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August 19, 2020

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Marija Tresoglavic, Acting Commission Secretary

Dear Ms. Tresoglavic:

Re: FortisBC Inc. (FBC)

Multi-Year Rate Plan for 2020 through 2024 approved by British Columbia Utilities Commission (BCUC) Order G-166-20 (MRP Plan)

Annual Review for 2020 and 2021 Rates

In accordance with the MRP Plan and BCUC Order G-211-20 setting out the Regulatory Timetable for FBC's Annual Review, FBC hereby attaches its Annual Review for 2020 and 2021 Rates Application materials.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties to the FortisBC Application for Multi-Year Rate Plan for 2020 through 2024

FortisBC Inc.

Multi-Year Rate Plan

for 2020 through 2024

Annual Review for 2020 and 2021 Rates

Volume 1 - Application

August 19, 2020

Table of Contents

List of Appendices

Index of Tables and Figures

1. APPROVALS SOUGHT, OVERVIEW OF THE APPLICATION AND PROPOSED PROCESS

1.1 *INTRODUCTION*

FortisBC Inc. (FBC or the Company) files this Application in compliance with British Columbia Utilities Commission (BCUC) Order G-166-20, which approved a Multi-Year Rate Plan (MRP or the Plan) for FBC for the years 2020 to 2024. In accordance with the MRP, an annual review process is required to set rates for each year of the MRP.

By Order G-303-19, the BCUC approved FBC's 2020 rates on an interim basis, pending a decision on the MRP. With the filing of this Application, FBC seeks to commence the annual review process to set permanent rates for 2020 and 2021.

The MRP approved by the Decision attached to Order G-166-20 (MRP Decision) provides stable levels of O&M funding while maintaining service quality. The approved Earnings Sharing Mechanism (ESM), set out in Section 10, aligns the incentive properties of the Plan between customers and the Company.

In the first year of the MRP, FBC anticipates relatively minor O&M savings in 2020 as compared to that allowed under the O&M formula, and as a result has not forecast any savings or related earnings sharing. The reason for FBC's expectation of relatively minor formulaic O&M savings is twofold. First, as described in its MRP application, FBC expects to face both continued and new cost pressures. Second, with the inclusion of a 0.5 percent Productivity Improvement Factor (PIF), which was directed by the BCUC as part of the MRP Decision, FBC will be challenged to achieve savings beyond the embedded PIF.

FBC will continue to pursue productivity improvements as it seeks to manage its business needs within the challenges described above. While such potential productivity improvements may lead to cost reductions, FBC's focus will be on efficient allocation of resources within the business and "doing more with what we have". FBC believes this approach to productivity represents an appropriate balancing of the ongoing need to manage costs and mitigate customer rate pressure, while providing resources to support growth and maintaining service levels.

1.1.1 Permanent 2020 Rates

The rates for 2020 that would flow from the approved formulas and forecasts set out in the Application result in a 1.93 percent rate increase from 2019 rates. This increase, before utilization of a portion of FBC's 2018-2019 Revenue Surplus deferral, which is further described in Section 1.4, incorporates the actual 2019 results of the final year of the 2014-2019 Performance Based Ratemaking (PBR) Plan. Overall, FBC proposes to recover \$0.250 million (before tax) in earnings sharing from customers in 2020. This amount is a true-up from FBC's 2019 projected earnings sharing and does not reflect savings in 2020 that may be achieved.

Order G-303-19 set FBC's interim rates at 1.00 percent over 2019 approved rates. Due to the expected timing of a decision on this Application, FBC is proposing to set permanent 2020 rates at the existing interim levels and to capture the revenue deficiency greater than the 1.00 percent approved as interim in the existing 2018-2019 Revenue Surplus deferral account as an offset to prior years' revenue surpluses.

1.1.2 Permanent 2021 Rates

The proposed rate change for 2021 after drawing down the 2018-2019 Revenue Surplus deferral account to zero is a 6.37 percent rate increase from 2020 rates. The increase is primarily due to an increase in depreciation and amortization expense and power supply costs compared to 2020 Projected, as discussed in Section 1.4 below.

As noted above, FBC anticipates relatively minor formulaic O&M savings in 2020. FBC continues to maintain a high level of service quality as indicated by meeting the Service Quality Indicators (SQIs) approved in the MRP Decision. Once 2020 results are known, FBC will determine the 2020 earnings sharing, if any, when setting rates for 2022.

In the sections below, FBC sets out the approvals it is seeking and provides an overview of the requirements for the annual review process. This is followed by a summary of FBC's proposed revenue requirements and rate changes for 2020 and 2021 and an overview of the SQIs. These matters are addressed in more detail in subsequent sections of the Application.

1.2 *APPROVALS SOUGHT*

With this Application, FBC requests BCUC approval for the following pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA):

1. Existing 2020 interim rates be made permanent, effective January 1, 2020;
2. A permanent rate increase of 6.37 percent, effective January 1, 2021;
3. The following deferral account approvals, as described in Sections 7.7 and 12.4:
    - Creation of rate base deferral accounts for the following regulatory proceedings:
        - Annual Reviews for 2020 to 2024 Rates, with balances to be amortized in the following year;
        - 2021 Long-Term Electric Resource Plan (LTERP);
        - 2020 Cost of Service Analysis (COSA) filing; and
        - BCUC-Initiated Inquiries, with balances to be amortized in the following year;
    - Creation of a rate base deferral account to capture costs related to the Indigenous Relations Agreement (Huth Substation);

- Creation of a rate base deferral account to capture the costs of the 2021 triennial Mandatory Reliability Standards (MRS) audit;
- Draw down of the 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
- The previously approved 2020 Revenue Requirement Application deferral account to be renamed to the 2020-2024 MRP Application deferral account, and amortized over a five-year period beginning January 1, 2020.

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

FBC also requests, pursuant to section 44.2(3) of the UCA, acceptance of a capital expenditure schedule consisting of the capital expenditures for the Playmor Substation Upgrade Project, as described in Appendix B.

A draft order is included in Appendix D.

1.3 *REQUIREMENTS FOR THE ANNUAL REVIEW*

On page 167 of the MRP Decision, the BCUC set out its expectations for the Annual Review component of the MRP. For reference, the table below sets out each requirement and FBC's response or where it is addressed in the Application.

Table 1-1: Annual Review Requirements

Item	Description	Response or Reference
1	Review of the current year projections and the upcoming year's forecast. For further clarity, these items are listed below:	See items 1(a) to 1(f) below
1(a)	Customer growth, volumes and revenues;	Section 3
1(b)	Year-end and average customers, and other cost driver information including inflation;	Section 2
1(c)	Expenses, determined by the indexing formula plus items forecast annually;	Section 6
1(d)	Capital expenditures (as provided for by the capital forecast), plus other items forecast annually;	Section 7
1(e)	Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates; and	Sections 7 and 12

Item	Description	Response or Reference
1(f)	Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year.	Section 10
2	Identification of any efficiency initiatives that the Utilities have undertaken, or intend to undertake, that require a payback period extending beyond the MRP period with recommendations to the BCUC with respect to the treatment of such initiatives.	FBC has not identified any efficiency initiatives with a payback beyond the end of the MRP period
3	Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the BCUC for review.	Section 12.2
4	Review of the Utilities' performance with respect to SQIs. Bring forward recommendations to the BCUC where there have been a "sustained serious degradation" of service.	Section 13
5	Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews.	FBC does not have any recommendations at this time
6	Reporting on the Innovation Fund status.	Not Applicable for FBC
7	Assess and make recommendations to the BCUC on potential issues or topics for future Annual Reviews.	FBC does not have any recommendations at this time

1.4 *REVENUE REQUIREMENT AND RATE CHANGES FOR 2020 AND 2021*

FBC has calculated the 2020 revenue requirement using a combination of the approved formula for O&M and the approved forecasts for Regular Capital from the MRP Decision as well as projected 2020 amounts for items that are forecast annually. The projected 2020 amounts for these forecast items include six months of actual results up to June 30, 2020.

The rates for 2020 flowing from the revenue requirement components set out in the Application result in a 1.93 percent increase from 2019 rates; however, FBC is proposing to make permanent the existing interim rates for 2020, effective January 1, 2020, and to capture the revenue deficiency greater than 1.00 percent in the existing 2018-2019 Revenue Surplus deferral account.

The proposed rates for 2021, after drawing down the balance in the 2018-2019 Revenue Surplus deferral account, result in a 6.37 percent increase from 2020 rates.

The following charts summarize the items that contribute to the 2020 and 2021 revenue deficiencies, including the proposed draw-down of $3.326 million in 2020 and $1.410 million in 2021 from the 2018-2019 Revenue Surplus deferral account. The charts show each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The 2020 and 2021 deficiencies of $3.587 million and $23.543 million, respectively, are then the sum of all of the previous bars and are shown at the end of the charts in blue. For 2020, the blue bar represents the sum required to bring the total revenue deficiency to the deficiency determined when setting interim rates for 2020 (1.00 percent). For 2021, the blue bar represents the total revenue deficiency of $23.543 million (6.37 percent) after the final draw-down of the 2018 – 2019 Revenue Surplus deferral account to zero.

Figure 1-1: 2020 Revenue Deficiency ($ millions)

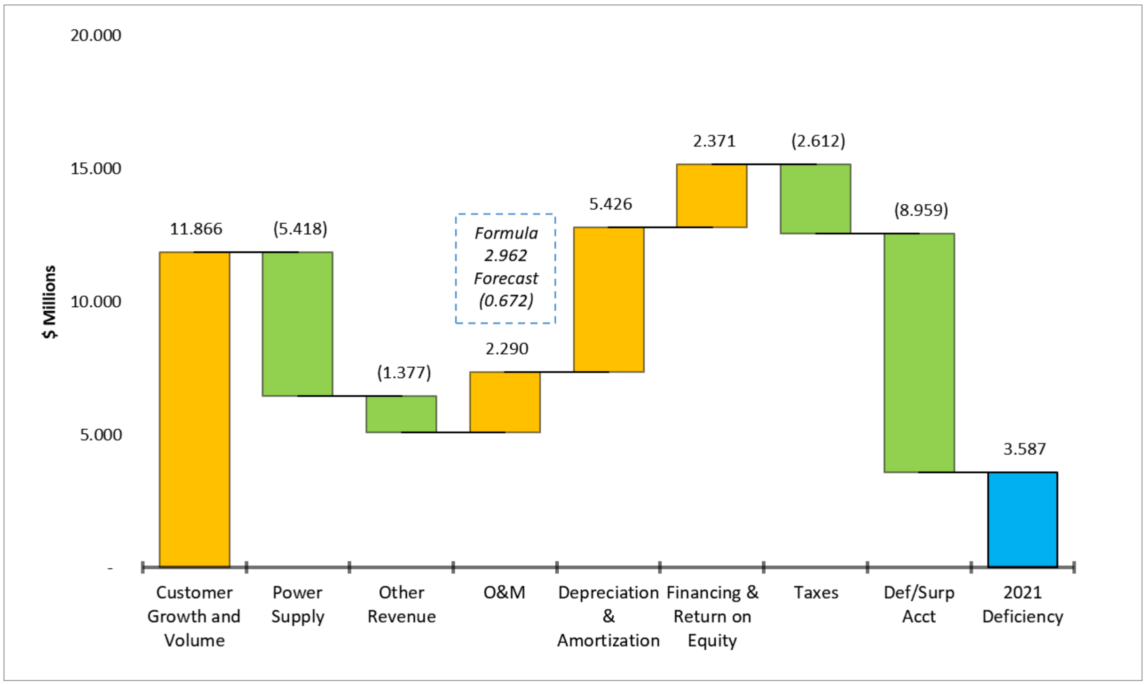
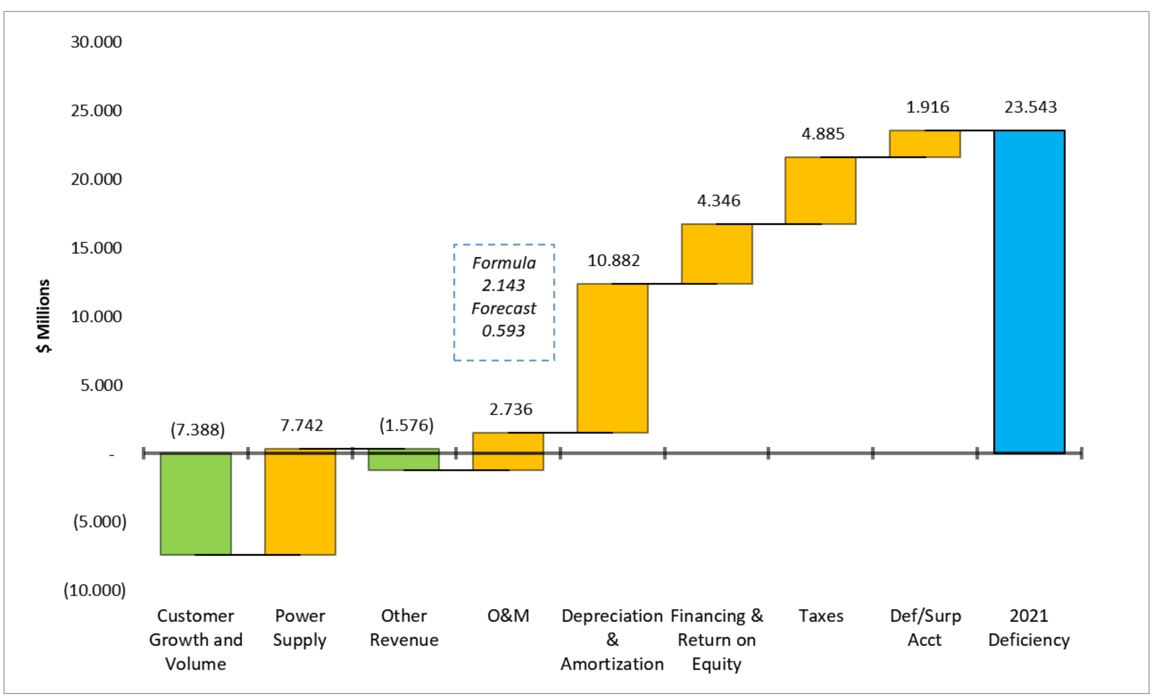


Figure 1-2: 2021 Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.4.1 Load Forecast (Section 3)

For 2020, FBC has projected a sales load decrease of 40 GWh from 2019 Approved primarily due to lower residential, commercial and wholesale usage on a per customer basis. These decreases are partially offset by an increase in industrial load and use per customer. Lighting and irrigation loads are projected to decease by 3 and 5 GWh, respectively, in 2020 when compared to 2019 Approved.

For 2021, FBC has forecast a sales load increase of 84 GWh from 2020 Projected primarily due to higher commercial, wholesale and industrial usage on a per customer basis. These increases are partially offset by a decrease in residential load and use per customer when compared to 2020 Projected.

FBC's 2020 Projected revenue at 2019 existing rates and 2021 Forecast revenue at 2020 approved interim rates is $358.668 million and $369.643 million, respectively.

1.4.2 Power Supply (Section 4)

Power Supply expense is projected to decrease in 2020 by $5.418 million, which is attributed to decreased purchases from the BC Hydro PPA due to a decrease in gross load and lower cost wholesale market purchases.

FBC has forecast Power Supply to increase by $7.742 million in 2021 compared to 2020 Projected. This increase is mainly the result of an increase in gross load and, correspondingly, a greater reliance on higher cost energy supplied by BC Hydro.

1.4.3 Other Revenue (Section 5)

Other Revenue is projected to increase in 2020 by $1.377 million. The main drivers of this increase are Apparatus and Facility Rental and Contract Revenue, partially offset by lower Late Payment Charges. For 2021, FBC has forecast Other Revenue to increase by $1.576 million due to increases in Contract Revenue and Late Payment Charges.

1.4.4 Operations and Maintenance (O&M) Expense (Section 6)

FBC establishes the majority of its O&M expense by formula during the MRP term. For 2020, the formula incorporates an inflation factor (I-Factor) of 2.309 percent, which is inclusive of a productivity improvement factor (X-Factor) of 0.5 percent, and uses a forecast of the change in average customers, for a total increase in formula O&M of 6.0 percent from 2019 Approved. O&M forecast outside of the formula is decreasing by 21.5 percent from 2019 Approved, primarily due to a number of items moving out of forecast O&M and into Base O&M, and a decrease in Pension and OPEB costs. The 2020 increase in total O&M expense net of capitalized overhead is $2.290 million.

For 2021, the O&M formula incorporates an inflation factor (I-Factor) of 3.793 percent, which is inclusive of a productivity improvement factor (X-Factor) of 0.5 percent and uses a forecast of the change in average customers for a total increase in formula O&M of 4.4 percent from 2020 formula O&M. O&M forecast outside of the formula is increasing by 24.2 percent over 2020 Projected, primarily due to Pension and OPEB and Insurance expense increases. The 2021 increase in total O&M expense net of capitalized overhead is $2.736 million.

1.4.5 Depreciation and Amortization (Section 7)

FBC's depreciation expense is projected to increase by $0.401 million in 2020. Depreciation increased by $2.373 million from adopting new depreciation rates as approved in the MRP Decision, with an offsetting $1.972 million decrease in expense from resetting plant to actual, which resulted in an increase in plant accounts with lower depreciation rates when compared to 2019 PBR plant balances. FBC's amortization expense increased by $5.025 million in 2020 predominantly from a decrease in the credit from FBC's Flow-through deferral account amortization in 2020 when compared to 2019.

FBC's 2021 depreciation and amortization expense increases by $3.123 million compared to 2020 Projected. Depreciation expense increases by approximately $1.000 million as a result of CPCN additions to plant for the Corra Linn Dam Spillway Gate Replacement Project, the Grand Forks Terminal Station (GFT) Reliability Project, and the Upper Bonnington (UBO) Old Units Refurbishment Project, as discussed in Section 7. Amortization expense in 2021 increases by $7.759 million primarily from the elimination of the credit flow-through variance embedded in 2020 rates from the final year of the 2014 – 2019 PBR Plan.

1.4.6 Financing and Return on Equity (Section 8)

The impact to FBC's 2020 and 2021 deficiency is a sum of financing rate changes, the ratio of long-term debt vs. short-term debt, and changes in rate base.

For 2020, FBC has issued $75 million of long-term debt in May 2020, and is projecting a short-term debt rate of 1.86 percent, a decrease from the 4.12 percent short-term debt rate embedded in the 2019 Approved revenue requirement. Overall, FBC's deficiency is reduced by $2.194 million from financing rate changes and further reduced by $0.141 million from the ratio change between long-term and short-term debt. The increase in 2020 rate base has contributed $4.706 million to FBC's deficiency when compared to 2019 Approved, due to a combination of the Corra Linn Dam Spillway Gate Replacement Project, the UBO Old Units Refurbishment Project, and the GFT Reliability Project entering rate base in 2020, as well as regular capital additions, as discussed in Section 7.

For 2021, FBC has forecast a mid-year long-term debt issue of $75 million and is forecasting a short-term debt rate of 2.22 percent, an increase from the 1.86 percent short-term debt rate embedded in the 2020 Projected revenue requirement. Overall, FBC's deficiency is reduced by $0.049 million from financing rate changes and further decreased by $0.005 million from the ratio change between long-term and short-term debt. The increase in 2021 rate base has contributed $4.400 million to FBC's deficiency when compared to 2020 Projected due to a combination of CPCN additions and regular capital additions entering rate base, as discussed in Section 7.

FBC has utilized the approved 2020 and 2021 capital structure and return on equity of 40 percent and 9.15 percent, respectively.

1.4.7 Taxes (Section 9)

FBC's 2020 property taxes are projected to increase by 1.7 percent or $0.280 million from 2019 Approved, and 2021 property taxes are forecast to increase by 7.4 percent or $1.249 million from 2020 Projected. The 2021 increases are driven by increases in rates for transmission and distribution lines.

There has been no change in the income tax rate of 27 percent from 2019. Taxes are forecast to decrease in 2020 by $2.892 million, primarily due to a decrease to adjustments to taxable income from the Federal government's Accelerated Investment Incentive regime, and increase in 2021 by $3.636 million due to increases in rate base and amortization of deferred charges.

1.5 *SERVICE QUALITY INDICATORS[1] (SECTION 13)*

FBC's June 2020 year-to-date SQI results indicate that the Company's overall performance to date is representative of a high level of service quality. At the end of June 2020, for the eight SQIs with benchmarks, all performed at or better than the thresholds. For the four SQIs that are informational only, performance generally remains at a level consistent with prior years. Details of the SQIs are included in Section 13.

[1] FBC's Final 2018 and 2019 SQIs, pertaining to the PBR Plan, are provided in Section 14.

2. FORMULA DRIVERS

2.1 INTRODUCTION AND OVERVIEW

This section provides the calculation of the Inflation Factor (or I-Factor) and Growth Factor used for calculating the 2020 and 2021 O&M amounts according to the MRP formula.

In the MRP Decision and Order G-166-20, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and a labour weighting based on the most recent completed year of actuals.[2]

The MRP Decision approved the elimination of the lagging growth factor and approved the use of a forecast of growth[3] to determine Formula O&M. Further, the MRP Decision determined that a growth factor multiplier of 75 percent for Formula O&M was appropriate.

The Inflation Factor and Growth Factor calculations utilize the above-described inputs and determinations. For 2020 and 2021, FBC has used July 2017 through June 2019 inflation data for the 2020 revenue requirement calculations and July 2018 through June 2020 inflation data for the 2021 revenue requirement calculations, using the Statistics Canada tables included in Appendix A1 of the Application.

2.2 INFLATION FACTOR CALCULATION SUMMARY

In the MRP Decision, the BCUC approved an Inflation Factor (I-Factor) using the actual CPI-BC and BC-AWE indices from the previous year and the actual labour weighting based on the most recent completed year of actuals. FBC uses inflation data from July through June and Statistics Canada Table 18-10-0004-01 (formerly CANSIM 326-0020) for CPI-BC and Table 14-10-0223-01 (formerly CANSIM 281-0063) to determine AWE-BC. The supporting Statistics Canada tables are provided in Appendix A1. The latest available month of May 2020 has been used as a placeholder for June 2020 for AWE-BC, as results for this period have not been released by Statistics Canada. Once results for this period are available, this placeholder will be replaced with actuals and included in an Evidentiary Update or Compliance Filing.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing actual CPI-BC and AWE-BC data. Applying the actual 2019 labour weighting of 62 percent, the calculation of the 2020 I-Factor is (2.692 percent x 38 percent) + (2.881 percent x 62 percent) = 2.809 percent, and the calculation of the 2021 I-Factor is (1.596 percent x 38 percent) + (5.946 percent x 62 percent) = 4.293 percent.

[2] FBC's most recent year of completed actuals is 2019 so that ratio has been used for both the 2020 and 2021 I-Factor calculation. The 2022 I-Factor calculation will be based on 2020 actual non-labour / labour split.

[3] Forecast of average customers for Formula O&M, including a true-up to actual customers in the following years.

Table 2-1: I-Factor Calculation

Line No.	Date	*Table: 18-10-0004-01* BC CPI index	*Table: 14-10-0223-01* BC AWE $	12 Mth Average CPI index	12 Mth Average AWE $	CPI %	AWE %	Last Completed labour %	Last Completed Labour %	I-Factor %	MRP Year
1	Jul-2017	125.6	939.88								
2	Aug-2017	125.9	939.79								
3	Sep-2017	125.7	951.51								
4	Oct-2017	125.6	950.29								
5	Nov-2017	125.9	952.12								
6	Dec-2017	125.2	958.25								
7	Jan-2018	126.1	957.22								
8	Feb-2018	127.0	962.48								
9	Mar-2018	127.4	963.99								
10	Apr-2018	127.7	953.93								
11	May-2018	128.4	956.99								
12	Jun-2018	128.6	967.63	126.6	954.51						
13	Jul-2018	129.7	974.29								
14	Aug-2018	129.6	979.82								
15	Sep-2018	128.9	975.65								
16	Oct-2018	129.4	978.07								
17	Nov-2018	128.9	979.83								
18	Dec-2018	129.0	976.63								
19	Jan-2019	129.1	973.10								
20	Feb-2019	129.8	974.09								
21	Mar-2019	130.7	986.67								
22	Apr-2019	131.2	991.01								
23	May-2019	131.8	1,001.50								
24	Jun-2019	131.9	993.45	130.0	982.01	2.692%	2.881%	38%	62%	2.809%	2020
25	Jul-2019	132.4	996.11								
26	Aug-2019	132.2	1,003.60								
27	Sep-2019	132.0	1,008.09								
28	Oct-2019	132.2	1,015.74								
29	Nov-2019	131.8	1,012.40								
30	Dec-2019	131.7	1,014.52								
31	Jan-2020	132.1	1,025.61								
32	Feb-2020	132.9	1,025.17								
33	Mar-2020	132.3	1,029.38								
34	Apr-2020	131.2	1,106.54								
35	May-2020	131.5	1,123.79								
36	Jun-2020	132.6	1,123.79	132.1	1,040.40	1.596%	5.946%	38%	62%	4.293%	2021

2.3 *GROWTH FACTOR CALCULATION SUMMARY*

As noted above, the BCUC approved the use of a forecast of average customers with a 75 percent modifier to determine Formula O&M. The calculation of average customers used to determine Formula O&M is summarized in the table below.

Table 2-2: Average Customer (AC) Growth Factor Calculation[4]

Line No.	Description	2020	2021	Reference
1	Average Customer Forecast - Prior Year	139,916	141,189	
2	Average Customer Forecast - Test Year	141,189	142,754	Section 11, Schedule 18, Row 8
3	Average Customer Change	1,273	1,565	Line 2 - Line 1
4	Customer Growth Factor Multiplier	75%	75%	Order G-166-20
5	Change in Customers - Rate Setting Purposes	955	1,174	Line 3 x Line 4
6				
7	*Average Customer Continuity for Rate Setting Purposes*			
8	Average Customer Forecast - Prior Year	139,916	140,871	Prior Year Line 10
9	Change in Customers - Rate Setting Purposes	955	1,174	Line 5
10	Average Customer Forecast - Rate Setting Purposes	140,871	142,045	Line 8 + Line 9

2.4 *INFLATION AND GROWTH CALCULATION SUMMARY*

A summary of the factors used to determine Formula O&M for 2020 and 2021 is provided in Table 2-3, including the I-Factors calculated in Section 2.2, the approved X-Factor of 0.5 percent, and the forecast of customers incorporating the growth factor multiplier determined in Section 2.3.

Table 2-3: Summary of Formula Drivers

Line No.	Description	2020	2021	Reference
1	CPI	2.692%	1.596%	Table 2-1, Lines 24 and 36
2	AWE	2.881%	5.946%	Table 2-1, Lines 24 and 36
3				
4	Non Labour	38%	38%	Table 2-1, Lines 24 and 36
5	Labour	62%	62%	Table 2-1, Lines 24 and 36
6				
7	CPI/AWE Inflation	2.809%	4.293%	(Line 1 x Line 4) + (Line 2 x Line 5)
8				
9	Productivity Factor	-0.500%	-0.500%	Order G-166-20
10				
11	Net Inflation Factor	2.309%	3.793%	Line 7 + Line 9
12				
13	Average Customer Forecast for Formula O&M purposes	140,871	142,045	Table 2-2, Line 10

In summary, the Net Inflation Factors for 2020 and 2021 are 2.309 percent and 3.793 percent, respectively. Formula O&M for 2020 and 2021 is determined using average customers of 140,871 and 142,045, respectively.

[4] Line 1 for 2020 (Average Customer Forecast – Prior Year) is 2019's actual average customer count.

3. LOAD FORECAST AND REVENUE AT EXISTING RATES

3.1 *INTRODUCTION AND OVERVIEW*

This section describes FBC's forecast of gross system load. The gross system load is a combination of residential, commercial, wholesale, industrial, street lighting and irrigation loads, system losses and company use. The forecast of gross system load includes the impacts of forecast load savings which include Demand Side Management (DSM) savings. These savings are further explained in Section 3.3 – Demand Side Management Savings.

FBC is forecasting a decrease in consumption in the 2020 Projected (2020P) forecast (which includes actuals to June 30, 2020) compared to the 2019 Approved. The 2020P gross load[5] is projected to be approximately 3,562 GWh, which is a 40 GWh decrease compared to the 2019 Approved gross load. The decrease in 2020 is due to decreased loads in the residential, commercial, wholesale, lighting and irrigation classes, partially offset by an increase in industrial load. Based on the 2019 Approved rates for each customer class, FBC's 2020 Projected revenue forecast is $358.668 million.

FBC is forecasting an increase in consumption in the 2021 Forecast (2021F) compared to the 2020 Projected forecast. The 2021F normalized gross load is forecast to be approximately 3,646 GWh, which is an increase of 84 GWh compared to the 2020 Projected gross load. The increase in 2021F is primarily due to increased loads in the industrial, commercial and wholesale classes, partially offset by lower residential load. Based on the 2020 Approved Interim rates for each customer class, FBC's 2021 revenue forecast is $369.643 million.

FBC has provided further information supporting its demand forecast in Appendix A of the Application.

3.2 *OVERVIEW OF FORECAST METHODS*

Consistent with the forecasting method followed by FBC in previous years, the load forecast relies on the following components:

- the residential and commercial customer count forecast;
- the residential use per customer (UPC) forecast;
- the commercial, lighting and irrigation load forecast; and
- the industrial and wholesale survey forecast.

The load forecast for residential customers is based on forecasts for the number of customers and UPC rates. Specifically, the average UPC is estimated and is then multiplied by the

[5] For the 2020P load, FBC replaced the first six months of projected normalized load with actual load.

corresponding forecast of the number of customers to derive the residential load forecast. The commercial load forecast is based on a regression against the Conference Board of Canada (CBOC) Gross Domestic Product (GDP) forecast, while the lighting and irrigation forecasts use the prior year's actual loads. Wholesale and industrial forecasts are primarily based on customer-specific survey results.

More detail on FBC's forecasting methods can be found in Appendix A of this filing.

The following sections set out the results of the load forecast. In the figures provided in the load forecast sections, the following three time periods are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year. For this Annual Review the latest calendar year for which full actual data exists is the 2019 calendar year.
- Projected Year: The Projected Year (2020P) is the year prior to the first forecast year. The Projected Year is forecast based on the latest years of actual data available (through 2019). The January through June forecast values were then replaced with Actual 2020 values.
- Forecast Year: This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, the forecast year is 2021 (2021F).
- Also included in the figures in this section is the prior year's forecasts, 2019F as presented in the Annual Review for 2019 Rates.

FBC acquired the utility assets and customers of the City of Kelowna's electric utility effective March 31, 2013, resulting in an increase in direct customers and changes in the composition of customers and sales load by class, which are reflected in the data and figures in this section.

3.3 *DEMAND SIDE MANAGEMENT SAVINGS*

FBC forecasts the DSM savings that are incremental to the DSM savings that are already embedded in historical loads up to and including 2019.

The DSM savings forecast is deducted from the before-savings forecast for all customer classes. All forecast values in the sections below are shown after being reduced by DSM savings unless explicitly stated otherwise.

The forecast DSM savings for 2021F are summarized in Table 3-1 below. The incremental forecasts for 2020 and 2021 shown in Table 3-1 are the forecast saving incremental to the savings embedded in the historical loads. Historical DSM savings can be found in Appendix A2.

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)

3.4 *LOAD FORECAST*

FBC's total load consists of the weather normalized[7] residential, commercial and wholesale load and the industrial, lighting and irrigation load. As shown in Figure 3-1 below, the total load, net of losses, is projected to be 3,273 GWh in 2020, a decrease of 46 GWh from 2019 Approved, and is forecast to be 3,355 GWh in 2021F, an increase of 82 GWh from 2020P.

[6] Both 2020 and 2021 columns are as compared to the embedded 2019 actual savings.

[7] Note that per the definition of the Projected Year in Section 3.2 above, January through June 2020 use actual (non-normalized) values.

Figure 3-1: Total Net Load (GWh)

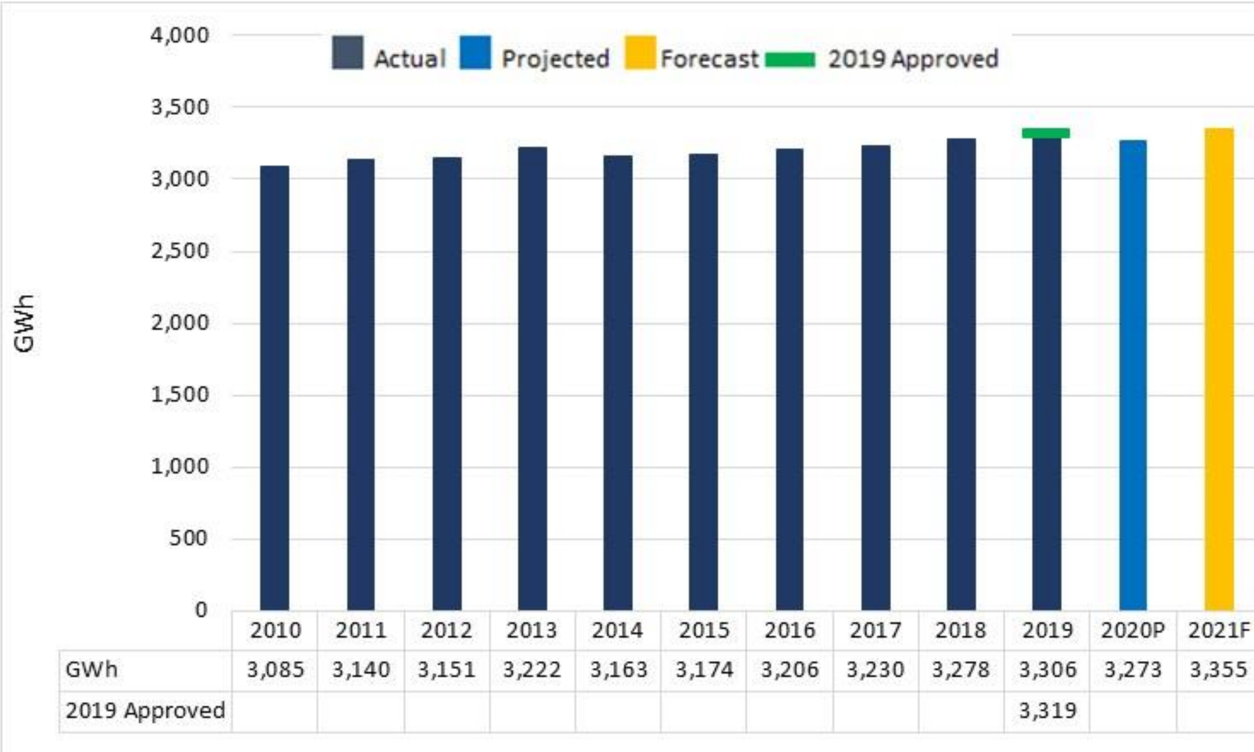


Table 3-2 below shows the normalized after-savings gross load by customer class as well as the system peak. For 2021F, the residential customer class is forecast to account for 34 percent of the normalized after-savings gross load.

Table 3-2: Normalized After-Savings Gross Load and System Peak

Line No.	Description	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
	Energy (GWh)												
1	Residential	1,242	1,249	1,229	1,353	1,296	1,298	1,296	1,320	1,313	1,266	1,289	1,252
2	Commercial	660	657	681	788	863	853	905	915	926	932	899	937
3	Wholesale	895	910	899	675	567	580	574	574	585	566	573	584
4	Industrial	234	271	291	352	381	380	373	363	403	495	464	537
5	Lighting	14	13	13	13	16	16	16	16	13	11	10	10
6	Irrigation	40	40	38	40	40	46	42	42	39	36	37	36
7	Net Load	3,085	3,140	3,151	3,222	3,163	3,174	3,206	3,230	3,278	3,306	3,273	3,355
8	Losses & Company Use	284	307	271	278	270	272	274	282	285	287	289	292
9	Gross Load	3,369	3,447	3,422	3,500	3,433	3,446	3,480	3,512	3,564	3,592	3,562	3,646
10													
11	System Peak (MW)												
12	Winter Peak	726	702	723	698	693	685	755	714	682	732	737	748
13	Summer Peak	566	537	589	600	620	611	593	605	631	639	609	627

The residential, commercial, wholesale, industrial, lighting and irrigation load forecasts are provided separately in the following subsections.

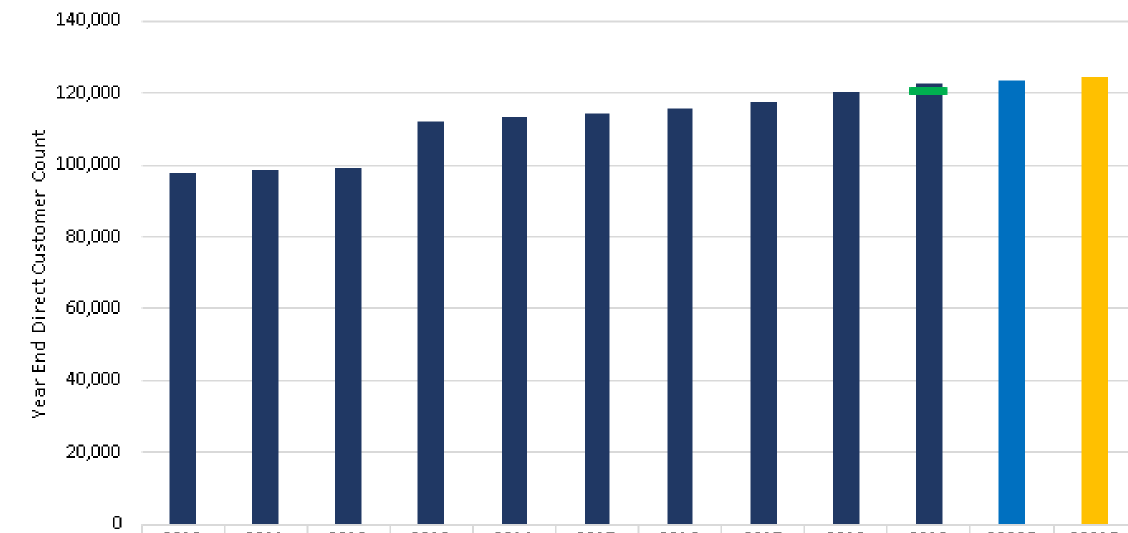
3.4.1 Residential

3.4.1.1 Residential Customers

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

Figure 3-2 shows the year-end residential customer count for FBC.

Figure 3-2: Year-End Direct Residential Customer Count



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Customers	97,883	98,795	99,228	111,862	113,431	114,166	115,772	117,748	120,291	122,465	123,407	124,603
2019 Approved										120,405		

3.4.1.2 Residential UPC

Normalized historical UPCs are obtained by dividing the weather-normalized residential load by the average customer count in each year. The before-savings UPC is forecast by applying a ten-year trend to the normalized historical UPCs. For 2020P, the first six months of the forecast were replaced by actual values. The before-savings UPC forecast is then multiplied by the forecast average customer count to derive the before-savings load forecast. DSM savings, which are incremental to the savings embedded in the historical data to 2019, are then deducted from the before-savings load forecast to determine the after-savings load forecast. The after-savings UPC forecast is then calculated by dividing the after-savings load forecast by the average customer count. As shown in Figure 3-3 below, the residential after-savings UPC is projected to remain close to 2019 Actual levels in 2020P and is forecast to decrease by 0.39 MWh during 2021F.

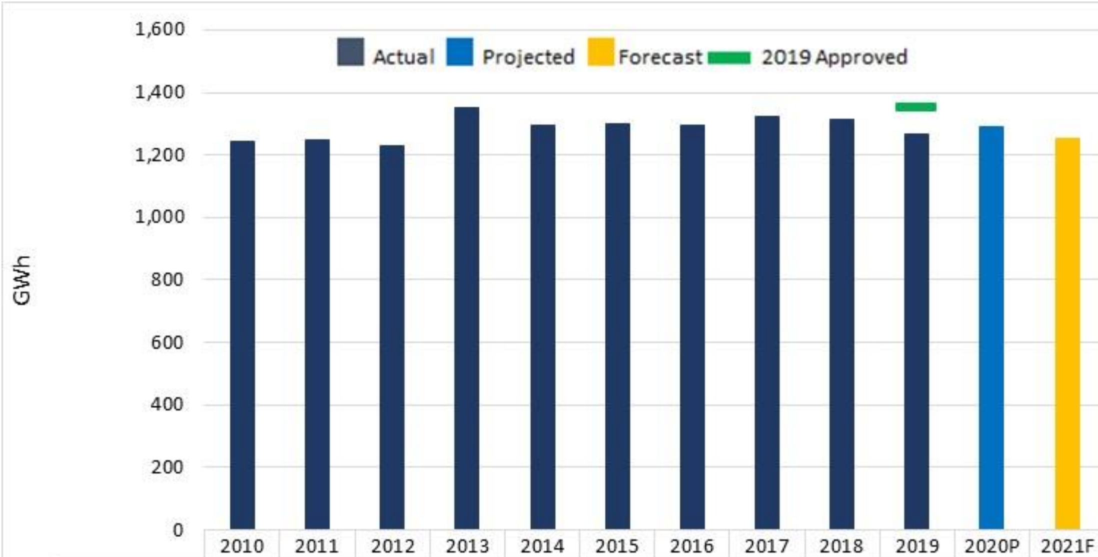
Figure 3-3: Normalized After-Savings Residential UPC (MWh)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
MWh	12.77	12.70	12.41	12.48	11.51	11.41	11.27	11.31	11.03	10.43	10.49	10.10
2019 Approved										11.27		

3.4.1.3 Residential Load

Consistent with past practice, the total before-savings load for the residential class is the product of the average annual residential customer count multiplied by the residential UPC. The after-savings load is produced by taking the before-savings load and then subtracting DSM savings. As shown in Figure 3-4 below, residential after-DSM savings load is forecast to increase by 23 GWh in 2020P from 2019 Actual levels and decrease by 37 GWh in 2021F from 2020P levels.

Figure 3-4: Normalized After-Savings Residential Load (GWh)



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
GWh	1,242	1,249	1,229	1,353	1,296	1,298	1,296	1,320	1,313	1,266	1,289	1,252
2019 Approved										1,349		

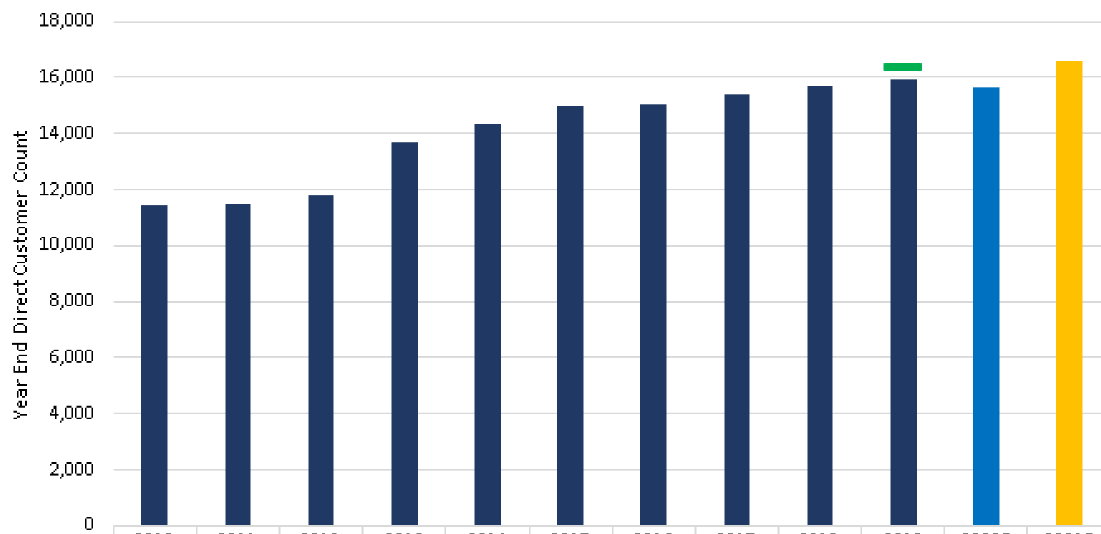
3.4.2 Commercial

3.4.2.1 Commercial Customers

The forecast commercial customer count is determined by a regression of the year-end customer accounts on the provincial GDP forecast from the CBOC, which is included in Appendix A1.

Figure 3-5 shows the year-end commercial customer count for FBC.

Figure 3-5: Year-End Direct Commercial Customer Count



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Customers	11,419	11,525	11,811	13,662	14,363	14,976	15,073	15,398	15,678	15,956	15,639	16,579
2019 Approved										16,405		

3.4.2.2 Commercial Load

The commercial class is forecast based on a regression of load on the provincial GDP forecast obtained from the CBOC. As shown in Figure 3-6 below, Commercial after-savings load is forecast to decrease by 33 GWh in 2020P from 2019 Actuals and increase by 38 GWh in 2021F from 2020P. The 2020P and 2021F fluctuations are due to a GDP projection from the CBOC that includes COVID-19 impacts and the projected economic recovery (-3.2 percent in 2020P and 6.3 percent in 2021F).

Figure 3-6: After-Savings Commercial Load (GWh)

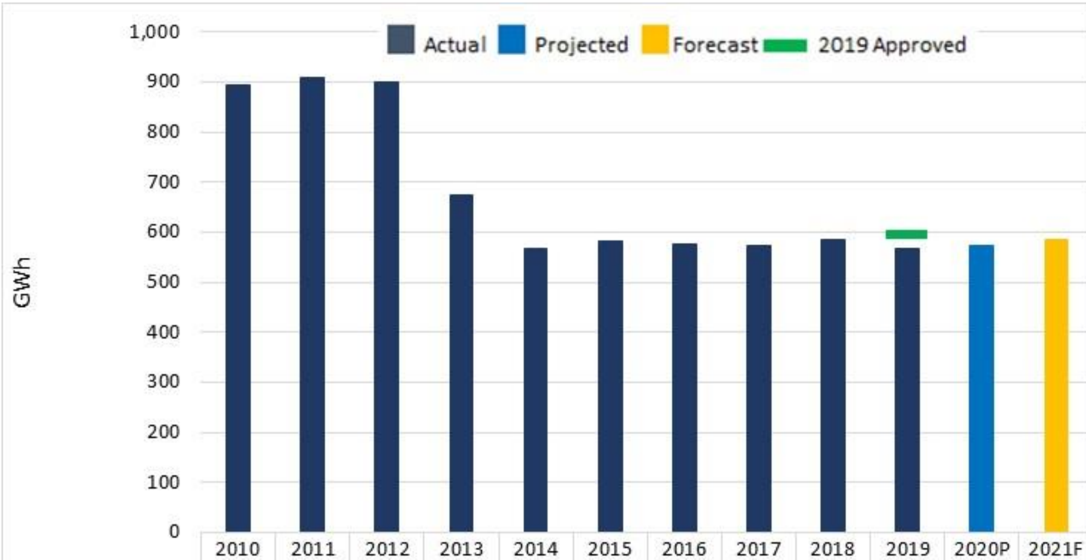
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
GWh	660	657	681	788	863	853	905	915	926	932	899	937
2019 Approved										935		

3.4.3 Wholesale

FBC sells wholesale power to municipalities for service to certain customers within its service territory that own and operate their own electrical distribution systems, and to BC Hydro. The wholesale customers' load composition is a combination of residential, commercial, industrial and street lighting.

Consistent with past practice, the wholesale class is forecast using survey information from each of the individual wholesale customers. FBC believes that the individual wholesale customers are best able to forecast their future load growth. All of the wholesale customers responded with their load forecast projections. As shown in Figure 3-7 below, after-savings wholesale load is forecast to increase by 7 GWh in 2020P and 11 GWh in 2021F.

Figure 3-7: Normalized After-Savings Wholesale Load (GWh)



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
GWh	895	910	899	675	567	580	574	574	585	566	573	584
2019 Approved										594		

3.4.4 Industrial

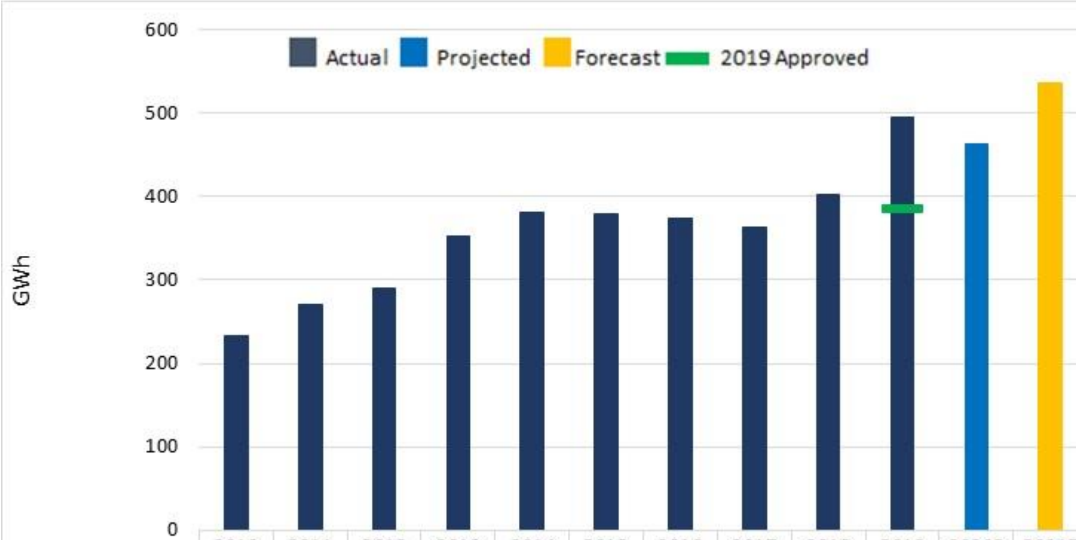
Consistent with past practice, the industrial forecast is determined through a combination of customer load surveys and, when not available, escalation of the most recent annual loads by the corresponding provincial GDP growth rates for individual industries.

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.

FBC forecasts industrial loads from new customers in 2020P and 2021F based on information from Key Account Managers.

As shown in Figure 3-8 below, after-savings industrial load is forecast to decrease by 31 GWh in 2020P when compared to 2019 Actual. Industrial load is forecast to increase by 73 GWh in 2021F compared to 2020P. This increase is mostly due to the addition of new customers and the expansions of existing customer loads in the FBC system.

Figure 3-8: After-Savings Industrial Load (GWh)

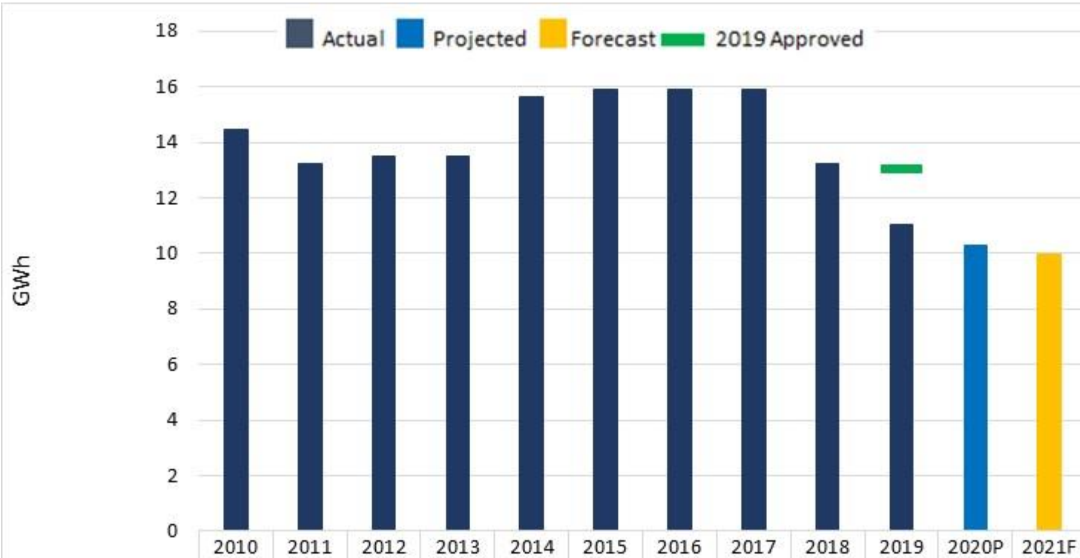


	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
GWh	234	271	291	352	381	380	373	363	403	495	464	537
2019 Approved										385		

3.4.5 Lighting

Due to the implementation of LED street lights, the lighting load has seen declines for the past two years. FBC used the 2019 Actuals as the forecast for this load and then reduced it by DSM savings. As shown in Figure 3-9 below, after-savings lighting load is forecast to decrease by 1 GWh in 2020P and then remain flat in 2021F. The lighting customer count forecast uses a five-year regression analysis.

Figure 3-9: After-Savings Lighting Load (GWh)

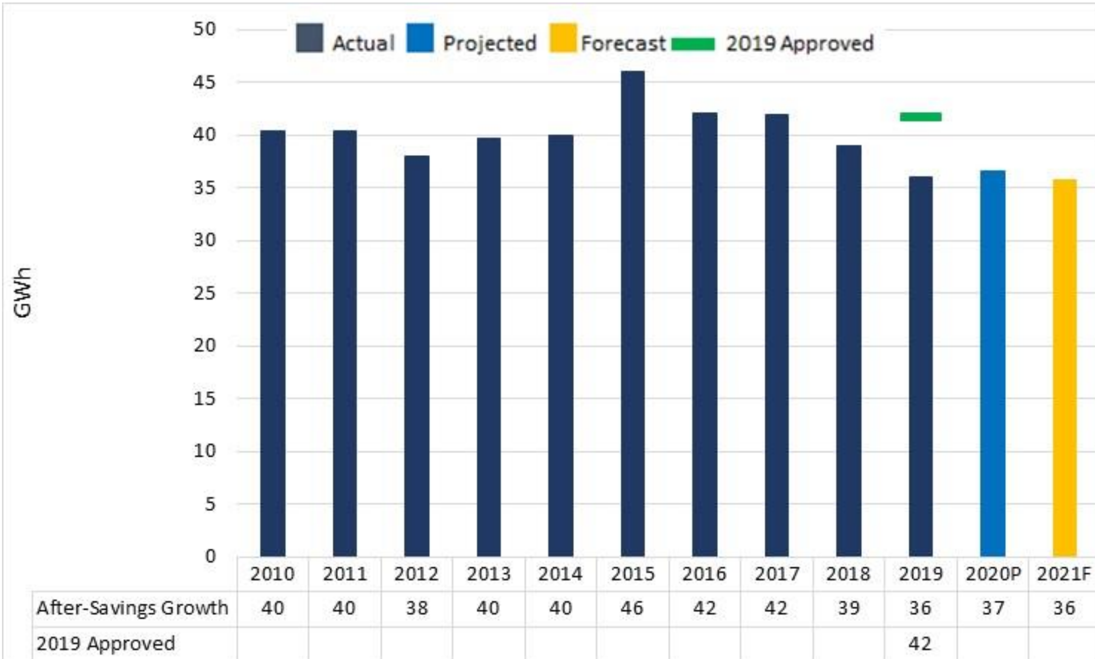


	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
GWh	14	13	13	13	16	16	16	16	13	11	10	10
2019 Approved										13		

3.4.6 Irrigation

Due to the variability in the load in the recent historical data, FBC has used the 2019 Actuals as the forecast for the Irrigation load. As shown in Figure 3-10 below, after-savings irrigation load is forecast to increase by 1 GWh in 2020P when compared to 2019 Actual as a result of higher use in the first half of 2020 and then return to 2019 levels in 2021F. The increase in 2020P compared to 2019 is due to the inclusion of 2020 January through June actual loads in the 2020P projection.

Figure 3-10: After-Savings Irrigation Load (GWh)



3.4.7 Losses and Company Use

FBC conducted a Losses Study in 2019[8] and, consistent with that study, has assumed a loss rate of 7.6 percent of gross load excluding company use. System losses consist of:

- Losses in the transmission and distribution system;
- Losses due to wheeling through the BC Hydro system; and
- Unaccounted-for load (meter inaccuracies and theft).

