FBC 2023 ANNUAL REVIEW OF RATES
EXHIBIT B-2

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August 5, 2022

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

Attention: Ms. Sara Hardgrave, Acting Commission Secretary

Dear Ms. Hardgrave:

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 2023 Rates

In accordance with the MRP Plan and BCUC Order G-193-22 setting out the Regulatory Timetable for FBC's Annual Review, FBC hereby attaches its Annual Review for 2023 Rates Application materials.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Interveners to the FBC Annual Review for 2022 Rates

FORTISBC INC.

Annual Review for 2023 Rates

August 5, 2022

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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.

The MRP provides stable levels of O&M funding and includes service quality indicators (SQIs) to monitor the maintenance of 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.

As explained in Section 10 of the Application, FBC proposes to distribute $0.911 million pre-tax ($0.665 million after-tax) in earnings sharing to customers in 2023.

The proposed rates for 2023 flowing from the approved formulas and forecasts set out in the Application, including returning the actual 2021 earnings sharing to customers, result in a 3.99 percent rate increase from 2022 rates. The increase is primarily due to an increase in power purchase expense (PPE) as well as rate base growth.

In the subsections 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 discussion of FBC's 2021 formula O&M savings and the productivity initiatives that FBC is developing. Finally, FBC provides a summary of its proposed revenue requirements and rate changes for 2023 and a summary of the SQI results. 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 and 89 of the *Utilities Commission Act* (UCA):

1. Approval to recover the 2023 revenue requirement and resultant rate change on an interim basis, effective January 1, 2023, as filed in the Application and subject to any adjustments identified by FBC during the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application. Rates will remain interim pending the outcomes of the BCUC's current generic cost of capital (GCOC) proceeding and FBC's 2023-2027 Demand Side Management (DSM) Plan proceeding.
2. The level of forecast growth, sustainment and other capital to be incorporated in rates for the years 2023 and 2024, as set out in Section 7.2.1.

3. The following deferral account approvals, as described in Section 7.6:

   - Creation of a rate base deferral account for the 2023 Joint Pole Use Audit, with the balance in the deferral account to be amortized over five years commencing January 1, 2023; and
   - Approval of a three-year amortization period for the existing COVID-19 Customer Recovery Fund Deferral Account, commencing January 1, 2023.

4. Approval to cease reporting on the COVID-19 Customer Recovery Fund Deferral Account, as described in Section 7.6.2.1.

FBC also seeks approval pursuant to section 99 of the UCA to vary the following Orders:

1. Directive 6 of Order G-42-21 in order to facilitate the return of the net incremental COVID-19 related cost reductions to customers through inclusion of the cost reductions in the Flow-through deferral account, as described in Section 12.2.1.

2. Directive 2 of Order G-83-14 to ensure that FBC continues to have approval from the BCUC to use US GAAP for regulatory accounting purposes, as described in Section 12.3.1.

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
1(f)	Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year.	Section 10

Item	Description	Response or Reference
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 *FORMULA O&M SAVINGS AND PRODUCTIVITY INITIATIVES*

1.4.1 Overview of 2021 Formula O&M Savings

For 2021, FBC achieved formula O&M savings in addition to meeting the embedded productivity improvement factor in the O&M formula. Total formula O&M savings before earnings sharing were approximately $3.4 million.

Approximately $0.9 million in formula O&M savings were realized due to the net incremental impact of the COVID-19 pandemic, which will be returned to customers via the Flow-through deferral account. Please refer to Section 12.2.1 for further details. Lower spending in the Finance and Information Systems departments of approximately $0.6 million from vacancies, reduced consulting, and lower computer consulting services and expenses contributed to the savings. Additionally, approximately $2.2 million of O&M savings were due to the timing of expenditures, such as vacancies and consulting expenditures, and lower general and miscellaneous expenditures. These savings were partially offset by approximately $0.3 million of higher spending compared to the formula amount for incremental expenditures related to System Operations, Integrity and Security. Please refer to Section 6.2.1 for further details. While some of the savings are one-time in nature (e.g., delay in filling vacancies), some of the savings are expected to continue into the future, recognizing that cost pressures in the future may offset the savings.

FBC will continue to pursue productivity improvements to achieve savings beyond the productivity improvement factor as it seeks to manage its business needs and cost pressures resulting from its evolving and challenging operating environment.

1.4.2 Productivity Initiatives

As mentioned in FBC's Annual Review for 2022 Rates (2022 Annual Review), in 2021, FortisBC Energy Inc. (FEI) and FBC (together FortisBC) initiated a working group consisting of senior managers and directors from different parts of the organization that is responsible for reviewing and identifying areas for productivity initiatives. An area of focus for potential productivity opportunities is initiatives that offer financial and customer service benefits and leverage technology and innovation to achieve these benefits.

Following is a summary of productivity initiatives from different parts of the organization FortisBC reviewed this past year and/or is investigating.

1. **Field Operations Improvements:** This initiative was investigated through collecting feedback and analyzing efficiency gains within FBC's Outage Management System (OMS) and Mobile Workforce Management System (MWFM). Changes have been made to the software and processes that allow for improved information sharing and functionality when dispatching and performing jobs. This allows for less manual intervention and a more streamlined workflow. On a separate, but related initiative, enhancements are also underway to provide FBC's storm response restoration teams with an improved interface to access triage information. This will allow for a better prioritization of repairs, and a more efficient allocation of the available resources, resulting in faster restorations.

2. **Use of Unmanned Aerial Vehicles (UAVs - Drones):** FBC is investigating using UAVs to perform transmission line condition assessments. In 2021, FBC requested its contractor performing condition assessments to incorporate the use of drones for collecting data for certain suspected deficiencies. This use of drones was expected to reduce the need for follow-up bucket truck inspections to confirm deficiencies that cannot be fully assessed from the ground, and allow FBC to prepare work-packages for deficiencies identified during condition assessments in a more timely manner. Additionally, some of the drone-collected data has been used to help assess potential system upgrades and reconfigurations without requiring additional field verification of existing assets. For 2022, FBC is developing a request for pricing to assess the potential efficiencies associated with a condition assessment program relying exclusively on drone-collected data and the use of artificial intelligence and machine learning to help identify and categorize deficiencies related to FBC's transmission assets. Should a proponent be identified through this process, it is expected that this work will help validate the use of these techniques for performing condition assessment work and also help quantify the potential cost-savings associated with a drone-based approach for condition assessments.

3. **Technology Investments to Support Enhanced Communications:** FBC introduced enhancements during the COVID-19 pandemic to enable employees to productively work remotely. The implementation of the Microsoft Teams platform was expedited in 2021, allowing for use of video meetings for employee communications. In 2021, FBC also introduced the Microsoft Teams mobile app that provided seamless integration and access to Teams meetings, Teams sites, calendar, chat functionality and a seamless transition

from phone to computer or vice versa during meetings. It was and continues to be a platform to reduce travel requirements for staff, providing options to meet in person less often, which enables continued savings on fuel costs, hotels, meals, and wear and tear on vehicles. Hybrid meetings support large audience attendance using Teams meetings, with the added benefit of not requiring time away from the home office and the resulting lost productivity. Additional functionality will continue to be added to the Teams platform (i.e., whiteboard, enhancements to breakout rooms, Presenter modes and group control of presentation, etc.) as Microsoft continues to develop and release upgrades. The mobile application will also see improvements.

The Company's rapid implementation of communications software during the pandemic has contributed to creating a productive work environment for employees to complete their work with the benefit of not requiring time away from the home office and lost productivity. In total, FBC invested approximately $0.2 million over the two years 2020 and 2021. This investment has contributed to achieving employee-related expense savings (i.e., travel) during the pandemic and will also help to permanently sustain some of the related savings post pandemic.

4. **Data Analytics:** This is an initiative to centralize the Company's data sources coupled with a suite of analytic tools to analyze and use the data to inform decision-making. Data analytics is the process of extracting and analyzing data sets to identify or uncover patterns, correlations, trends, customer preferences and other information for the purpose of allowing an organization to make more informed business decisions. Better decisions will lead to improved business operations and customer service and increased productivity. The ability to easily access and analyze data can be inhibited by internal processes, decentralization of information and a lack of understanding of the data. With Data Analytics, departments will be provided a common cleansed data source and the tools to create advanced analytics quickly and easily. Resources will be provided to business areas to help identify reporting and analytic needs that will lead to efficiencies. Through a centralized approach, this will provide the skills along with the data and the tools to drive business capability to support analytic needs and also provide better visibility to costs or benefits of data analytics initiatives.

   The requirements and business case for the necessary information systems infrastructure were completed in 2021. FBC plans to implement systems that will allow centralized data access in 2022 and add new data sources in priority sequence over time. Data usage cases for this initiative are being prioritized first for those that enable cost savings.

5. **Streamlining and Automating Reporting Process:** This initiative is one of the earlier usage cases that FBC is considering for the Data Analytics initiative. The focus is on streamlining the reporting processes for financial and management reporting information (i.e., internal cost reporting, key performance indicators, etc.). Currently, the reporting processes work well with clearly defined requirements and processes but rely on manual effort. Source system (i.e., SAP) reports are not formatted for users and SAP reports are data extracts and are not set-up for data integration and manipulation. Instead, Excel is

used to integrate, transform and format reports. FBC is presently assessing the feasibility of implementing an automated solution that will reduce the effort required to generate reports, with expected productivity gains. This automation is expected to be achieved through the use of a data model to aggregate data sources and a reporting tool to allow for self-service.

FBC will be in a better position at next year's Annual Review to provide details of this initiative should it be undertaken, and to provide details of other specific data analytics initiatives undertaken and the benefits achieved.

6. **Robotics Process Automation (RPA):** This is an efficiency initiative using automation software to alleviate repetitive and simple manual tasks. With the rising volume of manual tasks performed for operational work, such as financial transactions or project closeout activities, departments within FBC are challenged. Both the Finance and Engineering departments have experienced an increase in manual activities over several years. Between steps performed multiple times daily, to weekly, monthly or annually, the common theme is a manual and repetitive task with limited decision points.

   In the first phase of RPA implementation, the Company is evaluating opportunities within the Finance and Engineering areas to apply RPA. There are a number of processes being evaluated for RPA with the focus on processes requiring supporting manual activities. The processes vary from creating journal entries, generating third party billing, populating reports, filing documents, and collecting information for budgeting purposes.

   FBC will be in a better position at next year's Annual Review to provide details of this initiative, including the results and benefits achieved.

7. **Paperless Billing Customer Campaigns:** This initiative focuses on working with customers to encourage the switch to paperless billing. In addition to the convenience for customers of receiving their bill electronically and the environmental considerations of less paper and physical transport of the bills, an increased percentage of customers making the switch to paperless billing results in ongoing printing and postage cost savings. At the start of 2021, FBC had approximately 69,000 customers choosing paperless billing as their preferred bill delivery method. Following the success of several internal programs that encouraged employees to highlight this option with customers and including an external social media campaign that resulted in donations to food banks in need, FBC achieved an increase of approximately 8,000 customers choosing this option in 2021. This increase equates to approximately $0.07 million in printing and postage cost savings in 2021 as compared to 2020.[1]

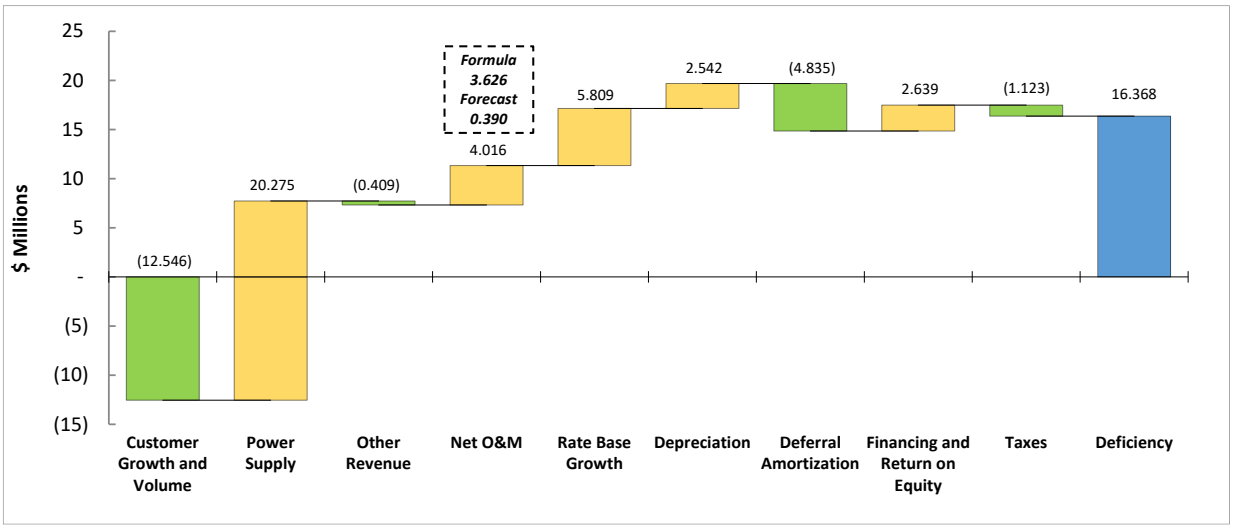
[1] Calculation is a high-level estimate based on the incremental monthly paperless billing growth at an average savings of approximately $1.24 per bill.

1.5 REVENUE REQUIREMENT AND RATE CHANGES FOR 2023

The revenue requirement components set out in the Application result in an effective rate increase of 3.99 percent for 2023 compared to 2022. The effective rate increase results from a revenue deficiency of $16.368 million.

The following chart summarizes the items that contribute to the 2023 revenue deficiency. The chart shows each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The 2023 deficiency of $16.368 million is then the sum of all of the previous bars and is shown at the end of the chart in blue.

Figure 1-1: 2023 Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.5.1 Customer Growth and Volume Forecast (Section 3)

For 2023, FBC forecasts a net load increase of 170 GWh compared to 2022 Approved, resulting in a decrease in FBC's 2023 revenue deficiency of $12.546 million. The increase in net load is primarily due to increased loads in the industrial classes, followed by smaller increases in the residential, commercial, wholesale, and irrigation classes. FBC's 2023 Forecast revenue at 2022 approved rates is $409.840 million.

1.5.2 Power Supply (Section 4)

FBC forecasts an increase in power supply of $20.275 million in 2023 compared to 2022 Approved. This increase is primarily due to the increase in load, and an increase in PPE under the BC Hydro Power Purchase Agreement (PPA) by approximately $27.240 million. This is offset by reduced market and contracted purchases by approximately $8.776 million.

1.5.3 Other Revenue (Section 5)

Other Revenue is forecast to increase by $0.409 million in 2023 compared to 2022 Approved. The main drivers of this increase are higher Late Payment Charges and the expected annual increases in rates for Apparatus and Facilities Rental, Contract Revenue and Transmission Access Revenue.

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

FBC establishes the majority of its O&M expense by formula during the MRP term. The O&M formula incorporates a net inflation factor of 4.017 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[2]. The 2023 Formula O&M net of capitalized overhead has increased by $3.626 million[3] when compared to the 2022 Formula O&M. Net O&M forecast outside of the formula is increasing by $0.390 million[4] over 2022 Approved, primarily due to an increase in pension and OPEB expense. Overall, the 2023 increase in total O&M expense net of capitalized overhead is $4.016 million (6.9 percent).

1.5.5 Rate Base Growth and Depreciation (Section 7)

The 2023 rate base is forecast to increase by approximately $92.524 million when compared to the 2022 Approved rate base, resulting in an increase to the 2023 revenue deficiency of $5.809 million. The increase in rate base is primarily the result of the mid-year impact of FBC's 2023 regular capital additions to plant, as well as the full-year impact of FBC's major capital project additions, including the Kelowna Bulk Transformer Additions (KBTA) project, the Corra Linn Dam Spillway Gates Replacement project, and the Playmor Substation Upgrade project, as described in Section 7.1.

The increase in rate base also results in an increase in 2023 depreciation expense by approximately $2.752 million compared to 2022 Approved, which is offset by approximately $0.210 million of CIAC from net additions, resulting in a net increase of $2.542 million in depreciation expense.

1.5.6 Amortization of Deferral Accounts (Section 7 and Section 12)

Amortization of deferral accounts in 2023 decreased by $4.835 million, primarily due to the credit amortization related to the 2020-2024 Flow-through non-rate base deferral account, partially offset by increases in the amortization expense of the DSM deferral account, the BCUC Initiated Inquiry Costs deferral account, and the COVID-19 Customer Recovery Fund deferral account. The credit amortization in the Flow-through deferral account in 2023 is $9.625 million, which is $5.698 million higher than the credit amortization in this account compared to 2022 Approved. As discussed in Section 12.4.2.1, the credit amortization in the Flow-through deferral account is

[2] Modified by 75 percent.
[3] Increase in gross formula O&M of $3.810 million (5.8 percent) compared to 2022 Approved.
[4] Increase in gross forecast O&M of $0.491 million (26.8 percent) compared to 2022 Approved.

primarily due to favourable revenue variances resulting from increased loads from industrial, commercial, wholesale, and residential classes.

1.5.7 Financing and Return on Equity (Section 8)

Financing and Return on Equity (ROE) increased the 2023 deficiency by $2.639 million through changes in financing rates, the ratio of long-term debt versus short-term debt, and changes in rate base.

For 2023, FBC is forecasting a short-term debt rate of 4.24 percent, which is an increase from the 1.51 percent short-term debt rate embedded in the 2022 Approved revenue requirement. Overall, FBC's deficiency is increased by $3.688 million from financing rate changes which is offset by $1.049 million from the ratio change between long-term and short-term debt.

In calculating its 2023 revenue deficiency, FBC has utilized its currently approved capital structure and ROE of 40 percent and 9.15 percent, respectively. As explained in Section 8.1, FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI. FEI is currently participating in the BCUC-initiated GCOC proceeding and has filed evidence on its recommended capital structure and ROE as part of Stage 1 of the proceeding. In Order G-156-21 and accompanying Reasons for Decision, the BCUC found that the effective date to implement a new cost of capital will depend on the timing and progress of the GCOC proceeding. FBC is seeking approval of interim 2023 rates pending the outcome of Stage 1 of the GCOC proceeding as well as a decision on FBC's 2023-2027 DSM Expenditure Plan. When a decision is reached on these proceedings, FBC will update its rate calculations and apply for permanent 2023 rates.

1.5.8 Taxes (Section 9)

FBC's 2023 property taxes are forecast to increase by 2.1 percent or $0.371 million from 2022 Approved. The increase is primarily due to changes in tax rates and increases in assessed values, as well as an increase in grants in-lieu of taxes which are calculated based on a fixed percentage of FBC's revenue.

There has been no change in the income tax rate of 27 percent from 2022. Taxes are forecast to decrease in 2023 by $1.494 million due to higher deductible temporary differences associated with amortization of deferred charges and property, plant and equipment, and lower taxable temporary differences associated with pension and OPEB.

1.6 *SERVICE QUALITY INDICATORS (SECTION 13)*

FBC reports on its 2021 and June 2022 year-to-date SQI results in Section 13. In 2021, for the eight SQIs with benchmarks, six met or were better than the benchmark, with two better than the threshold. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years. In 2022 to date, performance for the metrics with benchmarks is trending towards meeting the benchmark or the threshold.

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 2023 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.[5]

The MRP Decision approved the use of a forecast of growth[6] to determine formula O&M and 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 2023, FBC has used July 2020 through June 2022 inflation data for the 2023 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 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 for CPI-BC and Table 14-10-0223-01 to determine AWE-BC. The supporting Statistics Canada tables are provided in Appendix A1. The latest available month of April 2022 for AWE-BC has been used as a placeholder, as results to June 2022 have not been released by Statistics Canada. Once results for these periods 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 2021 labour weighting of 60 percent, the calculation of the 2023 I-Factor is (4.940 percent x 40 percent) + (4.235 percent x 60 percent) = 4.517 percent.

[5] FBC's most recent year of completed actuals is 2021 so that ratio has been used for the 2023 I-Factor calculation.
[6] 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 Year Non Labour %	Last Completed Year Labour %	I-Factor %	MRP Year
1	Jul-2020	132.6	1,093.72								
2	Aug-2020	132.4	1,089.35								
3	Sep-2020	132.5	1,093.75								
4	Oct-2020	132.9	1,095.32								
5	Nov-2020	133.3	1,102.95								
6	Dec-2020	132.8	1,110.36								
7	Jan-2021	133.6	1,113.22								
8	Feb-2021	134.1	1,114.21								
9	Mar-2021	134.9	1,107.66								
10	Apr-2021	135.2	1,112.04								
11	May-2021	135.1	1,118.59								
12	Jun-2021	135.8	1,115.40	133.8	1,105.55						
13	Jul-2021	136.7	1,140.52								
14	Aug-2021	137.0	1,142.40								
15	Sep-2021	137.2	1,139.64								
16	Oct-2021	137.9	1,136.85								
17	Nov-2021	138.1	1,132.25								
18	Dec-2021	138.0	1,134.84								
19	Jan-2022	139.4	1,157.19								
20	Feb-2022	140.4	1,153.88								
21	Mar-2022	143.0	1,161.22								
22	Apr-2022	144.2	1,176.54								
23	May-2022	146.1	1,176.54								
24	Jun-2022	146.5	1,176.54	140.4	1,152.37	4.940%	4.235%	40%	60%	4.517%	2023

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 2023 Formula O&M is summarized in the table below. The growth factor is applied to the unit cost O&M (UCOM), which was calculated based on 2019 average customers of 139,916 (shown on line 21 under year 2020 or line 28 in Table 2-2 below). Starting with this 2019 average customer count, the calculation adds 75 percent of the cumulative average of actual/forecast customer growth during the MRP term from 2020 to 2023 (shown on line 26 in Table 2-2 below) to determine the average customers for rate setting (shown on line 29 of Table 2-2 below).

Table 2-2: Calculation of 2023 Average Customer (AC) Growth Factor

Line No.	Date	Actual 2020	Actual 2021	Projected 2022	Forecast 2023	Total for 2023 Rate Setting	Reference
1	Prior Year Ending Customer Count	141,027	143,714	145,830	148,861		Appendix A2 - Section 3.1 Customers
2							
3	Additions:						
4	January	292	257	226	256		
5	February	174	89	194	266		
6	March	8	123	122	264		
7	April	110	113	178	264		
8	May	173	319	537	255		
9	June	172	116	250	261		
10	July	522	308	255	265		
11	August	129	187	252	262		
12	September	83	136	254	264		
13	October	545	132	255	265		
14	November	234	217	252	262		
15	December	245	119	256	266		
16	Total Additions	2,687	2,116	3,031	3,150		Appendix A2 - Section 3.2 Customer Additions
17	12-month Weighted Average Additions	1,294	1,163	1,587	1,701		
18							
19	Current Year Ending Customer Count	143,714	145,830	148,861	152,011		Line 1 + Line 16; Appendix A2 - Section 3.1 Customers
20							
21	Actual/Projected Prior Year Average Customers	139,916	142,321	144,877	147,417		2020: G-42-21; Sch 3, Line 13; 2021 and 2022: Prior Year Ending, Line 22
22	Average Customers for the Year	142,321	144,877	147,417	150,562		Line 1 + Line 17
23	Change in Average Customers	2,405	2,556	2,540	3,145	**10,646**	Sum of Annual Change in Average Customers on Line 23
24							
25	Growth Factor Multiplier					**75%**	G-166-20
26	Change in Average Customers for Rate Setting Purposes					**7,985**	Line 25 x Line 23
27							
28	Average Customers Used to Determine the Starting UCOM					**139,916**	Line 21, Yr 2020
29	**Average Customer Forecast for Rate Setting**					**147,901**	Line 28 + Line 26
30							
31	2021 Approved Average Customers for Rate Setting		142,473				2021: G-42-21; Sch 3, Line 22
32	2021 Actual Average Customers for Rate Setting		143,637				Line 21(2020) + Sum of Line 23 (2020 & 2021) x 0.75
33	**2021 True Up**		**1,164**				Line 32 - Line 31

2.4 *INFLATION AND GROWTH CALCULATION SUMMARY*

A summary of the factors used to determine formula O&M for 2023 is provided in Table 2-3, including the I-Factor calculated in Section 2.2, the approved X-Factor of 0.5 percent, and the forecast of average customers incorporating the growth factor multiplier determined in Section 2.3.

Table 2-3: Summary of Formula Drivers

Line No.		2023	Reference
1	CPI	4.940%	Table 2-1, Line 24
2	AWE	4.235%	Table 2-1, Line 24
3			
4	Non Labour	40%	Table 2-1, Line 24
5	Labour	60%	Table 2-1, Line 24
6			
7	CPI/AWE Inflation	4.517%	(Line 1 x Line 4) + (Line 2 x Line 5)
8			
9	Productivity Factor	-0.500%	Order G-166-20
10			
11	Net Inflation Factor	4.017%	Line 7 + Line 9
12			
13	Average Customers for Formula O&M purposes	147,901	Table 2-2, Line 29

In summary, the Net Inflation Factor for 2023 is 4.017 percent and formula O&M for 2023 is determined using average customers of 147,901.

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, 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 an increase in consumption in the 2023 Forecast (2023F) compared to the 2022 Approved. The 2023F gross load is forecast to be approximately 3,775 GWh, which is a 184 GWh increase compared to the 2022 Approved gross load. The increase in 2023F is due to increased loads in the industrial, commercial, wholesale, residential and irrigation classes. Based on the 2022 Approved rates for each customer class, FBC's 2023 revenue forecast is $409.840 million.

FBC has provided further information supporting its load 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 UPC forecast is multiplied by the corresponding forecast of the number of annual average 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, the lighting forecast uses the prior year's actual load, and the irrigation forecast uses a five-year historical average. 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 2021 calendar year.
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available,[7] and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2022 (2022S) and the Seed Year forecast is based on the latest actual years, including 2021. As such, the 2022 Seed Year forecast in this Application will differ from the 2022 Forecast presented in the Annual Review for 2022 Rates, for which 2021 actual data was not available.
- 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 2023 (2023F).
- Also included in the figures in this section is the prior year's forecast (shown as the green Approved lines in the figures below), as presented in the Annual Review for 2022 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 2021.

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 incremental DSM savings for 2023 are summarized in Table 3-1 below, and are the forecast savings incremental to the savings embedded in the historical loads. Historical DSM savings can be found in Appendix A2.

[7] FBC's load forecast is developed using only complete years of historical data. FBC requires the complete year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason, partial year data is not used in forecasting.

Table 3-1: Forecast Incremental 2023 DSM Savings (GWh)

Line No.	Description	DSM 2023
1	Residential	(8.9)
2	Commercial	(22.6)
3	Wholesale	(7.7)
4	Industrial	(16.2)
5	Lighting	(0.3)
6	Irrigation	(0.2)
7	Net	(55.9)
8	Losses	(4.6)
9	Gross Load	(60.5)

3.4 *LOAD FORECAST*

FBC's total load consists of the weather normalized residential, commercial and wholesale load and the actual industrial, lighting and irrigation load. In aggregate, the absolute load forecast variance in 2021 was 0.2 percent. As shown in Figure 3-1 below, the total load, net of losses, is forecast to be 3,476 GWh in 2023F, which is 3 GWh more than 2022S and an increase of 170 GWh from 2022 Approved.

Figure 3-1: Total Net Load (GWh)

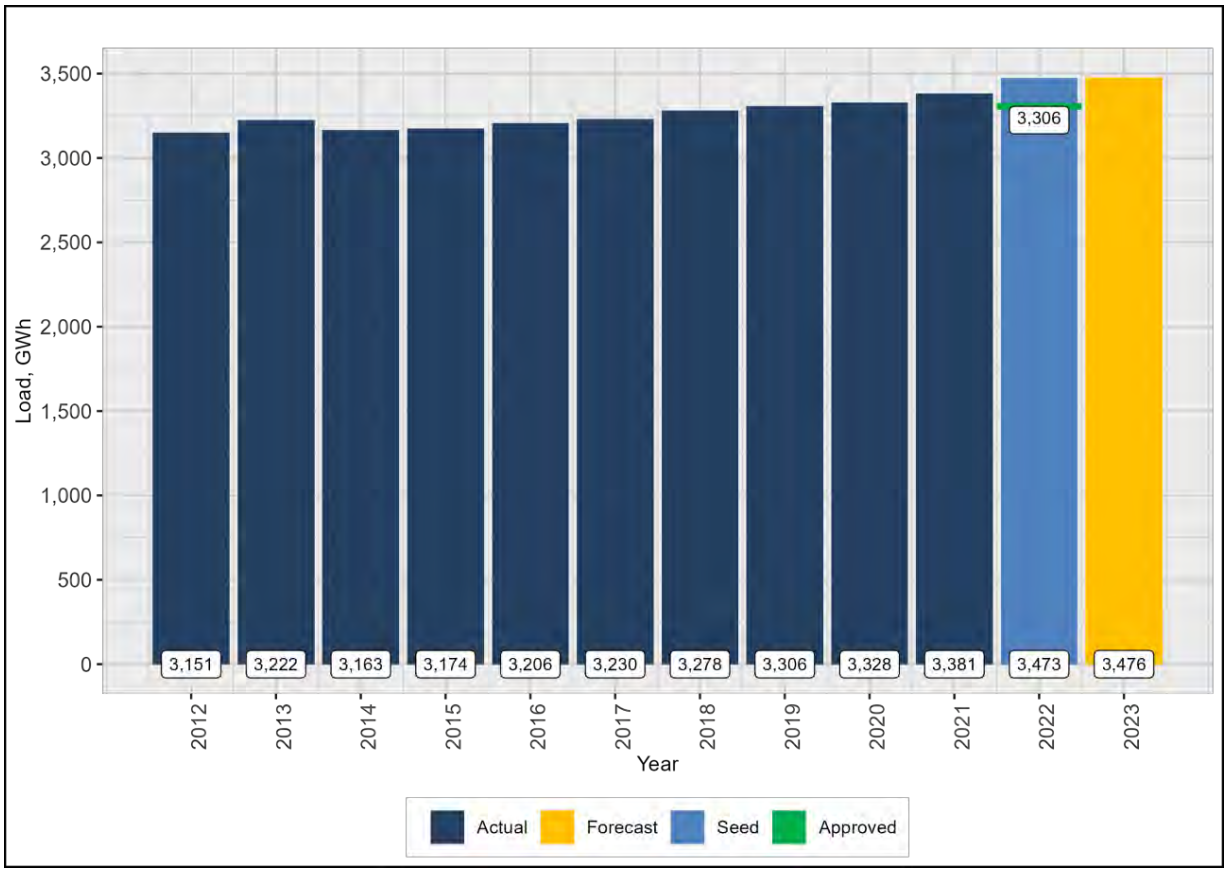


Table 3-2 below shows the normalized after-savings gross load by customer class as well as the system peak. For 2023F, the residential customer class is forecast to account for 34 percent of the normalized after-savings gross load.

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

Line No.	Description	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
	Energy (GWh)												
1	Residential	1,229	1,353	1,296	1,298	1,296	1,320	1,313	1,266	1,347	1,330	1,304	1,301
2	Commercial	681	788	863	853	905	915	926	932	922	960	962	973
3	Wholesale	899	675	567	580	574	574	585	566	569	566	579	578
4	Industrial	291	352	381	380	373	363	403	495	441	472	579	575
5	Lighting	13.5	13.5	15.6	15.9	15.9	15.9	13.2	11.0	10.8	9.7	9.5	9.4
6	Irrigation	38.0	39.7	40.0	46.0	42.1	41.9	39.0	36.0	37.3	43.6	39.5	39.4
7	Net Load	3,151	3,222	3,163	3,174	3,206	3,230	3,278	3,306	3,328	3,381	3,473	3,476
8	Losses & Company Use	271	278	270	272	274	282	285	287	288	295	299	299
9	Gross Load	3,422	3,500	3,433	3,446	3,480	3,512	3,564	3,592	3,616	3,677	3,771	3,775
10													
11	System Peak (MW)												
12	Winter Peak	723	698	693	685	755	714	682	732	731	685	782	786
13	Summer Peak	589	600	620	611	593	605	631	639	666	653	678	684

The residential, commercial, wholesale, industrial, lighting, irrigation, loss load and the winter and summer peak demand forecasts are provided separately in the following subsections.

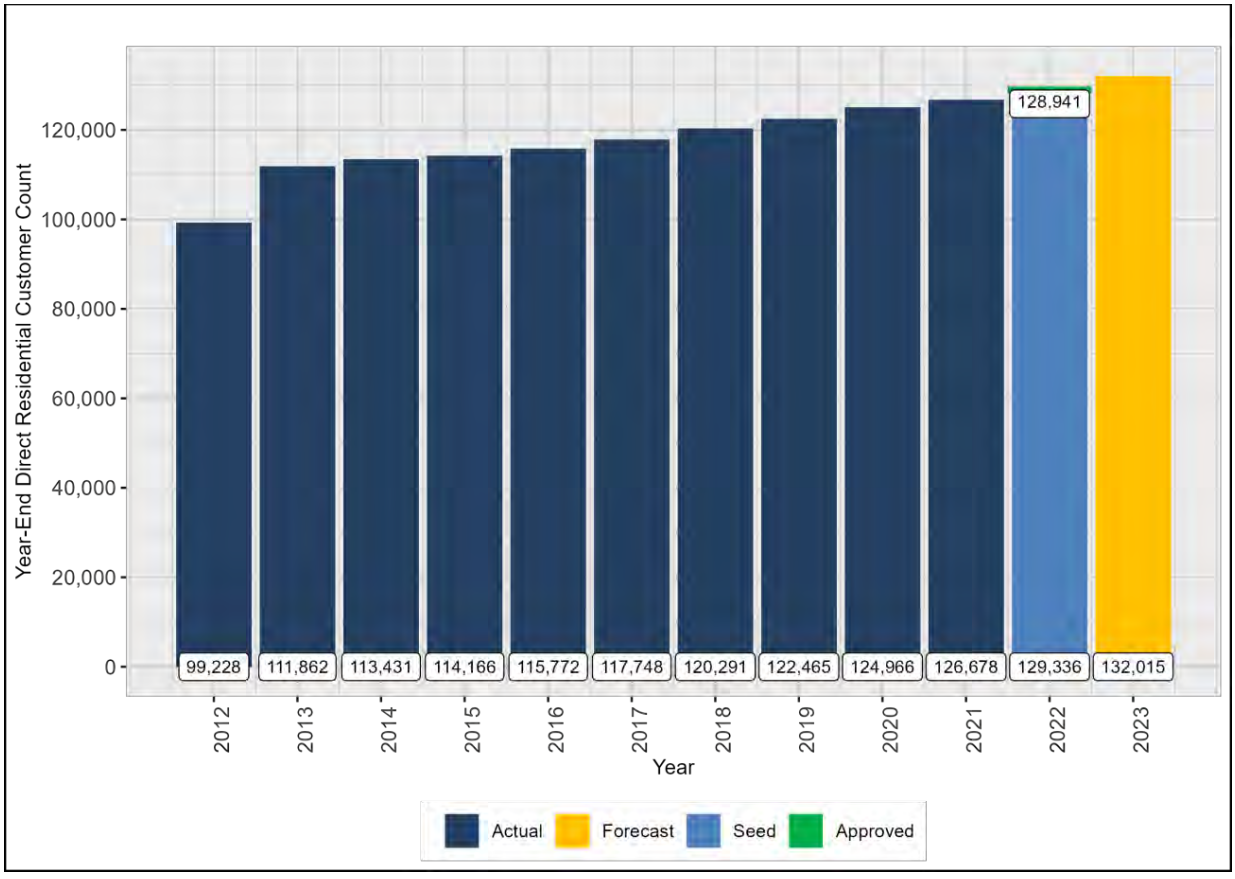
3.4.1 Residential

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

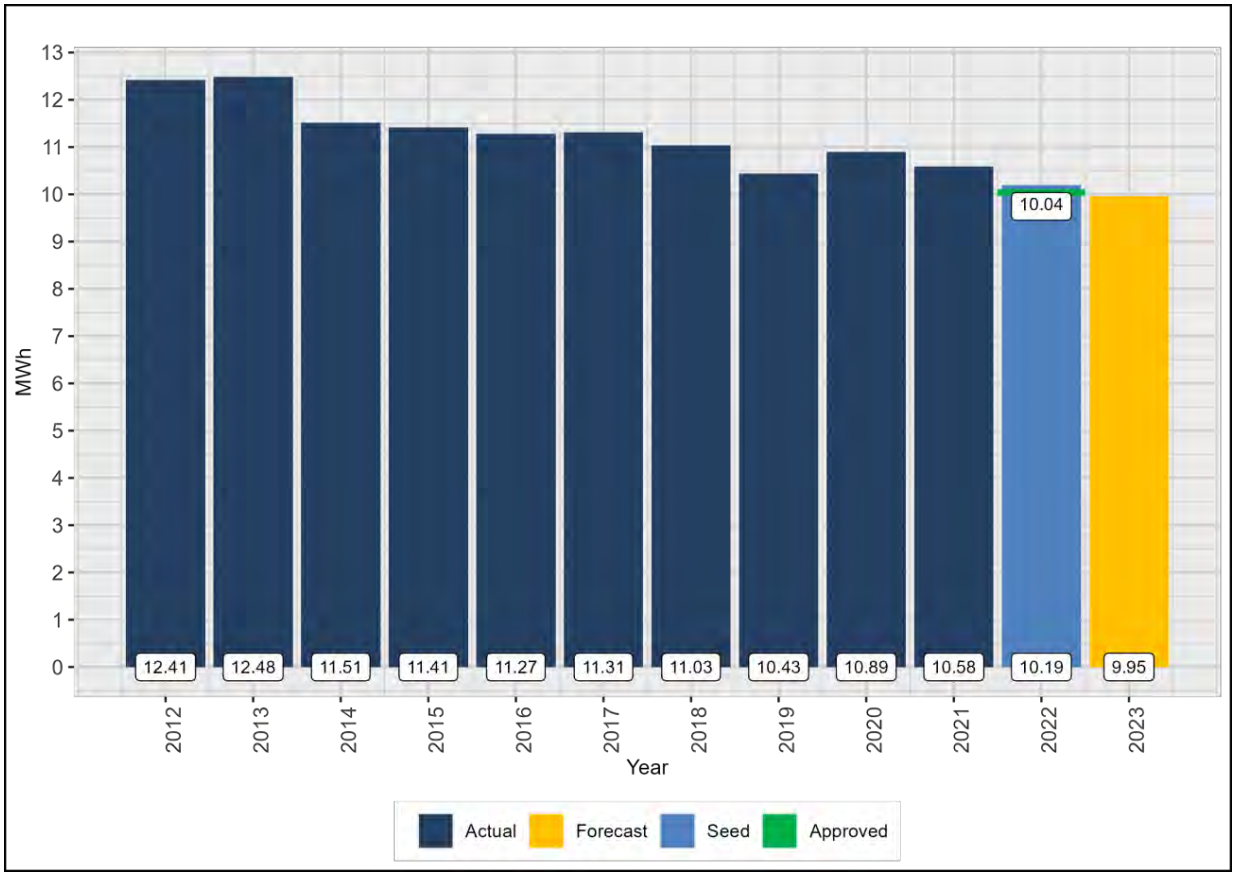


3.4.1.2 Residential UPC

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 10-year trend to the normalized historical UPCs. 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 2021, 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 forecast to decrease by 0.24 MWh in 2023F from 2022S and decrease by 0.09 MWh from 2022 Approved.

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

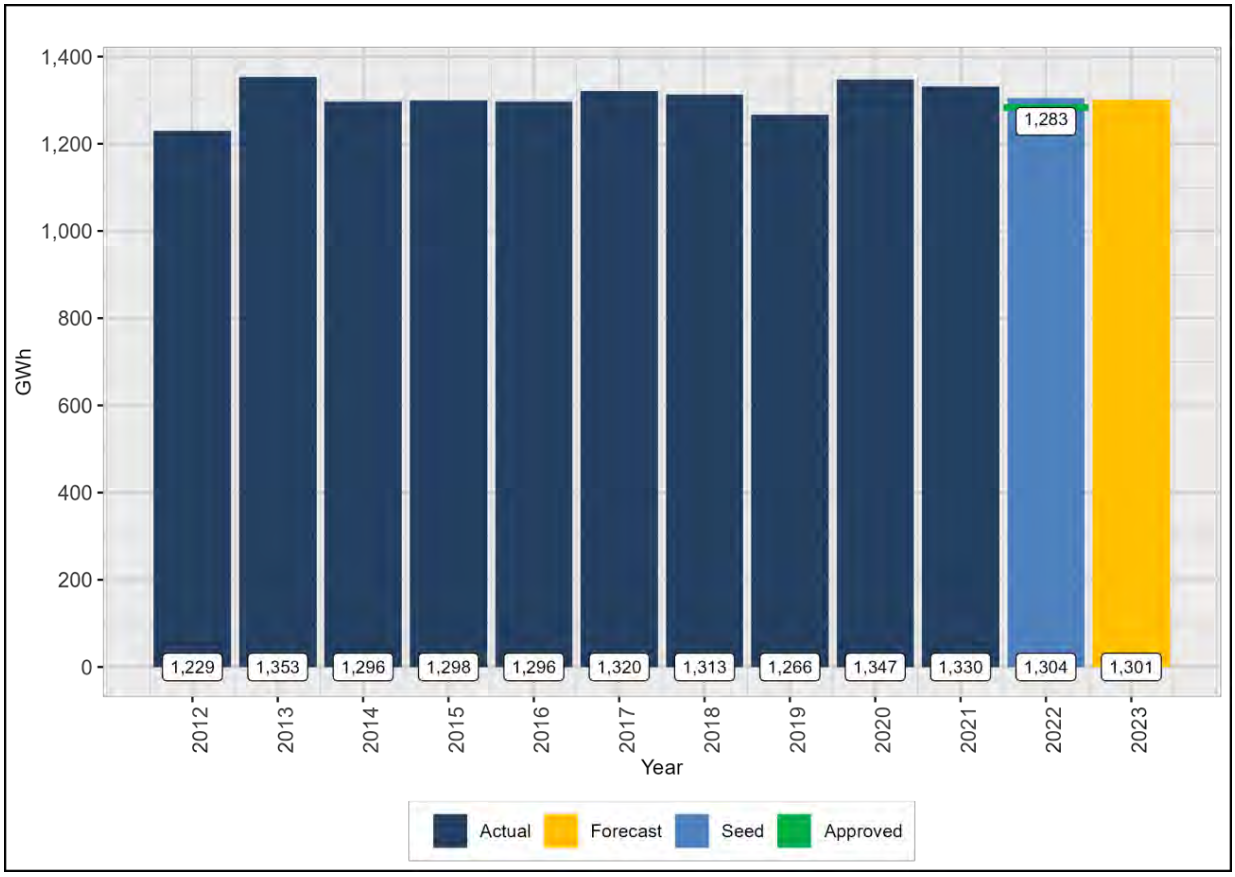


3.4.1.3 Residential Load

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 decrease by 3 GWh in 2023F from 2022S and increase by 18 GWh from 2022 Approved levels.

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

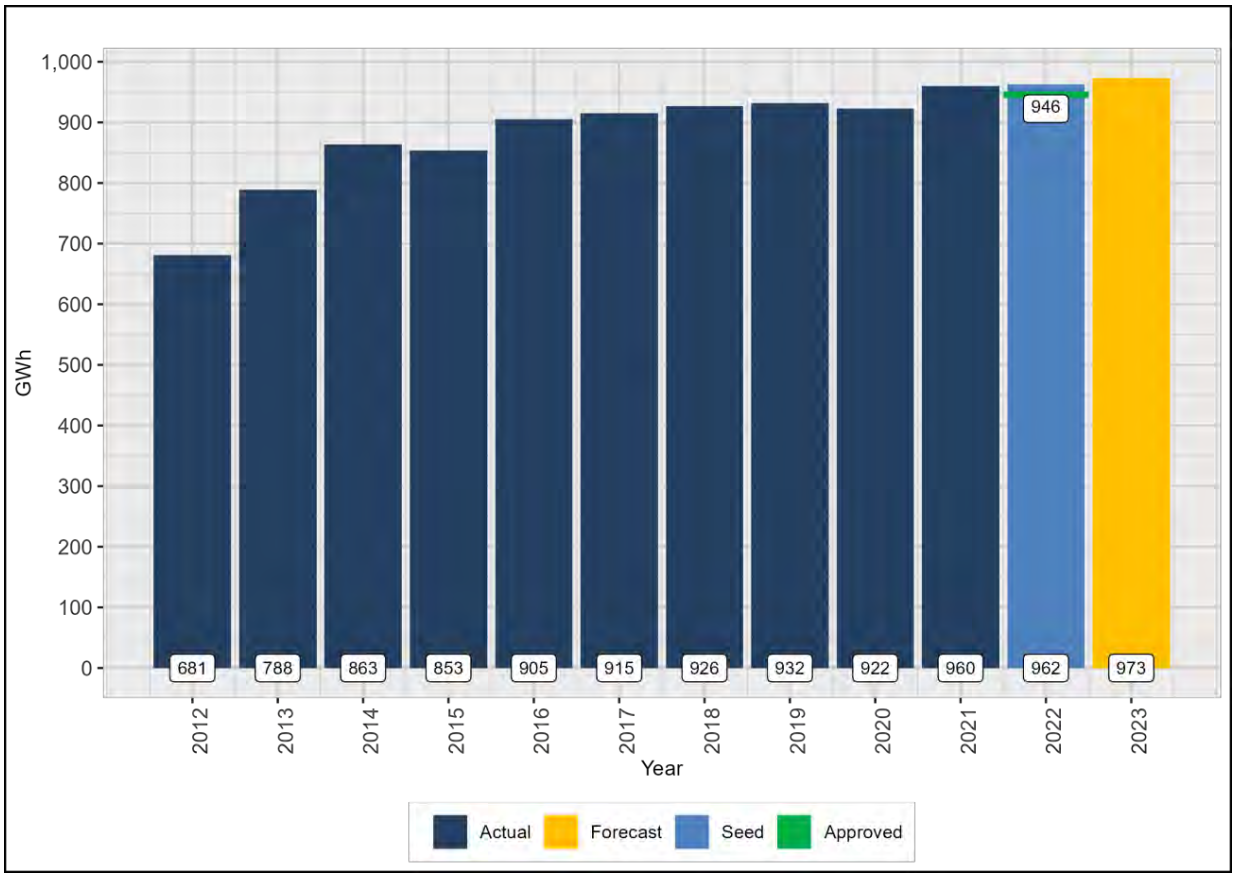


3.4.2 Commercial

3.4.2.1 Commercial Load

The commercial class is forecast based on a regression of load on the provincial GDP forecast obtained from the CBOC. The load for Electric Vehicle Direct Current Fast Chargers (EV DCFC) serviced by FBC are then added to 2022S and 2023F and account for less than a 1 GWh increase in both 2022S and 2023F. As shown in Figure 3-5 below, commercial after-savings load is forecast to increase by 11 GWh in 2023F from 2022S and increase by 27 GWh in 2023F from 2022 Approved.

Figure 3-5: After-Savings Commercial Load (GWh)



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 lighting.

Consistent with past practice, the wholesale class is forecast using survey information from each of the individual wholesale customers, as the individual wholesale customers are best able to forecast their future load growth. For 2023, all but one of the wholesale customers responded with their load forecast projections.

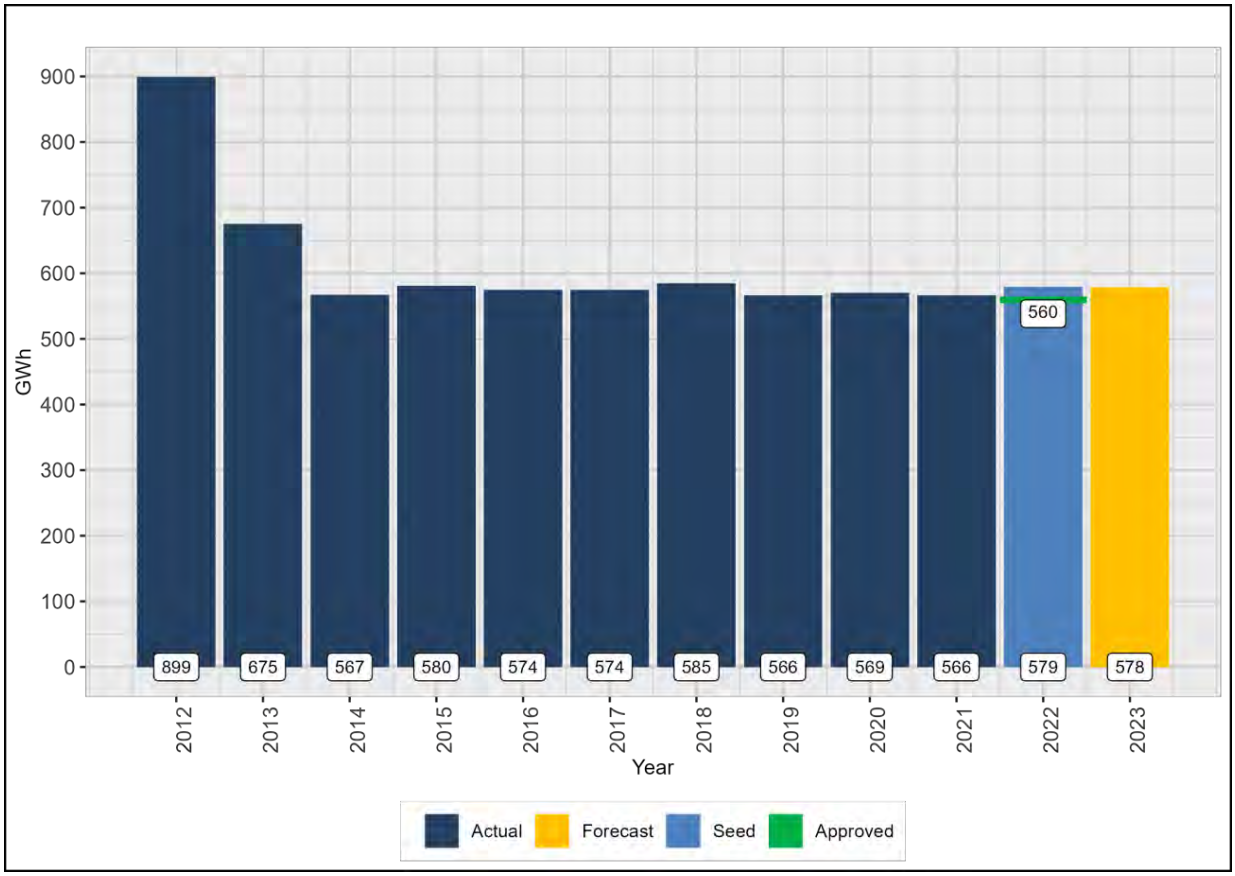
In the Annual Review for 2022 Rates Decision, the BCUC Panel directed FBC "to provide any efforts it has undertaken to improve the accuracy of its forecasts of wholesale customer load in the 2023 Annual Review, including the results of such efforts."[8] The BCUC Panel further requested that FBC work more closely with wholesale customers to develop more accurate forecasts. As such, in April of this year, FBC met with the City of Penticton, the District of

[8] FBC Annual Review for 2022 Rates Decision and Order G-374-21, p. 32.

Summerland and the City of Nelson to discuss load forecast methods, techniques and tools, as well as each City's/District's individual load forecasts. Both FBC and the Cities/District found the workshops to be informative and productive, and FBC intends to continue to conduct these workshops on an annual basis in the future.

As shown in Figure 3-6 below, after-savings wholesale load is forecast to decrease by 1 GWh in 2023F from 2022S and increase by 18 GWh in 2023F from 2022 Approved.

Figure 3-6: Normalized After-Savings Wholesale Load (GWh)



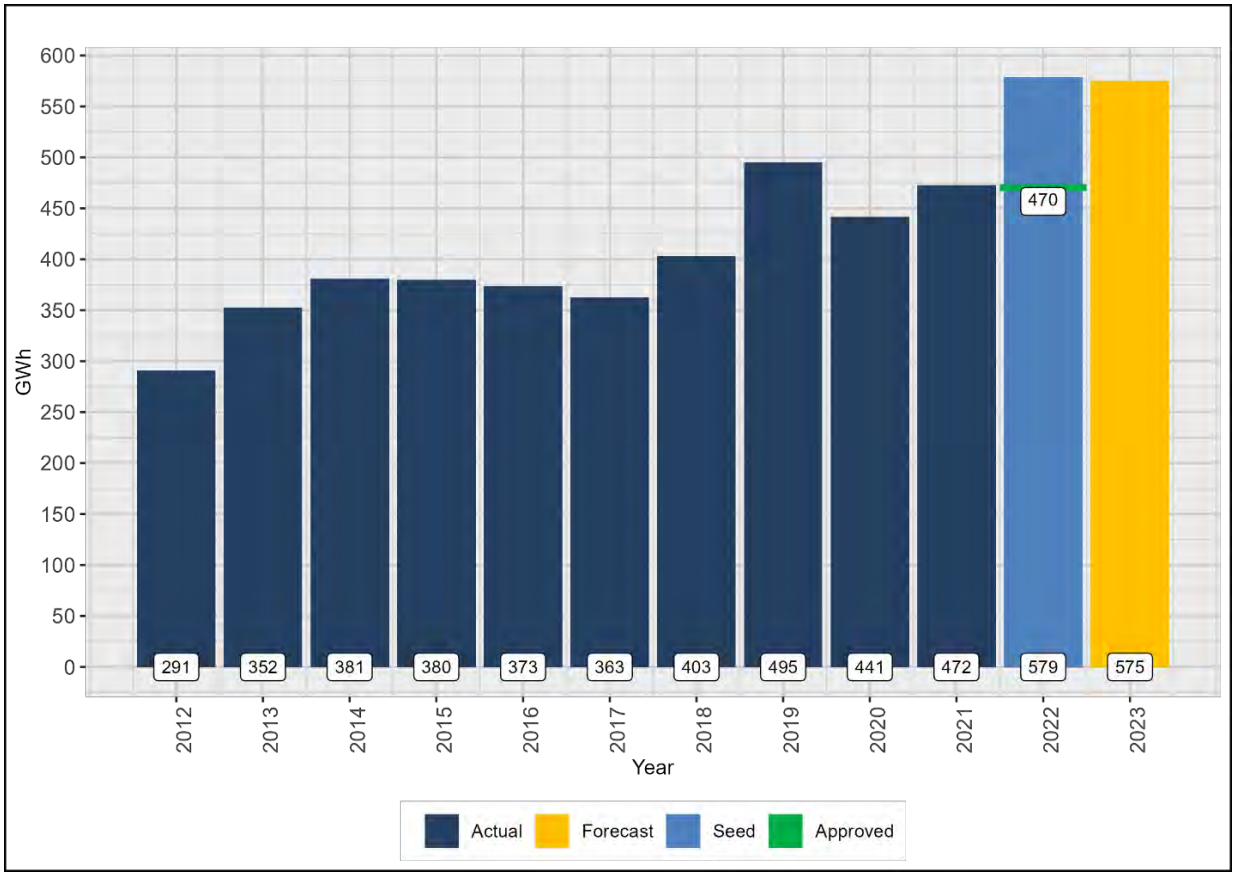
3.4.4 Industrial

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 five 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 81 percent (34 of 42) of the surveys sent out. The responding customers represent approximately 90 percent of the total industrial load.

As shown in Figure 3-7 below, after-savings industrial load is forecast to decrease by 4 GWh in 2023F when compared to 2022S and increase by 105 GWh in 2023F compared to 2022 Approved. The increased forecast in 2022S and 2023F compared to 2022 Approved is primarily due to projected increases in data centre loads.

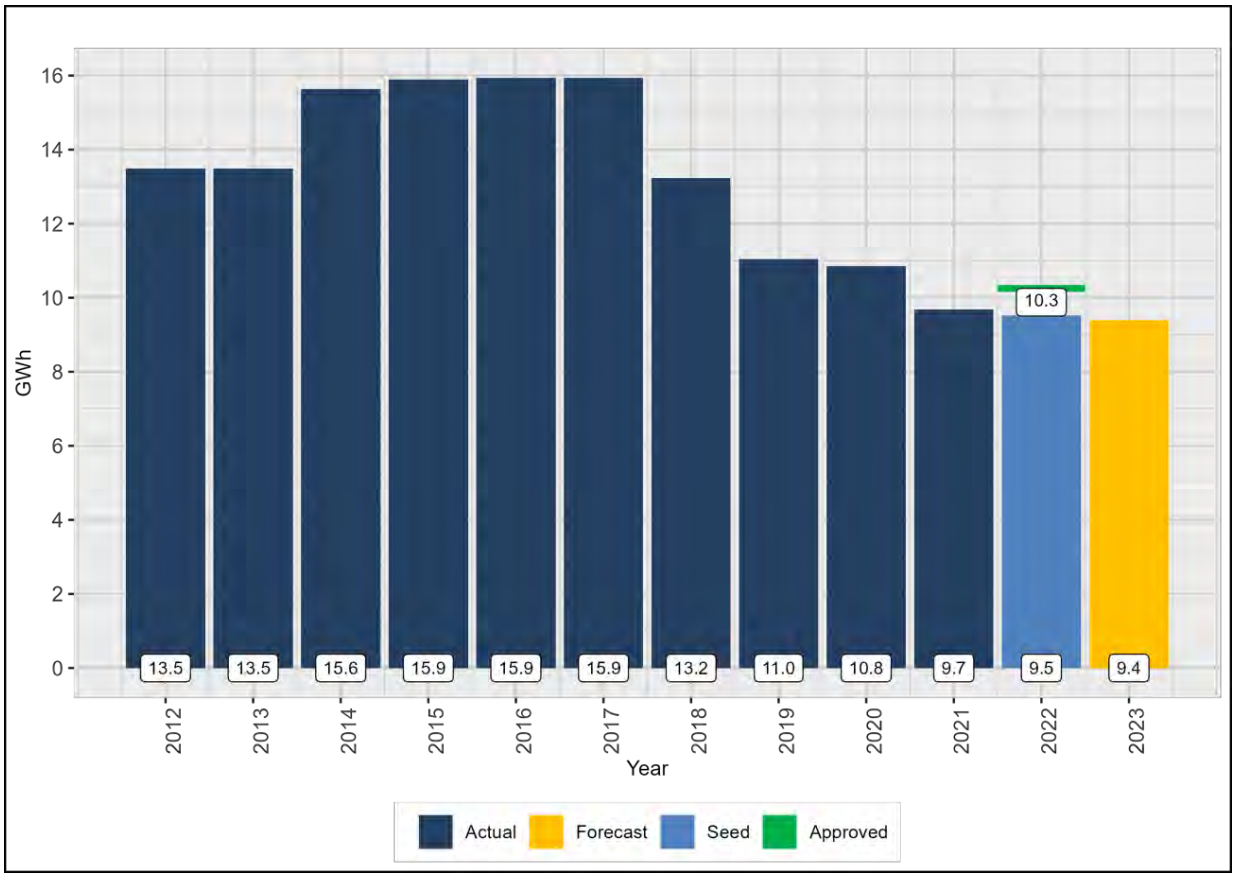
Figure 3-7: After-Savings Industrial Load (GWh)



3.4.5 Lighting

Due to the implementation of LED streetlights, the lighting load has seen declines for the past four years. FBC used the 2021 Actuals as the forecast for this load and then reduced it by DSM savings. As shown in Figure 3-8 below, after-savings lighting load is forecast to decrease by 0.1 GWh in 2023F from 2022S and decrease by 0.9 GWh when compared to 2022 Approved.

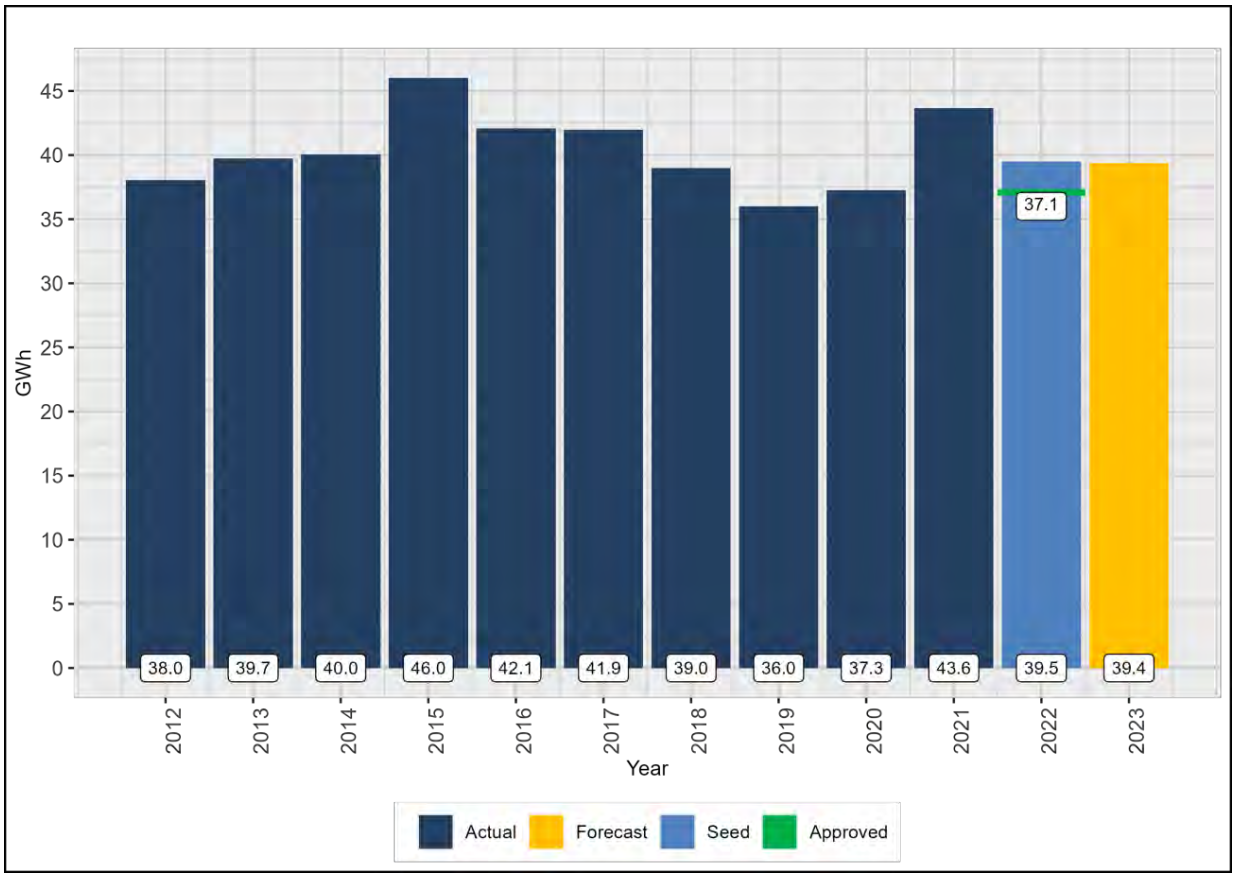
Figure 3-8: After-Savings Lighting Load (GWh)



3.4.6 Irrigation

Due to the variability in the load in the recent historical data, FBC used a five-year average as the forecast for the irrigation load. As shown in Figure 3-9 below, after-savings irrigation load is forecast to decrease 0.1 GWh from 2022S to 2023F and increase by 2.3 GWh in 2023F when compared to 2022 Approved.

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



3.4.7 Losses and Company Use

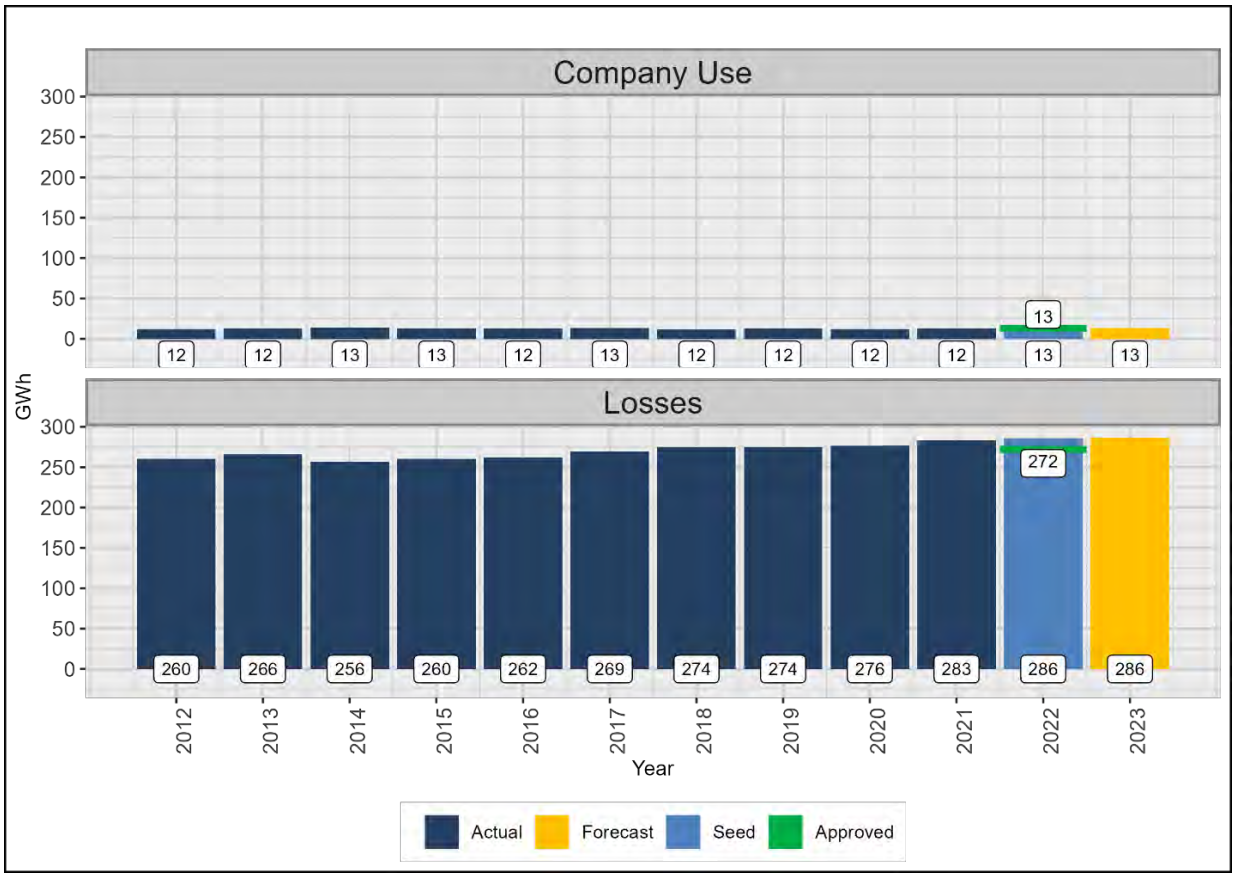
FBC conducted a Losses Study in 2019[9] and, consistent with that study, has assumed a loss rate of 7.6 percent of gross load (excluding company use). System losses consist of:

- 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 3-10 below, after-savings load losses are forecast to remain constant in 2023F because the gross load is forecast to be relatively stable when compared to 2022S. When compared to 2022 Approved, the 2023F after-savings load losses are forecast to increase by 14 GWh due to increased load. FBC has separated company use in the graph below, which is forecast at 13 GWh per year in 2023F, consistent with 2022S.

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

Figure 3-10: Normalized After-Savings Load Losses (GWh)



3.4.8 Peak Demand

The peak demand forecast is produced using the 10-year average of historical peaks, including peaks from the June 2021 “heat dome” event. 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 2022S and 2023F. 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 3-11: After-Savings Winter Peaks (MW)

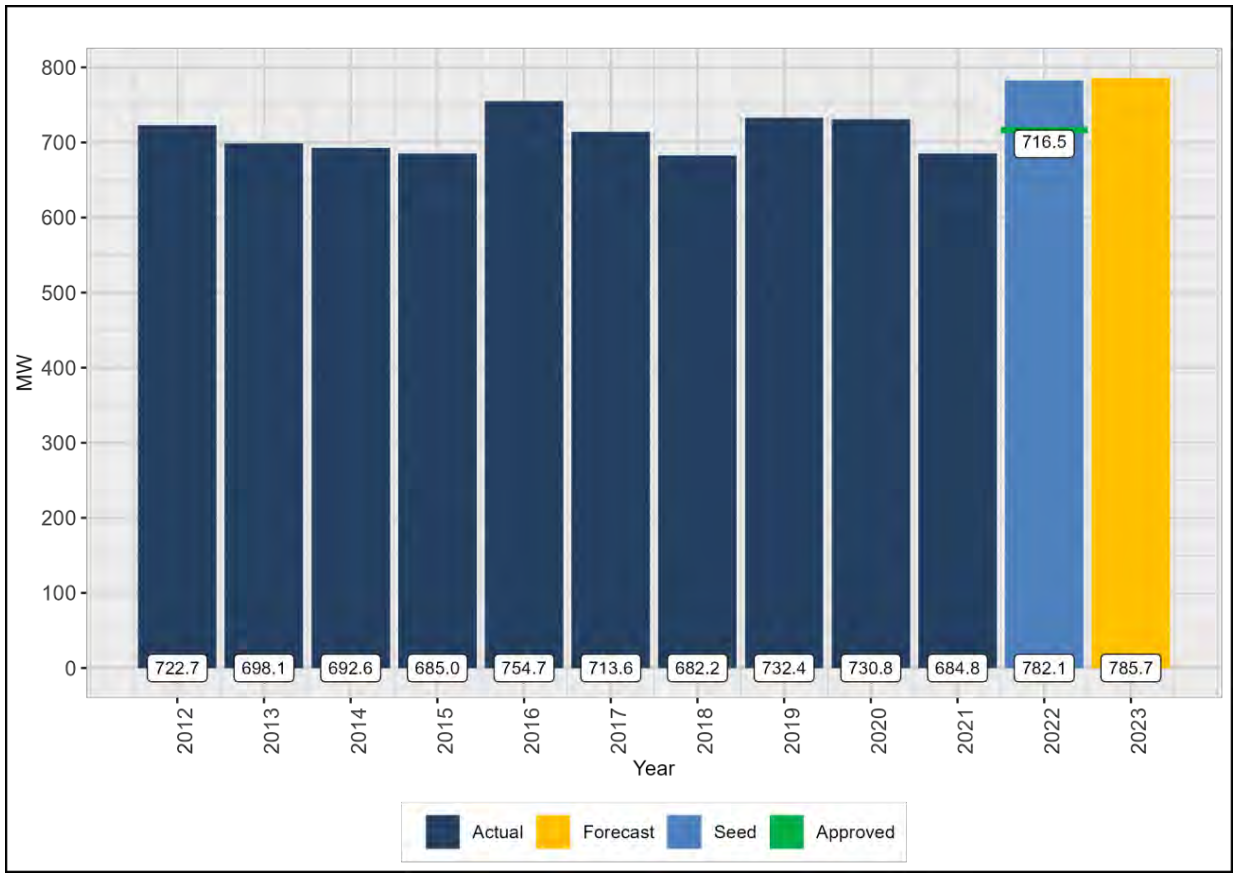
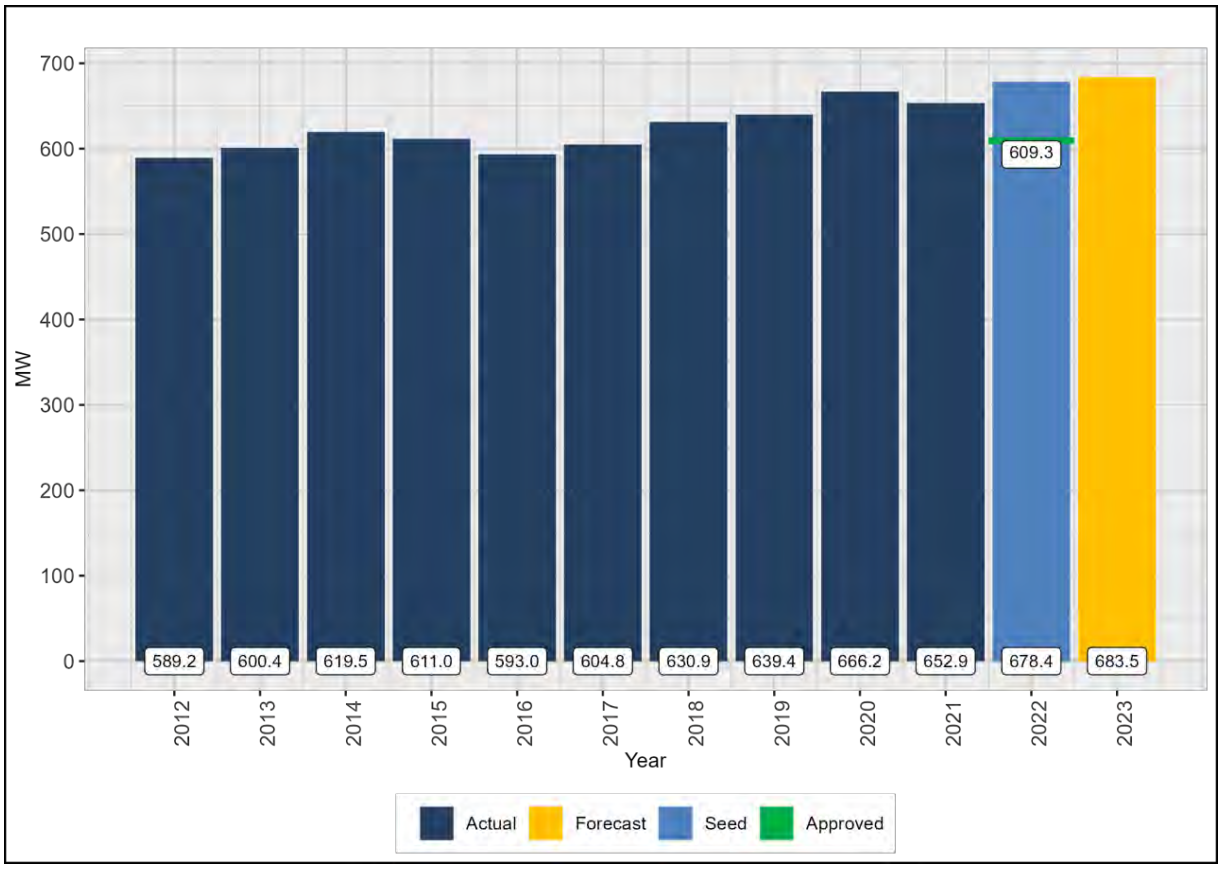


Figure 3-12: After-Savings Summer Peaks (MW)



3.5 *CUSTOMER FORECAST*

Table 3-3 shows the actual and forecast year-end customer count by rate class. The residential and commercial customer counts are forecast using the methods described in Sections 3.4.1 and 3.4.2, respectively. Industrial customers are forecast based on information on expected new loads provided by key account managers. The lighting customer forecast is prepared using a three-year regression of year-end customer counts. Wholesale and irrigation customer counts are assumed to remain at 2021 levels.

Overall, for 2023F, FBC is forecasting customer growth of 2.1 percent compared to 2022S and growth of 2.4 percent compared to 2022 Approved.

Table 3-3: Year-End Direct Customer Count

Line No.	Description	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
1	Residential	99,228	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,336	132,015
2	Commercial	11,811	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,995	17,496
3	Wholesale	7	6	6	6	6	6	6	6	6	6	6	6
4	Industrial	39	47	49	50	50	50	52	51	43	42	42	42
5	Lighting	1,739	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,379	1,349
6	Irrigation	1,091	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103
7	**Total**	113,915	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,861	152,011

3.6 REVENUE FORECAST

The forecast of revenues has been developed by applying approved 2022 rates to the forecast billing determinants for each customer class.

Table 3-4 below summarizes the 2022 Approved, 2022 Projected and 2023 Forecast sales revenue.

Table 3-4: Forecast Sales Revenue at Approved Rates ($ millions)[10]

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Residential	$ 195.058	$ 200.837	$ 197.962
2	Commercial	104.380	107.153	106.230
3	Wholesale	51.255	53.722	52.031
4	Industrial	40.804	46.764	47.856
5	Lighting	2.411	2.266	2.207
6	Irrigation	3.386	3.550	3.554
7	Total	$ 397.294	$ 414.292	$ 409.840

When comparing the 2022 Approved to 2022 Projected there is an increase in revenue of $16.998 million, the majority of which is due to increased residential and industrial loads.

The 2023 Forecast revenue is $12.546 million higher than 2022 Approved, primarily due to an increase in the industrial load, followed by small increases in the residential, commercial, and wholesale loads. These increases are slightly offset by a decrease in the lighting load resulting from the continued conversion to LED streetlights in the FBC service territory.

Variances between the revenue forecast in this section and the actual revenues realized are captured in the Flow-through deferral account.

3.7 SUMMARY

The normalized after-savings gross load forecast for 2023F is 3,775 GWh. Based on net load of 3,476 GWh at the approved 2022 rates, FBC's 2023 revenue forecast is $409.840 million. When comparing 2023F to 2022 Approved, there is an increase in net load of 170 GWh. The net load increase in 2023F is due to increased loads in the industrial, commercial, wholesale residential and irrigation classes.

[10] The commercial sales revenue includes the revenues under RS 96 EV DCFC Stations. Please refer to Section 5.8 for further detail on EV DCFC station costs and revenues.

4. POWER SUPPLY

4.1 INTRODUCTION AND OVERVIEW

This section includes a review of the 2022 Projected and 2023 Forecast 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 2023 Forecast power supply cost of $182.105 million represents an increase of 12.5 percent or $20.275 million compared to the 2022 Approved cost of $161.830 million. The increase in 2023 Forecast power supply cost is mainly due to increases in PPE, however, wheeling expense has increased as well. The 2023 Forecast PPE has increased as a result of increased gross load and a reduction in wholesale market purchases, which has resulted in a correspondingly greater reliance on energy supplied under BC Hydro Rate Schedule (RS) 3808. 2023 Forecast wheeling expense has increased as a result of both rates and usage. The 2023 Forecast water fee expense has decreased compared to 2022 Approved as a result of decreased usage.

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 2022	Projected 2022	Forecast 2023
1	Power Purchase Expense	$ 143.779	$ 153.164	$ 163.575
2	Wheeling Expense	6.093	6.330	6.987
3	Water Fees	11.958	11.916	11.543
4	Total Power Supply Cost	$ 161.830	$ 171.409	$ 182.105
5				
6	Gross Load (GWh)	3,591	3,786	3,775

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:

1. 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;
2. 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);

3. A power purchase agreement (PPA) with BC Hydro (a 200 MW contract) under BC Hydro RS 3808 (Order G-60-14);
4. 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);
5. A number of small Independent Power Producer (IPP) contracts; and
6. 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 all of its 2023 forecast annual energy requirements, and most of its forecast capacity requirements with the exception of a small number of hours during June and July. These forecast capacity gaps result from the Company's updated, increased load forecast. As mentioned in previous Annual Reviews, 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. However, in contrast to recent years, the regional electricity market has experienced a step change over the past year due to several factors that include resource adequacy concerns, increased natural gas prices, and increased severe weather events. This change in the market price environment has resulted in little opportunity to displace PPA purchases on a forward basis. 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 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 made under the Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex dated February 17, 2015, and accepted by Order E-10-15.

4.4 *FBC 2022/23 ANNUAL ELECTRIC CONTRACTING PLAN*

On May 2, 2022, FBC filed its 2022/23 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, 2022 and ending September 30, 2023, 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 could be more or less, depending on system conditions.[11] 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 forecasts of PPE for the remainder of 2022 and for 2023 are based on the plan detailed in the 2022/23 AECP, which was accepted by the BCUC on May 26, 2022, by Letter L-19-22.[12]

The AECP identified FBC's intention to make its annual energy nomination under the PPA for the 2022/23 contract year equal to 767 GWh, less any firm market contracts that FBC could enter into, as described in Section 5 of the 2022/23 AECP. Prior to the June 30, 2022 nomination deadline, FBC updated its forecast load and resource balance for the 2022/23 contract year and submitted a nomination of 774 GWh.

4.5 *2022 PROJECTED POWER PURCHASE EXPENSE*

As shown in Table 4-2 below, FBC's 2022 Projected gross load (after taking into account demand side management and other customer savings) is expected to be 195 GWh above the 2022 Approved value, and PPE is projected to be above the 2022 Approved value by $9.385 million. The increase in 2022 Projected PPE is primarily due to the increase in gross load above the 2022 Approved value. This increase in gross load drives increases in both the BC Hydro PPA and wholesale market expense to meet the additional load. In addition, increases in both the purchase price under the BC Hydro PPA and the average cost of purchases from the market further contributed to the increase in PPE.

[11] 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.

[12] The AECP was filed confidentially. The non-confidential Executive Summary is attached to Letter L-19-22.

Table 4-2: 2022 Power Purchase Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Difference
1	Brilliant	$ 41.841	$ 42.367	$ 0.526
2	BC Hydro PPA	44.062	49.539	5.477
3	Waneta Expansion	42.701	41.434	(1.267)
4	Market and Contracted Purchases	15.102	21.672	6.570
5	Independent Power Producers	0.073	0.058	(0.015)
6	Self-Generators	-	-	-
7	CPA Balancing Pool	-	(1.252)	(1.252)
8	Transmission Service Loss Recoveries	-	-	-
9	Special and Accounting Adjustments	-	(0.654)	(0.654)
10	Total	$ 143.779	$ 153.164	$ 9.385
11				
12	Gross Load (GWh)	3,591	3,786	195

4.6 *2023 FORECAST POWER PURCHASE EXPENSE*

As shown in Table 4-3 below, the 2023 Forecast PPE is $10.412 million greater than the 2022 Projected. The forecast increase from $153.164 million in 2022 to $163.575 million in 2023 is mainly a result of a reduction in market and contracted purchases as they increase in price and correspondingly, a greater reliance on energy supplied by BC Hydro as it becomes more cost effective compared to market. Furthermore, as a result of load growth and uneconomic wholesale market prices, FBC expects to take Tranche 1 PPA energy over the nominated amount during 2023. Tranche 1 PPA energy taken over the nominated amount costs 150 percent of the Tranche 1 embedded cost rate,[13] and this exposure to more expensive PPA energy is also contributing to increased costs. Also contributing to the increase are escalations to the Waneta Expansion and Brilliant contract rates.

Table 4-3 below shows a comparison of the 2022 Projected and 2023 Forecast PPE. Reasons for significant variances from the 2022 Projected PPE are discussed below.

[13] $50.94 per MWh x 150 percent = $76.41 per MWh.

Table 4-3: 2023 Forecast Power Purchase Expense ($ millions)

Line No.	Description	Projected 2022	Forecast 2023	Difference
		-		
1	Brilliant	$ 42.367	$ 44.050	$ 1.683
2	BC Hydro PPA	49.539	71.302	21.763
3	Waneta Expansion	41.434	41.834	0.400
4	Market and Contracted Purchases	21.672	6.326	(15.346)
5	Independent Power Producers	0.058	0.062	0.004
6	Self-Generators	-	-	-
7	CPA Balancing Pool	(1.252)	-	1.252
8	Transmission Service Loss Recoveries	-	-	-
9	Special and Accounting Adjustments	(0.654)	-	0.654
10	Total	$ 153.164	$ 163.575	$ 10.412
11				
12	Gross Load (GWh)	3,786	3,775	(11)

4.6.1 Brilliant

Brilliant expense is forecast to increase in 2023 by $1.683 million compared to 2022 Projected due to increased 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.

4.6.2 BC Hydro PPA

BC Hydro PPA expense is forecast to increase in 2023 by $21.763 million compared to the 2022 Projected expense. The drivers of the increase are a higher purchased volume (371 GWh), which increases the expense by $21.775 million, and an increase in BC Hydro rates, which accounts for an increase of $3.987 million, for a total of $25.763 million. FBC has decreased its 2023 Forecast of PPA expense by $7.000 million in savings to account for potential real-time opportunities to displace PPA purchases with lower cost market purchases. The 2022 Projected BC Hydro expense was reduced by $3.000 million to account for potential real-time opportunities during the remainder of 2022. This results in a variance between 2022 Projected and 2023 Forecast of $21.763 million[14], as shown in Table 4-3. Actual market savings for the remainder of 2022 and 2023 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.

4.6.3 Waneta Expansion

The $0.400 million increase in Waneta Expansion expense is due to the 2.1 percent annual fixed escalation of WAX CAPA rates, offset by a $0.291 million increase in forecast surplus sales revenue under the RCA and CEPSA. Revenue under the CEPSA is linked to the amount of

[14] $21.763 million is calculated as follows: Total increase of $25.763 million less the $4.000 million variance between the 2022 Projected and 2023 Forecast real-time opportunities, or, $25.763 million – ($7.000 million - $3.000 million).

capacity FBC releases to Powerex and 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 forward 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 and surplus sales is the same as in the Annual Review for 2022 Rates. The forecast of surplus capacity sales revenue in 2023, which is included in line 3 of Table 4-3, is approximately $10.700 million.

4.6.4 Market and Contracted Purchases

The $15.346 million decrease in Market and Contracted Purchases forecast for 2023 is due to a lesser volume purchased at higher rates when compared to 2022 Projected. Market and Contracted Purchases for 2022 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 2023 Forecast are based on fixed price contracts executed by the Company, with the exception of forecast real-time market purchases for Rate Schedule 37[15] load. As 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.

4.6.5 CPA Balancing Pool

The CPA Balancing Pool represents timing differences in entitlement energy storage under the CPA and is used to manage fluctuations in load and resource availability, or to take advantage of market opportunities. In the 2022 Projected PPE, FBC has stored a net total of 25 GWh of entitlement energy, valued at $1.252 million. For the 2023 Forecast, and consistent with past practice, FBC does not forecast any net use or storage of entitlement energy.

4.7 *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 (included in Tables 4-2 and 4-3, line 8), and also includes loss recovery as a firm resource. Because the recoveries are delivered physically, there is no associated cost or revenue. Table 4-4 shows the 2022 and 2023 loss recoveries.

[15] RS 37 is large commercial stand-by service, which is on-demand back-up and maintenance service provided to self-generating customers. This service is provided to the customer at an hourly market-based rate, reflective of FBC's cost of supply. FBC procures this supply on a real-time basis because there is little certainty as to when customers will use this service. Forecast RS 37 load for 2023 is 15 GWh or 0.4 percent of total gross load.

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

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Loss Recoveries	12	12	12

4.8 WHEELING EXPENSE

Wheeling expense includes wheeling service provided by BC Hydro under the Amended and Restated Wheeling Agreement (ARWA) and Open Access Transmission Tariff (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 RS 3817.

Wheeling expense is forecast using the same method as in the Annual Review for 2022 Rates. Table 4-5 below shows FBC's Wheeling Expense for 2022 and 2023.

Table 4-5: Wheeling Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Wheeling Nomination (MW Months)			
2	Okanagan Point of Interconnection	2,475	2,475	2,670
3	Creston	420	420	420
4				
5	Wheeling Expense			
6	Okanagan Point of Interconnection	$ 4.903	$ 4.976	$ 5.555
7	Creston	0.542	0.550	0.570
8	Other	0.648	0.804	0.863
9	Total Wheeling Expense	$ 6.093	$ 6.330	$ 6.987

Total 2022 Projected wheeling expense is $0.237 million greater than 2022 Approved. The 2022 Projected ARWA costs are $5.526 million (lines 6 and 7 in the table above), a $0.081 million increase when compared to 2022 Approved, which is a result of higher than expected BC-CPI and therefore ARWA rates. 2022 Projected Teck and OATT wheeling costs are $0.804 million (line 8 above), which is $0.156 greater than 2022 Approved. This is mainly due to increased use of OATT wheeling.

2023 Forecast wheeling expense is $0.657 million higher than 2022 Projected. This is a result of both increased use and rates. FBC increased the Okanagan wheeling nomination to 2,670 MW months in 2023 from 2,475 MW months in 2022. ARWA rates are forecast to increase on October 1 of both 2022 and 2023, based on forecast BC-CPI, as is the Teck wheeling rate as a result of a letter agreement made between Teck and FBC.

4.9 WATER FEES

Water fees are based on FBC's entitlement usage in the previous year and the rate increases are indexed to BC-CPI.

As shown in Table 4-6 below, the 2023 Forecast water fees are decreasing by $0.373 million from the 2022 Projected due to decreased entitlement use. 2023 water fees are forecast using the same method as in the Annual Review for 2022 Rates.

Table 4-6: Water Fees ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Plant Entitlement in Previous Year (GWh)	1,679	1,663	1,571
2				
3	Water Fees	$ 11.958	$ 11.916	$ 11.543

4.10 SUMMARY

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.

FBC's forecast of PPE is based on FBC's firm resources in place at the time of filing and is consistent with the 2022/23 AECP. Any variances in the power supply cost, including any decreases in PPE 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.[16]

FBC is forecasting Other Revenue for 2023 to be $0.409 million higher than 2022 Approved, primarily due to higher Late Payment Charges and expected annual increases in rates for Apparatus and Facilities Rental, Contract Revenue and Transmission Access Revenue.

2022 Projected Other Revenue is $1.335 million higher than 2022 Approved. The main drivers of this increase are the sales of carbon credits related to Electric Vehicle (EV) Direct Current Fast Charging (DCFC) stations, as well as higher Contract Revenue and Late Payment Charges.

Table 5-1: Other Revenue ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Apparatus and Facilities Rental	$ 6.018	$ 6.018	$ 6.108
2	Contract Revenue	2.277	2.750	2.367
3	Transmission Access Revenue	1.771	1.788	1.834
4	Interest Income	0.020	0.020	0.030
5	Late Payment Charges	0.875	1.095	0.994
6	Connection Charges	0.505	0.505	0.553
7	EV Stations Carbon Credits	-	0.625	-
8	Other Recoveries	0.366	0.366	0.355
9	Total Other Revenue	$ 11.832	$ 13.167	$ 12.241

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. There are no variances projected in 2022 compared to 2022 Approved, as final amounts have yet to be calculated since the majority of invoices are issued during the third quarter of the year. The 2023 Forecast is higher than 2022 Approved due to expected escalations in unit rental rates for continuing contracts.

[16] Variances in Other Revenue associated with Electric Vehicle (EV) stations carbon credits are treated as flow-through, as EV Direct Current Fast Charging (DCFC) stations are prescribed undertakings under section 5 of the GGRR and the cost of service associated with EV DCFC stations is subject to flow-through treatment.

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, fluctuates 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[17] and earn a transfer price profit revenue. Revenues may fluctuate from year to year depending on customer requirements.

The 2022 Projected revenue is higher than 2022 Approved due to an increase in costs related to the close-out of a multi-year asset refurbishment project for a third party that began in 2020, as well as certain costs that shifted from 2021 into 2022 for the same project. The 2023 Forecast is higher than 2022 Approved due to expected increases in the average cost of work and materials recovered from third-party customers.

5.4 TRANSMISSION ACCESS REVENUE

Transmission Access Revenue represents charges to customers for transmitting power over the FBC system. The 2022 Projected revenue is slightly higher than 2022 Approved due to a higher nomination than originally forecast for one customer. The 2023 Forecast is higher than 2022 Approved due to the phased increase in rates over three years 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 outstanding; as a result, no significant changes in interest income are expected in 2022 Projected or the 2023 Forecast.

5.6 LATE PAYMENT CHARGES

Late Payment Charges have historically been forecast based on the average of the most recent three years of actual Late Payment Charges earned. However, due to the impact of the COVID-19 pandemic and FBC's implementation of customer relief measures, which included the suspension of Late Payment Charges until March 2021, the actual amounts collected have fluctuated from year to year.

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

FBC continues to see fluctuations in Late Payment Charges. The 2022 Projected Late Payment Charges are higher than 2022 Approved by $0.220 million based on amounts charged so far in 2022 as well as growth in customers since the 2017 to 2019 period used to develop the 2022 Approved.

In consideration of the continued fluctuations being experienced, the 2023 Forecast has been calculated based on the average of 2021 Actual and 2022 Projected Late Payment Charges of $0.892 million and $1.095 million, respectively. This results in an increase in Late Payment Charges of $0.119 million compared to 2022 Approved.

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 2022 Projected is expected to be consistent with 2022 Approved based on amounts charged so far in 2022. The 2023 Forecast is expected to be higher than 2022 Approved based on customer growth and forecast customer reconnections.

5.8 CLEAN GROWTH INITIATIVE – EV DCFC STATIONS CARBON CREDITS

FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[18] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. The EV charging rates, the depreciation rate for EV charging stations, and the inclusion of related revenues and expenses associated with FBC's EV DCFC stations in FBC's regulated accounts were approved by the BCUC on November 24, 2021[19]. The revenues to be included in FBC's regulated accounts include the Other Revenue from the sale of carbon credits related to EV stations[20] earned under the Renewable Low Carbon Fuel Requirements Regulation (RLCFRR), which is embedded in the rate design of the EV DCFC stations.

At the time of the 2022 Annual Review, FBC did not have any carbon credits validated by the British Columbia Low Carbon Fuel Standard (BC-LCFS); as such, and as reflected in Table 5-1 above, FBC did not forecast any revenue from the sales of the credits for 2022 Approved. However, as of the end of the first quarter of 2022, the BC-LCFS has validated approximately 1,337 carbon credits for FBC that have accumulated since 2019, with an approximate market value of $0.625 million[21]. FBC anticipates monetizing these credits prior to the end of 2022 and has therefore reflected them in the 2022 Projected column in Table 5-1 above, and also included the $0.625 million credit in the Flow-through deferral account, to be returned to customers in 2023.

[18] Order G-215-21 dated July 14, 2021.
[19] FBC EV DCFC Service Application Decision and Order G-341-21.
[20] Includes both public charging stations owned by FBC as well as public stations owned by other entities (metered commercial accounts) as discussed in Exhibit B-6 of FBC's 2022 Annual Review, BCSEA IR1 4.3. Beginning in 2022, FBC will only be permitted to claim credits for charging stations owned by FBC. FBC does not currently claim credits for non-public EV charging services for either commercial or residential customers.
[21] 1,337 credits x $467.32 average Q1-2022 sales price (source: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf-017.pdf).

Consistent with the practice from the 2022 Annual Review, FBC does not forecast revenue from the sale of credits that are pending validation; FBC is therefore not forecasting any of these revenues in 2023.

As part of the 2022 Annual Review Decision, FBC was directed to include the following in future Annual Review filings:[22]

> …an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period.

FBC currently has a total of 40 EV DCFC stations in service across 23 sites and is planning to install two additional DCFC stations at two of the existing sites in 2022, resulting in a total of 42 EV DCFC stations across 23 sites. Consistent with the format of the information provided during the 2022 Annual Review[23], Table 5-2 below provides the costs and revenues for 2021 Actual (previous fiscal year), 2022 Projected, and 2023 Forecast. As highlighted in Table 3-4 of Section 3.6, the RS 96 EV DCFC revenue (i.e., Line 10 of Table 5-2 below) is included as part of the Commercial Sales Revenue. Please also refer to Section 6.3.4 for a discussion of the forecast O&M expenses for the EV DCFC stations and Section 7.2.2 for a discussion of the forecast capital expenditures for the EV DCFC stations, as well as information on how the two new stations are prescribed undertakings. Once the capital expenditures are included in rate base, they impact the depreciation, amortization of CIAC, income tax and earned return related to the EV DCFC stations that are shown in Table 5-2 below.

Table 5-2: EV DCFC Stations Costs and Revenues for 2021 Actual, 2022 Projected, and 2023 Forecast ($ millions)[24]

Line	Particulars	2021 Actual	2022 Projected	2023 Forecast	Cumulative
1	Cost of Energy	0.013	0.282	0.300	
2	Less: Power Purchase Expense	(0.013)	-	-	
3	O&M	0.101	0.187	0.193	
4	Depreciation	0.307	0.456	0.612	
5	Amortization of CIAC	(0.150)	(0.191)	(0.249)	
6	Other Revenue - Carbon Credits	-	(0.625)	-	
7	Income Tax	(0.299)	(0.199)	0.158	
8	Earned Return	0.124	0.172	0.183	
9	Total Cost of Service	0.083	0.082	1.196	
10	RS 96 Revenue	(0.058)	(0.155)	(0.178)	
11	(Surplus) / Deficiency	0.025	(0.072)	1.018	0.971
12	Prior Year 2018-2020 (Surplus)/Deficiency				(0.142)
13	Cumulative (Surplus) / Deficiency				0.828

[22] FBC 2022 Annual Review Decision and Order G-374-21, p. 32.
[23] Exhibit B-3, BCUC IR1 16.1.
[24] As explained in Exhibit B-3, BCUC IR1 16.1 of the FBC 2022 Annual Review, RS 96 was approved on an interim basis in 2021 by Order G-9-18 in which the cost of energy embedded was based on BC Hydro's RS 3808; therefore,

As directed by Order G-341-21, FBC is to file a detailed assessment of the EV DCFC service by no later than December 31, 2022 or within six months of Measurement Canada's approval of DCFC energy-based metering for FBC, whichever is earlier. FBC is not expecting to receive approval from Measurement Canada prior to December 31, 2022; thus, FBC will file the detailed assessment report by December 31, 2022. As directed by the BCUC, the detailed assessment will include:

- An update of the financial models with actual and forecast information and updated assumptions;
- A detailed assessment of RS 96 and alternative rate design options;
- An overview of the current EV fast charging service market and rates across Canada and the United States;
- A proposal for a depreciation rate for its EV DCFC stations and information to support its proposal; and
- An assessment as to whether idling fees are warranted.

5.9 *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 AMI radio-off meter read fees. There are no variances expected in 2022 Projected compared to 2022 Approved based on amounts recognized to date. The 2023 Forecast is expected to be slightly lower than 2022 Approved due to an expected reduction in AMI radio-off meter read fees resulting from a lower volume of customers choosing the radio-off option.

5.10 *SUMMARY*

FBC has forecast the Other Revenue components for 2023 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, with the exception of EV DCFC stations carbon credits, are shared with customers through the earnings sharing mechanism.

the cost of energy for 2021 Actual shown in Table 5-2 is equal to the power purchase expense. As approved in Order G-341-21, the permanent rate for RS 96 is based on FBC's commercial service RS 21. As such, starting in 2022, the cost of energy shown in Table 5-2 above is based on FBC's commercial service RS 21.

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 2023, the formula O&M is $69.957 million, representing a 5.8 percent increase from the 2022 formula O&M, primarily due to the formula drivers. O&M expenses forecast outside the formula for 2023 are $2.323 million, representing a 26.8 percent increase from the amount approved for 2022. Overall, the 2023 Forecast gross O&M expense is $72.789 million, which is an increase of approximately 7.0 percent from the 2022 Approved level.

The components of 2023 O&M expense are shown in Table 6-1 below.

Table 6-1: 2023 O&M Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Formula O&M	$ 66.147	$ 66.147	$ 69.957	Section 11, Schedule 20, Line 8
2	Forecast O&M	1.832	1.635	2.323	Section 11, Schedule 20, Line 20
3	Prior year O&M True-up	0.053	0.053	0.509	Table 6-2, line 16
4	Total Gross O&M	68.032	67.835	72.789	Line 1 through 3
5	Capitalized Overhead	(10.177)	(10.177)	(10.918)	Section 11, Schedule 20, Line 23
6	Net O&M	$ 57.855	$ 57.658	$ 61.871	Line 4 + Line 5

In the sections below, FBC provides further details on its formula and forecast O&M expenses for 2023. Additionally, in compliance with the BCUC's directive in the MRP Decision,[25] FBC provides information related to its System Operations, Integrity and Security expenditures in Subsection 6.2.1.

6.2 FORMULA O&M EXPENSE

The formula-driven portion of 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 then multiplied by 75 percent of the forecast growth in average customers, resulting in the current year inflation-indexed O&M before true-up. A true-up of formula O&M based on actual average customers from two years prior is then added to the current year inflation-indexed O&M.

As calculated in Section 2, the 2023 inflation based on prior year's BC-CPI and BC-AWE, less the productivity improvement factor, is 4.017 percent.

For 2023, the annual operating and maintenance expense under the formula is calculated as:

[25] MRP Decision, p. 118.

2022 Approved formula UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)] + 2021 Formula O&M True-up

Table 6-2 below shows the calculation of the 2023 Formula O&M, including the calculation of the 2021 Formula O&M true-up. FBC notes the true-up of formula O&M is a two-year lag based on actual average customer counts from 2021.

Table 6-2: Calculation of 2023 Formula O&M ($ millions)

Line No.	Description		Forecast 2023	Reference
1	Prior Year Base Unit Cost O&M ($/ customer)	$	455	G-374-21 FBC 2022 Annual Review
2	I-Factor		4.017%	Section 2, Table 2-3, Line 11
3	Current Year Unit Cost O&M ($/customer)	$	473	
4	Average Customer Forecast		147,901	Section 2, Table 2-3, Line 13
5	2023 Inflation-Indexed O&M before 2020 True-up	$	69.957	Line 3 x Line 4 / 1,000,000
6	2021 True-up O&M		0.509	Line 16
7	Inflation-Indexed O&M	$	70.466	Line 5 + Line 6
8				
9	2021 O&M True-up			
10	2021 Actual 12 month Average Customers		144,877	FBC 2021 Annual Report
11	2021 Forecast 12 month Average Customers		143,325	G-42-21 FBC 2020-2021 Annual Review
12	Difference		1,552	Line 10 + Line 11
13	Growth Factor		75%	G-166-20 FBC MRP Decision
14	Change in Customers - True-up		1,164	Line 12 x Line 13
15	2021 Unit Costs	$	437	G-42-21 FBC 2020-2021 Annual Review
16	O&M True-up for 2023	$	0.509	Line 14 x Line 15 / 1,000,000

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 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 for 2021 Formula O&M, 2021 Actual O&M, and the resulting variances, as well as the Cumulative Forecast/Actual variance for the first two years of the MRP.

Table 6-3: System Operations, Integrity and Security New/Incremental Spending ($ millions)

Line No.	Description	2021 Formula O&M[1]	Actual 2021 O&M	2021 Forecast/Actual Variance	Cumulative Forecast/Actual Variance[2]
1	Tree Management	$ 0.080	$ 0.278	$ 0.199	$ 0.436
2	Generation Dam Safety	$ 0.246	$ 0.415	$ 0.169	$ 0.137
3	Network Operations Apprentice Program	$ 0.209	$ 0.243	$ 0.034	$ (0.167)
4	Cyber Security	$ 0.085	$ 0.085	$ -	$ 0.250
5	Data Analytics	$ 0.105	$ -	$ (0.105)	$ (0.206)
6	Other	$ -	$ -	$ -	$ -
7	Total	$ 0.724	$ 1.021	$ 0.297	$ 0.449

Notes to Table:

[1] 2021 Formula O&M is the approved 2020 formula for incremental funding with Net Inflation factor applied (3.668%).
[2] Cumulative Forecast/Actual variance is the 2020 Actual variance plus the 2021 Actual variance.

Overall, total actual spending in 2021 was $1.021 million, which is $0.297 million higher than the 2021 Formula O&M amount. Areas with notable variances include tree management, generation dam safety and data analytics.

For tree management, FBC spent $0.199 million more than the formula amount to address an increased number of unhealthy trees as part of FBC's right-of-way management program.

For generation dam safety, FBC spent $0.169 million more than the formula amount due to the continuation of dam safety review activities from 2020, as FBC required more time to complete the analysis for the determination of the dam classifications for the Upper Bonnington, Lower Bonnington and South Slocan plants.

Offsetting the higher costs in these two categories was lower spending in data analytics. FBC spent $0.105 million less than the formula amount in 2021 primarily due to labour savings from a delay in hiring. In 2021, FBC focused on finalizing the requirements for the necessary information infrastructure, with the implementation of the systems that will allow centralized data access occurring in 2022 and the addition of new data sources in priority sequence over the remaining term of the MRP.

For the first two years of the MRP, FBC spent $0.449 million more than the formula amount. Over the term of the MRP, FBC anticipates the total new/incremental spending required in the combined categories of System Operations, Integrity and Security will continue to be higher than the amount embedded in the formula. FBC will continue to manage this spending within its overall O&M spending envelope.

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. For 2023, FBC has included incremental O&M for the Mandatory Reliability Standards (MRS) Assessment Report No. 13 (AR13), which was approved for exogenous treatment in the 2022 Annual Review.

The 2023 amounts are shown in Table 6-4 below along with a comparison to 2022.

Table 6-4: 2023 Forecast O&M ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Pension/OPEB (O&M Portion)	$ (1.716)	$ (1.716)	$ (1.297)
2	Insurance Premiums	2.223	2.291	2.457
3	BCUC Levies	0.373	0.373	0.385
4	Clean Growth Initiative - EV DCFC Stations	0.187	0.187	0.193
5	Exogenous Factor - MRS	0.765	0.500	0.585
6	Total Forecast O&M	$ 1.832	$ 1.635	$ 2.323

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expense 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 exogenous factors are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expense for 2023 is based upon actuarial estimates using a range of assumptions as of December 31, 2021 with an update of discount rate estimates as of April 30, 2022 provided by the Company's external third party actuary, Willis Towers Watson. The discount rate determined reflects the market yields of high quality Canadian corporate bonds which have increased since 2021. In addition to O&M, pension and OPEB expense is embedded in Capital Expenditures, as shown in Table 6-5.

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

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	O&M	$ (1.716)	$ (1.716)	$ (1.297)
2	Capital (Approved)	3.807	3.807	1.888
3	Capital (to Pension & OPEB Variance Deferral)[1]	(0.400)	(0.400)	-
4	Total	$ 1.691	$ 1.691	$ 0.591

Notes to Table:

[1] This line item represents the pension and OPEB expense difference between the estimates embedded in the Regular Capital Expenditure forecasts on Line 2 in this table, which were based on the pension and OPEB actuarial estimates provided in 2019 as part of the 2020 to 2024 MRP Application, and the actuarial estimates

updated for 2023 rate-setting purposes. There is no difference for 2023 since FBC was directed to file an updated forecast of the 2023 and 2024 Regular Capital Expenditures in the 2023 Annual Review, as directed in the MRP Decision and Order G-166-20.

The variance between the 2022 Approved and actual pension and OPEB expense, including the known capital variance on Line 3 of Table 6-5 above, and any variance between the 2023 Forecast and actual amounts, is 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.

The 2023 Forecast pension and OPEB expense has decreased by $1.100 million compared to the 2022 Approved expense primarily due to the following factors, which are all components of pension and OPEB expense:

- An approximate $3 million decrease in current service costs due to an increase in the discount rate. The discount rate, which is determined with reference to the market rate of interest on high quality debt instruments at a point in time, increased from 3.5 percent, which was used to determine the 2022 Approved expense, to 4.5 percent, which is used to determine the 2023 Forecast expense;

offset in part by:

- An approximate $2 million increase in interest costs due to an increase in the discount rate.

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 2022	Projected 2022	Forecast 2023	Reference
1	Insurance Premiums	$ 2.223	$ 2.291	$ 2.457	Section 11, Schedule 20, Line 16
2	Total	$ 2.223	$ 2.291	$ 2.457	

The 2022 Projected insurance premium expense of $2.291 million is $0.068 million higher than 2022 Approved, as it incorporates FBC's actual July 2022 to June 2023 insurance renewals of $2.253 million. The higher premiums experienced in 2022 are expected to continue into 2023, though at a lower rate of increase. The 2023 Forecast is $2.457 million, which is an increase of $0.166 million from 2022 Projected. The 2023 Forecast is calculated as the amount of the first six months of actual annual insurance premiums for January to June 2023 of $1.126 million and

applying a 5 percent increase for the remaining six months, plus the cost of fire fighting services FBC pays to the Province of $0.148 million.[26]

6.3.3 BCUC Levies

FBC's 2023 Forecast for BCUC levies is $0.385 million. The 2023 Forecast is based on Order G-188-22 for the BCUC's Fiscal 2022/23 year, which represents the best information available at this time, as the BCUC levy calculation for Fiscal 2023/24 will not be available until early or mid 2023.

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

6.3.4 Clean Growth Initiative – Electric Vehicle (EV) DCFC Stations

As discussed in Section 5.8, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[27] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. Please refer to Table 5-2 in Section 5.8 which provides a summary of the EV DCFC stations' costs and revenues from 2021 Actual to 2023 Forecast.

As shown in Table 6-7 below, the 2022 Projected EV DCFC station O&M expense is expected to be consistent with 2022 Approved[28], and consists of network management, repairs and maintenance, inspection fees and FBC labour costs. The 2023 Forecast EV DCFC station O&M expense is anticipated to be similar to the 2022 Projected level, with an approximate increase of $6 thousand primarily due to inflation.

Table 6-7: Clean Growth Initiative – EV DCFC Stations ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Clean Growth Initiative - EV DCFC	$ 0.187	$ 0.187	$ 0.193	Section 11, Schedule 20, Line 19
2	Total	$ 0.187	$ 0.187	$ 0.193	

6.3.5 MRS Incremental Operating Expenses

In the 2022 Annual Review Decision,[29] FBC received approval of exogenous factor treatment for the incremental O&M and capital costs associated with MRS AR13. As explained in the 2022

[26] $2.253 million/2 = $1.126 million. $1.126 million x 1.05 = $1.183 million. $1.126 million + $1.183 million + $0.148 million annual firefighting service fee = $2.457 million.
[27] Order G-215-21 dated July 14, 2021.
[28] Consistent with the 2022 Annual Review Decision, FBC included the 2022 forecast revenues and expenses associated with the EV DCFC stations in the Compliance Filing to the Annual Review Decision and Order G-374-21 because approval of the EV DCFC Service Application was not received until November 24, 2021. Accordingly, the 2022 Approved amount reflected in Table 6-7 is the amount included in the Compliance Filing.
[29] Decision and Order G-374-21, p. 21.

Annual Review, FBC expected to incur one-time costs in 2021 and 2022 related to the adoption of the standards in AR13 as well as ongoing incremental O&M expenses commencing in 2023[30].

BC Hydro issued AR13 on May 1, 2020 recommending adoption of seven standards, retirement of one standard, and holding one standard in abeyance pending resolution of the Planning Coordinator (PC) function along with the NERC Glossary dated August 12, 2019. The BCUC issued Order R-19-20 on September 8, 2020 accepting BC Hydro's recommendation and determined the effective dates of those standards. Of the standards and respective NERC Glossary terms assessed by FBC, five standards have associated costs, of which one was held in abeyance. The effective date for the four adopted standards is April 1, 2023, including the existing CIP-005-6 (Electronic Security Perimeter(s)), CIP-008-6 (Incident Reporting and Response Planning) and CIP-010-3 (Configuration Change Management and Vulnerability Assessments) standards and the new CIP-013-1 (Supply Chain Risk Management) standard. In order to address these changes, FBC is required to monitor and disconnect vendor remote access, evaluate and report attempts to compromise, ensure software downloads and installations are unaltered and secure, and assess risk for any product or service procured for Bulk Electrical System assets under the Critical Infrastructure and Protection (CIP) standards. These requirements are reflected in the 2022 Approved, 2022 Projected, and 2023 Forecast expenses in Table 6-8 below.

The following table provides the 2022 Approved and Projected and the 2023 Forecast of incremental O&M related to MRS AR13.

Table 6-8: Incremental O&M for MRS AR13 ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Labour	$ 0.335	$ 0.200	$ 0.490	
2	Non-Labour	0.280	0.250	0.095	
3	Contingency	0.150	0.050	-	
4	Total	$ 0.765	$ 0.500	$ 0.585	Section 11, Schedule 20, Line 18

The 2022 Projected O&M expense is lower than 2022 Approved by $0.265 million. The reduction of $0.265 million is a result of less overall effort required to modify existing programs and processes as mentioned above than originally expected.

The 2023 Forecast O&M expense of $0.585 million is related to the expected ongoing efforts to maintain procedures and processes, hardware and software that address supply chain risk assessments, ongoing licensing and maintenance of the hardware and software, and the documentation to maintain compliance of AR13. The 2023 Forecast is based on the expected costs in 2022 Projected and is therefore less than the 2022 Approved level. These costs are annual and will continue in future years.

[30] Exhibit B-2, Annual Review for 2022 Rates Application, Section 12.2.1, pp. 103-104; Exhibit B-3, BCUC IR1 24.2.

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 2022. After capitalized overhead, the net O&M expense is $61.871 million in 2023.

6.5 SUMMARY

Overall, the increase in gross O&M expense from 2022 Approved to 2023 Forecast is 7.0 percent. Formula-driven O&M is increasing at a rate of 5.8 percent, and O&M forecast outside the formula is 26.8 percent higher than 2022 Approved.

The capitalized overhead rate for 2023 remains unchanged from 2022.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

FBC forecasts its Rate Base to be $1.675 billion for 2023. Rate Base is comprised of mid-year net plant in service, work in progress not attracting AFUDC, unamortized deferred charges, working capital, and the utility plant acquisition adjustment.[31]

FBC's 2023 Rate Base includes the full-year impacts of the 2022 closing projected plant balances as well as the impact of the following amounts:

- Mid-year impact of regular capital additions, net of CIAC additions, of $94.209 million;
- Mid-year impact of plant depreciation, net of CIAC amortization, of $64.407 million; and
- Capital additions of CPCNs and other Major Projects totalling $45.439 million[32], as discussed in Section 7.3 below, which include:
    - Full-year impact of $21.250 million for the capital expenditures and related AFUDC for the Kelowna Bulk Transformer Additions (KBTA) Project, which is expected to complete in late 2022 or early 2023;
    - Full-year impact of $16.151 million for the final capital expenditures and related AFUDC for the Corra Linn Dam Spillway Gates Replacement Project, which is expected to complete in 2022; and
    - Full-year impact of $8.036 million for the final capital expenditures and related AFUDC for the Playmor Substation Upgrade Project, which is expected to complete in 2022.

