Please discuss whether FBC considers 2010 Actual results to be an outlier. Please explain why or why not.

Response:

No, FBC does not consider the 2010 Actual results to be an outlier. As discussed in the response to BCUC IR1 26.1.1, an outlier is a data point that differs significantly from other values in the same dataset. Although the 2010 results are somewhat higher than the other values in the 2010 to 2016 timeframe, the magnitude of the difference is not great enough from the other results to qualify as an outlier.

26.4 Please explain whether FBC considered any other methods to determine the new SAIDI and SAIFI benchmarks. If yes, please discuss what methods were considered and why they were not selected. If not, please explain why not.

Response:

In the MRP Decision (page 99), the BCUC directed FBC to propose SAIDI and SAIFI benchmarks and thresholds in its compliance filing as follows:

> Given the requirement for updated benchmarks and thresholds for SAIDI and SAIFI, the Panel directs FBC to propose new benchmarks and thresholds in the compliance filing to this decision.

Therefore, pursuant to Order G-166-20, FBC submitted its proposal for SAIDI and SAIFI benchmarks and thresholds in the FEI/FBC MRP Compliance Filing, the relevant portion of which is filed as Exhibit A2-1 in this proceeding.

FBC based the proposed SAIDI and SAIFI benchmarks on a three-year average methodology, consistent with that approved by the BCUC for the determination of the benchmarks during the 2014-2019 PBR Plan term. In its decision on the 2014 to 2019 Multi-Year Performance Based Ratemaking Plan, the BCUC determined at page 154 that “it to be appropriate to use a three-year average of 2010, 2011 and 2012 to set the benchmark around which a range can be established and we direct the use of this approach in setting benchmarks for SQIs that the Panel has directed to be modified or added.”

The choice of a three-year average approach incorporating the years impacted by the OMS is consistent with Order G-246-18 and accompanying decision regarding FBC's Annual Review for 2019 Rates (page 17), where the BCUC acknowledged the importance of incorporating the impact of the OMS on setting the future benchmark:

> Notwithstanding, the Panel takes note of the potential decline in SAIDI performance created by the implementation of the OMS, and encourages FBC to incorporate the impact of the OMS in setting a future benchmark for SAIDI.

Additionally, the BCUC stated in the MRP Decision that a rolling three-year average benchmark would make it difficult to detect changes in service quality and therefore rejected the suggestion from an intervener that FBC should calculate the benchmark on that basis.[7]

No other alternatives for setting the benchmarks and thresholds were suggested in the MRP proceeding, either by an intervener or the Panel in its Decision. Nor has FBC identified any other reasonable alternative to a three-year average methodology.

As a result, FBC saw no reason to deviate from considering and using a three-year average methodology in the determination of the proposed benchmarks for SAIDI and SAIFI, as the most recent SAIDI and SAIFI annual results (2017, 2018 and 2019) incorporate the impact of the OMS and the expected weather-related variations.

As FBC considered that the SAIDI and SAIFI benchmark and thresholds were settled in its Compliance Filing in accordance with the BCUC's direction in the MRP Decision, FBC did not request approval of the proposed SAIDI and SAIFI benchmarks and thresholds in the Application. However, to provide certainty that the benchmarks and thresholds are approved, FBC is amending its approvals sought to include approval of its proposed benchmarks and thresholds for the SAIDI and SAIFI and has included as Attachment 26.4 a revised draft Order requesting the BCUC's approval.

26.5 Please explain whether FBC considered any other methods to determine the new SAIDI and SAIFI thresholds. If yes, please discuss what methods were considered and why they were not selected. If not, please explain why not.

Response:

The methodology of basing the proposed thresholds on the historical variation of annual performance worked well in the prior PBR Plan term by establishing appropriate thresholds for monitoring service quality. In addition, the methodology was also accepted by interveners

[7] MRP Decision, page 99.

during the stakeholder consultation in the development of the Consensus Recommendation on the Thresholds for Service Quality Indicators Under the FortisBC Energy Inc. and FortisBC Inc. 2014-2019 PBR Plans. As a result, FBC did not consider other methods to determine the SAIDI and SAIFI thresholds.

26.6 Please explain why the updated benchmarks for SAIDI and SAIFI are based on three years of annual results whereas the updated thresholds for SAIDI and SAIFI are based on nine years of annual results. As part of the explanation, please discuss why annual results from 2010 to 2016 are relevant to setting the updated thresholds.

Response:

As discussed in the response to BCUC IR1 26.4, the updated benchmarks for SAIDI and SAIFI are based on a three-year average methodology.

In developing the proposed thresholds outlined in the MRP Compliance Filing, FBC used the 2010 to 2019 results in the calculation because it provided a relatively long period to assess the historical variation of annual results (i.e., 2010 to 2019 is 10 years). FBC recognized that calculating the proposed thresholds based only on the 2017 to 2019 results (after OMS) may not appropriately capture the historical variation of the SAIDI and SAIFI annual performance.

Additionally, as outlined in the response to BCUC IR1 26.7, calculating the thresholds based on a three-year average methodology (i.e., years 2017, 2018 and 2019, which include the OMS impact) generates similar thresholds as those based on the 2010 to 2019 annual results.

26.7 Using the proposed approach to measuring volatility (i.e. two standard deviations), please provide an alternative calculation of the SAIDI and SAIFI thresholds from the following scenarios:

- *Scenario 1:* Using the annual results from 2017 to 2019 only (i.e. after OMS); and
- *Scenario 2:* Using the annual results from 2010 to 2016 only (i.e. before OMS);

26.7.1 Please discuss whether FBC would be amenable to the thresholds calculated in each scenario above. If not, please explain why not.

26.7.1.1 Please discuss whether FBC would be amenable to a threshold based on a weighted-average calculation of two standard deviations before and after-OMS.

Response:

FBC's proposal to calculate SAIDI and SAIFI thresholds using the annual results from 2010 to 2019 results in SAIDI and SAIFI thresholds that are appropriate for monitoring performance during the MRP term. This approach considers a relatively long period of 10 years to assess the historical variation of annual results and incorporates the OMS data from 2017 to 2019. The other options raised in BCUC IR1 26.7, 26.7.1, 26.7.1.1, and 26.8 are either very similar to FBC's proposal, are inferior as they unjustifiably exclude relevant data, or are not feasible.

The tables below show FBC's proposed thresholds and the thresholds calculated using the feasible approaches suggested in the IRs listed above.

Service Quality Indicator	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	Proposed Benchmark	Proposed Threshold
From 2010 to 2019 - FBC's Proposed Thresholds												
System Average Interruption Duration Index - Normalized	2.84	1.86	1.95	2.01	2.32	2.13	2.10	4.05	3.15	2.45	3.22	4.52
System Average Interruption Frequency Index - Normalized	2.27	1.38	1.27	1.27	1.64	1.56	1.34	1.78	1.73	1.21	1.57	2.19
From 2017 to 2019 only - Scenario 1												
System Average Interruption Duration Index - Normalized								4.05	3.15	2.45	3.22	4.53
System Average Interruption Frequency Index - Normalized								1.78	1.73	1.21	1.57	2.09
From 2010 to 2016 only - Scenario 2												
System Average Interruption Duration Index - Normalized	2.84	1.86	1.95	2.01	2.32	2.13	2.10	4.05	3.15	2.45	3.22	3.83
System Average Interruption Frequency Index - Normalized	2.27	1.38	1.27	1.27	1.64	1.56	1.34	1.78	1.73	1.21	1.57	2.23
Exclude 2011 and 2017 SAIDI results; Exclude 2010 SAIFI result - Scenario 3												
System Average Interruption Duration Index - Normalized	2.84		1.95	2.01	2.32	2.13	2.10		3.15	2.45	3.22	4.02
System Average Interruption Frequency Index - Normalized		1.38	1.27	1.27	1.64	1.56	1.34	1.78	1.73	1.21	1.57	1.98

From 2010 to 2019 - FBC's Proposed Thresholds

In developing the proposed thresholds as outlined in the MRP Compliance Filing, FBC used the 2010 to 2019 results in the calculation because it provided a relatively long period (10 years) to assess the historical variation of annual results. FBC recognized that calculating the proposed

thresholds based only on 2017 to 2019 results (after OMS) may not appropriately recognize the historical variation of SAIDI and SAIFI annual performance.

From 2017 to 2019 only - Scenario 1

The thresholds calculated under Scenario 1, using only 2017 to 2019 results, would be similar to FBC's proposed thresholds. For SAIDI, instead of the proposed threshold of 4.52, the re-calculated threshold would be 4.53. For SAIFI, instead of the proposed threshold of 2.19, the re-calculated threshold would be 2.00. As the proposed thresholds under Scenario 1 are similar to that as proposed by FBC and incorporate after-OMS data, FBC would be amenable to this Scenario.

From 2010 to 2016 only - Scenario 2

The thresholds calculated under Scenario 2, using actual results from only 2010 to 2016, would be lower than FBC's proposed thresholds. As the thresholds under Scenario 2 do not incorporate data after the implementation of the OMS, FBC would not be amenable to this Scenario. As the OMS system is more accurate than FBC's previous manual reporting system, it will more accurately reflect variation in SAIFI and SAIDI results due to the impacts of weather events and other factors. Therefore, it is important to recognize the variation in annual performance in the years after OMS.

Exclude 2011 and 2017 Actual for SAIDI and 2010 Actual for SAIFI – Scenario 3

FBC does not agree with this approach. As discussed in the responses to BCUC IR1 26.1.1 (2011 SAIDI results), 26.2.1 (2017 SAIDI results), and 26.3.1 (2010 SAIFI results), FBC does not consider the referenced results to be outliers. The results fall within the range of normal volatility for the data being measured.

Weighted-average calculation of two standard deviations before and after-OMS

This approach is not feasible as it is unclear how a weighted-average calculation of two standard deviations of the data would be determined in a manner where it would result in a representative variation calculation.

26.8 Using the proposed approach to measuring volatility (i.e. two standard deviations), please provide an alternative calculation of the SAIDI and SAIFI thresholds using the annual results from 2010 to 2019 but excluding 2011 and 2017 Actual for SAIDI and 2010 Actual for SAIFI.

26.8.1 Please discuss whether FBC would be amenable to the thresholds calculated above. If not, please explain why not.

Response:

Please refer to the response to BCUC IR1 26.7.

On page 154 of the Application, FBC states regarding SAIDI: "The June 2020 year-to-date result of 3.36 is consistent with the proposed benchmark and threshold set out in the MRP Compliance Filing."

On page 55, FBC provides Table 13-11:

Table 13-11: Historical SAIDI Results

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual normalized results	2.32	2.13	2.10	4.05	3.15	2.45	3.36
Benchmark	2.22	2.22	2.22	2.22	2.22	2.22	3.22
Threshold	2.62	2.62	2.62	2.62	2.62	2.62	4.52

On page 155 of the Application, FBC states regarding SAIFI: "The June 2020 year-to-date result of 1.74 is consistent with the proposed benchmark and threshold set out in the MRP Compliance Filing."

On page 156 of the Application, FBC provides Table 13-12:

Table 13-12: Historical SAIFI Results

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual normalized results	1.64	1.56	1.34	1.78	1.73	1.21	1.74
Benchmark	1.64	1.64	1.64	1.64	1.64	1.64	1.57
Threshold	2.50	2.50	2.50	2.50	2.50	2.50	2.19

26.9 Please explain whether there have been any major events relevant to the SAIDI and SAIFI results for 2020 to date.

Response:

As stated on pages 154 and 155 of the Application:

> In 2020, there have been two days that qualified as a "major event" day. The first major event day was a heavy snowstorm that started in the afternoon of December 31, 2019 and continued to January 1, 2020. It resulted in approximately 20,000 customer hours interrupted and impacted 1,100 customers on December 31st. The January 1st totals were approximately 37,000 customer hours interrupted and impacted 5,000 customers. The second major event day

was on March 4, 2020 due to a major windstorm. It impacted approximately 13,750 customers and 63,800 customer hours.