As shown in Figure 3-11 below, after-savings load losses are forecast to increase by 2 GWh in 2020P and increase by 3 GWh in 2021F. FBC has separated company use in the graph below, which is forecast at 13 GWh per year in each of 2020P and 2021F.

[8] MRP Application, Exhibit B-1-1, Appendix B3.

Figure 3-11: Normalized After-Savings Load Losses (GWh)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Losses	273	295	259	267	259	261	262	269	272	274	276	279
Company Use	11	12	12	11	11	11	12	13	13	12	13	13
2019 Approved										283		

3.4.8 Peak Demand

The peak demand forecast is produced using the ten-year average of historical peaks. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system.

Normalized after-savings historical winter and summer peaks are shown below along with 2020P and 2021F. The peaks shown below are seasonal, where the winter peak can fall in either November or December of the current year or January and February of the following year, while the summer peak falls in June, July or August of the current year.

Figure 3-12: After-Savings Winter Peaks (MW)

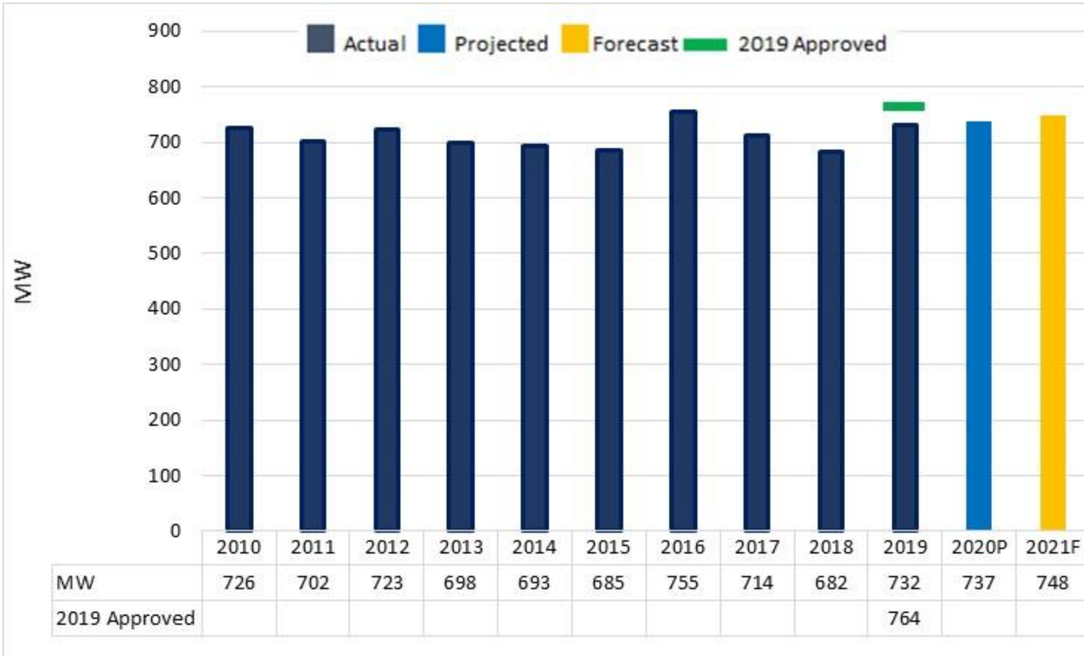
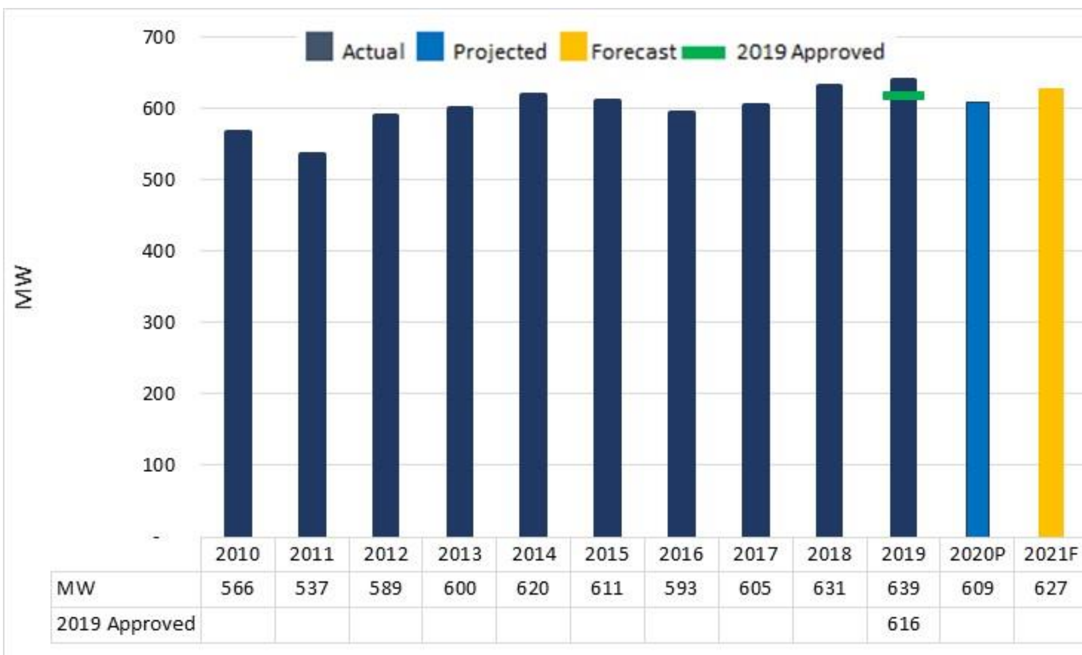


Figure 3-13: After-Savings Summer Peaks (MW)



3.5 *CUSTOMER FORECAST*

Table 3-3 shows the actual and forecast year-end customer count by rate class. The residential, commercial, and lighting customer counts are forecast using the methods described in Sections 3.4.1, 3.4.2 and 3.4.5, respectively. Industrial customers are forecast based on information on expected new loads provided by key account managers. Wholesale and Irrigation customer counts are assumed to remain at 2019 levels.

Overall, FBC is forecasting customer growth of 0.4 percent in 2020P compared to 2019 actual customers and 1.5 percent in 2021F compared to 2020P.

Table 3-3: Year-End Direct Customer Count

Description	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Residential	97,883	98,795	99,228	111,862	113,431	114,166	115,772	117,748	120,291	122,465	123,407	124,603
Commercial	11,419	11,525	11,811	13,662	14,363	14,976	15,073	15,398	15,678	15,956	15,639	16,579
Wholesale	7	7	7	6	6	6	6	6	6	6	6	6
Industrial	35	36	39	47	49	50	50	50	52	51	57	59
Lighting	1,830	1,803	1,739	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,425	1,393
Irrigation	1,075	1,092	1,091	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,082	1,082
Total	112,249	113,258	113,915	128,318	130,572	131,883	133,550	135,793	138,587	141,027	141,616	143,722

3.6 *REVENUE FORECAST*

The forecast of revenues has been developed by applying approved 2020 rates to the forecast billing determinants for each customer class.

Table 3-4 below summarizes the 2019 Approved, 2019 Actual, 2020 Projected and 2021 Forecast sales revenue.

Table 3-4: Forecast Sales Revenue at Approved Rates ($ millions)

		at 2019 Approved Rates			at 2020 Interim Rate
Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Residential	$ 187.887	$ 179.509	$ 178.565	$ 176.095
2	Commercial	94.508	94.065	89.191	95.850
3	Wholesale	49.519	48.962	47.938	49.466
4	Industrial	32.414	39.756	37.589	42.905
5	Lighting	2.661	2.316	2.219	2.167
6	Irrigation	3.554	3.042	3.166	3.160
7	Total	$ 370.543	$ 367.649	$ 358.668	$ 369.643

3.7 *SUMMARY*

The normalized after-savings gross load forecast for 2020P is 3,562 GWh. Based on net load of 3,273 GWh at the approved 2019 rates, FBC's 2020P revenue forecast is $358.668 million. The normalized after-savings gross load forecast for 2021F is 3,646 GWh. Based on net load of 3,355 GWh at the approved interim 2020 rates, FBC's 2021F revenue forecast is $369.643 million.

When comparing the 2019 Approved forecast to the 2020P, there is a decrease in gross load of 40 GWh. The decrease in 2020P is due to decreased loads in the residential, commercial, wholesale, irrigation and lighting classes.

When comparing the 2021F to the 2020P there is an increase in gross load of 84 GWh. The increase in 2021F is due to increased loads in the industrial, commercial and wholesale classes.

4. POWER SUPPLY

4.1 INTRODUCTION AND OVERVIEW

This section includes a review of the 2020 Projected compared to 2019 Approved and 2021 Forecast compared to 2020 Projected power purchase expense (PPE), wheeling expense and water fees. Collectively, the PPE, wheeling expense and water fees are referred to as the Power Supply cost.

As shown in Table 4-1 below, the 2020 Projected Power Supply cost of $155.347 million represents a $5.418 million or 3.4 percent decrease compared to the 2019 Approved cost of $160.765 million. The decrease in the 2020 Projected Power Supply cost is attributed to increased market savings as well as a decrease in gross load, both of which result in decreased purchases under the Company's power purchase agreement with BC Hydro. This decrease is slightly offset by increased rates for Waneta Expansion supply. The 2020 Projected wheeling expense is forecast to increase due to increased wheeling rates as well as increased use of the Open Access Transmission Tariff (OATT) and Teck 71 Line (71L) wheeling. 2020 Projected water fees have increased due to increased entitlement generation in 2019.

Also shown in Table 4-1, the 2021 Forecast Power Supply cost of $163.089 million represents an increase of $7.742 million or 5.0 percent compared to the 2020 Projected cost of $155.347 million. The increase in the 2021 Forecast Power Supply cost is mainly due to a gross load increase from 2020 Projected gross load, and therefore increased purchases under the Company's power purchase agreement with BC Hydro, as well as increased rates for BC Hydro and Waneta Expansion supply. The 2021 Forecast wheeling expense is forecast to increase due to increased wheeling rates. The 2021 Forecast water fees have increased due to increased rates.

Any variances between forecast and actual Power Supply costs are recorded in the Flow-through deferral account and returned to or recovered from customers in the subsequent year.

Table 4-1: Power Supply Cost ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Power Purchase Expense	$ 145.065	$ 139.002	$ 138.612	$ 146.260
2	Wheeling Expense	5.235	5.896	5.767	5.783
3	Water Fees	10.465	10.396	10.968	11.045
4	Total Power Supply Cost	$ 160.765	$ 155.294	$ 155.347	$ 163.089
5					
6	Gross Load (GWh)	3,602	3,618	3,562	3,646

4.2 SUMMARY OF POWER SUPPLY RESOURCES

FBC uses a combination of Company-owned generation entitlements, firm contracted supply and market purchases to meet its load requirements. The Company's firm resources consist of:

Canal Plant Agreement (CPA) Entitlements associated with the generation facilities owned by FBC. The costs associated with FBC-owned generation are not included in the power purchase estimates, except for the Balancing Pool adjustments, which account for year to year timing differences in the entitlement energy storage under the CPA;

The Brilliant Power Purchase Agreement (BPPA), a 125 MW contract (Order E-7-96), and an amendment to the BPPA which reflects the purchase of 20 MW of Brilliant Upgrade power (Letter L-57-00), and the 5 MW Brilliant Tailrace Capacity agreement (Order E-17-01);

A power purchase agreement (PPA) with BC Hydro (a 200 MW contract) under BC Hydro Rate Schedule 3808 (Order G-60-14);

The Waneta Expansion Capacity Purchase Agreement (WAX CAPA), which is a 40-year purchase agreement with the Waneta Expansion Limited Partnership for capacity entitlements under the CPA (Orders E-29-10 and E-15-12);

A number of small Independent Power Producer (IPP) contracts; and

A number of market purchase arrangements.

4.3 *PORTFOLIO OPTIMIZATION*

The primary objectives of FBC's power supply portfolio planning are to ensure that the Company has sufficient firm resources to meet expected load requirements, to ensure the availability of cost-effective reliable power for FBC's customers, to prudently manage exposure to the cost and availability of market power supplies, and to optimize the value of any surplus resources that are not needed to meet load requirements.

The Company currently has long-term, firm resources from which it can supply substantially all of its 2020 Projected and 2021 Forecast annual energy and capacity requirements. The nature of FBC's contracted resources, in particular the BC Hydro PPA, provides the Company some flexibility to participate in the market when conditions are favourable to mitigate the cost of holding those firm resources. Furthermore, although FBC's load requirements are forecast to grow over time, the amount of capacity provided under the WAX CAPA is currently greater than FBC's capacity requirements in most months, and FBC sells the surplus capacity to mitigate power purchase expense. FBC has contracted to release a 50 MW block of capacity purchased under the WAX CAPA to BC Hydro under the Residual Capacity Agreement (RCA), which was approved by the BCUC in Order G-161-14. The remaining surplus WAX CAPA will be sold to Powerex Corp. (Powerex) on a day-ahead basis, if and when it is not required to meet FBC load requirements. These sales are completed under the Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex, accepted pursuant to Order E-10-15, and amended in the First Amending Agreement dated April 20, 2019, accepted pursuant to Order E-19-19 dated October 24, 2019.

4.4 FBC 2020/21 ANNUAL ELECTRIC CONTRACTING PLAN

On March 31, 2020, FBC filed its 2020/21 Annual Electric Contracting Plan (AECP) with the BCUC. The purpose of the AECP is to outline FBC's plan to meet its peak demand requirements and annual energy requirements for the operating year commencing October 1, 2020 and ending September 30, 2021, and to facilitate FBC's annual energy nomination under the PPA. FBC is required to take or pay for 75 percent of the PPA Nomination, regardless of whether it schedules the energy. The difference between the PPA Nomination and the 75 percent minimum take provides flexibility to manage annual loads that are below forecast or to displace PPA purchases with lower cost market purchases. Therefore, real-time opportunities to displace PPA purchases are restricted to a maximum of 25 percent of the PPA nominated energy but depending on system conditions, could be more or less.[9] The AECP also outlines FBC's load and resource balance over the following four years, and FBC's plan for optimizing its portfolio over that period. FBC's forecast of PPE for the remainder of 2020 and for 2021 are based on the plan detailed in the 2020/21 AECP, which was accepted by the BCUC on May 19, 2020, by way of Letter L-28-20.[10]

The AECP identified FBC's intention to make its annual energy nomination under the PPA for the 2020/21 contract year equal to 779 GWh, less any firm market contracts that FBC could enter into, as described in section 5 of the 2020/21 AECP.

Before June 30, 2020, FBC entered into energy supply contracts (ESCs) with Powerex under the terms of the CEPSA, which provide FBC with 71 GWh of incremental market energy during the winter of 2020/21, and 168 GWh during the winter of 2021/22, all at a lower cost than if supplied under the PPA. The ESCs were submitted for BCUC approval on August 10, 2020 pursuant to Section 71 of the UCA. The ESCs and associated savings are included in the 2021 Forecast PPE. As a result of these contracts, and changes to the forecast gross load, the Company submitted a PPA nomination for the 2020/21 contract year of 674 GWh, as confirmed in a letter to the BCUC on June 25, 2020.

4.5 2020 PROJECTED POWER PURCHASE EXPENSE

As shown in Table 4-2 below, FBC's 2020 Projected gross load (after taking into account DSM and other customer savings) is projected to be 40 GWh below the 2019 Approved value, and 2020 PPE is projected to be $6.453 million less than 2019 Approved. The reduction in 2020 Projected power purchase expense is attributed to decreased purchases from the BC Hydro PPA due to decreased gross load and lower cost wholesale market purchases.

[9] For example, if loads were 50 GWh lower in a year than forecast, that must be adjusted for as part of the 25 percent PPA flexibility such that the amount of PPA energy that can be displaced by market purchases is also reduced by 50 GWh.

[10] The AECP was filed confidentially. The non-confidential Executive Summary is attached to Letter L-28-20.

Table 4-2: 2019 and 2020 Power Purchase Expense ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Difference
1	Brilliant	$ 41.865	$ 41.848	$ 41.505	$ (0.360)
2	BC Hydro PPA	52.174	40.740	42.088	(10.085)
3	Waneta Expansion	40.221	38.763	40.250	0.030
4	Market and Contracted Purchases	10.637	17.168	14.617	3.980
5	Sale of Surplus Power	-	(0.577)	-	-
6	Independent Power Producers	0.076	0.063	0.062	(0.014)
7	Self-Generators	0.093	0.059	0.110	0.017
8	CPA Balancing Pool	-	0.784	0.018	0.018
9	Special and Accounting Adjustments	-	0.154	(0.039)	(0.039)
10	Total	$ 145.065	$ 139.002	$ 138.612	$ (6.453)
11					
12	Gross Load (GWh)	3,602	3,618	3,562	(40)

4.6 *2021 FORECAST POWER PURCHASE EXPENSE*

As shown in Table 4-3 below, the 2021 Forecast PPE is approximately $7.648 million greater than the 2020 Projected. The forecast increase from $138.612 million in 2020 to $146.260 million in 2021 is mainly a result of an increase in gross load and correspondingly, a greater reliance on higher cost energy supplied by BC Hydro. Also contributing to the increase are reduced surplus sale expectations along with escalations to BC Hydro and Waneta Expansion contract rates.

Table 4-3 shows a comparison of the 2020 Projected and 2021 Forecast PPE. Reasons for significant variances from the 2020 Projected PPE are discussed below.

Table 4-3: 2020 Projected and 2021 Forecast Power Purchase Expense ($ millions)

Line No.	Description	Projected 2020	Forecast 2021	Difference
1	Brilliant	$ 41.505	$ 41.027	$ (0.478)
2	BC Hydro PPA	42.088	48.882	6.794
3	Waneta Expansion	40.250	41.462	1.212
4	Market and Contracted Purchases	14.617	14.751	0.134
5	Independent Power Producers	0.062	0.076	0.014
6	Self-Generators	0.110	0.061	(0.049)
7	CPA Balancing Pool	0.018	(0.000)	(0.018)
8	Special and Accounting Adjustments	(0.039)	-	0.039
9	Total	$ 138.612	$ 146.260	$ 7.648
10				
11	Gross Load (GWh)	3,562	3,646	85

Brilliant

Brilliant expense is forecast to decrease in 2021 by $0.478 million compared to 2020 Projected due to decreased rates, which are based on a forecast of the operating and maintenance cost of the plant, as well as a true up to the prior year's actual costs compared to forecast.

BC Hydro PPA

BC Hydro PPA expense is forecast to increase in 2021 by $6.794 million compared to the 2020 Projected expense. The two drivers of the increase are a forecast BC Hydro rate increase of 2.7 percent on April 1, 2021,[11] which accounts for $1.030 million, and a higher purchased volume (97 GWh), which increases the expense by $7.764 million, for a total of $8.794 million. FBC has reduced its forecast of PPA expense by an additional $2.000 million in savings to account for potential real-time opportunities to displace PPA purchases with lower cost market purchases, resulting in a variance between 2020 Projected and 2021 Forecast of $6.794 million, as shown in Table 4-3. Actual market savings for the remainder of 2020 and 2021 may be higher or lower and will depend on system and market conditions at the time. Any variance, including these savings, is recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

Waneta Expansion

The $1.212 million increase in Waneta Expansion expense forecast for 2021 is due to the 2.1 percent annual fixed escalation of WAX CAPA rates, as well as a $0.111 million decrease in forecast surplus sales revenue under the RCA and CEPSA. Revenue under the CEPSA is linked to the amount of capacity FBC releases to Powerex and to the day-ahead market prices at the Mid-Columbia River (Mid-C) trading hub. The Mid-C is the largest electricity trading hub in the Pacific Northwest and is located on the US portion of the Columbia River. FBC's forecast of Mid-C forward market prices is based on contracts that have been traded and/or bids and offers from future contracts on the Intercontinental Exchange Inc. (ICE), which is a global exchange, clearing, financial data and technology company. The method used to forecast market prices is the same as in the Annual Review for 2019 Rates, but the method to calculate surplus sales has changed. As a result of the First Amending Agreement to the CEPSA, the price FBC is paid for capacity sales was modified and the forecasting method was updated accordingly. Overall, the forecast of market prices has a relatively small effect on the overall PPE. The forecast of surplus capacity sales revenue in 2021, which is included in line 3 of Table 4-3, is approximately $8.960 million.

Market and Contracted Purchases

The $0.134 million increase in Market and Contracted Purchases forecast for 2021 is due to increased rates for the volume purchased compared to 2020 Projected. Market and Contracted Purchases for 2020 Projected include both fixed price contracted purchases and real-time market purchases made using the 25 percent flexibility of the PPA. All of the market purchases included in the 2021 Forecast are based on fixed price contracts executed by the Company. As

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[11] BC Hydro F2020-F2021 Revenue Requirements Application proceeding, Exhibit B-45-20, February 25, 2019.

discussed above in the BC Hydro PPA variance explanation, there may be opportunities for additional real-time market purchases using the flexibility of the PPA purchases.

4.7 WHEELING EXPENSE

Wheeling expense includes wheeling service provided by BC Hydro under the Amended and Restated Wheeling Agreement (ARWA) and OATT as needed to supply the Company's loads in the Okanagan, Creston and Princeton. Also included are charges paid to Teck Metals Ltd. (Teck) for the use of its 71 Line. Rates under the ARWA are specified in BC Hydro's Rate Schedule 3817.

Wheeling expense is forecast using the same method as in the Annual Review for 2019 Rates. Table 4-4 below shows FBC's Wheeling Expense for 2019 to 2021. ARWA costs account for the majority of FBC's wheeling expense for 2019 through 2021, with OATT and Teck 71L wheeling costs falling into the Other category.

Table 4-4: Wheeling Expense ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Wheeling Nomination (MW Months)				
2	Okanagan Point of Interconnection	2,400	2,400	2,400	2,400
3	Creston	471	471	438	420
4					
5	Wheeling Expense				
6	Okanagan Point of Interconnection	$ 4.514	$ 4.524	$ 4.633	$ 4.694
7	Creston	0.577	0.603	0.551	0.535
8	Other	0.144	0.769	0.583	0.555
9	Total Wheeling Expense	$ 5.235	$ 5.896	$ 5.767	$ 5.783

Total 2020 Projected wheeling expense is $0.532 million greater than 2019 Approved. The 2020 Projected ARWA costs are $5.184 million, a $0.093 million increase when compared to 2019 Approved, which is a result of higher rates. 2020 Projected Teck and OATT wheeling costs are $0.583 million, which is $0.439 greater than 2019 Approved. This is mainly due to increased use of both Teck and OATT wheeling.

2021 wheeling expense is forecast to increase by $0.016 million over 2020 Projected. This is a result of increased ARWA rates on October 1 of both 2020 and 2021, which are based on forecast BC-CPI, as well as increases to the Teck wheeling rate as a result of a letter agreement made between Teck and FBC.

4.8 TRANSMISSION SERVICE LOSS RECOVERIES

Transmission service customers taking service under FBC's Rate Schedules 100 and 101 currently physically deliver energy to FBC to compensate for the losses that are incurred on FBC's system as a result of wheeled energy. FBC includes transmission wheeling losses in its load forecast and also includes loss recovery as a firm resource. Because the recoveries are delivered physically, there is no associated cost or revenue. Table 4-5 shows the 2020 Projected and 2021 Forecast loss recoveries.

Table 4-5: Transmission Service Loss Recoveries (GWh)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Loss Recoveries	-	15	13	14

4.9 WATER FEES

Water fees are calculated using FBC's entitlement usage in the previous year and water power rental rates as published in the British Columbia Gazette. FBC's entitlement usage is a function of total entitlement available, storage use, and generation outages. Current year water power rental rates are derived by escalating the previous year's water power rental rates by BC-CPI. In order to forecast water fee expense, FBC forecasts its entitlement use in the previous year, and then applies its forecast of the BC-CPI to current water rental rates. This is the same method as used in the Annual Review for 2019 Rates.

As shown in Table 4-6 below, 2020 Projected water fee expense is $10.968 million, which is $0.503 million greater than the 2019 Approved cost of $10.465 million. This is a result of increased entitlement use and increased rates.

Additionally, the 2021 Forecast water fees represents an increase of $0.077 million over 2020 Projected due to increased rates.

Table 4-6 below shows FBC's Water Fees for 2019 to 2021.

Table 4-6: Water Fees ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Plant Entitlement in Previous Year (GWh)	1,574	1,575	1,604	1,585
2					
3	Water Fees	$ 10.465	$ 10.396	$ 10.968	$ 11.045

4.10 SUMMARY

FBC's forecast of power purchase expense is based on FBC's firm resources in place at the time of filing and is consistent with the 2020/21 AECP. Any variances in the costs of power supply, including any decreases in power purchase expense due to further portfolio optimization, are recorded in the Flow-through deferral account and returned to or recovered from customers in a subsequent year.

5. OTHER REVENUE

5.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of Other Revenue. In the MRP Decision (page 74), FBC was approved for variances between forecast and actual Other Revenue to be subject to earnings sharing.

FBC is projecting Other Revenue for 2020 to be $1.377 million higher than the amount approved for 2019. The main drivers of this increase are higher Apparatus and Facilities Rental due to a new pole attachment contract, and higher Contract Revenue due to a three-year asset refurbishment project for a third party. These increases are partially offset by lower Late Payment Charges as a result of customer relief measures implemented by FBC during the COVID-19 pandemic.

Other Revenue for 2021 is forecast to be $1.576 million higher than 2020 Projected due to higher Contract Revenue resulting from the timing of work expected to be performed on the asset refurbishment project for a third party, as well as a return to normal forecast of Late Payment Charges.

Table 5-1: Other Revenue ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Apparatus and Facilities Rental	$ 4.878	$ 5.915	$ 5.843	$ 5.930
2	Contract Revenue	1.766	2.076	2.305	3.088
3	Transmission Access Revenue	1.230	1.054	1.496	1.501
4	Interest Income	0.016	0.005	0.020	0.020
5	Late Payment Charges	0.861	0.929	0.205	0.829
6	Connection Charges	0.376	0.524	0.394	0.476
7	Other Recoveries	0.142	0.124	0.382	0.377
8	Total	$ 9.268	$ 10.627	$ 10.645	$ 12.221

In the following sections, FBC summarizes its projections and forecasts for each of the line items included in the table above.

5.2 APPARATUS AND FACILITIES RENTAL

Apparatus and Facilities Rental is comprised primarily of pole contact revenue from other utilities and businesses that attach their facilities to FBC infrastructure in order to deliver services to their customers, such as telephone and cable television providers. Rent is charged at a unit rate per pole contact multiplied by the number of poles that are contacted. The 2020 Projected 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.

5.3 *CONTRACT REVENUE*

FBC performs work under contract to third parties at the Waneta and Brilliant hydroelectric generating facilities. This third party work, and the associated management fees earned, fluctuate from year to year based on customer requirements, which include routine and non-routine work planned at the start of the customer's fiscal year.

The Company also operates and maintains a number of other facilities for third party entities through its non-regulated affiliate FortisBC Pacific Holdings Inc. (FPHI). Transactions between FBC and FPHI are conducted in accordance with FBC's Code of Conduct and Transfer Pricing Policy[12] and earn a transfer price profit revenue. Revenues may fluctuate from year to year depending on customer requirements.

The 2020 Projected and 2021 Forecast 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.

5.4 *TRANSMISSION ACCESS REVENUE*

Transmission Access Revenue represents charges to customers for transmitting power over the FBC system. 2020 Projected and 2021 Forecast revenues are higher than 2019 Approved due to the phased increase in rates beginning January 1, 2020, as approved by Order G-40-19.

5.5 *INTEREST INCOME*

Interest Income is primarily comprised of DSM loan interest income, as well as other banking interest income. The Company is not forecasting significant changes in the amount of DSM loans. As a result, no significant changes in Interest Income are expected in 2020 Projected or in the 2021 Forecast.

5.6 *LATE PAYMENT CHARGES*

FBC implemented a number of customer relief measures in 2020 due to the COVID-19 pandemic, including the suspension of Late Payment Charges. As a result, 2020 Projected Late Payment Charges are expected to be lower than 2019 Approved. In 2021, FBC expects the amount of Late Payment Charges to return to a more normal level.

[12] As approved by Order G-5-10A.

The 2021 Forecast for Late Payment Charges as part of Other Revenue is based on the 2017 to 2019 average of Late Payment Charges earned, while the calculation for 2020 Projected includes six months of actual results.

5.7 CONNECTION CHARGES

Connection Charges are calculated based on the fees specified in FBC's rate schedules applicable to new customer connections or current customer reconnections. The 2020 Projected and 2021 Forecast are expected to be higher than 2019 Approved due to customer growth and forecast customer reconnections.

5.8 OTHER RECOVERIES

Other Recoveries are primarily comprised of fees earned on the recovery of costs for miscellaneous services, such as street light maintenance charged to municipalities and, beginning in 2020, AMI radio-off meter read fees.[13] The 2020 Projected and 2021 Forecast are expected to be higher than 2019 Approved due to the inclusion of AMI radio-off meter read fees.

5.9 SUMMARY

FBC has forecast the Other Revenue components for 2020 and 2021 reflecting all applicable contracts and fixed revenues, and based on the Company's best knowledge of the factors that drive the variable components. Variances in Other Revenue affect ROE and are shared with customers through the earnings sharing mechanism.

[13] As approved by Order G-40-19.

6. O&M EXPENSE

6.1 INTRODUCTION AND OVERVIEW

Under the MRP, FBC's O&M expense is primarily determined by formula, with the addition of a number of items that are forecast outside the formula on an annual basis.

In the MRP Decision and Order G-166-20, the BCUC approved a Base 2019 O&M for FBC based on the adjusted actual 2018 O&M plus incremental O&M funding in certain areas.[14] As provided in the compliance filing to the MRP Decision, the resulting 2019 Base O&M for FBC is $57.630 million, which, divided by the 2019 Actual Average Customer count, results in a 2019 Base O&M per customer of $412.[15]

In 2020, the Formula O&M is $59.447 million, representing a 6.0 percent increase from the 2019 Formula O&M approved under the 2014-2019 PBR Plan and a 3.2 percent increase from the 2019 Base O&M. The increase of 6.0 percent is primarily the result of re-setting the Base O&M as part of the approved MRP as well as an increase resulting from the formula drivers. The increase of 3.2 percent from the 2019 Base O&M is entirely due to the formula drivers. For 2021, the Formula O&M is $62.073 million, representing a 4.4 percent increase from the 2020 Formula O&M, entirely due to the formula drivers.

O&M expenses forecast outside the formula for 2020 and 2021 are $2.448 million and $3.041 million, respectively.

Overall, there is an increase in Gross O&M Expense from 2019 Approved to 2020 Projected of 4.6 percent and an increase in Gross O&M Expense from 2020 Projected to 2021 Forecast of 5.2 percent.

The components of 2020 and 2021 O&M expense are shown in Table 6-1 below.

Table 6-1: O&M Expense

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021	Reference
1	Formula O&M	$ 56.081	$ 55.516	$ 59.447	$ 62.073	Section 11, Schedule 20, Line 8/Line 10
2	Forecast O&M	3.120	3.003	2.448	3.041	Section 11, Schedule 20, Line 15/Line 16
3	Total Gross O&M	59.201	58.519	61.895	65.114	Line 1 + Line 2
4	Capitalized Overhead (15%)	(8.880)	(8.880)	(9.284)	(9.767)	Section 11, Schedule 20, Line 19/Line 20
5	Net O&M	$ 50.321	$ 49.638	$ 52.611	$ 55.347	Line 3 + Line 4

In the sections below, FBC provides further details on its formula and forecast O&M expenses for 2020 and 2021. Additionally, in compliance with the BCUC's directive in the MRP Decision,[16] FBC provides information related to its System Operations, Integrity and Security expenditures in Subsection 6.2.1.

[14] MRP Decision, pp. 107-118.
[15] MRP Decision Compliance Filing, p. 6.
[16] MRP Decision, p. 118.

6.2 FORMULA O&M EXPENSE

Base O&M starts from the prior year's Approved Base O&M per Customer (UCOM), escalated by the prior year's inflation less a productivity improvement factor of 0.5 percent, and 75 percent of the forecast growth in average customers. As calculated in Section 2, the 2020 and 2021 inflation based on prior year's BC-CPI and BC-AWE, less the productivity improvement factor, is 2.309 percent in 2020 and 3.793 percent in 2021.

For 2020, the annual operating and maintenance expense under the formula is calculated as:

> 2019 Approved Base UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)]

For 2021, the annual operating and maintenance expense under the formula is calculated as:

> 2020 Approved formula UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)]

FBC considers the impacts of capital expenditures on O&M expense and estimates O&M impacts explicitly for Major Projects.[17] In its application for a CPCN for the Grand Forks Terminal Station (GFT) Reliability Project, FBC identified net O&M savings of $0.085 million ($2018) arising from the retirement of approximately 44.6 kilometres of transmission line beginning in 2021. Accordingly, FBC has reduced its Base O&M in 2021 by the equivalent per customer amount.[18]

Table 6-2 below shows the calculation of the 2020 and 2021 Formula O&M.

Table 6-2: Calculation of 2020 and 2021 Formula O&M ($ thousands)

Line No.	Description	Projected 2020	Forecast 2021	Reference
1	Prior Year Base Unit Cost O&M ($/ customer)	$ 412	$ 422	G-166-20FBC MRP Decision
2	GFT Reliability Project O&M Reduction	-	(0.64)	
3	Adjusted Base Unit Cost O&M	$ 412	$ 421	Line 1 + Line 2
4	I-Factor	2.309%	3.793%	Section 2, Table 2-3, Line 11
5	Current Year Unit Cost O&M ($/customer)	$ 422	$ 437	Line 3 x (1 + Line 4)
6	Average Customer Forecast	140,871	142,045	Section 2, Table 2-3, Line 13
7	Inflation-Indexed O&M	$ 59,447	$ 62,073	Line 5 x Line 6 ÷ 1000

6.2.1 New/Incremental System Operations, Integrity and Security Funding

In the MRP Decision (page 118), the BCUC directed FBC to provide in each Annual Review a breakdown and explanation of both annual and cumulative variances between forecast/actual

[17] MRP Application, Exhibit B-9, response to MoveUP IR1 10.1.

[18] FBC calculated the 2021 per customer savings in the same manner as the Base O&M per customer cost. The $2018 value was escalated in accordance with the PBR escalation factor for 2019 and dividing by the average 2019 customer count ($85 thousand × 102.382% ÷ 139,916 = $0.62). The 2019 per customer cost was escalated using the net inflation factors for 2020 ($0.62 × 102.309% = $0.64). This value is subtracted from the 2020 Base O&M per customer prior to applying the customer growth factor for 2021.

and formula O&M related to the approved new/incremental System Operations, Integrity and Security funding, and quantify the variances attributable to the following areas: tree management; generation dam safety; network operations apprentice program; cyber security; data analytics; and any other significant factors or miscellaneous items.

The table below shows the requested information, including the new/incremental funding in each category in 2019 dollars, escalated by the annual formula factors to arrive at the Formula O&M amounts, and the forecast amounts for 2020.

Table 6-3: System Operations, Integrity and Security New/Incremental Spending

System Operations, Integrity and Security		2020 Formula O&M[1]	Forecast 2020 O&M	2020 Forecast/Actual Variance	Cumulative Forecast/Actual Variance[2]
		$ millions			
Tree Management	$ 0.075	$ 0.077	$ 0.077	$ -	$ -
Generation Dam Safety	$ 0.232	$ 0.237	$ 0.237	$ -	$ -
Network Operations Apprentice Program	$ 0.197	$ 0.202	$ 0.202	$ -	$ -
Cyber Security	$ 0.080	$ 0.082	$ 0.082	$ -	$ -
Data Analytics	$ 0.099	$ 0.101	$ 0.101	$ -	$ -
Other	$ -	$ -	$ -	$ -	$ -
Total	$ 0.683	$ 0.699	$ 0.699	$ -	$ -

Notes:
(1) 2020 Formula O&M is the incremental funding with Net Inflatiion factor applied (2.309%)
(2) Cumulative Forecast/Actual variance is the same as the 2020 (first year of MRP) Forecast/Actual variance.

At the time of preparing this Application, FBC has critical initiatives underway and is in the process of finalizing its plans to implement further activities. As shown in the table above, FBC is forecasting to spend all of the incremental funding approved. For 2020, given that the MRP Decision was issued part way through the year, there will likely be a variance between the actual expenditures in 2020 and the amounts calculated using the formula escalators. Over the term of the MRP, FBC anticipates that the total new/incremental spending in the combined categories of System Operations, Integrity and Security required will be relatively close to the cumulative approved formula amounts, although there will continue to be variations from year to year.

In the MRP Decision, the BCUC also directed FBC to describe how it is prioritizing its new/incremental funding approved for System Operations, Integrity and Security.

The categories of the new/incremental System Operations, Integrity and Security funding, as shown in Table 6-3 above, were developed based on the anticipated requirements over the term of the MRP, recognizing that priorities may change and that the expenditures may vary from year to year depending upon factors such as the availability of resources (i.e., labour vacancies) and the timing of activities. The common theme underlying the need for the new/incremental funding is to support the safe and reliable delivery of energy to customers. In prioritizing the new/incremental funding, FBC will consider factors such as regulation changes, code requirements, safety and security requirements, and customer requirements which may create a higher priority and urgency for certain expenditures compared to other expenditures. Similar to what other organizations may do, funds are reprioritized as required depending on the business environment, conditions, and requirements the Company is facing. In prioritizing new/incremental spending, the safety and reliability of the system will be paramount.

6.3 O&M EXPENSE FORECAST OUTSIDE THE FORMULA

In addition to FBC's Formula O&M, FBC forecasts a number of O&M items outside of the formula annually, including pension and OPEB expense, insurance premiums, BCUC levies, and the cost of service associated with Clean Growth Initiatives, such as Electric Vehicle (EV) charging stations, as well as the O&M impacts of any exogenous factor items. FBC has also included in 2020 a reduction to O&M due to the foregone annual inspection of the fourth Upper Bonnington generating unit undergoing refurbishment. The 2020 and 2021 amounts are shown in Table 6-4 below along with a comparison to 2019.

Table 6-4: Forecast O&M ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Pension/OPEB (O&M Portion)	$ 1.692	$ 1.692	$ 0.470	$ 0.775
2	Insurance Premiums	1.283	1.381	1.691	1.916
3	BCUC Levies	-	-	0.330	0.350
4	Upper Bonnington Old Unit Inspections	(0.042)	(0.042)	(0.043)	-
5	Clean Growth Initiative - EV Charging Stations	-	-	-	-
6	Included in 2020 Formula O&M[1]	0.187	(0.028)	-	-
7	Forecast O&M	$ 3.120	$ 3.003	$ 2.448	$ 3.041
8					
9	[1]AMI net savings, MRS incremental O&M, Employer Health Tax, MSP Premium Elimination				

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expenses are captured in the Pension and OPEB Variance deferral account and variances in BCUC levies are captured in the BCUC Levies Variance deferral account. Variances in insurance premiums, the cost of service associated with EV charging stations, and the O&M portion of exogenous factors are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expense for 2020 is based upon actuarial estimates using a range of assumptions as at December 31, 2019 provided by the Company's external third party actuary, Willis Towers Watson. The pension and OPEB expense for 2021 is similarly based on actuarial assumptions determined at December 31, 2019 but has been further updated to reflect the volatility in the assumptions around expected return on assets and discount rates that has occurred during the first half of 2020, in part due to the COVID-19 pandemic. Pension and OPEB expense is segregated into O&M and capital categories, as shown in Table 6-5.

Table 6-5: Pension and OPEB Expense ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	O&M	$ 1.692	$ 1.692	$ 0.470	$ 0.775
2	Capital (Approved)	3.612	3.612	3.807	3.575
3	Capital (to Pension & OPEB Variance Deferral)[1]	-	-	0.247	1.454
4	Total	$ 5.304	$ 5.304	$ 4.524	$ 5.804

Notes:

[1] This line item represents the pension and OPEB expense difference between the estimates embedded in the Capital forecasts on Line 2 in this table, which were based on the pension and OPEB actuarial estimates provided in 2019, and the actuarial estimates updated for 2020 and 2021 rate setting purposes.

2019 Actual pension and OPEB expense equals the 2019 Approved expense as any variances from the approved amount for setting 2019 rates are flowed through to the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by Order G-139-14.[19]

Projected 2020 pension and OPEB expense has decreased by $0.780 million compared to the 2019 Approved expense primarily due to the following factors:

- A $1.2 million reduction due to the full elimination of the Medical Services Premium (MSP) in 2020 as compared to 50 percent MSP in place for 2019;
- A $1.6 million reduction in net benefit cost in 2020 and beyond as a result of a pension plan amendment that occurred in 2019; and
- A $0.5 million reduction in the annual amortization associated with the 2005 CICA OPEB regulatory asset, as established pursuant to Order G-110-12, which was fully amortized as at the end of 2019;

offset in part by:

- An approximately $2.5 million increase in amortization of actuarial losses and increases in current service costs and interest costs due to a decline in discount rates. The discount rates, which are determined with reference to the market rate of interest on high quality debt instruments at a point in time, decreased from 3.5 percent, which was used to determine 2019 Approved expense, to 3.0 percent, which is used to determine the 2020 Projected expense.

The 2021 total pension and OPEB expense is forecast to be $1.280 million higher than the 2020 Projected expense primarily due to two factors. First, there is a forecast further decline in

[19] Total pension and OPEB expense for 2019 was $4.292 million; therefore, a credit of $1.012 million was recorded in the deferral account in 2019.

discount rates in mid-2020 due to the volatility in capital debt markets. Second, while there has been a recovery in the value of pension plan assets since the beginning of the pandemic in 2020, it is still expected that the estimated annual asset return for 2020 will remain lower than expected and this expectation has been incorporated into the determination of the 2021 pension and OPEB expense.

With respect to the discount rates used in determining pension expense, due to the timing of filing this Application, the rates have been impacted by the financial market impacts of COVID-19. FBC will monitor the rates for the remainder of the year, and file an Evidentiary Update to reflect any significant changes.

6.3.2 Insurance Premiums

The component of insurance expense tracked outside of Formula O&M relates to the insurance premium expense allocated to FBC by Fortis Inc. as set out in Table 6-6 below.

Table 6-6: Insurance Premiums ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Insurance Premiums	$ 1.283	$ 1.381	$ 1.691	$ 1.916
2	Total	$ 1.283	$ 1.381	$ 1.691	$ 1.916

The projected insurance premium expense for 2020 of $1.691 million, which incorporates FBC's July 2020 insurance renewals, is an increase of $0.408 million from what was approved for 2019. The higher premiums experienced in 2020 are expected to continue into 2021. The forecast insurance premium expense for 2021 is $1.916 million, an increase of $0.225 million from 2020. 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.[20] 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.

6.3.3 BCUC Levies

FBC's forecast for BCUC levies for 2020 and 2021 is based on two components: (i) the BCUC levy; and (ii) FBC's portion of funding for the BCUC hearing room facilities.[21]

The 2020 Projected BCUC levies for FBC is $0.330 million and includes the following:

[20] $1.734 million/2 = $0.867 million. $0.867 million x 1.05 = $0.910 million. $0.867 million + $0.910 million + $0.139 million annual firefighting premium = $1.916 million.

[21] Located at 12th floor, 1125 Howe Street, Vancouver, BC and managed/operated by Allwest Reporting Ltd.

- The projected BCUC levy of $0.293 million. This amount is comprised of the levy amount from Order G-138-19A1 for the BCUC's Fiscal 2019/20 year which is applied to FBC's first fiscal quarter of 2020 (January to March),[22] and the levy amount from Order G-134-20 for the BCUC's Fiscal 2020/21 year which is applied to FBC's remaining three quarters of 2020 (April to December); and
- An estimate of $0.037 million for FBC's portion of the funding for the BCUC hearing room facilities.

The 2021 Forecast BCUC levies for FBC is $0.350 million and includes the following:

- The forecast BCUC levy of $0.313 million based on Order G-134-20 for the BCUC's Fiscal 2020/21 year because this is the best information available at this time. FBC notes that the BCUC levy calculation for Fiscal 2021/22 will not be available until early in 2021; and
- An estimate of $0.037 million for FBC's portion of the funding for the BCUC hearing room facilities.

The MRP Decision approved flow-through treatment for BCUC levies with annual variances between forecast and actual amounts in O&M expense being recorded in the BCUC Levies Forecast Variance deferral account and amortized over one year.

6.3.4 Annual Inspection Costs for Upper Bonnington Old Units

The Upper Bonnington Old (UBO) Units Refurbishment project commenced in 2017. Refurbishment of UBO Units 3, 4, and 1 have been completed in previous years, and Unit 2 is being completed in 2020. The Company has not carried out annual inspections on the units while out of service for refurbishment, and FBC has reduced its O&M expenditures accordingly.

The O&M reduction related to the annual unit inspections is a one-time reduction to O&M expense in the year that a unit is refurbished. Each unit will once again undergo annual inspections following refurbishment. Therefore, the level of Base O&M expenditures is not impacted on an ongoing basis. For this reason, the O&M reduction is outside of Formula O&M. Because these are avoided costs, there will not be a future true-up of this value.

The cost reductions are based on the estimated cost in 2017 of $0.040 million, escalated in accordance with the PBR and MRP formula drivers. As the final unit will be completed in 2020, annual inspections of all units will take place in 2021, with no further reductions to O&M expense.

[22] Which is the BCUC's Fiscal 2019/20 fourth quarter.

6.3.5 Clean Growth Initiative – Electric Vehicle (EV) Charging Stations

The cost of service associated with EV charging stations is subject to flow-through treatment, contingent upon approval by the BCUC for inclusion of EV charging stations in rate base.[23] FBC's application for rates for EV charging stations was adjourned in 2018; however, on July 10, 2020 the BCUC issued Order G-183-20 re-starting the review process. Following BCUC approval, FBC will forecast the associated cost of service annually. At this time, FBC has not forecast any amounts for O&M or other cost of service items related to EVs, but will capture any amounts that are approved in the Flow-through deferral account and recover them from or return them to customers in future rates.

6.4 *NET O&M EXPENSE*

Net O&M expense is Gross O&M less capitalized overhead. As approved by the BCUC in Order G-166-20, the capitalized overhead rate is set at 15 percent for FBC, unchanged from 2019. After capitalized overhead, the net O&M expense is $52.611 million and $55.347 million in 2020 and 2021, respectively.

6.5 *SUMMARY*

Overall, the increase in Gross O&M Expense from 2019 Approved to 2020 Projected is 4.6 percent. The formula-driven O&M is increasing at a rate of 6.0 percent, and O&M forecast outside the formula is 21.5 percent lower than 2019 Approved.

For 2021, Gross O&M Expense is forecast to increase by 5.2 percent from 2020 Projected. Formula-driven O&M is increasing at a rate of 4.4 percent, and O&M forecast outside the formula is 24.2 percent higher than 2020 Projected.

The capitalized overhead rate for 2020 and 2021 remains unchanged from 2019.

[23] Costs related to EV charging stations are held outside of rate base pending BCUC approval, pursuant to Order G-9-18.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

Rate Base for FBC is forecast to be $1.412 billion for 2020 and $1.479 billion for 2021. Rate Base is comprised of mid-year net plant in service, work in progress not attracting AFUDC, unamortized deferred charges, working capital, and the generation plant acquisition adjustment.[24]

FBC's 2020 Rate Base includes the full-year impacts of the 2019 closing plant balances as well as the impact of the following amounts:

- Mid-year impact of capital additions, net of Contributions in Aid of Construction (CIAC) additions, resulting from regular capital expenditures of $85.874 million;
- Mid-year impact of plant depreciation, net of CIAC amortization, of $63.910 million;
- Full-year impact of $20.427 million for the Corra Linn Dam Spillway Gate Replacement Project and the Upper Bonnington (UBO) Old Units Refurbishment Project as discussed in Section 7.3 below;
- Full-year impact of the 2019 capital formula dead band adjustment of $8.827 million as shown in Row 30, Column 7 in Table 14-3 in Section 14.4.1; and
- Full-year impact of the 2014-2019 cumulative capital expenditures within the dead band of $17.088 million as shown in Row 33, Column 2 in Table 14-3 in Section 14.4.1.

FBC's 2021 Rate Base includes the full-year impacts of the 2020 closing projected plant balances as well as the impact of the following amounts:

- Mid-year impact of capital additions, net of CIAC additions, resulting from regular capital expenditures of $92.133 million;
- Mid-year impact of plant depreciation, net of CIAC amortization, of $71.554 million; and
- Full-year impact of $40.407 million for the Corra Linn Dam Spillway Gate Replacement Project, the UBO Old Units Refurbishment Project, and the Grand Forks Terminal Station Reliability Project, as discussed in Section 7.3 below.

In addition, various changes in deferred charges, working capital and other items increase rate base by a net amount of $41.544 million in 2020 and $47.974 million in 2021.

[24] The utility plant acquisition adjustment relates to the 1982 purchase of Plants 2, 3, and 4 and is being amortized over a period of 64 years.

Details of the 2020 and 2021 Forecast plant balances can be found in Section 11, Schedules 5 through 9.

7.2 REGULAR CAPITAL EXPENDITURES

As part of the MRP Decision and Order G-166-20, FBC received the following approvals for capital expenditures:

- Approval of FBC's forecasts submitted for regular capital expenditures for the years 2020 through 2023; and
- Approval of a number of items to be forecast on an annual basis.

The components of 2020 and 2021 regular capital expenditures are shown in Table 7-1 below.

Table 7-1: Regular Capital Expenditures ($millions)

Line No.	Description	Approved 2019	Actual 2019	Approved 2020	Forecast 2021	Reference
1	Approved Capex	$ 48.474	$ 61.485	$ 93.244	$ 87.572	Table 7.2 Line 4
2	Flow-Through Capex	4.159	3.010	-	-	Table 7.3 Line
3	Total Gross Regular Capex	$ 52.633	$ 64.495	$ 93.244	$ 87.572	Sum of Lines 1 & 2
4	Less CIAC	(8.876)	(9.315)	(11.107)	(11.465)	Section 11, Schedule 9, Line 13
5	Net Regular Capex	$ 43.757	$ 55.180	$ 82.137	$ 76.107	Sum of Lines 3 & 4

In the subsections below, FBC provides further details on its regular capital expenditures for 2020 and 2021.

7.2.1 Approved Capital Expenditures

The level of forecast capital expenditures approved for 2020 and 2021 by the MRP Decision is shown in Table 7-2 below.

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

7.2.2 Flow-Through Capital Expenditures

FBC is afforded flow-through treatment for certain capital items due to a variety of factors, including their uncontrollable nature, because they drive incremental revenues, because they are related to clean growth initiatives, or because of the uncertainty in scope, costs and timing. The amounts for 2020 and 2021 are shown in Table 7-3 below along with a comparison to 2019.

Table 7-3: Flow-Through Regular Capital Expenditures ($ million)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021	Reference
1	Clean Growth Intitiative - EV Charging Stations	-	$ -	$ -	$ -	
2	Included in 2020/2021 Approved Capital[1]	4.159	3.010	-	-	
3	Forecast Capital Expenditures	$ 4.159	$ 3.010	-	-	
4						
5	[1]AMI sustainment capital, MRS incremental capital, Employer Health Tax, MSP Premium Elimination					

EV Charging Stations

As identified in Section 6.3, as a Clean Growth Initiative, EV charging stations expenditures are subject to flow-through treatment, contingent upon approval by the BCUC for inclusion of EV charging stations in rate base. At this time, FBC has not included its forecast capital expenditures related to EVs as the BCUC directed FBC in Order G-9-18 to exclude its EV assets from rate base. However, EV charging stations are now a prescribed undertaking under the *Greenhouse Gas Reduction (Clean Energy) Regulation* (GGRR)[25] and the BCUC has recommenced a proceeding to consider FBC's Application for Approval of Rate Design and Rates for Electric Vehicle Direct Current Fast Charging Service. Upon BCUC approval, FBC will transfer its existing EV charging stations to rate base and commence forecasting expenditures on EV charging stations in future annual reviews.

Items Included in 2020/2021 Forecast Capital

As indicated in Table 7-3 above, certain items, including AMI sustainment capital, MRS incremental capital, and the capital components of Employer Health Tax and MSP Premium Elimination were included as flow-through capital expenditures in 2019. Going forward as part of the MRP, these items have been included in the approved forecasts for regular capital expenditures and therefore the amounts for 2020 and 2021 are reflected in the applicable line items in Table 7-2.

7.3 MAJOR PROJECTS CAPITAL EXPENDITURES

Major Projects are capital expenditures that do not form part of regular capital spending as they are approved through a separate CPCN or other application. As part of the MRP Decision,[26] the BCUC approved the continuation of the current process of reviewing Major Projects outside of the proposed MRP and approved the continuation of the existing financial threshold for CPCNs of $20 million for FBC for the MRP term.

[25] The GGRR was amended on June 22, 2020 by Order in Council 339.
[26] MRP Decision, pp. 132-133.

For 2020 and 2021, FBC is forecasting capital expenditures related to the following approved projects: Corra Linn Dam Spillway Gate Replacement Project, the Grand Forks Terminal Station (GFT) Reliability Project, and the UBO Refurbishment Project.

Each of these approved projects is described further below.[27]

- The Corra Linn Dam Spillway Gate Replacement Project was approved by Order C-1-17 and involves the replacement of 14 spillway gates and upgrades to the associated infrastructure. The project is expected to be completed in 2022 at a cost of $74.405 million, inclusive of AFUDC and cost of removal, with $20.456 million of this amount incurred in 2020 and $12.072 million incurred in 2021. Expenditures are added to plant in service as the gate replacements are completed. Additions to plant are $11.840 million and $23.629 million in 2020 and 2021, respectively.

- The GFT Station Reliability Project was approved by Order C-2-19. It involves the installation of a second transformer at GFT and the removal of 44.6 km of transmission line between Christina Lake and Rossland. The project is estimated at $13.171 million, inclusive of AFUDC and cost of removal, of which $4.411 million will be incurred in 2020 and $7.648 million incurred in 2021. $8.686 million will be added to plant in service in 2021.

- The UBO Project was approved by Order G-8-17 and involves the refurbishment of the more than 100-year-old generating Units 1 – 4 (the Old Units). The refurbishments will be completed in 2021 at an estimated cost of $32.493 million, inclusive of AFUDC and cost of removal, of which $6.495 million will be incurred in 2020 and $1.808 million will be incurred in 2021. Additions to Plant are $8.587 million and $8.092 million in 2020 and 2021, respectively. As directed by the BCUC in the Annual Review for 2017 Rates, the UBO Project Status Report is included as Appendix C4.

In addition to the three projects described above that have already been approved, FBC is requesting approval under Section 44.2 of the UCA 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 Playmor Substation Upgrade Project proposes to rebuild the Playmor substation in South Slocan, BC on an expanded station footprint in order to increase station capacity. The project is necessary to meet load growth from existing customers and new customer requests, and to continue reliably supplying electricity to the surrounding area, including several large commercial and industrial customers. 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. Project

[27] Costs inclusive of AFUDC.

expenditures will enter rate base on January 1, 2023 upon completion. The business case for the project is provided in Appendix B.

7.4 2020 AND 2021 PLANT ADDITIONS

The 2020 and 2021 Plant Additions are comprised of: (i) FBC's 2020 and 2021 regular capital expenditures from Section 7.2; (ii) the Major Projects from Section 7.3 to the extent that portions of those projects are placed into service; (iii) the change in work in progress which adjusts for capital expenditures for projects that are in progress at year-end; (iv) AFUDC; and (v) overhead capitalized for the year. A reconciliation of capital expenditures to plant additions is shown below and is also provided in Section 11 – 2020 and Section 11 – 2021, Schedule 5.