In addition, various changes in deferred charges, working capital and other items increase rate base by a net amount of $24.303 million in 2023.

Details of the 2023 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 2022; and

[31] 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.

[32] The 2023 capital additions of $45.439 million also include $0.002 million for the close out costs and related AFUDC in 2022 for the UBO Old Units Refurbishment Project.

- Approval of a number of items to be forecast on an annual basis.

Further, in the MRP Decision the BCUC directed FBC to file an updated forecast of the 2023 and 2024 regular capital expenditures in the 2023 Annual Review.[33]

The components of FBC's 2023 regular capital expenditures are shown in Table 7-1 below.

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

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Forecast Capital	$ 81.925	$ 87.735	$ 94.428	Table 7-2 and Table 7-3, Line 4
2	Flow-Through Capital	0.935	2.430	0.248	Table 7-11, Line 3
3	Total Gross Regular Capital	$ 82.860	$ 90.165	$ 94.676	Sum of Lines 1 & 2
4	Less CIAC	(11.712)	(8.287)	(11.628)	Section 11, Schedule 9, Line 2
5	Net Regular Capital	$ 71.148	$ 81.878	$ 83.048	Sum of Lines 3 & 4

In Section 7.2.1, FBC provides its updated 2023 and 2024 regular capital forecasts. In Section 7.2.2, FBC provides details on its forecast flow-through expenditures for 2023, consistent with the format provided in previous annual reviews during this MRP term.

7.2.1 Updated 2023 and 2024 Forecast Regular Capital Expenditures

As stated above, in the MRP Decision and Order G-166-20[34], the BCUC directed FBC to file updated 2023 and 2024 regular capital forecasts as part of the 2023 Annual Review. The BCUC in its decision highlighted FBC's evolving operating environment and inherent uncertainties in the capital forecasts, and thus considered it appropriate for FBC to have the opportunity to true-up its capital spending and re-forecast its capital for the final two years of the MRP term. Specifically, the BCUC stated the following:

> …FEI and FBC face evolving operating environments and there are inherent uncertainties in the five-year forecast. Reviewing the capital forecast in 2022 allows for a review of any significant variances between forecast and actual to date and provides an opportunity to true-up the rate-base for actual spending and to re-forecast the remaining years in the MRP term.[35]

As further explained below, FBC has begun to experience pressures due to a variety of factors which are outside of the Company's control and could not have been anticipated at the time of the MRP proceeding, including supply chain issues and rising commodity prices and other inflationary pressures brought on by the COVID-19 pandemic and the war in Ukraine. These factors, as well as the increased cost and complexity in permitting and land acquisition as well as increased growth, are impacting FBC's ability to execute on all of its planned capital projects and programs. While FBC has pursued various mitigation measures to manage through the spending

[33] MRP Decision and Order G-166-20, p. 131.
[34] Directive 1.c. of Order G-166-20.
[35] MRP Decision and Order G-165-20, p. 131.

pressures, FBC requires an increase in its capital spending for 2023 and 2024 compared to its original forecasts to execute on its planned activities.

The following tables summarize the growth, sustainment and other capital expenditures[36]. The first table presents the 2020 through 2022 Approved forecasts (i.e., the forecasts approved in the MRP Decision) and the 2023 and 2024 forecasts which were reviewed during the MRP proceeding (Original Forecasts). The second table provides the Actual/Projected results for 2020 through 2022 and FBC's updated forecasts for 2023 and 2024 (Updated Forecasts).

Table 7-2: Regular Capital Expenditures, 2020-2022 Approved and 2023-2024 Original Forecasts ($ millions)

Line No.	Description	Approved 2020	Approved 2021	Approved 2022	Original Forecast 2023	Original Forecast 2024
1	Growth Capital	27.029	23.042	24.339	26.283	23.170
2	Sustainment Capital	50.463	49.818	42.830	44.377	53.470
3	Other Capital	15.752	14.712	14.756	15.281	15.134
4	Total	93.244	87.573	81.925	85.941	91.774

Table 7-3: Regular Capital Expenditures, 2020-2021 Actual, 2022 Projected and 2023-2024 Updated Forecasts ($ millions)

Line No.	Description	Actual 2020	Actual 2021	Projected 2022	Updated Forecast 2023	Updated Forecast 2024
1	Growth Capital	28.799	21.865	29.868	30.973	24.568
2	Sustainment Capital	47.325	49.601	41.486	45.797	58.673
3	Other Capital	16.036	15.349	16.381	17.658	17.213
4	Total	92.160	86.815	87.735	94.428	100.454

In Section 7.2.1.1, FBC describes its updated forecasts for growth and sustainment capital. In Section 7.2.1.2, FBC describes its updated forecasts for other capital.

7.2.1.1 Growth and Sustainment Capital

7.2.1.1.1 GROWTH CAPITAL

Growth capital expenditures involve transmission and distribution system improvements required to meet incremental customer and load growth, in addition to the cost of connecting new customers to the system.

The three main growth capital portfolios are: (i) Transmission Growth; (ii) Distribution Growth; and (iii) New Connects. In the MRP Application, FBC provided forecasts of these three categories of

[36] Excluding sustainment CIAC.

growth capital expenditures based on a bottom-up approach which included a two percent inflationary increase per year.

The following tables provide the 2020 to 2022 Approved vs Actual/Projected expenditures and the Original and Updated 2023 and 2024 Forecasts.

Table 7-4: Growth Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Transmission Growth	5.172	7.109	2.063	0.744	2.740	5.524
2	Distribution Growth	3.716	1.926	1.876	1.965	1.807	3.450
3	New Connects	18.141	19.764	19.104	19.156	19.792	20.894
4	Total Growth Capital	27.029	28.799	23.042	21.865	24.339	29.868

Table 7-5: Growth Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Transmission Growth	5.195	6.223	1.086	1.088
2	Distribution Growth	1.899	2.800	1.921	1.716
3	New Connects	19.188	21.951	20.163	21.764
4	Total Growth Capital	26.283	30.973	23.170	24.568

As shown in Table 7-5 above, FBC's Updated Forecasts for growth capital have increased by $4.690 million in 2023 and $1.398 million in 2024 compared to the Original Forecasts. FBC is forecasting increases in all three growth capital portfolios in 2023. For 2024, the increase is primarily in the New Connects portfolio, with FBC reducing the expenditures for the Distribution Growth portfolio to offset some of the required increases. These increases are described in Section 7.2.1.1.3 below.

7.2.1.1.2 SUSTAINMENT CAPITAL

The expenditures within sustainment capital include system improvements to the transmission and distribution system in order to maintain existing equipment to meet forecast load and for the safety, reliability and quality of the system. FBC operates and maintains four generating facilities with a total of 15 units. FBC regularly monitors its infrastructure to ensure it meets industry standards and guidelines, complies with regulations, and operates safely to minimize risk to the public and employees. FBC also identifies and addresses hazards and risks that require immediate attention through specific projects. FBC's telecommunications system is an integral component in the protection relaying system, remedial action schemes, substation operations and control, and generation dispatch systems. The system requires ongoing investment to replace aging or failed systems for safe and reliable operation of the system and to ensure business needs continue to be met.

The five main sustainment capital portfolios are: (i) Generation; (ii) Transmission Sustainment; (iii) Stations Sustainment; (iv) Distribution Sustainment; and (v) Telecommunications. In the MRP

Application, FBC provided forecasts of these five categories of sustainment capital expenditures based on a bottom-up approach which included a two percent inflationary increase per year.

The following tables provide the 2020 to 2022 Approved vs Actual/Projected expenditures and the Original and Updated 2023 and 2024 Forecasts.

Table 7-6: Sustainment Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Generation	6.697	5.884	6.766	6.949	6.309	6.731
2	Transmission Sustainment	8.353	12.506	6.387	10.667	5.698	7.841
3	Stations Sustainment	13.538	4.821	13.624	12.083	5.279	6.889
4	Distribution Sustainment	20.057	21.530	20.058	17.479	19.262	17.439
5	Telecommunications	1.818	2.584	2.983	2.423	6.280	2.587
6	Total Sustainment Capital	50.463	47.325	49.818	49.601	42.830	41.486

Table 7-7: Sustainment Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Generation	7.008	7.623	6.514	7.225
2	Transmission Sustainment	7.951	9.159	7.591	12.800
3	Stations Sustainment	3.793	7.928	15.971	15.229
4	Distribution Sustainment	19.710	17.480	19.922	18.219
5	Telecommunications	5.915	3.606	3.472	5.199
6	Total Sustainment Capital	44.377	45.797	53.470	58.673

As shown in Table 7-7 above, FBC's Updated Forecasts for sustainment capital have increased by $1.420 million in 2023 and $5.203 million in 2024 compared to the Original Forecasts. For 2023, the increases are primarily in the Transmission Sustainment and the Stations Sustainment portfolios, with FBC proposing to reduce the expenditures for the Distribution Sustainment and the Telecommunications portfolios to offset some of the required increases. For 2024, the increases are primarily in the Transmission Sustainment and Telecommunications portfolios, with FBC proposing to reduce the expenditures for the Distribution Sustainment and the Stations Sustainment portfolios to offset some of the required increases. These increases are described in Section 7.2.1.1.3 below.

7.2.1.1.3 DRIVERS OF UPDATED GROWTH AND SUSTAINMENT CAPITAL FORECASTS

The drivers of the increases in growth and sustainment capital are summarized as follows:

- Significant inflationary increases brought on by unanticipated events such as the COVID-19 pandemic and the war in Ukraine, which have resulted in large cost escalations in materials, labour and fuel;
- Increases in growth capital as a result of more customer applications; and
- Additional reliability, refurbishment or end of life projects being required that were not anticipated at the time of the MRP proceeding.

These cost drivers, as well as the mitigation efforts FBC has undertaken during the first three years of the MRP term, are described in the following subsections.

FBC is Experiencing Significant Inflationary Pressures

FBC's Original Forecasts were developed using an assumption of two percent for annual inflation. While FBC has generally managed its overall capital spending within the approved levels over the first two years of the MRP term, FBC has begun to experience pressures throughout its growth and sustainment portfolios. These pressures coincide with the significant global market events experienced during this time period, including the COVID-19 pandemic, supply chain disruptions, and the war in Ukraine. These unforeseen events have had a significant impact on market conditions for many commodities and services that make up FBC's supply chain, and the impacts are still being felt and continue to contribute to volatility in the supply chain and the overall commodity and services market in 2022.

In order to better understand the extent of the inflationary impacts that have affected North American utilities since 2020 and to compare the impacts on the industry with FBC's experience, FBC engaged Wood Mackenzie Supply Chain Consulting (Wood Mackenzie) to provide a market report on electric and gas utility transmission and distribution (T&D) markets from 2020 to 2022 and the anticipated impact until the end of 2024 (Wood Mackenzie Report). Wood Mackenzie identified an average escalation of 17.5 percent in capital costs for electric utilities between the period of the first quarter of 2020 and the first quarter of 2022. The Wood Mackenzie Report is based on the aggregated spend from utilities across North America, and incorporated over 150 indices which roll up to form the model for each category. Indices specific to BC have also been incorporated where appropriate, particularly around trades and other labour in the Province. This report has been included as Appendix C1.

FBC has experienced significant inflationary pressures during the first three years of the MRP term and expects these pressures will continue into 2023 and 2024. In particular, FBC has experienced the most significant inflationary cost pressures for poles, transformers and wires/cables. The projects in Transmission, Distribution and Station growth and sustainment portfolios have been impacted by incremental increases in the cost of these materials since 2020. Cost escalation is also impacting FBC due to steel commodity prices in North America, which have increased approximately 117 percent from the first quarter of 2020.

As shown in the Wood Mackenzie Report, it is expected that the average capital costs for electric utilities will continue to rise until the fourth quarter of 2024, although at a slower pace than what was experienced between the first quarter of 2020 and the first quarter of 2022, and will not come back down to the 2020 level. This expectation also aligns with the Bank of Canada's July 2022 Monetary Policy Report[37] which projects that CPI is expected to hover around 8 percent in the third quarter of 2022 before decreasing to approximately 3 percent by the fourth quarter of 2023 and 2 percent in 2024.

[37] https://www.bankofcanada.ca/wp-content/uploads/2022/07/mpr-2022-07-13.pdf.

Updated Forecasts Reflect Increased Growth

The New Connects category includes the installation of new electric services consisting of additions to FBC overhead and underground distribution facilities. These capital expenditures allow FBC to meet its obligation to provide reliable service to customers in its service area. This category also funds any costs associated with upgrading FBC facilities to provide service for an extension or drop service. Consistent with past practice, the forecast expenditures for New Connects are based on a historical rolling average of expenditures adjusted by inflation. The overall increase is due to more customer applications for connections.

Updated Forecasts Reflect New Growth and Sustainment Projects

As noted by the BCUC in the MRP Decision, there are inherent uncertainties in capital forecasting, particularly when forecasting projects over a five-year period. In the MRP Application, FBC identified projects over $1 million that it anticipated undertaking over the five-year MRP term. Due to a variety of reasons, such as land and permitting issues, re-prioritization of capital spending, and changes in capacity requirements, some projects have been delayed or cancelled while other new projects have been identified and prioritized.

For example, in order to address aging infrastructure and to support load growth while maintaining current levels of reliability, substation rebuild projects or transformer addition projects are required. In some cases, these projects require increasing the station footprint and acquiring more adjacent land or larger parcels of land in new locations. The selection of an appropriate land parcel can be a lengthy process that can include activities such as open houses as part of stakeholder consultation. Given the uncertainties related to consultation and purchase negotiation, it introduces risk to project timelines if these activities are not completed in advance of the project execution window. The need to acquire land has arisen in a number of FBC's planned projects and has resulted in increased costs and, at times, delays to the project schedule. Projects that have been impacted by land acquisition requirements are described in Appendix C2 and include, as an example, the Fruitvale Station Upgrade project.

As detailed in the MRP Application[38], FBC actively manages its capital plan to ensure projects are planned and executed efficiently. Accordingly, the timing, scope, and cost of the individual projects and programs within the overall regular capital forecasts are subject to change, and FBC may identify new projects and programs that need to be added over the term of the MRP. The capital plan contains a mix of projects across the portfolio categories, some of which are time sensitive and others that have some schedule flexibility. The plan is developed with the understanding that conditions change and the plan must be capable of adapting. This provides FBC flexibility to manage and execute normal levels of unforeseen urgent work that are expected to occur throughout the year within the resource and budget constraints of the capital plan. While this flexibility means that individual projects may move around, at a portfolio level, FBC has consistently executed a similar portfolio of work to the Original Forecasts.

[38] Section 3.4.1.5, page C-106.

In Appendix C2, FBC provides a list of the projects over $1 million which are included in the Updated Forecasts for 2023 and 2024.

FBC Employed Mitigation Strategies to Limit Cost Pressures

FBC has implemented the following strategies to mitigate the impact of the aforementioned cost pressures:

- Re-scheduling projects that can be safely re-scheduled to 2023 to accommodate other project costs increase that could not be deferred. As detailed in Section 3.2 (Capital Planning Process – page C-52) of the MRP Application, FBC manages its capital investment plan to maintain a safe and reliable system, optimize resources and spending, and achieve efficiencies and cost savings. The capital plan contains a mix of projects, some of which are time-sensitive and others that have some schedule flexibility. The plan is developed with the understanding that conditions change, and the plan must be capable of adapting. This provides FBC flexibility to manage and execute normal levels of unforeseen urgent work that is expected to occur throughout the year within the resource and budget constraints of the capital plan. While FBC has delayed some work with flexible timing to accommodate the increased demands in 2022, this has only mitigated part of the capital pressures due to the magnitude of market pressures;
- Entering into long-term supply contracts for many commonly used materials and service providers (e.g., engineering consultants, construction contractors, etc.);
- Competitively tendering large contracts for materials and services to ensure competitive pricing;
- Communicating with critical suppliers and contractors to discuss issues and mitigation strategies;
- Negotiating collective agreement with unionized FBC employees that provide longer-term stability for internal labour rates (IBEW and MoveUP agreement expires in 2023); and
- Optimally allocating construction work to internal or external construction crews as appropriate.

Despite the mitigation strategies listed above, FBC has not been able to fully mitigate cost increases due to the cost drivers described above.

7.2.1.2 Other Capital

In this section, FBC provides its Updated Forecasts for other capital. Other capital includes Equipment, Facilities and Information System (IS) expenditures.

Table 7-8 below shows the Approved and Actual/Projected other capital from 2020 to 2022 while Table 7-9 below shows the Original and Updated Forecasts of other capital for 2023 and 2024. FBC notes that the majority of the increase shown in the Updated Forecasts is related to Facilities, primarily as a result of the Kelowna Space Project.

Table 7-8: Approved and Actual/Projected Other Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Equipment	3.407	3.444	3.338	2.711	3.274	3.560
2	Facilities	3.264	3.434	2.346	3.685	2.346	2.846
3	Information Systems	9.081	9.158	9.028	8.953	9.136	9.975
4	Total Other Capital	15.752	16.036	14.712	15.349	14.756	16.381

Table 7-9: Original and Updated Forecasts of Other Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Equipment	3.681	4.099	3.388	3.717
2	Facilities	2.346	4.305	2.346	4.096
3	Information Systems	9.254	9.254	9.400	9.400
4	Total Other Capital	15.281	17.658	15.134	17.213

The following sections provide further details on the Updated Forecasts for other capital.

7.2.1.2.1 EQUIPMENT CAPITAL

Equipment capital expenditures include the acquisition of vehicles, specialized tools and equipment. Expenditures for the equipment listed above are driven by obsolescence, excessive wear and regulatory compliance.

FBC's 2023 and 2024 capital forecasts for Equipment have increased by $0.418 million and $0.329 million, respectively, compared to the Original Forecasts. The average unit cost per vehicle has risen significantly as supply of vehicles has reduced in relation to demand in the marketplace. In particular, FBC is experiencing the following changes to the average cost of the vehicles:

- Substantial reduction in volume-based concessions from manufacturers to all commercial fleet (from $10.5 thousand to $2.5 thousand per unit);
- Increased costs on steel, aluminum, glass and paint; and
- Inflationary surcharges on transport of materials, services and labour by manufacturers;

7.2.1.2.2 FACILITIES CAPITAL

Facilities capital expenditures include the acquisition or leasing of land, buildings, and building equipment. Facilities capital expenditures focus primarily on capacity planning, upgrading and replacement of end of life assets. The Facilities department ensures approved facilities projects are built to meet internal standards, building codes and regulations, and provide a long-term solution toward meeting the business requirements.

As shown in Table 7-9 above, FBC's 2023 and 2024 Facilities capital forecasts have increased by $1.959 million and $1.750 million in 2023 and 2024, respectively, compared to the Original

Forecasts. As further explained below, the majority of the increase is for the Kelowna Space Project. The remainder of the increase is related to: (i) energy management and GHG emissions reductions activities that FBC is planning to undertake to improve the adaptability and resiliency of FBC's facilities; and (ii) the installation of EV infrastructure at FBC's facilities.

Kelowna Space Project

FBC continues to experience capacity challenges at numerous locations for office, material storage and parking spaces and has been working to address these complex challenges. These capacity issues are impacting FBC's facilities across the Province and require different solutions depending on the location, as the challenges vary depending on the unique circumstances of each region. At the time of filing the MRP Application, FBC was in the process of developing a strategy for a cost-effective solution to the capacity issues in the Kelowna area, and therefore did not include this project in its Original Forecasts.

Both FEI and FBC have been experiencing space capacity challenges in the Kelowna region. Identifying solutions to address the space constraints has been very challenging, particularly due to the significant escalation in real estate costs to acquire new industrial land in the Kelowna area. However, the companies have now finalized a solution which leverages the use of FEI's and FBC's existing sites and results in the leasing of a new site for FEI's and FBC's Shared Services Departments. As further explained below, the Kelowna Space Project is a combined project for FEI and FBC, and the cost of the project has therefore been allocated between the two utilities accordingly. The total cost of the Kelowna Space Project is $13.930 million. Of this total, approximately $2.934 million is allocated to FBC based on employee count, with $1.209 million and $1.000 million reflected in FBC's Updated Forecasts for 2023 and 2024, respectively[39].

As part of the Kelowna Space Project, both FEI and FBC Shared Services Departments (Support Services) located in Kelowna will relocate to a new office lease facility approximately 25,000 ft^2 in size. Tenant improvements will be completed in 2023 and the Shared Services Departments will be relocated to this new leased facility. The allocation of leasing costs for this site will be determined using a cost driver approach based on the number of employees for FEI and FBC. In addition, FBC's Electrical Operations will move to the existing FEI-owned Springfield facility, as that location has a larger footprint and thus better aligns with the required Electrical Operations Space Program. FEI's Gas Operations will move to the existing FBC-owned Benvoulin property, as Gas Operations has a smaller footprint requirement. Broadly speaking, the Electrical and Gas Operations will "swap" locations.

Each building will require modifications to accommodate the Space Program requirements. Work will commence in late 2023 to complete the swap in 2025. Changes in building occupancy will be captured through new lease agreements where FEI will lease the entire Benvoulin building from

[39] There was also approximately $0.631 million and $0.094 million of actual costs related to the Kelowna Space Project allocated to FBC in 2020 and 2021, respectively, with the total allocation to FBC equaling approximately $2.934 million, including the forecast expenditures in 2023 and 2024.

FBC and FBC will lease the entire Springfield building from FEI. The buildings will remain operational while these changes are made.

The Kelowna Space Project results in a number of benefits for both FEI and FBC, including:

- Provision of sufficient space for both Operations and Support Services:
  - Support Services space requirement of 25,000 ft^2 of office at a new leased facility;
  - Gas Operations space requirement of 15,000 ft^2 of office and 12,000 ft^2 of industrial storage and shop space align with the sizing of the Benvoulin buildings and site; and
  - Electric Operations space requirement of 33,000 ft^2 of office and 13,000 ft^2 of industrial storage and shop space align with the sizing of the Springfield buildings and site;
- Retaining and updating the existing properties and adding a leased office facility results in a reasonable implementation timeline; changes are made at a measured pace to minimize business and employee disruption and do not require temporary relocation to another facility;
- The solution ensures Electric Operations remain located in an area that best supports their service territory; by not relocating this group farther from the city, potential inefficiencies are prevented;
- The solution is cost effective in contrast to other options such as purchasing new property or constructing a new Operation Hub, and utilizes FEI's and FBC's existing properties to the best extent possible; and
- Each Operations group is located in its own facility, increasing planning, operations, and management efficiencies.

Capital Expenditures to Support Energy Efficiency and GHG Reductions

The Updated 2023 and 2024 Forecasts include $0.750 million in each year for expenditures that are specifically in support of energy efficiency and GHG emissions reductions. These expenditures consist of projects that will result in reduced electrical and natural gas usage in FBC's facilities and/or will result in GHG emissions reductions. Where applicable, the planned projects are aligned with the ISO 50,001 Energy Management Standard, and enable FBC to prepare for the impacts of climate change and the transition to net-zero emissions. These planned projects will improve FBC's buildings' energy efficiency, support the adoption of electric vehicles, and contribute to efforts towards climate change and the Province's CleanBC Plan targets.

FBC is pursuing energy management and GHG emissions reduction opportunities for its buildings as part of the Company's climate action initiatives, including energy management activities related to climate adaptation, mitigation, and resiliency for buildings. FBC also plans to install EV charging infrastructure at FBC's facilities for fleet use.

Historically, the Facilities department has prioritized capital spending for capacity planning, end-of-life replacements, and meeting building codes and regulations. However, in light of the importance of addressing climate change, Facilities is now focusing on advancing climate action initiatives and strategies. Examples of advancements are installation of EV charging infrastructure, upgrading lighting to LED, completing energy audits to identify opportunities to inform capital planning, and incorporating energy efficiency components in long-term lease agreements.

7.2.1.2.3 INFORMATION SYSTEMS

FBC's Information Systems (IS) expenditures focus on enhancing, replacing, upgrading and sustaining existing applications and infrastructure or, as needed, introducing new technology capabilities in order to improve safety, customer service, reliability and efficiency.

As shown in Table 7-8 above, the actual/projected expenditures for 2020 through 2022 are generally consistent with what was forecast in the MRP Application. As such, FBC has not made any changes to the 2023 and 2024 IS capital forecasts (Table 7-9 above) compared to what was presented in the MRP Application as there have been no changes in circumstances or anticipated spending that would warrant revisions.

7.2.1.3 Summary of FBC's Updated Regular Capital for 2023 and 2024

FBC provided an updated forecast for regular growth, sustainment and other capital in 2023 and 2024. These Updated Forecasts are summarized in Table 7-10 below.

Table 7-10: Summary of 2023-2024 Updated Forecasts of Regular Capital

Line No.	Description	2023 Updated Forecast	2024 Updated Forecast
1	Growth Capital	30.973	24.568
2	Sustainment Capital	45.797	58.673
3	Other Capital	17.658	17.213
4	Total Regular Capital	94.428	100.454

For FBC's growth and sustainment capital, the Updated Forecasts reflect the significant and unanticipated cost pressures experienced over recent years. These pressures, generally experienced by North American utilities, are being driven by factors outside of FBC's control, and include, among others, the COVID-19 pandemic, supply chain pressures and the war in Ukraine, as well as growth-related expenditures and necessary reliability, refurbishment and end of life replacement projects. The Updated Forecasts will ensure FBC's ability to execute its planned growth and sustainment capital programs which are critical to ensuring the ongoing safe and reliable operation of FBC's system and ensuring that FBC is able to meet its customer's needs.

For FBC's other capital, the Updated Forecasts are primarily related to the Kelowna Space Project, as well as expenditures for activities at FBC's facilities related to energy efficiency and GHG emissions reductions.

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 2023 are shown in Table 7-11 below along with a comparison to 2022.

Table 7-11: Flow-Through Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Clean Growth Initiative - EV DCFC	$ -	$ 1.560	$ 0.248	
2	Exogenous Factor - MRS	0.935	0.870	-	
3	Forecast Capital Expenditures	$ 0.935	$ 2.430	$ 0.248	Section 11, Schedule 4, Line 10

7.2.2.1 EV DCFC Stations

As discussed in Section 5.8, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[40], and the cost of service associated with EV charging stations is subject to flow-through treatment. Please refer to Table 5-2 of Section 5.8 which provides a summary of the EV DCFC stations' costs and revenues from 2021 Actual to 2023 Forecast.

Table 7-11 above shows the EV DCFC stations capital expenditures for 2022 Approved[41], 2022 Projected, and 2023 Forecast. FBC originally did not forecast any EV DCFC station capital in 2022 during the 2022 Annual Review as FBC expected all construction activities to be completed in 2021. However, the originally planned construction activities in 2021 were delayed to 2022 mainly due to the flooding experienced in the latter part of 2021 which also led to FBC being required to undergo design changes to 16 of its DCFC sites to complete a required safety retrofit for the power supply kiosks. The flooding caused delays in construction and deployment for two planned DCFC stations in Keremeos and Princeton that were identified in FBC's Revised and Updated Application for EV DCFC Service and approved by Order G-215-21[42]. This resulted in an increase in capital expenditures for 2022 Projected when compared to 2022 Approved. FBC notes the reduction in expenditures for 2021 due to the delayed deployment of the Keremeos and Princeton stations was offset by the installation of two new DCFC stations in late 2021 at existing sites (i.e., Naramata and Grand Forks). Installations at Keremeos and Princeton are planned to be completed by the end of 2022, which by then will bring the total number of DCFC stations in service to 42 across the 23 sites. At this time, FBC is not expecting to construct any additional

[40] Order G-215-21 dated July 14, 2021.
[41] Consistent with the 2022 Annual Review Decision, FBC included the 2022 forecast revenues and expenses associated with the EV DCFC stations in the Compliance Filing to the Annual Review Decision and Order G-374-21 because approval of the EV DCFC Service Application was not received until November 24, 2021. Accordingly, the 2022 Approved amount reflected in Table 7-11 is the amount included in the Compliance Filing.
[42] FBC's Revised and Updated EV DCFC Service Application, Table 2-2, pp. 10-11.

stations or sites beyond the two additional DCFC stations noted above; however, station utilization will continue to be monitored to determine if any additional stations are warranted to meet customer demand. For 2023, FBC is forecasting to complete accessibility improvements for its existing EV DCFC sites. These improvements include new or additional lighting as the stations are available for use 24 hours a day, and paving for wheelchairs access to the charger.

The two new DCFC stations were installed at the existing Naramata and Grand Forks sites that only have a single DCFC station installed previously. Both Naramata and Grand Forks were identified in FBC's Revised Application for EV DCFC Service, and construction of these two additional stations was completed in late 2021. As directed by Order G-341-21[43], FBC is to include evaluation of any additional EV charging stations that were not originally identified in the Revised EV DCFC Service Application in FBC's Annual Review process, including review of whether the additional stations meet the criteria to be a prescribed undertaking under the GGRR and assessment of whether the levelized rate under RS 96 EV DCFC service will need to be recalculated as a result of the additional EV charging stations. Consistent with the information provided in FBC's Revised EV DCFC Application, Table 7-12 below shows that these two additional stations are prescribed undertakings and meet the requirements as set out in section 5 of the GGRR. Regarding the review of the levelized rate under RS 96 EV DCFC service, as discussed in Section 5.8, FBC is required to file a detailed assessment of the EV DCFC service by the end of December 31, 2022, which includes an update of the financial models with actual and forecast information as well as a detailed assessment of RS 96 and alternative rate design options. For the purposes of regulatory efficiency, FBC will address the review of the levelized rate under RS 96 EV DCFC service in the assessment report.

Table 7-12: Assessment of New EV DCFC Stations as Prescribed Undertakings Under the GGRR

	Greenhouse Gas Reduction Regulation Criteria						
GGRR Section	5(1)(a)	5(1)(b)	5(1)(c)	5(2)(a)	5(2)(b)(i)	5(2)(a)(ii)	5(2)(c)
	Station is available for use 24 hours a day by any member of the public	Station does not require users to be members of a charging network	Station is capable of charging electric vehicles of more than one make	Eligible charging station is constructed and operated or purchased and operated by the public utility	The public utility reasonably expects, on the date the public utility decides to construct or purchase an eligible charging station, that		For any eligible charging station coming into operation on or after January 1, 2022, the station uses or is configured to use the Open Charge Point Protocol.
					The station will come into operation by December 31, 2025. (Operation Date)	Is the station located in a limited municipality? (Population – 2021 Census)	
Sites							
Naramata	Yes	Yes	Yes	Yes	Q4 2021	No[1]	Yes
Grand Forks	Yes	Yes	Yes	Yes	Q4 2021	No (4,112)	Yes

[43] Decision and Order G-341-21, p. 27.

Note to Table:

[1] Not located in a municipality as defined by the Community Charter.

7.2.2.2 Mandatory Reliability Standards Incremental Capital

As explained in Section 6.3.5, the incremental capital expenditures related to the adoption of MRS AR13 were approved for exogenous factor treatment in the 2022 Annual Review Decision. These costs are for the implementation of changes/additions, including the development and implementation of methods to monitor network traffic and software tools to support the changes/additions to the standards. The implementation of the required changes/additions requires the purchase and installation of hardware and software to assess and evaluate network traffic and the development of software tools to track risk assessments of any product or service procured for Bulk Electrical System assets.

Table 7-13 below shows the incremental capital expenditures related to MRS AR13 with a breakdown between labour, non-labour and contingency for 2022 Approved, 2022 Projected and 2023 Forecast.

Table 7-13: Incremental Capital Expenditures for MRS AR13 ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Labour	$ 0.580	$ 0.680	$ -	
2	Non-Labour	0.205	0.140	-	
3	Contingency	0.150	0.050	-	
4	Total	$ 0.935	$ 0.870	-	Section 11, Schedule 4, Line 8

As shown in the table above, the 2022 Projected capital expenditures are approximately $0.065 million less than 2022 Approved. The reason for the variance is that FBC was able to purchase some software early (i.e., at the end of 2021 instead of 2022). Overall, there is no change to the original total estimate of $0.935 million (i.e., $0.065 million in 2021 Actual and $0.870 million in 2022 Projected).

As explained in the 2022 Annual Review[44], FBC is not expecting any incremental capital costs for 2023; therefore, the 2023 Forecast is zero. As the capital expenditures related to MRS AR13 are approved for flow-through treatment, any variances from Projected and Forecast amounts for the adoption of MRS AR13 will be trued up by way of the Flow-through deferral account and returned to, or recovered from, customers in future years.

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,[45] the

[44] Exhibit B-3, BCUC IR1 24.2.
[45] MRP Decision and Order G-166-20, pp. 132-133.

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.

For 2023, FBC is forecasting capital expenditures related to the KBTA project only. However, FBC's 2023 Forecast rate base also includes the full-year impact of capital additions related to the Corra Linn Dam Spillway Gate Replacement project, the UBO Old Units Refurbishment project, and the Playmor Substation Upgrade project, all of which are expected to complete in 2022. Each of these approved projects is described further below.

KBTA Project

The KBTA project was approved by Order C-4-20 and involves the installation of a third terminal transformer at the F.A. Lee Terminal Station, including the reconfiguration of the 138 kV bus into an industry standard ring bus configuration. The new transformer is scheduled to be in service by the end of 2022 or early 2023, with project close-out in 2023, at an estimated cost of $23.288 million, inclusive of AFUDC and cost of removal. FBC forecasts capital expenditures of $11.384 million and $1.710 million (excluding AFUDC) in 2022 and 2023, respectively, with $21.250 million to be added to rate base on January 1, 2023 and the remainder added to rate base on January 1, 2024.

Corra Linn Dam Spillway Gate Replacement Project

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 complete in 2022 at a cost of $79.727 million, inclusive of AFUDC and cost of removal. Thus, FBC is not forecasting any capital expenditures related to this project in 2023. Since 2020, a total of $51.768 million has been added to FBC's rate base with the remaining $16.151 million forecast to be added to rate base in 2023. Overall, $67.919 million is forecast to be added to rate base by January 1, 2023 ($51.768 million of actual from 2020 to 2022 plus $16.151 million of 2023 Forecast), plus $11.808 million of cost of removal, for a total estimated project cost of $79.727 million including AFUDC and cost of removal.

UBO Old Units Refurbishment Project

The UBO Old Units Refurbishment project was approved by Order G-8-17 and involves the refurbishment of four generating units that are more than 100 years old. The refurbishments were completed in 2021 at an estimated total project cost of $34.180 million, inclusive of AFUDC and cost of removal. FBC is projecting approximately $0.002 million of remaining close-out costs in 2022 which will be added to rate base January 1, 2023. Overall, $32.290 million is forecast to be added to rate base by January 1, 2023 ($32.288 million of actual from 2018 to 2022 and $0.002 million of 2023 Forecast), plus $1.890 million of cost of removal, for a total estimated project cost of $34.180 million including AFUDC and cost of removal. As directed by the BCUC in the Annual Review for 2017 Rates, the UBO Refurbishment Project Final Report is included as Appendix B2.

Playmor Substation Upgrade Project

The Playmor Substation Upgrade project was approved by Order G-42-21 and involves rebuilding the Playmor substation in South Slocan, BC on an expanded station footprint in order to increase station capacity. The project is expected to be complete in 2022 at an estimated cost of $8.036 million, inclusive of AFUDC, and approximately $0.300 million of cost of removal. As the project is expected to complete in 2022, FBC is not forecasting any capital expenditures related to this project in 2023, and all project costs, estimated to be $8.036 million (including AFUDC) are forecast to enter rate base on January 1, 2023, with $0.300 million to be recorded to cost of removal.

7.4 2023 PLANT ADDITIONS

The 2023 Plant Additions are comprised of: (i) FBC's 2023 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, Schedule 5.

Table 7-14: Reconciliation of 2023 Capital Expenditures to Plant Additions ($ millions)

Line No.	Description		Forecast 2023	Reference
1	Forecast Capital Expenditures	$	94.428	Section 11, Schedule 5, Line 2
2	Flow-Through Capital Expenditures		0.248	Section 11, Schedule 5, Line 3
3	Total Gross Regular Capital Expenditures		94.676	Sum of Lines 1 and 2
4				
5	Capitalized Overhead		10.918	Section 11, Schedule 5, Line 16
6	AFUDC		0.243	Section 11, Schedule 5, Line 17
7	Change in Work in Progress		-	Section 11, Schedule 5, Line 19
8	Total Regular Additions to Plant		**105.837**	Sum of Lines 3 through 7
9				
10	Special Projects and CPCN Capital Expenditures			
11	Kelowna Bulk Transformer Capacity Addition		1.710	Section 11, Schedule 5, Line 7
12	AFUDC		0.049	Section 11, Schedule 5, Line 23
13	Change in Work in Progress		43.680	Section 11, Schedule 5, Line 25
14	Total Special Projects and CPCN Additions to Plant		**45.439**	Sum of Lines 11 through 13
15				
16	Total Plant Additions	**$**	**151.276**	Line 8 + Line 14

7.5 ACCUMULATED DEPRECIATION

Rate base 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 2023, 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 by Order G-139-14.

Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance, the 2023 depreciation expense is calculated as $64.407 million.[46]

7.6 *DEFERRED CHARGES*

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[47] 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.

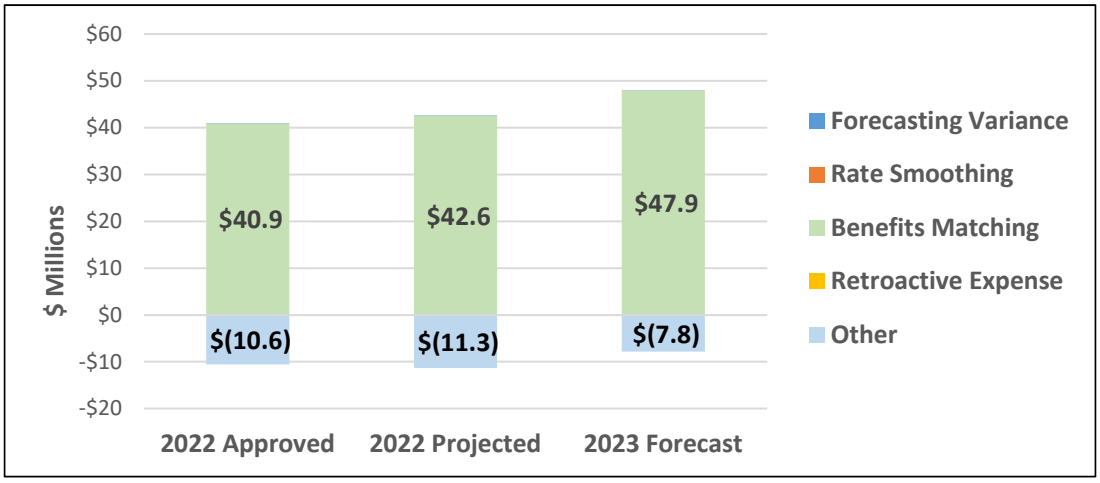
The checklist classifies deferral accounts as one of: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching (capital-like) account; (d) retroactive expense account; or (e) other. In Section 11, Schedule 11, FBC has classified its rate base deferral accounts in accordance with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

The 2023 Forecast mid-year balance of unamortized deferred charges in rate base for FBC is a debit of $40.045 million. The 2023 debit balance is driven largely by the balances in the Demand Side Management (DSM) and Deferred Debt Issue Costs deferral accounts, partially offset by the Pension and OPEB Liability deferral account.

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

[46] $69.474 million depreciation expense as shown in Section 11, Schedule 21, Line 2 less $5.067 million amortization of CIAC as shown in Section 11, Schedule 21, Line 8.
[47] 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 (rate base and non-rate base) using the approved and proposed amortization periods, the 2023 amortization expense is calculated as a credit of $3.277 million.[48] 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.

7.6.1 New Deferral Accounts

FBC is seeking approval to create one new rate base deferral account in this Application, as discussed below.

7.6.1.1 Joint Pole Use Audit 2023

Under the provisions of FBC's various joint use pole agreements, the parties are required to perform an audit of the joint use pole contacts once every five years, the last of which occurred in 2018.

Consistent with past treatment of costs for joint pole use audits, FBC is seeking approval to establish a rate base deferral account to capture costs incurred for the 2023 Joint Use Pole Audit, which are estimated at $0.435 million ($0.318 million after tax) to be incurred in 2023.

FBC is also requesting approval to amortize these costs over a five-year period beginning January 1, 2023, which represents the time period between the required audits.

Table 7-15 below addresses the considerations identified in the Regulatory Account Filing Checklist as they pertain to the above-described deferral account request.

[48] Section 11, Schedule 21, Column 3, Sum of Line 5 and 6.

Table 7-15: Deferral Account Filing Considerations

Item	Consideration	Joint Pole Use Audit 2023
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 2023 Joint Pole Use Audit deferral account is a new deferral account, consistent with the past treatment of joint pole use audits in previous years.
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
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 purpose of the requested account is to capture costs related to joint use pole audits that are required once every five years.
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 the account encompasses the conduct of the audit and subsequent amortization period, equivalent to the term of the benefit.
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 a deferral account, the costs of the audit would have to be forecast as an O&M expense (outside of the MRP formula O&M since the 2018 audit costs were deferred and excluded from Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FBC considers a deferral account to be the more appropriate treatment since it permits the amortization of costs over the five-year period between audits.
IV a)	Address: whether, or to what extent, the item is outside of management's control;	An audit of joint use poles is required at five-year intervals as a condition of FBC's agreements with the counter parties and is therefore outside of FBC's direct control.
b)	the degree of forecast uncertainty associated with the item;	FBC forecasts audit costs based on past experience. Actual costs are recorded in the account so that the actual, not forecast, costs are recovered in rates.
c)	the materiality of the costs	Refer to Section 7.6.1.1.
d)	any impact on intergenerational equity	FBC proposes to recover the deferred costs over the five-year period between the required audits.
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 classifies this account as a benefit matching account since the costs are recovered over the period between audits.
VI.	Identify if the regulatory account is a cash or non-cash account.	The joint use pole audit account is a cash account.

Item	Consideration	Joint Pole Use Audit 2023
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.	Costs include incremental labour, vehicle, and staff expense in addition to FBC's share of common costs such as data input costs. See Section 7.6.1.1.
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.
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.	FBC proposes to recover the deferred costs over the five-year period between the required audits.
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).
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral account can be reviewed as part of the present proceeding. Deferral account approvals and disposition are generally determined in revenue requirement proceedings. Where requested within CPCNs or other applications, the regulatory process will be included within the draft timetable for each specific application.

7.6.2 Existing Deferral Accounts

In the discussion below, FBC provides information on two existing deferral accounts and requests approval of an amortization period for one of them.

7.6.2.1 COVID-19 Customer Recovery Fund Deferral Account

7.6.2.1.1 DESCRIPTION AND FINANCIAL ESTIMATES

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:

1. any bill payment deferrals provided to customers due to the COVID-19 pandemic and subsequent payments of those deferred amounts;
2. any bill credits provided to customers due to the COVID-19 pandemic; and
3. 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 2022 and 2023 financial estimates and descriptions for each of the three items approved for inclusion in the COVID-19 Customer Recovery Fund Deferral Account. FBC also proposes to commence amortization of the deferral account balance in 2023 and to discontinue quarterly reporting.

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

The bill payment deferral program was offered to residential and small commercial customers affected by the COVID-19 pandemic. FBC experienced high collection rates in regard to this program, recovering approximately 85 percent of the outstanding balances through the regular monthly instalments. The remaining customer balances that were ultimately deemed unrecoverable have been designated as unrecoverable revenue and as such, a total of $0.119 million has been transferred to the COVID-19 Customer Recovery Fund Deferral Account. These additions to the deferral account are forecast in section (c), Table 7-18 *Unrecoverable Revenue Amounts*.

FBC ceased accepting new applications effective June 1, 2021 and is therefore not forecasting further additions related to this relief measure.

Table 7-16: Bill Payment Deferral Forecast Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.563	0.005	-
Additions	0.803	-	-	-
Repayments	(0.240)	(0.444)	-	-
Transfers	-	(0.114)	(0.005)	-
Ending Balance	0.563	0.005	-	-

(b) Bill credits provided to small commercial customers

The bill credit program offered to small commercial customers has been calculated using the existing balance of $0.132 million as of April 2022. Given the duration and period these credits were available for, as well as the June 1, 2021 closure of the program for new applications, FBC does not expect additional credits to be offered to customers throughout the remainder of 2022 or in 2023. As such, FBC is proposing to amortize the $0.132 million over three years, with the 2023 amortization amount shown in Table 7-17 below.

Table 7-17: Bill Credit Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.130	0.132	0.132
Additions	0.178	0.003	-	-
Tax	(0.048)	(0.001)	-	-
Amortization[49]	-	-	-	(0.044)
Ending Balance	0.130	0.132	0.132	0.088

[49] Based on a requested three-year amortization period, as discussed in Section 7.6.2.1.2.

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

This portion of the deferral account forecast represents the amount of customer balances owing (i.e., account receivables) that are recognized as unrecoverable due to the COVID-19 pandemic. As such, these amounts are in excess of the normal course forecast bad debt expense that is recognized in indexed-based O&M.

Table 7-18: Unrecoverable Revenue Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.011	0.134	0.375
Transfers[50]	-	0.114	0.005	-
Additions[51]	0.015	0.054	0.325	-
Tax	(0.004)	(0.045)	(0.089)	-
Amortization[49]	-	-	-	(0.125)
Ending Balance	0.011	0.134	0.375	0.250

The unrecovered revenue recorded in the deferral account includes:

- any remaining balances associated with the bill payment deferral program, described in section (a), that resulted from customers' inability to pay (shown as the Transfers line in Table 7-18 above); and
- any unrecovered revenue from all customer classes due to the COVID-19 pandemic, 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 (shown as the Additions line in Table 7-18 above).

The 2022 Projected transfers of $0.005 million represent the actual 2022 transfers for the months available and any remaining bill payment deferral loan balances that were not yet repaid. The 2022 Projected additions of $0.325 million have been calculated using actual additions for the months available with the remainder of the year forecast using an approach consistent with the prior year. That is, a factor of 15 percent has been applied to the total outstanding balance of customer accounts that are past due as at March 1, 2022. This approach was based on a pilot outreach program in 2021 where 15 percent of customers with an average balance of $800 confirmed that they were financially impacted by the COVID-19 pandemic and required support to bring their account into good standing.

[50] The actual 2021 unrecoverable revenue transfers of $0.114 million consist of $0.004 million of small commercial customer balances and $0.110 million of residential customer balances.

[51] The actual 2020 unrecoverable revenue additions of $0.015 million consist of $0.014 million of small commercial customer balances and $0.001 million of residential customer balances. The actual 2021 unrecoverable revenue additions of $0.054 million consist of $0.004 million of small commercial customer balances and $0.050 million of residential customer balances.

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

In this regard, to support the development of a consistent and appropriate approach for identifying amounts deemed unrecoverable due to COVID-19, FBC has created an internal set of guidelines to be used by members of the customer service team with an objective to identify and support customers that have been financially impacted by the COVID-19 pandemic. The underlying goal and intent of this approach is for customers to be able to maintain their gas services while maximizing recoveries associated with any balances due. These internal guidelines include questions that help identify the extent to which the customer has been impacted by COVID-19 as well as payment arrangement guidelines that include partial or full recognition of receivable balances as unrecoverable due to the COVID-19 pandemic.

7.6.2.1.2 DISPOSITION OF DEFERRAL ACCOUNT

As indicated in the 2022 Annual Review, additions to the COVID-19 Customer Recovery Fund Deferral Account for unrecovered revenues resulting from customers being unable to pay their bills due to the COVID-19 pandemic were expected to continue into 2022. As such, FBC has continued to capture unrecovered revenues in this deferral account during 2022.

Since the 2022 Annual Review, conditions have improved such that most COVID-19 pandemic restrictions in BC have been lifted.[52] The Federal government support programs such as the Canada Emergency Response Benefit (CERB) and the Canada Emergency Wage Subsidy (CEWS) for businesses have ended as the impact of the COVID-19 pandemic lessens. This, along with the improved economic conditions, although somewhat tempered recently with inflationary and recessionary considerations, suggests that ongoing pandemic support is not needed anymore.

Additionally, FBC has resumed most of its collection practices in 2022 with no significant uptick in unrecoverable revenues from customers experienced so far, and FBC anticipates full resumption of normal collection practices by mid-2022.

As a result, based on the positive current outlook for the COVID-19 pandemic and the lessened impact, FBC does not anticipate any further additions to the deferral account after 2022 and proposes to commence amortization of the balance in the deferral account on January 1, 2023 using a three-year amortization period. FBC considers a three-year amortization period to be appropriate because it matches the number of years during which the COVID-19 Customer Recovery Fund Deferral Account was active (i.e., 2020 through 2022).

Should public health and economic conditions deteriorate significantly due to the resurgence of the COVID-19 pandemic later this year or in the future (i.e., another wave of the pandemic which causes shutdowns and job losses impacting individuals and businesses), FBC may seek BCUC

[52] See Section 12.2.1 for further discussion and details.

approval again for deferral account treatment for the same purpose and reasons set out in the 2020 application.

7.6.2.1.3 REQUEST TO DISCONTINUE REPORTING

FBC seeks approval to discontinue the existing quarterly reporting requirements for the COVID-19 Customer Recovery Fund Deferral Account filed with the BCUC. If approved, the final quarterly report would be for Q4 2022 and would be submitted in Q1 2023.

With more than two full years of reporting complete, the closure of the deferral and credit program to new applicants as of June 1, 2021, and the planned discontinuation of additions to the deferral account as of December 31, 2022, FBC does not see further value in providing separate detailed reporting for this account.

7.6.2.2 Indigenous Relations Agreement (Huth Substation)

As part of the Annual Review for 2020 and 2021 Rates Decision and Order G-42-21, FBC received approval to establish the Indigenous Relations Agreement (Huth Substation) 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[53] history and culture, such as the discovery of ancestral remains found at the Huth substation while performing construction works.

The 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 the importance of the substation 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 stated in the 2020-2021 Annual Review that it would update its progress with respect to this matter in future annual reviews and request approval for recovery of costs captured in this deferral account once an agreement with the PIB had been reached and the impacts could be communicated.

FBC has been unable to continue preliminary discussions with the PIB on reconciliation efforts on the Huth substation. Due to impacts on the community from the COVID-19 pandemic, followed by the unique circumstances that arose in 2021 with the Kamloops Residential School findings, and as the Penticton Indian Band and FortisBC Energy Inc. are currently in discussions regarding the proposed Okanagan Capacity Upgrade project, FBC chose not to pursue further efforts regarding the Huth Substation until both parties agreed to proceed. FBC will continue to provide updates on this matter and on the deferral account in future annual review filings.

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

7.7 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. 2023 amounts are forecast based on 2021 Actual levels.

7.8 SUMMARY

FBC's rate base includes the impact of regular and Major Project capital expenditures, adjusted for work-in-progress, AFUDC and overheads capitalized. FBC has provided forecasts for all of its rate base deferral accounts in the financial schedules included in Section 11. In Section 7.2.1, FBC requested approval of its updated 2023 and 2024 regular capital (growth, sustainment and other) forecasts; in Section 7.6.1, FBC requested approval of one new deferral account; and in Section 7.6.2, FBC discussed two existing accounts, including requesting amortization of one of these existing accounts. Finally, the rate base includes cash and other working capital.

8. FINANCING AND RETURN OF 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 FEI.

FBC is currently participating in the BCUC-initiated Generic Cost of Capital (GCOC) proceeding and has filed evidence on its recommended capital structure and ROE as part of Stage 1 of the proceeding. In Order G-156-21 and accompanying Reasons for Decision, the BCUC found that the effective date to implement a new cost of capital will depend on the timing and progress of the GCOC proceeding. As explained in Section 1.2, FBC is seeking approval of interim 2023 rates pending the outcome of Stage 1 of the GCOC proceeding as well as a decision on FBC's 2023-2027 DSM Expenditure Plan. When a decision is reached on these proceedings, FBC will update its rate calculations and apply for permanent 2023 rates.

The 2023 Forecast 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 rate for 2023 (which is equal to its after-tax weighted average cost of capital) is 5.73 percent. 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; these approved capital structure and ROE values have been used to calculate rates in the Application.

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 debt.

8.3.1 Long-Term Debt

FBC is both a private and public issuer of long-term debt. In March 2022, FBC issued long-term debt of $100 million at a rate of 4.16 percent 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 2023 and will use the funds for the same purposes. The 2023 debt issuance is reflected in the financial schedules in July 2023 at a rate of 4.90 percent.[54] The exact timing, amount and rate of the 2023 issuance will depend on future market conditions and capital 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

FBC obtains short-term funding primarily through the issuance of commercial paper to Canadian institutional investors. FBC backstops the commercial paper issuances by maintaining a $150 million committed credit facility that matures in April 2026.[55] This facility is also used to issue letters of credit. The credit facility, along with a $10 million overdraft facility, provides FBC with short-term liquidity to fund its capital program and working capital requirements.

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. 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 2023 is 3.14 percent, which is a significant increase from the 0.47 percent approved in 2022. FBC is in a rising interest rate environment due to high inflation, Russia's invasion in Ukraine, and the removal of monetary policy actions that were prevalent during the initial years of the COVID-19 pandemic (i.e., 2020 and 2021). In addition, on July 13, 2022 the Bank of Canada completed its fourth rate hike of the year, raising the benchmark interest

[54] Section 11, Schedule 27, Line 10.
[55] On July 14, 2021, the credit facility was extended to April 27, 2026.

rate to 2.5 percent from 0.25 percent at the beginning of 2022 and signalling that more rate hikes will be announced in 2022. The market volatility is expected to persist given many ongoing elevated risk variables.

For 2023, FBC forecasts a similar level of other financing fees to the 2022 Approved amount. Other financing fees include the fees that FBC 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 2022	Projected 2022	Forecasted 2023
3-Month T-Bill Rate [1]	0.47%	3.08%	3.14%
Spread to CDOR	0.39%	0.36%	0.36%
CDOR Rate	0.86%	3.44%	3.50%
Spread to CP	-0.32%	-0.36%	-0.36%
CP Dealer Commission	0.10%	0.10%	0.10%
ST Interest Rate on Credit Facilities	**0.64%**	**3.18%**	**3.24%**
Fixed Financing Fees [2]			
Standby fee on Undrawn Credit [3]	0.44%	0.39%	0.44%
Renewal Fee on Undrawn Credit	0.17%	0.11%	0.12%
Other Financing Fees	0.26%	0.35%	0.44%
ST Interest Rate on Fixed Financing Fee	**0.87%**	**0.84%**	**1.00%**
FBC Short Term Rate	**1.51%**	**4.02%**	**4.24%**

Notes to Table:

[1] 3-Month T-Bill Rate for 2023 is a weighted average rate based on forecasts provided by Canadian Chartered banks in July 2022.

[2] Fixed financing fees represent the costs of maintaining the $150 million credit facility and letter of credit facility, which are fixed fees incurred regardless of whether 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.

4. Other financing fees include commercial paper issuance fees, letter of credit fees, customer deposit interest expense and miscellaneous bank administration costs. The letter of credit fees, customer deposit interest and miscellaneous bank administration costs are incurred regardless of whether FBC draws from the credit facility.

As noted above, FBC's interest rate forecasts are based on CDOR. An indirect result of the cessation of the publication of the London Interbank Offered Rate (LIBOR) is that Canada is reassessing its use of CDOR as a risk-free rate benchmark for financial instruments in multiple asset classes. This will impact FBC's credit facility agreement as Refinitiv Benchmark Services (UK) Limited (RBSL), CDOR's regulated administrator, announced that CDOR will cease to be published after June 28, 2024.[56] The Canadian Alternative Reference Rate Working Group

[56] https://www.bankofcanada.ca/markets/canadian-alternative-reference-rate-working-group/.

(CARR) was established to coordinate the transition to a new risk-free rate benchmark. It is anticipated that CDOR will transition to the Canadian Overnight Repo Rate Average (CORRA), a transaction-based overnight risk-free interest rate benchmark in existence since 1997.[57] FBC will work with its banking syndicate members to transition its credit facility agreement to CORRA and will revisit the methodology for short-term interest rate forecasting when such a transition is complete.

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 2023 long-term debt schedule for FBC can be found in Section 11, Schedule 27.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FBC applies AFUDC to projects that are greater than three months in duration and greater than $100 thousand. Based on the above information, FBC's AFUDC rate for 2023 (which is equal to its after-tax weighted average cost of capital) is 5.73 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2023

	Weight	Pre Tax Rate	After Tax Rate	Earned Return
Short Term Debt	5.44%	4.24%	3.10%	4.24%
Long Term Debt	54.56%	4.78%	3.49%	4.78%
Common Equity	40.00%	12.53%	9.15%	9.15%
Weighted Average	100.00%	7.85%	5.73%	6.50%

8.4 *SUMMARY*

FBC's equity financing and ROE have been forecast for 2023 at the same percentages as approved for 2022. 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; the embedded rate on long-term debt is forecast to decrease in 2023 as compared to 2022 Approved.

[57] https://www.bankofcanada.ca/wp-content/uploads/2021/12/CARR-Review-CDOR-Analysis-Recommendations.pdf.

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 2023, property taxes are forecast to increase by 2.1 percent from 2022 Approved, while income tax is forecast to decrease by 19.9 percent compared to 2022 Approved.

9.2 PROPERTY TAXES

Property taxes for 2023 of $18.260 million 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 2022	Projected 2022	Forecast 2023
1	Generating Plant	$ 3.210	$ 3.199	$ 3.253
2	Transmission and Distribution	7.428	6.950	7.189
3	Substation Equipment	3.948	4.156	4.208
4	Land and Buildings	1.165	1.201	1.322
5	In-Lieu	2.138	2.115	2.288
6	Total Property Taxes	$ 17.889	$ 17.621	$ 18.260
7				
8	Forecast Change from 2022 Approved			2.1%
9	Forecast Change from 2022 Projected			3.6%

As shown in the above table, in 2023 property taxes are forecast to increase by 2.1 percent from 2022 Approved and increase by 3.6 percent compared to 2022 Projected. In general, the 2023 increase from 2022 Projected is due to construction activities, market value changes, and changes in tax policies of local taxing authorities. The most significant drivers of the forecast changes are as follows:

1. **Changes in Tax Rates.** Tax Rates are expected to change for 2023 as follows:

   a) Municipal rates are expected to increase by 1.0 percent;

   b) School rates are expected to decrease by 1.0 percent;

   c) Rural rates are expected to decrease by 0.4 percent;

d) Tax rates on First Nations are expected to increase by 0.8 percent; and

e) Other rates are expected to decrease by 1.4 percent.

2. **Changes in Revenues to Calculate Grants In Lieu of Taxes.** Revenues reported to municipalities are expected to increase by 8.2 percent based on actual revenues applicable to the taxation year. Grants in-lieu of taxes are based on a fixed percentage of revenues; the overall actual increase in revenues reported to municipalities increases 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 expected inflationary increases. These include:

a) A 5.2 percent increase in assessed values of distribution lines and a 2.5 percent increase in transmission lines;

b) A 2.5 percent increase in assessed values for generating facilities calculated using legislated cost manuals for valuing generating facilities;

c) A 0.5 percent decrease in assessed values for substations calculated using legislated cost manuals for valuing substations; and

d) Land values are expected to increase between 4.3 percent to 11.4 percent for right of ways and properties owned in fee simple.

Any variances from the forecast of property taxes included in rates are recorded in the Flow-through deferral account and will be returned to or recovered 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 2023, which is unchanged from 2022. 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 2023 is forecast to decrease by $1.494 million or 19.9 percent compared to 2022 Approved. The 2023 Forecast decrease is primarily due to higher deductible temporary differences associated with amortization of deferred charges and property, plant and equipment, and lower taxable temporary differences associated with pension and OPEB, partially offset by higher rate base.

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

All other differences in income tax expense are subject to earnings sharing.

9.4 *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. Since FBC is unable to determine final earnings sharing until all items required for the ROE calculation are known, including the final rate base, there is a lag in when FBC distributes earnings sharing amounts. This is consistent with the calculations of formula O&M, where the true-up of the formula inputs happens only once actuals are known. Thus, for 2023 rates, it is the 2021 formula O&M and 2021 earnings sharing amounts that are calculated and impact rates in 2023.

For 2023, FBC proposes to distribute a $0.911 million pre-tax credit ($0.665 million after-tax) to customers, comprised of:

- The $0.665 million credit difference between the projected 2021 deferral account after-tax credit addition of zero embedded in 2022 rates, and the actual 2021 deferral account after-tax credit addition of $0.665 million as provided in FBC's 2021 Annual Report to the BCUC. This amount is also shown in the opening 2023 balance[58] in the financial schedules in the Application.

FBC proposes to distribute $0.911 million to customers in 2023 as a reduction in 2023 revenue requirements through amortization of the projected 2023 opening after-tax balance of $0.665 million in the MRP Earnings Sharing deferral account.

As part of future rate filings, the actual earnings sharing for 2022 will be distributed to or collected from customers in a similar manner as described above, which will account for the actual 2022 ROE variance from approved.

[58] Section 11, Schedule 12.2, Line 14, Column 2.

11. FINANCIAL SCHEDULES

Description	Schedule Reference
Summary Of Rate Change	1
Rate Base	
Utility Rate Base	2
Formula Inflation Factors	3
Capital Expenditures	4
Capital Expenditures To Plant Reconciliation	5
Plant In Service Continuity Schedule	6
Accumulated Depreciation Continuity Schedule	7
Schedule Not Applicable	8
Contributions In Aid Of Construction Continuity Schedule	9
Schedule Not Applicable	10
Unamortized Deferred Charges And Amortization - Rate Base	11
Unamortized Deferred Charges And Amortization - Non-Rate Base	12
Working Capital Allowance	13
Cash Working Capital	14
Schedule Not Applicable	15
Revenue Requirement	
Utility Income And Earned Return	16
Volume And Revenue	17
Revenue At Existing And Revised Rates	18
Cost Of Energy	19
Operating And Maintenance Expense	20
Depreciation And Amortization Expense	21
Property And Sundry Taxes	22
Other Revenue	23
Income Taxes	24
Capital Cost Allowance	25
Return On Capital	26
Embedded Cost Of Long Term Debt	27

SUMMARY OF RATE CHANGE
FOR THE YEAR ENDING DECEMBER 31, 2023
($millions)

Schedule 1

Line No.	Particulars	2023 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (12.546)		
3	Change in Other Revenue	(0.409)	(12.955)	
4				
5	**POWER SUPPLY**			
6	Power Purchases	19.796		
7	Wheeling	0.894		
8	Water Fees	(0.415)	20.275	
9				
10	**O&M CHANGES**			
11	Gross O&M Change	4.757		
12	Capitalized Overhead Change	(0.741)	4.016	
13				
14	**DEPRECIATION EXPENSE**			
15	Depreciation from Net Additions		2.752	
16				
17	**AMORTIZATION EXPENSE**			
18	CIAC from Net Additions	(0.210)		
19	Deferrals	(4.835)	(5.045)	
20				
21	**FINANCING AND RETURN ON EQUITY**			
22	Financing Rate Changes	3.688		
23	Financing Ratio Changes	(1.049)		
24	Rate Base Growth	5.809	8.448	
25				
26	**TAX EXPENSE**			
27	Property and Other Taxes	0.371		
28	Other Income Taxes Changes	(1.494)	(1.123)	
29				
30	**REVENUE DEFICIENCY (SURPLUS)**		**$ 16.368**	Schedule 16, Line 6, Column 4
31				
32	Revenue at Existing Rates		409.840	Schedule 18, Line 7, Column 3
33	Rate Change		3.99%	

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Section 11

Schedule 2

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 2,279,658	$ 2,375,297	$ 95,639	Schedule 6.1, Line 32, Column 3
2	Opening Balance Adjustment	4,512	-	(4,512)	Schedule 6.1, Line 32, Column 4
3	Net Additions	105,010	134,666	29,656	Schedule 6.1, Line 32, Column 5+6+7
4	Plant in Service, Ending	2,389,180	2,509,963	120,783	
5					
6	Accumulated Depreciation Beginning	$ (659,517)	$ (693,759)	$ (34,242)	Schedule 7.1, Line 32, Column 5
7	Opening Balance Adjustment	(569)	-	569	Schedule 7.1, Line 32, Column 6
8	Net Additions	(33,657)	(47,865)	(14,208)	Schedule 7.1, Line 32, Column 7+8+9
9	Accumulated Depreciation Ending	(693,743)	(741,624)	(47,881)	
10					
11	CIAC, Beginning	$ (232,291)	$ (243,101)	$ (10,810)	Schedule 9, Line 3, Column 2
12	Opening Balance Adjustment	(2,523)	-	2,523	
13	Net Additions	(11,712)	(11,628)	84	Schedule 9, Line 3, Column 5+6
14	CIAC, Ending	(246,526)	(254,729)	(8,203)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 84,284	$ 89,140	$ 4,856	Schedule 9, Line 7, Column 2
17	Opening Balance Adjustment	212	-	(212)	
18	Net Additions	4,857	5,067	210	Schedule 9, Line 7, Column 5+6
19	Accumulated Amortization Ending - CIAC	89,353	94,207	4,854	
20					
21	Net Plant in Service, Mid-Year	$ 1,506,015	$ 1,567,697	$ 61,682	
22					
23	Adjustment for timing of Capital additions	$ 16,181	$ 22,720	$ 6,539	
24	Capital Work in Progress, No AFUDC	19,332	34,306	14,974	
25	Unamortized Deferred Charges	30,372	40,045	9,673	Schedule 11, Line 26, Column 8
26	Working Capital	6,258	6,100	(158)	Schedule 13, Line 9, Column 3
27	Utility Plant Acquisition Adjustment	4,749	4,563	(186)	
28					
29	Mid-Year Utility Rate Base	$ 1,582,907	$ 1,675,431	$ 92,524	

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Schedule 3

FORMULA INFLATION FACTORS
FOR THE YEARS ENDING DECEMBER 31, 2020 to 2023
($000s)

Line No.	Particulars	Reference	2020	2021	2022	2023	Total for 2023 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Formula Cost Drivers**							
2	CPI		2.692%	1.596%	1.281%	4.940%		
3	AWE		2.881%	5.745%	6.455%	4.235%		
4	Labour Split							
5	Non Labour		38.000%	38.000%	37.000%	40.000%		
6	Labour		62.000%	62.000%	63.000%	60.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	2.809%	4.168%	4.541%	4.517%		
8	Productivity Factor	G-166-20	-0.500%	-0.500%	-0.500%	-0.500%		
9	Net Inflation Factor	Line 7 + Line 8	2.309%	3.668%	4.041%	4.017%		
10								
11								
12	**Growth in Average Customer Calculation**							
13	Actual/Projected Prior Year Average Customers		139,916	142,321	144,877	147,417		
14	Average Customers for the Year	Schedule 18, Line 7, Column 6	142,321	144,877	147,417	150,563		
15	Change in Average Customers	Line 14 - Line 13	2,405	2,556	2,541	3,145	10,647	
16								
17	Customer Growth Factor Multiplier	G-166-20					75%	
18	Change in Average Customers for Rate Setting Purposes	Line 15 x Line 17					7,985	
19								
20	Average Customers Used to Determine Starting UCOM	Line 13 Year 2020					139,916	
21								
22	Average Customer Forecast - 2023 Rate Setting Purposes	Line 18 + Line 20					147,901	

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Section 11

Schedule 4

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	Total CapEx	Cross Reference
	(1)	(2)	(3)
1	**Forecast Capital Expenditures**		
2	Growth Capital	$ 30,973	
3	Sustainment Capital	45,797	
4	Other Capital	17,658	
5	Total Forecast Capital	$ 94,428	
6			
7	**Flow-Through Capital Expenditures**		
8	MRS Capital	$ -	
9	EV Charging Stations	248	
10	Total Flow-Through Capital	$ 248	
11			
12	**Total Regular Capital Expenditures**	$ 94,676	

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Schedule 5

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2023 Formula		Cross Reference
	(1)	(2)		(3)
1	**CAPEX**			
2	Forecast Capital Expenditures	$	94,428	
3	Flow-Through Capital		248	
4	Total Regular Capital Expenditures	$	94,676	Schedule 4, Column 2, Line 12
5				
6	**Special Projects and CPCN's**			
7	Kelowna Bulk Transformer Capacity Addition	$	1,710	
8	Total Special Projects and CPCN's	$	1,710	
9				
10	**Total Capital Expenditures**	$	96,386	
11				
12				
13	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
14				
15	Regular Capital Expenditures	$	94,676	Line 4
16	Add - Capitalized Overheads		10,918	Schedule 20, Column 4, Line 23
17	Add - AFUDC		243	
18	Gross Capital Expenditures		105,837	
19	Change in Work in Progress		-	
20	**Total Regular Additions to Plant**	$	105,837	
21				
22	Special Projects and CPCN's Capital Expenditures	$	1,710	Line 8
23	Add - AFUDC		49	
24	Gross Capital Expenditures		1,759	
25	Change in Work in Progress		43,680	
26	**Total Special Projects and CPCN Additions to Plant**	$	45,439	
27				
28	**Grand Total Additions to Plant**	$	151,276	Schedule 6.1, Columns 5 + 6, Line 32

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PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	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	22,045	-	-	167	(12)	22,200	
4	332	Reservoirs, Dams & Waterways	119,076	-	16,151	7,747	(782)	142,192	
5	333	Water Wheels, Turbines and Gen.	105,453	-	2	699	(142)	106,012	
6	334	Accessory Equipment	51,357	-	-	128	(38)	51,447	
7	335	Other Power Plant Equipment	48,572	-	-	5	(1)	48,576	
8	336	Roads, Railroads and Bridges	1,287	-	-	-	-	1,287	
9			$ 348,752	$ -	$ 16,153	$ 8,746	$ (975)	$ 372,676	
10									
11		**Transmission Plant**							
12	350	Land Rights-R/W	$ 10,767	$ -	$ -	$ 118	$ -	$ 10,885	
13	350.1	Land Rights-Clearing	9,992	-	-	118	-	10,110	
14	353	Station Equipment	243,150	-	21,250	3,446	(305)	267,541	
15	355	Poles Towers & Fixtures	127,975	-	-	6,450	(291)	134,134	
16	356	Conductors and Devices	123,228	-	-	6,449	(313)	129,364	
17	359	Roads and Trails	959	-	-	-	-	959	
18			$ 516,071	$ -	$ 21,250	$ 16,581	$ (909)	$ 552,993	

FORTISBC INC.

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 6.1

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Distribution Plant**							
2	360	Land Rights-R/W	$ 7,185	$ -	$ -	$ 817	$ -	$ 8,002	
3	360.1	Land Rights-Clearing	11,630	-	-	374	-	12,004	
4	362	Station Equipment	304,310	-	8,036	13,065	(885)	324,526	
5	364	Poles Towers & Fixtures	258,898	-	-	13,410	(570)	271,738	
6	365	Conductors and Devices	436,812	-	-	20,531	(728)	456,615	
7	368	Line Transformers	193,494	-	-	14,165	(1,815)	205,844	
8	369	Services	9,521	-	-	-	-	9,521	
9	370.1	AMI Meters	41,459	-	-	532	-	41,991	
10	371	Installation on Customers' Premises	938	-	-	-	-	938	
11	373	Street Lighting and Signal System	14,178	-	-	170	(42)	14,306	
12	372	EV Stations Kiosks & Charger Connectors	5,993	-	-	-	-	5,993	
13			$ 1,284,418	$ -	$ 8,036	$ 63,064	$ (4,040)	$ 1,351,478	
14									
15		**General Plant**							
16	389	Land	$ 11,184	$ -	$ -	$ -	$ -	$ 11,184	
17	390.1	Structures - Masonry	48,652	-	-	2,785	(319)	51,118	
18	390.2	Operation Building	19,432	-	-	609	(23)	20,018	
19	390.1	Leasehold Improvements	2,872	-	-	-	-	2,872	
20	391	Office Furniture & Equipment	5,399	-	-	215	(237)	5,377	
21	391.1	Computer Hardware	13,614	-	-	3,330	(3,016)	13,928	
22	391.2	Computer Software	41,906	-	-	7,033	(4,015)	44,924	
23	391.2	AMI Software	13,439	-	-	(3)	-	13,436	
24	392.1	Light Duty Vehicles	5,967	-	-	549	(484)	6,032	
25	392.1	Heavy Duty Vehciles	28,678	-	-	1,523	(351)	29,850	
26	394	Tools and Work Equipment	8,507	-	-	724	(587)	8,644	
27	397	Communication Structures & Equipment	15,707	-	-	681	(1,456)	14,932	
28	397.1	Fibre	5,729	-	-	-	(198)	5,531	
29	397.2	AMI Communications Structure & Equipment	4,970	-	-	-	-	4,970	
30			$ 226,056	$ -	$ -	$ 17,446	$ (10,686)	$ 232,816	
31									
32		**Total Plant in Service**	$ 2,375,297	$ -	$ 45,439	$ 105,837	$ (16,610)	$ 2,509,963	
33									
34		Cross Reference			Schedule 5, Line 26, Column 2	Schedule 5, Line 20, Column 2			

FORTISBC INC.

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 7

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Hydraulic Production Plant**										
2	330	Land Rights	$ 962	1.07%	$ (382)	$ -	$ 10	$ -	$ -	$ -	$ (372)	
3	331	Structures and Improvements	22,045	1.68%	5,718	-	370	(12)	-	-	6,076	
4	332	Reservoirs, Dams & Waterways	135,227	1.90%	7,278	-	2,569	(782)	(1,857)	-	7,208	
5	333	Water Wheels, Turbines and Gen.	105,455	1.79%	20,564	-	1,888	(142)	(3)	-	22,307	
6	334	Accessory Equipment	51,357	3.13%	15,121	-	1,607	(38)	(130)	-	16,560	
7	335	Other Power Plant Equipment	48,572	2.12%	20,171	-	1,030	(1)	-	-	21,200	
8	336	Roads, Railroads and Bridges	1,287	1.44%	476	-	19	-	-	-	495	
9			$ 364,905		$ 68,946	$ -	$ 7,493	$ (975)	$ (1,990)	$ -	$ 73,474	
10												
11		**Transmission Plant**										
12	350	Land Rights-R/W	$ 10,767	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
13	350.1	Land Rights-Clearing	9,992	1.27%	2,485	-	127	-	-	-	2,612	
14	353	Station Equipment	264,400	2.33%	101,920	-	6,161	(305)	(159)	-	107,617	
15	355	Poles Towers & Fixtures	127,975	2.52%	39,342	-	3,225	(291)	(469)	-	41,807	
16	356	Conductors and Devices	123,228	2.52%	24,036	-	3,105	(313)	(469)	-	26,359	
17	359	Roads and Trails	959	1.96%	432	-	19	-	-	-	451	
18			$ 537,321		$ 168,215	$ -	$ 12,637	$ (909)	$ (1,097)	$ -	$ 178,846	

FORTISBC INC.

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 7.1

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Distribution Plant**										
2	360	Land Rights-R/W	$ 7,185	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	360.1	Land Rights-Clearing	11,630	1.25%	2,935	-	145	-	-	-	3,080	
4	362	Station Equipment	312,346	2.61%	93,321	-	8,152	(885)	(156)	-	100,432	
5	364	Poles Towers & Fixtures	258,898	2.73%	80,092	-	7,068	(570)	(567)	-	86,023	
6	365	Conductors and Devices	436,812	2.38%	129,625	-	10,396	(728)	(914)	-	138,379	
7	368	Line Transformers	193,494	3.13%	45,961	-	6,056	(1,815)	(347)	-	49,855	
8	369	Services	9,521	0.51%	6,807	-	49	-	-	-	6,856	
9	370.1	AMI Meters	41,459	6.25%	12,897	-	2,591	-	-	-	15,488	
10	371	Installation on Customers' Premises	938	0.00%	937	-	-	-	-	-	937	
11	373	Street Lighting and Signal System	14,178	4.95%	6,259	-	702	(42)	-	-	6,919	
12	372	EV Stations Kiosks & Charger Connectors	5,993	10.00%	914	-	599	-	-	-	1,513	
13			$ 1,292,454		$ 379,748	$ -	$ 35,758	$ (4,040)	$ (1,984)	$ -	$ 409,482	
14												
15		**General Plant**										
16	389	Land	$ 11,184	0.00%	$ 34	$ -	$ -	$ -	$ -	$ -	$ 34	
17	390.1	Structures - Masonry	48,652	2.53%	13,006	-	1,231	(319)	-	-	13,918	
18	390.2	Operation Building	19,432	1.63%	7,081	-	317	(23)	-	-	7,375	
19	390.1	Leasehold Improvements	2,872	1.63%	2,700	-	47	-	-	-	2,747	
20	391	Office Furniture & Equipment	5,399	4.42%	1,501	-	239	(237)	-	-	1,503	
21	391.1	Computer Hardware	13,614	21.60%	4,496	-	2,941	(3,016)	-	-	4,421	
22	391.2	Computer Software	41,906	8.96%	16,368	-	3,755	(4,015)	-	-	16,108	
23	391.2	AMI Software	13,439	10.00%	7,627	-	1,344	-	-	-	8,971	
24	392.1	Light Duty Vehicles	5,967	3.81%	2,528	-	227	(484)	77	-	2,348	
25	392.1	Heavy Duty Vehciles	28,678	6.50%	8,066	-	1,864	(351)	-	-	9,579	
26	394	Tools and Work Equipment	8,507	4.11%	3,500	-	350	(587)	-	-	3,263	
27	397	Communication Structures & Equipment	15,707	3.44%	5,067	-	540	(1,456)	(5)	-	4,146	
28	397.1	Fibre	5,729	6.97%	2,486	-	399	(198)	-	-	2,687	
29	397.2	AMI Communications Structure & Equipment	4,970	6.67%	2,390	-	332	-	-	-	2,722	
30			$ 226,056		$ 76,850	$ -	$ 13,586	$ (10,686)	$ 72	$ -	$ 79,822	
31												
32		**Total**	$ 2,420,736		$ 693,759	$ -	$ 69,474	$ (16,610)	$ (4,999)	$ -	$ 741,624	
33												
34		Cross Reference	Schedule 6.1, Line 32, Column 3+4+5									

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 9

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	CIAC	$ 243,101	$ -	$ -	$ 11,628	$ -	$ 254,729	
3	**Total**	$ 243,101	$ -	$ -	$ 11,628	$ -	$ 254,729	
4								
5	**Amortization**							
6	Amortization	$ (89,140)	$ -	$ -	$ (5,067)	$ -	$ (94,207)	
7	**Total**	$ (89,140)	$ -	$ -	$ (5,067)	$ -	$ (94,207)	
8								
9	**Net CIAC**	$ 153,961	$ -	$ -	$ 6,561	$ -	$ 160,522	

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**1. Forecasting Variance Accounts**								
2	BCUC Levies Variance Account	$ 32	$ -	$ -	$ -	$ (32)	$ -	$ 16	
3									
4	**2. Rate Smoothing Accounts**								
5									
6	**3. Benefits Matching Accounts**								
7	Preliminary and Investigative Charges	$ 2,646	$ -	$ (439)	$ -	$ -	$ 2,207	$ 2,427	Note 1
8	Demand Side Management	37,219	-	14,455	(3,903)	(5,829)	41,942	39,581	
9	Deferred Debt Issue Costs	4,074	-	600	(111)	(167)	4,396	4,235	
10	Joint Pole Use Audit 2023	-	-	435	(117)	(64)	254	127	
11	2021 Generic Cost of Capital Proceeding	675	-	450	(122)	-	1,003	839	
12	Annual Reviews for 2020-2024 Rates	154	-	200	(54)	(154)	146	150	
13	2021 Long Term Electric Resource Plan	264	-	250	(68)	(113)	333	298	
14	BCUC Initiated Inquiry Costs	109	-	100	(27)	(109)	73	91	
15	Mandatory Reliability Standards 2021 Audit	157	-	-	-	(79)	78	118	
16		$ 45,298	$ -	$ 16,051	$ (4,402)	$ (6,515)	$ 50,432	$ 47,866	
17									
18	**4. Retroactive Expense Accounts**								
19									
20	**5.Other Accounts**								
21	Pension and OPEB Liability	$ (10,592)	$ -	$ 4,664	$ -	$ -	$ (5,928)	$ (8,260)	
22	COVID-19 Customer Recovery Fund	507	-	-	-	(169)	338	423	
23	Indigenous Relations Agreement (Huth Substation)	-	-	-	-	-	-	-	
24		$ (10,085)	$ -	$ 4,664	$ -	$ (169)	$ (5,590)	$ (7,837)	
25									
26	**Total Rate Base Deferral Accounts**	$ 35,245	$ -	$ 20,715	$ (4,402)	$ (6,716)	$ 44,842	$ 40,045	
27									

28 Note 1: Gross Additions for Preliminary and Investigative Charges are after transfers to Construction Work in Progress. Additions of $0.851 million - transfer of $1.290 million = $(0.439) million.

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 12

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	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	$ 1,493	$ -	$ -	$ -	$ (604)	$ 889	$ 1,191	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	Tariff Applications	31	-	-	-	(31)	-	15	
10		$ 31	$ -	$ -	$ -	$ (31)	$ -	$ 15	
11									
12	**4. Retroactive Expense Accounts**								
13									
14	**5.Other Accounts**								
15									
16	**Total NRB Deferral Accounts at Short Term Interest**	$ 1,524	$ -	$ -	$ -	$ (635)	$ 889	$ 1,206	
17									
18	Financing Costs at STI	$ 8	$ -	$ 37	$ -	$ (8)	$ 37	$ 23	

FORTISBC INC.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 12.1

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	Mid-Year Average	Cross Ref
	(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									
7	**3. Benefits Matching Accounts**								
8	CPCN Projects Preliminary Engineering [1]	$ 980	$ -	$ 450	$ -	$ -	$ 1,430	$ 1,205	
9	2017 Rate Design Application	236	-	-	-	(118)	118	177	
10	2020 - 2024 Multi-Year Rate Plan Application	290	-	-	-	(145)	145	217	
11	Rate Design and Rates for Electric Vehicle Direct Current Fast Charging Service Application	127	-	-	-	(59)	68	98	
12		$ 1,633	$ -	$ 450	$ -	$ (322)	$ 1,761	$ 1,697	
13									
14	**4. Retroactive Expense Accounts**								
15									
16	**5.Other Accounts**								
17	US GAAP Pension and OPEB Transition Obligation	$ 348	$ -	$ (348)	$ -	$ -	$ -	$ 174	
18	Advanced Metering Infrastructure Radio-Off Shortfall	25	-	-	-	(25)	-	12	
19		$ 373	$ -	$ (348)	$ -	$ (25)	$ -	$ 186	
20									
21	**Total NRB Deferral Accounts at Weighted Average Cost of Debt**	$ 2,006	$ -	$ 102	$ -	$ (347)	$ 1,761	$ 1,883	
22									
23	Financing Costs at WACD	$ 64	$ -	$ 66	$ -	$ (64)	$ 66	$ 65	

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

FORTISBC INC.

Schedule 12.2

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2023	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	$ (9,625)	$ -	$ -	$ -	$ 9,625	$ -	$ (4,813)	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	On Bill Financing (OBF) Participant Loans	$ 1	$ -	$ (1)	$ -	$ -	$ -	$ 1	
10									
11	**4. Retroactive Expense Accounts**								
12									
13	**5.Other Accounts**								
14	MRP Earnings Sharing Account	$ (665)	$ -	$ -	$ -	$ 665	$ -	$ (333)	
15									
16	**Total NRB Deferral Accounts at Weighted Average Cost of Capital**	$ (10,289)	$ -	$ (1)	$ -	$ 10,290	$ -	$ (5,145)	
17									
18	Financing Costs at AFUDC	$ (757)	$ -	$ (317)	$ -	$ 757	(317)	(537)	
19									
20	**Non Rate Base Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50	
21									
22									
23	**Total Non Rate Base Deferral Accounts (including financing)**	**$ (7,394)**	**$ -**	**$ (113)**	**$ -**	**$ 9,993**	**$ 2,487**	**$ (2,455)**	

FORTISBC INC.

Schedule 13

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 7,065	$ 6,850	$ (215)	Schedule 14, Line 32, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Customers Loans	329	353	24	
6	Employee Loans	443	570	127	
7	Inventories - Materials and Supplies	612	649	37	
8	Employee Withholdings	(2,191)	(2,322)	(131)	
9	Total	$ 6,258	$ 6,100	$ (158)	

FORTISBC INC.

FBC Annual Review for 2023 Rates - August 5, 2022

Section 11

Schedule 14

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2023 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	$ 205,868	56.0	$ 11,528,608		
4	Commercial Tariff Revenue	110,473	45.1	4,982,332		
5	Wholesale Tariff Revenue	54,109	37.5	2,029,088		
6	Industrial Tariff Revenue	49,767	38.0	1,891,146		
7	Lighting Tariff Revenue	2,295	34.6	79,407		
8	Irrigation Tariff Revenue	3,696	47.0	173,712		
9						
10	**Other Revenue**					
11	Apparatus and Facilities Rental	$ 6,108	90.0	$ 549,720		
12	Contract Revenue	2,367	62.2	147,227		
13	Transmission Access Revenue	1,834	65.2	119,577		
14	Late Payment Charges	994	54.0	53,658		
15	Connection Charges	553	30.5	16,867		
16	Other Utility Income	385	63.4	24,409		
17	Total	$ 438,449		$ 21,595,751		49.3
18						
19	**EXPENSES**					
20	Power Purchases	$ 163,575	(51.5)	$ (8,424,126)		
21	Wheeling	6,987	(46.9)	(327,699)		
22	Water Fees	11,543	(1.4)	(16,160)		
23	Operating and Maintenance	61,871	(28.6)	(1,769,501)		
24	Property Taxes	18,260	(4.9)	(89,474)		
25	GST	593	(45.4)	(26,900)		
26	Income Tax	6,005	(15.2)	(91,276)		
27	Total	$ 268,833		$ (10,745,136)		(40.0)
28						
29	Net Lag (Lead) Days					9.3
30	Total Expenses				$	268,833
31						
32	Cash Working Capital				$	6,850

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 16

Line No.	Particulars	2022 Approved	2023 Forecast at 2022 Approved Rates	2023 Forecast Revised Revenue	2023 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (GWh)	3,306	3,476	-	3,476	170	Schedule 17, Line 8, Column 3
3							
4	**REVENUE**						
5	Sales	$ 397,294	$ 409,840	$ -	$ 409,840	$ 12,546	Schedule 17, Line 17, Column 3
6	Deficiency (Surplus)	-	-	16,368	16,368	16,368	
7	Total	397,294	409,840	16,368	426,208	28,914	Schedule 18, Line 7, Column 5
8							
9	**EXPENSES**						
10	Cost of Energy	$ 161,830	$ 182,105	$ -	$ 182,105	$ 20,275	Schedule 19, Line 30, Column 3
11	O&M Expense (net)	57,855	61,871	-	61,871	4,016	Schedule 20, Line 24, Column 4
12	Depreciation & Amortization	63,609	61,316	-	61,316	(2,293)	Schedule 21, Line 11, Column 3
13	Property Taxes	17,889	18,260	-	18,260	371	Schedule 22, Line 6, Column 3
14	Other Revenue	(11,832)	(12,241)	-	(12,241)	(409)	Schedule 23, Line 9, Column 3
15	Utility Income Before Income Taxes	107,943	98,529	16,368	114,897	6,954	
16							
17	Income Taxes	7,499	1,589	4,416	6,005	(1,494)	Schedule 24, Line 13, Column 3
18							
19	**EARNED RETURN**	$ 100,444	$ 96,940	$ 11,952	$ 108,892	$ 8,448	Schedule 26, Line 5, Column 7
20							
21	**UTILITY RATE BASE**	$ 1,582,907	$ 1,675,028		$ 1,675,431	$ 92,524	Schedule 2, Line 29, Column 3
22	**RATE OF RETURN ON UTILITY RATE BASE**	6.35%	5.79%		6.50%	0.15%	Schedule 26, Line 5, Column 6

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

Schedule 17

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (GWh)**				
2	Residential	1,283	1,301	18	
3	Commercial	946	973	27	
4	Wholesale	560	578	18	
5	Industrial	470	575	105	
6	Lighting	10	9	(1)	
7	Irrigation	37	39	2	
8	Total	3,306	3,476	170	
9					
10	**REVENUE AT EXISTING RATES**				
11	Residential	$ 195,058	$ 197,962	$ 2,904	
12	Commercial	104,380	106,230	1,850	
13	Wholesale	51,255	52,031	776	
14	Industrial	40,804	47,856	7,052	
15	Lighting	2,411	2,207	(204)	
16	Irrigation	3,386	3,554	168	
17	Total	$ 397,294	$ 409,840	$ 12,546	

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 18

Line No.	Particulars	2022 Approved Revenue	2023 Forecast Revenue at 2022 Approved Rates	2023 Forecast Effective Increase	2023 Forecast Revenue at Revised Rates	Average Number of Customers	GWh	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 195,058	$ 197,962	$ 7,906	$ 205,868	130,787	1,301	
2	Commercial	104,380	106,230	4,243	110,473	17,267	973	
3	Wholesale	51,255	52,031	2,078	54,109	6	578	
4	Industrial	40,804	47,856	1,911	49,767	42	575	
5	Lighting	2,411	2,207	88	2,295	1,358	9	
6	Irrigation	3,386	3,554	142	3,696	1,103	39	
7	Total	$ 397,294	$ 409,840	$ 16,368	$ 426,208	150,563	3,476	
8								
9	**Effective Increase**			3.99%				

FORTISBC INC. FBC Annual Review for 2023 Rates - August 5, 2022 Section 11

COST OF ENERGY Schedule 19
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**POWER PURCHASES**				
2	Gross Load (GWh)	3,591	3,775	184	
3					
4	**Power Purchase Expense**				
5	Brilliant	$ 41,841	$ 44,050	$ 2,209	
6	BC Hydro PPA	44,062	71,302	27,240	
7	Waneta Expansion	42,701	41,834	(867)	
8	Market and Contracted Producers	15,102	6,326	(8,776)	
9	Independent Power Producers	73	62	(11)	
10	Self-Generators	-	-	-	
11	CPA Balancing Pool	-	-	-	
12	Total	$ 143,779	$ 163,575	$ 19,796	
13					
14	**WHEELING**				
15	**Wheeling Nomination (MW months)**				
16	Okanagan Point of Interconnection	2,475	2,670	195	
17	Creston	420	420	-	
18					
19	**Wheeling Expense**				
20	Okanagan Point of Interconnect	$ 4,903	$ 5,555	$ 652	
21	Creston	542	570	28	
22	Other	648	863	215	
23	Total	$ 6,093	$ 6,987	$ 894	
24					
25	**WATER FEES**				
26	Plant Entitlement Use in previous year (GWh)	1,679	1,571	(108)	
27					
28	Water Fees	$ 11,958	$ 11,543	$ (415)	
29					
30	Total	$ 161,830	$ 182,105	$ 20,275	

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OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 20

Line No.	Particulars	Inflation Indexed O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Inflation Indexed O&M**				
2	2022 Base Unit Cost O&M	$ 455			
3	2023 Net Inflation Factor	4.017%			Schedule 3, Line 9, Column 6
4	2023 Base Unit Cost O&M	$ 473			Line 2 x (1 + Line 3)
5					
6	2023 Average Customer Forecast - Rate Setting Purpose	147,901			Schedule 3, Line 22, Column 7
7					
8	2023 Inflation Indexed O&M before prior year True-up	$ 69,957			Line 4 x Line 6 / 1,000
9					
10	2021 Average Customer True-up	509			
11					
12	2023 Inflation Indexed O&M	$ 70,466		$ 70,466	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ (1,297)		
16	Insurance Premiums		2,457		
17	BCUC Levies		385		
18	MRS		585		
19	EV Charging Stations		193		
20	Sub-total		$ 2,323	2,323	Sum of Lines 15 through 19
21					
22	**Total Gross O&M**			$ 72,789	Line 12 + Line 20
23	Capitalized Overhead			(10,918)	-15 % x Line 22
24	**Net O&M Expense**			$ 61,871	Sum of Lines 22 and 23

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 66,722	$ 69,474	$ 2,752	Schedule 7.1, Line 32, Column 7
3					
4	**Amortization**				
5	Rate Base Deferrals	$ 5,913	$ 6,716	$ 803	Schedule 11, Line 26, Column 6
6	Non-Rate Base Deferrals	(4,355)	(9,993)	(5,638)	Schedule 12.2, Line 23, Column 6
7	Utility Plant Acquisition Adjustment	186	186	-	
8	CIAC	(4,857)	(5,067)	(210)	Schedule 9, Line 7, Column 5
9		(3,113)	(8,158)	(5,045)	
10					
11	Total	$ 63,609	$ 61,316	$ (2,293)	

FORTISBC INC.

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Section 11

Schedule 22

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Generating Plant	$ 3,210	$ 3,253	$ 43	
2	Transmission and Distribution	7,428	7,189	(239)	
3	Substation Equipment	3,948	4,208	260	
4	Land and Buildings	1,165	1,322	157	
5	1% In-Lieu of Municipal Taxes	2,138	2,288	150	
6	Total	$ 17,889	$ 18,260	$ 371	

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OTHER REVENUE Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Apparatus and Facilities Rental	$ 6,018	$ 6,108	$ 90	
2	Contract Revenue	2,277	2,367	90	
3	Transmission Access Revenue	1,771	1,834	63	
4	Interest Income	20	30	10	
5	Late Payment Charges	875	994	119	
6	Connection Charges	505	553	48	
7	Other Recoveries	366	355	(11)	
8	EV Carbon Credits	-	-	-	
9	Total	$ 11,832	$ 12,241	$ 409	

FORTISBC INC.

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Section 11

Schedule 24

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 100,444	$ 108,892	$ 8,448	Schedule 16, Line 19, Column 5
2	Deduct: Interest on Debt	(42,510)	(47,571)	(5,061)	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	(37,660)	(45,084)	(7,424)	Line 32
4	Accounting Income After Tax	$ 20,274	$ 16,237	$ (4,037)	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 27,773	$ 22,242	$ (5,531)	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 7,499	$ 6,005	$ (1,494)	
11					
12	Previous Year Adjustment	-	-	-	
13	**Total Income Tax**	$ 7,499	$ 6,005	$ (1,494)	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 66,722	$ 69,474	$ 2,752	Schedule 21, Line 2, Column 3
19	Amortization of Deferred Charges	1,558	(3,277)	(4,835)	Schedule 21, Line 5+6, Column 3
20	Amortization of Utility Plant Acquisition Adjustment	186	186	-	Schedule 21, Line 7, Column 3
21	Pension Expense	84	(528)	(612)	
22	OPEB Expense	1,607	1,119	(488)	
23					
24	Deductions:				
25	Capital Cost Allowance	(86,398)	(89,854)	(3,456)	Schedule 25, Line 19, Column 6
26	CIAC Amortization	(4,857)	(5,067)	(210)	Schedule 21, Line 8, Column 3
27	Pension Contributions	(4,419)	(4,203)	216	
28	OPEB Contributions	(655)	(705)	(50)	
29	Overheads Capitalized Expensed for Tax Purposes	(10,177)	(10,918)	(741)	Schedule 20, Line 23, Column 4
30	Removal Costs	(1,200)	(1,200)	-	
31	All Other	(111)	(111)	-	
32	Total	$ (37,660)	$ (45,084)	$ (7,424)	

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Schedule 25

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Class	CCA Rate	12/31/2022 UCC Balance	2023 Additions & Opening Adjt	UCC Adjustment for AIIP *	2023 CCA	Forecast 12/31/2023 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 154,085	$ -	$ -	$ (6,163)	$ 147,922
2	1(b)	6%	33,091	3,043	1,521	(2,259)	33,875
3	2	6%	11,403	-	-	(684)	10,719
4	3	5%	648	-	-	(32)	616
5	6	10%	2	-	-	-	2
6	8	20%	3,694	842	421	(991)	3,545
7	10	30%	4,709	1,857	929	(2,250)	4,316
8	13	0%	11	-	-	-	11
9	14.1 (pre 2017)	7%	6,926	-	-	(485)	6,441
10	14.1 (post 2016)	5%	3,951	1,280	640	(294)	4,937
11	17	8%	156,652	22,036	11,018	(15,177)	163,511
12	42	12%	9,649	610	305	(1,268)	8,991
13	43.1	30%	566	(155)	-	(123)	288
14	45	45%	1	-	-	-	1
15	46	30%	2,708	-	-	(812)	1,896
16	47	8%	494,831	87,737	43,868	(50,115)	532,453
17	50	55%	2,800	9,286	4,643	(9,201)	2,885
18							
19	Total		$ 885,727	$ 126,536	$ 63,345	$ (89,854)	$ 922,409
20							
21	* Note - Accelerated Investment Incentive Property						

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Schedule 26

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved Earned Return	Amount	Ratio	2023 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 41,155	$ 914,178	54.56%	4.78%	2.61%	$ 43,709	$ 2,554	Schedule 27, Line 12, Column 6
2	Short Term Debt	1,355	91,081	5.44%	4.24%	0.23%	3,862	2,507	
3	Common Equity	57,934	670,172	40.00%	9.15%	3.66%	61,321	3,387	
4									
5	Total	$ 100,444	$ 1,675,431	100.00%		6.50%	$ 108,892	$ 8,448	
6									
7	Cross Reference		Schedule 2, Line 29, Column 3						

FORTISBC INC.

FBC Annual Review for 2023 Rates - August 5, 2022

Section 11

Schedule 27

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Average Principal Outstanding	Interest Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1993 Debt Issue - Series G	August 28, 1993	August 28, 2023	$ 16,370	8.800%	$ 1,441	
2	2005 Debt Issue - Series 1 - 05	November 9, 2005	November 9, 2035	100,000	5.600%	5,600	
3	2007 Debt Issue - Series 1 - 07	July 4, 2007	July 4, 2047	105,000	5.900%	6,195	
4	2009 Debt Issue - MTN - 09	June 2, 2009	June 2, 2039	105,000	6.100%	6,405	
5	2010 Debt Issue - MTN - 10	November 24, 2010	November 24, 2050	100,000	5.000%	5,000	
6	2014 Debt Issue - MTN - 14	October 28, 2014	October 28, 2044	200,000	4.000%	8,000	
7	2017 Debt Issue - MTN - 17	December 4, 2017	December 6, 2049	75,000	3.620%	2,715	
8	2020 Debt Issue - MTN - 20	May 11, 2020	May 11, 2050	75,000	3.120%	2,340	
9	2022 Debt Issue - MTN - 22	March 14, 2022	March 14, 2052	100,000	4.160%	4,160	
10	2023 Debt Issue - MTN - 23	July 1, 2023	July 1, 2053	37,808	4.900%	1,853	
11							
12	Total			$ 914,178		$ 43,709	
13							
14	Average Embedded Cost				4.78%		

12. ACCOUNTING MATTERS

12.1 INTRODUCTION AND OVERVIEW

In this section, FBC discusses "Exogenous Factors" under its MRP, providing an update on the exogenous factor treatment for the impacts of the COVID-19 pandemic. FBC also discusses emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FBC 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.

In the Annual Review for 2020 and 2021 Rates, FBC identified the COVID-19 pandemic as a potential exogenous factor affecting 2020 and future years, and the BCUC approved FBC's request to record COVID-19 pandemic incremental costs and cost reductions from 2020 and 2021 into the previously approved COVID-19 Customer Recovery Fund Deferral Account.[59] FBC also stated in the Annual Review for 2020 and 2021 Rates application that it would review the amounts in 2021 when actual 2020 amounts and forecasts for future years could be ascertained, and an appropriate recovery method could be determined. In the Annual Review for 2022 Rates application, FBC provided a status update on the COVID-19 pandemic net incremental costs (costs less cost reductions). In the following section, FBC reports on the net incremental cost reductions and proposes to return these cost reductions to customers.

[59] FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

12.2.1 COVID-19 Pandemic

During the COVID-19 pandemic, 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. This has resulted in net incremental O&M impacts.

12.2.1.1 FBC Has Reasonably Tracked the Impact of the COVID-19 Pandemic on Net Operating Costs

Consistent with the MRP, FBC's general approach to managing its formula O&M funding is at an overall Company level. O&M funding is prioritized and allocated as required to meet the business environment, conditions and requirements the Company faces. Funding utilized for a specific purpose in one year may be used differently in the following year. As a result, this makes the determination of COVID-19 pandemic net incremental O&M costs from year to year challenging and fluid, particularly for cost reductions, as the Company reprioritizes its funding regularly to meet its needs to provide safe and reliable operations.

Further, the COVID-19 pandemic has a broad impact throughout the organization, making the determination of the incremental costs more challenging. The impact of the COVID-19 pandemic varies in different parts of the business. For example, there may be additional overtime costs in departments that are indirectly influenced by the pandemic (e.g., less internal resources available due to reassignment to assist with other priorities), which are difficult to specifically identify. Also, there may be delays in work scheduled as a result of the pandemic that may increase the total cost of the work required, which are not specifically identified as COVID-19 pandemic related.

Recognizing the above circumstances, FBC has undertaken its best efforts to track and report on the net incremental O&M costs that are directly related to the COVID-19 pandemic. FBC has included below all costs that are specifically identifiable as attributable to activities required to respond to the COVID-19 pandemic as part of the overall net incremental costs (costs less cost reductions). While acknowledging there are uncertainties, the following summary of net incremental cost reductions provides a reasonable representation of the overall COVID-19 pandemic impact on the Company.

12.2.1.2 Summary of Net Incremental Costs

The combined impact in 2020 and 2021 as a result of the COVID-19 pandemic is a decrease by approximately $1.03 million in FBC's net incremental O&M expense (costs less cost reductions).

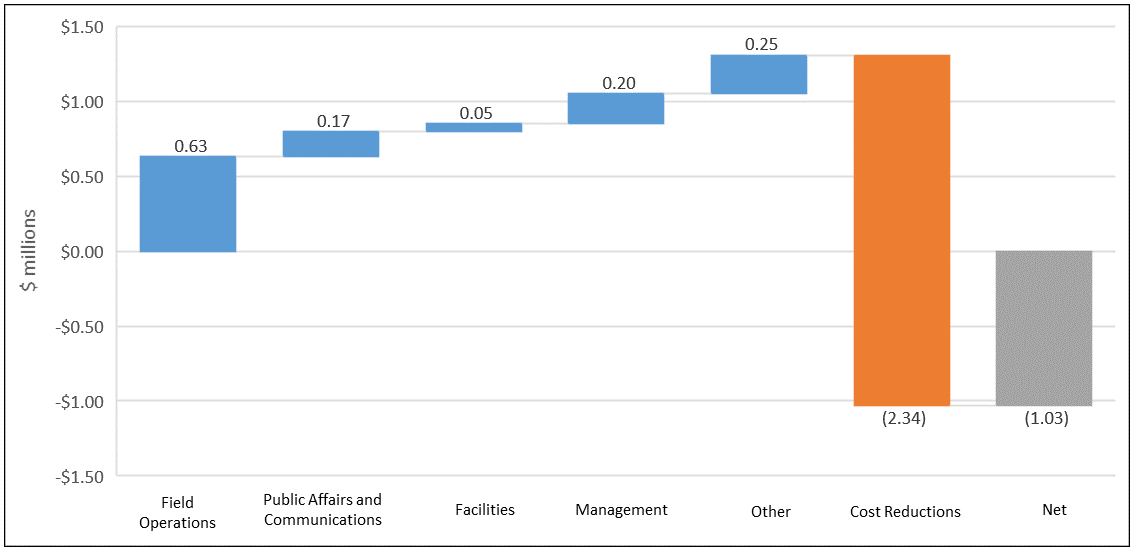
Table 12-1: Net Incremental Cost Reductions ($ millions)

	2020	2021	2020/2021
Direct Costs			
Field Operations	$ 0.46	$ 0.18	$ 0.63
Public Affairs and Communications	$ 0.16	$ 0.01	$ 0.17
Facilities	$ 0.04	$ 0.01	$ 0.05
Management	$ 0.10	$ 0.10	$ 0.20
Other	$ 0.18	$ 0.07	$ 0.25
Total Direct Costs	$ 0.94	$ 0.36	$ 1.31
Cost Reductions	$ (1.05)	$ (1.29)	$ (2.34)
Net difference	$ (0.10)	$ (0.93)	$ (1.03)

12.2.1.3 2020 and 2021 COVID-19 Pandemic Impact

While the COVID-19 pandemic increased many areas of O&M costs in 2020 and 2021, these costs were more than offset by lower employee related expenses. In 2020 and 2021, FBC incurred approximately $1.31 million in O&M costs related to the COVID-19 pandemic. These costs were primarily to ensure the health, safety and well-being of FBC's customers, employees, and their communities, and to continue to operate the system safely and reliably. The incremental costs were offset by approximately $2.34 million in employee expense related reductions. The figure below shows the categories of costs incurred and the offsetting savings. Each of the categories is described further below.

Figure 12-1: FBC COVID-19 Pandemic 2020 and 2021 Net O&M Cost Reductions



12.2.1.3.1 INCREASED O&M EXPENDITURES DUE TO THE COVID-19 PANDEMIC

In the Field Operations area, FBC incurred approximately $0.63 million related to the COVID-19 pandemic, with the majority of the costs related to the sequestering of system control centre employees from having to return to their homes and separation of the operators between the system control centre and Kootenay operating centre sites to ensure a safe and healthy work environment for this critical function. FBC also incurred costs for personal protective equipment (i.e., masks, gloves and sanitizers).

In the Public Affairs and Communications area, FBC incurred approximately $0.17 million for activities to keep customers and key stakeholders informed of the Company's assistance available during the COVID-19 pandemic, including the support required to develop the materials and to monitor and maintain messaging as needed. The costs were for advertising, various communication materials such as bill inserts, and labour and consultant services required to develop the materials and to monitor and maintain messaging as needed.

FBC incurred approximately $0.05 million for Facilities-related resources and activities including safety supplies, additional cleaning, first aid coverage, and signage.

Under the category of Management, approximately $0.20 million in management resource costs were added to support the following areas: the operation of the Emergency Operating Centre (EOC); the Human Resources and Environmental, Health and Safety groups' response to COVID-19 pandemic incidents and issues for employees and contractors; and the increased needs of supporting departments such as Information Systems, Supply Chain, Communications, and Business Continuity. The resources were necessary to respond to the COVID-19 pandemic and to address the various needs of the health authorities, regulators, and organizations like Emergency Management BC.

The Other category of approximately $0.25 million includes miscellaneous items such as different support group costs (e.g., Information Systems and TELUS Babylon health service).

12.2.1.3.2 O&M COST REDUCTIONS OFFSET INCREASED COSTS

The cost reductions that FBC achieved consist primarily of lower employee expenses, in part as a response to the travel restrictions, including in and out of Province travel, and the effect that the COVID-19 pandemic has had on social interactions. Employee expenses that were not incurred include course fees, travel, meals and accommodation, Company function expenses, and employee hiring and relocation expenses.

For the years 2020 and 2021, the reduced employee expenses were estimated at approximately $2.34 million.

12.2.1.3.3 CUMULATIVE NET IMPACT

The variances for the 2020 and 2021 net incremental O&M (costs less cost reductions) total to a net decrease of approximately $1.03 million.

Accordingly, FBC requests approval to return the exogenous factor savings of $1.03 million to customers in 2023, as further described below.

12.2.1.4 2022 COVID-19 Pandemic Impact

With the Company's transition to normal operations, FBC does not anticipate further impacts on its costs in 2022 requiring exogenous factor treatment. As mentioned in FBC's 2022 Annual Review, FBC started the transition to normal operations in September 2021 with the Province achieving Step 4 of the Province of BC Four Step Restart Plan. Step 4 included the lifting of restrictions with normal social contact allowed and workplaces fully reopened. For FBC, this meant having its employees return to offices and worksites starting September 7, 2021 with 100 percent of employees on site at least 50 percent of the time while maintaining building capacity at 50 percent.

The transition to normal operations continued into early 2022 with the provincial government lifting the workplace safety order on April 8, 2022, enabling businesses to transition back to communicable disease plans to reduce risk of all communicable disease, instead of maintaining a COVID-19 safety plan. At the same time, the provincial government also removed restrictions on gatherings and events, including at restaurants, bars, pubs and nightclubs. With the lifting of the workplace safety order, FBC accordingly adjusted its existing COVID-19 safety protocols at its worksites to balance safety with the return to normal operations. The adjustments included suspension of COVID-19 daily health check confirmation and the removal of mandatory mask wearing, although the practice of wearing a mask is still recommended. As of July 4, 2022, employees have returned to a primarily office-based work model. Employee-related activities and expenses for business purposes (i.e., travel, accommodation, etc.) have also returned to normal.

12.2.1.5 Mechanism to Return Cost Reductions to Customers

As part of the Annual Review for 2020 and 2021 Rates, FBC proposed (and was approved by Order G-42-21) to include the amounts related to incremental COVID-19 costs and cost reductions in the previously approved COVID-19 Customer Recovery Fund Deferral Account.

However, upon further review of FBC's original proposal, FBC has concluded that a better approach is to record these amounts in the Flow-through deferral account. This approach is preferable for three reasons:

1. It is consistent with the treatment of other exogenous items;
2. It will allow the O&M reported in the Annual Reports to be more reflective of the actual amounts incurred, as using the Flow-through deferral account does not result in direct adjustments to O&M, but rather one catch-all account for all flow-through adjustments. Alternatively, transferring the actual O&M savings directly to the COVID-19 Customer Recovery Fund Deferral Account would result in those O&M actual amounts being effectively booked back to the forecast amounts; and

3. The COVID-19 incremental savings will be returned to customers immediately in 2023, as opposed to over three years, which is the amortization period being proposed for the COVID-19 Customer Recovery Fund Deferral Account in Section 7.6.2.1.

From a customer perspective, there is no negative impact from the proposed change in treatment as customers will still have the full net savings returned to them. The benefit of the proposed treatment, as described above, is that the net savings will be returned to customers over one year as opposed to three years.

As such, FBC has included the O&M savings shown above in the 2022 Flow-through projection provided in Table 12-3 below, on Line 15, so that the net amount will be returned to customers in 2023 via the amortization of the Flow-through deferral account forecast in this Application.

Accordingly, FBC seeks a variance to Directive 6 of Order G-42-21. FBC requests that Directive 6 be varied as followed: "FBC is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the Flow-through deferral account."

12.2.1.6 Conclusion

FBC proposes to refund to customers for years 2020 and 2021, via the Flow-through deferral Account, the cumulative net variance of the net incremental O&M (costs less reductions) of $1.03 million in 2023.

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.

There are no new accounting policy changes that FBC is proposing, or that are required to be implemented under US GAAP, that result in a change in accounting for 2023; however, FBC provides an update on its exemptive relief to report under US GAAP.

12.3.1.1 Ontario Securities Commission Exemption to use US GAAP

FBC follows US GAAP for both financial and regulatory accounting purposes. Since 2011, FBC has made use of an exemption from the Ontario Securities Commission (OSC) permitting FBC to prepare and file its financial statements in accordance with US GAAP. Like other reporting issuers, FBC also has the option to obtain an exemption permitting the use of US GAAP by

qualifying as a US Securities and Exchange Commission Issuer (SEC Issuer) pursuant to Canadian securities law. During 2022, FBC sought and received approval from its primary securities regulator, the BC Securities Commission (BCSC), for the same exemptive relief as the 2011 OSC exemption. FBC's original exemption from 2011 was filed jointly with FBC's parent company Fortis Inc., whose primary securities regulator is the OSC; however, Fortis Inc. is now an SEC Issuer and no longer makes use of the OSC exemption. As a result, FBC obtained an exemption on a stand-alone basis from the BCSC.

The BCUC has approved FBC's use of US GAAP for regulatory accounting purposes since 2011.[60] As part of the most recent BCUC approval to use US GAAP, the BCUC directed the following:[61]

> Approval is granted until such time as the FortisBC Utilities no longer has an Ontario Securities Commission exemption to use US GAAP or is no longer reporting under US GAAP for financial reporting purposes.

FBC considers that the intention of the above direction was to ensure that FBC has an exemption from its securities regulator to use US GAAP, and not that an exemption specifically from the OSC was required, as opposed to a different securities regulator that had jurisdiction. It was not contemplated at the time of the above direction that FBC would make use of a BCSC exemption rather than an OSC exemption.

To ensure that FBC has approval from the BCUC to use US GAAP for regulatory accounting purposes, FBC is seeking a variance of Directive 2 to Order G-83-14 to remove the reference to the OSC, so that it removes the reference to the Ontario Securities Commission, and states:

> Approval is granted until such time as FBC no longer has an exemption to prepare and file its financial statements in accordance with US GAAP or is no longer reporting under US GAAP for financial reporting purposes.

FBC notes that there have been no other changes in circumstances beyond the change in the regulatory body granting exemptive relief. However, similar to the original 2011 OSC exemptive relief, the 2022 BCSC exemptive relief is not permanent and would expire January 1, 2027 unless extended further. Should FBC plan to no longer report under US GAAP (e.g., convert from US GAAP to IFRS), it would file an application for approval from the BCUC at that time

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.

[60] Order G-117-11 dated July 7, 2011 and Order G-83-14 dated July 3, 2014.
[61] Order G-83-14, Directive 2.

In the following section, FBC 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 New Deferral Accounts

FBC is not seeking approval of any new non-rate base deferral accounts in this Application.

12.4.2 Existing Deferral Accounts

In the section below, FBC discusses the Flow-through deferral account.