There have been no other Major Event days as of the end of August 2020.

26.10 Please explain the factors that led to a SAIDI result above the proposed benchmark for June 2020 year-to-date (YTD).

Response:

The June 2020 YTD SAIDI results were slightly above the proposed benchmark. This was largely due to worse than average performance in the second quarter. SAIDI for the second quarter of 2020 was 39 percent above the three-year average for that period, with the leading contributors being adverse weather, tree contacts and foreign interference. System reliability performance has improved since the end of June with the August YTD results currently at 3.17.

26.11 Please explain the factors that led to a SAIFI result above the proposed benchmark for June 2020 YTD.

Response:

The June 2020 YTD SAIFI results were negatively impacted by second quarter results that were 33 percent above the three-year average for the same period. The leading contributors to SAIFI for the quarter were tree contacts, adverse weather and foreign interference. SAIFI performance has improved since the end of June with the August YTD results now close to the benchmark at 1.63.

On page 156 of the Application, FBC provides Table 13-13:

Table 13-13: Historical Generator Forced Outages

	2014	2015	2016	2017	2018	2019	June 2020 YTD
FBC	1.7%	0.1%	0.8%	0.6%	0.4%	0.1%	1.0%
CEA	6.3%	6.2%	6.2%	6.2%	6.7%	TBD	TBD

Further, FBC states: "The June 2020 year-to-date result of 1.0 percent is generally consistent with prior years' results. The year-to-date result was impacted by an outage in June 2020 at the UBO [Upper Bonnington Old Units Refurbishment] Unit 1 related mainly to the generator, lasting approximately 14 days."

26.12 Please explain the root cause(s) of the UBO Unit 1 forced outage of June 2020.

Response:

The outage was primarily caused by oil contamination from the guide bearing on the generator brush gear (rings and brushes). The presence of oil on the brush gear was creating a path to ground for the voltage supplying the generator rotor, and caused the protective relay used to monitor the leakage current to ground to trigger its alarm.

26.12.1 Please explain whether these root causes have been addressed. If not, please explain when they will be addressed.

Response:

The root cause of oil contamination from the guide bearing has been addressed by manufacturing and installing a seal above the guide bearing that will reduce the amount of oil misting from the guide bearing, resulting in a reduced oil flow rate. In addition, the brush gear was painted with glyptal (an electrical insulating substance) and the number of brushes on each ring was reduced to increase the insulation to ground.

On page 157 of the Application, FBC provides Table 13-14:

Table 13-14: Interconnection Utilization

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Interconnection Utilization	99.99%	99.94%	99.99%	99.95%	99.96%	99.98%	99.90%
Benchmark	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Threshold	n/a	n/a	n/a	n/a	n/a	n/a	n/a

26.13 Please provide statistics and root causes for the interconnection outages leading to the drop in 2020 YTD Interconnection Utilization compared to past years.

Response:

In general, each of the interconnections are performing at or near historical levels except for the City of Nelson's Coffee Creek interconnection. There have been 14 interruptions at Coffee Creek as of the end of June, with five of those occurring during Major Events on the FBC system. Of the 14 interruptions, 13 were due to environmental conditions such as snow, wind or lightning. The other interruption was due to a loss of transmission supply from the BC Hydro system. FBC has implemented several initiatives to improve service to both the City of Nelson customers as well as the FBC customers in the area. FBC is also actively exploring further options that could reduce the frequency and duration of outages when they occur.

26.14 Please explain whether FBC has received any customer complaints related to interconnection outages 2020 YTD.

Response:

FBC has not received any customer complaints related to interconnection outages for 2020 YTD.

27.0 Reference: SERVICE QUALITY INDICATORS (SQI)

FortisBC MRP Decision, p. 168

Content for Annual Review Filings

On page 168 of the MRP Decision, the BCUC directed that the content for annual review filings must include the following, among other things:

> 4. Review of the Utilities' performance with respect to SQI's. Bring forward recommendations to the BCUC where there have been a "sustained serious degradation" of service;
>
> 5. Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews

27.1 Please explain whether FBC views any of its SQIs as having a 'sustained serious degradation of service.' Please explain why or why not.

Response:

FBC does not view any of its SQIs as indicating a 'sustained serious degradation of service.' The SQI results indicate that the Company is meeting service quality standards.

Consistent with the BCUC's direction issued in its Reasons for Decision accompanying Order G-44-16, FBC will review service quality for a year in the following year's annual review, when the full year of actual results are known. Further, the determination of a 'sustained serious degradation of service' is subject to the approved review process as outlined in the Consensus Recommendation on the Thresholds for Service Quality under the FortisBC Energy Inc. and FortisBC Inc. 2014-2019 PBR Plans.

FBC presented its 2019 SQI results in Section 14.5 of the Application. FBC's 2019 SQI results indicate that the Company's overall performance meets service quality standards.

FBC presented the June 2020 year-to-date SQI results in Section 13 of the Application. FBC's overall SQI performance to date shows that it is meeting service quality requirements. In accordance with Order G-44-16, the BCUC will evaluate FBC's actual 2020 SQI performance in the Annual Review for 2022 Rates (to be filed in 2021) when the actual 2020 SQI results are known.

27.2 Please explain whether FBC recommends any new SQIs that should be reviewed in future Annual Reviews. In your response, please provide any relevant assessments.

Response:

As stated in Table 1-1 of the Application, FBC does not have any recommendations for new SQIs to be considered at this time.

FBC completed an assessment of the SQIs as part of the recently completed MRP Application process. Based on the assessment, FBC replaced its Informational Indicator of Telephone Abandonment Rate with another Informational Indicator, Average Speed of Answer and added a new Informational Indicator, Interconnection Utilization. Otherwise, FBC determined that the set of SQIs used during the previous PBR term continued to remain appropriate and useful in monitoring service quality during the MRP term. In the MRP Decision, the BCUC approved the SQIs as proposed by FBC to use in monitoring service quality.

J. PERFORMANCE BASED RATEMAKING ELEMENTS

28.0 Reference: PERFORMANCE BASED RATEMAKING (PBR) ELEMENTS

Exhibit B-2, Section 14.3, p. 159

2019 Flow-through Deferral Account Additions

On page 159 of the Application, FBC states that the final amount to be distributed to customers in 2020 is a credit of $7.475 million (after tax), as shown in Table 14-1, which is comprised of:

- A net variance between approved and actual of $6.352 million (credit) in flow-through items for 2019; and
- A true-up to actual of $1.122 million (credit) to the projected ending 2018 Flow-through account balance.

For 2019 variances, FBC states, "The variance is primarily the result of lower power purchase expense, lower income taxes and higher apparatus rental revenue, partially offset by lower sales revenue."

FBC states that the $1.122 million credit is the difference between the projected ending 2018 Flow through deferral account balance embedded in 2019 rates of $12.788 million (credit) and the acutal ending 2018 deferral account balance of $13.910 million (credit).

28.1 Please explain why 2019 Actual power purchase expenses were $6.063 million less than 2019 Approved, as shown in line 3 of Table 14-1.

Response:

Actual 2019 power purchase expense was $6.063 million less than 2019 Approved due to several factors. First, FBC was able to displace purchases under the BC Hydro PPA with less expensive market purchases over the course of the year, resulting in $6.159 million in savings. Additionally, the Waneta Expansion expense was $0.451 million lower than forecast. Surplus sales revenue also reduced costs by $0.414 million. These decreases were partially offset by other factors such as increased load, foreign exchange rate variance, and generation availability, which added $0.961 million to power purchase expenses.

28.2 Please explain why 2019 Actual income taxes were $2.436 million less than 2019 Approved, as shown in line 25 of Table 14-1.

Response:

The 2019 Actual income taxes were $2.436 million less than 2019 Approved primarily due to:

- Lower income tax on a higher capital cost allowance deduction as a result of the June 2019 enactment of the new enhanced capital cost allowance rules, which was not incorporated in 2019 Approved;
- Lower income tax on higher actual deductible removal costs included in taxable income, which was not incorporated in 2019 Approved; and
- The reduction was partially offset by the net-of-tax effect on other flow-through variances between Actual 2019 and Approved 2019.

28.3 Please explain and provide the variance in 2019 Actual apparatus rental revenue compared to 2019 Approved as a component of the $1.359 variance in Other Revenue shown in line 21 of Table 14-1.

Response:

The variance in Apparatus and Facilities Rental revenue of $1.037 million between 2019 Approved and 2019 Actual was comprised of the following:

- Approximately $0.310 million related to audit costs and a higher number of pole contacts associated with the results of an audit of unreported contacts which was finalized in December 2018 and therefore was not captured in 2019 Approved;
- Approximately $0.325 million related to a new pole attachment contract that became effective in early 2019 and was not captured in 2019 Approved; and
- Higher than estimated rental rates, which are calculated annually for each customer.

28.4 Please explain why 2019 Actual sales revenue were $2.885 million less than 2019 Approved, as shown in line 2 of Table 14-1.

Response:

2019 Actual sales revenue was $2.885 million less than 2019 Approved sales revenue primarily because the actual residential UPC was lower than forecast.

28.5 Please provide a table in the same format as Table 14-1, showing the breakdown of the projected ending 2018 Flow-through deferral account balance embedded

in 2019 rates of $12.788 (credit) and actual ending 2018 deferral account balance of $13.910 million (credit), in order to explain the 2018 ending deferral account balance true-up of $1.122 million (credit).

28.5.1 Please provide an explanation for significant variances identified in the response above.

Response:

Details of the true-up of the 2018 Flow-through deferral account are provided in the table below. Explanations for the variances in revenue, power purchase expense, other revenue and income tax follow.

Line No.	Particulars	Approved 2018	Actual 2018	Actual Variance	Projected 2018	Projected Variance	Difference
	(1)	(2)	(3)	(4)=(2)-(3)	(4)	(5)=(2)-(4)	(6)=(4)-(5)
1	Revenue	$ (356.340)	$ (359.882)	$ (3.542)	$ (366.184)	$ (9.844)	$ 6.302
2							
3	Power Purchase Expense	133.071	123.842	(9.229)	130.247	(2.824)	(6.405)
4							
5	Water Fees	10.208	10.264	0.056	10.287	0.079	(0.023)
6							
7	Wheeling	5.171	5.523	0.351	5.281	0.110	0.241
8							
9	O&M Tracked Outside of Formula						
10	Insurance Premiums	1.265	1.245	(0.020)	1.246	(0.019)	(0.001)
11	Advanced Metering Infrastructure Project	(1.139)	(1.203)	(0.064)	(1.139)	-	(0.064)
12	Mandatory Reliability Standards	1.070	1.024	(0.046)	1.040	(0.030)	(0.016)
13	Upper Bonnington Unit 3 Annual Inspection	(0.040)	(0.040)	-	(0.040)	-	-
14	MSP Premium Reduction		(0.177)	(0.177)	(0.168)	(0.168)	(0.009)
15							
16	Property Tax	16.684	16.147	(0.537)	16.143	(0.541)	0.004
17							
18	Depreciation and Amortization	52.667	53.052	0.385	52.995	0.328	0.057
19							
20	Other Revenue	(8.416)	(10.139)	(1.723)	(9.609)	(1.193)	(0.530)
21							
22	Interest Expense	40.059	40.069	0.010	40.059	-	0.010
23							
24	Income Tax	9.633	12.545	2.912	13.225	3.592	(0.680)
25							
26	Working Capital Adjustment for AMI			(0.030)		(0.024)	(0.006)
27							
28	After-Tax Flow-Through Addition to Deferral Account			$ (11.656)		$ (10.534)	$ (1.122)

Revenue:

Actual 2018 revenue was $6.302 million lower than Projected 2018. The largest components of the variance are a lower industrial load, primarily due to a new load being lower than anticipated (-$7.463 million), lower than forecast residential UPC (-$4.219 million), and lower commercial load (-$1.913 million). These decreases were partially offset by higher than anticipated wholesale revenue ($6.929 million) from a new large load customer. The remainder of the variance ($0.365 million) is attributable to variances in lighting and irrigation load and revenue.