Table 7-4: Reconciliation of Capital Expenditures to Plant Additions ($millions)

Line No.	Description	Projected 2020	Forecast 2021	Reference
1	Forecast Capital Expenditures	$ 93.244	$ 87.573	Table 7-1, Line 1
2	Flow-Through Capital Expenditures	-	-	Table 7-1, Line 2
3	Total Regular Capital Expenditures	93.244	87.573	
4				
5	Capitalized Overhead	9.284	9.767	Table 6-1
6	AFUDC	0.288	0.542	Section 11, Schedule 5, Line 21
7	Change in Work in Progress	(5.836)	5.717	Section 11, Schedule 5, Line 23
8	Total Regular Additions to Plant	96.981	103.599	
9				
10	Major Projects Capital Expenditures	27.341	21.938	Section 11, Schedule 5, Line 27
11	Major Projects AFUDC	1.960	1.857	Section 11, Schedule 5, Line 28
12	Change in Work in Progress	(8.873)	16.612	Section 11, Schedule 5, Line 31
13	Major Projects Additions to Plant	20.428	40.407	
14				
15	Plant Additions	$ 117.409	$ 144.006	

7.5 CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)

Rate base is reduced by CIAC. Gross CIAC is composed of opening contributions plus additions during the year. 2020 and 2021 CIAC additions are forecast at $11.107 million and $11.465 million, respectively. The year-end CIAC balances net of accumulated amortization are $140.959 million (projected) in 2020 and $148.008 million (forecast) in 2021.

7.6 ACCUMULATED DEPRECIATION

The rate base of FBC includes both the accumulated depreciation on plant in service and accumulated amortization of CIAC. Both are increased through depreciation expense, and decreased through retirements.

The depreciation rates used for 2020 and 2021, which were approved by Order G-166-20 and are based on FBC's most recent depreciation study, include the recovery of the estimated future costs of removal over the average service life of the assets (net salvage) in accumulated depreciation. Depreciation is calculated beginning January 1 of the year after the assets are placed in service, which is the treatment approved in Order G-139-14.

Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance, the 2020 depreciation expense is calculated as $56.472 million,[28] and 2021 depreciation expense is calculated as $59.372 million.[29]

7.7 RATE BASE DEFERRED CHARGES

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[30] The stated purpose of the checklist is to assist regulated entities when filing regulatory account requests and to facilitate an efficient review by the BCUC.

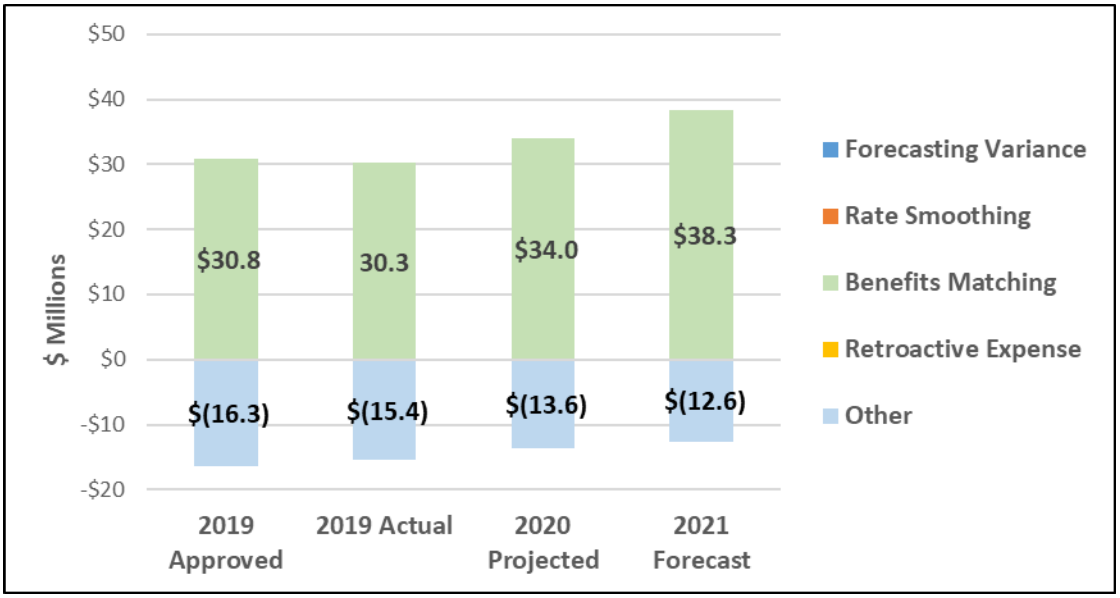
The checklist classifies deferral accounts as one of: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching (capital-like) account; (d) retroactive expense account; or (e) other. In Section 11, Schedule 11, FBC has classified its rate base deferral accounts in accordance with this classification.

The forecast mid-year balance of unamortized deferred charges in rate base for FBC is approximately $20.420 million in 2020 and approximately $25.728 million in 2021. This balance is driven largely by the balances in deferral accounts for DSM, Pension and OPEB funding liability and deferred debt issue expense.

Figure 7-1 provides the mid-year deferral account balances summarized by deferral account category.

[28] $60.666 million depreciation expense as shown in Section 11 - 2020, Schedule 21, Line 2 less $4.194 million amortization of CIAC as shown in Section 11 - 2020, Schedule 21, Line 8.
[29] $63.789 million depreciation expense as shown in Section 11 - 2021, Schedule 21, Line 2 less $4.417 million amortization of CIAC as shown in Section 11 - 2021, Schedule 21, Line 8.
[30] BCUC Letter, Log No. 53608, Appendix B.

Figure 7-1: FBC Forecast Mid-Year Balances of Rate Base Deferral Accounts by Category



Based on amortizing the opening deferral account balances using the approved and proposed amortization periods, the 2020 amortization expense for rate base deferral accounts is calculated as $4.691 million[31] and the 2021 amortization expense is calculated as $5.536 million.[32] The subsections below include a discussion on new rate base deferral accounts and changes or updates to existing rate base deferral accounts. For a discussion on non-rate base deferral accounts, please refer to Section 12.

7.7.1 New Deferral Accounts

FBC seeks approval of six new deferral accounts, four of which are related to regulatory proceedings. One new deferral account relates to periodic costs not included in FBC's Formula O&M Expense and one new deferral account relates to the strengthening of the relationship between FBC and its Indigenous stakeholders. The proposed new deferral accounts are:

- Annual Reviews for 2020 – 2024 Rates;
- 2021 Long-Term Electric Resource Plan;
- 2020 Cost of Service Analysis;
- BCUC-Initiated Inquiry Costs;
- MRS 2021 Audit; and
- Indigenous Relations Agreement (Huth Substation).

[31] Section 11 - 2020, Schedule 11, Line 24, Column 6.
[32] Section 11 - 2021, Schedule 11, Line 24, Column 6.

Each of these proposed deferral accounts is described in more detail below.

7.7.1.1 Annual Reviews for 2020 – 2024 Rates

FBC is requesting approval to establish a deferral account to capture costs related to the Annual Reviews for 2020 – 2024 Rates. Consistent with other deferral accounts related to regulatory applications, the Annual Review deferral account will capture costs such as BCUC costs, intervener and participant funding costs, consulting costs, external legal fees, and miscellaneous facilities, stationary and supplies costs. FBC forecasts additions of $0.140 million ($0.102 million after tax) in each of 2020 and 2021.

7.7.1.2 2021 Long-Term Electric Resource Plan

FBC will file its 2021 Long-Term Electric Resource Plan (LTERP) on or before December 1, 2021 as directed by Order G-117-18. Consistent with historical and approved practice, FBC is seeking 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, including expert and consulting fees, external legal fees, public consultation, BCUC costs and intervener funding. FBC estimates that total costs of the LTERP application proceeding, which will conclude in 2022, will be $0.725 million ($0.529 million after tax). Annual expenditures are estimated to be $0.260 million, $0.145 million, and $0.320 million before tax ($0.190 million, $0.106 million and $0.234 million after tax) in 2020, 2021, and 2022, respectively.

FBC typically amortizes the costs of its resource plans over the time period between filings, and will apply for disposition of the account in a future annual review, following completion of the regulatory process for the 2021 LTERP.

7.7.1.3 2020 Cost of Service Analysis

FBC will file a Cost of Service Analysis (2020 COSA) on or before December 31, 2020 as directed in Order G-40-19. As provided for in the accompanying Decision to Order G-40-19, the 2020 COSA will provide an update to the Revenue to Cost ratios derived as part of the 2017 COSA and Rate Design Application such that there will be an opportunity for rebalancing before customer classes move too far outside the range of reasonableness. FBC anticipates it will incur $0.080 million ($0.058 million after tax) of costs in 2020 and an additional $0.020 million ($0.015 million after tax) in 2021 to manage any regulatory process. FBC will apply for disposition of the account in a future annual review.

7.7.1.4 BCUC-Initiated Inquiry Costs

FBC is seeking a deferral account to capture, in aggregate, costs associated with its participation in BCUC-initiated inquiries and proceedings for the purpose of determining provincial regulatory policy or ensuring consistency of treatment among utilities. These costs represent BCUC costs, participant funding, consulting costs and external legal fees. The following proceedings are currently included or will be included in this 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.

FBC 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. FBC further proposes to amortize costs in the year following when the expenses are forecast.

7.7.1.5 Mandatory Reliability Standards (MRS) 2021 Audit

FBC's triennial MRS compliance audit is scheduled to occur in 2021. This audit will be performed by the administrator of the BC MRS Program, the Western Electricity Coordinating Council (WECC), and will include a review, at a minimum, of all applicable reliability standards identified in the Actively Monitored List, to be issued in November 2020. This will include Critical Infrastructure Protection (CIP) and Operations and Planning (O&P) standards. Eligible costs are incremental labour and expenses directly caused by the periodic audit and therefore not included in Formula O&M Expense. Based on previous audits, FBC forecasts costs of $0.350 million before tax ($0.256 after tax) in 2021.

FBC will propose the disposition of this account in a future annual review.

7.7.1.6 Indigenous Relations Agreement (Huth Substation)

In November 2019, the BC government passed Bill 41 (Declaration on the Rights of Indigenous Peoples Act). The BC Government passed this legislation to implement the United Nations Declaration on the Rights of Indigenous Peoples. Since this legislation has come into force, many First Nations are asking FortisBC to act in the spirit of the legislation and make efforts towards reconciliation. FBC is seeking a deferral account to capture costs to address the Penticton Indian Band's (PIB) concerns regarding the Huth Substation in Penticton and the impacts the substation has had on Syilx[33] history and culture, such as the discovery of ancestral remains found at the Huth substation while performing construction works.

[33] The PIB is a community of the Syilx people.

Huth Substation is a vital component of the South Okanagan area power system, providing direct service to both FBC customers and the municipal utility of the City of Penticton. This hub is connected to five major transmission lines (42L, 49L, 47L, 52L and 53L) and to two City of Penticton distribution substations. Given this importance to the supply of power in the South Okanagan and the historical value of the land to the PIB and the Syilx people, FBC has engaged in reconciliation efforts with the PIB, consistent with the recent legislation passed by the Provincial government.

FBC is unable to publicly disclose the nature of potential costs associated with these reconciliation efforts or estimate an amount of costs to be incurred while the negotiation process is underway. FBC will update its progress with respect to this matter in its next Annual Review filing and will request approval for recovery of costs captured in this deferral account in a future revenue requirements proceeding once an agreement with the PIB has been reached and the impacts can be communicated.

Table 7-5 below addresses the considerations identified in the Regulatory Account Filing Checklist as they pertain to the deferral accounts requested in Sections 7.7.1.1 to 7.7.1.6 above.

1 **Table 7-5: Deferral Account Filing Considerations**

Item	Consideration	Regulatory Proceeding Costs	MRS Compliance Audit	Indigenous Relations Agreement (Huth Substation)
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	The four regulatory proceeding cost accounts are new deferral accounts, consistent with previously approved regulatory proceeding deferral accounts.	The 2021 MRS Compliance Audit account is a new deferral account.	The Indigenous Relations Agreement (Huth Substation) account is a new deferral account.
a)	If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	N/A	N/A	N/A
b)	If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The requested accounts are regulatory proceeding cost accounts, which are routinely sought by utilities to capture external costs related to the preparation, filing, and regulatory review of applications.	The requested account will capture periodic incremental costs of the MRS compliance audit.	The requested account will capture costs related to reconciliation efforts.
II.	Propose a term (i.e., length of time) that the regulatory account should be approved for and explain why that term is appropriate.	The term of each account encompasses the preparation and filing of the relevant regulatory application and its review by the BCUC.	The term of the account encompasses the conduct of the audit and subsequent amortization period, equivalent to the term of the benefit.	The term of the account encompasses the period of negotiation with the PIB and the subsequent amortization period.

Item	Consideration	Regulatory Proceeding Costs	MRS Compliance Audit	Indigenous Relations Agreement (Huth Substation)
III.	Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of deferral accounts for regulatory proceedings, the costs of regulatory proceedings would have to be forecast as an O&M expense (outside of the MRP formula O&M since regulatory proceeding costs are not included in Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FBC considers this to be a more cumbersome and less efficient means of accounting for regulatory proceeding costs. It is accepted regulatory practice to defer the costs of regulatory applications for review and recovery following the regulatory review of the application itself. Review and recovery after the completion of the regulatory process allows for more transparency as the history of the costs is simpler to track and report on.	In the absence of a deferral account, the audit costs would have to be forecast as an O&M expense (outside of the MRP formula O&M, as the costs are not included in Base O&M Expense) and trued up by way of the Flow-Through deferral account. FBC considers this to be a more cumbersome and less efficient means of managing the audit costs. In addition, the use of a deferral account permits multi-year cost recovery, which is consistent with the three-year period between audits, as opposed to recovery in a single year.	In the absence of a deferral account, the costs would have to be forecast as an O&M expense (outside of the MRP formula O&M, as the costs are not included in Base O&M Expense) and trued up by way of the Flow-Through deferral account. Since the terms of the agreement have not yet been negotiated, FBC is unable to forecast expenditures with confidence at this time, or to determine an appropriate period for recovery.

Item	Consideration	Regulatory Proceeding Costs	MRS Compliance Audit	Indigenous Relations Agreement (Huth Substation)
IV	Address:			
a)	whether, or to what extent, the item is outside of management's control;	Regulatory proceeding cost accounts are necessary because the number and type of regulatory proceedings can vary significantly by year. Further, once a regulatory proceeding is identified, the costs of that proceeding cannot be accurately forecast by the utility given that they can vary substantially, are not known at the time of making the regulatory account request, are unique to the circumstances for each application, may change as the regulatory review process unfolds, and are dependent on factors not within the utility's control. Factors not within the control of the utility include the regulatory process determined by the BCUC and the degree of involvement of interveners.	Compliance audits of MRS are conducted every three years. The scope and complexity of audits varies depending on the standards under review, and are not within the control of the Company.	Costs to settle Indigenous Relations issues may be necessary depending on the particular circumstances, can vary significantly and are largely outside the control of the Company.
b)	the degree of forecast uncertainty associated with the item;	Refer to IV. a). FBC forecasts additions to the deferral accounts based on the expected type of review process and degree of intervener involvement. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.	Refer to IV.a). FBC forecasts additions to the deferral account based on past audit experience. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.	Negotiations and the final agreement will determine the total costs incurred. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.

Item	Consideration	Regulatory Proceeding Costs	MRS Compliance Audit	Indigenous Relations Agreement (Huth Substation)
c)	the materiality of the costs	The number and size of regulatory proceedings vary from year to year, and represent costs not included in Base O&M for the purpose of determining formula O&M Expense under the MRP. See sections 7.7.1.1 to 7.7.1.4.	Audit preparation and participation impacts many individuals and business units and is not manageable within FBC's formula O&M Expense.	Negotiations and the final agreement will determine the total costs incurred and represent costs not included in FBC's formula O&M expense.
d)	any impact on intergenerational equity	Generally, FBC recovers the costs of regulatory proceedings over the period of time related to the application, which serves to match the costs and benefits. See sections 7.7.1.1 to 7.7.1.4. There are no intergenerational inequities inherent in this practice.	FBC expects to recover the audit costs over the period of time between audits, which serves to match the costs and benefits. There are no intergenerational inequities inherent in this practice.	FBC expects to recover the costs over the period of time which serves to match the costs and benefits. There are no intergenerational inequities inherent in this practice.
V.	Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other.	FBC generally classifies regulatory proceeding accounts as benefit matching accounts since the costs are recovered over the period of time related to the applications, which serves to match the costs and benefits of the application.	The account is classified as a benefit matching account since the costs will be recovered over the period of time between audits, which serves to match the costs and benefits of the audit.	The account is classified as "other".
VI.	Identify if the regulatory account is a cash or non-cash account.	Regulatory proceeding cost accounts are cash accounts.	The compliance audit deferral account is a cash account.	The Indigenous Relations Agreement account is a cash account.

Item	Consideration	Regulatory Proceeding Costs	MRS Compliance Audit	Indigenous Relations Agreement (Huth Substation)
VII.	Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	Eligible costs include the BCUC's direct costs, notice publication costs, fees for consultants or experts, external legal counsel fees, courier and miscellaneous administrative costs, and participant assistance cost awards incurred in the preparation, filing and regulatory review of the applications. Regular labour and staff expenses related to regulatory applications are included in formula O&M Expense.	Eligible costs are incremental to ongoing MRS expenses and include labour, consulting and miscellaneous expenses not included in Formula O&M Expense.	FBC is unable to publicly disclose the nature or potential costs associated with these reconciliation efforts during the negotiation process.
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements by way of amortization expense.	Costs will be recovered in revenue requirements by way of amortization expense.	Costs will be recovered in revenue requirements by way of amortization expense.
IX.	Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	Generally, FBC amortizes the costs of regulatory proceedings over the period of time related to the application, which serves to match the timing of costs and benefits. See sections 7.7.1.1 to 7.7.1.4.	FBC will propose the recovery of costs in a subsequent Annual Review. Recovery of the costs over the period of time between audits serves to match the costs and benefits of the audit.	FBC will propose the recovery of costs in a subsequent Annual Review.

Item	Consideration	Regulatory Proceeding Costs	MRS Compliance Audit	Indigenous Relations Agreement (Huth Substation)
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	Rate base deferral accounts are included in rate base and are therefore implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and are therefore implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and are therefore implicitly financed using the weighted average cost of capital (WACC).
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral accounts can be reviewed as part of the present proceeding. Deferral account approvals and disposition are generally determined in revenue requirements proceedings.		

7.7.2 Existing Deferral Accounts

7.7.2.1 COVID-19 Customer Recovery Fund Deferral Account

In June 2020, FBC received approval through Order G-133-20 to establish the COVID-19 Customer Recovery Fund Deferral Account in rate base to record three items:

(a) any bill payment deferrals provided to customers due the COVID-19 pandemic and subsequent payments of those deferred amounts;

(b) any bill credits provided to customers due to the COVID-19 pandemic; and

(c) any unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic, which will be tracked separately by rate schedule.

The following section provides 2020 and 2021 financial estimates and descriptions for each of the three items for inclusion in the COVID-19 Customer Recovery Fund Deferral Account.

(a) Bill payment deferrals provided to residential and small commercial customers

The 3-month bill payment deferral program has been offered to residential and small commercial customers affected by COVID-19 from April to June 2020. The bill payment deferrals are to be repaid by customers over a 12-month period with such repayments beginning in July 2020.

Table 7-6: Bill Payment Deferral Forecast

COVID-19 Deferral Account	Year	Opening Bal.	Gross Additions	Less Taxes	Amortization Expense	Ending Bal.
COVID-19 Customer Recovery Fund - Bill Payment Deferrals	**2020**	-	424	-	-	424
COVID-19 Customer Recovery Fund - Bill Payment Deferrals	**2021**	424	(424)	-	-	-

The deferral account gross additions of $0.424 million related to this customer relief offering have been estimated as the outstanding customer accounts receivable balances of $0.848 million as of July 2020, less the estimated customer repayments from July 2020 through to the end of 2020. As customers are expected to repay the balances over a 12-month term, beginning in July 2020, there is not expected to be an ending balance of bill payment deferral balances as at the end of 2021.

Any of the customers enrolled in the bill payment deferral program that are unable to repay their outstanding balances will be designated as unrecoverable revenue. This change in classification will entail a reduction in the bill payment deferral portion of the deferral account in this section (a) and will be reallocated as an addition to the unrecovered revenue (section c) component. There could be customers that default on their repayment of the bill deferral arrangements and these would also be allocated to the unrecovered revenue (section c). No such defaults have been forecast in section (a) as they are assumed to be incorporated in the estimates provided in section (c) associated with unrecovered revenue.

(b) Bill credits provided to small commercial customers

The 3-month bill credit program offered to small commercial customers for April through June 2020 has been estimated using the customer balances of $0.161 million as of July 2020.

Table 7-7: Bill Credit Forecast

COVID-19 Deferral Account	Year	Opening Bal.	Gross Additions	Less Taxes	Amortization Expense	Ending Bal.
COVID-19 Customer Recovery Fund - Bill Credits	**2020**	-	161	(43)	-	118
COVID-19 Customer Recovery Fund - Bill Credits	**2021**	118	-	-	-	118

While the bill credits are available for the three-month period from April through June 2020, the forecast balance of bill credits are still subject to change after June 2020. This is primarily due to the expectation that there could still be small commercial customers that have yet to apply for bill credit relief for the qualifying three-month period, as well as certain billing cycles yet to be completed.

(c) Unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic.

Unrecovered revenues are representative of accounts receivable balances that are determined to be uncollectible due to COVID-19 and therefore include the write-offs of bad debts. These forecast balances are meant to represent the unrecovered revenues specific to COVID-19 that are recognized in the deferral account and therefore are in excess of the normal course forecast bad debt expense that is recognized in indexed-based O&M. While FBC has currently forecast the bad debt expense to be recognized in indexed-based O&M for 2020 and 2021 as representative of the normalized bad debt expense that was embedded in the Base O&M, the actual bad debt expense recognized in O&M could differ. This is in part due to the timing of recognizing the bad debt expense in O&M versus the write-offs of bad debts in the deferral account, as well as the uncertainty around the duration and significance of the pandemic on customers' ability to pay their bills.

Table 7-8: Unrecoverable Revenue Forecast

COVID-19 Deferral Account	Year	Opening Bal.	Gross Additions	Less Taxes	Amortization Expense	Ending Bal.
COVID-19 Customer Recovery Fund - Unrecoverable Revenue	**2020**	-	801	(216)		585
COVID-19 Customer Recovery Fund - Unrecoverable Revenue	**2021**	585	1,747	(472)	-	1,860

The unrecovered revenue recorded in the deferral account will include:

- any remaining balances associated with the bill payment deferral program, described in section (a), that resulted from customers' inability to pay; and
- any unrecovered revenue from all customer classes due to COVID-19, including industrial and large commercial customers and those residential and small commercial customers that did not participate in the bill payment deferral or bill credit relief offerings.

There has been a minimal amount of confirmed customer bad debt write-offs relating to COVID-19 in the first four to five months since the relief options have been offered to customers. While there still exists uncertainty around the effects of COVID-19 on customers' ability to make payments for current and future billed revenues, it is probable and reasonable to expect that unrecovered revenue will materialize in the last half of 2020 and through 2021. Accordingly, FBC has developed a methodology to estimate additions to the deferral account by applying an estimated loss rate on forecast 2020 revenues to determine the potential unrecovered revenue from customers resulting from the COVID-19 pandemic. To clarify, the ending balance of $1.860 million is based on the estimated bad debt write offs calculated on revenues billed in 2020 and does not take into account bad debt write offs associated with revenue billed in 2021 or beyond. Due to the significant uncertainty around the extent and duration of the pandemic on FBC's customers' ability to pay in the future, there could also be unrecovered revenues that are recognized in the deferral account beyond the forecast periods of 2020 and 2021.

For residential and small commercial customers, the loss rate took into account the relative increase in the forecast 2020 unemployment rate for BC from 5.0 percent prior to the pandemic to 8.2 percent. Similarly, there was a loss rate applied for industrial and large commercial customers which incorporated the forecast 2020 GDP decrease in BC of 4.5 percent. The loss rate was then applied to forecast revenues from March 2020 through to December 2020. The unemployment and GDP indicators are macroeconomic factors based on forecasts from five financial institutions and corroborated through the Conference Board of Canada.

Applying macroeconomic factors to estimating unrecoverable revenues is consistent with the principles for external financial reporting. US GAAP ASU 2016-13 *Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments* discussed in Section 12.3.1.1 of this Application requires entities to consider historical experience, current conditions and reasonable forecasts to determine the expected amount of credit losses that will occur. Accordingly, FBC has estimated $0.8 million and $1.7 million of unrecoverable revenue additions for 2020 and 2021, respectively, to the COVID-19 Customer Recovery Fund Deferral Account.

While the forecasts of the unrecovered revenue additions rely on estimates and broader macroeconomic factors, the actual amounts that accumulate in the deferral account are expected to be representative of balances that are attributable to specific customers that cannot make payment due to COVID-19.

FUTURE DISPOSITION OF DEFERRAL ACCOUNT BALANCES

At the time of the original COVID-19 Customer Recovery Fund Deferral Account application in early April 2020, there was significant uncertainty around the effect of the pandemic and the overall economic effect on FortisBC's customers. The combination of the programs offered to customers and the deferral account have been successful and are working as intended to the date of this filing. However, there continues to be uncertainty around future unrecovered revenues and the possibility as to whether further extensions or additional relief offerings will be required for the balance of 2020 and into 2021.

Rather than suggesting partial disposition for the three items in the deferral account, FBC recommends a more comprehensive approach to the disposition of the deferral account, particularly given that the effects of COVID-19 on these measures could occur over multiple years. Therefore, FBC is not yet proposing an amortization period for the deferral account in 2020 or 2021. FBC has forecast additions to the deferral account for 2020 and 2021 and will propose a disposition of the deferral account in the Annual Review for 2022 Rates filing, to take place in 2021.

7.8 WORKING CAPITAL

The working capital component of rate base is comprised of cash working capital and other working capital.

Cash working capital is defined as the average amount of capital provided by investors in the Company to bridge the gap between the time expenditures are required to provide service (expense lag) and the time collections are received for that service (revenue lag). The cash working capital requirements that have been included reflect the most recent Lead Lag Study results, as approved through Order G-166-20.

Other working capital includes customer (DSM) loans, employee loans and withholdings and inventory of materials and supplies.

2020 amounts are projected based on 2019 levels, while also including six months of actual results for 2020. 2021 amounts are based on similar inputs and include inflation where applicable.

7.9 SUMMARY

FBC's rate base includes the impact of Regular and Major Projects capital expenditures, adjusted for work-in-progress, AFUDC and overheads capitalized. FBC has provided forecasts for all of its rate base deferral accounts in its financial schedules in Section 11. Finally, the rate base includes cash and other working capital.

8. FINANCING AND RETURN ON EQUITY

8.1 *INTRODUCTION AND OVERVIEW*

FBC has prepared this Application using a capital structure of 60 percent debt and 40 percent equity and a Return on Equity (ROE) of 9.15 percent as approved by Orders G-129-16 and G-47-14. FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FortisBC Energy Inc. (FEI). The 2020 Projection for financing costs, including the interest expense on issued long- and short-term debt and on new issuances that are forecast, has been updated as described in Section 8.3 below. Based on the updated financing costs, FBC's AFUDC rates for 2020 and 2021 (which are equal to its after-tax weighted average cost of capital) are 5.77 percent and 5.76 percent, respectively. Any variances from interest rates used to set rates, and any variances in interest resulting from items subject to flow-through in the Flow-through deferral account, will be flowed through to customers. All other differences in interest expense will affect the achieved ROE and be subject to earnings sharing.

8.2 *CAPITAL STRUCTURE AND RETURN ON EQUITY*

The Company finances its investment in rate base assets with a mix of debt and equity, as approved by the BCUC from time to time. Order G-47-14 approved a capital structure for FBC of 60.0 percent debt and 40.0 percent equity with an equity risk premium of 40 basis points over the benchmark ROE, which was set at 8.75 percent by Order G-129-16.

FBC has therefore prepared this Application using an ROE of 9.15 percent and a common equity percentage of 40.0 percent.

8.3 *FINANCING COSTS*

Debt financing costs include the borrowing costs on issued debt as well as on new issuances that are forecast. Debt consists of both long- and short-term (unfunded) debt.

8.3.1 Long-term Debt

FBC is both a private and public issuer of long-term debt. In May 2020, FBC completed a private placement of $75 million long-term debt at a rate of 3.12 percent[34] for a term of 30 years. The net proceeds were used to repay existing indebtedness and finance the Company's capital expenditure program. FBC plans to issue additional long-term debt of approximately $75 million in 2021, the proceeds of which will be used for the same purposes. The 2021 debt issuance is reflected in the financial schedules in July 2021 at a rate of 3.90 percent.[35] The exact timing, amount and rate of the 2021 issuance will depend on future market conditions and capital

[34] Section 11 – 2020 and 2021, Schedule 27, Line 9.
[35] Section 11 – 2021, Schedule 27, Line 10.

expenditure requirements. Variances in interest expense related to the timing and amount of the issuances of the debt or the rates at which they are issued will be captured in the Flow-through deferral account.

8.3.2 Short-term Debt

Since mid-2019, FBC has been obtaining short-term funding primarily through the issuance of commercial paper to Canadian institutional investors. Until 2019, the Company was only able to issue Bankers' Acceptances. FBC backstops the commercial paper issuances by maintaining a $150 million committed credit facility that matures in April 2024. The credit facility, along with a $10 million overdraft facility, provides FBC with short-term liquidity to fund FBC's capital program and working capital requirements. The Company also issues letters of credit as part of this facility. The short-term debt rate reflects FBC's commercial paper and letter of credit issuances.

8.3.3 Forecast of Interest Rates

FBC uses interest rate forecasts to estimate future interest expense. Forecasts of Treasury Bills and benchmark Government of Canada Bond interest rates are used in determining the overall interest rates for short-term debt and for rates on new issues of long-term debt, respectively. The forecasts are based on available projections made by Canadian Chartered banks.

Credit spreads on new long-term debt are based on current indicative rates, on the assumption that the current credit ratings of FBC are maintained.

FBC's short-term borrowing rate is based on the rate at which it issues commercial paper and letters of credit. Since commercial paper issuance rates are not forecast by economists, a forecast needs to be derived by FBC. The forecast is based on the historical differential between the Canadian Deposit Overnight Rate (CDOR) and the rate obtained by FBC under its commercial paper program. CDOR is used because FBC's short-term borrowings under its credit facility are priced based on CDOR and therefore CDOR is tracked relative to FBC's commercial paper borrowings. As CDOR is not forecast by economists, FBC must first obtain the 3-Month T-Bill rate forecast and then convert it to a CDOR forecast. FBC does this by taking the 3-year historical spread between CDOR and the 3-month T-Bill rate. Then, to derive the short-term borrowing rate forecast, FBC adjusts the CDOR forecast with the historical spread between CDOR and rates of issuances under its commercial paper program.

The 3-Month T-Bill forecast for 2020 and 2021 has been significantly impacted by the COVID-19 pandemic and is projected to decrease from 2.05 percent in 2019 to approximately 0.51 percent in 2020 and 0.45 percent in 2021. As noted above, the 2019 short-term interest rate forecast reflects Bankers' Acceptance issuances by FBC whereas the 2020 and 2021 short-term rates assume FBC exclusively issues commercial paper. For 2020 and 2021, FBC has also forecast other financing fees similarly to 2019, which includes the fees that it incurs for its letters of credit under the $150 million credit facility, as well as interest paid on customer deposits. The short-term borrowing rate forecast is shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecast

FBC Short Term Interest Rate	Approved 2019	Actual 2019	Projected 2020	Forecasted 2021
3-Month T-Bill Rate [1]	2.05%	1.79%	0.51%	0.45%
Spread to CDOR	0.42%	0.42%	0.44%	0.44%
Acceptance Fee Rate	1.00%	-	-	-
CDOR Rate	3.47%	2.21%	0.95%	0.89%
Spread to CP	-	-0.17%	-0.22%	-0.22%
CP Dealer Commission	-	0.10%	0.10%	0.10%
ST Interest Rate on Credit Facilities	**3.47%**	**2.14%**	**0.83%**	**0.77%**
Fixed Financing Fees [2]				
Standby fee on Undrawn Credit [3]	0.24%	0.34%	0.51%	0.77%
Renewal Fee on Undrawn Credit	0.07%	0.14%	0.19%	0.29%
Other Financing Fees	0.34%	0.45%	0.33%	0.40%
ST Interest Rate on Fixed Financing Fee	**0.65%**	**0.93%**	**1.03%**	**1.45%**
FBC Short Term Rate	**4.12%**	**3.07%**	**1.86%**	**2.22%**

Notes:

1 3-Month T-Bill Rate for 2020 based on a composite of actual historical rates up to June 30, 2020 and forecast rates for the remainder of the year.

2 Fixed financing fees represent the costs of maintaining $150 million credit facility and letter of credit facility, which are fixed fees regardless if FBC draws from the credit facility. The fees have been converted into a short-term rate for forecast purposes.

3 A standby fee of 20 bps is charged on undrawn credit facility amounts, which would change if credit facility amounts are drawn through banker acceptances or prime loans. However, the forecast assumes FBC will borrow through commercial paper and will not change the undrawn credit facility fee percentage.

8.3.4 Interest Expense Forecast

The interest expense forecast reflects FBC's existing and forecast borrowing costs on long- and short-term debt.

Short-term interest expense is determined by applying the forecast short-term debt rate to the estimated short-term debt balance. Long-term debt interest expense is determined using the straight-line method by multiplying the average balance of the specific debenture by the debt coupon rate, or forecast coupon rate, if it is a new issue. The 2020 and 2021 long-term debt schedules for FBC can be found in Section 11 – 2020 and Section 11 - 2021, Schedule 27.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FBC applies AFUDC to projects that are greater than 3 months in duration and greater than $100 thousand. Based on the above information, FBC's AFUDC rates for 2020 and 2021 (which are equal to its after-tax weighted average cost of capital) are 5.77 percent and 5.76 percent, respectively. The calculation of the rates are shown in the following table.

Table 8-2: Calculation of AFUDC Rates for 2020 and 2021

		2020				2021			
Line No.	Description	Weight	Pre-Tax Rate	After-Tax Rate	Earned Return	Weight	Pre-Tax Rate	After-Tax Rate	Earned Return
1	Short Term Debt	4.55%	1.86%	1.36%	1.86%	2.84%	2.22%	1.62%	2.22%
2	Long Term Debt	55.45%	5.05%	3.69%	5.05%	57.16%	4.93%	3.60%	4.93%
3	Common Equity	40.00%	12.53%	9.15%	9.15%	40.00%	12.53%	9.15%	9.15%
4									
5	Weighted Average	100.00%	7.90%	5.77%	6.55%	100.00%	7.90%	5.76%	6.54%

8.4 *SUMMARY*

FBC's equity financing and ROE have been forecast for 2020 and 2021 at the same percentages as approved for 2019. FBC's debt financing costs on rate base are primarily determined by embedded rates on long-term debt, and to a lesser degree by short-term debt rates; both of these rates are forecast to decrease in 2020 and 2021 as compared to 2019 Approved.

9. TAXES

9.1 INTRODUCTION AND OVERVIEW

This section discusses FBC's forecasts of property taxes and income tax which have been forecast on a basis consistent with prior years. In 2020, property taxes are projected to increase by 1.7 percent from 2019 Approved, with a further increase of 7.4 percent in 2021 compared to the 2020 Projected amount. Income tax is projected to decrease by 36.9 percent in 2020 compared to 2019 Approved, and then increase by 73.7 percent in 2021 compared to the 2020 Projected amount.

9.2 PROPERTY TAXES

Property taxes for 2020 and 2021 of $16.993 million and $18.242 million, respectively, incorporate Company forecasts of assessed values of taxable assets, mill rates and taxes from revenues earned from electricity consumed within municipalities. A breakdown of property taxes by asset type is provided in Table 9-1 below.

Table 9-1: Property Taxes ($ millions)

Line No.	Description	Approved 2019	Actual 2019	Projected 2020	Forecast 2021
1	Generating Plant	$ 3.082	$ 3.036	$ 3.092	$ 3.087
2	Transmission and Distribution	6.705	6.532	6.756	8.075
3	Substation Equipment	3.741	3.838	3.825	3.843
4	Land and Buildings	1.019	1.092	1.057	1.112
5	In-Lieu	2.166	2.166	2.263	2.125
6	Total Property Taxes	$ 16.713	$ 16.664	$ 16.993	$ 18.242
7					
8	2019 Actual to Approved		-0.3%		
9	2020 Projected Change from 2019 Approved			1.7%	
10	2021 Forecast Change from 2020 Projected				7.4%

Projected 2020 property taxes in the table above include actual payments of $16.954 million and projected payments of $0.039 million for the remainder of the year. Property taxes in 2020 are projected to increase by 1.7 percent compared to 2019 Approved, with a further forecast increase in 2021 of 7.4 percent compared to 2020 Projected. In general, the 2021 increase from 2020 Projected is primarily due to the increases in rates for transmission and distribution lines. The most significant forecast drivers of the changes are as follows:

1. **Changes in Tax Rates.** Tax Rates are expected to change for 2021 as follows:
   a) Municipal rates are expected to increase by 0.50 percent;
   b) School rates are expected to decrease by 2.5 percent to offset assessment increases resulting from the BC Assessment Utility Class model updates;

   c) Rural rates are expected to increase by 1.0 percent;
   d) Tax rates on First Nations are expected to increase 0.25 percent; and
   e) Other rates are expected to increase by 1.0 percent.
2. **Changes in Revenues to Calculate Grants In Lieu of Taxes.** Revenues reported to municipalities are expected to decrease by 2.0 percent based on actual revenues to be reported. Grants in-lieu of taxes are based on a fixed percentage of revenues; the overall decrease in revenues reported to municipalities decreases the grants in-lieu of taxes due.
3. **Changes in Assessed Values.** Forecast changes in the assessed values of FBC's property are based on the increases that BC Assessment was proposing at the time the forecast was developed. These include:
   a) Distribution lines are expect to increase by 20 percent and transmission lines are expected to increase by 30 percent because of a major review of linear properties by BC Assessment that is expected to be implemented starting in 2021;
   b) A 2.0 percent increase in assessed values for generating facilities calculated using legislated cost manuals for valuing generating facilities;
   c) A 2.0 percent increase in assessed values for substations calculated using legislated cost manuals for valuing substations; and
   d) Land values are expected to increase on average 3.0 percent for both right of ways and properties owned in fee simple.

Any variances from the forecast of property taxes included in rates will be recorded in the Flow-through deferral account and returned to or collected from customers in the following year.

9.3 *INCOME TAX*

FBC is subject to corporate income taxes imposed by the Federal and BC governments. Current income taxes have been calculated using the flow-through (taxes payable) method, consistent with BCUC-approved past practice, at the corporate tax rate of 27 percent for 2020 and 2021, which is unchanged from 2019. The corporate tax rates used in this Application are based on the Canada Income Tax Act and the BC Income Tax Act enacted legislation and are updated each year as part of the annual rate setting process.

Income tax for 2020 is projected to decrease by $2.892 million or 36.9 percent compared to 2019 Approved and then increase by $3.636 million or 73.7 percent in 2021 compared to the 2020 Projected amount. The 2020 decrease is primarily due to a decrease to adjustments to taxable income from the Federal government's Accelerated Investment Incentive regime as discussed below, partially offset by increases in rate base and amortization of deferred charges.

In 2021, the income tax increase is primarily due to increases in rate base and amortization of deferred charges.

Any tax rate variances and variances in income taxes on items that are flowed through in rates will also be subject to flow-through treatment.

All other differences in income tax expense will affect the achieved ROE and be subject to earnings sharing.

9.4 *ACCELERATED INVESTMENT INCENTIVE*

On November 21, 2018, the Federal government introduced the Accelerated Investment Incentive regime, which enabled FBC to claim additional Capital Cost Allowance (CCA) deductions in the year of addition for all qualifying expenditures made after November 20, 2018 and before January 1, 2028. The impact of the additional CCA deductions has been incorporated in tax forecasts for 2020 and 2021. The benefits of the additional CCA deductions for 2018 and 2019 were included in the Flow-through deferral account and will be returned to customers through amortization of the deferral account balance.

9.5 *SUMMARY*

FBC has forecast its property and income taxes on a basis consistent with prior years, utilizing enacted legislation for income taxes and forecast changes for property tax rates and assessments.

10. EARNINGS SHARING

In the MRP Decision (at page 82), the BCUC approved an earnings sharing mechanism from 2020 to 2024 whereby 50 percent of the achieved ROE above or below the allowed ROE will be shared with customers.

As discussed in Section 1.1, FBC is proposing to set 2020 permanent rates at existing interim levels by capturing the revenue requirement difference in the 2018-2019 Revenue Surplus deferral account. The revenue requirement for 2020 includes an amount for earnings sharing related to the Actual 2019 results from the final year of the 2014-2019 PBR Plan, the details of which are discussed in Section 14.

As also discussed in Section 1.1, FBC is not projecting any earnings sharing from 2020 to be included in 2021 rates, as FBC anticipates relatively minor formulaic O&M savings in 2020 for a variety of reasons, such as the inclusion of a 0.5 percent X-Factor in the calculation of Formula O&M, as directed by the BCUC in the MRP Decision. Further, 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. While many of these items are treated as flow-through and therefore the variances do not impact earnings sharing, certain forecast items, such as Other Revenue and depreciation on regular capital, are subject to earnings sharing. For the foregoing reasons, FBC is not projecting any earnings sharing (i.e., 50 percent of the variance between achieved ROE and allowed ROE) from 2020 to be included in the 2021 rates. An adjustment to include the difference between the projected amount of zero and final actual amounts of earnings sharing from 2020 will be trued-up in 2021 and amortized in 2022 rates.

11. FINANCIAL SCHEDULES

SUMMARY OF RATE CHANGE Schedule 1
FOR THE YEAR ENDING DECEMBER 31, 2020
($000,000s)

Line No.	Particulars	2020 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	11.866		
3	Change in Other Revenue	(1.377)	10.489	
4				
5	**POWER SUPPLY**			
6	Power Purchases (net of customer growth and volume)	(6.453)		
7	Wheeling	0.532		
8	Water Fees	0.503	(5.418)	
9				
10	**O&M CHANGES**			
11	Gross O&M Change	2.694		
12	Capitalized Overhead Change	(0.404)	2.290	
13				
14	**DEPRECIATION EXPENSE**			
15	Depreciation Rate Change (Depreciation Study)	2.373		
16	Depreciation from Net Additions	(1.972)	0.401	
17				
18	**AMORTIZATION EXPENSE**			
19	CIAC Amortization Rate Change (Depreciation Study)	(0.189)		
20	CIAC from Net Additions	0.167		
21	Deferral Accounts	5.047	5.025	
22				
23	**FINANCING AND RETURN ON EQUITY**			
24	Financing Rate Changes	(2.194)		
25	Financing Ratio Changes	(0.141)		
26	Rate Base Growth	4.706	2.371	
27				
28	**TAX EXPENSE**			
29	Property and Other Taxes Changes	0.280		
30	Other Income Taxes Changes	(2.892)	(2.612)	
31				
32	2019 Revenue Surplus		(5.633)	
33	Deferred 2020 Revenue Deficiency		(3.326)	
34				
35	Revenue Deficiency (Surplus)		$ 3.587	Schedule 16, Line 6, Column 4
36				
37	Revenue at Existing Rates		358.668	Schedule 16, Line 5, Column 3
38	Rate Change		1.00%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 2

Line No.	Particulars	2019 Approved	2020 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning [1]	$ 2,040,679	$ 2,112,240	$ 71,561	Schedule 6.1, Line 19, Column 3
2	Opening Balance Adjustment	12,007	(47,893)	(59,900)	Schedule 6.1, Line 19, Columns 4+5
3	Net Additions	66,540	98,457	31,917	Schedule 6.1, Line 19, Columns 6+7+8
4	Plant in Service, Ending	2,119,226	2,162,803	43,577	
5					
6	Accumulated Depreciation Beginning	$ (631,022)	$ (664,986)	$ (33,964)	Schedule 7.1, Line 19, Column 5
7	Opening Balance Adjustment	-	72,871	72,871	Schedule 7.1, Line 19, Columns 6+7
8	Net Additions	(42,176)	(49,153)	(6,977)	Schedule 7.1, Line 19, Columns 8+9+10+11
9	Accumulated Depreciation Ending	(673,198)	(641,268)	31,930	
10					
11	CIAC, Beginning	$ (199,444)	$ (209,719)	$ (10,275)	Schedule 9, Line 1, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(8,876)	(11,107)	(2,231)	Schedule 9, Line 1, Column 4
14	CIAC, Ending	(208,320)	(220,826)	(12,506)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 71,910	$ 75,672	$ 3,762	Schedule 9, Line 3, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	4,172	4,194	22	Schedule 9, Line 3, Column 4
19	Accumulated Amortization Ending - CIAC	76,082	79,867	3,784	
20					
21	Net Plant in Service, Mid-Year	$ 1,303,960	$ 1,359,381	$ 55,420	
22					
23	Adjustment for timing of Capital additions	$ 7,170	$ 10,214	$ 3,044	
24	Capital Work in Progress, No AFUDC	8,921	11,228	2,307	
25	Unamortized Deferred Charges	14,480	20,420	5,940	Schedule 11, Line 24, Column 8
26	Working Capital	2,107	5,713	3,606	Schedule 13, Line 16, Column 3
27	Utility Plant Acquistion Adjustment	5,307	5,121	(186)	
28					
29	Mid-Year Utility Rate Base	$ 1,341,945	$ 1,412,075	$ 70,130	
30					
31	Note 1: Pursuant to Order G-9-18, the costs of FBC's Electric Vehicle DCFC stations are excluded from rate base until the Commission directs otherwise.				

FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 3

Line No.	Particulars	Reference	2020	Cross Reference
	(1)	(2)	(3)	(4)
1	**Cost Drivers for O&M**			
2	CPI		2.692%	
3	AWE		2.881%	
4	Labour Split			
5	Non Labour		38.000%	
6	Labour		62.000%	
7	Inflation Factor for Costs	(Line 2 x Line 5) + (Line 3 x Line 6)	2.809%	
8	Productivity Factor	G-166-20	-0.500%	
9	Net Inflation Factor for Costs	Line 7 + Line 8	2.309%	
10				
11				
12	**Growth in Average Customer Calculation**			
13	Average Customer - Prior Year		139,916	
14	Average Customer Forecast - Test Year	Schedule 18, Line 8, Column 6	141,189	
15	Average Customer Change	Line 14 - Line 13	1,273	
16	Customer Growth Factor Multiplier	G-166-20	75%	
17	Change in Customers - Rate Setting Purposes	Line 15 x Line 17	955	
18				
19	**Average Customer Continuity for Rate Setting Purposes**			
20	Average Customer Forecast - Prior Year	Prior Year Line 22	139,916	
21	Change in Customers - Rate Setting Purposes	Line 17	955	
22	Average Customer Forecast - Rate Setting Purposes	Line 20 + Line 21	**140,871**	

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 4

Line No.	Particulars	2020	Cross Reference
	(1)	(2)	(3)
1	**Forecast Capital Expenditures**		
2	Growth Capital	$ 27,029	
3	Sustainment Capital	50,463	
4	Other Capital	15,752	
5	Total Forecast Capital	$ 93,244	
6			
7	Flow-Through Capital Expenditures	$ -	
8			
9	**Total Regular Capital Expenditures**	$ 93,244	
10			
11	**CPCN and Special Projects**		
12	Corra Linn Spillway Gate Replacement	16,768	
13	Upper Bonnington Old Units Refurbishment	5,886	
14	Grand Forks Terminal Station	4,204	
15	Playmor Substation Rebuild Project	483	
16	Total CPCN and Special Projects	$ 27,341	
17			
18	**Total Capital Expenditures Before CIAC**	$ 120,585	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 5

Line No.	Particulars	2020	Cross Reference
	(1)	(2)	(3)
1	**CAPITAL EXPENDITURES**		
2			
3	Forecast Capital Expenditures	93,244	
4	Flow-Through Capital Expenditures	-	
5	Total Regular Capital Expenditures	$ 93,244	Schedule 4, Column 2, Line 9
6			
7	**CPCN and Special Projects**		
8	Corra Linn Spillway Gate Replacement	16,768	
9	Upper Bonnington Old Units Refurbishment	5,886	
10	Grand Forks Terminal Station	4,204	
11	Playmor Substation Rebuild	483	
12	Total CPCN and Special Projects	$ 27,341	Schedule 4, Column 2, Line 16
13			
14	**Total Capital Expenditures**	$ 120,585	Schedule 4, Column 2, Line 18
15			
16			
17	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**		
18			
19	Regular Capital Expenditures	$ 93,244	Line 5, Column 2
20	Add - Capitalized Overheads	9,284	Schedule 20,- Line 19, Column 4
21	Add - AFUDC	288	
22	Gross Capital Expenditures	$ 102,816	
23	Change in Work in Progress	(5,836)	
24	**Total Additions to Plant**	$ 96,981	
25			
26			
27	**CPCN and Special Projects**	$ 27,341	Line 12, Column 2
28	Add - AFUDC	1,960	
29	Gross Capital Expenditures	29,301	
30	Change in Work in Progress	(8,873)	
31	**Total Additions to Plant**	$ 20,428	
32			
33	**Grand Total Additions to Plant**	$ 117,409	Schedule 6.1, Line 19, Columns 6 + 7

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 6

Line No.	Account	Particulars	12/31/19	Opening Balance Adjustment	Amortization Accounting Transition[1]	CPCNs	Additions	Retirements	12/31/20	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1		**Hydraulic Production Plant**								
2	330	Land Rights	$ 950	$ 12	$ -	$ -	$ -	$ -	$ 962	
3	331	Structures and Improvements	19,152	235	-	-	615	(88)	19,914	
4	332	Reservoirs, Dams & Waterways	37,328	458	-	1,021	2,094	(159)	40,742	
5	333	Water Wheels, Turbines and Gen.	107,552	1,320	-	14,299	1,167	(100)	124,237	
6	334	Accessory Equipment	46,607	572	-	3,064	1,031	(72)	51,203	
7	335	Other Power Plant Equipment	45,095	553	-	-	945	(97)	46,497	
8	336	Roads, Railroads and Bridges	1,272	16	-	-	-	-	1,287	
9			$ 257,956	$ 3,165	$ -	$ 18,384	$ 5,852	$ (516)	$ 284,841	
10		**Transmission Plant**								
11	350	Land Rights-R/W	$ 8,899	$ 109	$ -	$ -	$ 604	$ -	$ 9,613	
12	350.1	Land Rights-Clearing	8,134	100	-	-	604	-	8,838	
13	353	Station Equipment	237,427	2,913	-	2,043	2,078	(305)	244,155	
14	355	Poles Towers & Fixtures	114,556	1,405	-	-	3,988	(82)	119,868	
15	356	Conductors and Devices	111,692	1,370	-	-	3,988	(87)	116,964	
16	359	Roads and Trails	1,108	14	-	-	-	-	1,121	
17			$ 481,815	$ 5,911	$ -	$ 2,043	$ 11,262	$ (473)	$ 500,559	
18		**Distribution Plant**							-	
19	360	Land Rights-R/W	$ 7,098	$ 87	$ -	$ -	$ -	$ -	$ 7,185	
20	360.1	Land Rights-Clearing	11,489	141	-	-	-	-	11,630	
21	362	Station Equipment	251,685	3,088	-	-	14,460	(334)	268,899	
22	364	Poles Towers & Fixtures	222,863	2,734	-	-	11,961	(564)	236,995	
23	365	Conductors and Devices	359,689	4,413	-	-	25,790	(641)	389,251	
24	368	Line Transformers	172,847	2,121	-	-	7,331	(1,484)	180,815	
25	369	Services	9,406	115	-	-	-	-	9,521	
26	370	Meters	50	1	-	-	-	(1)	50	
27	370.1	AMI Meters	40,501	497	-	-	140	-	41,137	
28	371	Installation on Customers' Premises	927	11	-	-	-	-	938	
29	373	Street Lighting and Signal System	13,300	163	-	-	865	(144)	14,184	
30			$ 1,089,855	$ 13,371	$ -	$ -	$ 60,547	$ (3,167)	$ 1,160,606	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Account	Particulars	12/31/19	Opening Balance Adjustment	Amortization Accounting Transition[1]	CPCNs	Additions	Retirements	12/31/20	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1		**General Plant**								
2	389	Land	$ 10,970	$ 135	$ -	$ -	$ -	$ -	$ 11,105	
3	390	Structures - Frame & Iron	-	-	-	-	-	-	-	
4	390.1	Structures - Masonry	44,310	544	-	-	1,682	-	46,536	
5	390.2	Operation Building	15,364	188	-	-	1,682	-	17,235	
6	390.1	Leasehold Improvements	2,837	35	-	-	-	-	2,872	
7	391	Office Furniture & Equipment	8,101	99	(2,841)	-	224	(315)	5,269	
8	391.1	Computer Equipment	33,803	415	(20,932)	-	3,519	(2,385)	14,419	
9	391.2	Computer Software	78,274	960	(39,126)	-	5,103	(4,750)	40,461	
10	391.2	AMI Software	9,473	116	-	-	1,364	-	10,954	
11	392.1	Light Duty Vehicles	4,384	54	-	-	891	(184)	5,144	
12	392.1	Heavy Duty Vehicles	24,773	304	-	-	2,078	(1,042)	26,114	
13	394	Tools and Work Equipment	14,082	173	(5,187)	-	777	(759)	9,086	
14	397	Communication Structures & Equipment	17,207	211	(3,188)	-	1,999	(3,913)	12,316	
15	397.1	Fibre	14,127	173	(2,535)	-	-	(1,448)	10,318	
16	397.2	AMI Communications Structure & Equipment	4,909	60	-	-	-	-	4,970	
17			$ 282,614	$ 3,467	$ (73,808)	$ -	$ 19,319	$ (14,795)	$ 216,798	
18										
19		**Total Plant in Service**	$ 2,112,240	$ 25,915	$ (73,808)	$ 20,427	$ 96,981	$ (18,951)	$ 2,162,803	
20										
21										
22		Note 1: The amortization method of accounting includes the retirement of assets at the end of the amortization period. A change to amortization accounting was recommended in FBC's 2017 Depreciation Study, which was approved by Order G-166-20.								
23										
24		Cross Reference				Schedule 5 Line 31 Column 2	Schedule 5 Line 24 Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 7

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/19	Opening Balance Adjustment	Amortization Accounting Transition[1]	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/20	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Hydraulic Production Plant**											
2	330	Land Rights	$ 962	1.07%	$ (413)	$ (1)	$ -	$ 10	$ -	$ -	$ -	$ (403)	
3	331	Structures and Improvements	19,387	1.68%	4,959	7	-	326	(88)	18	-	5,222	
4	332	Reservoirs, Dams & Waterways	38,807	1.90%	4,224	6	-	737	(159)	282	-	5,091	
5	333	Water Wheels, Turbines and Gen.	123,171	1.79%	19,819	28	-	2,205	(100)	1,757	-	23,709	
6	334	Accessory Equipment	50,243	3.13%	12,309	17	-	1,573	(72)	453	-	14,281	
7	335	Other Power Plant Equipment	45,649	2.12%	17,621	25	-	968	(97)	-	-	18,517	
8	336	Roads, Railroads and Bridges	1,287	1.44%	419	1	-	19	-	-	-	438	
9			$ 279,505		$ 58,940	$ 83	$ -	$ 5,837	$ (516)	$ 2,510	$ -	$ 66,854	
10		**Transmission Plant**											
11	350	Land Rights-R/W	$ 9,008	0.00%	$ (0)	$ (0)	$ -	$ -	$ -	$ -	$ -	$ (0)	
12	350.1	Land Rights-Clearing	8,234	1.27%	2,148	3	-	105	-	-	-	2,256	
13	353	Station Equipment	242,382	2.33%	87,143	123	-	5,648	(305)	302	-	92,911	
14	355	Poles Towers & Fixtures	115,961	2.52%	31,584	45	-	2,922	(82)	419	-	34,888	
15	356	Conductors and Devices	113,062	2.52%	25,343	36	-	2,849	(87)	465	-	28,606	
16	359	Roads and Trails	1,121	1.96%	369	1	-	22	-	-	-	391	
17			$ 489,769		$ 146,587	$ 207	$ -	$ 11,545	$ (473)	$ 1,186	$ -	$ 159,052	
18		**Distribution Plant**											
19	360	Land Rights-R/W	$ 7,185	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
20	360.1	Land Rights-Clearing	11,630	1.25%	2,499	4	-	145	-	-	-	2,648	
21	362	Station Equipment	254,773	2.61%	75,088	106	-	6,650	(334)	155	-	81,665	
22	364	Poles Towers & Fixtures	225,597	2.73%	64,709	91	-	6,159	(564)	790	-	71,185	
23	365	Conductors and Devices	364,102	2.38%	107,926	152	-	8,666	(641)	1,274	-	117,377	
24	368	Line Transformers	174,968	3.13%	36,822	52	-	5,476	(1,484)	1,312	-	42,178	
25	369	Services	9,521	0.51%	6,660	9	-	49	-	-	-	6,718	
26	370	Meters	50	6.68%	1,229	2	-	3	(1)	-	-	1,234	
27	370.1	AMI Meters	40,998	6.25%	3,945	6	-	2,562	-	-	-	6,513	
28	371	Installation on Customers' Premises	938	0.00%	937	1	-	-	-	-	-	938	
29	373	Street Lighting and Signal System	13,463	4.95%	4,499	6	-	666	(144)	-	-	5,028	
30			$ 1,103,226		$ 304,315	$ 429	$ -	$ 30,377	$ (3,167)	$ 3,530	$ -	$ 335,484	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 7.1

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/19	Opening Balance Adjustment	Amortization Accounting Transition[1]	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/20	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1		**General Plant**											
2	389	Land	$ 11,105	0.00%	$ 34	$ 0	$ -	$ -	$ -	$ -	$ -	$ 34	
3	390	Structures - Frame & Iron	-	0.56%	-	-	-	-	-	-	-	-	
4	390.1	Structures - Masonry	44,853	2.53%	9,610	14	-	1,135	-	-	-	10,758	
5	390.2	Operation Building	15,552	1.63%	6,285	9	-	254	-	-	-	6,548	
6	390.1	Leasehold Improvements	2,872	1.63%	2,559	4	-	47	-	-	-	2,610	
7	391	Office Furniture & Equipment	5,360	4.42%	4,441	6	(2,841)	237	(315)	-	-	1,528	
8	391.1	Computer Equipment	13,285	21.60%	26,861	38	(20,932)	2,870	(2,385)	-	-	6,450	
9	391.2	Computer Software	40,108	8.96%	58,084	82	(39,126)	3,594	(4,750)	-	-	17,884	
10	391.2	AMI Software	9,590	10.00%	4,346	6	-	959	-	-	-	5,311	
11	392.1	Light Duty Vehicles	4,437	3.81%	3,170	4	-	169	(184)	45	-	3,204	
12	392.1	Heavy Duty Vehicles	25,077	6.50%	5,811	8	-	1,630	(1,042)	105	-	6,513	
13	394	Tools and Work Equipment	9,067	4.11%	10,131	14	(5,187)	373	(759)	-	-	4,572	
14	397	Communication Structures & Equipment	14,230	3.44%	13,616	19	(3,188)	490	(3,913)	62	-	7,086	
15	397.1	Fibre	11,766	6.97%	8,799	12	(2,535)	820	(1,448)	-	-	5,650	
16	397.2	AMI Communications Structure & Equipment	4,970	6.67%	1,397	2	-	331	-	-	-	1,730	
17			$ 212,273		$ 155,143	$ 219	$ (73,808)	$ 12,907	$ (14,795)	$ 212	$ -	$ 79,878	
18													
19	108	Total Accumulated Depreciation	$ 2,084,774		$ 664,986	$ 937	$ (73,808)	$ 60,666	$ (18,951)	$ 7,438	$ -	$ 641,268	
20													
21													
22		[1]Explanation											
23													
24		Cross Reference	Schedule 6.1 Line 19 Columns 3+4+5+6										

SCHEDULE NOT APPLICABLE

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 9

Line No.	Particulars	12/31/19	Adjustment	Additions	Retirements	12/31/20	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**	$ 209,719	$ -	$ 11,107	$ -	$ 220,826	
2							
3	**Amortization**	(75,672)	-	(4,194)	-	(79,867)	
4							
5	**Net CIAC**	$ 134,047	$ -	$ 6,913	$ -	$ 140,959	

SCHEDULE NOT APPLICABLE

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	12/31/19	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/20	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	1. Forecasting Variance Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
2									
3	2. Rate Smoothing Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
4									
5	3. Benefits Matching Accounts								
6	Demand Side Management	$ 27,369	$ -	$ 10,600	$ (2,862)	$ (4,532)	$ 30,576	$ 28,972	
7	Deferred Debt Issue Costs	3,352	-	625	(63)	(160)	3,754	3,553	
8	Preliminary and Investigative Charges	825	-	650	-	-	1,476	1,150	Note 1
9	Annual Reviews for 2020 -2024 Rates	-	-	140	(38)	-	102	51	
10	2020 Cost of Service Analysis	-	-	80	(22)	-	58	29	
11	2021 Long-Term Electric Resource Plan	-	19	235	(63)	-	190	104	
12	BCUC-Initiated Inquiry Costs	-	87	176	(48)	-	215	151	
13	MRS 2021 Audit	-	-	-	-	-	-	-	
14		$ 31,546	$ 105	$ 12,507	$ (3,096)	$ (4,691)	$ 36,372	$ 34,012	
15									
16	4. Retroactive Expense Accounts	-	-	-	-	-	-	-	
17									
18	5. Other Accounts								
19	Pension and OPEB Liability	$ (14,253)	$ -	$ 196	$ -	$ -	$ (14,057)	$ (14,155)	
20	Indigenous Relations Agreement (Huth Substation)	-	-	-	-	-	-	-	
21	COVID-19 Customer Recovery Fund	-	-	1,386	(260)	-	1,126	563	
22		$ (14,253)	$ -	$ 1,582	$ (260)	$ -	$ (12,931)	$ (13,592)	
23									
24	**Total Rate Base Deferral Accounts**	$ 17,293	$ 105	$ 14,089	$ (3,355)	$ (4,691)	$ 23,441	$ 20,420	
25									
26	Note 1: Gross additions for Preliminary and Investigative Charges are after transfers to Construction Work in Progress. Additions of $1.339 million - transfers of $0.689 million = $0.650 million.								