12.4.2.1 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 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

In accordance with the method set out in the table above, the calculation of the 2022 Projected Flow-through amount of $5.007 million credit is shown in Table 12-3 below. To calculate the amount to be distributed to customers, FBC has also included the following adjustment:

- The $4.618 million credit difference between the projected ending 2021 deferral account credit balance of $3.927 million[62] embedded in 2022 rates, and the actual ending 2021 deferral credit balance of $8.545 million. A more detailed breakout of the 2021 variance is provided in Table 12-4 below. FBC notes that the financing return on this account is included in the aggregate financing of deferral accounts at Section 11, Schedule 12.2, Line 18.

Table 12-3: 2022 Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2022 Approved	2022 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (397.294)	$ (414.292)	$ (16.998)
2				
3	**Total Power Purchase Expense**	143.779	153.164	9.385
4				
5	**Total Wheeling**	6.093	6.330	0.237
6				
7	**Total Water Fees**	11.958	11.916	(0.042)
8				
9	**Net O&M Expense**			
10	Pension & OPEB	(1.716)	(1.716)	-
11	Insurance	2.223	2.291	0.068
12	BCUC Fees	0.373	0.373	-
13	MRS	0.765	0.500	(0.265)
14	EV DCFC	0.187	0.187	-
15	COVID-19 Pandemic	-	(1.030)	(1.030)
16	Capitalized Overhead	(10.177)	(10.177)	-
17				
18	**Depreciation and Amortization**			
19	Amortization of Deferrals	1.558	1.558	-
20	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
22				
23	**Total Property Taxes**	17.889	17.621	(0.268)
24				
25	**Other Revenues**			
26	EV Carbon Credits	-	(0.625)	(0.625)
27				
28	**Interest Expense**			
29	Long-term debt interest expense variance	41.155	41.794	0.639
30	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
31	Short-term debt rate variance	-	2.253	2.253
32	Short-term debt volume variance from long-term debt issue variance	-	(1.005)	(1.005)
33	Short-term debt timing variance from long-term debt issue timing	-	0.793	0.793
34				
35	**Income Tax Expense**			
36	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
37	Income tax/CCA rate changes	-	-	-
38	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	-	1.852	1.852
39				
40	**2022 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**(5.007)**
41				
42	2021 Ending Deferral Account Balance True-up			(4.618)
43				
44	**2023 After-Tax Amortization**			**(9.625)**

[62] FBC Annual Review for 2022 Rates, Compliance Filing financial schedules, Schedule 12.2, Line 4, Column 2.

12.4.2.1.1 2022 PROJECTED FLOW-THROUGH VARIANCES

FBC provides the following explanations for the 2022 Projected flow-through variances shown in Table 12-3 above:

- The variance in revenue is due to increased industrial, commercial, wholesale and residential loads;
- The variance in power purchase expense is primarily due to an increase in gross load. Increasing gross load drove additional market purchases as well as BC Hydro PPA energy and capacity purchases at a higher than anticipated total cost. Rising rates further contributed to the increase in power purchase expense;
- Variances in wheeling and water fees are discussed in Section 4;
- Flow-through O&M amounts are discussed in Section 6;
- Amortization expense is equal to the approved value;
- Variances in property taxes are described in Section 9;
- Variances in other revenues are described in Section 5;
- The projected interest expense variances are derived from FBC issuing long-term debt later in 2022 than forecast, but at a higher amount and higher rate than forecast, and FBC projecting a higher short-term interest rate than the approved short-term interest rate, both as described in Section 8; and
- The income tax variance is derived as 27 percent of the aforementioned variances.

An adjustment to include the difference between the projected and final actual amounts for 2022 subject to flow-through will be recorded in the deferral account in 2022 and amortized in 2024 rates.

12.4.2.1.2 2021 FLOW-THROUGH DEFERRAL ACCOUNT TRUE-UP

As mentioned above, FBC is also providing a breakdown of the 2021 true-up amount of $4.618 million credit in Table 12-4 below, along with an explanation of the variances.

Table 12-4: 2021 Actual vs. Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2021 Projected	2021 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (389.100)	$ (404.247)	$ (15.147)
2				
3	**Total Power Purchase Expense**	141.747	152.473	10.726
4				
5	**Total Wheeling**	5.836	6.000	0.164
6				
7	**Total Water Fees**	10.878	10.741	(0.137)
8				
9	**Net O&M Expense**			
10	Pension & OPEB	0.775	0.775	-
11	Insurance	2.022	1.924	(0.098)
12	BCUC Fees	0.350	0.350	-
13	MRS	0.100	0.052	(0.048)
14	2021 Wildfires	0.155	0.155	-
15	Capitalized Overhead	(9.795)	(9.795)	-
16				
17	**Depreciation and Amortization**			
18	Amortization of Deferrals	5.110	5.110	-
19	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.301)	(0.301)
20	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21				
22	**Total Property Taxes**	17.225	17.262	0.037
23				
24	**Interest Expense**			
25	Long-term debt interest expense variance	40.698	40.251	(0.447)
26	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.059)	(0.059)
27	Short-term debt rate variance	(0.500)	(0.593)	(0.092)
28	Short-term debt volume variance from long-term debt issue variance	-	0.303	0.303
29	Short-term debt timing variance from long-term debt issue timing	0.910	-	(0.910)
30				
31	**Income Tax Expense**			
32	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	0.048	0.048
33	Income tax/CCA rate changes	-	-	-
34	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	1.571	3.097	1.526
35				
36	EV DCFC Service Application 2018-2021 adjustment	0.107	(0.074)	(0.181)
37				
38	**2021 Ending Deferral Account Balance True-up**			**(4.618)**

The 2021 Actual variances shown in Table 12-4 above are described as follows:

- The favourable variance in revenue of $15.147 million was due to higher than projected residential, commercial, wholesale and irrigation loads, mainly due to weather variations. Favourable variances in residential ($12.209 million), commercial ($2.614 million), wholesale ($1.552 million), and irrigation ($0.815 million) revenue were partially offset by unfavourable variances in industrial ($1.939 million) and lighting ($0.104 million) revenue;
- The increase in power purchase expense of $10.726 million was due several factors including increased market expenses, increased load, and reduced generation availability. Increased load and market expenses were primarily due to several extreme weather events, such as the June 2021 heat dome event. This increase was partially offset by increased surplus capacity sales under the CEPSA Agreement;
- The increase in wheeling costs of $0.164 million was primarily due to increased use of wheeling under BC Hydro's Open Access Transmission Tariff;
- The decrease in water fees of $0.137 million was primarily due to reduced water rental rates compared to forecast;

- The flow-through components of O&M expense were $0.146 million lower than projected, with all items comparable to the projected amounts;
- Actual property tax expense was relatively consistent with the projected amount;
- The variance between the actual (0.81 percent) and projected (1.03 percent) short-term debt interest rates results in an amount to be returned to customers of $0.092 million,[63] shown on Line 27 of the table above. The long-term debt interest expense variance of $0.447 million to be returned to customers is due to the projected 2021 long-term debt issuance not actually occurring. The net variance of $0.607 million to be returned to customers on Lines 28 and 29 of Table 12-4 above is due to the impact of a lower actual short-term interest rate than projected, partially offset by the delay in the 2021 long-term debt issuance;
- The unfavourable income tax variance of $1.526 million is calculated as 27 percent of the aforementioned variances;
- The favourable variance of $0.181 million for the EV DCFC Service Application 2018-2021 adjustment relates to the true-up of the 2021 cost of service amounts. As discussed in the Compliance Filing to the 2022 Annual Review Decision, FBC estimated the 2018-2021 EV cost of service amounts to be a $0.107 million debit recoverable from customers, using the 2018-2020 actual cost of service amounts and a 2021 projected amount. The actual 2021 EV cost of service was lower than projected, mainly related to favourable taxes, resulting in the $0.181 million overall credit true-up amount to be returned to customers; and
- The combined favourable variance of $0.312 million related to depreciation, CIAC amortization, interest and tax variances on Clean Growth/CPCN/exogenous capital amounts, shown on Lines 19, 20, 26 and 32, respectively, were derived for 2021 by comparing the actual 2021 cost of service impacts of the UBO, Grand Forks Terminal Station and Corra Linn projects to the amounts forecast for those same projects.

12.5 *SUMMARY*

FBC has requested approval to return the incremental net cost reductions related to the COVID-19 pandemic exogenous factor to customers in 2023 through inclusion in the Flow-through deferral account. FBC has also provided an update on certain accounting related matters, and included information on the Flow-through deferral account.

[63] (0.81% - 1.03%) x $42.042 million forecast 2021 short-term debt in Schedule 26 of October 28, 2020 Evidentiary Update financial schedules.

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.

In the subsections below, FBC reports on its 2021 and June 2022 year-to-date performance as measured against the SQI benchmarks and thresholds. In 2021, for the eight SQIs with benchmarks, six met or were better than the benchmark, with two better than the threshold. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years. In 2022 to date, performance for the metrics with benchmarks are trending towards meeting the benchmark or the threshold.

Consistent with how SQIs were reviewed during the 2014-2019 PBR Plan term,[64] FBC has provided 2021 and year-to-date 2022 SQI results in this annual review. In accordance with Order G-44-16, the BCUC will evaluate FBC's actual 2022 SQI performance in the Annual Review for 2024 Rates when actual SQI results are known. FBC also notes that it will provide information on the 2023 year-to-date SQI results in the Annual Review for 2024 Rates.

13.2 REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS

For each SQI, Table 13-1 provides a comparison of FBC's 2021 and June year-to-date performance for 2022 to the proposed benchmarks and thresholds approved as part of the MRP. Actual 2021 and June year-to-date results for 2022 are also provided for the four informational SQIs.

[64] 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."

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

Performance Measure	Description	Benchmark	Threshold	2021 Results	June 2022 YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within two hours	>=93%	90.6%	93%	95%
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	0.67	0.80
Responsiveness to Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	>=78%	74%	82%	78%
Billing Index	Measure of customer bills produced meeting performance criteria	<=3.0	5.0	0.12	0.14
Meter Reading Accuracy	Number of scheduled meters that were read	>=98%	96%	99%	99%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>=70%	68%	70%	63%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.4	8.4
Average Speed of Answer	Informational indicator – the amount of time it takes to answer a call (seconds)	-	-	65	98
Reliability SQIs					
System Average Interruption Duration Index (SAIDI) – Normalized	Annual SAIDI (average of cumulative customer outage time)	3.22[65]	4.52	4.27	2.94
System Average Interruption Frequency Index (SAIFI) - Normalized	Annual SAIFI (average customer outage)	1.57	2.19	2.08	1.58
Generator Forced Outage Rate	Informational indicator – Percent of time a generating unit is removed from service due to component failure or other events.	-	-	0.23%	0.85%
Interconnection Utilization	Informational indicator – percent of time that an interconnection point was available and providing electrical service to wholesale customers.	-	-	99.90%	99.91%

[65] Benchmarks and thresholds for SAIDI and SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

In the following sections, FBC reviews each SQI's year-to-date individual performance in 2021 and 2022. Discussion is also provided for the informational SQIs.

13.2.1 Safety Service Quality Indicators

13.2.1.1 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 2021 result was 93 percent which met the benchmark. The June 2022 year-to-date performance is 95 percent, which is better than the benchmark.

For comparison, the Company's annual results under the 2014-2019 PBR Plan, the 2020 and 2021 results and the June 2022 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	2020	2021	June 2022 YTD
Results	91%	92%	97%	93%	94%	92%	92%	93%	95%
Benchmark	93%								
Threshold	90.6%								

13.2.1.2 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 2021 (three-year rolling average) result was 0.67 which was better than the benchmark of 1.64. The 2021 annual AIFR was 0.89 which reflected 3 Medical Treatments and 1 Lost Time Injury.

The June 2022 year-to-date performance (three-year rolling average) result is 0.80 which is better than the benchmark. The June 2022 year-to-date performance (annual) is 1.25 and reflects 2 Medical Treatments and 1 Lost Time Injury.

Strengthening the safety culture continues to be a key driver for FBC, building on the commitment to learn from safety events, identify safety hazards, assess risk and continually improve through the implementation and sustainment of robust safety barriers and controls.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date AIFR results are provided below.

Table 13-3: Historical All Injury Frequency Rate Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	3.21	1.54	1.15	1.13	1.56	0.46	0.66	0.89	1.25
Three year rolling average	2.58	2.52	1.97	1.27	1.28	1.06	0.87	0.67	0.80
Benchmark	1.64								
Threshold	2.39								

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

13.2.2.1 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 2021 result was 82 percent which was better than the benchmark of 78 percent. The June 2022 year-to-date performance is 78 percent which meets the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-4: Historical First Contact Resolution Levels

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	73%	76%	79%	80%	82%	82%	82%	82%	78%
Benchmark	78%								
Threshold	72%						74%		

13.2.2.2 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 2021 result was 0.12 which was better than the benchmark of 3.0. No significant billing issues occurred in 2021. The June 2022 year-to-date result is 0.14, which is also better than the benchmark.

The 2021 Billing Index sub-measures calculation is as follows.

Table 13-5: Calculation of 2021 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),100*(1.05-PA))	=5000*(1-99.99885%)	0.06

Billing sub-measure	Percent Achieved (PA)	Formula		Result
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	0.00
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target: 95%	99.60%	(100%-PA)*100	=(100%-99.69%)*100	0.31
Billing Service Quality Indicator; Target < 3.0		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0.06+0+0.31) /3	0.12

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-6: Historical Billing Index Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	2.34	0.39	0.57	0.15	0.29	1.96	0.13	0.12	0.14
Benchmark	5.0						3.0		
Threshold	5.0								

13.2.2.3 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 2021 result was 99 percent, which was better than the benchmark of 98 percent. The June 2022 year-to-date result is 99 percent, which is better than the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-7: Historical Meter Reading Accuracy Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	98%	96%	99%	99%	99%	99%	99%	99%	99%
Benchmark	97%						98%		
Threshold	94%						96%		

13.2.2.4 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 2021 result was 70 percent which met the benchmark. The June 2022 year-to-date performance is 63 percent, which is below the threshold.

Several challenging circumstances were faced in the first quarter of 2022 that have contributed to a year-to-date performance in the non-emergency TSF below threshold. These challenges include higher than normal attrition levels being experienced in the contact centre coupled with colder weather that resulted in approximately 27 percent more high bill inquiries in the first quarter than the average of the preceding two years[66]. Each of these is described further below.

Customer Service is experiencing higher than expected levels of attrition, having lost approximately 20 percent of its Customer Service Representatives in 2021.[67] All exits were in the last half of 2021, resulting in fewer and less experienced employees prepared to support call volumes in the first quarter of 2022. To mitigate the impact of this, FBC accelerated the timing of planned new hire classes as well as the size of new hire classes in both 2021 and 2022. While

[66] FBC experienced approximately 1,000 high bill inquiries in Q1 2022 which compares to an average of approximately 790 in the first quarter for the two-year period 2020-2021.

[67] On average, FBC has approximately 20 customer service representatives, and 4 left the organization in the latter part of 2021. This compares to typical annual attrition in the range of 1-2 customer service representatives from the organization.

some success has been achieved, FBC has continued to face challenges recruiting and retaining newly hired contact centre employees in 2022. In addition, it takes on average approximately 12 months for new employees to be proficient and fully trained in order to support all customer inquiries and calls, and as such, average call handle times remain higher than normal while a greater portion of employees gain this experience.

High bill inquiries are expected in the first quarter of the year and planned for with staffing levels and schedules adjusted, new hire classes timed accordingly, and refresher training offered to those employees who may need it. However, the colder temperatures resulted in a volume of high bill inquiries that was greater than anticipated and lasted longer than typical, carrying into April instead of early March. This particular call type is often longer in duration and may also result in follow-up work and investigation. As noted above, there were fewer and less experienced employees prepared to support these types of calls. Thus, the contact centre experienced the compounding impact of fewer employees along with a higher volume of this call type, resulting in overall longer average wait times and a lower percentage of calls answered within thirty seconds or less.

Although the start of 2022 has been challenging, strong performance in first contact resolution, in addition to the promotion of self-service and the call back feature, continues to mitigate the impacts of lower TSF on customer experience and service quality. Further, the recovery of the non-emergency TSF remains a focus, with FBC expecting to recover to threshold levels on a year-to-date basis within the fourth quarter. Finally, the customer service index has remained high throughout 2021 and 2022 to date, indicating that the mitigation measures and focus on first contact resolution continue to result in an overall high quality of service being experienced by customers.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 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	2020	2021	June 2022 YTD
Annual Results	48%	71%	70%	70%	72%	70%	70%	70%	63%
Benchmark					70%				
Threshold					68%				

13.2.2.5 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 annual CSI score for 2021 was 8.4, slightly lower than that obtained in 2020. There were no statistically significant shifts from 2020 to 2021 in the five measures that make up the overall customer satisfaction score. The score for overall satisfaction, which has the highest weighting, decreased from 8.5 in 2020 to 8.4 in 2021. The scores for satisfaction with the energy conservation information and contact centre metrics decreased from 7.6 in 2020 to 7.5 in 2021, and 8.5 in 2020 to 8.4 in 2021, respectively. In addition, the scores for the satisfaction with the accuracy of meter reading and field services metrics remained static at 8.2 and 9.0 in 2021, respectively.

The score for 2022 year-to-date is 8.4, consistent with the annual score recorded for 2021. Of the five measures that make up the overall customer satisfaction score, the results for June 2022 year-to-date were higher in one area, lower in one, and static in three when compared to the annual 2021 scores. The score for the satisfaction with the accuracy of meter reading metric increased from 8.2 to 8.3. The score for the satisfaction with field services metric decreased from 9.0 to 8.8. The scores for the overall satisfaction, energy conservation information, and contact centre metrics were static at 8.4, 7.5 and 8.4, respectively, from results achieved in 2021. None of these changes are statistically significant.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-9: Historical Customer Satisfaction Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	8.1	8.1	8.2	8.2	8.3	8.5	8.5	8.4	8.4
Benchmark	n/a								
Threshold	n/a								

13.2.2.6 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 2021 result was 65 seconds, and the June 2022 year-to-date performance is 98 seconds.

As with previous years, 2021 remained within a reasonable range from a customer experience perspective in that, on average, calls to the contact centre were answered in and around the one-minute mark. With respect to 2022, the year-to-date performance reflects the challenging circumstances in the first quarter of the year described above for the Telephone Service Factor (Non-Emergency). Recovery of the ASA back towards normal performance is expected to continue through the remainder of the year.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.[68]

Table 13-10: Average Speed of Answer

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	226	49	48	49	49	49	71	65	98
Benchmark	n/a								
Threshold	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.

[68] 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.

13.2.3.1 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 2021 result was 4.27 which was better than the threshold of 4.52 but below the benchmark of 3.22. The June 2022 year-to-date performance is 2.94 which is better than the benchmark. The 2021 results were negatively impacted by multiple external factors which did not meet the threshold for normalization.

The July 2021 results were nearly five times the three-year average and were heavily influenced by several factors that did not meet the threshold for normalization. The largest single event that influenced the July results was the collapse of a construction crane on July 12 in downtown Kelowna. The immediate response to this event was to de-energize a large portion of the surrounding area so that first responders could safely attend to the scene. This incident interrupted power to over 2,600 customers and accounted for over 36,000 customer hours interrupted.

British Columbia also experienced an unprecedented run of extreme heat at the end of June and early July which dried forest fuels earlier than usual and led to one of the worst fire seasons on record. FBC transmission and distribution infrastructure were both impacted by the wildfires with dozens of structures burned to the ground. The largest single outage due to these fires was in the Oliver area and contributed over 21,000 customer hours to July.

In addition to the damaged infrastructure, FBC Operations proactively de-energized portions of the system at the request of BC Wildfire Services to assist in fire suppression efforts. System operations were also impacted by proactively disabling automatic line reclosing in parts of the system to reduce the risk of igniting a fire from trees contacting FBC lines. This led to larger and longer outages in areas of the system where automatic line reclosing was disabled to allow field crews time to assess the cause and confirm that it was safe to re-energize the system. FBC estimates that the combination of fire damage, proactive de-energization, and disabling of automatic line reclosing contributed to over 52,000 customer hours of interruption in July.

There were three Major Event Days that met the threshold for normalization in 2021:

- On January 13, a major windstorm across the Okanagan and Kootenays caused approximately 11,000 customer-interruptions and totalled over 155,000 customer-hours of interruption.
- On April 18, a major windstorm across the West Kootenays qualified for a Major Event Day causing approximately 19,800 customer-interruptions and totalled over 200,800 customer-hours of interruption.
- On November 15, a major storm affected multiple areas in the Okanagan causing approximately 27,474 customer-interruptions and totalled over 218,720 customer-hours of interruption. This event is the highest total customer-hours of interruption FBC has on record (back to 2003).

There have been no Major Event Days in 2022 to-date.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 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. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[69]

Table 13-11: Historical SAIDI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual normalized results	2.32	2.13	2.10	4.05	3.15	2.45	3.17	4.27	2.94
Benchmark	2.22						3.22		
Threshold	2.62						4.52		

13.2.3.2 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.

[69] The benchmark and threshold for SAIDI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

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

The 2021 result was 2.08 and the June 2022 year-to-date performance is 1.58, with both better than the threshold of 2.19. The 2021 results for SAIFI were similarly impacted by the crane collapse, wildfires and storms that were discussed in the SAIDI section. FBC also completed system upgrades on several radial transmission lines where no alternate supply was available which impacted a large number of customers. These outages were scheduled in advance during "off peak" hours to minimize the impact to homes and businesses.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 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. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[70]

Table 13-12: Historical SAIFI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual normalized results	1.64	1.56	1.34	1.78	1.73	1.21	1.64	2.08	1.58
Benchmark	1.64						1.57		
Threshold	2.50						2.19		

13.2.3.3 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 2021 result for GFOR was 0.23 percent. The June 2022 year-to-date performance is 0.85 percent.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

[70] The benchmark and threshold for SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

Table 13-13: Historical Generator Forced Outages

	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
FBC	1.7%	0.1%	0.8%	0.6%	0.4%	0.1%	1.3%	0.23%	0.85%
CEA	6.3%	6.2%	6.2%	6.2%	6.7%	4.9%	4.60	TBD	

13.2.3.4 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 2021 result of 99.90 percent and June 2022 year-to-date result of 99.91 percent are generally consistent with prior years' results. The City of Nelson interconnection at Coffee Creek was negatively impacted by two of the three Major Events on the FBC system described previously in the SAIDI section. For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-14: Interconnection Utilization

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Interconnection Utilization	99.99%	99.94%	99.99%	99.95%	99.96%	99.98%	99.89%	99.90%	99.91%
Benchmark	n/a								
Threshold	n/a								

13.3 *SUMMARY*

In summary, FBC's 2021 and June 2022 year-to-date SQI results indicate that the Company's overall performance meets service quality requirements. In 2021, for the eight SQIs with benchmarks, six met or were better than the benchmark with two better than the threshold. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years.

Appendix A

LOAD FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: Consumer Price Index (CPI)

Products and product groups[3, 4]	All-items
Reference period	
	2002=100
July 2020	132.6
August 2020	132.4
September 2020	132.5
October 2020	132.9
November 2020	133.3
December 2020	132.8
January 2021	133.6
February 2021	134.1
March 2021	134.9
April 2021	135.2
May 2021	135.1
June 2021	135.8
July 2021	136.7
August 2021	137.0
September 2021	137.2
October 2021	137.9
November 2021	138.1
December 2021	138.0
January 2022	139.4
February 2022	140.4
March 2022	143.0
April 2022	144.2
May 2022	146.1
June 2022	146.5

Table A1-2: Average Weekly Earnings (AWE)

North American Industry Classification System (NAICS)[5]		Industrial aggregate excluding unclassified businesses[6, 7]
Geography	Reference period	
		Dollars
British Columbia (map)	July 2020	1,093.72[B]
	August 2020	1,089.35[B]
	September 2020	1,093.75[B]
	October 2020	1,095.32[B]
	November 2020	1,102.95[B]
	December 2020	1,110.36[B]
	January 2021	1,113.22[B]
	February 2021	1,114.21[B]
	March 2021	1,107.66[B]
	April 2021	1,112.04[B]
	May 2021	1,118.59[B]
	June 2021	1,115.40[B]
	July 2021	1,140.52[B]
	August 2021	1,142.40[B]
	September 2021	1,139.64[B]
	October 2021	1,136.85[B]
	November 2021	1,132.25[B]
	December 2021	1,134.84[B]
	January 2022	1,157.19[B]
	February 2022	1,153.88[B]
	March 2022	1,161.22[B]
	April 2022	1,176.54[B]

Table A1-3: British Columbia Two-Year Outlook 2022

Key Economic Indicators: British Columbia, 2021-23
(forecast completed February 18, 2022)

	2021Q1	2021Q2	2021Q3	2021Q4	2022Q1	2022Q2	2022Q3	2022Q4	2023Q1	2023Q2	2023Q3	2023Q4	2021	2022	2023
GDP at market prices ($ millions)	328,577	329,385	334,551	339,673	343,417	348,045	350,673	353,935	356,447	359,588	361,919	364,178	333,047	349,017	360,533
	1.5	*0.2*	*1.6*	*1.5*	*1.1*	*1.3*	*0.8*	*0.9*	*0.7*	*0.9*	*0.6*	*0.6*	*7.7*	*4.8*	*3.3*
GDP at market prices (2012 $ millions)	278,978	277,225	279,564	281,275	283,897	288,030	290,551	293,351	295,260	297,122	298,139	299,057	279,261	288,957	297,395
	0.7	*-0.6*	*0.8*	*0.6*	*0.9*	*1.5*	*0.9*	*1.0*	*0.7*	*0.6*	*0.3*	*0.3*	*4.7*	*3.5*	*2.9*
GDP at basic prices (2012 $ millions)	258,225	257,607	258,824	259,977	262,651	266,678	269,275	272,107	273,828	275,566	276,523	277,352	258,659	267,678	275,817
	0.5	*-0.2*	*0.5*	*0.4*	*1.0*	*1.5*	*1.0*	*1.1*	*0.6*	*0.6*	*0.3*	*0.3*	*4.8*	*3.5*	*3.0*
Consumer price index (2002 = 1.000)	1.342	1.354	1.370	1.380	1.401	1.412	1.424	1.433	1.441	1.449	1.456	1.463	1.361	1.418	1.452
	0.9	*0.9*	*1.2*	*0.7*	*1.6*	*0.7*	*0.9*	*0.6*	*0.6*	*0.6*	*0.5*	*0.5*	*2.8*	*4.1*	*2.5*
Implicit price deflator—GDP at market prices	1.178	1.188	1.197	1.208	1.210	1.208	1.207	1.207	1.207	1.210	1.214	1.218	1.193	1.208	1.212
(2012 = 1.000)	*0.8*	*0.9*	*0.7*	*0.9*	*0.2*	*-0.1*	*-0.1*	*0.0*	*0.1*	*0.2*	*0.3*	*0.3*	*2.9*	*1.3*	*0.4*
Wages and salary per employee ($ 000s)	54.6	55.5	56.8	57.2	57.3	57.2	57.3	57.6	57.9	58.1	58.5	58.8	56.0	57.3	58.3
	1.2	*1.7*	*2.2*	*0.8*	*0.1*	*-0.1*	*0.2*	*0.5*	*0.5*	*0.5*	*0.5*	*0.6*	*4.1*	*2.3*	*1.7*
Primary household income ($ millions)	232,341	235,256	242,425	248,720	249,890	251,061	252,734	254,925	256,921	259,217	261,239	263,382	239,685	252,153	260,190
	1.9	*1.3*	*3.0*	*2.6*	*0.5*	*0.5*	*0.7*	*0.9*	*0.8*	*0.9*	*0.8*	*0.8*	*9.1*	*5.2*	*3.2*
Household disposable income ($ millions)	210,080	211,206	215,909	216,925	215,827	216,553	218,063	219,981	220,758	222,983	224,889	226,886	213,530	217,606	223,879
	1.2	*0.5*	*2.2*	*0.5*	*-0.5*	*0.3*	*0.7*	*0.9*	*0.4*	*1.0*	*0.9*	*0.9*	*2.4*	*1.9*	*2.9*
Household net savings rate (per cent)	7.3	7.8	4.5	4.2	3.3	2.9	3.1	3.3	2.8	2.8	2.6	2.5	6.0	3.1	2.7
Population (000s)	5,164	5,186	5,215	5,250	5,259	5,268	5,276	5,284	5,296	5,307	5,320	5,332	5,204	5,272	5,314
	0.1	*0.4*	*0.6*	*0.7*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*1.0*	*1.3*	*0.8*
Employment (000s)	2,629	2,631	2,669	2,696	2,694	2,685	2,690	2,698	2,704	2,714	2,718	2,723	2,656	2,692	2,715
	1.6	*0.1*	*1.4*	*1.0*	*-0.1*	*-0.3*	*0.2*	*0.3*	*0.2*	*0.4*	*0.2*	*0.2*	*6.6*	*1.3*	*0.9*
Labour force (000s)	2,836	2,825	2,846	2,852	2,850	2,858	2,866	2,872	2,877	2,882	2,887	2,892	2,840	2,862	2,884
	1.4	*-0.4*	*0.8*	*0.2*	*-0.1*	*0.3*	*0.3*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*3.7*	*0.8*	*0.8*
Labour force participation rate (per cent)	65.6	65.2	65.3	65.0	64.8	64.8	64.9	64.8	64.8	64.7	64.7	64.7	65.3	64.8	64.7
Unemployment rate (per cent)	7.3	6.9	6.2	5.5	5.5	6.1	6.1	6.0	6.0	5.8	5.8	5.8	6.5	5.9	5.9
Retail sales ($ millions)	98,731	99,233	98,267	96,315	95,494	95,987	96,084	97,049	97,750	98,331	99,140	99,888	98,136	96,153	98,777
	3.7	*0.5*	*-1.0*	*-2.0*	*-0.9*	*0.5*	*0.1*	*1.0*	*0.7*	*0.6*	*0.8*	*0.8*	*12.1*	*-2.0*	*2.7*
Housing starts (units, 000s)	52,902	49,795	45,224	42,507	40,000	39,536	36,171	35,850	35,530	35,209	34,889	34,568	47,607	37,889	35,049
	30.7	*-5.9*	*-9.2*	*-6.0*	*-5.9*	*-1.2*	*-8.5*	*-0.9*	*-0.9*	*-0.9*	*-0.9*	*-0.9*	*26.2*	*-20.4*	*-7.5*
Net interprovincial migration (000s)	16.7	17.4	17.7	31.4	15.2	10.4	7.1	5.2	7.9	7.5	7.1	6.8	20.8	9.5	7.3
Net international migration (000s)	52.6	52.2	19.8	18.8	20.9	22.2	24.4	27.3	35.2	38.2	40.3	41.6	35.8	23.7	38.8

Shaded area represents forecast data, *italics indicate percentage change*.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
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.

Note: Table above is from the Conference Board of Canada, British Columbia Two-Year Outlook, March 30, 2022.



Appendix A2

Load Forecast Tables

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1. INTRODUCTION

This appendix provides the historical and forecast load data used in Section 3 of the Application. The tables in Section 2 show 10 years of historical data and the before-savings and after-savings forecast for 2022S and 2023F. Section 3 shows the customer forecast data while Section 4 presents the residential UPC data. The tables in Section 5 show the load forecast. Table 5.3 shows the DSM that was deducted from the before-savings forecast to provide the after-savings forecast for 2023F. Tables 6.1 and 6.2 show the variance of the customer accounts and forecasts from 2016 to 2021 when compared to the actuals. Table 6.3 shows the annual growth of customer and load that FBC has experienced since 2016. Tables 6.4 and 6.5 show the Residential UPC and Winter peak variances from forecast from 2019 to 2021. Finally, Table 6.6 shows the system load factor from the years 2016 to 2021 and the forecast load factor for 2022S and 2023F.

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 2021.
- after-savings – the load after DSM and includes Normalized loads to December 2021.

2.1 GROSS LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
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
2020	382,181	332,609	303,499	246,152	239,601	248,354	309,611	303,017	260,523	282,780	333,207	374,349	3,615,884
2021	378,637	338,019	319,817	276,739	257,155	259,320	306,943	294,834	257,175	285,567	334,065	368,654	3,676,926
Before-Savings													
2022S	393,190	335,138	331,640	280,553	267,153	271,396	321,383	310,626	274,609	295,951	337,171	383,507	3,802,317
2023F	396,339	337,950	334,411	282,950	269,568	273,870	324,232	313,473	277,139	298,596	340,037	386,627	3,835,192
After-Savings													
2022S	390,444	332,413	328,981	277,979	264,668	268,968	318,980	308,194	272,123	293,371	334,512	380,802	3,771,436
2023F	390,866	332,540	329,150	277,874	264,687	269,119	319,544	308,746	272,326	293,617	334,927	381,448	3,774,844

2.2 NET LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
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
2020	346,177	302,227	279,953	229,763	224,464	231,690	285,178	279,540	242,297	262,136	304,435	339,684	3,327,545
2021	345,746	308,157	294,337	255,440	238,210	239,708	282,793	272,125	237,826	263,832	306,218	337,045	3,381,436
Before-Savings													
2022S	356,872	305,644	305,096	260,549	249,414	252,595	296,341	287,118	255,390	274,469	309,030	348,812	3,501,329
2023F	359,759	308,223	307,659	262,783	251,668	254,896	298,970	289,745	257,738	276,922	311,668	351,673	3,531,705
After-Savings													
2022S	354,335	303,127	302,639	258,171	247,118	250,352	294,120	284,871	253,093	272,084	306,573	346,312	3,472,795
2023F	354,702	303,224	302,798	258,093	247,157	250,505	294,638	285,378	253,291	272,322	306,947	346,888	3,475,944

2.3 RESIDENTIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
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
2020	150,634	126,164	117,219	93,211	89,289	91,128	111,958	103,644	86,533	100,913	126,958	149,181	1,346,832
2021	151,923	132,351	117,698	95,324	88,510	89,335	114,977	114,763	58,293	98,449	123,064	145,645	1,330,331
Before-Savings													
2022S	149,350	118,436	116,520	92,400	89,399	86,970	106,340	99,003	84,580	98,837	120,281	146,323	1,308,438
2023F	149,488	118,545	116,628	92,485	89,481	87,050	106,438	99,094	84,658	98,928	120,392	146,458	1,309,643
After-Savings													
2022S	148,891	117,988	116,106	92,031	89,075	86,679	106,062	98,712	84,257	98,468	119,867	145,876	1,304,011
2023F	148,568	117,647	115,796	91,743	88,830	86,464	105,876	98,507	84,003	98,180	119,551	145,549	1,300,714

2.4 COMMERCIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Normliazed Actuals													
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
2020	88,558	80,807	76,026	63,736	65,028	67,948	79,777	81,941	74,160	76,659	80,994	86,252	921,886
2021	88,860	79,418	80,125	72,153	73,680	74,618	79,949	69,139	96,038	76,264	81,554	87,844	959,641
Before-Savings													
2022S	91,281	81,781	81,825	71,225	73,270	74,552	85,487	85,537	76,428	79,040	83,178	90,148	973,752
2023F	93,329	83,616	83,662	72,825	74,916	76,228	87,409	87,461	78,147	80,815	85,045	92,172	995,624
After-Savings													
2022S	90,298	80,801	80,856	70,272	72,331	73,624	84,563	84,609	75,489	78,086	82,209	89,168	962,307
2023F	91,368	81,668	81,740	70,935	73,057	74,392	85,584	85,632	76,304	78,952	83,163	90,278	973,073

Note: The commercial class is normalized from 2014 to 2020 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													
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
2020	64,233	56,219	48,768	39,333	33,066	35,088	44,642	44,913	39,548	45,075	55,660	62,943	569,488
2021	63,822	56,888	51,016	42,771	35,118	32,874	43,009	44,315	36,150	44,201	57,331	58,330	565,827
Before-Savings													
2022S	64,807	54,940	51,149	42,542	37,128	36,250	46,538	46,193	38,848	45,583	55,516	63,082	582,577
2023F	65,192	55,265	51,454	42,796	37,362	36,483	46,834	46,485	39,088	45,858	55,846	63,460	586,125
After-Savings													
2022S	64,456	54,593	50,813	42,220	36,821	35,954	46,246	45,897	38,540	45,261	55,180	62,735	578,717
2023F	64,492	54,573	50,785	42,156	36,752	35,895	46,253	45,897	38,481	45,223	55,184	62,779	578,470

2.6 INDUSTRIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
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
2020	41,115	37,485	36,324	30,596	32,632	32,899	39,933	39,350	35,590	36,265	39,250	39,794	441,233
2021	39,629	38,120	44,021	42,125	34,088	34,473	33,956	35,536	42,333	41,558	42,792	43,684	472,315
Before-Savings													
2022S	49,922	49,087	54,123	51,558	43,838	48,000	48,703	47,580	50,264	47,957	48,513	47,775	587,321
2023F	50,238	49,396	54,438	51,852	44,129	48,312	49,017	47,901	50,575	48,269	48,844	48,099	591,072
After-Savings													
2022S	49,195	48,360	53,402	50,840	43,130	47,296	48,007	46,881	49,566	47,241	47,795	47,067	578,779
2023F	48,797	47,968	53,031	50,464	42,773	46,975	47,708	46,597	49,287	46,956	47,539	46,827	574,920

2.7 LIGHTING (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
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
2020	929	892	955	900	914	874	932	949	878	907	863	852	10,846
2021	838	774	836	795	858	787	802	805	770	851	776	791	9,682
Before-Savings													
2022S	820	759	817	809	839	797	813	829	798	830	782	789	9,682
2023F	820	759	817	809	839	797	813	829	798	830	782	789	9,682
After-Savings													
2022S	804	743	802	795	826	784	801	816	785	816	766	773	9,511
2023F	788	728	788	783	816	775	792	808	777	807	758	765	9,385

2.8 IRRIGATION (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
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
2020	708	660	662	1,987	3,535	3,752	7,936	8,743	5,588	2,317	709	662	37,260
2021	674	606	641	2,272	5,957	7,621	10,099	7,568	4,242	2,508	701	751	43,640
Before-Savings													
2022S	692	642	661	2,015	4,940	6,025	8,459	7,976	4,472	2,222	760	695	39,559
2023F	692	642	661	2,015	4,940	6,025	8,459	7,976	4,472	2,222	760	695	39,559
After-Savings													
2022S	691	641	660	2,013	4,935	6,015	8,442	7,956	4,456	2,213	756	693	39,471
2023F	690	640	659	2,011	4,930	6,004	8,425	7,936	4,440	2,204	752	691	39,382

2.9 SYSTEM PEAK (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
Historical Normalized Actuals														
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
2020	732	680	609	500	482	515	666	665	551	549	631	667	731	666
2021	711	731	555	495	488	653	597	635	486	509	628	675	685	653
Before-Savings														
2022S	725	687	608	516	488	588	658	661	502	537	645	722	783	679
2023F	732	693	614	521	493	593	664	667	506	542	650	728	788	685
After-Savings														
2022S	725	686	608	515	488	587	657	660	501	536	644	721	782	678
2023F	730	692	612	519	491	592	662	665	505	540	649	727	786	684

Note: The peaks shown 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 and includes the June 2021 Heat Dome.

3. CUSTOMER FORECAST

3.1 CUSTOMERS

Customer Count	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	99,228	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,336	132,015
Commercial	11,811	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,995	17,496
Wholesale	7	6	6	6	6	6	6	6	6	6	6	6
Industrial	39	47	49	50	50	50	52	51	43	42	42	42
Lighting	1,739	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,379	1,349
Irrigation	1,091	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103
Total Direct	113,915	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,861	152,011

3.2 CUSTOMER ADDITIONS

Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	912	12,634	1,569	735	1,606	1,976	2,543	2,174	2,501	1,712	2,658	2,679
Commercial	106	1,851	701	613	97	325	280	278	209	429	401	501
Wholesale	-	(1)	-	-	-	-	-	-	-	-	-	-
Industrial	1	8	2	1	-	-	2	(1)	(8)	(1)	-	-
Lighting	(27)	(95)	(24)	(30)	(31)	(48)	(29)	(15)	(24)	(36)	(28)	(30)
Irrigation	17	6	6	(8)	(5)	(10)	(2)	4	9	12	-	-
Total Direct	1,009	14,403	2,254	1,311	1,667	2,243	2,794	2,440	2,687	2,116	3,031	3,150

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

MWh/Customer	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	12.41	12.48	11.51	11.41	11.27	11.31	11.03	10.43	10.89	10.58	10.19	9.95

5. LOAD

5.1 NORMALIZED AFTER-SAVINGS LOAD

Energy (GWh)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	1,229	1,353	1,296	1,298	1,296	1,320	1,313	1,266	1,347	1,330	1,304	1,301
Commercial	681	788	863	853	905	915	926	932	922	960	962	973
Wholesale	899	675	567	580	574	574	585	566	569	566	579	578
Industrial	291	352	381	380	373	363	403	495	441	472	579	575
Lighting	13	13	16	16	16	16	13	11	11	10	10	9
Irrigation	38	40	40	46	42	42	39	36	37	44	39	39
Net	3,151	3,222	3,163	3,174	3,206	3,230	3,278	3,306	3,328	3,381	3,473	3,476
Losses & Company Use	271	278	270	272	274	282	285	287	288	295	299	299
Gross	3,422	3,500	3,433	3,446	3,480	3,512	3,564	3,592	3,616	3,677	3,771	3,775
System Peak (MW)												
Winter Peak	723	698	693	685	755	714	682	732	731	685	782	786
Summer Peak	589	600	620	611	593	605	631	639	666	653	678	684

5.2 NORMALIZED AFTER-SAVINGS WHOLESALE LOAD

Wholesale (GWh)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2021S	2022F
BCH Lardeau	6	6	6	6	6	8	8	7	6	6	7	7
BCH Kingsgate	5	5	5	5	5	5	5	5	5	4	5	5
City of Grand Forks	41	41	39	41	41	39	46	37	38	36	36	36
City of Nelson	80	83	81	83	80	86	88	84	82	86	79	78
City of Penticton	341	348	342	348	345	338	340	338	340	337	351	351
District of Summerland	95	98	94	97	98	98	99	95	99	97	101	101
City of Kelowna	332	94	-	-	-	-	-	-	-	-	-	-
Total	899	675	567	580	574	574	585	566	569	566	579	578

5.3 DSM (GWH) WITHOUT LOSSES

Energy (GWh)	2017	2018	2019	2020	2021	2022S	2023F
Demand Side Management	(28)	(31)	(26)	(26)	(30)	(28)	(56)

6. VARIANCES TO FORECAST

6.1 CUSTOMER COUNT VARIANCE

Customer Count	2016	2017	2018	2019	2020	2021
Actual						
Residential	115,772	117,748	120,291	122,465	124,966	126,678
Commercial	15,073	15,398	15,678	15,956	16,165	16,594
Wholesale	6	6	6	6	6	6
Industrial	50	50	52	51	43	42
Lighting	1,559	1,511	1,482	1,467	1,443	1,407
Irrigation	1,090	1,080	1,078	1,082	1,091	1,103
Total	133,550	135,793	138,587	141,027	143,714	145,830
Forecast						
Residential	115,758	116,031	117,774	120,405	124,076	124,603
Commercial	15,042	15,813	16,122	16,405	16,220	16,579
Wholesale	6	6	6	6	6	6
Industrial	49	50	50	51	57	59
Lighting	1,620	1,590	1,559	1,511	1,425	1,393
Irrigation	1,103	1,095	1,090	1,080	1,082	1,082
Total	133,578	134,585	136,602	139,459	142,865	143,721
Variance (customers)						
Residential	14	1,717	2,517	2,060	890	2,075
Commercial	31	(415)	(444)	(449)	(55)	15
Wholesale	0	0	0	0	0	0
Industrial	1	0	2	0	(14)	(17)
Lighting	(61)	(79)	(77)	(44)	18	14
Irrigation	(13)	(15)	(12)	2	9	21
Total	(28)	1,208	1,986	1,569	849	2,109
Variance (%)						
Residential	0.0%	1.5%	2.1%	1.7%	0.7%	1.6%
Commercial	0.2%	-2.7%	-2.8%	-2.8%	-0.3%	0.1%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	2.0%	0.0%	3.8%	0.0%	-32.6%	-40.5%
Lighting	-3.9%	-5.2%	-5.2%	-3.0%	1.3%	1.0%
Irrigation	-1.2%	-1.4%	-1.1%	0.2%	0.8%	1.9%
Total	0.0%	0.9%	1.4%	1.1%	0.6%	1.4%

6.2 LOAD VARIANCE, NORMALIZED ACTUAL TO FORECAST

Energy (GWh)	2016	2017	2018	2019	2020	2021
Normalized						
Residential	1,296	1,320	1,313	1,266	1,347	1,330
Commercial	905	915	926	932	922	960
Wholesale	574	574	585	566	569	566
Industrial	373	363	403	495	441	472
Lighting	16	16	13	11	11	10
Irrigation	42	42	39	36	37	44
Net	3,206	3,230	3,278	3,306	3,328	3,381
Gross	3,480	3,512	3,564	3,592	3,616	3,677
Forecast						
Residential	1,367	1,353	1,280	1,349	1,326	1,255
Commercial	871	879	912	935	902	952
Wholesale	579	587	586	594	567	584
Industrial	393	407	379	385	453	537
Lighting	13	14	15	13	11	10
Irrigation	39	40	41	42	35	36
Net	3,262	3,282	3,213	3,319	3,294	3,374
Gross	3,540	3,559	3,485	3,602	3,602	3,664
Variance (GWh)						
Residential	(71)	(33)	33	(83)	21	75
Commercial	34	36	14	(3)	20	7
Wholesale	(5)	(13)	(1)	(28)	2	(18)
Industrial	(20)	(44)	24	110	(12)	(64)
Lighting	3	1	(2)	(2)	0	(0)
Irrigation	3	2	(2)	(6)	2	8
Net	(56)	(52)	65	(13)	34	8
Gross	(59)	(47)	79	(10)	14	13
Variance (%)						
Residential	-5.5%	-2.5%	2.5%	-6.6%	1.6%	5.6%
Commercial	3.8%	3.9%	1.5%	-0.4%	2.2%	0.8%
Wholesale	-0.8%	-2.3%	-0.2%	-5.0%	0.4%	-3.1%
Industrial	-5.3%	-12.3%	5.9%	22.2%	-2.7%	-13.6%
Lighting	16.3%	9.4%	-13.4%	-17.8%	2.1%	-2.8%
Irrigation	7.7%	3.9%	-5.2%	-16.7%	5.3%	17.9%
Net	-1.7%	-1.6%	2.0%	-0.4%	1.0%	0.2%
Gross	-1.7%	-1.3%	2.2%	-0.3%	0.4%	0.4%

6.3 NORMALIZED AFTER-SAVINGS ANNUAL PERCENT GROWTH

Energy (GWh)	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	1,296	1,320	1,313	1,266	1,347	1,330	1,304	1,301
Commercial	905	915	926	932	922	960	962	973
Wholesale	574	574	585	566	569	566	579	578
Industrial	373	363	403	495	441	472	579	575
Lighting	16	16	13	11	11	10	10	9
Irrigation	42	42	39	36	37	44	39	39
Net	3,206	3,230	3,278	3,306	3,328	3,381	3,473	3,476
Losses & Company Use	274	282	285	287	288	295	299	299
Gross	3,480	3,512	3,564	3,592	3,616	3,677	3,771	3,775
System Peak								
Winter Peak (MW)	755	714	682	732	731	685	782	786
Summer Peak (MW)	593	605	631	639	666	653	678	684

Growth Year over Year	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	0%	2%	-1%	-4%	6%	-1%	-2%	0%
Commercial	6%	1%	1%	1%	-1%	4%	0%	1%
Wholesale	-1%	0%	2%	-3%	1%	-1%	2%	0%
Industrial	-2%	-3%	11%	23%	-11%	7%	23%	-1%
Lighting	0%	0%	-17%	-17%	-2%	-11%	-2%	-1%
Irrigation	-9%	0%	-7%	-8%	4%	17%	-10%	0%
Net	1%	1%	1%	1%	1%	2%	3%	0%
Losses & Company Use	1%	3%	1%	0%	1%	2%	1%	0%
Gross	1%	1%	1%	1%	1%	2%	3%	0%
System Peak								
Winter Peak (MW)	10%	-5%	-4%	7%	0%	-6%	14%	0%
Summer Peak (MW)	-3%	2%	4%	1%	4%	-2%	4%	1%

Customer Count	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	115,772	117,748	120,291	122,465	124,966	126,678	129,336	132,015
Commercial	15,073	15,398	15,678	15,956	16,165	16,594	16,995	17,496
Wholesale	6	6	6	6	6	6	6	6
Industrial	50	50	52	51	43	42	42	42
Lighting	1,559	1,511	1,482	1,467	1,443	1,407	1,103	1,103
Irrigation	1,090	1,080	1,078	1,082	1,091	1,103	1,379	1,349
Total Direct	133,550	135,793	138,587	141,027	143,714	145,830	148,861	152,011

Growth Year over Year	2016	2017	2018	2019	2020	2021	2022S	2023F
Residential	1%	2%	2%	2%	2%	1%	2%	2%
Commercial	1%	2%	2%	2%	1%	3%	2%	3%
Wholesale	0%	0%	0%	0%	0%	0%	0%	0%
Industrial	0%	0%	4%	-2%	-16%	-2%	0%	0%
Lighting	-2%	-3%	-2%	-1%	-2%	-2%	-22%	0%
Irrigation	0%	-1%	0%	0%	1%	1%	25%	-2%
Total Direct	1%	2%	2%	2%	2%	1%	2%	2%

6.4 RESIDENTIAL UPC, NORMALIZED ACTUAL TO FORECAST

Residential UPC (MWh)	2019	2020	2021
After- Savings Normalized Actual UPC	10.43	10.89	10.58
Forecast	11.27	10.75	10.10
Variance	(0.84)	0.13	0.49
Variance (%)	-8.0%	1.2%	4.6%

6.5 WINTER PEAK , ACTUAL TO FORECAST

Winter Peak (MW)	2019	2020	2021
After- Savings Actual Peak	732	725	777
Forecast	764	737	748
Variance	(32)	(12)	29
Variance (%)	-4%	-2%	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	Energy (MWh)	Peak (MW)	Load Factor
2016	3,480,297	755	0.53
2017	3,511,820	714	0.56
2018	3,563,824	682	0.60
2019	3,592,459	732	0.56
2020	3,615,884	731	0.56
2021	3,676,926	685	0.61
2022S	3,771,436	782	0.55
2023F	3,774,844	786	0.55

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



Appendix A3

Load Forecast Methods

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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[1]. For the 2023 Annual Review the latest calendar year for which full actual data exists is the 2021 calendar year.
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2022 (2022S) and the Seed Year forecast is based on the latest actual years, including 2021. As such, the 2022 Seed Year forecast in this Application will differ from the 2022 Forecast presented in the Annual Review for 2022 Rates, for which 2021 actual data was not available.
- 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, 2023 is the Forecast Year (2023F).

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[2]. The results from the regression for these four rate classes are shown below. The regressions result in high R^2 values for all seasons for the residential, wholesale and commercial[3] load classes; therefore these classes are normalized. The irrigation class shows a low R^2 value for the winter, summer and fall seasons; therefore, this class was not normalized.

[1] FBC's load forecast is developed using only full years of historical data. FBC requires the full year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason partial year data is not used in forecasting.
[2] Industrial and lighting loads are typically insensitive to the weather.
[3] The commercial class data is normalized from 2014 to 2021 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	39,370	66,140	70,359	64,926
Slope HDD	172	109	-	92
Slope CDD	-	-	245	-
Adjusted R^2	0.72	0.76	0.84	0.77

Table A3-2: Wholesale Regression Table

Wholesale	Winter	Spring	Summer	Fall
Intercept	61,401	57,123	58,803	60,135
Slope HDD	58	47	-	36
Slope CDD	-	-	90	-
Adjusted R^2	0.91	0.92	0.85	0.91

Table A3-3: Commercial Regression Table

Commercial	Winter	Spring	Summer	Fall
Intercept	48,156	51,092	49,674	54,643
Slope HDD	24	16	-	(0)
Slope CDD	-	-	78	-
Adjusted R^2	0.58	0.54	0.68	0.53

Table A3-4: Irrigation Regression Table

Irrigation	Winter	Spring	Summer	Fall
Intercept	1,634	5,218	5,079	6,034
Slope HDD	(1)	(11)	-	(10)
Slope CDD	-	-	23	-
Adjusted R^2	0.04	0.76	0.45	0.43

Steps for weather (temperature) normalization are as follows:

1. Calculate monthly Heating Degree Days (HDD)[4] and Cooling Degree Days (CDD)[5] 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

[4] Heating degree-days for a given day are the number of Celsius degrees that the mean temperature is below 18 Celsius degrees.
[5] 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 2021:

   (a) obtain the month's HDD (or CDD) information from Environment Canada;

   (b) calculate the deviation from the 10-year average (2012-2021) 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, commerical 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 weather normalized historical loads. These are referred to as the "before-savings[6]" loads. DSM savings that are incremental to those embedded in historical loads (up to and including 2021) 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:

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

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

[6] The term "before-savings" is used in the remainder of this section and refers to "before incremental savings after 2021".

The before-savings UPC was based on a 10-year historic trend of annual UPC values from 2012 to 2021. FBC reviews the forecast methods on an annual basis. As FBC found that there was a strong correlation, it therefore applied a 10-year trend.

Table A3-5: Results of UPC Trend Analysis

Regression	UPC
Start Year	2012
End Year	2021
R^2	0.84
Adjusted R^2	0.82
df	9
Intercept	414
Slope UPC	-0.20

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.

$$Year\ End\ Customer\ Count_t = b_0 + b_1 \times Population_t$$

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

Table A3-6: Results of Residential Regression

Regression	Residential
Start Year	2019
End Year	2021
R^2	1.00
Adjusted R^2	0.99
df	2
Intercept	(118,476)
Slope Population	0.88

The residential class represented 39.3 percent of the net load in 2021.

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.

$$Before\ Savings\ Load_t = (b_0 + b_1 \times GDP_t + b_2 \times CoK\ Event_t) + FBC\ EV\ DC\ Fast\ Chargers$$

The CoK_t is a binary variable for the City of Kelowna integration event in 2013. Coefficients b0, b1 and b2 are obtained from an ordinary least squares (OLS) regression analysis on the 2007 to

2021 data. The FBC EV DCFCs are Electric Vehicle Direct Current Fast Chargers serviced by FBC which are added to the forecast. The commercial class represented 28.4 percent of the net load in 2021.

Table A3-7: Results of Commercial Regression

Regression	Commercial
Start Year	2007
End Year	2021
R^2	0.99
Adjusted R^2	0.99
df	14
Intercept	123,607
Slope GDP	3
Slope CoK Event	132,847

1.2.3 Wholesale

The Company forecasts the wholesale load based on load surveys from the wholesale customers. For this forecast, FBC received surveys from all the wholesale customers except one. This customer was contacted multiple times but did not respond. Since there was no response, FBC kept their load at 2021 levels. 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. The wholesale class represented 16.7 percent of the net load in 2021.

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. 81 percent of FBC's industrial customers responded to the surveys, accounting for 90 percent of 2021 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. The industrial class represented 14.0 percent of the net load in 2021.

1.2.5 Irrigation

The before-savings irrigation load forecast uses a five-year average so that the extreme weather events such as those that occurred in 2021 are included in the forecast but do not overly influence it. The irrigation class represented 1.3 percent of the net load in 2021.

1.2.6 Lighting

The before-savings lighting load uses the 2021 actuals due to the variability in the load primarily due to streetlight LED replacement programs which reduced the loads from 2018 to 2021. The lighting class represented 0.3 percent of the net load in 2021.

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 2019-2022 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 Seed 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 10-year average (2012-2021) 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 12 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
PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-8-17 – FBC ANNUAL REVIEW FOR 2017 RATES						
1.	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.	Complete (Final Report filed in this Annual Review)	Appendix B2
G-165-20 AND G-166-20 – FEI AND FBC MULTI-YEAR RATE PLAN FOR 2020 THROUGH 2024						
2.	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	Section 12.4.2.1

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
3.	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
4.	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
5.	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

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
6.	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
7.	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.	Complete	Section 7.2.1
G-42-21 – FBC ANNUAL REVIEW FOR 2020 AND 2021 RATES						
8.	21		COVID-19 Customer Recovery Fund Deferral Account	The Panel approves the following deferral account requests: f. Recording of the 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.	Status of COVID-19 exogenous factor treatment provided in this Application	Section 12.2.1
G-374-21 – FBC ANNUAL REVIEW FOR 2022 RATES						
9.	32	7	Wholesale Customer Load Forecast	The Panel directs FBC to provide details of any efforts it has undertaken to improve the accuracy of its forecasts of wholesale customer load in the 2023 Annual Review, including the results of such efforts.	Complete	Section 3.4.3
10.	32	8	EV Charging Updates	The Panel directs FBC to include in future Annual Review filings an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period.	Ongoing	Section 6.3.4

Appendix B2

FortisBC Inc.

Upper Bonnington Old Units Refurbishment Project

Final Report

August 2022

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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 (UBO) Old Units Refurbishment (UBO Refurbishment Project, or the 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 involved 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 20 years or more. The Project also reduced the safety and environmental risks associated with failures of the aged equipment.

FBC submits the following final report regarding the UBO Refurbishment Project in compliance with Directive 6 of Order G-8-17, including final Project costs (Final Report).

The Project scope of work was completed and closed out in Q4 2021. The four generating units and associated equipment have been put into commercial operation and are performing well.

The Project successfully eliminated or reduced the safety and environmental risks previously associated with operating the plant.

[1] Order G-8-17, Appendix A, page 21.

With regard to the major environmental and safety accomplishments achieved during Project execution, FBC reports that it followed the Environmental Management Plan (EMP) developed in 2017 and the Project had no reportable environmental incidents. Further, the Project accumulated approximately 160 thousand hours without a lost time incident. The majority of the effort on the Project was internal FBC labour, with approximately 19 thousand hours supplied externally. While the COVID-19 pandemic presented challenges during the second half of the Project, the policies and procedures implemented by FBC minimized the risk of infection and Project interruption.

1.2 *WORK COMPLETED SINCE AUGUST 2021 STATUS REPORT*

The following is a brief summary of the work completed since the August 2021 status report filed as Appendix B2 to FBC's Annual Review for 2022 Rates application.

Balance of Plant

The scope of the balance of plant work evolved as the Project progressed and included the following:

Floor modifications – As equipment was removed, the concrete bases were demolished and floor repairs were completed. The plant floor loadings, drawings, demarcation, procedures and site signage updates were completed.

Ventilation access walkway – With the removal of the old switchgear concrete structure, both wall and floor repairs were required. The switchgear concrete structure provided access to plant ventilation systems; with the removal of this concrete, new access walkways and ladders were designed and installed.

Water wheel excitation decommissioning – The water wheel exciters and associated equipment were removed and the intakes were plugged with concrete. The holes through the generator and turbine floors were capped with steel plates. The exciter rheostats and buss were removed and the rheostat room was repurposed for plant equipment storage.

Units 2 and 3

Minor work was completed on Units 2 and 3 which was intentionally delayed until site conditions were preferable in 2021. The work included painting, hazardous materials removal, and the rotor oil leak repair on Unit 3.

Project Close

The Project was closed in Q4 2021 with all equipment and plant transferred back to generation operations.

2. PROJECT SCHEDULE

The following table is updated to show the final completion dates for each unit as well as the balance of plant work.

Table B2-1: 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	Q4, 2020	Complete
Procurement of All Major Mechanical/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[1]	Q4, 2020	Q4, 2019	Complete
Refurbishment of Unit 2[1]	Q4, 2019	Q4, 2020	Complete
U3 Oil Leak Deficiency Repair	Q1, 2021	Q2, 2021	Complete
Balance of Plant Work	Q2, 2021	Q3, 2021	Complete
Closeout	Q3, 2021	Q4, 2021	Complete

Note:

[1] *Units 1 and 2 construction years were changed from the original schedule to gain efficiencies by removing equipment while operating a live plant.*

2.1 *SCHEDULE SUMMARY*

The rotor oil leak repair work on Unit 3 delayed portions of the Balance of Plant scope of work from Q2 2021 to Q3 2021. The work completed on Units 2 and 3 as outlined above in Section 1.2 was completed in parallel with the Balance of Plant work, and the Project was closed in Q4 2021.

While some of the work was re-scheduled around sequencing concerns and operational constraints, the overall Project duration was as originally planned.

3. PROJECT COSTS

The following table outlines the final Project expenditures.

Table B2-2: Cost Summary

Description	Application/ Control Budget	Final Costs	Variance	Variance
	($000s)			(%)
Unit 4	6,634	8,058	1,424	21%
Unit 3	4,079	6,529	2,450	60%
Unit 2	5,641	6,606	965	17%
Unit 1	8,050	8,287	237	3%
Balance of Plant	860	1,657	797	93%
Subtotal - Construction	25,264	31,137	5,873	23%
Cost of Removal	1,880	1,840	-40	-2%
Project Contingency	3,771	-	-3,771	-
Subtotal - Construction & Removal	30,916	32,997	2,062	7%
AFUDC	867	1,174	307	35%
Total Project Cost	31,783	34,151	2,369	7%

3.1 *PROJECT COST SUMMARY*

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). The Project's cost estimate was at an AACE Class 4 estimate class because of the difficulty in defining the full scope without dismantling the units. Final Project costs (including $1.174 million of AFUDC and $1.840 million of removal costs) are $34.151 million, which is 7 percent or approximately $2.4 million over the control budget. This is well within the typical accuracy range of an AACE Class 4 cost estimate as stated in AACE Recommended Practice 69R-12, Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Hydropower Industry. As reported in the August 2020 status report, this approximately $2.4 million variance resulted primarily from higher than planned costs to rewind the generators and to refurbish the concealed turbine components.

The cost variances in each Project category are further described below.

Units 1-4 – These variances are explained in the August 2020 status report. In 2021, both Units 2 and 3 painting scope of work that had been delayed was completed. Unit 3 rotor oil leak repair work was completed for a final cost of approximately $0.252 million. These completed scopes are included in the final costs presented in Table B2-2.

Balance of Plant Work – The balance of plant work scope of work was completed with an unfavourable variance of $0.797 million. The Balance of Plant scope of work evolved as the

Project progressed. The installation of new equipment and removal of old equipment within an operating facility presented unanticipated challenges that were not able to be defined during the planning stage. This variance is primarily due to the extra effort required to remove equipment and cabling which was not expected to contain asbestos and the additional civil structural scopes, as well as the floor modifications required to facilitate the new plant equipment.

Cost of Removal – The forecast total for cost of removal is $1.840 million, which represents a favourable variance of $0.040 million.

Contingency – Project contingency has been utilized to offset the variances that were encountered among the different Units.

AFUDC – The total cost for AFUDC is $1.174 million, which represents an unfavourable variance of $0.307 million due to the higher overall Project costs.

3.2 *PROJECT SCOPE CHANGE SUMMARY*

Throughout the Project, FBC made adjustments to address unforeseen challenges and issues which were either not considered or not accessible during the planning stage. These adjustments totalled approximately $2.015 million and were explained in the August 2020 status report.

4. CONCLUSION

The UBO Refurbishment Project is complete and has successfully eliminated or reduced the safety and environmental risks previously associated with operating the plant. The Project maintained schedule and returned the Units to commercial service within the year planned. The final Project costs were well within the typical accuracy range of an AACE Class 4 cost estimate and totalled $34.151 million. This approximately $2.4 million increase was required to complete scope and ensure the units could operate safely for 20 years or more, as originally planned.

Appendix C
PROJECTS AND MARKET REPORT

Market Report: Gas and Electric Transmission and Distribution Cost Impacts 2020-2024

May 2022

The Engagement

FortisBC has engaged Wood Mackenzie Supply Chain Consulting to provide a market report detailing how market factors have impacted and are anticipated to impact North American utility spend between 2020 and 2024. Wood Mackenzie is a global research and consulting firm that provides energy clients with data, analytics, and insights that they rely on for their decision making. Wood Mackenzie Supply Chain Consulting (SCC), formerly PowerAdvocate, utilizes proprietary cloud-based software solutions and bespoke consulting services to enable our clients to leverage data analysis and assist them in navigating an ever-changing marketplace.

Market dynamics over the last two years have created significant inflationary pressures across both materials and services. This market report is specific to two portfolios: electric transmission and distribution (T&D) and gas T&D capital expenditures at Canadian utilities, with labour specific to British Columbia, Canada. In both portfolios, market escalation has been observed since FortisBC's initial Multi-Year Rate Plan (MRP) filing (Quarter 1, 2020 through Quarter 1, 2022). This report also includes a forecast of potential impacts from Quarter 2, 2022 through Quarter 4, 2024.

Qualifications

Wood Mackenzie Supply Chain Intelligence is a suite of cloud-based software solutions that includes a product, Cost Intelligence, which enables our clients to identify market-based risks and opportunities. Cost Intelligence includes thousands of cost models and indices that enable users to understand what a project or item should cost in a dynamic market. Wood Mackenzie Cost Intelligence models were developed to support the energy market. The Wood Mackenzie team starts with industry specifications, technical drawings, supplier 10ks, and other industry information to develop detailed items that tie cost inputs to dynamic market indices. Those indices are then weighted and loaded on the cloud-based platform. The items are combined into categories and sub-categories that reflect clients spend profiles, or specific capital project expenditures.

Methodology

North American Gas and Electric Utility Cost Models

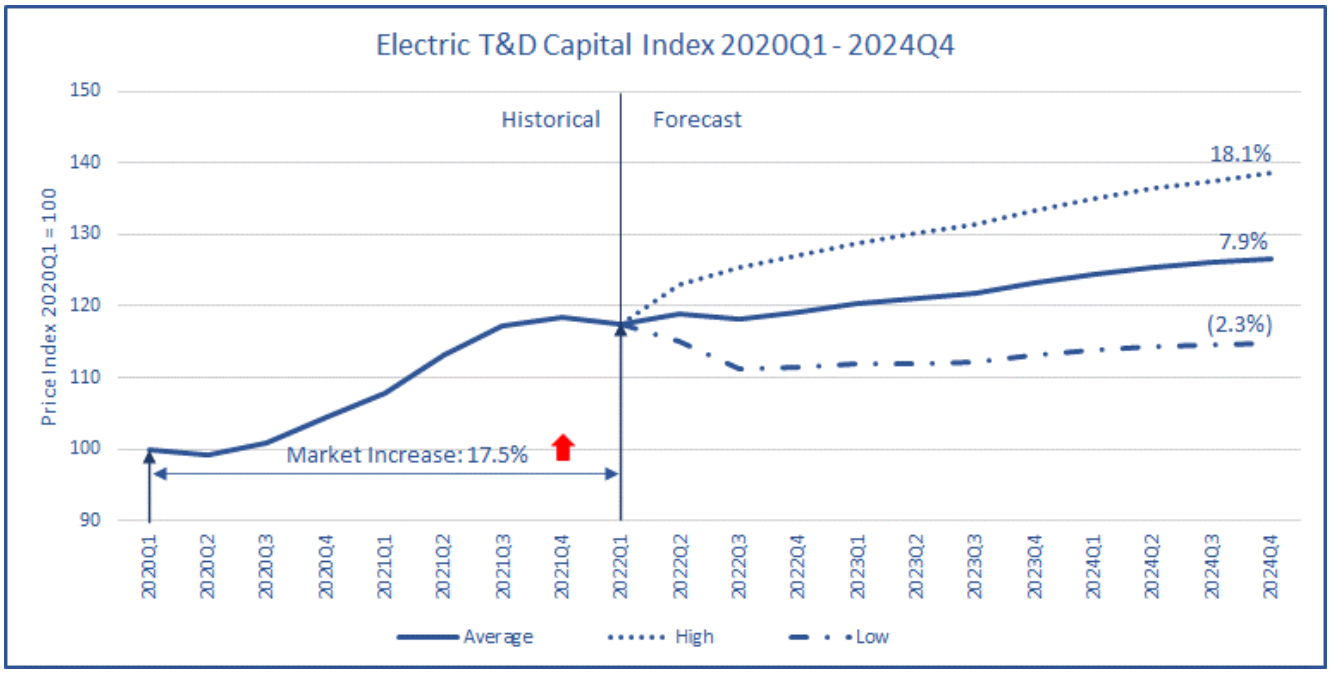
Wood Mackenzie built two customized cost models – Electric Transmission and Distribution and Gas Transmission and Distribution. Each cost model is built from aggregated spend from utilities across North America and over $550M (CAD) in total spend. The models apply indices to spend at an item level and roll up to sub-category, category, and facility level. Each model incorporates over 150 indices tracked monthly by Wood Mackenzie.

Customization for British Columbia Specific Labour Pool

British Columbia (BC) has a unique labour pool and, where appropriate, the models incorporate indices specific to BC, particularly around trade labour and any other labour activities specific to the BC province.

Market Insights

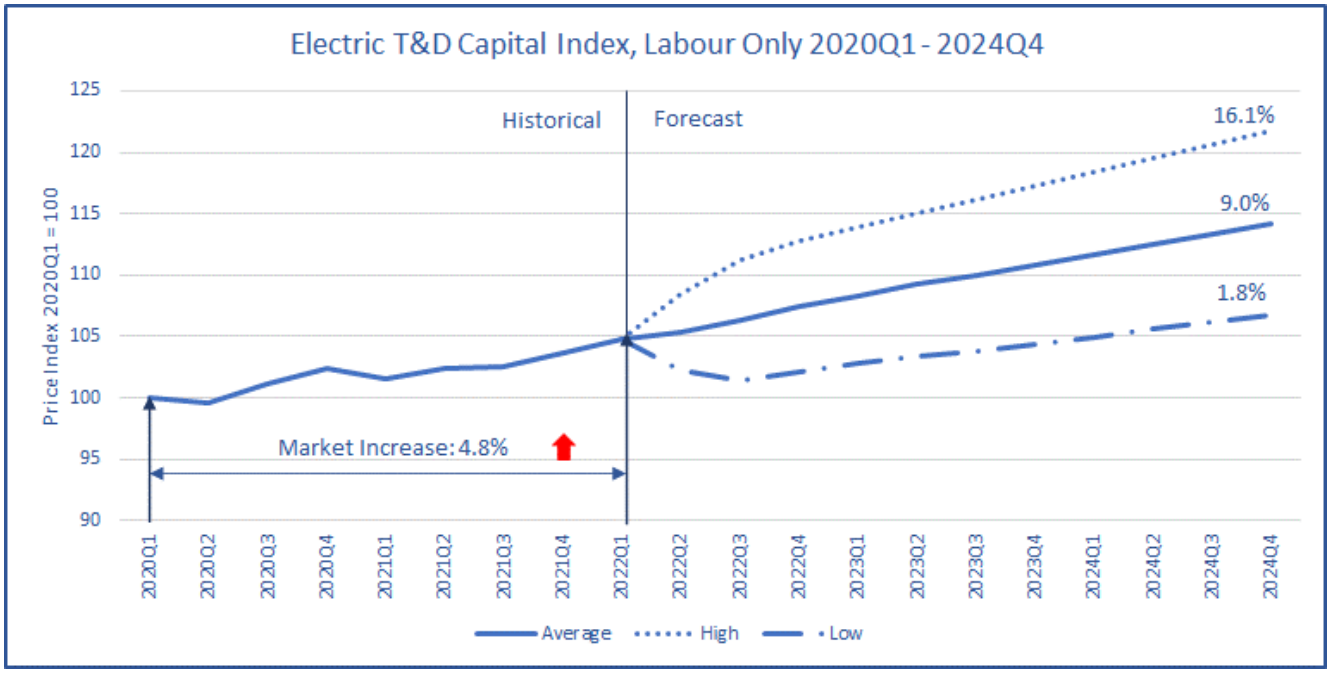
Electric Transmission and Distribution 2020Q1-2024Q4



*This graph includes an aggregate of multiple indices, including both labour and material cost components.
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

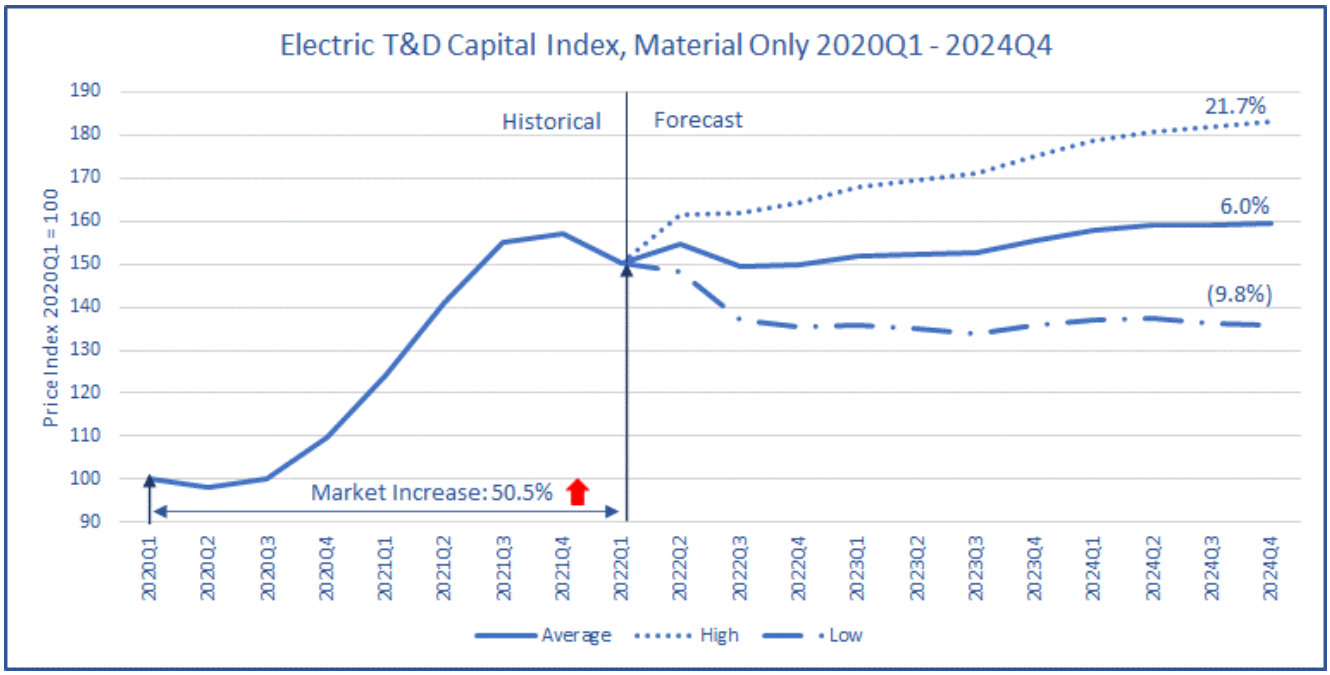
Since execution of FortisBC's MRP (Q1 2020 – Q1 2022), market factors have caused an escalation in capital costs for electric T&D of 17.5%. Forward-looking forecasts for Q1 2022 – Q4 2024 average 7.9%. Table 1 shows the ten most impactful commodities and services in the electric T&D model, and their individual escalations since the beginning of the MRP. Sharp increases in steel and aluminum prices starting in Q3 2020 drove escalations through Q3 2021. Prices of steel and aluminum have leveled off since Q4 2022 which is reflected in the forecast through 2024. The total market split for Electric T&D between labour and materials is 65% and 35% respectively. Labour costs are expected to continue to rise, while material costs level out.

Electric Transmission and Distribution - Labour 2020Q1-2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Electric Transmission and Distribution - Material 2020Q1-2024Q4



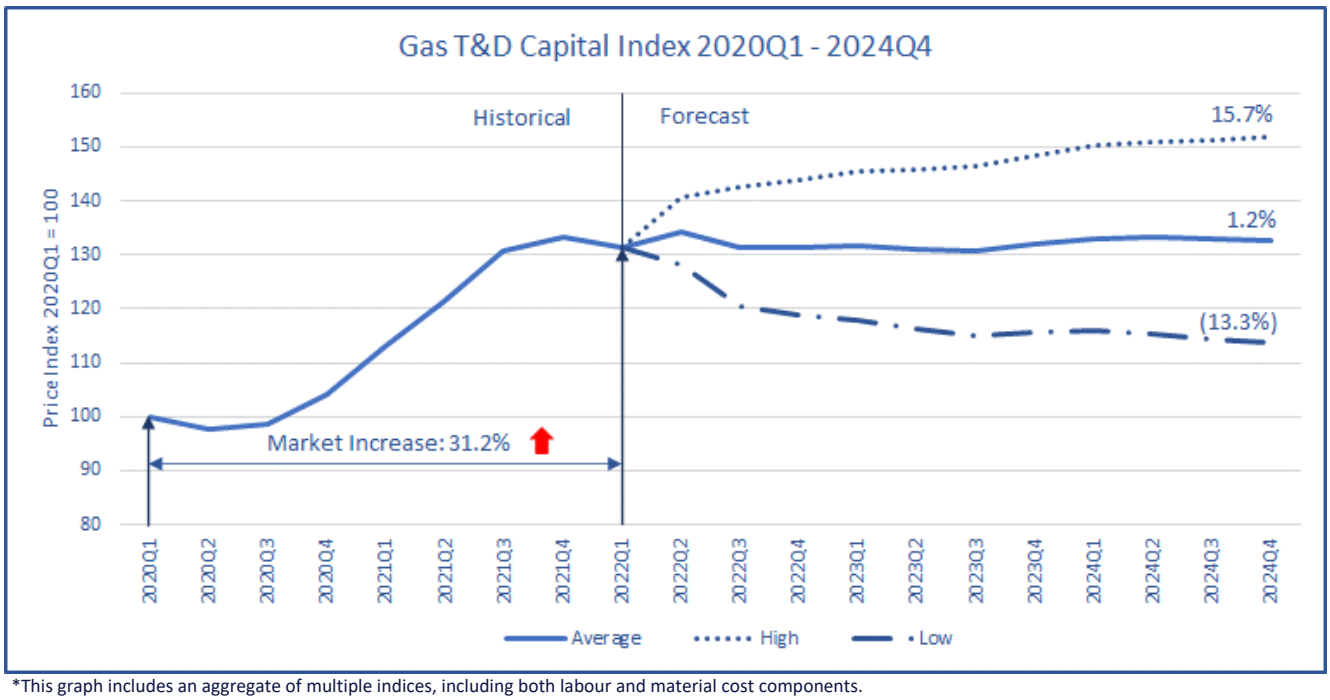
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Table 1. Electric T&D High-impact Commodities and Services

Electric T&D High Impact Commodities and Services	Q1 2020 – Q2 2022 (%)
AHE: Mechanical and Electrical Trades, Basic Construction Union Wages, BC	1.5
AHE: Construction, Private Compensation, BC	10.8
ECEC: Benefits, Private Construction	3.3
SPM: Steel, Hot-Rolled Coil	117.3
PPI: Cement, Canada	(3.4)
AHE: Heavy Equipment Operator, Basic Construction Union Wages, BC	2.6
AWE: Repair and Maintenance, BC	4.3
SPM: Aluminum, High Grade	83.2
PPI: Springs and Wire Products, Canada	42.2
IM: Transmission Conductor	160.4

AHE: Average Hourly Earnings, Employer Costs for Employee Compensation, SPM: Spot Price Metal, IPPI: Producer Price Index, AWE: Average Weekly Earnings, IM: Industry Margin

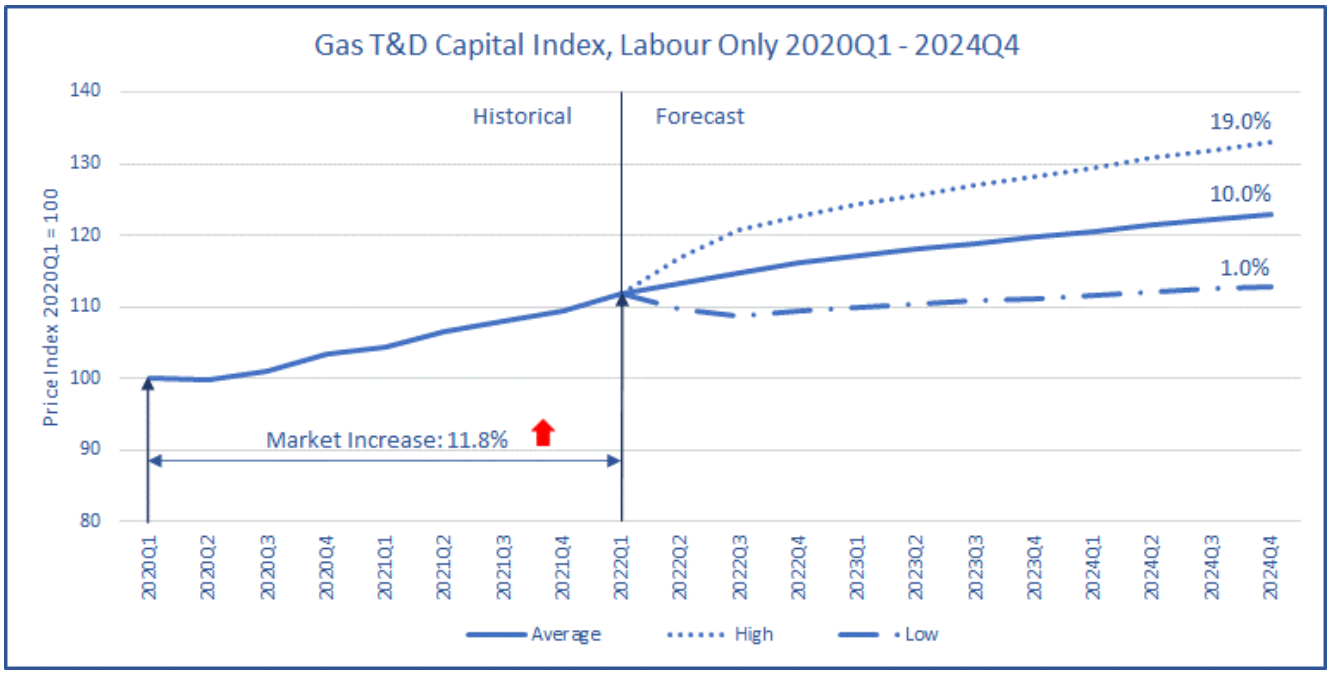
Gas Transmission and Distribution 2020Q1 – 2024Q4



*This graph includes an aggregate of multiple indices, including both labour and material cost components.
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

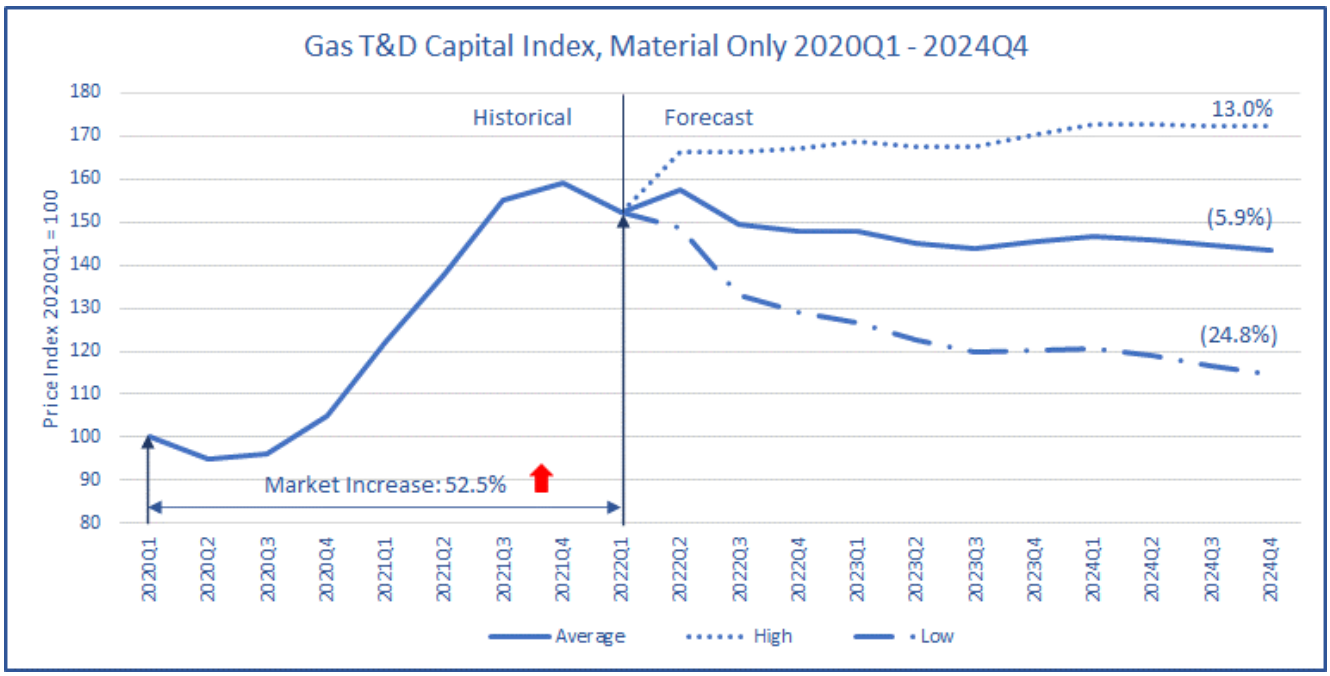
Since execution of FortisBC's MRP (Q1 2020 – Q1 2022), market factors have caused an escalation in capital costs for gas T&D of 31.2%. Forward-looking forecasts for Q1 2022 – Q4 2024 average 1.2%. Table 2 shows the ten most impactful commodities and services in the gas T&D model, and their individual escalations since the beginning of the MRP. Sharp increases in steel and aluminum prices starting in Q3 2020 drove escalations through Q3 2021. Prices of steel and aluminum have leveled off since Q4 2022 which is reflected in the forecast through 2024. The total market split for Gas T&D Construction between labour and materials is 44% and 56% respectively. Labour costs are expected to continue to rise, while material costs are expected to drop slightly, driven by declining steel prices.

Gas Transmission and Distribution - Labour 2020Q1 – 2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Gas Transmission and Distribution - Material 2020Q1 – 2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Table 2. Gas T&D High-impact Commodities and Services

Gas T&D High Impact Commodities and Services	Q1 2020 – Q2 2022 Escalation (%)
AHE: Construction, Private, Compensation, BC	10.8
SPM: Steel Plate, Cut-to-Length	173.7
SPM: Steel, Hot-Rolled Coil	117.3
PPI: Hand and Edge Tools	2.7
PPI: Commercial and Industrial Machinery and Equipment Rental	(2.2)
AHE: Professional, Scientific and Technical Services, BC	11.6
SPM: Steel Plate, Coiled	117.3
AHE: Architectural and Finishing Trades, Basic Construction, BC	1.4
AHE Manufacturing, BC	9.8
PPI: Metal Building and Construction Materials, Canada	51.1

AHE: Average Hourly Earnings, SPM: Spot Price Metal, PPI: Producer Price Index

Pre-MRP Market Escalations

The market conditions for both electric and gas T&D vary significantly from the five years prior to the execution of the MRP. Table 3 uses the same models as above to observe the market between Q1 2015 through Q4 2019. Two years (2015 and 2019) experienced a decrease in market price, and the total escalations over this period were 7.6% and 7.5% for electric T&D and gas T&D, respectively.

Table 3. Annual Market Adjustments for Electric and Gas T&D

Year Q1 – Q4	Electric T&D Market Change (%)	Gas T&D Market Change (%)
2019	(0.2)	(3.6)
2018	1.0	4.5
2017	1.8	1.2
2016	4.1	3.6
2015	(1.7)	(3.5)

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Appendix C2

Project Descriptions for Forecast Growth and Sustainment Capital

August 2022

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1. INTRODUCTION

In this appendix, FBC provides descriptions of growth and sustainment capital projects over $1 million.

As described in Section 7 of the Application, FBC's growth capital is divided into the following portfolios:

1. Transmision Growth;
2. Distribution Growth; and
3. New Connects.

FBC's sustainment capital is divided into the following portfolios:

1. Generation;
2. Transmission Sustainment;
3. Stations Sustainment;
4. Distribution Sustainment; and
5. Telecommunications.

The projects over $1 million in each of these categories are described below.

2. GROWTH CAPITAL

2.1 *TRANSMISSION GROWTH*

Regular Transmission Growth capital consists of discrete projects as dictated by transmission system capacity requirements based on forecast load for adequate supply during periods of peak demand and adverse weather conditions.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application.[1]

[1] MRP Application, Section 3.4.1.1.1, Table C3-23, pp. C-82 and C-83.

Table C2-1: FBC Transmission Growth Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
Sexsmith 2nd Transformer Addition	4,633	-	-	-	-
Summerland Transformer Replacement	539	2,063	-	-	-
Beaver Park Substation Upgrade	-	-	2,740	5,195	-
DG Bell 2nd Transformer Addition	-	-	-	-	1,086

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-2: Updated FBC Transmission Growth Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
Sexsmith 2nd Transformer Addition	5,311	66	-	-	-
Beaver Park Substation Upgrade	-	636	4,936	6,223	-
Duck Lake 2nd Transformer Addition	-	-	-	-	1,088

Each of these projects is described further below.

- **Sexsmith Second Transformer Addition:** Peak load on the existing 32 MVA Sexsmith T1 transformer was forecast to exceed nameplate capacity in 2020. In order to continue to maintain the current levels of reliability and meet the planning criteria for this area of Kelowna, a second transformer was installed and put into service at the Sexsmith substation in 2020. The actual costs of this project were approximately $5.3 million with the bulk of capital expenditures occurring in 2020.
- **Summerland Transformer Replacement:** The existing 20 MVA Summerland substation transformer supplies one of two wholesale delivery points to the District of Summerland municipal utility. Due to anticipated new commercial development in Summerland, peak load at this wholesale delivery point was previously forecast to exceed 95 percent of the contract demand limit during the MRP term. Since the most recent load forecast projects that peak load will not exceed this threshold until 2026, no project expenditures are planned during the MRP term. FBC will continue to engage with the District of Summerland municipal utility to discuss options to increase wholesale capacity. This project is thus not included in Table C2-2.
- **Beaver Park Substation Upgrade:** This project is driven by load growth in the Trail area and equipment condition issues as the BEP T1 transformer tap changer cannot be adequately maintained. The project seeks to rebuild the Beaver Park substation on an expanded station footprint. To meet planning criteria and continue to provide a reliable supply, the existing transformer will be replaced, and a second transformer will be installed. The estimated total project cost including direct overhead is approximately $11.8

million. The total project costs have increased since the MRP Application filing in 2019 due to several factors, including archaeological requirements and increases in engineering, materials and construction costs. Commodity cost increases have placed significant pressure on materials.

- **Duck Lake Second Transformer Addition:** This project is driven by significant development occurring in the area served by the Duck Lake substation. FBC planning studies indicate that a second distribution transformer is required at Duck Lake to maintain the current level of reliability and support distribution contingency planning criteria. As the pace and scale of development has exceeded what was anticipated when the MRP Application was filed, this project has now been advanced ahead of the DG Bell project described below. The estimated cost of this project is $5.3 million; however, the cost could increase further as a result of potential commodity cost increases impacting the cost of materials.
- **DG Bell Second Transformer Addition:** FBC planning studies indicate that a second distribution transformer is required at DG Bell to maintain the current level of reliability and support distribution contingency planning criteria. This project has been deferred from the original 2024-25 construction schedule to accommodate the Duck Lake Second Transformer Addition. This project is now planned for 2025-26 with an estimated in-service date of 2026. This project is thus not included in Table C2-2.

2.2 *DISTRIBUTION GROWTH*

Similar to its transmission system, FBC evaluates distribution system capacity on an annual basis, based on the projected loads. FBC's Distribution Growth capital includes two ongoing programs, small (planned) growth projects and unplanned growth projects. Larger individual distribution growth projects are also included.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application.[2]

Table C2-3: FBC Distribution Growth Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
DG Bell Feeder 4 Addition	1,970	-	-	-	-

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

[2] MRP Application, Section 3.4.1.1.2, Table C3-24, pp. C-83 and C-84.

Table C2-4: Updated FBC Distribution Growth Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
DG Bell Feeder 4 Addition	-	26	1,870	-	-
Huth CoP 13KV Supply	1,219	62	-	-	-

Each of these projects is described further below.

- **DG Bell Feeder 4 Addition:** This project was deferred due to the timing of City of Kelowna road construction from 2020 to 2022; however, the total actual project cost is lower than forecast in the MRP Application.
- **Huth CoP 13KV Supply:** This project was added in 2020. The project was required to ensure that FBC continues to meet the terms of its Wholesale Agreement with the City of Penticton at the Huth substation Point of Delivery.

2.3 *NEW CONNECTS*

There are no projects over $1 million that have been completed or are planned to be completed during the MRP term.

3. SUSTAINMENT CAPITAL

3.1 *GENERATION SUSTAINMENT*

FBC operates and maintains four generating facilities with a total of 15 units. FBC regularly monitors its infrastructure to ensure it meets industry standards and guidelines, complies with regulations, and operates safely to minimize risk to the public and employees. FBC's Generation capital is grouped into four capital programs: (i) Hydraulic Dam Structures; (ii) Generating Equipment; (iii) Generation Auxiliary Equipment; and (iv) Buildings and Structures.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application[3].

Table C2-5: FBC Generation Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	Category	2020	2021	2022	2023	2024
Concrete Structures Rehabilitation	Hydraulic Dam Structures	685	821	979	1,128	1,019
LBO Spillway Gates Refurbishment	Hydraulic Dam Structures	1,467	1,396	-	-	-

[3] MRP Application, Section 3.4.1.2.1, pp. C-84 to C-88.

	Category	2020	2021	2022	2023	2024
Other Gates Upgrades	Hydraulic Dam Structures	481	100	414	241	545
Dam Safety Instrumentation	Hydraulic Dam Structures	715	765	-	-	806
Guarding of Rotating Parts	Hydraulic Dam Structures	194	324	458	295	287
UBO Unit 6 Turbine Runner Replacement	Generating Equipment	-	35	582	2,035	-
Generator Excitation System and Control Systems	Generating Equipment	-	67	556	556	-
Generator Thrust Bearing Cooling System	Generating Equipment	247	271	295	198	198
Dewatering and Drainage Systems	Generation Auxiliary Equipment	116	349	349	349	349
Station Service Upgrade	Generation Auxiliary Equipment	333	495	286	286	300
COR Annex Building Replacement	Buildings and Structures	-	-	-	198	1,606

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-6: Updated FBC Generation Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	Category	2020	2021	2022	2023	2024
Concrete Structures Rehabilitation	Hydraulic Dam Structures	715	745	1,128	651	1,061
LBO Spillway Gates Refurbishment	Hydraulic Dam Structures	1,436	2,893	-	-	-
Dam Safety Instrumentation	Hydraulic Dam Structures	896	287	1,059	100	100
Rehabilitation of Dam Stability Anchors	Hydraulic Dam Structures	78	442	392	326	-
UBO Unit 6 Turbine Runner Replacement	Generating Equipment	-	22	501	1,395	2,085
Generator Excitation System and Control Systems	Generating Equipment	-	271	344	485	836
Dewatering and Drainage Systems	Generation Auxiliary Equipment	126	217	655	1,166	222

	Category	2020	2021	2022	2023	2024
Station Service Upgrade	Generation Auxiliary Equipment	298	577	834	512	260
COR Annex Building Replacement	Buildings and Structures	4	4	186	200	1,606

Each of these projects is described in further detail below:

- **Concrete Structures Rehabilitation Project:** This is a continuation of the program started in 2014 to address requirements of the BC Dam Safety Regulation and deterioration of concrete structures. The cost for this project is $0.332 million lower than forecast in the MRP Application due mainly to reduced scope at the Lower Bonnington Dam as safety issues are restricting access to lower areas of the construction scaffold in the tailrace during unit start-up. FBC is working on designing a solution to this issue.
- **Lower Bonnington Dam (LBO) Spillway Gates Refurbishment Project:** This project was completed in 2021 at a higher cost than forecast due to complexities encountered during construction and the implementation of a monorail system for the installation of stoplogs that was not considered initially.
- **Other Gates Upgrade Project:** This project is now forecast to cost less than $1 million due to FBC implementing a simpler solution for strengthening the LBO intake superstructure. This project is thus not included in Table C2-6.
- **Dam Safety Instrumentation Project:** This project addresses the requirement in section 19(1) of the BC Dam Safety Regulation for instrumentation to adequately monitor the dam and the area surrounding or adjacent to the dam. The project began in 2018 and includes the installation of dam monitoring systems at FBC's plants. FBC has thus far completed the installation of dam safety instrumentation at LBO and UBO and will complete the installation of dam safety instrumentation at South Slocan (SLC) in 2022. The higher costs are primarily due to higher drilling costs. The installation of the dam safety instrumentation at Corra Linn (COR) has been delayed with only the engineering being planned to occur in 2023-2024.
- **Guarding of Rotating Parts Project:** This project is now forecast to cost less than $1 million due to a reduction in scope. The original forecast included installing guards on spillway and intake gates, but during detail design, more effective administrative and operational methods were developed and implemented which have resulted in cost reductions. This project is thus not included in Table C2-6.
- **Rehabilitation of Dam Stability Anchors:** This project was included in the Other Hydraulic Dam Structures Projects category in the MRP Application, as at the time of filing it was expected to cost less than $1 million. However, the scope of work has increased from $0.302 million to $1.238 million due to damage to the anchors' heads being more extensive and the number of anchor heads that required repairs being higher than initially anticipated; the degree of the anchor head damage could only be established while

inspecting the anchors which are located on the overflow spillway. The rehabilitation of the LBO dam stability anchors will be competed in 2022. Rehabilitation of the COR dam stability anchors will commence in 2023 and will complete in 2025.

- **Upper Bonnington Dam (UBO) Unit 6 Turbine Runner Replacement Project:** This project includes the replacement of the UBO Unit 6 turbine runner that has reached the end of its service life. Work on this project was accelerated to mitigate the anticipated delays in the global supply chain due to the COVID-19 pandemic. The estimated cost of this project is approximately $1.445 million higher than originally forecast due to the costs of the runner being higher. The expected in-service date is December 2024.
- **Generator Excitation System and Control System Replacement Project:** This project addresses the replacement of some of the generator excitation systems beginning in 2022 with Unit 6 at UBO. The updated cost of this project is approximately $0.765 million higher due mainly to higher costs with the procurement of the control and excitation systems.
- **Generator Thrust Bearing Cooling System Upgrade Project:** This project is now forecast to cost less than $1 million as FBC has implemented a better designed solution that has resulted in cost savings. This project is thus not included in Table C2-6.
- **Dewatering and Drainage Systems Rehabilitation Project:** This project was budgeted based on costs including rehabilitation of pipes valves and other components of the dewatering and drainage systems. During detail design it was discovered that this solution was not feasible and a new solution was designed and is being implemented which is based on a pump in gate design that has an increased cost of $0.690 million. The first system is planned to be put in service at SLC in 2023 and engineering for the next plant will occur in 2024.
- **Station Service Upgrade Project:** This project includes upgrading the protection system of FBC's station service system and neutral grounding in order to address safety hazards, replacement of station service transformers that have reached the end of their service life and other small station service improvements. The estimated cost of this project is $0.186 million higher due to the need to address deficiencies related to LBO powerhouse grounding and bonding issues that were uncovered while doing investigations in 2021.
- **Corra Linn Annex Building Replacement Project:** FBC has decided to start the preliminary engineering in 2022 and is planning to complete the project in 2024.

3.2 *TRANSMISSION SUSTAINMENT*

Transmission Sustainment expenditures are required to proactively manage the condition and integrity of FBC's transmission line facilities, manage the risk to employees and public safety, and maintain an acceptable level of service for customers.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application[4].

Table C2-7: FBC Transmission Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
30 Line Rehabilitation	1,100	-	-	-	-
30, 32, 19 Lines Right of Way	647	651	658	656	652

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-8: Updated FBC Transmission Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
30 Line Rehabilitation	1,087	91	-	-	-
30, 32, 19 Lines Right of Way	458	637	652	652	648

Each of these projects is described in further detail below:

- **30 Line Rehabilitation between the South Slocan and Coffee Creek Substations:** This project included expenditures for structural stabilization of the transmission line, based on the 2018 condition assessment, including stubbing poles and replacing poles and cross-arms. The project was completed as planned in 2020.
- **30, 32 and 19 Line Right of Way Improvements:** The scope of this multi-year project involves acquiring an additional right of way predominantly upslope of the existing right of way for 30 Line (Nelson to Coffee Creek Substation), 32 Line (Creston to Crawford Bay), and 19 Line (Slocan Valley) and clearing the additional right of way to reduce the number of tree-related outages. Portions of these lines are in steep terrain. Of FBC's 72 transmission lines, tree contacts on 30 Line account for 17 percent of the transmission related outages. Tree contacts on 32 Line and 19 Line each account for approximately 8 percent of FBC's transmission related outages. These projects are in progress, with FBC implementing land owner agreements to widen the right of way.

3.3 *STATIONS SUSTAINMENT*

FBC's substation sustainment capital expenditures are driven by a combination of time-based and condition-based scheduling. Currently, FBC employs a substation Computerized Maintenance Management System (CMMS) which tracks basic equipment data and condition information for FBC's substation assets and is used to assist in scheduling maintenance tasks.

[4] MRP Application, Section 3.4.1.2.2, pp. C-89 and C-90.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application.[5]

Table C2-9: FBC Stations Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	2020	2021	2022	2023	2024
AS Mawdsley Tranformer Replacement	-	-	-	-	3,802
Trout Creek Transformer Replacement	2,263	-	-	-	-
Kaleden Transformer Replacement	-	-	-	-	2,716
Salmo Station Upgrade	3,718	7,154	-	-	-
Fruitvale Station Upgrade	-	-	-	-	3,802

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-10: Updated FBC Stations Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	2020	2021	2022	2023	2024
Trout Creek Transformer Replacement	153	2,660	1,568	-	-
Keremeos 2nd Transformer Addition	-	-	-	543	2,700
Salmo Station Upgrade	4,778	5,143	-	-	-
Fruitvale Station Upgrade	-	-	-	1,087	7,021

Each of these projects is described in further detail below:

- **AS Mawdsley Transformer Replacement:** FBC is now planning to file a Certificate of Public Convenience and Necessity (CPCN) application for this project as the cost is forecast to be above the $20 million materiality threshold. This project is thus not included in Table C2-10.
- **Trout Creek Transformer Replacement:** This project is driven by asset condition, as the transformer is 52 years old and uses the most unreliable Load Tap Changer (LTC) in the FBC fleet (Pioneer TC546). The acetylene levels and a barrel collecting the excess oil moving from the main tank to LTC indicated a cracked LTC terminal board. The project is currently in execution with an estimated in-service date of 2022. Increases in project costs are due to delays related to the lands purchase and ALR approval, along with significant additional work related to other end of life station equipment. Further

[5] MRP Application, 3.4.1.2.3, Tables C3-34 and C3-35, pp. C-91 to C-93.

investigation of the station after the MRP proceeding revealed that the entire station was in a similar condition as the transformer which resulted in a rebuild of the station.

- **Keremeos Second Transormer Addition:** This project is driven by asset condition. The Keremeos transformer has a 48 year old LTC that is not functioning. Based on the resulting operational challenges with the control of customer voltages, this transformer replacement is a high priority.
- **Kaleden Transformer Replacement:** This project has been deferred until after the end of the MRP term to accommodate the previously unforeseen Keremeos Transformer Replacement project. The existing Keremeos transformer presents a larger risk at this time, but planning remains underway for replacement of the Kaleden transformer in 2025-26. This project is thus not included in Table C2-10.
- **Salmo Station Upgrade:** This project was driven by equipment condition issues and aging infrastructure at the Salmo and Ymir substations. The project rebuilt the Salmo substation on the existing station footprint and decommissioned the Ymir substation. The Ymir substation customers were permanently transferred to the Salmo substation. Construction began in 2020 and was completed in 2021. The total cost of this project was $9.9 million. The overall total project cost was less than forecast due primarily to lower actual costs for the distribution and transmission line work. The replacement of the Salmo Station 13 kV Switchgear was also included in this project.
- **Fruitvale Station Upgrade:** This project is driven by equipment condition issues and aging infrastructure at the Fruitvale and Hearns substations. The Hearns single phase transformer units are approximately 72 years old, and the Fruitvale metal-clad switchgear is approximately 55 years old; this equipment is at risk of failing. The project seeks to rebuild and relocate the Fruitvale substation, while decommissioning the Hearns substation. The Hearns substation customers would be permanently transferred to the Fruitvale substation. The existing Fruitvale substation footprint is too small to accommodate the rebuild, and land will need to be acquired for the upgrade. To meet planning criteria and continue to provide a reliable supply to the Fruitvale area, the existing transformer will be replaced, and a second transformer will be installed. The estimated total project cost including direct overhead is $12.5 million. FBC forecasts spending $1.1 million in 2023, $7.0 million in 2024, and $4.4 million in 2025 with an estimated in-service date of 2025. The total project costs have increased since the MRP Application due to several factors, including land acquisition requirements and increases in engineering, material and construction costs.

3.4 *DISTRIBUTION SUSTAINMENT*

There are no projects over $1 million that have been completed or are planned to be completed during the MRP term.

3.5 TELECOMMUNICATIONS SUSTAINMENT

FBC's telecommunications system is an integral component in the protection relaying system, remedial action schemes, substation operations and control, and generation dispatch systems. The system requires ongoing investment to replace aging or failed systems for safe and reliable operation of the system and to ensure business needs continue to be met.

The table below shows the original spend profile of the projects greater than $1 million in this category during the MRP term, as provided in the MRP Application[6].

Table C2-11: FBC Telecommunications Sustainment Capital Expenditures on Projects Greater than $1 million in MRP Application ($000s)

	Category	2020	2021	2022	2023	2024
Backbone Transport Technology Migration	Systems Upgrades and Replacements	-	-	937	953	-
SCADA System Replacement	Systems Upgrades and Replacements	-	1,086	2,192	2,188	1,086
VHF Radio System Replacement	Systems Upgrades and Replacements	-	-	548	875	-

The table below shows the updated forecast spend profile of the projects greater than $1 million in this category during the MRP term.

Table C2-12: Updated FBC Telecommunications Sustainment Capital Expenditures on Projects Greater than $1 million ($000s)

	Category	2020	2021	2022	2023	2024
Backbone Transport Technology Migration	Systems Upgrades and Replacements	-	-	-	841	853
SCADA System Replacement	Systems Upgrades and Replacements	-	-	-	543	1,080
VHF Radio System Replacement	Systems Upgrades and Replacements	-	-	-	-	540

Each of these projects is described in further detail below:

- **Backbone Transport Technology Migration:** This project will replace FBC's existing SONET network with a new high-speed data network supporting all present and anticipated future applications needed to provide safe and reliable service. The project, which was originally forecast to start in 2022, is now expected to commence in 2023.
- **SCADA System Replacement Project:** This project was planned to start in 2021; however, due to limited resources the business analysis was not initiated until late 2021,

[6] MRP Application, Section 3.4.1.2.5, pp. C-99 to C-101.

resulting in delays to determine the best SCADA solution. The estimated cost of this project has decreased to approximately $6 million.

- **VHF Radio System Replacement Project:** The existing FBC Electric VHF Radio system is at the end of its service life (>20 years old) and the technology is obsolete. Parts are still available but are becoming more difficult to source and the legacy technology is difficult to support as new hires are not trained or experienced with the legacy technology. New 2-way radio technologies bring significant benefits with respect to sharing of channels, ease of maintenance, superior coverage and ability to send data in addition to voice. In 2024, the first stages of the VHF radio replacement project are expected to start, with the project continuing into 2025.

Appendix D
DRAFT ORDER

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British Columbia
Utilities Commission

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ORDER NUMBER
G-xx-xx

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

and

FortisBC Inc.
Annual Review for 2023 Rates

BEFORE:
E. B. Lockhart, Panel Chair
C. M. Brewer, Commissioner
A. Pape-Salmon, 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 a Multi-Year Rate Plan (MRP) for 2020 through 2024 (2020-2024 MRP Decision) for FortisBC Inc. (FBC). In accordance with the 2020-2024 MRP Decision, FBC is to conduct an annual review (Annual Review) process to set its rates for each year;

B. By letter dated June 28, 2022, FBC proposed a regulatory timetable for the Annual Review of its 2023 rates;

C. By Order G-193-22 dated July 15, 2022, the BCUC established the regulatory timetable for the Annual Review of FBC's 2023 rates, which included FBC filing its Annual Review materials, intervener registration, one round of information requests, a workshop, FBC's responses to undertakings at the workshop, and written final and reply arguments;

D. On August 5, 2022, FBC submitted its materials for the Annual Review for 2023 Rates Application (Application). In the Application, FBC requests a 3.99 percent rate increase over 2022 rates, effective January 1, 2023, among other things; and

E. The BCUC has reviewed the Application, evidence and arguments filed in the proceeding and makes the following determination.

NOW THEREFORE pursuant to sections 59 to 61, 89 and 99 of the *Utilities Commission Act*, for the reasons stated in the decision issued concurrently with this order, the BCUC orders as follows:

1. FBC is approved to recover the 2023 revenue requirement and resultant rate change on an interim basis, effective January 1, 2023, as filed in the Application and subject to any adjustments identified by FBC during

the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application. Rates will remain interim pending the outcomes of Stage 1 of the BCUC's current generic cost of capital (GCOC) proceeding and FBC's 2023-2027 Demand Side Management (DSM) Plan proceeding.

2. The level of forecast growth, sustainment and other capital to be incorporated in rates for the years 2023 and 2024, as set out in Section 7.2.1, is approved.

3. FBC is approved to:

    a. Create a rate base deferral account for the 2023 Joint Pole Use Audit and amortize the deferral account over five years commencing January 1, 2023; and

    b. Amortize the existing COVID-19 Customer Recovery Fund Deferral Account over three years commencing January 1, 2023.

4. FBC is approved to cease reporting on the COVID-19 Customer Recovery Fund Deferral Account.

5. Directive 6 of Order 42-21 is varied as follows: "FBC is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the Flow-through deferral account".

6. Directive 2 of Order G-83-14 is varied as follows: "Approval is granted until such time as FBC no longer has an exemption to prepare and file its financial statements in accordance with US GAAP or is no longer reporting under US GAAP for financial reporting purposes".

7. FBC is directed to file with the BCUC as a compliance filing, within 15 days of the issuance of this order, amended tariff pages and finalized financial schedules for 2023, in accordance with the terms of this order.

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

FBC 2024 ANNUAL REVIEW OF RATES
EXHIBIT B-2

Sarah Walsh
Director, Regulatory Affairs

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August 4, 2023

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

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

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 2024 Rates

In accordance with the MRP Plan and BCUC Order G-191-23 setting out the Regulatory Timetable for FBC's Annual Review, FBC hereby attaches its Annual Review for 2024 Rates Application materials.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners in the FBC Annual Review for 2023 Rates proceeding.

FORTIS BC™

FORTISBC INC.

Multi-Year Rate Plan for 2020 through 2024

Annual Review for 2024 Rates

August 4, 2023

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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.

The MRP provides stable levels of O&M funding and includes service quality indicators (SQIs) to monitor the maintenance of 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.

As explained in Section 10 of the Application, FBC proposes to distribute $2.396 million pre-tax ($1.749 million after-tax) in earnings sharing to customers in 2024.

The proposed rates for 2024 flowing from the forecasts and approved formulas set out in the Application, including returning the actual 2022 earnings sharing to customers, result in a 4.83 percent rate increase from 2023 rates. The increase is primarily due to an increase in power purchase expense (PPE), followed by an increase in income tax expense.

In the subsections 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 discussion of FBC's 2022 formula O&M savings and the productivity initiatives that FBC is developing. Finally, FBC provides a summary of its proposed revenue requirements and rate changes for 2024 and a summary of the SQI results. 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. Approval to recover the 2024 revenue requirement and resultant rate change on a permanent basis, effective January 1, 2024, as filed in the Application and subject to any adjustments identified by FBC during the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application.
2. Creation of the following rate base deferral accounts, as described in Section 7.6:
    - 2025 Multi-year Rate Plan (MRP) Application deferral account, with the amortization period to be determined in a future proceeding;

- 2024 Mandatory Reliability Standards (MRS) Audit deferral account, with an amortization period of three years, commencing January 1, 2024;
- PST Rebate on Select Machinery and Equipment deferral account, with an amortization period of one year, commencing January 1, 2024;
- BC Cost of Living Credit deferral account, with an amortization period of one year, commencing January 1, 2024; and
- Climate Change Operational Adaptation (CCOA) Plan deferral account, with an amortization period of four years, commencing January 1, 2024.

A draft order is included in Appendix C.

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
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

Item	Description	Response or Reference
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 FORMULA O&M SAVINGS AND PRODUCTIVITY INITIATIVES

1.4.1 Overview of 2022 Formula O&M Savings

For 2022, FBC achieved formula O&M savings in addition to meeting the embedded productivity improvement factor in the O&M formula. Total formula O&M savings before earnings sharing were approximately $3.7 million, excluding the COVID-19 pandemic approved exogenous factor credit for net O&M cost reductions of approximately $1.0 million.

Of the approximate $3.7 million in formula O&M savings realized in 2022, approximately $3 million are due to labour savings, including overtime. The remaining savings are due to a variety of factors including reduced postage and printing costs from paperless billing and general timing of non-labour expenditures. While some of the savings are one-time in nature (e.g., required time to fill vacancies from turnover), some of the savings are expected to continue into the future, recognizing that cost pressures in the future may offset the savings.

FBC will continue to pursue productivity improvements to achieve savings beyond the productivity improvement factor as it seeks to manage its business needs and cost pressures resulting from its evolving and challenging operating environment.

1.4.2 Productivity Initiatives

As described in FBC's Annual Review for 2022 Rates, in 2021, FBC and FortisBC Energy Inc. (together FortisBC) initiated a working group consisting of senior managers and directors from different parts of the organization that is responsible for reviewing and identifying productivity initiatives. Following is a summary of these productivity initiatives.