Power Purchase Expense:

Actual Power Purchase Expense (PPE) was $6.405 million lower than Projected 2018 due to several factors. First, FBC was able to displace purchases under the BC Hydro PPA with less expensive market purchases over the course of the year, resulting in $3.867 million in savings. Additionally, Waneta Expansion capacity purchases were lower than forecast, and surplus sales revenue was higher than forecast, which together also reduced costs by a further $2.663 million. These decreases were partially offset by the remaining PPE items, which added $0.125 million to the variance.

Other Revenue:

Actual 2018 Other Revenue was $0.530 million higher than Projected 2018. The increase was primarily attributable to higher Apparatus and Facilities Rental comprised of approximately $0.480 million related to a true-up associated with the results of an audit of unreported contacts. The audit results were finalized in December 2018 and therefore the revenue was not captured in 2018 Projected.

Income Tax:

Actual 2018 Income Tax was $0.680 million lower than Projected 2018. The decrease was primarily due to lower income tax on higher actual deductible removal costs of $0.559 million, which was not projected, and lower income tax on higher capital cost allowance deductions of $0.355 million, which was based on the actual costs allocated in each capital cost allowance class. These variances were partially offset by the net of tax effect on other flow-through variances between Actual 2018 and Projected 2018 of $0.355 million.

28.6 Please provide the percentage impact of the $7.475 million (after tax) credit on the calculated 1.93 percent rate increase for 2020 (i.e. in the absence of this credit, what would be the calculated rate increase for 2020?)

Response:

The impact of the $7.475 million flow-through credit itself is 2.86 percent (calculated as the before-tax value divided by the revenue at existing rates, $7.475 million ÷ (1-27%) = $10.240 million ÷ $358.668 million = 2.86%). Added to the 1.93 percent increase, which is the increase in the absence of the revenue surplus amortization, the total rate increase would be 4.79 percent.

29.0 Reference: PBR ELEMENTS

Exhibit B-2, Section 14.5, p. 164

2019 SQI Results

On pages 164-165 of the Application, FBC provides Table 14-7. An excerpt with respect to 2019 SAIDI and SAIFI results is as follows:

Reliability SQIs				
System Average Interruption Duration Index (SAIDI) – Normalized	3 year average of SAIDI (average of cumulative customer outage time)	<=2.22	2.62	3.22
System Average Interruption Frequency Index (SAIFI) - Normalized	3 year average of SAIFI (average customer outage)	<=1.64	2.50	1.57

On page 165 of the Application, FBC explains that its SAIDI results have been influenced by the implementation of the OMS. On page 166 of the Application, FBC quotes BCUC Order G-246-18 regarding FBC's 2018 results:

> The Panel finds no evidence to suggest a serious degradation of service has occurred and, accordingly, does not consider that a financial penalty is warranted. Notwithstanding, the Panel takes note of the potential decline in SAIDI performance created by the implementation of the OMS, and encourages FBC to incorporate the impact of the OMS in setting a future benchmark for SAIDI.

29.1 Please explain whether FBC has experienced any factors in 2019 regarding its SAIDI results to suggest a 'serious degradation of service has occurred' or will occur.

Response:

No, FBC has not experienced any factors in 2019 regarding its SAIDI results to suggest a serious degradation of service has occurred or will occur. As explained in the Application,[8] FBC attributes the higher 2019 SAIDI results to the impact of the OMS, similar to that observed for the 2018 SAIDI results. In the BCUC's Decision and Order G-246-18 regarding 2018 SAIDI performance, the BCUC accepted FBC's explanation for the higher SAIDI results as being due to the introduction of the OMS, adverse weather, foreign interference (i.e., vehicle incidents) and wildfires. The BCUC found no evidence to suggest a serious degradation of service occurred for SAIDI in 2018. The 2019 SAIDI results should be interpreted in a similar manner and also considered to be acceptable.

[8] Annual Review for 2020 and 2021 Rates, pages 165 – 166.

29.1.1 Please explain whether it would be difficult to discern if a serious degradation in SAIDI and SAIFI results was occurring due to implementation of the OMS.

Response:

The implementation of the OMS, which, as expected, was accompanied by changes to the reported SAIDI and SAIFI values, made it more difficult in recent years (i.e., 2017 to 2019) to discern if a degradation in SAIDI and SAIFI was occurring. However, the changes in reported SAIDI and SAIFI values for FBC appear to be similar to changes experienced by other utilities who have deployed similar systems. FBC does not believe the changes are indicative of a serious degradation of service.

There is still limited data available since the deployment in 2017, but it is expected that with the new benchmarks and thresholds established based on recent results incorporating the OMS, it will become easier in the future to determine whether a degradation in reliability performance is occurring. It should be noted that in 2019, which was a very good year weather wise, the SAIDI and SAIFI results with the OMS were not significantly different from results in previous years without an OMS.

K. PLAYMOR STATION UPGRADE BUSINESS CASE

30.0 Reference: PLAYMOR SUBSTATION UPGRADE BUSINESS CASE
Exhibit B-2, Appendix B, Section 2, pp. 1-7
Project Need

On page 1 of Appendix B, FBC describes the location of the Playmor (PLA) substation: "The PLA substation is located on Sentinel Rd in South Slocan, BC between Castlegar and Nelson."

On page 4 of Appendix B, FBC describes the drivers for the project:

> There are three primary drivers for the PLA Station Upgrade Project.
>
> 1. Station capacity constraints are preventing growth in the PLA area for new and existing customers;
> 2. FBC customers in the PLA area are potentially exposed to lengthy outages, due to the limited ability of the neighbouring substations to support the PLA load in the event of an outage to PLA T1; and
> 3. Station equipment is aging, poor health, and/or obsolete, presenting safety and reliability risks in the event of a failure.

On pages 5-6 of Appendix B, FBC describes its load growth under Alternative A and Alternative B.

30.1 Please provide copies of Figures 3 and 4 with the Time axis extended to 2060.

Response:

The revised figures are provided below. Based on an extrapolation of the current 20-year forecast, winter peak load in the Playmor area would reach 23 MVA in approximately 2060 considering actual/forecast loads, or 26 MVA considering the additional potential new loads.

It should be noted that there is low confidence in any projection this many years in the future. The actual rate of peak load growth over this period will be dependent on factors such as large capacity requests, Electric Vehicle adoption, and other influences on electric usage that cannot be reasonably foreseen at this time.

Figure 1: Alternative A

Figure 2: Alternative B

30.2 Please indicate when the Forecast Winter Peak Load will exceed the Post Upgrade winter limits under Alternative A and Alternative B.

Response:

Figures 1 and 2 from the response to BCUC IR1 30.1 show the post-upgrade PLA station winter limits in the event of a single PLA transformer outage under Alternatives A and Alternative B from the years 2015 to 2060.

Under Alternative A, the remaining unit can carry the entire station load during a single PLA transformer outage at winter peak loads below 23.75 MVA. Considering the actual/forecast winter peak load (solid blue line), the remaining unit can carry the entire station load for the next 40 years. Considering the actual/forecast winter peak load, including the potential new loads (dotted blue line), the remaining unit can carry the entire station load until 2050.

Under Alterative B, there would continue to be no ability at PLA station to supply load during a transformer outage without support from a mobile transformer or the installation of a second transformer.

On page 6 of Appendix B, FBC discusses Reliability as a project driver: "only 13 percent of the total PLA customers could be supplied during a PLA T1 transformer outage under peak load conditions. During a PLA T1 outage, all customers supplied by distribution feeders PLA1 and PLA3, and 866 customers supplied by PLA2 would be without service."

30.3 Please provide outage statistics for the PLA T1 transformer for the past 10 years. Please indicate customer outage data in the statistics.

Response:

Please refer to the table below for the requested outage statistics.

Year	Down Date	Up Date	Customer Count	Outage Duration (hours)	Outage Cause
2010	5/30/2010 6:12:00 AM	5/30/2010 1:13:00 PM	2,507	7.02	Planned outage[1]
2012	10/8/2012 7:09:38 AM	10/8/2012 7:15:07 AM	2,551	0.09	Protection mis-operation
2015	8/15/2015 3:25:31 AM	8/15/2015 7:04:00 AM	2,588	3.64	Tree on incoming 25L line
2019	10/31/2019 1:36:47 PM	10/31/2019 2:12:52 PM	2,710	0.60	Tree on incoming 25L line
2019	3/15/2019 9:03:17 AM	3/15/2019 10:26:52 AM	2,704	1.39	Animal
2019	10/31/2019 1:01:38 PM	10/31/2019 1:06:20 PM	2,710	0.08	Tree on incoming 25L line

Notes:

[1] The planned outage in 2010 was required to complete station egress upgrades due to station configuration and lack of redundancy.

30.3.1 Please compare customer outage statistics for customers served from PLA substation with customers served from other similar rural substations in FBC's service territory.

Response:

Please refer to the below tables for outage statistics related to SAIDI and SAIFI for PLA and three other rural substations which have similar sized transformers and support a similar number of customers:

- A.A. Lambert Terminal substation (AAL) outside of Creston (distribution transformer, which serves a smaller rural area);
- Blueberry substation (BLU) near Castlegar; and
- Cascade substation (CSC) in Rossland.

SAIDI											
Station	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Average**
PLA	7.02	0.00	0.09	0.00	0.00	3.64	0.00	0.00	0.00	2.07	1.28
AAL	1.29	0.35	0.16	0.23	0.00	0.00	0.00	0.88	0.20	0.00	0.31
BLU	0.33	0.67	0.00	0.00	0.00	0.00	0.00	0.88	2.77	0.00	0.47
CSC	0.06	0.00	0.07	0.23	0.00	0.00	0.00	0.00	2.43	2.70	0.55

SAIFI											
Station	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**Average**
PLA	1.00	0.00	1.00	0.00	0.00	1.00	0.00	0.00	0.00	3.00	0.60
AAL	2.00	1.00	2.00	1.00	0.00	0.00	0.00	2.00	1.00	0.00	0.90
BLU	1.00	2.00	0.00	0.00	0.00	0.00	0.00	1.00	1.00	0.00	0.50
CSC	1.00	0.00	1.00	3.00	0.00	0.00	0.00	0.00	2.00	1.00	0.80

30.4 Please explain whether FBC is required to have N-1 reliability for the customer fed from the PLA substation.

Response:

FBC only applies the N-1 planning criteria to transmission planning. FBC's distribution planning criteria reference the voltage levels of the distribution system (the voltages needed to provide

customers with voltages meeting CSA standards) after offloading due to a distribution transformer outage.

FBC's Distribution Planning Criteria state:

> **3.2.2 Distribution Transformer Contingencies**
>
> When determining the capability of the distribution system, in the event of the loss of the single transformer, the minimum voltage level will be allowed to drop by 2V from the normal planning criteria to 113V for three phase and 111 V for single phase.
>
> Planning will take corrective action, when for the predicted loading, the distribution system is not capable of meeting this backup criteria with the following exceptions.
>
> - Rural substations with feeders that extend long distances with open points >5km from both sources at 12.5kV will be reviewed on a case by case basis to determine whether or not it is reasonable and practical to meet this criteria. Attention should be given to costs of upgrades required, # of customers affected, and risk of an outage.