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE Schedule 12
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	12/31/19	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/20	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Short Term Interest Rate**								
2									
3	1. Forecasting Variance Accounts								
4	2014-2019 Flow-Through Accounts	$ (7,429)	$ -	$ (46)	$ -	$ 7,475	$ -	$ (3,715)	
5	Pension & Other Post Retirement Benefits (OPEB) Variance	(1,927)	-	-	-	779	(1,148)	(1,538)	
6		$ (9,356)	$ -	$ (46)	$ -	$ 8,254	$ (1,148)	$ (5,252)	
7									
8	2. Rate Smoothing Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
9									
10	3. Benefits Matching Accounts								
11	Annual Reviews for 2015-2019 Rates	$ (14)	$ -	$ -	$ -	$ 14	$ -	$ (7)	
12	Self-Generation Policy Application, Stage II	108	-	-	-	(108)	-	54	
13	Net Metering Program Tariff Update	2	-	-	-	(2)	-	1	
14	2018 Demand Side Management Expenditure Schedule Application	2	-	-	-	(2)	-	1	
15		$ 98	$ -	$ -	$ -	$ (98)	$ -	$ 49	
16									
17	4. Retroactive Expense Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
18									
19	5. Other Accounts								
20	2014-2019 Earnings Sharing Account	$ 145	$ -	$ 52	$ (14)	$ (183)	$ -	$ 72	
21	BC Hydro Waneta 2017 Transactions	19	-	-	-	(19)	-	9	
22		$ 164	$ -	$ 52	$ (14)	$ (202)	$ -	$ 82	
23									
24	**Total Deferral Accounts at Short Term Interest**	$ (9,094)	$ -	$ 6	$ (14)	$ 7,954	$ (1,148)	$ (5,121)	
25									
26	Financing Costs at STI	$ (90)	$ -	$ (96)	$ -	$ 90	$ (96)	$ (93)	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd Schedule 12.1
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	12/31/19	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/20	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Debt**								
2									
3	1. Forecasting Variance Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
4									
5	2. Rate Smoothing Accounts								
6	2018 - 2019 Revenue Surplus	$ (3,458)	$ -	$ 3,326	$ (898)	$ -	$ (1,030)	$ (2,244)	
7									
8	3. Benefits Matching Accounts								
9	CPCN Projects Preliminary Engineering[1]	$ 166	$ -	$ 264	$ -	$ -	$ 430	$ 298	
10	2016 Long Term Electric Resource Plan	310	-	-	-	(103)	207	258	
11	2017 Rate Design Application	590	-	-	-	(118)	472	531	
12	2020 - 2024 Multi-Year Rate Plan Application	589	-	115	(31)	(135)	539	564	
13	2019 - 2022 Multi-Year DSM Expenditure Schedule	108	-	-	-	(36)	72	90	
14	2018 Joint Pole Use Audit	79	-	-	-	(26)	53	66	
15	EV Charging Stations Rate Design and Tariff Application	13	-	80	(34)	-	59	36	
16		$ 1,855	$ -	$ 459	$ (65)	$ (418)	$ 1,831	$ 1,842	
17									
18	4. Retroactive Expense Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
19									
20	5. Other Accounts								
21	US GAAP Pension and OPEB Transitional Obligation	$ 1,389	$ -	$ (347)	$ -	$ -	$ 1,042	$ 1,215	
22	Advanced Metering Infrastructure Radio-Off Shortfall	97	-	-	-	(24)	72	85	
23		$ 1,486	$ -	$ (347)	$ -	$ (24)	$ 1,114	$ 1,300	
24									
25									
26	**Total Deferral Accounts at Weighted Average Cost of Debt**	$ (117)	$ -	$ 3,438	$ (963)	$ (442)	$ 1,915	$ 899	
27									
28	Financing Costs at WACD	$ 151	$ -	$ 47	$ -	$ (151)	$ 47	$ 99	
29									
30	Note 1: Gross additions for CPCN Projects Preliminary Engineering after transfers to Construction Work in Progress.								

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 12.2

Line No.	Particulars	12/31/19	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/20	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Capital**								
2									
3	1. Forecasting Variance Accounts								
4	2020 - 2024 Flow-Through Deferral Account	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5									
6	2. Rate Smoothing Accounts								
7									
8	3. Benefit Matching Accounts								
9	On Bill Financing (OBF) Participant Loans	$ 5	$ -	$ (1)	$ -	$ -	$ 4	$ 4	
10									
11	4. Other								
12	MRP Earnings Sharing Account	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
13									
14	Total Deferral Accounts at Weighted Average Cost of Capital	$ 5	$ -	$ (1)	$ -	$ -	$ 4	$ 4	
15									
16	Financing Costs at AFUDC	$ 1	$ -	$ 0	$ (0)	$ (1)	$ 0	$ 1	
17									
18	**Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50	
19									
20	**Total Non Rate Base Deferral Accounts (including financing)**	$ (9,094)	$ -	$ 3,395	$ (977)	$ 7,450	$ 772	$ (4,162)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 13

Line No.	Particulars	2019 Approved	2020 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 5,077	$ 6,393	$ 1,316	Schedule 14, Line 35, Column 5
3					
4	Add: Funds Unavailable				
5	Customer Loans	470	470	-	
6	Employee Loans	350	340	(10)	
7	Uncollectible Accounts	2,000	-	(2,000)	
8	Inventory (average monthly investment)	650	630	(20)	
9					
10	Less: Funds Available				
11	Average Customer Deposits	(5,470)		5,470	
12	Average Employee Withholdings		(2,120)	(2,120)	
13	Average Provincial Sales Tax	(600)	-	600	
14	Average Goods and Services Tax	(370)	-	370	
15					
16	Total	$ 2,107	$ 5,713	$ 3,606	
17					
18	Note: Uncollectible Accounts and Goods and Services Tax included in Cash Working Capital calculation (Schedule 14) beginning in 2020.				

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 14

Line No.	Particulars	2020 at Revised Rates	Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	$ 180,351	56.0	$ 10,100		
4	Commercial Tariff Revenue	90,083	45.1	4,063		
5	Wholesale Tariff Revenue	48,417	37.5	1,816		
6	Industrial Tariff Revenue	37,965	38.0	1,443		
7	Lighting Tariff Revenue	2,241	34.6	78		
8	Irrigation Tariff Revenue	3,198	47.0	150		
9						
10	**Other Revenue**					
11	Apparatus and Facilities Rental	5,843	90.0	526		
12	Contract Revenue	2,305	62.2	143		
13	Transmission Revenue	1,496	65.2	98		
14	Late Payment Charges	205	54.0	11		
15	Connection Charge	394	30.5	12		
16	Other Recoveries	402	63.4	25		
17						
18	Total	$ 372,900		$ 18,464	49.5	
19						
20	**EXPENSES**					
21	Power Purchases	$ 138,612	51.5	7,139		
22	Wheeling	5,767	46.9	270		
23	Water Fees	10,968	1.4	15		
24	Operating & Maintenance	52,611	28.6	1,505		
25	Property Taxes	16,993	4.9	83		
26	GST	8,212	45.4	373		
27	Income Tax	4,935	15.2	75		
28						
29	Total	$ 238,098		$ 9,460	(39.7)	
30						
31	Net Lag (Lead) Days				9.8	
32						
33	Total Expenses				$ 238,098	
34						
35	Cash Working Capital				$ 6,393	

SCHEDULE NOT APPLICABLE

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 16

Line No.	Particulars	2019 Approved	2020 Forecast at Existing Rates	2020 Forecast Revised Revenue	2020 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (GWh)	3,319	3,272		3,272	(47)	Schedule 17, Line 9, Column 3
3							
4	**REVENUE**						
5	Sales	$ 370,534	$ 358,668	$ -	$ 358,668	$ (11,866)	Schedule 17, Line 19, Column 3
6	Deficiency (Surplus)	-	-	3,587	3,587	3,587	
7	Total	370,534	358,668	3,587	362,255	(8,279)	Schedule 18, Line 8, Column 5
8							
9	**EXPENSES**						
10	Cost of Energy	160,765	155,347	-	155,347	(5,418)	Schedule 19, Line 33, Column 3
11	O&M Expense (net)	50,321	52,611	-	52,611	2,290	Schedule 20, Line 20, Column 4
12	Depreciation & Amortization	48,473	53,899	-	53,899	5,426	Schedule 21, Line 11, Column 3
13	Property Taxes	16,713	16,993	-	16,993	280	Schedule 22, Line 7, Column 3
14	Other Revenue	(9,268)	(10,645)	-	(10,645)	(1,377)	Schedule 23, Line 9, Column 3
15	Deferred 2019 Revenue Surplus / 2020 Revenue Deficiency	5,633	(3,326)	-	(3,326)	(8,959)	
16	Utility Income Before Income Taxes	97,897	93,788	3,587	97,377	(520)	
17							
18	Income Taxes	7,827	3,966	969	4,935	(2,892)	Schedule 24, Line 13, Column 3
19							
20	**EARNED RETURN**	$ 90,071	$ 89,822	$ 2,619	$ 92,442	$ 2,371	Schedule 26, Line 5, Column 7
21							
22	**UTILITY RATE BASE**	$ 1,341,649	$ 1,412,075		$ 1,412,075	$ 70,426	Schedule 2, Line 29, Column 3
23	**RATE OF RETURN ON UTILITY RATE BASE**	6.71%	6.36%		6.55%	-0.16%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 17

Line No.	Particulars	2019 Approved	2020 Projected	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (GWh)**				
2	Residential	1,349	1,289	(60)	
3	Commercial	935	899	(36)	
4	Wholesale	594	573	(21)	
5	Industrial	385	464	79	
6	Lighting	13	10	(3)	
7	Irrigation	42	37	(5)	
8					
9	Total	3,319	3,272	(47)	
10					
11	**REVENUE AT EXISTING RATES**				
12	Residential	$ 187,887	$ 178,565	$ (9,322)	
13	Commercial	94,508	89,191	(5,317)	
14	Wholesale	49,519	47,938	(1,581)	
15	Industrial	32,414	37,589	5,175	
16	Lighting	2,661	2,219	(442)	
17	Irrigation	3,544	3,166	(378)	
18					
19	Total	$ 370,534	$ 358,668	$ (11,865)	

REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 18

Line No.	Particulars	2019 Approved Revenue	2020 Forecast Revenue at Existing Rates	2020 Forecast Effective Increase	2020 Forecast Revenue at Revised Rates	Average Number of Customers	GWh	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 187,887	$ 178,565	$ 1,786	$ 180,351	122,412	1,289	
2	Commercial	94,508	89,191	892	90,083	16,187	899	
3	Wholesale	49,519	47,938	479	48,417	6	573	
4	Industrial	32,414	37,589	376	37,965	54	464	
5	Lighting	2,661	2,219	22	2,241	1,446	10	
6	Irrigation	3,544	3,166	32	3,198	1,084	37	
7								
8	Total	$ 370,534	$ 358,668	$ 3,587	$ 362,255	141,189	3,272	
9								
10	**Effective Increase**				1.00%			

COST OF ENERGY
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 19

Line No.	Particulars	2019 Approved	2020 Projected	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**POWER PURCHASES**				
2	Gross Load (GWh)	3,602	3,562	(40)	
3					
4	**Power Purchase Expense**				
5	Brilliant	$ 41,865	$ 41,505	$ (360)	
6	BC Hydro PPA	52,174	42,088	(10,085)	
7	Waneta Expansion	40,221	40,250	30	
8	Market and Contracted Producers	10,637	14,617	3,980	
9	Independent Power Producers	76	62	(14)	
10	Self-Generators	93	110	17	
11	CPA Balancing Pool	-	18	18	
12	Special and Accounting Adjustments	-	(39)	(39)	
13	Total	$ 145,065	$ 138,612	$ (6,453)	
14					
15	Note 1: No cost is associated with loss recoveries, which are physically delivered to FBC.				
16					
17	**WHEELING**				
18	**Wheeling Nomination (MW months)**				
19	Okanagan Point of Interconnection	2,400	2,400	-	
20	Creston	471	438	(33)	
21					
22	**Wheeling Expense**				
23	Okanagan Point of Interconnect	$ 4,514	$ 4,633	$ 119	
24	Creston	577	551	(26)	
25	Other	144	583	439	
26	Total	$ 5,235	$ 5,767	$ 532	
27					
28	**WATER FEES**				
29	Plant Entitlement Use in previous year (GWh)	1,574	1,604	30	
30					
31	Water Fees	$ 10,465	$ 10,968	$ 503	
32					
33	Total	$ 160,765	$ 155,347	$ (5,418)	

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 20

Line No.	Particulars	Formula O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Inflation Indexed O&M**				
2	2019 Base Unit Cost	$ 412			
3	Net Inflation Factor	2.309%			Schedule 3, Line 9, Column 3
4	Unit Cost O&M	$ 422			Line 2 x (1 + Line 3)
5					
6	2020 Average Customer Forecast - Rate Setting Purposes	140,871			Schedule 3, Line 22, Column 3
7					
8	2020 Inflation Indexed O&M	$ 59,447		$ 59,447	Line 4 x Line 6 / 1000
9					
10	**O&M Tracked Outside of Formula**				
11	Pension & OPEB (O&M Portion)		$ 470		
12	Insurance Premiums		1,691		
13	Upper Bonnington Old Unit Inspections		(43)		
14	BCUC levies		330		
15	Total		$ 2,448	2,448	
16					
17	**Total Gross O&M**			$ 61,895	
18					
19	Capitalized Overhead - 15% of Total Gross O&M			(9,284)	
20	**Net O&M Expense**			$ 52,611	

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 21

Line No.	Particulars	2019 Approved	2020 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 60,265	$ 60,666	$ 401	Schedule 7.1, Line 19, Column 8
3					
4	**Amortization**				
5	Rate Base deferrals	$ 5,313	$ 4,691	$ (622)	Schedule 11, Line 24, Column 6
6	Non-Rate Base deferrals	(13,119)	(7,450)	5,669	Schedule 12.2 , Line 20, Column 6
7	Utility Plant Acquisition Adjustment	186	186	-	
8	CIAC	(4,172)	(4,194)	(22)	Schedule 9, Line 3, Column 4
9		(11,792)	(6,767)	5,025	
10					
11	Total	$ 48,473	$ 53,899	$ 5,426	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 22

Line No.	Particulars	2019 Approved	2020 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Generating Plant	$ 3,082	$ 3,092	$ 10	
2	Transmission and Distribution	6,705	6,756	51	
3	Substation Equipment	3,741	3,825	84	
4	Land and Buildings	1,019	1,057	38	
5	1% In-Lieu of Municipal Taxes	2,166	2,263	97	
6					
7	Total	$ 16,713	$ 16,993	$ 280	

OTHER REVENUE Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	2019 Approved	2020 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Apparatus and Facilities Rental	$ 4,878	$ 5,843	$ 965	
2	Contract Revenue	1,766	2,305	539	
3	Transmission Access Revenue	1,230	1,496	266	
4	Interest Income	16	20	4	
5	Late Payment Charges	861	205	(656)	
6	Connection Charge	376	394	18	
7	Other Recoveries	142	382	240	
8					
9	Total	$ 9,268	$ 10,645	$ 1,377	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 24

Line No.	Particulars	2019 Approved	2020 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 90,071	$ 92,442	$ 2,371	Schedule 16, Line 20, Column 5
2	Deduct: Interest on Debt	(40,956)	(40,760)	196	Schedule 26, Lines 1+2, Column 7
3	Adjustments to Taxable Income	(27,954)	(38,340)	(10,386)	Schedule 24, Line 30, Column 3
4	Accounting Income After Tax	$ 21,161	$ 13,342	$ (7,819)	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 28,988	$ 18,276	$ (10,712)	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 7,827	$ 4,935	$ (2,892)	
11					
12	Previous Year Adjustment	-	-	-	
13	Total Income Tax	$ 7,827	$ 4,935	$ (2,892)	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 60,265	$ 60,666	$ 401	Schedule 21, Line 2, Column 3
19	Amortization of Deferred Charges	(7,806)	(2,759)	5,047	Schedule 21, Lines 5+6, Column 3
20	Amortization of Utility Plant Acquisition Adjustment	186	186	-	Schedule 21, Line 7, Column 3
21	Pension & OPEB Expense	5,304	4,524	(780)	
22					
23	Deductions:				
24	Capital Cost Allowance	(67,203)	(80,952)	(13,749)	Schedule 25, Line 20, Column 6
25	CIAC Amortization	(4,172)	(4,194)	(22)	Schedule 21, Line 8, Column 3
26	Pension & OPEB Contributions	(5,537)	(5,216)	321	
27	Overheads Capitalized Expensed for Tax Purposes	(8,880)	(9,284)	(404)	Schedule 20, Line 19, Column 4
28	Removal Costs	-	(1,200)	(1,200)	
29	All Other	(111)	(111)	-	
30	Total	$ (27,954)	$ (38,340)	$ (10,386)	

CAPITAL COST ALLOWANCE Schedule 25
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Class	CCA Rate	12/31/2019 UCC Balance	Adjustments	2020 Additions	2020 CCA	12/31/2020 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 174,159	$ -	$ -	$ (6,966)	$ 167,193
2	1(b)	6%	32,636	-	3,060	(2,234)	33,463
3	2	6%	13,729	-	-	(824)	12,905
4	3	5%	756	-	-	(38)	718
5	6	10%	4	-	-	(0)	3
6	8	20%	4,412	-	911	(1,156)	4,167
7	9	25%	-	-	-	-	-
8	10	30%	4,642	-	2,700	(2,608)	4,735
9	12	100%	-	-	-	-	-
10	13	0%	11	-	-	-	11
11	14.1	5%	8,430	-	-	(421)	8,008
12	14.1	7%	1,433	-	1,099	(216)	2,317
13	17	8%	115,437	-	21,711	(11,840)	125,308
14	42	12%	6,381	-	1,818	(1,093)	7,106
15	45	45%	3	-	-	(1)	2
16	46	30%	7,896	-	-	(2,369)	5,527
17	47	8%	446,849	-	54,397	(42,276)	458,971
18	50	55%	2,579	-	9,081	(8,910)	2,750
19							
20	Total		$ 819,358	$ -	$ 94,776	$ (80,952)	$ 833,183

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Line No.	Particulars	2019 Approved Earned Return	2020 Amount	2020 Ratio	2020 Average Embedded Cost	2020 Cost Component	2020 Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 38,068	$ 783,000	55.45%	5.05%	2.80%	$ 39,565	$ 1,498	Schedule 27, Line 10, Column 6
2	Short Term Debt	2,888	64,245	4.55%	1.86%	0.08%	1,195	(1,693)	
3	Common Equity	49,115	564,830	40.00%	9.15%	3.66%	51,682	2,567	
4									
5	Total	$ 90,071	$ 1,412,075	100.00%		6.55%	$ 92,442	$ 2,372	
6									
7	Cross Reference		Schedule 2 Line 29 Column 3						

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2020
($000s)

Schedule 27

Line No.	Particulars	Issue Date	Maturity Date	Average Principal Outstanding	Interest Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Series G	August 28, 1993	August 28, 2023	$ 25,000	8.800%	$ 2,200	
2	Series I	December 1, 1997	December 1, 2021	25,000	7.810%	1,953	
3	Series 1 - 05	November 9, 2005	November 9, 2035	100,000	5.600%	5,600	
4	Series 1 - 07	July 4, 2007	July 4, 2047	105,000	5.900%	6,195	
5	MTN - 09	June 2, 2009	June 2, 2039	105,000	6.100%	6,405	
6	MTN - 10	November 24, 2010	November 24, 2050	100,000	5.000%	5,000	
7	MTN - 14	October 28, 2014	October 28, 2044	200,000	4.000%	8,000	
8	MTN - 17	December 4, 2017	December 6, 2049	75,000	3.620%	2,715	
9	MTN - 20	May 11, 2020	May 11, 2050	48,000	3.120%	1,498	
10	Total			$ 783,000		$ 39,565	
11							
12	Average Embedded Cost				5.05%		

SUMMARY OF RATE CHANGE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000,000s)

Schedule 1

Line No.	Particulars	2021 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	(7.388)		
3	Change in Other Revenue	(1.576)	(8.964)	
4				
5	**POWER SUPPLY**			
6	Power Purchases (net of customer growth and volume)	7.648		
7	Wheeling	0.016		
8	Water Fees	0.077	7.742	
9				
10	**O&M CHANGES**			
11	Gross O&M Change	3.219		
12	Capitalized Overhead Change	(0.483)	2.736	
13				
14	**DEPRECIATION EXPENSE**			
15	Depreciation from Net Additions	3.123	3.123	
16				
17	**AMORTIZATION EXPENSE**			
18	CIAC from Net Additions	(0.223)		
19	Deferral Accounts	7.982	7.759	
20				
21	**FINANCING AND RETURN ON EQUITY**			
22	Financing Rate Changes	(0.049)		
23	Financing Ratio Changes	(0.005)		
24	Rate Base Growth	4.400	4.346	
25				
26	**TAX EXPENSE**			
27	Property and Other Taxes Changes	1.249		
28	Other Income Taxes Changes	3.636	4.885	
29				
30	2020 Revenue Deficiency		3.326	
31	2021 Revenue Deficiency		(1.410)	
32				
33	Revenue Deficiency (Surplus)		$ 23.543	Schedule 16, Line 6, Column 4
34				
35	Revenue at Existing Rates		369.643	Schedule 16, Line 5, Column 3
36	Rate Change		6.37%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 2

Line No.	Particulars	2020 Projected	2021 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning [1]	$ 2,112,240	$ 2,162,803	$ 50,564	Schedule 6.1, Line 19, Column 3
2	Opening Balance Adjustment	(47,893)	-	47,893	Schedule 6.1, Line 19, Column 4
3	Net Additions	98,457	126,798	28,341	Schedule 6.1, Line 19, Columns 5+6+7
4	Plant in Service, Ending	2,162,803	2,289,601	126,798	
5					
6	Accumulated Depreciation Beginning	$ (664,986)	$ (641,268)	$ 23,718	Schedule 7.1, Line 19, Column 5
7	Opening Balance Adjustment	72,871	-	(72,871)	Schedule 7.1, Line 19, Column 6
8	Net Additions	(49,153)	(58,763)	(9,610)	Schedule 7.1, Line 19, Columns 7+8+9+10
9	Accumulated Depreciation Ending	(641,268)	(700,031)	(58,763)	
10					
11	CIAC, Beginning	$ (209,719)	$ (220,826)	$ (11,107)	Schedule 9, Line 1, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(11,107)	(11,465)	(358)	Schedule 9, Line 1, Column 4
14	CIAC, Ending	(220,826)	(232,291)	(11,465)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 75,672	$ 79,867	$ 4,194	Schedule 9, Line 3, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	4,194	4,417	222	Schedule 9, Line 3, Column 4
19	Accumulated Amortization Ending - CIAC	79,867	84,283	4,417	
20					
21	Net Plant in Service, Mid-Year	$ 1,359,381	$ 1,411,069	$ 51,689	
22					
23	Adjustment for timing of Capital additions	$ 10,214	$ 20,204	$ 9,990	
24	Capital Work in Progress, No AFUDC	11,228	11,228	-	
25	Unamortized Deferred Charges	20,420	25,728	5,309	Schedule 11, Line 24, Column 8
26	Working Capital	5,713	6,083	370	Schedule 13, Line 12, Column 3
27	Utility Plant Acquistion Adjustment	5,121	4,935	(186)	
28					
29	Mid-Year Utility Rate Base	$ 1,412,075	$ 1,479,247	$ 67,172	
30					
31	Note 1: Pursuant to Order G-9-18, the costs of FBC's Electric Vehicle DCFC stations are excluded from rate base until the Commission directs otherwise.				

FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 3

Line No.	Particulars	Reference	2020	2021	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cost Drivers for O&M**				
2	CPI		2.692%	1.596%	
3	AWE		2.881%	5.946%	
4	Labour Split				
5	Non Labour		38.000%	38.000%	
6	Labour		62.000%	62.000%	
7	Inflation Factor for Costs	(Line 2 x Line 5) + (Line 3 x Line 6)	2.809%	4.293%	
8	Productivity Factor	G-166-20	-0.500%	-0.500%	
9	Net Inflation Factor for Costs	Line 7 + Line 8	2.309%	3.793%	
10					
11					
12	**Growth in Average Customer Calculation**				
13	Average Customer - Prior Year	Prior Year Line 14	139,916	141,189	
14	Average Customer Forecast - Test Year	Schedule 18, Line 8, Column 6	141,189	142,754	
15	Average Customer Change	Line 14 - Line 13	1,273	1,565	
16	Customer Growth Factor Multiplier	G-166-20	75%	75%	
17	Change in Customers - Rate Setting Purposes	Line 15 x Line 17	955	1,174	
18					
19	**Average Customer Continuity for Rate Setting Purposes**				
20	Average Customer Forecast - Prior Year	Prior Year Line 22	139,916	140,871	
21	Change in Customers - Rate Setting Purposes	Line 17	955	1,174	
22	Average Customer Forecast - Rate Setting Purposes	Line 20 + Line 21	**140,871**	**142,045**	

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 4

Line No.	Particulars	2021	Cross Reference
	(1)	(2)	(3)
1	**Forecast Capital Expenditures**		
2	Growth Capital	$ 23,042	
3	Sustainment Capital	49,818	
4	Other Capital	14,712	
5	Total Forecast Capital	$ 87,573	
6			
7	Flow-Through Capital Expenditures	$ -	
8			
9	**Total Regular Capital Expenditures**	$ 87,573	
10			
11	**CPCN and Special Projects**		
12	Corra Linn Spillway Gate Replacement	8,640	
13	Upper Bonnington Old Units Refurbishment	1,782	
14	Grand Forks Terminal Station	2,806	
15	Playmor Substation Rebuild Project	8,710	
16	Total CPCN and Special Projects	$ 21,938	
17			
18	**Total Capital Expenditures Before CIAC**	$ 109,511	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 5

Line No.	Particulars	2021	Cross Reference
	(1)	(2)	(3)
1	**CAPITAL EXPENDITURES**		
2			
3	Forecast Capital Expenditures	87,573	
4	Flow-Through Capital Expenditures	-	
5	Total Regular Capital Expenditures	$ 87,573	Schedule 4, Column 2, Line 9
6			
7	**CPCN and Special Projects**		
8	Corra Linn Spillway Gate Replacement	8,640	
9	Upper Bonnington Old Units Refurbishment	1,782	
10	Grand Forks Terminal Station	2,806	
11	Playmor Substation Rebuild Project	8,710	
12	Total CPCN and Special Projects	$ 21,938	Schedule 4, Column 2, Line 16
13			
14	**Total Capital Expenditures**	$ 109,511	Schedule 4, Column 2, Line 18
15			
16			
17	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**		
18			
19	Regular Capital Expenditures	$ 87,573	Schedule 5, Column 2, Line 5
20	Add - Capitalized Overheads	9,767	Schedule 20, Line 20, Column 4
21	Add - AFUDC	542	
22	Gross Capital Expenditures	$ 97,882	
23	Change in Work in Progress	5,717	
24	**Total Additions to Plant**	$ 103,599	
25			
26			
27	**CPCN and Special Projects**	$ 21,938	Schedule 5, Column 2, Line 12
28	Add - AFUDC	1,857	
29	Gross Capital Expenditures	23,795	
30	Change in Work in Progress	16,612	
31	**Total Additions to Plant**	$ 40,407	
32			
33	**Grand Total Additions to Plant**	$ 144,006	Schedule 6.1, Line 19, Columns 5 + 6

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 6

Line No.	Account	Particulars	12/31/20	Opening Bal. Adjustment	CPCNs	Additions	Retirements	12/31/21	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Hydraulic Production Plant**							
2	330	Land Rights	$ 962	$ -	$ -	$ -	$ -	$ 962	
3	331	Structures and Improvements	19,914	-	-	782	(88)	20,607	
4	332	Reservoirs, Dams & Waterways	40,742	-	1,616	3,987	(159)	46,186	
5	333	Water Wheels, Turbines and Gen.	124,237	-	22,621	1,286	(100)	148,044	
6	334	Accessory Equipment	51,203	-	4,847	1,755	(72)	57,733	
7	335	Other Power Plant Equipment	46,497	-	-	1,264	(97)	47,664	
8	336	Roads, Railroads and Bridges	1,287	-	-	-	-	1,287	
9			$ 284,841	$ -	$ 29,084	$ 9,074	$ (516)	$ 322,483	
10		**Transmission Plant**							
11	350	Land Rights-R/W	$ 9,613	$ -	$ -	$ 610	$ -	$ 10,222	
12	350.1	Land Rights-Clearing	8,838	-	-	610	-	9,448	
13	353	Station Equipment	244,155	-	9,705	2,786	(305)	256,342	
14	355	Poles Towers & Fixtures	119,868	-	-	3,021	(82)	122,807	
15	356	Conductors and Devices	116,964	-	-	3,021	(87)	119,898	
16	359	Roads and Trails	1,121	-	162	-	-	1,283	
17			$ 500,559	$ -	$ 9,867	$ 10,047	$ (473)	$ 520,000	
18		**Distribution Plant**						-	
19	360	Land Rights-R/W	$ 7,185	$ -	$ -	$ -	$ -	$ 7,185	
20	360.1	Land Rights-Clearing	11,630	-	-	-	-	11,630	
21	362	Station Equipment	268,899	-	-	19,498	(334)	288,063	
22	364	Poles Towers & Fixtures	236,995	-	-	11,599	(564)	248,030	
23	365	Conductors and Devices	389,251	-	1,457	25,932	(641)	415,999	
24	368	Line Transformers	180,815	-	-	7,671	(1,484)	187,002	
25	369	Services	9,521	-	-	-	-	9,521	
26	370	Meters	50	-	-	-	(1)	49	
27	370.1	AMI Meters	41,137	-	-	144	-	41,281	
28	371	Installation on Customers' Premises	938	-	-	-	-	938	
29	373	Street Lighting and Signal System	14,184	-	-	82	(144)	14,123	
30			$ 1,160,606	$ -	$ 1,457	$ 64,926	$ (3,167)	$ 1,223,821	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 6.1

Line No.	Account	Particulars	12/31/20	Opening Bal. Adjustment	CPCNs	Additions	Retirements	12/31/21	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**General Plant**							
2	389	Land	$ 11,105	$ -	$ -	$ -	$ -	$ 11,105	
3	390	Structures - Frame & Iron	-	-	-	-	-	-	
4	390.1	Structures - Masonry	46,536	-	-	1,180	-	47,716	
5	390.2	Operation Building	17,235	-	-	1,180	-	18,415	
6	390.1	Leasehold Improvements	2,872	-	-	-	-	2,872	
7	391	Office Furniture & Equipment	5,269	-	-	327	(243)	5,354	
8	391.1	Computer Equipment	14,419	-	-	3,599	(4,825)	13,193	
9	391.2	Computer Software	40,461	-	-	5,068	(4,188)	41,342	
10	391.2	AMI Software	10,954	-	-	1,312	-	12,265	
11	392.1	Light Duty Vehicles	5,144	-	-	916	(184)	5,875	
12	392.1	Heavy Duty Vehicles	26,114	-	-	2,137	(1,042)	27,209	
13	394	Tools and Work Equipment	9,086	-	-	642	(860)	8,869	
14	397	Communication Structures & Equipment	12,316	-	-	3,189	(1,708)	13,798	
15	397.1	Fibre	10,318	-	-	-	(3)	10,316	
16	397.2	AMI Communications Structure & Equipment	4,970	-	-	-	-	4,970	
17			$ 216,798	$ -	$ -	$ 19,551	$ (13,051)	$ 223,298	
18									
19		**Total Plant in Service**	$ 2,162,803	$ -	$ 40,407	$ 103,598	$ (17,208)	$ 2,289,601	
20									
21		Cross Reference			Schedule 5 Line 31 Column 2	Schedule 5 Line 24 Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/20	Opening Bal. Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/21	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Hydraulic Production Plant**										
2	330	Land Rights	$ 962	1.07%	$ (403)	$ -	$ 10	$ -	$ -	$ -	$ (393)	
3	331	Structures and Improvements	19,914	1.68%	5,222	-	335	(88)	8	-	5,476	
4	332	Reservoirs, Dams & Waterways	42,358	1.90%	5,091	-	805	(159)	259	-	5,996	
5	333	Water Wheels, Turbines and Gen.	146,858	1.79%	23,709	-	2,629	(100)	1,574	-	27,811	
6	334	Accessory Equipment	56,050	3.13%	14,281	-	1,754	(72)	409	-	16,373	
7	335	Other Power Plant Equipment	46,497	2.12%	18,517	-	986	(97)	-	-	19,406	
8	336	Roads, Railroads and Bridges	1,287	1.44%	438	-	19	-	-	-	457	
9			$ 313,925		$ 66,854	$ -	$ 6,537	$ (516)	$ 2,250	$ -	$ 75,125	
10		**Transmission Plant**										
11	350	Land Rights-R/W	$ 9,613	0.00%	$ (0)	$ -	$ -	$ -	$ -	$ -	$ (0)	
12	350.1	Land Rights-Clearing	8,838	1.27%	2,256	-	112	-	-	-	2,368	
13	353	Station Equipment	253,861	2.33%	92,911	-	5,915	(305)	493	-	99,014	
14	355	Poles Towers & Fixtures	119,868	2.52%	34,888	-	3,021	(82)	421	-	38,247	
15	356	Conductors and Devices	116,964	2.52%	28,606	-	2,947	(87)	4,789	-	36,256	
16	359	Roads and Trails	1,283	1.96%	391	-	25	-	-	-	416	
17			$ 510,426		$ 159,052	$ -	$ 12,020	$ (473)	$ 5,703	$ -	$ 176,302	
18		**Distribution Plant**										
19	360	Land Rights-R/W	$ 7,185	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
20	360.1	Land Rights-Clearing	11,630	1.25%	2,648	-	145	-	-	-	2,793	
21	362	Station Equipment	268,899	2.61%	81,665	-	7,018	(334)	469	-	88,817	
22	364	Poles Towers & Fixtures	236,995	2.73%	71,185	-	6,470	(564)	841	-	77,932	
23	365	Conductors and Devices	390,708	2.38%	117,377	-	9,299	(641)	1,357	-	127,392	
24	368	Line Transformers	180,815	3.13%	42,178	-	5,660	(1,484)	1,351	-	47,704	
25	369	Services	9,521	0.51%	6,718	-	49	-	-	-	6,767	
26	370	Meters	50	6.68%	1,234	-	3	(1)	-	-	1,236	
27	370.1	AMI Meters	41,137	6.25%	6,513	-	2,571	-	-	-	9,084	
28	371	Installation on Customers' Premises	938	0.00%	938	-	-	-	-	-	938	
29	373	Street Lighting and Signal System	14,184	4.95%	5,028	-	702	(144)	-	-	5,586	
30			$ 1,162,063		$ 335,484	$ -	$ 31,917	$ (3,167)	$ 4,018	$ -	$ 368,251	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 7.1

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/20	Opening Bal. Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/21	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**General Plant**										
2	389	Land	$ 11,105	0.00%	$ 34	$ -	$ -	$ -	$ -	$ -	$ 34	
3	390	Structures - Frame & Iron	-	0.56%	-	-	-	-	-	-	-	
4	390.1	Structures - Masonry	46,536	2.53%	10,758	-	1,177	-	-	-	11,935	
5	390.2	Operation Building	17,235	1.63%	6,548	-	281	-	-	-	6,829	
6	390.1	Leasehold Improvements	2,872	1.63%	2,610	-	47	-	-	-	2,656	
7	391	Office Furniture & Equipment	5,269	4.42%	1,528	-	233	(243)	-	-	1,518	
8	391.1	Computer Equipment	14,419	21.60%	6,450	-	3,114	(4,825)	-	-	4,740	
9	391.2	Computer Software	40,461	8.96%	17,884	-	3,625	(4,188)	-	-	17,322	
10	391.2	AMI Software	10,954	10.00%	5,311	-	1,095	-	-	-	6,406	
11	392.1	Light Duty Vehicles	5,144	3.81%	3,204	-	196	(184)	45	-	3,261	
12	392.1	Heavy Duty Vehicles	26,114	6.50%	6,513	-	1,697	(1,042)	105	-	7,274	
13	394	Tools and Work Equipment	9,086	4.11%	4,572	-	373	(860)	-	-	4,086	
14	397	Communication Structures & Equipment	12,316	3.44%	7,086	-	424	(1,708)	62	-	5,864	
15	397.1	Fibre	10,318	6.97%	5,650	-	719	(3)	-	-	6,366	
16	397.2	AMI Communications Structure & Equipment	4,970	6.67%	1,730	-	331	-	-	-	2,061	
17			$ 216,798		$ 79,878	$ -	$ 13,314	$ (13,051)	$ 212	$ -	$ 80,353	
18												
19	108	Total Accumulated Depreciation	$ 2,203,211		$ 641,268	$ -	$ 63,789	$ (17,208)	$ 12,182	$ -	$ 700,031	
20												
21		Cross Reference	Schedule 6.1									
22			Line 19									
23			Columns 3+4+5									

SCHEDULE NOT APPLICABLE

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 9

Line No.	Particulars	12/31/20	Adjustment	Additions	Retirements	12/31/21	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**	$ 220,826	$ -	$ 11,465	$ -	$ 232,291	
2							
3	**Amortization**	(79,867)	-	(4,417)	-	(84,283)	
4							
5	**Net CIAC**	$ 140,959	$ -	$ 7,048	$ -	$ 148,008	

SCHEDULE NOT APPLICABLE

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Particulars	12/31/20	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/21	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	1. Forecasting Variance Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
2									
3	2. Rate Smoothing Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
4									
5	3. Benefits Matching Accounts								
6	Demand Side Management	$ 30,576	$ -	$ 11,100	$ (2,997)	$ (5,040)	$ 33,639	$ 32,107	
7	Deferred Debt Issue Costs	3,754	-	625	(97)	(178)	4,104	3,929	
8	Preliminary and Investigative Charges	1,476	-	365	-	-	1,840	1,658	Note 1
9	Annual Reviews for 2020 -2024 Rates	102	-	140	(38)	(102)	102	102	
10	2020 Cost of Service Analysis	58	-	20	(5)	-	73	66	
11	2021 Long-Term Electric Resource Plan	190	-	145	(39)	-	296	243	
12	BCUC-Initiated Inquiry Costs	215	-	5	(1)	(215)	4	110	
13	MRS 2021 Audit	-	-	350	(95)	-	256	128	
14		$ 36,372	$ -	$ 12,750	$ (3,272)	$ (5,536)	$ 40,313	$ 38,342	
15									
16	4. Retroactive Expense Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
17									
18	5. Other Accounts								
19	Pension and OPEB Liability	$ (14,057)	$ -	$ (218)	$ -	$ -	$ (14,275)	$ (14,166)	
20	Indigenous Relations Agreement (Huth Substation)	-	-	-	-	-	-	-	
21	COVID-19 Customer Recovery Fund	1,126	-	1,323	(472)	-	1,978	1,552	
22		$ (12,931)	$ -	$ 1,105	$ (472)	$ -	$ (12,298)	$ (12,614)	
23									
24	**Total Rate Base Deferral Accounts**	$ 23,441	$ -	$ 13,854	$ (3,744)	$ (5,536)	$ 28,016	$ 25,728	
25									

26 Note 1: Gross additions for Preliminary and Investigative Charges are after transfers to Construction Work in Progress.
Additions of $1.045 million - transfers of $0.680 million = $0.365 million.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 12

Line No.	Particulars	12/31/20	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/21	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Short Term Interest Rate**								
2									
3	1. Forecasting Variance Accounts								
4	Pension & Other Post Retirement Benefits (OPEB) Variance	$ (1,148)	$ -	$ -	$ -	$ 706	$ (442)	$ (795)	
5									
6	2. Rate Smoothing Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
7									
8	3. Benefits Matching Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
9									
10	4. Retroactive Expense Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
11									
12	5. Other Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
13									
14	**Total Deferral Accounts at Short Term Interest**	$ (1,148)	$ -	$ -	$ -	$ 706	$ (442)	$ (795)	
15									
16	Financing Costs at STI	$ (96)	$ -	$ (19)	$ -	$ 96	$ (19)	$ (57)	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Particulars	12/31/20	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/21	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Debt**								
2									
3	1. Forecasting Variance Accounts								
4									
5	2. Rate Smoothing Accounts								
6	2018 - 2019 Revenue Surplus	$ (1,030)	$ -	$ 1,410	$ (381)	$ -	$ -	$ (515)	
7									
8	3. Benefits Matching Accounts								
9	CPCN Projects Preliminary Engineering[1]	$ 430	$ -	$ (430)	$ -	$ -	$ -	$ 215	
10	2016 Long Term Electric Resource Plan	207	-	-	-	(103)	103	155	
11	2017 Rate Design Application	472	-	-	-	(118)	354	413	
12	2020 - 2024 Multi-Year Rate Plan Application	539	-	-	-	(135)	404	471	
13	2019 - 2022 Multi-Year DSM Expenditure Schedule	72	-	-	-	(36)	36	54	
14	2018 Joint Pole Use Audit	53	-	-	-	(26)	26	40	
15	EV Charging Stations Rate Design and Tariff Application	59	-	170	(34)	-	196	127	
16		$ 1,831	$ -	$ (260)	$ (34)	$ (418)	$ 1,119	$ 1,475	
17									
18	4. Retroactive Expense Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
19									
20	5. Other Accounts								
21	US GAAP Pension and OPEB Transitional Obligation	1,042	$ -	$ (347)	$ -	$ -	$ 695	$ 868	
22	Advanced Metering Infrastructure Radio-Off Shortfall	72	-	-	-	(24)	48	60	
23		$ 1,114	$ -	$ (347)	$ -	$ (24)	$ 743	$ 929	
24									
25									
26	**Total Deferral Accounts at Weighted Average Cost of Debt**	$ 1,915	$ -	$ 804	$ (415)	$ (442)	$ 1,862	$ 1,889	
27									
28	Financing Costs at WACD	47	$ -	$ 92	$ -	$ (47)	$ 92	$ 69	

29 Note 1: Gross additions for CPCN Projects Preliminary Engineering after transfers to Construction Work in Progress.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd Schedule 12.2
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Particulars	12/31/20	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/21	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Deferral Accounts Financed at Weighted Average Cost of Capital**								
2									
3	1. Forecasting Variance Accounts								
4	2020 - 2024 Flow-Through Deferral Account	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5									
6	2. Rate Smoothing Accounts	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
7									
8	3. Benefit Matching Accounts								
9	On Bill Financing (OBF) Participant Loans	$ 4	$ -	$ -	$ -	$ -	$ 4	$ 4	
10									
11	4. Other								
12	MRP Earnings Sharing Account	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
13									
14	Total Deferral Accounts at Weighted Average Cost of Capital	$ 4	$ -	$ -	$ -	$ -	$ 4	$ 4	
15									
16	Financing Costs at AFUDC	$ 0	$ -	$ -	$ -	$ (0)	$ -	$ 0	
17									
18	**Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50	
19									
20	**Total Non Rate Base Deferral Accounts (including financing)**	$ 772	$ -	$ 877	$ (415)	$ 313	$ 1,547	$ 1,160	

WORKING CAPITAL ALLOWANCE Schedule 13
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Particulars	2020 Projected	2021 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 6,393	$ 6,805	$ 412	Schedule 14, Line 35, Column 5
3					
4	Add: Funds Unavailable				
5	Customer Loans	470	470	-	
6	Employee Loans	340	340	-	
7	Inventory (average monthly investment)	630	630	-	
8					
9	Less: Funds Available				
10	Average Employee Withholdings	(2,120)	(2,163)	(42)	
11					
12	Total	$ 5,713	$ 6,083	$ 370	
13					
14	Note: Uncollectible Accounts and Goods and Services Tax included in Cash Working Capital calculation (Schedule 14) beginning in 2020.				