1. **Field Operations Improvements:** A review of the meter reading routes was undertaken and updated to achieve optimized routes, resulting in reduced overtime and increased employee safety. In addition to optimizing meter reading routes, range extenders continue to be added to reduce the number of manual meter reads required, resulting in reduced travel time for meter readers and consistent, reliable meter readings for customers. Additionally, Operations is undertaking work to accurately map meters to their corresponding transformer which has operational benefits. Mapping the transformer-to-meter relationship provides accurate capacity information which can be used to determine

where EV charging load growth is and where it can be added to utilize existing infrastructure. Another benefit is that customer outage mapping improves the ability for technicians to more effectively and quickly troubleshoot system trouble calls.

2. **Use of Unmanned Aerial Vehicles (UAVs - Drones):** FBC's contract resources that are tasked with performing transmission line condition assessments continue to rely on the use of UAVs to aid in the completion of this work. Although UAVs have not eliminated the need for human resources to complete condition assessment work, primarily due to limitations on the operation of UAVs beyond visual line of sight, they have allowed FBC to reduce the need for follow-up bucket truck inspections to confirm deficiencies that cannot be fully assessed from a ground-based inspection. Additionally, FBC has equipped its Operations crews with small drones that allow for visual inspections during trouble or outage events where ground access may be difficult or restricted. FBC will continue to monitor industry developments regarding the use of UAVs for supporting utility operations.

3. **Data Analytics:** This is an initiative to centralize the Company's data sources coupled with a suite of analytic tools to analyze and use the data to inform decision-making. FortisBC uses data to inform decision making, but its current data is spread across dozens of disparate systems. Data is often siloed within departments and the volume, variety, and velocity of data coming into FortisBC is increasing. It can be difficult and time consuming to gather, clean, and filter the data needed to create useful information. As part of the solution, Enterprise Analytics creates a data fabric atop core FortisBC source and storage systems to facilitate advanced analytics opportunities. It addresses key barriers by integrating existing data into a single, scalable platform to deliver easily accessible and reliable data. It also simplifies connecting data assets to reduce cost and effort to create reports that can be easily updated and enables automation of reporting. Enterprise Analytics enables improvement in key performance indicators selected by each business area, and provides enhanced data quality, and work efficiency. Benefits are realized from shared information and sharing of insight across business units. Additionally, quality assurance is better enabled as information is reconciled and standardized.

   In 2022, efforts focused on developing solutions for three business areas: Customer Service, Major Projects, and Energy Supply. For Customer Service, Enterprise Analytics is delivering a new reporting dashboard displaying key Customer Service data all in one place (gas and electric). Benefits include providing a clear and easily accessible view of factors contributing to performance, insights identifying strengths and opportunities to grow FortisBC's relationships with its customers, operational savings through more efficient customer interactions, and less effort to share metrics with parties outside of customer service. This is only the starting point, as more data sources could be included, and new ways of using the dashboard will be discovered, providing the potential to optimize continuous improvement with additional available, integrated data. For the Major Projects area, Enterprise Analytics is enabling it to provide analytical insight through dashboarding and reporting on Major Projects project budgets, schedule, and project development. Lastly, for the Energy Supply area, Enterprise Analytics is providing analytic

insights for energy loss, broadly accounting for power at different points within the FBC electricity supply chain, leveraging FBC AMI data to estimate unbilled power, improve the assignment of costs to customers, inform rate design and power purchases, and identify system losses more accurately. FBC expects to realize total O&M savings of approximately $0.125 million by the end of 2025.

Enterprise Analytics will also support streamlining existing reporting processes for financial and management reporting. Currently, the reporting processes work well with clearly defined requirements and processes but rely on manual effort. Enterprise Analytics provides an automated solution that reduces the effort required to generate reports, with expected productivity gains. This automation is achieved through the use of a data model to aggregate data sources and a reporting tool to allow for self-service. FBC plans to implement two or three automated reporting solutions in 2023.

4. **Robotics Process Automation (RPA):** This is an efficiency initiative using automation software to alleviate repetitive and simple manual tasks. With the rising volume of manual tasks performed for operational work, such as financial transactions or project closeout activities, departments within FortisBC are challenged.

   In 2022, the Company initiated the first phase of RPA implementation, working to automate several repetitive and manual processes in the Finance department and one in the Engineering department. The processes chosen were small, low-risk opportunities to introduce RPA to the organization. The first Finance process went into production in mid-2022 with others following throughout the remainder of the year. The Engineering process went into production in the first half of 2023. The automation of the Finance processes has resulted in:

   - faster and more timely processing of monthly journal entries, allowing for earlier and increased analysis and review time;
   - a shift in how time is spent, moving from data-entry-style rote work on several processes;
   - a reduction in time spent reperforming work due to human errors; and
   - an overall reduction in time spent on certain processes.

   The operational efficiency value gained by RPA is incremental but compounds as more processes are automated.

   In 2023, the Company is adding to automation within the Finance area as well as evaluating opportunities in other business areas to grow the RPA initiative. Additional process opportunities include populating Financial and Internal Audit reports and filings, application of customer bill payments, net-metering amendment of Electric bills, processing of rebate applications, onboarding of new users within IS systems, and automating manual document control processes within Engineering projects. A

governance structure will also be established to prioritize and control RPA implementations, as well as ensuring that RPA implementations align with the overall business strategy and objectives, and that the necessary resources and support are available for successful implementation and ongoing maintenance of the automated processes. FBC expects to realize total O&M savings of approximately $0.025 million by the end of 2024.

5. **Paperless Billing Customer Campaigns:** This initiative focuses on working with customers to encourage the switch to paperless billing. In addition to the convenience for customers of receiving their bill electronically and the environmental considerations of less paper and physical transport of the bills, an increased percentage of customers making the switch to paperless billing results in ongoing printing and postage cost savings. At the start of 2022, FBC had approximately 77,000 customers choosing paperless billing as their preferred bill delivery method. Following the success of several internal programs that encouraged employees to highlight this option with customers and including an external social media campaign that resulted in donations to food banks in need, FBC achieved an increase of approximately 6,500 customers choosing this option in 2022. This increase equates to approximately $0.05 million in printing and postage cost savings for FBC in 2022 as compared to 2021.[1]

6. **Other Initiatives:** FortisBC is continuously looking for efficiencies and improvements in its activities, in a larger scale as the initiatives described above, or at a smaller scale as described in the following initiatives.

Mobile enabling applications: FortisBC has different initiatives to digitize forms and provide the ability to complete these forms on mobile devices in the field or office. Digitizing these forms supports effective data capture, and improves consistency, reliability, comprehension of data collected and reduces risk of manual errors. Additionally, it reduces the administrative efforts that occur with paper forms. FortisBC expects to realize minor savings by the end of 2023, and additional savings will be realized as FortisBC continues to mobile-enable and digitize other paper forms.

Automated patching: FortisBC has started taking advantage of technologies for automated patching. Moving to automated patching has streamlined the patching process for several applications in the FortisBC environment. With automated patching, the process can be scheduled to run during a more appropriate business outage window with no user involvement required. Repetitive tasks can be automated, eliminating human error, increasing productivity, and decreasing administrative costs. FortisBC expects to realize minor O&M savings by the end of 2023 with increased patch cadence and accuracy. Additional time savings will be seen as more systems transition to automated patching.

[1] Calculation is a high-level estimate based on the incremental monthly paperless billing growth at an average savings of approximately $1.21 per bill.

Other IS Initiatives: A High Availability (HA) operating environment enables applications to continue to operate even if one of the information technology components fails, and to ensure continuous operation and uptime. HA allows IS to schedule upgrades, patches, and release tasks during business hours, ultimately improving business operations and reducing overtime costs. IS has also expanded the use of automated testing. The expanded use of automation allows for an increase in system testing and improved product quality with a decrease in proportionate need for additional testing resources. Automation is expected to continue to expand in use at FortisBC in the future.

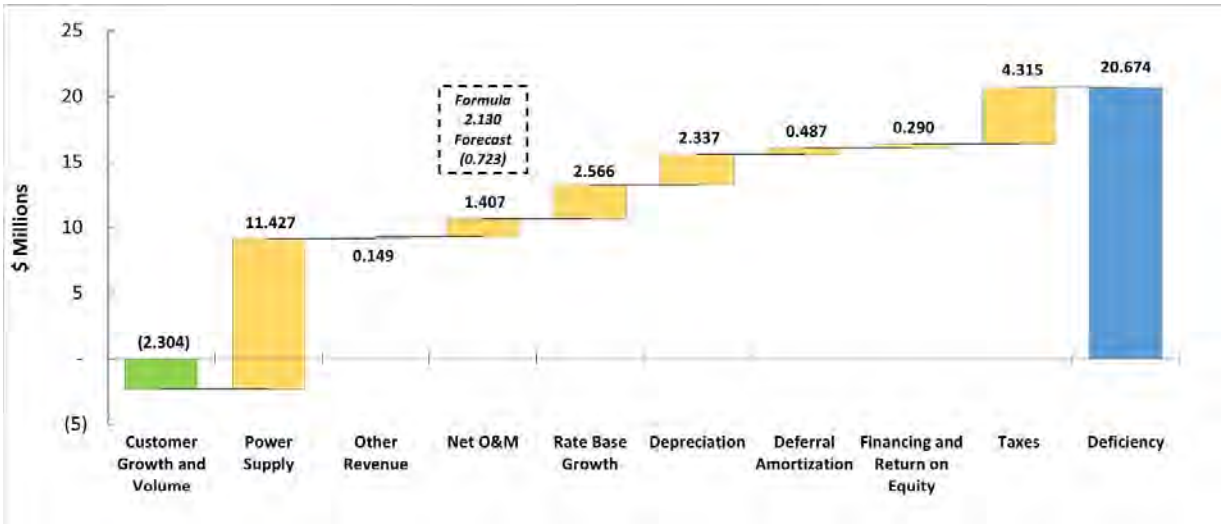
Customer Service Initiatives: Ongoing smaller initiatives include automating the tracking of collections and refund cases, improving training materials for high volume call types, and introducing emails for electric collections customers. While on a smaller scale, these initiatives contribute to improving customers' experience with FortisBC and the Company maintaining a focus on being cost effective in its use of resources.

1.5 REVENUE REQUIREMENT AND RATE CHANGES FOR 2024

The revenue requirement components set out in the Application result in an effective rate increase of 4.83 percent for 2024 compared to 2023. The effective rate increase results from a revenue deficiency of $20.674 million.

The following chart summarizes the items that contribute to the 2024 revenue deficiency. The chart shows each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The 2024 deficiency of $20.674 million is then the sum of all of the previous bars and is shown at the end of the chart in blue.

Figure 1-1: 2024 Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.5.1 Customer Growth and Volume Forecast (Section 3)

For 2024, FBC forecasts the net load to decrease by approximately 1 GWh when compared to 2023 Approved, with the forecast increases from the wholesale and commercial customer classes completely offset by decreases in the residential, industrial, and irrigation customer classes. Despite the slight decrease in net load of 1 GWh forecast for 2024, FBC is forecasting a small increase in revenue of $2.304 million, primarily due to the forecast increase in load from the wholesale customers as well as a forecast increase in residential and commercial customer counts (resulting in a small increase in the fixed monthly/bi-monthly customer charges). FBC's 2024 Forecast revenue at 2023 approved rates is $428.377 million.

1.5.2 Power Supply (Section 4)

FBC forecasts an increase in power supply of $11.427 million in 2024 compared to 2023 Approved. This increase is primarily due to the higher purchase rates for power from the market and contracted producers (included as part of the power purchase expense), followed by smaller increases in the BC Hydro Power Purchase Agreement (PPA), wheeling expenses, and water fees.

1.5.3 Other Revenue (Section 5)

Other Revenue is forecast to increase the 2024 revenue deficiency by $0.149 million, primarily due to reduced contract revenue and transmission access revenue.

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

FBC establishes the majority of its O&M expense by formula during the MRP term. The O&M formula incorporates a net inflation factor of 3.580 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.[2] The 2024 Formula O&M net of capitalized overhead has increased by $2.130 million[3] when compared to the 2023 Formula O&M, which is partially offset by a decrease in net O&M forecast outside of the formula by approximately $0.723 million,[4] primarily due to a decrease in pension and OPEB expense. Overall, the 2024 increase in total O&M expense net of capitalized overhead is $1.407 million (2.3 percent).

1.5.5 Rate Base Growth (Section 7)

The 2024 rate base is forecast to increase by approximately $39.492 million when compared to the 2023 Approved rate base, resulting in an increase to the 2024 Forecast earned return and the 2024 revenue deficiency of approximately $2.566 million. The increase in rate base is primarily due to the mid-year impact of FBC's 2024 regular capital additions to plant, followed by, to a lesser extent, the full-year impact of FBC's major capital project additions, including the Kelowna

[2] Modified by 75 percent.
[3] Increase in gross formula O&M of $2.506 million (3.6 percent) compared to 2023 Approved.
[4] Decrease in gross forecast O&M of $0.850 million (-36.2 percent) compared to 2023 Approved.

Bulk Transformer Additions (KBTA) project and the Corra Linn Dam Spillway Gates Replacement project.

1.5.6 Depreciation (Section 7)

Depreciation expense in 2024 is forecast to increase the 2024 revenue deficiency by $2.579 million compared to 2023 Approved. This increase is due to the forecast increase in rate base discussed above. The increase in depreciation expense is partially offset by approximately $0.242 million of CIAC from net additions, resulting in a net increase of $2.337 million in depreciation expense.

1.5.7 Amortization of Deferral Accounts (Section 7 and Section 12)

Amortization of deferral accounts in 2024 is forecast to increase by $0.487 million, primarily due to a reduction in the credit amortization related to the 2020-2024 Flow-through non-rate base deferral account. This increase in amortization expense due to the reduced credit amortization from the Flow-through deferral account is partially offset by an increase in credit amortization from the MRP Earnings Sharing deferral account as well as the amortization of credit balances in the Princeton Office Disposition deferral account, the proposed BC Cost of Living Credit deferral account, and the proposed PST Rebate on Select Machinery and Equipment deferral account.

1.5.8 Financing and Return on Equity (Section 8)

Financing and Return on Equity (ROE) increased the 2024 deficiency by $0.290 million through changes in financing rates, the ratio of long-term debt versus short-term debt, and changes in rate base.

For 2024, FBC is forecasting a short-term debt rate of 5.21 percent, which is an increase from the short-term debt rate embedded in the 2023 Approved revenue requirement of 4.24 percent. Overall, FBC's revenue deficiency is increased by $0.346 million from financing rate changes, which is offset by $0.056 million from the ratio change between long-term and short-term debt.

In calculating its 2024 revenue deficiency, FBC has utilized its currently approved capital structure and return on equity (ROE) of 40 percent and 9.15 percent, respectively, as approved by Orders G-129-16 and G-47-14. As explained in Section 8.1, FBC's ROE is set at a premium of 40 basis points over the benchmark ROE, which is the ROE approved for FEI. FBC is currently awaiting a decision on Stage 1 of the BCUC-initiated Generic Cost of Capital (GCOC) proceeding which is expected to be issued in the upcoming months. FBC will provide an update to its rate calculations as part of an Evidentiary Update subsequent to the GCOC decision being issued.

1.5.9 Taxes (Section 9)

FBC's 2024 property taxes are forecast to increase by 1.7 percent or $0.313 million from 2023 Approved. The increase is primarily due to changes in tax rates and increases in assessed values.

There has been no change in the income tax rate of 27 percent from 2023. Taxes are forecast to increase in 2024 by $4.002 million. The largest driver of the increase in 2024 is the lower income tax deductible through capital cost allowance (CCA), which led to an increase in income tax expense by approximately $2.849 million. The lower CCA is partly due to reduced undepreciated capital cost (UCC) additions in higher rate CCA classes in the 2024 Forecast compared to 2023 Approved, and partly due to the phase-out of Canada's Accelerated Investment Incentive starting from 2024 (i.e., enhanced 50 percent first-year allowance to be phased out in 2024). Income tax is also higher as a result of higher 2024 Forecast earned return and depreciation expense, which is partially offset by lower amortization of deferred charges.

1.6 SERVICE QUALITY INDICATORS (SECTION 13)

FBC reports on its 2022 and June 2023 year-to-date SQI results in Section 13. In 2022, for the eight SQIs with benchmarks, six met or were better than the benchmark, with the First Contact Resolution SQI better than the threshold and the Telephone Service Factor (Non-Emergency) SQI lower than the threshold. For the four SQIs that are informational only, the Average Speed of Answer results were higher due to the same challenges impacting the Telephone Service Factor (Non-Emergency), while performance in 2022 for the other three informational metrics generally remained at a level consistent with prior years. In 2023 to date, performance for the metrics with benchmarks is trending towards meeting the benchmark or the threshold.

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 2024 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.[5]

The MRP Decision approved the use of a forecast of growth[6] to determine formula O&M and 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 2024, FBC has used July 2021 through June 2023 inflation data for the 2024 revenue requirement calculations, using the Statistics Canada tables included in Appendix A1 of the Application.

Section 2.2 below explains how FBC determined the 2024 Inflation Factor based on prior years' BC-CPI and BC-AWE, and Section 2.3 below explains how FBC determined the average customer count. Both the inflation factor and the average customer count are used to calculate the formula O&M discussed in Section 6.

2.2 INFLATION FACTOR CALCULATION SUMMARY

In the MRP Decision, the BCUC approved an 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 for CPI-BC and Table 14-10-0223-01 to determine AWE-BC. The supporting Statistics Canada tables are provided in Appendix A1. The latest available month of April 2023 for AWE-BC has been used as a placeholder, as results to June 2023 have not been released by Statistics Canada. Once results for these periods 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 2022 labour weighting of 57 percent, the calculation of the 2024 I-Factor is (6.031 percent x 43 percent) + (2.609 percent x 57 percent) = 4.080 percent.

[5] FBC's most recent year of completed actuals is 2022 so that ratio has been used for the 2024 I-Factor calculation.
[6] 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 Year Non Labour %	Last Completed Year Labour %	I-Factor %	MRP Year
1	Jul-2021	136.7	1,143.76								
2	Aug-2021	137.0	1,143.96								
3	Sep-2021	137.2	1,142.37								
4	Oct-2021	137.9	1,140.94								
5	Nov-2021	138.1	1,129.51								
6	Dec-2021	138.0	1,132.93								
7	Jan-2022	139.4	1,155.32								
8	Feb-2022	140.4	1,153.57								
9	Mar-2022	143.0	1,161.00								
10	Apr-2022	144.2	1,164.51								
11	May-2022	146.1	1,159.89								
12	Jun-2022	146.5	1,167.14	140.4	1,149.58						
13	Jul-2022	147.6	1,162.26								
14	Aug-2022	147.0	1,171.52								
15	Sep-2022	147.8	1,171.94								
16	Oct-2022	148.6	1,174.29								
17	Nov-2022	148.1	1,176.97								
18	Dec-2022	147.1	1,153.31								
19	Jan-2023	148.1	1,180.04								
20	Feb-2023	149.1	1,175.83								
21	Mar-2023	149.7	1,191.20								
22	Apr-2023	150.4	1,199.14								
23	May-2023	151.0	1,199.14								
24	Jun-2023	151.6	1,199.14	148.8	1,179.57	6.031%	2.609%	43%	57%	4.080%	2024

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 2024 Formula O&M is summarized in the table below. The growth factor is applied to the unit cost O&M (UCOM), which was calculated based on 2019 average customers of 139,916 (shown on line 21 under year 2020 or line 28 in Table 2-2 below). Starting with this 2019 average customer count, the calculation adds 75 percent of the cumulative average of actual/forecast customer growth during the MRP term from 2020 to 2024 (shown on line 26 in Table 2-2 below) to determine the average customers for rate setting (shown on line 29 of Table 2-2 below).

Table 2-2: Calculation of 2024 Average Customer (AC) Growth Factor

Line No.	Date	Actual 2020	Actual 2021	Actual 2022	Projected 2023	Forecast 2024	Total for 2024 Rate Setting	Reference
1	Prior Year Ending Customer Count	141,027	143,714	145,830	148,435	150,761		Appendix A2 - Section 3.1 Customers
2								
3	Additions:							
4	January	292	257	226	162	192		
5	February	174	89	194	189	194		
6	March	8	123	122	192	191		
7	April	110	113	178	169	193		
8	May	173	319	(25)	277	185		
9	June	172	116	353	121	192		
10	July	522	308	352	245	193		
11	August	129	187	204	193	191		
12	September	83	136	155	195	193		
13	October	545	132	261	197	195		
14	November	234	217	319	190	188		
15	December	245	119	266	197	195		
16	Total Additions	2,687	2,116	2,605	2,326	2,302		Appendix A2 - Section 3.2 Customer Additions
17	12-month Weighted Average Additions	1,294	1,163	1,282	1,242	1,245		
18								
19	Current Year Ending Customer Count	143,714	145,830	148,435	150,761	153,063		Line 1 + Line 16; Appendix A2 - Section 3.1 Customers
20								
21	Actual/Projected Prior Year Average Customers	139,916	142,321	144,877	147,112	149,677		2020: G-42-21; Sch 3, Line 13; 2021-2024: Prior Year, Line 22
22	Average Customers for the Year	142,321	144,877	147,112	149,677	152,006		Line 1 + Line 17
23	Change in Average Customers	2,405	2,556	2,235	2,565	2,329	**12,090**	Sum of Annual Change in Average Customers on Line 23
24								
25	Growth Factor Multiplier						**75%**	G-166-20
26	Change in Average Customers for Rate Setting Purposes						**9,068**	Line 25 x Line 23
27								
28	Average Customers Used to Determine the Starting UCOM						**139,916**	Line 21, Yr 2020
29	**Average Customer Forecast for Rate Setting**						**148,984**	Line 28 + Line 26
30								
31	2022 Approved Average Customers for Rate Setting			145,378				2022: G-374-21; Sch 3, Line 22
32	2022 Actual Average Customers for Rate Setting			145,313				Line 21 (2020) + Sum of Line 23 (2020, 2021, 2022) x 0.75
33	**2022 True Up**			**(65)**				Line 32 - Line 31

2.4 INFLATION AND GROWTH CALCULATION SUMMARY

A summary of the factors used to determine formula O&M for 2024 is provided in Table 2-3, including the I-Factor calculated in Section 2.2, the approved X-Factor of 0.5 percent, and the forecast of average customers incorporating the growth factor multiplier determined in Section 2.3.

Table 2-3: Summary of Formula Drivers

Line No.	Description	2024	Reference
1	CPI	6.031%	Table 2-1, Line 24
2	AWE	2.609%	Table 2-1, Line 24
3			
4	Non Labour	43%	Table 2-1, Line 24
5	Labour	57%	Table 2-1, Line 24
6			
7	CPI/AWE Inflation	4.080%	(Line 1 x Line 4) + (Line 2 x Line 5)
8			
9	Productivity Factor	-0.500%	Order G-166-20
10			
11	Net Inflation Factor	3.580%	Line 7 + Line 9
12			
13	Average Customer Forecast for Formula O&M purposes	148,984	Table 2-2, Line 29

In summary, the Net Inflation Factor for 2024 is 3.580 percent and formula O&M for 2024 is determined using average customers of 148,984.

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, 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 2024 Forecast (2024F) compared to the 2023 Approved. The 2024F gross load is forecast to be approximately 3,773 GWh, which is 2 GWh lower than the 2023 Approved gross load. The decrease is primarily due to a reduction in loads from the residential, industrial, and irrigation classes, which almost completely offsets the increase in loads from the wholesale and commercial customers. Despite the decrease in the 2024 Forecast gross load, FBC is forecasting the 2024 revenue to be $428.377 million, which is an increase of $2.304 million when calculated based on the 2023 Approved rates for each customer class. The increase in revenue for 2024 is primarily due to the forecast increase in load from the wholesale customers, as well as an increase in recoveries from the fixed monthly/bimonthly customer charges resulting from the forecast increase in customer counts in the residential and commercial classes.

FBC has provided further information supporting its load 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 UPC forecast is multiplied by the corresponding forecast of the number of annual average 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, the lighting forecast uses the prior year's actual load, and the irrigation forecast uses a five-year historical average. Finally, 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 2022 calendar year.

- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available,[7] and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2023 (2023S) and the Seed Year forecast is based on the latest actual years, including 2022. As such, the 2023 Seed Year forecast in this Application will differ from the 2023 Forecast presented in the Annual Review for 2023 Rates, for which 2022 actual data was not available.

- 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 2024 (2024F).

- Also included in the figures in this section is the prior year's forecast (shown as the green Approved lines in the figures below), as presented in the Annual Review for 2023 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 2022.

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 incremental DSM savings for 2024 are summarized in Table 3-1 below, and are the forecast savings incremental to the savings embedded in the historical loads. Historical DSM savings can be found in Appendix A2.

[7] FBC's load forecast is developed using only complete years of historical data. FBC requires the complete year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason, partial year data is not used in forecasting.

Table 3-1: Forecast Incremental 2024 DSM Savings (GWh)

Line No.	Description	DSM 2024
1	Residential	(9.1)
2	Commercial	(22.3)
3	Wholesale	(7.6)
4	Industrial	(13.5)
5	Lighting	(0.2)
6	Irrigation	(0.2)
7	Net	(52.9)
8	Losses	(4.3)
9	Gross Load	(57.2)

3.4 LOAD FORECAST

FBC's total load consists of the weather normalized residential and wholesale load and the actual commercial,[8] industrial, lighting and irrigation load. In aggregate, the absolute load forecast variance in 2022 was 4.7 percent, which was primarily due to higher industrial loads and more residential customers coming onto the system than forecast. As shown in Figure 3-1 below, the total load, net of losses, is forecast to be 3,473.9 GWh in 2024F, which is 1.8 GWh less than 2023S and 1.4 GWh less than 2023 Approved.

[8] Commercial loads are tested for weather sensitivity each year. For 2024, there is a low correlation with weather and as a result, the actual historic commercial loads are used in the preparation of Figures 3-1 and 3-5. Please refer to Section 1.1 of Appendix A-3 for further detail.

Figure 3-1: Total Net Load (GWh)

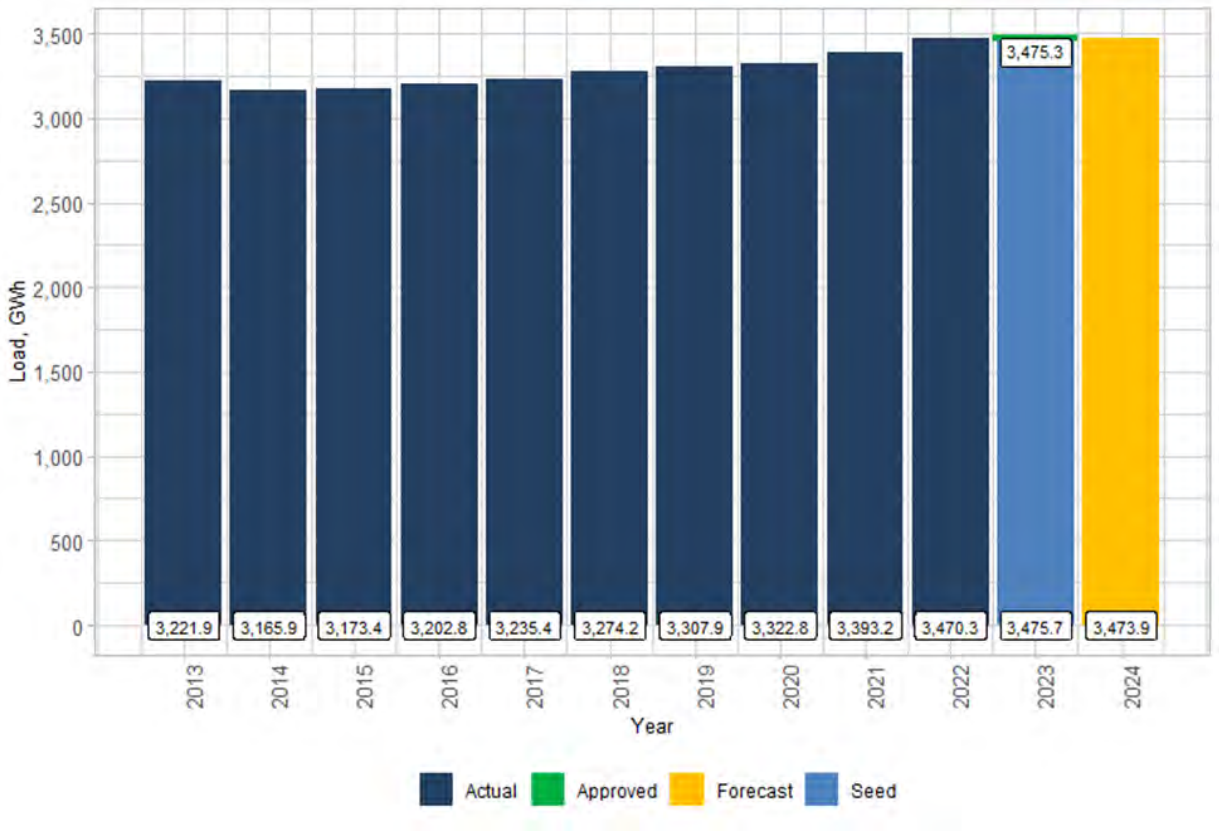


Table 3-2 below shows the normalized after-savings gross load by customer class as well as the system peak. For 2024F, the residential customer class is forecast to account for 34 percent of the normalized after-savings gross load.

Table 3-2: After-Savings Gross Load and System Peak[9]

Line No.	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
	Energy (GWh)												
1	Residential	1,352.9	1,296.5	1,298.1	1,295.6	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4	1,307.6	1,298.9
2	Commercial	788.2	865.7	853.2	901.4	920.4	922.0	933.9	917.2	971.4	969.1	967.5	974.2
3	Wholesale	675.2	567.1	580.5	574.4	574.1	584.7	566.0	569.5	565.8	575.5	590.7	589.8
4	Industrial	352.3	380.9	379.7	373.4	362.6	402.7	494.9	441.2	472.3	558.5	562.1	563.5
5	Lighting	13.5	15.6	15.9	15.9	15.9	13.2	11.0	10.8	9.7	9.3	9.2	9.1
6	Irrigation	39.7	40.0	46.0	42.1	41.9	39.0	36.0	37.3	43.6	37.6	38.6	38.5
7	Net Load	3,221.9	3,165.9	3,173.4	3,202.8	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3	3,475.7	3,473.9
8	Losses & Company Use	278.1	270.1	272.4	273.8	282.3	285.1	286.9	287.9	299.7	314.6	298.9	298.7
9	Gross Load	3,500.0	3,436.0	3,445.8	3,476.6	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8	3,774.5	3,772.7
10													
11	System Peak (MW)												
12	Winter Peak	698.1	692.6	685.0	754.7	713.6	682.2	732.4	730.8	684.8	734.3	783.4	785.0
13	Summer Peak	600.4	619.5	611.0	593.0	604.8	630.9	639.4	666.2	652.9	689.1	696.2	697.3

[9] The system peaks shown on Lines 12 and 13 are weather-normalized winter and summer peaks. Refer to Section 3.4.8 for further details.

The residential, commercial, wholesale, industrial, lighting, irrigation, loss load and the winter and summer peak demand forecasts are provided separately in the following subsections.

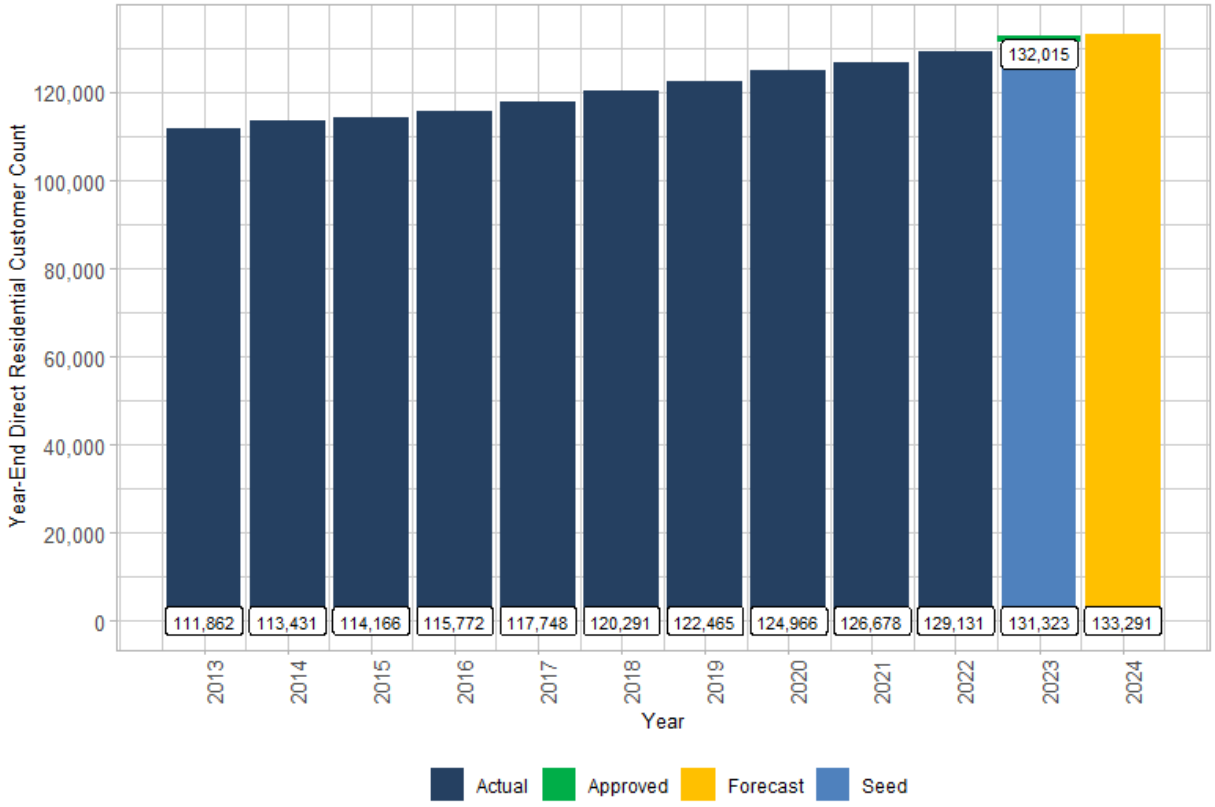
3.4.1 Residential

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 direct residential customer count for FBC.

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



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 10-year trend to the normalized historical UPCs. 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 2022, 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 forecast to decrease by 0.22 MWh in 2024F from 2023S and decrease by 0.13 MWh from 2023 Approved.

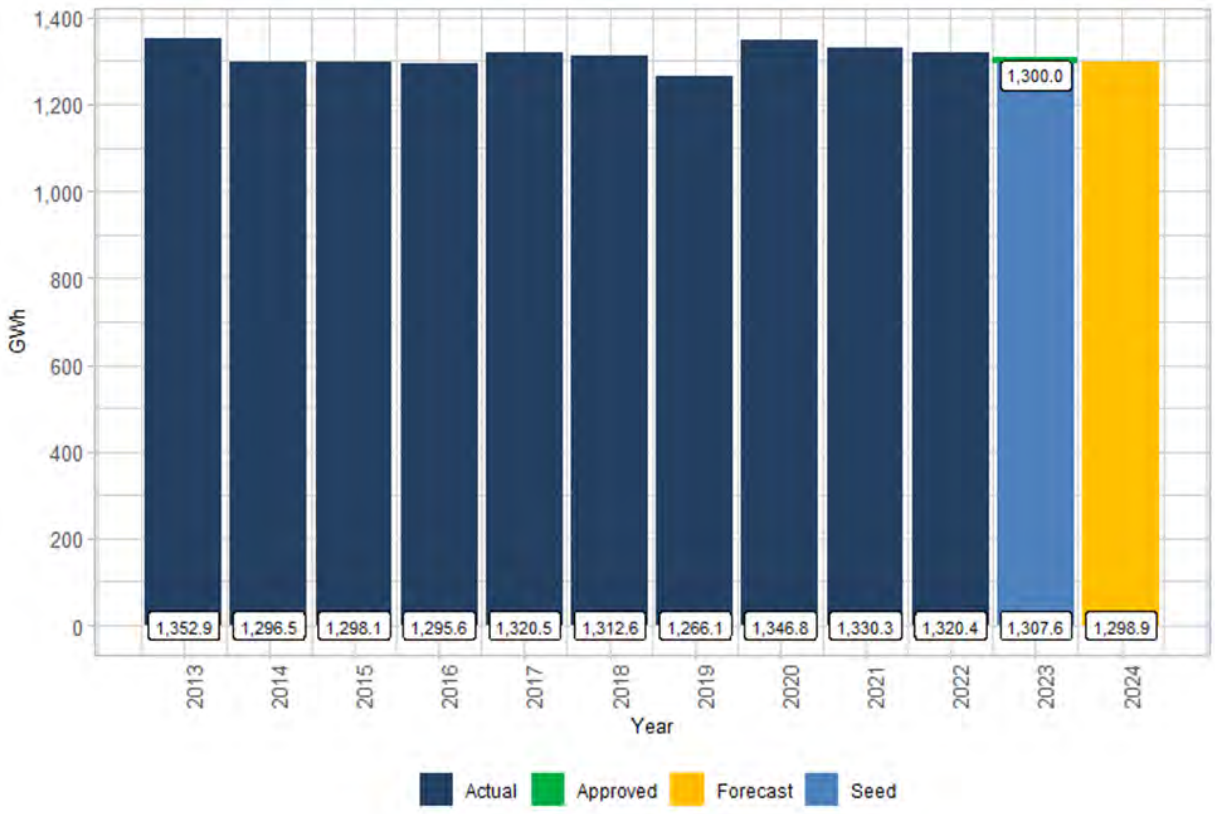
Figure 3-3: Normalized After-Savings Residential UPC (MWh)



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 decrease by 8.7 GWh in 2024F from 2023S and decrease by 1.1 GWh from 2023 Approved levels.

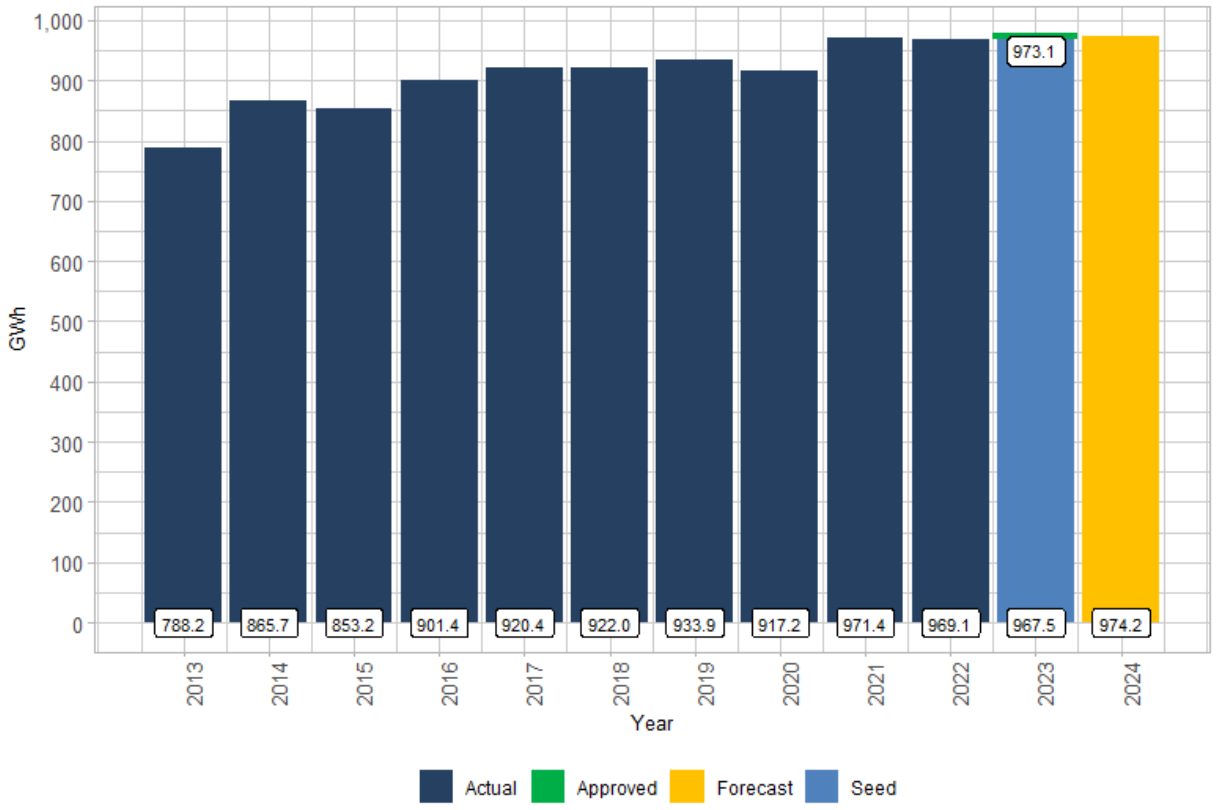
Figure 3-4: Normalized After-Savings Residential Load (GWh)



3.4.2 Commercial

The commercial class load and customer forecasts are based on regressions against the provincial GDP forecast obtained from the CBOC. The load for Electric Vehicle Direct Current Fast Chargers (EV DCFC) serviced by FBC are then added to 2023S and 2024F and account for a less than 1 GWh increase in both 2023S and 2024F. As shown in Figure 3-5 below, commercial after-savings load is forecast to increase by 6.7 GWh in 2024F from 2023S and increase by 1.1 GWh in 2024F from 2023 Approved.

Figure 3-5: After-Savings Commercial Load (GWh)



3.4.3 Wholesale

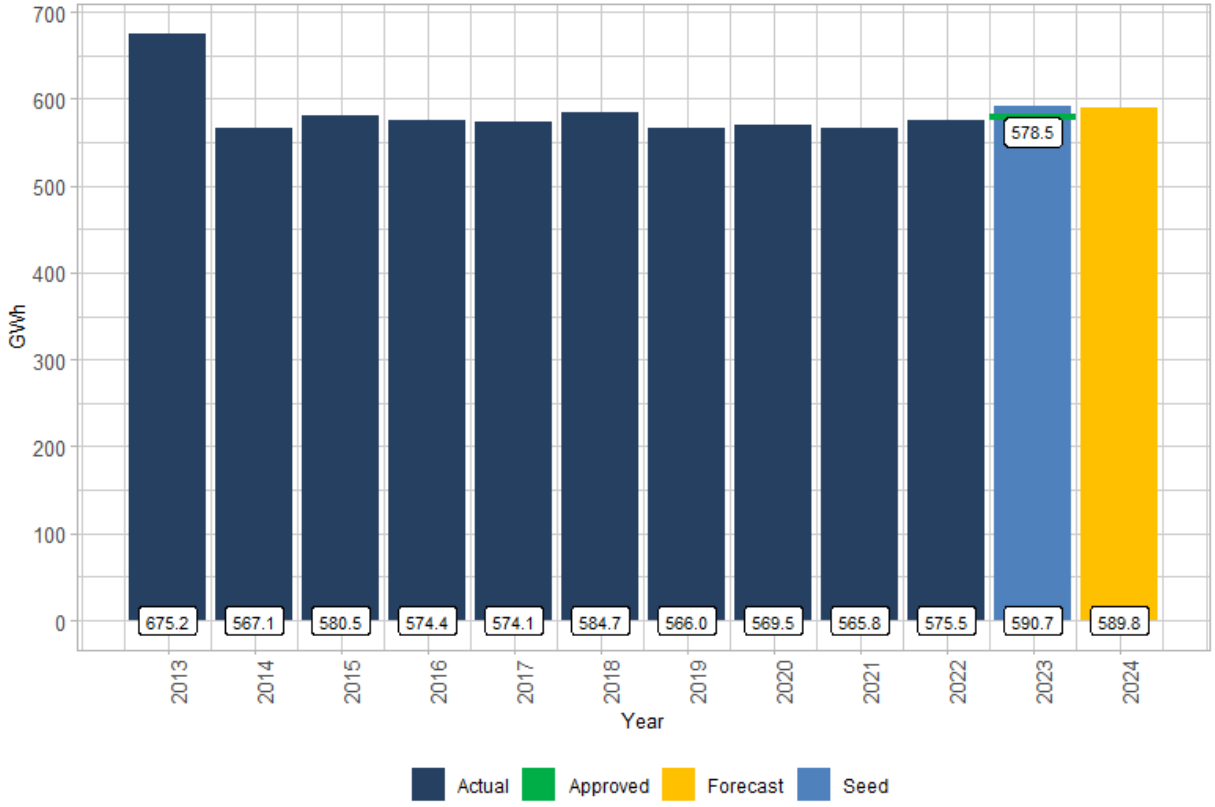
FBC sells wholesale power to municipalities for service to certain customers within its service territory that own and operate their own electrical distribution systems, and to BC Hydro. The wholesale customers' load composition is a combination of residential, commercial, industrial and lighting.

Consistent with past practice, the wholesale class is forecast using survey information from each of the individual wholesale customers, as the individual wholesale customers are best able to forecast their future load growth. For 2024, all wholesale customers responded with their load forecasts.

Consistent with the approach taken when preparing last year's wholesale load forecast (i.e., the load forecast presented in the Annual Review for 2023 Rates), FBC once again invited each wholesale customer to a workshop. In April 2023, workshops were completed with both the City of Penticton and the City of Nelson. The remainder of the wholesale customers declined the invitation. FBC continues to find these information sharing sessions valuable and plans to continue them in the future.

As shown in Figure 3-6 below, after-savings wholesale load is forecast to decrease by 0.9 GWh in 2024F from 2023S and increase by 11.3 GWh in 2024F from 2023 Approved.

Figure 3-6: Normalized After-Savings Wholesale Load (GWh)



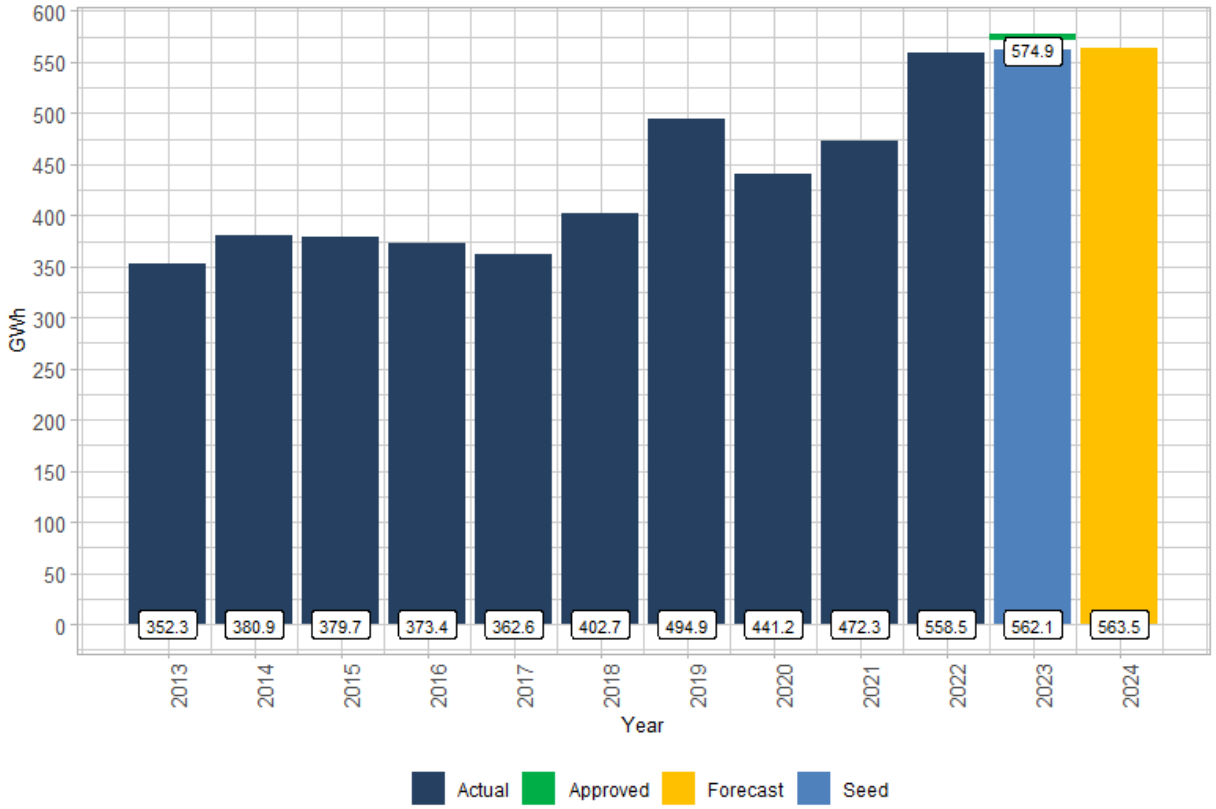
3.4.4 Industrial

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 five 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 76 percent (32 of 42) of the surveys sent out. The responding customers represent approximately 91 percent of the total industrial load.

As shown in Figure 3-7 below, after-savings industrial load is forecast to increase by 1.4 GWh in 2024F when compared to 2023S and decrease by 11.4 GWh in 2024F compared to 2023 Approved.

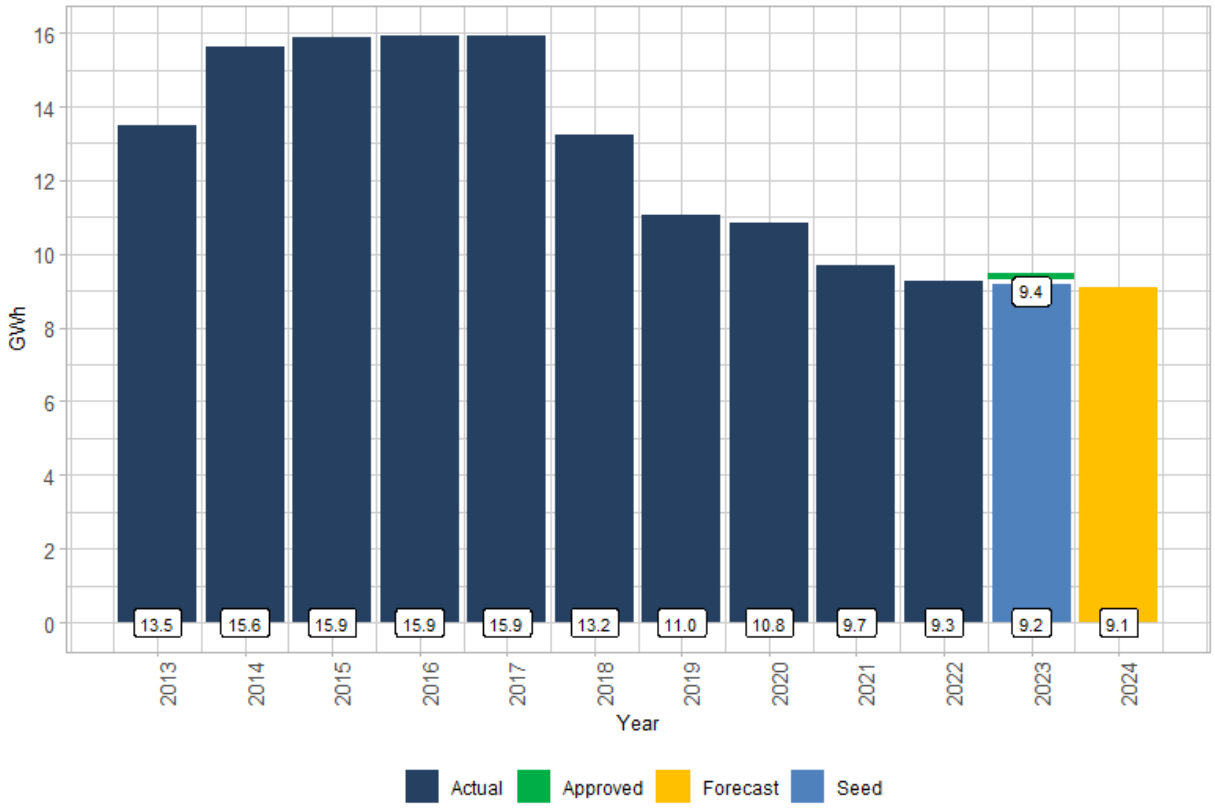
Figure 3-7: After-Savings Industrial Load (GWh)



3.4.5 Lighting

Due to the implementation of LED streetlights, the lighting load has been declining since 2017. FBC used the 2022 actuals as the forecast for this load and then reduced it by DSM savings. As shown in Figure 3-8 below, after-savings lighting load is forecast to decrease by 0.1 GWh in 2024F from 2023S and decrease by 0.3 GWh when compared to 2023 Approved.

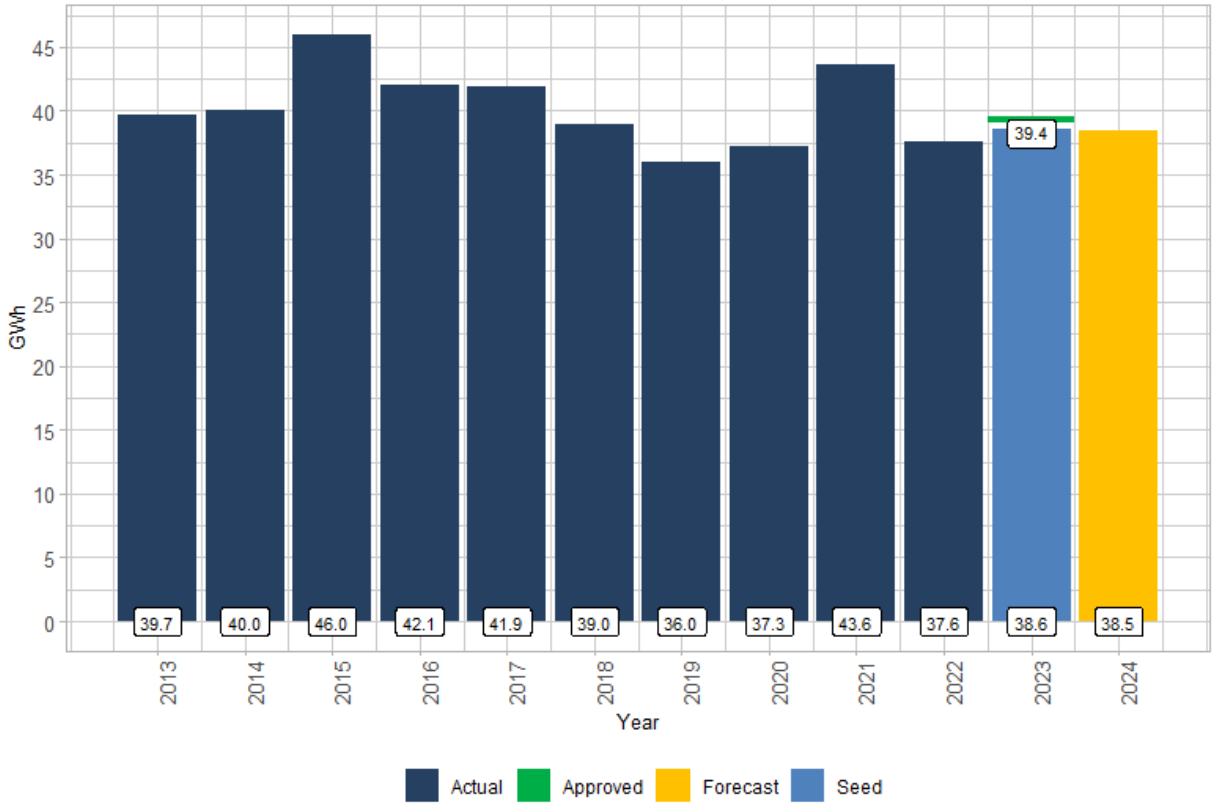
Figure 3-8: After-Savings Lighting Load (GWh)



3.4.6 Irrigation

Due to the variability in the load in the recent historical data, FBC used a five-year average as the forecast for the irrigation load. As shown in Figure 3-9 below, after-savings irrigation load is forecast to decrease by 0.1 GWh from 2023S to 2024F and decrease by 0.9 GWh in 2024F when compared to 2023 Approved.

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



3.4.7 Losses and Company Use

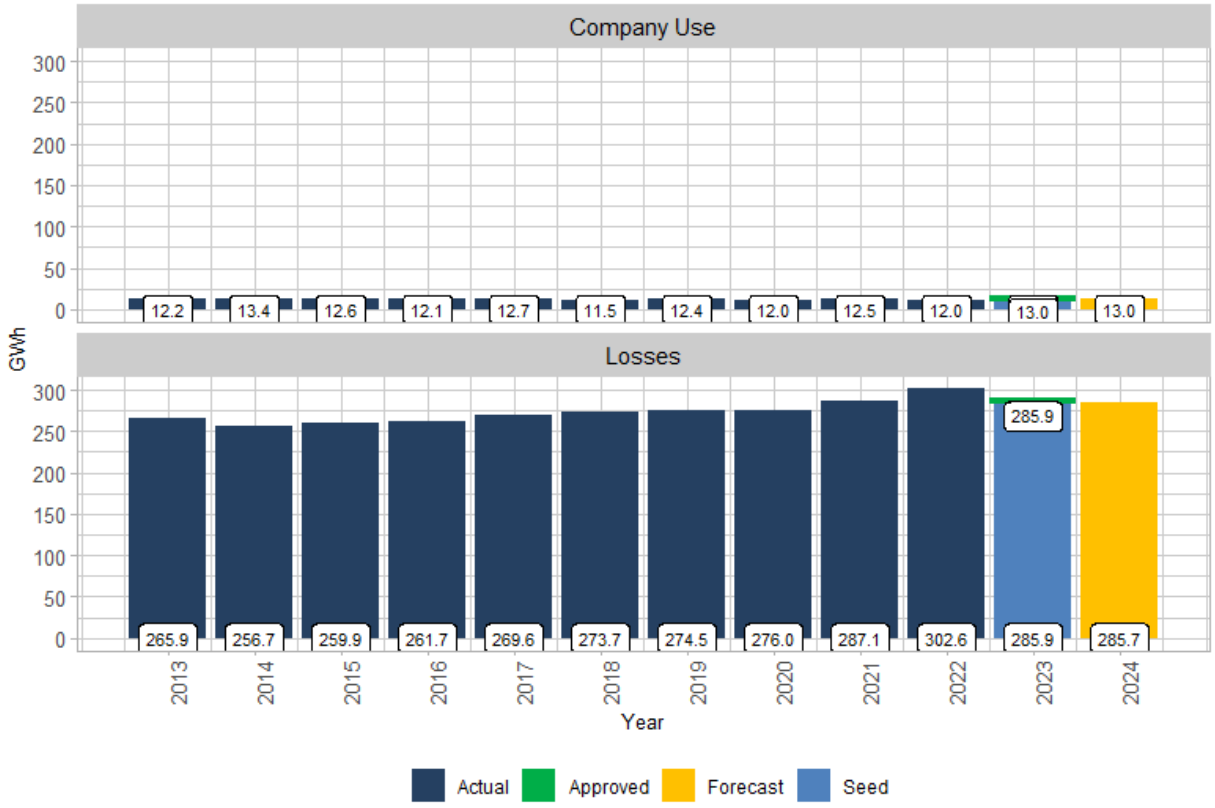
FBC conducted a Losses Study in 2019[10] and, consistent with that study, has assumed a loss rate of 7.6 percent of gross load (excluding company use). System losses consist of:

- 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 3-10 below, after-savings load losses are forecast to remain constant in 2024F because the gross load is forecast to be relatively stable when compared to 2023S. When compared to 2023 Approved, the 2024F after-savings load losses are forecast to decrease by 0.2 GWh due to decreased load. FBC has separated company use in the graph below, which is forecast at 13 GWh per year in 2024F, consistent with 2023S.

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

Figure 3-10: Normalized After-Savings Load Losses (GWh)



3.4.8 Peak Demand

The peak demand forecast is produced using the 10-year average of historical peaks, including peaks from the June 2021 “heat dome” event. 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.

Figures 3-11 and 3-12 below provide the historical winter peaks and summer peaks, respectively, from 2013 to 2022, as well as the estimates for 2023S and 2024F. To illustrate the non-weather-related growth in both winter and summer peaks over the last 10 years, the historical winter and summer peaks shown between 2013 and 2022 in Figures 3-11 and 3-12 below are weather-normalized and after-savings.

Furthermore, the peaks shown in both figures below are seasonal, i.e., the winter peak can fall in any month between November of the current year and February of the following year, and the summer peak can fall in any month between June and August.

Figure 3-11: After-Savings Winter Peaks (MW)

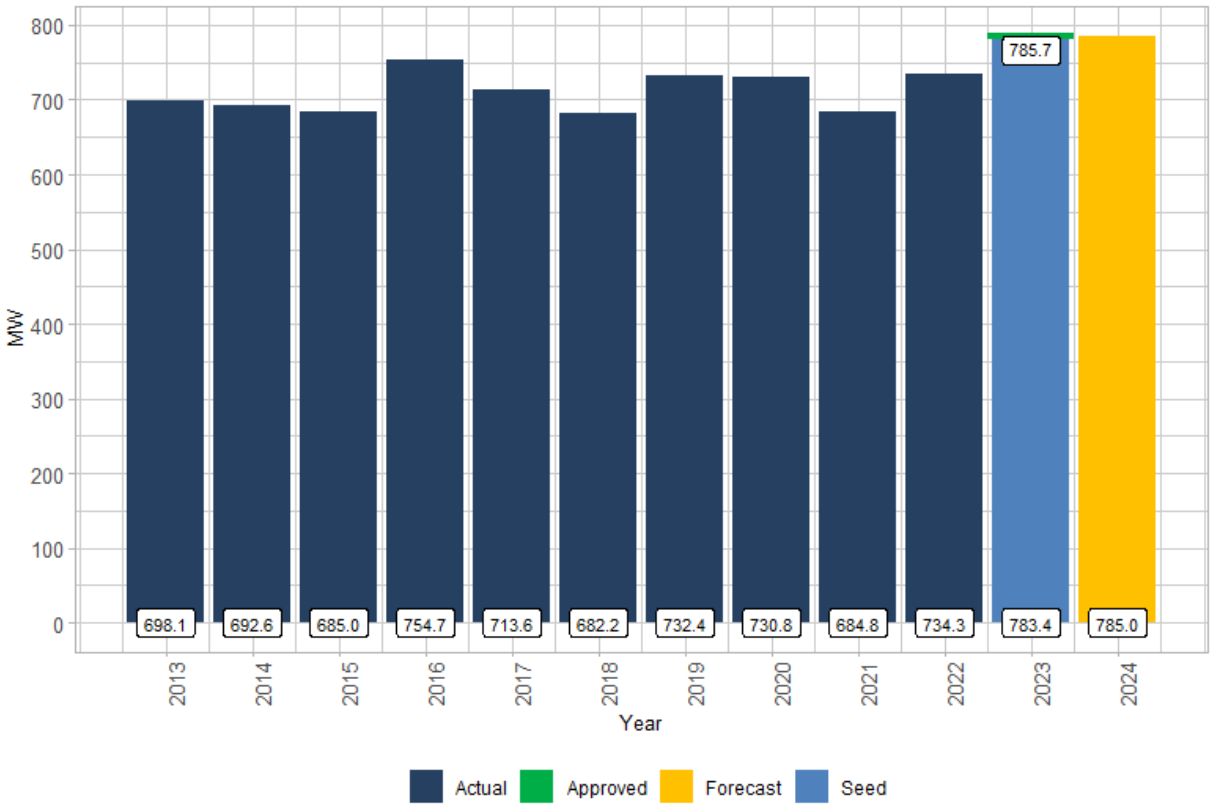
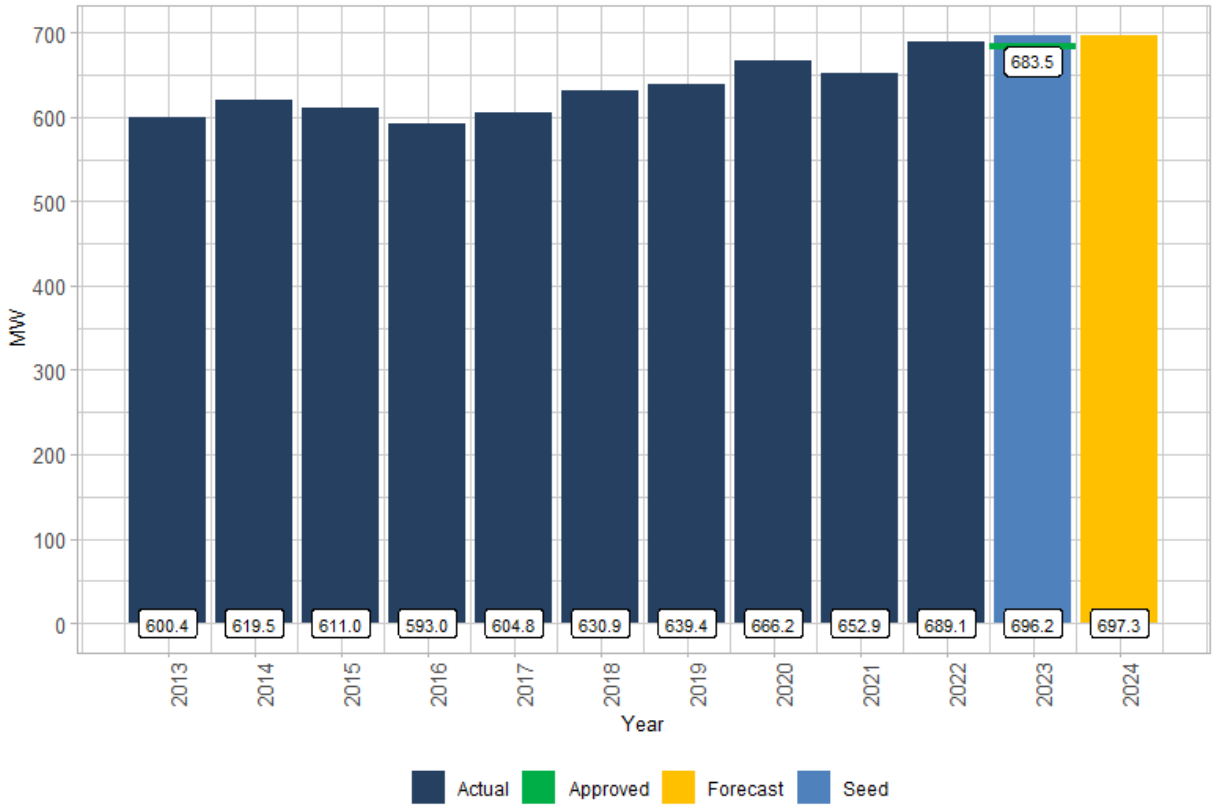


Figure 3-12: After-Savings Summer Peaks (MW)



3.5 CUSTOMER FORECAST

Table 3-3 shows the actual and forecast year-end customer counts by rate class. The residential and commercial customer counts are forecast using the methods described in Sections 3.4.1 and 3.4.2. Industrial customers are forecast based on information on expected new loads provided by key account managers. The lighting customer forecast is prepared using a five-year regression of year-end customer counts. Wholesale and irrigation customer counts are assumed to remain at 2022 levels.

Overall, for 2024F, FBC is forecasting customer growth of 1.5 percent compared to 2023S and growth of 0.7 percent compared to 2023 Approved.

Table 3-3: Customer Forecast[11]

Line No.	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
1	Residential	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,131	131,323	133,291
2	Commercial	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,773	16,930	17,290
3	Wholesale	6	6	6	6	6	6	6	6	6	6	6	6
4	Industrial	47	49	50	50	50	52	51	43	42	42	42	42
5	Lighting	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,380	1,357	1,330
6	Irrigation	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103	1,103
7	**Total**	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,435	150,761	153,063

3.6 RATE SCHEDULE 96 EV DCFC SERVICE FORECAST

On July 14, 2021, the BCUC issued Order G-215-21, which concluded that FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR and approved flow-through treatment for the cost of service associated with the charging stations. By Order G-341-21 dated November 24, 2021, the BCUC approved the depreciation rate for the EV charging stations, and the inclusion of related revenues and expenses in FBC's regulated accounts. Following FBC's clarification on November 29, 2021 for the electricity input cost as directed in Decision and Order G-341-21, the BCUC approved the RS 96 rates on a permanent basis, by Order G-350-21 dated November 30, 2021, which include a time-based levelized rate[12] of $0.26 per minute and $0.54 per minute for FBC's 50 kW and 100 kW EV DCFC stations, respectively. FBC currently has a total of 42 EV DCFC stations in service across 22 sites and no additional stations are planned for 2023 or 2024.

As part of the Annual Review for 2022 Rates Decision and Order G-347-21[13], FBC was directed to:

- Provide an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period in future Annual Review filings.

Table 3-4 below provides the 2018 to 2022 Actual (i.e., previous fiscal years), 2023 Projected, and 2024 Forecast charging minutes and the resulting RS 96 revenues. Consistent with the approach presented in FBC's Revised and Updated EV DCFC Service Application dated September 30, 2020, the 2023 Projected and 2024 Forecast of charging minutes were determined based on the growth rates for ZEV sales targeted in the *BC ZEV Act*. These targets are 10 percent of ZEV sales by 2025, 30 percent by 2030, and 100 percent by 2040.[14]

[11] Direct customers only, i.e., excludes indirect wholesales customer counts.
[12] Including 15 percent transaction fees from FBC's EV DCFC vendor (i.e., AddEnergie, operator of the FLO EV charging network).
[13] Page 32.
[14] FBC's Revised and Updated EV DCFC Application, BCUC IR1 8.4 and CEC IR1 8.2. Additionally, as discussed in the RS 96 Assessment Report dated December 29, 2022, for forecasting purposes, FBC assumed the growth rates remain the same but are delayed by one year due to the COVID-19 pandemic.

It can be seen from Table 3-4 below that since the inception of FBC's charging stations (i.e., 50 kW in 2018 and 100 kW in 2021), the utilization rate has continued to grow, including in 2020 and 2021 when travel restrictions were in place due to the COVID-19 pandemic. Table 3-4 below also shows that there was a material increase in charging minutes from 2021 to 2022, which coincides with the ending of the aforementioned travel restrictions. FBC is expecting the upward trend will continue into 2024 with the growing number of electric vehicles available in the market. The upward trend that FBC is seeing with its EV DCFC service is consistent with the growth rates developed based on the ZEV sales targets used for the purpose of forecasting the charging minutes.

Table 3-4: FBC RS 96 EV DCFC Forecast

Line No.	Description	Actual 2018	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Projected 2023	Forecast 2024
1	RS 96 Charging Minutes							
2	50 kW	15,309	94,386	110,504	229,342	410,783	584,194	782,820
3	100 kW	-	-	-	16,539	54,933	111,234	149,053
4	Total (Minutes)	15,309	94,386	110,504	245,881	465,716	695,428	931,874
5								
6	RS 96 Revenue, excl. 15% fee ($ millions)	$ 0.004	$ 0.024	$ 0.028	$ 0.058	$ 0.116	$ 0.180	$ 0.241

Table 3-5 below provides the cost of FBC's EV DCFC service for 2022 Actual, 2023 Projected and 2024 Forecast, including the RS 96 revenues shown in Table 3-4 above, and the prior years' surplus from 2018 to 2021.

FBC is currently forecasting a cumulative deficiency of $0.932 million from 2018 to 2024, including the 2024 forecast costs and revenue. FBC notes that the current RS 96 rates are set on a levelized basis which are designed to fully recover the forecast cost of service of the charging stations over the life of the stations, as such, deficiencies are expected in the early years of the service offering. Also contributing to the cumulative deficiency to date is the impact of the COVID-19 pandemic from 2019 to 2021 on the utilization of FBC's charging stations. As mentioned above, there has been a significant increase in the utilization of FBC's charging stations since 2022 and FBC expects the growth will continue. Furthermore, consistent with the approach in the Annual Review for 2023 Rates, FBC does not forecast revenue from the sale of carbon credits for future years due to the uncertainty in the timing of the credit validation as well as the market pricing. As such, FBC is not forecasting any carbon credit revenues in 2024. Please refer to Section 5.8 for further discussion of the carbon credits associated with FBC's EV DCFC stations which are recorded as Other Revenue. FBC expects the monetization of carbon credits will continue, which should help to reduce the overall deficiency in the future.

Table 3-5: EV DCFC Stations Costs and Revenues for 2022 Actual, 2023 Projected, and 2024 Forecast ($ millions)

Line No.	Description	Actual 2022	Projected 2023	Forecast 2024	Cumulative
1	Cost of Energy	0.136	0.177	0.197	
2	O&M	0.213	0.181	0.310	
3	Depreciation	0.456	0.551	0.593	
4	Amortization of CIAC	(0.190)	(0.236)	(0.249)	
5	Other Revenue - Carbon Credits	(0.744)	(0.544)	-	
6	Income Tax	(0.007)	0.048	0.132	
7	Earned Return	0.170	0.192	0.200	
8	Total Cost of Service	0.035	0.370	1.183	
9	RS 96 Revenue	(0.116)	(0.180)	(0.241)	
10	(Surplus) / Deficiency	(0.081)	0.190	0.942	1.050
11	Prior Year 2018-2021 (Surplus)/Deficiency				(0.119)
12	Cumulative (Surplus) / Deficiency				0.932

The RS 96 revenue (i.e., Line 9 of Table 3-5 above) is part of FBC's commercial sales revenue as presented in Section 3.7 below. Please also refer to Section 6.3.4 for a discussion of the forecast O&M expenses and Section 7.2.2 for a discussion of the forecast capital expenditures for the EV DCFC stations. Once the capital expenditures are included in rate base, they impact the depreciation, amortization of CIAC, income tax and earned return related to the EV DCFC stations that are shown in Table 3-5 above.

As directed by Order G-341-21, FBC filed a detailed assessment of the EV DCFC service on December 29, 2022 (RS 96 Assessment Report), which was accepted by the BCUC on June 19, 2023 by Letter L-33-23. As part of the RS 96 Assessment Report, FBC committed to providing an updated RS 96 Assessment Report by December 31, 2023, if an application for energy-based rates is not filed with the BCUC prior to this date.

3.7 REVENUE FORECAST

The forecast of revenues has been developed by applying approved 2023 rates to the forecast billing determinants for each customer class. Table 3-6 below summarizes the 2023 Approved, 2023 Projected and 2024 Forecast sales revenue. The commercial sales revenue shown in Table 3-6 below also includes the revenue from FBC's RS 96 EV DCFC stations discussed in Section 3.6.

Table 3-6: Forecast Sales Revenue at Approved Rates ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Residential	$ 205.734	$ 208.939	$ 206.007
2	Commercial	110.490	111.741	110.808
3	Wholesale	54.100	55.279	55.574
4	Industrial	49.759	49.797	49.800
5	Lighting	2.295	2.298	2.221
6	Irrigation	3.695	3.666	3.967
7	Total	$ 426.073	$ 431.720	$ 428.377

When comparing the 2023 Projected to 2023 Approved, there is an increase in revenue of $5.647 million, primarily due to increases from the residential customer class, followed by increases from the commercial and wholesale customer classes.

For 2024, despite FBC forecasting a small reduction in net load of approximately 1 GWh (reduction in gross load of 2 GWh), FBC is forecasting an increase in revenue of $2.304 million when compared to 2023 Approved. The increase in revenue between 2024 Forecast and 2023 Approved is primarily due to the forecast increase in load from the wholesale customers as well as a forecast increase in residential and commercial customer counts (resulting in a small increase in the fixed monthly/bi-monthly customer charge). These increases are partially offset by reduced revenue from variable charges (i.e., $ per GWh) due to the forecast reduction in load from residential, industrial, and irrigation customers.

Variances between the revenue forecast in this section and the actual revenues realized are captured in the Flow-through deferral account.

3.8 SUMMARY

FBC is forecasting a decrease in consumption in 2024 compared to 2023 Approved. The 2024F gross load is forecast to be approximately 3,773 GWh, which is a 2 GWh decrease compared to the 2023 Approved gross load. Although the forecast load is decreasing in 2024, FBC is forecasting 2024 revenue to be $428.377 million, which is an increase of $2.304 million from 2023 Approved. This increase in revenue is primarily due to the forecast increase in load from the wholesale customers as well as an increase in residential and commercial customer counts (resulting in a small increase in the fixed monthly/bi-monthly customer charge), which is partially offset by reductions in load from residential, industrial, and irrigation customers.

4. POWER SUPPLY

4.1 INTRODUCTION AND OVERVIEW

This section includes a review of the 2023 Projected and 2024 Forecast 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 2024 Forecast power supply cost of $193.532 million represents an increase of 6.3 percent or $11.427 million compared to the 2023 Approved cost of $182.105 million. The increase in 2024 Forecast power supply cost is driven primarily by the increase in PPE, although wheeling and water fee expenses have increased as well. The increase in the 2024 Forecast PPE is primarily the result of increased purchase rates for power. The 2024 Forecast wheeling expense has increased as a result of rates, partially offset by lower use. The 2024 Forecast water fee expense has increased compared to 2023 Approved as a result of rates and use.

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 2023	Projected 2023	Forecast 2024
1	Power Purchase Expense	$ 163.575	$ 170.873	$ 173.694
2	Wheeling Expense	$ 6.987	$ 7.294	$ 7.324
3	Water Fees	$ 11.543	$ 12.433	$ 12.513
4	Total Power Supply Cost	$ 182.105	$ 190.600	$ 193.532
5				
6	Gross Load (GWh)	3,775	3,813	3,773

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:

1. 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;
2. 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);

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

4. 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);

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

6. A number of market purchase arrangements.

4.3 PORTFOLIO OPTIMIZATION

The primary objectives of FBC's power supply portfolio planning are:

1. to ensure that the Company has sufficient firm resources to meet expected load requirements;

2. to ensure the availability of cost-effective reliable power for FBC's customers;

3. to prudently manage exposure to the cost and availability of market power supplies; and

4. 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 most of its forecast annual energy and capacity requirements. FBC's long-term, firm resources are capable of meeting FBC's forecast capacity requirements with the exception of June and a small number of hours during July. Consistent with the capacity self-sufficiency policy in FBC's 2021 Long Term Electric Resource Plan (LTERP), FBC will procure forward market blocks to cover these shortfalls on a planning basis. In addition, FBC is now forecasting small energy shortfalls emerging in November and December starting in 2024. Consistent with the accepted 2023/24 Annual Electric Contracting Plan (AECP), FBC will purchase winter energy blocks to address tightening winter energy supply and mitigate exposure to potential extreme spot market prices, should load exceed expected levels.

FBC's contracted resources, in particular the BC Hydro PPA, provide the Company some flexibility to participate in the market when conditions are favourable to mitigate the cost of holding these firm resources. However, over the past several years, the regional electricity market has been in a state of consistently higher prices compared to recent historical levels. This is due to several factors that include resource adequacy concerns, increased natural gas prices, and increased severe weather events. This change in the market price environment has resulted in little opportunity to displace Tranche 1, nominated PPA purchases on a forward basis.

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 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 made under the Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex dated February 17, 2015, and accepted by Order E-10-15.

4.4 FBC 2023/24 ANNUAL ELECTRIC CONTRACTING PLAN

On April 28, 2023, FBC filed its 2023/24 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, 2023 and ending September 30, 2024, 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 could be more or less, depending on system conditions.[15] 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 forecasts of PPE for the remainder of 2023 and for 2024 are based on the plan detailed in the 2023/24 AECP, which was accepted by the BCUC on June 1, 2023, by Letter L-24-23.[16]

The AECP identified FBC's intention to make its annual energy nomination under the PPA for the 2023/24 contract year equal to 929 GWh, less any firm market contracts that FBC could enter, as described in Section 5 of the 2023/24 AECP. Prior to the June 30, 2023 nomination deadline, FBC updated its forecast load and resource balance for the 2023/24 contract year and submitted a nomination of 929 GWh.

4.5 2023 PROJECTED POWER PURCHASE EXPENSE

As shown in Table 4-2 below, FBC's 2023 Projected gross load (after taking into account demand side management and other customer savings) is expected to be 38 GWh above the 2023 Approved value, and PPE is projected to be above the 2023 Approved value by $7.298 million. The rise in 2023 Projected PPE is primarily due to increased Market and Contracted Purchase expense as a result of increased volumes and rates.

[15] 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.

[16] The AECP was filed confidentially. The non-confidential Executive Summary is attached to Letter L-24-23.

A majority of the increase in volume and cost was due to FBC purchasing wholesale market power from the spot market, at rates economic to the PPA during the first six months of the year to reduce required purchases above the BC Hydro PPA Nomination. In contrast, there was a relatively small amount of wholesale market contracts included in the 2023 Approved figures, as forward market contract prices resulted in little opportunity to displace PPA on a forward basis. In addition, FBC purchased forward market blocks to cover projected capacity shortfalls in June 2023 and reduce exposure to Tranche 2 energy under the PPA with BC Hydro. Also included in the Projected 2023 expense are planned wholesale market purchases in November and December 2023, consistent with the strategy presented in the 2023/24 AECP.

While forecast market savings included in the 2023 Approved[17] did materialize during the first six months of the year, FBC has not included any forecast savings for the remainder of 2023 within the Projected PPE. This is due to the current forward market price premium compared to rates for PPA purchases for the remainder of 2023.

Partially offsetting the increase in PPE is a reduction to the Waneta Expansion Expense due to increased forecast surplus sales revenue under the RCA and CEPSA.

Table 4-2: 2023 Power Purchase Expense ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Difference
1	Brilliant	$ 44.050	$ 44.048	$ (0.002)
2	BC Hydro PPA	71.302	70.702	(0.600)
3	Waneta Expansion	41.834	38.351	(3.483)
4	Market and Contracted Purchases	6.326	18.624	12.297
6	Independent Power Producers	0.062	0.195	0.133
7	Self-Generators	-	0.044	0.044
8	CPA Balancing Pool	(0.000)	(1.570)	(1.570)
9	Transmission Service Loss Recoveries	-	-	-
10	Special and Accounting Adjustments	-	0.479	0.479
11	Total	$ 163.575	$ 170.873	$ 7.298
12				
13	Gross Load (GWh)	3,775	3,813	38

4.6 2024 FORECAST POWER PURCHASE EXPENSE

As shown in Table 4-3 below, the 2024 Forecast PPE is $2.821 million above the 2023 Projected. The forecast increase from $170.873 million in 2023 to $173.694 million in 2024 is primarily a result of an increase in BC Hydro PPA expenses and escalation of Waneta Expansion rates. This is partially offset by a decrease in Market and Contracted Purchases due to volume. FBC is increasingly reliant on energy supplied by BC Hydro as it is generally more cost effective than the market during most times of the year. However, FBC also requires wholesale market purchases

[17] 2023 Approved included $7.000 million in potential real-time opportunities, including $3.500 million forecast for the first six months. FBC was able to exceed the $3.500 million during the first six months of 2023 but does not expect any further savings for the remainder of 2023.

to address supply gaps and reduce exposure to potentially extreme market prices, beyond what can be supplied by the PPA. Escalations to the Brilliant contract rates are also contributing to increased costs.

Table 4-3 below shows a comparison of the 2023 Projected and 2024 Forecast PPE. Reasons for significant variances from the 2023 Projected PPE are discussed below.

Table 4-3: 2024 Forecast Power Purchase Expense ($ millions)

Line No.	Description	Projected 2023	Forecast 2024	Difference
1	Brilliant	$ 44.048	$ 44.433	$ 0.385
2	BC Hydro PPA	$ 70.702	71.680	0.978
3	Waneta Expansion	$ 38.351	40.365	2.014
4	Market and Contracted Purchases	$ 18.624	16.972	(1.652)
5	Independent Power Producers	$ 0.195	0.245	0.050
6	Self-Generators	$ 0.044	-	(0.044)
7	CPA Balancing Pool	$ (1.570)	0.000	1.570
8	Transmission Service Loss Recoveries	-	-	-
9	Special and Accounting Adjustments	$ 0.479	-	(0.479)
10	Total	$ 170.873	$ 173.694	$ 2.821
11				
12	Gross Load (GWh)	3,813	3,773	(40)

4.6.1 Brilliant

Brilliant expense is forecast to increase in 2024 by $0.385 million compared to 2023 Projected due to increased 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.

4.6.2 BC Hydro PPA

BC Hydro PPA expense is forecast to increase in 2024 by $0.978 million compared to the 2023 Projected expense. The drivers of the variance are a higher purchased volume (62 GWh), which increases the expense by $4.046 million, offset by a lower average purchase rate for BC Hydro PPA,[18] which accounts for a decrease of $0.068 million, for a total increase of $3.978 million. FBC has decreased its 2024 Forecast of PPA expense by $3.000 million in savings to account for potential real-time opportunities to displace PPA purchases with lower cost market purchases. The 2023 Projected BC Hydro expense does not include any adjustment for potential real-time opportunities for the remainder of 2023. This results in a variance between 2023 Projected and 2024 Forecast of $0.978 million[19], as shown in Table 4-3. Actual market savings for the remainder of 2023 and 2024 may be higher or lower and will depend on system and market conditions at

[18] A higher PPA nomination for the 2023/24 contract year results in less penalty charges from energy taken over and above the PPA nomination and a lower average BC Hydro PPA purchase rate.

[19] $0.978 million is calculated as follows: Total increase of $3.978 million less the $3.000 million 2024 Forecast real-time opportunities.

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.

4.6.3 Waneta Expansion

The $2.014 million increase in Waneta Expansion expense is due to the 2.1 percent annual fixed escalation of WAX CAPA rates, and a $0.549 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 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. CEPSA revenue is forecast using the average monthly sales revenue from the past three years. The forecast of surplus capacity sales revenue in 2024, which is included in Line 3 of Table 4-3, is approximately $13.636 million.

4.6.4 Market and Contracted Purchases

The $1.652 million decrease in Market and Contracted Purchases forecast for 2024 is a result of reduced volume when compared to 2023 Projected. Market and Contracted Purchases for 2023 Projected include fixed price contracted purchases, year to date real-time market purchases and forecast purchases in November and December 2023 at forward market rates. Market purchases included in the 2024 Forecast include fixed price contracted purchases, as well as forecast wholesale market purchases at current forward market rates to cover energy requirements in January, February, November and December, and capacity shortfalls in June and July 2024. Forecast real-time market purchases for Rate Schedule 37[20] load are also included. As 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.

4.6.5 CPA Balancing Pool

The CPA Balancing Pool represents timing differences in entitlement energy storage under the CPA and is used to manage fluctuations in load and resource availability, or to take advantage of market opportunities. In the 2023 Projected PPE, FBC has stored a net total of 31 GWh of entitlement energy, valued at $1.570 million. For the 2024 Forecast, and consistent with past practice, FBC does not forecast any net use or storage of entitlement energy.

4.7 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

[20] RS 37 is large commercial stand-by service, which is an on-demand back-up and maintenance service provided to self-generating customers. This service is provided to the customer at an hourly market-based rate, reflective of FBC's cost of supply. FBC procures this supply on a real-time basis because there is little certainty as to when customers will use this service. Forecast RS 37 load for 2024 is 15 GWh or 0.4 percent of total gross load.

forecast (included in Tables 4-2 and 4-3, Line 8), and also includes loss recovery as a firm resource. Because the recoveries are delivered physically, there is no associated cost or revenue. Table 4-4 shows the 2023 and 2024 loss recoveries.

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

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Loss Recoveries	12	12	12

4.8 WHEELING EXPENSE

Wheeling expense includes wheeling service provided by BC Hydro under the Amended and Restated Wheeling Agreement (ARWA) and Open Access Transmission Tariff (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 RS 3817.

Wheeling expense is forecast using the same method as in the Annual Review for 2023 Rates.[21] Table 4-5 below shows FBC's Wheeling Expense for 2023 and 2024.

Table 4-5: Wheeling Expense ($ millions)

Line No.	Description		Approved 2023	Projected 2023	Forecast 2024
1	Wheeling Nomination (MW Months)				
2	Okanagan Point of Interconnection		2,670	2,670	2,595
3	Creston		420	420	450
4					
5	Wheeling Expense				
6	Okanagan Point of Interconnection	$	5.555	5.786	5.813
7	Creston		0.570	0.593	0.658
8	Other		0.863	0.914	0.854
9	Total Wheeling Expense	$	6.987	7.294	7.324

Total 2023 Projected wheeling expense is $0.307 million greater than 2023 Approved. The 2023 Projected ARWA costs are $6.380 million (Lines 6 and 7 in the table above), a $0.255 million increase when compared to 2023 Approved, which is a result of higher than expected BC-CPI and therefore ARWA rates. 2023 Projected Teck and OATT wheeling costs are $0.914 million (Line 8 above), which is $0.051 greater than 2023 Approved. This is mainly due to increased use of OATT wheeling.

[21] ARWA expense is forecast using known volumes and prior year's rates escalated by estimated BC-CPI. Teck wheeling is forecast based on the previous year's costs and escalated by 2 percent annually per contract. OATT wheeling costs are estimated using an average of prior years' expenses.

2024 Forecast wheeling expense is $0.030 million higher than 2023 Projected. This is a result of increased rates. FBC decreased the ARWA Okanagan wheeling nomination to 2,595 MW months in 2024 from 2,670 MW months in 2023. ARWA rates are forecast to increase on October 1 of both 2023 and 2024 based on forecast BC-CPI, as is the Teck wheeling rate as a result of a letter agreement made between Teck and FBC.

4.9 WATER FEES

Water fees are based on FBC's entitlement usage in the previous year and the rate increases are indexed to BC-CPI.

As shown in Table 4-6 below, the 2024 Forecast water fees are increasing by $0.080 million from the 2023 Projected due to increased rates.

Table 4-6: Water Fees ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Plant Entitlement in Previous Year (GWh)	1,571	1,585	1,561
2				
3	Water Fees	$ 11.543	$ 12.433	$ 12.513

4.10 SUMMARY

FBC's forecast of PPE is based on FBC's firm resources in place at the time of filing, as well as forecast market purchases, and is consistent with the 2023/24 AECP. Any variances in the power supply cost, including any decreases in PPE 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.[22]

FBC is forecasting Other Revenue for 2024 to be $0.149 million lower than 2023 Approved, primarily due to lower Contract Revenue and Transmission Access Revenue.

2023 Projected Other Revenue is $0.622 million higher than 2023 Approved. The main drivers of this increase are the sales of carbon credits related to Electric Vehicle (EV) Direct Current Fast Charging (DCFC) stations, as well as higher Contract Revenue.

Table 5-1: Other Revenue ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Apparatus and Facilities Rental	$ 6.108	$ 6.108	$ 6.199
2	Contract Revenue	2.367	2.591	2.260
3	Transmission Access Revenue	1.834	1.716	1.723
4	Interest Income	0.030	0.035	0.037
5	Late Payment Charges	0.994	0.961	0.962
6	Connection Charges	0.553	0.553	0.561
7	EV Stations Carbon Credits	-	0.544	-
8	Other Recoveries	0.355	0.355	0.351
9	Total Other Revenue	$ 12.241	$ 12.863	$ 12.092

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. There are no variances projected in 2023 compared to 2023 Approved, as final amounts have yet to be calculated since the majority of invoices are issued during the third quarter of the year. The 2024 Forecast is higher than 2023 Approved due to expected escalations in unit rental rates for continuing contracts.

[22] Variances in Other Revenue associated with Electric Vehicle (EV) stations carbon credits are treated as flow-through, as EV Direct Current Fast Charging (DCFC) stations are prescribed undertakings under section 5 of the GGRR and the cost of service associated with EV DCFC stations is subject to flow-through treatment.

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, fluctuates 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[23] and earn a transfer price profit revenue. Revenues may fluctuate from year to year depending on customer requirements.

The 2023 Projected revenue is higher than 2023 Approved due to higher expected transfer price profit revenue on facilities operated and maintained by FPHI, based on amounts earned so far in 2023. The 2024 Forecast is slightly lower than 2023 Approved due to less customer requirements expected as a result of a higher level of work performed in the last few years for one customer, which is expected to decrease the need for non-routine work.

5.4 TRANSMISSION ACCESS REVENUE

Transmission Access Revenue represents charges to customers for transmitting power over the FBC system. The 2023 Projected revenue is lower than 2023 Approved due to a lower nomination than originally forecast for one customer. The 2024 Forecast is also lower than 2023 Approved due to lower nominations expected.

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 outstanding or cash balances on hand attracting interest; as a result, although higher interest rates are available, no significant changes in interest income are expected in 2023 Projected or the 2024 Forecast.

5.6 LATE PAYMENT CHARGES

As explained in the Annual Review for 2023 Rates, Late Payment Charges were historically forecast based on the average of the most recent three years of actual Late Payment Charges earned. However, due to a number of factors in the most recent years, including the COVID-19 pandemic and FBC's implementation of customer relief measures, the actual amounts collected have fluctuated significantly from year to year. As these fluctuations would still be present in the most recent three years of actual results (i.e., 2020, 2021 and 2022), FBC has utilized the same

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

approach used to calculate the 2023 Approved Late Payment Charges in the 2023 Annual Review. Accordingly, the 2024 Forecast for Late Payment Charges is calculated based on the average of 2022 Actual Late Payment Charges of $0.962 million and 2023 Projected of $0.961 million. This results in a forecast decrease in Late Payment Charges of $0.032 million compared to 2023 Approved and is generally consistent with the 2023 Projected amount.

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 2023 Projected is expected to be consistent with 2023 Approved based on amounts charged so far in 2023. The 2024 Forecast is expected to be slightly higher than 2023 Approved based on customer growth and forecast customer reconnections.

5.8 CLEAN GROWTH INITIATIVE – EV DCFC STATIONS CARBON CREDITS

As discussed in Section 3.6, FBC's EV DCFC stations are prescribed undertakings under Section 5 of the GGRR[24] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. Please refer to Table 3-5 in Section 3.6 for a summary of EV DCFC station costs and revenues from 2022 Actual to 2024 Forecast.

The sale of the carbon credits related to EV DCFC stations[25] earned under the Renewable Low Carbon Fuel Requirements Regulation (RLCFRR) is recorded as Other Revenue in FBC's regulated accounts, which is embedded in the rate design of the EV DCFC stations.

FBC anticipates that 1,210 credits from the 2021 compliance period, with an approximate value of $0.544 million,[26] will be monetized prior to the end of 2023 and has therefore included this amount in 2023 Projected Other Revenue. Since FBC did not forecast any monetization of carbon credits in the 2023 Approved amount as part of the Annual Review for 2023 Rates, the variance between the 2023 Projected amount of $0.544 million and the 2023 Approved amount of zero will be captured in the Flow-through deferral account and returned to customers in 2024 rates. Consistent with the approach described in the Annual Review for 2023 Rates, FBC does not forecast revenue from the sale of credits for future years due to the uncertainty in the timing of the credit validation as well as the market pricing. As such, FBC is not forecasting any carbon credit revenues in 2024. As noted above, the cost of service associated with EV DCFC stations is subject to flow-through treatment. Therefore, any variances between actual and forecast sales

[24] Order G-215-21 dated July 14, 2021.

[25] Includes both public charging stations owned by FBC as well as public stations owned by other entities (metered commercial accounts) as discussed in Exhibit B-6 of FBC's Annual Review for 2022 Rates, BCSEA IR1 4.3. Beginning in 2022, FBC is only permitted to claim credits for charging stations owned by FBC. FBC does not currently claim credits for non-public EV charging services for either commercial or residential customers.

[26] 1,210 credits x $449.20 average Q1-2023 sales price (source: https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/renewable-low-carbon-fuels/credits-market)

of carbon credits will be captured in the Flow-through deferral account and returned to customers in the subsequent year.

5.9 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 AMI radio-off meter read fees. There are no variances expected in 2023 Projected compared to 2023 Approved based on amounts recognized to date. The 2024 Forecast is expected to be slightly lower than 2023 Approved due to an expected reduction in AMI radio-off meter read fees resulting from a lower volume of customers choosing the radio-off option.

5.10 SUMMARY

FBC has forecast the Other Revenue components for 2024 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, with the exception of EV DCFC stations carbon credits, are shared with customers through the earnings sharing mechanism.

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 certain items that are forecast outside the formula on an annual basis.

In 2024, the formula O&M is $72.823 million, representing a 3.6 percent increase from the 2023 formula O&M, primarily due to the formula drivers. O&M expenses forecast outside the formula for 2024 are $1.499 million, representing a 36.2 percent decrease from the amount approved for 2023. Overall, the 2024 Forecast gross O&M expense is $74.322 million, which is an increase of approximately 2.3 percent from the 2023 Approved level.

The components of 2024 O&M expense are shown in Table 6-1 below.

Table 6-1: 2024 O&M Expense ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Formula O&M	$ 70.318	$ 70.318	$ 72.823	Section 11, Schedule 20, Line 8
2	Forecast O&M	2.349	2.361	1.499	Section 11, Schedule 20, Line 20
3	Total Gross O&M	72.667	72.679	74.322	Line 1 + Line 2
4	Capitalized Overhead	(10.900)	(10.900)	(11.148)	Section 11, Schedule 20, Line 23
5	Net O&M	$ 61.767	$ 61.779	$ 63.174	Line 3 + Line 4

In the sections below, FBC provides further details on its formula and forecast O&M expenses for 2024. Additionally, in compliance with the BCUC's directive in the MRP Decision,[27] FBC provides information related to its System Operations, Integrity and Security expenditures in Subsection 6.2.1.

6.2 FORMULA O&M EXPENSE

The formula-driven portion of 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 then multiplied by 75 percent of the forecast growth in average customers, resulting in the current year inflation-indexed O&M before true-up. A true-up of formula O&M based on actual average customers from two years prior is then added to the current year inflation-indexed O&M.

As calculated in Section 2, the 2024 inflation based on prior year's BC-CPI and BC-AWE, less the productivity improvement factor, is 3.580 percent.

For 2024, the annual operating and maintenance expense under the formula is calculated as:

[27] MRP Decision, p. 118.

2023 Approved formula UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)] + 2022 Formula O&M True-up

Table 6-2 below shows the calculation of the 2024 Formula O&M, including the calculation of the 2022 Formula O&M true-up. FBC notes the true-up of formula O&M is a two-year lag based on actual average customer counts from 2022.

Table 6-2: Calculation of 2024 Formula O&M ($ millions)

Line No.	Description		Forecast 2024	Reference
1	Prior Year Base Unit Cost O&M ($/ customer)	$	472	G-382-22 FBC 2023 Annual Review
2	I-Factor		3.580%	Section 2, Table 2-3, Line 11
3	Current Year Unit Cost O&M ($/customer)	$	489	
4	Average Customer Forecast		148,984	Section 2, Table 2-3, Line 13
5	2024 Inflation-Indexed O&M before 2022 True-up	$	72.853	Line 3 x Line 4 / 1,000,000
6	2022 True-up O&M		(0.030)	Line 16
7	Inflation-Indexed O&M	$	72.823	Line 5 + Line 6
8				
9	2022 O&M True-up			
10	2022 Actual 12 month Average Customers		147,112	FBC 2022 Annual Report
11	2022 Forecast 12 month Average Customers		147,199	G-374-21 FBC 2022 Annual Review
12	Difference		(87)	Line 10 + Line 11
13	Growth Factor		75%	G-166-20 FBC MRP Decision
14	Change in Customers - True-up		(65)	Line 12 x Line 13
15	2022 Unit Costs	$	455	G-374-21 FBC 2022 Annual Review
16	O&M True-up for 2024	$	(0.030)	Line 14 x Line 15 / 1,000,000

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 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 for 2022 Formula O&M, 2022 Actual O&M, and the resulting variances, as well as the Cumulative Forecast/Actual variance for the first three years of the MRP.

Table 6-3: System Operations, Integrity and Security New/Incremental Spending ($ millions)

Line No.	Description	2022 Formula O&M	Actual 2022 O&M	2022 Forecast/Actual Variance	Cumulative Forecast/Actual Variance[2]
1	Tree Management	$ 0.083	$ 0.434	$ 0.352	$ 0.787
2	Generation Dam Safety	$ 0.256	$ 0.111	$ (0.145)	$ (0.007)
3	Network Operations Apprentice Program	$ 0.217	$ 0.245	$ 0.027	$ (0.140)
4	Cyber Security	$ 0.088	$ 0.264	$ 0.176	$ 0.426
5	Data Analytics	$ 0.109	$ -	$ (0.109)	$ (0.316)
6	Other	$ -	$ -	$ -	$ -
7	Total	$ 0.754	$ 1.054	$ 0.301	$ 0.750

Notes to Table:

[1] 2022 Formula O&M is the approved 2021 formula for incremental funding with Net Inflation factor applied (4.041%).
[2] Cumulative Forecast/Actual variance is the 2020, 2021 and 2022 Actual variance.

Overall, total actual spending in 2022 was $1.054 million, which is $0.301 million higher than the 2022 Formula O&M amount. Areas with notable variances include tree management, generation dam safety, cyber security and data analytics.

For tree management, FBC spent $0.352 million more than the formula amount to address an increased number of unhealthy trees as part of FBC's right-of-way management program.

For generation dam safety, FBC spent $0.145 million less than the formula amount primarily due to the completion of dam safety review activities in 2021. As explained in Section 6.2.1 of the Annual Review for 2023 Rates, FBC spent $0.199 million more than the formula amount in 2021 due to the continuation of dam safety review activities. The spending overall on these activities has been consistent with the formula amount, as the cumulative variance is only $0.007 million for the first three years of the MRP term (as shown in Table 6-3 above).

For cyber security, FBC spent $0.176 million more than the formula amount. The higher spending was for additional consulting resources in the following areas: an additional consulting resource to augment cybersecurity requirements due to additional threat management needs; emergency management consulting for emergency exercises; physical security threat intelligence services to manage security risk; and the use of consulting services to update the business continuity program.

In data analytics, FBC spent $0.109 million less than the formula amount in 2022 primarily due to labour savings from a delay in hiring. In 2022, the focus was on building solutions in business areas including providing enhanced reporting using dashboards. For further details, please refer to Section 1.4.2 of the Application.

For the first three years of the MRP, FBC spent $0.750 million more than the formula amount. Over the term of the MRP, FBC anticipates the total new/incremental spending required in the combined categories of System Operations, Integrity and Security will continue to be higher than the amount embedded in the formula. FBC will continue to manage this spending within its overall O&M spending envelope.

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. For 2024, FBC continues to include the incremental O&M resulting from the Mandatory Reliability Standards (MRS) Assessment Report No. 13 (AR13), which was approved for exogenous treatment in the Annual Review for 2022 Rates.

The 2024 amounts are shown in Table 6-4 below along with a comparison to 2023.

Table 6-4: 2024 Forecast O&M ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Pension/OPEB (O&M Portion)	$ (1.297)	$ (1.297)	$ (2.532)
2	Insurance Premiums	2.457	2.507	2.678
3	BCUC Levies	0.385	0.385	0.458
4	Clean Growth Initiative - EV DCFC	0.219	0.181	0.310
5	Exogenous Factor - MRS	0.585	0.585	0.585
6	Total Forecast O&M	$ 2.349	$ 2.361	$ 1.499

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expense 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 exogenous factors are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expense for 2024 is based upon actuarial estimates using a range of assumptions as of December 31, 2022. In addition to O&M, pension and OPEB expense is embedded in capital expenditures, as shown in Table 6-5.

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

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	O&M	$ (1.297)	$ (1.297)	$ (2.532)
2	Capital	1.888	1.888	1.875
3	Total Pension & OPEB Expense	$ 0.591	$ 0.591	$ (0.657)

The variance between the 2023 Approved/Projected and actual pension and OPEB expense is included in the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by Order G-139-14.

The 2024 Forecast pension and OPEB expense is lower than 2023 Approved by $1.248 million. The difference is primarily due to the following factors:

- A decrease of approximately $1.7 million due to an increase in investment returns as a result of a higher balance of pension plan assets; and
- A decrease of approximately $0.3 million due to the US GAAP Pension & OPEB Transition Obligation non-rate base deferral account being fully amortized in 2023.

The above decreases are offset in part by:

- An approximate increase of $0.8 million in interest costs due to an increased discount rate, which is determined with reference to the market rate of interest on high-quality debt instruments at a point in time (a discount rate of 4.50 percent was used to determine the 2023 Approved expense compared to a discount rate of 5.25 percent used to determine the 2024 Forecast expense).

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 2023	Projected 2023	Forecast 2024
1	Insurance Premiums	$ 2.457	$ 2.507	$ 2.678

FBC's annual insurance renewal occurs in July of each year. The 2023 Projected insurance premium expense of $2.507 million is $0.050 million higher than 2023 Approved, as it incorporates the first six months of FBC's actual July 2023 to June 2024 insurance renewals. The 2024 Forecast is $2.678 million, which is an increase of $0.171 million from 2023 Projected. The 2024 Forecast is calculated based on the six months of actual insurance premiums from July 2023 to June 2024 of $1.234 million, plus a 5 percent increase for the remaining six months, and the cost of fire fighting services FBC pays to the Province of $0.148 million.[28]

6.3.3 BCUC Levies

FBC's 2024 Forecast for BCUC levies is $0.458 million. The 2024 Forecast is based on Order G-134-23 for the BCUC's Fiscal 2023/24 year, which represents the best information available at

[28] $2.468 million/2 = $1.234 million. $1.234 million x 1.05 = $1.295 million. $1.234 million + $1.295 million + $0.148 million annual firefighting service fee = $2.678 million.

this time, as the BCUC levy calculation for its Fiscal 2024/25 year will not be available until early or mid 2024.

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

6.3.4 Clean Growth Initiative – Electric Vehicle (EV) DCFC Stations

As discussed in Section 3.6, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[29] and the cost of service associated with EV DCFC stations is subject to flow-through treatment. Please refer to Table 3-5 in Section 3.6 which provides a summary of the EV DCFC stations' costs and revenues from 2022 Actual to 2024 Forecast.

Table 6-7 below provides a breakdown of the 2023 Approved, 2023 Projected and 2024 Forecast O&M expenses for FBC's EV DCFC service. The O&M expenses consist of network management, repairs and maintenance, inspection fees, FBC internal labour, and the electricity costs from third-party utilities (i.e., for stations in Grand Forks, Nelson, and Penticton).

Table 6-7: Clean Growth Initiative – EV DCFC Stations ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Network Management	$ 0.047	$ 0.037	$ 0.050
2	Repairs and Maintenance	0.009	0.040	0.050
3	Inspection Fees	0.067	0.042	0.096
4	FBC Labour Costs	0.070	0.030	0.070
5	Third Party Utilities Costs	0.026	0.032	0.044
6	Total	$ 0.219	$ 0.181	$ 0.310

As shown in Table 6-7 above, the 2023 Projected O&M expense for the EV DCFC service is $0.038 million lower than 2023 Approved. This is primarily due to reduced FBC labour costs as a result of a vacancy, and reduced inspection fees as the new inspection agreement did not commence until mid-2023. These decreases are partially offset by the increase in repairs and maintenance costs as well as the increase in third-party utilities costs. The 2023 Projected repairs and maintenance costs are higher than 2023 Approved because the 2023 Approved amount did not account for the regular maintenance costs for stations where the warranty period expired, whereas the 2023 Projected amount includes an estimate of the ongoing regular maintenance costs at stations that are no longer covered by the vendor's warranty period. With regard to the increase in third-party utilities costs, this is primarily due to increased utilization at the stations located in the service areas of third-party utilities (i.e., Grand Forks, Nelson, and Penticton) as well as the rate increases by the third-party utilities.

[29] Order G-215-21 dated July 14, 2021.

The 2024 Forecast is $0.129 million higher than 2023 Projected. This is primarily due to increased inspection fees due to the full year impact of the inspection agreement, and higher FBC labour costs as FBC expects to fill the vacancy for 2024. Other drivers of the increase are higher FLO Global Management Service fees for network management, as well as an increase in third-party utilities costs due to a combination of expected increases in utilization of stations located in the service areas of the third-party utilities and the estimated increase in the rates of the third-party utilities.

6.3.5 MRS Incremental Operating Expenses

In the Annual Review for 2022 Rates Decision,[30] FBC received approval of exogenous factor treatment for the incremental O&M and capital costs associated with MRS AR13. As explained in the Annual Review for 2022 Rates proceeding, FBC expected to incur one-time costs in 2021 and 2022 related to the adoption of the standards in AR13 as well as ongoing incremental O&M expenses commencing in 2023[31].

Table 6-8 below provides the 2023 Approved, 2023 Projected, and 2024 Forecast of incremental O&M related to MRS AR13.

Table 6-8: Incremental O&M for MRS AR13 ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Labour	$ 0.490	$ 0.490	$ 0.490
2	Non-Labour	0.095	0.095	0.095
3	Total	$ 0.585	$ 0.585	$ 0.585

The 2023 Projected O&M is consistent with 2023 Approved. For 2024, FBC is forecasting the same level of spending as in 2023. The spending is related to the ongoing efforts to maintain procedures and processes, hardware and software that address supply chain risk assessments, ongoing licensing and maintenance of the hardware and software, and the documentation to maintain compliance of AR13. As noted in the Annual Review for 2022 Rates, FBC expects these costs to continue in future years.

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 2023. After capitalized overhead, the net O&M expense is $63.174 million in 2024.

[30] Decision and Order G-374-21, p. 21.
[31] Exhibit B-2, Annual Review for 2022 Rates Application, Section 12.2.1, pp. 103-104; Exhibit B-3, BCUC IR1 24.2.

6.5 SUMMARY

Overall, the increase in gross O&M expense from 2023 Approved to 2024 Forecast is 2.3 percent. Formula-driven O&M is increasing at a rate of 3.6 percent while O&M forecast outside the formula is decreasing by approximately 36.2 percent from 2023 Approved.

The capitalized overhead rate for 2024 remains unchanged from 2023.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

FBC forecasts its Rate Base to be $1.714 billion for 2024. Rate Base is comprised of mid-year net plant in service, work in progress not attracting AFUDC, unamortized deferred charges, working capital, and the utility plant acquisition adjustment.[32]

FBC's 2024 Rate Base includes the full-year impacts of the 2023 closing projected plant balances as well as the impact of the following amounts:

- Mid-year impact of regular capital additions, net of CIAC additions, of $97.783 million;
- Mid-year impact of plant depreciation, net of CIAC amortization, of $66.744 million; and
- Capital additions of CPCNs and other Major Projects totalling $5.500 million, as discussed in Section 7.3 below, which include:
    - Full-year impact of $2.769 million for the final capital expenditures and related AFUDC in 2023 for the Kelowna Bulk Transformer Additions (KBTA) Project; and
    - Full-year impact of $2.731 million for the final capital expenditures and related AFUDC in 2023 for the Corra Linn Dam Spillway Gates Replacement Project.

In addition, various changes in deferred charges, working capital and other items increase rate base by a net amount of $2.735 million in 2024.

Details of the 2024 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 (i.e., growth, sustainment, and other) for the years 2020 through 2022; and
- Approval of several items to be forecast on an annual basis.

Further, as part of FBC's 2023 Annual Review Decision and Order G-382-22, and Reconsideration Decision and Order G-87-23, FBC received approval of its forecasts of regular capital expenditures for the years 2023 and 2024.

The components of FBC's 2024 regular capital expenditures are shown in Table 7-1 below.

[32] 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.

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

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Forecast Capital	$ 92.440	$ 92.440	$ 93.433	Table 7-2, Line 4
2	Flow-Through Capital	0.248	0.580	0.500	Table 7-3, Line 2
3	Total Gross Regular Capital	$ 92.688	$ 93.020	$ 93.933	Sum of Lines 1 & 2
4	Less CIAC	(11.628)	(11.623)	(7.539)	Section 11, Schedule 9, Line 2
5	Net Regular Capital	$ 81.060	$ 81.397	$ 86.394	Sum of Lines 3 & 4

FBC notes that, pursuant to Order G-135-23, FBC is directed to file a CPCN application for the Fruitvale Substation Project prior to the start of construction. This project was included in the approved regular capital expenditure forecasts for 2023 and 2024. As the Fruitvale Substation Project now requires a CPCN, FBC has removed the capital expenditures from the 2023 Approved, 2023 Projected, and 2024 Forecast regular capital amounts shown in Tables 7-1 and 7-2 (forecast regular capital of $1.087 million in 2023 and $7.021 million in 2024). These expenditures will now be treated in the same manner as FBC's other CPCN and Major Project capital expenditures. Please refer to Section 7.3 for further detail.

In the subsections below, FBC provides further details on its regular capital expenditures for 2024.

7.2.1 Approved Capital Expenditures

The level of forecast capital expenditures approved for 2024 by Orders G-382-22[33] and G-87-23[34] is shown in Table 7-2 below. As discussed above, following Order G-135-23, FBC removed the 2023 Approved, 2023 Projected and 2024 Forecast sustainment capital expenditures related to the Fruitvale Substation Project; therefore, the amounts shown in Table 7-2 exclude the Fruitvale Substation Project expenditures.

Table 7-2: Approved Capital Expenditures ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Growth Capital	$ 30.072	$ 30.072	$ 24.568	Section 11, Schedule 4, Line 2
2	Sustainment Capital	44.710	44.710	51.652	Section 11, Schedule 4, Line 3
3	Other Capital	17.658	17.658	17.213	Section 11, Schedule 4, Line 4
4	Total	$ 92.440	$ 92.440	$ 93.433	Section 11, Schedule 4, Line 5

[33] FBC Annual Review for 2023 Rates Decision and Order G-382-22.
[34] FBC Reconsideration Decision and Order G-87-23 regarding the FBC Application for Reconsideration and Variance of Decision and Order G-382-22.

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 2024 are shown in Table 7-3 below along with a comparison to 2023.