PLA is considered a rural distribution substation. There are two neighboring stations, Passmore (PAS) station and Tarrys (TAR) station. The winter normal station capacity for PAS is 6.2 MVA and TAR has a station capacity of 8.8 MVA.

Currently, to maintain voltage within planning criteria limits in the event of a PLA T1 outage, only a small portion of the PLA load can be supplied by PAS. The load limitation is due to the undersized distribution feeders resulting in voltage outside the planning criteria and limited station capacity at PAS. No load can be offloaded to TAR. Under peak load conditions, all customers supplied by Playmor Feeder 1 and Playmor Feeder 3, which includes an industrial customer, and 863 customers on Playmor Feeder 2 would be without service. Of the total 2,729 PLA area customers, 2,381 customers would be offline. Therefore, only 348 customers or 13 percent of the total PLA customers could be supplied during a PLA T1 transformer outage under peak load conditions. For this reason, FBC considers that the backup criteria should be met for a distribution transformer contingency at Playmor.

Once a second transformer is installed, all PLA load could be supplied during a PLA T1 outage under peak load conditions. No customer outages would be required. The second transformer would improve reliability for all residential, commercial, and industrial customers.

30.4.1 Please explain why N-1 reliability for customers in South Slocan is reasonable, including a discussion of the reliability for other similar rural substations.

Response:

As explained in the response to BCUC IR1 30.4, N-1 contingency planning criteria are not applicable to distribution planning. Please also refer to the response to BCUC IR1 30.3.1 which compares the reliability of PLA to similar distribution substations.

On page 7 of Appendix B, FBC describes the aging condition of PLA T1.

30.5 Please provide any maintenance records or condition assessment reports for PLA T1 to support the analysis.

Response:

Please refer to Attachment 30.5 for a copy of the Condition and Life Assessment Report Playmor T1 Transformer, Rev 0.1.

30.6 Please compare the age and condition of PLA T1 to other similar transformers in the FBC system.

Response:

Please refer to the table below for a list of FBC-owned units with similar MVA size, operating at the same voltage levels and an overall estimate of their condition:

Location	Name	Mfg. Date	MVA	Transformer Active Core Condition	Load Tap Changer (LTC) Condition
KAL - Kaleden	T1	1959	7.5	Good	Acceptable
BEP - Beaver Park	T1	1965	10	Poor	Poor
PLA - Playmor	T1	1966	16	Trending towards poor	Trending towards poor
BLU - Blueberry	T1	1968	10	Acceptable	Acceptable
SAL - Salmo	T1	1968	10	Poor	Poor
VAL - Valhalla	T2	1973	15	Good	Good
CRE - Creston	T1	1974	15	Acceptable	Acceptable

Location	Name	Mfg. Date	MVA	Transformer Active Core Condition	Load Tap Changer (LTC) Condition
CAS - Castlegar	T1	1976	15	Good	Good
CRE - Creston	T2	1976	15	Good	Trending towards poor
OKF - OK Falls	T1	1976	15	Good	Good
OSO - Osoyoos	T1	1977	15	Good	Good
FRU - Fruitvale	T1	1986	8	Poor	Acceptable
GLM - Glenmerry	T1	1995	20	Good	Good
TAR - Tarry's	T1	2001	8	Good	Good
CRA - Crawford Bay	T5	2007	15	Good	Good

Further on page 7, FBC states:

> Furthermore, there is a deficiency in the station DC [Direct Current] system that continues to trigger ground fault alarms. Properly addressing this issue requires replacing the station circuitry and the obsolete DC panel.
>
> As a result of these equipment deficiencies, it is not feasible to replace these individual components, and it is therefore necessary to rebuild the substation.

30.7 Please explain whether it would be possible to troubleshoot and repair the station DC system without replacing it.

30.8 Please explain whether FBC considered a project alternative that doesn't involve rebuilding the substation. Please explain whether it would be possible to replace only the failed or faulty pieces of equipment without rebuilding the entire substation.

Response:

Yes, troubleshooting intermittent ground faults alarms is possible, but would be costly. At PLA, due to the aging of the conductor insulation, it is more practical to replace the circuitry producing the intermittent faults.

Replacing only the failed or faulty pieces of equipment would still result in a large portion of the station being rebuilt, as it is unlikely the equipment would be replaced with similarly sized units, necessitating civil work and reconfiguration to the bus. The replacement of some of the components would also require extensive engineering and customized solutions resulting in non-standard design and equipment.

Rebuilding the entire station improves the protection and fault selectivity, reduces the likelihood of an arc-flash event, provides for future expansion and customer base increases, and improves system redundancy.

1 Due to the customized design, a piece-by-piece replacement would likely result in a higher cost
2 than a station rebuild and would not provide the best overall solution to upgrade the station.

3

31.0 Reference: PLAYMOR SUBSTATION UPGRADE BUSINESS CASE
Exhibit B-2, Appendix B, Section 3, pp. 9–12
Project Alternatives

On page 9 of the Application, FBC describes the advantages of Alternative A:

- Installed capacity summer limit 40 MVA and winter limit 47.5 MVA;
- Ability to supply large load requests in the area and native load growth;
- Reliability concerns addressed with redundant transformer. The remaining transformer can carry peak station load during a PLA transformer outage with no customers outages required;
- Mobile transformer no longer required for PLA transformer outage given redundant transformer; and
- Aging infrastructure and obsolete equipment replaced. Non arc-flash rated switchgear and asbestos exposure risks removed.

31.1 Please explain whether FBC expects further large load requests. If yes, please provide any details of the anticipated requests, including the size of the load and the expected service date.

Response:

FBC has received additional requests since the time of filing the Application and has approved requests expected to materialize in 2020 totalling approximately 2.4 MVA, with the majority of this increase associated with a single large industrial customer and the remainder of the increase from three agricultural facilities. FBC is confident this load will connect, as design/construction is either underway or completed for these service requests.

FBC did not approve two larger requests, which were also for agricultural facilities, at their requested load levels due to capacity constraints at the station. If these customers were to connect at their requested load levels once capacity is available, this would add approximately 2.5 MVA of load. There is currently no timeline to connect one of these requests (1.25 MVA). The second request plans to connect in Summer 2021 at a reduced load level of 0.4 MVA and may increase its load by a further 0.8 MVA in future.

31.2 Please explain how many substations share the mobile transformer availability today.

Response:

FBC has four available mobile transformers:

- M12 – 12MVA, 132/66kV: 25/14.4/12.5/7.2kV
- M18 – 18MVA, 138/63kV: 26/15/8.66/5/4.3/2.5 kV
- M25 – 25MVA, 132/66kV:13kV
- M32 – 32MVA, 132/66kV: 26/15/8.66/5kV

The M12 and M18 are designated for the Kootenay stations, including PLA (21 stations). The M18 is the preferred unit for restoration at PLA because the M12 cannot restore the entire load. There are six stations, including PLA, which can only be restored with the M18. In a best case scenario, installing the M18 mobile in PLA would take a minimum of 12 hours.

The M25 and M32 are designated for the Okanagan stations (24 stations). These units may be shared with the Kootenay stations if the M12 and M18 were not available. As noted in the business case, there are several downsides with using a transformer from the Okanagan region. Transporting and installing a mobile in PLA that is normally parked for the Okanagan would take a minimum of 24 hours. Further, restoration using the M32 may not be an option due to BC road restrictions (March to June) and BC road conditions. If M32 were successfully deployed to the Kootenay region, then the Okanagan region would be at a higher risk while M32 resides in the Kootenay region and maintenance and transportation costs for M32 would also increase due to additional wear and tear on the unit.

31.3 Please explain how frequently FBC employees are exposed to the arc-flash and asbestos hazard at PLA substation.

31.3.1 Please explain what safety precautions are taken in the face of these hazards.

Response:

FBC employees could potentially be exposed to the arc-flash and asbestos hazards several times a year during regular maintenance work, distribution line switching/isolation, and unexpected equipment failures due to the age and condition of the equipment.

To mitigate the arc-flash impact, FBC has implemented arc-flash and fast bus protection. This type of mitigation reduces the arc-flash hazard but does not completely eliminate it. If this installed protection and its associated equipment fails for any reason or is taken out of service, the arc-flash hazard remains.

FBC also has operating procedures and controls in place to mitigate arc-flash and asbestos hazards, including administrative and engineering controls such as employee training and written procedures. Warning signs highlighting the type of hazard, type of personal protective

equipment required, and controlled access requirements are posted at the switchgear access doors.

Despite these procedures and controls, a safety incident involving exposure to arc-flash or asbestos hazards has a very high consequence potential. Therefore, even if the probability of future incidents is low, the risk is high.

31.4 Please explain what FBC's standard station configuration for a new 40MVA substation would be today, if FBC was building a new substation in a new location. Please explain whether FBC would install a single-transformer substation, or a two-transformer substation. Please explain why, weighing costs and benefits.

Response:

The station configuration for a new 40 MVA substation is dependent on many factors, including load requirements for the area, the number of transmission and distribution lines in/out of the station, distribution offload capability, and the size/availability of a mobile transformer in the area.

FBC determines whether to use a single-transformer or two-transformer substation configuration on a case-by-case basis. In this particular case, FBC recommends installing two 20 MVA transformers as there is limited offload capability to neighbouring substations, and the 18 MVA mobile transformer available will not be able to support the PLA area forecast load by 2036.

Please refer to Section 3 of Appendix B for a detailed list of the costs and benefits of a two-transformer station (Alternative A) versus a single-transformer station (Alternative B).

On page 11, FBC lists some disadvantages of Alternative B, including: "During a PLA transformer outage, restoring customers will require the use of the mobile transformer. Availability of the mobile transformer will be dependent on BC road conditions, BC road restrictions (March to June), and if it is already designated to another station;"

31.5 Please explain how many days, annually, FBC has experienced road conditions that would affect the transportation of the Mobile Transformer from its current location to South Slocan. In your response, please indicate how many days, annually, the required roads are closed to traffic.

31.6 Please explain how many times in the past FBC has experienced road conditions that have prevented FBC from moving a mobile transformer when necessary due to a forced outage or transformer failure.

Response:

The timing and duration of seasonal road restrictions varies from year to year based on ground conditions and is communicated by the Ministry of Transportation through Drive BC. The period of restrictions can be approximately 90 days. Travel restrictions, if occurring at the time of an outage at PLA, could delay the restoration of PLA load.

FBC is not aware of any statistics on past road closures. On at least one occasion, Commercial Vehicle Safety and Enforcement (CVSE) has denied M18 mobile travel. Under heavy winter conditions, FBC itself may delay the deployment of the Mobile due to unsafe road conditions. This could postpone emergency restoration by one to three days.

Further on page 11, FBC explains that beyond 2036, the M18 mobile would be insufficient to carry the winter peak station load.

31.7 Please explain whether there may be other forces driving FBC to purchase a replacement mobile transformer on or before 2036, such as increased load at other substations that also rely on the M18 mobile transformer, in the event of an outage or failure.

Response:

FBC does not expect to purchase another mobile for the Kootenay substations before 2036 unless required as a result of a sudden failure or rapid deterioration of condition of either the M18 or M12 mobile transformers. Due to the small footprint of most FBC Kootenay substations, a bigger MVA mobile transformer would most likely not be a good fit.

On pages 11-12, FBC discusses Option C: Do Nothing.

31.8 Please discuss whether FBC considers a Do Nothing project alternative to be a viable solution.

Response:

FBC does not consider a Do Nothing project alternative to be a viable solution. The primary driver for this project is load growth in the area. In order to accommodate native load growth, load increases for existing commercial/industrial customers and the recent large capacity requests, it is necessary to increase the station capacity.

31.9 Please discuss whether FBC considered any other project alternatives in its analysis.

Response:

The three alternatives considered were provided in Appendix B – Playmor Station Upgrade Business Case. These alternatives included installing two transformers at PLA, installing one transformer at PLA with a mobile transformer connection, and the status quo (do nothing).