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 14

Line No.	Particulars	2021 at Revised Rates	Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	$ 187,311	56.0	$ 10,489		
4	Commercial Tariff Revenue	101,955	45.1	4,598		
5	Wholesale Tariff Revenue	52,617	37.5	1,973		
6	Industrial Tariff Revenue	45,638	38.0	1,734		
7	Lighting Tariff Revenue	2,305	34.6	80		
8	Irrigation Tariff Revenue	3,361	47.0	158		
9						
10	**Other Revenue**					
11	Apparatus and Facilities Rental	5,930	90.0	534		
12	Contract Revenue	3,088	62.2	192		
13	Transmission Revenue	1,501	65.2	98		
14	Late Payment Charges	829	54.0	45		
15	Connection Charge	476	30.5	15		
16	Other Recoveries	397	63.4	25		
17						
18	Total	$ 405,408		$ 19,941	49.2	
19						
20	**EXPENSES**					
21	Power Purchases	$ 146,260	51.5	7,532		
22	Wheeling	5,783	46.9	271		
23	Water Fees	11,045	1.4	15		
24	Operating & Maintenance	55,347	28.6	1,583		
25	Property Taxes	18,242	4.9	89		
26	GST	8,212	45.4	373		
27	Income Tax	8,571	15.2	130		
28						
29	Total	$ 253,461		$ 9,995	(39.4)	
30						
31	Net Lag (Lead) Days				9.8	
32						
33	Total Expenses				$ 253,461	
34						
35	Cash Working Capital				$ 6,805	

SCHEDULE NOT APPLICABLE

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 16

Line No.	Particulars	2020 Projected	2021 Forecast At 2020 Approved Interim Rates	2021 Forecast Revised Revenue	2021 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (GWh)	3,272	3,356		3,356	84	Schedule 17, Line 9, Column 3
3							
4	**REVENUE**						
5	Sales	$ 362,255	$ 369,643	$ -	$ 369,643	$ 7,388	Schedule 17, Line 19, Column 3
6	Deficiency (Surplus)		-	23,544	23,544	23,544	
7	Total	362,255	369,643	23,544	393,187	30,932	Schedule 18, Line 8, Column 5
8							
9	**EXPENSES**						
10	Cost of Energy	155,347	163,089	-	163,089	7,742	Schedule 19, Line 31, Column 3
11	O&M Expense (net)	52,611	55,347	-	55,347	2,736	Schedule 20, Line 21, Column 4
12	Depreciation & Amortization	53,899	64,781	-	64,781	10,882	Schedule 21, Line 11, Column 3
13	Property Taxes	16,993	18,242	-	18,242	1,249	Schedule 22, Line 7, Column 3
14	Other Revenue	(10,645)	(12,221)	-	(12,221)	(1,576)	Schedule 23, Line 9, Column 3
15	Deferred 2020/2021 Revenue Deficiency	(3,326)	(1,410)	-	(1,410)	1,916	
16	Utility Income Before Income Taxes	97,377	81,815	23,544	105,359	7,982	
17							
18	Income Taxes	4,935	2,214	6,357	8,571	3,636	Schedule 24, Line 13, Column 3
19							
20	**EARNED RETURN**	$ 92,442	$ 79,601	$ 17,187	$ 96,788	$ 4,346	Schedule 26, Line 5, Column 7
21							
22	**UTILITY RATE BASE**	$ 1,412,075	$ 1,479,247		$ 1,479,247	$ 67,172	Schedule 2, Line 29, Column 3
23	**RATE OF RETURN ON UTILITY RATE BASE**	6.55%	5.38%		6.54%	0.00%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 17

Line No.	Particulars	2020 Projected	2021 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (GWh)**				
2	Residential	1,289	1,252	(37)	
3	Commercial	899	937	38	
4	Wholesale	573	584	11	
5	Industrial	464	537	73	
6	Lighting	10	10	-	
7	Irrigation	37	36	(1)	
8					
9	Total	3,272	3,356	84	
10					
11	**REVENUE AT APPROVED RATES**				
12	Residential	$ 178,565	$ 176,095	$ (2,470)	
13	Commercial	89,191	95,850	6,659	
14	Wholesale	47,938	49,466	1,528	
15	Industrial	37,589	42,905	5,316	
16	Lighting	2,219	2,167	(52)	
17	Irrigation	3,166	3,160	(6)	
18					
19	Total	$ 358,668	$ 369,643	$ 10,975	

REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Particulars	2020 Projected Revenue	2021 Forecast At 2020 Approved Interim Rates	2021 Forecast Effective Increase	2021 Forecast Revenue at Revised Rates	Average Number of Customers	GWh	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 180,351	$ 176,095	$ 11,216	$ 187,311	124,055	1,252	
2	Commercial	90,083	95,850	6,105	101,955	16,148	937	
3	Wholesale	48,417	49,466	3,151	52,617	6	584	
4	Industrial	37,965	42,905	2,733	45,638	59	537	
5	Lighting	2,241	2,167	138	2,305	1,405	10	
6	Irrigation	3,198	3,160	201	3,361	1,082	36	
7								
8	Total	$ 362,255	$ 369,643	$ 23,544	$ 393,187	142,754	3,356	
9								
10	**Effective Increase**				6.37%			

COST OF ENERGY
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 19

Line No.	Particulars	2020 Projected	2021 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**POWER PURCHASES**				
2	Gross Load (GWh)	3,562	3,646	84	
3					
4	**Power Purchase Expense**				
5	Brilliant	$ 41,505	$ 41,027	$ (478)	
6	BC Hydro PPA	42,088	48,882	6,794	
7	Waneta Expansion	40,250	41,462	1,212	
8	Market and Contracted Producers	14,617	14,751	134	
9	Independent Power Producers	62	76	14	
10	Self-Generators	110	61	(49)	
11	CPA Balancing Pool	18	(0)	(18)	
12	Special and Accounting Adjustments	(39)	-	39	
13	Total	$ 138,612	$ 146,260	$ 7,648	
14					
15	**WHEELING**				
16	**Wheeling Nomination (MW months)**				
17	Okanagan Point of Interconnection	2,400	2,400	-	
18	Creston	438	420	(18)	
19					
20	**Wheeling Expense**				
21	Okanagan Point of Interconnect	$ 4,633	$ 4,694	$ 60	
22	Creston	551	535	(16)	
23	Other	583	555	(28)	
24	Total	$ 5,767	$ 5,783	$ 16	
25					
26	**WATER FEES**				
27	Plant Entitlement Use in previous year (GWh)	1,604	1,585	(19)	
28					
29	Water Fees	$ 10,968	$ 11,045	$ 77	
30					
31	Total	$ 155,347	$ 163,089	$ 7,742	

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 20

Line No.	Particulars	Formula O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Inflation Indexed O&M**				
2	2020 Base Unit Cost	$ 422			
3	GFT Reliability Project O&M Reduction	(0.6)			
4	Adjusted Base Unit Cost	$ 421			
5	Net Inflation Factor	3.793%			Schedule 3, Line 9, Column 4
6	2021 Base Unit Cost	$ 437			Line 4 x (1 + Line 5)
7					
8	2021 Average Customer Forecast - Rate Setting Purposes	142,045			Schedule 3, Line 22, Column 4
9					
10	2021 Inflation Indexed O&M	$ 62,073		$ 62,073	Line 6 x Line 8 / 1000
11					
12	**O&M Tracked Outside of Formula**				
13	Pension & OPEB (O&M Portion)		$ 775		
14	Insurance Premiums		1,916		
15	BCUC levies		350		
16	Total		$ 3,041	3,041	
17					
18	**Total Gross O&M**			$ 65,114	
19					
20	Capitalized Overhead - 15% of Total Gross O&M			(9,767)	
21	**Net O&M Expense**			$ 55,347	

Schedule 21

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Particulars	2020 Projected	2021 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 60,666	$ 63,789	$ 3,123	Schedule 7.1, Line 19, Column 7
3					
4	**Amortization**				
5	Rate Base deferrals	$ 4,691	$ 5,536	$ 845	Schedule 11, Line 24, Column 6
6	Non-Rate Base deferrals	(7,450)	(313)	7,137	Schedule 12.2, Line 20, Column 6
7	Utility Plant Acquisition Adjustment	186	186	-	
8	CIAC	(4,194)	(4,417)	(223)	Schedule 9, Line 3, Column 4
9		(6,767)	992	7,759	
10					
11	Total	$ 53,899	$ 64,781	$ 10,882	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 22

Line No.	Particulars	2020 Projected	2021 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Generating Plant	$ 3,092	$ 3,087	$ (5)	
2	Transmission and Distribution	6,756	8,075	1,319	
3	Substation Equipment	3,825	3,843	18	
4	Land and Buildings	1,057	1,112	55	
5	1% In-Lieu of Municipal Taxes	2,263	2,125	(138)	
6					
7	Total	$ 16,993	$ 18,242	$ 1,249	

Schedule 23

OTHER REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Particulars	2020 Projected	2021 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Apparatus and Facilities Rental	$ 5,843	$ 5,930	$ 87	
2	Contract Revenue	2,305	3,088	783	
3	Transmission Access Revenue	1,496	1,501	5	
4	Interest Income	20	20	-	
5	Late Payment Charges	205	829	624	
6	Connection Charge	394	476	82	
7	Other Recoveries	382	377	(5)	
8					
9	Total	$ 10,645	$ 12,221	$ 1,576	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 24

Line No.	Particulars	2020 Projected	2021 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 92,442	$ 96,788	$ 4,346	Schedule 16, Line 20, Column 5
2	Deduct: Interest on Debt	(40,760)	(42,647)	(1,887)	Schedule 26, Lines 1+2, Column 7
3	Adjustments to Taxable Income	(38,340)	(30,968)	7,373	Schedule 24, Line 30, Column 3
4	Accounting Income After Tax	$ 13,342	$ 23,173	$ 9,831	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 18,276	$ 31,744	$ 13,468	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 4,935	$ 8,571	$ 3,636	
11					
12	Previous Year Adjustment	-	-	-	
13	Total Income Tax	$ 4,935	$ 8,571	$ 3,636	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 60,666	$ 63,789	$ 3,123	Schedule 21, Line 2, Column 3
19	Amortization of Deferred Charges	(2,759)	5,223	7,982	Schedule 21, Lines 5+6, Column 3
20	Amortization of Utility Plant Acquisition Adjustment	186	186	-	Schedule 21, Line 7, Column 3
21	Pension & OPEB Expense	4,524	5,804	1,280	
22		-			
23	Deductions:	-			
24	Capital Cost Allowance	(80,952)	(85,236)	(4,284)	Schedule 25, Line 20, Column 6
25	CIAC Amortization	(4,194)	(4,417)	(223)	Schedule 21, Line 8, Column 3
26	Pension & OPEB Contributions	(5,216)	(5,239)	(23)	
27	Overheads Capitalized Expensed for Tax Purposes	(9,284)	(9,767)	(483)	Schedule 20, Line 20, Column 4
28	Removal Costs	(1,200)	(1,200)	-	
29	All Other	(111)	(111)	-	
30	Total	$ (38,340)	$ (30,968)	$ 7,373	

CAPITAL COST ALLOWANCE Schedule 25
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Line No.	Class	CCA Rate	12/31/2020 UCC Balance	Adjustments	2021 Additions	2021 CCA	12/31/2021 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 167,193	$ -	$ -	$ (6,688)	$ 160,505
2	1(b)	6%	33,463	-	2,040	(2,191)	33,311
3	2	6%	12,905	-	-	(774)	12,131
4	3	5%	718	-	-	(36)	682
5	6	10%	3	-	-	(0)	3
6	8	20%	4,167	-	874	(1,096)	3,946
7	9	25%	-	-	-	-	-
8	10	30%	4,735	-	2,770	(2,667)	4,838
9	12	100%	-	-	-	-	-
10	13	0%	11	-	-	-	11
11	14.1	5%	8,008	-	-	(400)	7,608
12	14.1	7%	2,317	-	552	(220)	2,649
13	17	8%	125,308	-	37,311	(14,502)	148,117
14	42	12%	7,106	-	2,983	(1,390)	8,700
15	45	45%	2	-	-	(1)	1
16	46	30%	5,527	-	-	(1,658)	3,869
17	47	8%	458,971	-	66,122	(44,652)	480,440
18	50	55%	2,750	-	9,028	(8,960)	2,817
19							
20	Total		$ 833,183	$ -	$ 121,680	$ (85,236)	$ 869,627

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 26

Line No.	Particulars	2020 Projected Earned Return	2021 Amount	2021 Ratio	2021 Average Embedded Cost	2021 Cost Component	2021 Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 39,565	$ 845,500	57.16%	4.93%	2.82%	$ 41,714	$ 2,149	Schedule 27, Line 11, Column 6
2	Short Term Debt	1,195	42,048	2.84%	2.22%	0.06%	933	(261)	
3	Common Equity	51,682	591,699	40.00%	9.15%	3.66%	54,140	2,458	
4									
5	Total	$ 92,442	$ 1,479,247	100.00%		6.54%	$ 96,788	$ 4,346	
6									
7	Cross Reference		Schedule 2 Line 29 Column 3						

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2021
($000s)

Schedule 27

Line No.	Particulars	Issue Date	Maturity Date	Average Principal Outstanding	Interest Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Series G	August 28, 1993	August 28, 2023	$ 25,000	8.800%	$ 2,200	
2	Series I	December 1, 1997	December 1, 2021	23,000	7.810%	1,796	
3	Series 1 - 05	November 9, 2005	November 9, 2035	100,000	5.600%	5,600	
4	Series 1 - 07	July 4, 2007	July 4, 2047	105,000	5.900%	6,195	
5	MTN - 09	June 2, 2009	June 2, 2039	105,000	6.100%	6,405	
6	MTN - 10	November 24, 2010	November 24, 2050	100,000	5.000%	5,000	
7	MTN - 14	October 28, 2014	October 28, 2044	200,000	4.000%	8,000	
8	MTN - 17	December 4, 2017	December 6, 2049	75,000	3.620%	2,715	
9	MTN - 20	May 11, 2020	May 11, 2050	75,000	3.120%	2,340	
10	MTN - 21	July 1, 2021	July 1, 2051	37,500	3.900%	1,463	
11	Total			$ 845,500		$ 41,714	
12							
13	Average Embedded Cost				4.93%		

12. ACCOUNTING MATTERS

12.1 *INTRODUCTION AND OVERVIEW*

In this section, FBC discusses "Exogenous Factors" under its MRP (identifying one potential exogenous factor that affects 2020), emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FBC requests approval for the disposition of two existing deferral accounts. FBC also provides information on the Flow-through deferral account.

12.2 *EXOGENOUS (Z) FACTORS*

FBC is permitted to adjust the cost of service for "Exogenous Factors" under the MRP. The BCUC established the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment:

1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;
2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;
3. The impact of the event was unforeseen;
4. The costs must be prudently incurred; and
5. The costs/savings related to each exogenous event must exceed the BCUC-defined materiality threshold.

The materiality threshold (item 5) for FBC has been established at $0.150 million, as approved in the MRP Decision.

The COVID-19 pandemic is a potential exogenous factor affecting 2020 and future years, as described below.

12.2.1 COVID-19 Pandemic

During the COVID-19 public health emergency, FBC has taken the necessary steps as a critical infrastructure service provider to ensure the health, safety and well-being of its customers, employees and their communities, and to continue to operate its system safely and reliably.

Any incremental O&M and capital impacts related to COVID-19 would meet the first three Exogenous Factor requirements based on the following:

- The COVID-19 pandemic is an event outside the control of a prudently operated utility.

- Costs to address COVID-19 were not included in the 2019 Base O&M expense or the forecast regular capital expenditures approved as part of the MRP. Therefore, these costs would satisfy the criterion that they be "outside the base upon which rates were originally derived".

- The COVID-19 pandemic started to have measurable impacts in mid-March 2020 in BC, and was unforeseen at the time of the close of evidence related to the MRP Application. The BCUC commented on the pandemic in the MRP Decision,[36] stating that the pandemic has raised questions about the validity of some fundamental assumptions underlying various elements of the MRPs. The BCUC concluded that the situation is fluid with many uncertainties and outcomes that are difficult to predict and manage in the circumstances and that the BCUC must adjudicate the merits of the MRP Application based on the evidence submitted. The BCUC also pointed to the Annual Review process and other safeguards such as exogenous factors as avenues that could provide relief to FBC and ratepayers should such relief become necessary.

For the remaining criteria - the determination of whether the amounts are directly related to COVID-19 and the prudency and materiality of costs - these determinations cannot be made until after the impacts of the exogenous factor are known.

To date in 2020, FBC has incurred incremental O&M expenditures for COVID-19 related items, including the following:

- cleaning and disinfecting of facilities to promote a safe work environment;

- sequestering of system control centre employees from having to return to their homes to ensure a safe and healthy work environment (i.e., 10 employees were sequestered from April 3 to May 14, both for days on and off shift); and

- Public Affairs Emergency communications activities to keep our customers informed of the assistance available during this challenging time.

FBC expects to continue to incur additional expenditures for the remainder of the year. Additionally, FBC is monitoring for any significant savings related to COVID-19 such as a temporary reduction in employee-related expenses that may help to offset the incremental expenditures. However, with the uncertainty regarding COVID-19's duration and impact (i.e., timing of 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 2020 or for future years.

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

[36] MRP Decision, p. 170.

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-19 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.

12.3 *ACCOUNTING MATTERS*

In the following section, FBC provides information on emerging accounting guidance.

12.3.1 Emerging Accounting Guidance

In the PBR Plan decision, the BCUC directed FBC to "communicate any accounting policy changes and updates to the Commission and other stakeholders as part of the Annual Review process during the PBR period." While this directive was not included as part of the MRP Decision, FBC will continue to provide accounting policy changes and updates as part of the Annual Review materials. FBC discusses one accounting matter below:

- Credit Losses - for Accounting Standards Update (ASU) 2016-13, *Measurement of Credit Losses on Financial Instruments:* The accounting assessment of this new standard is not expected to directly affect how FBC sets its revenue requirements or rates, but some principles within the new guidance have been applied in the determination of forecast unrecovered revenue for 2020 and 2021 to be captured in the COVID-19 Customer Recovery Fund Deferral Account.

12.3.1.1 Credit Losses

Effective January 1, 2020, FBC adopted ASU No. 2016-13, *Measurement of Credit Losses on Financial Instruments*, which requires the use of reasonable and supportable forecasts in the estimate of credit losses (also referred to as allowance for doubtful accounts) and the recognition of expected losses (also referred to as bad debt expense) upon initial recognition of a financial instrument, in addition to using past events and current conditions.

Consistent with prior accounting under US GAAP, FBC records an allowance for credit losses to reduce accounts receivable for amounts estimated to be uncollectible. As a result of this ASU, the credit loss allowance is estimated by taking into account historical experience, current conditions, reasonable and supportable economic forecasts and accounts receivable aging. In addition to historical collection patterns, FBC considers customer class, customer size, economic indicators and certain other risk characteristics when evaluating the credit loss allowance.

ASU 2016-13 is not expected to change how FBC determines its revenue requirements for 2020 and 2021. However, since ASU 2016-13 provides entities with additional guidance on how to estimate future credit losses, some principles within the new guidance have been applied in the determination of forecast unrecovered revenue for 2020 and 2021 to be captured in the COVID-

19 Customer Recovery Fund Deferral Account. Details of this deferral account are provided in Section 7.7.2.1.

The focus of ASU 2016-13 is to develop a forward-looking provision for credit losses, or bad debt expense, at the beginning of the revenue cycle relying on broader principles and macroeconomic factors. The unrecovered revenue captured in the COVID-19 Customer Recovery Fund Deferral Account is intended to represent specific customer bad debt write-offs that occur potentially many months after initially being billed the revenue for consumption. Therefore, under US GAAP, FBC will recognize the initial credit loss expense against the deferral account explained in Section 7.7.2.1 with the offset against accounts receivable. This entry will only be applied for external financial reporting purposes and will not affect the deferral account or O&M for regulatory accounting purposes or setting rates. Over the entire revenue, billing and collection cycle, the credit losses recognized under ASU 2016-13 will approximate the actual customer account write-offs.

12.4 *NON RATE BASE DEFERRAL ACCOUNTS*

FBC maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base and earn a rate base return. In contrast, non-rate base deferral accounts are outside of rate base and may have varying rates of return, depending on the nature of the account and the return approved by the BCUC.

The forecast mid-year balance of unamortized non-rate base deferred charges is a credit balance of approximately \$4.162 million in 2020 and a debit balance of approximately \$1.160 million in 2021.

In the following sections, FBC requests disposition of two previously approved deferral accounts, and provides information on its Flow-through deferral account. Information on FBC's non-rate base earnings sharing deferral account is included in Section 10.

12.4.1 Existing Deferral Accounts

12.4.1.1 2018-2019 Revenue Surplus Deferral Account

As part of the Annual Review for 2018 Rates, FBC received approval through Order G-131-18 to establish the 2018 Revenue Deficiency deferral account to capture the 2018 revenue deficiency of \$0.896 million (\$0.654 million after tax) resulting from maintaining 2018 rates at existing 2017 levels.

As part of the Annual Review for 2019 Rates, FBC received approval through Order G-246-18 to capture the 2019 revenue surplus of \$5.633 million (\$4.112 million after tax) in the same deferral account and to rename the account to the 2018-2019 Revenue Surplus deferral account. As a result of the 2019 addition, the net credit balance in the deferral account was $4.737 million ($3.458 million after tax).[37]

In this Application, FBC is requesting approval to draw down $3.326 million[38] pre-tax of the deferral account balance in 2020 rates, which will result in a total forecast revenue deficiency of $3.587 million and a 1.00 percent rate increase, maintaining 2020 permanent rates at interim levels.

FBC is also requesting approval to draw down the remaining balance of the deferral account in 2021 rates, which equals $1.410 million pre-tax,[39] which will result in a 6.37 percent 2021 rate increase compared to 2020 rates. Without returning a portion of the existing surplus in 2021, the 2021 rate increase would be 6.75 percent compared to 2020 levels.

As shown in Table 12-1 below, the ending 2021 after-tax balance in the deferral account is forecast to be zero.[40]

Table 12-1: 2018-2019 Revenue Surplus Deferral Account Continuity ($ millions)

Line No.	Description	Opening Balance	(Additions)/ Drawdowns	Taxes	Ending Balance
1	2018 Actuals	$ -	$ 0.896	$ (0.242)	$ 0.654
2	2019 Actuals	0.654	(5.633)	1.521	(3.458)
3	2020 Projected	(3.458)	3.326	(0.898)	(1.030)
4	2021 Forecast	(1.030)	1.410	(0.381)	-

12.4.1.2 2020 – 2024 Multi-Year Rate Plan Application

As part of the Annual Review for 2018 Rates Application, FBC received approval through Order G-38-18 to establish the 2020 Revenue Requirements deferral account to capture the costs related to filing that application and the related regulatory proceeding. Further, FBC noted that it would request an amortization period for this account in a future application.

Consistent with past practice, FBC is proposing to amortize this deferral account over five years commencing January 1, 2020, which represents the period covered by the MRP Application.

FBC notes that it has renamed the deferral account from 2020 Revenue Requirements to 2020–2024 Multi-Year Rate Plan Application to better reflect the nature of the deferral account.

12.4.1.3 Flow-Through Deferral Account (2020-2024)

As approved by Order G-166-20, the Flow-through deferral account is used to capture the annual variances between the approved and actual amounts for all costs and revenues which

[37] Section 11 – 2020, Schedule 12.1, Line 6, Column 2.
[38] Section 11 – 2020, Schedule 12.1, Line 6, Column 4.
[39] Section 11 – 2021, Schedule 12.1, Line 6, Column 4.
[40] Section 11 – 2021, Schedule 12.1, Line 6, Column 7.

are forecast annually, are not subject to earnings sharing, and which do not have a previously approved deferral account. The specific items included in the Flow-through deferral account were set out in Table C4-1 of the MRP Application, reproduced below.

Table 12-2: Variances Captured in the Flow-through Deferral Account

	FEI	FBC
Delivery Revenues (FEI):		
Residential and commercial use rate variances	RSAM	N/A
Customer variances	Flow-through deferral	N/A
Industrial and all other revenue variances	Flow-through deferral	N/A
Revenues and Power Supply (FBC):		
Revenue variances	N/A	Flow-through deferral
Power Supply variances net of PSI	N/A	Flow-through deferral
Gross O&M:		
Index-based O&M variances	Subject to earnings sharing	Subject to earnings sharing
BCUC fees variances	BCUC variances deferral	BCUC variances deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances [1,3]	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	No variance	No variance
Depreciation and Amortization:		
Depreciation rate variances	No variance	No variance
Depreciation on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other depreciation variances	Subject to earnings sharing	Subject to earnings sharing
Amortization of deferrals	No variance	No variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Other Revenues :		
SCP Mitigation revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
Revenues from Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
All other other revenue/income variances	Subject to earnings sharing	Subject to earnings sharing
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
Interest rate variances	Flow-through deferral	Flow-through deferral
Interest on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other interest variances	Subject to earnings sharing	Subject to earnings sharing
Income Tax:		
Income tax rate variances	Flow-through deferral	Flow-through deferral
Income tax on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other income tax variances	Subject to earnings sharing	Subject to earnings sharing

1: Including items forecast outside of the formula such as insurance premiums, NGT stations, biomethane, variable LNG production, integrity digs and EV charging stations.
2: Cost of service for NGT fueling stations and tankers, variable LNG production, and EV stations will be captured in the Flow-through deferral account.
3: Biomethane other revenues will continue to capture the actual cost of service of the biomethane capital assets and transfer it to the BVA

FBC has included a discussion on the final amounts accumulated in the Flow-through deferral account during the 2014-2019 PBR Plan term in Section 14 of this Application.

Similar to the discussion in Section 10 on FBC's 2020 Projected earnings sharing amount, 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.

An adjustment to include the difference between the projected amount of zero[41] and final actual amounts for 2020 subject to flow-through will be recorded in the deferral account in 2021 and amortized in 2022 rates.

12.5 *SUMMARY*

FBC has discussed one new exogenous factor that may affect rates in 2021, has provided an update on certain accounting related matters, requested approval for the disposition of two existing deferral accounts, and included information on the Flow-through deferral account.

[41] Section 11 - 2020, Schedule 12.2, Line 4, Column 4.

13. SERVICE QUALITY INDICATORS

13.1 *INTRODUCTION AND OVERVIEW*

Under the MRP, SQIs are used to monitor the Utility's performance to ensure that any efficiencies and cost reductions do not result in a degradation of the quality of service to customers.

In the MRP Decision and Order G-166-20, the BCUC approved a balanced set of SQIs for FBC, covering safety, responsiveness to customer needs, and reliability. Eight of the SQIs have benchmarks and performance ranges set by a threshold level. Four of the SQIs are for information only and as such do not have benchmarks or performance ranges.

The BCUC has determined that the process used during the 2014-2019 PBR Plan to interpret metric performance will remain in effect for the MRP.[42] Consistent with the BCUC's direction issued in its Reasons for Decision accompanying Order G-44-16 in FBC's All Injury Frequency Rate Compliance Filing, FBC will review service quality for a year in the following year's annual review. As 2019 SQI results pertain to the 2014-2019 PBR Plan, they are discussed separately in Section 14.

In the subsections below, FBC reports on its June 2020 year-to-date performance as measured against the SQI benchmarks and thresholds. The June 2020 year-to-date SQI results indicate that the Company's overall performance to date meets service quality requirements. For the eight SQIs with benchmarks, all performed at or better than the thresholds. For the four SQIs that are informational only, performance generally remains at a level consistent with prior years.

Consistent with how SQIs were reviewed during the 2014-2019 PBR Plan term, FBC has provided year-to-date 2020 SQI results in this annual review. In accordance with Order G-44-16, the BCUC will evaluate FBC's actual 2020 SQI performance in the Annual Review for 2022 Rates when actual SQI results are known. FBC also notes that it will provide information on the 2021 year-to-date SQI results in the Annual Review for 2022 Rates.

13.2 *REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS*

For each SQI, Table 13-1 provides a comparison of FBC's June year-to-date performance for 2020 to the proposed benchmarks and thresholds as part of the MRP. Actual June year-to-date results for 2020 are also provided for the four informational SQIs.

[42] MRP Decision page 99 "the Panel determines that the existing approved process for interpreting metric performance is to remain in effect over the term of the MRPs".

1 **Table 13-1: Approved SQIs, Benchmarks and Actual Performance**

Performance Measure	Description	Benchmark	Threshold	June 2020 YTD
Safety SQIs				
Emergency Response Time	Percent of calls responded to within two hours	>=93%	90.6%	91%
All Injury Frequency Rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	<=1.64	2.39	0.85
Responsiveness to Customer Needs SQIs				
First Contact Resolution	Percent of customers who achieved call resolution in one call	>=78%	74%	82%[43]
Billing Index	Measure of customer bills produced meeting performance criteria	<=3.0	5.0	0.20
Meter Reading Accuracy	Number of scheduled meters that were read	>=98%	96%	99%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>=70%	68%	73%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.4
Average Speed of Answer	Informational indicator – the amount of time it takes to answer a call (seconds)	-	-	47
Reliability SQIs				
System Average Interruption Duration Index (SAIDI) – Normalized	Annual SAIDI (average of cumulative customer outage time)	3.22[44]	4.52	3.36
System Average Interruption Frequency Index (SAIFI) - Normalized	Annual SAIFI (average customer outage)	1.57	2.19	1.74
Generator Forced Outage Rate	Informational indicator – Percent of time a generating unit is removed from service due to component failure or other events.	-	-	1.0%

[43] First Contact Resolution surveying was suspended from Mar 23 - May 3 2020 as a result of the COVID-19 pandemic, thus the YTD figure does not contain data for the period that surveys were suspended.
[44] Benchmarks and thresholds for SAIDI and SAIFI as calculated in the MRP Compliance Filing.

Performance Measure	Description	Benchmark	Threshold	June 2020 YTD
Interconnection Utilization	Informational indicator – percent of time that an interconnection point was available and providing electrical service to wholesale customers.	-	-	99.90%

In the following sections, FBC reviews each SQI's year-to-date individual performance in 2020. Discussion is also provided for the informational SQIs.

13.2.1 Safety Service Quality Indicators

Emergency Response Time

Emergency Response Time is the time elapsed from the initial identification of a loss of electrical power (via a customer call or internal notification) to the arrival of FBC personnel on site at the trouble location. This metric provides ongoing information to assess FBC crew sizes and crew locations in response to system trouble. The target measures the percentage of emergency calls responded to within two hours. The measure is calculated as follows:

$$\frac{\text{Number of emergency calls responded to within two hours}}{\text{Total number of emergency calls in the year}}$$

There are many variables affecting the response time, including time of day (i.e., during business hours or after business hours), number and type of events (i.e., widespread outages), available resources, location (i.e., travel times and traffic congestion) and weather conditions.

The June 2020 year-to-date performance is 91 percent, which is above the threshold.

For comparison, the Company's annual results under the 2014-2019 PBR Plan and 2020 year-to-date emergency response time results are provided below. While the results have been relatively consistent, variables such as the location and severity of outage and the number of trouble calls contribute to the observed volatility in the annual performance for this metric.

Table 13-2: Historical Emergency Response Time

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Results	91%	92%	97%	93%	94%	92%	91%
Benchmark	93%	93%	93%	93%	93%	93%	93%
Threshold	90.6%	90.6%	90.6%	90.6%	90.6%	90.6%	90.6%

All Injury Frequency Rate

The All Injury Frequency Rate (AIFR) is an employee safety performance indicator based on injuries per 200,000 hours worked, with injuries defined as lost time injuries (i.e., one or more days missed from work) and medical treatments (i.e., medical treatment was given or prescribed). The annual performance for this metric is calculated as:

$$\frac{\text{Number of Employee Injuries x 200,000 hours}}{\text{Total Exposure Hours Worked}}$$

For the purpose of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

The June 2020 year-to-date performance (three-year rolling average) result is 0.85, which is better than the benchmark. The 2020 year-to-date performance reflects zero Medical Treatments and zero Lost Time Injuries.

Safety continues to be a core value for FBC and prevention of injury remains a key focus. FBC continues to focus on and reinforce the fundamentals of safety through effective safe work planning, identifying hazards and mitigating risks, detailed work observations, and thorough event analysis, capturing learnings and identifying opportunities for continued improvement.

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date AIFR results are provided below.

Table 13-3: Historical All Injury Frequency Rate Results

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	3.21	1.54	1.15	1.13	1.56	0.46	0.00
Three year rolling average	2.58	2.52	1.97	1.27	1.28	1.06	0.85
Benchmark	1.64	1.64	1.64	1.64	1.64	1.64	1.64
Threshold	2.39	2.39	2.39	2.39	2.39	2.39	2.39

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

First Contact Resolution

First Contact Resolution (FCR) measures the percentage of customers who receive resolution to their issue in one contact with FBC. The Company determines the FCR results using a customer survey, tracking the number of customers who responded that their issue was resolved in the first contact with the Company. The FCR rate is impacted by factors such as the quality and effectiveness of the Company's coaching and training programs and the composition of the different call drivers.

The June 2020 year-to-date performance is 82 percent. This result excludes the period of March 23 to May 3, 2020, as all Service Quality Measurement (SQM) surveys were suspended during that time due to the COVID-19 pandemic.

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below.

Table 13-4: Historical First Contact Resolution Levels

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	73%	76%	79%	80%	82%	82%	82%
Benchmark	78%	78%	78%	78%	78%	78%	78%
Threshold	72%	72%	72%	72%	72%	72%	74%

Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing system by measuring the percentage of customer bills produced meeting performance criteria. The Billing Index is a composite index with three components:

- Billing completion (percent of accounts billed within two days of the billing due date);
- Billing timeliness (percent of invoices delivered to Canada Post within two days of file creation); and
- Billing accuracy (percent of bills without a production issue based on input data).

The objective is to achieve a score of five or less.

The Billing Index is impacted by factors such as the performance of the Company's billing system, weather variability, which can cause a high volume of billing checks and estimation issues, and mail delivery by Canada Post.

The 2020 year-to-date result is 0.20, which is better than the benchmark of 3.0. No significant billing issues have arisen in 2020 so far.

The 2020 Billing Index sub-measures calculation is as follows.

Table 13-5: Calculation of 2020 Billing Index

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Accuracy (Percent of bills without a Production Issue, based on input data); Target: 99.9%	100.00%	If (PA≥99.9%,5000*(1 - PA),1.05-PA))	=5000*(1-1)	0.00
Billing Timeliness (Percent of invoices delivered to Canada Post within 2 days of file creation); Target: 95%	100.00%	(100%-PA)*100	=(100%-100%)*100	0
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target: 95%	99.39%	(100%-PA)*100	=(100%-99.39%)*100	0.61
Billing Service Quality Indicator; Target < 3.0		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0+0+.61) /3	0.20

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below.

Table 13-6: Historical Billing Index Results

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	2.34	0.39	0.57	0.15	0.29	1.96	0.20
Benchmark	5.0	5.0	5.0	5.0	5.0	5.0	3.0
Threshold	5.0	5.0	5.0	5.0	5.0	5.0	5.0

Meter Reading Accuracy

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:

$$\frac{\text{Number of scheduled meters read}}{\text{Number of scheduled meters for reading}}$$

The 2020 year-to-date result is 99 percent, which is better than the benchmark.

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below.

Table 13-7: Historical Meter Reading Accuracy Results

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	98%	96%	99%	99%	99%	99%	99%
Benchmark	97%	97%	97%	97%	97%	97%	98%
Threshold	94%	94%	94%	94%	94%	94%	96%

Telephone Service Factor (Non-Emergency)

The Telephone Service Factor (Non-Emergency) measures the percentage of non-emergency calls that are answered in 30 seconds. It is calculated as:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Number of non-emergency calls received}}$$

The TSF is a measure of how well the Company can balance costs and service levels with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers. The principal factors influencing the TSF results include volume and type of inbound calls received and the resources available to answer those calls. Staffing is matched to the expected call volume based on historical data in order to reach the service level benchmark desired. Other factors that can influence the TSF are billing system related issues and weather patterns that may generate high numbers of billing related queries and the complexity of the calls.

The June 2020 year-to-date performance is 73 percent, which is better than the benchmark.

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below. As discussed in the Annual Review for 2015 Rates, the 2014 result was negatively impacted by events such as the first verified meter readings occurring after the IBEW labour disruption ended in December 2013, introduction of the Residential Conservation Rate, and the integration of the City of Kelowna customers.

Table 13-8: Historical TSF Results

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	48%	71%	70%	70%	72%	70%	73%
Benchmark	70%	70%	70%	70%	70%	70%	70%
Threshold	68%	68%	68%	68%	68%	68%	68%

Customer Satisfaction Index

The Customer Satisfaction Index (CSI) is an informational indicator that measures overall customer satisfaction with the Company. The index reflects customer feedback about important service touch points including the contact centre, perceived accuracy of meter reading, energy conservation information and field services. The index includes feedback from both residential and commercial customers. The survey is conducted quarterly and results are presented as a score out of ten.

The CSI survey investigates service quality as well as customer attitudes that are often influenced by factors outside the Company's control. Important examples include storm-related unplanned outages and media coverage.

The average index score for June 2020 year-to-date is 8.4, slightly lower than the 8.5 score for the same period last year. 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.

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below.

Table 13-9: Historical Customer Satisfaction Results

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	8.1	8.1	8.2	8.2	8.3	8.7	8.4
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

Average Speed of Answer

The Average Speed of Answer (ASA) is an informational indicator that measures the amount of time it takes for a customer service representative to answer a customer's call (seconds).

The June 2020 year-to-date result of 47 seconds is consistent with prior years' results.

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below.[45]

[45] ASA in 2014 is higher than other years due to the impact of the six months of job action that took place in Q3 and Q4 of 2013. This job action resulted in a higher number of bill estimates, which led to a higher volume of customer inquiries in 2014 as bill adjustments were made reflecting actual meter reads.

Table 13-10: Average Speed of Answer

Description	2014	2015	2016	2017	2018	2019	June 2020 YTD
Annual Results	226	49	48	49	49	49	47
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

13.2.3 Reliability Service Quality Indicators

FBC measures transmission and distribution system reliability according to the Institute of Electrical and Electronics Engineers (IEEE) method of normalizing reliability statistics by excluding “major events”. Major events are identified as those that cause outages exceeding a threshold number of customer-hours. Threshold values are calculated by applying a statistical method called the “2.5 Beta” adjustment to historical reliability data. Any single outage event that exceeds the threshold value is excluded from the reliability data. Excluding major events allows them to be studied separately and reveals trends in daily operations that would be hidden or skewed if they were included in the data set. Major event days in the FBC service territory have been caused by mudslides, wind or snow storms, and wildfires.

Reported outages included in these measures are of one minute or longer in duration, which is consistent with the Canadian Electricity Association (CEA) standard for reporting.

System Average Interruption Duration Index (SAIDI) – Normalized

SAIDI is the amount of time the average customer’s power is off during the year (i.e., the total amount of time the average customer’s clock would lose during a year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Customer Hours of Interruption}}{\text{Total Number of Customers Served}}$$

Customer Hours of Interruption related to a power outage are calculated by multiplying the number of customers affected by the outage by the duration of the outage.

For the purpose of this SQI, the measurement of performance is based on the annual results.

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. To adjust the benchmark for the influence of the Outage Management System (OMS), FBC proposed to update the existing SAIDI three-year rolling average benchmark using the most recent three full years of results (i.e., 2017, 2018 and 2019), which incorporate the impact of the OMS. Similar to the approach used to determine the thresholds for the 2014-2019 PBR Plan term, the proposed threshold is based on statistical analysis (i.e., standard deviation) of the SAIDI historical results from 2010 to 2019.

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.

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. For 2020, the benchmark is based on an average of the most recent three-year results (i.e., 2017, 2018 and 2019) with the threshold based on historical volatility as described above.

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

System Average Interruption Frequency Index (SAIFI) – Normalized

SAIFI is the average number of interruptions per customer served per year (i.e., the number of times the average customer would have to reset their clock during the year), after adjusting for the impact of major events as described above, and is calculated as follows:

$$\frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

The Number of Customer Interruptions related to a power outage is the number of customers affected by the outage.

For the purpose of this SQI, the measurement of performance is based on the annual results.

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. To adjust the benchmark for the influence of the OMS on the reported results, FBC proposed to update the existing SAIFI three-year rolling average benchmark using the most recent three full years of results (i.e., 2017, 2018 and 2019), which incorporate the impact of the OMS. Similar to the approach used to determine the thresholds for the 2014-2019 PBR Plan term, the proposed threshold is based on statistical analysis (i.e., standard deviation) of the SAIFI historical results from 2010 to 2019.

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below. From 2014 to 2019, the benchmark and the threshold reflect the values established under the PBR Plan using three-year rolling average results. For 2020, the benchmark is based on an average of the most recent three-year results (i.e., 2017, 2018 and 2019) with the threshold based on historical volatility.

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

Generator Forced Outage Rate

Generator Forced Outage Rate (GFOR), an informational indicator, is a measure of the percentage of time in one year that the generating units experienced forced outages compared to the amount of time they could have operated without a forced outage. A forced outage means the removal of a generating unit from service due to the occurrence of a component failure or other event, making it unavailable to produce power due to the unexpected breakdown. The GFOR is defined by the CEA as follows:

$$\frac{\text{Total Forced Outage Time}}{\text{Total Forced Outage Time + Total Operating Time}} \text{ X } 100$$

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 Unit 1 related mainly to the generator, lasting approximately 14 days.

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below.

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

Interconnection Utilization

Interconnection Utilization, an informational indicator, is a measurement of the time that an interconnection point was available and providing electrical service to the municipal wholesale customers (City of Penticton, City of Summerland, City of Grand Forks and City of Nelson). There are twelve points of interconnection combined between the four customers.

The Interconnection Utilization metric for the interconnection points listed is calculated as follows:

$$\frac{\text{Total Operating Hours}}{\text{Total Operating Hours + Total Outage Time}}$$

The June 2020 year-to-date result of 99.90 percent is consistent with prior years' results.

For comparison, the Company's 2014 to 2019 annual and 2020 year-to-date results are provided below.

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

13.3 *SUMMARY*

In summary, FBC's June 2020 year-to-date SQI results indicate that the Company's overall performance meets service quality requirements. At the end of June 2020, for the eight SQIs with benchmarks, all performed at or better than the thresholds. For the four SQIs that are informational only, performance generally remains at a level consistent with prior years.

14. PBR ELEMENTS

14.1 *INTRODUCTION AND OVERVIEW*

The setting of rates for 2020 includes elements related to the conclusion of the 2014-2019 PBR Plan, which are discussed in this section. Calculations for the true-up of rate base, 2019 Flow-through account, Earnings Sharing Mechanism, and Service Quality Indicator results are included in this section.

14.2 *TRUE-UP OF PBR PLAN RATE BASE*

During the term of the 2014-2019 PBR Plan, capital expenditures in excess of formula but within the defined dead band (10 percent on an annual basis, or 15 percent on a two-year basis) were excluded from rate base. For FBC, the cumulative amount of capital excluded from rate base was $17.088 million (Table 14-3, Line 33, Column 2). As provided in the 2014-2019 PBR Plan, this amount is added to plant in service effective January 1, 2020.

Also included in the January 1, 2020 adjustment to plant in service is the $8.827 million in 2019 expenditures that exceeded the dead band (Table 14-3, Line 30, Column 7). Under the 2014-2019 PBR Plan, expenditures outside of the dead band enter rate base on January 1 of the following year. The total adjustment to plant in service at January 2020 is therefore $25.915 million ($17.088 million plus $8.827 million) as shown in Section 11 – 2020, Schedule 6.1, Line 19, Column 4.

Correspondingly, depreciation expense reflects the aforementioned adjustments to 2020 opening plant.

14.3 *2019 FLOW-THROUGH ACCOUNT*

As approved by Order G-163-14, the Flow-through deferral account is used to capture the annual variances during the 2014-2019 PBR Plan term between the approved and actual amounts for all costs and revenues which are included in rates on a forecast basis and which do not have a previously approved deferral account.

The final amount to be distributed to customers in 2020 is a credit of $7.475 million (after tax) and is comprised of the following:

- A net variance between approved and actual of $6.352 million (credit) in flow-through items for 2019. 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; and
- A true-up to actual of $1.122 million (credit) to the projected ending 2018 Flow-through account balance, also resulting from lower power purchase expense, lower income taxes

and higher apparatus rental revenue, partially offset by lower sales revenue. 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[46] (credit) and the actual ending 2018 deferral account balance of $13.910 million (credit).

The total of the amounts above results in a return to customers of $7.475 million (after tax) in 2020, as shown in the non-rate base deferral section of the financial schedules in Section 11 - 2020, Schedule 12 and in Table 14-1 below.

Table 14-1: 2019 Flow-Through Deferral Account Additions ($ millions)

Line No.	Particulars	Approved 2019	Actual 2019	Variance
	(1)	(2)	(3)	(4)
1	Revenue	$ (370.534)	$ (367.649)	$ 2.885
2				
3	Power Purchase Expense	145.065	139.002	(6.063)
4				
5	Water Fees	10.465	10.396	(0.069)
6				
7	Wheeling	5.235	5.896	0.660
8				
9	O&M Tracked Outside of Formula			
10	Insurance Premiums	1.283	1.381	0.098
11	Advanced Metering Infrastructure Project	(1.161)	(1.296)	(0.134)
12	Mandatory Reliability Standards	0.940	0.891	(0.049)
13	Upper Bonnington Unit 3 Annual Inspection	(0.042)	(0.042)	-
14	MSP Premium Reduction	(0.168)	(0.180)	(0.012)
15	Employer Health Tax	0.576	0.556	(0.020)
16				
17	Property Tax	16.713	16.664	(0.049)
18				
19	Depreciation and Amortization	48.473	49.291	0.818
20				
21	Other Revenue	(9.268)	(10.627)	(1.359)
22				
23	Interest Expense	40.956	40.465	(0.491)
24				
25	Income Tax	7.827	5.391	(2.436)
26				
27	2018 Working Capital Adjustment for AMI			(0.046)
28	2019 Working Capital Adjustment for AMI			(0.085)
29				
30	2019 After-Tax Flow-Through Addition to Deferral Account			$ (6.352)
31				
32	2018 Ending Deferral Account Balance True-Up			$ (1.122)
33	2020 After-Tax Amortization			$ (7.475)

[46] Annual Review for 2019 Rates Compliance Filing financial schedules, Schedule 12, Line 5, Column 2.

14.4 EARNINGS SHARING

For 2020, FBC is proposing to recover through rates a $0.250 million pre-tax debit ($0.183 million after tax) as shown in Table 14-2 below. This amount is comprised of:

- 2019 actual sharing on formula O&M and capital expenditures;
- An adjustment for actual customer growth in 2018 and 2019; and
- The true-up of the 2018 projected earnings sharing to actual.

Table 14-2: Summary of Earnings Sharing to be Returned in 2020[47] ($ millions)

Line No.	Description	After-tax Amount	Reference
1	2019 Actual Sharing	$ 0.106	Table 14-3, Line 52
2	2018 Actual Customer Growth Adjustment	0.011	Table 14-4, Line 18
3	2019 Actual Customer Growth Adjustment	0.012	Table 14-5, Line 18
4	2019 Actual Customer Growth Adjustment O&M	0.026	Table 14-5, Line 27
5	2018 Projected vs. Actual Ending Balance True-Up	0.026	Table 14-6, Line 3
6			
7	2020 After-Tax Amount Collected from Customers	0.183	
8	2020 Pre-Tax Amount Collected from Customers	0.250	

Each of these items is discussed in the sections below.

14.4.1 2019 Earnings Sharing

As set out in FBC's letter dated November 7, 2014 in response to Order G-163-14 and as approved by Order G-107-15 for FBC's Annual Review for 2015 Rates, the earnings sharing is calculated each year as one-half of the pre-tax earnings impact of the variances in the formula-driven gross O&M and cumulative capital expenditures, as follows:

Formula-driven O&M less actual base O&M[48] x 50% +

((Cumulative formula-driven capital expenditures less cumulative actual base capital expenditures[49]) x equity percentage x approved return on equity x 50%) divided by (1 – the tax rate)

In 2019, FBC achieved formula-driven O&M savings of $0.565 million, and 2019 capital expenditures exceeded the formula by $13.011 million. The $13.011 million excess 2019 capital expenditures exceeded the dead band by $8.827 million; therefore, FBC has removed the $8.827 million amount above the dead band in the calculation of 2019 earnings sharing, as shown in Line 30 of Table 14-3 below.

[47] Financing on the deferral account balance is included in the deferred charges schedule in Section 11 - 2020, Schedule 12, Line 26.
[48] Excluding items that are reforecast outside of the formula.
[49] Ibid.

Table 14-3: Calculation of 2019 Earnings Sharing ($ millions)

Line No.	Particulars								Cross Reference
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)
1	Approved Formula O&M	$ 56,081							G-246-18
2									
3	Actual Gross O&M	58,519							
4									
5	Less: O&M Tracked Outside of Formula								
6	Pension/OPEB (O&M Portion)	1,692							
7	Insurance Premiums	1,381							
8	Advanced Metering/Infrastructure Costs/Savings	(1,296)							
9	Mandatory Reliability Standards	891							
10	Upper Bonnington Unit 3 Annual Inspection	(42)							
11	Employer Health Tax	556							
12	MSP Reduction	(180)							
13	Total	3,003							Sum of Lines 6 - 12
14									
15	Actual Base O&M	55,516							Line 3 - Line 13
16									
17	O&M Subject to Sharing	$ (565)							Line 15 - Line 1
18									
19			Annual Capital Expenditures						
20			2014	2015	2016	2017	2018	2019	Note 1
21									
22	Cumulative Formula Capital Expenditures	$ 259,385	$ 42,193	$ 42,384	$ 42,874	$ 43,254	$ 43,818	$ 44,862	
23									
24	Cumulative Total Regular Capital Expenditures	336,600	49,061	49,043	49,512	62,908	64,592	61,485	
25									
26	Less: Cumulative Pension and OPEB								
27	Tracked Outside of Formula	25,104	6,396	4,253	3,674	3,539	3,630	3,612	
28									
29	Actual Base Capital Expenditures	311,497	42,665	44,791	45,838	59,369	60,962	57,873	Line 24 - Line 27
30	Dead Band Adjustment	(35,024)				(12,075)	(14,122)	(8,827)	Adjustment to stay within deadband
31	Actual Base Capital Expenditure for ESM Calculation	276,473	42,665	44,791	45,838	47,293	46,840	49,046	Line 29 - Line 30
32									
33	Actual Base Capital Expenditure Variance	17,088	472	2,407	2,964	4,039	3,022	4,184	Line 31 - Line 22
34									
35	Single Year Deadband % Variance (after adjustment)		0.97%	5.16%	6.37%	8.63%	6.37%	8.63%	Line 33 ÷ (Line 22 + Line 27)
36	Two year Cumlative Deadband % Variance (after adjustment)			6.13%	11.53%	15.00%	15.00%	15.00%	
37									
38									
39									
40	Equity Component of Rate Base	40.00%							
41	Approved Return on Equity	9.15%							
42	After Tax Capital Expenditures Subject to Sharing	$ 625							Product of Lines 33, 40 & 41
43									
44	Tax Rate	27.00%							
45									
46	Before Tax Capital Expenditures Subject to Sharing	$ 857							Line 42 ÷ (1 - Line 44)
47									
48	Total Before Tax Sharing Account	292							Line 17 + Line 46
49	Sharing Percentage	50.00%							G-139-14
50									
51	2019 Actual Earnings Sharing (Pre-Tax)	$ 146							Line 48 x Line 49
52	2019 Actual Earnings Sharing (After-Tax)	$ 106							Line 51 x 0.73

Notes
1 Actual results from BCUC Annual Report

14.4.2 Actual Customer Growth Adjustment

As set out in Order G-15-15 in relation to formula capital expenditures:

> FEI and FBC are approved to recover the variance in earned return driven by the use of prior year customer additions for the growth term when compared to the actual customer additions. This positive or negative variance in earned return resulting from the Growth Term shall be recovered from or returned to customers in the subsequent year through the earnings sharing mechanism.

Also as set out in Order G-15-15 in relation to formula O&M expenditures:

> At the end of the PBR term, or any subsequent extension to the PBR term, FEI and FBC are approved to adjust the earnings sharing calculation for the last year of the PBR term to account for the actual growth in the last year of the PBR term.

Based on its actual customer additions, FBC has calculated the resulting adjustments of $0.015 million debit ($0.011 million debit after tax) for 2018 capital expenditures, $0.017 million debit ($0.012 million debit after tax) for 2019 capital expenditures, and $0.036 million debit ($0.026 million debit after tax) for 2019 O&M expenditures, as shown in Tables 14-4 and 14-5 below.

Table 14-4: Calculation of Earnings Sharing Adjustment for 2018 Actual Customer Growth ($ millions)

Line No.	Description		Reference
1	Average Customers 2018	137,299	
2	Average Customers 2017	134,246	
3	Growth in Average Customers	3,054	Line 1 - Line 2
4	Average Customer Growth	2.275%	Line 3 ÷ Line 2
5		50%	G-139-14
6	Average Customer Growth to be recast in Formula	1.137%	
7	2018 Net Inflation Factor	0.671%	G-38-18 Compliance Filing, Section 11, Schedule 3, Line 9, Column 7
8	2017 Reforecast Formulaic Capital	$ 43.491	Annual Review for 2019 Rates, Table 10-3, Line 9
9	2018 Reforecast Formulaic Capital	$ 44.281	Line 8 x (1 + Line 7) x (1 + Line 6)
10	2018 Year Formulaic Capital	$ 43.818	G-38-18 Compliance Filing, Section 11, Schedule 4, Line 17, Column 4
11			
12	Increase in Capital Requirements from Actual Growth	$ 0.463	Line 9 - Line 10
13	Mid-Year	$ 0.231	Line 12 x 0.5
14			
15	Equity Cost Component	3.66%	G-38-18 Compliance Filing, Section 11, Schedule 26, Line 3, Column 6
16	Debt Cost Component	3.03%	G-38-18 Compliance Filing, Section 11, Schedule 26, Lines 1+2, Column 6
17	Earned Return on Incremental Capital Requirements (Pre-Tax)	$ 0.015	Line 13 x (line 15 + Line 16)
18	Earned Return on Incremental Capital Requirements (After-Tax)	$ 0.011	Line 17 x 0.73

Table 14-5: Calculation of Earnings Sharing Adjustment for 2019 Actual Customer Growth ($ millions)

Line No.	Description		Reference
1	Average Customers 2019	139,916	
2	Average Customers 2018	137,299	
3	Growth in Average Customers	2,616	Line 1 - Line 2
4	Average Customer Growth	1.906%	Line 3 ÷ Line 2
5		50%	G-139-14
6	Average Customer Growth to be recast in Formula	0.953%	
7	2019 Net Inflation Factor	1.481%	G-246-18 Compliance Filing, Section 11, Schedule 3, Line 9, Column 8
8	2018 Reforecast Formulaic Capital	$ 44.281	Note 1
9	2019 Reforecast Formulaic Capital	$ 45.365	Line 8 x (1 + Line 7) x (1 + Line 6)
10	2019 Year Formulaic Capital	$ 44.862	G-246-18 Compliance Filing, Section 11, Schedule 4, Line 20, Column 4
11			
12	Increase in Capital Requirements from Actual Growth	$ 0.503	Line 9 - Line 10
13	Mid-Year	$ 0.251	Line 12 x 0.5
14			
15	Equity Cost Component	3.66%	G-246-18 Compliance Filing, Section 11, Schedule 26, Line 3, Column 6
16	Debt Cost Component	3.06%	G-246-18 Compliance Filing, Section 11, Schedule 26, Lines 1+2, Column 6
17	Earned Return on Incremental Capital Requirements (Pre-Tax)	$ 0.017	Line 13 x (line 15 + Line 16)
18	Earned Return on Incremental Capital Requirements (After-Tax)	$ 0.012	Line 17 x 0.73
19			
20			
21	Average Customer Growth to be recast in Formula	0.953%	Line 6
22	2019 Net Inflation Factor	1.481%	Line 7
23	2018 Formula O&M	$ 54.776	G-246-18 Compliance Filing, Section 11, Schedule 20, Line 19, Column 2
24	2019 Reforecast O&M	$ 56.117	Line 23 x (1 + Line 22) x (1 + Line 21)
25	2019 Formulaic O&M	$ 56.081	G-246-18 Compliance Filing, Section 11, Schedule 20, Line 22, Column 2
26	2019 O&M difference from Actual Customer Growth (pre-tax)	$ 0.036	Line 24 - Line 25
27	2019 O&M difference from Actual Customer Growth (after-tax)	$ 0.026	Line 26 x 0.73

Notes
1 Table 14-4 (2018), Line 9

14.4.3 True-Up for 2018 Actual Earnings Sharing

In FBC's 2018 Annual Report to the BCUC, FBC calculated the final 2018 earnings sharing based on the final 2018 results. The final amount of earnings sharing for 2018 was $0.226 million, which was $0.026 million lower than the $0.252 million projected for 2018, as shown in Table 14-6 below. As a result, FBC is recovering the 2018 earnings sharing variance between the projected and actual amounts of $0.026 million (after-tax) in 2020 rates.

Table 14-6: Calculation of 2018 Actual Earnings Sharing True-up ($millions)

Line No.	Description	After-tax Amount	Reference
1	2018 Actual Earnings Sharing Account Ending Balance	$ (0.226)	2018 Annual Report to BCUC
2	2018 Projected Earnings Sharing Account Ending Balance	(0.252)	G-246-18 Compliance Filing, Section 11, Schedule 12, Line 26, Column 2
3	2018 Earnings Sharing Account True-Up	$ 0.026	

14.4.4 Summary of 2019 Earnings Sharing

After calculating the 2019 actual earnings sharing and including the adjustments described above, FBC proposes to recover $0.250 million pre-tax ($0.183 million after tax) from customers in 2020 revenue requirements.

14.5 *SERVICE QUALITY INDICATORS*

For the 2014-2019 PBR Plan, the BCUC approved a balanced set of SQIs covering safety, responsiveness to customer needs, and reliability. Eight of the SQIs have benchmarks and performance ranges set by a threshold level, as outlined in the Consensus Recommendation approved by the BCUC in Order G-14-15. Three of the SQIs are for information only, and as such do not have benchmarks or performance ranges.

For each SQI, Table 14-7 below provides a comparison of FBC's 2019 SQI results under the 2014-2019 PBR Plan to the BCUC-approved benchmarks and includes the performance range thresholds that have been agreed to in the Consensus Recommendation that was approved by the BCUC. Actual 2019 results are also provided for the three informational SQIs.

Table 14-7: Approved SQIs, Benchmarks and Actual Performance

Performance Measure	Description	Benchmark	Threshold	2019 Results
Safety SQIs				
Emergency Response Time	Percent of calls responded to within two hours	>=93%	90.6%	92%
All Injury frequency rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	<=1.64	2.39	1.05
Responsiveness to Customer Needs SQIs				
First Contact Resolution	Percent of customers who achieved call resolution in one call	>=78%	72%	82%
Billing Index	Measure of customer bills produced meeting performance criteria	<=5.0	<=5.0	1.96
Meter Reading Accuracy	Number of scheduled meters that were read	>=97%	94%	99%

Performance Measure	Description	Benchmark	Threshold	2019 Results
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>=70%	68%	70%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.7
Telephone Abandon Rate	Informational indicator – percent of calls abandoned by the customer before speaking to a customer service representative	-	-	5.7%
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
Generator Forced Outage Rate	Informational indicator – Percent of time a generating unit is removed from service due to component failure or other events.	-	-	0.1%

For all the SQIs with BCUC-approved benchmarks and agreed upon thresholds, except for SAIDI, 2019 annual performance was better than the thresholds. Further, with the exception of Emergency Response Time, 2019 annual performance met or was better than the approved benchmarks. For the SAIDI and SAIFI SQIs, in 2019, there were no qualifying Major Events.

As discussed in the FBC Annual Review for 2019 Rates, SAIDI results in recent years have been influenced by the implementation of the Outage Management System (OMS), a system used to record distribution outages based on the Outage Start Time. With the change to the OMS and a different definition to the Outage Start Time, the reported outage times have increased, causing the SAIDI values reported to increase, even though there has been no change in the Company's operating practices.

In the BCUC's Decision and Order G-246-18 regarding 2018 performance, the BCUC accepted FBC's explanation for the higher SAIDI results (at page 17):

> While the Panel acknowledges ICG's concerns regarding FBC's SAIDI performance, we accept FBC's explanation that the decline in SAIDI results are related to a combination of the introduction of the OMS, adverse weather, foreign interference (e.g. vehicle incidents) and forest fires. 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.

Similarly, the higher SAIDI and SAIFI results in 2019 were due to the impact of the OMS. Therefore, FBC submits that the SAIDI results for 2019 are acceptable.

For 2020 and future years, FBC will use updated benchmarks and thresholds that incorporate the impact of the OMS, as set out in the Company's July 20, 2020 MRP Compliance Filing in response to Directive 35 of the MRP Decision: Updated Benchmarks and Thresholds for FBC's SQIs SAIDI and SAIFI.

In summary, FBC's 2019 SQI results indicate that the Company's overall performance meets service quality standards.