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

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Clean Growth Initiative - EV DCFC	0.248	0.580	0.500	
2	Total Forecast Capital Expenditures	$ 0.248	$ 0.580	$ 0.500	Section 11, Schedule 4, Line 8

7.2.2.1 EV DCFC Stations

As discussed in Section 3.6, FBC's EV DCFC stations are prescribed undertakings under section 5 of the GGRR[35], and the cost of service associated with EV charging stations is subject to flow-through treatment. Please refer to Table 3-5 of Section 3.6 which provides a summary of the EV DCFC stations' costs and revenues from 2022 Actual to 2024 Forecast.

Table 7-3 above shows the EV DCFC stations capital expenditures for 2023 Approved, 2023 Projected, and 2024 Forecast. The 2023 Projected EV DCFC stations capital expenditures are $0.332 million higher than 2023 Approved, primarily due to unbilled charges from 2022 construction activities, which are related to the planned DCFC stations in Keremeos and Princeton that were identified in FBC's Revised and Updated Application for EV DCFC Service and approved by Order G-215-21.[36] The construction was completed in 2022, but FBC did not receive all invoices for the work until 2023.

The 2024 Forecast capital expenditures are related to the accessibility improvement work at FBC's existing EV DCFC sites that was started in 2023. In 2023, FBC is projecting to complete the improvement work at four sites (which was included as part of the 2023 Approved expenditures), while the remaining sites are expected to complete in 2024. As noted in the Annual Review for 2023 Rates, the scope of the improvements include new or additional lighting, as the stations are available for use 24 hours a day, and paving for wheelchair access to the charger.

FBC is not forecasting the construction of any additional stations in 2024 at this time; however, FBC will continue to monitor the station utilization and customer demand to determine if additional stations are warranted.

[35] Order G-215-21 dated July 14, 2021.
[36] FBC's Revised and Updated EV DCFC Service Application, Table 2-2, pp. 10-11.

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,[37] 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.

For 2024, FBC is not forecasting any capital expenditures related to Major Projects. However, FBC's 2024 Forecast rate base includes the full-year impact of capital additions related to the KBTA Project and the Corra Linn Dam Spillway Gate Replacement Project. FBC also provides a brief discussion on the Fruitvale Substation Project, as FBC is expecting to submit a CPCN application for this project in 2023. Each of these projects is described further below.

KBTA Project

The KBTA project was approved by Order C-4-20 and involves the installation of a third terminal transformer at the F.A. Lee Terminal Station, including the reconfiguration of the 138 kV bus into an industry standard ring bus configuration. The project is expected to complete in 2023 with an estimated final cost of $23.287 million, inclusive of AFUDC and cost of removal. A total of $19.941 million (plus $0.577 million of removal costs) were included in FBC's rate base on January 1, 2023, with the remaining $2.769 million expected to enter FBC's rate base on January 1, 2024.

Corra Linn Dam Spillway Gates Replacement Project

The Corra Linn Dam Spillway Gates Replacement Project was approved by Order C-1-17 and involves the replacement of 14 spillway gates and upgrades to the associated infrastructure. As explained in FBC's Reconsideration Application to the Decision and Order G-382-22 for the Annual Review for 2023 Rates, which was approved by Order G-87-23, the replacement of all spillway gates was complete in 2022 and the costs were included in FBC's rate base between 2018 and 2023, with the remaining close-out activities delayed to 2023. The close-out activities, including lighting, outstanding claims, and clean-up, are estimated to be approximately $2.731 million and are expected to be complete in 2023; therefore, the costs are forecast to enter FBC's rate base on January 1, 2024. The final project cost is expected to be $80.835 million, inclusive of AFUDC and removal costs.

Fruitvale Substation Project

The Fruitvale Substation Project was included as part of FBC's regular capital forecasts for 2023 and 2024 in the Annual Review for 2023 Rates (forecast regular capital of $1.087 million in 2023 and $7.021 million in 2024). FBC's 2023 and 2024 regular capital forecasts were approved as part of the BCUC's Decision and Order G-382-22. However, following a complaint regarding the location of the proposed substation in Fruitvale, the BCUC issued Order G-135-23 on June 9, 2023, directing FBC to file an application for a CPCN related to the proposed Fruitvale Substation

[37] MRP Decision and Order G-166-20, pp. 132-133.

Project. As discussed in Section 7.2, FBC has removed the 2023 and 2024 capital expenditures related to the Fruitvale Substation Project from regular capital, as the expenditures will now be treated in the same manner as FBC's other CPCN and Major Project capital expenditures. FBC expects to file an application for a CPCN for the Fruitvale Substation Project before the end of 2023.

7.4 2024 PLANT ADDITIONS

The 2024 Plant Additions are comprised of: (i) FBC's 2024 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, Schedule 5.

Table 7-4: Reconciliation of 2024 Capital Expenditures to Plant Additions ($ millions)[38]

Line No.	Description		Forecast 2024	Reference
1	Forecast Capital Expenditures	$	93.433	Section 11, Schedule 5, Line 2
2	Flow-Through Capital Expenditures		0.500	Section 11, Schedule 5, Line 3
3	Total Gross Regular Capital Expenditures		93.933	Sum of Lines 1 and 2
4				
5	Capitalized Overhead		11.148	Section 11, Schedule 5, Line 16
6	AFUDC		0.241	Section 11, Schedule 5, Line 17
7	Change in Work in Progress		-	Section 11, Schedule 5, Line 19
8	Total Regular Additions to Plant		**105.322**	Sum of Lines 3 through 7
9				
10	Special Projects and CPCN			
11	Capital Expenditures		-	Section 11, Schedule 5, Line 22
12	AFUDC		0.001	Section 11, Schedule 5, Line 23
13	Change in Work in Progress		5.499	Section 11, Schedule 5, Line 25
14	Total Special Projects and CPCN Additions to Plant		**5.500**	Sum of Lines 11 through 13
15				
16	Total Plant Additions	**$**	**110.822**	Line 8 + Line 14

7.5 ACCUMULATED DEPRECIATION

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

[38] Line 11 of Table 7-4 is zero because, as described in Section 7.3, there are no capital expenditures forecast in 2024 for the two approved CPCN Projects (i.e., the KBTA Project and the Corra Linn Dam Spillway Gates Replacement Project). Further, FBC will be filing for a CPCN related to the Fruitvale Substation Project in 2023, as such, FBC has not included the forecast capital expenditures related to this project.

The depreciation rates used for 2024, 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 by Order G-139-14.

Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance, the 2024 depreciation expense is calculated as $66.744 million.[39]

7.6 DEFERRED CHARGES

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[40] 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 2024 Forecast mid-year balance of unamortized deferred charges in rate base for FBC is a debit of $51.287 million.

The 2024 debit balance is driven largely by the balance in the Demand Side Management (DSM) deferral account of $44.063 million.

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

[39] $72.053 million depreciation expense as shown in Section 11, Schedule 21, Line 2 less $5.309 million amortization of CIAC as shown in Section 11, Schedule 21, Line 8.
[40] BCUC Letter, Log No. 53608, Appendix B.

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



Based on the approved amortization and the opening balances of each deferral account, the amortization expense, including both rate base and non-rate base deferral accounts, is calculated to be a credit of $2.860 million,[41] which will be returned to customers through the proposed 2024 rates. 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.

7.6.1 New Deferral Accounts

FBC is seeking approval to create five new rate base deferral accounts in this Application:

- 2025 Multi-year Rate Plan (MRP) Application;
- 2024 Mandatory Reliability Standards Audit;
- PST Rebate on Select Machinery and Equipment;
- BC Cost of Living Credit; and
- Climate Change Operational Adaptation (CCOA) Plan.

Table 7-5 below addresses the considerations identified in the Regulatory Account Filing Checklist as they pertain to each deferral accounts requested. For a detailed description of each deferral account, please refer to Sections 7.6.1.1 to 7.6.1.5 below.

[41] Section 11, Schedule 21, Column 3, Sum of Lines 5 and 6.

Table 7-5: Deferral Account Filing Considerations

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
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 2025 MRP Application is a new deferral account. Please refer to Section 7.6.1.1 for additional information.	The 2024 MRS Audit is a new deferral account. Please refer to Section 7.6.1.2 for additional information.	The PST Rebate on Select Machinery and Equipment is a new deferral account. Please refer to Section 7.6.1.3 for additional information.	The BC Hydro Cost of Living Credit is a new deferral account. Please refer to Section 7.6.1.4 for additional information.	The Climate Change Operation Adaptation Plan is a new deferral account. Please refer to Section 7.6.1.5 for additional information.
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	N/A	N/A

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
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 account is a regulatory proceeding cost account, which is 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 PST Rebates on Select Machinery and Equipment received from the Province of BC.	The requested account will capture the residual balance of the BC Cost of Living Credit.	The requested account will capture costs related to the development of the Climate Change Operational Adaptation Plan.
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 the account encompasses the preparation and filing of the relevant regulatory application and its review by the BCUC.	The term of the account encompasses the required time to conduct the audit.	The term of the account encompasses the required time for the Province of BC to approve the qualified claim filed by FBC and issue the refund payment.	The term of the account encompasses the time required to distribute the credits to all applicable customers.	The term of the account encompasses the time required for the development of the CCOA Plan and subsequent business cases as discussed in the 2021 Long Term Electric Resource Plan (LTERP).
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 index-based O&M as regulatory proceeding costs are not included in Base O&M Expense) and trued up annually by way of the	In the absence of a deferral account, the audit costs would have to be forecast as an O&M expense (outside of the MRP index-based O&M, as the 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	In the absence of a deferral account, the rebate would be recorded as an offset in the applicable accounts where the original PST costs were recorded, whether those accounts were O&M or capital. FBC considers this to be a less transparent way of recording the rebates as it is the cost-of-	In the absence of a deferral account, the credit would remain in an FBC liability account until the residual balance is distributed through inquiries. FBC does not expect there will be enough inquiries to distribute the total residual balance. Eventually, the residual balance would be recorded as	In the absence of a deferral account, the costs would have to be forecast as an O&M expense (outside of the MRP index-based O&M, as the 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

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
		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.	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.	service impacts of the amounts credited to capital that would be returned to customers over a longer timeframe, rather than the rebate amount itself over one year as proposed using the deferral account approach.	income, and FBC would need to request a method of returning that income to customers, either via the Flow-Through deferral or by including the amount in its revenue requirements. The use of a deferral account permits the remaining credits to be used to benefit all customers, in a timely and efficient manner, consistent with the purpose of the credit.	and less efficient means of managing these costs.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
IV a)	Address: 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.	The final amount of PST rebates claimed by FBC are subject to approval by the Province of BC.	The amount of credit available to FBC and the eligibility criteria was determined by the Province of BC.	As a result of the ongoing impacts of global climate change, FBC has determined it is imperative to address the risks of climate change risk on its system. Therefore, although direct costs are within Management's control, the need to incur these costs is considered necessary.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
b)	the degree of forecast uncertainty associated with the item;	Refer to IV. a). FBC forecasts additions to the deferral account 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.	Refer to IV. a). FBC forecasts additions to the deferral account based on the rebates received to date plus those claimed and expected to be received. Actual expected rebates will be recorded in the account so that actual, not forecast, rebates are returned in rates.	Refer to IV. a). FBC forecasts additions to the deferral account based on the residual balance of credits remaining to date. The actual residual balance, inclusive of further eligible inquiries, will be recorded in the account so that the actual, not forecast, remaining credits are returned in rates.	Refer to IV. a). FBC forecasts additions to the deferral account based on expected incremental resources required to complete the plan. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.
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. Please refer to Section 7.6.1.1 for additional information.	Audit preparation and participation impacts many individuals and business units and is not manageable within FBC's formula O&M Expense. FBC expects costs related to the MRS Audit of approximately $0.375 million ($0.274 million after-tax). Please refer to Section 7.6.1.2 for additional information.	FBC expects rebates of approximately $0.591 million ($0.431 million after-tax). Please refer to Section 7.6.1.3 for additional information.	FBC expects the remaining credit to be approximately $0.507 million ($0.370 million after-tax). Please refer to Section 7.6.1.4 for additional information.	FBC expects costs related to the CCOA Plan of approximately $0.225 million ($0.164 million after tax) in 2023 and a further $0.192 million ($0.140 million after-tax) in 2024. Please refer to Section 7.6.1.5 for additional information.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
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. 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 return the rebates over the same period of time as the qualifying period to make the PST rebate claims. There are no intergenerational inequities in this practice.	FBC expects to return the remaining credit over the same period of time as the credit is made available by the Province of BC. There are no intergenerational inequities in this practice.	FBC expects to recover the costs of the CCOA Plan over the period of time required to develop the plan and subsequent business cases as outlined in the 2021 LTERP. 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”.	The account is classified as “other”.	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 MRS Audit deferral account is a cash account.	The PST Rebate on Select Machinery and Equipment is a cash account.	The BC Cost of Living Credit deferral account is a cash account.	The Climate Change Operational Adaptation Plan deferral account is a cash account.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
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.	PST Rebates received from the Province of BC for claims filed by FBC for the qualifying period. Please refer to Section 7.6.1.3 for additional information.	The remaining credit is the total funds received by FBC less any credit already applied to customer bills as of June 2023. FBC will continue to capture any credits provided to customers from eligible inquiries for the credit. Please refer to Section 7.6.1.4 for additional information.	Eligible costs include fees for consultants required for the development of the plan.
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 are recovered in revenue requirements by way of amortization expense.	Rebates will be refunded in revenue requirements by way of amortization expense.	Credits will be refunded in revenue requirements by way of amortization expense.	Costs are recovered in revenue requirements by way of amortization expense.

Item	Consideration	2025 MRP Application	2024 MRS Audit	PST Rebate on Select Machinery and Equipment	BC Cost of Living Credit	Climate Change Operational Adaptation Plan
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 proposes to amortize the costs of regulatory proceedings over the period of time related to the application, which serves to match the timing of costs and benefits. Please refer to Sections 7.6.1.1 for additional information.	FBC proposes to amortize the costs over three years beginning January 1, 2024, to reflect the period until the next audit. Recovery of the costs over the period of time between audits serves to match the costs and benefits of the audit. Please refer to Section 7.6.1.2 for additional information.	FBC proposes to refund the rebates over one year beginning January 1, 2024, to match the approximate qualifying period of eligible PST paid on purchases. Please refer to Section 7.6.1.3 for additional information.	FBC proposes to refund the remaining credits over one year beginning January 1, 2024. Please refer to Section 7.6.1.4 for additional information.	FBC proposes to amortize the costs over four years beginning January 1, 2024 to reflect the CCOA Plan timeline discussed in the 2021 LTERP. Please refer to Section 7.6.1.5 for additional information.
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 therefore, implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).	Rate base deferral accounts are included in rate base and 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 account can be reviewed as part of the present proceeding. Deferral account approvals and disposition are generally determined in revenue requirement proceedings.				

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7.6.1.1 2025 Multi-Year Rate Plan (MRP) Application

FBC's current Multi-year Rate Plan (MRP) approved by Order G-166-20 will end in 2024. FBC has started developing its next rate plan and expects to file this rate plan with the BCUC in early 2024. FBC will incur regulatory costs related to the development of the application and is requesting approval to establish a rate base deferral account to capture these costs, which will include BCUC costs, participant funding costs, external legal fees, expert/consulting costs, notice publication costs, and miscellaneous facilities, stationery, and supplies costs. FBC forecasts costs of $0.350 million ($0.256 million after-tax) in 2023 and $1.200 million ($0.876 million after-tax) in 2024. Actual costs will vary depending on how the application progresses and will be confirmed after the regulatory process is completed.

FBC is only requesting approval to establish this deferral account. FBC will propose an amortization period for the deferral account in a future rate-setting application (i.e., subsequent to the completion of the 2025 MRP application proceeding).

7.6.1.2 2024 Mandatory Reliability Standards (MRS) Audit

FBC's triennial MRS compliance audit is scheduled to occur in 2024. 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 minimum, of all applicable reliability standards identified in the Actively Monitored List. 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 $0.375 million before tax ($0.274 after tax) in 2024.

FBC is requesting approval to establish a rate base deferral account to capture the costs related to the 2024 MRS Audit. Further, FBC is proposing to amortize these costs over three years beginning January 1, 2024. This amortization period is appropriate as it reflects the period until the next MRS triennial audit.

7.6.1.3 PST Rebate on Select Machinery and Equipment

The BC PST Rebate on Select Machinery and Equipment is a provincial government program to help corporations recover from the financial impacts of the COVID-19 pandemic. Eligible businesses can receive as a rebate the PST paid on purchases of specified equipment and software during the qualifying period between September 17, 2020 and March 31, 2022.

FBC is eligible to claim a BC PST Rebate on Select Machinery and Equipment on capital purchases of software and equipment and has filed for these rebates for the qualifying periods as set out by the Province of BC. To date, FBC has received $0.029 million ($0.021 million after-tax) in rebates and expects additional rebates of approximately $0.562 million ($0.410 million after-tax) to be received by December 31, 2023.

FBC is requesting approval to establish a rate base deferral account to capture the PST Rebates on Select Machinery and Equipment received from the Province of BC. Further, FBC is proposing to amortize these rebates to customers over one year beginning January 1, 2024, to match the approximate qualifying period of eligible PST paid on purchases.

7.6.1.4 BC Cost of Living Credit

On November 18, 2022, the Province of BC issued OIC 571/2022[42] for a one-time cost-of-living credit to all eligible residential and commercial electricity customers through a BC Hydro bill credit, including those who receive their electricity service from FBC or a municipal utility.

FBC received funds through BC Hydro for applying the credits to all eligible residential electricity customers in the amount of a one-time $100 cost-of-living credit and to all eligible commercial electricity customers as a one-time bill credit calculated based on their prior year electricity consumption.

FBC received a total of $23.816 million and applied $23.290 million of credits to all eligible customers as of March 10, 2023. In addition to the bill credits applied to eligible customers, FBC has committed to provide credits to customers if/when a customer inquires about such credits to FBC (and if the customer is determined to be eligible)[43]. Between March 10, 2023 and May 31, 2023, FBC received a total of six inquiries (three residential and three commercial customers), resulting in a further $0.019 million of credits applied. The total credits applied to eligible customers as of June 10, 2023 are therefore $23.309 million, with $0.507 million ($0.370 million after-tax) of residual credits which FBC proposes to include as a credit amortization (i.e., return to all customers) in 2024 rates.

FBC requested and received confirmation from the Ministry of Energy, Mines and Low Carbon Innovation (EMLI) that there is no expectation or requirement for FBC to return the residual credits to either BC Hydro or the Province of BC. Furthermore, EMLI agreed that the remaining funds could be used to benefit all FBC customers through rates, which is consistent with the purpose of the bill credits. As such, FBC is requesting approval in this Application to establish a rate base deferral account to capture the residual balance of the BC Cost of Living Credit and to amortize the residual credits to customers through rates over a one-year period beginning January 1, 2024.

As agreed with EMLI, FBC will continue to field inquiries from customers and will provide bill credits to customers that are determined to be eligible. As noted above, FBC only received a total of six inquiries from March to May 2023 and has received no inquiries since then. As such, FBC is expecting a very limited number of inquiries to occur in the remaining months of 2023 and into 2024. However, should any further bill credits be issued to eligible customers in 2023 or 2024, FBC will record these issued amounts in the deferral account. If there is any remaining balance

[42] https://www.bclaws.gov.bc.ca/civix/document/id/oic/oic_cur/0571_2022.

[43] OIC 571/2022 sets out the eligibility criteria which defined that customers must be a customer and receiving service on October 1, 2022. Due to the timing lapse between October 1, 2022 and when the credits are distributed starting from December 2022 to March 2023 (the credit was announced by the Province of BC on November 18, 2022), customers could be connecting to and/or leaving FBC's system, potentially resulting in eligible customers not receiving the bill credit. As such, FBC agreed to field inquiries and continue to pay out any eligible credits.

(credit or debit) at the end of 2024, FBC will amortize the remaining balance into rates in the subsequent year (i.e., 2025).

7.6.1.5 Climate Change Operational Adaptation (CCOA) Plan

As discussed in FBC's most recent Long Term Electric Resource Plan (2021 LTERP) accepted by Order G-380-22, the threat that climate change presents to FBC infrastructure and operations is a continuing reality that FBC is taking seriously; accordingly, FBC is developing a roadmap for climate change adaptation.[44] FBC's Climate Change Operational Adaptation (CCOA) Plan focuses on addressing the climate change risks associated with five hazards: wildfires, flooding, extreme temperatures, snowstorms, and windstorms. During the initial phase of the CCOA Plan, FBC is working with consultants to identify assets vulnerable to each hazard, define the current and future risk profiles of the vulnerable assets due to these hazards, and propose adaptation strategies. These strategies may consist of, but are not limited to, system hardening, asset replacement, or modification of design standards. Future phases will apply these results and strategies to existing assets to determine whether risk reduction projects will be required.

FBC is requesting approval to establish a rate base deferral account to capture the costs related to the CCOA Plan. FBC forecasts costs of $0.225 million ($0.164 million after-tax) in 2023 and a further $0.192 million ($0.140 million after-tax) in 2024. The costs are primarily related to the resources required to develop the roadmap for climate change adaptation and, stemming from the roadmap, develop the business cases for the five key hazard areas (i.e., wildfires, flooding, extreme temperatures, snowstorms and windstorms). FBC is proposing to amortize these costs over four years beginning January 1, 2024. This period aligns with the CCOA Plan timeline discussed in the 2021 LTERP, which states that the development of the CCOA Plan and subsequent business cases would occur between now and 2027. FBC will continue to provide updates on the progress of the CCOA Plan and the deferral account in future annual reviews or revenue requirement applications.

7.6.2 Existing Deferral Accounts

In the discussion below, FBC provides information on one existing deferral account.

7.6.2.1 Princeton Office Disposition Deferral Account

On January 24, 2023, pursuant to Order G-14-23, FBC was approved to sell the Princeton Office Properties, consisting of the land and buildings located on Bridge Street in Princeton, BC, to the Town of Princeton. FBC was also approved to establish the Princeton Office Disposition non-rate base deferral account to capture the net gain on the sale, and to transfer the balance in the non-rate base deferral account to a rate base deferral account on January 1, 2024 and commence amortization of the deferral account over one year in 2024. FBC was directed to provide details

[44] FBC 2021 LTERP Application, p. 140; Exhibit B-2, BCUC IR1 24.4.

on the final balance in the Princeton Office Disposition deferral account in the Annual Review for 2024 Rates.

FBC received written notification of the removal of the Buyer's Subject Conditions on February 10, 2023, and on March 13, 2023, the sale of the Princeton Office Properties was fully completed. The final projected ending balance of the deferral account (i.e., projected to the end of 2023) is approximately $0.406 million, and this credit amount has been included in the 2024 revenue requirements and rates.

Please refer to Table 7-6 below for a breakdown of the net gain on the sale of the Princeton Office Properties. FBC notes that the estimated net gain on sale at the time of filing the Princeton Office Properties Application was $0.346 million. The difference between the original estimate and the final projected ending balance is solely due to a difference in the net book value of the land and building. When preparing this Application, FBC discovered that it incorrectly calculated the accumulated depreciation on the building at the time of filing the Princeton Office Properties Application. FBC has now corrected this error and, as a result, the net gain on sale to be provided to customers is higher than originally forecast in the Princeton Office Properties Application.

Table 7-6: Breakdown of Final Net Gain on Sale of the Princeton Office Properties

		$ millions
Sales Proceeds		0.474
Less:	Net Book Value of Land and Building	(0.041)
	Disposal Costs	(0.019)
	Taxes Payable	(0.008)
Gain on Sale		**0.406**

7.7 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. 2024 amounts are forecast based on 2022 Actual levels.

7.8 SUMMARY

FBC's rate base includes the impact of regular and Major Project capital expenditures, adjusted for work-in-progress, AFUDC and overheads capitalized. FBC has provided forecasts for all of its

rate base deferral accounts in the financial schedules included in Section 11. In Section 7.6.1, FBC requested approval of five new deferral accounts; and in Section 7.6.2, FBC discussed one existing deferral account. 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 FEI. FBC is currently awaiting a decision on Stage 1 of the BCUC-initiated Generic Cost of Capital (GCOC) proceeding which it expects to be issued in the upcoming months. FBC will provide an update to its rate calculations as part of an Evidentiary Update subsequent to the GCOC decision being issued.

The 2024 Forecast 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 rate for 2024 (which is equal to its after-tax weighted average cost of capital) is 5.75 percent.[45] 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. Pursuant to Order G-47-14, FBC used the currently approved capital structure of 60.0 percent debt and 40.0 percent equity, with an equity risk premium of 40 basis point over the benchmark ROE, which was set at 8.75 percent by Order G-129-16, effective January 1, 2016, to calculate rates in this Application.

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 debt.

8.3.1 Long-Term Debt

FBC is both a private and public issuer of long-term debt. FBC plans to issue additional long-term debt of approximately $100 million in April 2024 and will use the funds to repay existing indebtedness and finance the Company's capital expenditure program. The 2024 debt issuance is reflected in the financial schedules at a rate of 4.90 percent.[46] The exact timing, amount and rate of the 2024 issuance will depend on future market conditions and capital expenditure

[45] As part of the Evidentiary Update, FBC will update the AFUDC rate for 2024 to reflect any changes resulting from the GCOC decision.
[46] Section 11, Schedule 27, Line 9.

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

FBC obtains short-term funding primarily through the issuance of commercial paper to Canadian institutional investors. FBC backstops the commercial paper issuances by maintaining a $150 million committed credit facility that matures in April 2027.[47] This facility is also used to issue letters of credit. The credit facility, along with a $10 million overdraft facility, provides FBC with short-term liquidity to fund its capital program and working capital requirements.

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. 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 2024 is 4.27 percent, which is an increase from the 3.14 percent approved in 2023. FBC continues to face a rising interest rate environment due to high inflation and the Bank of Canada continuing to raise its policy interest rate in an attempt to slow economic growth and reduce core inflation. While the inflation in Canada eased to 3.40 percent in May 2023 from a high of 8.10 percent from a year ago, the downward movement was driven largely by lower energy prices rather than easing underlying inflation. The Bank of Canada's latest interest rate

[47] On July 14, 2023, FBC filed an application with the BCUC to increase the principal amount of the credit facility from $150 million to $200 million and to extend the maturity date of the credit facility to April 2028. If this application is approved, FBC will include any related impacts in the Evidentiary Update which FBC expects to file subsequent to the GCOC decision being issued.

increase in July 2023 brings the overnight rate to 5.0 percent, which was the tenth interest rate increase since March 2022 when the overnight rate was at 0.25 percent.

For 2024, FBC forecasts higher Other Financing Fees than the 2023 Approved amount due to higher customer deposit interest, resulting from a higher prime rate in 2023. Other Financing Fees include the fees that FBC incurs for its letters of credit under the 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 2023	Projected 2023	Forecasted 2024
3-Month T-Bill Rate [1]	3.14%	5.04%	4.27%
Spread to CDOR	0.36%	0.41%	0.41%
CDOR Rate	3.50%	5.45%	4.69%
Spread to CP	-0.36%	-0.47%	-0.47%
CP Dealer Commission	0.10%	0.10%	0.10%
ST Interest Rate on Credit Facilities	**3.24%**	**5.09%**	**4.32%**
Fixed Financing Fees [2]			
Standby fee on Undrawn Credit [3]	0.44%	0.24%	0.32%
Renewal Fee on Undrawn Credit	0.12%	0.07%	0.09%
Other Financing Fees	0.44%	0.34%	0.49%
ST Interest Rate on Fixed Financing Fee	**1.00%**	**0.64%**	**0.89%**
FBC Short Term Rate	**4.24%**	**5.73%**	**5.21%**

Notes to Table:

[1] 3-month T-Bill rate for 2024 is a weighted average rate based on forecasts provided by Canadian Chartered banks in July 2023.

[2] Fixed financing fees represent the costs of maintaining the credit facility and letter of credit facility, which are fixed fees incurred regardless of whether 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.

4. Other financing fees include commercial paper issuance fees, letter of credit fees, customer deposit interest expense and miscellaneous bank administration costs. The letter of credit fees, customer deposit interest and miscellaneous bank administration costs are incurred regardless of whether FBC draws from the credit facility.

As noted above, FBC's interest rate forecasts are based on CDOR. An indirect result of the cessation of the publication of the London Interbank Offered Rate (LIBOR) is that Canada is planning to discontinue using CDOR as a risk-free rate benchmark for financial instruments in multiple asset classes. This will impact FBC's credit facility agreement as Refinitiv Benchmark Services (UK) Limited (RBSL), CDOR's regulated administrator, announced that CDOR will cease to be published after June 28, 2024.[48] The Canadian Alternative Reference Rate Working Group (CARR) was established to coordinate the transition to a new risk-free rate benchmark. In January

[48] https://www.bankofcanada.ca/markets/canadian-alternative-reference-rate-working-group/.

2023, CARR announced a development of a Term Canadian Overnight Repo Rate Average (Term CORRA), a risk-free interest rate benchmark for one- and three-month terms. Term CORRA is expected to replace CDOR and will become available in the latter half of 2023. As the Term CORRA rate is not yet available, FBC continues to use the CDOR methodology, consistent with its previous Annual Reviews, to forecast the short-term interest rate for 2024.

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 2024 long-term debt schedule for FBC can be found in Section 11, Schedule 27.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FBC applies AFUDC to projects that are greater than three months in duration and greater than $100 thousand. Based on the above information, FBC's AFUDC rate for 2024 (which is equal to its after-tax weighted average cost of capital) is 5.75 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2024

Description	Weight	Pre-Tax Rate	After-Tax Rate	Earned Return
Short Term Debt	5.46%	5.21%	3.80%	5.21%
Long Term Debt	54.54%	4.72%	3.45%	4.72%
Common Equity	40.00%	12.53%	9.15%	9.15%
Weighted Average	100.00%	7.87%	5.75%	6.52%

8.4 SUMMARY

FBC's equity financing and ROE have been forecast for 2024 at the same percentages as by Orders G-47-14 and G-129-16. 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; the embedded rate on long-term debt is forecast to decrease in 2024 compared to 2023 (4.72 percent forecast for 2024 compared to 2023 Approved of 4.78 percent).

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 2024, property taxes are forecast to increase by $0.313 million (1.7 percent) from 2023 Approved, while income tax is forecast to increase by $4.002 million (65.9 percent) compared to 2023 Approved.

9.2 PROPERTY TAXES

The 2024 Forecast of property taxes is approximately $18.573 million and is based on the Company's 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 2023	Projected 2023	Forecast 2024
1	Generation Plant	$ 3.253	$ 3.201	$ 3.259
2	Transmission and Distribution	7.189	7.104	7.317
3	Substation Equipment	4.208	4.204	4.328
4	Land and Buildings	1.322	1.438	1.532
5	In Lieu	2.288	2.301	2.137
6	Total Property Taxes	$ 18.260	$ 18.248	$ 18.573
7				
8	2024 Forecast Change from 2023 Approved			1.7%
9	2024 Forecast Change from 2023 Projected			1.8%

As shown in the above table, in 2024 property taxes are forecast to increase by 1.7 percent from 2023 Approved and by 1.8 percent from 2023 Projected. In general, the 2024 increase from 2023 Projected is due to construction activities, market value changes, and changes in tax policies of local taxing authorities. The most significant drivers of the forecast changes are as follows:

1. ***Changes in Tax Rates.*** Tax Rates are expected to change for 2024 as follows:
    a) Municipal rates are expected to increase by 0.6 percent;
    b) School rates are expected to decrease by 1.2 percent;
    c) Rural rates are expected to decrease by 0.5 percent;
    d) Tax rates on First Nations are expected to increase by 0.8 percent; and
    e) Other rates are expected to decrease by 1.1 percent.

2. ***Changes in Revenues to Calculate Grants In Lieu of Taxes.*** Revenues reported to municipalities are expected to decrease by 7.1 percent based on actual revenues applicable to the taxation year. Grants in-lieu of taxes are based on a fixed percentage of revenues; the overall actual 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 expected inflationary increases. These include:

   a) A 5.2 percent increase in assessed values of distribution lines and a 4.7 percent increase in transmission lines;

   b) A 4.1 percent increase in assessed values for generating facilities calculated using legislated cost manuals for valuing generating facilities;

   c) A 2.1 percent decrease in assessed values for substations calculated using legislated cost manuals for valuing substations; and

   d) A 7.1 percent increase for offices.

Any variances from the forecast of property taxes included in rates are recorded in the Flow-through deferral account and will be returned to or recovered 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 2023, which is unchanged from 2022. 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 2024 is forecast to increase by $4.002 million or 65.9 percent compared to 2023 Approved. The largest driver of the increase in 2024 is the lower income tax deductible through capital cost allowance (CCA) by approximately $2.849 million. The lower deductibility is partly due to reduced undepreciated capital cost (UCC) additions in higher rate CCA classes in the 2024 Forecast compared to 2023 Approved, and partly due to the phase-out of Canada's Accelerated Investment Incentive starting from 2024 (i.e., enhanced 50 percent first-year allowance to be phased out in 2024).[49] Income tax is also higher as a result of higher 2024 Forecast earned return and depreciation expense, which is partially offset by lower amortization of deferred charges.

[49] https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/sole-proprietorships-partnerships/report-business-income-expenses/claiming-capital-cost-allowance/accelerated-investment-incentive.html#AppPhaseOut.

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

All other differences in income tax expense are subject to earnings sharing.

9.4 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. Since FBC is unable to determine final earnings sharing until all items required for the ROE calculation are known, including the final rate base, there is a lag in when FBC distributes earnings sharing amounts. This is consistent with the calculations of formula O&M, where the true-up of the formula inputs happens only once actuals are known. Thus, for 2024 rates, it is the 2022 formula O&M and 2022 earnings sharing amounts that are calculated and impact rates in 2024.

For 2024, FBC proposes to distribute a $2.396 million pre-tax credit ($1.749 million after-tax) to customers, comprised of:

- The $1.749 million credit difference between the projected 2022 deferral account after-tax addition of zero embedded in 2023 rates, and the actual 2022 deferral account after-tax credit addition of $1.749 million as provided in FBC's 2022 Annual Report to the BCUC. This amount is also shown in the opening 2024 balance[50] in the financial schedules in the Application.

FBC proposes to distribute $2.396 million to customers in 2024 as a reduction in 2024 revenue requirements through amortization of the projected 2024 opening after-tax balance of $1.749 million in the MRP Earnings Sharing deferral account.

As part of future rate filings, the actual earnings sharing for 2023 will be distributed to or collected from customers in a similar manner as described above, which will account for the actual 2023 ROE variance from approved.

[50] Section 11, Schedule 12.2, Line 14, Column 2.

11. FINANCIAL SCHEDULES

Description	Schedule Reference
Summary Of Rate Change	1
Rate Base	
Utility Rate Base	2
Formula Inflation Factors	3
Capital Expenditures	4
Capital Expenditures To Plant Reconciliation	5
Plant In Service Continuity Schedule	6
Accumulated Depreciation Continuity Schedule	7
Schedule Not Applicable	8
Contributions In Aid Of Construction Continuity Schedule	9
Schedule Not Applicable	10
Unamortized Deferred Charges And Amortization - Rate Base	11
Unamortized Deferred Charges And Amortization - Non-Rate Base	12
Working Capital Allowance	13
Cash Working Capital	14
Schedule Not Applicable	15
Revenue Requirement	
Utility Income And Earned Return	16
Volume And Revenue	17
Revenue At Existing And Revised Rates	18
Cost Of Energy	19
Operating And Maintenance Expense	20
Depreciation And Amortization Expense	21
Property And Sundry Taxes	22
Other Revenue	23
Income Taxes	24
Capital Cost Allowance	25
Return On Capital	26
Embedded Cost Of Long Term Debt	27

SUMMARY OF RATE CHANGE
FOR THE YEAR ENDING DECEMBER 31, 2024
($millions)

Line No.	Particulars	2024 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (2.304)		
3	Change in Other Revenue	0.149	(2.155)	
4				
5	**POWER SUPPLY**			
6	Power Purchases	10.119		
7	Wheeling	0.337		
8	Water Fees	0.971	11.427	
9				
10	**O&M CHANGES**			
11	Gross O&M Change	1.655		
12	Capitalized Overhead Change	(0.248)	1.407	
13				
14	**DEPRECIATION EXPENSE**			
15	Depreciation from Net Additions		2.579	
16				
17	**AMORTIZATION EXPENSE**			
18	CIAC from Net Additions	(0.242)		
19	Deferrals	0.487	0.245	
20				
21	**FINANCING AND RETURN ON EQUITY**			
22	Financing Rate Changes	0.346		
23	Financing Ratio Changes	(0.056)		
24	Rate Base Growth	2.566	2.856	
25				
26	**TAX EXPENSE**			
27	Property and Other Taxes	0.313		
28	Other Income Taxes Changes	4.002	4.315	
29				
30	**REVENUE DEFICIENCY (SURPLUS)**		**$ 20.674**	Schedule 16, Line 6, Column 4
31				
32	Revenue at Existing Rates		428.377	Schedule 18, Line 7, Column 3
33	Rate Change		4.83%	

FORTISBC INC.

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 2

Line No.	Particulars	2023 Approved	2024 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 2,375,297	$ 2,505,386	$ 130,089	Schedule 6.1, Line 32, Column 3
2	Opening Balance Adjustment	-	-	-	Schedule 6.1, Line 32, Column 4
3	Net Additions	133,903	96,482	(37,421)	Schedule 6.1, Line 32, Column 5+6+7
4	Plant in Service, Ending	2,509,200	2,601,868	92,668	
5					
6	Accumulated Depreciation Beginning	$ (693,759)	$ (741,726)	$ (47,967)	Schedule 7.1, Line 32, Column 5
7	Opening Balance Adjustment	-	-	-	Schedule 7.1, Line 32, Column 6
8	Net Additions	(48,025)	(52,613)	(4,588)	Schedule 7.1, Line 32, Column 7+8+9
9	Accumulated Depreciation Ending	(741,784)	(794,339)	(52,555)	
10					
11	CIAC, Beginning	$ (243,101)	$ (254,724)	$ (11,623)	Schedule 9, Line 3, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(11,628)	(7,539)	4,089	Schedule 9, Line 3, Column 5+6
14	CIAC, Ending	(254,729)	(262,263)	(7,534)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 89,140	$ 94,207	$ 5,067	Schedule 9, Line 7, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	5,067	5,309	242	Schedule 9, Line 7, Column 5+6
19	Accumulated Amortization Ending - CIAC	94,207	99,516	5,309	
20					
21	Net Plant in Service, Mid-Year	$ 1,567,236	$ 1,623,963	$ 56,727	
22					
23	Adjustment for timing of Capital additions	$ 22,720	$ 2,750	$ (19,970)	
24	Capital Work in Progress, No AFUDC	34,306	25,574	(8,732)	
25	Unamortized Deferred Charges	40,045	51,287	11,242	Schedule 11, Line 34, Column 8
26	Working Capital	6,099	6,510	411	Schedule 13, Line 9, Column 3
27	Utility Plant Acquisition Adjustment	4,563	4,377	(186)	
28					
29	Mid-Year Utility Rate Base	$ 1,674,969	$ 1,714,461	$ 39,492	

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Schedule 3

FORMULA INFLATION FACTORS
FOR THE YEARS ENDING DECEMBER 31, 2020 to 2024
($000s)

Line No.	Particulars	Reference	2020	2021	2022	2023	2024	Total for 2024 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Formula Cost Drivers**								
2	CPI		2.692%	1.596%	1.281%	4.940%	6.031%		
3	AWE		2.881%	5.745%	6.455%	3.944%	2.609%		
4	Labour Split								
5	Non Labour		38.000%	38.000%	37.000%	40.000%	43.000%		
6	Labour		62.000%	62.000%	63.000%	60.000%	57.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	2.809%	4.168%	4.541%	4.342%	4.080%		
8	Productivity Factor	G-166-20	-0.500%	-0.500%	-0.500%	-0.500%	-0.500%		
9	Net Inflation Factor	Line 7 + Line 8	2.309%	3.668%	4.041%	3.842%	3.580%		
10									
11									
12	**Growth in Average Customer Calculation**								
13	Actual/Projected Prior Year Average Customers		139,916	142,321	144,877	147,112	149,677		
14	Average Customers for the Year	Schedule 18, Line 7, Column 6	142,321	144,877	147,112	149,677	152,006		
15	Change in Average Customers	Line 14 - Line 13	2,405	2,556	2,235	2,565	2,329	12,090	
16									
17	Customer Growth Factor Multiplier	G-166-20						75%	
18	Change in Average Customers for Rate Setting Purposes	Line 15 x Line 17						9,068	
19									
20	Average Customers Used to Determine Starting UCOM	Line 13 Year 2020						139,916	
21									
22	Average Customer Forecast - 2024 Rate Setting Purposes	Line 18 + Line 20						148,984	

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Schedule 4

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	Total CapEx	Cross Reference
	(1)	(2)	(3)
1	**Forecast Capital Expenditures**		
2	Growth Capital	$ 24,568	
3	Sustainment Capital	51,652	
4	Other Capital	17,213	
5	Total Forecast Capital	$ 93,433	
6			
7	**Flow-Through Capital Expenditures**		
8	EV Charging Stations	$ 500	
9			
10	**Total Regular Capital Expenditures**	$ 93,933	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2024 Formula		Cross Reference
	(1)	(2)		(3)
1	**CAPEX**			
2	Forecast Capital Expenditures	$	93,433	
3	Flow-Through Capital		500	
4	Total Regular Capital Expenditures	$	93,933	Schedule 4, Line 10, Column 2
5				
6	**Special Projects and CPCN's**			
7				
8	Total Special Projects and CPCN's	$	-	
9				
10	**Total Capital Expenditures**	$	93,933	
11				
12				
13	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
14				
15	Regular Capital Expenditures	$	93,933	Line 4
16	Add - Capitalized Overheads		11,148	Schedule 20, Line 23, Column 4
17	Add - AFUDC		241	
18	Gross Capital Expenditures	$	105,322	
19	Change in Work in Progress		-	
20	**Total Regular Additions to Plant**	$	105,322	
21				
22	Special Projects and CPCN's Capital Expenditures	$	-	Line 8
23	Add - AFUDC		1	
24	Gross Capital Expenditures		1	
25	Change in Work in Progress		5,499	
26	**Total Special Projects and CPCN Additions to Plant**	$	5,500	
27				
28	**Grand Total Additions to Plant**	$	110,822	Schedule 6.1, Line 32, Columns 5 + 6

FORTISBC INC.

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 6

Line No.	Account	Particulars	12/31/2023	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2024	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	22,199	-	-	166	(12)	22,353	
4	332	Reservoirs, Dams & Waterways	139,590	-	2,731	7,690	(777)	149,234	
5	333	Water Wheels, Turbines and Gen.	106,005	-	-	694	(141)	106,558	
6	334	Accessory Equipment	51,447	-	-	128	(38)	51,537	
7	335	Other Power Plant Equipment	48,576	-	-	5	(1)	48,580	
8	336	Roads, Railroads and Bridges	1,287	-	-	-	-	1,287	
9			$ 370,066	$ -	$ 2,731	$ 8,683	$ (969)	$ 380,511	
10									
11		**Transmission Plant**							
12	350	Land Rights-R/W	$ 10,884	$ -	$ -	$ 118	$ -	$ 11,002	
13	350.1	Land Rights-Clearing	10,109	-	-	118	-	10,227	
14	353	Station Equipment	264,083	-	2,769	3,420	(303)	269,969	
15	355	Poles Towers & Fixtures	134,762	-	-	6,403	(289)	140,876	
16	356	Conductors and Devices	129,994	-	-	6,403	(310)	136,087	
17	359	Roads and Trails	959	-	-	-	-	959	
18			$ 550,791	$ -	$ 2,769	$ 16,462	$ (902)	$ 569,120	

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PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6.1
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	12/31/2023	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Distribution Plant**							
2	360	Land Rights-R/W	$ 7,995	$ -	$ -	$ 810	$ -	$ 8,805	
3	360.1	Land Rights-Clearing	12,001	-	-	372	-	12,373	
4	362	Station Equipment	324,416	-	-	12,969	(879)	336,506	
5	364	Poles Towers & Fixtures	271,743	-	-	13,565	(577)	284,731	
6	365	Conductors and Devices	456,680	-	-	20,383	(722)	476,341	
7	368	Line Transformers	205,825	-	-	14,062	(1,803)	218,084	
8	369	Services	9,521	-	-	-	-	9,521	
9	370.1	AMI Meters	41,986	-	-	528	-	42,514	
10	371	Installation on Customers' Premises	938	-	-	-	-	938	
11	373	Street Lighting and Signal System	14,304	-	-	168	(42)	14,430	
12	372	EV Stations Kiosks & Charger Connectors	6,265	-	-	-	-	6,265	
13			$ 1,351,674	$ -	$ -	$ 62,857	$ (4,023)	$ 1,410,508	
14									
15		**General Plant**							
16	389	Land	$ 11,268	$ -	$ -	$ -	$ -	$ 11,268	
17	390.1	Structures - Masonry	50,339	-	-	2,765	(317)	52,787	
18	390.2	Operation Building	20,014	-	-	605	(22)	20,597	
19	390.9	Leasehold Improvements	3,727	-	-	-	-	3,727	
20	391	Office Furniture & Equipment	5,376	-	-	214	(5)	5,585	
21	391.1	Computer Hardware	13,899	-	-	3,305	(1,278)	15,926	
22	391.2	Computer Software	44,861	-	-	6,982	(4,254)	47,589	
23	391.2	AMI Software	13,436	-	-	(3)	-	13,433	
24	392.1	Light Duty Vehicles	6,031	-	-	545	(481)	6,095	
25	392.1	Heavy Duty Vehciles	29,840	-	-	1,512	(348)	31,004	
26	394	Tools and Work Equipment	8,637	-	-	719	(658)	8,698	
27	397	Communication Structures & Equipment	14,926	-	-	676	(836)	14,766	
28	397.1	Fibre	5,531	-	-	-	(247)	5,284	
29	397.2	AMI Communications Structure & Equipment	4,970	-	-	-	-	4,970	
30			$ 232,855	$ -	$ -	$ 17,320	$ (8,446)	$ 241,729	
31									
32		**Total Plant in Service**	$ 2,505,386	$ -	$ 5,500	$ 105,322	$ (14,340)	$ 2,601,868	
33									
34		Cross Reference			Schedule 5, Line 26, Column 2	Schedule 5, Line 20, Column 2			

FORTISBC INC.

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2023	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2024	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Hydraulic Production Plant**										
2	330	Land Rights	$ 962	1.07%	$ (372)	$ -	$ 10	$ -	$ -	$ -	$ (362)	
3	331	Structures and Improvements	22,199	1.68%	6,076	-	373	(12)	-	-	6,437	
4	332	Reservoirs, Dams & Waterways	142,321	1.90%	7,167	-	2,704	(777)	(1,894)	-	7,200	
5	333	Water Wheels, Turbines and Gen.	106,005	1.79%	22,308	-	1,897	(141)	(3)	-	24,061	
6	334	Accessory Equipment	51,447	3.13%	16,560	-	1,610	(38)	(133)	-	17,999	
7	335	Other Power Plant Equipment	48,576	2.12%	21,200	-	1,030	(1)	-	-	22,229	
8	336	Roads, Railroads and Bridges	1,287	1.44%	495	-	19	-	-	-	514	
9			$ 372,797		$ 73,434	$ -	$ 7,643	$ (969)	$ (2,030)	$ -	$ 78,078	
10												
11		**Transmission Plant**										
12	350	Land Rights-R/W	$ 10,884	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
13	350.1	Land Rights-Clearing	10,109	1.27%	2,612	-	128	-	-	-	2,740	
14	353	Station Equipment	266,852	2.33%	107,657	-	6,218	(303)	(162)	-	113,410	
15	355	Poles Towers & Fixtures	134,762	2.52%	41,827	-	3,396	(289)	(479)	-	44,455	
16	356	Conductors and Devices	129,994	2.52%	26,379	-	3,275	(310)	(479)	-	28,865	
17	359	Roads and Trails	959	1.96%	451	-	19	-	-	-	470	
18			$ 553,560		$ 178,926	$ -	$ 13,036	$ (902)	$ (1,120)	$ -	$ 189,940	

FORTISBC INC.

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 7.1

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2023	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2024	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Distribution Plant**										
2	360	Land Rights-R/W	$ 7,995	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
3	360.1	Land Rights-Clearing	12,001	1.25%	3,080	-	150	-	-	-	3,230	
4	362	Station Equipment	324,416	2.61%	100,441	-	8,467	(879)	(159)	-	107,870	
5	364	Poles Towers & Fixtures	271,743	2.73%	86,032	-	7,419	(577)	(578)	-	92,296	
6	365	Conductors and Devices	456,680	2.38%	138,391	-	10,868	(722)	(933)	-	147,604	
7	368	Line Transformers	205,825	3.13%	49,872	-	6,442	(1,803)	(354)	-	54,157	
8	369	Services	9,521	0.51%	6,856	-	49	-	-	-	6,905	
9	370.1	AMI Meters	41,986	6.25%	15,488	-	2,624	-	-	-	18,112	
10	371	Installation on Customers' Premises	938	0.00%	937	-	-	-	-	-	937	
11	373	Street Lighting and Signal System	14,304	4.95%	6,919	-	708	(42)	-	-	7,585	
12	372	EV Stations Kiosks & Charger Connectors	6,265	10.00%	1,422	-	627	-	-	-	2,049	
13			$ 1,351,674		$ 409,438	$ -	$ 37,354	$ (4,023)	$ (2,024)	$ -	$ 440,745	
14												
15		**General Plant**										
16	389	Land	$ 11,268	0.00%	$ 34	$ -	$ -	$ -	$ -	$ -	$ 34	
17	390.1	Structures - Masonry	50,339	2.53%	14,019	-	1,274	(317)	-	-	14,976	
18	390.2	Operation Building	20,014	1.63%	7,376	-	326	(22)	-	-	7,680	
19	390.9	Leasehold Improvements	3,727	1.63%	2,747	-	61	-	-	-	2,808	
20	391	Office Furniture & Equipment	5,376	4.42%	1,503	-	238	(5)	-	-	1,736	
21	391.1	Computer Hardware	13,899	21.60%	4,422	-	3,002	(1,278)	-	-	6,146	
22	391.2	Computer Software	44,861	8.96%	16,106	-	4,020	(4,254)	-	-	15,872	
23	391.2	AMI Software	13,436	10.00%	8,971	-	1,344	-	-	-	10,315	
24	392.1	Light Duty Vehicles	6,031	3.81%	2,352	-	230	(481)	79	-	2,180	
25	392.1	Heavy Duty Vehciles	29,840	6.50%	9,582	-	1,940	(348)	-	-	11,174	
26	394	Tools and Work Equipment	8,637	4.11%	3,262	-	355	(658)	-	-	2,959	
27	397	Communication Structures & Equipment	14,926	3.44%	4,145	-	513	(836)	(5)	-	3,817	
28	397.1	Fibre	5,531	6.97%	2,687	-	386	(247)	-	-	2,826	
29	397.2	AMI Communications Structure & Equipment	4,970	6.67%	2,722	-	331	-	-	-	3,053	
30			$ 232,855		$ 79,928	$ -	$ 14,020	$ (8,446)	$ 74	$ -	$ 85,576	
31												
32		**Total**	$ 2,510,886		$ 741,726	$ -	$ 72,053	$ (14,340)	$ (5,100)	$ -	$ 794,339	
33												
34		Cross Reference	Schedule 6.1, Line 32, Column 3+4+5									

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 9

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	CIAC	$ 254,724	$ -	$ -	$ 7,539	$ -	$ 262,263	
3	**Total**	$ 254,724	$ -	$ -	$ 7,539	$ -	$ 262,263	
4								
5	**Amortization**							
6	Amortization	$ (94,207)	$ -	$ -	$ (5,309)	$ -	$ (99,516)	
7	**Total**	$ (94,207)	$ -	$ -	$ (5,309)	$ -	$ (99,516)	
8								
9	**Net CIAC**	$ 160,517	$ -	$ -	$ 2,230	$ -	$ 162,747	

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

Schedule 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**1. Forecasting Variance Accounts**								
2	BCUC Levies Variance Account	$ 36	$ -	$ -	$ -	$ (36)	$ -	$ 18	
3									
4	**2. Rate Smoothing Accounts**								
5									
6	**3. Benefits Matching Accounts**								
7	Preliminary and Investigative Charges '	$ 2,923	$ -	$ 328	$ -	$ -	$ 3,251	$ 3,087	Note 1
8	Demand Side Management	41,573	-	15,436	(4,168)	(6,287)	46,554	44,063	
9	Deferred Debt Issue Costs	4,391	-	-	(110)	(196)	4,084	4,237	
10	2025 Multi-year Rate Plan Application	256	-	1,200	(324)	-	1,132	694	
11	2023 - 2027 DSM Expenditure Schedule	62	-	-	-	(16)	47	55	
12	Mandatory Reliability Standards 2024 Audit	-	-	375	(101)	(91)	183	91	
13	Joint Pole Use Audit 2023	356	-	-	-	(89)	267	312	
14	2021 Generic Cost of Capital Proceeding	770	-	-	-	-	770	770	
15	Annual Reviews for 2020-2024 Rates	49	-	90	(25)	(49)	66	58	
16	2021 Long Term Electric Resource Plan	329	-	-	-	(174)	155	242	
17	BCUC Initiated Inquiry Costs	(57)	-	-	-	57	-	(28)	
18	EV Fleet & Workplace Charging Funding Account	-	169	576	(155)	(17)	572	371	
19	Mandatory Reliability Standards 2021 Audit	78	-	-	-	(78)	-	39	
20		$ 50,730	$ 169	$ 18,005	$ (4,883)	$ (6,940)	$ 57,080	$ 53,991	
21									
22	**4. Retroactive Expense Accounts**								
23									
24	**5.Other Accounts**								
25	Pension and OPEB Liability	$ (5,046)	$ -	$ 5,220	$ -	$ -	$ 174	$ (2,436)	
26	COVID-19 Customer Recovery Fund	139	-	-	-	(70)	68	104	
27	Climate Change Operational Adaptation (CCOA)	164	-	192	(52)	(41)	263	214	
28	BC Cost of Living Credit	(370)	-	-	-	370	-	(185)	
29	Princeton Office Disposition	-	(406)	-	-	406	-	(203)	
30	PST Rebate on Select Machinery and Equipment	(431)	-	-	-	431	-	(216)	
31	Indigenous Relations Agreement (Huth Substation)	-	-	-	-	-	-	-	
32		$ (5,545)	$ (406)	$ 5,412	$ (52)	$ 1,096	$ 506	$ (2,722)	
33									
34	**Total Rate Base Deferral Accounts**	$ 45,221	$ (237)	$ 23,417	$ (4,935)	$ (5,880)	$ 57,586	$ 51,287	
35									

36 Note 1: Gross Additions for Preliminary and Investigative Charges are after transfers to Construction Work in Progress. Additions of $1.60 million - transfer of $1.272 million = $0.328 million.

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 12

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	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	$ (169)	$ -	$ -	$ -	$ (246)	$ (415)	$ (292)	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	Tariff Applications	86	-	75	(20)	(86)	54	70	
10									
11	**4. Retroactive Expense Accounts**								
12									
13	**5.Other Accounts**								
14									
15	**Total NRB Deferral Accounts at Short Term Interest**	$ (83)	$ -	$ 75	$ (20)	$ (332)	$ (361)	$ (222)	
16									
17	Financing Costs at STI	$ 27	$ -	$ (7)	$ -	$ (27)	$ (7)	$ 10	

FORTISBC INC.

Schedule 12.1

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	Mid-Year Average	Cross Ref
	(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									
7	**3. Benefits Matching Accounts**								
8	CPCN Projects Preliminary Engineering [1]	$ 2,666	$ -	$ (255)	$ -	$ -	$ 2,411	$ 2,538	Note 1
9	2017 Rate Design Application	118	-	-	-	(118)	-	59	
10	2020 - 2024 Multi-Year Rate Plan Application	145	-	-	-	(145)	-	72	
11	Rate Design and Rates for Electric Vehicle Direct Current Fast Charging Service Application	68	-	-	-	(59)	9	38	
12		$ 2,996	$ -	$ (255)	$ -	$ (322)	$ 2,420	$ 2,707	
13									
14	**4. Retroactive Expense Accounts**								
15									
16	**5.Other Accounts**								
17									
18	**Total NRB Deferral Accounts at Weighted Average Cost of Debt**	$ 2,996	$ -	$ (255)	$ -	$ (322)	$ 2,420	$ 2,707	
19									
20	Financing Costs at WACD	$ 76	$ -	$ 95	$ -	$ (76)	$ 95	$ 86	

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

FORTISBC INC.

Schedule 12.2

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE cont'd
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	12/31/2024	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	$ (6,520)	$ -	$ -	$ -	$ 6,520	$ -	$ (3,260)	
5									
6	**2. Rate Smoothing Accounts**								
7									
8	**3. Benefits Matching Accounts**								
9	EV Fleet & Workplace Charging Funding Account	$ 169	$ (169)	$ -	$ -	$ -	$ -	$ -	
10									
11	**4. Retroactive Expense Accounts**								
12									
13	**5.Other Accounts**								
14	MRP Earnings Sharing Account	$ (1,749)	$ -	$ -	$ -	$ 1,749	$ -	$ (875)	
15	Princeton Office Disposition	(406)	406	-	-	-	-	-	
16									
17	**Total NRB Deferral Accounts at Weighted Average Cost of Capital**	$ (8,506)	$ 237	$ -	$ -	$ 8,269	$ -	$ (4,135)	
18									
19	Financing Costs at AFUDC	$ (1,228)	$ -	$ (272)	$ -	$ 1,228	(272)	(750)	
20									
21	**Non Rate Base Deferral Accounts Non-Interest Bearing**	$ 50	$ -	$ -	$ -	$ -	$ 50	$ 50	
22									
23									
24	**Total Non Rate Base Deferral Accounts (including financing)**	$ (6,668)	$ 237	$ (364)	$ (20)	$ 8,740	$ 1,924	$ (2,254)	

FORTISBC INC.

FBC Annual Review for 2024 Rates - August 4, 2023

Section 11

Schedule 13

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 6,849	$ 7,367	$ 518	Schedule 14, Line 32, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Customers Loans	353	306	(47)	
6	Employee Loans	570	509	(61)	
7	Inventories - Materials and Supplies	649	783	134	
8	Employee Withholdings	(2,322)	(2,455)	(133)	
9	Total	$ 6,099	$ 6,510	$ 411	

FORTISBC INC.

FBC Annual Review for 2024 Rates - August 4, 2023

Section 11

Schedule 14

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2024 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	$ 215,950	56.0	$ 12,093,200		
4	Commercial Tariff Revenue	116,156	45.1	5,238,636		
5	Wholesale Tariff Revenue	58,256	37.5	2,184,600		
6	Industrial Tariff Revenue	52,203	38.0	1,983,714		
7	Lighting Tariff Revenue	2,328	34.6	80,549		
8	Irrigation Tariff Revenue	4,158	47.0	195,426		
9						
10	**Other Revenue**					
11	Apparatus and Facilities Rental	$ 6,199	90.0	$ 557,894		
12	Contract Revenue	2,260	62.2	140,563		
13	Transmission Access Revenue	1,723	65.2	112,340		
14	Late Payment Charges	962	54.0	51,922		
15	Connection Charges	561	30.5	17,104		
16	Other Utility Income	388	63.4	24,606		
17	Total	$ 461,143		$ 22,680,554		49.2
18						
19	**EXPENSES**					
20	Power Purchases	$ 173,694	(51.5)	$ (8,945,261)		
21	Wheeling	7,324	(46.9)	(343,514)		
22	Water Fees	12,513	(1.4)	(17,518)		
23	Operating and Maintenance	63,174	(28.6)	(1,806,768)		
24	Property Taxes	18,573	(4.9)	(91,008)		
25	GST	703	(45.4)	(31,916)		
26	Income Tax	10,075	(15.2)	(153,140)		
27	Total	$ 286,057		$ (11,389,125)		(39.8)
28						
29	Net Lag (Lead) Days					9.4
30	Total Expenses				$	286,057
31						
32	Cash Working Capital				$	7,367

SCHEDULE NOT APPLICABLE

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 16

Line No.	Particulars	2023 Approved	2024 Forecast at 2023 Approved Rates	Revised Revenue	2024 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (GWh)	3,475	3,474	-	3,474	(1)	Schedule 17, Line 8, Column 3
3							
4	**REVENUE**						
5	Sales	$ 426,073	$ 428,377	$ -	$ 428,377	$ 2,304	Schedule 17, Line 17, Column 3
6	Deficiency (Surplus)	-	-	20,674	20,674	20,674	
7	Total	426,073	428,377	20,674	449,051	22,978	Schedule 18, Line 7, Column 5
8							
9	**EXPENSES**						
10	Cost of Energy	$ 182,105	$ 193,532	$ -	$ 193,532	$ 11,427	Schedule 19, Line 29, Column 3
11	O&M Expense (net)	61,767	63,174	-	63,174	1,407	Schedule 20, Line 24, Column 4
12	Depreciation & Amortization	61,246	64,070	-	64,070	2,824	Schedule 21, Line 11, Column 3
13	Property Taxes	18,260	18,573	-	18,573	313	Schedule 22, Line 6, Column 3
14	Other Revenue	(12,241)	(12,092)	-	(12,092)	149	Schedule 23, Line 8, Column 3
15	Utility Income Before Income Taxes	114,936	101,120	20,674	121,794	6,859	
16							
17	Income Taxes	6,073	4,498	5,577	10,075	4,002	Schedule 24, Line 13, Column 3
18							
19	**EARNED RETURN**	$ 108,863	$ 96,622	$ 15,097	$ 111,719	$ 2,857	Schedule 26, Line 5, Column 7
20							
21	**UTILITY RATE BASE**	$ 1,674,969	$ 1,713,933		$ 1,714,461	$ 39,492	Schedule 2, Line 29, Column 3
22	**RATE OF RETURN ON UTILITY RATE BASE**	6.50%	5.64%		6.52%	0.02%	Schedule 26, Line 5, Column 6

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

VOLUME AND REVENUE Schedule 17
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (GWh)**				
2	Residential	1,300	1,299	(1)	
3	Commercial	973	974	1	
4	Wholesale	579	590	11	
5	Industrial	575	564	(11)	
6	Lighting	9	9	-	
7	Irrigation	39	38	(1)	
8	Total	3,475	3,474	(1)	
9					
10	**REVENUE AT EXISTING RATES**				
11	Residential	$ 205,734	$ 206,007	$ 273	
12	Commercial	110,490	110,808	318	
13	Wholesale	54,100	55,574	1,474	
14	Industrial	49,759	49,800	41	
15	Lighting	2,295	2,221	(74)	
16	Irrigation	3,695	3,967	272	
17	Total	$ 426,073	$ 428,377	$ 2,304	

FORTISBC INC. FBC Annual Review for 2024 Rates - August 4, 2023 Section 11

REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 18

Line No.	Particulars	2023 Approved Revenue	2024 Forecast: Revenue at 2023 Approved Rates	2024 Forecast: Effective Increase	2024 Forecast: Revenue at Revised Rates	Average Number of Customers	GWh	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Residential	$ 205,734	$ 206,007	$ 9,943	$ 215,950	132,389	1,299	
2	Commercial	110,490	110,808	5,348	116,156	17,125	974	
3	Wholesale	54,100	55,574	2,682	58,256	6	590	
4	Industrial	49,759	49,800	2,403	52,203	42	564	
5	Lighting	2,295	2,221	107	2,328	1,341	9	
6	Irrigation	3,695	3,967	191	4,158	1,103	38	
7	Total	$ 426,073	$ 428,377	$ 20,674	$ 449,051	152,006	3,474	
8								
9	**Effective Increase**			4.83%				

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COST OF ENERGY Schedule 19
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**POWER PURCHASES**				
2	Gross Load (GWh)	3,775	3,773	(2)	
3					
4	**Power Purchase Expense**				
5	Brilliant	$ 44,050	$ 44,433	$ 383	
6	BC Hydro PPA	71,302	71,680	378	
7	Waneta Expansion	41,834	40,365	(1,469)	
8	Market and Contracted Producers	6,326	16,972	10,646	
9	Independent Power Producers	62	245	183	
10	CPA Balancing Pool	-	0	0	
11	Total	$ 163,575	$ 173,694	$ 10,119	
12					
13	**WHEELING**				
14	**Wheeling Nomination (MW months)**				
15	Okanagan Point of Interconnection	2,670	2,595	(75)	
16	Creston	420	450	30	
17					
18	**Wheeling Expense**				
19	Okanagan Point of Interconnect	$ 5,555	$ 5,813	$ 258	
20	Creston	570	658	88	
21	Other	863	854	(9)	
22	Total	$ 6,987	$ 7,324	$ 337	
23					
24	**WATER FEES**				
25	Plant Entitlement Use in previous year (GWh)	1,571	1,561	(10)	
26					
27	Water Fees	$ 11,543	$ 12,513	$ 971	
28					
29	Total	$ 182,105	$ 193,532	$ 11,427	

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OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 20

Line No.	Particulars	Inflation Indexed O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Inflation Indexed O&M**				
2	2023 Base Unit Cost O&M	$ 472			
3	2024 Net Inflation Factor	3.580%			Schedule 3, Line 9, Column 7
4	2024 Base Unit Cost O&M	$ 489			Line 2 x (1 + Line 3)
5					
6	2024 Average Customer Forecast - Rate Setting Purpose	148,984			Schedule 3, Line 22, Column 8
7					
8	2024 Inflation Indexed O&M before prior year True-up	$ 72,853			Line 4 x Line 6 / 1,000
9					
10	2022 Average Customer True-up	(30)			
11					
12	2024 Inflation Indexed O&M	$ 72,823		$ 72,823	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ (2,532)		
16	Insurance Premiums		2,678		
17	BCUC Levies		458		
18	MRS		585		
19	EV Charging Stations		310		
20	Sub-total		$ 1,499	1,499	Sum of Lines 15 through 19
21					
22	**Total Gross O&M**			$ 74,322	Line 12 + Line 20
23	Capitalized Overhead			(11,148)	-15 % x Line 22
24	**Net O&M Expense**			$ 63,174	Sum of Lines 22 and 23

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 69,474	$ 72,053	$ 2,579	Schedule 7.1, Line 32, Column 7
3					
4	**Amortization**				
5	Rate Base Deferrals	$ 6,716	$ 5,880	$ (836)	Schedule 11, Line 34, Column 6
6	Non-Rate Base Deferrals	(10,063)	(8,740)	1,323	Schedule 12.2, Line 24, Column 6
7	Utility Plant Acquisition Adjustment	186	186	-	
8	CIAC	(5,067)	(5,309)	(242)	Schedule 9, Line 7, Column 5
9		(8,228)	(7,983)	245	
10					
11	Total	$ 61,246	$ 64,070	$ 2,824	

FORTISBC INC.

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Section 11

Schedule 22

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Generating Plant	$ 3,253	$ 3,259	$ 6	
2	Transmission and Distribution	7,189	7,317	128	
3	Substation Equipment	4,208	4,328	120	
4	Land and Buildings	1,322	1,532	210	
5	1% In-Lieu of Municipal Taxes	2,288	2,137	(151)	
6	Total	$ 18,260	$ 18,573	$ 313	

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OTHER REVENUE Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Apparatus and Facilities Rental	$ 6,108	$ 6,199	$ 91	
2	Contract Revenue	2,367	2,260	(107)	
3	Transmission Access Revenue	1,834	1,723	(111)	
4	Interest Income	30	37	7	
5	Late Payment Charges	994	962	(32)	
6	Connection Charges	553	561	8	
7	Other Recoveries	355	351	(4)	
8	Total	$ 12,241	$ 12,092	$ (149)	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 108,863	$ 111,719	$ 2,856	Schedule 16, Line 19, Column 5
2	Deduct: Interest on Debt	(47,559)	(48,970)	(1,411)	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	(44,884)	(35,508)	9,376	Line 32
4	Accounting Income After Tax	$ 16,420	$ 27,241	$ 10,821	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 22,493	$ 37,316	$ 14,823	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 6,073	$ 10,075	$ 4,002	
11					
12	Previous Year Adjustment	-	-	-	
13	**Total Income Tax**	$ 6,073	$ 10,075	$ 4,002	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Depreciation	$ 69,474	$ 72,053	$ 2,579	Schedule 21, Line 2, Column 3
19	Amortization of Deferred Charges	(3,347)	(2,860)	487	Schedule 21, Line 5+6, Column 3
20	Amortization of Utility Plant Acquisition Adjustment	186	186	-	Schedule 21, Line 7, Column 3
21	Pension Expense	(528)	(1,501)	(973)	
22	OPEB Expense	1,119	844	(275)	
23					
24	Deductions:				
25	Capital Cost Allowance	(89,602)	(81,899)	7,703	Schedule 25, Line 18, Column 6
26	CIAC Amortization	(5,067)	(5,309)	(242)	Schedule 21, Line 8, Column 3
27	Pension Contributions	(4,203)	(3,811)	392	
28	OPEB Contributions	(705)	(752)	(47)	
29	Overheads Capitalized Expensed for Tax Purposes	(10,900)	(11,148)	(248)	Schedule 20, Line 23, Column 4
30	Removal Costs	(1,200)	(1,200)	-	
31	All Other	(111)	(111)	-	
32	Total	$ (44,884)	$ (35,508)	$ 9,376	

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Schedule 25

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Class	CCA Rate	12/31/2023 UCC Balance	2024 Additions & Opening Adjt	Adjustment	2024 CCA	Forecast 12/31/2024 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 147,922	$ -	$ -	$ (5,917)	$ 142,005
2	1(b)	6%	33,070	3,010	-	(2,165)	33,915
3	2	6%	10,719	-	-	(643)	10,076
4	3	5%	616	-	-	(31)	585
5	6	10%	2	-	-	-	2
6	8	20%	3,538	833	-	(874)	3,497
7	10	30%	4,308	1,838	-	(1,844)	4,302
8	13	0%	11	-	-	-	11
9	14.1 (pre 2017)	7%	6,441	-	-	(451)	5,990
10	14.1 (post 2016)	5%	4,926	1,266	-	(310)	5,882
11	17	8%	161,210	8,533	-	(13,579)	156,164
12	42	12%	8,987	604	-	(1,151)	8,440
13	43.1	30%	477	-	-	(143)	334
14	46	30%	1,896	-	-	(569)	1,327
15	47	8%	530,216	64,669	-	(47,591)	547,294
16	50	55%	2,869	9,188	-	(6,631)	5,426
17							
18	Total		$ 917,208	$ 89,941	$ -	$ (81,899)	$ 925,250

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Schedule 26

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved Earned Return	Amount	Ratio	2024 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 43,709	$ 935,137	54.54%	4.72%	2.57%	$ 44,097	$ 388	Schedule 27, Line 11, Column 6
2	Short Term Debt	3,850	93,540	5.46%	5.21%	0.28%	4,873	1,023	
3	Common Equity	61,304	685,784	40.00%	9.15%	3.66%	62,749	1,445	
4									
5	Total	$ 108,863	$ 1,714,461	100.00%		6.52%	$ 111,719	$ 2,856	
6									
7	Cross Reference		Schedule 2, Line 29, Column 3						

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Section 11

Schedule 27

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Average Principal Outstanding	Interest Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	2005 Debt Issue - Series 1 - 05	November 9, 2005	November 9, 2035	$ 100,000	5.600%	$ 5,600	
2	2007 Debt Issue - Series 1 - 07	July 4, 2007	July 4, 2047	105,000	5.900%	6,195	
3	2009 Debt Issue - MTN - 09	June 2, 2009	June 2, 2039	105,000	6.100%	6,405	
4	2010 Debt Issue - MTN - 10	November 24, 2010	November 24, 2050	100,000	5.000%	5,000	
5	2014 Debt Issue - MTN - 14	October 28, 2014	October 28, 2044	200,000	4.000%	8,000	
6	2017 Debt Issue - MTN - 17	December 4, 2017	December 6, 2049	75,000	3.620%	2,715	
7	2020 Debt Issue - MTN - 20	May 11, 2020	May 11, 2050	75,000	3.120%	2,340	
8	2022 Debt Issue - MTN - 22	March 14, 2022	March 14, 2052	100,000	4.160%	4,160	
9	2024 Debt Issue - MTN - 24	April 1, 2024	April 1, 2054	75,137	4.900%	3,682	
10							
11	Total			$ 935,137		$ 44,097	
12							
13	Average Embedded Cost				4.72%		

12. ACCOUNTING MATTERS

12.1 INTRODUCTION AND OVERVIEW

In this section, FBC discusses "Exogenous Factors" under its MRP. FBC also discusses emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FBC 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.

In 2022 and thus far in 2023, FBC has not identified any items that merit exogenous factor treatment.

12.3 ACCOUNTING MATTERS

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

12.3.1 Emerging Accounting Guidance

In the 2014-2019 PBR Plan Decision and Order G-139-14, 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.

There are no new accounting policy changes that FBC is proposing, or that are required to be implemented under US GAAP, that result in a change in accounting for 2024.

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.

In the following section, FBC 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 New Deferral Accounts

FBC is not seeking approval of any new non-rate base deferral accounts in this Application.

12.4.2 Existing Deferral Accounts

In the section below, FBC discusses the Flow-through deferral account.

12.4.2.1 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 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 12-1: 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

In accordance with the method set out in the table above, the calculation of the 2023 Projected Flow-through amount of $2.898 million debit is shown in Table 12-2 below. To calculate the overall combined amount to be distributed to customers, FBC has also included the following adjustment:

- The $9.418 million credit difference between the projected ending 2022 deferral account credit balance of $9.693 million[51] embedded in 2023 rates, and the actual ending 2022 deferral credit balance of $19.111 million. A more detailed breakout of the 2022 variance is provided in Table 12-3 below. FBC notes that the financing return on this account is included in the aggregate financing of deferral accounts at Section 11, Schedule 12.2, Line 19.

Table 12-2: 2023 Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2023 Approved	2023 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (426.073)	$ (431.720)	$ (5.647)
2				
3	**Total Power Purchase Expense**	163.575	170.873	7.298
4				
5	**Total Wheeling**	6.987	7.294	0.307
6				
7	**Total Water Fees**	11.543	12.433	0.890
8				
9	**Net O&M Expense**			
10	Pension & OPEB	(1.297)	(1.297)	-
11	Insurance	2.457	2.507	0.050
12	BCUC Fees	0.385	0.385	-
13	MRS	0.585	0.585	-
14	EV Charging Stations	0.219	0.181	(0.038)
15	Capitalized Overhead	(10.900)	(10.900)	-
16				
17	**Depreciation and Amortization**			
18	Amortization of Deferrals	(3.347)	(3.347)	-
19	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
20	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21				
22	**Total Property Taxes**	18.260	18.248	(0.012)
23				
24	**Other Revenues**			
25	EV Carbon Credits	-	(0.544)	(0.544)
26				
27	**Interest Expense**			
28	Long-term debt interest expense variance	43.709	41.856	(1.853)
29	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
30	Short-term debt rate variance	-	1.353	1.353
31	Short-term debt volume variance from long-term debt issue variance	-	2.166	2.166
32	Short-term debt timing variance from long-term debt issue timing	-	-	-
33				
34	**Income Tax Expense**			
35	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
36	Income tax/CCA rate changes	-	-	-
37	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	-	(1.072)	(1.072)
38				
39	**2023 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**2.898**
40				
41	2022 Ending Deferral Account Balance True-up			(9.418)
42				
43	**2024 After-Tax Amortization**			**(6.520)**

[51] FBC Annual Review for 2023 Rates, April 24, 2023 finalized financial schedules supporting 2023 Interim Rates, Schedule 12.2, Line 4, Column 2.

12.4.2.1.1 2023 PROJECTED FLOW-THROUGH VARIANCES

FBC provides the following explanations for the 2023 Projected flow-through variances shown in Table 12-2 above:

- The variance in revenue is due to increased sales from residential, commercial, and wholesale customers;
- The variance in power purchase expense is primarily due to increased Market and Contracted Purchases required to address supply gaps and reduce exposure to potentially extreme market prices. FBC purchased forward market blocks to cover projected capacity shortfalls in June 2023 and reduce exposure to Tranche 2 energy under the PPA with BC Hydro. FBC also purchased wholesale market power from the spot market, at rates economic to the PPA during the first six months of the year, to reduce required purchases above the BC Hydro PPA Nomination. Also included in the Projected 2023 expense are planned wholesale market purchases in November and December 2023, consistent with the strategy presented in the 2023/24 Annual Electric Contracting Plan (AECP);
- Variances in wheeling and water fees are discussed in Section 4;
- Flow-through O&M amounts are discussed in Section 6;
- Amortization expense is equal to the approved value;
- Variances in property taxes are described in Section 9;
- Variances in other revenues are described in Section 5;
- The projected interest expense variances are derived from FBC forecasting issuing long-term debt in 2023 in the Annual Review for 2023 Rates, whereas FBC is no longer projecting a debt issuance, and FBC projecting a higher short-term interest rate than the approved short-term interest rate, both as described in Section 8; and
- The income tax variance is derived as 27 percent of the aforementioned variances.

An adjustment to include the difference between the projected and final actual amounts for 2023 subject to flow-through will be recorded in the deferral account in 2023 and amortized in 2025 rates.

12.4.2.1.2 2022 FLOW-THROUGH DEFERRAL ACCOUNT TRUE-UP

Table 12-3 below provides a breakdown of the 2022 true-up amount of $9.418 million credit.

Table 12-3: 2022 Actual vs. Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2022 Projected	2022 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Total Revenue**	$ (414.385)	$ (425.782)	$ (11.397)
2				
3	**Total Power Purchase Expense**	153.164	153.457	0.293
4				
5	**Total Wheeling**	6.330	6.898	0.568
6				
7	**Total Water Fees**	11.916	11.838	(0.078)
8				
9	**Net O&M Expense**			
10	Pension & OPEB	(1.716)	(1.716)	-
11	Insurance	2.291	2.286	(0.005)
12	BCUC Fees	0.373	0.373	-
13	MRS	0.500	0.468	(0.032)
14	EV Charging Stations	0.187	0.213	0.026
15	COVID-19 Pandemic	(1.030)	(1.030)	-
16	Capitalized Overhead	(10.177)	(10.177)	-
17				
18	**Depreciation and Amortization**			
19	Amortization of Deferrals	1.558	1.558	-
20	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.027)	(0.027)
21	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	0.021	0.021
22				
23	**Total Property Taxes**	17.621	17.385	(0.236)
24				
25	**Other Revenues**			
26	EV Carbon Credits	(0.625)	(0.744)	(0.119)
27				
28	**Interest Expense**			
29	Long-term debt interest expense variance	41.794	41.794	(0.000)
30	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.041)	(0.041)
31	Short-term debt rate variance	2.253	0.964	(1.289)
32	Short-term debt volume variance from long-term debt issue variance	(1.005)	(0.646)	0.359
33	Short-term debt timing variance from long-term debt issue timing	0.793	0.510	(0.283)
34				
35	**Income Tax Expense**			
36	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.470)	(0.470)
37	Income tax/CCA rate changes	-	-	-
38	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	1.877	5.169	3.292
39				
40	**2022 Ending Deferral Account Balance True-up**			**(9.418)**

FBC provides the following explanations of the 2022 Actual variances shown in Table 12-3 above:

- The favourable variance in revenue of $11.397 million was primarily due to higher than projected residential and wholesale loads resulting largely from weather variations. Favourable variances in residential ($11.641 million), industrial ($0.270 million) and wholesale ($0.201 million) revenue were partially offset by unfavourable variances in commercial ($0.547 million), irrigation ($0.146 million) and lighting ($0.022 million) revenue;

- The increase in power purchase expense of $0.293 million was due to several factors including increased load, increased market purchases, and increased reliance on the BC Hydro PPA. Increased load and PPA purchases were primarily a result of prolonged cold weather at the end of 2022. This increase was partially offset by increased surplus capacity sales under the Capacity and Energy Purchase and Sale Agreement (CEPSA);

- The increase in wheeling costs of $0.568 million was primarily due to increased use of wheeling under BC Hydro's Open Access Transmission Tariff;

- The decrease in water fees of $0.078 million was primarily due to reduced water rental rates compared to forecast;

- The flow-through components of O&M expense were $0.011 million lower than projected, with all items comparable to the projected amounts;

- Actual property tax expense was relatively consistent with the projected amount;

- The flow-through components of other revenue were $0.119 million higher than projected, with the variance in EV Carbon Credit revenue due to approximately 329 carbon credits related to FBC's EV charging stations that were validated by BC-LCFS and monetized in 2022 but were not accounted for in the 2022 Projected amount;

- The variance between the actual (2.58 percent) and projected (4.02 percent) short-term debt interest rates results in an amount to be returned to customers of $1.289 million,[52] shown on Line 31 of the table above. There was no variance in long-term debt interest expense as actuals were as projected. The net variance of $0.076 million to be collected from customers on Lines 32 and 33 of Table 12-3 above is due to the impact of a lower actual short-term interest rate than projected;

- The unfavourable income tax variance of $3.292 million is calculated as 27 percent of the aforementioned variances; and

- The combined favourable variance of $0.517 million related to depreciation, CIAC amortization, interest and tax variances on Clean Growth/CPCN/exogenous capital amounts, shown on Lines 20, 21, 30 and 36, respectively, were derived for 2022 by comparing the actual 2022 cost of service impacts of the EV stations and the UBO, Grand Forks Terminal Station and Corra Linn projects to the amounts forecast for those same projects.

12.5 SUMMARY

FBC is not seeking any exogenous factor treatment in this Application. FBC is also not seeking approval of any new non-rate base deferral accounts but has provided an update on the Flow-through deferral account.

[52] (2.584% - 4.02%) x $89.744 million forecast 2022 short-term debt in Schedule 26 of Annual Review for 2022 Rates Compliance Filing financial schedules.

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.

In the subsections below, FBC reports on its 2022 and June 2023 year-to-date performance as measured against the SQI benchmarks and thresholds. In 2022, for the eight SQIs with benchmarks, six met or were better than the benchmark, with the First Contact Resolution better than the threshold and the Telephone Service Factor (Non-Emergency) lower than the threshold. For the four SQIs that are informational only, with the exception of the Average Speed of Answer results being higher due to the same challenges impacting the Telephone Service Factor (Non-Emergency), performance in 2022 for the other three informational metrics generally remains at a level consistent with prior years. In 2023 to date, performance for the metrics with benchmarks are trending towards meeting the benchmark or the threshold.

Consistent with how SQIs were reviewed during the 2014-2019 PBR Plan term,[53] FBC has provided 2022 and year-to-date 2023 SQI results in this annual review.

13.2 REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS

For each SQI, Table 13-1 provides a comparison of FBC's 2022 and June year-to-date performance for 2023 to the proposed benchmarks and thresholds approved as part of the MRP. Actual 2022 and June year-to-date results for 2023 are also provided for the four informational SQIs.

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

Performance Measure	Description	Benchmark	Threshold	2022 Results	June 2023 YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within two hours	>=93%	90.6%	94%	93%
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	1.42	1.76

[53] 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."

Performance Measure	Description	Benchmark	Threshold	2022 Results	June 2023 YTD Results
Responsiveness to Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	>=78%	74%	77%	78%
Billing Index	Measure of customer bills produced meeting performance criteria	<=3.0	5.0	0.14	2.20
Meter Reading Accuracy	Number of scheduled meters that were read	>=98%	96%	99%	99%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>=70%	68%	65%	72%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.4	8.5
Average Speed of Answer	Informational indicator – the amount of time it takes to answer a call (seconds)	-	-	98	60
Reliability SQIs					
System Average Interruption Duration Index (SAIDI) – Normalized	Annual SAIDI (average of cumulative customer outage time)	3.22[54]	4.52	2.42	3.21
System Average Interruption Frequency Index (SAIFI) - Normalized	Annual SAIFI (average customer outage)	1.57	2.19	1.52	1.48
Generator Forced Outage Rate	Informational indicator – Percent of time a generating unit is removed from service due to component failure or other events.	-	-	0.50%	0.65%
Interconnection Utilization	Informational indicator – percent of time that an interconnection point was available and providing electrical service to wholesale customers.	-	-	99.94%	99.98%

In the following sections, FBC reviews each SQI's year-to-date individual performance in 2022 and 2023. Discussion is also provided for the informational SQIs.

[54] Benchmarks and thresholds for SAIDI and SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

13.2.1 Safety Service Quality Indicators

13.2.1.1 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 2022 result was 94 percent which was better than the benchmark. The June 2023 year-to-date performance is 93 percent, which meets the benchmark.

For comparison, the Company's annual results under the 2014-2019 PBR Plan, the 2020, 2021, and 2022 results and the June 2023 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	2020	2021	2022	June 2023 YTD
Results	91%	92%	97%	93%	94%	92%	92%	93%	94%	93%
Benchmark	93%									
Threshold	90.6%									

13.2.1.2 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 2022 (three-year rolling average) result was 1.42 which was better than the benchmark of 1.64. The 2022 annual AIFR was 2.60 which reflected 4 Medical Treatments and 8 Lost Time Injuries. The increase in AIFR was particularly prevalent in Q4 2022, after a sudden change in winter conditions led to a notable spike in slips, trips, and falls resulting in more serious injuries. FBC responded to this by issuing an immediate safety alert (Safely Navigating Winter Conditions) to all field employees, which was also reviewed at all safety meetings, and providing access to traction aids throughout Operations.

The June 2023 year-to-date performance (three-year rolling average) result is 1.76 which is better than the threshold. The June 2023 year-to-date performance (annual) is 2.54 and reflects 3 Medical Treatments and 3 Lost Time Injuries. Thus far in 2023, FBC continues to see an increase in total minor preventable injuries, predominately those sustained while performing activities involving repetitive work and/or awkward positioning. FBC has responded to this by engaging its Ergonomist and Injury Prevention Specialist to provide more education and treatment throughout the Company. FBC also hired an Injury Management Specialist to provide proactive educational sessions, as well as customized Recover at Work plans for employees. In addition, FBC has implemented customized ergonomics courses for some of the higher risk areas.

Strengthening the safety culture continues to be a key driver for FBC, building on the commitment to learn from safety events, identify safety hazards, assess risk and continually improve the safety management system through the implementation and sustainment of robust safety defences and controls.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June year-to-date AIFR results are provided below.

Table 13-3: Historical All Injury Frequency Rate Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	3.21	1.54	1.15	1.13	1.56	0.46	0.66	0.89	2.60	2.54
Three year rolling average	2.58	2.52	1.97	1.27	1.28	1.06	0.87	0.67	1.42	1.76
Benchmark	1.64									
Threshold	2.39									

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

13.2.2.1 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 2022 result was 77 percent which was better than the threshold of 74 percent. The reduction in FCR for 2022 as compared to previous years, as shown in Table 13-4 below, is largely attributable to the increased volume of high bill inquiries. Depending on the nature of the high bill, there may be a need for customers to follow up on their bill, resulting in more than one contact to resolve their concerns. As well, high bill calls can require longer-term payment arrangements which at times may require changes, leading to customers connecting with FBC multiple times for the same reason. The June 2023 year-to-date performance is 78 percent which meets the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-4: Historical First Contact Resolution Levels

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	73%	76%	79%	80%	82%	82%	82%	82%	77%	78%
Benchmark	78%									
Threshold	72%						74%			

13.2.2.2 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 2022 result was 0.14 which was better than the benchmark of 3.0. No significant billing issues occurred in 2022. The June 2023 year-to-date result of 2.20 is attributable to a technical issue experienced in February which resulted in a timing delay between the creation of the bills and those bills being sent to the print vendor. This technical issue has been corrected.

The 2022 Billing Index sub-measures calculation is as follows.

Table 13-5: Calculation of 2022 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),100*(1.05-PA))	=5000*(1-100%)	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	0.00
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target: 95%	99.57%	(100%-PA)*100	=(100%-99.57%)*100	0.43
Billing Service Quality Indicator; Target < 3.0		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0.+0+0.43) /3	0.14

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-6: Historical Billing Index Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	2.34	0.39	0.57	0.15	0.29	1.96	0.13	0.12	0.14	2.20
Benchmark	5.0						3.0			
Threshold	5.0									

13.2.2.3 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 2022 result was 99 percent, which was better than the benchmark of 98 percent. The June 2023 year-to-date result is 99 percent, which is better than the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-7: Historical Meter Reading Accuracy Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	98%	96%	99%	99%	99%	99%	99%	99%	99%	99%
Benchmark	97%						98%			
Threshold	94%						96%			

13.2.2.4 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 2022 result was 65 percent, which was lower than the threshold. The June 2023 year-to-date performance is 72 percent, which is better than the benchmark.

FBC experienced several challenging circumstances in 2022 that contributed to the year-end performance being below the threshold. These challenges included higher than expected attrition being experienced in the contact centre, compounded by an increased amount of high bill inquiries in the first and fourth quarters. Each of these is described further below.

Customer Service is experiencing higher than expected levels of attrition, having lost approximately 40 percent of its Customer Service Representatives in 2022, compared to 20 percent in 2021.[55] Exits in 2021 occurred during the third and fourth quarters, resulting in fewer and less experienced employees prepared to support call volumes at the start of 2022. Additionally, 2022 exits were spread throughout 2022 with the majority in the first and fourth quarters. To mitigate the impact of this attrition, FBC accelerated the timing of planned new hire

[55] On average, FBC has approximately 20 customer service representatives, and 8 left the organization in 2022 and 4 in 2021. This compares to typical annual attrition in the range of 1-2 customer service representatives from the organization.

classes as well as the size of new hire classes in 2021, 2022 and 2023. While some success was achieved, FBC continued to face challenges recruiting and retaining newly hired contact centre employees in 2022. In addition, it takes approximately 12 months for new employees to be proficient and fully trained to support all customer inquiries and calls, and as such, average call handle times remain higher than normal while a greater portion of employees gain this experience.

High bill inquiries are expected in the first quarter of the year and planned for with staffing levels and schedules adjusted, new hire classes timed accordingly, and refresher training offered to those employees who may need it. However, the colder temperatures resulted in a volume of high bill inquiries that was greater than anticipated and lasted longer than typical. This particular call type is often longer in duration and may also result in follow-up work and investigation. Compounded by attrition, there were fewer and less experienced employees prepared to support these types of calls, resulting in overall longer average wait times and a lower percentage of calls answered within 30 seconds or less.

The additional hiring and training classes in 2023 have proven to be successful, with year-to-date performance better than the benchmark. Additionally, the customer service index has remained high throughout 2022 and 2023 year-to-date, indicating that the focus on first contact resolution continues to result in an overall high quality of service being experienced by customers.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 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 (Non-Emergency) Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	48%	71%	70%	70%	72%	70%	70%	70%	65%	72%
Benchmark	70%									
Threshold	68%									

13.2.2.5 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 10.

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 annual CSI score for 2022 was 8.4, consistent with 2021. There were no statistically significant shifts from 2021 to 2022 in the five measures that make up the overall customer satisfaction score. The score for the accuracy of meter reading metric increased from 8.2 in 2021 to 8.3 in 2022. The score for the satisfaction with energy conservation information metric decreased from 7.5 in 2021 to 7.4 in 2022. In addition, the scores for overall satisfaction, satisfaction with the contact centre and field services metrics remained static at 8.4, 8.4, and 9.0 in 2022, respectively.

The score for 2023 year-to-date is 8.5, slightly higher than the annual score recorded for 2022. Of the five measures that make up the overall customer satisfaction score, the results for June 2023 year-to-date were higher in three areas and static in two when compared to the annual 2022 scores. The scores for the satisfaction with energy conservation, contact centre, and field services metrics increased from 7.4 to 7.5, 8.4 to 8.5, and 9.0 to 9.2, respectively. The scores for the overall satisfaction and satisfaction with the accuracy of meter reading metrics remained static at 8.4 and 8.3, respectively, from results achieved in 2022. None of these changes are statistically significant.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-9: Historical Customer Satisfaction Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	8.1	8.1	8.2	8.2	8.3	8.5	8.5	8.4	8.4	8.5
Benchmark	n/a									
Threshold	n/a									

13.2.2.6 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 2022 result was 98 seconds, and the June 2023 year-to-date performance is 60 seconds.

2022 performance reflects the challenging circumstances described above for the Telephone Service Factor (Non-Emergency). Recovery of the ASA commenced in March 2023 with monthly ASA performance returning to typical levels of approximately 1 minute. This is expected to continue through the remainder of the year.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.[56]

Table 13-10: Average Speed of Answer

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	226	49	48	49	49	49	71	65	98	60
Benchmark	n/a									
Threshold	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.

13.2.3.1 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 2022 result was 2.42 which was better than the benchmark of 3.22. The June 2023 year-to-date performance is 3.21 which is better than the benchmark. The 2022 results improved

[56] 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.

compared to 2021 due to the absence of multiple external factors (i.e., fires, storms, collapse of crane incident in Kelowna in 2021)[57] which negatively impacted the 2021 SAIDI results.

There were no Major Event Days that met the threshold for normalization in 2022, and one Major Event Day in 2023 year-to-date. On May 21, 2023, a windstorm impacted the Kootenay region (centered in Salmo) resulting in outages to over 13,500 customers for a total of just under 46,200 customer hours lost.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 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. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[58]

Table 13-11: Historical SAIDI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual normalized results	2.32	2.13	2.10	4.05	3.15	2.45	3.17	4.27	2.42	3.21
Benchmark	2.22						3.22			
Threshold	2.62						4.52			

13.2.3.2 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 2022 result was 1.52 which was better than the benchmark, and the June 2023 year-to-date performance is 1.48 which is also better than the benchmark. The 2022 SAIFI results improved compared to 2021 due to the absence of the same multiple external factors (i.e., fires, storms and collapse of crane incident in Kelowna in 2021) discussed in the SAIDI section above.

[57] Refer to the FBC Annual Review for 2023 Rates, pages 140-141 for further details.
[58] The benchmark and threshold for SAIDI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 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. Starting in 2020, the benchmark and threshold reflect the values approved by the BCUC for the MRP term.[59]

Table 13-12: Historical SAIFI Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual normalized results	1.64	1.56	1.34	1.78	1.73	1.21	1.64	2.08	1.52	1.48
Benchmark	1.64						1.57			
Threshold	2.50						2.19			

13.2.3.3 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 2022 result for GFOR was 0.50 percent. The June 2023 year-to-date performance is 0.65 percent.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-13: Historical Generator Forced Outages

	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
FBC	1.7%	0.1%	0.8%	0.6%	0.4%	0.1%	1.3%	0.2%	0.5%	0.65%
CEA	6.3%	6.2%	6.2%	6.2%	6.7%	4.9%	4.6%	5.0%	TBD	

[59] The benchmark and threshold for SAIFI were approved in the FBC Annual Review for 2020 and 2021 Rates Decision and Order G-42-21.

13.2.3.4 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 12 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 2022 result of 99.94 percent and June 2023 year-to-date result of 99.98 percent are generally consistent with prior years' results. There were no notable major events in 2022 that impacted the interconnection utilization performance. For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-14: Interconnection Utilization

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Interconnection Utilization	99.99%	99.94%	99.99%	99.95%	99.96%	99.98%	99.89%	99.90%	99.94%	99.98%
Benchmark	n/a									
Threshold	n/a									

13.3 SUMMARY

In summary, FBC's 2022 and June 2023 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2022, for the eight SQIs with benchmarks, six met or were better than the benchmark with one, First Contact Resolution, better than the threshold and the Telephone Service Factor (Non-Emergency) lower than the threshold. For the four SQIs that are informational only, with the exception of the Average Speed of Answer results being higher, performance in 2022 for the other three informational metrics generally remains at a level consistent with prior years.

Appendix A

LOAD FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: Consumer Price Index (CPI)

Reference period	
	2002=100
July 2021	136.7
August 2021	137.0
September 2021	137.2
October 2021	137.9
November 2021	138.1
December 2021	138.0
January 2022	139.4
February 2022	140.4
March 2022	143.0
April 2022	144.2
May 2022	146.1
June 2022	146.5
July 2022	147.6
August 2022	147.0
September 2022	147.8
October 2022	148.6
November 2022	148.1
December 2022	147.1
January 2023	148.1
February 2023	149.1
March 2023	149.7
April 2023	150.4
May 2023	151.0
June 2023	151.6

Table A1-2: Average Weekly Earnings (AWE)

Reference period	
	Dollars
July 2021	1,143.76[B]
August 2021	1,143.96[B]
September 2021	1,142.37[B]
October 2021	1,140.94[B]
November 2021	1,129.51[B]
December 2021	1,132.93[B]
January 2022	1,155.32[B]
February 2022	1,153.57[B]
March 2022	1,161.00[B]
April 2022	1,164.51[B]
May 2022	1,159.89[B]
June 2022	1,167.14[B]
July 2022	1,162.26[B]
August 2022	1,171.52[B]
September 2022	1,171.94[B]
October 2022	1,174.29[B]
November 2022	1,176.97[B]
December 2022	1,153.31[B]
January 2023	1,180.04[B]
February 2023	1,175.83[B]
March 2023	1,191.20[B]
April 2023	1,199.14[B]

Table A1-3: British Columbia Three-Year Outlook 2023

Key Economic Indicators: British Columbia, 2022–25
(forecast completed February 6, 2023)

	2023Q1	2023Q2	2023Q3	2023Q4	2024Q1	2024Q2	2024Q3	2024Q4	2025Q1	2025Q2	2025Q3	2025Q4	2022	2023	2024	2025
GDP at market prices ($ millions)	391,736	395,415	399,177	403,736	406,355	410,776	415,451	420,228	424,501	428,452	432,006	435,380	387,452	397,516	413,202	430,085
	0.8	*0.9*	*1.0*	*1.1*	*0.6*	*1.1*	*1.1*	*1.1*	*1.0*	*0.9*	*0.8*	*0.8*	*10.5*	*2.6*	*3.9*	*4.1*
GDP at market prices (2012 $ millions)	288,445	288,783	289,747	291,630	293,450	295,974	298,578	301,260	303,505	305,509	307,230	308,858	288,561	289,651	297,315	306,276
	-0.4	*0.1*	*0.3*	*0.6*	*0.6*	*0.9*	*0.9*	*0.9*	*0.7*	*0.7*	*0.6*	*0.5*	*2.3*	*0.4*	*2.6*	*3.0*
GDP at basic prices (2012 $ millions)	268,952	269,263	270,150	271,927	273,661	276,038	278,453	280,981	283,105	284,983	286,596	288,138	268,886	270,073	277,283	285,705
	-0.4	*0.1*	*0.3*	*0.7*	*0.6*	*0.9*	*0.9*	*0.9*	*0.8*	*0.7*	*0.6*	*0.5*	*2.4*	*0.4*	*2.7*	*3.0*
Consumer price index (2002 = 1.000)	1.494	1.511	1.518	1.525	1.537	1.547	1.553	1.559	1.567	1.578	1.584	1.590	1.455	1.512	1.549	1.580
	1.0	*1.1*	*0.5*	*0.5*	*0.8*	*0.6*	*0.4*	*0.4*	*0.6*	*0.7*	*0.4*	*0.4*	*6.9*	*3.9*	*2.4*	*2.0*
Implicit price deflator—GDP at market prices	1.358	1.369	1.378	1.384	1.385	1.388	1.391	1.395	1.399	1.402	1.406	1.410	1.343	1.372	1.390	1.404
(2012 = 1.000)	*1.1*	*0.8*	*0.6*	*0.5*	*0.0*	*0.2*	*0.3*	*0.2*	*0.3*	*0.3*	*0.3*	*0.2*	*8.1*	*2.2*	*1.3*	*1.0*
Wages and salary per employee ($ 000s)	62.6	63.0	63.4	63.9	64.3	64.7	65.2	65.5	65.8	66.2	66.6	66.9	61.3	63.2	64.9	66.4
	1.4	*0.6*	*0.6*	*0.8*	*0.7*	*0.6*	*0.6*	*0.6*	*0.4*	*0.6*	*0.6*	*0.6*	*7.5*	*3.2*	*2.7*	*2.2*
Primary household income ($ millions)	271,333	273,731	277,762	281,397	284,854	288,183	291,553	294,696	297,304	300,218	303,091	306,018	263,680	276,056	289,821	301,658
	1.0	*0.9*	*1.5*	*1.3*	*1.2*	*1.2*	*1.2*	*1.1*	*0.9*	*1.0*	*1.0*	*1.0*	*9.3*	*4.7*	*5.0*	*4.1*
Household disposable income ($ millions)	238,251	238,085	241,327	244,400	246,131	248,862	251,726	254,524	256,290	258,790	261,242	263,730	230,486	240,516	250,311	260,013
	0.8	*-0.1*	*1.4*	*1.3*	*0.7*	*1.1*	*1.2*	*1.1*	*0.7*	*1.0*	*0.9*	*1.0*	*6.4*	*4.4*	*4.1*	*3.9*
Household net savings rate (per cent)	6.5	5.4	5.4	5.3	5.0	4.9	4.8	4.8	4.7	4.6	4.7	4.7	5.1	5.6	4.9	4.7
Population (000s)	5,395	5,422	5,447	5,472	5,496	5,519	5,542	5,564	5,586	5,608	5,631	5,652	5,303	5,434	5,530	5,619
	0.5	*0.5*	*0.5*	*0.5*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*2.1*	*2.5*	*1.8*	*1.6*
Employment (000s)	2,767	2,766	2,781	2,794	2,804	2,816	2,827	2,837	2,847	2,857	2,866	2,875	2,748	2,777	2,821	2,861
	0.3	*0.0*	*0.6*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*3.1*	*1.0*	*1.6*	*1.4*
Labour force (000s)	2,910	2,916	2,929	2,939	2,949	2,959	2,969	2,979	2,989	2,999	3,008	3,017	2,880	2,923	2,964	3,003
	0.9	*0.2*	*0.4*	*0.4*	*0.3*	*0.3*	*0.4*	*0.3*	*0.3*	*0.3*	*0.3*	*0.3*	*1.0*	*1.5*	*1.4*	*1.3*
Labour force participation rate (per cent)	64.3	64.1	64.1	64.0	64.0	63.9	63.9	63.8	63.8	63.7	63.7	63.6	64.9	64.1	63.9	63.7
Unemployment rate (per cent)	4.9	5.1	5.0	4.9	4.9	4.8	4.8	4.8	4.8	4.7	4.7	4.7	4.6	5.0	4.8	4.7
Retail sales ($ millions)	100,889	101,567	102,870	104,222	105,539	106,986	108,360	109,565	110,577	111,794	112,829	113,854	101,049	102,387	107,613	112,263
	0.0	*0.7*	*1.3*	*1.3*	*1.3*	*1.4*	*1.3*	*1.1*	*0.9*	*1.1*	*0.9*	*0.9*	*2.5*	*1.3*	*5.1*	*4.3*
Housing starts (units, 000s)	39,451	38,118	38,500	40,000	42,000	43,584	43,850	43,838	43,692	43,528	43,340	43,127	46,721	39,017	43,318	43,422
	-23.3	*-3.4*	*1.0*	*3.9*	*5.0*	*3.8*	*0.6*	*0.0*	*-0.3*	*-0.4*	*-0.4*	*-0.5*	*-1.9*	*-16.5*	*11.0*	*0.2*
Net interprovincial migration (000s)	15.2	17.7	16.3	16.8	17.0	17.3	17.5	17.8	18.0	18.3	18.5	18.8	12	16.5	17.4	18.4
Net international migration (000s)	89.7	85.5	81.8	78.9	76.5	74.6	73.1	72.0	72.3	71.6	71.0	70.5	118.4	84.0	74.1	71.3

Shaded area represents forecast data, *italics indicate percentage change*.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
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.

Note: Table above is from the Conference Board of Canada, British Columbia Three-Year Outlook, March 31, 2023.



Appendix A2

Load Forecast Tables

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1. INTRODUCTION

This appendix provides the historical and forecast load data used in Section 3 of the Application. The tables in Section 2 of this appendix show 10 years of historical data and the before-savings and after-savings forecast for 2023S and 2024F. Section 3 shows the customer forecast data while Section 4 presents the residential UPC data. The tables in Section 5 show the load forecast. Table 5.3 shows the DSM that was deducted from the before-savings forecast to provide the after-savings forecast for 2024F. Tables 6.1 and 6.2 show the variance of the customer accounts and forecasts from 2017 to 2022 when compared to the actuals. Table 6.3 shows the annual growth of customer and load that FBC has experienced since 2017. Tables 6.4 and 6.5 show the Residential UPC and Winter peak variances from forecast from 2020 to 2022. Finally, Table 6.6 shows the system load factor from the years 2017 to 2022 and the forecast load factor for 2023S and 2024F.

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 2022.
- after-savings – the load after DSM and includes Normalized loads to December 2022.

2.1 GROSS LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historic Loads													
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	363,245	306,420	303,949	253,146	241,945	242,396	285,626	270,799	229,532	256,624	301,612	380,684	3,435,977
2015	364,636	317,325	299,476	250,366	249,815	247,921	287,307	276,774	233,611	256,959	300,534	361,093	3,445,816
2016	362,417	311,090	292,322	268,567	248,286	243,400	287,329	280,865	234,850	266,011	328,783	352,683	3,476,603
2017	364,284	298,155	307,568	263,749	249,610	251,126	300,242	289,240	246,675	265,495	324,809	356,765	3,517,718
2018	373,759	312,050	306,251	264,157	273,363	256,750	308,108	296,176	231,268	262,444	302,321	372,719	3,559,367
2019	371,601	294,208	316,259	261,193	267,746	257,893	295,882	292,659	260,751	291,966	314,389	370,267	3,594,813
2020	380,978	331,422	304,284	246,809	239,849	247,702	308,135	302,775	260,553	282,819	332,127	373,313	3,610,765
2021	379,923	340,308	320,380	275,424	255,599	264,059	313,426	294,626	255,445	284,819	333,861	374,965	3,692,835
2022	395,393	344,739	328,117	275,896	259,774	274,145	317,727	309,709	265,171	280,605	337,000	396,554	3,784,830
Before-Savings													
2023S	393,099	343,506	322,822	275,878	267,544	279,101	319,086	308,550	269,588	290,246	343,143	391,122	3,803,684
2024F	395,405	345,601	324,885	277,934	269,596	281,241	321,367	310,778	271,994	292,344	345,298	393,394	3,829,838
After-Savings													
2023S	390,501	340,929	320,309	273,448	265,202	276,815	316,824	306,260	267,245	287,810	340,630	388,565	3,774,539
2024F	390,223	340,479	319,905	273,132	264,983	276,752	316,937	306,307	267,435	287,618	340,441	388,467	3,772,679

2.2 NET LOAD (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historic Loads													
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	329,517	279,546	279,656	235,365	226,070	226,002	263,980	251,199	214,732	238,897	276,987	343,940	3,165,892
2015	330,474	288,500	275,700	232,842	232,855	230,716	265,292	256,237	218,219	239,080	275,925	327,535	3,173,373
2016	328,972	283,576	269,823	248,799	231,696	226,952	265,539	259,978	219,469	247,136	300,036	320,866	3,202,843
2017	330,163	272,433	282,574	244,425	232,665	233,492	276,339	266,935	229,621	246,479	296,394	323,921	3,235,440
2018	338,459	284,446	281,783	245,037	253,552	238,619	283,364	273,179	216,362	244,085	277,755	337,598	3,274,238
2019	336,960	269,648	290,510	242,633	248,852	239,769	273,123	270,359	242,250	269,764	288,203	335,853	3,307,924
2020	345,128	301,193	280,588	230,312	224,658	231,093	283,880	279,297	242,295	262,137	303,482	338,771	3,322,834
2021	344,200	308,531	294,270	255,141	238,455	245,309	288,355	272,273	237,823	263,831	304,896	340,091	3,393,175
2022	356,904	312,144	300,781	255,512	242,069	254,001	291,969	285,142	246,240	260,155	307,481	357,859	3,470,257
Before-Savings													
2023S	356,862	312,701	297,618	256,528	249,790	259,327	294,420	285,377	251,055	269,568	314,129	355,218	3,502,592
2024F	358,989	314,632	299,533	258,433	251,695	261,304	296,522	287,433	253,266	271,513	316,120	357,317	3,526,758
After-Savings													
2023S	354,461	310,320	295,296	254,283	247,626	257,215	292,330	283,261	248,891	267,317	311,807	352,855	3,475,662
2024F	354,202	309,899	294,931	253,996	247,433	257,156	292,429	283,302	249,053	267,146	311,631	352,765	3,473,943

2.3 RESIDENTIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
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
2020	150,634	126,164	117,219	93,211	89,289	91,128	111,958	103,644	86,533	100,913	126,958	149,181	1,346,832
2021	151,923	132,351	117,698	95,324	88,510	89,335	114,977	114,763	58,293	98,449	123,064	145,645	1,330,331
2022	150,247	130,107	119,338	92,786	83,362	90,463	111,776	99,512	80,706	95,008	120,814	146,242	1,320,362
Before-Savings													
2023S	148,630	127,563	116,282	92,342	85,724	88,930	111,180	104,355	74,030	96,625	121,724	144,778	1,312,162
2024F	148,154	127,155	115,910	92,046	85,450	88,645	110,824	104,021	73,793	96,316	121,335	144,314	1,307,962
After-Savings													
2023S	148,150	127,096	115,852	91,964	85,397	88,640	110,904	104,066	73,703	96,247	121,295	144,311	1,307,625
2024F	147,193	126,221	115,051	91,290	84,797	88,068	110,274	103,444	73,140	95,560	120,475	143,379	1,298,891

2.4 COMMERCIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
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	80,354	73,607	69,309	70,566	73,342	72,255	76,262	75,406	66,710	60,531	66,112	81,292	865,746
2015	80,156	72,259	68,665	64,591	71,392	74,678	72,149	71,980	68,558	62,811	67,227	78,701	853,168
2016	81,888	75,253	71,663	71,537	69,950	67,264	75,224	78,198	68,802	70,075	79,061	92,524	901,438
2017	87,580	76,292	77,390	69,008	70,517	72,425	82,456	81,640	72,344	73,698	77,035	80,003	920,385
2018	85,824	76,573	78,401	70,827	73,372	72,287	81,199	81,422	70,961	73,116	75,837	82,157	921,978
2019	85,718	80,999	80,956	69,682	72,347	72,907	78,731	80,774	73,021	75,361	78,350	85,041	933,887
2020	87,508	79,773	76,660	64,284	65,222	67,351	78,479	81,698	74,157	76,661	80,042	85,339	917,174
2021	87,315	79,792	80,058	71,855	73,925	80,219	85,512	69,286	96,034	76,263	80,232	90,890	971,380
2022	93,663	80,863	81,664	72,557	71,986	71,849	84,690	88,145	74,835	75,357	80,089	93,445	969,143
Before-Savings													
2023S	91,951	82,346	81,646	71,485	72,319	75,155	85,172	81,902	83,920	78,188	82,324	92,357	978,766
2024F	93,611	83,835	83,122	72,779	73,628	76,515	86,710	83,382	85,437	79,602	83,812	94,025	996,458
After-Savings													
2023S	90,995	81,393	80,699	70,545	71,387	74,230	84,248	80,976	82,989	77,249	81,377	91,404	967,494
2024F	91,705	81,937	81,239	70,914	71,779	74,679	84,880	81,551	83,599	77,757	81,960	92,169	974,168

2.5 WHOLESALE (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Normalized Actuals													
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
2020	64,233	56,219	48,768	39,333	33,066	35,088	44,642	44,913	39,548	45,075	55,660	62,943	569,488
2021	63,822	56,888	51,016	42,771	35,118	32,874	43,009	44,315	36,150	44,201	57,331	58,330	565,827
2022	64,786	56,887	52,353	41,723	35,185	36,472	44,017	44,848	38,048	41,846	54,139	65,162	575,466
Before-Savings													
2023S	67,256	57,713	51,399	42,651	38,415	37,652	45,051	46,169	40,005	46,783	57,049	64,421	594,563
2024F	67,539	57,947	51,611	42,840	38,640	37,900	45,329	46,428	40,224	47,006	57,281	64,693	597,438
After-Savings													
2023S	66,907	57,368	51,064	42,331	38,109	37,357	44,759	45,873	39,699	46,463	56,714	64,076	590,719
2024F	66,842	57,258	50,944	42,202	38,032	37,313	44,750	45,843	39,618	46,374	56,622	64,014	589,812

2.6 INDUSTRIAL (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
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
2020	41,115	37,485	36,324	30,596	32,632	32,899	39,933	39,350	35,590	36,265	39,250	39,794	441,233
2021	39,629	38,120	44,021	42,125	34,088	34,473	33,956	35,536	42,333	41,558	42,792	43,684	472,315
2022	46,629	42,908	45,937	46,285	47,294	50,460	43,070	43,215	46,443	44,094	50,708	51,418	558,461
Before-Savings													
2023S	47,521	43,708	46,835	47,439	48,308	51,817	43,854	44,015	47,362	44,605	51,508	52,182	569,155
2024F	48,181	44,325	47,433	48,156	48,954	52,472	44,495	44,665	48,074	45,222	52,168	52,806	576,954
After-Savings													
2023S	46,915	43,102	46,233	46,841	47,721	51,233	43,279	43,436	46,785	44,009	50,910	51,595	562,059
2024F	46,977	43,131	46,259	46,998	47,826	51,360	43,409	43,582	47,004	44,123	51,075	51,743	563,488

2.7 LIGHTING (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
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
2020	929	892	955	900	914	874	932	949	878	907	863	852	10,846
2021	838	774	836	795	858	787	802	805	770	851	776	791	9,682
2022	820	724	772	760	790	729	784	762	767	800	766	788	9,262
Before-Savings													
2023S	804	743	797	763	796	743	783	782	751	796	748	756	9,262
2024F	804	743	797	763	796	743	783	782	751	796	748	756	9,262
After-Savings													
2023S	796	735	789	756	790	737	776	775	744	788	740	748	9,173
2024F	787	727	781	749	783	730	770	769	737	781	732	739	9,084

2.8 IRRIGATION (MWH)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Historical Actuals													
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
2020	708	660	662	1,987	3,535	3,752	7,936	8,743	5,588	2,317	709	662	37,260
2021	674	606	641	2,272	5,957	7,621	10,099	7,568	4,242	2,508	701	751	43,640
2022	760	655	718	1,400	3,452	4,028	7,631	8,660	5,441	3,049	965	804	37,563
Before-Savings													
2023S	699	628	660	1,848	4,227	5,029	8,381	8,154	4,987	2,571	776	724	38,684
2024F	699	628	660	1,848	4,227	5,029	8,381	8,154	4,987	2,571	776	724	38,684
After-Savings													
2023S	698	627	659	1,846	4,222	5,018	8,364	8,134	4,970	2,561	771	722	38,592
2024F	698	626	657	1,844	4,217	5,007	8,346	8,113	4,954	2,552	767	720	38,500

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														
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
2020	732	680	609	500	482	515	666	665	551	549	631	667	731	666
2021	711	731	555	495	488	653	597	635	486	509	628	675	685	653
2022	685	676	572	490	432	615	681	689	629	480	673	734	734	689
Before-Savings														
2023S	723	701	615	519	494	607	682	676	527	537	655	742	788	700
2024F	728	705	619	522	497	611	687	681	531	541	660	747	793	705
After-Savings														
2023S	719	696	611	515	490	603	678	672	523	533	651	738	783	696
2024F	720	696	611	514	490	603	679	673	523	533	652	739	785	697

Note: The peaks shown 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 and includes the June 2021 Heat Dome.