Alternatives such as Demand Response (DR), local utility generation, or customer-owned generation (such as solar installations that typically enroll in FBC's Net Metering program) are not viable alternatives to the proposed project, as explained below.

DR can be an effective means of reducing or shifting peak load and FBC is investigating the potential use of DR for mitigating system peaks. A DR pilot is currently underway in the Kelowna area. However, the DR pilot is a proof-of-concept initiative with a target of 1.75 MW capacity, which would be insufficient to defer the Playmor Project even if similar results could be achieved in the much smaller area served by Playmor.

In its recent CPCN application for the proposed Kelowna Bulk Transformer Addition Project, FBC discussed the potential for local generation resources, such as a gas turbine, and rejected the option due to its high capital cost. Due to the high capital costs, this option would be viable only if the generation were also required to meet resource planning needs. However, on the basis of FBC's 2016 Long Term Electric Resource Plan (LTERP) and preliminary results for the 2021 LTERP, there is no requirement for additional capacity resources at this time.[9]

Solar resources, whether utility-scale or customer-owned, would not provide significant winter peak load reductions since the winter peak in FBC's service territory typically occurs after sunset, and are therefore not a viable solution in this case.

In addition, none of these potential options address the equipment condition and aging infrastructure issues at the Playmor substation, which are required to be addressed no later than 2027. Accordingly, FBC submits that the alternatives examined in the business case are the viable alternatives for the Playmor Project.

[9] FBC Application for a CPCN for the Kelowna Bulk Transformer Addition Project, Exhibit B-1, pp. 22-23.

32.0 Reference: PLAYMOR SUBSTATION UPGRADE BUSINESS CASE

Exhibit B-2, Appendix B, Section 4.1, p. 17

Project Risks

On page 17 of Appendix B to the Application, FBC discusses the project risks. Among the risks, FBC states:

> Availability of labour and materials may be at risk due to Covid-19 and the current state of the economy. FBC has partially mitigated the risk of any financial or schedule pressures by developing preliminary equipment specifications and obtaining quotes from vendors. Any residual risk will be managed through project planning and contractual performance guarantees;

32.1 Please discuss whether FBC has experienced any availability of labour and materials issues on its other capital projects in 2020 as a result of COVID-19.

Response:

To date, FBC has faced some minor issues with the COVID-19 pandemic. These include minor material and schedule delays due to review and modification of work procedures and methods. Cost impacts have been minor. Availability of labour has not been an issue as of yet, but will remain a risk due to the uncertainty of the pandemic.

Currently, FBC does not expect major schedule or cost impacts to its capital program; however, the future impact of the pandemic is uncertain. If the situation escalates and FBC begins to see labour shortages, more significant material delays, or delays in approval processes for permits, this could have larger impacts to the schedule and costs of capital projects. If this were to occur, FBC would need to evaluate the magnitude of the impacts and the options for managing its capital program under the circumstances.

33.0 Reference: PLAYMOR SUBSTATION UPGRADE BUSINESS CASE

Exhibit B-2, Appendix B, Section 4.2, p. 17

Project Cost Estimate

On page 17 of Appendix B to the Application, FBC provides Table 2. Table 2 contains a project cost estimate summary.

Table 2: Total estimate project cost summary ($ millions)

Project Component	Total Project Cost	As Spent $
Station Work (incl. 15% contingency)	$ 8.672	$ 8.848
T&D Line Work (incl. 10% contingency)	0.799	0.815
Land	0.076	0.076
AFUDC	0.866	0.866
Construction Cost	**$ 10.413**	**$ 10.605**
Station Work COR	0.251	0.260
T&D Line Work COR	0.038	0.039
AFUDC	0.018	0.018
Net Removal Cost	**$ 0.307**	**$ 0.318**
Total Project Cost	**$ 10.719**	**$ 10.922**

33.1 Please provide a breakdown of the project costs in further detail, separating out overhead and contingency. In your estimate, please include line items for labour, materials, engineering, dismantling, etc.

Response:

Please see the table below for a breakdown of the project costs in further detail.

Project Component		Total Project Cost	As Spent $
Station Work			
	Line Work	0.001	0.001
	Engineering	0.554	0.566
	Material	3.953	4.034
	Labour	0.999	1.019
	Civil & Site	1.125	1.147
	Buildings	0.107	0.109
	Structure & Buswork	0.044	0.045
	Station Equipment & Apparatus	0.222	0.226
	Communication & SCADA	0.004	0.004
	Protection, Control & Metering	0.024	0.024
	Commissioning	0.041	0.042
	Project Management - Labour	0.648	0.661
	Contingency	0.951	0.971
	SUBTOTAL	$ 8.672	$ 8.848
T&D Lines Work			
	Engineering	0.132	0.135
	Labour	0.261	0.266
	Material	0.180	0.183
	Construction	0.117	0.119
	Project Management - Labour	0.036	0.037
	Contingency	0.073	0.075
	SUBTOTAL	$ 0.799	$ 0.815
Land & AFUDC			
	Land	0.076	0.076
	AFUDC	0.866	0.866
	SUBTOTAL	$ 0.942	$ 0.942
		$ 10.413	**$ 10.605**
TOTAL Construction Cost			
	Station Cost of Removal	0.196	0.203
	Station Cost of Removal Labor	0.022	0.023
	Station Cost of Removal Contingency	0.033	0.034
	T&D Line Cost of Removal	0.003	0.003
	T&D Line Cost of Removal Labor	0.035	0.036
	AFUDC	0.018	0.018
Net Removal Cost		**$ 0.307**	**$ 0.318**
Total Project Cost		**$ 10.719**	**$ 10.922**

1

2

34.0 Reference: PLAYMOR SUBSTATION UPGRADE BUSINESS CASE

Exhibit B-2, Appendix B, Section 5, p. 19

Consultation

On page 19 of Appendix B to the Application, FBC explains the public consultation it has undertaken to date and how FBC has planned its work to minimize disturbance to neighbours. FBC states: "Letters were sent out to residents within 150 meters of the project in August of 2020 notifying them of the project and footprint expansion."

34.1 Please provide any responses or contact FBC has received as a result of sending the letters to residents.

Response:

FBC did not receive a response to its letters.

A FortisBC representative visited the three closest properties and discussed the project directly with the residents. As the area is rural, and sparsely populated, these three properties are much closer to the substation than other properties, and FBC determined a personal visit was warranted. The residents had no concerns.

34.2 Please explain any feedback FBC has received on the project.

Response:

The only feedback that FBC has received is that the three closest landowners have no concerns.

34.3 Please explain FBC's plan for further consultation with local residents and neighbours.

Response:

Closer to the construction date, FBC plans to send another letter to residents outlining the timing of the project. At that time, a FBC representative will again visit the nearest properties to ensure the residents are aware of the scope and timing of work and have contact information for FBC should they have any concerns or questions.

On page 19 of Appendix B to the Application, FBC states:

> The PLA station upgrade does not trigger a requirement for First Nations consultation, as FBC believes that Aboriginal Rights and Title will not be affected by this Project. The proposed substation site is not near any known archaeological site and is not in a zone of high archeological potential.

34.4 Please explain whether FBC has notified any First Nations of the PLA project.

34.4.1 If not, please explain why not.

Response:

FBC has sent Indigenous communities a letter notifying them of the project and requesting their feedback. FBC also discussed the project directly with the Ktunaxa Nation and the Lower Kootenay Band. The list of notified Communities and Nations was generated from the Provinces' Consultative Area Database and consists of:

- Secwepemc Nation;
- Penticton Indian Band;
- Okanagan Nation Alliance;
- Lower Similkameen Indian Band;
- Shuswap Indian Band; and
- Ktunaxa Nation Council.

34.5 Please explain further why FBC has determined that consultation was not required with First Nations for the PLA project.

Response:

Despite FBC's initial assessment that consultation was not required, FBC has since reviewed the project requirements and has determined that engagement with Indigenous communities is preferred. A list of communities engaged regarding the project can be found in the response to BCUC IR1 34.4.

L. PRIOR YEAR DIRECTIVES

35.0 Reference: AMI PROJECT NET O&M COSTS AND SAVINGS
Exhibit B-2, Appendix C2, pp. 6–7
Unit 3 Deficiency

On page 3 of Appendix C2, FBC explains the changes resulting from monthly billing options for customers under the Advanced Metering Infrastructure (AMI) project:

> Order G-16-14 approved the introduction of a monthly billing option for customers previously billed on a bi-monthly basis, and ordered that any incremental working capital benefits resulting from an increase in monthly billings be returned to customers during the PBR term.

Further, on page 7 of Appendix C2, FBC states: "Overall, the proportion of FBC customers billed on a monthly basis increased from less than 6 percent prior to the implementation of AMI to approximately 26.5 percent at year-end 2019."

35.1 Please explain whether FBC anticipates further customers to sign up for monthly billing in future years.

35.1.1 If yes, please explain whether FBC will return any working capital benefits from these changes to customers.

Response:

The statement on page 7 of Appendix C2 reads: "Overall, the proportion of FBC customers billed on a monthly basis increased from less than 15 percent prior to the implementation of AMI to approximately 26.5 percent at year-end 2019." [Emphasis added.]

FBC anticipates that the number of customers on monthly billing will continue to increase. This growth is attributable to all new FBC customers being placed on a monthly billing cycle, and current FBC customers moving from a bi-monthly billing cycle to monthly billing on request.

FBC updates the inputs to the working capital calculation periodically, most recently in the MRP Application as approved in Order G-166-20. The lead-lag study filed and approved in the MRP Application used 2017 actual data, which followed the completion of the AMI project. The impacts of the working capital adjustment on revenue requirements during the previous PBR term were relatively minor (the average impact of the working capital benefits over the period 2016 to 2019 was $40 thousand). Therefore, FBC does not propose to revise the working capital calculation prior to the end of the MRP term.

36.0 Reference: UPPER BONNINGTON UNIT REFURBISHMENT PROJECT STATUS REPORT

Exhibit B-2, Appendix C4, pp. 6–7

Unit 3 Deficiency

On page 2 of Appendix C4, FBC describes the Upper Bonnington (UBO) Refurbishment Project budget:

> The UBO Refurbishment Project was approved with a Class 4 capital cost estimate of $31.783 million in as-spent dollars (including $0.867 million of AFUDC and $1.880 million of removal costs). Project expenditures to May 30, 2020 are approximately $28.534 million. Final project costs (including $1.096 million of AFUDC and $1.679 million of removal costs) are currently forecast to be $34.180 million.

On pages 6-7 of Appendix C4, FBC describes the UBO Unit 3 deficiency:

> The rotor spider on Unit 3 is an original 1908 cast steel component that as designed allows lubricating oil to return from the upper guide bearing back through the center of the spider to the reservoir. …. As Unit 2 and Unit 3 rotor spiders are identical, the same issue exists on Unit 2. FBC is currently developing a repair procedure for Unit 2 and is planning to re-use the existing spider. The source of the problem is suspected to be voids within the casting at the microscopic level and therefore it is not possible to predict the success of the planned repair. Once Unit 2 is returned to service, FBC will be able to determine if the repair was successful. If successful, Unit 3 will be removed from service in Q1 2021 to have the same repair applied. The current cost forecast includes this repair on Unit 3 at an estimated cost of $0.166 million and a schedule delay of four weeks. If the repair is not successful for Unit 2, both rotor spiders will need to be replaced. FBC is currently exploring options and costing to replace the rotors if required.

36.1 Please explain whether the updated project budget includes the cost of performing the repair on Unit 2.

Response:

The updated project budget of $34.180 million includes the cost of performing the repair on Unit 2. It does not include costs for replacement of the rotor spiders if the repair is unsuccessful.