Appendix A

LOAD FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: Table 18-10-0004-01 (formerly CANSIM 326-0020)

Add/Remove data

Consumer Price Index, monthly, not seasonally adjusted [1 2 3]

Frequency: Monthly

Table: 18-10-0004-01 (formerly CANSIM 326-0020)

Geography: Canada, Province or territory, Census subdivision, Census metropolitan area, Census metropolitan area part

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Products and product groups [3 4]	Reference period	British Columbia (map)
		2002=100
All-items	July 2017	125.6
	August 2017	125.9
	September 2017	125.7
	October 2017	125.6
	November 2017	125.9
	December 2017	125.2
	January 2018	126.1
	February 2018	127.0
	March 2018	127.4
	April 2018	127.7
	May 2018	128.4
	June 2018	128.6
	July 2018	129.7
	August 2018	129.6
	September 2018	128.9
	October 2018	129.4
	November 2018	128.9
	December 2018	129.0
	January 2019	129.1
	February 2019	129.8

	March 2019	130.7
	April 2019	131.2
	May 2019	131.8
	June 2019	131.9
	July 2019	132.4
	August 2019	132.2
	September 2019	132.0
	October 2019	132.2
	November 2019	131.8
	December 2019	131.7
	January 2020	132.1
	February 2020	132.9
	March 2020	132.3
	April 2020	131.2
	May 2020	131.5
	June 2020	132.6

Table A1-2: Table 14-10-0223-01 (formerly CANSIM 281-0063)

Add/Remove data

Employment and average weekly earnings (including overtime) for all employees by province and territory, monthly, seasonally adjusted [1 2 3 4 5]

Frequency: Monthly

Table: 14-10-0223-01 (formerly CANSIM 281-0063)

Geography: Canada, Province or territory

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Geography	Estimate	Reference period	Industrial aggregate including unclassified businesses [6 7]	Industrial aggregate excluding unclassified businesses [6 7]
			Dollars	
British Columbia (map)	Average weekly earnings including overtime for all employees [5]	July 2017	..	939.88[A]
		August 2017	..	939.79[A]
		September 2017	..	951.51[A]
		October 2017	..	950.29[A]
		November 2017	..	952.12[A]
		December 2017	..	958.25[A]
		January 2018	..	957.22[A]
		February 2018	..	962.48[A]
		March 2018	..	963.99[A]
		April 2018	..	953.93[A]
		May 2018	..	956.99[A]
		June 2018	..	967.63[A]
		July 2018	..	974.29[A]
		August 2018	..	979.82[A]
		September 2018	..	975.65[A]
		October 2018	..	978.07[A]
		November 2018	..	979.83[A]
		December 2018	..	976.63[A]
		January 2019	..	973.10[A]
		February 2019	..	974.09[A]

		March 2019	..	986.67[A]
		April 2019	..	991.01[A]
		May 2019	..	1,001.50[A]
		June 2019	..	993.45[A]
		July 2019	..	996.11[A]
		August 2019	..	1,003.60[A]
		September 2019	..	1,008.09[B]
		October 2019	..	1,015.74[B]
		November 2019	..	1,012.40[B]
		December 2019	..	1,014.52[B]
		January 2020	..	1,025.61[B]
		February 2020	..	1,025.17[B]
		March 2020	..	1,029.38[B]
		April 2020	..	1,106.54[B]
		May 2020	..	1,123.79[B]

Symbol legend:

.. not available for a specific reference period

A data quality: excellent

B data quality: very good

Table A1-3: British Columbia Preliminary Economic Forecast, Conference Board of Canada, Provincial Outlook Economic Forecast, Spring 2020

British Columbia, preliminary economic forecast

(forecast completed April 6, 2020)

	2020	2021	2022	2023	2024
Real GDP at basic prices (2012 $ millions)	243,649	258,884	264,208	267,544	271,587
	–3.2	*6.3*	*2.1*	*1.3*	*1.5*
Employment (000s)	2,453	2,547	2,580	2,604	2,628
	–4.1	*3.8*	*1.3*	*0.9*	*0.9*
Unemployment rate (per cent)	8.0	5.2	5.0	5.1	5.0
Housing starts (units)	35,300	35,890	34,080	32,321	30,562
	–21.4	*7.8*	*–10.5*	*–5.2*	*–5.4*

Italics indicate percentage change.
For each indicator, the first line is the level, and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Appendix A-2

Load Forecast Tables

Table of Contents

1. INTRODUCTION

This appendix provides the historical and forecast load data used in Section 3 of the Application. Tables 2.1 to 5.2 show ten years of historical data and the before-savings and after-savings forecast for 2020 and 2021. The 2020 forecast includes actual loads until June of 2020. Table 5.3 shows the DSM that was deducted from the before-savings forecast to provide the after-savings forecast for 2021. Tables 6.1 and 6.2 show the variance of the customer accounts and forecasts from 2015 to 2019 when compared to the actuals. Table 6.3 shows the annual growth of customer and load that FBC has experienced since 2015. Table 6.4 and 6.5 show the Residential UPC and Winter peak variances from forecast from 2015 to 2019. Finally Table 6.6 shows the system load factor from the years 2015 to 2019 and the forecast load factor for 2020 and 2021.

The tables in this appendix reflect the acquisition by FBC of the assets and customers of the City of Kelowna electric utility effective March 31, 2013. The acquisition resulted in an increase in direct customers to FBC and a re-distribution of load from wholesale to other rate classes in 2013 and 2014.

2. MONTHLY LOAD FORECAST

Forecast loads are shown:

- before-savings – the load before DSM and includes Normalized loads to December 2019 and Actual loads from January 2020 to June 2020.
- after-savings – the load after DSM and include Normalized loads to December 2019 and actual loads to June 2020.

2.1 *GROSS LOAD (MWH)*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2010	358,574	304,251	288,022	253,247	237,451	232,285	274,190	265,937	227,770	258,133	303,172	365,668	3,368,701
2011	374,096	313,764	312,059	254,039	235,722	242,276	268,421	273,732	242,593	260,877	307,093	362,607	3,447,280
2012	354,376	315,497	304,411	253,594	237,899	233,308	272,143	275,122	236,457	262,538	313,757	362,555	3,421,657
2013	372,939	327,919	300,296	255,888	249,987	235,093	291,183	274,786	241,239	266,317	303,923	380,406	3,499,975
2014	363,947	304,540	303,886	253,159	241,999	242,933	284,643	269,971	229,496	256,060	300,844	381,603	3,433,082
2015	365,681	319,636	299,774	250,449	249,965	245,501	286,189	276,449	233,713	256,762	300,047	361,987	3,446,152
2016	363,248	311,848	292,351	268,698	248,319	242,786	289,259	280,588	234,770	266,284	332,085	350,062	3,480,297
2017	361,265	295,737	307,586	263,795	249,642	251,284	299,544	288,941	246,701	265,695	326,103	355,527	3,511,820
2018	375,664	309,496	306,028	264,140	273,621	256,591	308,227	297,251	231,377	262,531	302,555	376,342	3,563,824
2019	372,224	288,274	315,330	261,324	268,354	257,653	298,081	293,227	260,757	291,917	313,593	371,724	3,592,459
Before-Savings													
2020P	369,327	321,446	312,382	255,630	244,802	245,197	300,412	297,184	250,693	284,422	322,171	371,703	3,575,370
2021F	379,971	308,249	319,777	274,167	275,653	264,579	311,599	306,562	257,766	291,168	330,083	381,060	3,700,634
After-Savings													
2020P	369,327	321,446	312,382	255,630	244,802	245,197	298,826	295,348	248,578	281,976	319,393	368,613	3,561,518
2021F	376,570	304,617	315,983	270,255	271,648	260,442	307,276	301,953	252,810	285,768	324,255	374,865	3,646,444

2.2 *NET LOAD (MWH)*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2010	322,764	275,389	264,054	233,827	220,707	215,751	252,308	245,260	211,831	238,568	276,095	328,561	3,085,116
2011	333,975	282,076	283,208	233,733	218,542	223,679	246,555	251,059	223,951	240,135	278,304	324,686	3,139,902
2012	321,730	286,779	279,732	235,517	222,312	217,842	252,099	254,667	220,598	243,793	286,926	328,517	3,150,511
2013	337,728	297,641	276,667	237,842	233,199	219,696	268,867	254,751	225,078	247,419	279,078	343,897	3,221,865
2014	330,080	277,952	279,588	235,366	226,108	226,460	263,122	250,470	214,691	238,394	276,319	344,675	3,163,224
2015	331,359	290,442	275,968	232,925	232,996	228,619	264,346	255,968	218,317	238,919	275,526	328,297	3,173,683
2016	329,697	284,239	269,871	248,933	231,743	226,433	267,219	259,761	219,415	247,393	302,834	318,710	3,206,245
2017	327,600	270,353	282,545	244,429	232,661	233,596	275,700	266,639	229,612	246,617	297,428	322,834	3,230,015
2018	340,082	282,343	281,627	245,049	253,803	238,507	283,500	274,131	216,479	244,187	277,988	340,643	3,278,339
2019	337,457	264,607	289,706	242,736	249,368	239,550	274,993	270,833	242,244	269,708	287,514	337,042	3,305,758
Before-Savings													
2020P	334,772	293,291	287,337	237,129	228,146	225,140	276,956	274,193	233,469	263,232	294,723	336,977	3,285,366
2021F	344,683	282,083	294,089	254,316	256,163	246,005	287,115	282,806	240,077	269,582	302,076	345,587	3,404,583
After-Savings													
2020P	334,772	293,291	287,337	237,129	228,146	225,140	275,496	272,504	231,523	260,983	292,167	334,135	3,272,623
2021F	341,555	278,742	290,598	250,718	252,479	242,199	283,137	278,566	235,517	264,614	296,715	339,888	3,354,728

2.3 RESIDENTIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2010	144,415	116,176	112,135	94,505	85,285	75,333	96,222	91,300	72,613	94,047	110,964	148,667	1,241,663
2011	150,580	112,169	121,527	98,312	80,093	79,957	85,233	91,744	76,608	88,720	117,345	146,806	1,249,094
2012	134,187	105,958	112,447	88,508	81,808	82,946	97,309	91,118	73,417	89,175	117,807	154,029	1,228,709
2013	145,263	115,730	114,637	112,100	90,869	85,319	120,666	100,397	73,591	97,867	124,661	171,845	1,352,945
2014	147,191	120,724	129,852	84,813	80,792	77,673	105,443	102,753	73,260	95,314	119,531	159,107	1,296,452
2015	150,230	122,084	120,304	91,957	76,652	84,441	110,145	97,235	73,384	99,324	125,839	146,556	1,298,150
2016	147,429	121,286	113,080	99,963	91,648	85,702	101,212	96,335	77,431	96,417	129,741	135,335	1,295,580
2017	145,663	112,986	118,857	102,166	94,155	86,021	106,392	95,082	82,012	96,745	129,829	150,584	1,320,492
2018	154,740	121,081	119,975	97,261	100,276	86,146	109,349	100,153	70,342	89,942	112,695	150,638	1,312,598
2019	147,714	98,552	116,377	90,039	91,727	81,739	100,157	94,674	87,612	98,618	112,609	146,320	1,266,137
Before-Savings													
2020P	145,685	112,894	119,674	95,364	99,183	84,668	103,477	94,964	78,605	93,456	116,330	146,599	1,290,899
2021F	144,697	107,404	114,697	93,469	92,401	81,986	102,003	93,612	77,485	92,125	114,672	144,511	1,259,064
After-Savings													
2020P	145,685	112,894	119,674	95,364	99,183	84,668	103,315	94,771	78,365	93,155	115,960	146,165	1,289,199
2021F	144,213	106,893	114,187	92,980	91,941	81,545	101,555	93,121	76,913	91,445	113,876	143,615	1,252,284

2.4 COMMERCIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Normliazed Actuals													
2010	58,527	55,666	53,799	51,561	52,546	56,272	56,380	52,416	51,844	54,570	57,594	58,382	659,556
2011	57,742	59,980	55,524	50,675	51,759	55,477	59,401	55,911	50,918	50,637	53,116	55,779	656,918
2012	64,101	63,452	59,292	53,673	54,431	49,553	55,968	62,008	56,661	52,596	57,398	51,423	680,553
2013	65,750	60,623	56,214	57,036	69,494	61,665	67,834	73,941	72,704	67,185	66,229	69,533	788,208
2014	80,917	72,012	69,241	70,566	73,379	72,714	75,404	74,677	66,669	60,028	65,444	82,026	863,078
2015	81,041	74,201	68,933	64,674	71,533	72,581	71,204	71,712	68,657	62,650	66,828	79,463	853,478
2016	82,612	75,915	71,711	71,671	69,996	66,744	76,904	77,981	68,748	70,333	81,859	90,367	904,841
2017	85,017	74,211	77,360	69,012	70,513	72,529	81,817	81,344	72,335	73,835	78,070	78,916	914,960
2018	87,447	74,470	78,245	70,839	73,624	72,175	81,335	82,374	71,079	73,218	76,070	85,202	926,078
2019	86,215	75,958	80,152	69,784	72,863	72,688	80,601	81,248	73,015	75,305	77,661	86,230	931,722
Before-Savings													
2020P	85,762	84,491	78,977	65,616	56,898	66,672	80,567	80,968	71,536	73,496	76,617	82,747	904,346
2021F	89,205	77,467	81,301	72,292	74,832	74,967	84,058	84,476	74,635	76,681	79,937	86,333	956,184
After-Savings													
2020P	85,762	84,491	78,977	65,616	56,898	66,672	79,983	80,295	70,763	72,614	75,621	81,640	899,332
2021F	87,998	76,174	79,940	70,875	73,362	73,438	82,454	82,774	72,814	74,724	77,841	84,108	936,501

Note: The commercial class is normalized from 2014 to 2019 since weather correlation appeared in the data at that time, all numbers before 2014 are actuals.

2.5 WHOLESALE (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2010	98,545	83,945	77,442	67,108	59,780	59,833	72,144	70,068	60,545	64,123	82,201	99,603	895,337
2011	100,725	84,225	82,112	65,996	58,766	60,441	68,427	71,106	64,187	70,871	84,304	98,386	909,548
2012	96,036	85,333	81,119	66,560	58,307	59,084	69,719	70,177	60,311	72,646	82,146	97,532	898,971
2013	103,661	88,423	80,309	42,225	37,653	34,630	44,414	42,889	38,531	44,175	51,637	66,656	675,204
2014	64,115	50,647	51,900	41,917	35,985	34,959	43,081	42,482	38,972	41,116	53,678	68,270	567,123
2015	65,841	58,564	51,584	41,088	41,147	36,029	45,222	43,897	37,441	42,668	51,945	65,059	580,485
2016	64,687	55,006	49,218	43,812	36,262	35,106	48,506	43,480	37,096	43,408	59,685	58,167	574,434
2017	61,637	51,026	51,573	40,753	35,692	35,965	47,044	49,971	39,411	42,639	56,771	61,621	574,101
2018	65,721	51,837	50,293	43,769	41,467	33,766	45,024	47,275	36,478	47,576	54,103	67,407	584,715
2019	61,944	48,097	50,091	42,390	39,513	36,881	47,393	44,924	37,351	44,052	49,804	63,534	565,972
Before-Savings													
2020P	61,985	53,969	51,205	41,439	36,633	35,685	46,476	47,379	37,738	44,745	53,547	64,172	574,973
2021F	64,794	51,671	52,012	43,439	39,934	36,491	47,734	48,661	38,760	45,957	54,997	65,910	590,359
After-Savings													
2020P	61,985	53,969	51,205	41,439	36,633	35,685	46,283	47,155	37,477	44,440	53,195	63,775	573,240
2021F	64,357	51,205	51,529	42,947	39,436	35,982	47,205	48,095	38,142	45,276	54,251	65,105	583,530

2.6 *INDUSTRIAL (MWH)*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2010	19,449	17,896	18,991	18,389	18,616	18,603	18,551	20,146	19,259	21,495	22,097	20,207	233,699
2011	23,160	24,129	21,555	17,261	24,902	22,812	25,671	21,690	22,374	24,978	20,262	21,971	270,764
2012	24,973	30,356	25,036	25,285	23,707	21,432	22,094	22,115	22,666	22,863	26,328	23,917	290,771
2013	19,966	30,774	23,744	24,489	31,517	33,006	29,815	29,726	31,598	32,105	32,500	33,084	352,325
2014	35,943	32,746	26,411	34,532	30,112	32,770	29,719	22,362	30,032	38,104	35,138	33,043	380,912
2015	32,138	33,574	32,797	31,186	36,574	26,261	27,971	34,078	32,395	29,853	27,852	34,997	379,676
2016	32,901	29,835	33,180	28,953	27,588	31,785	31,632	32,805	30,120	33,350	28,559	32,687	373,396
2017	33,109	30,227	32,593	30,117	27,928	31,621	29,477	29,518	28,665	28,831	30,770	29,734	362,590
2018	30,089	33,113	31,062	30,455	32,718	39,030	38,264	35,307	33,245	30,034	33,591	35,836	402,744
2019	40,014	40,563	41,563	37,886	39,198	40,876	38,967	41,784	39,929	49,045	45,695	39,390	494,911
Before-Savings													
2020P	39,704	40,302	35,771	32,283	31,263	30,747	37,814	42,390	40,509	48,359	46,711	41,992	467,844
2021F	44,315	44,054	44,431	42,850	44,138	45,835	44,698	47,564	44,115	51,643	50,951	47,366	551,959
After-Savings													
2020P	39,704	40,302	35,771	32,283	31,263	30,747	37,342	41,849	39,901	47,667	45,948	41,171	463,947
2021F	43,403	43,071	43,384	41,737	42,971	44,604	43,413	46,206	42,691	50,113	49,348	45,715	536,656

2.7 *LIGHTING (MWH)*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
2010	1,132	1,100	1,172	1,047	1,184	1,513	1,767	1,246	1,123	1,111	1,045	1,041	14,480
2011	1,114	1,027	1,674	582	1,092	1,098	1,086	1,113	1,615	560	1,121	1,153	13,233
2012	1,618	1,031	1,232	601	1,666	601	1,661	1,137	611	1,127	1,137	1,064	13,487
2013	1,532	863	1,003	1,112	1,186	1,101	1,151	1,069	1,135	1,132	1,080	1,114	13,479
2014	1,282	1,273	1,251	1,310	1,327	1,331	1,329	1,374	1,257	1,255	1,260	1,382	15,633
2015	1,319	1,339	1,261	1,321	1,372	1,382	1,299	1,347	1,248	1,349	1,295	1,359	15,891
2016	1,245	1,363	1,341	1,362	1,361	1,347	1,404	1,381	1,294	1,191	1,251	1,388	15,930
2017	1,394	1,233	1,390	1,286	1,339	1,301	1,383	1,382	1,289	1,335	1,270	1,330	15,932
2018	1,385	1,178	1,291	1,307	1,198	1,118	1,068	998	988	952	848	894	13,225
2019	907	808	873	943	965	937	917	949	955	947	909	928	11,039
Before-Savings													
2020P	936	958	883	702	779	1,066	925	914	887	888	831	866	10,636
2021F	1,012	884	976	971	962	922	925	914	887	888	831	866	11,039
After-Savings													
2020P	936	958	883	702	779	1,066	888	872	837	827	760	784	10,292
2021F	926	796	889	887	881	843	846	831	797	787	720	746	9,949

2.8 *IRRIGATION (MWH)*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
2010	698	605	514	1,217	3,296	4,198	7,243	10,085	6,448	3,223	2,194	660	40,381
2011	654	545	816	908	1,931	3,894	6,737	9,495	8,249	4,369	2,156	590	40,345
2012	816	650	606	890	2,393	4,226	5,348	8,113	6,933	5,385	2,109	552	38,019
2013	1,557	1,228	759	880	2,480	3,974	4,986	6,729	7,519	4,955	2,970	1,666	39,704
2014	633	549	932	2,227	4,512	7,013	8,146	6,822	4,501	2,578	1,267	847	40,025
2015	790	680	1,089	2,698	5,718	7,925	8,506	7,700	5,192	3,074	1,768	863	46,003
2016	822	834	1,341	3,172	4,888	5,748	7,561	7,778	4,724	2,694	1,739	765	42,065
2017	780	670	772	1,096	3,035	6,160	9,587	9,343	5,898	3,231	719	649	41,939
2018	700	662	761	1,419	4,521	6,271	8,461	8,024	4,348	2,465	681	666	38,979
2019	663	630	650	1,694	5,103	6,429	6,958	7,254	3,381	1,741	835	640	35,978
Before-Savings													
2020P	701	678	827	1,725	3,390	6,302	7,696	7,578	4,194	2,289	688	602	36,670
2021F	659	604	672	1,295	3,896	5,805	7,696	7,578	4,194	2,289	688	602	35,978
After-Savings													
2020P	701	678	827	1,725	3,390	6,302	7,685	7,562	4,180	2,280	683	600	36,613
2021F	658	603	670	1,292	3,888	5,786	7,665	7,539	4,162	2,269	679	598	35,808

2.9 *SYSTEM PEAK (MW)*

System Peak (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
Historical Normalized Actuals														
2010	683	629	536	499	486	420	566	554	448	487	652	726	726	566
2011	722	666	593	516	472	448	529	537	509	508	632	691	702	537
2012	702	675	560	523	493	418	589	540	453	501	624	723	723	589
2013	720	631	549	493	515	442	600	565	523	502	598	698	698	600
2014	651	580	562	469	403	482	620	605	412	467	572	645	693	620
2015	693	679	568	488	501	523	611	587	437	514	669	631	685	611
2016	685	683	569	540	490	582	587	593	443	480	613	724	755	593
2017	755	673	595	510	597	505	600	605	561	515	594	648	714	605
2018	714	648	583	516	602	533	630	631	429	459	609	659	682	631
2019	678	682	651	514	568	502	626	639	538	562	622	701	732	639
Before-Savings														
2020P	732	621	572	479	432	503	596	602	463	501	625	672	738	610
2021F	701	656	591	495	469	531	614	620	477	516	644	692	750	628
After-Savings														
2020P	732	621	572	479	432	503	596	601	462	500	624	671	737	609
2021F	700	655	590	494	467	530	613	618	475	514	642	690	748	627

Note: The peaks show in the table above are seasonal peaks. The seasonal winter peak is based on November and December of the current year and January and February of the following year. The seasonal summer peak is based on June, July and August of the current year.

3. CUSTOMER FORECAST

3.1 CUSTOMERS

Customer Count	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Residential	97,883	98,795	99,228	111,862	113,431	114,166	115,772	117,748	120,291	122,465	123,407	124,603
Commercial	11,419	11,525	11,811	13,662	14,363	14,976	15,073	15,398	15,678	15,956	15,639	16,579
Wholesale	7	7	7	6	6	6	6	6	6	6	6	6
Industrial	35	36	39	47	49	50	50	50	52	51	57	59
Lighting	1,830	1,803	1,739	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,425	1,393
Irrigation	1,075	1,092	1,091	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,082	1,082
Total Direct	112,249	113,258	113,915	128,318	130,572	131,883	133,550	135,793	138,587	141,027	141,616	143,722

3.2 CUSTOMER ADDITIONS

Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Residential	1,318	912	433	12,634	1,569	735	1,606	1,976	2,543	2,174	942	1,196
Commercial	111	106	286	1,851	701	613	97	325	280	278	(317)	939
Wholesale	-	-	-	(1)	-	-	-	-	-	-	-	-
Industrial	2	1	3	8	2	1	-	-	(6)	(9)	6	2
Lighting	(44)	(27)	(64)	(95)	(24)	(30)	(31)	(48)	(29)	(15)	(42)	(32)
Irrigation	9	17	(1)	6	6	(8)	(5)	(10)	(2)	4	-	-
Total Direct	1,396	1,009	657	14,403	2,254	1,311	1,667	2,243	2,786	2,432	589	2,105

1 # 4. NORMALIZED AFTER-SAVINGS USE PER CUSTOMER (UPC)

MWh/Customer	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
2 Residential	12.77	12.70	12.41	12.48	11.51	11.41	11.27	11.31	11.03	10.43	10.49	10.10

5. LOAD

5.1 NORMALIZED AFTER-SAVINGS LOAD

Load (GWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
Residential	1,242	1,249	1,229	1,353	1,296	1,298	1,296	1,320	1,313	1,266	1,289	1,252
Commercial	660	657	681	788	863	853	905	915	926	932	899	937
Wholesale	895	910	899	675	567	580	574	574	585	566	573	584
Industrial	234	271	291	352	381	380	373	363	403	495	464	537
Lighting	14	13	13	13	16	16	16	16	13	11	10	10
Irrigation	40	40	38	40	40	46	42	42	39	36	37	36
Net	3,085	3,140	3,151	3,222	3,163	3,174	3,206	3,230	3,278	3,306	3,273	3,355
Losses & Company Use	284	307	271	278	270	272	274	282	285	287	289	292
Gross	3,369	3,447	3,422	3,500	3,433	3,446	3,480	3,512	3,564	3,592	3,562	3,646
System Peak (MW)												
Winter Peak	726	702	723	698	693	685	755	714	682	732	737	748
Summer Peak	566	537	589	600	620	611	593	605	631	639	609	627

5.2 NORMALIZED AFTER-SAVINGS WHOLESALE LOAD

Wholesale (GWh)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020P	2021F
BCH Lardeau	10	8	6	6	6	6	6	8	8	7	7	8
BCH Kingsgate	3	3	5	5	5	5	5	5	5	5	5	5
City of Grand Forks	41	41	41	41	39	41	41	39	46	37	38	38
City of Nelson	90	88	80	83	81	83	80	86	88	84	86	81
City of Penticton	341	344	341	348	342	348	345	338	340	338	340	343
District of Summerland	97	96	95	98	94	97	98	98	99	95	97	108
City of Kelowna	314	329	332	94								
Total	895	910	899	675	567	580	574	574	585	566	573	584

5.3 DSM (GWH) WITHOUT LOSSES

Load (GWh)	2015	2016	2017	2018	2019	2020P	2021F
Demand Side Management	(12)	(23)	(28)	(31)	(26)	(19)	(54)

6. VARIANCES TO FORECAST

6.1 CUSTOMER COUNT VARIANCE

Customer Count	2014	2015	2016	2017	2018	2019
Actual						
Residential	113,431	114,166	115,772	117,748	120,291	122,465
Commercial	14,363	14,976	15,073	15,398	15,678	15,956
Wholesale	6	6	6	6	6	6
Industrial	49	50	50	50	52	51
Lighting	1,620	1,590	1,559	1,511	1,482	1,467
Irrigation	1,103	1,095	1,090	1,080	1,078	1,082
Total	130,572	131,883	133,550	135,793	138,587	141,027
Forecast						
Residential	113,229	114,855	115,758	116,031	117,774	120,405
Commercial	13,739	14,531	15,042	15,813	16,122	16,405
Wholesale	6	6	6	6	6	6
Industrial	48	49	49	50	50	51
Lighting	1,742	1,620	1,620	1,590	1,559	1,511
Irrigation	1,091	1,103	1,103	1,095	1,090	1,080
Total	129,855	132,164	133,578	134,585	136,602	139,459
Variance (customers)						
Residential	202	(689)	14	1,717	2,517	2,060
Commercial	624	445	31	(415)	(444)	(449)
Wholesale	-	-	-	-	-	-
Industrial	1	1	1	-	2	-
Lighting	(122)	(30)	(61)	(79)	(77)	(44)
Irrigation	12	(8)	(13)	(15)	(12)	2
Total	717	(281)	(28)	1,208	1,986	1,569
Variance (%)						
Residential	0.2%	-0.6%	0.0%	1.5%	2.1%	1.7%
Commercial	4.3%	3.0%	0.2%	-2.7%	-2.8%	-2.8%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	2.0%	2.0%	2.0%	0.0%	3.8%	0.0%
Lighting	-7.5%	-1.9%	-3.9%	-5.2%	-5.2%	-3.0%
Irrigation	1.1%	-0.7%	-1.2%	-1.4%	-1.1%	0.2%
Total	0.5%	-0.2%	0.0%	0.9%	1.4%	1.1%

1 ## 6.2 LOAD VARIANCE, NORMALIZED ACTUAL TO FORECAST

Load (GWh)	2014	2015	2016	2017	2018	2019
Normalized						
Residential	1,296	1,298	1,296	1,320	1,313	1,266
Commercial	863	853	905	915	926	932
Wholesale	567	580	574	574	585	566
Industrial	381	380	373	363	403	495
Lighting	16	16	16	16	13	11
Irrigation	40	46	42	42	39	36
Net	3,163	3,174	3,206	3,230	3,278	3,306
Gross	3,433	3,446	3,480	3,512	3,564	3,592
Forecast						
Residential	1,402	1,397	1,367	1,353	1,280	1,349
Commercial	813	808	871	879	912	935
Wholesale	581	593	579	587	586	594
Industrial	389	371	393	407	379	385
Lighting	13	14	13	14	15	13
Irrigation	42	40	39	40	41	42
Net	3,240	3,224	3,262	3,282	3,213	3,319
Gross	3,519	3,499	3,540	3,559	3,485	3,602
Variance (GWh)						
Residential	(106)	(99)	(71)	(33)	33	(83)
Commercial	50	45	34	36	14	(3)
Wholesale	(14)	(13)	(5)	(13)	(1)	(28)
Industrial	(9)	9	(20)	(44)	24	110
Lighting	3	2	3	1	(2)	(2)
Irrigation	(2)	6	3	2	(2)	(6)
Net	(77)	(50)	(56)	(52)	65	(13)
Gross	(86)	(53)	(59)	(47)	79	(10)
Variance (%)						
Residential	-8.2%	-7.6%	-5.5%	-2.5%	2.5%	-6.6%
Commercial	5.9%	5.3%	3.8%	3.9%	1.5%	-0.4%
Wholesale	-2.5%	-2.2%	-0.8%	-2.3%	-0.2%	-5.0%
Industrial	-2.2%	2.3%	-5.3%	-12.3%	5.9%	22.2%
Lighting	18.2%	12.7%	16.3%	9.4%	-13.4%	-17.8%
Irrigation	-4.9%	12.1%	7.7%	3.9%	-5.2%	-16.7%
Net	-2.4%	-1.6%	-1.7%	-1.6%	2.0%	-0.4%
Gross	-2.5%	-1.5%	-1.7%	-1.3%	2.2%	-0.3%

2

1 ## 6.3 NORMALIZED AFTER-SAVINGS ANNUAL PERCENT GROWTH

Load (GWh)	2014	2015	2016	2017	2018	2019	2020P	2021F
Residential	1,296	1,298	1,296	1,320	1,313	1,266	1,289	1,252
Commercial	863	853	905	915	926	932	899	937
Wholesale	567	580	574	574	585	566	573	584
Industrial	381	380	373	363	403	495	464	537
Lighting	16	16	16	16	13	11	10	10
Irrigation	40	46	42	42	39	36	37	36
Net	3,163	3,174	3,206	3,230	3,278	3,306	3,273	3,355
Losses & Company Use	270	272	274	282	285	287	289	292
Gross	3,433	3,446	3,480	3,512	3,564	3,592	3,562	3,646
System Peak								
Winter Peak (MW)	693	685	755	714	682	732	737	748
Summer Peak (MW)	620	611	593	605	631	639	609	627

Growth Year over Year	2014	2015	2016	2017	2018	2019	2020P	2021F
Residential		0%	0%	2%	-1%	-4%	2%	-3%
Commercial		-1%	6%	1%	1%	1%	-3%	4%
Wholesale		2%	-1%	0%	2%	-3%	1%	2%
Industrial		0%	-2%	-3%	11%	23%	-6%	16%
Lighting		2%	0%	0%	-17%	-17%	-7%	-3%
Irrigation		15%	-9%	0%	-7%	-8%	2%	-2%
Net		0%	1%	1%	1%	1%	-1%	3%
Losses & Company Use		1%	1%	3%	1%	0%	1%	1%
Gross		0%	1%	1%	1%	1%	-1%	2%
System Peak								
Winter Peak (MW)		-1%	10%	-5%	-4%	7%	1%	1%
Summer Peak (MW)		-1%	-3%	2%	4%	1%	-5%	3%

Customer Count	2014	2015	2016	2017	2018	2019	2020P	2021F
Residential	113,431	114,166	115,772	117,748	120,291	122,465	123,407	124,603
Commercial	14,363	14,976	15,073	15,398	15,678	15,956	15,639	16,579
Wholesale	6	6	6	6	6	6	6	6
Industrial	49	50	50	50	52	51	57	59
Lighting	1,620	1,590	1,559	1,511	1,482	1,467	1,425	1,393
Irrigation	1,103	1,095	1,090	1,080	1,078	1,082	1,082	1,082
Total Direct	130,572	131,883	133,550	135,793	138,587	141,027	141,616	143,722

Growth Year over Year	2014	2015	2016	2017	2018	2019	2020P	2021F
Residential		1%	1%	2%	2%	2%	1%	1%
Commercial		4%	1%	2%	2%	2%	-2%	6%
Wholesale		0%	0%	0%	0%	0%	0%	0%
Industrial		2%	0%	0%	4%	-2%	12%	4%
Lighting		-2%	-2%	-3%	-2%	-1%	-3%	-2%
Irrigation		-1%	0%	-1%	0%	0%	0%	0%
Total Direct		1%	1%	2%	2%	2%	0%	1%

2

6.4 RESIDENTIAL UPC, NORMALIZED ACTUAL TO FORECAST

Residential UPC (MWh)	2017	2018	2019
After- Savings Normalized Actual UPC	11.31	11.03	10.43
Forecast	11.71	10.92	11.27
Variance	(0.40)	0.11	(0.84)
Variance (%)	-3.5%	1.0%	-8.0%

6.5 WINTER PEAK , ACTUAL TO FORECAST

Winter Peak (MW)	2017	2018	2019
After- Savings Actual Peak	663	691	732
Forecast	734	712	764
Variance	(71)	(21)	(32)
Variance (%)	-10%	-3%	-4%

Note: The peaks reflected in this table are the actual seasonal peaks are not normalized.

6.6 SYSTEM LOAD FACTOR

The following table shows annual after-savings gross load, peak load and load factor. The annual load factor is calculated as annual load ÷ peak hourly load x number of hours in a year (8,760).

Year	Load (MWh)	Peak (MW)	Load Factor
2014	3,433,619	651	0.60
2015	3,446,152	693	0.57
2016	3,480,006	724	0.55
2017	3,512,293	755	0.53
2018	3,563,824	714	0.57
2019	3,592,459	701	0.58
2020P	3,561,518	737	0.55
2021F	3,646,444	748	0.56

Note: The peaks in this table represent annual peaks meaning they happened in the calendar year and are not the seasonal peaks.

Appendix A-3

Load Forecast Methods

Table of Contents

1. LOAD FORECAST METHODS

This appendix describes FBC's load forecast methods on which the forecast in section 3 of the Application is based.

In the figures provided in this appendix, the following three time frames are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year. For the 2021 Annual Review the latest calendar year for which full actual data exists is the 2019 calendar year.
- Forecast Year(s): This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, 2021 is the Forecast Year (2021F).
- Projected Year: The Projected Year is the year prior to the first forecast year. The Projected Year is combination of a forecast based on the latest years of actual data available and actuals loads for that year. For this Application the Projected Year is 2020 (2020P) and includes actuals to June of 2020,

1.1 *WEATHER NORMALIZATION*

Electricity consumption is impacted by weather, particularly by temperature. For example, load requirements in an extremely cold winter month can be significantly higher than requirements in normal weather conditions in the same month, due to additional heating loads. As the load forecast is made under an assumption of normal weather, it is necessary to remove those extreme weather effects from the historical data. This is the first step in forecasting.

Statistical tests were made to check whether the residential, wholesale, commercial and irrigation loads were sensitive to temperature due to heating and cooling demands and whether the irrigation load was sensitive to the amount of precipitation[1]. The results from the regression for these four rate classes are shown below. The results show significant results with high R^2 values greater than 0.60 for all seasons for the residential, wholesale and commercial[2] load classes; therefore these classes are normalized. The irrigation class shows a R^2 value of less than 0.60 for the Winter, Summer and Fall seasons; therefore this class was not normalized.

[1] Industrial and street lighting loads are typically insensitive to the weather.
[2] The commercial class data is normalized from 2014 to 2019 since a strong correlation was present in those years. All commercial data prior to 2014 is actual because it did not show a correlation to weather at that time.

Table A3-1: Residential Regression Table

Residential	Winter	Spring	Summer	Fall
Intercept	39,515	73,227	71,387	62,477
Slope HDD	175	101	-	115
Slope CDD	-	-	220	-
Adjusted R^2	0.73	0.61	0.84	0.73

Table A3-2: Wholesale Regression Table

Wholesale	Winter	Spring	Summer	Fall
Intercept	55,586	47,677	57,858	59,812
Slope HDD	70	57	-	31
Slope CDD	-	-	112	-
Adjusted R^2	0.95	0.73	0.96	0.94

Table A3-2: Commercial Regression Table

Commercial	Winter	Spring	Summer	Fall
Intercept	42,373	52,329	52,801	52,855
Slope HDD	32	15	-	0
Slope CDD	-	-	45	-
Adjusted R^2	0.78	0.70	0.80	0.75

Table A3-2: Irrigation Regression Table

Irrigation	Winter	Spring	Summer	Fall
Intercept	2,010	4,889	5,068	6,671
Slope HDD	(2)	(11)	-	(12)
Slope CDD	-	-	24	-
Adjusted R^2	0.06	0.74	0.36	0.44

Steps for weather (temperature) normalization are as follows:

1. Calculate monthly Heating Degree Days (HDD)[3] and Cooling Degree Days (CDD)[4] for the Penticton weather station.
2. Calculate 10-year HDD and CDD averages for each month of the year. These are used as the parameters of normal weather.
3. For each of the residential, wholesale and commercial classes, regress load on HDD or CDD on a seasonal basis. Four seasons were defined: winter (November to February), spring (March to May), summer (June to August) and fall (September to October). Thus all monthly load and degree day data for each season is used and four separate

[3] Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18 Celsius degrees.
[4] Cooling degree-days for a given day are the number of Celsius degrees that the mean temperature is above 18 Celsius degrees.

regressions are calculated for each class. The City of Kelowna (CoK) Event variables were included in the regressions to recognize the integration of the CoK in 2013 into the FBC direct customer base.

4. To normalize a month, e.g. February 2019:
   (a) obtain the month's HDD (or CDD) information from Environment Canada;
   (b) calculate the deviation from the 10-year average (2010-2019) HDD (CDD) as found in Step 2;
   (c) apply the regression slope obtained in Step 3 to this deviation to come up with a normalization adder; and
   (d) add the normalization adder to the month's load (residential or wholesale).

The general equation to normalize load requirements in month t is shown below.

$$Normalized\ Load_t = Load_t - HDD\ Slope_t \times (HDD_t - Normal\ HDD_t)$$

$$where\ HDD\ is\ Heating\ Degree\ Days\ and\ t = Spring, Fall\ and\ Winter$$

And

$$Normalized\ Load_t = Load_t - CDD\ Slope_t \times (CDD_t - Normal\ CDD_t)$$

$$where\ CDD\ is\ Cooling\ Degree\ Days\ and\ t = Summer$$

1.2 *LOAD FORECAST*

FBC forecasts energy requirements by customer class based on historical loads as set out in the previous section. These are referred to as the "before-savings" loads. DSM savings that are incremental to those embedded in historical loads (up to and including 2019) are also forecast for each customer class and subtracted from the before-savings loads to arrive at the "after-savings" loads. This section discusses the before-savings forecast load requirements for each of FBC's load classes.

1.2.1 Residential

The formula to forecast the expected before-savings residential load in year *t* is:

$$Before\ Savings\ Load_t = UPC_t \times Average\ Customer\ Growth_t$$

where UPC (use per customer in MWh per customer per year) is before-savings.

The before-savings UPC was based on a ten-year historic trend of annual UPC values from 2010 to 2019. FBC reviews the forecast methods on an annual basis. As FBC found that there was a strong statistically significant correlation, it herefore applied a ten year trend.

Table A3-3: Results of UPC Trend Analysis

Regression	UPC
Start Year	2010
End Year	2019
R^2	0.95
Adjusted R^2	0.90
df	9
Intercept	488
Slope UPC	-0.24

Next, average customer count in year *t* is calculated as:

$$Average\ Customer\ Count_t = \frac{(Year\ End\ Count_t - Year\ End\ Count_{t-1})}{2}$$

The year-end customer count was based on the least squares regression model below.

$$Average\ Customer\ Count_t = b_0 + b_1 \times Population_t$$

$Population_t$ is the population data supplied by BC Stats for the Company's direct service area.

Table A3-4: Results of Residential Regression

Regression	Residential
Start Year	1995
End Year	2019
R^2	0.98
Adjusted R^2	0.98
df	24
Intercept	(23,964)
Slope Population	0.48

1.2.2 Commercial

The expected before-savings commercial load in year *t* is forecast based on the provincial GDP supplied by the CBOC. The relationship was estimated from the following equation.

$$Before\ Savings\ Load_t = b_0 + b_1 \times GDP_t + b_2 \times Princeton\ Event_t + b_3 \times CoK\ Event_t$$

Princeton $Event_t$ is a binary variable for the Princeton Light and Power (PLP) integration event in 2007, CoK_t is a binary variable for the City of Kelowna integration event in 2013. Coefficients b0, b1, b2, and b3 are obtained from an ordinary least squares (OLS) regression analysis on the 2005 to 2019 data.

Table A3-5: Results of Commercial Regression

Regression	Commercial
Start Year	2005
End Year	2019
R^2	0.99
Adjusted R^2	0.98
df	14
Intercept	110,014
Slope GDP	2.61
Slope PLP Event	36,536
Slope CoK Event	134,808

1.2.3 Wholesale

The Company forecasts the wholesale load based on load surveys from all wholesale customers. For this forecast, the response rate was 100 percent. FBC then summed the wholesale customers' forecasts to calculate the before-savings wholesale load forecast. This approach recognizes that in the near to medium term, the wholesale customers themselves are best able to forecast their load growth based on their knowledge of their customer mix, load behaviors, development projects with associated load requirements, etc.

1.2.4 Industrial

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. Eighty percent of FBC's industrial customers responded to the surveys, accounting for 92 percent of 2019 load.

FBC assumes no new industrial customers in the current forecast unless there is a confirmed commitment from an industrial customer. FBC works with key account managers to identify new customers and existing customers with expansion plans that have commited contracts that are being added to the system. The key account managers work with the new customers directly and relay the load requirements to the forecasting group.

1.2.5 Irrigation

The before-savings irrigation load forcast uses the 2019 actuals as the forecast due to the variability in the load in recent years.

1.2.6 Lighting

The before-savings lighting load uses the 2019 actuals due to the variability in the load primarily due to streetlight LED replacement programs which reduced the load for 2018 and 2019.

1.2.7 Demand Side Mangment (DSM) Savings

FBC forecasts load reductions resulting from its DSM programs.

The forecast of DSM savings is consistent with the Company's approved 2019 DSM Plan. DSM measures are grouped into applicable programs that are then added to produce the three primary sector (residential, commercial & industrial) annual plan savings targets. Finally, the annual sector targets beginning with the Projected Year are converted into a cumulative time series, and disaggregated into the customer rate classes and commensurate system loss reductions.

1.3 *PEAK DEMAND FORECAST*

The peak demand forecast is produced by taking the ten year average (2010-2019) of historical peak data. The historical peak data is escalated by the gross load growth rate before it is averaged to account for the growth of demand on the FBC system. Self-generating customers are removed from the historical load data since the underlying trends that impact other loads do not apply. Seasonal peaks were used for both the winter and the summer. The twelve monthly peaks, as well as the seasonal peaks, were then escalated by the annual load growth rates in the forecast period to produce forecast monthly peaks. The winter peak and the summer peak are assumed to replace monthly peaks in December and July, respectively.

The after DSM peak forecast was calculated by subtracting DSM capacity savings forecast from the before DSM peak forecast for each month in each year.

Appendix B

PLAYMOR STATION UPGRADE BUSINESS CASE

FortisBC Inc.

Playmor Station Upgrade

Business Case

Table of Contents

List of Appendices

Index of Tables and Figures

1. PROJECT SUMMARY

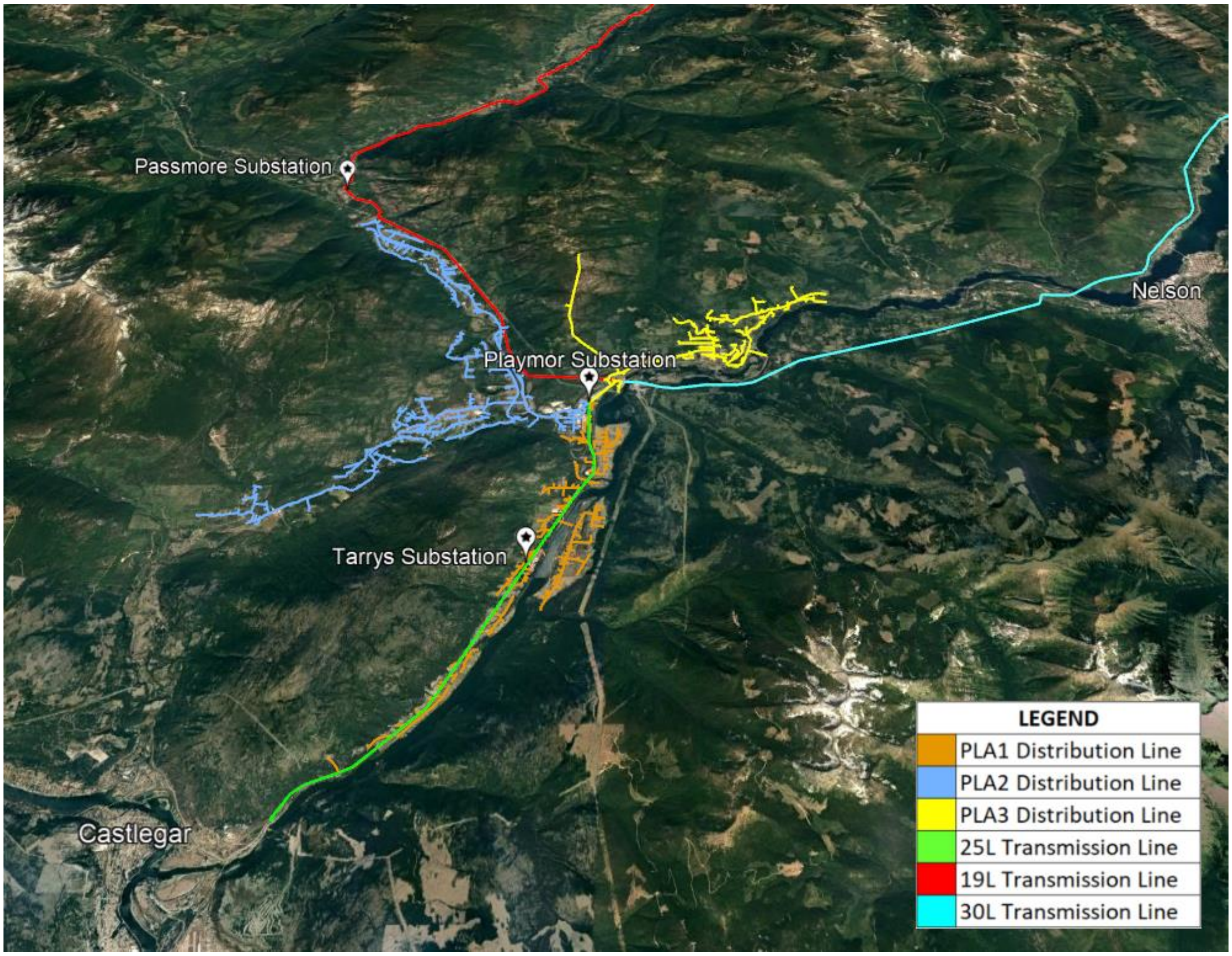
The Playmor Station Upgrade project proposes to rebuild the Playmor (PLA) substation on an expanded station footprint and increase station capacity by installing two 63kV/13/25 kV transformers (the Project). The Project is necessary to meet load growth, and to continue to reliably supply electricity to the surrounding area, including several large commercial and industrial customers. The Project will also address aging infrastructure and equipment condition issues.

The estimated total cost of the Project is $10.922 million in as-spent dollars, including AFUDC and cost of removal. FBC plans to initiate the detailed design, procurement and construction for the Project early in the first quarter of 2021. The substation is scheduled to be in service by December 2021, with Project completion and close-out by February 2022.

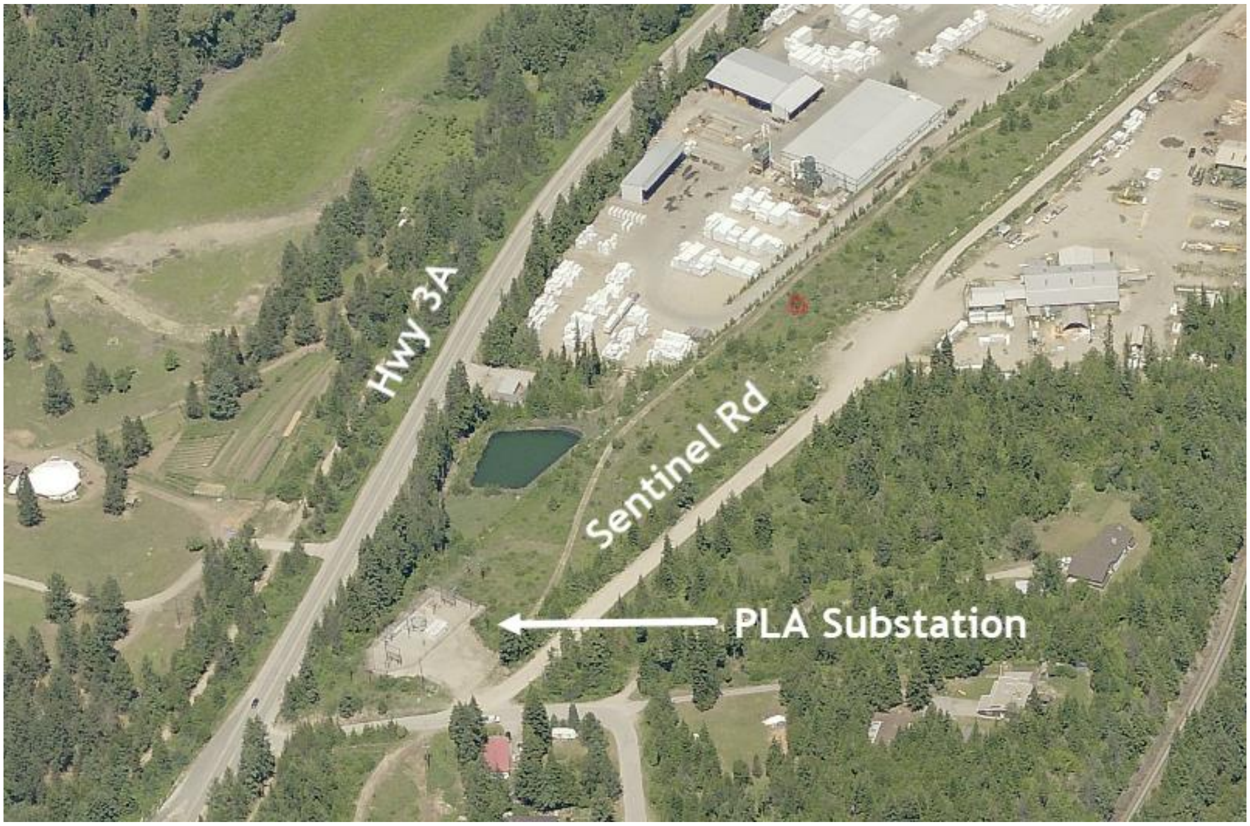
1.1 *BACKGROUND*

The PLA substation is located on Sentinel Rd in South Slocan, BC between Castlegar and Nelson. The existing station consists of a single 63/13 kV 16 MVA transformer (PLA T1) and is supplied by FBC's 63 kV transmission line 25 Line (25L). The station also provides a 13 kV distribution supply source to the area through three distribution feeders (PLA1, PLA2 and PLA3). The PLA station presently serves 2,484 residential customers, 270 commercial customers, and 1 industrial customer. The following figures show the area served by PLA and the PLA substation property location.

1 **Figure 1: Playmor Substation, Distribution Supply, Transmission Supply, and Surrounding Area**

2 

1 **Figure 2: PLA Substation Existing Location**



2

2. PROJECT NEED

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.

An upgrade to the PLA substation, encompassing the replacement of the existing 16 MVA transformer with either two new 20 MVA 63/25/13 kV transformers (Alternative A) or a single 40 MVA 63/25/13 kV transformer (Alternative B), is required to address these issues, as discussed below.

2.1 *GROWTH CAPACITY*

PLA area load experiences its peak load in the winter season. The existing winter limit for PLA T1 in normal operation is 16.6 MVA as a result of equipment condition issues with the load tap changer (LTC) as noted in section 2.3.

Due to capacity constraints at the station, two potential new large load requests could not be connected at the requested load levels. 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.

For each of the Alternatives, Figures 3 and 4 below show the actual/forecast winter peak PLA area load and the actual/forecast winter peak PLA area load including the potential new loads that could not be recently connected at the requested load levels.

The actual/forecast winter peak load will exceed the existing winter limit in normal operation in year 2028 assuming native load growth. However, if the potential new loads are also considered, the limit would be exceeded immediately. The winter rating in normal operation for the upgraded station would be 47.5 MVA (each 20 MVA transformer has a normal winter rating of 23.75 MVA as confirmed by the manufacturer), providing incremental capacity of 30.9 MVA compared to the current winter limit of 16.6 MVA.

Figure 3: PLA Area Winter Peak Load and Limits Under Alternative A (2x20 MVA)

Figure 4: PLA Area Winter Peak Load and Limits Under Alternative B (1x40 MVA)

2.2 RELIABILITY

As shown in Figure 1 above, there are two neighbouring stations near PLA: Passmore (PAS) substation and Tarrys (TAR) substation. PAS and TAR both have limited station capacity, limiting FBC's ability to offload residential and commercial customers from PLA to these substations. Consequently, 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.

Figures 3 and 4 above show the existing and post-upgrade PLA station winter limits in the event of a single PLA transformer outage under Alternatives A and B.

Under Alternative A, the remaining unit can carry the entire station load during a single PLA transformer outage for the next twenty years, at winter peak loads below 23.75 MVA. No customer outages would be required, improving reliability for PLA area customers.

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.

The largest mobile transformer (M18) that may be available for substations in the Kootenay region is rated 18 MVA. A larger 32 MVA mobile transformer (M32) is located in the Okanagan region but transporting this unit can be challenging given its size, winter road conditions, and potential BC road restrictions (depending on the timing of an outage). The use of the M32 would also be subject to its availability at the time of a transformer outage event. The 20-year load forecast indicates that in 2036, PLA station winter peak load will exceed 18 MVA. Relying on the larger 32 MVA unit could result in extended outages to customers (minimum 24 hours) and would leave the Okanagan region at risk while the mobile transformer was relocated to the Kootenays.

Figures 3 and 4 illustrate that while there is a significant amount of capacity available in normal operation under both alternatives, by installing two 20 MVA transformers at PLA, a single transformer could carry the entire station load during a PLA transformer outage for the next 20 years.

2.3 AGING INFRASTRUCTURE AND EQUIPMENT CONDITION

PLA T1 was manufactured in 1966 and is now 54 years old. Recent Dissolved Gas Analysis (DGA) results indicate a fast paper insulation aging process. Additionally, the LTC for PLA T1 is experiencing abnormal arcing. The LTC is obsolete and repair is not possible because of the unavailability of parts. Replacing the LTC would not be cost-effective, compared to replacement of the transformer itself.

Other substation components are also in need of replacement. The PLA metal-clad switchgear is obsolete and there are no spare breakers. The arc shoots are also suspected to contain asbestos. The arc flash hazard at PLA is on the higher side (Category 3 with 13 cal/cm^2 incident energy at the switchgear). Failure of the switchgear would result in a substation outage with no ability to restore service until replacement parts or switchgear could be sourced. The switchgear needs to be replaced by 2027, even without the substation upgrade.

Furthermore, there is a deficiency in the station DC 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.

2.4 *SUMMARY OF PROJECT OBJECTIVES*

To summarize, the objectives of the PLA Station Upgrade project are as follows:

- Increase station capacity to support growth in the area;
- Address reliability concerns during a PLA transformer outage to minimize potential customer outages; and
- Replace aging infrastructure and obsolete equipment consistent with FBC equipment standards to address reliability and safety concerns.

3. PROJECT ALTERNATIVES

FBC considered two alternatives to increase the capacity of PLA, which are a two-transformer solution and a one-transformer solution. These alternatives are described and evaluated below.