3. CUSTOMER FORECAST

3.1 CUSTOMERS

Customer Count	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,131	131,323	133,291
Commercial	13,662	14,363	14,976	15,073	15,398	15,678	15,956	16,165	16,594	16,773	16,930	17,290
Wholesale	6	6	6	6	6	6	6	6	6	6	6	6
Industrial	47	49	50	50	50	52	51	43	42	42	42	42
Lighting	1,644	1,620	1,590	1,559	1,511	1,482	1,467	1,443	1,407	1,380	1,357	1,330
Irrigation	1,097	1,103	1,095	1,090	1,080	1,078	1,082	1,091	1,103	1,103	1,103	1,103
Total Direct	128,318	130,572	131,883	133,550	135,793	138,587	141,027	143,714	145,830	148,435	150,761	153,063

3.2 CUSTOMER ADDITIONS

Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	(433)	1,569	735	1,606	1,976	2,543	2,174	2,501	1,712	2,453	2,192	1,969
Commercial	489	701	613	97	325	280	278	209	429	179	157	360
Wholesale	(1)	-	-	-	-	-	-	-	-	-	-	-
Industrial	(4)	2	1	-	-	2	(1)	(8)	(1)	-	-	-
Lighting	(95)	(24)	(30)	(31)	(48)	(29)	(15)	(24)	(36)	(27)	(23)	(26)
Irrigation	6	6	(8)	(5)	(10)	(2)	4	9	12	-	-	-
Total Direct	(38)	2,254	1,311	1,667	2,243	2,794	2,440	2,687	2,116	2,605	2,326	2,302

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

MWh/Customer	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	12.48	11.51	11.41	11.27	11.31	11.03	10.43	10.89	10.57	10.32	10.04	9.82

5. LOAD

5.1 AFTER-SAVINGS LOAD

Energy (GWh)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1,352.9	1,296.5	1,298.1	1,295.6	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4	1,307.6	1,298.9
Commercial	788.2	865.7	853.2	901.4	920.4	922.0	933.9	917.2	971.4	969.1	967.5	974.2
Wholesale	675.2	567.1	580.5	574.4	574.1	584.7	566.0	569.5	565.8	575.5	590.7	589.8
Industrial	352.3	380.9	379.7	373.4	362.6	402.7	494.9	441.2	472.3	558.5	562.1	563.5
Lighting	13.5	15.6	15.9	15.9	15.9	13.2	11.0	10.8	9.7	9.3	9.2	9.1
Irrigation	39.7	40.0	46.0	42.1	41.9	39.0	36.0	37.3	43.6	37.6	38.6	38.5
Net	3,221.9	3,165.9	3,173.4	3,202.8	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3	3,475.7	3,473.9
Losses & Company Use	278.1	270.1	272.4	273.8	282.3	285.1	286.9	287.9	299.7	314.6	298.9	298.7
Gross	3,500.0	3,436.0	3,445.8	3,476.6	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8	3,774.5	3,772.7
System Peak (MW)												
Winter Peak	698.1	692.6	685.0	754.7	713.6	682.2	732.4	730.8	684.8	734.3	783.4	785.0
Summer Peak	600.4	619.5	611.0	593.0	604.8	630.9	639.4	666.2	652.9	689.1	696.2	697.3

5.2 NORMALIZED AFTER-SAVINGS WHOLESALE LOAD

Wholesale (GWh)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
BCH Lardeau	6.3	6.3	6.5	5.9	8.4	7.8	7.1	6.1	5.9	5.0	6.6	6.5
BCH Kingsgate	4.9	4.6	4.8	4.9	4.6	4.7	4.6	5.0	4.1	4.0	4.6	4.6
City of Grand Forks	41.1	39.5	40.7	40.5	38.7	45.8	36.9	37.5	36.3	37.0	37.5	37.5
City of Nelson	82.7	80.9	83.0	79.6	86.1	88.0	83.8	82.0	85.6	86.0	84.5	83.2
City of Penticton	348.4	341.9	348.4	345.2	338.0	340.0	338.4	340.3	337.0	347.0	357.9	357.9
District of Summerland	97.9	94.0	97.1	98.2	98.2	98.5	95.1	98.5	96.9	96.0	99.7	100.1
City of Kelowna	93.9	-	-	-	-	-	-	-	-	-	-	-
Total	675.2	567.1	580.5	574.4	574.1	584.7	566.0	569.5	565.8	575.0	590.7	589.8

5.3 DSM (GWH) WITHOUT LOSSES

Energy (GWh)	2018	2019	2020	2021	2022	2023S	2024F
Demand Side Management	(31.4)	(25.8)	(26.3)	(30.0)	(35.9)	(26.9)	(52.8)

6. VARIANCES TO FORECAST

6.1 CUSTOMER COUNT VARIANCE

Customer Count	2017	2018	2019	2020	2021	2022
Actual						
Residential	117,748	120,291	122,465	124,966	126,678	129,131
Commercial	15,398	15,678	15,956	16,165	16,594	16,773
Wholesale	6	6	6	6	6	6
Industrial	50	52	51	43	42	42
Lighting	1,511	1,482	1,467	1,443	1,407	1,380
Irrigation	1,080	1,078	1,082	1,091	1,103	1,103
Total	135,793	138,587	141,027	143,714	145,830	148,435
Forecast						
Residential	116,031	117,774	120,405	124,076	124,603	128,941
Commercial	15,813	16,122	16,405	16,220	16,579	16,975
Wholesale	6	6	6	6	6	6
Industrial	50	50	51	57	59	43
Lighting	1,590	1,559	1,511	1,425	1,393	1,406
Irrigation	1,095	1,090	1,080	1,082	1,082	1,091
Total	134,585	136,602	139,459	142,865	143,721	148,462
Variance (customers)						
Residential	1,717	2,517	2,060	890	2,075	190
Commercial	(415)	(444)	(449)	(55)	15	(202)
Wholesale	0	0	0	0	0	0
Industrial	0	2	0	(14)	(17)	(1)
Lighting	(79)	(77)	(44)	18	14	(26)
Irrigation	(15)	(12)	2	9	21	12
Total	1,208	1,986	1,569	849	2,109	(27)
Variance (%)						
Residential	1.5%	2.1%	1.7%	0.7%	1.6%	0.1%
Commercial	-2.7%	-2.8%	-2.8%	-0.3%	0.1%	-1.2%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	0.0%	3.8%	0.0%	-32.6%	-40.5%	-2.4%
Lighting	-5.2%	-5.2%	-3.0%	1.3%	1.0%	-1.9%
Irrigation	-1.4%	-1.1%	0.2%	0.8%	1.9%	1.1%
Total	0.9%	1.4%	1.1%	0.6%	1.4%	0.0%

6.2 LOAD VARIANCE, NORMALIZED/HISTORIC ACTUAL TO FORECAST[1]

Energy (GWh)	2017	2018	2019	2020	2021	2022
Historic						
Residential	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4
Commercial	920.4	922.0	933.9	917.2	971.4	969.1
Wholesale	574.1	584.7	566.0	569.5	565.8	575.5
Industrial	362.6	402.7	494.9	441.2	472.3	558.5
Lighting	15.9	13.2	11.0	10.8	9.7	9.3
Irrigation	41.9	39.0	36.0	37.3	43.6	37.6
Net	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3
Gross	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8
Forecast						
Residential	1,353.0	1,280.0	1,349.3	1,325.6	1,255.4	1,283.2
Commercial	879.4	912.0	935.2	901.7	952.3	945.5
Wholesale	587.3	586.0	594.0	567.5	583.5	559.5
Industrial	407.0	379.0	385.0	453.0	536.7	470.4
Lighting	14.4	15.0	13.0	10.6	9.9	10.3
Irrigation	40.3	41.0	42.0	35.3	35.8	37.1
Net	3,282.2	3,213.0	3,318.5	3,293.7	3,373.7	3,306.0
Gross	3,559.0	3,485.0	3,602.0	3,602.0	3,664.0	3,591.0
Variance (GWh)						
Residential	(32.5)	32.6	(83.2)	21.3	74.9	37.1
Commercial	41.0	10.0	(1.3)	15.5	19.1	23.6
Wholesale	(13.2)	(1.3)	(28.0)	2.0	(17.7)	16.0
Industrial	(44.4)	23.7	109.9	(11.8)	(64.3)	88.1
Lighting	1.5	(1.8)	(2.0)	0.2	(0.3)	(1.0)
Irrigation	1.7	(2.0)	(6.0)	2.0	7.8	0.5
Net	(46.8)	61.2	(10.6)	29.2	19.5	164.3
Gross	(41.3)	74.4	(7.2)	8.8	28.9	193.9
Variance (%)						
Residential	-2.5%	2.5%	-6.6%	1.6%	5.6%	2.8%
Commercial	4.4%	1.1%	-0.1%	1.7%	2.0%	2.4%
Wholesale	-2.3%	-0.2%	-5.0%	0.4%	-3.1%	2.8%
Industrial	-12.3%	5.9%	22.2%	-2.7%	-13.6%	15.8%
Lighting	9.4%	-13.4%	-17.8%	2.1%	-2.8%	-10.7%
Irrigation	3.9%	-5.2%	-16.7%	5.3%	17.9%	1.3%
Net	-1.4%	1.9%	-0.3%	0.9%	0.6%	4.7%
Gross	-1.2%	2.1%	-0.2%	0.2%	0.8%	5.1%

[1] Residential and Wholesale historic loads shown are normalized loads. All other rate classes show historic actual loads.

6.3 NORMALIZED AFTER-SAVINGS ANNUAL PERCENT GROWTH

Energy (GWh)	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1,320.5	1,312.6	1,266.1	1,346.8	1,330.3	1,320.4	1,307.6	1,298.9
Commercial	920.4	922.0	933.9	917.2	971.4	969.1	967.5	974.2
Wholesale	574.1	584.7	566.0	569.5	565.8	575.5	590.7	589.8
Industrial	362.6	402.7	494.9	441.2	472.3	558.5	562.1	563.5
Lighting	15.9	13.2	11.0	10.8	9.7	9.3	9.2	9.1
Irrigation	41.9	39.0	36.0	37.3	43.6	37.6	38.6	38.5
Net	3,235.4	3,274.2	3,307.9	3,322.8	3,393.2	3,470.3	3,475.7	3,473.9
Losses & Company Use	282.3	285.1	286.9	287.9	299.7	314.6	298.9	298.7
Gross	3,517.7	3,559.4	3,594.8	3,610.8	3,692.8	3,784.8	3,774.5	3,772.7
System Peak								
Winter Peak (MW)	713.6	682.2	732.4	730.8	684.8	734.3	783.4	785.0
Summer Peak (MW)	604.8	630.9	639.4	666.2	652.9	689.1	696.2	697.3

Growth Year over Year	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1.9%	-0.6%	-3.5%	6.4%	-1.2%	-0.7%	-1.0%	-0.7%
Commercial	2.1%	0.2%	1.3%	-1.8%	5.9%	-0.2%	-0.2%	0.7%
Wholesale	-0.1%	1.8%	-3.2%	0.6%	-0.6%	1.7%	2.7%	-0.2%
Industrial	-2.9%	11.1%	22.9%	-10.8%	7.0%	18.2%	0.6%	0.3%
Lighting	0.0%	-17.0%	-16.5%	-1.7%	-10.7%	-4.3%	-1.0%	-1.0%
Irrigation	-0.3%	-7.1%	-7.7%	3.6%	17.1%	-13.9%	2.7%	-0.2%
Net	1.0%	1.2%	1.0%	0.5%	2.1%	2.3%	0.2%	0.0%
Losses & Company Use	3.1%	1.0%	0.6%	0.4%	4.1%	5.0%	-5.0%	0.0%
Gross	1.2%	1.2%	1.0%	0.4%	2.3%	2.5%	-0.3%	0.0%
System Peak								
Winter Peak (MW)	-5.4%	-4.4%	7.4%	-0.2%	-6.3%	7.2%	6.7%	0.2%
Summer Peak (MW)	2.0%	4.3%	1.4%	4.2%	-2.0%	5.5%	1.0%	0.1%

Customer Count	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	117,748	120,291	122,465	124,966	126,678	129,131	131,323	133,291
Commercial	15,398	15,678	15,956	16,165	16,594	16,773	16,930	17,290
Wholesale	6	6	6	6	6	6	6	6
Industrial	50	52	51	43	42	42	42	42
Lighting	1,511	1,482	1,467	1,443	1,407	1,380	1,103	1,103
Irrigation	1,080	1,078	1,082	1,091	1,103	1,103	1,357	1,330
Total Direct	135,793	138,587	141,027	143,714	145,830	148,435	150,761	153,063

Growth Year over Year	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential	1.7%	2.2%	1.8%	2.0%	1.4%	1.9%	1.7%	1.5%
Commercial	2.2%	1.8%	1.8%	1.3%	2.7%	1.1%	0.9%	2.1%
Wholesale	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Industrial	0.0%	4.0%	-1.9%	-15.7%	-2.3%	0.0%	0.0%	0.0%
Lighting	-3.1%	-1.9%	-1.0%	-1.6%	-2.5%	-1.9%	-20.1%	0.0%
Irrigation	-0.9%	-0.2%	0.4%	0.8%	1.1%	0.0%	23.0%	-1.9%
Total Direct	1.7%	2.1%	1.8%	1.9%	1.5%	1.8%	1.6%	1.5%

6.4 RESIDENTIAL UPC, NORMALIZED ACTUAL TO FORECAST

Residential UPC (MWh)	2020	2021	2022
After- Savings Normalized Actual UPC	10.89	10.57	10.32
Forecast	10.75	10.10	10.04
Variance	0.13	0.48	0.29
Variance (%)	1.2%	4.5%	2.8%

6.5 WINTER PEAK, ACTUAL TO FORECAST

Winter Peak (MW)	2020	2021	2022
Actual Peak	725.0	777.0	835.0
Forecast	737.0	748.0	716.5
Variance	(12.0)	29.0	118.5
Variance (%)	-2%	4%	17%

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	Energy (MWh)	Peak (MW)	Load Factor
2017	3,517,718	714	0.56
2018	3,559,367	682	0.60
2019	3,594,813	732	0.56
2020	3,610,765	731	0.56
2021	3,692,835	684	0.62
2022	3,784,830	733	0.59
2023S	3,774,539	783	0.55
2024F	3,772,679	785	0.55

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



Appendix A3

Load Forecast Methods

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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[1]. For the 2024 Annual Review the latest calendar year for which full actual data exists is the 2022 calendar year.
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2023 (2023S) and the Seed Year forecast is based on the latest actual years, including 2022. As such, the 2023 Seed Year forecast in this Application will differ from the 2023 Forecast presented in the Annual Review for 2023 Rates, for which 2022 actual data was not available.
- 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, 2024 is the Forecast Year (2024F).

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[2]. The results from the regression for these four rate classes are shown below. The regressions result in high R^2 values for all seasons for the residential and wholesale load classes; therefore these classes are normalized. The commercial class shows a low R^2 value for all seasons and the irrigation class for the winter, summer and fall seasons; therefore, these classes were not normalized.

[1] FBC's load forecast is developed using only full years of historical data. FBC requires the full year of load data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason partial year data is not used in forecasting.
[2] Industrial and lighting loads are typically insensitive to the weather.

Table A3-1: Residential Regression Table

Residential	Winter	Spring	Summer	Fall
Intercept	35,802	71,302	76,725	70,811
Slope HDD	180	108	-	93
Slope CDD	-	-	250	-
Adjusted R^2	0.77	0.75	0.83	0.78

Table A3-2: Wholesale Regression Table

Wholesale	Winter	Spring	Summer	Fall
Intercept	63,808	60,024	33,068	34,997
Slope HDD	60	49	-	32
Slope CDD	-	-	103	-
Adjusted R^2	0.91	0.95	0.85	0.79

Table A3-3: Commercial Regression Table

Commercial	Winter	Spring	Summer	Fall
Intercept	50,957	49,648	69,253	71,660
Slope HDD	25	18	-	(2)
Slope CDD	-	-	78	-
Adjusted R^2	0.31	0.28	0.36	(0.05)

Table A3-4: Irrigation Regression Table

Irrigation	Winter	Spring	Summer	Fall
Intercept	1,382	5,363	5,017	5,846
Slope HDD	(1)	(12)	-	(11)
Slope CDD	-	-	24	-
Adjusted R^2	0.01	0.78	0.53	0.52

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 and wholesale classes, regress load on HDD or CDD on a seasonal basis. Four seasons were defined: winter (November to February), spring

[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.

(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 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 2022:

   (a) obtain the month's HDD (or CDD) information from Environment Canada;

   (b) calculate the deviation from the 10-year average (2013-2022) 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 weather normalized historical loads. These are referred to as the "before-savings[5]" loads. DSM savings that are incremental to those embedded in historical loads (up to and including 2022) 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:

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

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

[5] The term "before-savings" is used in the remainder of this section and refers to "before incremental savings after 2022".

The before-savings UPC was based on a 10-year historic trend of annual UPC values from 2013 to 2022.

Table A3-5: Results of UPC Trend Analysis

Regression	UPC
Start Year	2013
End Year	2022
R^2	0.825
Adjusted R^2	0.803
df	9
Intercept	395
Slope UPC	-0.19

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.

$$Year\ End\ Customer\ Count_t = b_0 + b_1 \times Population_t$$

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

Table A3-6: Results of Residential Customer Count Regression

Regression	Residential
Start Year	2017
End Year	2022
R^2	0.996
Adjusted R^2	0.995
df	5
Intercept	(3,342)
Slope Population	0.46

The residential class represented 38.0 percent of the net load in 2022.

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.

$$Before\ Savings\ Load_t = (b_0 + b_1 \times GDP_t + b_2 \times CoK\ Event_t) + FBC\ EV\ DC\ Fast\ Chargers$$

The CoK_t is a binary variable for the City of Kelowna integration event in 2013. Coefficients b0, b1 and b2 are obtained from an ordinary least squares (OLS) regression analysis on the 2008 to 2022 data. The FBC EV DCFCs are Electric Vehicle Direct Current Fast Chargers serviced by FBC which are added to the forecast. The commercial class represented 27.9 percent of the net load in 2022.

Table A3-7: Results of Commercial Regression

Regression	Commercial
Start Year	2008
End Year	2022
R^2	0.987
Adjusted R^2	0.985
df	14
Intercept	186,072
Slope GDP	2
Slope CoK Event	136,787

1.2.3 Wholesale

The Company forecasts the wholesale load based on load surveys from the wholesale customers. For this forecast, FBC received surveys from all the wholesale customers. 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. The wholesale class represented 16.6 percent of the net load in 2022.

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. 76 percent of FBC's industrial customers responded to the surveys, accounting for 91 percent of 2022 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. The industrial class represented 16.1 percent of the net load in 2022.

1.2.5 Irrigation

The before-savings irrigation load forecast uses a five-year average so that the extreme weather events such as those that occurred in 2022 are included in the forecast but do not overly influence it. The irrigation class represented 1.1 percent of the net load in 2022.

1.2.6 Lighting

The before-savings lighting load uses the 2022 actuals due to the variability in the load primarily due to streetlight LED replacement programs which reduced the loads from 2018 to 2022. The lighting class represented 0.3 percent of the net load in 2022.

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 2019-2022 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 Seed 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 10-year average (2013-2022) 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 12 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
PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-166-20 – FBC MULTI-YEAR RATE PLAN FOR 2020 THROUGH 2024						
1.	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	Section 12.4.2.1
2.	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). 4. 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
3.	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
4.	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

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
5.	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
G-374-21 – FBC ANNUAL REVIEW FOR 2022 RATES						
6.	32	8	EV Charging Updates	The Panel directs FBC to include in future Annual Review filings an update on its EV DCFC charging stations' costs and revenues for the previous fiscal year along with a forecast of costs and revenues for the test period.	Ongoing	Sections 3.6, 5.8, 6.3.4 and 7.2.2.1
G-14-23 – FBC PRINCETON BRIDGE STREET PROPERTIES DISPOSITION						
7.	n/a	4	Princeton Office Disposition Deferral Account	FBC is directed to provide details of the final balance in the Princeton Office Disposition deferral account in the FBC Annual Review for 2024 Rates.	Complete	Section 7.6.2.1

Appendix C
DRAFT ORDER

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

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

and

FortisBC Inc.
Annual Review for 2024 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-165-20 for FortisBC Energy Inc. and Order G-166-20 for FortisBC Inc. (FBC) approving a Multi-Year Rate Plan for 2020 through 2024 (MRP Decision). In accordance with the MRP Decision, FBC is to conduct an annual review (Annual Review) process to set rates for each year;

B. By letter dated June 28, 2023, FBC proposed a regulatory timetable for the Annual Review of its 2024 rates;

C. By Order G-191-23, the BCUC established a regulatory timetable for the Annual Review for FBC's 2024 rates, which included FBC filing its Annual Review materials, the deadline for intervener registration, one round of information requests, a workshop, FBC's response to undertakings at the workshop, and written final and reply arguments;

D. On August 4, 2023, FBC submitted its materials for the Annual Review for 2024 Rates Application (Application). In the Application, FBC requests a 4.83 percent rate increase over the 2023 rates, effective January 1, 2024, among other things; and

E. The BCUC has reviewed the Application, evidence and arguments filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act*, for the reasons stated in the decision issued concurrently with this order, the BCUC orders as follows:

1. FBC is approved to recover the 2024 revenue requirement and resultant rate change on a permanent basis, effective January 1, 2024, as filed in the Application and subject to any adjustments identified by FBC during

the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application.

2. FBC is approved to establish the following rate base deferral accounts:

    a. 2025 Multi-year Rate Plan (MRP) Application deferral account, with the amortization period to be determined in a future proceeding;

    b. 2024 Mandatory Reliability Standards (MRS) Audit deferral account, with an amortization period of three years, commencing January 1, 2024;

    c. PST Rebate on Select Machinery and Equipment deferral account, with an amortization period of one year, commencing January 1, 2024;

    d. BC Cost of Living Credit deferral account, with an amortization period of one year, commencing January 1, 2024; and

    e. Climate Change Operational Adaptation (CCOA) Plan deferral account, with an amortization period of four years, commencing January 1, 2024.

3. FBC is directed to file as a compliance filing, the finalized financial schedules and updated tariff pages within 10 days from the date of the issuance of this order.

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

Northland Utilities
A NI and ATCO Company

March 7, 2023

Northwest Territories Public Utilities Board
203 – 62 Woodland Drive
Box 4211
Hay River, NT X0E 1G1

To: Mr. Gordon Van Tighem
Board Chairman

RE: Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)

By letter dated January 31, 2023, the Northwest Territories Public Utilities Board (Board) accepted Northland Utilities (NWT) Limited's (Northland) proposal to file its Amended 2023 General Rate Application (Application) and its Hay River Franchise Property Disposition Application by March 7, 2023.[1]

In addition to the requested approval of the Hay River Franchise Property Disposition in a separate Application, the only other significant update included in this Application, as compared to the original 2023 GRA submitted on September 22, 2022, is Section 14 (Supplemental Information) which includes a scenario whereby the Town of Hay River remains in Northland's Revenue Requirement. This information is for illustration purposes and has been prepared to aid the Board in reviewing and comparing rate impacts when the Town of Hay River is included in Revenue Requirement. There are no other substantive changes in this Application as compared to the original 2023 GRA filed on September 22, 2022.

As outlined in Section 1, the Application is primarily driven by the discontinuation of the Hay River Franchise Agreement and the disposition of the Hay River franchise assets to the Town of Hay River. The Application is for a single Test Year in 2023 to allow the Board to review the public interest considerations associated with the discontinuation of

[1] Board Letter dated January 31, 2023.

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service and disposition of assets in Hay River and the resulting rates for Northland's remaining customers.

This Application includes:

- Determination of the 2023 Revenue Requirement for remaining Northland customers in Sections 1, 2-15;
- Northland's request for a Hay River Transition Deferral in Section 1B; and
- Business Cases for Capital Additions in Section 16, including two Business Cases that require Project Permits.

As set out in the proposed schedule below, a final decision is not expected until later in 2023. Therefore, Northland requests interim approval for the following:

- Rate changes for the remaining Northland customers as outlined in Sections 1, 2 to 15; and
- Interim use of the proposed Hay River Transition Deferral requested in Section 1B.
- New Transmission rate requested in Section 1B.

Interim approval will create administrative efficiencies, reduce complexities with the Hay River Disposition and limit future true-ups. A Decision for Interim Refundable Rates approval must be received prior to April 21, 2023, to ensure rates are incorporated into the billing system.

Northland proposes the following written process:

Process Step	Written Process
File Application	March 7, 2023
Notice of Application	March 13, 2023
Intervener Registration	March 20, 2023
IRs to Northland from Board & Interveners	March 27, 2023
IR Responses from Northland	April 17, 2023
Interim Refundable Rate Approval	April 21, 2023

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Process Step	Written Process
Intervener Evidence, if necessary	April 24, 2023
IRs to Interveners on Evidence	May 1, 2023
IR Responses from Interveners	May 15, 2023
Rebuttal Evidence, if necessary	May 25, 2023
Argument	June 6, 2023
Reply Argument	June 19, 2023

Due to the narrow scope of the Application, Northland's relatively small size, and in an effort to promote Regulatory Efficiency, Northland proposes to limit the number of intervener Information Requests to a maximum of 50, including sub-parts.[2]

Subject to the Board's approval and in accordance with Section 22(5) of the *Public Utilities Act (PUA)* and Section 13.1 of Rules of Practice and Procedure, Northland is prepared to commence the public notification process with respect to the Application. Advertisements will be placed in News/North, The Hub, and any other news outlet Northland deems appropriate. Northland will provide copies of each advertisement to the Board.

If you have any questions with respect to this Application, please contact me at Elizabeth.Rogers@atco.com.

Yours truly,

Beth Rogers
Director, Regulatory

[2] In an effort to reduce regulatory burden measures such as this have been adopted by the Alberta Utilities Commission, most recent in Proceeding 27062, Exhibit 27062-X0273.

Northland Utilities
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Section 9 **Taxes Other Than Income**

Section 10 **Other Revenues - Intentionally Left Blank**

Section 11 **Capital Additions**

Section 12 **Affiliate Transactions**

Section 13 **Prior Board Directions**

Section 14 **Supplemental Information – Revenue Requirement Including Town of Hay River**

Attachment 1 – Schedules with Hay River

Section 15 **Rate and Rider Adjustments**

Attachment 1 – Rate Schedules

Section 16 **Business Cases**

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Section 1 – Introduction

Summary

1. This Section outlines:

- Approvals requested from the NWT Public Utilities Board (Board);
- Background on Northland Utilities (NWT) Limited (Northland);
- Hay River Disposition and 2023 Revenue Requirement;
- Overview of the Pandemic Impact;
- Applied-For Revenue Requirement;
- Rate Rider Adjustment;
- Deferral Accounts;
- Key Assumptions;
- Return on Equity (ROE) and Capital Structure;
- Common Costs Treatment; and
- Revenue Requirement Analysis including Town of Hay River.

Approvals Requested from the Board

2. Northland seeks the following approvals from the Board:

(1) Approval for a deferral account to address the timing of transfer of Hay River assets effective January 1, 2023 (included in Section 1B);

(2) Approval for a separate long-term deferral account for costs associated with the extended Taltson shut down (included in Section 1B);

(3) Approval of Northland's revenue requirement for the 2023 Test Year (one-year Test Period);

(4) Approval of a final Rate Adjustment Rider (Rider R), a new Transmission Rate, and updates to Riders A & F (included in Sections 1B & 15);

(5) Interim Refundable Rates approval by April 21, 2023, to be implemented May 1, 2023 (as sought in the cover letter);

(6) Approval for continuation of existing deferral accounts listed below;

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(7) Approval of the ROE risk premium described in Section 7;

(8) Project permits for two projects in 2024 consistent with Section 54 of the *Public Utilities Act (PUA)* described in Section 16; and

(9) Such further and other relief as the Board may determine is appropriate.

About Northland

3. Northland is a wholly-owned subsidiary of Northland Utilities Enterprises Ltd. (NUE). NUE is 50% owned by ATCO Electric Ltd. through Norven Holdings Inc., and 50% owned by Denendeh Investments Incorporated.

4. Northland started operations in Hay River in 1951 with three small diesel engines located on Vale Island. The Company served 96 customers plus an additional 14 streetlights. In 1972, Enterprise and Fort Providence were added to Northland's service area. Sambaa K'e became part of the Northland's service area in 1986 and Wekweeti in 1987.

5. In 1988, Northland completed a $3.5 million Transmission Line from Pine Point to Hay River after Cominco completed mining operations. Hay River continues to be supplied with renewable energy from the Taltson Hydro System.

6. Prior to the Hay River disposition request herein, Northland provided electrical service to approximately 2,700 customers in the communities of Sambaa K'e, Wekweeti, Kakisa, Enterprise, Dory Point, Hay River, Fort Providence and the K'atl'odeeche First Nation Reserve. Northland operates five diesel power plants, in addition to receiving energy from the Taltson Hydro System.

7. On March 24, 2016, the Town of Hay River (the Town) notified Northland that it would not be renewing the Franchise Agreement and that it intended to exercise its right to purchase the Franchise Assets. As a result of the discontinuation of the Franchise Agreement and subsequent sale of the Franchise Assets (collectively,

the Hay River Disposition), Northland's 2023 forecasts exclude the assets, customers and costs related to Hay River.

Hay River Disposition and 2023 Revenue Requirement

8. Herein, Northland is seeking approval of a 2023 revenue requirement which has been forecast to reflect the Hay River Disposition effective January 1, 2023. As a result of the Hay River Disposition, Northland requires new rates for the remaining customers. Due to uncertainty regarding the specific timing of transfer of the Franchise Assets to the Town, Northland is also requesting approval of a deferral account related to the Hay River Disposition. The deferral would capture any surpluses or shortfalls for the time Northland operates the Franchise Assets beyond January 1, 2023. This proposed deferral account is further discussed in Section 1B.

Impact of the Pandemic

9. In 2020, the COVID-19 pandemic caused lockdowns, work from home orders, travel and border restrictions, and general economic uncertainty. As an essential service, Northland experienced a number of changes from historical trends with respect to energy usage patterns for residential and commercial customers as work from home mandates were imposed; requirements to reassign staff and shift work; and costs related to supply chain issues and personal protective equipment.

10. As pandemic restrictions lift, the economy is expected to return to pre-pandemic levels in 2023 and, given worldwide events (like supply chain constraints), Northland has seen upward pressure on material and labour prices. This is reflected in higher-than-normal inflation assumptions used for 2023 (which are discussed further below).

11. The impact of COVID-19 was considered in the development of the 2023 proposed sales forecast, O&M, and capital expenditure forecasts where appropriate.

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Applied-For Revenue Requirement

12. The associated tariffs and revenue requirement applied for are detailed in Schedules 2.0, 2.1, 3.0 and 3.1 and are summarized in Table 1-1, below.

Table 1-1 – Applied-For Revenue Requirement ($000s)

	2023		
	Total Company	**Hydro Zone**	**Thermal Zone**
Northland Revenue Requirement (before Transmission Revenue and Fuel Prices)	5,357	1,893	3,464
Increase Over Existing Rates	1,420	1,128	293
Revenue Requirement Increase (Before Transmission Revenue and Fuel Prices) (%)	**36%**	**147%**	**9%**
Revenue Requirement Increase (Decrease) Net of Transmission Revenues and Fuel Prices	(354)	17	(371)
Revenue Requirement Increase Net of Increase in Fuel Prices (%)	**-9%**	**2%**	**-12%**

Rate Adjustment Rider (Rider R)

13. As explained in Section 15, Northland is requesting interim approval to update the Rate Adjustment Rider (Rider R) for implementation on May 1, 2023, to begin collecting the applied-for Revenue Requirement shortfall on a refundable basis.

14. To implement Rider R on May 1, 2023, Board approval is required on or before April 21, 2023.

15. Any adjustments required to Rider R following a Board Decision will be made in a subsequent Compliance Filing.

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Deferral Accounts

16. The previously accepted criteria for establishing a deferral account have not changed from Northland's 2011-2013 Phase I GRA. The criteria are:

    (a) not under the control of the company and not reasonably forecastable; or

    (b) an error in forecasting could produce a loss or gain of substantial magnitude.

17. Northland is requesting approval to use the following Deferral Accounts during the Test Year, refer to Table 1-2.

Table 1-2 – Deferral Accounts

Deferral Account	Section	Previously Approved
Timing of Hay River Asset Disposition	Section 1B	New Request
Backup Generation for Taltson Shutdown	Section 1B	New Request
Purchase Power Flow Through	Section 3	9-2014
Diesel Fuel Price Variance	Section 4	9-2014
Hay River Diesel Generation Variance	Section 4	9-2014
Defined Benefit Pension Plan	Section 5	9-2014
Income Tax Rate Deferral Account	Section 8	9-2014

18. In addition to the deferral accounts listed above, Northland is requesting approval to continue its deferral account used to record amounts associated with any Board Decisions, or changes to statutory or legislative provisions, that result in changes to the rules or parameters under which Northland operates, including such areas as the billing system, collection practices or the frequency of meter reading, and that impact Northland's 2023 Revenues and/or Revenue Requirements. For clarity, no such recorded amounts would be approved by the Board as part of this Application. Rather, the balance(s) would be brought forward by Northland for consideration in a future application to the Board.

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Key Assumptions

	2023
Labour Inflation – In Scope	3.5%
Labour Inflation – Out of Scope	4.0%
Other Inflation	6.0%
Vacancy Rate	0.0%

19. For the 2023 Test Year, in-scope (subject to a collective agreement) and out-of-scope (not subject to a collective agreement) labour have been escalated by 3.5 percent and 4.0 percent, respectively. This escalation rate reflects Northland's forecast given the current labour market for specialized skills in the North of 60 and inflation pressures. To ensure Northland is able to attract and retain talent in a challenging and evolving labour market, Northland has aligned labour inflation assumptions to trends realized in Alberta, where a large portion of employees have historically been recruited from. The last collective agreement in place at Northland was for the period January 1, 2019 to December 31, 2021. A final agreement for 2022 and beyond has not been reached.

20. For non-labour costs, the forecast provided by the Bank of Canada (BoC) Monetary Policy Report dated July 2022,[1] has been applied to the Test Year. Events such as the Russian invasion of Ukraine, continued supply chain challenges, and changes to inflation expectations, have all increased the inflation outlook. While high inflation in Canada is largely the result of international factors, domestic demand pressures are becoming more prominent, and price pressures have broadened. This has resulted in high inflation, which is expected to persist over the next one to two years. Given the foregoing, Northland has utilized the sustained higher inflation forecast as it is seen to be reasonable for the 2023 Test Year, as rising inflation over the past couple of years has led to expectations of continued high inflation among firms surveyed by the BoC. It is thus doubtful that

[1] https://www.bankofcanada.ca/wp-content/uploads/2022/07/mpr-2022-07-13.pdf.

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the past two years of high inflation being experienced in Northwest Territories and Canada will reverse any time soon.

21. As described in Section 5, Northland has not forecast a vacancy rate, as the complement forecast is the minimum number of FTEs possible to operate the system safely and reliably, recognizing that vacancies or leave time must be filled with contractors or external resources going forward.

22. Northland is not forecasting any new long-term debt to be issued within this Test Year.

Return on Equity (ROE) and Capital Structure

23. As outlined in Section 7, consistent with previously approved methodologies, Northland requests setting the ROE for the Test Year at the percentage determined on a generic basis for all Alberta Utilities for 2023, as determined by the Alberta Utilities Commission (AUC) in the 2023 Alberta Generic Cost of Capital Proceeding (2023 GCOC Proceeding),[2] plus a risk premium of 1.25 percent to reflect the added business risk due to the Hay River Disposition.

24. Northland is not requesting a change to the five percent adder previously approved for the common equity ratio.

Common Costs Treatment

25. In its letter dated January 31, 2023, the Board requested that Northland address the determination and treatment of common costs following the Hay River Disposition.[3] In order to determine the impacts on common costs, please refer to

[2] Proceeding ID 27084.
[3] Board Letter dated January 31, 2023.

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Section 5 Operations and Maintenance (O&M) expenses and associated explanations related to common costs, post Hay River Disposition.

Revenue Requirement Including the Town of Hay River

26. For purposes of aiding the Board with respect to reviewing the impact on Revenue Requirement and Rates related to the Hay River Disposition, Northland has prepared Revenue Requirement calculations for the 2023 Test Year that, in addition to the Diesel communities, include the Town of Hay River. This Revenue Requirement calculation essentially represents a 'Status Quo' scenario that includes all of Northland's communities, including the Town of Hay River. Please refer to Section 14 Supplemental Information for the Revenue Requirement calculations that include the Town of Hay River, as well as discussion respecting the methodologies associated with the determination and treatment of common costs.

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Section 1B – Implications of the Hay River Disposition

Background

1. While approval of the Hay River Disposition is being sought in a separate Application, the consequence of the proposed transaction significantly affects all aspects of this Application. This Section outlines various considerations that are inextricable from the disposition, particularly:

   i. Expected timing of the disposition and transaction;
   ii. Backup Generation for Taltson Shutdown;
   iii. Hay River Transition Deferral Account;
   iv. Costs related to the disposition of the Franchise Assets; and
   v. New Rates.

Expected Timing and Sales Transaction

2. The transaction for the purchase and sale of the Franchise Assets has not yet closed. A full transition of the Franchise Assets to Hay River is expected to occur later in 2023. While the exact transfer date is unknown, the following table estimates the transaction value as of January 1, 2023. Upon closing of the transaction and transfer of the Franchise Assets to the Town, Northland will notify the Board of the final actual amounts.

Table 1B-1 – Estimated Transaction Dollar Value as of January 1, 2023 ($000s)

Item to be Transferred	Estimated Dollar Value as of January 1, 2023
Net Book Value (net of contributions and negative salvage)	6,656
Deferral Accounts	(367)
Impact on utility Books	**6,289**
Costs Related to the Hay River Disposition	1,421
Premium Approved (1)	2,215
Total Proceeds (2)	**9,925**

(1) Per arbitration – should have no impact to utility customers.
(2) Excludes amounts approved by the arbitrator related to data acquisition.

Disposition of Net Book Value (net of Contributions)

3. Below are the Franchise Assets that will be transferred.

Table 1B-2 - Transferred Assets
($000s)

Asset	Estimate Net Book Value
Distribution (incl. Substation)	4,998
Generation	714
General	944
Net Book Value (net of Contributions)	**6,656**

Disposition of Deferral Accounts

4. As a result of the Hay River Disposition, Northland will true-up deferral account balances to apportion those amounts for which Hay River customers are responsible.

Table 1B-3 – Disposition of Deferral Accounts
($000s)

Deferral Account	Estimated Dollar to be Transferred December 31, 2022
Purchase Power Flow Through	(41)
Diesel Variance	438
Pension Deferral	(54)
Reserve Balances	(587)
Franchise Tax Balances	11
Net Metering Deferral Account	33
Rider H (Cost of Capital Refund)	(167)
Hay River Transition Deferral	0
Backup Generation -Taltson Shutdown	0
Total Deferral Amount Transferred	**(367)**

5. Northland notes that these deferrals will be trued-up at the time of transition as the table reflects estimates. Throughout the Application, Northland is proposing to

continue using previously approved deferrals. The Hay River transition deferral and rate are discussed further in section below.

Backup Generation for Taltson Shutdown

6. In its letter to the Board dated December 15, 2022, Northland indicated that it was notified by NTPC that the Taltson Hydro Overhaul would run from approximately April 2023 to November 2023.[1] With generation costs estimated to be approximately $1 million per month and the timing of the Hay River Disposition expected to occur later into 2023, Northland is seeking approval to record the costs related to providing back-up generation during the shutdown in a separate long-term deferral account, 'Backup Generation for Taltson Shutdown' that is amortized over the expected life of NTPC's generation assets. Accordingly, Northland proposes to amortize the 'Backup Generation for Taltson Shutdown' cost on a 50-year basis, matching NTPC's approved IOWA curve 50-S2[2] for Account 333 Hydro Plan-Water, Wheels, Turbines and Generators.

7. Northland notes that attempting to include these costs in Northland's approved Hay River Diesel Generation deferral account (as outlined in Section 4) and recovering the costs over a one or two year timeframe would result in rate shock and inappropriately burden current ratepayers with costs that have intergenerational benefits. Further, Northland submits this treatment is consistent with the Board's practices as well as utility regulators in other jurisdictions which approved capital treatment during a prolonged shut down.

8. Expenditures expected to be included in the proposed deferral account include fuel, labor and any other supplies required to operate Hay River diesel generators

[1] Northland Letter to the Board dated December 15, 2022.
[2] From NTPC 2022-23 GRA Appendix A, 2020 Depreciation Study, pages 3-5.

during the shutdown. If approved, the deferral will be trued-up and the entire balance will be transferred over to the Town of Hay River at the time of transition.

Hay River Transition Deferral

9. Northland understands the transition date may change depending on how this proceeding unfolds. Therefore, Northland hereby requests a deferral account to track any surpluses or shortfalls associated with Northland providing service to Hay River beyond January 1, 2023.

10. The proposed deferral account will function as follows:

    i. Hay River customers will continue to be served on existing rates, whereas Northland's remaining customers (i.e., non-Hay River Customers) will have rates adjusted in accordance with Board approvals.

    ii. Actual costs incurred to operate the Hay River system – including, but not limited to, operating and administrative costs, financing costs, depreciation and tax – will be collected in this deferral beginning January 1, 2023.

    iii. Any shortfall or surplus resulting from continued service by Northland to Hay River customers beyond January 1, 2023, under existing rates will be recorded in a deferral account and will be invoiced or refunded to the Town or the utility operator at the time of the transition, in accordance with Board approvals. Other existing deferral accounts will be trued up at this time, as well.

    iv. Any costs or efficiencies realized from shared costs as a result of Northland continuing to serve Hay River in 2023 that may impact Northland's remaining customers will be trued-up in a Compliance Filing.

Costs Related to the Hay River Disposition

11. In addition to the Net Book Value transfer amount and Deferral accounts discussed above, additional prudently incurred utility costs result from the Hay River Disposition, as shown in Table 1B-4 below.

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Table 1B-4 – Estimated Transfer of Costs to the Town of Hay River ($000s)

Cost Incurred	Estimated Outstanding Amounts
Long Term Debt Break Fees [3]	476
Employee Severance Costs	275
Costs Related to the Segregation of Assets	150
Legal & Consultant Fees	520
Total Costs Transferred	**1,421**

12. In its letter dated January 31, 2023, the Board requested that Northland address costs related to the Hay River Disposition in a separate Application.[4] Accordingly, please refer to Northland's concurrent Hay River Disposition Application for further details regarding the appropriateness of these Disposition Costs and Northland's requested approval in a separate Application.

13. This Application excludes these costs related to the Hay River Franchise area from the 2023 Test Year, as these costs are being addressed in Northland's Disposition Application. Accordingly, Northland respectfully requests that, the Board approve the Disposition Costs as shown in Table 1B-4, which are further supported in Northland's Hay River Disposition Application, and that these costs be included with the Hay River Transition Deferral amounts and be invoiced directly to the Town or utility operator at the time of transition. In the alternative, if the Board determines that it is not appropriate for these costs to be directly invoiced to the Town or the utility operator, Northland requests approval to include these prudently incurred utility costs in its 2023 GRA such that they can be recovered from Northland's remaining customers. While Northland's position is that customers within the Town should be responsible for the Disposition Costs, if the Board is of a different view, Northland submits that the Board should allow Northland to

[3] Please refer to Northland's concurrent Hay River Disposition proceeding regarding update for LT Debt Break fees.
[4] Board Letter dated January 31, 2023.

recover these costs from its remaining customers given that they were reasonably and prudently incurred utility costs.

New Transmission Rate

14. As a result of the Hay River Disposition, Northland's transmission assets will be segregated from its customers. Electricity will first flow to Hay River over Northland's transmission line, and then wheeled over the Hay River distribution system to provide wholesale service back to Northland at a metering point where the electricity leaves the Hay River distribution system.

15. Northland is allocating the transmission costs to the Town of Hay River using the energy allocator, in accordance with Decision 1-2016 and the Guideline 4 from the GNWT Electricity Rate Policy Guidelines. Northland notes this allocator significantly limits the expected rate impacts for the remaining Northland customers, which are highly sensitive to deviations in revenue requirement due to remaining billing determinants. For example, absent any transmission revenue offset, the remaining customers in the Hydro Zone would see an approximate 147 percent rate increase or, in other words, every $100,000 in costs allocated to the remaining Hydro Zone ratepayers will result in a rate increase of approximately 13 percent. Any changes to the allocation of costs or approved revenue requirements will have significant implications on the resulting rates for Northland's remaining customers and should be a consideration in Northland's concurrent Hay River Disposition proceeding when assessing whether the disposition of the Hay River franchise meets the public interest test, particularly any harm to existing customers.

16. Please refer to Schedule 3.2 for the transmission cost calculations and Attachment 1 for the price schedule related to transmission services, effective immediately following the Hay River Disposition.

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Conclusion

17. While approval of the Hay River Disposition forms part of a separate Application, the implications of the Hay River Disposition and timing thereof impact this Application. Accordingly, Northland requests approval of the following:

(i) Disposition of approved deferrals as set out in Table 1B-3 above, including the costs associated with Backup Generation of the Taltson Shutdown.

(ii) The Hay River Transition Deferral to true-up any surpluses or shortfall associated with Northland providing service to Hay River beyond January 1, 2023, including the recovery of approved of Disposition costs as outlined in Table 1B-4.

(iii) A new Transmission rate to recover transmission costs related to the Town of Hay River.

Effective: _____
Supersedes: _____

NORTHLAND UTILITIES (NWT) LIMITED
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HYDRO RATE ZONE
TRANSMISSION RATE SCHEDULE

Available

- In the Northwest Territories for the operator of the distribution system in the Town of Hay River.

Applicable

- For electricity delivered over the transmission line from Pine Point to the Town of Hay River.

Rates

- Fixed Charge of:
  $92,599 per month
- Energy Charge of
  $0.00 per kWh
- Demand Charge of
  $0.00 per kW
- The minimum monthly charge is the Fixed Charge

Options and Riders

Price Adjustments – the following price adjustments (Riders) may apply:

- Diesel Fuel Cost Adjustment (Rider A)
- Temporary Refund/Surcharge (Rider E)
- Purchase Power Cost Adjustment (Rider F)
- Cost Recovery/Refund (Rider H)
- Interim Refundable Rate (Rider K)
- Rate Adjustment Rider (Rider R)
- Franchise Tax

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Section 2 – Sales and Revenue

Sales

Overview

1. As discussed in Section 1, the 2023 forecast excludes the sales and revenues for Hay River, effective January 1, 2023. Table 2.1 below provides the breakdown of sales by customer class. The sharp drop in 2023 sales is due to the Hay River Disposition. Sales and Revenue for remaining customers are forecast to be flat in 2023.

Table 2.1 – Northland Energy Sales by Customer Class (MWh)

	Actual			Forecast	
Customer Class	**2019**	**2020**	**2021**	**2022**	**2023[1]**
Residential	11,478	12,193	12,188	11,790	2,890
Commercial	21,392	20,339	20,441	20,457	3,240
Streetlights	552	548	546	547	135
Sentinel Lights	190	199	198	194	50
Total Company	**33,612**	**33,280**	**33,373**	**32,988**	**6,315**

[1] Excludes Town of Hay River

2. The COVID-19 global pandemic impacted Residential and Commercial Usage Per Customer (UPC) in 2020 and 2021. During this period, Residential UPC increased as more people were working from home and Commercial UPC decreased as businesses were impacted by COVID-19 restrictions as well as the decrease in employees working in offices. As pandemic restrictions ease, policies and procedures are beginning to normalize, such that the 2023 forecast anticipates UPCs to return to pre-pandemic levels for both residential and commercial customers.

3. Northland's detailed energy sales by customer class, along with corresponding revenue for 2019-2021 (Actual) and 2022-2023 (Forecast), are provided in Schedule 2.1.

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Background

4. In 2020 and 2021, the economy of the NWT was disrupted by the pandemic. GDP fell by 11 percent in 2020 and modestly recovered by 6.3 percent in 2021.[1] Little population growth has occurred over the past several years in NWT, with the population growing at an annual average rate of 0.3 percent from 2016-2021.[2] With pandemic related restrictions recently starting to ease, 2022 UPC is beginning to return to pre-pandemic levels.

5. In 2021, Northland's service territory covered the Town of Hay River, Enterprise, K'atl'odeeche First Nation Reserve, Fort Providence, Wekweeti, Sambaa K'e, Kakisa, and Dory Point. As Table 2.2 below indicates, sales to residential customers in the Hydro Rate Zone communities (the Town of Hay River, Enterprise, and K'atl'odeeche First Nation Reserve) accounted for 84 percent of Northland's total residential sales in 2021, with Fort Providence accounting for 11 percent and the remaining communities accounting for five percent. Likewise, commercial sales in the Hydro Rate Zone communities accounted for 90 percent of Northland's total commercial sales in 2021, with sales to Fort Providence accounting for seven percent and the remaining communities accounting for three percent.

6. In terms of the distribution of energy sales by rate class, residential customers accounted for 37 percent of Northland's total energy sales in 2021, while sales to commercial customers and lighting accounted for 61 percent and two percent, respectively. Table 2.2 below, provides the 2021 annual average customer numbers and the associated energy sales by community for residential and commercial classes.

[1] Gross Domestic Product Northwest Territories, 2021 Preliminary. From: https://www.statsnwt.ca/economy/gdp/May2022_GDP.pdf, accessed July 11, 2022.
[2] Northwest Territories Population, April 2022. From: https://www.statsnwt.ca/population/population-estimates/PopEst_Apr2022.pdf, accessed July 11, 2022.

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Table 2.2 - 2021 Northland Residential and Commercial Customers and Sales by Community

		Residential				Commercial			
Community	Rate Zone	Customers[1]	Share (%)	Energy (MWh)	Share (%)	Customers[1]	Share (%)	Energy (MWh)	Share (%)
Hay River	Hydro	1,468	73	9,133	75	439	69	17,104	84
Ft. Providence	Thermal	284	14	1,399	11	79	12	1,388	7
K'atl'odeeche	Hydro	89	4	721	6	29	4	821	4
Enterprise	Hydro	59	3	387	3	43	7	430	2
Wekweeti	Thermal	43	2	251	2	19	3	376	2
Sambaa K'e	Thermal	40	2	200	2	17	3	202	1
Dory Point/Kakisa	Thermal	21	1	97	1	15	2	120	1
Total		**2,004**	**100**	**12,188**	**100**	**640**	**100**	**20,441**	**100**

1) Annual Averages

Forecast Process

7. Similar to the past methodology, the sales forecasts for 2022 and 2023 are prepared by customer class. The 2022 forecast includes actual data for January to June.

(i) Residential

8. The residential sales forecast has two key inputs: the net customer additions and the UPC. The energy sales forecast is calculated by multiplying the forecast number of customers by the UPC forecast.

9. The number of customer additions is based on information collected from the municipal/community officials, local developers in each community, and historical customer additions.

10. Residential energy consumption in normal circumstances is typically very similar for most families. In general, temperature can play a role in residential energy consumption, although other factors such as the size of the dwelling, the size of household, and economic factors also influence residential energy consumption. The 2022 residential sales forecast includes six months of actual data. Energy for the remaining months of 2022 and 2023 is forecast by multiplying the monthly customer forecast by the corresponding forecast of UPC. The Residential UPC forecast is calculated using the community's three-year average UPC from the pre-pandemic period of 2017 to 2019. K'atl'odeeche and Dory Point/Kakisa

forecast UPC is the same as in 2019. The historical UPC is weather-normalized for communities where temperature is found to have an impact on usage.

(ii) Commercial

11. The forecast of commercial customer additions is derived using information collected from Northland's customers, the communities, and local developers, as well as historical customer additions. The energy sales forecast is calculated by multiplying the forecast number of customers by the UPC forecast.

12. The 2022 commercial sales forecast includes six months of actual data. Energy for the remaining months in 2022 and 2023 for each community is forecast by multiplying the monthly customer forecast by the UPC forecast. The Commercial UPC forecast is calculated using the community's three-year average UPC from the pre-pandemic period of 2017 to 2019. Dory Point/Kakisa and Sambaa K'e forecast UPC is the same as in 2019. In K'atl'odeeche, customer additions since 2019 were forecast separately.

13. Section 2, Attachment 1 provides the data and the detailed calculations of the residential and commercial UPC forecast by community.

(iii) Street and Sentinel Lighting

14. The energy forecast for street and sentinel lighting is obtained by multiplying the forecast number of customers by the average usage per light. Average usage is calculated based on wattage characteristics and light types. The customer additions forecast is based on discussions with developers in the community and consultation with community officials as well as historical customer additions.

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2023 Forecast

(i) Residential

15. Energy sales to residential customers are expected to decrease by 76 percent and customer numbers are expected to decrease by 73 percent in 2023, largely due to the discontinuation of the Franchise Agreement.

16. In the remaining communities, energy sales are expected to mildly increase compared to pre-pandemic levels.

Table 2.3 – Residential Energy Sales (MWh) by Area

	2019	2020	2021	2022	2023
		Actual		Forecast	
Hay River	8,671	9,147	9,133	8,825	-
Remaining Hydro	979	1,076	1,108	1,033	1,013
Thermal	1,828	1,971	1,946	1,932	1,877
Total	**11,478**	**12,193**	**12,188**	**11,790**	**2,890**

(ii) Commercial

17. Energy sales to commercial customers are expected to decrease by 84 percent and customer numbers are expected to decrease by 68 percent in 2023 mainly due to the discontinuation of the Franchise Agreement.

18. In the remaining Hydro communities, energy sales are expected to mildly increase compared to pre-pandemic levels, whereas energy sales in the Thermal communities are expected to mildly decrease compared to pre-pandemic levels.

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Table 2.4 – Commercial Energy Sales (MWh) by Area

	2019	2020	2021	2022	2023
		Actual		Forecast	
Hay River	18,122	17,175	17,104	17,172	-
Remaining Hydro	1,231	1,181	1,251	1,261	1,274
Thermal	2,039	1,983	2,085	2,024	1,966
Total	**21,392**	**20,339**	**20,441**	**20,457**	**3,240**

(iii) Street and Sentinel Lighting

19. Energy sales to lighting customers are forecast to decrease 74 percent in 2023 due to the discontinuation of the Franchise Agreement. In the remaining communities, lighting customers and sales are expected to remain flat.

Revenue

Base Rate Revenue

20. To forecast revenue on existing rates, the current rates in place effective August 1, 2022, were applied to the sales forecast. Details of revenue by rate class are provided in Schedule 2.1.

Transmission Revenue

21. As discussed in Section 1B, Northland is seeking approval to recover revenue for transmission expenses from the Town.

Other Revenue

22. Northland's other revenues have been included with retail sales revenues as part of the revenue requirement. These amounts are detailed in Schedule 10.0.

23. Services to outside party revenues have been forecast based on a three-year historic average increase. Penalty revenue, reconnect revenue, and other revenues are based on three-year historic averages. Joint use revenues are based on forecast pole attachments and attachment rates.

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Variables Definition

NWT

Definition of the variables used in the regression equation

Name	Definition
MHDD	Monthly Heating Degree Days
MCCNT	Monthly Commercial Customer Count
MCENCNS	Monthly Commercial Energy Consumption
MCUPC	Monthly Commercial Average Use Per Customer (UF
MRCNT	Monthly Residential Customer Count
MRENCNS	Monthly Residential Energy Consumption
MRUPC	Monthly Residential Average Use Per Customer (UP(
N_MHDD	"Normal" (20-yr Average) HDD

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Enterprise - Data

Enterprise

			Residential						Commercial			
Year	Month	monthly	MRCNT	MRENCNS (MWh)	MRUPC (kWh)	MHDD (Hay River)	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	MCCNT	MCENCNS (MWh)	MCUPC (kWh)	Annual UPC (kWh)
2005	1	Jan-05	35	29.6	847.1	1259.5	835.2		36	53	1,479	
2005	2	Feb-05	35	28.7	819.8	1034.4	827.1		36	62	1,723	
2005	3	Mar-05	35	21.0	599.7	949.1	613.1		36	51	1,416	
2005	4	Apr-05	36	20.2	560.6	542.4	586.4		36	52	1,447	
2005	5	May-05	36	17.0	472.8	407.1	466.4		39	40	1,038	
2005	6	Jun-05	36	13.9	386.4	208.8	374.4		39	35	907	
2005	7	Jul-05	36	12.8	354.7	86.0	349.1		39	42	1,079	
2005	8	Aug-05	36	14.5	403.1	143.2	395.4		39	45	1,144	
2005	9	Sep-05	38	14.1	371.5	308.0	360.9		42	44	1,043	
2005	10	Oct-05	37	14.6	394.1	473.7	405.7		35	36	1,035	
2005	11	Nov-05	37	17.0	460.4	767.1	484.5		35	43	1,233	
2005	12	Dec-05	37	21.7	587.5	866.3	652.9	**6,351**	35	38	1,072	**14,615**
2006	1	Jan-06	37	23.1	623.3	1164.8	634.9		35	53	1,523	
2006	2	Feb-06	37	21.5	582.2	927.4	615.9		35	42	1,202	
2006	3	Mar-06	37	21.5	582.1	904.4	606.5		35	46	1,304	
2006	4	Apr-06	37	19.3	521.7	497.2	558.7		37	41	1,120	
2006	5	May-06	37	15.3	412.6	312.1	429.7		39	31	798	
2006	6	Jun-06	38	15.0	396.0	98.3	411.3		39	32	814	
2006	7	Jul-06	37	16.3	441.8	85.2	436.5		40	36	891	
2006	8	Aug-06	37	12.9	348.8	90.1	354.2		40	29	737	
2006	9	Sep-06	37	12.7	343.4	203.1	358.8		40	29	728	
2006	10	Oct-06	38	14.3	377.1	524.3	376.1		43	38	872	
2006	11	Nov-06	38	19.3	508.3	1042.4	464.3		37	42	1,134	
2006	12	Dec-06	39	23.7	607.5	925.2	658.3	**5,905**	37	47	1,269	**12,394**
2007	1	Jan-07	39	23.4	601.3	1108.2	626.8		37	48	1,286	
2007	2	Feb-07	39	22.7	583.2	1168.2	557.3		37	44	1,193	
2007	3	Mar-07	39	27.8	711.9	1099.9	687.9		37	44	1,192	
2007	4	Apr-07	37	19.7	533.3	559.6	554.9		37	39	1,066	
2007	5	May-07	40	16.2	404.4	368.0	407.7		37	31	832	
2007	6	Jun-07	39	15.6	399.5	161.2	399.2		40	47	1,180	
2007	7	Jul-07	38	17.2	452.3	37.8	458.7		40	46	1,154	
2007	8	Aug-07	38	12.4	326.3	187.3	307.7		40	25	617	
2007	9	Sep-07	38	14.5	380.8	365.5	356.0		41	32	769	
2007	10	Oct-07	40	15.4	385.3	489.4	392.9		39	28	729	
2007	11	Nov-07	41	21.0	511.7	849.8	515.3		37	35	945	
2007	12	Dec-07	42	20.5	489.1	1188.0	474.8	**5,739**	41	38	921	**11,885**
2008	1	Jan-08	40	26.9	673.6	1215.4	672.6		42	51	1,215	
2008	2	Feb-08	40	26.8	670.7	1201.8	636.4		38	47	1,227	
2008	3	Mar-08	42	25.5	608.1	1090.8	586.3		43	45	1,038	
2008	4	Apr-08	41	19.7	481.2	689.4	470.6		40	44	1,092	
2008	5	May-08	41	18.0	439.1	358.0	444.9		40	37	926	
2008	6	Jun-08	43	15.8	367.4	154.9	368.7		39	34	876	
2008	7	Jul-08	44	13.3	301.8	35.2	308.8		40	31	765	
2008	8	Aug-08	43	16.2	376.6	102.8	378.9		41	33	799	
2008	9	Sep-08	45	15.6	346.2	315.4	333.7		40	36	896	
2008	10	Oct-08	43	15.0	349.0	477.7	359.6		41	29	718	
2008	11	Nov-08	41	20.3	496.0	777.7	517.5		28	30	1,060	
2008	12	Dec-08	44	21.2	480.8	1280.6	443.6	**5,522**	36	41	1,145	**11,758**
2009	1	Jan-09	44	30.4	690.8	1237.6	684.4		34	48	1,408	
2009	2	Feb-09	44	21.4	486.6	1084.9	481.3		34	39	1,161	
2009	3	Mar-09	44	24.4	554.5	1116.3	526.5		36	48	1,340	
2009	4	Apr-09	44	20.0	455.2	623.2	461.0		36	42	1,172	
2009	5	May-09	44	17.3	392.2	489.9	365.3		41	29	718	
2009	6	Jun-09	42	18.1	430.7	192.7	422.6		42	33	794	
2009	7	Jul-09	43	15.5	359.9	101.3	350.6		42	33	781	
2009	8	Aug-09	43	14.4	334.4	87.7	340.4		42	33	775	
2009	9	Sep-09	43	16.5	384.5	176.8	406.4		42	36	851	
2009	10	Oct-09	43	16.9	392.4	559.7	382.7		42	35	837	
2009	11	Nov-09	43	17.1	397.4	824.5	407.3		37	23	611	
2009	12	Dec-09	43	22.0	511.0	1163.4	502.8	**5,331**	37	34	923	**11,372**
2010	1	Jan-10	43	27.5	640.0	1229.1	635.6		37	40	1,073	
2010	2	Feb-10	43	23.0	535.1	900.2	575.6		37	36	978	
2010	3	Mar-10	43	19.7	458.4	718.9	528.7		37	35	957	
2010	4	Apr-10	43	18.8	436.1	491.0	474.7		37	31	844	
2010	5	May-10	43	16.7	388.5	401.5	383.5		37	22	592	
2010	6	Jun-10	43	18.0	417.8	120.0	427.7		41	30	723	
2010	7	Jul-10	43	15.0	349.6	45.3	354.2		42	27	652	
2010	8	Aug-10	45	17.2	381.2	109.4	381.9		42	32	768	
2010	9	Sep-10	46	16.7	362.8	293.5	355.8		42	31	728	
2010	10	Oct-10	46	17.8	387.9	463.7	402.0		42	30	709	
2010	11	Nov-10	45	22.8	507.4	810.3	520.8		39	34	876	
2010	12	Dec-10	45	26.6	591.4	1214.7	570.5	**5,611**	39	39	994	**9,892**
2011	1	Jan-11	45	30.8	685.0	1289.0	665.8		40	45	1,113	
2011	2	Feb-11	45	34.3	763.2	1007.4	777.1		40	50	1,249	
2011	3	Mar-11	45	30.8	685.3	1041.3	675.8		40	41	1,036	
2011	4	Apr-11	45	25.4	564.6	720.1	546.5		40	38	939	
2011	5	May-11	45	22.2	492.6	360.5	497.7		42	27	649	
2011	6	Jun-11	45	18.6	414.0	168.2	412.0		44	33	752	
2011	7	Jul-11	45	17.8	395.1	36.6	401.8		45	31	697	
2011	8	Aug-11	45	17.8	396.5	85.7	403.0		45	30	677	
2011	9	Sep-11	46	19.9	432.5	205.7	447.2		45	35	789	
2011	10	Oct-11	46	17.8	387.5	470.8	399.8		40	26	656	
2011	11	Nov-11	47	21.4	455.7	952.1	434.0		40	30	754	
2011	12	Dec-11	47	28.9	614.9	978.4	652.5	**6,313**	40	43	1,063	**10,375**
2012	1	Jan-12	47	27.6	586.7	1184.0	593.5		40	40	1,001	
2012	2	Feb-12	47	32.3	686.3	913.4	723.5		40	45	1,120	
2012	3	Mar-12	47	26.5	564.4	991.7	567.2		40	38	952	
2012	4	Apr-12	47	26.8	570.7	676.1	563.4		40	36	907	
2012	5	May-12	47	21.7	462.2	276.5	488.1		40	28	701	
2012	6	Jun-12	47	21.3	452.7	155.5	453.8		45	33	736	
2012	7	Jul-12	48	18.8	390.9	13.3	403.4		46	34	747	
2012	8	Aug-12	48	19.1	398.0	59.5	411.0		46	36	784	
2012	9	Sep-12	49	17.4	355.4	178.2	377.0		46	35	762	
2012	10	Oct-12	49	19.8	404.7	574.9	391.2		40	28	706	
2012	11	Nov-12	49	24.0	490.6	1010.5	454.5		40	33	833	
2012	12	Dec-12	49	30.6	625.3	1328.4	576.2	**6,003**	40	42	1,046	**10,294**
2013	1	Jan-13	49	41.2	840.5	1291.6	820.7		40	47	1,163	
2013	2	Feb-13	49	35.1	715.9	927.5	749.6		37	41	1,114	
2013	3	Mar-13	50	28.2	563.7	1076.5	545.5		38	36	951	
2013	4	Apr-13	50	31.6	631.1	785.1	596.8		38	37	972	
2013	5	May-13	50	23.2	463.2	332.8	475.2		38	31	812	
2013	6	Jun-13	50	20.3	405.6	134.7	411.9		43	30	692	
2013	7	Jul-13	50	23.5	470.4	82.6	465.8		42	33	778	
2013	8	Aug-13	50	22.6	452.5	77.7	461.0		44	32	727	
2013	9	Sep-13	50	22.8	455.5	179.7	476.6		44	33	747	
2013	10	Oct-13	50	21.8	435.4	458.2	450.8		38	24	633	
2013	11	Nov-13	50	28.9	577.7	886.6	572.2		38	33	859	
2013	12	Dec-13	50	42.0	840.0	1339.9	788.1	**6,814**	38	52	1,365	**10,813**
2014	1	Jan-14	50	44.9	897.4	1,200	900.3		38	43	1,141	
2014	2	Feb-14	50	26.8	535.0	1,188	504.1		38	41	1,083	
2014	3	Mar-14	49	38.1	777.0	1,121	747.7		38	46	1,210	
2014	4	Apr-14	49	22.3	455.8	691	445.0		38	38	997	
2014	5	May-14	49	22.6	461.4	380	461.6		39	30	758	
2014	6	Jun-14	48	20.3	423.5	158	424.1		45	36	793	
2014	7	Jul-14	48	19.3	402.7	35	409.9		45	32	706	
2014	8	Aug-14	49	22.2	453.6	104	455.6		45	33	739	
2014	9	Sep-14	49	18.5	378.1	274	376.0		44	31	713	
2014	10	Oct-14	49	22.9	467.2	521	467.0		39	25	651	

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Enterprise - Data

Enterprise

			Residential						Commercial			
Year	Month	monthly	MRCNT	MRENCNS (MWh)	MRUPC (kWh)	MHDD (Hay River)	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	MCCNT	MCENCNS (MWh)	MCUPC (kWh)	Annual UPC (kWh)
2014	11	Nov-14	48	29.2	608.4	910	597.2		39	33	853	
2014	12	Dec-14	50	43.5	869.4	1,144	866.1	**6,655**	39	44	1,118	**10,762**
2015	1	Jan-15	50	37.4	748.6	1,225	745.3		39	45	1,150	
2015	2	Feb-15	50	27.4	548.2	1,104	538.2		39	37	936	
2015	3	Mar-15	50	32.9	657.2	955	669.1		39	46	1,187	
2015	4	Apr-15	50	19.4	388.0	571	406.7		39	30	765	
2015	5	May-15	50	21.0	419.9	305	438.8		39	26	663	
2015	6	Jun-15	50	22.2	443.9	126	452.3		44	35	795	
2015	7	Jul-15	50	15.4	308.2	67	307.3		45	31	679	
2015	8	Aug-15	50	19.3	385.3	98	388.9		45	34	761	
2015	9	Sep-15	52	31.5	605.4	264	605.7		45	37	822	
2015	10	Oct-15	52	22.5	432.4	508	435.5		38	23	614	
2015	11	Nov-15	54	31.5	583.0	768	607.0		39	39	990	
2015	12	Dec-15	54	34.2	632.8	1,025	659.0	**6,254**	39	38	987	**10,349**
2016	1	Jan-16	54	30.7	569.4	1,087	600.1		39	35	900	
2016	2	Feb-16	54	31.1	576.7	1,050	580.1		38	39	1,014	
2016	3	Mar-16	54	29.4	544.3	925	563.6		39	37	956	
2016	4	Apr-16	54	22.4	415.2	683	406.3		39	30	778	
2016	5	May-16	53	24.4	459.6	312	476.7		39	32	833	
2016	6	Jun-16	53	21.9	412.3	105	425.9		45	34	752	
2016	7	Jul-16	53	15.7	295.9	47	300.1		45	27	608	
2016	8	Aug-16	54	18.5	341.9	79	350.0		47	33	703	
2016	9	Sep-16	54	27.6	510.3	250	514.2		48	32	674	
2016	10	Oct-16	54	20.6	381.4	566	370.0		42	30	718	
2016	11	Nov-16	54	27.6	510.3	722	545.6		43	36	828	
2016	12	Dec-16	54	36.3	671.8	1,191	656.7	**5,789**	43	51	1,185	**9,951**
2017	1	Jan-17	54	28.5	527.6	1,072	562.1		43	42	972	
2017	2	Feb-17	53	29.8	562.1	948	590.8		42	43	1,027	
2017	3	Mar-17	54	30.6	566.9	1,033	559.3		42	54	1,280	
2017	4	Apr-17	54	21.7	401.6	667	396.5		42	29	695	
2017	5	May-17	54	27.2	503.3	284	527.4		42	34	805	
2017	6	Jun-17	54	20.6	381.7	152	383.8		48	31	640	
2017	7	Jul-17	54	19.5	362.0	56	364.0		48	30	619	
2017	8	Aug-17	56	18.8	335.9	60	348.7		48	33	681	
2017	9	Sep-17	56	23.7	423.2	205	438.2		48	41	849	
2017	10	Oct-17	55	26.0	473.6	507	476.9		42	30	722	
2017	11	Nov-17	55	29.9	542.8	976	515.3		42	42	996	
2017	12	Dec-17	55	35.0	636.9	1,084	648.4	**5,811**	42	46	1,086	**10,373**
2018	1	Jan-18	56	38.8	692.8	1,265	679.5		42	47	1,116	
2018	2	Feb-18	56	34.9	624.0	1,044	629.0		42	44	1,036	
2018	3	Mar-18	56	33.9	605.1	992	607.8		42	46	1,085	
2018	4	Apr-18	56	26.3	470.0	723	451.1		42	36	862	
2018	5	May-18	56	28.2	504.0	327	517.5		42	35	839	
2018	6	Jun-18	56	23.1	412.3	157	413.0		48	33	677	
2018	7	Jul-18	57	22.7	398.0	74	395.4		47	31	656	
2018	8	Aug-18	57	22.8	400.5	119	398.8		47	34	729	
2018	9	Sep-18	59	23.8	403.5	425	364.0		47	31	662	
2018	10	Oct-18	59	31.6	536.2	566	524.9		46	34	736	
2018	11	Nov-18	59	32.9	558.1	880	554.3		40	36	912	
2018	12	Dec-18	59	41.9	711.0	1,046	731.8	**6,267**	40	47	1,183	**10,495**
2019	1	Jan-19	59	40.3	682.3	1,223	679.4		40	47	1,175	
2019	2	Feb-19	59	39.7	673.7	1,153	651.5		40	38	960	
2019	3	Mar-19	59	34.9	591.5	710	664.1		39	37	955	
2019	4	Apr-19	59	26.8	453.4	567	473.3		40	20	511	
2019	5	May-19	59	29.7	504.1	433	491.3		41	33	797	
2019	6	Jun-19	59	28.4	480.7	196	471.8		45	37	818	
2019	7	Jul-19	59	26.5	448.5	100	439.5		45	22	487	
2019	8	Aug-19	59	23.2	392.9	153	382.8		45	28	624	
2019	9	Sep-19	59	24.7	419.2	265	419.3		46	29	636	
2019	10	Oct-19	58	28.9	498.7	516	499.7		46	31	671	
2019	11	Nov-19	59	30.6	519.0	849	522.9		40	31	774	
2019	12	Dec-19	59	47.2	800.6	1,227	776.8	**6,472**	38	41	1,087	**9,495**
2020	1	Jan-20	59	45.1	764.2	1,289	744.9		39	46	1,185	
2020	2	Feb-20	59	42.0	711.8	1,106	701.4		40	37	917	
2020	3	Mar-20	59	33.2	563.3	1,078	544.7		39	34	861	
2020	4	Apr-20	59	34.1	577.4	734	555.8		41	31	768	
2020	5	May-20	59	26.9	456.8	460	437.3		37	39	1,045	
2020	6	Jun-20	59	28.7	486.2	207	474.7		41	32	783	
2020	7	Jul-20	59	27.8	470.8	76	467.9		47	30	631	
2020	8	Aug-20	59	24.6	416.3	116	415.4		48	22	455	
2020	9	Sep-20	59	30.3	512.9	273	510.9		48	31	648	
2020	10	Oct-20	59	29.0	491.4	586	475.3		48	32	658	
2020	11	Nov-20	58	36.0	621.2	927	605.7		39	36	918	
2020	12	Dec-20	58	41.0	706.0	1,077	719.3	**6,653**	39	42	1,089	**9,959**
2021	1	Jan-21	58	44.8	772.3	1,099	800.1		38	38	988	
2021	2	Feb-21	58	39.1	674.8	1,227	634.3		39	46	1,169	
2021	3	Mar-21	59	41.8	708.2	1,031	701.4		40	41	1,026	
2021	4	Apr-21	59	33.3	564.3	698	551.5		41	38	928	
2021	5	May-21	59	27.9	472.2	403	466.8		41	35	845	
2021	6	Jun-21	59	27.0	458.2	146	461.7		47	37	777	
2021	7	Jul-21	59	27.7	469.9	64	469.8		47	32	691	
2021	8	Aug-21	59	23.8	404.1	118	402.7		47	33	697	
2021	9	Sep-21	60	23.8	396.7	233	404.7		47	37	792	
2021	10	Oct-21	60	27.4	456.1	458	471.6		42	30	713	
2021	11	Nov-21	60	29.5	492.5	822	503.0		43	31	717	
2021	12	Dec-21	60	41.2	687.5	1,337	636.4	**6,504**	40	33	825	**10,168**
2022	1	Jan-22	60	52.6	875.9	1,263	863.2		43	48	1,121	
2022	2	Feb-22	60	39.6	660.4	1,200	626.7		42	38	904	
2022	3	Mar-22	60	36.9	614.2	1,047	603.3		43	52	1,200	
2022	4	Apr-22	60	28.8	480.0	707	465.2		43	39	911	
2022	5	May-22	59	26.3	445.9	393	442.9		42	37	875	
2022	6	Jun-22					422.9				818	
2022	7	Jul-22					399.7				487	
2022	8	Aug-22					376.8				624	
2022	9	Sep-22					407.1				636	
2022	10	Oct-22					500.5				671	
2022	11	Nov-22					530.9				774	
2022	12	Dec-22					719.0	**6,358**			1,087	**10,108**
2023	1	Jan-23					640.3				1,175	
2023	2	Feb-23					623.7				960	
2023	3	Mar-23					610.4				955	
2023	4	Apr-23					440.3				511	
2023	5	May-23					512.1				797	
2023	6	Jun-23					422.9				818	
2023	7	Jul-23					399.7				487	
2023	8	Aug-23					376.8				624	
2023	9	Sep-23					407.1				636	
2023	10	Oct-23					500.5				671	
2023	11	Nov-23					530.9				774	
2023	12	Dec-23					719.0	**6,184**			1,087	**9,495**

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Enterprise - Regression

ENTERPRISE
Summary Output, Residential
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.808857206
R Square	0.65424998
Adjusted R Square	0.652307564
Standard Error	75.01436412
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	1895354.153	1895354	336.8228	6.55872E-43
Residual	178	1001633.559	5627.155		
Total	179	2896987.712			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	351.5068574	9.938182786	35.36933	1.97E-82	331.8950374	371.118677	331.895037	371.118677
MHDD	0.247606263	0.01349152	18.35273	6.56E-43	0.220982356	0.27423017	0.22098236	0.27423017

Summary Output, Commercial
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.686161034
R Square	0.470816964
Adjusted R Square	0.467844026
Standard Error	162.8388535
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	4199351.845	4199352	158.3675	2.17745E-26
Residual	178	4719935.616	26516.49		
Total	179	8919287.461			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	691.2307513	21.57349876	32.04073	7.99E-76	648.6580211	733.803481	648.658021	733.803481
MHDD	0.368559468	0.029286972	12.58442	2.18E-26	0.310765116	0.42635382	0.31076512	0.42635382

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
K'atl'odeeche - Data

K'atl'odeeche First Nation Reserve

Residential									Commercial				
Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
2005	1	Jan-05	81	82	1,013	1,260	1,000.7		24	93	3,883	
2005	2	Feb-05	81	59	731	1,034	738.9		23	80	3,489	
2005	3	Mar-05	80	58	722	949	735.8		23	80	3,472	
2005	4	Apr-05	80	52	646	542	673.1		23	78	3,378	
2005	5	May-05	78	54	691	407	684.0		23	82	3,545	
2005	6	Jun-05	78	46	591	209	578.6		23	74	3,230	
2005	7	Jul-05	79	43	544	86	538.4		25	70	2,804	
2005	8	Aug-05	80	46	576	143	567.8		25	69	2,769	
2005	9	Sep-05	80	45	567	308	555.7		24	81	3,385	
2005	10	Oct-05	79	55	698	474	710.1		27	92	3,424	
2005	11	Nov-05	80	57	718	767	743.1		25	87	3,461	
2005	12	Dec-05	82	63	768	866	836.6	**8,363**	25	90	3,617	**40,457**
2006	1	Jan-06	83	76	913	1,165	924.9		24	94	3,929	
2006	2	Feb-06	81	62	767	927	802.3		24	87	3,633	
2006	3	Mar-06	80	58	725	904	750.9		24	104	4,339	
2006	4	Apr-06	80	52	646	497	684.8		23	88	3,830	
2006	5	May-06	80	50	626	312	643.9		24	86	3,604	
2006	6	Jun-06	88	50	571	98	586.7		22	73	3,340	
2006	7	Jul-06	88	52	591	85	585.2		23	82	3,550	
2006	8	Aug-06	90	49	550	90	555.6		24	67	2,802	
2006	9	Sep-06	89	50	563	203	579.1		23	77	3,341	
2006	10	Oct-06	89	61	681	524	680.4		23	87	3,791	
2006	11	Nov-06	89	69	772	1,042	725.2		23	89	3,850	
2006	12	Dec-06	89	68	764	925	817.6	**8,337**	23	85	3,704	**43,713**
2007	1	Jan-07	90	86	957	1,108	983.6		22	92	4,184	
2007	2	Feb-07	90	73	812	1,168	784.2		22	87	3,954	
2007	3	Mar-07	90	69	771	1,100	745.7		22	92	4,198	
2007	4	Apr-07	90	71	784	560	806.9		22	86	3,894	
2007	5	May-07	91	53	584	368	587.1		22	76	3,452	
2007	6	Jun-07	92	54	585	161	585.0		22	82	3,734	
2007	7	Jul-07	92	54	584	38	590.6		22	79	3,595	
2007	8	Aug-07	91	45	493	187	473.7		22	71	3,218	
2007	9	Sep-07	93	57	613	366	586.4		22	84	3,832	
2007	10	Oct-07	96	59	613	489	621.3		22	82	3,748	
2007	11	Nov-07	93	64	684	850	687.5		22	88	3,984	
2007	12	Dec-07	93	68	728	1,188	712.5	**8,164**	22	83	3,774	**45,567**
2008	1	Jan-08	93	97	1,039	1,215	1,037.5		22	107	4,876	
2008	2	Feb-08	92	78	843	1,202	807.1		22	88	4,010	
2008	3	Mar-08	91	68	747	1,091	723.8		22	89	4,053	
2008	4	Apr-08	91	68	752	689	740.4		23	88	3,842	
2008	5	May-08	91	61	671	358	677.4		23	86	3,739	
2008	6	Jun-08	91	57	624	155	625.7		23	71	3,066	
2008	7	Jul-08	92	47	512	35	519.2		23	80	3,484	
2008	8	Aug-08	90	53	594	103	596.7		24	77	3,194	
2008	9	Sep-08	91	50	547	315	533.8		24	72	2,998	
2008	10	Oct-08	91	55	609	478	620.4		24	78	3,259	
2008	11	Nov-08	91	72	794	778	816.8		24	92	3,839	
2008	12	Dec-08	91	71	780	1,281	741.1	**8,440**	24	83	3,441	**43,800**
2009	1	Jan-09	91	100	1,100	1,238	1,093.0		24	91	3,794	
2009	2	Feb-09	91	74	810	1,085	804.3		24	83	3,479	
2009	3	Mar-09	91	84	918	1,116	888.0		24	94	3,933	
2009	4	Apr-09	90	67	750	623	755.9		24	83	3,448	
2009	5	May-09	91	53	584	490	555.9		22	72	3,277	
2009	6	Jun-09	90	57	637	193	628.5		24	83	3,469	
2009	7	Jul-09	90	52	583	101	572.9		24	72	3,007	
2009	8	Aug-09	88	51	574	88	580.6		24	68	2,841	
2009	9	Sep-09	87	50	575	177	597.9		24	71	2,961	
2009	10	Oct-09	89	53	590	560	579.7		24	75	3,144	
2009	11	Nov-09	93	70	748	825	758.7		24	95	3,979	
2009	12	Dec-09	93	71	769	1,163	760.1	**8,575**	24	90	3,752	**41,082**
2010	1	Jan-10	93	95	1,021	1,229	1,016.2		24	108	4,489	
2010	2	Feb-10	93	70	754	900	796.7		24	88	3,668	
2010	3	Mar-10	93	63	682	719	756.8		24	88	3,669	
2010	4	Apr-10	94	63	675	491	715.6		24	85	3,528	
2010	5	May-10	92	57	623	402	617.4		24	87	3,635	
2010	6	Jun-10	91	50	551	120	561.1		25	76	3,031	
2010	7	Jul-10	89	48	542	45	547.3		25	69	2,777	
2010	8	Aug-10	89	51	571	109	572.1		24	66	2,747	
2010	9	Sep-10	88	49	555	294	548.1		25	68	2,720	
2010	10	Oct-10	89	56	631	464	645.3		25	86	3,444	
2010	11	Nov-10	90	59	653	810	666.7		25	90	3,590	
2010	12	Dec-10	90	69	765	1,215	743.2	**8,186**	26	98	3,778	**41,076**
2011	1	Jan-11	91	79	866	1,289	846.0		26	94	3,603	
2011	2	Feb-11	90	75	831	1,007	846.1		26	101	3,901	
2011	3	Mar-11	90	72	803	1,041	792.5		26	99	3,801	
2011	4	Apr-11	89	55	617	720	597.6		26	80	3,069	
2011	5	May-11	88	57	647	361	652.6		25	87	3,466	
2011	6	Jun-11	88	50	568	168	565.5		25	75	2,992	
2011	7	Jul-11	84	45	532	37	538.6		25	63	2,534	
2011	8	Aug-11	84	50	599	86	605.7		24	66	2,737	
2011	9	Sep-11	85	50	590	206	605.1		24	70	2,919	
2011	10	Oct-11	83	53	633	471	646.1		24	79	3,310	
2011	11	Nov-11	83	63	760	952	737.0		24	89	3,709	
2011	12	Dec-11	84	68	808	978	848.2	**8,281**	24	88	3,667	**39708.70**
2012	1	Jan-12	83	70	849	1,184	856.0		24	83	3,474	
2012	2	Feb-12	83	77	932	913	971.5		24	95	3,948	
2012	3	Mar-12	83	67	802	992	804.8		24	91	3,779	
2012	4	Apr-12	83	58	701	676	693.6		24	83	3,453	
2012	5	May-12	81	55	681	277	708.6		24	87	3,610	
2012	6	Jun-12	82	48	588	156	589.5		24	76	3,181	
2012	7	Jul-12	81	49	605	13	618.2		24	70	2,909	
2012	8	Aug-12	81	47	575	60	588.5		24	64	2,669	
2012	9	Sep-12	81	47	582	178	604.7		24	67	2,789	
2012	10	Oct-12	80	55	689	575	675.1		24	83	3,445	
2012	11	Nov-12	81	58	721	1,011	683.3		24	83	3,458	
2012	12	Dec-12	81	69	847	1,328	795.1	**8,589**	23	85	3,696	**40411.93**
2013	1	Jan-13	81	83	1,025	1,292	1,003.6		23	91	3,942	
2013	2	Feb-13	80	72	900	928	935.6		23	88	3,845	
2013	3	Mar-13	84	66	780	1,077	760.7		24	82	3,405	
2013	4	Apr-13	85	65	763	785	726.7		24	83	3,441	
2013	5	May-13	84	54	640	333	652.8		24	77	3,222	
2013	6	Jun-13	81	49	610	135	616.5		24	74	3,100	
2013	7	Jul-13	80	47	592	83	586.9		24	60	2,509	
2013	8	Aug-13	80	46	578	78	587.1		24	62	2,563	
2013	9	Sep-13	81	50	613	180	635.8		24	58	2,397	
2013	10	Oct-13	82	52.2	637.1	458.2	653.4		24	70	2,915	
2013	11	Nov-13	81	66.9	825.8	886.6	820.0		24	75	3,145	
2013	12	Dec-13	82	79.3	966.9	1339.9	912.1	**8,891**	24	80	3,319	**37,802**
2014	1	Jan-14	82	81.8	997.3	1,200	1,000.3		23	72	3,141	
2014	2	Feb-14	82	62.5	762.0	1,188	729.4		23	67	2,934	
2014	3	Mar-14	81	75.9	937.1	1,121	906.2		23	83	3,620	
2014	4	Apr-14	81	51.8	638.9	691	627.5		23	61	2,669	
2014	5	May-14	81	48.4	597.6	380	597.8		23	61	2,652	
2014	6	Jun-14	76	42.8	563.7	158	564.3		23	54	2,344	
2014	7	Jul-14	77	47.2	613.2	35	620.8		23	54	2,340	
2014	8	Aug-14	78	48.3	619.7	104	621.7		23	58	2,528	
2014	9	Sep-14	79	47.5	601.6	274	599.3		24	52	2,158	
2014	10	Oct-14	80	50.9	636.0	521	635.7		24	65	2,719	

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
K'atl'odeeche - Data

K'atl'odeeche First Nation Reserve

			Residential							Commercial			
Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	Normalized UPC (kWh)	Annual Normalized UPC (kWh)	MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
2014	11	Nov-14	80	67.1	838.4	910	826.6		24	80	3,322	
2014	12	Dec-14	80	69.9	874.2	1,144	870.6	**8,600**	25	76	3,040	**33,467**
2015	1	Jan-15	81	71.6	884.1	1,225	880.7		25	77	3,066	
2015	2	Feb-15	81	64.9	800.9	1,104	790.3		25	70	2,805	
2015	3	Mar-15	81	74.3	916.9	955	929.5		25	92	3,683	
2015	4	Apr-15	81	40.3	497.2	571	516.9		25	60	2,397	
2015	5	May-15	81	46.2	570.8	305	590.8		25	66	2,656	
2015	6	Jun-15	78	49.6	636.2	126	645.1		25	56	2,229	
2015	7	Jul-15	78	38.4	492.1	67	491.2		25	45	1,810	
2015	8	Aug-15	78	46.0	589.5	98	593.4		25	52	2,094	
2015	9	Sep-15	77	45.1	586.0	264	586.3		25	52	2,075	
2015	10	Oct-15	76	52.6	692.3	508	695.6		25	78	3,132	
2015	11	Nov-15	79	62.6	792.3	768	817.6		25	77	3,061	
2015	12	Dec-15	80	60.6	757.8	1,025	785.4	**8,323**	25	77	3,068	**32,074**
2016	1	Jan-16	80	58.5	730.7	1,087	763.1		25	69	2,779	
2016	2	Feb-16	79	62.2	787.9	1,050	791.5		25	77	3,087	
2016	3	Mar-16	78	53.4	685.2	925	705.6		25	67	2,677	
2016	4	Apr-16	78	47.2	604.8	683	595.4		25	64	2,552	
2016	5	May-16	79	48.9	619.1	312	637.2		25	63	2,509	
2016	6	Jun-16	78	45.7	585.7	105	600.0		25	53	2,126	
2016	7	Jul-16	77	39.3	510.1	47	514.5		25	43	1,702	
2016	8	Aug-16	78	45.3	581.0	79	589.5		25	50	1,993	
2016	9	Sep-16	78	45.0	577.4	250	581.6		25	50	2,006	
2016	10	Oct-16	77	47.9	621.5	566	609.4		25	61	2,459	
2016	11	Nov-16	78	55.5	711.5	722	748.8		25	76	3,054	
2016	12	Dec-16	78	71.6	917.4	1,191	901.4	**8,038**	25	96	3,837	**30,781**
2017	1	Jan-17	78	60.8	779.8	1,072	816.2		25	72	2,873	
2017	2	Feb-17	79	53.2	673.2	948	703.5		25	70	2,803	
2017	3	Mar-17	78	56.3	721.4	1,033	713.5		25	75	3,007	
2017	4	Apr-17	77	41.2	535.4	667	530.0		25	58	2,310	
2017	5	May-17	77	53.2	690.5	284	716.0		25	74	2,957	
2017	6	Jun-17	75	37.5	500.1	152	502.3		24	54	2,235	
2017	7	Jul-17	74	41.1	555.5	56	557.6		24	53	2,223	
2017	8	Aug-17	74	44.8	605.2	60	618.8		24	55	2,304	
2017	9	Sep-17	75	40.5	539.9	205	555.7		24	53	2,214	
2017	10	Oct-17	75	53.8	718.0	507	721.5		24	77	3,206	
2017	11	Nov-17	74	51.5	696.0	976	667.0		23	69	3,020	
2017	12	Dec-17	75	60.0	800.3	1,084	812.3	**7,914**	24	76	3,159	**32,311**
2018	1	Jan-18	75	72.3	963.9	1,265	949.8		24	75	3,104	
2018	2	Feb-18	75	48.0	639.4	1,044	644.7		24	62	2,575	
2018	3	Mar-18	75	51.4	685.5	992	688.4		24	72	3,011	
2018	4	Apr-18	75	46.9	625.0	723	605.0		24	70	2,933	
2018	5	May-18	76	46.6	612.6	327	626.8		24	62	2,602	
2018	6	Jun-18	76	42.9	564.5	157	565.3		24	58	2,421	
2018	7	Jul-18	74	40.8	551.9	74	549.1		26	56	2,169	
2018	8	Aug-18	75	46.9	625.6	119	623.9		26	62	2,397	
2018	9	Sep-18	75	42.4	564.7	425	523.0		26	64	2,456	
2018	10	Oct-18	76	50.5	663.9	566	652.0		26	79	3,032	
2018	11	Nov-18	77	48.9	635.3	880	631.2		26	79	3,039	
2018	12	Dec-18	77	53.1	689.0	1,046	711.0	**7,770**	25	78	3,111	**32,850**
2019	1	Jan-19	77	55.5	720.4	1,223	717.3		26	85	3,255	
2019	2	Feb-19	78	56.1	718.8	1,153	695.3		26	73	2,789	
2019	3	Mar-19	78	51.0	653.6	710	730.3		26	74	2,861	
2019	4	Apr-19	78	45.0	577.1	567	598.1		26	71	2,749	
2019	5	May-19	84	46.6	555.0	433	541.5		26	75	2,888	
2019	6	Jun-19	84	44.9	534.6	196	525.2		26	67	2,585	
2019	7	Jul-19	86	44.9	522.0	100	512.5		26	59	2,285	
2019	8	Aug-19	85	35.6	419.4	153	408.8		26	51	1,955	
2019	9	Sep-19	90	42.3	469.7	265	469.8		26	57	2,180	
2019	10	Oct-19	90	51.7	575.0	516	576.1		26	74	2,857	
2019	11	Nov-19	90	51.0	566.9	849	571.0		26	66	2,535	
2019	12	Dec-19	90	73.8	819.6	1,227	794.4	**7,140**	26	84	3,227	**32,168**
2020	1	Jan-20	90	63.1	701.6	1,289	681.3		26	72	2,782	
2020	2	Feb-20	90	60.9	676.5	1,106	665.6		27	69	2,573	
2020	3	Mar-20	90	61.2	679.9	1,078	660.3		27	81	2,986	
2020	4	Apr-20	90	54.9	610.5	734	587.7		27	61	2,269	
2020	5	May-20	90	46.0	511.1	460	490.5		27	51	1,888	
2020	6	Jun-20	90	49.1	545.7	207	533.5		27	54	1,993	
2020	7	Jul-20	90	52.2	580.1	76	577.0		28	50	1,790	
2020	8	Aug-20	90	46.6	517.5	116	516.5		28	43	1,524	
2020	9	Sep-20	90	57.2	635.6	273	633.5		28	64	2,278	
2020	10	Oct-20	90	56.4	626.3	586	609.2		29	73	2,521	
2020	11	Nov-20	90	61.4	681.9	927	665.5		29	77	2,645	
2020	12	Dec-20	91	68.3	750.3	1,077	764.3	**7,385**	27	75	2,768	**28,017**
2021	1	Jan-21	91	80.6	885.9	1,099	915.3		29	87	3,005	
2021	2	Feb-21	90	74.8	831.3	1,227	788.6		29	78	2,676	
2021	3	Mar-21	90	64.4	715.3	1,031	708.1		29	74	2,568	
2021	4	Apr-21	90	58.3	647.5	698	634.0		29	71	2,452	
2021	5	May-21	90	49.4	548.9	403	543.3		29	67	2,316	
2021	6	Jun-21	90	48.6	540.3	146	543.9		28	66	2,375	
2021	7	Jul-21	88	52.8	600.5	64	600.4		28	54	1,912	
2021	8	Aug-21	87	47.0	540.4	118	538.9		28	50	1,776	
2021	9	Sep-21	88	50.1	569.8	233	578.2		28	55	1,962	
2021	10	Oct-21	88	54.8	622.8	458	639.2		28	70	2,494	
2021	11	Nov-21	89	62.7	704.9	822	715.9		29	72	2,468	
2021	12	Dec-21	89	77.3	868.9	1,337	815.0	**8,021**	30	78	2,590	**28,595**
2022	1	Jan-22	89	81.7	918.1	1,263	904.7		30	73	2,449	
2022	2	Feb-22	89	65.2	732.8	1,200	697.2		30	71	2,350	
2022	3	Mar-22	89	63.8	716.6	1,047	705.1		30	69	2,316	
2022	4	Apr-22	89	48.4	543.8	707	528.1		29	60	2,066	
2022	5	May-22	80	49.7	621.5	393	618.4		15	21	1,426	
2022	6	Jun-22					525.2				2,414	
2022	7	Jul-22					512.5				2,226	
2022	8	Aug-22					408.8				2,219	
2022	9	Sep-22					469.8				2,283	
2022	10	Oct-22					576.1				3,031	
2022	11	Nov-22					571.0				2,865	
2022	12	Dec-22					794.4	**7,311**			3,166	**28,811**
2023	1	Jan-23					717.3				3,078	
2023	2	Feb-23					695.3				2,722	
2023	3	Mar-23					730.3				2,960	
2023	4	Apr-23					598.1				2,664	
2023	5	May-23					541.5				2,816	
2023	6	Jun-23					525.2				2,414	
2023	7	Jul-23					512.5				2,226	
2023	8	Aug-23					408.8				2,219	
2023	9	Sep-23					469.8				2,283	
2023	10	Oct-23					576.1				3,031	
2023	11	Nov-23					571.0				2,865	
2023	12	Dec-23					794.4	**7,140**			3,166	**32,443**

K'atl'odeeche First Nation Reserve
Summary Output, Residential
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.833652517
R Square	0.694976519
Adjusted R Square	0.693262903
Standard Error	72.18598657
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	2113307.296	2113307	405.5616	9.11473E-48
Residual	178	927525.365	5210.817		
Total	179	3040832.661			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	525.0222711	9.563468778	54.89873	1.6E-113	506.1499046	543.8946377	506.1499046	543.8946377
MHDD	0.26145549	0.012982829	20.13856	9.11E-48	0.235835424	0.287075557	0.235835424	0.287075557

Summary Output, Commercial
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.56461866
R Square	0.318794232
Adjusted R Square	0.314967233
Standard Error	485.9774572
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	19673624.98	19673625	83.30137	1.51748E-16
Residual	178	42038987.82	236174.1		
Total	179	61712612.8			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	2665.681184	64.38410638	41.40278	2.72E-93	2538.626819	2792.735549	2538.626819	2792.735549
MHDD	0.797734977	0.087404253	9.126958	1.52E-16	0.625253095	0.970216859	0.625253095	0.970216859

Northland Utilities (NWT) Limited (Northland)
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Fort Providence

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	Normalized UPC (kWh)	Annual Normalized UPC (kWh)
2005	1	Jan-05	249	140	561	1,260	552.1	
2005	2	Feb-05	250	121	486	1,034	508.4	
2005	3	Mar-05	250	115	461	949	486.1	
2005	4	Apr-05	247	122	494	542	515.4	
2005	5	May-05	248	75	301	407	297.6	
2005	6	Jun-05	247	93	375	209	367.7	
2005	7	Jul-05	248	88	357	86	349.1	
2005	8	Aug-05	249	85	342	143	336.1	
2005	9	Sep-05	253	105	415	308	410.2	
2005	10	Oct-05	251	102	406	474	412.8	
2005	11	Nov-05	251	124	494	767	514.4	
2005	12	Dec-05	251	106	421	866	461.6	**5,212**
2006	1	Jan-06	248	143	576	1,165	581.6	
2006	2	Feb-06	249	122	491	927	528.7	
2006	3	Mar-06	250	117	469	904	500.7	
2006	4	Apr-06	250	106	422	497	450.4	
2006	5	May-06	250	94	375	312	384.5	
2006	6	Jun-06	254	89	349	98	357.7	
2006	7	Jul-06	253	93	369	85	361.9	
2006	8	Aug-06	255	89	348	90	350.2	
2006	9	Sep-06	254	99	389	203	399.6	
2006	10	Oct-06	256	105	409	524	408.2	
2006	11	Nov-06	253	120	476	1,042	456.3	
2006	12	Dec-06	255	135	528	925	559.9	**5,340**
2007	1	Jan-07	257	143	555	1,108	568.7	
2007	2	Feb-07	254	126	497	1,168	499.5	
2007	3	Mar-07	253	128	504	1,100	507.2	
2007	4	Apr-07	253	112	444	560	462.8	
2007	5	May-07	249	97	388	368	390.2	
2007	6	Jun-07	251	97	385	161	384.2	
2007	7	Jul-07	252	87	344	38	343.4	
2007	8	Aug-07	251	101	403	187	390.5	
2007	9	Sep-07	254	99	391	366	377.6	
2007	10	Oct-07	252	113	450	489	454.5	
2007	11	Nov-07	262	137	525	850	533.3	
2007	12	Dec-07	259	156	603	1,188	596.3	**5,508**
2008	1	Jan-08	276	159	575	1,215	573.2	
2008	2	Feb-08	278	143	516	1,202	513.9	
2008	3	Mar-08	282	129	457	1,091	461.1	
2008	4	Apr-08	283	128	452	689	451.8	
2008	5	May-08	278	110	397	358	400.4	
2008	6	Jun-08	278	114	409	155	409.4	
2008	7	Jul-08	277	84	302	35	301.9	
2008	8	Aug-08	276	109	394	103	394.5	
2008	9	Sep-08	278	110	395	315	388.5	
2008	10	Oct-08	277	108	390	478	396.0	
2008	11	Nov-08	273	144	529	778	548.5	
2008	12	Dec-08	276	134	484	1,281	464.4	**5,304**
2009	1	Jan-09	274	176	644	1,238	638.5	
2009	2	Feb-09	275	141	513	1,085	528.4	
2009	3	Mar-09	277	132	476	1,116	476.9	
2009	4	Apr-09	276	132	478	623	487.9	
2009	5	May-09	276	107	387	490	371.1	
2009	6	Jun-09	279	99	354	193	348.5	
2009	7	Jul-09	279	108	386	101	376.2	
2009	8	Aug-09	276	104	378	88	380.2	
2009	9	Sep-09	272	109	401	177	415.5	
2009	10	Oct-09	275	118	431	560	425.3	
2009	11	Nov-09	280	140	499	825	511.3	
2009	12	Dec-09	270	136	503	1,163	500.4	**5,460**
2010	1	Jan-10	279	171	614	1,229	609.4	
2010	2	Feb-10	278	135	485	900	526.8	
2010	3	Mar-10	281	125	446	719	504.8	
2010	4	Apr-10	284	133	470	491	499.0	
2010	5	May-10	282	125	445	402	441.9	
2010	6	Jun-10	280	118	420	120	425.2	
2010	7	Jul-10	281	113	402	45	400.7	
2010	8	Aug-10	283	98	347	109	346.4	
2010	9	Sep-10	286	106	370	294	367.6	
2010	10	Oct-10	286	121	424	464	432.6	
2010	11	Nov-10	284	121	425	810	439.5	
2010	12	Dec-10	288	145	503	1,215	492.9	**5,487**
2011	1	Jan-11	291	181	621	1,289	608.0	
2011	2	Feb-11	287	156	544	1,007	570.8	
2011	3	Mar-11	290	159	547	1,041	558.9	
2011	4	Apr-11	289	135	468	720	463.8	
2011	5	May-11	288	133	462	361	464.4	
2011	6	Jun-11	286	104	362	168	360.6	
2011	7	Jul-11	288	110	382	37	381.4	
2011	8	Aug-11	286	104	364	86	366.8	
2011	9	Sep-11	288	102	356	206	365.6	
2011	10	Oct-11	287	112	390	471	397.6	
2011	11	Nov-11	291	119	409	952	402.8	
2011	12	Dec-11	291	144	495	978	519.6	**5,460**
2012	1	Jan-12	290	172	594	1,184	595.8	
2012	2	Feb-12	285	156	547	913	587.1	
2012	3	Mar-12	289	152	528	992	546.5	
2012	4	Apr-12	290	140	482	676	483.8	
2012	5	May-12	292	128	440	277	455.2	
2012	6	Jun-12	292	106	363	156	363.7	
2012	7	Jul-12	285	105	369	13	371.8	
2012	8	Aug-12	287	110	384	60	390.2	
2012	9	Sep-12	286	97	339	178	353.0	
2012	10	Oct-12	285	104	365	575	357.3	
2012	11	Nov-12	285	116	408	1,011	393.0	
2012	12	Dec-12	289	142	490	1,328	463.4	**5,361**
2013	1	Jan-13	289	160	555	1,292	541.4	
2013	2	Feb-13	287	168	584	928	622.4	
2013	3	Mar-13	285	126	443	1,077	449.1	
2013	4	Apr-13	284	120	421	785	407.5	
2013	5	May-13	284	138	485	333	491.8	
2013	6	Jun-13	281	110	390	135	393.6	
2013	7	Jul-13	276	96	347	83	339.8	
2013	8	Aug-13	282	107	378	78	381.8	
2013	9	Sep-13	281	107	380	180	394.2	
2013	10	Oct-13	282	111	392.5	458.2	401.6	
2013	11	Nov-13	284	136	478.5	886.6	475.3	
2013	12	Dec-13	283	155	547.2	1339.9	516.7	**5,415**
2014	1	Jan-14	285	157	550.6	1,200	552.4	
2014	2	Feb-14	283	134	475.0	1,188	456.8	
2014	3	Mar-14	282	131	463.3	1,121	446.1	
2014	4	Apr-14	282	116	411.9	691	405.5	
2014	5	May-14	284	115	405.5	380	405.6	
2014	6	Jun-14	278	101	363.1	158	363.4	
2014	7	Jul-14	278	100	358.8	35	363.0	
2014	8	Aug-14	281	100	355.8	104	356.9	
2014	9	Sep-14	281	97	344.1	274	342.8	
2014	10	Oct-14	281	132	470.5	521	470.3	
2014	11	Nov-14	280	131	468.5	910	461.9	
2014	12	Dec-14	283	148	522.5	1,144	520.5	**5,145**
2015	1	Jan-15	284	157	554.1	1,225	552.1	

Commercial

MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
77	181	2,356	
77	113	1,472	
80	166	2,073	
83	79	949	
82	113	1,377	
80	110	1,381	
78	104	1,333	
78	112	1,441	
76	126	1,653	
77	103	1,333	
81	118	1,453	
83	120	1,450	**18,272**
80	148	1,846	
80	135	1,682	
76	128	1,678	
77	120	1,560	
75	103	1,379	
75	108	1,441	
75	95	1,261	
73	125	1,707	
73	115	1,573	
74	112	1,509	
73	132	1,803	
72	108	1,500	**18,939**
72	151	2,098	
72	140	1,945	
73	121	1,654	
75	110	1,466	
77	138	1,789	
80	119	1,493	
85	114	1,346	
91	112	1,233	
91	106	1,161	
86	125	1,455	
79	143	1,812	
75	135	1,799	**19,251**
77	145	1,884	
76	149	1,966	
76	120	1,581	
77	111	1,441	
79	114	1,443	
81	118	1,451	
82	99	1,210	
81	132	1,628	
79	97	1,223	
76	108	1,421	
75	138	1,843	
75	122	1,623	**18,713**
73	154	2,107	
73	131	1,789	
74	129	1,748	
73	113	1,553	
77	124	1,613	
75	102	1,365	
77	110	1,432	
75	122	1,629	
75	114	1,524	
69	110	1,594	
69	125	1,814	
67	106	1,580	**19,746**
71	178	2,507	
73	130	1,777	
72	112	1,554	
73	117	1,607	
74	117	1,579	
75	116	1,552	
74	129	1,739	
74	108	1,464	
74	125	1,689	
74	108	1,457	
69	104	1,512	
68	128	1,882	**20,319**
69	151	2,196	
69	133	1,934	
69	141	2,040	
69	120	1,746	
69	107	1,558	
73	95	1,297	
73	114	1,559	
74	108	1,460	
73	99	1,355	
69	95	1,382	
69	93	1,342	
69	109	1,582	**19,449**
67	134	2,002	
68	120	1,770	
68	126	1,856	
69	126	1,832	
69	111	1,603	
72	92	1,282	
72	107	1,487	
72	116	1,613	
73	110	1,512	
70	94	1,346	
70	100	1,427	
70	137	1,951	**19,680**
70	150	2,149	
70	147	2,101	
74	123	1,667	
74	119	1,614	
74	120	1,616	
77	109	1,410	
77	114	1,486	
77	122	1,591	
76	116	1,525	
74	111	1,497	
74	130	1,760	
75	164	2,180	**20,594**
75	146	1,947	
76	130	1,712	
75	131	1,745	
75	113	1,513	
78	110	1,413	
79	115	1,458	
78	129	1,648	
77	123	1,603	
79	118	1,494	
73	103	1,411	
75	129	1,722	
75	134	1,789	**19,455**
74	138	1,863	

Northland Utilities (NWT) Limited (Northland)
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Fort Providence

Residential									Commercial			
			MRCNT	MRENCNS	UPC	MHDD	Normalized	Annual Normalized	MCCNT	MCENCNS	UPC	Annual
Year	Month	monthly		(MWh)	(kWh)	(Hay River)	UPC (kWh)	UPC (kWh)		(MWh)	(kWh)	UPC (kWh)
2015	2	Feb-15	283	140	493.3	1,104	487.5		74	126	1,697	
2015	3	Mar-15	282	126	446.6	955	453.7		74	128	1,728	
2015	4	Apr-15	283	107	376.7	571	387.7		74	118	1,596	
2015	5	May-15	283	112	396.2	305	407.3		74	113	1,522	
2015	6	Jun-15	281	98	348.1	126	353.0		77	124	1,617	
2015	7	Jul-15	282	90	317.8	67	317.3		79	121	1,535	
2015	8	Aug-15	283	108	381.6	98	383.7		78	112	1,435	
2015	9	Sep-15	280	93	332.4	264	332.5		80	120	1,503	
2015	10	Oct-15	282	115	409.0	508	410.8		76	117	1,533	
2015	11	Nov-15	281	125	445.3	768	459.4		76	126	1,659	
2015	12	Dec-15	284	145	511.0	1,025	526.4	**5,071**	76	133	1,756	**19,445**
2016	1	Jan-16	285	145	507.1	1,087	525.2		76	136	1,787	
2016	2	Feb-16	286	135	472.3	1,050	474.3		76	122	1,611	
2016	3	Mar-16	284	119	419.1	925	430.4		76	130	1,708	
2016	4	Apr-16	285	114	399.7	683	394.5		76	117	1,544	
2016	5	May-16	286	110	383.2	312	393.3		75	105	1,397	
2016	6	Jun-16	283	103	363.7	105	371.8		79	108	1,363	
2016	7	Jul-16	286	94	330.4	47	332.8		79	116	1,470	
2016	8	Aug-16	286	102	357.5	79	362.2		78	111	1,429	
2016	9	Sep-16	287	100	346.7	250	349.0		80	108	1,346	
2016	10	Oct-16	286	121	423.8	566	417.1		75	116	1,551	
2016	11	Nov-16	287	126	439.7	722	460.4		76	120	1,574	
2016	12	Dec-16	287	145	506.9	1,191	498.0	**5,009**	75	135	1,796	**18,577**
2017	1	Jan-17	287	149	518.0	1,072	538.3		75	131	1,751	
2017	2	Feb-17	287	118	410.4	948	427.3		75	123	1,637	
2017	3	Mar-17	287	129	448.6	1,033	444.2		75	133	1,777	
2017	4	Apr-17	287	103	358.5	667	355.6		75	104	1,384	
2017	5	May-17	286	117	407.5	284	421.6		75	111	1,475	
2017	6	Jun-17	284	98	343.5	152	344.7		80	107	1,335	
2017	7	Jul-17	285	91	317.8	56	319.0		80	113	1,412	
2017	8	Aug-17	286	104	365.3	60	372.9		79	105	1,326	
2017	9	Sep-17	287	93	324.9	205	333.7		79	107	1,351	
2017	10	Oct-17	285	111	389.1	507	391.0		80	112	1,403	
2017	11	Nov-17	286	129	452.2	976	436.0		80	123	1,540	
2017	12	Dec-17	285	135	473.1	1,084	479.9	**4,864**	80	126	1,570	**17,962**
2018	1	Jan-18	285	146	511.7	1,265	503.8		83	135	1,631	
2018	2	Feb-18	285	121	423.4	1,044	426.3		83	121	1,463	
2018	3	Mar-18	285	109	381.4	992	383.1		82	119	1,446	
2018	4	Apr-18	285	108	378.4	723	367.3		78	125	1,602	
2018	5	May-18	284	114	403.2	327	411.1		78	98	1,260	
2018	6	Jun-18	281	94	333.6	157	334.0		82	106	1,290	
2018	7	Jul-18	284	97	343.2	74	341.7		82	112	1,367	
2018	8	Aug-18	282	100	355.4	119	354.4		82	103	1,262	
2018	9	Sep-18	284	86	301.9	425	278.6		82	103	1,253	
2018	10	Oct-18	284	115	403.7	566	397.0		79	114	1,437	
2018	11	Nov-18	285	141	494.9	880	492.6		79	145	1,836	
2018	12	Dec-18	285	105	370.1	1,046	382.3	**4,672**	79	124	1,573	**17,420**
2019	1	Jan-19	285	140	492.7	1,223	491.0		79	130	1,643	
2019	2	Feb-19	283	124	437.0	1,153	423.9		79	123	1,559	
2019	3	Mar-19	287	116	402.5	710	445.3		79	119	1,507	
2019	4	Apr-19	280	97	345.7	567	357.4		77	112	1,449	
2019	5	May-19	286	104	362.7	433	355.2		77	105	1,362	
2019	6	Jun-19	278	91	325.7	196	320.4		82	108	1,319	
2019	7	Jul-19	279	88	314.2	100	308.9		82	118	1,434	
2019	8	Aug-19	279	96	345.8	153	339.8		81	101	1,249	
2019	9	Sep-19	283	95	334.1	265	334.1		82	99	1,210	
2019	10	Oct-19	280	107	381.0	516	381.6		78	111	1,422	
2019	11	Nov-19	285	123	429.9	849	432.3		77	109	1,414	
2019	12	Dec-19	283	135	478.0	1,227	464.0	**4,654**	76	138	1,822	**17,391**
2020	1	Jan-20	285	145	507.4	1,289	496.1		77	138	1,790	
2020	2	Feb-20	287	125	434.2	1,106	428.1		78	116	1,485	
2020	3	Mar-20	285	114	399.7	1,078	388.8		78	130	1,661	
2020	4	Apr-20	284	107	377.2	734	364.5		77	104	1,347	
2020	5	May-20	284	111	391.4	460	379.9		77	90	1,174	
2020	6	Jun-20	284	109	383.6	207	376.8		77	87	1,134	
2020	7	Jul-20	283	102	360.1	76	358.3		80	105	1,315	
2020	8	Aug-20	283	100	351.8	116	351.3		80	107	1,338	
2020	9	Sep-20	284	103	363.4	273	362.2		80	104	1,304	
2020	10	Oct-20	285	114	400.4	586	390.9		80	117	1,465	
2020	11	Nov-20	285	124	433.9	927	424.7		76	124	1,636	
2020	12	Dec-20	286	146	510.6	1,077	518.4	**4,840**	75	129	1,716	**17,366**
2021	1	Jan-21	286	145	507.1	1,099	523.5		76	123	1,614	
2021	2	Feb-21	285	127	445.8	1,227	422.0		76	135	1,771	
2021	3	Mar-21	285	127	446.0	1,031	442.0		76	121	1,592	
2021	4	Apr-21	285	123	431.0	698	423.5		76	96	1,268	
2021	5	May-21	285	98	343.8	403	340.7		76	113	1,485	
2021	6	Jun-21	285	101	352.7	146	354.7		76	98	1,295	
2021	7	Jul-21	281	95	337.7	64	337.6		81	115	1,417	
2021	8	Aug-21	285	100	349.8	118	349.0		81	102	1,262	
2021	9	Sep-21	283	99	349.1	233	353.8		81	104	1,280	
2021	10	Oct-21	281	111	393.9	458	403.0		81	126	1,555	
2021	11	Nov-21	284	136	479.7	822	485.9		82	107	1,308	
2021	12	Dec-21	285	138	483.1	1,337	453.1	**4,889**	82	148	1,809	**17,658**
2022	1	Jan-22	285	158	553.6	1,263	546.1		77	131	1,706	
2022	2	Feb-22	285	141	495.0	1,200	475.2		81	106	1,310	
2022	3	Mar-22	285	143	501.8	1,047	495.4		76	105	1,377	
2022	4	Apr-22	284	91	320.3	707	311.5		77	132	1,710	
2022	5	May-22	285	108	379.1	393	377.3		77	116	1,508	
2022	6	Jun-22					333.1				1,315	
2022	7	Jul-22					323.2				1,404	
2022	8	Aug-22					355.7				1,279	
2022	9	Sep-22					315.5				1,272	
2022	10	Oct-22					389.9				1,421	
2022	11	Nov-22					453.6				1,597	
2022	12	Dec-22					442.1	**4,818**			1,655	**17,552**
2023	1	Jan-23					511.0				1,675	
2023	2	Feb-23					425.9				1,553	
2023	3	Mar-23					424.2				1,577	
2023	4	Apr-23					360.1				1,478	
2023	5	May-23					396.0				1,366	
2023	6	Jun-23					333.1				1,315	
2023	7	Jul-23					323.2				1,404	
2023	8	Aug-23					355.7				1,279	
2023	9	Sep-23					315.5				1,272	
2023	10	Oct-23					389.9				1,421	
2023	11	Nov-23					453.6				1,597	
2023	12	Dec-23					442.1	**4,730**			1,655	**17,591**