36.2 Please explain the range of possible costs and options for Unit 2 and Unit 3 if the repair described in the preamble is not successful.

Response:

If the repair to address the oil leak in the U2 rotor is not successful, the only remaining feasible option is to replace the rotors on both U2 and U3. FBC is currently estimating the costs to replace both rotors. While the final costs are not yet determined, FBC's preliminary estimate for the two rotor replacements is in the magnitude of $3.5 - $4.5 million and would delay the project by approximately 32 weeks.

Attachment 9.1.1

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 22.1

FORTISBC INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	Forecast Mid-Year 2019	Balance 12-31-2018	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Balance 12-31-2019	Mid-Year Average	Difference	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Benefit Matching Accounts										
2	Demand Side Management	$ 26,427	$ 24,148	$ -	$ 9,986	$ (2,696)	$ (4,069)	$ 27,369	$ 25,759	$ (668)	
3	Deferred Debt Issue Costs	3,448	3,543	-	-	(29)	(162)	3,352	3,448	-	
4	Preliminary and Investigative Charges	341	195	-	630	-	-	825	510	169	Note 1
5	Accounting Treatment of Non-AMI Meters	541	1,081	-	1	-	(1,082)	-	541	-	
6		$ 30,756	$ 28,967	$ -	$ 10,617	$ (2,725)	$ (5,313)	$ 31,546	$ 30,258	$ (498)	
7											
8	Other Accounts										
9	Pension and OPEB Liability	(16,276)	(16,586)	-	2,333	-	-	(14,253)	(15,420)	856	
10		$ (16,276)	$ (16,586)	$ -	$ 2,333	$ -	$ -	$ (14,253)	$ (15,420)	$ 856	
11											
12	**Total Rate Base Deferral Accounts**	$ 14,480	$ 12,381	$ -	$ 12,950	$ (2,725)	$ (5,313)	$ 17,293	$ 14,838	$ 358	
13											

14 Note 1: Additions are net of transfers to Construction Work in Progress

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	Forecast Mid-Year 2019	Balance 12-31-2018	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Balance 12-31-2019	Mid-Year Average	Difference	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**Deferral Accounts Financed at Short Term Interest Rate**										
2											
3	Forecast Variance Accounts										
4	Revenue and Power Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Note 1
5	Flow-Through Accounts	(6,394)	(13,910)	-	(6,307)	-	12,788	(7,429)	(10,670)	(4,276)	Page 12.2, Line 29
6	Pension & Other Post Retirement Benefits (OPEB) Variance	(562)	(866)	-	(1,327)	-	266	(1,927)	(1,397)	(835)	
7		$ (6,956)	$ (14,776)	$ -	$ (7,634)	$ -	$ 13,054	$ (9,356)	$ (12,067)	$ (5,111)	
8											
9	Rate Smoothing Accounts										
10	2018 Revenue Deficiency	$ -	$ 654	$ (654)	$ -	$ -	$ -	-	$ -	$ -	
11		$ -	$ 654	$ (654)	$ -	$ -	$ -	$ -	$ -	$ -	
12											
13	Benefit Matching Accounts										
14	2014-2019 Performance Based Ratemaking Application	$ 123	$ 247	$ -	$ (1)	$ -	$ (246)	$ -	$ 124	$ 1	
15	Annual Reviews for 2015 - 2019 Rates	40	69	-	(5)	1	(79)	(14)	28	(12)	
16	Self-Generation Policy Application, Stage II	18	48	-	130	(35)	(35)	108	78	60	
17	Net Metering Program Tariff Update	19	39	-	1	-	(38)	2	21	2	
18	BCUC Residential Inclining Block Rate Report	2	5	-	-	-	(5)	-	3	1	
19	2017 Demand Side Management Expenditure Schedule Application	-	(1)	-	-	-	1	-	(1)	(1)	
20	2018 Demand Side Management Expenditure Schedule Application	27	55	-	1	-	(54)	2	29	2	
21	Community Solar Pilot Project	(14)	(27)	-	-	-	27	-	(14)	-	
22	Tariff Applications	(37)	(74)	-	-	-	74	-	(37)	-	
23		$ 177	$ 361	$ -	$ 126	$ (34)	$ (355)	$ 98	$ 231	$ 53	
24											
25	Oher Accounts										
26	2014-2019 Earnings Sharing Account	$ (126)	$ (226)	$ -	$ 161	$ (43)	$ 253	$ 145	$ (41)	$ 85	Page 26.1, Line 53
27	Castlegar Office Disposition	(220)	(439)	-	-	-	439	-	(220)	(0)	
28	BC Hydro 2017 Waneta Transaction	45	110	-	-	-	(91)	19	72	27	
29		$ (300)	$ (555)	$ -	$ 161	$ (43)	$ 601	$ 164	$ (196)	$ 105	
30											
31											
32	**Total Deferral Accounts at Short Term Interest**	$ (7,078)	$ (14,316)	$ (654)	$ (7,347)	$ (77)	$ 13,300	$ (9,094)	$ (12,032)	$ (4,953)	
33											
34	Financing Costs at STI	$ (317)	$ (8)	$ -	$ (416)	$ -	$ 334	$ (90)	$ (49)	$ 268	
35											
36											

37 Note 1: Revenue and Power Supply Variances are included in the Flow-Through Accounts during the PBR Term.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2019
($000s)

Line No.	Particulars	Forecast Mid-Year 2019	Balance 12-31-2018	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Balance 12-31-2019	Mid-Year Average	Difference	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**Deferral Accounts Financed at Weighted Average Cost of Debt**										
2											
3	Rate Smoothing Accounts										
4	2018 - 2019 Revenue Surplus	$ (1,402)	$ -	$ 654	$ (5,633)	$ 1,521	$ -	$ (3,458)	$ (1,402)	$ -	
5		$ (1,402)	$ -	$ 654	$ (5,633)	$ 1,521	$ -	$ (3,458)	$ (1,402)	$ -	
6											
7	Benefit Matching Accounts										
8	CPCN Projects Preliminary Engineering	$ 127	$ 176	$ -	$ (10)	$ -	$ -	$ 166	$ 171	$ 44	Note 1
9	2016 Long Term Electric Resource Plan	360	413	-	-	-	(103)	310	362	2	
10	2017 Rate Design Application	701	347	-	557	(150)	(164)	590	469	(232)	
11	2020 Revenue Requirements	520	151	-	600	(162)	-	589	370	(150)	
12	2019-2022 Multi-Year DSM Expenditure Schedule	155	124	-	46	(12)	(50)	108	116	(39)	
13	2018 Joint Pole Use Audit	102	117	-	(12)	3	(29)	79	98	(4)	
14	EV Charging Stations Rate Design and Tariff Application	44	13	-	-	-	-	13	13	(31)	
15		$ 2,009	$ 1,341	$ -	$ 1,181	$ (321)	$ (346)	$ 1,855	$ 1,599	$ (410)	
16											
17	Other										
18	US GAAP Pension and OPEB Transitional Obligation	$ 1,645	$ 1,901	$ (512)	$ -	$ -	$ -	$ 1,389	$ 1,389	$ (256)	
19	Advanced Metering Infrastructure Radio-Off Shortfall	94	105	-	18	(5)	(21)	97	101	7	
20		$ 1,739	$ 2,006	$ (512)	$ 18	$ (5)	$ (21)	$ 1,486	$ 1,490	$ (249)	
21											
22	**Total Deferral Accounts at Weighted Average Cost of Debt**	$ 2,347	$ 3,347	$ 142	$ (4,434)	$ 1,195	$ (367)	$ (117)	$ 1,687	$ (659)	
23											
24	Financing Costs at WACD	$ 135	$ 189	$ -	$ 109	$ -	$ (147)	$ 151	$ 170	$ 35	
25											
26	**Deferral Accounts Financed at AFUDC**										
27											
28	Benefit Matching Accounts										
29	On Bill Financing (OBF) Participant Loans	$ 7	$ 7	$ -	$ (2)	$ -	$ -	$ 5	$ 6	$ (1)	
30											
31	Financing Costs at AFUDC	$ -	$ 1	$ -	$ 1	$ -	$ (1)	$ 1	$ 1	$ 1	
32											
33	**Deferral Accounts Non-Interest Bearing**										
34											
35	Kettle Valley Future Development	$ 50	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50	$ -	
36											
37											
38	**Total Non Rate Base Deferral Accounts (including financing)**	$ (4,856)	$ (10,730)	$ (512)	$ (12,089)	$ 1,118	$ 13,119	$ (9,094)	$ (10,167)	$ (5,311)	
39											
40	Cross Reference								Page 12, Lines 32+34		
41									+ Page 12.1, Lines 22+24+29+31+35		
42	Note 1: Gross additions for CPCN Projects Preliminary Engineering after transfers to Construction Work in Progress.										

Attachment 26.4

bcuc
British Columbia
Utilities Commission

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
Annual Review for 2020 and 2021 Rates

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On June 22, 2020, the British Columbia Utilities Commission (BCUC) issued its Decision and Order G-166-20 approving for FortisBC Inc. (FBC) a Multi-Year Rate Plan (MRP) for 2020 through 2024 (the MRP Decision). In accordance with the MRP Decision, FBC is to conduct an Annual Review process to set rates for each year;

B. By Order G-303-19, dated November 28, 2019, the BCUC approved a 1.0 percent general rate increase from 2019 rates on an interim and refundable/recoverable basis, effective January 1, 2020, pending a decision on the MRP application;

C. On July 20, 2020, FBC together with FortisBC Energy Inc. submitted a Compliance Filing pursuant to Orders G-165-20 and G-166-20 (MRP Compliance Filing). The MRP Compliance Filing included, among other things, proposed benchmarks and thresholds for the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) Service Quality Indicators (SQIs);

D. By letter dated July 20, 2020, FBC proposed a regulatory timetable for its annual review for permanent 2020 and 2021 rates;

E. By Order G-211-20 dated August 11, 2020, the BCUC established the regulatory timetable and on August 19, 2020, FBC submitted its Annual Review for 2020 and 2021 Rates Application (Application);

F. In the Application, FBC's forecast revenue requirements for 2020 result in a general rate increase of 1.93 percent from 2019 rates. FBC requests approval to make the existing interim rates permanent, effective January 1, 2020, and to capture the revenue deficiency greater than the 1.0 percent general rate increase already incorporated into the interim rates in the existing 2018-2019 Revenue Surplus deferral account as an offset to prior years' revenue surpluses;

Deleted: &

G. The Application also requests approval of a general rate increase of 6.37 percent from 2020 rates, effective January 1, 2021, after drawing down the 2018-2019 Revenue Surplus deferral account; and

H. The BCUC has reviewed the Application and evidence filed in the proceeding and considers that approval is warranted.

NOW THEREFORE pursuant to sections 44.2(3) and 59 to 61 of the *Utilities Commission Act*, for the reasons attached as Appendix A to this order, the BCUC orders as follows:

1. FBC is approved to make permanent the existing 2020 interim rates, effective January 1, 2020.

2. FBC's permanent rate increase of 6.37 percent, effective January 1, 2021, is approved.

3. The following deferral account requests are approved:

    a. Creation of rate base deferral accounts for the following regulatory proceedings:

        i. The Annual Reviews during the MRP term, with balances to be amortized in the following year;

        ii. FBC's 2021 Long-Term Electric Resource Plan;

        iii. FBC's 2020 Cost of Service Analysis filing; and

        iv. Participation in BCUC-Initiated Inquiries, with balances to be amortized in the following year**;**

    b. Creation of a rate base deferral account to capture costs related to the Indigenous Relations Agreement (Huth Substation);

    c. Creation of a rate base deferral account to capture the costs of the 2021 triennial Mandatory Reliability Standards audit;

    d. Draw down of the existing 2018-2019 Revenue Surplus deferral account in the amount of $3.326 million in 2020 and $1.410 million in 2021, bringing the account balance to zero; and

    e. The previously approved 2020 Revenue Requirement Application deferral account is renamed to the 2020-2024 MRP Application deferral account, and amortized over a five-year period beginning January 1, 2020.