3.1 ALTERNATIVE A: INSTALL TWO TRANSFORMERS

Alternative A includes replacing PLA T1 with two new dual voltage 63/25/13 kV 20 MVA transformers. The station will be entirely rebuilt with all new equipment that is consistent with FBC equipment standards and will resolve other equipment age and condition issues. To accommodate the upgrade, the station footprint will be expanded.

The upgraded station will continue to have three feeders (PLA1, PLA2, and PLA3). A spare breaker will be installed for a future fourth feeder (PLA4). The conduit for PLA4 will be installed and capped off outside the station fence. Any new conductor required for the reconfiguration of the overhead feeders will use 477 ACSR. To provide offload capability, bypass switches will be required between PLA1 and PLA2, and PLA3 and PLA4. Finally, the transmission switches PLA 25-1 and 25-2 will be salvaged and held as spares.

Additional property has been acquired to the north and adjacent to the existing site. The expanded site allows for construction of the upgrade while maintaining service to customers with the existing substation in-service. Some reconfiguration of the transmission line (25L) and distribution feeders (PLA1, PLA2, and PLA3) in the immediate vicinity of the substation is also be required to allow for construction of the new station.

The Class 3 capital cost estimate for this alternative is $10.719 million ($2020), including AFUDC and removal costs. A single-line diagram is included as Appendix 1.

3.1.1 Advantages

The advantages of Alternative A are:

- 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.

3.1.2 Disadvantages

The disadvantages of Alternative A are:

- Station needs to be expanded to accommodate the second transformer and allow for construction of the upgrade while maintaining service to customers with the existing station in-service; and
- Incremental O&M costs of approximately $15,000 per year. The increase in O&M costs are primarily associated with the installation of a second transformer and three high voltage circuit breakers.

3.2 *ALTERNATIVE B: INSTALL SINGLE TRANSFORMER*

Alternative B includes replacing PLA T1 with a single new dual voltage 63/25/13 kV 40 MVA transformer. The station will be entirely rebuilt with all new equipment that is consistent with FBC equipment standards and will resolve other equipment age and condition issues. A mobile transformer connection is required. Space has been provisioned for the installation of second transformer in the future if required. To accommodate the upgrade, the station footprint will be expanded. All other aspects of the project will be similar to Alternative A.

The Class 4 capital cost estimate for this alternative is $9.499 million (2020$), including AFUDC and removal costs.

3.2.1 Advantages

The advantages of Alternative B are:

- 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;
- Incremental O&M costs of approximately $7 thousand per year, which is slightly lower than for Alternative A. The increase in O&M costs are associated with the installation of two high voltage circuit breakers; and
- Aging infrastructure and obsolete equipment replaced. Non arc-flash rated switchgear and asbestos exposure risks removed.

3.2.2 Disadvantages

The disadvantages of Alternative B are:

- No transformer redundancy at PLA. Reliability concerns persist in the event of a PLA transformer outage;

- 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;
- The largest mobile transformer (M18) that is available in the Kootenays is 18 MVA. As per the 20-year load forecast, the M18 can only carry the winter peak station load until 2036;
- Beyond 2036, one of the following solutions will be required, as the M18 can no longer carry the winter peak station load. The customer restoration times associated with each option for a transformer outage are also provided below;
    a) Purchase a new mobile transformer rated 32 MVA for the Kootenay region (approximately >$2 million). Customer restoration times may be upwards of 8 hours. B.C road restrictions prevent the transportation of a larger unit (>32 MVA) as a mobile transformer;
    b) Procure and install a second 63/25/13 kV 40 MVA transformer at PLA. Project will require costs for installing a second transformer and station equipment (approximately $1.2 million);
    c) FBC would need to rely on the larger mobile transformer unit (M32, 32 MVA), which resides in the Okanagan region. Customer restoration times may be extended to a minimum of 24 hours due to transport and availability of the mobile transformer from the Okanagan region. Restoration using the M32 may not be an option due to BC road restrictions (March to June) and BC road conditions. Okanagan region will be at a higher risk while M32 resides in the Kootenay region. Maintenance and transportation costs for M32 will increase due to additional wear and tear on the unit;
- Station needs be expanded to allow for construction of the upgrade while maintaining service to customers with the existing station in-service and to provide space for a potential future second transformer (land has already been acquired); and
- Excluded from the $9.499 million capital cost is the cost of purchasing a new mobile transformer in year 2036 (assumed Option A selected). FBC assumes the cost of that addition to be $2 million subject to inflation. These 2036 costs have been included in the 40-year financial analysis of this project for comparability to Alternatives A.

3.3 *ALTERNATIVE C: DO NOTHING*

The Do Nothing Option would involve no modifications to the substation equipment.

3.3.1 Advantages

The advantages of Alternative C are:

- No immediate costs.

3.3.2 Disadvantages

The disadvantages of Alternative C are:

- Would not address station capacity issues. Inability to sustain native load growth or new load requests in the near future;
- Would not address reliability issues;
- Would not address aging infrastructure or equipment condition issues. Safety concerns associated with the switchgear (arc-flash) and asbestos would persist;
- Urgent repair expenditures at this site can be expected to rise. Major component failures would require long lead times;
- Potential to negatively affect community relations and local economy with minimal ability to connect to new load requests;
- Failure of the switchgear would result in the inability to restore customers until replacement parts or switchgear can be sourced; and
- Failure of PLA T1 would require restoration through M18, if available. Additional costs for M18 monitoring and maintenance to incur due to extended period in service.

3.4 *OPTION SUMMARY AND RECOMMENDATION*

Table 1 below summarizes the analysis of the three options.

Revenue requirements analyses for Alternatives A and B are included as Appendices 2 and 3, respectively.

Table 1: PLA Station Upgrade Project Alternatives Comparison

Criteria	Alternative A – Two Transformers	Alternative B – Single transformer	Alternative C – Do Nothing
Capital Cost ($2020)	$10.719 million	$ 9.499 million	$ -
Incremental O&M ($2020)	$ 0.015 million	$ 0.007 million	$ -
Present Value Incremental Revenue Requirement	$ 11.683 million	$ 11.522	N/A
Levelized Rate Impact	0.19%	0.18%	N/A

Criteria	Alternative A – Two Transformers	Alternative B – Single transformer	Alternative C – Do Nothing
Addresses station capacity constraints	Yes	Yes	No
Addresses reliability issues	Yes	No	No
Addresses aging infrastructure and equipment condition issues	Yes	Yes	No
Resolution Window	> 20 Years	14 years	1-2 years
Alternative Evaluation			
Ranking	1	2	3

Alternative A, installing two 20 MVA transformers, is the preferred option as it achieves all of the Project criteria, and provides the longest term solution for the area (>20 years). By installing two transformers at PLA, a single transformer could carry the entire forecast station load during a PLA transformer outage for the next 20 years. With the ability to offload the entire station load to either transformer, no customer outages would be required during a transformer outage under Alternative A. Furthermore, although Alternative B has a lower capital cost initially, it would require future capital expenditures after 2036 (not included in the table above) to ensure the winter peak station load could be supplied during a PLA transformer outage. Finally, the rate impact to customers is 0.01 percent higher for Alterative A as compared to Alternative B.

4. PROJECT DESCRIPTION

4.1 PROJECT SCOPE

The scope of the preferred Alternative A for the Playmor Station Upgrade project includes, but is not limited to, the following:

Station Work:

- Extend site for new station adjacent to existing site, built to current FBC standards;
- Install new station fence;
- Install two (2) new 20MVA, 63kV/13/25 kV transformers with OLTC;
- Install transformer containment, FQ stone and access steps;
- Install two new 69kV A-frames for line connection;
- Install transformer drainage, external sump, dry pump, soak pit;
- Install two 69kV, 1200A transformer disconnects with MODs;
- Install two 69kV, 1200A line breakers and disconnects;
- Install 69kV, 1200A tie breaker and disconnects;
- Install three aluminium breaker platforms;
- Install new 69kV bus per SLD;
- Install two, 2 bay distribution structures;
- Install two, 25kV, 2000A Main breakers and load side disconnects;
- Install four, 25kV, 1200A feeder breakers and disconnects;
- Install two feeder bypass breakers 25kV, 1200A, vertical break bypass switches;
- Install 25kV, 2000A bus breaker and disconnects;
- Install four new feeder egress structures;
- Install 7.2kV/14.4k 3 phase VTs and fuses for each distribution structure;
- Install 7.2kV/14.4k, 25kV station service transformer and fuse for each distribution structure;
- Install new station AC/DC station service;

- Install temporary distribution feeds during construction (under Transmission and Distribution work);
- Install new Control building and cable pull pit;
- Install new station duct & cable trench system;
- Install new standard Class II metering and protection;
- Install new SCADA infrastructure;
- Install new station ground grid & interconnect with existing;
- Install 4-40m ground wells;
- Install new station lighting;
- Complete station ground grid study;
- Complete station geotechnical study;
- Realign 69kV lines to new station A-frames (under Transmission and Distribution work);
- Demolish all remaining existing structures & equipment;
- Salvage existing major station equipment;
- Demolish existing buildings on site (switchgear), remove hazardous materials as required;
- Demolish existing transformer containment (Sorbweb);
- Salvage transformer; and
- Animal protection cover-up of substation equipment to reduce the number of animal-caused outages.

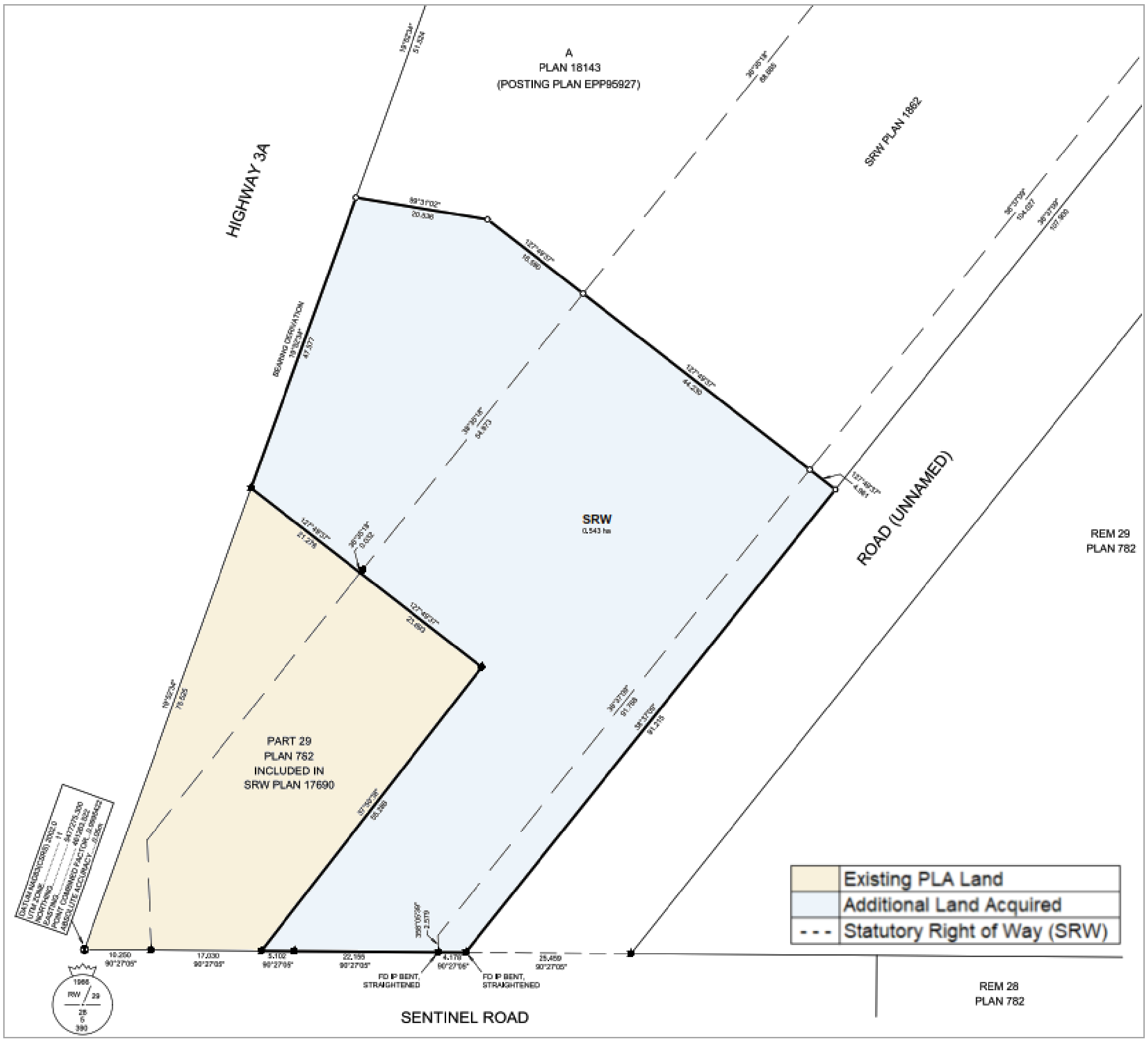
Transmission and Distribution Work:

- Re-route 25L to accommodate new PLA substation site build;
- Re-route existing distribution feeders (PLA1, PLA2 and PLA3) to accommodate the new PLA substation site build;
- Cutover/tie-in line(s) to the new PLA substation; and
- New conductor is assumed for all new spans 477 ASCR for transmission and distribution underbuild with 3/0 ACSR Neutral, and 750 MCM for distribution underground cables with 4/0 Copper poly Neutral underground cable.

Land Acquisition:

In 2020, additional property was acquired north and adjacent to the existing site to increase the station footprint. The expanded site will allow for construction of the upgrade while maintaining service to customers with the existing station remaining in service (a single brief outage for two to three hours is anticipated for PLA3 feeder as part of the distribution re-route work). Figure 5 below shows the existing PLA land and the additional land that was acquired.

Figure 5: Additional land acquired adjacent to existing station



4.1 *PROJECT RISKS*

The potential risks to the PLA Station Upgrade project identified to date include the following.

- Unforeseen environmental or archaeological discoveries during the construction phase. The risk of such occurrences is considered low, based on FBC's previous construction experience at PLA substation. In 2019, a preliminary site investigation revealed no indicators of previous contamination or other obvious environmental concerns and therefore concluded that further intrusive investigation is not warranted. All capital projects include an environmental management plan, which provides guidance on management of environmental risks during the construction phase;
- 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; and
- Outages to be coordinated with system and operational planning to have minimal system impact.

4.2 *PROJECT COST ESTIMATE*

The PLA Station Upgrade project has a capital cost of $10.719 million in 2020$ (including $0.289 million of removal costs). The cost estimate for the Project has been developed to a Class 3 degree of accuracy as defined in the AACE International Recommended Practice No. 10S-90.

Table 2 below summarizes the total estimate project cost 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**

1 ## 4.3 PROJECT SCHEDULE

2 The project is expected to be complete by February 2022, assuming approval is provided for the
3 preferred Alternative A by December 2020, engineering and design for the IFC package begins
4 in September 2020, and construction begins in March 2021.

5 The preliminary high-level project schedule is provided in Figure 6. Under the proposed schedule,
6 final commissioning and construction of the new station would be complete by December 2021,
7 and the station, transmission and distribution salvage would take place in January and February
8 2022.

9 **Figure 6: Preliminary high-level project schedule**

Task Name	Duration	Start	Finish
PLA Station Rebuild			
Stations			
Major material procurement	40 days	Mon 12/7/20	Fri 1/29/21
Engineering	109 days	Tue 9/1/20	Fri 1/29/21
Engineering IFC package	6 days	Fri 2/5/21	Fri 2/12/21
RFP tender process	30 days	Mon 2/15/21	Fri 3/26/21
Civil construction	70 days	Mon 4/5/21	Fri 7/9/21
Physical construction	50 days	Mon 6/21/21	Fri 8/27/21
Electrical construction	60 days	Mon 8/9/21	Fri 10/29/21
Transformer delivery	5 days	Mon 8/16/21	Fri 8/20/21
Commissioning	30 days	Mon 11/1/21	Fri 12/10/21
Energization	5 days	Mon 12/13/21	Fri 12/17/21
Demo existing station/equipment	25 days	Mon 1/10/22	Fri 2/11/22
Transmission/Distribution			
Engineering	60 days	Mon 9/7/20	Fri 11/27/20
Material procurement	40 days	Mon 1/4/21	Fri 2/26/21
Construction	20 days	Mon 3/8/21	Fri 4/2/21
Station H/V connections	5 days	Mon 10/11/21	Fri 10/15/21
Feeder demo	10 days	Mon 1/10/22	Fri 1/21/22

10

5. PUBLIC AND FIRST NATIONS CONSULATION

Three residential customers are located within 150 meters from the substation, with the closest residential customer approximately 75 meters from the existing station. As shown in Figure 2, residential customers have limited visibility of the station due to tree coverage. There is also limited visibility of the station from Highway 3A since it is located on a hill and behind a tree line. The new station will be built adjacent to the existing station and visibility of the rebuilt substation will be similar.

Letters were sent out to residents within 150 meters of the project in August of 2020 notifying them of the project and footprint expansion.

Finally, the transmission and distribution work will be completed in a staged approach to relocate existing facilities to accommodate the new substation and minimize outages to customers as best as possible, in particular to the distribution services where there are limited backup capabilities.

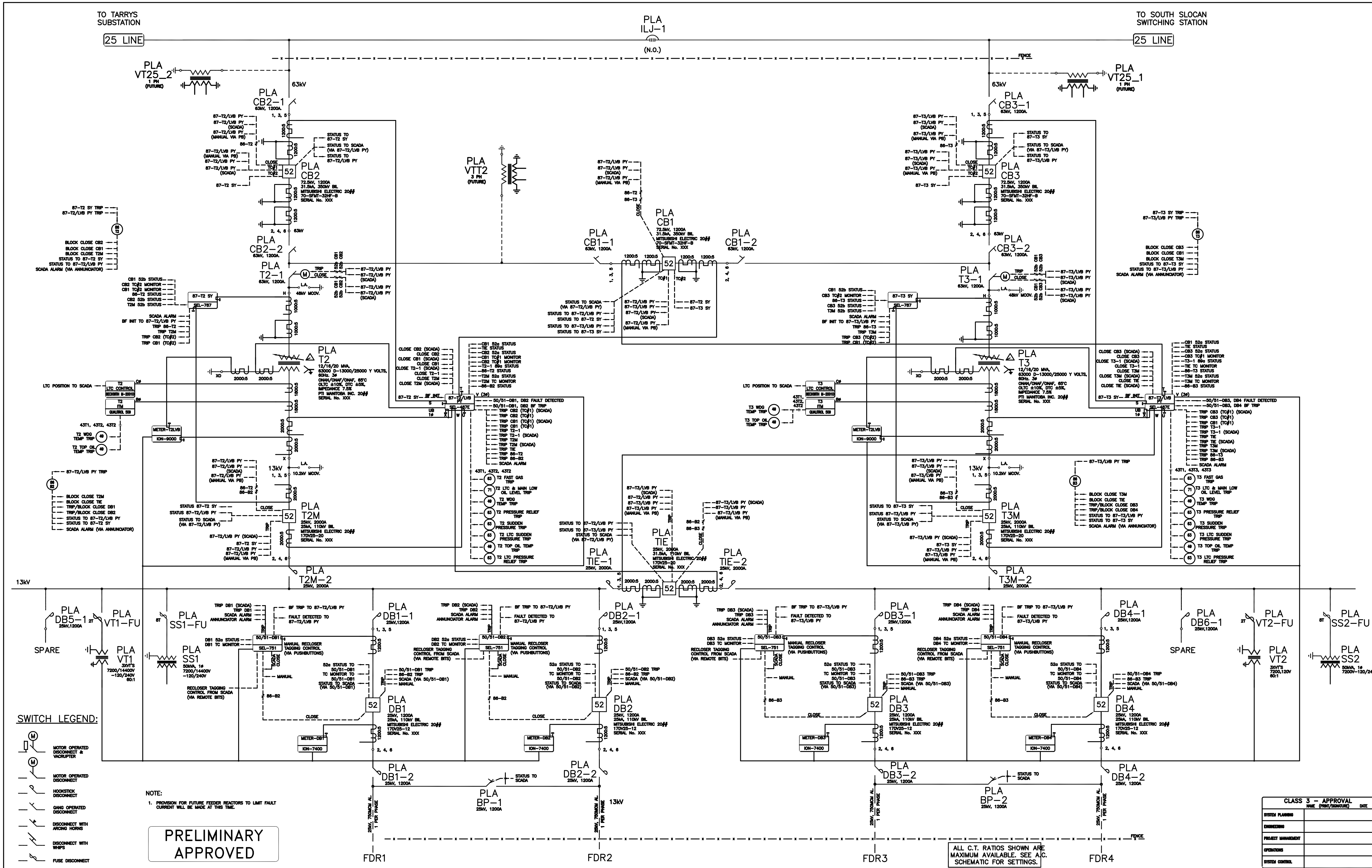
The PLA station upgrade does not trigger a requirement for First Nations consultation, as FBC believes that Aboriginal Rights and Title will not be affected by this Project. The proposed substation site is not near any known archaeological site and is not in a zone of high archeological potential.

6. CONCLUSION

The Company respectfully submits that the PLA Station Upgrade project is necessary to support growth and improve reliability of service for new and existing customers in the PLA area. Based on the evaluation of all feasible alternatives, Alternative A provides the best solution that would allow the Company to meet all Project objectives and requirements. The substation is scheduled to be in service by December 2021, with Project completion and close-out by February 2022.

Appendix 1

ALTERNATIVE A SINGLE LINE DIAGRAM



REV	DATE	BY	CHECKED	DESCRIPTION	REVISION APPROVAL	DATE
20P1	AUG/19	SHT	MMF	PRELIMINARY - PLAYMORE STATION UPGRADE PLANNING, PLN11-1168		

REVISIONS

DRAWN BY: H.J. URSAKI JUL/91
DESIGNED BY:
CHECKED BY:
APPROVALS: ELECTRICAL / CIVIL / MANAGEMENT

FORTIS BC

DIVISION: KOOTENAY
DEPARTMENT: PROTECTION-CONTROL
LOCATION: PLAYMOR SUBSTATION
TITLE: SINGLE LINE DIAGRAM

SCALE: NONE
SCALE FACTOR: 1.25
DRAWING NUMBER: 3-131-2000
REVISION: 20P1

Appendix 2

ALTERNATIVE A REVENUE REQUIREMENTS ANALYSIS

FortisBC Inc.
Playmor Station Upgrade - Alternative A
August 2020
($000s), unless otherwise stated

Line	Particulars	Reference	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2045	2050	2055	2060	2064
1	**Cost of Service**																											
2	Operation & Maintenance - Net of Capitalized Overhead	Line 23	-	-	-	13	13	13	14	14	14	14	15	15	15	16	16	16	16	17	17	17	18	20	22	24	26	29
3	Property Taxes	Line 28	-	-	-	70	70	70	70	70	71	71	71	71	71	71	72	72	72	72	72	72	73	74	75	77	85	92
4	Depreciation Expense	Line 54	-	-	-	277	277	277	277	277	277	277	277	277	277	277	277	278	278	278	278	278	278	278	279	217	128	129
5	Income Taxes	Line 96	-	-	(546)	(6)	13	28	41	53	64	73	82	89	96	102	107	111	115	118	120	122	124	126	121	90	50	46
6	Earned Return	Line 79	-	-	-	698	691	673	655	637	619	601	583	565	547	529	511	493	475	457	439	421	403	313	223	138	77	43
7	**Incremental Annual Revenue Requirement**	Sum of Line 1 to Line 6	**-**	**-**	**(546)**	**1,052**	**1,063**	**1,060**	**1,056**	**1,051**	**1,044**	**1,036**	**1,027**	**1,017**	**1,006**	**995**	**982**	**969**	**955**	**941**	**926**	**911**	**895**	**810**	**719**	**546**	**367**	**339**
8	PV of Revenue Requirement (After-tax WACC of 5.77%)	Line 7 / (1 + Line 81)^Yr	-	-	(461)	840	803	757	713	671	630	591	554	519	485	453	423	395	368	343	319	297	276	188	126	72	37	27
9	**Total PV of Annual Revenue Requirement**	Sum of Line 8	***11,683***																									
10																												
11	2021 Approved Revenue Requirement (2021 Advanced Materials)		393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512
12	% change in Rates	Line 7 / Line 11	0.00%	0.00%	-0.14%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.26%	0.26%	0.26%	0.26%	0.25%	0.25%	0.25%	0.24%	0.24%	0.24%	0.23%	0.23%	0.21%	0.18%	0.14%	0.09%	0.09%
13																												
14	PV of Annual 2021 Approved Revenue Requirement	Line 11 / (1 + Line 81)^Yr	372,040	351,740	332,548	314,403	297,248	281,029	265,695	251,197	237,491	224,532	212,281	200,698	189,747	179,394	169,605	160,351	151,601	143,329	135,509	128,115	121,124	91,494	69,112	52,205	39,434	31,507
15	Total PV of 2021 Approved Revenue Requirement	Sum of Line 14	6,272,492																									
16	**Levelized % Increase (45 yrs) on 2021 Rate**	**Line 9 / Line 15**	**0.19%**																									
17																												
18	**Operation & Maintenance**																											
19	Labour Costs		-	-	-	15	15	16	16	16	17	17	17	18	18	18	19	19	19	20	20	21	21	23	26	28	31	34
20	Non-Labour Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Total Gross O&M Expenses	Line 19 + Line 20	-	-	-	15	15	16	16	16	17	17	17	18	18	18	19	19	19	20	20	21	21	23	26	28	31	34
22	Less: Capitalized Overhead	Overhead Rate of 15%	-	-	-	(2)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(5)	(5)
23	**Net O&M Expenses**	Line 21 + Line 22	-	-	-	13	13	13	14	14	14	14	15	15	15	16	16	16	16	17	17	17	18	20	22	24	26	29
24																												
25	**Property Taxes**																											
26	General, School and Other		-	-	-	70	70	70	70	70	71	71	71	71	71	71	72	72	72	72	72	72	73	74	75	77	85	92
27	1% in Lieu of General Municipal Tax[1]	1% of Line 7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	**Total Property Taxes**	Line 26 + Line 27	-	-	-	70	70	70	70	70	71	71	71	71	71	71	72	72	72	72	72	72	73	74	75	77	85	92
29	1 - Calculation is based on the second preceding year, e.g. 2019 is based on 2017 revenue																											
30																												
31	**Capital Spending**																											
32	Project Capital Spending[2]		483	8,710	546	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	AFUDC		8	283	575	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Total Annual Capital Spending & AFUDC	Sum of Line 32 to 35	490	8,993	1,122	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Cost of Removal		-	31	286	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Contributions in Aid of Construction (CIAC)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Total Annual Project Cost - Capital	Line 34 + Line 35	490	9,024	1,408	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38																												
39	**Total Project Cost (incl. AFUDC)**	**Sum of Line 34**	**10,605**																									
40	**Net Project Cost (incl. Removal and/or CIAC)**	**Sum of Line 37**	**10,922**																									
41	2 - Excluding capitalized overhead; First year of analysis includes all prior year spending																											
42																												
43	**Gross Plant in Service (GPIS)**																											
44	GPIS - Beginning[3]	Preceding Year, Line 48	-	-	-	10,605	10,607	10,610	10,612	10,614	10,617	10,619	10,622	10,624	10,627	10,630	10,632	10,635	10,638	10,641	10,644	10,647	10,650	10,666	10,684	8,706	5,467	5,482
45	Additions to Plant[4]		-	-	-	2	2	2	2	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	4	4	5	5
46	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,261)
47	Net Addition to Plant	Sum of Line 45 to 46	-	-	-	2	2	2	2	2	2	3	3	3	3	3	3	3	3	3	3	3	3	3	4	4	5	(5,256)
48	GPIS - Ending	Line 44 + Line 47	-	-	-	10,607	10,610	10,612	10,614	10,617	10,619	10,622	10,624	10,627	10,630	10,632	10,635	10,638	10,641	10,644	10,647	10,650	10,653	10,670	10,688	8,710	5,472	226
49	3 - Consistent with treatment of CPCN, additions (when work complete and placed in-service) is shown in the opening balance of plant on Jan 1 of following year)																											
50	4 - Includes capitalized overhead																											
51																												
52	**Accumulated Depreciation**																											
53	Accumulated Depreciation - Beginning	Preceding Year, Line 57	-	-	-	-	40	(237)	(513)	(790)	(1,067)	(1,344)	(1,622)	(1,899)	(2,176)	(2,453)	(2,731)	(3,008)	(3,286)	(3,563)	(3,841)	(4,119)	(4,397)	(5,787)	(7,180)	(6,514)	(4,249)	(4,759)
54	Depreciation Expense[5]	Line 44 @ 2.63%	-	-	-	(277)	(277)	(277)	(277)	(277)	(277)	(277)	(277)	(277)	(277)	(277)	(277)	(278)	(278)	(278)	(278)	(278)	(278)	(278)	(279)	(217)	(128)	(129)
55	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,261
56	Cost of Removal		-	-	-	317	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57	Accumulated Depreciation - Ending	Sum of Line 53 to 55	-	-	-	40	(237)	(513)	(790)	(1,067)	(1,344)	(1,622)	(1,899)	(2,176)	(2,453)	(2,731)	(3,008)	(3,286)	(3,563)	(3,841)	(4,119)	(4,397)	(4,674)	(6,065)	(7,458)	(6,731)	(4,378)	374
58	5 - Depreciation & Amortization Expense calculation is based on opening balance x composite depreciation rate; The composite rate of all assets addition to plant is 2.63%																											
59																												

FortisBC Inc.
Playmor Station Upgrade - Alternative A
August 2020
($000s), unless otherwise stated

Line	Particulars	Reference	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2045	2050	2055	2060	2064
60	**Rate Base and Earned Return**																											
61	Gross Plant in Service - Beginning	Line 44	-	-	-	10,605	10,607	10,610	10,612	10,614	10,617	10,619	10,622	10,624	10,627	10,630	10,632	10,635	10,638	10,641	10,644	10,647	10,650	10,666	10,684	8,706	5,467	5,482
62	Gross Plant in Service - Ending	Line 48	-	-	-	10,607	10,610	10,612	10,614	10,617	10,619	10,622	10,624	10,627	10,630	10,632	10,635	10,638	10,641	10,644	10,647	10,650	10,653	10,670	10,688	8,710	5,472	226
63																												
64	Accumulated Depreciation - Beginning	Line 53	-	-	-	-	40	(237)	(513)	(790)	(1,067)	(1,344)	(1,622)	(1,899)	(2,176)	(2,453)	(2,731)	(3,008)	(3,286)	(3,563)	(3,841)	(4,119)	(4,397)	(5,787)	(7,180)	(6,514)	(4,249)	(4,759)
65	Accumulated Depreciation - Ending	Line 57	-	-	-	40	(237)	(513)	(790)	(1,067)	(1,344)	(1,622)	(1,899)	(2,176)	(2,453)	(2,731)	(3,008)	(3,286)	(3,563)	(3,841)	(4,119)	(4,397)	(4,674)	(6,065)	(7,458)	(6,731)	(4,378)	374
66																												
67	CIAC - Beginning	Line 59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	CIAC - Ending	Line 59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
69																												
70	Accumulated Amortization of CIAC - Beginning	Line 59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
71	Accumulated Amortization of CIAC - Ending	Line 59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72																												
73	Net Plant in Service, Mid-Year	(Sum of Lines 61 to Line 71) / 2	-	-	-	10,626	10,510	10,236	9,961	9,687	9,412	9,137	8,863	8,588	8,314	8,039	7,764	7,490	7,215	6,940	6,666	6,391	6,116	4,742	3,367	2,086	1,156	661
74	Cash Working Capital	Line 48 x FBC CWC/Closing GPIS %	-	-	-	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	26	16	1
75	**Total Rate Base**	**Sum of Line 73 to 74**	**-**	**-**	**-**	**10,657**	**10,541**	**10,267**	**9,992**	**9,718**	**9,443**	**9,169**	**8,894**	**8,620**	**8,345**	**8,070**	**7,796**	**7,521**	**7,246**	**6,972**	**6,697**	**6,422**	**6,147**	**4,773**	**3,399**	**2,112**	**1,172**	**662**
76																												
77	Equity Return	Line 75 x ROE x Equity %	-	-	-	390	386	376	366	356	346	336	326	315	305	295	285	275	265	255	245	235	225	175	124	77	43	24
78	Debt Component	[7]	-	-	-	308	305	297	289	281	273	265	257	249	241	233	225	218	210	202	194	186	178	138	98	61	34	19
79	**Total Earned Return**	**Line 77 + Line 78**	**-**	**-**	**-**	**698**	**691**	**673**	**655**	**637**	**619**	**601**	**583**	**565**	**547**	**529**	**511**	**493**	**475**	**457**	**439**	**421**	**403**	**313**	**223**	**138**	**77**	**43**
80	Return on Rate Base %	Line 79 / Line 75	0.00%	0.00%	0.00%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%
81	After- Tax Weighted Average Cost of Capital (WACC)	[8]	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%
82	6 - (Line 47 + Line 54 + Line 59) x [(Days In-service/365)-1/2]																											
83	7 - Line 75 x (LTD Rate x LTD% + STD Rate x STD %)																											
84	8 - ROE Rate x Equity Component + [(STD Rate x STD Portion) + (LTD Rate x LTD Portion)] x (1- Income Tax Rate)]																											
85																												
86	**Income Tax Expense**																											
87	Earned Return	Line 79	-	-	-	698	691	673	655	637	619	601	583	565	547	529	511	493	475	457	439	421	403	313	223	138	77	43
88	Deduct: Interest on debt	Line 78	-	-	-	(308)	(305)	(297)	(289)	(281)	(273)	(265)	(257)	(249)	(241)	(233)	(225)	(218)	(210)	(202)	(194)	(186)	(178)	(138)	(98)	(61)	(34)	(19)
89	Add: Depreciation Expense	Line 54	-	-	-	277	277	277	277	277	277	277	277	277	277	277	277	278	278	278	278	278	278	278	279	217	128	129
90	Deduct: Overhead Capitalized Expenses for Tax Purposes		-	-	-	(2)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(5)	(5)
91	Deduct: Removal Costs	Line 35	-	-	(317)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
92	Deduct: Capital Cost Allowance	Line 104	-	-	(1,160)	(680)	(626)	(576)	(530)	(487)	(448)	(412)	(379)	(349)	(321)	(296)	(272)	(250)	(230)	(212)	(195)	(179)	(165)	(109)	(72)	(47)	(31)	(22)
93	Taxable Income After Tax	Sum of Line 87 to 92	-	-	(1,476)	(16)	34	74	111	143	172	198	221	241	259	275	288	300	310	318	325	331	335	341	328	243	135	126
94	Income Tax Rate		27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
95																												
96	**Total Income Tax Expense**	Line 93 / (1 - Line 94) x Line 94	**-**	**-**	**(546)**	**(6)**	**13**	**28**	**41**	**53**	**64**	**73**	**82**	**89**	**96**	**102**	**107**	**111**	**115**	**118**	**120**	**122**	**124**	**126**	**121**	**90**	**50**	**46**
97																												
98	**Capital Cost Allowance**																											
99	Opening Balance	Proceeding Year, Line 105	-	-	-	8,579	7,899	7,273	6,697	6,168	5,680	5,232	4,819	4,440	4,091	3,770	3,474	3,202	2,952	2,722	2,510	2,316	2,136	1,434	971	666	465	354
100	Additions to Plant	Line 34	-	-	10,605	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
101	Less: AFUDC	Line 33	-	-	(866)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
102	Less: CIAC	Line 36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
103	Net Addition for CCA	Sum of Line 100 through 102	-	-	9,739	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
104	**CCA**	**[Line 99 + (Line 103/2)] x CCA Rate**	**-**	**-**	**(1,160)**	**(680)**	**(626)**	**(576)**	**(530)**	**(487)**	**(448)**	**(412)**	**(379)**	**(349)**	**(321)**	**(296)**	**(272)**	**(250)**	**(230)**	**(212)**	**(195)**	**(179)**	**(165)**	**(109)**	**(72)**	**(47)**	**(31)**	**(22)**
105	Closing Balance	Line 99 + Line 103 + Line 104	-	-	8,579	7,899	7,273	6,697	6,168	5,680	5,232	4,819	4,440	4,091	3,770	3,474	3,202	2,952	2,722	2,510	2,316	2,136	1,971	1,325	899	618	433	332

FortisBC Inc.
Playmor Station Upgrade - Alternative A
August 2020
($000s), unless otherwise stated

Line	Particular	Reference	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2045	2050	2055	2060	2064
1	**Cash Flow**																											
2	Add: Revenue	Business Case, Line 7	-	-	(546)	1,052	1,063	1,060	1,056	1,051	1,044	1,036	1,027	1,017	1,006	995	982	969	955	941	926	911	895	810	719	546	367	339
3	Less: O&M, Property Tax Expense	Business Case, -(Line 2 + Line 3)	-	-	-	(82)	(83)	(83)	(84)	(84)	(85)	(85)	(86)	(86)	(86)	(87)	(87)	(88)	(88)	(89)	(89)	(90)	(91)	(93)	(96)	(101)	(111)	(120)
4	EBITDA[1]	Line 2 + Line 3	-	-	(546)	969	980	977	973	967	959	951	942	931	920	908	895	881	867	852	837	821	805	717	623	445	255	219
5	Capital Expenditures[2]	Business Case, -Line 37	(490)	(9,024)	(1,408)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Pre-Tax Cash Flow	Line 4 + Line 5	(490)	(9,024)	(1,954)	969	980	977	973	967	959	951	942	931	920	908	895	881	867	852	837	821	805	717	623	445	255	219
7	Income Tax Expense	Line 4 x Income Tax Rate @ 27%	-	-	147	(262)	(265)	(264)	(263)	(261)	(259)	(257)	(254)	(251)	(248)	(245)	(242)	(238)	(234)	(230)	(226)	(222)	(217)	(194)	(168)	(120)	(69)	(59)
8	Overhead Capitalized Tax Shield	Business Case, -Line 90 x Income Tax Rate	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
9	CCA Tax Shield & Removal Costs	Business Case, -(Line 92 + Line 91) x Income Tax Rate	-	-	399	184	169	155	143	132	121	111	102	94	87	80	73	68	62	57	53	48	45	29	19	13	8	6
10	Terminal Value of CCA Tax Shield	[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40
11	Terminal Value	[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	600
12																												
13	Free Cash Flow	Sum of Line 6 to Line 11	(490)	(9,024)	(1,408)	892	885	869	854	838	822	806	790	775	759	743	727	712	696	680	664	648	633	554	475	339	196	807
14																												
15	After Tax WACC %	Business Case, Line 81	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%
16	Present value of Free Cash Flow[5]	Line 13 / (1 + Line 15)^Yr	(464)	(8,066)	(1,190)	713	669	621	576	535	496	460	426	395	366	339	313	290	268	248	229	211	195	129	83	45	20	65
17	Total Present Value of Free Cash Flow	Sum of Line 16	**(532)**																									
18																												

19 1 - Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)
20 2 - Net of CIAC and removal costs (if applicable)
21 3- [UCC Closing Balance x CCA Rate / (CCA Rate + WACC)] x Income Tax Rate
22 4 - Evaluation period reflects less than the useful life of the assets, therefore terminal value equals the net book value of assets at end of evaluation period
23 5 - 2020 present value calculates capital expenditure to occur at time zero

Appendix 3

ALTERNATIVE B REVENUE REQUIREMENTS ANALYSIS

FortisBC Inc.
Playmor Station Upgrade - Alternative B
August 2020
($000s), unless otherwise stated

Line	Particulars	Reference	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2045	2050	2055	2060	2064
1	**Cost of Service**																											
2	Operation & Maintenance - Net of Capitalized Overhead	Line 23	-	-	-	6	6	6	6	7	7	7	7	7	7	7	8	8	8	8	8	8	9	9	10	12	13	14
3	Property Taxes	Line 28	-	-	-	70	70	70	70	70	71	71	71	71	71	71	72	72	72	72	72	72	73	74	75	77	85	92
4	Depreciation Expense	Line 54	-	-	-	244	244	244	244	244	244	244	244	244	244	244	244	244	244	317	317	317	317	317	317	262	184	184
5	Income Taxes	Line 96	-	-	(495)	(4)	12	25	37	48	57	65	73	79	85	90	95	99	80	90	98	104	110	128	132	108	74	70
6	Earned Return	Line 79	-	-	-	618	612	596	580	564	548	533	517	501	485	469	453	437	512	583	563	542	521	418	315	216	138	90
7	**Incremental Annual Revenue Requirement**	Sum of Line 1 to Line 6	**-**	**-**	**(495)**	**933**	**945**	**942**	**938**	**933**	**927**	**920**	**912**	**903**	**893**	**882**	**871**	**860**	**916**	**1,070**	**1,057**	**1,044**	**1,029**	**946**	**849**	**675**	**494**	**450**
8	PV of Revenue Requirement (After-tax WACC of 5.77%)	Line 7 / (1 + Line 81)^Yr	-	-	(419)	746	713	673	633	596	559	525	492	460	431	402	376	350	353	390	364	340	317	220	149	90	50	36
9	**Total PV of Annual Revenue Requirement**	Sum of Line 8	***11,522***																									
10																												
11	2021 Approved Revenue Requirement (2021 Advanced Materials)		393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512	393,512
12	% change in Rates	Line 7 / Line 11	0.00%	0.00%	-0.13%	0.24%	0.24%	0.24%	0.24%	0.24%	0.24%	0.23%	0.23%	0.23%	0.23%	0.22%	0.22%	0.22%	0.23%	0.27%	0.27%	0.27%	0.26%	0.24%	0.22%	0.17%	0.13%	0.11%
13																												
14	PV of Annual 2021 Approved Revenue Requirement	Line 11 / (1 + Line 81)^Yr	372,040	351,740	332,548	314,403	297,248	281,029	265,695	251,197	237,491	224,532	212,281	200,698	189,747	179,394	169,605	160,351	151,601	143,329	135,509	128,115	121,124	91,494	69,112	52,205	39,434	31,507
15	Total PV of 2021 Approved Revenue Requirement	Sum of Line 14	6,272,492																									
16	**Levelized % Increase (45 yrs) on 2021 Rate**	**Line 9 / Line 15**	**0.18%**																									
17																												
18	**Operation & Maintenance**																											
19	Labour Costs		-	-	-	7	7	7	8	8	8	8	8	8	9	9	9	9	9	9	10	10	10	11	12	14	15	16
20	Non-Labour Costs		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Total Gross O&M Expenses	Line 19 + Line 20	-	-	-	7	7	7	8	8	8	8	8	8	9	9	9	9	9	9	10	10	10	11	12	14	15	16
22	Less: Capitalized Overhead	Overhead Rate of 15%	-	-	-	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(2)	(2)
23	**Net O&M Expenses**	Line 21 + Line 22	-	-	-	6	6	6	6	7	7	7	7	7	7	7	8	8	8	8	8	8	9	9	10	12	13	14
24																												
25	**Property Taxes**																											
26	General, School and Other		-	-	-	70	70	70	70	70	71	71	71	71	71	71	72	72	72	72	72	72	73	74	75	77	85	92
27	1% in Lieu of General Municipal Tax[1]	1% of Line 7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	**Total Property Taxes**	Line 26 + Line 27	-	-	-	70	70	70	70	70	71	71	71	71	71	71	72	72	72	72	72	72	73	74	75	77	85	92
29	1 - Calculation is based on the second preceding year, e.g. 2019 is based on 2017 revenue																											
30																												
31	**Capital Spending**																											
32	Project Capital Spending[2]		473	7,625	499	-	-	-	-	-	-	-	-	-	-	-	-	-	2,746	-	-	-	-	-	-	-	-	-
33	AFUDC		7	251	507	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Total Annual Capital Spending & AFUDC	Sum of Line 32 to 35	480	7,876	1,006	-	-	-	-	-	-	-	-	-	-	-	-	-	2,746	-	-	-	-	-	-	-	-	-
35	Cost of Removal		-	31	286	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Contributions in Aid of Construction (CIAC)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Total Annual Project Cost - Capital	Line 34 + Line 35	480	7,907	1,292	-	-	-	-	-	-	-	-	-	-	-	-	-	2,746	-	-	-	-	-	-	-	-	-
38																												
39	**Total Project Cost (incl. AFUDC)**	**Sum of Line 34**	**12,108**																									
40	**Net Project Cost (incl. Removal and/or CIAC)**	**Sum of Line 37**	**12,425**																									
41	2 - Excluding capitalized overhead; First year of analysis includes all prior year spending																											
42																												
43	**Gross Plant in Service (GPIS)**																											
44	GPIS - Beginning[3]	Preceding Year, Line 48	-	-	-	9,363	9,364	9,365	9,366	9,367	9,368	9,369	9,371	9,372	9,373	9,374	9,376	9,377	9,378	12,125	12,127	12,128	12,130	12,138	12,146	10,393	7,529	7,536
45	Additions to Plant[4]		-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	2,747	1	1	1	2	2	2	2	2	2
46	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(4,639)
47	Net Addition to Plant	Sum of Line 45 to 46	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	2,747	1	1	1	2	2	2	2	2	(4,637)
48	GPIS - Ending	Line 44 + Line 47	-	-	-	9,364	9,365	9,366	9,367	9,368	9,369	9,371	9,372	9,373	9,374	9,376	9,377	9,378	12,125	12,127	12,128	12,130	12,131	12,139	12,148	10,396	7,531	2,899
49	3 - Consistent with treatment of CPCN, additions (when work complete and placed in-service) is shown in the opening balance of plant on Jan 1 of following year)																											
50	4 - Includes capitalized overhead																											
51																												
52	**Accumulated Depreciation**																											
53	Accumulated Depreciation - Beginning	Preceding Year, Line 57	-	-	-	-	73	(171)	(415)	(659)	(904)	(1,148)	(1,392)	(1,636)	(1,881)	(2,125)	(2,369)	(2,614)	(2,858)	(3,103)	(3,419)	(3,736)	(4,053)	(5,638)	(7,223)	(6,993)	(5,351)	(6,086)
54	Depreciation Expense[5]	Line 44 @ 2.63%	-	-	-	(244)	(244)	(244)	(244)	(244)	(244)	(244)	(244)	(244)	(244)	(244)	(244)	(244)	(244)	(317)	(317)	(317)	(317)	(317)	(317)	(262)	(184)	(184)
55	Retirements		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,639
56	Cost of Removal		-	-	-	317	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57	Accumulated Depreciation - Ending	Sum of Line 53 to 55	-	-	-	73	(171)	(415)	(659)	(904)	(1,148)	(1,392)	(1,636)	(1,881)	(2,125)	(2,369)	(2,614)	(2,858)	(3,103)	(3,419)	(3,736)	(4,053)	(4,370)	(5,955)	(7,541)	(7,255)	(5,535)	(1,631)
58	5 - Depreciation & Amortization Expense calculation is based on opening balance x composite depreciation rate; The composite rate of all assets addition to plant is 2.63%																											
59																												

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August 2020
($000s), unless otherwise stated

Line	Particulars	Reference	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2045	2050	2055	2060	2064
60	**Rate Base and Earned Return**																											
61	Gross Plant in Service - Beginning	Line 44	-	-	-	9,363	9,364	9,365	9,366	9,367	9,368	9,369	9,371	9,372	9,373	9,374	9,376	9,377	9,378	12,125	12,127	12,128	12,130	12,138	12,146	10,393	7,529	7,536
62	Gross Plant in Service - Ending	Line 48	-	-	-	9,364	9,365	9,366	9,367	9,368	9,369	9,371	9,372	9,373	9,374	9,376	9,377	9,378	12,125	12,127	12,128	12,130	12,131	12,139	12,148	10,396	7,531	2,899
63																												
64	Accumulated Depreciation - Beginning	Line 53	-	-	-	-	73	(171)	(415)	(659)	(904)	(1,148)	(1,392)	(1,636)	(1,881)	(2,125)	(2,369)	(2,614)	(2,858)	(3,103)	(3,419)	(3,736)	(4,053)	(5,638)	(7,223)	(6,993)	(5,351)	(6,086)
65	Accumulated Depreciation - Ending	Line 57	-	-	-	73	(171)	(415)	(659)	(904)	(1,148)	(1,392)	(1,636)	(1,881)	(2,125)	(2,369)	(2,614)	(2,858)	(3,103)	(3,419)	(3,736)	(4,053)	(4,370)	(5,955)	(7,541)	(7,255)	(5,535)	(1,631)
66																												
67	CIAC - Beginning	Line 59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	CIAC - Ending	Line 59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
69																												
70	Accumulated Amortization of CIAC - Beginning	Line 59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
71	Accumulated Amortization of CIAC - Ending	Line 59	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72																												
73	Net Plant in Service, Mid-Year	(Sum of Lines 61 to Line 71) / 2	-	-	-	9,400	9,315	9,072	8,829	8,586	8,343	8,100	7,857	7,614	7,371	7,128	6,885	6,642	7,772	8,865	8,550	8,235	7,919	6,342	4,765	3,271	2,087	1,359
74	Cash Working Capital	Line 48 x FBC CWC/Closing GPIS %	-	-	-	28	28	28	28	28	28	28	28	28	28	28	28	28	36	36	36	36	36	36	36	31	22	9
75	**Total Rate Base**	**Sum of Line 73 to 74**	**-**	**-**	**-**	**9,427**	**9,343**	**9,100**	**8,857**	**8,614**	**8,371**	**8,128**	**7,885**	**7,642**	**7,399**	**7,156**	**6,912**	**6,669**	**7,807**	**8,901**	**8,586**	**8,270**	**7,955**	**6,378**	**4,801**	**3,301**	**2,109**	**1,367**
76																												
77	Equity Return	Line 75 x ROE x Equity %	-	-	-	345	342	333	324	315	306	297	289	280	271	262	253	244	286	326	314	303	291	233	176	121	77	50
78	Debt Component	7	-	-	-	273	270	263	256	249	242	235	228	221	214	207	200	193	226	257	248	239	230	184	139	95	61	40
79	**Total Earned Return**	**Line 77 + Line 78**	**-**	**-**	**-**	**618**	**612**	**596**	**580**	**564**	**548**	**533**	**517**	**501**	**485**	**469**	**453**	**437**	**512**	**583**	**563**	**542**	**521**	**418**	**315**	**216**	**138**	**90**
80	Return on Rate Base %	Line 79 / Line 75	0.00%	0.00%	0.00%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%	6.55%
81	After- Tax Weighted Average Cost of Capital (WACC)	8	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%
82	6 - (Line 47 + Line 54 + Line 59) x [(Days In-service/365)-1/2]																											
83	7 - Line 75 x (LTD Rate x LTD% + STD Rate x STD %)																											
84	8 - ROE Rate x Equity Component + [(STD Rate x STD Portion) + (LTD Rate x LTD Portion)] x (1- Income Tax Rate)]																											
85																												
86	**Income Tax Expense**																											
87	Earned Return	Line 79	-	-	-	618	612	596	580	564	548	533	517	501	485	469	453	437	512	583	563	542	521	418	315	216	138	90
88	Deduct: Interest on debt	Line 78	-	-	-	(273)	(270)	(263)	(256)	(249)	(242)	(235)	(228)	(221)	(214)	(207)	(200)	(193)	(226)	(257)	(248)	(239)	(230)	(184)	(139)	(95)	(61)	(40)
89	Add: Depreciation Expense	Line 54	-	-	-	244	244	244	244	244	244	244	244	244	244	244	244	244	244	317	317	317	317	317	317	262	184	184
90	Deduct: Overhead Capitalized Expenses for Tax Purposes		-	-	-	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(2)	(2)
91	Deduct: Removal Costs	Line 35	-	-	(317)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
92	Deduct: Capital Cost Allowance	Line 104	-	-	(1,023)	(600)	(552)	(508)	(467)	(430)	(395)	(364)	(335)	(308)	(283)	(261)	(240)	(221)	(313)	(398)	(366)	(336)	(310)	(204)	(134)	(89)	(58)	(42)
93	Taxable Income After Tax	Sum of Line 87 to 92	-	-	(1,339)	(12)	33	68	100	129	154	177	197	215	231	244	256	267	216	244	264	282	297	345	357	293	201	190
94	Income Tax Rate		27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%	27%
95																												
96	**Total Income Tax Expense**	Line 93 / (1 - Line 94) x Line 94	**-**	**-**	**(495)**	**(4)**	**12**	**25**	**37**	**48**	**57**	**65**	**73**	**79**	**85**	**90**	**95**	**99**	**80**	**90**	**98**	**104**	**110**	**128**	**132**	**108**	**74**	**70**
97																												
98	**Capital Cost Allowance**																											
99	Opening Balance	Proceeding Year, Line 105	-	-	-	7,574	6,974	6,422	5,915	5,448	5,018	4,622	4,259	3,924	3,616	3,333	3,072	2,833	2,612	5,045	4,647	4,282	3,945	2,626	1,757	1,184	806	599
100	Additions to Plant	Line 34	-	-	9,363	-	-	-	-	-	-	-	-	-	-	-	-	-	2,746	-	-	-	-	-	-	-	-	-
101	Less: AFUDC	Line 33	-	-	(766)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
102	Less: CIAC	Line 36	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
103	Net Addition for CCA	Sum of Line 100 through 102	-	-	8,597	-	-	-	-	-	-	-	-	-	-	-	-	-	2,746	-	-	-	-	-	-	-	-	-
104	**CCA**	**[Line 99 + (Line 103/2)] x CCA Rate**	**-**	**-**	**(1,023)**	**(600)**	**(552)**	**(508)**	**(467)**	**(430)**	**(395)**	**(364)**	**(335)**	**(308)**	**(283)**	**(261)**	**(240)**	**(221)**	**(313)**	**(398)**	**(366)**	**(336)**	**(310)**	**(204)**	**(134)**	**(89)**	**(58)**	**(42)**
105	Closing Balance	Line 99 + Line 103 + Line 104	-	-	7,574	6,974	6,422	5,915	5,448	5,018	4,622	4,259	3,924	3,616	3,333	3,072	2,833	2,612	5,045	4,647	4,282	3,945	3,636	2,422	1,622	1,095	747	557

FortisBC Inc.
Playmor Station Upgrade - Alternative B
August 2020
($000s), unless otherwise stated

Line	Particular	Reference	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2045	2050	2055	2060	2064
1	**Cash Flow**																											
2	Add: Revenue	Business Case, Line 7	-	-	(495)	933	945	942	938	933	927	920	912	903	893	882	871	860	916	1,070	1,057	1,044	1,029	946	849	675	494	450
3	Operation & Maintenance - Net of Capit	Business Case, -(Line 2 + Line 3)	-	-	-	(76)	(76)	(76)	(77)	(77)	(77)	(78)	(78)	(78)	(79)	(79)	(79)	(80)	(80)	(80)	(81)	(81)	(81)	(83)	(85)	(88)	(97)	(106)
4	EBITDA[1]	Line 2 + Line 3	-	-	(495)	857	868	866	861	856	850	842	834	824	814	804	792	780	836	990	977	963	948	862	764	587	397	344
5	Capital Expenditures[2]	Business Case, -Line 37	(480)	(7,907)	(1,292)	-	-	-	-	-	-	-	-	-	-	-	-	-	(2,746)	-	-	-	-	-	-	-	-	-
6	Pre-Tax Cash Flow	Line 4 + Line 5	(480)	(7,907)	(1,788)	857	868	866	861	856	850	842	834	824	814	804	792	780	(1,910)	990	977	963	948	862	764	587	397	344
7	Income Tax Expense	Line 4 x Income Tax Rate @ 27%	-	-	134	(231)	(234)	(234)	(233)	(231)	(229)	(227)	(225)	(223)	(220)	(217)	(214)	(211)	(226)	(267)	(264)	(260)	(256)	(233)	(206)	(158)	(107)	(93)
8	Overhead Capitalized Tax Shield	Business Case, -Line 90 x Income Tax Rate	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1
9	CCA Tax Shield & Removal Costs	Business Case, -(Line 92 + Line 91) x Income Tax Rate	-	-	362	162	149	137	126	116	107	98	90	83	76	70	65	60	84	107	99	91	84	55	36	24	16	11
10	Terminal Value of CCA Tax Shield	[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75
11	Terminal Value	[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,268
12																												
13	Free Cash Flow	Sum of Line 6 to Line 11	(480)	(7,907)	(1,292)	788	783	769	755	741	727	713	699	685	671	657	643	629	(2,051)	830	812	794	776	685	594	453	306	1,607
14																												
15	After Tax WACC %	Business Case, Line 81	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%
16	Present value of Free Cash Flow[5]	Line 13 / (1 + Line 15)^Yr	(454)	(7,068)	(1,092)	630	592	549	510	473	439	407	377	350	324	300	277	256	(790)	302	280	259	239	159	104	60	31	129
17	Total Present Value of Free Cash Flow	Sum of Line 16	**(464)**																									