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Fort Providence - Regression

FORT PROVIDENCE
Summary Output, Residential
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.81927083
R Square	0.67120469
Adjusted R Square	0.66935752
Standard Error	42.5043593
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	656472.1572	656472.2	363.3702	7.37732E-45
Residual	178	321578.46	1806.621		
Total	179	978050.6173			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	340.830914	5.631136079	60.52614	1.1E-120	329.718538	351.9432906	329.718538	351.9432906
MHDD	0.14572182	0.007644515	19.06227	7.38E-45	0.130636284	0.160807362	0.130636284	0.160807362

Summary Output, Commercial
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.66335964
R Square	0.44004601
Adjusted R Square	0.4369002
Standard Error	176.708491
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	4367979.346	4367979	139.8833	3.4428E-24
Residual	178	5558208.556	31225.89		
Total	179	9926187.902			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	1355.61216	23.41100006	57.90492	2.1E-117	1309.41334	1401.81098	1309.41334	1401.81098
MHDD	0.3758865	0.031781461	11.82723	3.44E-24	0.313169572	0.438603428	0.313169572	0.438603428

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Dory Point Kakisa - Data

Dory Point & Kakisa

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	UPC (kWh)	Annual UPC (kWh)
2005	1	Jan-05	21	12	576	1,260		
2005	2	Feb-05	21	8	395	1,034		
2005	3	Mar-05	21	8	384	949		
2005	4	Apr-05	21	11	523	542		
2005	5	May-05	21	10	464	407		
2005	6	Jun-05	21	9	447	209		
2005	7	Jul-05	21	9	413	86		
2005	8	Aug-05	21	8	392	143		
2005	9	Sep-05	21	11	512	308		
2005	10	Oct-05	21	10	474	474		
2005	11	Nov-05	21	11	527	767		
2005	12	Dec-05	21	13	596	866		**5,704**
2006	1	Jan-06	21	15	722	1,165		
2006	2	Feb-06	20	9	468	927		
2006	3	Mar-06	21	9	430	904		
2006	4	Apr-06	21	8	399	497		
2006	5	May-06	21	9	432	312		
2006	6	Jun-06	21	11	517	98		
2006	7	Jul-06	21	11	500	85		
2006	8	Aug-06	21	8	402	90		
2006	9	Sep-06	21	11	511	203		
2006	10	Oct-06	21	11	508	524		
2006	11	Nov-06	21	14	667	1,042		
2006	12	Dec-06	21	13	613	925		**6,169**
2007	1	Jan-07	21	12	575	1,108		
2007	2	Feb-07	23	11	494	1,168		
2007	3	Mar-07	23	10	427	1,100		
2007	4	Apr-07	23	10	445	560		
2007	5	May-07	24	12	485	368		
2007	6	Jun-07	25	9	371	161		
2007	7	Jul-07	24	9	391	38		
2007	8	Aug-07	24	9	369	187		
2007	9	Sep-07	24	10	427	366		
2007	10	Oct-07	24	10	418	489		
2007	11	Nov-07	24	14	564	850		
2007	12	Dec-07	24	12	486	1,188		**5,450**
2008	1	Jan-08	25	17	698	1,215		
2008	2	Feb-08	24	11	478	1,202		
2008	3	Mar-08	24	10	417	1,091		
2008	4	Apr-08	25	10	396	689		
2008	5	May-08	25	10	409	358		
2008	6	Jun-08	25	9	358	155		
2008	7	Jul-08	25	7	279	35		
2008	8	Aug-08	25	12	489	103		
2008	9	Sep-08	25	8	301	315		
2008	10	Oct-08	25	10	414	478		
2008	11	Nov-08	25	14	548	778		
2008	12	Dec-08	26	14	531	1,281		**5,318**
2009	1	Jan-09	26	16	610	1,238		
2009	2	Feb-09	26	10	373	1,085		
2009	3	Mar-09	26	9	347	1,116		
2009	4	Apr-09	26	10	399	623		
2009	5	May-09	26	10	366	490		
2009	6	Jun-09	26	9	344	193		
2009	7	Jul-09	26	10	395	101		
2009	8	Aug-09	26	9	350	88		
2009	9	Sep-09	26	9	348	177		
2009	10	Oct-09	26	11	418	560		
2009	11	Nov-09	26	12	477	825		
2009	12	Dec-09	26	13	481	1,163		**4,909**
2010	1	Jan-10	26	16	606	1,229		
2010	2	Feb-10	26	10	376	900		
2010	3	Mar-10	26	8	293	719		
2010	4	Apr-10	26	10	376	491		
2010	5	May-10	26	11	423	402		
2010	6	Jun-10	26	11	419	120		
2010	7	Jul-10	24	11	446	45		
2010	8	Aug-10	26	10	387	109		
2010	9	Sep-10	26	10	387	294		
2010	10	Oct-10	26	11	440	464		
2010	11	Nov-10	26	10	396	810		
2010	12	Dec-10	26	12	453	1,215		**5,003**
2011	1	Jan-11	26	14	523	1,289		
2011	2	Feb-11	26	12	478	1,007		
2011	3	Mar-11	26	9	361	1,041		
2011	4	Apr-11	26	9	338	720		
2011	5	May-11	26	10	403	361		
2011	6	Jun-11	26	10	400	168		
2011	7	Jul-11	25	9	373	37		
2011	8	Aug-11	26	9	350	86		
2011	9	Sep-11	26	9	359	206		
2011	10	Oct-11	26	10	382	471		
2011	11	Nov-11	26	10	396	952		

Commercial

MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
18	25	1,384	
18	17	931	
18	17	919	
17	17	1,027	
17	16	922	
22	13	583	
22	11	513	
23	11	479	
19	14	732	
17	14	800	
18	16	901	
19	18	944	**10,136**
19	22	1,175	
19	19	1,003	
18	15	834	
19	17	905	
19	12	643	
22	13	589	
19	12	636	
19	10	511	
20	14	704	
18	14	759	
20	26	1,307	
20	23	1,148	**10,212**
21	18	881	
18	21	1,190	
18	18	992	
20	15	727	
20	15	732	
20	11	528	
20	9	472	
20	10	482	
20	12	606	
18	14	795	
18	19	1,077	
19	19	1,024	**9,505**
24	25	1,053	
23	21	895	
23	25	1,087	
23	26	1,120	
26	21	814	
29	13	442	
29	8	278	
28	16	567	
28	17	610	
26	20	772	
22	30	1,386	
22	22	1,012	**10,036**
20	33	1,652	
21	53	2,520	
23	41	1,771	
25	27	1,084	
28	22	798	
27	14	523	
28	12	439	
28	14	486	
25	11	459	
28	17	622	
23	15	671	
20	16	786	**11,812**
20	30	1,504	
20	16	794	
19	13	706	
19	16	862	
22	17	770	
24	17	697	
24	12	519	
24	10	432	
24	11	456	
24	14	578	
19	16	816	
20	21	1,045	**9,177**
18	28	1,576	
20	31	1,550	
19	25	1,316	
19	24	1,237	
21	26	1,217	
24	19	782	
24	12	515	
24	10	426	
24	11	457	
19	11	577	
19	16	830	

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Dory Point Kakisa - Data

Dory Point & Kakisa

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	UPC (kWh)	Annual UPC (kWh)
2011	12	Dec-11	26	12	453	978		**4,815**
2012	1	Jan-12	26	14	537	1,184		
2012	2	Feb-12	26	12	459	913		
2012	3	Mar-12	26	10	388	992		
2012	4	Apr-12	26	9	347	676		
2012	5	May-12	26	10	378	277		
2012	6	Jun-12	26	10	378	156		
2012	7	Jul-12	26	10	374	13		
2012	8	Aug-12	26	11	434	60		
2012	9	Sep-12	26	9	359	178		
2012	10	Oct-12	26	10	387	575		
2012	11	Nov-12	26	11	423	1,011		
2012	12	Dec-12	26	11	429	1,328		**4,894**
2013	1	Jan-13	26	14	530	1,292		
2013	2	Feb-13	26	13	495	928		
2013	3	Mar-13	26	10	381	1,077		
2013	4	Apr-13	26	10	368	785		
2013	5	May-13	26	11	412	333		
2013	6	Jun-13	26	8	312	135		
2013	7	Jul-13	26	7	285	83		
2013	8	Aug-13	24	8	323	78		
2013	9	Sep-13	24	7	307	180		
2013	10	Oct-13	24	12	506	458		
2013	11	Nov-13	24	11	450	887		
2013	12	Dec-13	24	12	485	1,340		**4,852**
2014	1	Jan-14	24	11	449	1,200		
2014	2	Feb-14	24	11	459	1,188		
2014	3	Mar-14	24	7	287	1,121		
2014	4	Apr-14	24	8	325	691		
2014	5	May-14	24	7	278	380		
2014	6	Jun-14	24	8	328	158		
2014	7	Jul-14	25	9	354	35		
2014	8	Aug-14	24	8	314	104		
2014	9	Sep-14	24	7	312	274		
2014	10	Oct-14	24	10	429	521		
2014	11	Nov-14	24	8	326	910		
2014	12	Dec-14	24	8	344	1,144		**4,206**
2015	1	Jan-15	24	10	422	1,225		
2015	2	Feb-15	24	8	334	1,104		
2015	3	Mar-15	24	4	182	955		
2015	4	Apr-15	24	6	253	571		
2015	5	May-15	24	6	254	305		
2015	6	Jun-15	24	8	350	126		
2015	7	Jul-15	24	8	315	67		
2015	8	Aug-15	24	7	305	98		
2015	9	Sep-15	23	7	299	264		
2015	10	Oct-15	23	9	402	508		
2015	11	Nov-15	23	9	379	768		
2015	12	Dec-15	23	8	337	1,025		**3,832**
2016	1	Jan-16	23	10	424	1,087		
2016	2	Feb-16	23	7	306	1,050		
2016	3	Mar-16	23	9	385	925		
2016	4	Apr-16	23	6	278	683		
2016	5	May-16	23	7	304	312		
2016	6	Jun-16	23	1	51	105		
2016	7	Jul-16	23	17	740	47		
2016	8	Aug-16	23	8	351	79		
2016	9	Sep-16	23	8	335	250		
2016	10	Oct-16	23	12	517	566		
2016	11	Nov-16	23	7	299	722		
2016	12	Dec-16	23	4	177	1,191		**4,169**
2017	1	Jan-17	23	10	431	1,072		
2017	2	Feb-17	23	8	333	948		
2017	3	Mar-17	23	8	363	1,033		
2017	4	Apr-17	22	5	240	667		
2017	5	May-17	22	7	334	284		
2017	6	Jun-17	22	10	440	152		
2017	7	Jul-17	22	8	361	56		
2017	8	Aug-17	22	7	327	60		
2017	9	Sep-17	22	6	254	205		
2017	10	Oct-17	22	11	478	507		
2017	11	Nov-17	22	6	277	976		
2017	12	Dec-17	22	7	328	1,084		**4,165**
2018	1	Jan-18	21	10	459	1,265		
2018	2	Feb-18	21	8	372	1,044		
2018	3	Mar-18	20	4	221	992		
2018	4	Apr-18	20	7	345	723		
2018	5	May-18	20	5	272	327		
2018	6	Jun-18	20	13	647	157		
2018	7	Jul-18	20	4	224	74		
2018	8	Aug-18	20	6	294	119		
2018	9	Sep-18	20	4	198	425		
2018	10	Oct-18	19	11	565	566		

Commercial

MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
19	19	1,022	**11,505**
19	26	1,343	
19	24	1,238	
19	22	1,167	
19	22	1,152	
21	23	1,072	
24	17	714	
24	13	522	
24	13	538	
25	11	435	
20	11	557	
20	17	825	
20	18	916	**10,479**
20	24	1,200	
19	19	1,021	
19	16	830	
19	15	785	
25	15	584	
25	12	488	
25	9	368	
24	9	367	
24	9	378	
24	13	521	
24	17	697	
18	21	1,156	**8,396**
18	21	1,189	
18	16	902	
18	17	948	
18	13	734	
19	12	634	
23	10	416	
23	7	304	
23	9	402	
23	9	399	
19	10	528	
20	16	812	
20	20	1,014	**8,283**
19	23	1,205	
19	28	1,451	
19	25	1,309	
19	15	799	
20	12	607	
23	8	331	
23	6	282	
24	9	387	
24	11	469	
19	10	537	
19	13	681	
18	16	908	**8,966**
18	18	1,013	
18	17	934	
18	14	792	
18	15	830	
17	13	762	
22	-4	(201)	
22	21	964	
22	9	422	
22	11	479	
17	10	572	
17	17	1,021	
17	15	880	**8,468**
17	18	1,072	
17	15	897	
17	16	934	
17	12	724	
17	11	663	
22	7	296	
22	9	399	
22	10	459	
22	11	520	
17	10	604	
17	19	1,121	
17	15	897	**8,586**
17	19	1,107	
17	16	915	
17	17	978	
17	15	871	
19	13	664	
21	3	125	
22	13	578	
22	9	413	
21	12	572	
16	6	396	

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Dory Point Kakisa - Data

Dory Point & Kakisa

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	UPC (kWh)	Annual UPC (kWh)
2018	11	Nov-18	19	10	552	880		
2018	12	Dec-18	18	2	117	1,046		**4,267**
2019	1	Jan-19	18	8	428	1,223		
2019	2	Feb-19	18	10	548	1,153		
2019	3	Mar-19	18	6	315	710		
2019	4	Apr-19	18	5	300	567		
2019	5	May-19	18	9	514	433		
2019	6	Jun-19	18	8	454	196		
2019	7	Jul-19	19	9	467	100		
2019	8	Aug-19	19	12	625	153		
2019	9	Sep-19	19	7	356	265		
2019	10	Oct-19	19	7	356	516		
2019	11	Nov-19	19	5	285	849		
2019	12	Dec-19	19	5	255	1,227		**4,903**
2020	1	Jan-20	19	11	587	1,289		
2020	2	Feb-20	19	8	406	1,106		
2020	3	Mar-20	19	8	431	1,078		
2020	4	Apr-20	19	9	462	734		
2020	5	May-20	19	6	316	460		
2020	6	Jun-20	19	10	550	207		
2020	7	Jul-20	19	6	304	76		
2020	8	Aug-20	19	10	506	116		
2020	9	Sep-20	19	4	216	273		
2020	10	Oct-20	20	10	523	586		
2020	11	Nov-20	20	9	469	927		
2020	12	Dec-20	21	8	363	1,077		**5,133**
2021	1	Jan-21	20	11	559	1,099		
2021	2	Feb-21	20	7	365	1,227		
2021	3	Mar-21	20	8	404	1,031		
2021	4	Apr-21	20	6	319	698		
2021	5	May-21	20	6	305	403		
2021	6	Jun-21	20	11	544	146		
2021	7	Jul-21	21	7	344	64		
2021	8	Aug-21	21	7	311	118		
2021	9	Sep-21	21	16	762	233		
2021	10	Oct-21	21	3	122	458		
2021	11	Nov-21	21	6	273	822		
2021	12	Dec-21	21	9	437	1,337		**4,745**
2022	1	Jan-22	21	14	650	1,263	650	
2022	2	Feb-22	21	10	480	1,200	480	
2022	3	Mar-22	21	7	352	1,047	352	
2022	4	Apr-22	21	4	203	707	203	
2022	5	May-22	21	8	392	393	392	
2022	6	Jun-22			454		454	
2022	7	Jul-22			467		467	
2022	8	Aug-22			625		625	
2022	9	Sep-22			356		356	
2022	10	Oct-22			356		356	
2022	11	Nov-22			285		285	
2022	12	Dec-22			255		255	**4,876**
2023	1	Jan-23			428		428	
2023	2	Feb-23			548		548	
2023	3	Mar-23			315		315	
2023	4	Apr-23			300		300	
2023	5	May-23			514		514	
2023	6	Jun-23			454		454	
2023	7	Jul-23			467		467	
2023	8	Aug-23			625		625	
2023	9	Sep-23			356		356	
2023	10	Oct-23			356		356	
2023	11	Nov-23			285		285	
2023	12	Dec-23			255		255	**4,903**

Commercial

MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
16	20	1,257	
16	10	653	**8,530**
16	15	942	
16	10	609	
16	13	801	
16	11	702	
20	8	423	
20	6	316	
21	5	250	
20	3	171	
21	19	581	
16	-1	402	
14	13	1,277	
14	16	664	**7,137**
14	12	865	
14	12	843	
14	11	776	
14	9	662	
14	11	762	
14	4	307	
19	9	454	
19	6	310	
19	12	615	
19	7	355	
14	9	658	
14	16	1,109	**7,715**
14	9	676	
14	13	940	
12	10	866	
12	12	980	
14	10	749	
19	4	226	
19	9	447	
19	9	449	
19	-1	(45)	
13	14	1,102	
14	12	870	
14	17	1,242	**8,502**
13	13	1,010	
14	13	950	
14	13	918	
14	13	930	
14	10	725	
		316	
		250	
		171	
		581	
		402	
		1,277	
		664	**8,194**
		942	
		609	
		801	
		702	
		423	
		316	
		250	
		171	
		581	
		402	
		1,277	
		664	**7,137**

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Dory Point Kakisa Regression

DORY POINT & KAKISA
Summary Output, Residential
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.227066
R Square	0.051559
Adjusted R Square	0.046231
Standard Error	104.75
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	106175.0018	106175	9.676401	0.002174317
Residual	178	1953117.817	10972.57		
Total	179	2059292.819			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	367.9571	13.87767676	26.51431	1.02E-63	340.5711111	395.3429953	340.5711111	395.3429953
MHDD	0.058604	0.018839556	3.110691	0.002174	0.021426424	0.095781662	0.021426424	0.095781662

Summary Output, Commercial
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.73888
R Square	0.545944
Adjusted R Square	0.543393
Standard Error	238.5921
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	12183450.07	12183450	214.0219	2.44524E-32
Residual	178	10132859.78	56926.18		
Total	179	22316309.85			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	402.2924	31.6095682	12.72692	8.38E-27	339.9146563	464.6700918	339.9146563	464.6700918
MHDD	0.627771	0.042911377	14.62949	2.45E-32	0.543090991	0.712451976	0.543090991	0.712451976

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Sambaa K'e - Data

Sambaa K'e

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	UPC (kWh)	Annual UPC (kWh)
2005	1	Jan-05	33	20	605	1,260		
2005	2	Feb-05	33	14	428	1,034		
2005	3	Mar-05	32	13	394	949		
2005	4	Apr-05	32	15	460	542		
2005	5	May-05	32	12	377	407		
2005	6	Jun-05	32	11	348	209		
2005	7	Jul-05	34	12	348	86		
2005	8	Aug-05	33	14	426	143		
2005	9	Sep-05	34	11	332	308		
2005	10	Oct-05	35	13	371	474		
2005	11	Nov-05	33	14	420	767		
2005	12	Dec-05	33	16	479	866		**4,986**
2006	1	Jan-06	33	21	632	1,165		
2006	2	Feb-06	33	13	385	927		
2006	3	Mar-06	33	13	408	904		
2006	4	Apr-06	33	15	440	497		
2006	5	May-06	33	12	359	312		
2006	6	Jun-06	34	13	389	98		
2006	7	Jul-06	35	14	394	85		
2006	8	Aug-06	35	16	454	90		
2006	9	Sep-06	34	9	267	203		
2006	10	Oct-06	35	12	354	524		
2006	11	Nov-06	34	15	432	1,042		
2006	12	Dec-06	36	18	501	925		**5,014**
2007	1	Jan-07	38	19	497	1,108		
2007	2	Feb-07	36	15	420	1,168		
2007	3	Mar-07	36	16	441	1,100		
2007	4	Apr-07	36	16	456	560		
2007	5	May-07	36	12	331	368		
2007	6	Jun-07	36	13	355	161		
2007	7	Jul-07	42	13	321	38		
2007	8	Aug-07	38	14	364	187		
2007	9	Sep-07	39	15	379	366		
2007	10	Oct-07	40	14	344	489		
2007	11	Nov-07	39	18	454	850		
2007	12	Dec-07	39	18	468	1,188		**4,829**
2008	1	Jan-08	39	19	482	1,215		
2008	2	Feb-08	41	20	487	1,202		
2008	3	Mar-08	43	23	530	1,091		
2008	4	Apr-08	41	15	369	689		
2008	5	May-08	42	13	305	358		
2008	6	Jun-08	41	12	288	155		
2008	7	Jul-08	41	13	323	35		
2008	8	Aug-08	41	17	409	103		
2008	9	Sep-08	40	16	408	315		
2008	10	Oct-08	40	14	339	478		
2008	11	Nov-08	40	17	421	778		
2008	12	Dec-08	41	18	428	1,281		**4,790**
2009	1	Jan-09	41	20	496	1,238		
2009	2	Feb-09	40	22	550	1,085		
2009	3	Mar-09	41	17	420	1,116		
2009	4	Apr-09	42	17	397	623		
2009	5	May-09	42	18	431	490		
2009	6	Jun-09	42	15	348	193		
2009	7	Jul-09	42	16	382	101		
2009	8	Aug-09	42	13	298	88		
2009	9	Sep-09	42	14	329	177		
2009	10	Oct-09	42	16	379	560		
2009	11	Nov-09	42	21	493	825		
2009	12	Dec-09	42	16	387	1,163		**4,909**
2010	1	Jan-10	42	23	546	1,229		
2010	2	Feb-10	42	17	408	900		
2010	3	Mar-10	43	17	387	719		
2010	4	Apr-10	42	18	431	491		
2010	5	May-10	42	13	304	402		
2010	6	Jun-10	41	13	325	120		
2010	7	Jul-10	42	16	389	45		
2010	8	Aug-10	43	13	301	109		
2010	9	Sep-10	43	13	291	294		
2010	10	Oct-10	43	16	377	464		
2010	11	Nov-10	43	18	409	810		
2010	12	Dec-10	43	19	451	1,215		**4,620**
2011	1	Jan-11	43	22	509	1,289		
2011	2	Feb-11	44	23	530	1,007		
2011	3	Mar-11	44	17	396	1,041		
2011	4	Apr-11	43	22	518	720		
2011	5	May-11	43	16	362	361		
2011	6	Jun-11	43	15	355	168		
2011	7	Jul-11	43	16	382	37		
2011	8	Aug-11	43	11	266	86		
2011	9	Sep-11	43	16	361	206		
2011	10	Oct-11	43	13	305	471		
2011	11	Nov-11	43	14	334	952		

Commercial

MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
15	21	1,417	
15	16	1,062	
15	14	929	
15	14	963	
15	11	759	
15	12	811	
15	12	782	
15	11	719	
16	9	586	
16	10	634	
16	14	856	
15	17	1,101	**10,621**
15	20	1,302	
15	13	842	
15	15	1,022	
15	15	971	
19	13	660	
14	15	1,045	
15	15	984	
14	13	932	
14	10	679	
14	11	760	
14	15	1,040	
15	17	1,134	**11,370**
15	17	1,148	
16	20	1,269	
17	15	907	
16	22	1,350	
16	14	878	
16	16	1,003	
16	19	1,200	
16	12	769	
16	16	985	
16	13	826	
16	17	1,042	
16	20	1,236	**12,612**
16	19	1,184	
16	16	1,013	
16	27	1,671	
16	9	581	
16	13	802	
16	11	693	
16	13	836	
16	23	1,423	
16	18	1,101	
16	15	956	
16	17	1,069	
16	16	998	**12,326**
16	18	1,130	
16	22	1,349	
16	16	1,027	
15	19	1,251	
16	18	1,131	
16	17	1,045	
16	18	1,147	
16	13	823	
16	16	1,016	
16	17	1,051	
16	21	1,322	
16	19	1,158	**13,450**
16	25	1,593	
15	18	1,222	
16	20	1,226	
17	22	1,275	
17	16	953	
17	17	1,017	
17	22	1,318	
17	16	945	
17	16	932	
17	20	1,159	
17	21	1,262	
17	23	1,327	**14,230**
17	26	1,515	
17	23	1,357	
17	20	1,184	
17	23	1,379	
17	18	1,041	
17	16	966	
17	18	1,051	
17	15	869	
17	18	1,085	
17	14	831	
17	15	906	

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Sambaa K'e - Data

Sambaa K'e

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	UPC (kWh)	Annual UPC (kWh)
2011	12	Dec-11	43	19	438	978		**4,756**
2012	1	Jan-12	43	21	494	1,184		
2012	2	Feb-12	43	22	514	913		
2012	3	Mar-12	43	17	397	992		
2012	4	Apr-12	43	18	424	676		
2012	5	May-12	43	16	364	277		
2012	6	Jun-12	43	18	422	156		
2012	7	Jul-12	44	14	310	13		
2012	8	Aug-12	42	13	318	60		
2012	9	Sep-12	44	16	370	178		
2012	10	Oct-12	44	12	268	575		
2012	11	Nov-12	44	19	439	1,011		
2012	12	Dec-12	44	22	502	1,328		**4,822**
2013	1	Jan-13	44	21	479	1,292		
2013	2	Feb-13	44	22	507	928		
2013	3	Mar-13	44	20	454	1,077		
2013	4	Apr-13	45	20	435	785		
2013	5	May-13	45	14	306	333		
2013	6	Jun-13	45	17	369	135		
2013	7	Jul-13	45	17	371	83		
2013	8	Aug-13	44	15	340	78		
2013	9	Sep-13	44	19	424	180		
2013	10	Oct-13	44	17	384	458		
2013	11	Nov-13	43	19	435	887		
2013	12	Dec-13	44	21	488	1,340		**4,993**
2014	1	Jan-14	44	21	483	1,200		
2014	2	Feb-14	44	18	418	1,188		
2014	3	Mar-14	44	19	422	1,121		
2014	4	Apr-14	44	16	364	691		
2014	5	May-14	44	15	346	380		
2014	6	Jun-14	42	14	337	158		
2014	7	Jul-14	43	18	421	35		
2014	8	Aug-14	42	17	416	104		
2014	9	Sep-14	42	14	322	274		
2014	10	Oct-14	42	18	424	521		
2014	11	Nov-14	42	19	454	910		
2014	12	Dec-14	42	22	515	1,144		**4,922**
2015	1	Jan-15	42	23	550	1,225		
2015	2	Feb-15	42	17	409	1,104		
2015	3	Mar-15	43	23	543	955		
2015	4	Apr-15	43	8	182	571		
2015	5	May-15	43	15	342	305		
2015	6	Jun-15	43	14	333	126		
2015	7	Jul-15	43	15	350	67		
2015	8	Aug-15	42	15	348	98		
2015	9	Sep-15	43	16	367	264		
2015	10	Oct-15	43	17	391	508		
2015	11	Nov-15	43	19	431	768		
2015	12	Dec-15	43	18	429	1,025		**4,677**
2016	1	Jan-16	43	21	486	1,087		
2016	2	Feb-16	42	17	397	1,050		
2016	3	Mar-16	42	16	376	925		
2016	4	Apr-16	42	16	389	683		
2016	5	May-16	42	15	355	312		
2016	6	Jun-16	42	14	339	105		
2016	7	Jul-16	42	14	330	47		
2016	8	Aug-16	42	15	349	79		
2016	9	Sep-16	42	13	308	250		
2016	10	Oct-16	41	18	437	566		
2016	11	Nov-16	42	15	362	722		
2016	12	Dec-16	42	17	405	1,191		**4,533**
2017	1	Jan-17	42	18	440	1,072		
2017	2	Feb-17	42	15	361	948		
2017	3	Mar-17	42	17	402	1,033		
2017	4	Apr-17	42	13	306	667		
2017	5	May-17	42	15	369	284		
2017	6	Jun-17	42	14	341	152		
2017	7	Jul-17	42	15	366	56		
2017	8	Aug-17	42	15	361	60		
2017	9	Sep-17	42	13	318	205		
2017	10	Oct-17	41	15	365	507		
2017	11	Nov-17	41	17	410	976		
2017	12	Dec-17	41	16	385	1,084		**4,425**
2018	1	Jan-18	41	20	490	1,265		
2018	2	Feb-18	41	15	365	1,044		
2018	3	Mar-18	41	17	406	992		
2018	4	Apr-18	41	18	442	723		
2018	5	May-18	41	16	390	327		
2018	6	Jun-18	41	16	386	157		
2018	7	Jul-18	41	18	443	74		
2018	8	Aug-18	41	18	437	119		
2018	9	Sep-18	41	18	436	425		
2018	10	Oct-18	41	18	428	566		

Commercial

MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
15	17	1,146	**13,331**
16	22	1,355	
16	19	1,176	
15	17	1,129	
15	18	1,208	
15	17	1,102	
15	18	1,225	
16	16	978	
16	15	941	
16	19	1,166	
16	14	891	
15	22	1,454	
15	25	1,674	**14,298**
15	22	1,439	
15	23	1,565	
16	33	2,087	
15	24	1,598	
15	18	1,174	
16	19	1,181	
16	18	1,141	
16	17	1,052	
16	21	1,326	
16	20	1,234	
16	20	1,254	
17	25	1,467	**16,519**
17	22	1,291	
17	21	1,225	
17	20	1,192	
17	18	1,076	
17	17	1,014	
16	17	1,087	
16	18	1,113	
16	14	898	
17	18	1,082	
17	19	1,103	
17	21	1,234	
17	25	1,491	**13,806**
17	25	1,448	
17	23	1,345	
16	26	1,638	
16	12	755	
16	17	1,050	
16	17	1,051	
16	16	1,003	
16	16	1,028	
16	17	1,054	
16	18	1,147	
15	18	1,219	
16	23	1,454	**14,192**
16	23	1,461	
16	19	1,177	
16	18	1,105	
16	18	1,108	
16	15	957	
16	14	857	
16	13	840	
15	15	970	
16	15	965	
16	16	1,003	
16	21	1,304	
16	22	1,390	**13,137**
16	21	1,310	
16	20	1,234	
16	22	1,392	
16	17	1,060	
16	19	1,184	
16	16	973	
16	16	1,004	
16	16	982	
16	15	944	
16	18	1,145	
16	20	1,252	
16	24	1,522	**14,002**
16	21	1,322	
16	22	1,347	
16	19	1,201	
16	20	1,238	
16	19	1,179	
17	17	1,001	
17	17	1,004	
17	16	968	
17	16	945	
17	25	1,455	

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Sambaa K'e - Data

Sambaa K'e

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	UPC (kWh)	MHDD (Hay River)	UPC (kWh)	Annual UPC (kWh)
2018	11	Nov-18	41	11	260	880		
2018	12	Dec-18	41	28	678	1,046		**5,159**
2019	1	Jan-19	41	20	498	1,223		
2019	2	Feb-19	40	24	598	1,153		
2019	3	Mar-19	41	13	321	710		
2019	4	Apr-19	41	15	373	567		
2019	5	May-19	41	15	370	433		
2019	6	Jun-19	41	16	379	196		
2019	7	Jul-19	37	15	404	100		
2019	8	Aug-19	38	14	369	153		
2019	9	Sep-19	38	13	341	265		
2019	10	Oct-19	38	13	341	516		
2019	11	Nov-19	38	21	543	849		
2019	12	Dec-19	38	21	547	1,227		**5,086**
2020	1	Jan-20	38	22	578	1,289		
2020	2	Feb-20	38	18	473	1,106		
2020	3	Mar-20	39	17	448	1,078		
2020	4	Apr-20	39	16	408	734		
2020	5	May-20	40	16	404	460		
2020	6	Jun-20	40	16	390	207		
2020	7	Jul-20	40	18	443	76		
2020	8	Aug-20	41	14	342	116		
2020	9	Sep-20	41	19	462	273		
2020	10	Oct-20	41	17	414	586		
2020	11	Nov-20	41	19	459	927		
2020	12	Dec-20	41	26	642	1,077		**5,463**
2021	1	Jan-21	41	22	532	1,099		
2021	2	Feb-21	41	20	479	1,227		
2021	3	Mar-21	40	13	315	1,031		
2021	4	Apr-21	41	18	427	698		
2021	5	May-21	41	15	358	403		
2021	6	Jun-21	41	16	380	146		
2021	7	Jul-21	40	14	340	64		
2021	8	Aug-21	40	14	355	118		
2021	9	Sep-21	40	16	410	233		
2021	10	Oct-21	40	16	405	458		
2021	11	Nov-21	40	19	464	822		
2021	12	Dec-21	40	19	473	1,337		**4,938**
2022	1	Jan-22	40	24	601	1,263	601	
2022	2	Feb-22	40	15	366	1,200	366	
2022	3	Mar-22	39	17	445	1,047	445	
2022	4	Apr-22	40	15	384	707	384	
2022	5	May-22	40	11	275	393	275	
2022	6	Jun-22			369		369	
2022	7	Jul-22			404		404	
2022	8	Aug-22			389		389	
2022	9	Sep-22			365		365	
2022	10	Oct-22			378		378	
2022	11	Nov-22			404		404	
2022	12	Dec-22			536		536	**4,918**
2023	1	Jan-23			476		476	
2023	2	Feb-23			441		441	
2023	3	Mar-23			376		376	
2023	4	Apr-23			374		374	
2023	5	May-23			376		376	
2023	6	Jun-23			369		369	
2023	7	Jul-23			404		404	
2023	8	Aug-23			389		389	
2023	9	Sep-23			365		365	
2023	10	Oct-23			378		378	
2023	11	Nov-23			404		404	
2023	12	Dec-23			536		536	**4,890**

Commercial

MCCNT	MCENCNS (MWh)	UPC (kWh)	Annual UPC (kWh)
17	13	775	
17	32	1,898	**14,333**
18	28	1,557	
16	20	1,222	
18	22	1,202	
17	14	829	
17	16	941	
17	14	804	
17	13	791	
16	12	772	
16	9	585	
16	16	1,029	
16	16	1,026	
16	16	1,001	**11,757**
16	19	1,197	
16	16	987	
16	17	1,060	
16	14	864	
16	13	827	
16	12	747	
16	14	874	
16	15	931	
17	14	821	
17	16	955	
17	18	1,075	
16	13	825	**11,162**
16	20	1,231	
16	19	1,178	
17	22	1,287	
17	13	747	
17	16	939	
17	13	771	
17	15	865	
17	14	849	
17	13	746	
17	18	1,036	
17	17	1,009	
17	23	1,359	**12,017**
16	18	1,121	
17	23	1,368	
17	17	1,023	
15	17	1,119	
17	19	1,137	
		804	
		791	
		772	
		585	
		1,029	
		1,026	
		1,001	**11,774**
		1,557	
		1,222	
		1,202	
		829	
		941	
		804	
		791	
		772	
		585	
		1,029	
		1,026	
		1,001	**11,757**

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Sambaa K'e - Regression

Sambaa K'e

Summary Output, Residential

Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.637574864
R Square	0.406501708
Adjusted R Square	0.403167448
Standard Error	57.90991231
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	408854.4395	408854.4	121.9166	6.34552E-22
Residual	178	596933.314	3353.558		
Total	179	1005787.753			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	332.8616019	7.672121205	43.38586	1.39E-96	317.7215845	348.0016192	317.7215845	348.0016192
MHDD	0.115000783	0.010415242	11.04159	6.35E-22	0.094447545	0.135554022	0.094447545	0.135554022

Summary Output, Commercial

Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.559613874
R Square	0.313167688
Adjusted R Square	0.30930908
Standard Error	204.7802085
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3403472.081	3403472	81.16078	3.18276E-16
Residual	178	7464418.215	41934.93		
Total	179	10867890.3			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	908.9651334	27.13004592	33.504	8.68E-79	855.4272192	962.5030475	855.4272192	962.5030475
MHDD	0.331800882	0.036830229	9.008928	3.18E-16	0.259120812	0.404480952	0.259120812	0.404480952

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Wekweeti - Data

Wekweeti

			Residential						Commercial			
			MRCNT	MRENCNS	MRUPC	MHDD	UPC	Annual	MCCNT	MCENCNS	MCUPC	Annual
Year	Month	monthly		(MWh)	(kWh)	(Yellowknife)	(kWh)	UPC (kWh)		(MWh)	(kWh)	UPC (kWh)
2005	1	Jan-05	38	23	605	1,376			16	30	1,857	
2005	2	Feb-05	41	24	586	1,140			15	29	1,923	
2005	3	Mar-05	45	21	477	1,027			14	29	2,063	
2005	4	Apr-05	43	23	534	613			14	31	2,181	
2005	5	May-05	41	22	535	459			14	26	1,854	
2005	6	Jun-05	42	19	444	165			14	23	1,608	
2005	7	Jul-05	43	20	454	84			14	22	1,573	
2005	8	Aug-05	43	18	414	155			14	18	1,293	
2005	9	Sep-05	44	20	462	364			14	23	1,654	
2005	10	Oct-05	42	21	492	547			14	22	1,600	
2005	11	Nov-05	43	20	460	812			14	24	1,744	
2005	12	Dec-05	44	28	633	967		**6,095**	14	39	2,761	**22,109**
2006	1	Jan-06	43	23	545	1,239			14	29	2,066	
2006	2	Feb-06	43	21	498	994			14	27	1,905	
2006	3	Mar-06	43	20	468	896			14	27	1,935	
2006	4	Apr-06	43	23	534	597			14	28	1,997	
2006	5	May-06	43	20	474	307			14	30	2,142	
2006	6	Jun-06	43	20	469	81			14	24	1,687	
2006	7	Jul-06	44	18	402	59			14	15	1,056	
2006	8	Aug-06	43	19	433	85			14	17	1,179	
2006	9	Sep-06	42	19	461	244			15	22	1,460	
2006	10	Oct-06	42	20	478	582			15	24	1,569	
2006	11	Nov-06	42	20	482	1,063			15	26	1,702	
2006	12	Dec-06	42	31	729	1,015		**5,971**	15	40	2,686	**21,384**
2007	1	Jan-07	42	19	449	1,221			15	30	2,019	
2007	2	Feb-07	42	25	594	1,205			15	28	1,850	
2007	3	Mar-07	42	17	415	1,180			15	37	2,473	
2007	4	Apr-07	41	21	506	629			15	25	1,644	
2007	5	May-07	41	17	407	386			15	25	1,674	
2007	6	Jun-07	41	18	433	149			15	26	1,766	
2007	7	Jul-07	42	17	396	20			15	23	1,511	
2007	8	Aug-07	42	13	298	181			15	19	1,277	
2007	9	Sep-07	43	16	364	392			15	21	1,401	
2007	10	Oct-07	42	18	419	562			15	22	1,498	
2007	11	Nov-07	43	23	531	908			15	31	2,060	
2007	12	Dec-07	42	22	522	1,306		**5,336**	15	33	2,213	**21,386**
2008	1	Jan-08	42	24	568	1,365			15	36	2,418	
2008	2	Feb-08	41	25	603	1,297			15	32	2,145	
2008	3	Mar-08	42	25	599	1,184			15	35	2,358	
2008	4	Apr-08	41	18	451	761			15	32	2,118	
2008	5	May-08	41	18	445	335			15	26	1,735	
2008	6	Jun-08	41	18	450	133			15	23	1,552	
2008	7	Jul-08	41	17	407	33			15	21	1,395	
2008	8	Aug-08	41	15	360	115			15	20	1,337	
2008	9	Sep-08	40	17	429	369			15	22	1,481	
2008	10	Oct-08	40	17	425	518			17	23	1,324	
2008	11	Nov-08	40	22	544	827			16	28	1,750	
2008	12	Dec-08	40	20	497	1,420		**5,778**	16	28	1,734	**21,346**
2009	1	Jan-09	39	24	614	1,353			15	33	2,181	
2009	2	Feb-09	39	24	625	1,161			14	28	2,007	
2009	3	Mar-09	40	19	469	1,188			16	33	2,087	
2009	4	Apr-09	37	22	598	691			12	25	2,120	
2009	5	May-09	40	19	467	516			16	36	2,250	
2009	6	Jun-09	39	17	433	175			16	25	1,567	
2009	7	Jul-09	39	17	446	80			16	18	1,132	
2009	8	Aug-09	38	16	414	102			16	17	1,054	
2009	9	Sep-09	40	15	376	227			17	22	1,271	
2009	10	Oct-09	40	17	430	603			17	24	1,407	
2009	11	Nov-09	40	23	567	867			17	33	1,933	
2009	12	Dec-09	40	21	526	1,238		**5,965**	17	36	2,113	**21,122**
2010	1	Jan-10	38	26	671	1,307			17	36	2,090	
2010	2	Feb-10	40	23	564	960			17	33	1,932	
2010	3	Mar-10	40	21	524	866			16	22	1,405	
2010	4	Apr-10	40	22	553	515			17	43	2,515	
2010	5	May-10	40	17	426	384			17	23	1,342	
2010	6	Jun-10	40	18	462	109			17	23	1,342	
2010	7	Jul-10	40	18	449	40			17	21	1,238	
2010	8	Aug-10	39	19	485	90			15	15	985	
2010	9	Sep-10	40	20	494	308			17	27	1,596	
2010	10	Oct-10	40	16	389	544			17	22	1,283	
2010	11	Nov-10	39	22	562	899			16	22	1,391	
2010	12	Dec-10	39	23	591	1,238		**6,168**	17	30	1,768	**18,887**
2011	1	Jan-11	40	26	652	1,394			17	35	2,054	
2011	2	Feb-11	40	27	687	1,140			18	34	1,906	
2011	3	Mar-11	40	22	557	1,109			18	34	1,916	
2011	4	Apr-11	40	23	570	817			18	29	1,594	
2011	5	May-11	40	21	523	327			18	29	1,597	
2011	6	Jun-11	39	19	488	148			17	21	1,264	
2011	7	Jul-11	40	19	467	26			18	22	1,248	
2011	8	Aug-11	40	15	378	88			18	21	1,144	
2011	9	Sep-11	40	16	408	242			18	18	1,001	
2011	10	Oct-11	40	19	469	514			17	27	1,608	
2011	11	Nov-11	40	19	482	985			18	27	1,477	

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Wekweeti - Data

Wekweeti

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	MRUPC (kWh)	MHDD (Yellowknife)	UPC (kWh)	Annual UPC (kWh)
2011	12	Dec-11	41	24	586	1,100		**6,268**
2012	1	Jan-12	41	29	699	1,252		
2012	2	Feb-12	41	22	533	1,013		
2012	3	Mar-12	41	20	496	1,059		
2012	4	Apr-12	41	19	462	723		
2012	5	May-12	41	18	440	311		
2012	6	Jun-12	41	18	439	79		
2012	7	Jul-12	41	18	447	7		
2012	8	Aug-12	41	19	465	64		
2012	9	Sep-12	40	18	449	203		
2012	10	Oct-12	41	18	440	601		
2012	11	Nov-12	41	23	564	1,066		
2012	12	Dec-12	41	27	653	1,402		**6,087**
2013	1	Jan-13	41	32	775	1,428		
2013	2	Feb-13	41	31	745	1,035		
2013	3	Mar-13	41	22	526	1,128		
2013	4	Apr-13	41	20	491	809		
2013	5	May-13	41	20	497	353		
2013	6	Jun-13	41	21	517	105		
2013	7	Jul-13	41	18	434	80		
2013	8	Aug-13	41	18	434	99		
2013	9	Sep-13	41	18	439	245		
2013	10	Oct-13	41	25	599	518		
2013	11	Nov-13	41	26	639	963		
2013	12	Dec-13	41	28	678	1,501		**6,774**
2014	1	Jan-14	41	26	646	1,343		
2014	2	Feb-14	41	28	683	1,234		
2014	3	Mar-14	40	23	569	1,192		
2014	4	Apr-14	40	19	482	769		
2014	5	May-14	40	19	477	408		
2014	6	Jun-14	40	18	461	114		
2014	7	Jul-14	38	16	409	40		
2014	8	Aug-14	39	21	541	136		
2014	9	Sep-14	39	11	286	346		
2014	10	Oct-14	39	25	645	559		
2014	11	Nov-14	39	19	488	1,036		
2014	12	Dec-14	39	25	635	1,213		**6,321**
2015	1	Jan-15	39	22	564	1,340		
2015	2	Feb-15	39	26	673	1,230		
2015	3	Mar-15	39	21	527	1,039		
2015	4	Apr-15	39	18	453	661		
2015	5	May-15	39	18	464	323		
2015	6	Jun-15	39	17	436	114		
2015	7	Jul-15	39	16	406	64		
2015	8	Aug-15	39	17	444	102		
2015	9	Sep-15	39	21	544	302		
2015	10	Oct-15	39	17	432	595		
2015	11	Nov-15	39	23	587	841		
2015	12	Dec-15	39	24	620	1,106		**6,150**
2016	1	Jan-16	41	23	555	1,172		
2016	2	Feb-16	41	22	542	1,199		
2016	3	Mar-16	41	23	562	985		
2016	4	Apr-16	41	19	461	754		
2016	5	May-16	41	15	366	304		
2016	6	Jun-16	41	17	418	90		
2016	7	Jul-16	40	19	466	41		
2016	8	Aug-16	40	23	579	87		
2016	9	Sep-16	40	21	532	301		
2016	10	Oct-16	40	19	472	615		
2016	11	Nov-16	40	25	622	757		
2016	12	Dec-16	40	22	555	1,263		**6,130**
2017	1	Jan-17	40	23	586	1,195		
2017	2	Feb-17	40	23	583	1,082		
2017	3	Mar-17	40	16	395	1,131		
2017	4	Apr-17	40	18	440	726		
2017	5	May-17	40	18	439	298		
2017	6	Jun-17	40	18	442	144		
2017	7	Jul-17	40	16	408	52		
2017	8	Aug-17	41	17	410	65		
2017	9	Sep-17	41	20	489	232		
2017	10	Oct-17	41	16	397	591		
2017	11	Nov-17	41	20	491	1,026		
2017	12	Dec-17	41	22	532	1,218		**5,613**
2018	1	Jan-18	41	21	518	1,303		
2018	2	Feb-18	41	19	470	1,154		
2018	3	Mar-18	41	19	453	1,032		
2018	4	Apr-18	41	19	459	762		
2018	5	May-18	41	22	539	369		
2018	6	Jun-18	41	11	263	132		
2018	7	Jul-18	39	17	447	64		
2018	8	Aug-18	39	20	513	157		
2018	9	Sep-18	39	15	386	464		
2018	10	Oct-18	40	21	517	623		

Commercial

MCCNT	MCENCNS (MWh)	MCUPC (kWh)	Annual UPC (kWh)
18	31	1,716	**18,525**
18	38	2,107	
17	25	1,466	
18	35	1,933	
18	33	1,810	
18	26	1,434	
19	25	1,329	
19	21	1,089	
19	21	1,117	
19	18	929	
19	26	1,355	
19	29	1,552	
19	37	1,931	**18,052**
19	42	2,222	
18	37	2,033	
19	36	1,881	
19	31	1,615	
19	30	1,585	
19	29	1,547	
19	23	1,188	
19	22	1,180	
19	19	990	
19	26	1,363	
19	32	1,665	
18	39	2,189	**19,458**
19	34	1,805	
19	32	1,664	
19	33	1,743	
19	29	1,536	
19	27	1,430	
19	19	1,010	
19	23	1,193	
17	18	1,051	
19	32	1,674	
19	24	1,248	
19	39	2,058	
19	41	2,182	**18,595**
19	40	2,087	
19	38	2,010	
19	37	1,946	
19	36	1,889	
19	29	1,541	
19	23	1,185	
19	20	1,074	
18	18	978	
19	24	1,240	
19	33	1,733	
18	30	1,693	
19	40	2,099	**19,474**
19	35	1,819	
19	40	2,082	
18	33	1,826	
18	33	1,824	
18	27	1,494	
18	23	1,298	
17	23	1,341	
19	17	885	
19	24	1,242	
19	32	1,684	
19	30	1,553	
18	33	1,858	**18,907**
19	39	2,073	
19	36	1,912	
19	34	1,790	
19	29	1,524	
19	30	1,563	
19	22	1,143	
19	18	954	
19	18	922	
18	20	1,130	
19	31	1,657	
19	34	1,770	
19	36	1,904	**18,342**
19	37	1,942	
19	36	1,918	
19	28	1,497	
19	34	1,784	
18	22	1,242	
19	27	1,437	
19	21	1,089	
18	18	1,020	
19	27	1,404	
19	30	1,576	

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Wekweeti - Data

Wekweeti

Residential

Year	Month	monthly	MRCNT	MRENCNS (MWh)	MRUPC (kWh)	MHDD (Yellowknife)	UPC (kWh)	Annual UPC (kWh)
2018	11	Nov-18	40	22	544	940		
2018	12	Dec-18	41	20	494	1,135		**5,603**
2019	1	Jan-19	41	24	584	1,354		
2019	2	Feb-19	40	16	392	1,233		
2019	3	Mar-19	41	24	583	862		
2019	4	Apr-19	41	19	452	681		
2019	5	May-19	41	19	460	449		
2019	6	Jun-19	41	17	424	174		
2019	7	Jul-19	40	16	401	106		
2019	8	Aug-19	40	17	434	163		
2019	9	Sep-19	40	17	413	302		
2019	10	Oct-19	40	17	413	572		
2019	11	Nov-19	41	30	730	927		
2019	12	Dec-19	41	9	224	1,375		**5,509**
2020	1	Jan-20	42	29	682	1,362		
2020	2	Feb-20	42	17	399	1,216		
2020	3	Mar-20	42	21	491	1,163		
2020	4	Apr-20	42	22	515	789		
2020	5	May-20	41	19	460	466		
2020	6	Jun-20	42	19	449	159		
2020	7	Jul-20	42	20	488	58		
2020	8	Aug-20	42	21	495	104		
2020	9	Sep-20	42	22	516	332		
2020	10	Oct-20	42	22	514	615		
2020	11	Nov-20	42	20	477	1,003		
2020	12	Dec-20	42	25	590	1,219		**6,075**
2021	1	Jan-21	42	24	582	1,233		
2021	2	Feb-21	42	22	531	1,302		
2021	3	Mar-21	42	28	666	1,109		
2021	4	Apr-21	42	9	226	799		
2021	5	May-21	42	23	540	457		
2021	6	Jun-21	42	16	392	133		
2021	7	Jul-21	42	20	475	76		
2021	8	Aug-21	43	19	435	150		
2021	9	Sep-21	42	18	440	281		
2021	10	Oct-21	44	24	546	479		
2021	11	Nov-21	44	24	553	873		
2021	12	Dec-21	44	22	506	1,408		**5,892**
2022	1	Jan-22	44	29	656	1,432	656	
2022	2	Feb-22	44	17	388	1,304	388	
2022	3	Mar-22	44	24	555	1,105	555	
2022	4	Apr-22	44	22	510	775	510	
2022	5	May-22	44	33	756	380	756	
2022	6	Jun-22			376		376	
2022	7	Jul-22			419		419	
2022	8	Aug-22			452		452	
2022	9	Sep-22			429		429	
2022	10	Oct-22			442		442	
2022	11	Nov-22			588		588	
2022	12	Dec-22			417		417	**5,989**
2023	1	Jan-23			563		563	
2023	2	Feb-23			482		482	
2023	3	Mar-23			477		477	
2023	4	Apr-23			450		450	
2023	5	May-23			480		480	
2023	6	Jun-23			376		376	
2023	7	Jul-23			419		419	
2023	8	Aug-23			452		452	
2023	9	Sep-23			429		429	
2023	10	Oct-23			442		442	
2023	11	Nov-23			588		588	
2023	12	Dec-23			417		417	**5,575**

Commercial

MCCNT	MCENCNS (MWh)	MCUPC (kWh)	Annual UPC (kWh)
19	35	1,829	
19	43	2,288	**19,025**
19	34	1,778	
18	34	1,913	
19	32	1,707	
19	31	1,608	
19	30	1,590	
19	24	1,286	
19	21	1,107	
19	20	1,058	
19	21	1,125	
18	29	1,598	
19	23	1,196	
19	49	2,591	**18,557**
16	30	1,853	
19	40	2,097	
19	34	1,782	
19	27	1,445	
19	24	1,255	
19	18	962	
19	17	877	
18	16	909	
18	22	1,216	
18	32	1,779	
19	36	1,920	
19	37	1,958	**18,051**
19	35	1,839	
19	39	2,032	
17	30	1,780	
19	41	2,182	
18	28	1,569	
19	29	1,524	
19	24	1,271	
19	20	1,039	
19	27	1,401	
18	27	1,498	
19	31	1,655	
18	44	2,461	**20,251**
19	38	1,983	
19	44	2,313	
19	34	1,783	
19	34	1,792	
19	6	296	
		1,289	
		1,050	
		1,000	
		1,220	
		1,610	
		1,598	
		2,261	**18,196**
		1,931	
		1,914	
		1,665	
		1,638	
		1,465	
		1,289	
		1,050	
		1,000	
		1,220	
		1,610	
		1,598	
		2,261	**18,641**

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Wekweeti - Regression

WEKWEETI
Summary Output, Residential
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.601632566
R Square	0.36196174
Adjusted R Square	0.35837726
Standard Error	73.40099025
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	544051.2272	544051.2	100.9801	4.20719E-19
Residual	178	959011.5557	5387.705		
Total	179	1503062.783			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	418.781332	9.65379229	43.37998	1.42E-96	399.7307228	437.831941	399.730723	437.831941
MHDD	0.1213862	0.012079566	10.04889	4.21E-19	0.097548615	0.14522379	0.09754862	0.14522379

Summary Output, Commercial
Data: 2005:1 - 2019:12

Regression Statistics	
Multiple R	0.762093244
R Square	0.580786112
Adjusted R Square	0.578430978
Standard Error	255.8640982
Observations	180

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	16144301.77	16144302	246.6043	1.94608E-35
Residual	178	11653025.74	65466.44		
Total	179	27797327.51			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
INTERCEPT	1204.430244	33.65157405	35.7912	3.09E-83	1138.022871	1270.83762	1138.02287	1270.83762
MHDD	0.661239903	0.042107434	15.70364	1.95E-35	0.578145898	0.74433391	0.5781459	0.74433391

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Hay River - HDD

Hay River Heating Degree Day (HDD) Degree Days Below 18.0 ºC Month	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	20-year Normal HDD (2002-2021)
JAN	1,225.8	1,217.8	1,345.8	1,259.5	1,164.8	1,108.2	1,215.4	1,237.6	1,229.1	1,289.0	1,184.0	1,291.6	1,199.7	1,224.6	1,087.4	1,072.0	1,265.3	1,223.3	1,289.1	1,099.0	1,262.7	**1,211.4**
FEB	1,069.3	1,152.0	1,066.5	1,034.4	927.4	1,168.2	1,201.8	1,084.9	900.2	1,007.4	913.4	927.5	1,188.5	1,104.0	1,049.9	947.7	1,043.5	1,153.3	1,105.6	1,227.0	1,199.9	**1,063.6**
MAR	1,141.5	1,054.1	1,030.1	949.1	904.4	1,099.9	1,090.8	1,116.3	718.9	1,041.3	991.7	1,076.5	1,121.2	954.7	924.9	1,033.4	991.8	709.7	1,078.1	1,030.5	1,047.1	**1,002.9**
APR	791.0	575.7	651.2	542.4	497.2	559.6	689.4	623.2	491.0	720.1	676.1	785.1	690.5	571.3	682.6	667.3	723.0	566.6	734.2	698.4	706.9	**646.8**
MAY	524.8	357.4	532.3	407.1	312.1	368.0	358.0	489.9	401.5	360.5	276.5	332.8	380.4	304.6	312.2	283.9	326.6	432.8	459.8	402.8	393.1	**381.2**
JUN	146.7	201.4	211.4	208.8	98.3	161.2	154.9	192.7	120.0	168.2	155.5	134.7	157.8	126.0	105.1	151.5	157.2	196.2	206.6	146.2	0.0	**160.0**
JUL	93.3	68.9	69.8	86.0	85.2	37.8	35.2	101.3	45.3	36.6	13.3	82.6	34.6	67.2	47.0	55.7	74.2	100.1	75.6	64.2	0.0	**63.7**
AUG	156.0	118.4	177.6	143.2	90.1	187.3	102.8	87.7	109.4	85.7	59.5	77.7	104.4	97.5	79.4	60.3	118.7	152.7	115.8	118.0	0.0	**112.1**
SEP	274.5	285.4	331.1	308.0	203.1	365.5	315.4	176.8	293.5	205.7	178.2	179.7	273.8	264.3	249.5	204.8	424.7	265.0	273.3	233.0	0.0	**265.3**
OCT	612.8	459.3	614.7	473.7	524.3	489.4	477.7	559.7	463.7	470.8	574.9	458.2	521.3	507.9	566.3	507.0	565.8	516.2	585.7	457.7	0.0	**520.4**
NOV	778.9	884.4	852.4	767.1	1,042.4	849.8	777.7	824.5	810.3	952.1	1,010.5	886.6	909.6	767.7	721.8	975.5	879.9	848.6	927.2	822.1	0.0	**864.5**
DEC	923.4	1,024.2	1,244.4	866.3	925.2	1,188.0	1,280.6	1,163.4	1,214.7	978.4	1,328.4	1,339.9	1,143.9	1,024.8	1,191.4	1,084.2	1,046.4	1,226.5	1,076.9	1,336.5	0.0	**1,130.4**
TOTAL	**7,738.0**	**7,399.0**	**8,127.3**	**7,045.6**	**6,774.5**	**7,582.9**	**7,699.7**	**7,658.0**	**6,797.6**	**7,315.8**	**7,362.0**	**7,572.8**	**7,725.5**	**7,014.6**	**7,017.5**	**7,043.3**	**7,617.1**	**7,391.0**	**7,927.9**	**7,635.4**	**4,609.7**	**7,422.3**

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Yellowknife - HDD

Yellowknife Heating Degree Day (HDD) Degree Days Below 18.0 ºC Month	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	20-year "Normal" HDD (2002-2021)
JAN	1,342.1	1,365.4	1,470.0	1,376.2	1,239.0	1,220.9	1,364.8	1,352.9	1,307.3	1,394.2	1,251.6	1,427.8	1,342.7	1,340.3	1,172.4	1,194.6	1,303.1	1,354.0	1,362.4	1,232.5	1,431.7	**1,320.7**
FEB	1,164.8	1,288.2	1,139.2	1,140.3	993.7	1,205.4	1,297.2	1,160.8	960.1	1,139.9	1,013.4	1,035.4	1,233.9	1,229.7	1,198.6	1,082.3	1,154.0	1,233.3	1,216.1	1,302.1	1,303.8	**1,159.4**
MAR	1,228.5	1,163.7	1,151.2	1,027.3	895.9	1,180.2	1,183.6	1,187.9	866.0	1,109.0	1,059.1	1,128.0	1,191.5	1,038.9	985.3	1,131.0	1,032.0	862.2	1,163.0	1,109.0	1,104.6	**1,084.7**
APR	885.7	620.0	801.1	612.5	597.2	629.2	760.5	691.0	514.9	816.5	723.4	809.1	768.6	660.7	753.6	725.6	762.1	680.5	788.9	799.4	775.3	**720.0**
MAY	554.9	402.8	605.9	459.1	306.8	385.9	334.9	516.3	384.4	327.3	310.8	353.2	408.2	323.0	304.3	297.6	369.4	448.9	465.6	457.0	380.2	**400.8**
JUN	130.9	166.4	188.8	165.1	80.6	149.0	132.6	174.8	109.0	148.0	79.2	105.0	114.3	114.3	89.7	143.5	132.2	173.5	158.9	132.9	0.0	**134.4**
JUL	62.3	45.0	49.5	84.1	59.3	20.2	32.8	79.7	40.3	25.7	7.1	80.1	40.2	63.5	40.8	52.3	63.5	106.2	58.4	76.0	0.0	**54.4**
AUG	176.2	119.5	177.9	154.5	84.8	180.9	114.6	101.7	89.8	88.2	63.9	98.6	136.1	101.8	87.1	65.1	157.0	162.9	104.3	149.5	0.0	**120.7**
SEP	310.4	289.5	373.3	363.8	243.9	392.0	369.3	227.0	307.6	241.7	202.9	244.9	346.4	301.7	301.2	231.7	464.0	302.0	331.5	280.5	0.0	**306.3**
OCT	671.3	479.3	681.0	546.9	581.8	561.8	518.0	603.0	544.3	514.3	600.6	517.8	558.9	595.0	614.8	591.1	623.1	571.5	615.3	478.5	0.0	**573.4**
NOV	878.9	937.6	988.6	811.5	1,063.0	907.7	826.9	866.5	899.1	985.0	1,065.8	962.8	1,035.6	841.1	756.5	1,026.2	940.3	927.1	1,002.8	873.1	0.0	**929.8**
DEC	993.6	1,118.3	1,383.3	966.7	1,015.1	1,305.9	1,420.4	1,238.3	1,237.8	1,099.5	1,401.9	1,500.9	1,213.4	1,106.0	1,263.4	1,217.7	1,135.2	1,375.2	1,218.5	1,408.0	0.0	**1,231.0**
TOTAL	**8,399.6**	**7,995.7**	**9,009.8**	**7,708.0**	**7,161.1**	**8,139.1**	**8,355.6**	**8,199.9**	**7,260.6**	**7,889.3**	**7,779.7**	**8,263.6**	**8,389.8**	**7,716.0**	**7,567.7**	**7,758.7**	**8,135.9**	**8,197.3**	**8,485.7**	**8,298.5**	**4,995.6**	**8,035.6**

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Section 3 – Purchase Power

Overview

1. As discussed in Section 1, the 2023 forecast excludes the Purchase Power for Hay River, effective January 1, 2023. The Purchase Power included in this Application is outlined in Schedule 4.3 and is set out in the following table.

Table 3-1 – Purchase Power
($000s)

	2019	2020	2021	2022	2023
	Actual			Forecast	Test Year
Purchase Power	3,765	3,632	3,704	3,565	307

2. The Hay River Disposition results in 2023 Purchase Power expenses decreasing by 91 percent or $3,258,000 compared to forecast costs for 2022.

3. In the Test Year, 37 percent of Northland's total required power supply is forecast to be purchased from NTPC, down from 84 percent in 2022, due to the Hay River Disposition. The purchased power in 2023 is required for the remaining customers in the Hydro zone.

Deferral Account

4. Consistent with previous approvals, Northland is requesting continued approval of purchase power deferral.

5. Consistent with the previously approved methodology, the purchase price is based on NTPC's approved rates that were in effect on May 1, 2022. Subsequent increases or decreases to these rates approved by the Board for 2023, and subsequent years, will be flowed through to Northland's customers using the existing Rider F, as approved by the Board.

6. Further, Northland is proposing to use the purchase power deferral to recover losses and station service usage during any interim period between

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January 1, 2023, and the final transition of the Franchise Assets to the Town, while Northland is still purchasing energy at Pine Point. For customers in Hay River, as described in Section 15, the existing Rider F will remain for any period of time where Northland owns and operates the Franchise Assets beyond January 1, 2023, and the existing NTPC Wholesale Rate remains unchanged. As described in Section 1B, any deferral balance will be trued-up at the time of the transition.

7. Post transition, Northland has assumed it will no longer purchase power at Pine Point and will, instead, purchase power further downstream off the Hay River Distribution system.

Forecast Process

8. The energy component of the purchase power cost is determined by applying NTPC's rates to the total forecast energy (kWh) purchases as shown on Schedule 4.3. Line losses have been forecast using the methodology described in Section 4. Total forecast purchases are determined by applying line loss percentages to Northland's sales load forecast.

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Section 4 – Diesel Fuel Costs

Overview

1. As discussed in Section 1, the 2023 forecast excludes the purchase power for Hay River, effective January 1, 2023. The diesel fuel costs included in this Application are outlined in Schedule 4.1 and are set out in Table 4-1, below.

Table 4-1 – Diesel Fuel Costs (Schedule 4.1)
($000s)

	2019	2020	2021	2022	2023
	Actual			Forecast	Test Year
Diesel Fuel Costs	1,527	1,325	1,463	2,618	1,932

2. The actual diesel fuel cost increase of $1,091,000 from 2019 to 2022 is mainly due to the increase in the price of diesel fuel. The forecast for the 2023 Test Year decreased by $686,000 mainly due to the Hay River Disposition.

3. Please refer to Schedule 4.1 for the details associated with the calculation of diesel fuel costs for 2019 to 2023.

Background

4. Diesel fuel is purchased for each of the diesel plants operated by Northland. Northland conducts a fuel tendering process through which a vendor is selected to be the exclusive provider of fuel to Northland.

5. Fuel costs are recorded as the diesel fuel is consumed by the diesel plant.

Forecasting Fuel Costs

6. Diesel fuel costs are a function of forecast sales, station service, line losses, plant efficiencies, and delivered fuel prices.

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Station Service

7. In accordance with Board Direction 18 in Decision 25-2008, forecast station service has been calculated using a weighted average of three years of actual data with a weighting of “3” given to the lowest station service year, a weighting of “2” to the middle station service year, and a weighting of “1” to the highest station service year.

Line Losses

8. In accordance with past practice, forecast line losses were determined for the level of line losses in each community.

Plant Efficiencies

9. In accordance with Board Directions 14 and 15 in Decision 25-2008, forecast plant efficiencies were calculated using a weighted average of three years of actual data with a weighting of “3” given to the highest efficiency year, a weighting of “2” to the middle efficiency year and a weighting of “1” given to the lowest efficiency year, adjusted for the forecast fuel efficiencies of any new engines forecast to be in service.

Fuel Price Forecasts

10. Price forecasts for each community are based on the current prices in place for diesel fuel as of June 2022. The respective fuel prices for each location are shown in Schedule 4.1.

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Deferral Accounts

(a) Diesel Fuel Price Variance

11. Consistent with the previously approved deferral account, Northland proposes to continue to refund, or collect from, customers the variance between actual and forecast fuel prices

(b) Hay River Diesel Generation Variance

12. Northland proposes that the Hay River Diesel Generation Deferral will remain in place as it operates today until the closing of the purchase and sale transaction related to the Franchise Assets, and will be trued-up at the same time as the Hay River Transition Deferral proposed in Section 1B. Upon transfer of the Franchise Assets, the deferral account balance will transfer to the Town. The Deferral account will operate as before, as described in the following paragraphs.

13. Northland proposes the variance between actual and forecast fuel and O&M costs associated with operating the Hay River generation facilities, for a level of generation that is greater or less than the 4.2 percent of total supply included in this Application, continue to be recovered from, or refunded to, customers, as applicable, subject to Board approval. The use of 4.2 percent of total supply is based on previously approved generation requirements.

14. The deferral balance will track for recovery (or return) actual incremental O&M costs or savings associated with the level of generation being greater than or less than the 4.2 percent of total supply included in this Application.

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Section 5 – Operations and Maintenance (O&M) Expenses

Overview

1. As discussed in Section 1, the 2023 forecast excludes operating and maintenance costs and other taxes attributable to the Hay River Franchise, effective January 1, 2023.

Operations and Maintenance (O&M) Expenses

2. Total O&M expenses included in this Application, as outlined and explained in detail in Schedules 5.1, 5.2 and 5.3, are as follows:

Table 5-1 - Operations and Maintenance (O&M) Expenses ($000s)

Operations and Maintenance Expense	2019	2020	2021	2022	2023
	Actual			Forecast	Test Year
Production	1,028	1,014	1,015	1,055	727
Transmission	57	67	67	84	75
Distribution	1,047	939	1,326	1,355	421
General	40	38	41	40	31
Public Information	93	63	73	76	68
Customer Accounting	447	442	319	424	174
Administration and General	1,329	1,383	1,488	1,402	1,024
Other Taxes	363	374	369	367	5
Less Donations	(9)	(7)	(9)	(14)	(10)
Total	**4,395**	**4,313**	**4,689**	**4,789**	**2,516**

Forecast Process

3. Development of Northland's O&M forecast for the 2023 Test Year involved a detailed review of the business requirements after the Hay River Disposition to continue the provision of safe and reliable electricity service for the remaining communities and the transmission facilities from Pine Point to Hay River. The O&M

forecast for the Test Year was developed using the best information available at the time. Separate forecasts were developed for labour and non-labour costs.

4. Northland's year over year variances between actuals and forecast costs during the 2019 to 2022 period were mainly attributable to the deferral of line and substation maintenance expenses in 2020 when contractors were unavailable due to COVID-19 restrictions. To make up for O&M activities that were deferred in 2020, the maintenance schedule was expanded in 2021 and 2022 when restrictions lifted, and contractors were available again. Aside from inflationary increases, the three-year average O&M expenses from 2020-2022 remained flat compared to 2019 O&M expenses.

5. The forecast for the 2023 Test Year was developed by examining labour and non-labour costs in each activity of the business to identify costs required to operate in the remaining communities after the Hay River Disposition. Please refer to Schedule 5.2 for an explanation of the methodologies used for each activity for 2023.

Labour Costs

6. Labour costs are calculated based on the rate of pay for each required job class. These labour costs are then distributed to O&M accounts or capital accounts depending on the nature of work being performed by the staff in that job class.

7. When the Hay River Franchise was not renewed, Northland made the decision not to replace vacant permanent PLT positions, and instead utilized Alberta-based PLT Services until the terms of the Hay River Disposition were resolved. In 2019 through 2022, Powerline Technician (PLT) services were contracted from ATCO Electric in the amounts of $0.5 million, $0.4 million, $0.9 million, and $1.0 million, respectively. The related party PLT costs have been removed from the forecast for the 2023 Test Year.

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8. To continue to provide safe and reliable service to remaining customers in 2023, Northland will require 5.96 FTEs, five (5) of which are full time to Northland and 0.96 of which are shared employees with Northland Utilities (Yellowknife) Ltd. Consistent with Northland's past practice, this will maximize efficiencies and take advantage of economies of scale. This complement ensures that Northland has the right skillsets available and proper coverage for standby and vacations; however, this is the minimum number of FTEs possible to operate the system safely and reliably, recognizing that vacancies or leave time must be filled with contractors or external resources going forward. In addition, Northland will receive services from ATCO Electric equating to 3.01 FTEs, further discussed below. Please refer to Attachment 1 for the 2023 Organization Chart and Schedule 5.2.

Defined Benefit and Defined Contribution Pension Plans Cash Contributions and Defined Benefit Deferral Account

9. As a result of the defined benefit pension plan actuarial valuations of assets and liabilities, pension funding requirements have changed as shown below.

Year	Defined Benefit (Annual Lump Sum, $000s)
2019	99
2020	42
2021	52
2022	53

10. Consistent with Northland's most recent GRAs, forecast pension expense is based on the cash basis for the Test Year.

11. For purposes of this Application, the 2023 Test Year assumes the same defined benefit contribution rates as 2022. For 2023, Northland is seeking approval to continue the existing deferral account to flow through increases or decreases to required cash contributions to the defined benefit pension plan. This request is

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based on the need for annual actuarial valuations to determine defined benefit pension funding for the year beginning January 1, 2023.

12. Northland also has a defined contribution pension plan that applies to employees that were hired after January 1, 1997. The company's contribution to the defined contribution plan is six percent.

Non-Labour Costs

13. Non-labour costs are forecast in two parts: (i) ongoing operational and administrative activities, and (ii) new programs or projects.

14. In the Test Year, ongoing operational and administrative costs were forecast based on activities required to provide safe and reliable service. Cost drivers were examined and used; for example, costs that closely follow the FTE count (training and staff expenses, etc.) were based on the remaining FTE count. Other drivers used included, remoteness of communities, number of remaining customers and energy consumption. There were also Administrative and General costs that are fixed regardless of the size of the company (e.g., Audit Fees, Financial Services, etc.).

15. In the 2023 Test Year, Northland did not include any additional costs for new O&M programs or one-time projects.

16. For more detail on the buildup of the 2023 O&M forecast refer to Schedule 5.2.

Related Party Costs

17. Northland continues to outsource certain administrative functions to related party companies, such as ATCO Electric, to take advantage of the economies of scale associated with obtaining services from a larger utility. The cost of these services is detailed in Schedule 12.0 and is based on a fully allocated cost methodology that does not contain any element of profit or return.

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18. Northland purchases labour support from ATCO Electric for various services including financial reporting, after-hours assistance, ongoing regulatory support, human resources, governance and communications. The 2023 head office support costs are based on historical requirements and adjusted for known changes. The Hay River Disposition had very little impact on the requirement for these services in 2023 compared to prior years.

19. In addition to the typical support costs purchased from ATCO Electric, Northland has been utilizing Alberta-based PLT services to cover vacant PLT positions due to the uncertainty of the outcome surrounding the Hay River Disposition. These services will no longer be required after the closing of the purchase and sale transaction related to the Franchise Assets and have been excluded from the 2023 forecast.

20. Refer to Schedule 12.0 for Related Party Costs in O&M.

Common Costs – Post Hay River Disposition

21. Northland has allocated common costs in accordance with Decision 1-2016. For the 2023 Test Period all operating and administrative costs, including common costs, were reduced to reflect reductions in the cost drivers as a result of the disposition of Hay River. Northland iterates that a portion of administrative costs are fixed in nature, regardless of the size of the customer base Northland serves. Northland is a taxable, legal entity and will continue to incur costs associated with financial reporting, management reporting, asset management, taxation and regulatory requirements following the disposition of Hay River.

Taxes Other than Income

22. Total taxes other than income included in this Application are included in the table below.

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Table 5-2 – Total Taxes other than Income
($000s)

Other Taxes		2019	2020	2021		2022	2023
		Actual				Forecast	Test Year
Franchise Taxes		324	334	324		321	-
Property Taxes		39	40	45		46	5

23. Following the Hay River Disposition, no communities served by Northland will impose a franchise fee in 2023 as they are not tax-based communities.

24. The franchise fee paid to the Town in actuals/forecast is based on the terms of the Franchise Agreement from June 2, 2006, which granted Northland exclusive rights for the distribution of electrical energy to the Town and its residents until November 30, 2016. In line with the terms in the Franchise Agreement, Northland will continue to pay and recover the franchise fee until the purchase and sale transaction related to the Franchise Assets has closed. Franchise fees are recovered from customers through the Franchise Fee Rider, which is a flow-through of the fee paid to the Town. It is currently calculated based on four percent of revenue generated from the sale of electricity in the Town of Hay River. Northland will no longer require the Franchise Fee Rider in 2023 after the closing of the purchase and sale transaction related to the Franchise Assets. As discussed in Section 1B, Northland will continue to charge existing rates to Hay River customers for the period it operates the Franchise Assets in 2023, with any balances trued-up in the transition deferral.

25. Property taxes are paid to the communities annually for Northland's office building, generation facilities, substation properties and power lines. The 2023 property taxes have been reduced to exclude the Franchise Assets.

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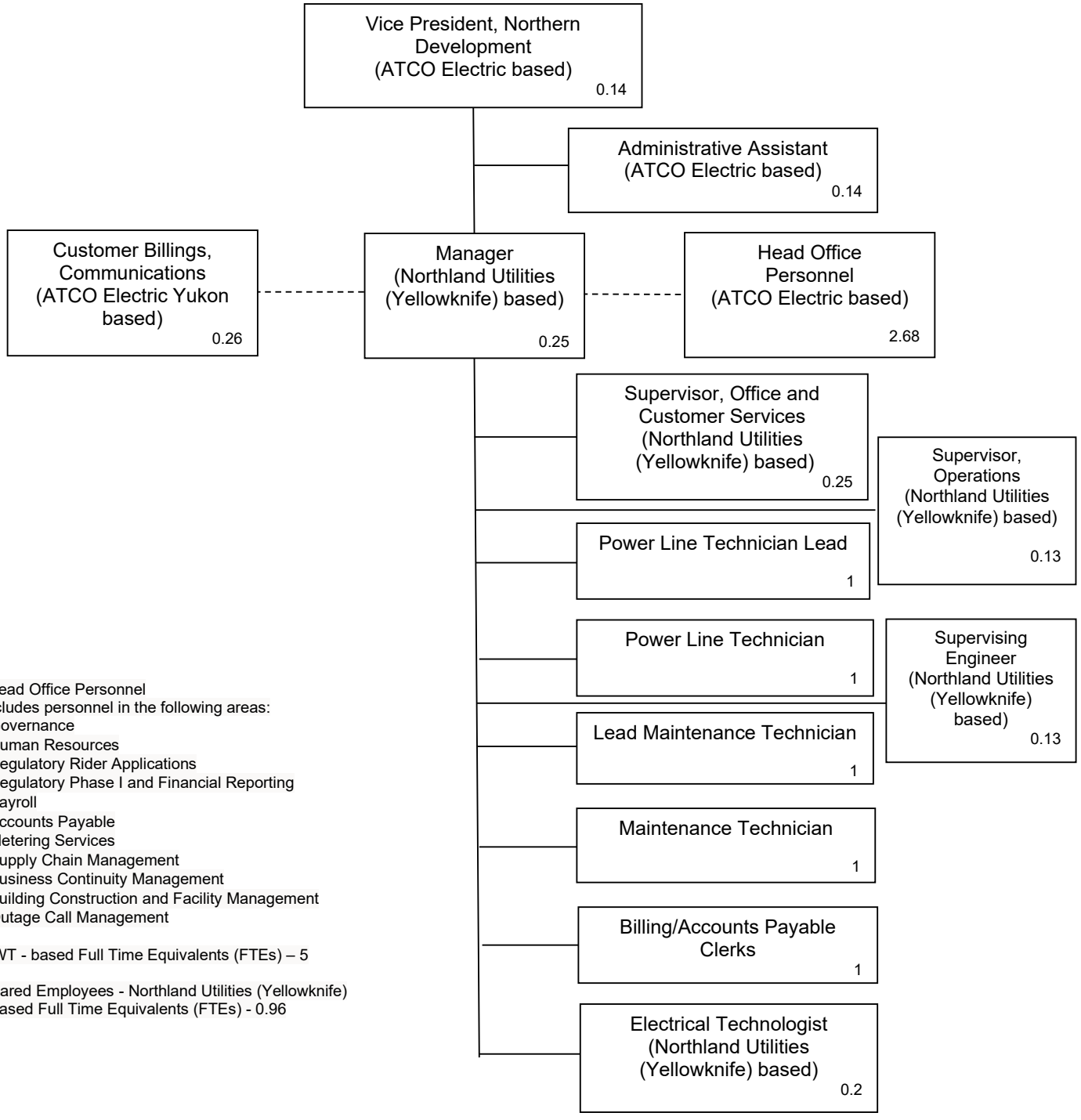
Organizational Chart
Northland Utilities (NWT) Limited
2023



*Head Office Personnel
Includes personnel in the following areas:
- Governance
- Human Resources
- Regulatory Rider Applications
- Regulatory Phase I and Financial Reporting
- Payroll
- Accounts Payable
- Metering Services
- Supply Chain Management
- Business Continuity Management
- Building Construction and Facility Management
- Outage Call Management

NWT - based Full Time Equivalents (FTEs) – 5

Shared Employees - Northland Utilities (Yellowknife) - based Full Time Equivalents (FTEs) - 0.96

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Section 6 – Depreciation

Overview

1. As discussed in Section 1, the 2023 forecast excludes the depreciation for Franchise Assets, effective January 1, 2023. The Depreciation Expense included in this Application, and outlined in Schedules 6.1 through 6.3 is as follows:

Table 6-1 – Depreciation Expense
(Schedules 6.0, 6.1 and 6.4)
($000s)

	2019	2020	2021	2022	2023
	Actual			Forecast	Test Year
Depreciation Expense	1,494	1,471	1,481	1,493	803

2. Northland is not requesting any changes to previously approved depreciation rates or parameters in this Application.

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Section 7 – Return on Rate Base

Overview

1. The Return on Rate Base included in this Application is outlined in Schedule 7.0 and is as follows:

Table 7-1 – Return on Rate Base
(Schedule 7.0)
($000s)

	2019	2020	2021	2022	2023
	Actual			Forecast	Test Year
Return on Rate Base	1,009	1,171	982	820	514

2. The increase in the Return on Rate Base between 2019 and 2020 is mainly due to lower operating costs due to travel restrictions and higher tax deductions. The 2023 Return on Rate Base is reflective of removal of rate base related to the Hay River Disposition.

3. The components of the return on rate base are as follows and are discussed below:

    1. Cost of Capital
        - o Capital Structure and Cost of Capital
        - o Risk Premium
        - o Forecast Long Term Debt Rates
        - o Customer Deposits
        - o No Cost Capital
    2. Rate Base
        - o Capital Additions
        - o Contributions
        - o Deferred Charges & Credits
            - ▪ Attachment 1 – Schedule of Plant Maintenance 2019-2023
    3. Working Capital
        - o Overview

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Cost of Capital

Background

4. Northland's most recent Cost of Capital was determined by way of a negotiated settlement in its 2014-2015 GRA. In Decision 9-2014, the Board determined that the Return on Equity (ROE) would be the generic ROE determined by the AUC in the 2013 GCOC Proceeding,[1] plus a risk premium of 0.35 percent. Similarly, the common equity ratio would be equal to that of ATCO Electric Distribution, plus five percent to align Northland with the common equity ratios of comparator utilities.

5. The ROE set by the AUC in the 2013 GCOC Decision[2] was 8.3 percent. ATCO Electric Distribution was awarded an equity ratio of 38 percent. Therefore, Northland's current ROE is 8.65 percent, and its current common equity ratio is 43 percent:

Table 7-2 – Current Approved

	ROE	Common Equity (%)
2013 GCOC	8.3%	38
Plus	35 bps	5
Equals	**8.65%**	**43**

6. Prior to Decision 9-2014, in Decision 25-2008, the Board approved a 9.15 percent ROE and 44 percent equity ratio. In that Decision, the Board stated: "NUL's business risks are somewhat higher than those of an average electric utility due primarily to its small size and economic characteristics of the service area."[3]

Approvals Sought

7. Consistent with past Board findings, Northland respectfully requests that the Board approve an update to Northland's ROE and common equity to reflect the AUC's

[1] Proceeding ID 2191.
[2] Decision 2191-D01-2015.
[3] Decision 25-2008, NWT Phase 1 GRA, page 14.

2023 GCOC Decision, which approved an ROE of 8.5 percent and common equity ratio of 37 percent for ATCO Electric Distribution,[4] as a starting point in determining Northland's ROE and Equity ratio.

8. Further, Northland respectfully requests that the Board approve an increase to its equity risk premium from 0.35 percent to 1.25 percent to reflect its increased business risk following the Hay River Disposition. Northland is not seeking a change to the five percent adder to its common equity ratio.

9. If approved as filed for 2023, Northland's cost of capital would be as follows:

Table 7-3 – Proposed Cost of Capital

	ROE	Common Equity (%)
AUC Approved 2023 GCOC	8.5%	37
Plus	125 bps	5
Equals	**9.75%**	**42**

10. The proposed changes will ensure that Northland has an opportunity to earn a fair return,[5] with the approvals sought reflecting the change in business risk affecting Northland following the Hay River Disposition. Section 50 of the *PUA* requires the Board to fix a fair return on equity on the rate base of public utilities. This includes setting the portion of rate base financed by common equity.

AUC-Approved 2023 GCOC

11. In Decision 9-2014, the Board adopted the AUC's latest approved GCOC for both the ROE and Common Equity as a starting point. Northland submits the latest AUC approval for cost of capital continues to be a reasonable starting point for determining Northland's ROE and Common Equity. In Decision 27084-D01-2022,

[4] Decision 27084-D01-2022.
[5] By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise… The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. *Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] SCR 186 at 192-93, [1929] 2 DLR 4 *TransCanada Pipelines Ltd. (Re)*, 2013 LNCNEB 2, at paragraph 565.

the AUC approved a ROE of 8.5 percent and Common Equity of 37 percent for the Distribution Utilities in Alberta except for Apex Utilities:

> In this decision, the Alberta Utilities Commission approves the return on equity (ROE) of 8.5 per cent and deemed equity ratio of 37 per cent, except for an approved deemed equity ratio for Apex Utilities Inc. of 39 per cent (together, the ROE and deemed equity ratios are also referred to as "parameters") for 2023 on a final basis.[6]

Risk Premium – ROE

12. Since Decision 9-2014, Northland's risk profile has increased due to the Hay River Disposition. As will be detailed throughout this Section, Northland is requesting a ROE risk premium of 125 basis points, up from the currently approved 35 basis points.

13. As shown in the table below, customer counts and billing determinants have decreased significantly, geographic spread has been accentuated, and sales and service have shifted on balance to communities where Northland is the main generator (using thermal assets), as well the distributor. This has resulted in increased market demand and operational risk as discussed further below. Please refer to Table 7-4 below:

Table 7-4 – Asset Disposition

	2022 Forecast Before Hay River Asset Disposition	2023 Test Year After Hay River Asset Disposition	% Change
Customer count (Residential + Commercial)	2,631	736	(72%)
Rate Base ($000s)	13,501	7,648	(43%)
Purchases (MWh)	30,825	2,536	(92%)
Sales (MWh)	32,988	6,315	(81%)
Proportion of Purchases to Sales	93.4%	40.1%	(57%)
Revenue Requirement ($000s)	$13,538	$5,463	(60%)

14. The substantial changes resulting from the Hay River Disposition have altered Northland's operations to a level not previously seen in past rate Applications,

[6] Decision 27084-D01-2022, paragraph 1.

thereby requiring an increase to Northland's risk premium. Consistent with Decision 25-2008, the additional business risk must be contemplated in the risk premium awarded (over and above the AUC starting point).

15. In addition, in Decision 25-2008, the Board recognized that interest coverage and funds from operations (FFO) interest coverage ratios are one set of factors among many others that rating agencies have regard to in assessing investment risk.[7] Please refer to Table 7-5 below for Northland's interest coverage and FFO interest coverage ratios.

Table 7-5 – Interest Coverage and FFO Interest Coverage Ratios

	2010 per Decision 25-2008	2023 Test Year (as proposed)
Interest Coverage	2.78	1.06
FFO Interest Coverage	4.90	5.93

Market Demand Risk

16. Market demand risks relate to the volatility of sales and their impact on the fair return. With the Hay River Disposition, this risk has increased significantly compared to past proceedings. Northland is more susceptible to many variables including the weather (particularly given the range of temperatures in northern Canada), seasonal volatility of business activity, concentration of sales among fewer customers, the economic health of the community at large, as well as adoption of new technologies and decarbonization, both of which are reflected in the net metering program and government policy. For example, one of the guiding principles of the GNWT's 2030 Energy Strategy is the transition to a lower carbon economy by reducing GHG emissions, increasing the use of renewable and alternative energy and improving energy efficiency within its own operations.

17. Since the last cost of capital review, transformational change has started to occur in the electric utility industry with emphasis on decarbonization, increased focus

[7] Decision 25-2008, NWT Phase 1 GRA, page 15.

on Environmental, Social and Governance (ESG), the need for grid modernization, and general changes to the way in which customers receive utility service (e.g., self-supply). These changes increase risk and uncertainty for utilities to a level never experienced before, and particularly affect Northland because of its small customer base over which costs can be shared.

18. Compounding Northland's risk is the fact that it serves a relatively small market with considerably less economic strength and diversity than the service areas of other utilities. Northland does not have any industrial customers and its residential and commercial sales are primarily affected by the general economic activity within the communities served. The loss of revenue from a few customers has a greater effect on Northland than it does on a larger utility with a larger, more diverse customer base.

19. Finally, the Hay River Disposition has the effect of increasing the size of NTPC and restricting Northland's opportunities to grow its business.

Operating Cost Risk

20. Operating cost risks essentially comprise the potential for the actual ROE to fall short of the approved ROE due to under-estimation of capital expenditures, financing costs, and O&M expenses. The uncertainty of O&M expenses has increased for Northland since the last cost of capital review. Northland is not immune from the recent supply chain disruptions and high rates of inflation affecting the world today. In fact, the risks are higher for Northland due to the remote locations it serves, particularly after the Hay River Disposition, which may result in higher than anticipated repair costs for unplanned maintenance for either generation or distribution facilities. For example, in an unplanned maintenance situation, flights must be chartered for staff and materials to allow timely access into certain communities. This increases the risk from both a cost perspective and service level commitment, all of which is further complicated by the complexities resulting from transformational changes and their effect on the system.

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21. Operating risk is further elevated by the unpredictable and extreme weather conditions that can occur in northern Canada. Repair costs can deviate substantially from those forecast in operating budgets which are based on normal weather conditions. The length of the winter period increases the probability that these severe weather conditions can be experienced. Supply and physical risks faced by Northland must also be considered, such as loss of supply. Due to the harsh physical and climate characteristics, as well as the geographic spread, of Northland's remaining service territory (post Hay River Disposition), the risk is greater for Northland than for other utilities that a loss of supply may result in reduced revenues and earnings.

22. As mentioned above, following the Hay River Disposition, Northland's profile has proportionally shifted to being more of a generator (using thermal assets), as well as a distributor. It is an established principle that generation facilities are riskier than transmission or distribution facilities.[8] Following the Hay River Disposition, generation-related facilities now comprise 26 percent of Northland's PPE (compared with 15 percent pre-disposition), clearly indicating that Northland's operational risks have increased.

23. Given the foregoing, Northland submits that its request for a 125-basis point equity risk premium is reasonable and appropriate. Since the last review by the Board, the risk profile from both a market demand and operational standpoint has increased significantly, particularly following the Hay River Disposition. Northland submits that the requested ROE risk premium will ensure these additional risks are factored into providing the utility with an opportunity to earn a fair return.

[8] British Columbia Utilities Commission Generic Cost of Capital Proceeding Stage 2, Exhibit B1-72, FBC Evidence, Appendix B, McShane Evidence pages 14-15.
GCOC Stage 2 - FBC Evidence (bcuc.com), accessed June 30, 2022.

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Comparator Utilities

24. Another factor that must be contemplated as part of ensuring Northland has an opportunity to earn a fair return is conducting a comparability assessment to other jurisdictions. Northland has compiled Table 7-6 below containing information about similar utilities including their approved ROE and common equity ratios.

Table 7-6 – Information on Comparator Utilities

Utility	Equity Ratio	ROE	Customer Count	Total Sales	Rate Base	Decision Reference
Northland (2023F)	**42%**	**9.75% (Includes 1.25% equity risk premium)**	**736**	**631 MWh**	**$10.63M**	**TBD**
Northland Utilities (Yellowknife) Limited	43%	9.30%	7,952 (2010 actual)	156 GWh (2010 actual)	$36.7M (2010 actual)	12-2011
ATCO Electric Yukon	40%	9.00% (including 0.25% equity risk premium)	17,600 (2015 actual)	315.89 GWh (2015 actual)	$93.0M (2015 actual)	2017-01
FortisBC Inc. (FBC)	40%	9.15% (including 0.40% equity risk premium)	147,199	3,306 GWh	$1.58B	G-75-13
Maritime Electric	45%	9.35%	84,000	1,326 GWh	$471M (2023F)	UE20944
Nova Scotia Power Inc.	37.5%	9.00%	525,000	10,196 GWh	$4.58B 2023F	NSUARB 42
Alaska Electric Light & Power Co. (AEL&P)	58.18%	11.95%	17,500	404 MWh	$109M (2013)	U-16-086

25. Due to Northland's unique characteristics that are described above, there are no direct comparators that face the same market and operational risks – particularly with respect to its size and operational challenges. However, both AEL&P and FBC are reasonable comparators for the following reasons.

26. AEL&P is a good comparator as it is the sole utility providing electrical energy service in Juneau, Alaska, which is a geographically isolated community with no electric interconnections. Similar to Northland's service territory, the local economy

in Juneau is driven by a few primary industries: government, tourism, commercial fishing, and mining. Like Northland, AEL&P has operating cost risk due to its lack of interconnectivity to any other electric grids and adverse impacts could result from an extended outage at one of its hydroelectric generating stations or the availability or cost of replacement power (i.e., diesel). On the other hand, with 17,500 customers, AEL&P has far more customers than Northland (with roughly 740 customers remaining after the Hay River Disposition).

27. Further, despite being on the lower range of ROEs, FBC is also a decent comparator utility because FBC is a fully integrated electric utility consisting of generation, transmission, and distribution. Similar to Northland, FBC has more concentrated assets and a less diverse customer base. However, as shown in the table above, FBC is orders of magnitude larger in size and does not face the same geographical challenges as Northland. Considering these differences, Northland submits that, based on its size and the geographical challenges it faces, a 125-bps ROE premium is appropriate.

28. As shown in Table 7-6, risk premiums are common and are based on the size and specific risks each utility faces. Given the range of approved ROEs shown in the table and the risks it faces, Northland submits the proposed overall return of 9.75 percent is reasonable.

Customer Deposits

29. The customer deposits, or security deposits, included in this Application relate to deposits paid by customers to Northland if they have been unable to establish a satisfactory credit rating, been disconnected or restricted by a current-limiting device or have not paid all past due charges. Customer deposits related to Hay River customers will be transferred as part of the Hay River Disposition. The balances of customer deposits included in Schedule 8.1 are as follows:

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Table 7-7 – Customer Deposits
($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Test Year
Customer Deposits	190	190	196	196	35

Capital Additions

Table 7-8 – Rate Base
($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Test Year
Capital Expenditures	695	771	935	1,463	2,624
Capital Additions to Rate Base	674	695	861	1,089	1,470

30. These additions are primarily driven by a requirement to upgrade, enhance and replace components on the distribution and generation systems as well as general property and equipment that have reached the end of their life cycle.

Contributions

31. Contributions in aid of construction are received from customers in accordance with the company's investment policy. The contributions outlined in Schedule 11.5 are:

Table 7-9 – Contributions
($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Test Year
Contributions in Aid of Construction (per year)	187	294	413	209	4

32. Northland's forecast process involves a review of projects included in the capital additions outlined in Section 11 to identify those which will require a customer contribution.

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Deferred Charges and Credits

33. The mid-year deferred charges and credit amounts included in rate base are outlined in Schedule 11.7 and are as follows in the table below.

Table 7-10 – Deferred Charges and Credits
($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Test Year
Mid-Year Balance	741	940	1,157	1,151	196

34. The deferred charges and credit amount in 2023 are reflective of a transfer of the balances related to Hay River customers as part of the Hay River Disposition and includes the following:

(a) Rate Case Reserve

35. Northland has continued using a reserve account to flow through rate case costs to customers for GRAs filings. The annual rate case write off has remained unchanged, $226,000 annually, from that approved in the 2014-2015 GRA through to 2022. In 2022 a placeholder of $550,000 costs has been forecast for the 2023 GRA. In 2023, Northland will transfer the balances of rate case reserve costs related to Hay River customers as part of the Hay River Disposition and the remaining $327,000 will be flowed through back to customers to bring the overall rate case reserve balance to $nil at the end of 2023.

(b) Reserve for Injuries and Damages

36. This reserve is used for uninsured and uninsurable losses and the deductible portion of insurance claims. Maintaining the reserve mitigates rate fluctuations by smoothing out the charges to O&M with respect to these types of losses. The establishment of the reserve provides financial advantages overpaying significantly higher insurance premiums to reduce deductibles or to insure items which carry prohibitively high premiums.

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37. The 2022 forecast for this reserve includes a placeholder of $50,000 costs for the damages caused by the unprecedented flood in Hay River in the Spring of 2022. The town issued an evacuation notice May 12, 2022, which was lifted May 19, 2022. Heavy flooding caused damage to Northland infrastructure included loss of approximately twelve distribution line poles throughout the Hay River area that required replacement, flooding of underground transformers that required cleaning and testing to put back into service, Additional manpower was brought in from Northland Yellowknife and NTPC to assist in repairs and patrols. Furthermore, numerous commercial and residential customers experienced flooding of homes and businesses, this required working closely with the GNWT electrical inspector to determine which ones could be left on and which would require isolation and repairs before reconnection. As discussions with insurance providers are ongoing Northland has put a placeholder to be trued up once finalized.

38. Consistent with the 2014-2015 Application, no charges are forecast for 2023. Northland will transfer the balances related to Hay River customers as part of the Hay River Disposition and the remaining $98,000 owing from customers at the end of 2022 over the test year to bring the overall reserve for injuries and damages balance to $nil at the end of 2023.

(c) Plant Maintenance Reserve

39. Northland continues to use a reserve account to flow through to customers the costs associated with cyclical top-end plant overhauls and rebuilds outside of Hay River. Please refer to Attachment 1 for a listing of actual, as well as, forecast overhauls for the period 2019-2023. The plant maintenance reserve write off has remained unchanged, $58,000 annually, from that approved in the 2014-2015 GRA through to 2022. Inclusive of the remaining $228,000 owing from customers in the test year, the overall plant maintenance reserve balance will be $nil by the end of 2023.

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40. Consistent with IFRS, major overhauls are capitalized and amortized over the period between the major overhauls.

Working Capital

41. Working capital is a component of the company's total rate base as generally the payment of expense occurs in advance of the receipt of revenues.

42. The components of working capital are:

- Purchase Power;
- Operating Expenses;
- Income Tax;
- Goods and Services Tax;
- Depreciation Expense;
- Interest Expense;
- Common Equity (retained earnings component);
- Common Equity (dividend component); and
- Materials and Supplies Inventory (based on the estimated inventory balance).

43. The nature of the revenues and expenses in the remaining communities and the payment terms from the previous lead/lag study have not changed materially since the preparation of the 2014-2015 GRA Application. However, in the test year each category in working capital was adjusted to remove Hay River related transactions. The removal of Hay River from working capital in 2023 was partially offset by the one-time tax credit for the implementation of the new billing system.

44. The working capital included in rate base in this Application is outlined on Schedule 11.9 with the details on the components incorporating working capital disclosed on Schedule 11.9 and is as follows:

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Table 7-11 – Working Capital
($000)

	2019 Actual	2020 Actual	2021 Actual	2022 Forecast	2023 Test Year
Working Capital	1,335	1,269	1,359	1,582	1,428

Northland Utilities (NWT) Limited (Northland)
2023 Amended General Rate Application (GRA)
Schedule of Plant Maintenance for 2019-2023
($000)

Line No.		Unit Info	Size (kW)	Type of Maintenance	Location	Amount
1	**2019 Actual**					
2						
3	CUL#324	Cat 3508	500	Top-End Overhaul	Fort Providence	23
4	CUL#506	Volvo TAD733GE	150	Top-End Overhaul	Dory Point	4
5						27
6	**2020 Actual**					
7						
8	CUL#324	Cat 3508	500	Top-End Overhaul	Fort Providence	69
9	CUL#570	Cummins QSK23	725	Top-End Overhaul	Fort Providence	131
10	CUL#587	Volvo TAD734GE	185	Top-End Overhaul	Wekweeti	5
11	CUL#594	Volvo TAD733GE	150	Top-End Overhaul	Wekweeti	7
12						213
13	**2021 Actual**					
14						
15	CUL#324	Cat 3508	500	Top-End Overhaul	Fort Providence	(13)
16	CUL#506	Volvo TAD733GE	150	Top-End Overhaul	Dory Point	4
17						(10)
18	**2022 Forecast**					
19						
20	CUL#506	Volvo TAD733GE	150	Spare Replacement	Dory Point	35
21	CUL#604	Volvo TAD733GE	150	Top-End Overhaul	Wekweeti	26
22						61
23	**2023 Test Period**					
24						
25	CUL#570	Cummins QSK23	725	Top-End Overhaul	Fort Providence	90
26	CUL#603	Volvo TAD733GE	150	Top-End Overhaul	Samba' Ke	36
27	CUL#594	Volvo TAD733GE	150	Top-End Overhaul	Wekweeti	31
28	CUL#587	Volvo TAD734GE	185	Top-End Overhaul	Wekweeti	38
29						195

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Section 8 – Income Taxes

Overview

1. The Income Tax expense included in this Application is outlined in Schedule 8.0 and is as follows:

Table 8-1 – Income Tax
($000s)

	2019	2020 Actual	2021	2022 Forecast	2023 Test Year
Income Tax Expense	410	352	275	72	(327)

2. Northland continues to use the flow through method in calculating income tax expense. Under the flow through method, Northland calculates the income tax expense based on taxable income which is minimized by claiming the maximum of all available deductions including Capital Cost Allowance (CCA). Northland also does not record deferred taxes under this methodology.

3. The 2023 Income Tax forecast is lower than 2022 mainly due to the Hay River Disposition as well as the higher CCA deduction in 2023 related to the CIS capital addition. This deduction will not be available in future years.

Income Tax Rate Variance Deferral Account

4. Income taxes forecast by Northland in this Application are based on the currently enacted Federal and Territorial statutory income tax and CCA rates.

5. As there is potential for these tax rates to change, Northland is requesting approval for the continued use of an income tax rate variance deferral account. Any changes from these rates will be used to determine an updated revenue requirement. This updated revenue requirement will be compared to the final Board-approved revenue requirement for the year in question and any difference will be either refunded to, or collected from, customers.

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Section 9 – Taxes Other Than Income

1. As Northland no longer operates in tax-based communities for the Test Year, any costs associated with taxes other than income have been included in Section 5.

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Section 10 – Other Revenues

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Section 11 - Capital Additions

Overview

1. The capital expenditures and additions included in this Application are outlined in Schedule 11.8 and are set out in the following table.

Table 11-1 – Capital Expenditures and Additions
($000s)

	2019	2020	2021	2022	2023
	Actual			Forecast	Test Year
Capital Expenditures	695	771	935	1,463	2,624
Capital Additions to Rate Base	674	695	861	1,089	1,470

2. The capital additions are broken down into the categories set out below.

Generation

3. Generation assets are continually monitored through power plant inspections and testing. Components are repaired or replaced in accordance with manufacturer specifications. The reliability and integrity of the power generation system is a key consideration when critical replacement decisions are being contemplated. Growth from the communities (load), premature failure, safety requirements, community-identified needs, obsolescence and environmental regulations can dictate the need for additional generation assets to be put in place.

Transmission

4. Transmission assets are inspected through line patrols which Northland conducts twice per year. From those inspections, assets that require replacement due to age and deterioration are identified. Northland is continuing its Pole Test and Treat Program to identify poles that have reached the end of their useful life cycle or present an immediate risk to the public or Northland's operational staff.

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New Extensions

5. Northland develops its new extension capital forecast based on discussions with communities, developers, engineering firms, and customers, in addition to known areas of development within its service area. Northland assesses the ability of the existing infrastructure to accommodate the proposed growth, taking into account the specific service requirements of the customer. An estimate is developed for the facilities required for the new extension and inserted into the forecast. In addition, Northland considers historical customer additions to account for walk-in customers that inevitably will require service.

6. Based on known activity in the remaining communities, Northland forecasts minimal new extensions in the 2023 Test Year.

Distribution Improvements

7. Distribution improvement projects fall into four major categories:

   i. System Performance Projects – are required to maintain system performance at an acceptable level. This category includes system protection, voltage, current and line clearance projects.

   ii. Life Extension Projects – are required to increase the life cycle of the distribution system. This category includes new feeder installations and streetlight upgrades.

   iii. System Replacement Projects – are required to replace distribution system facilities on a planned basis when they have reached the end of their life cycle. This includes replacement of overhead/underground system and equipment.

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iv. Forced Projects – are required to correct unplanned system failures and line relocates where customers or government agencies request the relocation of the distribution facilities or where no easements exist.

8. In addition to the above, Northland tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast.

9. Northland reviews unplanned outages that may be attributed to system deficiencies.

10. Northland reviews the options that are available to correct a problem and seeks engineering input to determine the most effective way to complete the required work.

11. Northland works closely with each of its communities and completes much of its work in conjunction with the community's road works program. Working together with the communities has proven to be efficient and cost effective when improvements to the electrical system are required.

12. Northland is not forecasting any planned distribution improvements in the 2023 Test Year.

Street and Sentinel Lights

13. Expenditures are required to provide street and sentinel lighting in Northland's service area. Streetlights that require replacement due to age and obsolescence are included in this category. New installations or requests from customers and developers are also included. All streetlight work is completed in consultation with the communities. The forecast is determined based on known areas of development in the communities, the results of streetlight audits, as well as a review of historic replacement requirements.

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Meters

14. Expenditures are required to upgrade from discontinued mechanical meters to electronic meters and to install new meters to accommodate load growth associated with customer requests for service. These expenditures allow Northland to meet its obligation to provide metered service connections. New meter additions are forecast based on known areas of development and expected connection requests.

15. Northland is not forecasting any planned meter replacements in the 2023 Test Year.

Transformers and Regulators

16. Distribution transformers are required to meet customer growth and to replace spare transformers that are being used for new extensions or for service upgrades.

17. Northland is not forecasting any planned transformer purchases in the 2023 Test Year.

General Plant and Equipment

18. This portion of the capital forecast provides for replacement of equipment and for the purchase of new equipment required to support the utility's operations. These include tools, office furniture, office computer equipment, software, communication equipment, transportation equipment and lands & buildings.

19. Northland follows a similar process to that indicated under Distribution Improvements to identify and justify expenditures in this area.

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Section 12 – Affiliate Transactions

1. Please refer to Section 5 for Related Party Transactions.

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Section 13 – Prior Board Directions

Summary

1. The following provides a response to prior Board Directions.

Board Directions

2014-2015 GRA Phase II: Board Decision 1-2016 (Dated February 29, 2016)[1]

	Direction	Response
4	The Board notes that under the NWT Utilities Minimum Filing Requirements approved in Decision 13-2014, details of costs at the account level, by zone, are required to be provided by NUL at the time of its next GRA. In the Board's view this information ought to facilitate examination of costs that have been directly assigned as well as those that have been allocated to rate zones, at the account level. The Board expects the account level information including basis of allocation or assignment of costs at the account level, to be reflected in future cost of service studies and supporting schedules. *(paragraph #60)*	Please refer to Schedule 5.1
10	In order to meet the requirements in GNWT Instruction 5a) that costs associated with Net Metering should be transparent and should be tracked by utilities and reported through the Board to the GNWT and, in order to calculate and account for the revenue loss arising from net metering, NUL is directed as follows: a) File an annual report within 90 days of each year end, commencing with 2015, a calculation of on-site generation in the following format: Annual Report On net Metering Customers Customer # | Customer Class | Type of Customer | Location | Size of Installation | Date Installed | Net Energy Export/Import kWh | Customer's on-site use kWh | Total on site Generation A | B | C | D | E | F | G | H | I Col A: Customer Identification #-no requirement to disclose confidential information Col B: The rate class to which the customer belongs Col C: Whether the customer is an individual, community organization, commercial entity etc Col D: Name of Community Col E: Number of kW installed Col F: Commissioning date Col G: net energy=Export Energy Minus Import Energy Col H: Estimated or metered on-site consumption by customer Col I: Energy used for subsidy calculations=Col G plus Col H b) File an annual calculation within 90 days of each year end, commencing with 2015, of lost revenues arising from net metering and the accounting thereof: i) Calculate loss of revenue (gross) using on-site generation times the supply rate for that customer's rate class and zone; on-site generation equals on-site customer use (from estimated or	The cumulative lost revenue from 2015-2021 is $51,841. Northland has assigned this balance based on location of solar installations. This amount will be directly assigned to communities according to the location of the net metering customer.

[1] Northland Utilities (NWT) Limited 2014-2015 GRA – Phase II.

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	metered on-site generation) ± net export within annual netting period; ii) Include the loss of revenue calculated in i) as part of sales revenue with the corresponding amount included in a deferral account to be disposed of in accordance with the paragraphs that follow. c) Disposition of deferral account: i) If accumulated lost revenue is below 1% of the actual annual earnings for the year, NUL may apply to recover lost revenue from customers in NUL's next Phase I GRA. ii) If accumulated lost revenue exceeds the 1% of the actual annual earnings threshold NUL may apply to the Board for approval to recover the excess over the 1% threshold by way of GNWT subsidies at the time of the next GRA or when the excess reaches a value of $10,000 whichever event is the earlier. *(paragraph #111)*	

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Section 14 – Supplemental Information

Revenue Requirement Including Town of Hay River

Overview

1. For purposes of aiding the Board with reviewing the impact on Revenue Requirement and Rates related to the Hay River Disposition, Northland has prepared Revenue Requirement calculations for the 2023 Test Year that, in addition to the Diesel communities, include the Town of Hay River. This Revenue Requirement calculation essentially represents a 'Status Quo' scenario, as though the Town of Hay River were to remain with Northland. Within the Status Quo scenario, Northland has capitalized legal fees incurred in connection with the Franchise Agreement process. The legal fees are assumed to be amortized over a 10-year term, which is consistent with the treatment of legal fees associated with renewal of the previous Franchise Agreement. The impacts of amortizing these fees are included in the capital additions, depreciation, and return on rate base sections below.

2. The tariffs and revenue requirement amounts associated with the Status Quo scenario are detailed in Section 14 Attachment 1, Schedules 2.0, 2.1, 3.0 and 3.1. Table 14-1 below, compares Northland's proposed Revenue Requirement Rate Impacts, as set out in Section 1 (i.e., Revenue Requirement excluding the Town of Hay River), and Revenue Requirement Rate Impacts, including the Town of Hay River (Status Quo):

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Table 14-1 – 2023 Revenue Requirement Rate Impacts %

	Section 14 w Hay River Rate Impacts	Section 1 w/o Hay River Rate Impacts	Difference
Thermal Zone	-17%	-12%	-5%
Hydro Zone [1]	4%	2%	2%
Total Company	**-2%**	**-9%**	**7%**

Note 1:
Please note that the Hydro Zone Rate Impacts from Section 1 (without HR as proposed) exclude any impacts to Hay River following the disposition and the implications of the disposition outlined in Section 1B of the Application.

Sales and Revenue

3. The Sales and Revenue forecast for the Status Quo scenario has been performed using the previously approved methodology as described in Section 2 of the Application. The energy sales and corresponding revenue based on the Status Quo scenario are provided in Section 14 Attachment 1, Schedule 2.1. Tables 14-2, 14-3 and 14-4 provide a breakdown of the Status Quo scenario by summarizing Energy Sales by Customer Class and by Area.