4. FBC is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 in the previously approved COVID-19 Customer Recovery Fund Deferral Account, as discussed in Section 12.2.1 of the Application.

5. FBC's proposed SQI benchmarks of 3.22 for SAIDI and 1.57 for SAIFI, and thresholds of 4.52 for SAIDI and 2.19 for SAIDI, are approved.

6. The BCUC accepts the capital expenditures for the Playmor Substation Upgrade Project, as described in Appendix B to the Application.

Deleted: FortisBC Inc. (FBC)

Deleted: into

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment 30.5

CONDITION AND LIFE ASSESSMENT REPORT PLAYMOR T1 TRANSFORMER

Rev 0.1

By FortisBC Stations Assets

Prepared by	Checked by	Date	Rev #
Paul Gheorghe P.Eng	Jonathan Reimer P.Eng	Sept 2020	0.0
Paul Gheorghe P.Eng		Jan 2020	1

Table of Contents

1. INTRODUCTION

This report was prepared for FortisBC internal use. The report represents a condition assessment of Ferranti Packard Playmor T1 distribution transformer.

The design parameters and identification numbers are shown below:

Unit ID	Playmor T1
Manufacturer	Ferranti Packard
Rating	12(/16//18)* MVA ONAN(/ONAF)* 3ph 60Hz
Voltage	66 kV Δ – 12.47 kV Y
HV Lightning Insulation Levels	350 kV
LV Lightning Insulation Levels	110 kV
Rated current	HV 147 Amps LV 740 Amps
Temperature rise	55/65ºC
Serial number	12559
Impedance	6.67%
Manufacturing Date	1966

*16//18 ONAF rating currently not available because there are no fans installed

2. SITE INSPECTION REPORT

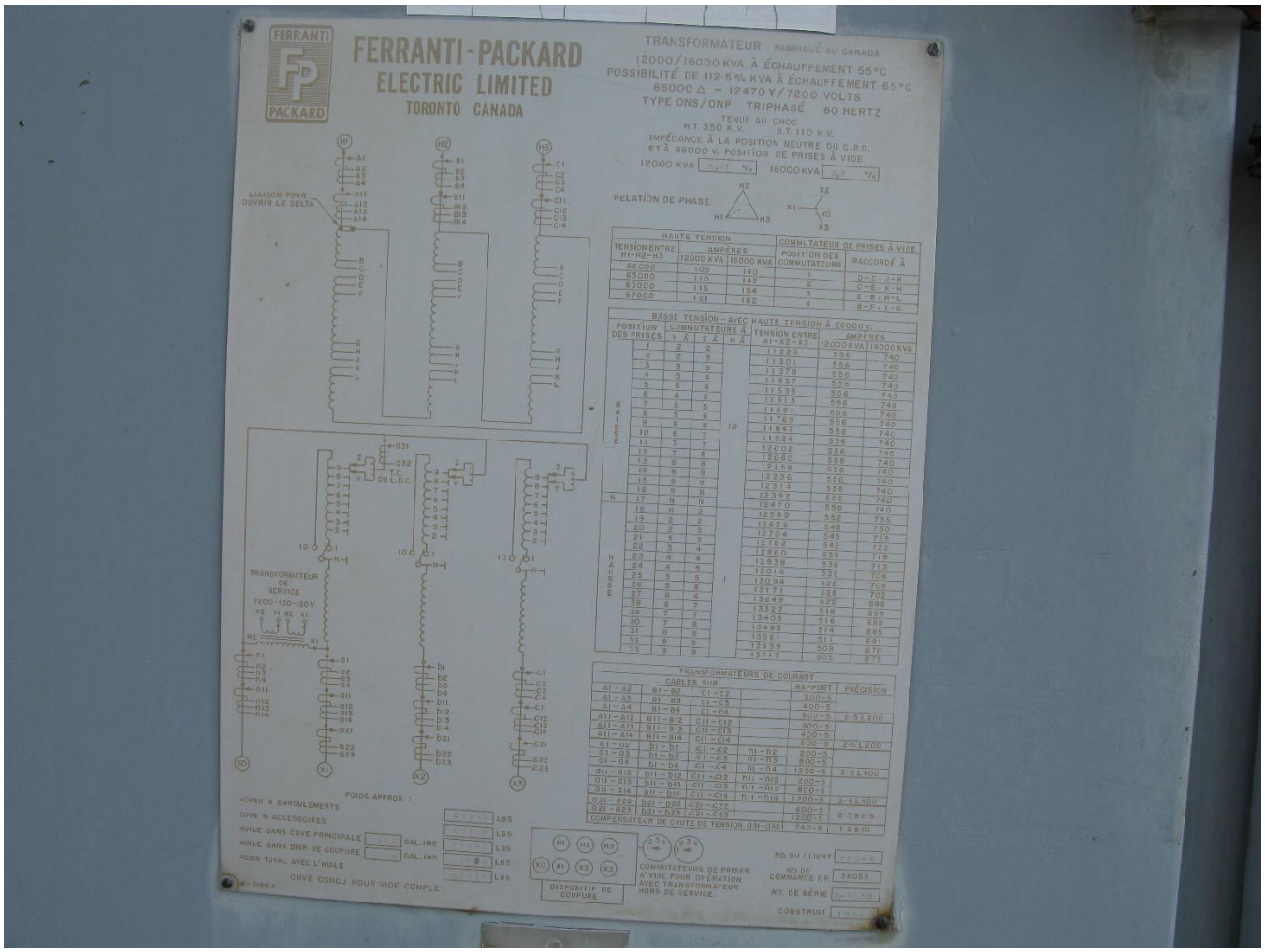
Below is the site inspection report for the PLA T1 transformer as inspected on May 7, 2019.

Ambient (ºC)	8
Load (MVA)	5.6
Oil Temperature as found (ºC)	51
Oil Temperature max recorded (ºC)	58
Winding Temperature as found (ºC)	None available
Winding Temperature max recorded (ºC)	None available
Oil Level Status	OK
Tank/Conservator	Fair Condition
Bushings	OK
Coolers/Radiators	OK
LTC # of operations	46415
LTC condition	Known issues
Fans	None

- PLA T1 was operating at the time of inspection.
- Based on FBC standards this unit should be protected with an HV breaker (>15MVA).
- This unit has no fans and no winding temperature gauge.
- The oil temperature during inspection seemed high for the recorded loading.
- The oil level was normal.
- The silica gel breather was changed.
- Radiators looked in good condition.
- There were consistent signs of aging, oil leaks and rust.
- The LTC oil filtration unit was in acceptable working conditions, with some oil leaking around the hoses and fittings.

- The unit has a bolted cover.
- There is a Sorbweb oil containment pit.
- The oil level in all HV bushings was good. The HV bushings were replaced during the PCB mitigation program. LV bushings have no indicators for oil level.
- There is no online Dissolved Gas Analysis monitor.
- The conservator is not equipped with an air cell.
- There is a consistent amount of oil leaking from radiator valves and flanges.
- A flashover was noted on the LV arresters. This issue should be investigated.

3. PLA T1 NAMEPLATE



4. PLA T1 LAYOUT

5. OBSERVATIONS

This is an illustration of a few of the noted deficiencies:

- This unit has a unique LTC for FBC fleet-McGraw Edison 550B. Only some miscellaneous repair parts can be purchased at http://www.circuitbreakerstore.com.
- There are consistent leaks from around the radiator valves and flanges.
- The LV bushings are the original ones.
- This unit still has the “goose neck” pressure relief devices (See UBO WSCB recommendations).

6. DISSOLVED GAS IN OIL ANALYSIS REVIEW

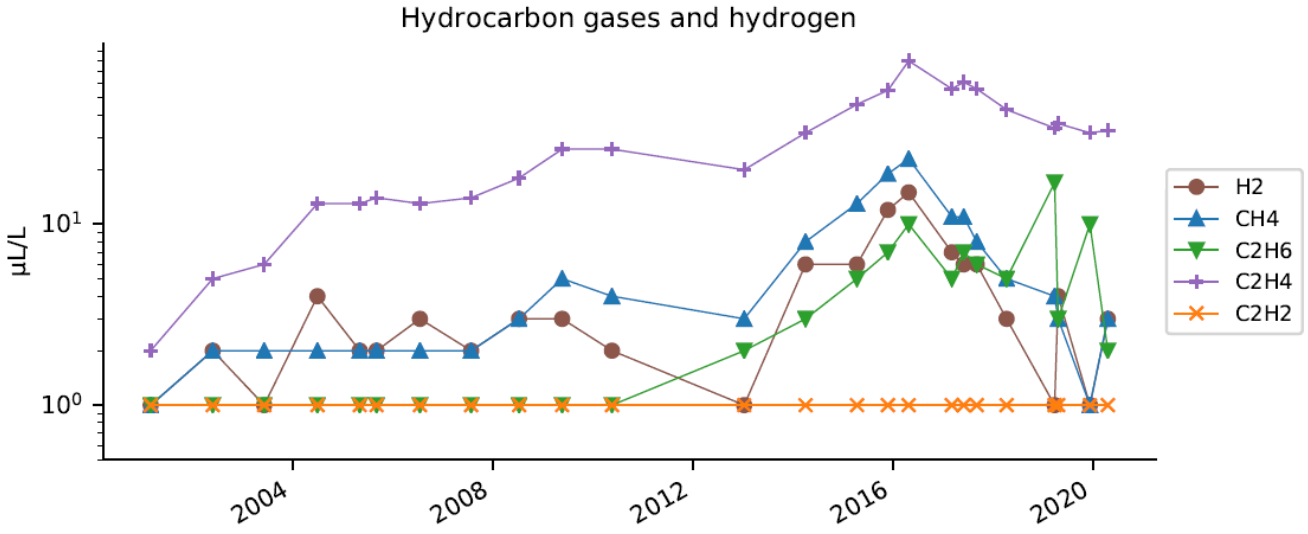
The dissolved gas analysis (DGA) review has been done according to Table 1 of IEEE C57.104-2008. The limits for different gasses suggested in this Table are to be used as a guide to assess the severity of the problem. A higher level indicates a worsening condition that requires increased monitoring and actions. Below is a short description of the four conditions referred to in the analysis:

Condition 1: Transformer is operating satisfactorily.
Condition 2: A fault may be present. Take DGA samples at least often enough to calculate the amount of gas generation per day for each gas.
Condition 3: Indicates a high level of decomposition of cellulose insulation and/or oil. Take DGA samples at least often enough to calculate the amount of gas generation per day.
Condition 4: Indicates excessive decomposition of cellulose insulation and/or oil. Continued operation could result in failure of the transformer.