18

19 1 - Earnings Before Interest, Taxes, Depreciation & Amortization (EBITDA)

20 2 - Net of CIAC and removal costs (if applicable)

21 3- [UCC Closing Balance x CCA Rate / (CCA Rate + WACC)] x Income Tax Rate

22 4 - Evaluation period reflects less than the useful life of the assets, therefore terminal value equals the net book value of assets at end of evaluation period

23 5 - 2020 present value calculates capital expenditure to occur at time zero

Appendix C

PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-169-14 – FBC ADVANCED METERING INFRASTRUCTURE (AMI) ENABLED BILLING OPTIONS FOR CUSTOMERS						
1.	6	4	Incremental Working Capital Benefits	FBC must flow through any incremental working capital benefits to customers as part of the new [PBR] flow through deferral account, approved in Order G-163-14, or another appropriate flow through account.	Completed.	Section 14 and Appendix C2
2.	n/a	5	Incremental Costs and Savings	FBC must report these incremental costs and savings in each of the annual reviews during the Performance Based Ratemaking term.	Completed	Appendix C2
G-107-15 – FBC ANNUAL REVIEW FOR 2015 RATES						
3.	15	n/a	Advanced Metering Infrastructure (AMI) Theft Reduction	The Commission Panel directs FBC to include, in its next and subsequent annual PBR reports, the impact of AMI on losses through theft deterrence. This directive will improve regulatory efficiency in the review of FBC's proposed actions (and FBC's incentives to undertake these actions while under PBR) related to the reduction of theft related costs. The information to be submitted should include: (i) a comparison of the projected GWh reduction for the test year and proceeding years to the estimated GWh theft reduction assumed in the AMI decision for those years; and (ii) a description of FBC's operational activities and costs incurred in reducing electricity theft (for example, related to FBC's Revenue Protection Program) and the regulatory treatment of these costs.	Completed	Appendix C2
G-8-17 – FBC ANNUAL REVIEW FOR 2017 RATES						
4.	15	5	Ruckles Substation Rebuild Project	The Panel directs FBC to report in each of its annual review applications during the remainder of the PBR term the following information on the Ruckles Substation Rebuild project: • The status of the Ruckles project, including a comparison of the project timeline provided in the current Application to the updated project timeline, as at the time of filing each annual review application. • Updated cost estimates and scope descriptions compared to the cost estimates and scope descriptions provided in the current Application, including explanations for any variances/changes to the cost estimates or project scope. • Actual costs incurred to date on the Ruckles project as at the time of filing each annual review application. • The final actual project cost, including a description of the scope of work completed relative to the cost estimate and scope description provided in the Application, with explanations for any variances.	Completed	Appendix C3

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
5.	21	6	Upper Bonnington Old Units Refurbishment Project	The Panel directs FBC to report in each of its annual review applications during the remainder of the PBR term the following information on the UBO Refurbishment project: • The status of both the UBO Refurbishment project as a whole and of the individual units, including a comparison of the project timeline provided in the current Applicaton to any updated project timeline as at the time of filing each annual review application. • Updated cost estimates and cost descriptions compared to the cost estimates and scope descriptions provided in the current Application, including explanations for any variances/changes to the cost estimates or project scope. • Actual costs incurred to date on the UBO Refurbishment project as a whole and on each individual unit as at the time of filing each annual review application. • Final actual refurbishment costs at the completion of each unit, including a description of the scope of work completed relative to the conditions found and against the cost estimate.	Ongoing until Project complete	Appendix C4
G-9-18 – FBC APPLICATION FOR APPROVAL OF RATE DESIGN AND RATES FOR ELECTRIC VEHICLE DIRECT CURRENT FAST CHARGING SERVICE						
6.	2	2	Electric Vehicle DCFC Stations	FBC is directed to separately track and account for all costs associated with the EV DCFC stations and exclude all such costs from its utility rate base until the Commission directs otherwise.	Ongoing until further BCUC direction.	Section 11, Schedule 2
G-246-18 – FBC ANNUAL REVIEW FOR 2019 RATES						
7.	15		Loss Recovery Request	The Panel directs FBC to provide forecast Loss Recoveries in future revenue requirements applications.	Ongoing	Section 4.8

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-165-20 – FEI MULTI-YEAR RATE PLAN FOR 2020 THROUGH 2024						
8.	48	11	Setting the I-Factor	Based on these findings the Panel determines that the I-factor formula will be as follows: I = X $x\ AWE{:}BCt{-}1$ + Y $x\ CPI{:}BCt{-}1$ Where: • I = Inflation Factor • AWE:BC = labour index • CPI:BC = non - labour index • t - 1 = most recent July to June value • X = the previous year's labour ratio; and • Y = the previous year's non-labour ratio. FortisBC is directed to provide the results of the completed formula based on 2019 results for FEI and FBC to set the base for 2020 as part of its compliance filing. Thereafter, the formula will be informed by the previous year's results and reviewed as part of the Annual Review Process.	Completed	Section 2.2
9.	75	24	General Flow-through Deferral Account	The Panel directs [FBC] to provide a detailed analysis of the individual forecast variances recorded in the Flow-through deferral account in each Annual Review.	Ongoing during the MRP term	n/a for 2020 and 2021 as no amounts are forecast
10.	87	32	Efficiency Carry-Over Mechanism	Therefore, the Panel determines the following process for the handling of an ECM application: 1. An ECM can be applied for at any time in the last three years of the MRPs, either in advance or following the action or initiative being undertaken. 2. For proposed activities where identifiable savings are expected to extend beyond the term of the MRP, FortisBC is to file an ECM proposal describing the initiative, its timing, costs and benefits and savings. 3. Parties will have the opportunity to review and comment on the proposal and the BCUC will determine whether to approve the ECM proposal (an Approved ECM Initiative). FortisBC must submit details of continued savings annually under an Approved ECM Initiative as part of the Annual Review process. The net savings will be shared equally between ratepayers and the Utilities will carry forward past the end of the MRP for a maximum period of three years.	No approved ECM initiatives to report on	n/a

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
11.	99	35	SAIDI and SAIFI major events	The Panel also directs FBC to include a discussion of major events relevant to the SAIDI and SAIFI results in future Annual Review materials.	Ongoing during the MRP term	Section 13
12.	99-100		SQI Informational Indicators	In addition to the SQIs, the Panel approves the following informational indicators for the Utilities: • Customer Satisfaction Index (measures overall customer satisfaction) – FEI and FBC. • Average Speed of Answer (average number of seconds to answer emergency and non-emergency calls) – FEI and FBC. • Generator Forced Outage Rate (percent of time a generating unit is removed from service due to component failure or other events) – FBC only. • Interconnection Utilization (percent of time that an interconnection point was available and providing electrical service to wholesale customers) – FBC only. The Utilities are directed to report on these informational indicators along with the SQIs as part of the Annual Review process.	Ongoing during the MRP term	Section 13
13.	118	42	System Operations, Integrity and Security Expenditures	The Panel directs FBC to provide the following information related to System Operations, Integrity and Security expenditures in its future revenue requirements applications over the term of the Proposed MRPs: 1. A breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to System Operations, Integrity and Security expenditures, which quantify the variances attributable to the following areas: • Tree management; • Generation dam safety; • Network operations apprentice program; • Cyber security; • Data analytics; and • Any other significant factors or miscellaneous items. 2. A description of how FBC is prioritizing its System Operations, Integrity and Security expenditures.	Ongoing during the MRP term	Section 6.2.1
14.	131	49	Forecast Capital Expenditures	The Panel directs FortisBC to file an updated forecast of the 2023 to 2024 capital expenditures in the 2023 Annual Review.	Will be filed in FBC's Annual Review for 2023 Rates	n/a

1. INTRODUCTION

In this appendix FBC provides the final 2018 and 2019 results for Advanced Metering Infrastructure (AMI) related impacts on system losses, net O&M costs and savings, and cash working capital.

2. AMI IMPACT ON DETERRING THEFT OF POWER

FBC's implementation of AMI (approved by Order C-7-13) was expected to positively impact losses (unaccounted-for energy) by deterring theft of power, mainly from indoor marijuana grow sites. In Order G-107-15 in FBC's Annual Review for 2015 Rates, FBC was directed to include in its next and subsequent Annual Review materials the impact of AMI on theft deterrence, including:

(i) a comparison of the projected GWh reduction for the test year and proceeding years to the estimated GWh theft reduction assumed in the AMI decision for those years; and

(ii) a description of FBC's operational activities and costs incurred in reducing electricity theft (for example, related to FBC's Revenue Protection Program) and the regulatory treatment of these costs.[1]

FBC estimates that the implementation of AMI had a positive impact on losses (unaccounted-for energy) by deterring theft of power, mainly from indoor marijuana grow sites. Beginning with the 2016 year, FBC included in its forecast of system losses an adjustment based on estimates developed in the AMI Project CPCN application and subsequently adjusted pursuant to the BCUC's decision on the AMI Project, Order C-7-13.

Operationally, FBC has implemented its energy balancing program, facilitated by AMI, and is also leveraging the tamper detection functionality of the AMI system for theft identification. In 2019 FBC carried out a study of system losses, employing newly-available AMI data. The results of that study[2] incorporate the impact of those operational improvements. Therefore, for 2020 and future estimates of system losses (described in Section 3.4.7 of the Application), FBC will no longer make adjustments to reflect AMI impacts.

The O&M expenditures incurred in reducing electricity theft that were incremental to those included in the PBR Base O&M related primarily to the addition of a Revenue Protection Analyst for managing the development and operation of the AMI-enabled energy balancing program, as well as the necessary field resources for the periodic deployment and relocation of the feeder

1 Order G-107-15, page 15.
2 The 2019 Losses Study was filed as Appendix B3 of the FEI-FBC MRP Application.

metering devices as required. The incremental costs to manage the AMI-enabled energy balancing program included 2019 O&M expenditures of $0.206 million.

During the PBR term, the AMI costs and savings, including those associated with FBC's Revenue Protection Program, that were incremental to the Revenue Protection program costs included in formula O&M were forecast and tracked outside of the PBR formula, as set out in the following section.

3. AMI IMPACT ON O&M EXPENSE

Incremental O&M costs related to the implementation of the AMI project are being offset by post-implementation savings, resulting in a net decrease to O&M expense during the PBR period. Because of the high variability of AMI costs and savings during the implementation period, net AMI costs, including the costs of AMI-enabled billing options, were forecast and tracked outside of the PBR formula.

Table C2-1 below compares 2014 through 2019 net AMI savings to the net savings forecast in the AMI CPCN application.

Table C2-1: AMI Costs and Savings ($ millions)

Line		2014-2018			2019			Total		
No.		Actual	Approved	CPCN[1]	Actual	Approved	CPCN[1]	Actual	Approved	CPCN[1]
1	AMI Costs	$ 7.153	$ 7.829	$ 8.752	$ 1.920	$ 2.055	$ 1.951	$ 9.073	$ 9.884	$ 10.703
2	AMI Savings	(10.290)	(10.841)	(14.863)	(3.216)	(3.216)	(4.244)	(13.506)	(14.057)	(19.107)
3	Net AMI Costs/(Savings)	$ (3.137)	$ (3.012)	$ (6.111)	$ (1.296)	$ (1.161)	$ (2.293)	$ (4.433)	$ (4.173)	$ (8.404)
4										
5	[1]CPCN estimates adjusted to include reclassification of software from capital pursuant to Order G-13-14.									

As reported previously, AMI-related costs and savings from 2014 to 2017 lag those estimated in the AMI CPCN primarily due to delayed project timing following an extensive CPCN review process and the BCUC's directive to file for approval of an opt-out program prior to meter installation. The AMI project was substantially completed during 2016, such that 2017 was the first year of fully realized costs and savings for the AMI project.

Following implementation, costs were approximately as forecast in the CPCN application, while annual savings were lower than the CPCN forecast of $4.424 million. As shown in Table C2-1 above, the 2019 actual savings of $3.153 million are approximately $1.0 million lower. This variance is driven by meter reading, Measurement Canada compliance savings, and other smaller factors as explained below.

3.1.1.1 Meter Reading

The CPCN forecast was a comparison of the savings that would be achieved with the AMI project to the costs that would otherwise be incurred to support the continuation of a manual meter reading program. As such, the AMI CPCN forecast savings required a cost forecast of continuing with manual meter reading. The manual meter reading cost forecasts used in the CPCN for 2013 and 2014 (the last full years of manual meter reading) were higher than the costs actually experienced in those years. These savings resulted largely from efficiencies found in absorbing the City of Kelowna manual meter reading work. As a result, the savings potential was diminished in 2015 and beyond.

CPCN forecast costs for meter reading were also based in part on the forecast number of customers. This customer count forecast in the CPCN application was an average of 1.9 percent growth per year between 2014 and 2016 (the last year of comparative meter reading costs), which was higher than the 1.3 percent actually experienced.

In total, the meter reading savings contribute approximately $0.400 million of the total AMI savings variance in 2019.

3.1.1.2 Measurement Canada Compliance

One of the benefits of replacing the majority of the meter fleet with AMI meters was a reduction in Measurement Canada compliance costs. As with meter reading, forecasting these savings required a forecast of the cost of meter exchanges that would have been required in the absence of AMI. In the CPCN application, FBC forecast that 2018 would be the peak year in terms of the number of electromechanical and non-AMI digital meter replacements due to the Measurement Canada SS-06 regulation (in the absence of AMI). These non-AMI compliance costs were estimated to be $0.400 million higher than the forecast of Measurement Canada cost for 2019. This $0.400 million avoided cost does not result in a reduction to 2019 O&M costs, but will still result in lower rates for customers than in the absence of AMI.

3.1.1.3 Other Factors

Other factors contributing to the $1.0 million AMI Savings variance in 2019 include:

1. Approximately $0.100 million lower savings due to higher post-AMI manual disconnect and reconnect costs than forecast. The higher post-AMI costs are due to not forecasting an increase in the unit cost of manual disconnects and reconnects at substantially lower post-AMI volumes.
2. Approximately $0.100 million lower savings due to lower pre-AMI Measurement Canada compliance exchange costs than forecast. As with the lower pre-AMI meter reading costs discussed above, this reduced the post-AMI savings potential.

4. AMI WORKING CAPITAL ADJUSTMENT

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. FBC calculated the impact on working capital due to the AMI Project, which resulted from changes in the proportion of monthly-billed to bi-monthly-billed customers facilitated by AMI. In this Appendix, FBC calculates the impact to cash working capital for 2018 and 2019, the final two years of the PBR term, based on changes in billing determinants from the approved.

In 2018 and 2019, the impact of AMI on cash working capital resulted in decreases of $0.035 million and $0.085 million respectively to revenue requirements, which is being returned to customers in 2020. The calculations of the revenue requirements impacts are provided below.

4.1 *2018 AMI WORKING CAPITAL IMPACT*

As can be seen by comparing columns c and f in Table C2-2 below, for the two largest customer classes, residential and commercial, the proportion of customers receiving monthly rather than bi-monthly bills was greater in 2018 than forecast (approved). The periods between taking service and meter reading, and between billing and collection are shorter for customers on a monthly billing cycle. Hence, the total revenue lag days is lower than calculated in the approved cash working capital calculation.

Table C2-2: Calculation of 2018 Revenue Lag

Line		Service Period to Meter Read		Approved			Actual			Meter Read to Billing	
				Proportion Billed		Consumption	Proportion Billed		Consumption		
No.	Customer Class	Monthly	Bimonthly	Monthly	Bimonthly	Lag	Monthly	Bimonthly	Lag	Processing Lag	
		a	b	c	d	e=a*c+b*d	f	g	h=a*f+b*g	i	
1	Residential	15.2	30.4	14.6%	85.4%	28.2	19.7%	80.3%	27.4	1.0	
2	Commercial	15.2	30.4	19.6%	80.4%	27.4	25.2%	74.8%	26.6	1.0	
3	Wholesale	15.2	30.4	100.0%	0.0%	15.2	100.0%	0.0%	15.2	1.0	
4	Industrial	15.2	30.4	100.0%	0.0%	15.2	100.0%	0.0%	15.2	1.0	
5	Lighting	15.2	30.4	40.3%	59.7%	24.3	43.9%	56.1%	23.7	1.0	
6	Irrigation	15.2	30.4	16.2%	83.8%	27.9	18.9%	81.1%	27.5	1.0	
7											
8											
9		Billing to		Approved			Actual			Approved	Actual
10		Collection		Proportion Billed		Clearing	Proportion Billed		Clearing		
11		Monthly	Bimonthly	Monthly	Bimonthly	Lag	Monthly	Bimonthly	Lag	Total Lag Days	
12		j	k	l=c	m=d	n=j*l+k*m	o=f	p=g	q=j*o+k*p	r=e+i+n	s=h+i+q
13	Residential	17	22	14.6%	85.4%	21.3	19.7%	80.3%	21.0	50.5	49.4
14	Commercial	17	22	19.6%	80.4%	21.0	25.2%	74.8%	20.7	49.4	48.3
15	Wholesale	17	22	100.0%	0.0%	17.0	100.0%	0.0%	17.0	33.2	33.2
16	Industrial	17	22	100.0%	0.0%	17.0	100.0%	0.0%	17.0	33.2	33.2
17	Lighting	17	22	40.3%	59.7%	20.0	43.9%	56.1%	19.8	45.3	44.5
18	Irrigation	17	22	16.2%	83.8%	21.2	18.9%	81.1%	21.1	50.1	49.6

Table C2-3 below recalculates 2018 cash working capital assuming the revenue lags for 2018. Cash working capital is reduced by $0.583 million, therefore reducing rate base by the same amount.

Table C2-3: AMI Adjustment to 2018 Cash Working Capital ($ millions)

Line No.	Description	2018 Approved	Revised Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Reference (2018 Rates Compliance Filing)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	178.976	49.4	$ 8.845		
4	Commercial Tariff Revenue	90.669	48.3	4.380		
5	Wholesale Tariff Revenue	48.565	33.2	1.612		
6	Industrial Tariff Revenue	31.712	33.2	1.053		
7	Lighting Tariff Revenue	2.903	44.5	0.129		
8	Irrigation Tariff Revenue	3.515	49.6	0.174		
9						
10	**Other Revenue**	8.416		0.257		Section 11, Schedule 14, Lines 11 - 15
11						
12	Total	$ 364.756		$ 16.451	45.1	
13						
14	**EXPENSES**	$ 264.629		$ 10.353	(39.1)	Section 11, Schedule 14, Line 35
15						
16	Net Lag (Lead) Days				6.0	
17						
18	Total Expenses				$ 264.629	
19						
20	Cash Working Capital, Revised Lag Days				$ 4.350	
21						
22	Cash Working Capital in 2018 Rates				$ 4.930	Section 11, Schedule 14, Line 41
23						
24	Reduction in Cash Working Capital				$ (0.580)	

Finally, Table C2-4 calculates the revenue requirements impact of the $0.580 million reduction in rate base by applying the pre-tax weighted average cost of capital. The adjustment of $0.046 million (credit) is included in the additions to the Flow-through deferral account, as shown in the Application, Section 14, Table 14-1 at line 27.

Table C2-4: 2018 Revenue Requirements Impact of AMI Adjustment to Cash Working Capital ($ millions)

Line No.	Description	Weight	CWC Component	Pre-Tax Rate	Adjustment for Cash Working Capital	Reference (2018 Rates Compliance Filing)
1	Long Term Debt	55.63%	$ (0.323)	5.18%	$ (0.017)	Section 11, Schedule 26, Line 1
2	Short Term Debt	4.37%	(0.025)	3.45%	(0.001)	Section 11, Schedule 26, Line 2
3	Common Equity	40.00%	(0.232)	12.36%	(0.029)	Note 1
4						
5						
6	Weighted Average	100.00%	$ (0.580)	7.98%	$ (0.046)	
7						
8	Note 1: Pre-tax value = approved ROE of 9.15%/(1-26%)= 12.36%					

4.2 *2019 AMI WORKING CAPITAL IMPACT*

Similarly, in 2019 the proportion of residential and commercial customers receiving monthly rather than bi-monthly bills was greater than forecast (approved), as seen in columns c and f of Table C2-5. The total revenue lag days for these categories are lower than calculated in the approved cash working capital calculation.

Table C2-5: Calculation of 2019 Revenue Lag

Line No.	Customer Class	Service Period to Meter Read Monthly	Service Period to Meter Read Bimonthly	Approved Proportion Billed Monthly	Approved Proportion Billed Bimonthly	Approved Consumption Lag	Actual Proportion Billed Monthly	Actual Proportion Billed Bimonthly	Actual Consumption Lag	Meter Read to Billing Processing Lag
		a	b	c	d	e=a*c+b*d	f	g	h=a*f+b*g	i
1	Residential	15.2	30.4	14.6%	85.4%	28.2	23.2%	76.8%	26.9	1.0
2	Commercial	15.2	30.4	19.6%	80.4%	27.4	28.9%	71.1%	26.0	1.0
3	Wholesale	15.2	30.4	100.0%	0.0%	15.2	100.0%	0.0%	15.2	1.0
4	Industrial	15.2	30.4	100.0%	0.0%	15.2	100.0%	0.0%	15.2	1.0
5	Lighting	15.2	30.4	40.3%	59.7%	24.3	47.0%	53.0%	23.3	1.0
6	Irrigation	15.2	30.4	16.2%	83.8%	27.9	57.3%	42.7%	21.7	1.0
7										
8										

Line No.	Customer Class	Billing to Collection Monthly	Billing to Collection Bimonthly	Approved Proportion Billed Monthly	Approved Proportion Billed Bimonthly	Approved Clearing Lag	Actual Proportion Billed Monthly	Actual Proportion Billed Bimonthly	Actual Clearing Lag	Total Lag Days Approved	Total Lag Days Actual
12		j	k	l=c	m=d	n=j*l+k*m	o=f	p=g	q=j*o+k*p	r=e+i+n	s=h+i+q
13	Residential	17	22	14.6%	85.4%	21.3	23.2%	76.8%	20.8	50.5	48.7
14	Commercial	17	22	19.6%	80.4%	21.0	28.9%	71.1%	20.6	49.4	47.6
15	Wholesale	17	22	100.0%	0.0%	17.0	100.0%	0.0%	17.0	33.2	33.2
16	Industrial	17	22	100.0%	0.0%	17.0	100.0%	0.0%	17.0	33.2	33.2
17	Lighting	17	22	40.3%	59.7%	20.0	47.0%	53.0%	19.7	45.3	43.9
18	Irrigation	17	22	16.2%	83.8%	21.2	57.3%	42.7%	19.1	50.1	41.8

Cash working capital is reduced by $1.061 million, shown in Table C2-6, reducing rate base by the same amount.

Table C2-6: AMI Adjustment to 2019 Cash Working Capital ($ millions)

Line No.	Description	2019 Forecast	Revised Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Reference (2019 Compliance Filing)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	187.887	48.7	$ 9.153		
4	Commercial Tariff Revenue	94.508	47.6	4.495		
5	Wholesale Tariff Revenue	49.519	33.2	1.644		
6	Industrial Tariff Revenue	32.414	33.2	1.076		
7	Lighting Tariff Revenue	2.661	43.9	0.117		
8	Irrigation Tariff Revenue	3.544	41.8	0.148		
9						
10	**Other Revenue**	9.268		0.330		Section 11, Schedule 14, Lines 11 - 16
11						
12	Total	$ 379.802		$ 16.963	44.7	
13						
14	**EXPENSES**	$ 276.581		$ 10.904	(39.4)	Section 11, Schedule 14, Line 36
15						
16	Net Lag (Lead) Days				5.3	
17						
18	Total Expenses				$ 276.581	
19						
20	Cash Working Capital, Revised Lag Days				$ 4.016	
21						
22	Cash Working Capital in 2019 Rates				$ 5.077	Section 11, Schedule 14, Line 42
23						
24	Reduction in Cash Working Capital				$ (1.061)	

Table C2-7 calculates the revenue requirements impact of the $0.293 million reduction in rate base by applying the pre-tax weighted average cost of capital. The adjustment of $0.085 million (credit) is included in the additions to the Flow-through deferral account, as shown in the Application, Section 14, Table 14-1 at line 28.

Table C2-7: 2019 Revenue Requirements Impact of AMI Adjustment to Cash Working Capital ($ millions)

Line No.	Description	Weight	CWC Component	Pre-Tax Rate	Adjustment for Cash Working Capital	Reference (2019 Compliance Filing)
1	Long Term Debt	54.77%	$ (0.581)	5.18%	$ (0.030)	Section 11, Schedule 26, Line 1
2	Short Term Debt	5.23%	(0.055)	4.12%	(0.002)	Section 11, Schedule 26, Line 2
3	Common Equity	40.00%	(0.424)	12.36%	(0.052)	Note 1
4						
5						
6	Weighted Average	100.00%	$ (1.061)	8.00%	$ (0.085)	
7						
8	Note 1: Pre-tax value = approved ROE of 9.15%/(1-26%)= 12.36%					

4.3 SUMMARY

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. By including the working capital impact in the Flow-through deferral account, FBC has returned the working capital benefits of its AMI project to customers.

Appendix C3

FortisBC Inc.

Ruckles Substation Rebuild Project

Final Report

Table of Contents

1. PROJECT STATUS

1.1 PROJECT BACKGROUND

On January 20, 2017, the British Columbia Utilities Commission (BCUC) approved capital expenditures related to the Ruckles Substation Rebuild project (Ruckles project) by Order G-8-17. The BCUC directed FBC to provide the following information about the progress of the Ruckles project as part of its annual review applications.

- The status of the Ruckles project, including a comparison of the project timeline provided in the [Annual Review for 2017 Rates] Application to the updated project timeline, as at the time of filing each annual review application.
- Updated cost estimates and scope descriptions compared to the cost estimates and scope descriptions provided in the [Annual Review for 2017 Rates] Application, including explanations for any variances/changes to the cost estimates or project scope.
- Actual costs incurred to date on the Ruckles project as at the time of filing each annual review application.
- The final actual project cost, including a description of the scope of work completed relative to the cost estimate and scope description provided in the [Annual Review for 2017 Rates] Application, with explanations for any variances.[1]

The Ruckles project involved rebuilding the Ruckles Substation, together with the necessary transmission and distribution modifications, primarily to address issues of age and the substation's location in the identified flood zone of the Kettle River, in order to continue the safe supply of electricity to the City of Grand Forks (CoGF) municipal electric utility and surrounding area. FBC submits this final report in compliance with the above directive of BCUC Order G-8-17.

1.2 GENERAL PROJECT STATUS

In the Annual Review for 2017 Rates in which approval was requested, the Ruckles project had an AACE Class 3 capital cost estimate of $8.288 million in as-spent dollars (including $0.428 million of AFUDC and $0.301 million of removal costs). Final project costs are $6.403 million, or $1.885 million or 22.8 percent lower than estimated, due to savings associated with the elimination of 13 kV to 4 kV step-down equipment that was no longer necessary (discussed further below), favourable actual costs for major equipment compared to budget allowances, and the release of project contingency.

[1] G-8-17, Appendix A, page 15.

FBC maintained the project schedule as presented in the business case. FBC completed all construction, including project deficiencies mitigation and closeout, by December 31, 2018.

Significant areas of Grand Forks, including the old Ruckles Substation, experienced extensive flooding in May 2018. The floodwaters reached levels consistent with those expected for a 1 in 200-year event. The possibility of such an event was one of the main drivers for the Ruckles project. Emergency flood response, including the installation of a mobile transformer, placement of concrete blocks and sandbags for flood control, and contractor support to operate dewatering pumps and provide site clean up resulted in a small amount of additional costs to the project. The newly constructed, elevated Ruckles Substation did not sustain flood damage. By successfully maintaining scheduled milestones, FBC installed, commissioned, and energized the new equipment before the floodwaters damaged the old substation, thereby avoiding extended and extensive outages to FBC and CoGF customers.

1.3 *MAJOR ACCOMPLISHMENTS, WORK COMPLETED AND KEY DECISIONS MADE*

1.3.1 Project Engineering

As described in the previous Status Reports, Ruckles Substation is supplied by two FBC transmission lines and provides a distribution supply source to direct residential, irrigation and commercial customers of FBC (at 13 kV), the electrical utility of the CoGF (at both 13 kV and 4 kV), and an industrial sawmill customer (at 4 kV).

Following BCUC approval of the Ruckles project, and to seek out project cost savings, FBC initiated discussions with the CoGF municipal electric utility to explore whether the CoGF would be willing to advance its ongoing 4 kV to 13 kV system voltage conversion project so that it would be completed by June 1, 2018. The CoGF was originally anticipating completion of the conversion project in 2018/2019. An earlier conversion allowed FBC to eliminate the 4 kV infrastructure requirements associated with the CoGF supply from this project and to achieve project cost savings. In June 2017, the CoGF accepted FBC's offer to contribute a portion of the project savings in order to advance the voltage conversion.

FBC also held discussions with its industrial customer, Interfor Corporation (Interfor) to explore whether Interfor would also be willing to convert its equipment from 4 kV to 13 kV by June 1, 2018. Following initial discussions, Interfor engaged a third party to develop a scope and estimate for the conversion. FBC and Interfor then reached an agreement whereby FBC contributed a portion of Interfor's costs of conversion.

By removing the 4 kV supply infrastructure from the Ruckles project, gross cost savings were approximately $0.500 million, less contributions to the CoGF and Interfor. Including the contributions, the net cost savings were approximately $0.250 million.

FBC completed all civil and structural design and issued the electrical tender package to four vendors on June 6, 2017 as part of the Request for Quotation (RFQ). The detailed electrical construction package was issued in September 2017.

1.3.2 Procurement

FBC received all major equipment, which was installed on site. The Electrical construction contract is 100 percent complete. The contract scope of work included the civil and site, structures and bus work, station equipment and apparatus, protection, control, and metering, and removal of existing equipment.

1.3.3 Environmental Planning

FBC developed a site specific Environmental Management Plan for the project. Both internal FBC crews and contractors met or exceeded the environmental requirements.

1.3.4 Permits and Approvals

There are no outstanding permits or approvals required.

1.4 *PROJECT CHALLENGES AND ISSUES*

1.4.1 Detailed Engineering

FBC completed geotechnical and soil characterization studies to verify site conditions. FBC also used surveys and historical information to determine site elevations. This allowed engineering to design the project above the flood plain by reconstructing the station two metres above the existing grade.

1.4.2 Communications and Stakeholder Engagement

Communications with the CoGF and Interfor are complete. Both parties agreed to convert from a 4 kV to 13 kV supply. As explained in section 1.3.1, this reduced the project capital cost, improved system reliability by reducing the amount of installed equipment, and allowed FBC to achieve efficiencies by not having to maintain non-standard 4 kV equipment.

1.4.3 Construction and Commissioning

The Ruckles Substation and surrounding areas in the Grand Forks area experienced extensive flooding in May 2018, with water levels consistent with those expected for a 1 in 200-year event.

On the morning of May 11, rising floodwaters breached a temporary sandbag dike erected by FBC around the old Ruckles Substation. Water levels in the station yard and control buildings quickly reached the levels foreseen in the project application (refer to Project photos in section 1.4.4 below). This forced the de-energization of the station to manage the extreme safety hazards associated with flooded high voltage equipment. Although not all aspects of the project were complete, construction of the new station was sufficiently advanced that the electrical infrastructure was available to provide safe and reliable service. FBC was able to expedite the remaining commissioning and only a short unplanned outage occurred before load was transferred from the unserviceable equipment in the old Ruckles Substation to the new substation equipment. Additional emergency flood response, including the installation of a mobile transformer to provide a temporary 4 kV supply, concrete block and sandbag installations, and contractor support to operate dewatering pumps and site clean-up, resulted in approximately $70 thousand of additional costs to the project, but no significant schedule delays occurred.

Field equipment commissioning was completed by a third party contractor. All protection and control commissioning was completed by internal FBC employees. Both Interfor and the CoGF have fully converted to the new 13 kV voltage and are being supplied from the new Ruckles Substation.

1.4.4 Project Photos

Figure C3-1: Old Ruckles Substation T1 transformer and FDR4 / FDR5 circuit breakers three days after peak flooding (note high water marks on equipment)

Figure C3-2: Old Ruckles Substation control building interior (note high water marks on switchgear panels)

Figure C3-3: New Ruckles Substation control building (left) and general area flooding (note substantial elevation difference between old substation fence on the right and the new fence on the left)

Figure C3-4: New Ruckles Substation
(photo taken shortly after the flood peak)

2. PROJECT SCHEDULE

Major milestones are as shown in the schedule below.

Table C3-1: Milestone Summary

Milestone	Planned Completion Date	Actual Completion Date	Status
Engineering/Procurement:	Q4-2018	December 2018	Complete
9L 63 kV reconfiguration(IFC)	Q1-2017	March 31, 2017	Complete
Control room (IFC)	Q2-2017	May 11, 2017	Complete
Site/Civil (IFC)	Q2-2017	April 14, 2017	Complete
Electrical/Physical (IFC)	Q2-2017	June 5, 2017	Complete
Issue RFQ	Q2-2017	June 6, 2017	Complete
Steel (IFC)	Q2-2017	June 15, 2017	Complete
Issue Contract	Q3-2017	July 14, 2017	Complete
Major equipment delivery	Q4-2017	December 2018	Complete
Construction:			
Civil/site Phase 1 (pre-construction)	Q4-2017	November 2017	Complete
Civil/Site Phase 2 (completion)	Q4-2018	September 2018	Complete
Buildings	Q2-2018	May 2018	Complete
Structures/Buswork	Q4-2018	May 2018	Complete
Station Equipment/Apparatus	Q3-2018	June 2018	Complete
Communication/SCADA	Q2-2018	June 2018	Complete
Protection/Control/Metering	Q2-2018	May 2018	Complete
Commissioning	Q3-2018	June 2018	Complete
Distribution Line work	Q3-2018	September 2018	Complete
Equipment removal	Q4-2018	September 2018	Complete
Project Completion	Q4-2018	December 2018	Complete

2.1 *SCHEDULE PERFORMANCE*

FBC completed construction, engineering, and project closeouts on schedule.

2.2 *SCHEDULE PROJECTION GOING FORWARD*

The Ruckles project is 100 percent complete with no outstanding deficiencies.

2.3 SCHEDULE DIFFICULTIES AND VARIANCES

Floodwaters in 2018 slightly delayed construction, but FBC maintained the schedule and completed major construction in September 2018.

2.4 PROJECT SCOPE CHANGE SUMMARY

Successful negotiations with the CoGF and Interfor allowed FBC to remove the 4 kV portion of the project. This created some Civil and Electrical design changes for the project. Specifically, two padmount transformers and the associated containment systems and foundations were removed from the scope of work.

FBC change management procedures were used to manage design and scope change.

3. PROJECT COSTS

The following table outlines the total project expenditures.

Table C3-2: Cost Summary

Description	Application/ Control Budget	Total Expenditures	Percent Variance	Variance Explanation
	(1)	(2)	(3)=((2)-(1))/(1)	
	($000s)		(%)	
Line Work	241	259	7	High water table when transmission poles installed. Vacuum truck required
Civil & Site	1,688	1,663	-1	
Buildings	191	205	7	
Structures & Buswork	427	505	18	Scope addition for animal guarding and capacitor bank breaker replacement
Station Equipment & Apparatus[2]	2,602	1,777	-32	4 kV to 13 kV voltage conversion savings and favourable equipment pricing
Communications & SCADA	32	34	6	
Protection, Control & Metering	270	246	-9	
Design	627	714	14	Additional engineering required for 4 kV-13 kV conversion
Commissioning	132	122	-7	
Project Management	544	300	-45	Internal FBC dual role construction / project manager. Did not have to contract out on site
Subtotal - Construction	6,754	5,824	-14	
Cost of Removal	301	175	-42	Savings on non-PCB oil disposal and salvage credits
Project Contingency	805	0	-100	Identified potential risks did not materialize
Subtotal- Construction & Removal	7,860	6,000	-24	
AFUDC	428	403	-6	
Total Project Cost	**8,288**	**6,403**	**-23**	

The project cost is $1.885 million lower than the business case forecast as a result of eliminating the 4 kV equipment from the substation, favourable actual costs for major equipment compared to budget allowances, and the release of project risk and contingency. Additional details are included in Table C3-2 above.

4. PROJECT RISKS

The Ruckles project is now 100 percent complete so no project risks remain.

5. CONCLUSION

FBC successfully energized the new Ruckles Substation in May 2018 to address imminent damage to equipment in the old Ruckles Substation resulting from flooding in the Grand Forks area. Had FBC not proceeded with the project, extensive and extended outages to FBC direct customers, CoGF customers, and the Interfor sawmill would have been inevitable. There would also have been substantial unforeseen costs associated with addressing damaged equipment and potential environmental mitigation.

Project cost savings resulted from successful negotiations with Interfor and the CoGF allowing FBC to remove the 4 kV voltage system requirements from the project scope. Favourable equipment pricing and the release of risk and contingency also contributed to the project cost savings.

Appendix C4

FortisBC Inc.

Upper Bonnington Unit Refurbishment Project

Status Report

August 2020

Table of Contents

1. PROJECT STATUS

1.1 PROJECT BACKGROUND

On January 20, 2017, the British Columbia Utilities Commission (BCUC) approved capital expenditures related to the Upper Bonnington Old Units Refurbishment (UBO Refurbishment Project) in Order G-8-17. Directive 6 of Order G-8-17 required FBC to file specific information on the project's updated scope, progress and costs as part of FBC's future annual review applications. Specifically, the BCUC directed FBC to provide the following information about the progress of the project:

- The status of both the UBO Refurbishment Project as a whole and of the individual units, including a comparison of the project timeline provided in the [Annual Review for 2017 Rates] Application to any updated project timeline as at the time of filing each annual review application.
- Updated cost estimates and cost descriptions compared to the cost estimates and scope descriptions provided in the [Annual Review for 2017 Rates] Application, including explanations for any variances/changes to the cost estimates or project scope.
- Actual costs incurred to date on the UBO Refurbishment Project as a whole and on each individual unit as at the time of filing each annual review application.
- Final actual refurbishment costs at the completion of each unit, including a description of the scope of work completed relative to the conditions found and against the cost estimate.[1]

The UBO Refurbishment Project involves the refurbishment of generating Units 1-4 (the Old Units), which are over 100 years old, in order to extend their lives for an additional twenty years or more. The project will also reduce the safety and environmental risks associated with failures of the aged equipment.

FBC submits the following report regarding the UBO Refurbishment Project in compliance with Directive 6 of Commission Order G-8-17, including costs to June 30, 2020.

1.2 GENERAL PROJECT STATUS

The Project has progressed well since the last submitted progress report. FBC encountered challenges refurbishing Units 3, 4, and 1, but ultimately overcame those challenges while maintaining scope and schedule. The as-found condition of the turbine components was and

[1] G-8-17, Appendix A, page 21.

continues to be the main challenge encountered due to higher than anticipated levels of corrosion and wear.

Unit 2 is currently under construction and is scheduled to return to service in Q4 2020. The balance of the plant work will begin immediately after Unit 2 is in service, and is expected to be complete by Q2 2021. The following table shows the status of each of the generating units being worked on as part of the Project.

Table C4-1: Project Status

Upper Bonnington Refurbishment	Project Start	Project Duration	Inservice Date	Remaining Work
Unit 3	Q1 2017	10 Months	Q4 2017	Painting and Rotor Leak Deficiency[1]
Unit 4	Q1 2018	10 Months	Q4 2018	Painting
Unit 1	Q1 2019	10 Months	Q4 2019	Painting
Unit 2	Q1 2020	9 Months		Reassembly Alignment, Commissioning, Painting
Balance of Plant	Q2 2020	7 Months		
Demobilization	Q2 2020	1 Month		

Notes:

[1] Unit 3 Rotor Leak Deficiency is explained in more detail in Section 1.4.1.

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.

The construction schedule remains unchanged from the previous update provided in the Annual Review for 2019 Rates.

1.3 MAJOR ACCOMPLISHMENTS, WORK COMPLETED AND KEY DECISIONS MADE

1.3.1 Detailed Engineering

FBC has predominantly completed detailed engineering for all units. Minor engineering work to complete Unit 2 commissioning will be completed after the balance of plant work.

1.3.2 Procurement (2017-2020)

The majority of the procurement for the project is complete. When possible, FBC procured components as a single tender for all units, to standardize equipment and realize savings by purchasing bulk material. The remaining procurement activities on the Project include finalizing the machining and fabrication contract services for Unit 2 and balance of plant work.

1.3.3 Construction (2017-2020)

Units 3, 1, and 4 are complete and have been put back into commercial operation. These units are performing well.

Refurbishment of Unit 2 is progressing well compared to plan. FBC dismantled Unit 2 in Q1 2020 with all of the mechanical components shipped throughout British Columbia and Alberta to be refurbished. This procurement strategy, similar to Units 1, 3, and 4, was used to ensure quality, schedule, and cost of the components. Quality assurance measures were completed by engineering at the various machine shops to ensure each product was being refurbished against the requirements outlined within the technical specifications. Most of the Unit 2 components are completed and returned to site.

The following is a brief update on Unit 2 work:

- Modifications to generator are 100 percent complete;
- Unit 2 trash racks and support beams are 90 percent complete;
- The installation of the new Unit 2 excitation system is 54 percent complete;
- The installation of the new Unit 2 protection and control systems are 20 percent complete;
- The installation of the new bearing lubrication system is 20 percent complete;
- The installation of the new brake system is 38 percent complete;
- The installation of the new governor system is 72 percent complete;
- The installation of the new cooling water system is 21 percent complete; and
- Removal of the old water wheel excitation system is 30 percent complete.

Reassembly and alignment of Unit 2 will begin in Q3 2020. The project remains on schedule and FBC anticipates returning Unit 2 to service in Q4 2020.

The COVID-19 pandemic has introduced challenges to Unit 2 work which were not present for the other units. Restrictions placed on the site to protect the workforce has caused delays. Suppliers have also changed their procedures as a result of the COVID-19 pandemic, which has created interferences primarily with the delivery of components. However, to date the Project has been able to progress through the COVID-19 pandemic with only minor impacts to schedule and cost.

1.3.4 Construction Pictures

The following pictures show some comparisons of typical components before and after refurbishment.

Figure C4-1: Unit 2 Replacement Operating Rings

Figure C4-2: Unit 2 Operating Ring

Figure C4-3: New Trash Racks

Figure C4-4: Old Trash Racks

Figure C4-5: New Governor Interface

Figure C4-6: Old Governor Interface

Figure C4-7: Rotor Spider

Figure C4-8: Rotor Refurbishment Complete

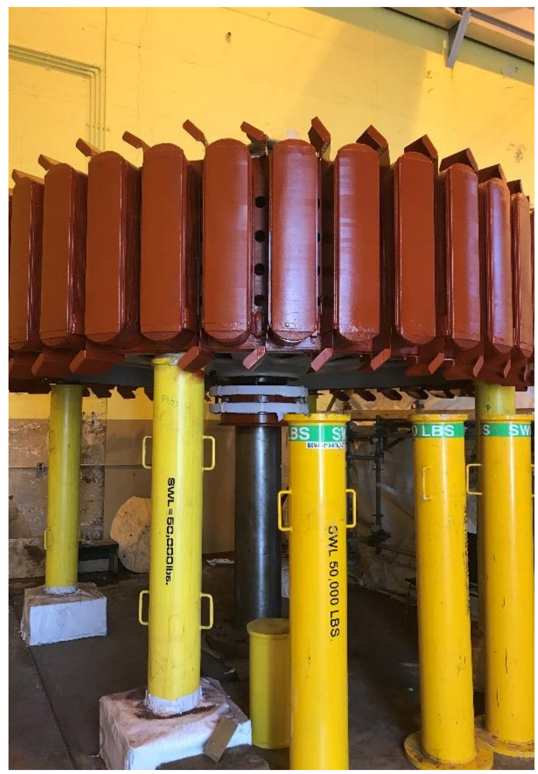

Figure C4-9: New Transformer (Unit 1)

Figure C4-10: Old Transformer (Unit 1)

1.3.5 Environmental

FBC continues to follow the Environmental Management Plan (EMP) developed in 2017 and to date there have been no reportable environmental incidents.

1.4 *PROJECT CHALLENGES AND ISSUES*

1.4.1 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 the oil is flowing back to the reservoir, it is able to flow over and into the voids of the steel that were formed as part of the original casting process. As the rotor spins, centrifugical forces push the oil away from the center of the spider towards the outer edge and oil is exposed to atmosphere at various locations along the spider. As the oil seeps out of the voids, the wind generated from the operating unit blows the oil onto the rotor and various other components creating the need for maintainance to clean off the oil. 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.

1.4.2 Unit 4

Due to the refurbished mechanical components and tighter tolerances obtained through the refurbishment, Unit 4 produced more power than was anticipated. The generating unit was not designed to accommodate the higher output, and therefore the unit output was reduced and limited to the design rating (FBC's energy entitlements are limited to the ratings set out in the Canal Plant Agreement). Operating the unit at a reduced output should also increase the life expectancy of the Unit.

1.4.3 Unit 1

While commissioning Unit 1, the new trash racks developed a vibration when the unit was operating under full load conditions. The vibration was resolved by changing the fastening configuration on the racks. Although Units 3 and 4 did not have the vibration, the fastening methods were changed to match Unit 1 as a precautionary measure and for consistency.

1.4.4 Unit 2 Stator

The Unit 2 stator and rotor were rewound in 1995 following failure. The installation of the new brake system interfered with the main lead cabling and equipment that was installed as part of the rewind in the mid 1990s. This interference created additional scope on Unit 2 as it required the generator cables and equipment to be relocated.

1.4.5 Common Challenges and Issues (All Units)

- **The Governor Systems** – The as-found condition of the existing equipment planned to be reused was worse than anticipated resulting in a complete replacement and redesign of the high pressure governor system. FBC worked collaboratively with the governor manufacturer to determine an appropriate solution.

- **Trash Racks** – The scope of the trashrack work was based on the original design. Upon inspection of each unit, the as-found condition of each unit's supporting beam (deck beam), although not originally anticipated to require replacement, was found to be in poor condition and was replaced.

- **Components Machining and Refurbishment Scope** – The condition of the concealed components varied throughout Units 1-4. FBC developed custom scopes of work for each component based on the condition of each component. The additional effort to customize each scope was offset by the savings related to not replacing the components.

2. PROJECT SCHEDULE

Major milestones complete and remaining for the project have been identified in the milestone summary below.

Table C4-2: Milestone Summary

Milestone	Planned Completion Date	Actual Completion Date	Status
Engineering			
Mechanical Components – Machining and Fabrication Specifications	Q4, 2017	Q4, 2017	Complete
All Units Detailed Engineering	Q1, 2018	Q1, 2018	Complete
Balance of Plant Engineering	Q3, 2020		
Procurement			
All Major Unit Mechanical	Q2, 2020	Q2,2020	Complete.
All Major Unit Electrical	Q2, 2020	Q2, 2020	Complete
Construction			
Refurbishment of Unit 3	Q4, 2017	Q4, 2017	Complete
Refurbishment of Unit 4	Q4, 2018	Q4, 2018	Complete
Refurbishment of Unit 1	Q4, 2019	Q4, 2019	Complete
Refurbishment of Unit 2	Q4, 2020		Ongoing
Installation of U2 High Pressure Governor System	Q3, 2020		Ongoing
Installation of U2 Excitation System	Q3, 2020		Ongoing, cubicles installed.
Installation of U2 Unit Protection and Control	Q3, 2020		Ongoing, cabinets installed.
Generator U2 Modifications	Q2, 2020	Q2, 2020	Complete
U2 Re-Assembly	Q3,2020		
U2 Returned to Commercial Service	Q4, 2020		
U3 Oil Leak Deficiency Repair	Q1, 2021		
Balance of Plant	Q2, 2021		

1 # 3. PROJECT COSTS

2 The following table outlines the project expenditures to June 30, 2020 and the forecast project expenditures to completion.

3 **Table C4-3: Cost Summary**

Description	Application/ Control Budget	Spent to Date	Estimate to Complete	Forecast Total to Complete	Variance
	(1)	(2)	(3)	(4)=(2)+(3)	(5)=((4)-(1))/(1)
	($000s)				(%)
Unit 4	6,634	8,043	11	8,055	21%
Unit 3	4,079	6,235	182	6,417	57%
Unit 2	5,641	3,918	2,529	6,447	14%
Unit 1	8,050	8,268	(15)	8,253	3%
Balance of Plant	860	429	1,589	2,018	135%
Subtotal - Construction	25,264	26,893	4,296	31,190	23%
Cost of Removal	1,880	1,456	233	1,689	-10%
Project Contingency	3,771	-	229	229	-94%
Subtotal- Construction & Removal	30,916	28,350	4,758	33,108	7%
AFUDC	867	974	98	1,072	24%
Total Project Cost	31,783	29,324	4,856	34,180	8%

4

3.1.1 Project Cost Summary

Unit 4 – The forecast total for Unit 4 is currently $8.055 million, which represents a variance of $1.421 million. This variance is mainly due to the higher than estimated costs to rewind the stator and rotor, the as-found condition of the concealed components and the challenges associated with installing a modern system in an antiquated operating plant.

Unit 3 - The forecast total for Unit 3 is currently $6.417 million, which represents a variance of $2.388 million. This variance is mainly due to the additional upfront engineering costs as this was the first unit to be refurbished, and the higher than estimated costs to rewind the stator and rotor. Additionally, after the commissioning of Unit 3, a leak developed due to the rotor casting flaws of the generator.

Unit 2 - The forecast total for Unit 2 is currently $6.447 million, which represents a variance of $0.806 million. This variance is mainly due to the additional work required to modify the existing stator equipment to facilitate the new braking system, the as-found condition of the concealed components and the challenges associated with installing a modern system in an antiquated operating plant.

Unit 1 - The forecast total for Unit 1 is currently $8.253 million, which represents a variance of $0.203 million. The total variance on Unit 1 was offset by a positive variance of $0.813 million savings on the GSU transformer replacement.

The common variances associated with Units 1-4 are the higher than estimated costs to rewind the stator and rotor, the as-found condition of the concealed components and the challenges associated with installing a modern system in an antiquated operating plant. The estimate to rewind the generators was developed using a combination of actual costs from other rewound units and vendor input. When the generator rewind work was tendered to three contractors, the costs received were higher than budgeted. The costs to rewind all generators was approximately $1.442 million higher than estimated.

Balance of Plant - The forecast total for the balance of plant work is currently $2.018 million, which represents a variance of $1.158 million. The scope of this work has evolved as the project progressed. The installation of new equipment and removal of old equipment within an operating facility presents unanticipated challenges that could not be defined during the planning stage. This variance is mainly due to the extra effort required to remove equipment and cabling which was not initially expected to contain asbestos, and the additional scope created by the relocation of plant equipment.

Cost of Removal – The forecast total for cost of removal is $1.683 million, which represents a positive variance of $0.191 million. This variance is mainly due to lower than anticipated removals for stator and rotor and the lower engineering and construction management costs during these removals.

AFUDC – The forecast total for AFUDC is $1.072 million, which represents a variance of $0.205 million. The variance is mainly due to the advancing of engineering and equipment procurement early on in the project. This variance was offset by efficiencies in engineering and economies of scale in procurement within the individual system costs.

Contingency – Project contingency has been utilized to offset the variences that were encountered amoung the different Units. The remaining project contingency of $229 thousand is for risks that may still be realized.

The project estimate was approved as Class 4 in the Annual Review for 2017 Rates because it was difficult to achieve further definition without dismantling the units. The solutions developed to address the uncertainties by FBC engineering and construction crews resulted in learnings which were applied as the work progressed. FBC has realized efficiencies as the Project progressed, but could not overcome the budget pressures caused by higher than planned rewind costs, the condition of the turbine components, and the scope changes required during the project.

3.2 *PROJECT SCOPE CHANGE SUMMARY*

Throughout detailed engineering, FBC made adjustments in order to address unforeseen challenges and issues not considered during the planning stage. These adjustments and other construction changes orders total approximately $1.763 million.

The following table is a summary of changes on the project over $50 thousand.

Table C4-4: Change Summary

	Title	Cost ($thousands)	Status	Comment
1	Revised Protection & Control Costs	$102	Complete	Detailed design required changes to equipment
2	Rotor and Stator Quality Control	$70	Complete	Third party oversight while Voith performed rewinds
3	Specialized Tool Purchase	$223	Complete	The dismantle of the generators required pedestals and specialty tools
4	Turbine Condition Assessments	$125	Complete	To reduce procurement risk the turbines were inspected prior to refurbishment
5	Additional Tailrace Gate	$50	Complete	The additional tailrace gate was required to maintain outage water levels through freshet.
6	Washcar Trailer	$112	Complete	The wash car initially planned for the project was condemned due to structural and infestation issues.
7	Trash Rack Upper Beam Repair	$198	Complete	Main deck supporting beam was deteriorated an all four units
8	Governor Interface, Actuators and Gate Locks	$551	Complete	The governor actuator and its interfacing required redesign and replacement for all governor systems

	Title	Cost ($thousands)	Status	Comment
9	Runner Plate Replacement Unit 4 Thrust Assembly	$93	Complete	The as found condition of the runner plate did not meet specification and required replacement .
10	Unit 2 Generator Modifications	$239	Complete	Equipment relocation and reconfiguration to facilitate new brakes and controls.

4. PROJECT RISKS

The project risk has significantly diminished from the last submitted report as the components are completed. The remaining risks to the project are the balance of plant scope of work, the repair of the oil leak on Units 2 and 3 rotor spiders, and the Covid-19 pandemic.

4.1 BALANCE OF PLANT

FBC engineering is currently finalizing the scope of work for the balance of plant work. As the plant remains operational during the balance of plant activities, there is a risk that outages will occur resulting in impacts to cost and schedule.

4.2 OIL LEAK REPAIR UNITS 2 AND 3

As outlined in section 1.4.1, Unit 3 which has already been refurbished, has an oil leak which needs to be addressed. While refurbishing Unit 2, an identical unit, a solution will be implemented and monitored throughout commissioning and early online operation. If the solution is successful, Unit 3 will be taken offline in 2021 to be repaired. If not successful, Unit 2 and Unit 3 will have to be re-assessed and likely have a new rotor spider built. The project is holding sufficient contingency to repair Unit 3 based on the solution being implemented for Unit 2.

4.3 COVID-19 PANDEMIC

The COVID-19 pandemic has introduced challenges to construction as explained in Section 1.3.3; however, many operational responses have been developed to continue construction activities. The project team will continue the Covid operational responses, following the provincial guidelines. It is unknown what effects the pandemic may have on the schedule or budget of the project.

5. CONCLUSION

The UBO Refurbishment Project continues to track well against scope and schedule. While the forecast total project cost has increased to $34.108, the increase was required to maintain scope to extend the units' lives for an additional twenty years or more. The project has been successful in reducing the safety and environmental risks associated with failures of the aged equipment. FBC continues to focus on the safe and efficient execution of construction work, and on reducing the risk profile of the project.

Appendix D

DRAFT ORDER

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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;

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

D. 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);

E. In the Application, FBC's 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;

F. 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

G. 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. FortisBC Inc. (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 into the previously approved COVID-19 Customer Recovery Fund Deferral Account as discussed in Section 12.2.1 of the Application.

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

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