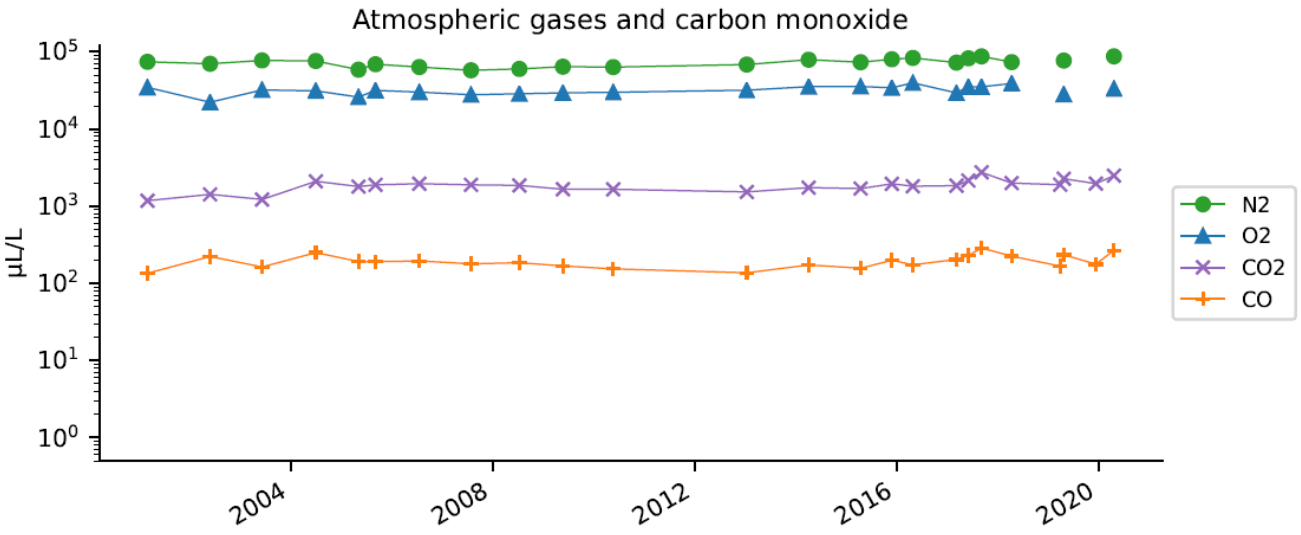
Available DGA and Oil Quality data covers the period of time from 2001 up to today (May 2020).

This is a summary review of the available data:

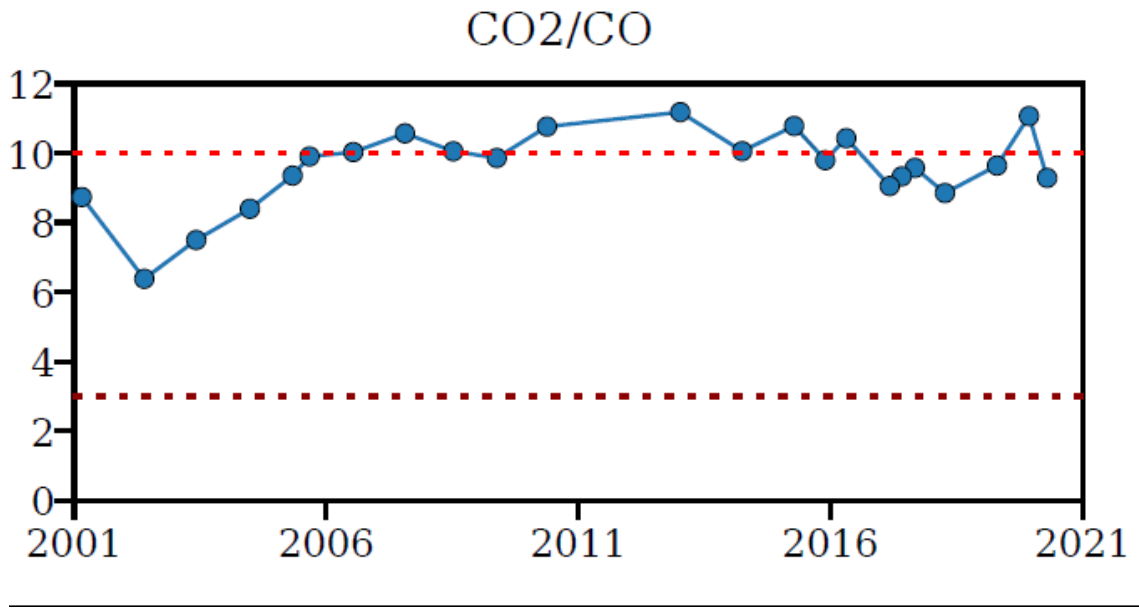
The concentration level of hydrogen (H2) and all hydrocarbon gases (CH4, C2H4, C2H6, C2H2) have been Condition Level 2 per IEEE C57.104-2008 guide. A sharp increase in C2H4- Ethylene levels was observed since 2013 and has peaked in 2016. The likely cause of this upwards trend was determined as abnormal arcing and overheating of main contacts inside the LTC. After a few rushed interventions, the local overheating issue was addressed and the unit seems stable.



The Carbon Dioxide and Carbon Monoxide levels seem stable and low during this unit life, which is abnormal. Since this is a free breathing unit and the dissolved CO and CO2 have not reached critical levels, this might be the resultant of a normal load related aging of this unit.



For healthy and properly designed transformers, normal CO2/CO ratios are typically in the range of 3 to 10. For free breathing transformers with an ample supply of oxygen, there are typically high levels of carbon oxides generated under normal loading conditions. It is also typical that some of the CO will be converted to CO2 in the presence of large quantities of oxygen. Oxygen acts as a catalyst to increase the generation rates of CO, CO2 and combustible gases. Since the CO2/CO ratio was always around 10, it is possible that this unit is aging faster than expected for the recorded MVA loadings.



The Oxygen (O2) level was always at the saturation point because the unit has no air cell. The presence of large concentrations of Oxygen in oil can promote the formation of acids in the oil and cellulose, accelerate the aging rate of the insulation and aid in more gas generation.

This design does not prevent moisture to dissolve into oil and consequently be transferred into paper. Nonetheless, due to proper maintenance during the unit life, moisture has not increased to critical levels.

7. GENERAL OIL QUALITY

Table below shows a summary of the latest oil quality measurements performed on this unit.

Fluid Quality

Lab Report Number	7236693	7004693	6773474	6606309	6502498	
Sample date	2019-04-23	2017-03-07	2015-04-14	2013-11-18	2013-01-10	
Sample temp	35	30	26		25	°C
Diel brk D1816 (1 mm)	34.0	35.0	35.0		26.0	kV
PF at 25°C	0.061	0.069	0.062		0.068	%
Acid number	0.019	0.023	0.030		0.023	mg KOH/g
Interfacial tension	31.5	30.2	32.8		29.5	mN/m
Oxidation inhibitor				**0.098***		%
Color	1.5	1.0	1.5		1.5	
Oil quality index	0.6	0.8	0.9		0.8	
Visual	CLR&BRIGHT	CLR&BRIGHT	CLR&SPRK		CLR&SPRK	
Fluid quality retest days	365	365	365		365	days
Fluid quality retest date	2020-04-22	2018-03-07	2016-04-13		2014-01-10	
FQ result	1	1	1		1	
Inhibitor code				2		

Symbol legend: *: abnormal level

The following can be observed from the assessment of the oil quality using the Standard IEEE C57.106-2015, Tables 2 and 3 test limits for new and in-service mineral oil.

- Measured oil dielectric breakdown voltages are steady above 25 kV/mm based on D1816-1mm method. Results are all above the suggested limit for in-service transformers of 28 kV minimum for a ≥69 kV unit.
- The interfacial tension should have a minimum 30 mN/m. In this case, the measured interfacial tensions are above this limit.
- The measured acid numbers in the past few years were below the recommended maximum of 0.15 mg KOH/g by IEEE C57.106-2015 for transformers.
- The measured power factor values at 25°C are all below the recommended limit of 0.5%. The measured values were between 0.061% and 0.069%.
- The last measured water content was 10 ppm, which is below the recommended maximum of 25 ppm by IEEE C57.106-2015 for ≥69 kV transformers. The relative saturation of 11% is still acceptable.
- The recorded oxidization inhibitor level is just above the lower limit recommended concentration that is between 0.08 and 0.30% (0.098). The first choice of attack by oxygen in the oil is the inhibitor molecules. This keeps the oil free from oxidation and its harmful by-products. As a transformer ages, the oxidation inhibitor is used up and needs to be replaced. This task should be completed during next maintenance cycle.
- As found oil colour is 1.5, which indicates the beginning of the aging process and the possible presence of sludge formation initiators.

- Furan Analysis is a measure of the degradation of the cellulose paper. As paper ages, the degree of polymerization is reduced and the mechanical strength also decreases. The degree of polymerization (DP) can only be measured by testing a sample of the paper in question, which is not practical for a transformer still in service. 2019 furan results indicate no furans in the oil and that is most likely due to the 2013 oil processing which has removed the decomposition by-products already formed.
- Dissolved PCB level is just below Environment Canada 2025 requirements. 4.6 ppm vs the required less than 5 ppm.

8. POWER FACTOR AND CAPACITANCE MEASUREMENTS

The latest available Doble Power Factor and Capacitance tests were performed in July 2018.

The following is noted:

The measured power factor and capacitance for HV windings overall are acceptable however the LV power factor has slightly increased to 0.5% indicating possible increased paper moisture . NETA Maintenance test specifications 2005 Table 100.3 specifies for oil filled power transformers a recommended maximum power factor of 1%.

Overall Tests

	Insulation	Test kV	mA	Watts	PF*TCF [%]	Corr Fctr	Cap (pF)	Manual
1	CH+CHL	10.002	36.364	1.348	0.371	1	9645.690	
2	CH	10.002	7.748	0.216	0.279	1	2055.185	
3	CHL (Measured)	10.001	28.581	1.169	0.409	1	7581.225	
4	CHL	0	28.616	1.132	0.396	1	7590.505	
5	CL+CHL	10.004	73.011	3.712	0.508	1	19366.530	
6	CL	10.003	44.409	2.567	0.578	1	11779.649	
7	CHL (Measured)	10.002	28.564	1.175	0.411	1	7576.791	
8	CHL	0	28.602	1.145	0.400	1	7586.881	

Winding without Attached Bushing Calculation							
CH-C1	CH'		5.535	0.162	0.292	1	1468.062
CL-C1	CL'		44.409	2.567	0.578	1	11779.649

The crew has tested the LV bushings using the hot-collar method. Bushings results were acceptable. No new winding resistance test results are available.

9. RECENT MAINTENANCE HISTORY

The following mitigation work was completed during the last few years:

- 2018 September LTC repair was completed using aftermarket parts.
- 2016 May-LTC rushed intervention due to abnormal arcing and overheating. LTC parts were rotated, from tap positions rarely used, such that operation could continue.
- 2014 June-LTC rushed intervention due to abnormal arcing.

The McGraw Edison 550B type LTC has proven quite reliable in the past, but during last 6 years has developed issues that could not be properly addressed due to the lack of OEM support. The only parts source for this type of LTC is online and supplies only a hand full of the required parts for

refurbishment. If a major LTC component fails, we will need to take the transformer off line and since LTC refurbishment is not an option, most likely scrap it.

10. LOSS OF LIFE CALCULATION

Since this unit was purchased used, the original Factory Acceptance Tests are not available and without a hot spot gradient calculating a cumulative unit loss of life would be meaningless. More over an approximation of the hot spot temperature cannot be produced because this unit does not have a winding temperature gauge.

Over the 54 years of service life of this transformer (1966-2020), the estimated loss of insulation life would amount to about 80-90%. This would indicate a mature to old transformer, however due to the issues with the LTC the end of life for this unit can come abruptly.

Due to the known issues, the estimated Risk of Failure (RoF) exceeds acceptable levels. Ignoring the unit condition and considering age as the only factor the RoF of PLA T1, as per CIGRE WG 12-05 survey, could be extrapolated at around 10-15%. The actual RoF of any piece of station equipment will only increase in time and it is FBC Station Asset Management estimate that the RoF will reach 20% around 2026.

11. RECOMMENDATIONS

Due to the unit age, the known issues with the LTC, the fact that LTC refurbishment is not a possible solution, the lack of fast HV transformer protection, and a lack of built-in redundancy, it is FBC Station Asset Management recommendation to prepare a contingency plan for this unit's unforeseen failure and replace PLA T1 before next maintenance cycle (2024-2026).