Table 14-2 – Northland Energy Sales by Customer Class (MWh)

	2022 Forecast	2023 w/Hay River	2023 w/o Hay River	Difference
Customer Class				
Residential	11,790	11,338	2,890	8,448
Commercial	20,457	21,546	3,240	18,306
Streetlights	547	547	135	412
Sentinel Lights	194	194	50	144
Total Company	**32,988**	**33,624**	**6,315**	**27,309**

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Table 14-3 – Residential Energy Sales by Area (MWh)

	2022	2023		
	Forecast	w/Hay River	w/o Hay River	Difference
Hay River	8,825	8,448	-	8,448
Remaining Hydro	1,033	1,013	1,013	-
Thermal	1,932	1,877	1,877	-
Total	**11,790**	**11,338**	**2,890**	**8,448**

Table 14-4 – Commercial Energy Sales by Area (MWh)

	2022	2023		
	Forecast	w/Hay River	w/o Hay River	Difference
Hay River	17,172	18,306	-	18,306
Remaining Hydro	1,261	1,274	1,274	-
Thermal	2,024	1,966	1,966	-
Total	**20,457**	**21,546**	**3,240**	**18,306**

Purchase Power

4. The Purchase Power included in the Status Quo is outlined in Section 14 Attachment 1, Schedule 4.3 and is set out in the following table.

Table 14-5 – Purchase Power ($000s)

	2022	2023		
	Forecast	w/Hay River	w/o Hay River	Difference
Purchase Power	3,565	3,877	307	3,570

5. When Hay River remains with Northland, Purchase Power increases by 8.75 percent, or $312,000, compared to forecast costs for 2022. Note the Purchase Power amount is for normal operations and approval for the deferral account related to increased diesel caused by the Taltson Hydro shutdown would still be required in this scenario.

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Diesel Fuel Costs

6. The Diesel Fuel costs included in the Status Quo are outlined in Section 14 Attachment 1, Schedule 4.1 and are set out in the following table.

Table 14-6 – Diesel Fuel Costs
($000s)

	2022	2023		
	Forecast	w/Hay River	w/o Hay River	Difference
Diesel Fuel Costs	2,618	2,308	1,932	376

7. The actual Diesel Fuel cost increase of $781,000 from 2019 to 2022 is mainly due to the increase in the price of diesel fuel. The forecast for the 2023 Test Year decreased by $310,000 mainly due to the duration of the plant shutdown in 2022.

8. Please refer to Section 14 Attachment 1, Schedule 4.1 for the details associated with the calculation of Diesel Fuel costs for 2019 to 2023.

Operations and Maintenance (O&M)

9. Total Operations and Maintenance (O&M) expenses and other taxes attributable to the Hay River Franchise included in the Status Quo, and as outlined in detail in Section 14 Attachment 1, Schedules 5.0 and 5.1, are set out as follows in the Table below.

Table 14-7 - Operations and Maintenance (O&M) Expenses
($000s)

Operations and Maintenance Expense		2022	2023		
		Forecast	w/Hay River	w/o Hay River	Difference
Production		1,055	992	727	265
Transmission		84	90	75	15
Distribution		1,355	1,342	421	921
General		40	32	31	1
Public Information		76	80	68	12

Operations and Maintenance Expense		2022	2023		
		Forecast	w/Hay River	w/o Hay River	Difference
Customer Accounting		424	413	174	239
Administration and General		1,402	1,416	1,024	392
Other Taxes		367	382	5	377
Less Donations		(14)	(10)	(10)	-
Total		**4,789**	**4,738**	**2,516**	**2,222**

10. In the above table Northland notes that the Administration and General costs do not reduce proportionally compared to other areas when comparing the two scenarios. This is a result of a significant portion of these costs being fixed (Audit Fees, Financial Services, etc.) as well as the labour requirement for safe and reliable services, further details are provided in Section 5 of this Application.

Depreciation

11. The Depreciation Expense included for the Status Quo, and outlined in Section 14 Attachment 1, Schedule 6.0, are as follows:

Table 14.8 – Depreciation Expense
($000s)

	2022	2023		
	Forecast	w/Hay River	w/o Hay River	Difference
Depreciation Expense	1,493	1,594	803	791

12. Consistent with the explanation provided in Section 6 of the Application, Northland is not applying any changes to previously approved depreciation rates or parameters for this scenario.

13. A portion of the increase in the 2023 depreciation expenses cost is a result of the treatment of the incurred legal fees because of the Hay River Disposition process. In the Status Quo scenario, these costs are amortized over the term of the Franchise Agreement, which is the same treatment that was applied to legal fees

incurred in connection with renewal of the previous Franchise Agreement. In the scenario without Hay River, these costs are included in the proposed deferral account.

Return on Rate Base

14. The Return on Rate Base for the Status Quo is outlined in Section 14 Attachment 1, Schedule 7.0, and is as follows:

Table 14-9 – Return on Rate Base
($000s)

	2022	2023		
	Forecast	w/Hay River	w/o Hay River	Difference
Return on Rate Base	820	860	514	346

15. The 2023 return on rate base is comparable to that of 2022 in the Status Quo scenario, with the slight difference mainly due to the Franchise Agreement legal fees that were capitalized.

Return on Equity (ROE) and Capital Structure

16. For the Status Quo, Return on Equity (ROE) has been applied consistent with the previously approved methodology as outlined in Section 7. Northland has set the ROE for the Test Year at the percentage determined on a generic basis for all Alberta Utilities for 2023, as determined by the Alberta Utilities Commission (AUC) in the 2023 Alberta Generic Cost of Capital Proceeding (2023 GCOC proceeding),[1] plus a risk premium of 0.35 percent. Northland has used the approved risk premium of 0.35 percent for illustrative purposes.

[1] Decision 27084-D01-2020.

17. Consistent with the rationale outlined in Section 7 of the Application, Northland is not requesting a change to the approved common equity adder of five percent for the Status Quo.

Capital Additions

18. The capital expenditures and additions included in the Status Quo are outlined in Section 14 Attachment 1, Schedule 11.8 and are set out in the following Table:

Table 14-10 – Capital Expenditures and Additions ($000s)

	2022	2023		
	Forecast	w/Hay River	w/o Hay River	Difference
Capital Expenditures	1,463	2,624	2,624	-
Capital Additions to Rate Base	1,089	1,990	1,470	520

19. Due to the immaterial amount of anticipated capital expenditures and additions related to Hay River, Northland has no additional capital additions included for this scenario.

20. As noted in the depreciation section above, only the legal fees related to the Hay River Disposition have been included in additions in the Status Quo scenario in the test period and are amortized over 10-years.

Distribution Rate and Rider Adjustments

21. Northland has updated the Rider calculations for the Status Quo. Northland is not requesting to implement these rates and has provided these calculations for illustration purposes. Please refer to Section 14 Attachment 1, Schedules 15.1 to 15.3 for the updated Rider calculations.

22. Northland has calculated rider deferral balances as of December 31, 2022 and has estimated the rate impacts for the Status Quo.

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23. The Rider A Fuel Cost Adjustment Rider has been updated per Section 14 Attachment 1, Schedule 15.2 to reflect a change in the Rider A rate, which was implemented effective November 1, 2022, after Northland's original 2023 GRA was submitted in September 2022.

24. The impact of the Rider changes on a sample Residential and Commercial customer's monthly bill for the Status Quo, with Hay River included in the Rider calculations, has been determined for each rate Zone in the following table.

Table 14-11 – Impact on Customers' Bills by Rate Zone

Zone/Rate Class	w/Hay River	w/o Hay River	Difference
[1]**Hydro Residential**			
[2]Non-Government %	+0.5%	+0.3%	+0.2%
[2]Non-Government $	$0.98	$0.52	$0.46
Government %	-2.1%	-5.1%	+3.0%
Government $	($4.92)	($12.12)	$7.20
[3]**Hydro General Service**			
Non-Gov & Gov %	-4.0%	-7.1%	+3.1%
Non-Gov & Gov $	($12.66)	($22.53)	$9.87
Thermal Residential[1]			
[2]Non-Government %	+0.4%	+0.4%	-0.1%
[2]Non-Government $	$0.76	$0.92	($0.16)
Government %	+4.1%	+13.2%	-9.1%
Government $	$21.17	$68.35	($47.18)
[3]**Thermal General Service**			
[2]Non-Government %	+0.0%	+0.0%	+0.0%
[2]Non-Government $	$0.0	$0.0	$0.0
Government %	+4.0%	+13.6%	-9.6%
Government $	$30.40	$102.67	($72.27)

Notes

[1] Residential customer using 600kWh per month

[2] For Non-Government Customers:
Residential includes GREP (Thermal Zone only) and TPSP
General Service includes GREP (Thermal Zone only)

[3] General Service customer using 1000kWh & 5kW per month

25. As evident from Table 14-11 above, not all customers are better served from the Disposition of the Town of Hay River. Namely, while customer's bills in the Hydro

zone increase when Hay River is included in revenue requirement (this comparison does not reflect the potential impact to Hay River customers following the disposition), customer's bills in the Thermal zone decrease when Hay River is included in revenue requirement at a higher magnitude of dollars for many customer classes.

Revenue Requirement Reconciliation

26. To assist the Board in reviewing the impacts on revenues and costs, Northland has provided a Revenue Requirement comparison by Zone for scenarios with and without Hay River. Northland has also provided explanations for the Thermal zone differences to illustrate the impact on revenue requirement when the Town of Hay River is excluded and when the Town of Hay River is included.

27. With the removal of the Town of Hay River, there is a significant reduction in the Revenue Requirement for the Hydro zone. This reduction is partially offset by the Transmission Revenue impact, as discussed in Section 1B. In addition, Northland has included in the Status Quo scenario legal fees incurred for the Hay River Disposition as these costs are prudently incurred costs associated with maintaining the Hay River Franchise regardless of service provider. These costs have been included in Rate Base and amortized over a 10-year period.

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Table 14-12 – Hydro Zone Difference with/without Hay River Revenues

Description	Hydro Zone w/Hay River	Hydro Zone w/o Hay River	Difference
		2023	
Revenues			
Retail Revenues	8,726	782	7,944
Other Revenue	170	21	149
Transmission Revenue	-	1,111	(1,111)
Total Revenues	8,896	1,914	6,982
Costs			
Purchase Power	3,877	307	3,570
Diesel Fuel	376	-	376
Operations and Maintenance	3,805	1,283	2,522
Depreciation	1,161	370	791
Amortization of Contributions	(94)	(41)	(53)
Amortization of Deferred Costs/Credits	(639)	(52)	(587)
Return on Rate Base	563	123	440
Income Taxes	(153)	(77)	(76)
Total Costs	8,896	1,914	6,982

Table 14-13 – Thermal Zone Difference with/without Hay River Revenues

Description	Thermal Zone w/Hay River	Thermal Zone w/o Hay River	Difference
		2023	
Revenues			
Retail revenues	3,289	3,464	(176)
Other revenue	65	85	(20)
Total Revenues	3,354	3,549	(196)
Costs			
Diesel Fuel	1,932	1,932	-
Operations and maintenance	933	1,233	(300)
Depreciation	433	433	-
Amortization of contributions	(44)	(44)	-
Amortization of deferred costs/credits	(146)	(146)	-
Return on rate base	297	391	(94)
Income taxes	(51)	(250)	199
Total Costs	3,354	3,549	(195)

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28. Please refer to the explanations below for the Thermal Zone differences:

(a) Operations and Maintenance: The difference in Operations and Maintenance (O&M) amounts is mainly due to the impact of the approved allocation methodology. Northland has used a consistent allocation methodology based on energy usage in both scenarios (revenue requirements With and Without Hay River) for Administration and General (A&G) costs. As the Thermal Zone has relatively less energy usage, the allocated A&G costs for the Thermal Zone are lower when combined with Hay River.

Similarly, Northland used a consistent allocation mechanism in both scenarios for allocating customer accounting and billing costs based on number of customers. As the Thermal Zone has relatively less customers, the allocated customer accounting and billing costs are lower for the Thermal zone when combined with Hay River.

(b) Return on Rate Base: The difference in the Return on Rate Base is mainly a result of the allocation methods for ATCO's Customer Information System (CIS) replacement program and working capital amounts. For the CIS replacement program, the costs have been allocated based on the number of customers and Working Capital costs have been allocated based on PP&E. As the Thermal Zone has relatively less customers and relatively less PP&E, the allocated CIS Replacement Program costs and working capital amounts are lower for the Thermal Zone when combined with Hay River.

(c) Income Taxes: The difference in income tax amounts is driven by the tax deductions related to the CIS replacement program as they are allocated based on the number of customers, as well as the changes in O&M amounts as described above.

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Conclusion:

29. Northland has presented the above Status Quo scenario to aid the Board with reviewing the impact on Revenue Requirement and Rates related to the Hay River Disposition additional details can be found in Section 14 Attachment 1.

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Section 14 - Attachment 1 - Schedules with Hay River

Filed as an Excel document only.

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Section 15 – Distribution Rate and Rider Adjustments

Background

1. As discussed in Section 1, the 2023 revenue requirement excludes operating and maintenance costs and other taxes attributable to the Hay River Franchise, effective January 1, 2023. Rate and rider adjustments are required to properly reflect the removal of Hay River Franchise Assets, effective January 1, 2023.

2. In this section, Northland is providing updates to deferral balances and estimated rates for the following:

    a. The Rate Adjustment Rider, Rider R;
    b. The Purchase Power Adjustment Rider, Rider F; and
    c. The Fuel Cost Adjustment Rider, Rider A.

3. Northland is proposing rider updates for remaining customers outside of Hay River. In Hay River, Northland will leave the currently approved riders as-is for any time where Northland operates the Hay River assets beyond January 1, 2023, within reason.[1] Any balances will be distributed to the Town of Hay River at the time of transition.

4. All balances will be trued-up and finalized at the time of the Compliance Filing.

5. Updated Price Schedules are included in Attachment 1 - Rider Schedules.

Riders for Remaining Customers

Rate Adjustment Rider (Rider R)

6. As outlined in Section 1, Northland is seeking interim refundable approval for the proposed rate increase via the Rate Adjustment Rider – Rider R – applicable to each rate class within Northland's remaining communities in each zone, effective

[1] Northland will endeavor to manage deferral account balances appropriately and, if needed, will seek Board approval for any required changes to riders for Hay River.

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May 1, 2023. To implement Rider R by this effective date, Northland requires Board approval by April 21, 2023. Adjustments, if any, to final rates will be made to Rider R in the Compliance Filing to this Application.

7. Rider R will recover the 2023 revenue requirement shortfall by zone. The revenue requirement shortfall is the difference between the forecast 2023 revenue requirement and the forecast 2023 revenue from existing rates. In this Application, Rider R has been designed to collect the 2023 revenue requirement shortfall in each zone, by setting the rider to 2.30 percent in the Hydro Zone, and 9.20 percent in the Thermal Zone. The detailed derivations of Rider R can be found in Schedule 15.1.

Fuel Cost Adjustment Rider (Rider A)

8. Rider A refunds or recovers amounts that are tracked in two deferrals: 1) the Diesel Fuel Price Variance deferral; and 2) the Hay River Diesel Generation Variance deferral.

9. The Diesel Fuel Price Variance component of Rider A records variances between Board approved fuel prices and actual fuel prices. From 2023 going forward, this deferral account will be based on community-specific plant information in the Thermal Zone (shown in Schedule 4.1).

10. Considering the Hay River Disposition includes the generating assets, Northland will no longer incorporate the Diesel Generation Variance deferral in the Rider A balance for remaining customers beyond 2022. Accordingly, Northland is also proposing to finalize Rider A for remaining customers in the Hydro Zone and exclude these customers from Rider A going forward after any residual balance is depleted.

11. Finally, Northland proposes to decrease the threshold from +/- $220,000 to +/- $80,000 to trigger changes to the Rider A Rate This translates to approximately

two percent of the 2023 revenue requirement for remaining Thermal Zone communities.

12. Refer to Schedule 15.2 for the deferral balance estimate and proposed Rider A rates, effective May 1, 2023. Also, please note that Rider A has been revised from the original GRA filed in September 2022, due to a change in Rider A, effective November 1, 2022.

Purchase Power Adjustment Rider (Rider F)

13. Consistent with past approvals, Rider F is used to flow-through costs related to wholesale rate changes in the Hydro Rate Zone which are tracked in the associated Purchase Power Flow Through deferral account.

14. Due to the uncertain timing of the Hay River Disposition, Northland is proposing to use Rider F to recover the ongoing difference between forecast and actual Transmission losses and station service amounts between January 1, 2023, and the Hay River Disposition. Eventually, Northland expects a Distribution Wholesale rate to be available at points where its remaining Hydro Zone customers are connected to the Hay River distribution system, forgoing the need for station service energy and transmission losses to be included in its revenue requirement (as reflected in Schedule 4.1). Once a Distribution Wholesale rate is available, Northland expects to remove this component from Rider F.

15. The estimated Rider F for Northland's remaining customers (excluding Hay River) in the Hydro Zone, effective May 1, 2023, is shown in Schedule 15.3.

Impact to Remaining Customers' Bills

16. The impact of the proposed rider changes on sample residential and commercial customer monthly bills has been determined for each rate zone. An average monthly consumption of 600 kWh has been used for a sample residential customer and 1,000 kWh consumption and 5 kW demand for a sample general service

customer. The changes reported in the table include the impacts, as applicable, of the GNWT Rate Equalization Program (GREP) and the Territorial Power Subsidy Program (TPSP) for non-government residential and commercial customers.

Table 15-1 – Impact on Remaining Customers' Bills by Rate Zone

Rate Class	Hydro Zone		Thermal Zone	
	($)	(%)	($)	(%)
Residential[1]				
Non-Government[2]	$0.52	+0.3%	$0.92	+0.4%
Government	($12.12)	-5.1%	$68.35	+13.2%
General Service[3]				
Non-Government	($22.53)	-7.1%	$0.00	+0.0%
Government	($22.53)	-7.1%	$102.67	+13.6%

Notes

[1] Residential customer using 600kWh per month

[2] For Non-Government Customers:
Residential includes GREP (Thermal Zone only) and TPSP
General Service includes GREP (Thermal Zone only)

[3] General Service customer using 1000kWh & 5kW per month

For Hay River Customers

Rate Adjustment Rider (Rider R)

17. The currently approved Rider R will remain in place for Hay River during any period where Northland owns and operates the Franchise Assets beyond January 1, 2023. Any residual balance in this account will be trued-up upon transition of the Franchise Assets to the Town.

Fuel Cost Adjustment Rider (Rider A)

18. As discussed in Section 4, Northland proposes to continue to use the Hay River Diesel Generation Variance deferral to record variances between actual and forecast fuel and O&M costs associated with operating the Hay River generation facilities that are greater to or less than an approved percentage of total supply. This balance, along with any residual fuel price variance amounts, will be trued-up at the time of transition of the Franchise Assets to the Town.

Purchase Power Adjustment Rider (Rider F)

19. For customers in Hay River, the existing Rider F will remain for any period of time where Northland owns and operates the Franchise Assets beyond January 1, 2023, and the existing NTPC Wholesale Rate remains unchanged. Any residual amount in the Rider F balance for customers in Hay River will be trued-up at the time of transition to the Town.

Summary of Riders

20. Please refer to the following table which outlines applied-for riders for remaining customers and Hay River customers effective May 1, 2023.

Table 15-2 – Summary of Riders

	R: Rate adjustment			A: Fuel Cost Adjustment			F: Purchase Power	
Community	Hay River	Hydro	Thermal	Hay River	Hydro	Thermal	Hay River	Hydro
Hay River	-0.52%			$0.0366			$0.0244	
Enterprise		2.30%			$0.0224			$0.0069
K'atl'odeeche		2.30%			$0.0224			$0.0069
Dory Point			9.20%			$0.0658		
Fort Providence								
Wekweeti								
Sambaa K'e								

Section 15
Attachment 1

Effective: 2023-05-01
Supersedes: 2022-11-01

NORTHLAND UTILITIES (NWT) LIMITED
An ATCO Company

RIDER A
FUEL COST ADJUSTMENT

Available

- Throughout Northland Utilities (NWT) Ltd. service area.

Applicable

- To all classes of service

Rates

- This Rider is used to collect/(refund):
    - Fuel price variances between actual fuel costs and fuel costs based on the Board approved diesel prices included in base rates.
- Service will be rendered at the available rates with the following surcharge or (refund) relating to the cost of fuel.

Hydro Zone	$0.0224 / kWh
Thermal Zone	$0.0658 / kWh
Hay River	$0.0366 / kWh

Section 15
Attachment 1

Effective: 2023-05-01
Supersedes: 2022-06-01

NORTHLAND UTILITIES (NWT) LIMITED
An ***ATCO*** Company

RIDER F
PURCHASE POWER COST ADJUSTMENT

Available

- Within the Northland Utilities (NWT) Ltd, Hydro Rate Zone.

Applicable

- To all classes of service.

Rate

- A surcharge will be applied to all energy consumption for bills issued
- Rider F is required to flow through the costs related to wholesale rate changes in the Hydro Rate Zone.

Hydro Zone	$0.0069 / kWh
Hay River	$0.0244 / kWh

Section 15
Attachment 1

Effective: 2023-05-01
Supersedes: 2022-06-01

NORTHLAND UTILITIES (NWT) LIMITED
An ATCO Company

RIDER R
RATE ADJUSTMENT RIDER

Available

- Throughout Northland Utilities (NWT) Ltd. service area.

Applicable

- To all classes of service.

Rates

- This Rider is applied to base rates to collect or (refund) the difference between the revenue requirement and approved base rates.
- All of the company's base rate revenue will be adjusted by the following rates:

Hydro Zone	2.30 %
Thermal Zone	9.20 %
Hay River	-0.52 %

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Section 16 – Business Cases

1. Business Cases are provided for all projects greater than $100,000 in accordance with the negotiated settlement approved in Decision 17-2011.

2. The Business Cases fall into the following three categories:

   I. Not Filed in Previous Rate Applications – these projects have been completed since the last rate Application.

Number	Name
1	McBryan Drive Upgrade
2	Hay River Underground Cable Replacement
3	Hay River Pole Replacement
4	Portable Emergency Generator
6	Hay River CUL 197 Overhaul
7	Fort Providence CUL 570 Overhaul
8	2021 Pole Test and Treat
10	Sambaa K'e CUL 411 Replacement

   II. 2023 Capital Business Cases – these projects will be completed and added to rate base in the Test Year.

Number	Name
5	6L10 Pole Replacement
9	ATCO CIS Replacement
13	Fort Providence CUL 570 Replacement

   III. 2024 Capital Business Cases – Northland is seeking a project permit for the following two projects in 2024, consistent with Section 54 of the *PUA* which states:

> **54**. (1) A public utility shall apply to the Board for a project permit before undertaking a capital project having a total cost projected to exceed (a) $5,000,000, or ***(b) 10% of the utility's rate base. [emphasis]***

Number	Name
11	Saamba K'e Plant Move
12	Pine Point Transmission Transformer Replacement

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

McBryan Drive Upgrade

Business Case #01

Northland Utilities
A NU and ATCO Company

Executive Summary

Replace a section of underground power cable that has reached end of life and upgrade infrastructure during road works in the area.

Background

The Town of Hay River is replacing the water and sewer in the area, and the cables are end of life (originally installed in 1970). Replacing the cables, will bring them up to current standards thereby improving safety and reliability.

Project Description

Replace a section of underground power cable, install cable conduit, two overhead transformers with underground transformers and add new primary cable. The work will be completed during the replacement of the water and sewer systems in this area. Northland will work closely with the Town's contractor and engineering group to coordinate and complete this install.

Project Schedule

2015 - $713,000

Business Drivers and Benefits

The business drivers and benefits of the McBryan Drive Upgrade are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers, including minimizing unplanned outages.
- By completing the install in conjunction with the Town's work, Northland will not be required to dig up and replace roadways, pavement, sidewalks and/or customer driveways, as the work will align with the water and sewer replacement.

- Planning and scheduling the replacement allows Northland to reduce the number of outages that occur in unfavourable conditions and ensure that it has materials and equipment available to complete the work.

- Aligning with the water and sewer system replacement results in cost savings and minimizes disruption to customers in the area.

Evaluation of Viable Alternatives

Alternative 1 - Do nothing. This impacts the reliability of the system as the cables have reached end of life. This alternative presents the greatest disruption to customers in the near future (i.e., digging up roads again if work is not aligned with the water and sewer replacement) and forgoes any savings from aligning work with the Town.

Alternative 2 - Replace underground cables and upgrade to current standards as part of a planned project. This alternative ensures the reliability of the system based on known issues and the age of the infrastructure to prevent future outages, and allows Northland to complete the work most efficiently. In addition, the new line will meet current standards allowing for future load growth in that area.

Recommendation

Replace underground cables and upgrade to current standards.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Hay River Underground Cable Replacement

Business Case #02

Northland Utilities
A NU and ATCO Company

Executive Summary

Replace a section of underground power cable on Riverview Drive that has reached end of life, and where repeated failures have occurred.

Background

In this area, other cables have previously failed and have had to be replaced under undesirable circumstances, such as unplanned outages in winter. Due to the congested nature of the area, and other underground facilities, extensive hydrovac truck use is required to expose cables for replacement. The first portion of the section has already been replaced due to a fault, and this section was identified as the next priority due to the age and install date of the cables. This section of cable is part of Northland's underground loop that serves the schools, sewer lift station and downtown core.

Project Description

Replace a section of underground power cable.

Project Schedule

2017 - $178,383

Business Drivers and Benefits

The business drivers and benefits of the Hay River Underground Cable Replacement are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers, including minimizing unplanned outages.
- Portions of the cable have already failed and caused outages, indicating a need to replace cables in this area.

- Planning and scheduling the replacement allows Northland to prevent outages in unfavourable conditions and ensure that it has materials and equipment available to complete the work.

Evaluation of Viable Alternatives

Alternative 1 - Do nothing. This impacts the reliability of the system with failures occurring at any time and restoration being impacted based on conditions at the time of failure.

Alternative 2 - Replace underground cables as part of a planned project. This alternative ensures the reliability of the system based on a known issue and the age of the infrastructure to prevent future outages, and allows Northland to complete the work under ideal conditions. To ensure safety, availability of hydrovac truck and operator is key due to other underground infrastructure in the area.

Recommendation

Replace the underground cable.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Hay River Pole Replacement

Business Case #03

Northland Utilities
A NU and ATCO Company

Executive Summary

Replace poles in the community of Hay River as identified through pole testing, overhead line patrols, and damaged poles reported by third parties.

Background

In 2017, poles were replaced in the community of Hay River. Poles replaced were either determined to be end of life or had been damaged.

Project Description

Replace distribution poles.

Project Schedule

2017 - $119,092

Business Drivers and Benefits

The business drivers and benefits of the Hay River Pole Replacement are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers; and
- Replacing the poles that are at the end of their life or that have been damaged is essential to supplying power and avoiding unplanned outages due to structure failures.

Evaluation of Viable Alternatives

Alternative 1 - Do nothing. This alternative presents a safety risk to the public and causes unplanned power interruptions as poles failing increases due to the condition of the poles.

Alternative 2 - Replace poles identified as end of life or damaged. Ensure the safety and reliability of Northland's grid through required replacements.

Recommendation

Replace poles identified as needed for replacement.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Portable Emergency Generator

Business Case #04

Northland Utilities
A NU and ATCO Company

Executive Summary

Purchase an emergency portable generator – Volvo TAD753GE 200 kW – to enable the restoration of communities served by Northland when an emergency outage arises at its isolated generation sites or radial distribution systems.

Background

The existing communities Northland serves can have longer timelines for restoration due to their isolation, distance from service points, and lack of available material for major repairs. The emergency portable generator is sized to serve Sambaa K'e, Wekweeti, Dory Point and part of Fort Providence. It is a self-contained unit with a fuel system, cooling, and switch gear. The portable unit is physically sized to fit into an aircraft for transfer to those communities.

Project Description

Purchase a Volvo TAD753GE 200 kW unit for emergency restoration.

Project Schedule

2017 - $113,399

Business Drivers and Benefits

The business drivers and benefits of Portable Emergency Generator are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers, including in the event of emergencies beyond its control.
- Enable restoration or partial restoration at plant sites or areas throughout the system where major restoration is required after an outage.
- Unit can be transferred to either community and/or left onsite for extended periods of time, if required.

Evaluation of Viable Alternatives

Alternative 1 - Continue operating as is. In the event of an outage, power will be off for extended periods with few or no options to re-energize.

Alternative 2 - Purchase emergency generator. Based on the communities served, outages may occur such that generation is required. The emergency generator may also be required during cold weather to perform unplanned maintenance.

Recommendation

Purchase Emergency Generation unit.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

6L10 Pole Replacement

Business Case #05

Northland Utilities
A NI and ATCO Company

Executive Summary

Several poles were identified for replacement following the 2021 Pole Test and Treat work on the Transmission Line 6L10 between the Pine Point Substation and Hay River Substation.

Background

After identifying poles that require replacement (due to end of life or damage), Northland will replace the poles on the 6L10 transmission line between Hay River and Pine Point in 2023.

Project Description

Replace poles on the 6L10 transmission line and impacted structures. Given the extent of the pole replacements required, the target for completion of this work is during the extended Taltson outage in 2023.

Project Schedule

2023 - $275,000

Business Drivers and Benefits

The business drivers and benefits of the 6L10 Pole Replacement are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers, including reliable transmission of electricity from the Taltson Hydro Electric System to customers in Hay River, K'atl'odeeche First Nation, and Enterprise.
- Limit the unplanned outages through regular capital maintenance to continue to operate the system without unknown structure failures.

Evaluation of Viable Alternatives

Alternative 1 - Do Nothing. This alternative presents a safety risk to the public and causes unplanned power interruptions as poles failing increases due to the condition of the poles.

The poles are also adjacent to the highway posing a safety risk to others.

Alternative 2 - Replace poles and complete structure repairs as identified in the 2021 Test and Treat Report. Ensure the safety and reliability of Northland's grid through required replacements.

Recommendation

Replace poles identified for replacement on 6L10, during the 2023 extended hydro shutdown.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Hay River CUL 197 Overhaul

Business Case #06

Northland Utilities
A NI and ATCO Company

Executive Summary

Major overhaul is required on unit CUL-197 in accordance with the manufacturer's recommended maintenance schedule. CUL-197 is a 1997 CAT 3512 800 kW unit and is required to supply electricity to the Town of Hay River and surrounding Hydro communities. It is essential that CUL-197 runs reliably and is available, when required, to provide uninterrupted electrical supply in the Town of Hay River and surrounding Hydro communities.

Background

CUL-197 was installed in 1997 and is used in combination with other units within the Hay River power plant to provide backup power to the Town of Hay River and surrounding communities when the NTPC hydro supply is not available.

Project Description

Engine components need to be replaced per the Original Equipment Manufacturer (OEM) maintenance schedule recommendations. During regular inspection of CUL-197, rainwater was found to have entered the engine through the exhaust system. An inspection of the unit was required to assess possible damage. The disassembly and inspection of the unit, as well as repairs required, were similar in nature to the upcoming scheduled major overhaul. To avoid duplicative work and expense, the major overhaul was required. Considering NTPC had a major 7-month shutdown scheduled for 2023, it is imperative to have all units available at the Hay River Power Plant.

Project Schedule

2021 - $219,631

Business Drivers and Benefits

The business drivers and benefits of the Hay River CUL 197 Overhaul are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers, which includes regular maintenance of its back-up generation systems.
- The overhaul of CUL-197 will ensure reliable and safe delivery of electricity to the customers of Hay River and surrounding areas when needed.
- Failure to complete the overhaul of unit CUL -197 could result in engine failure and the potential inability to meet the electrical requirements of the community.
- The overhaul will also reduce compounding damage that can affect other components of the engine.

Evaluation of Viable Alternatives

Alternative 1 - Do nothing and continue to run CUL-197 as is. This alternative is not practical or responsible as failing to replace and maintain components of the engine could result in failure of the engine and cause a disruption in service for the customers in Hay River and surrounding communities.

Alternative 2 - Replace the entire CUL-197 engine with a new engine. This alternative would be costly as the entire engine would be replaced rather than just certain components. This would also have the potential to impact and call for replacement of other systems within the plant (e.g. electric components).

Alternative 3 - Complete the overhaul of CUL-197 as per the manufacturer's recommendation. The overhaul will allow Northland's staff to complete an internal inspection of the engine while completing the overhaul of certain components. An overhaul of the existing engine ensures that other systems within the plant do not require upgrading of changing.

Recommendation

Complete the overhaul of CUL-197.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Fort Providence CUL 570 Overhaul

Business Case #07

Northland Utilities
A NI and ATCO Company

Executive Summary

CUL-570 required a top end overhaul due to coolant in the oil system. In addition, an overhaul was performed in accordance with the manufacturer's scheduled maintenance service.

Background

CUL-570 is a Cummins QSK23 725 kW unit and is required to supply electricity to the community of Fort Providence. It is essential that operation of CUL-570 is reliable and efficient, ensuring it can supply uninterrupted electrical supply in the community of Fort Providence. CUL-570 was installed in 2015 and is the largest of the four units that power Fort Providence.

Project Description

CUL-570 was showing signs of internal engine failure. Upon inspection by Northland, it was found that CUL-570 had coolant in the oil system. The unit was removed from service and shipped for further inspection and repair. A top end overhaul was required to repair the coolant in the oil system. While at the repair shop and disassembled, it was also identified that the unit would soon be due for a scheduled maintenance overhaul. Therefore, to avoid the duplicative expense of Northland receiving the repaired unit, and then sending it back again for the manufacturer's recommended engine overhaul, the engine overhaul was completed slightly ahead of schedule concurrent with the top end overhaul to repair coolant in the oil system.

Project Schedule

2017 - $213,589

Business Drivers and Benefits

The business drivers and benefits of the Fort Providence CUL-570 Overhaul are as follows:

- Northland has an obligation to provide safe, reliable supply of electricity, which includes maintenance of its back-up generation systems.
- The overhaul of CUL-570 will ensure reliable and safe delivery of electricity to the customers of Fort Providence.
- Failure to complete the overhaul of unit CUL-570 could result in engine failure and the potential inability to meet the electrical requirements of the community.
- The overhaul will also reduce compounding damage that can affect other components of the engine.

Evaluation of Viable Alternatives

Alternative 1 - Do nothing and continue to run CUL-570 as is. This alternative is not practical or responsible as failing to replace and maintain components of the engine could result in failure of the engine and cause a disruption in service for the customers in Fort Providence.

Alternative 2 - Replace the entire CUL-570 engine with a new engine. This alternative would be costly as the entire engine would be replaced rather than just certain components. This would also have the potential to impact and call for replacement of other systems within the plant (e.g., electric components).

Alternative 3 - Complete the major overhaul of CUL-570 as per the manufacturer's recommendation. The overhaul will allow Northland's staff to complete an internal inspection of the engine while completing the overhaul of certain components. An overhaul of the existing engine ensures that other systems within the plant do not require upgrading of changing.

Recommendation

Proceed with completing the overhaul of CUL-570.



Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

2021 Pole Test and Treat

Business Case #08

Northland Utilities
A NU and ATCO Company

Executive Summary

Pole testing and treating is completed on a 9-year cycle throughout the system to assess the health and treat the poles to extend their lifecycle. The poles on Transmission Line 6L10 required testing and were originally scheduled to be tested and treated in 2020 and 2021, with half the poles on the line tested and treated in each year. However, due to the pandemic, no poles were tested or treated in 2020. As a result, all poles on 6L10 were tested and treated in 2021 to make up for the lost year due to the pandemic.

Background

Pole Test and Treat involves qualified professionals assessing and treating poles across Northland's system to protect them from decay and to extend their useful life. Test and treat were not performed in 2020 because of COVID-19 and the resulting border restrictions that were put in place. Therefore, the work was completed in 2021 for work that was previously scheduled to take place in 2020 and 2021.

Project Description

Pole Test and Treat Program for Transmission Line 6L10.

Project Schedule

2021 - $173,840

Business Drivers and Benefits

The business drivers and benefits of the Pole Test and Treat Program follow:

- Northland has an obligation to provide safe and reliable electricity service to customers.
- Testing and treating poles assist in ensuring a reliable transmission connection to the Hydroelectric system and reduces unplanned outages due to structure failures.

- Testing and treating identifies poles in need of replacement while simultaneously treating other poles to extend their useful life.

- Testing and treating is performed on a 9-year cycle to ensure the entire system is reviewed on a regular basis, and poles can be replaced as identified to prevent structure failures and unplanned outages. This work is undertaken in conjunction with overhead line patrols that ensure the safety and reliability of Northland's system.

Evaluation of Viable Alternatives

Alternative 1 - Complete test and treat on only half of the poles on the Transmission Line. This alternative limits the full understanding of the scope required to address any issues with poles on Transmission Line 6L10.

Alternative 2 – Catch-up for 2020 and complete the testing and treatment for the full Transmission Line in 2021. This alternative defines the full scope of work to be completed on the 6L10 Transmission Line with sufficient time to plan for this work to be completed during NTPC's extended Taltson Plant shutdown.

Recommendation

Complete full testing and treating for the entirety of the 6L10 Transmission Line in 2021.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

ATCO CIS Replacement

Business Case #9

Northland Utilities
A NU and ATCO Company

Executive Summary

Lifecycle replacement of ATCO CIS with Oracle Customer Cloud Service solution (CSS) to mitigate risks associated with the current (end-of-life) system and to provide Northland with the right tools to perform customer care and billing (CC&B) in an accurate, reliable and efficient manner.

Background

ATCO CIS was built in the early 1990s and is an end-of-life asset. As a result, it is increasingly costly and difficult to maintain the underlying COBOL programming language as well as add functionality. In particular, the internal resources that understand the highly customized nature of ATCO CIS are beginning to retire, and the number of skilled COBOL programmers in the marketplace is decreasing. The combination of these effects contributes to the increasing costs to maintain and support ATCO CIS.

Furthermore, the cyber security risks increase with continued use of an antiquated system compared to modern software applications that are designed to minimize the ever-increasing risk of malicious attackers taking advantage of application vulnerabilities. Given that ATCO CIS enables critical business functions fundamental to Northland's regulated, integrated electric distribution business, the risk of not replacing ATCO CIS was too great.

In addition, Northland and its systems must be flexible, supportive, and responsive to increasing demands of electrification, including renewable technologies such as solar panels, as well as increasing the complexity of the billing systems. The replacement of the legacy ATCO CIS will allow Northland to continue to meet its billing requirements and ensure needs can be met into the future.

Project Description

The ATCO CIS system was built in the early 1990s and is used by the ATCO utilities, including Northland. Due to the age and highly customized functionality of ATCO CIS,

and consistent with the conclusion of a third-party report, it was determined that ATCO CIS posed too great of a business risk and should be replaced.[1] As a result, Northland conducted a procurement process to compare Oracle CCS against Tier 3 niche products available in the marketplace for fully integrated utilities that serve less than 100,000 customers. The evaluation confirmed Oracle CCS as the best alternative.

In addition to achieving the lowest cost option for customers, the goals of the project were: to maximize out-of-the-box functionality and minimize customization to facilitate lifecycle management, minimize future operating costs and risk, maintain a high level of customer care and billing service, support regulatory requirements, and reduce technology risk. Northland will, as required, utilize the specialist(s) within ATCO to support Oracle CCS and related functions, including vendor support and CCS updates.[2]

Resources Required

In general, resources will be staffed through a combination of internal ATCO business employees and contractors (i.e., direct labour). Northland also leveraged the expertise of TMG Consulting during the procurement process.

Project Schedule

2023 - $1,062,179

Business Drivers and Benefits

The business drivers and benefits of the ATCO CIS Replacement are as follows:

- ATCO CIS is a critical system relied upon to manage all aspects of the meter to cash cycle. Without a working and capable CIS, Northland would be unable to

[1] In Decision 26616-D01-2022, the Alberta Utilities Commission (AUC) approved CIS Replacement for the ATCO Distribution Utilities, paras 254, 261-262
[2] A Tier 3 niche solution would have required additional resources to support the billing Application unique to Northland.

Northland Utilities
A APUI and ATCO Company

accept new customers, manage customer moves, calculate usage and charges, bill customers or collect and manage revenue.

- Sudden or unexpected outages could have negative impacts on Northland's ability to maintain acceptable levels of CC&B and meet its obligation to serve.
- Existing CIS is end-of-life.
- Cybersecurity threats – modern software applications are designed to minimize the ability of attackers to take advantage of application vulnerabilities.
- Availability of resources – the number of skilled COBOL programmers in the marketplace is decreasing, creating a significant and growing skills gap. The number of experienced and qualified internal resources continues to decline as ATCO CIS ages.
- Ongoing internal support of existing CIS is disappearing as parent company no longer supports.
- The electricity industry is currently undergoing a transformation, including electrification (electric vehicles and Distributed Energy Resources), two-way communication between utilities and customers, and the better enablement of price signals through rate design such as time of use (TOU) rates.
- Oracle CCS was selected because of the high degree of functional fit with business requirements, technical compatibility and integration because Northland already utilizes Oracle Enterprise Resource Planning software.
- Finally, Oracle CCS is a subscription-based service. The latter helps maintain protection from cybersecurity threats.

Evaluation of Viable Alternatives

Alternative 1 – Status quo. NUL continues to operate ATCO CIS. This option is neither acceptable nor feasible given the business drivers identified above. The ATCO CIS system is end of life and requires replacement. In addition, no other ATCO utility will be using ATCO CIS beyond 2023.

Alternative 2 – Replace ATCO CIS with Oracle CCS. This option reduces the risk of a critical system failing and reduces cyber security threats. This option is the lowest cost alternative to customers, as Northlands will utilize the expertise gained from ATCO Utilities for both implementation and to perform CC&B services.

Alternative 3 – Replace ATCO CIS with Tier 3 COTS solution. This option reduces the risk of a critical system failing and reduces cyber security threats. However, this option is more costly as it requires specialized implementation resources and training to use the system (e.g. interface training, upgrades and maintenance).

Recommendation

ATCO CIS is end-of-life and requires replacement. Northland recommends proceeding with the replacement of ATCO CIS with Oracle CCS, as detailed in the sections above. The business risk associated with continued use of ATCO CIS is unacceptable. Replacing ATCO CIS with Oracle CCS is beneficial to Northland and its customers.



Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Sambaa K'e CUL 411 Replacement

Business Case #10

Northland Utilities
A NU and ATCO Company

Executive Summary

Replace CUL-411 engine with a 150 kW Volvo TWD733GE unit, in accordance with manufacturer's hours limit specifications. This unit is part of Northland's Sambaa K'e Power Plant that provides power to the community of Sambaa K'e.

Background

The existing engine CUL-411 was installed in 1996 and is a 150 kW Volvo TWD710G. Due to the age of the existing unit, there is no longer a reliable supply of parts and materials to service the engine. A new Volvo unit was purchased to replace CUL 411.

Project Description

Purchase and install the new 150 kW Volvo TWD 733 GE.

Project Schedule

2020 - $172,411

Business Drivers and Benefits

The business drivers and benefits of the Sambaa K'e CUL 411 Replacement are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers.
- Failure of this unit would hinder Northland's ability to supply power to the community of Sambaa K'e.
- Failure to replace the engine of CUL-411 could result in the unit's failure and the possible inability to meet the electrical requirements of the community.

Evaluation of Viable Alternatives

Alternative 1 – Do nothing and continue to run CUL-411 as is. This alternative is not practical or responsible as failing to replace and maintain components of the engine could result in failure of the engine and cause a disruption in service for the customers

Alternative 2 – Replace CUL-411 with a similar engine. As parts have become scarce and, in most cases, not available, replacement with a similar engine is most prudent and reduce the risk of unplanned outages. In addition, due to the location, a planned replacement ensures access to the remote community is planned and the unit is brought in on the available winter road and replaced during planned outages.

Alternative 3 – Undertake major overhaul on CUL-411. Materials have stopped being made available or produced by the manufacturer. Additional complications could result from the remote nature if parts end up not being compatible or not available during an emergency repair situation.

Recommendation

Proceed with the replacement of CUL-411 with a similar engine.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Sambaa K'e Plant Move

Business Case #11

Northland Utilities
A NU and ATCO Company

Executive Summary

Northland is proposing to relocate the existing powerplant to the outskirts of the town, driven by the expansion of the town near the facility and proximity of diesel storage to nearby lakes. The plant was installed in its current location in 1987, and the town has since grown around it, and it is now adjacent to the school and store. Relocating the plant also aligns with a request from the Community of Sambaa K'e to move it further away from the town.

The new location will be further away from the Town and nearby lakes. The project involves acquiring property, civil works construction (for fencing, grounding, etc.), oil storage support for the new site, moving the power plant, and reclamation of the current site.

Background

When the plant was first commissioned in 1987, the nearest building was a nearby maintenance shop which used the waste heat from the plant. In the years since the plant was installed, a school and store have been built adjacent to the plant. The existing powerplant is located 37 meters away from the elementary school's playground and roughly 50 meters away from the closest store. Please refer to Figure 1 below, which shows the proximity of the school and local businesses. In turn, noise and exhaust from the plant disrupt the surrounding community, which has ultimately led to a request from the community to relocate the plant.

Northland Utilities
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Figure 1 - Layout of Town Around Power Plant



This project involves consultation and agreement on a new site, construction of the new site, relocating the plant and reconnecting it to the grid, and reclaiming the existing site.

Project Description

Relocating the existing Diesel Power Plant feeding the community of Sambaa K'e. The project involves acquiring property, civil works for site prep, running temporary power from a standby plant, relocating the power plant, reconnecting the plant to the grid, testing, and reclaiming the current site.

Project Schedule

2024 - $1,232,570

Northland Utilities
A NU and ATCO Company

Business Drivers and Benefits

The main driver for this Project is the proximity of the Town to the existing powerplant location, due to the Town's growth. These new community centres are now exposed to noise, exhaust, and an operating generation plant. In addition, moving the plant eliminates the need for diesel storage in close proximity to water bodies and drainage ditches. Northland notes that while measures are being taken to reduce any environmental issues, as experienced in 2008, environmental concerns of the community persist due to the current location and have increased due to the proximity of the school and storefronts.

The benefit of this Project is that a new location would result in noise and exhaust reduction within the community and reduced environmental exposure. The move also aligns with the community's desire to relocate the power plant further away from Town. Northland is seeking a location at least 500 m away from Town.

Evaluation of Viable Alternatives

Alternative 1 – Keep the power plant in the same location. This alternative would continue to provide reliable service but does not address the continued noise and emissions from the plant in close proximity to the community centre, environmental concerns, and is not aligned with the community's request.

Alternative 2 - Relocate the plant to a new site away from the community centre. This is preferred by the customers and the community due to the environmental and societal benefits described above.

Alternative 3 – Decommission the existing plant and build a new power plant. A new power plant is expected to cost several million dollars and is not expected to be economically viable with the small customer base currently served by the power plant.

Recommendation

Proceed with relocating the plant (Alternative 2) and continue to work with the community to minimize disruption of the existing plant in the interim.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Pine Point Transmission Transformer Replacement

Business Case #12

Northland Utilities
A NI and ATCO Company

Executive Summary

The existing transformer at Pine Point Substation has reached end of life and is having issues with leaking that need to be addressed. Given the age of the transformer and the limited availability of replacement parts, it is recommended that the transformer be replaced instead of repaired.

Background

The transformer at the Pine Point Substation was originally built in 1968 and was leaking, which needed to be addressed. The transformer is a critical piece of infrastructure on the path to all downstream hydro communities in the Taltson Zone.

In 2016, Northland attempted a limited-impact repair to address the transformer leak, but it was not successful. To repair the existing transformer, radiators need to be removed and the oil needs to be reconditioned. The existing transformer has already exceeded the expected life span (typically, transformers of this style have a 40-year life span). Therefore, replacing the transformer is preferable to attempting to repair it again.

Project Description

Replacement of the Pine Point Substation transformer

Project Schedule

2024 – $1,885,000

Business Drivers and Benefits

The primary business drivers and benefits of the Pine Point Transmission Transformer are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers.

- Any failure of the transformer would constitute a major repair and would make the downstream communities rely on diesel generation. The resulting outage due to the loss of this transformer could be weeks in length (or longer).
- The existing transformer is at the end of its useful life.
- Replacing the transformer allows leaks to be addressed.

Evaluation of Viable Alternatives

Alternative 1 - Do nothing. As the asset is end of life, this will not address the impact on reliability, the increased use of back up diesel generation for any outage, and increased power costs based on fuel prices while the diesel generation is running, and the hydro power is not able to be distributed.

Alternative 2 - Remove the radiators to repair the leak and recondition the oil and clean up the released substances. The asset is end of life and does not address the risk of unplanned failure and outages. Previous attempts to fix the existing transformer were unsuccessful. Due to the unique characteristics of the transformer and remote location, costs to fully service, disassemble and reassemble the existing transformer would exceed costs to replace it.

Alternative 3 - Replace the existing transformer with a new transformer. This alternative allows Northland to plan and time the replacement with other work to minimize the need for diesel generation, as well as enhances the reliability of the substation to continue to provide power.

Recommendation

Replace the transformer with a new transformer.

Northland Utilities (NWT) Limited

2023 Amended General Rate Application (GRA)

Fort Providence CUL 570 Replacement

Business Case #13

Northland Utilities
A NI and ATCO Company

Executive Summary

Replace CUL-570 generation unit, which is a 725 kW unit that failed prior to the scheduled major overhaul in 2022, with a Cummins QSK23 725 kW unit.

Background

The existing engine CUL-570 failed prior to being removed and sent for a major overhaul. This unit is part of the plant that supports the community of Fort Providence for which all power is provided through diesel generation. The failure of the unit was caused by damage arising from valve contact with the piston, causing the valve to break off resulting in significant internal damage to the engine. CUL-570 has had a history of issues, despite keeping to manufactures maintenance schedules.

Project Description

The replacement for CUL-570 was installed in 2022.

Project Schedule

2022 - $150,000

Business Drivers and Benefits

The business drivers and benefits of the Fort Providence CUL 570 Replacement are as follows:

- Northland has an obligation to provide safe and reliable electricity service to customers.
- Failure of the current unit puts the safe and reliable supply of electricity to Fort Providence in jeopardy.

- Availability of a suitable replacement in a timely manner will ensure risk is limited in the event of other unexpected unit failures within the plant, and prior to the winter months when demand will be greater.

Evaluation of Viable Alternatives

Alternative 1 – Repair CUL-570 engine. This alternative is a higher cost option compared to replacement of the unit due to the major damaged discovered. The timeline to repair could further escalate and put the supply of electricity to Fort Providence at risk.

Alternative 2 – Replace CUL-570 with a similar engine. A new engine was less costly than a repair due to the major damage discovered. In addition, the manufacturer had a replacement engine available which could be installed to achieve stabilization of the plant on a predictable schedule and will ensure the reliable supply of electricity to the community.

Recommendation

Replace CUL-570 with a similar engine in 2022.

Canada Revenue Agency | Agence du revenu du Canada

Schedule 444
Code 2301
Protected B
when completed

Yukon Business Carbon Price Rebate (2023 and later tax years)

Corporation's name	Business number	Tax year-end Year / Month / Day

- You can claim the Yukon business carbon price rebate (which includes the general business carbon price rebate and the mining business carbon price rebate) under section 16 of the Yukon Income Tax Act, if **both** of the following conditions apply:
  - You are an eligible Yukon business taxpayer or an eligible Yukon mining business taxpayer
  - You used an eligible Yukon asset or an eligible Yukon mining asset in the tax year, principally in carrying on an eligible Yukon business or an eligible Yukon mining business
- The Yukon business carbon price rebate applies to an eligible Yukon business taxpayer and, for tax years ending after 2022, to an eligible Yukon mining business taxpayer.
- The Yukon mining business carbon price rebate is a refundable tax credit equal to the amount of the mining business rebate factor for the financial year in which the tax year ends multiplied by the eligible Yukon mining undepreciated capital cost (UCC) to the taxpayer as of the end of the tax year.
- The Yukon general business carbon price rebate is a refundable tax credit equal to the amount of the general business rebate factor for the financial year in which the tax year ends multiplied by the amount of the eligible Yukon UCC to the taxpayer as of the end of the tax year that exceeds the amount of the eligible Yukon mining UCC, if any, if you are an eligible Yukon mining business taxpayer.
- The terms **eligible Yukon business taxpayer**, **eligible Yukon mining business taxpayer**, **eligible Yukon asset**, **eligible Yukon mining asset**, **eligible Yukon UCC**, **eligible Yukon mining UCC**, **eligible Yukon business**, **eligible Yukon mining business**, and **cross-border transport equipment** are defined in subsection 16(1) of the Yukon Income Tax Act.
- To claim the Yukon business carbon price rebate, file a completed copy of this schedule with your T2 Corporation Income Tax Return.

Part 1 – Eligible Yukon mining UCC for eligible Yukon mining assets

Are you an eligible Yukon mining business taxpayer? . . . . . ☐ Yes ☐ No

If **yes**, complete Part 1.

If **no**, go to Part 4.

1 Class number of eligible Yukon mining asset [1]	2 Prescribed inclusion rate [2]	3 Prescribed fraction [3]	4 UCC at the end of the year (enter amount from line 220 of Schedule 8, Capital Cost Allowance, that relates to the eligible Yukon mining asset)	5 Capital cost allowance (enter amount from line 217 of Schedule 8, Capital Cost Allowance, that relates to the eligible Yukon mining asset)	6 Column 4 **plus** column 5	7 Eligible Yukon UCC at the end of the year for eligible Yukon mining assets (column 2 **multiplied** by column 3 **multiplied** by column 6)

Total _____ A

Eligible Yukon mining UCC

Amount A _____ × Prescribed mining adjustment factor [4] _____ = ... _____ B

Part 2 – Eligible Yukon mining UCC allocated from partnerships

Eligible Yukon mining UCC allocated from partnerships [5] . . . . . _____ C

Part 3 – Yukon mining business carbon price rebate

Total eligible Yukon mining UCC (amount B **plus** amount C) . . . . . _____ D

Yukon mining business carbon price rebate [6]

Amount D _____ × Mining business rebate factor [7] _____ = ... _____ E

Enter amount E on line 696 of Schedule 5, Tax Calculation Supplementary – Corporations.

Canada

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when completed

Part 4 – Eligible Yukon UCC for eligible Yukon assets

Include eligible Yukon mining assets (other than classes 41 and 41.2) in this part.

1 Class number of eligible Yukon asset [8] 200	2 Prescribed inclusion rate [9] 205	3 Prescribed fraction [3] 208	4 UCC at the end of the year (enter amount from line 220 of Schedule 8, Capital Cost Allowance, that relates to the eligible Yukon asset) 210	5 Capital cost allowance (enter amount from line 217 of Schedule 8, Capital Cost Allowance, that relates to the eligible Yukon asset) 215	6 Column 4 **plus** column 5	7 Eligible Yukon UCC at the end of the year (column 2 **multiplied** by column 3 **multiplied** by column 6) 220
					Total	F

Part 5 – Eligible Yukon UCC allocated from partnerships

Eligible Yukon UCC allocated from partnerships [10] . . . . . 320 _____

Part 6 – Yukon general business carbon price rebate

Total eligible Yukon UCC (amount F **plus** line 320) . . . . . _____ G

Total eligible Yukon mining UCC [11] . . . . . _____ H

Net eligible Yukon UCC (amount G **minus** amount H, if negative enter "0") . . . . . _____ I

Yukon general business carbon price rebate [6]

Amount I _____ × General business rebate factor [12] 500 _____ = ... _____ J

Enter amount J on line 699 of Schedule 5, Tax Calculation Supplementary – Corporations.

Notes

[1] The following classes are prescribed for the purposes of the definition **eligible Yukon mining asset**:

(a) Classes 1, 3, 10, 10.1, 13, 16, 22, 28, 29, 38, 39, 40, 41, 41.2, 43, and 53

(b) Classes 43.1, 43.2, 54, 55, and 56

The classes prescribed for the purposes of the definition **eligible Yukon mining asset** are subject to change.

Where the list of classes provided here differs from that provided in the Carbon Price Rebate General Regulation, the latter takes precedence.

[2] The inclusion rates for prescribed classes of eligible Yukon mining assets are:

(a) Classes 1, 3, 10, 10.1, 13, 16, 22, 28, 29, 38, 39, 40, 41, 41.2, 43, and 53: 100%

(b) Classes 43.1, 43.2, 54, 55, and 56: 500% **multiplied by** the general business rebate factor for the financial year in which the tax year ends **divided by** the mining business rebate factor for that financial year.

[3] If you don't use cross-border transport equipment, enter "1".

If you use cross-border transport equipment principally to transport passengers or goods from Yukon to outside Yukon, or you make an election under subsection 16(11) of the Yukon Income Tax Act, enter the prescribed fraction.

The prescribed fraction equals the net fuel quantity you used in Yukon for operating the cross-border transport equipment for the tax year, divided by the net fuel quantity you used worldwide (including in Yukon) in operating that equipment.

Enter a decimal number less than or equal to 1 with a maximum of two decimal places to express this fraction.

[4] If you carry on a specified placer mining business in the tax year and do not carry on a specified quartz mining business in the tax year, enter "4". If you carry on a specified quartz mining business in the tax year, enter "1".

[5] If you are a member of a partnership that is an eligible Yukon mining business partnership, the eligible Yukon mining UCC at the end of the year from the partnership is equal to your specified proportion of the eligible Yukon mining UCC to the partnership at the end of the partnership's fiscal period.

Enter the total of all eligible Yukon mining UCCs provided by the partnerships of which you are a member.

[6] If the tax year is shorter than 12 months, prorate the Yukon mining business carbon price rebate or the Yukon general business carbon price rebate by the number of days in the tax year divided by 365.

[7] Use the mining business rebate factor for the Yukon financial year in which the tax year ends.

The mining business rebate factor is equal to:

- $5.27 for each $1,000 of eligible Yukon mining UCC if your tax year ends between January 1, 2023 and March 31, 2023 (enter 0.00527)
- $21.08 for each $1,000 of eligible Yukon mining UCC if your tax year ends after March 31, 2023 (enter 0.02108)

[8] The following classes are prescribed for the purposes of the definition **eligible Yukon asset**:

(a) Classes 1 and 3

(b) Classes 10, 10.1, 13, 16, 22, 28, 29, 38, 39, 40, 43 and 53

(c) Classes 43.1, 43.2, 54, 55 and 56

The classes prescribed for the purposes of the definition **eligible Yukon asset** are subject to change.

Where the list of classes provided here differs from that provided in the Carbon Price Rebate General Regulation, the latter takes precedence.

[9] The inclusion rates for prescribed classes of eligible Yukon assets are:

(a) Classes 1 and 3: 50%

(b) Classes 10, 10.1, 13, 16, 22, 28, 29, 38, 39, 40, 43 and 53: 250%

(c) Classes 43.1, 43.2, 54, 55 and 56: 500%

[10] If you are a member of a partnership that is an eligible Yukon business partnership, the eligible Yukon UCC at the end of the year from the partnership is equal to your specified proportion of the eligible Yukon UCC to the partnership at the end of the partnership's fiscal period.

Enter the total of all eligible Yukon UCCs provided by the partnerships of which you are a member.

[11] If you are an eligible Yukon mining business taxpayer, enter amount D. Otherwise, enter "0".

[12] Use the general business rebate factor for the Yukon financial year in which the tax year ends.

The general business rebate factor is equal to:

- $39.62 for each $1,000 of eligible Yukon UCC if your tax year ends before April 1, 2023 (enter 0.03962 at line 500)
- $21.89 for each $1,000 of eligible Yukon UCC if your tax year ends after March 31, 2023 (enter 0.02189 at line 500)

YUKON UTILITIES BOARD

YUKON ELECTRIC COMPANY LIMITED 2016-2017 GENERAL RATE APPLICATION

P R O C E E D I N G S

Volume 3

November 3, 2016

Whitehorse, Yukon

Proceedings taken at the Coast High Country Inn, at 4051-4th Avenue, Whitehorse, Yukon.

Volume 3

November 3, 2016

Mr. R. Laking	Chair
Mr. A. Fortin	Board Member
Ms. B. King	Board Member
Ms. M. Hannam	Board Member
Mr. P. Fitzgerald	Board Member
Ms. A. Sabo	Board Counsel
Ms. L. Mullen	Board Staff
Mr. B. Clarke	Board Staff
Mr. D. Ward	Board Staff
Ms. D. Lemke	Board Staff
Mr. B. Williams	For the Yukon Electric Company Limited
Mr. J. Epp	For the Yukon Energy Corporation
Mr. T. Marriott	For the City of Whitehorse
Mr. R. Rondeau	For the Utilities Consumers' Group
Ms. A. Middler	For the Yukon Conservation Society
Mr. J. Maissan	In his own stead
Ms. D. Harmata, CSR(A) Ms. A. Jones, CSR()	Official Court Reporters

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(PROCEEDINGS COMMENCED AT 8:34 A.M.)

THE CHAIR: Good morning, everyone. Thank you for being here.

We still have the YECL panel up. And I just remind everyone about cellphones again. I did mine.

And do we have any housekeeping matters this morning?

MR. WILLIAMS: Yes, sir.

T. MARTINO, J. GRATTAN, D. TENNEY, J. MASSIE

(For ATCO Electric Yukon General Panel), previously sworn

UNDERTAKING RESPONSES:

MR. WILLIAMS: We have three undertakings. Maybe I'll start the morning by saying I'm sure I'm not the only one thankful to be in the Pacific time zone this morning given last night's baseball game. 08:34

The first undertaking, sir, is Volume 2 of the transcript, page 226, lines 18 to 20. And that is an undertaking given by Mr. Martino to Mr. Rondeau.

THE CHAIR: So I think that will be Exhibit B-20; is that correct? Yes? B-20.

EXHIBIT B-20 - RESPONSE TO UNDERTAKING PROVIDED BY MR. MARTINO TO MR. RONDEAU IN VOLUME 2, PAGE 226, LINES 18 TO 20 08:35

THE CHAIR: All right.

MR. WILLIAMS: Thank you, sir.

The next is Transcript Volume 2, page 242, lines 6

to 11. And that is an undertaking given by Mr. Tenney to Mr. Rondeau.

THE CHAIR: That will be Exhibit B-21.

MR. WILLIAMS: Thank you.

EXHIBIT B-21 - RESPONSE TO UNDERTAKING PROVIDED BY MR. TENNEY TO MR. RONDEAU, VOLUME 2, PAGE 242, LINES 6 TO 11.

MR. WILLIAMS: And the final one I have for you this morning, which would be Number 9 on your list. So we're skipping Number 8 this morning. And that is Transcript Volume 2, page 385, lines 11 to 16. And that is an undertaking given by Mr. Tenney to Ms. Sabo, and I believe that would be 22. 08:36

THE CHAIR: Yes. That will be B-22.

EXHIBIT B-22 - RESPONSE TO UNDERTAKING PROVIDED BY MR. TENNEY TO MS. SABO, VOLUME 2, PAGE 385, LINES 11 TO 16

THE CHAIR: So what do we have left at this point? 08:36

MR. WILLIAMS: At this point, sir, I believe we have -- we're cleared off the board for Day 1. We have Number 8 on your list from yesterday outstanding.

THE CHAIR: All right.

MR. WILLIAMS: And I'm not sure that we're going to be able to get that to you today. So we may need to get that in after the proceeding closes for the day today.

And I also understand that one of the subject to checks provided yesterday will need a follow-up. So we'll have two follow-ups arising from yesterday that are unlikely to be delivered before the close of proceedings today.

THE CHAIR: Thank you. 08:37

So are we ready to proceed now?

Yes. All right. Ms. Sabo.

MS. SABO: Thank you, Mr. Chairman.

MS. SABO QUESTIONS THE PANEL:

Q. Yesterday we left off, panel, on FTEs, and I'd like to take you this morning to Exhibit B-9, which is the responses to the Board, 28(a) and 28 (b), which are on pdf page 268, hard copy page 101.

And these responses are in respect to ATCO Electric staff reductions as a result of the 08:38 restructuring. And we understand that ATCO Electric Yukon doesn't know the number of positions reduced.

But are you aware whether ATCO Electric Limited undertook a general reduction to all departments, or were there department-specific reductions?

A. MR. GRATTAN: So I can respond to that. So to answer your question, there were reductions within ATCO Electric across all aspects of the organization. And subsequent to the response to this interrogatory, I can advise that ATCO Electric -- I was able to determine that ATCO Electric decreased its labour complement by approximately 600 people last year.

Q. Okay. And, Mr. Grattan, I don't think we have a lot of information available on this record on the restructuring. Can you give us an idea why the ATCO Group undertook the reorganization? And I understand it's partly due to the economic downturn, but maybe you can help us out and give us some context. 08:39

A. MR. GRATTAN: So I would rephrase that slightly -- actually, significantly --

Q. Okay.

A. MR. GRATTAN: -- I would say in large part due to the economic downturn in Alberta. Alberta, as well as ATCO Electric, in the years leading up to 2015, was seeing tremendous growth, and that all came to an end as 2014 rolled around, and then into 2015 and continuing through to today. 08:40

So that is, by far, the largest driver as to what ATCO Electric is dealing with in Alberta.

Q. Okay. And similarly, what impact, if any, did the

ATCO Group reorganization have on ATCO Electric Yukon's workforce complement?

A. MR. TENNEY: It didn't have any impact on our -- ATCO Electric Yukon specifically.

Q. And why is that the case, Mr. Tenney?

A. MR. TENNEY: Well, we're obviously in a -- a standalone utility. We are in a separate geographical location. We also were instructed to review our workforce as it related to our -- what we needed to do to accomplish -- to continue to provide safe, reliable. 08:41
So we did also have a look at our staffing, and we didn't deem that we needed to change anything on a go-forward basis.

Q. Okay. So just to make sure I understand, is it fair to say that the ATCO Group reorganization was company-wide but specifically for ATCO Electric Yukon, the top-down direction was just to review it due to the specific needs of ATCO Electric Yukon?

A. MR. TENNEY: Right. I think that's what, I mean, ATCO Group, the way I understand it, was looking 08:42
at all aspects, and every group took a look at what their -- what it looked like in the coming years. And we were no different. We were instructed to do the same, as was in the Northwest Territories.

Q. Okay. Thank you. And now moving to IR 27(a) of that

same exhibit. In the response to Part (a), it states, in part, on pdf page 267: (as read)

"No across-the-board wage freezes were imposed in the 2014-'16 period. Employees received increases in 2014, and some employees received wage increases in '15 and '16."

And did all employees in 2014 receive wage increases?

A. MR. TENNEY: I don't have that at the tip of my fingers, but I would suggest that probably all employees received wage increases in 2014. 08:43

Q. Okay.

A. MR. TENNEY: It would have been subject to satisfactory performance reviews, but absent that, I would think everybody did in 2014.

Q. And for 2015 and 2016, for those staff that did not receive wage increases, were they all out-of-scope positions, or were some of those in-scope positions?

A. MR. TENNEY: In 2014 and 2015, as well as 2016, we -- the folks that are in-scope were covered by a collective bargaining, so they for sure received wage increases. 08:43

So in the updated response, where we talked about 15 percent did not receive wage increases in 2015, and 17 percent in 2017 that did not receive them would have

all been out-of-scope.

Q. Okay. And just for the record, that's --

A. MR. GRATTAN: Sorry.

Q. Sorry?

A. MR. TENNEY: Sorry, yeah, I said 2017. I was talking about '15 and '16. So in 2015, 15 percent did not receive wage increases. And in 2016, 17 percent did not.

Q. Thank you. Mr. Tenney, I was going to do that myself. Yeah, the exhibit that, where you're talking about the update, is the September 9th, 2016, response to that same IR 27(a), and that's Exhibit B-11. So thank you for that correction. 08:44

I would like to talk a little bit about labour inflation, and I'm going to take you to Board Order 2014-06, Appendix A, and page 24. And while you're finding that, there's a paragraph that reads: (as read)

"In the application, YECL submitted the labour inflation rate of 3.5 percent for 2013, '14, and '15, for both in- and out-of-scope labour. YECL stated that the 2013 and 2014 escalators were based on its collective agreement that expires on December 31st, 2014, and the 2015 08:45

escalations are based on its forecast of the increase required."

And then in the findings sections, the views of Board, it states at 5.3.2: (as read)

"The Board recognizes that YECL's labour inflation forecasts have been reviewed in this proceeding, and in light of the awards in other jurisdictions is confident that the labour inflation forecasts provided are reasonable for the test period." 08:46

And then they approved those labour inflation increases.

So given that ATCO Electric Yukon was awarded an inflationary increase for labour in 2015 and given that wages for out-of-scope labour did not increase as to the level forecasted in 2015, how have those considerations been factored into the proposed labour inflation increases for out-of-scope employees in '16 and '17?

A. MR. TENNEY: Sure. I think any time you prepare a forecast, you're using the best information you have at the time you prepare the forecast. And obviously as you move throughout that test period, certain line items are going to be greater than -- actuals are going to come in greater than forecast, and some are going to come in less than forecast. That's 08:47

just the nature of how it works.

So on a go-forward basis when we prepared our forecast, we were using the best information we had at the time, and that was what we came to on labour escalations.

And I think if we look back historically -- and Mr. Massie can probably jump in and help me with the exact percentages -- but I think overall when you look at what the Board approved in the 2013 to 2015 time period for O&M, I think our actual numbers came in 08:47
fairly close to those forecasts, and yet when you go to any particular line item, you can find where we were not on on forecast. But, in total, we were pretty close.

Q. And I think that was mentioned yesterday as well. Mr. Massie, anything to add?

A. MR. MASSIE: Yeah, I would say Mr. Tenney is referring to our overall O&M forecast. And, again, we -- as stated yesterday in our application page 52 -- we were within 1.1 percent of our $35 million forecast. 08:48

And, really, on those line items that we look at in there, there was, again, higher and lower values between the actuals and what was forecasted, but overall, the bottom number, I guess, is what we were discussing there of being fairly accurate.

Q. Okay. And, Mr. Massie, are you able to confirm the actual inflationary increases for in-scope employees from -- for each of the years from 2013 to '15? Do you have those numbers?

A. MR. TENNEY: Your question was for in-scope employees; correct?

Q. That's correct.

A. MR. MASSIE: I don't have those at my fingertips. They are subject to the collective agreement. I know our collect -- we had collective agreements for each of those years in place, including 2016 is the expiry of the current collective agreement.

Apparently, my colleague does have it. So...

So for '13, '14, and '15 for the three years for in-scope in our collective agreement were 3.5 percent increases in labour for each one of those years.

Q. Okay. Thank you. In responses to several Board IRs between 40 -- Numbers 40 and 45, ATCO Electric Yukon explained that parts of the reason for the variances in certain accounts, for example, production accounts, related to inflation and cost-of-living adjustment.

Can you explain the relationship between the cost-of-living adjustment and the increases in the inflation that affects those accounts?

It's between 40 and 45 of the IRs, Mr. Grattan.

08:49

08:50

A. MR. MASSIE: Sorry. I think we've got this figured out. So looking at the -- and we'll look at specifically YUB-40 in the tables there, because they're very similar for -- as you say, for 40 to 45.

Q. Thank you.

A. MR. MASSIE: The inflation number -- in that number, we do have our labour inflation for year to year. There will be general inflation. So the CPI on materials, and if we need any contractor help in those -- in those accounts, that will be caught in there. So materials, labour. 08:53

Anything else? Are caught in that inflation number.

In the COLA, I believe Mr. Grattan will speak to.

A. MR. GRATTAN: So all that -- that COLA relates to is the pension, the change in pension funding requirements between 2015 and 2016.

And as part of this application, ATCO Electric Yukon has requested that 100 percent of COLA be included in the forecast, subject to it being a placeholder to ultimately be determined by the Alberta Utilities Commission tied to a current pension application that is before the regulator down there. 08:53

So if you harken back to the last general rate application and ATCO Electric Yukon being before this

Board, there was a determination by this Board that COLA should be limited to 50 percent, included in revenue requirement, cost-of-living allowance.

So if is -- if the funding required by the actuarial parties said that ATCO Electric Yukon needed to fund pension dollar, and that dollar related to COLA, this Board made a determination that only 50 cents of that dollar should be included in the revenue requirement.

Q. Okay. Thank you, Mr. Grattan, and, Mr. Massie. 08:55

I think we were just a little confused by the language on there, whether the inflationary increase in COLA were having an impact -- a corresponding impact to each other. And I think I'm hearing that, no, they're separate components there.

A. MR. GRATTAN: Yes.

Q. Okay. Thank you.

I would like to take you to our final aid to cross, Aid to Cross 7, which is Schedule 5.1, O&M maintenance expenses. 08:55

Okay. And the aid to cross simply adds in the columns and the variances between the actual and the approved for the three years, '13, '14, and '15.

And I should note for the panel, Board staff has calculated the variance percentages from those variance

column numbers that are highlighted in grey on those -- those tables are blue if you're -- you've got an electronic copy. I'll be referring to variance percentages in these questions.

And I would appreciate -- I know the panel's going to have to take those subject to check. So if any of them are wrong, please let us know.

At a high level -- or maybe I should ask first: Is there any corrections to the variance amounts in this table? Have you looked at that, panel? 08:57

A. MR. GRATTAN: We haven't been advised by our financial folks that there's any concerns on it yet, but subject to check, it should be okay.

Q. Okay. Thank you. And I just would like some responses at a high level. I don't want to get too detailed in the numbers. We're looking at trends. But for the production section, starting at line 1, the largest variances pertain to hydrogeneration, which is Account 62600, and diesel maintenance, which is Account 84600 at lines 2 and 6 respectively. The 08:58 average variance over the three years in our calculation is about 36 percent for the hydrogeneration and about 15 percent favourable for the account for diesel maintenance.

And for these accounts there appears to be a trend

of underspending relative to the approved amount for each of these three years. So we would just like a high-level explanation on why that's the case.

A. MR. MASSIE: Okay. I'll -- I'll give the high-level overview of it.

So as we looked at -- the aid to cross, noticed the variances that you noted. Some of the things that we looked at that would cause that came to light. So we're really seeing a decrease -- one of the items is a decrease in labour, internal labour, as our folks really got focussed, again, on that intensive generation capital program that we had. 08:59

We -- quite frankly, we underestimated how much time and effort that they would need to be put into that capital program. So that offset part of those operating accounts.

With -- also in line with that generation capital program, we realized that -- and if we look at the test years of '13, '14, and '15, and I believe we put in seven new diesel generators, one new hydro unit. So that was another miss that I think we had with our forecasts, was understanding the -- how the new units would have less maintenance needed during that test period. 08:59

Brand new units obviously going into service would

be requiring less maintenance in that short term. And if I could turn you to UCG-44, Attachment 1, and you might be able to have a look at that and see it more clearly.

Q. I'm there, sir.

A. MR. MASSIE: Okay. So in this response, we were asked for our capital expenditures and O&M expenditures and -- in diesel, just diesel -- for this ten-year span. And if we just focus at that top line at capital expenditures and we look at, 09:01
specifically at 2012. So you'll notice the capital expenditures for those six years prior were significantly less than our program that started in 2012, '13, and '14, and '15. So the capital expenditures, as our program ramped up, and we had quite a bit of work to do, as seen there in those numbers.

And then you'll notice in -- a similar trend with O&M expenditures that were fairly flat for '11 and '12, and then that dip happened in '13, '14, and '15, 09:01
compared to those earlier years.

And, really, I think that just illustrates what I was explaining there, that our program, our capital program, was fairly intensive. So it off-loaded both our labour, as well as the maintenance on the actual

units. And I think that's one thing that we -- we missed in that forecast, just being that it's been some time since we had as intensive a capital program in generation.

But that being said, if we go back to the aid to cross and your hydrogeneration specifically on line 2, you know, we've realized that, and we've adjusted our forecast. You'll notice from the approved level in '15, a significant drop to '16 and moving forward.

So the forecast was -- there was a couple items missed, for sure, in the last go-around. We feel that we've adjusted for that going forward, though. 09:02

Q. Okay. And, Mr. Massie, looking at line 5, which is hydro maintenance costs, would that same rationale, too, apply -- those same reasons you just gave me apply to the -- why there's an increase of 25 percent from 2016 to 2017 forecasts?

MR. WILLIAMS: Sorry, if I could just -- before Mr. Massie answers that, I just want to be clear on the record that the aid to cross is the original Schedule 5.1, and there's an updated Schedule 5.1. 09:03

MS. SABO: So, yeah, the only addition to the aid to questioning is the grey portions.

MR. WILLIAMS: No, and that's why while we were just talking the actuals --

MS. SABO: Yeah.
MR. WILLIAMS: I don't see any problem, but if we're going to start talking about '16, '17, I'm fine to continue with the aid to cross, obviously, but I just want to be clear on the record that there is an updated Schedule 5.1.
MS. SABO: Yes. And certainly, yeah, if we need to refer to that updated schedule, we will. Thank you for that addition, Mr. Williams.
MR. WILLIAMS: Sorry for interrupting. 09:04
MS. SABO: No, that's -- thank you.
A. MR. MASSIE: So line 5 hydro maintenance, the increase in '17 will reflect the full year of the mechanical technologist being in place. That's in part of that, the labour increase for that position as that position is split between the hydro and diesel accounts.
Q. Okay.
A. MR. MASSIE: Also, in '17, we've factored in that we have an updated dam safety review that needs to be done for our Fish Lake project. So those are a requirement of our water license. And we have -- they get updated every year. So we have one in place, and every year we have a subject matter expert head out there, complete that review. 09:05

In 2017, it's -- we're having a third party subject matter expert basically to ensure that what he's being doing for us for the last 10 years is accurate. So, next year, the new person or contractor that we put in place to do that review will have to start with a blank piece of paper, whereas, when we get those done on a yearly basis, they're able -- our fellow is able to look at his notes from the year before at different changes for the Fish Lake system to it. So it's not as intensive as it will be in '17. 09:06

Q. Okay. Now turning to the distribution section of that table, starting at line 8. Account 8700 for supervision appears to have a consistent negative variance; that is, actuals exceed approved levels. So can you explain that, sir, what's going on there?

A. MR. MASSIE: That the actuals year over year are more than the approved levels?

Q. Yes.

A. MR. MASSIE: Is that the question?

Okay. I really think that would be a factor of being a full complement. The -- that account, 87000, the labour charges that get charged in there are preset. So there's no -- our PLTs, our technicians that work in the distribution that have labour accounts in there, they do time sheets on a regular basis to 09:06

whatever account that they're working on at the time.

The supervisors and management that have preset labour, they'll use those -- that account there in distribution to put it -- to put their labour too.

So it really should be -- the only fluctuations that would be in there is if we have fluctuations in our complement as it -- again, they're preset labour costs to those -- to that account.

Q. Okay. And taking that the next step, can you explain why supervision is expected to increase in 2016 over 2015 actual levels? 09:08

A. MR. MASSIE: I think that increase -- I see that increase is at 2.5 percent. That would be the increase from '15 to '16.

Q. I don't have the updated schedule in front of me, Mr. Massie. So, yeah, just -- I'm just generally...

A. MR. MASSIE: Okay. Yeah. That's what -- I have the column here beside the '15 to '16 increase. Yes. At 2.5 percent. So at 2.5 percent, I would assume that's the -- our general inflation numbers that we have in our -- that we've applied for. 09:08

Yeah. Without digging into it further, Ms. Sabo, that would be what I would think is in there for the 2.5 percent.

Q. Okay. Thank you.

At line 10 for Account 87100 for brushing costs, 2014 brushing costs were underspent, and your application stated that this is due to availability of resources.

So can you give me some detail on the issue with brushing in 2014?

A. MR. MASSIE: Sure. In our brushing account, we have, actually, fairly small labour dollars. We have just a person that will coordinate our brushing program. The vast majority of the costs are 09:09
contractors, brushing contractors that we -- we employ.

So in 2014, there was an issue in getting the brushing contractors focussed on our program. There's other programs in the territory by -- the Yukon Government has their highway brushing program. Yukon Energy has a brushing program. There's a number of other competing companies out there that employ these individuals. And if they're locked down on those projects, sometimes it's very difficult to get them back in to focus on our program. 09:10

So I believe that's what our description was about in the 5.2 schedule, was that the contractors -- there was a tough time getting -- getting them that year.

Q. And that's what happened in '14; yes?

A. MR. MASSIE: '14.

Q. Moving to line 11 for Account 87200, vehicle depreciation, can you explain why there's been a positive variance in past years, '13 to '15?

A. MR. GRATTAN: So all that is, is the -- our vehicles are -- have a charge per hour. So when an employee uses a vehicle for O&M purposes or capital purposes, it goes into a vehicle pool. And whether that includes -- or that includes insurance and gas and maintenance and that the depreciation of the vehicle.

So depending on whether that particular vehicle was used for more or less capital-related items, we have to back out more or less out of the O&M to account for that depreciation that's being charged into O&M. 09:11

Q. Thank you, Mr. Grattan.

The streetlight maintenance at line 17, which is Account 87800, is expected to increase in 2016 over actual levels. And we would just like to know the drivers for that increase.

A. MR. MASSIE: Okay. Just having a quick look at it, the line down there, I would say, it isn't so much the increase in '16 as it was a decrease in '15. If we look at our actuals from '13 and '14 of 238 and 252, more indicative of what we would expect out of our streetlight maintenance program. 09:12

In '15, it was less than any one of those years,

of '13, '14, and '16. And I would say that, quite honestly, the streetlight maintenance account is -- even though we are proactive and we do patrol and we find out what streetlights are off and repair them, get them running again, it can be very reactive. If there's less streetlights that burn out or to fix, there's less work to do.

So I would say in '15 that that -- that would be the only cause for that drop in '15. So the '16 number I would say is more indicative of what we've looked at or had for streetlight repairs in the past. 09:13

Q. For Account 70220, which is at line 26, that's the general public information account, the forecast increase from 2016 is -- we calculated it at 15 percent. It might not be that percentage in the updated table.

Can you give an explanation on why the increase between 2016 and '17 forecast?

A. **MR. MASSIE: What I think we looked at for that general public information really was the -- there's a focus -- or it's more of a demand by customers of better information for the projects that we do. So one of the learnings we had was just this year in our Selkirk Street substation -- in the past we've gone -- we had a project; we had a business need. We went out** 09:14

and did the project. There really is more of a concern or a want from the public to understand what we're doing a bit more.

So for our Selkirk Street substation this year, we went and met with the Riverdale Community Association, heard any concerns they had. We had a town hall meeting. We did -- out of that, we did a program where we sent out messaging to all those customers of what the project was, what we were doing, why we were clearing out a section of the forest in the back of Riverdale to put a new substation in there. 09:16

So we did all this messaging specifically for the community association. We had message boards near the site to ensure that everybody knew why it was going there. We had meetings where the local high school and elementary school that were nearby, just so they understood that it was a construction site.

So just looking at the amount of effort that we put in before we even started that project really made us realize that this public messaging is going to grow a bit. There is that want and that need from the general public to understand what we're doing, as opposed to our past business practices of, you know, we have a project to do, we're just going to go do it. 09:16

Q. Okay. For the customer accounting group of accounts

starting at line 28, using these numbers for those accounts, the Board noticed that often the variance percentages is 4 percent or greater. And, Mr. Grattan, I'm just wondering if you can give me a sense on any important changes within those accounts that would explain why some of the variances are higher than inflation -- or Mr. Massie.

A. MR. GRATTAN: Yeah, I'll be able to speak a little bit to Account 713, which is the customer billing and accounting line, but that one -- that one's -- that was what I was mentioning yesterday where we had a significant decrease in what has actually been incurred in customer billing and accounting. So that's ATCO 71300. 09:17

Q. And that's at line 32?

A. MR. GRATTAN: Line 32, exactly. And as I mentioned yesterday, that account went from an actual of $774,000 last year down to -- sorry, two years ago, 2014, down to an actual of 600,000 in 2015. And that was -- that decrease is due in large part to ATCO Electric Yukon and ATCO as a whole changing customer care and billing service providers -- or, sorry, no longer going with an affiliate ATCO ITBS and going internally well with Wipro. 09:18

So that decrease -- and that decrease also

includes the additional FTE that we were talking about yesterday.

Q. Okay.

A. MR. GRATTAN: So on a net basis, there still is a decrease, even though we've added to the complement of one FTE.

Q. Okay. And, Mr. Massie, can you identify any others there that require specific mention on variances?

A. MR. MASSIE: I can -- I'll walk through the accounts, and I'm just trying to highlight the ones that have the variances. 09:19

So, again, the 7-1, the first item there, line 29, supervision, that is a preset number based out of the supervisory folks that work in that account. So they had preset labour levels, very similar to the -- what I spoke to earlier.

The next line item, customer applications and services, that -- the costs in there are, when customers phone in, they need us to go out and -- they're moving in to an apartment, moving out. We are going to read the meter, disconnect, reconnect those services. So it's very reactive. So it's based on our historical numbers. The increase into '16 I would say is based on our past historicals of what we think is going to happen for customer services. So I would 09:20

guess it would be, as customers are added, as our customer base grows, there should be more people that we'll have to deal with in that account.

Meter reading is pretty straightforward. These are the costs for our fellows in the field that go out to read the meters every day. This is a cost for each one of our communities throughout the Yukon. So...

Again, the increase to '16 from '15 -- I'm just trying to get my head around why we'd -- why there would be the increase from the actuals in '15. Labour inflation in COLA. So, really, there's no -- other than the incremental growth of customers and having a few more meters to read, there would be a few more meters to read, as well as in there should be labour inflation in those COLA percentages that Mr. Grattan spoke to earlier. 09:21

Q. Okay.

A. MR. GRATTAN: And just to make sure that everybody's on the same page with regards to COLA, as part of our update that we filed in October, we've reflected the latest information from our actuary that has resulted in a reduction in the pension funding requirements for 2016. So as Mr. Tenney mentioned earlier, all of these numbers are going to be slightly lower in 2016 if we were to go through this exact same 09:22

exercise after reflecting reductions in COLA.

Q. Understood, Mr. Grattan. Thank you for that addition.

A. MR. MASSIE: Okay. And revenue collections I would say were beneath the 174 in '16 is under the three-year average. So, again, we work of historical averages in that it's a pretty straightforward account and revenue collections of what we do there.

Q. You must have been watching the baseball game last night, Mr. Massie.

A. MR. MASSIE: I may have. I'm a Cubs fan, so I'm pretty -- yeah, I was okay with the outcome. 09:23

All right. And I see the line item 34, 71,500 is -- is an average of those three years. The 130 is average of those three years, so that's what we've looked at for that as well as, I believe, for that last line item.

Again, those are -- they're very reactive accounts, the collection of delinquent accounts and uncollectible accounts. So we base them on our recent historicals. 09:24

Q. Okay. Thank you, Mr. Massie.

MS. SABO: Chairman Laking, if we could mark exhibit -- or the Aid to Questioning Number 7 with an exhibit number, that would be appreciated.

THE CHAIR: Yes. I think that would be

Exhibit A-21.

EXHIBIT A-21 - AID TO QUESTIONING

NUMBER 7

Q. MS. SABO: I would like to move to some questions on depreciation and income tax. And I would like to take you, Mr. Grattan, to Schedule 7.4 of your GRA schedules at Exhibit BB-1(a). And, specifically, Schedule 7.4 at line 50.

And at line 50, the amortization of reserve differences amount is $402,000 for 2016 and '17. 09:25

Do you see that, sir?

A. MR. GRATTAN: I do.

Q. And is that amount the same as the amount that you used in the 2013 to 2015 GRA?

A. MR. GRATTAN: When you say "used in the 2013 to '15 GRA," do you mean what was approved?

Q. Yes. What you forecasted to be approved, yes.

A. MR. GRATTAN: I'm going to say, yes, because that's what -- it's a consistent number throughout the '13 through '17 period of 402. So, yes. 09:25

Q. Thank you.

And keep that schedule open, but I'm going to move to Board Order 2014-06, Appendix A, page 44. And you might not need to pull it up.

In that section, the Board denied the collection

of future removal and site restoration costs in its depreciation rates; yes?

A. MR. GRATTAN: Correct.

Q. Okay. Can you confirm if FRSR is essentially the same as a negative -- as negative net salvage, which is represented by the percentage net salvage amounts shown in Schedule 7.4?

A. MR. GRATTAN: At a global basis, I would say the future reserve for site restoration is collecting money today from -- to pay for future site restoration costs. So I think I can agree with your characterization. 09:27

Q. Okay. Thank you.

So do the FRSR negative salvage percentages form a component of the depreciation rate or the calculation of the amortization reserve of differences amounts shown in Schedule 7.4?

A. MR. GRATTAN: Actually, you know what, I'm going to correct my statement on that. So I apologize.

Q. Okay.

A. MR. GRATTAN: So the amortization of differences is not relating to a collection of amounts that are going to be used for future site restoration. It's basically, as I understand it, a -- the difference between what depreciations were previously versus what the latest depreciation study that was approved in 09:27

2013-'15 GRA and amortizing those differences on a go-forward basis. So it is separate and distinct from collecting dollars today to be used tomorrow for future reserve site restoration purposes.

Q. Okay.

A. MR. GRATTAN: I apologize.

Q. No problem. So can you explain how that -- that's reflected in the component of the depreciation rates shown in Schedule 7.4?

A. MR. GRATTAN: Can I show? I'm not sure I can show you much more than what is there -- 09:29

Q. Okay.

A. MR. GRATTAN: -- other than to say that we have simply continued what the Board approved as part of the 2013-'15 General Rate Application for amortization of differences, that $402,000 going forward into this test period. And that would be consistent with past practice when we don't have a depreciation study before the Board.

Q. One moment. Okay. And now I have a question on approved depreciation rates and depreciation expense. So if I could take you to Schedule 7.2. 09:30

A. MR. GRATTAN: I am there.

Q. Great. At line 46, a depreciation or amortization rate of 20 percent is being used for Account 49300,

Demand Side Management; yes?

A. MR. GRATTAN: Yes, five years.

Q. And can you confirm that the 20 percent depreciation rate shown is the current Board-approved depreciation rate? Because when we pulled up the schedules from the last GRA, it seemed to be that 10 percent was in that account, Mr. Grattan. I know I'm kind of putting you on the spot, but can you help me out with that?

A. MR. GRATTAN: So, actually, maybe I need to go back to the Board -- the Board Order 2014- -- 09:31

Q. 2014- --

A. MR. GRATTAN: -- 06. This may just take a minute.

Q. Take your time, sir.

And I think you might want to look at pdf page 95. That may or may not have the amount, or you might have to go to the schedule.

A. MR. GRATTAN: Okay. So I haven't found it. So I think the concern appears to be whether it should be amortized at 10 percent as opposed to 20 percent? 09:33

Q. Yes. Yes, Mr. Grattan.

A. MR. GRATTAN: Is that the concern?

So if I could undertake -- rather than eating up time here, if I could undertake to confirm why we've -- why we've got it at 20 percent for five years, would

that be helpful?

Q. Yes. Thank you, Mr. Grattan.

If you could undertake to check that and get back to us either at a break or in writing.

A. MR. GRATTAN: Most definitely.

Q. Thank you.

UNDERTAKING - CONFIRM THAT THE 20 PERCENT DEPRECIATION RATE SHOWN IN BOARD ORDER 2014-06 IS THE CURRENT BOARD-APPROVED DEPRECIATION RATE

09:31

Q. MS. SABO: Thank you. And in Account 49300 for Demand Site Management on Schedule 7.2, we would like more detail on the underlying calculation of the recovery of the DSM program through depreciation. In our review, the information, there were capital additions in 2016 of 534,000 that do not appear to be attracting depreciation or amortization expense in any amount. So the depreciation expense calculation does not appear to follow other accounts. And we were just wondering if you knew why that was the case.

09:34

A. MR. GRATTAN: So I think if I'm -- as I look at the schedule, as we've done it, we have -- as I understand, we have proposed to add the $534,000 of DSM costs incurred in the years -- I'm going to say '14, '15, and '16. Just one moment. Let me just

double-check that, please.

Q. Take your time.

A. MR. GRATTAN: Yes. So I think I've got it right. Include the DSM incurred in 2 -- DSM costs incurred in 2014, '15, and '16, a total of 535 that was previously approved by the Board. Add it to rate base in 2000 and -- capital rate base in 2016. And we, per these schedules, begin to amortize that on a five-year basis, beginning in 2017. That's what -- the way the schedules are shown. 09:36

Q. Okay.

A. MR. GRATTAN: And if I -- just to -- there is a -- as you've already noted, there is a previous amount in property, plant, and equipment that, as you've noted, we've been amortizing over five years prior to the transfer of the 534 in 2016.

Q. Thank you. So if you're capitalizing it in 2016, why isn't it attracting depreciation?

A. MR. GRATTAN: It's a good question, and I don't have a great answer for you. If it was ultimately 09:37 **determined that that was the reasonable way to go, I wouldn't have a problem with that.**

Q. Okay. And is there -- there's -- is there a specific reason why it's reflected as it is? Can you...

A. MR. GRATTAN: I do not have a good answer for

you on that.

Q. Okay.

A. MR. GRATTAN: To be helpful, I can certainly undertake with my financial folks if you would like a better answer. I've got no problem taking an undertaking on that.

Q. Yeah, that would be helpful, Mr. Grattan. Maybe you could provide me an explanation on why it's been reflected the way it has and --

A. MR. GRATTAN: Sure. 09:38

Q. -- alternately, if it should be attracting depreciation.

A. MR. GRATTAN: I will undertake to find out why we're starting to amortize that 534,000 in 2017 as opposed to 2016.

Q. Thank you.

UNDERTAKING - TO ADVISE AS TO WHY THE 534,000 IS STARTING TO BE AMORTIZED IN 2017 AS OPPOSED TO 2016

Q. MS. SABO: Similarly, we were looking at 09:38 Accounts 423 and 425 again in Schedule 7.2. And we're trying to determine whether there's been a mixup between these accounts. So if you look at Schedule 7.2, I'm looking at lines 3 and 4 which deal with those accounts. And I would like you to compare

the plant balances for those accounts between those used in Schedule 7.2 -- so the ones that are there -- with the ones in the technical update that were provided in response to the City of Whitehorse 19, which is at Exhibit BB-1(a), pdf page 167. So, again, that's 19 is the IR number, and the pdf page is 167.

A. MR. GRATTAN: One moment, please.

Q. I'm sorry, the responses to the City of Whitehorse are at Exhibit B-4.

A. MR. GRATTAN: And, sorry, what page of the Attachment 1 was the reference that you had? 09:39

Q. 167 of 346.

A. MR. GRATTAN: I don't have that. I've got the technical update detailed on page 1. I've got 42 pages --

Q. Oh, sorry, 42 of 42.

A. MR. GRATTAN: Okay. Thank you.

Q. So I'll give you the context here, Mr. Grattan, as you're looking at that. So on a mid-year basis for Account 423 for hydro reservoirs, dams and waterways, 09:40 Schedule 7.2 indicates an opening PP&E balance of 2.2 million and a 2016 capital addition of

.735 million, which translates roughly to a mid-year balance of 2.6 million. Is that about right?

A. MR. GRATTAN: Yes.

Q. Okay. And similarly, for Account 425, hydro generators, it indicates the 2016 opening PP&E balance of 5.2 million and a 2016 capital addition of 1.6 million, which translates roughly to a mid-year balance of $6 million. Yes?

A. MR. GRATTAN: Yeah, I can agree with you.

Q. Okay. Now, turning to the technical update at page 42 of that IR response, in comparing these totals to the mid-year balances for the same two accounts, they do not result in equivalent mid-year balances. For example, Account 423 is 5.1 million rather the 2.6 million is Schedule 7.2. So that's why we're wondering if there's maybe a reversal in those accounts or there's been an error. 09:41

A. MR. GRATTAN: So all good questions, and I think I'm going to need to undertake to --

Q. Okay. 09:41

A. MR. GRATTAN: -- make sure that we've either got a correction or whether it's right.

Q. Okay. So to confirm the undertaking, Mr. Grattan, you'll undertake to provide us with an explanation or a correction explaining Account 423 and 425 and whether

there's been a reversal or error in those two accounts.

A. MR. GRATTAN: Yes. I will undertake to do that.

Q. Thank you.

UNDERTAKING - TO PROVIDE AN EXPLANATION OR A CORRECTION EXPLAINING ACCOUNT 423 AND 425 AND WHETHER THERE'S BEEN A REVERSAL OR ERROR IN THOSE TWO ACCOUNTS

Q. MS. SABO: I would like to move to income tax. And can you turn up your response to the Board IRs, 49(b). And that's Exhibit B-9. And the pdf page I've got 333 of 414. So 333 is the pdf. 09:42

A. MR. GRATTAN: I am there.

Q. Okay. Thank you.

Since the time of the IR response on July 11th, 2016, and specifically Part (b), which indicated that ATCO Electric Yukon was not aware of any proposed changes to income tax rates, have you received any updated information with respect to any enacted or announcements that would affect federal or territorial income tax rates? 09:43

A. MR. GRATTAN: Yes. And it's -- I don't want to give the liberals a plug, but one of the parties that I'm aware of as part of its election platform has stated they will reduce the territorial tax rate from 15 percent to 12 percent if they are elected.

So I'm not -- not aware of what the two other parties have or have not said, but I did note that that has occurred at least with regards to the Liberal Party platform.

And this is part and parcel of why we were -- are requesting it. We don't know what's going to happen after the election. The territorial rate may go up; it may go down.

Q. Okay.

A. MR. GRATTAN: At least one party is promising that it's going to go down. 09:44

Q. Do you have a view, sir, on how likely changes would be to occur in 2017, given the fact that there may be a new government?

A. MR. GRATTAN: How likely? Well, I can -- I can say in -- well, how likely? I don't want to speculate. I'm not supposed to be doing that.

I can state in Alberta when a new government got into power, the following year they did make changes in tax -- in provincial taxes. So it can happen within the following year. So if that answers your question. 09:45

Q. Thank you, Mr. Grattan.

I would like to move to capital additions, which is Section 9 of the application. And I would like to take you to the IR response to the City of Whitehorse

in Exhibit C3-4. And the IR response is the first one, actually, 1(a). Sorry. It's B-4. And, yeah, so CW-YECL-1(a).

On page 1 of the IR response in the second paragraph, ATCO Electric Yukon submitted that: (as read)

"Controllable capital was within 3.2 percent of that approved as part of YECL's 2013-'15 GRA."

Can ATCO Electric Yukon explain what is meant by "controllable capital"? 09:46

A. MR. MASSIE: Sure. What we were trying to show in that table, again, was the -- the difference with the new extension forecast from the actuals. So we looked at our total capital program from '13 to '15, the actuals to approved. There was a large variance between that. And what we wanted to do was focus or pull out the fact that new extensions was a big part of that variance.

And the fact that in new extensions being customer-driven projects, we really have little control over that. We have an obligation to serve when they're ready to dig in their next stage of Whistle Bend -- I use that one because it's the big new development that is out there. We serve it. 09:47

Obviously that changed in the last test period. So, really, with that table, we were looking at pulling that part out, the things that are outside of our control.

Controllable capital really is our -- the remaining distribution generation. In general are GP&E projects that are driven by us. We have full control of those projects. So we consider those -- those are the ones that we really should be -- that we want to measure ourselves against. 09:48

Q. Okay. And in consideration of the ones that are non-controllable capital, such as Whistle Bend, how much control do you have over timing or costing those types of items for what you call "non-controllable capital"?

A. MR. MASSIE: So the control over -- sorry, the costing?

Q. Or the timing.

A. MR. MASSIE: Well, we do have our meetings with the developers. We will flag our -- any constraints 09:49 **that we have out there with our labour force or with contractor labour force that we see.**

But, really, in the Yukon, the -- the construction season can be fairly short compared to other locations, just for the -- these subdivisions -- well, again,

specifically for Whistle Bend, it's an underground subdivision. So it's -- you dig in everything. So really doesn't work well throughout the winter. They usually start their projects in the late spring in the Yukon; so April, May.

We are -- so as those projects go, the developer will be in there. They'll have their civil contractor in there digging in deep utilities, water, sewer, building the streets. So until they get to a certain completion point, there's just no point in us being in there trying to do our work. 09:50

So it really is -- we flag our concerns. We meet with the developers. We talk with them of what's ideal for us. I can guarantee you we don't always get what went. Big projects like that can -- can move and shift the timing. And given how the first stages of those projects go will dictate when we are available to go in there and do our work.

Q. Okay. And in terms of costs, Mr. Massie?

A. MR. MASSIE: So the overall cost of the project, again, we'll sit down with the developer and the design of the subdivision. They'll give us their lot layout, their street layout. We start working on the electrical design of the subdivision and those streets. We really -- we really don't have a lot of 09:51

control in the costs of that project. They'll -- they'll lay out their streets; we'll come up with our design. This is what -- they'll dictate, you know, what they're looking for. We will supply them options. They're usually not -- there isn't a host of options for them. It's pretty straightforward.

When we light up a street to the lighting standard that needs to be, it's very well confined to a standard, so I would say there isn't much control we have over the costs that the customer is going to be mostly contributing to the project. 09:52

Q. Okay. And maybe I'll ask it this way, Mr. Massie. You would have some control over the equipment or maybe the hardware that you're using, those types of things? Do you ever have those discussions on maybe using something that's more cost-effective?

A. **MR. MASSIE: Oh, yes. In that manner, yes. We definitely do have our standards for -- for cables, for transformers, for equipment of that nature.**

When we start talking about streetlights, for instance, we've had discussions with the developer about the next phases and the LED options of streetlights. We've given them a number of options that are available that we can find to supply them with. It really -- it really comes down to their final 09:52

choice of what -- what is going to be installed in that -- in that subdivision.

So, again, we're -- we have, you know, our set amounts of investment with -- for streetlights and the loads for the terms and conditions, but they are going to dictate what they want. We'll give them options, but in the end, they will -- they'll be selecting the options.

Q. Okay. And in preparing your 2016-'17 forecasts, and, in particular, for the new extensions forecast, how does ATCO Electric account for the specific customer requirements in determining your forecasts? 09:53

A. MR. MASSIE: So when we look at it, we have one line item for Whistle Bend Stage 3 in 2017. That number is really based on their design as proposed for the subdivision. Again, we've submitted our electrical design. There could be changes by the time 2017 construction season starts, really, again, their discretion.

The top lines there within our overhead services and underground line extensions, really, we build those based on our recent -- recent years of actuals. So we look at what has happened in the last test period for actuals. We, again, try to forecast, as best we can, when these stages will open up and when the uptake from 09:54

customers will be.

It's -- there's a lot of inputs into the equation that are outside of our control, which makes it a difficult process for sure to -- to forecast and nail down. But the -- we do work with those developers to understand when the lots will be available. And, again, looking in the rear-view mirror, basing it on our recent historical actuals is the blend of what -- how we come up with that.

Q. Okay. And maybe some specific numbers may help us understand, Mr. Massie. I'm going to take you to Schedule 2.1 of the application, Exhibit BB-1(a), and it's the GRA schedules, 2.1. 09:55

A. MR. MASSIE: I am there.

Q. Okay. And in that schedule, sir, with respect to 2014-'15, the Board notes that the number of actual residential and commercial customers are very close to forecast.

And now I'm going to take you to Schedule 9.2, which relates to new general overhead services for various subdivisions and new underground line extensions. And we see in those line items for the same period that the amounts are less than forecast, approximately 2.5 million in '13, 2.5 million in '14, and 3.3 million in '15. 09:56

So given the context of those accounts, can ATCO Electric Yukon provide an explanation regarding the overforecasting of new extensions for 2013 to '15?

A. **MR. MASSIE: So in those accounts, not only the -- do we try to forecast the uptake of new subdivisions -- and you note in 2014 was the first forecast for the Whistle Bend Stage 3. That was to be put in in '14. Obviously, things changed with the developer, so that stage of that subdivision didn't progress at that time.** 09:58

So not only do we try to work with them to figure out when new lots will become available. As of recently, in the city of Whitehorse with -- along with the densification of the downtown core, there has been a -- changes to bylaws to try to allow people to have garden suites in the back of existing properties. We try to -- you know, when we put that forecast together in '13, we try to forecast, as best we can, not only the new subdivisions that open up, but we also base it on the recent historicals. And, again, if we look at 09:58 **the -- and I believe it's UCG-38, the new extensions in 2011 were in $6 million range. In 2012, they were almost $5 million.**

I should bring that up before I carry on.

Yes, there's a table UCG-38(d), as in David.

Q. I'm there, sir.
A. **MR. MASSIE: Yeah, and, again, the combination of looking forward, as well as blending with the historicals, you know, we had some fairly significant years in 2011 and '12 at that 6 million and the $5 million approximate averages, so we looked at those recent historicals, looked at what was coming before us and put that forecast together based on that.**

The correlation to the actual number of customers that have been added -- I can't really explain the correlation, as you pointed out in 2.1, how they're fairly similar, but there still is that drop in new extensions. 09:59

Q. Okay.
A. **MR. MASSIE: So, yes. Again, looking at those historicals, forecasting going forward, one of the things we do in those -- in new extensions, which is invested into, is the streetlights. I would imagine that would be part of the variance. If there isn't as -- you know, if that stage of Whistle Bend is not developed, there will be no streetlights in there either to invest in, just the individual customers. Those numbers are lumped into new extensions also.** 10:01
Q. Gentlemen, and anyone who wants to weigh in on this question, as you're well aware, the City of Whitehorse

has evidence on overforecasting in this proceeding at Exhibit C3-3.

And, Mr. Tenney, you and I talked about this a little bit this morning in terms of O&M, but when we get arguments on overforecasting, what factor should the Board consider in looking at how to deal with issues of overforecasting, either as a general reduction or by account?

A. MR. TENNEY: I'm not sure I'm going to give you a great answer about what issues you should consider, but the one thing for us, I think that we've said continually here -- and Mr. Massie's talked about it -- is overall over that three-year period we think in total that our forecast is pretty accurate. 10:02

And, as you've pointed out, you went through a number of line items. You can pick line items where we're high or line items where we're lower, but overall is what we're most focussed on, not by individual line item.

And I think that fits with some previous Board directions that certainly I know when I look back at 2014-06 where the Board talked about FTEs and said, you know, it's not -- it's not up to us to decide where those are cut. It's here's the cuts. You figure out what positions you really need to cut and which ones 10:02

you need to fill.

And so that's the way we look at that in total, is we're going to need to manage our O&M in total, not necessarily by line item.

Q. And, similarly, for capital projects as well?

A. MR. TENNEY: With the exception that there are capital projects that are customer driven and with our obligation to serve, we think those are a given that they need to move forward.

There's others, as I've mentioned in the last couple of days, safety items, those are for us givens that we need to move forward on them no matter what, and then there's some discretion when you get past that. 10:03

Q. Okay. On --

A. MR. MASSIE: I would just say, you know, I agreed with the operating accounts. And just speaking specifically to the capital program and specifically to new extensions here, we have realized that, you know, we missed the mark in new extensions for that test period. I'd say that we've reflected it in our '16 and '17 forecasts. 10:04

And, you know, when we -- when we saw this and we looked at our forecasts and even for '16, you know, this is one thing we've been tracking a little bit

closer to see how we're doing to see if it made a difference what we've adjusted.

And so far in '16 we're -- you know, we're forecasting to be right close to that, that number that we forecast at the beginning of the year.

Q. Okay. And just moving back to O&M again, Mr. Tenney, you know, when you look at individual line items and adjusting your forecasts for things that might have been over, can you just give me a sense of what you do? What does the company actually undertake when reviewing those accounts to make adjustments when you see some things vastly over or vastly under? 10:05

A. MR. TENNEY: I'm going to hope that Mr. Massie jumps in on some of the individual bits, but I obviously -- the first place you're going to start with is why are you over or under. You're going to need some variance explanations to figure out what exactly had been happening and what you can do to rectify that or if you need to rectify that or if you're over or under where you're going to make up for it. 10:05

So I think those are kind of -- I don't know if that's exactly what you were looking for.

Q. Okay. I'm just -- from a pragmatic perspective, that helps. You've got to look at your inputs.

You know, maybe Mr. Massie can give us some more

things that you look at.

A. MR. MASSIE: Yeah. You know, when we -- we sat down in the first quarter this year to -- to really build this forecast for '16-'17. We sat down, first, you know, going through the variances of what happened in the last -- where our forecasts ended up and explaining each one of those variances.

Whatever changed is that going to continue on. That's what we start with. We also -- we've sat down and went through this line by line and say, okay, these historical costs. Are these accurate. Are they going to continue. And then we put a different -- different additions or reductions in there for certain things that we know are coming or popping up in the maintenance, such as that dam safety review that I mentioned. We know that's coming; that's a known. So we plugged that into the forecast. 10:06

So, yes, we do sit down. We go through these line by line, analyze them with a look at the historicals, looking at our labour force, and any of the known maintenance items that will be added to it, such as diesel maintenance and generation. The -- there's -- in there are top end or minor overhauls, are in there. Those are fairly lumpy expenses. So we forecast those out and add those into our forecasts. 10:07

So there are the knowns, and we plug those into our forecasts.

Q. Okay. Thank you.

MS. SABO: Mr. Chairman, since we started early, this would be a good time for me to break, but I'm okay to continue into a new area. It's up to you.

THE CHAIR: Well, we were thinking maybe 10:15. So we're close enough to that. So why don't we break now for 15 minutes. So we'll come back at 25 after 10:00. 10:08

MS. SABO: Thank you.

THE CHAIR: Thank you.

(ADJOURNMENT)

THE CHAIR: All right. We will call this hearing back to order. And are we -- we don't have any materials just now?

MR. WILLIAMS: No, sir, nothing arising.

THE CHAIR: All right. So we'll just carry on with Ms. Sabo.

MS. SABO: Thank you. 10:30

Q. Mr. Massie, before the break, we were talking about new extensions, and you used streetlights as an example while we were having that exchange. And I just want to confirm that, in Schedule 9.2, new extension and street lighting are different capital expenditure line items.

That's right. Yes?

A. MR. MASSIE: Yes, in Schedule 9.2, that's correct, yeah.

Q. So we just wanted to make sure that when you were explaining the reasons for the variances and new extensions, that wasn't part of that response. You were just using streetlights as an example of an area where there could be variability.

A. MR. MASSIE: Yes. Because -- yeah. Very good point. It's not part of new extensions. Its own appropriation. But in new -- or in streetlights, there are -- our driven projects -- our projects, as well as customer-driven projects. So very similar to new extensions. 10:31

Q. Okay. Thank you.

And can you undertake to provide an update for your new extension actuals for 2016 that are available to date?

A. MR. MASSIE: Yes, I can undertake to provide.

Q. Thank you, sir. 10:31

UNDERTAKING - TO PROVIDE AN UPDATE FOR YOUR NEW EXTENSION ACTUALS FOR YOUR 2016 THAT ARE AVAILABLE TO DATE

Q. MS. SABO: I'm going to start out in capital projects with some follow-up questions on the

studies -- the various studies that have been already discussed over the past few days. And I'd like to start with the study for the Watson Lake project.

I want to confirm that there's not going to be an additional study for Phase 2 of the project. That all of the study costs will be in the previous study?

A. MR. TENNEY: That's correct.

Q. Okay. And at a high level, Mr. Tenney, can you summarize the results of the Watson Lake LNG study for us? 10:32

A. MR. TENNEY: Can I summarize the results?

Q. Yeah. What did you find? We have costs incurred. What do those relate to, and where are we at?

A. MR. TENNEY: I know there's an IR on it, and you just have give me a second to try and find it where we described everything that was done in the study. So...

I'm not sure I'm going to find it right now. I will look. But the results of all of the feasibility studies that we've done to date on Watson Lake, there's 10:34 **a number of things that we had to understand from the fees -- the economic feasibility of it, the technical feasibility of it, and the environmental feasibility of moving forward with the project.**

We had to go down a lot of avenues because, when

we were first working on the Watson Lake bi-fuel project back in the earlier 2013-2014 time period, it, of course, was the first of its kind. And so there really were no -- there were a lot of new policy that had to be developed by the Yukon Government. We needed to understand better the technical bits to it, had to understand the safety issues that arose from it.

So there was a number of things that had to be understood in those feasibility studies. Ultimately, though, it resulted in us bringing forward -- it -- the results were positive, in that we moved forward with the project in the 2013 to '15 GRA. 10:35

Q. And how did those results shape the recommendations for Watson Lake Phase 1 and Phase 2?

A. MR. TENNEY: Well, again, I think -- I think this is where you're going, hopefully. Back then we were the first LNG project in Yukon, and so one of the things that came forward out of that, through the YESAB application, was that we needed to -- weren't sure what the final results of the omissions. So there was testing that needed to be done after Phase 1 was complete before we moved forward with the other five engines. So that partially shaped how we moved forward. 10:36

But overall, we still -- you know, it -- we

decided to move forward with all six engines being converted. At the time, based on some of those, we had structured it to use an affiliate company that had some expertise in the design of this that we didn't have. So that was part of how we moved forward at the time.

Obviously we've since changed that, partially as a result of Board Decision 2014-06.

Q. And with respect to just the study, how should the Board assess the prudency of the costs? You said, you know, it was the first of its kind. Can you give us any more detail on how some of those items flowed into the ultimate costs for the study? 10:37

A. MR. TENNEY: I think all of those costs flowed into the costs of the study. And for me, I was quite happy when I read previous Board decisions where they recognized that, as a utility company, if we're going to try to get off diesel in some of our communities, we're going to have to expend some resources to try to find those alternatives.

And I think that's good news, because not all of the things that we look at that we study are going to turn out to be projects. And so if all we're left with is taking a risk with no chance to recover those costs, it's certainly going to make you think twice about whether you're going to pursue any alternatives. 10:37

And so this one, I believe, we're fortunate in that the studies have resulted in a project that we think is viable. And so think -- in our application, we've currently asked for those to be in deferred charges. And I think that we've acknowledged that just as easily we would be happy to put those into rate base just as well.

Q. Okay. Thank you.

And I'm going to -- I'm going to go back to Watson Lake more specifically later, but I want to keep it on the studies for now, Mr. Tenney. 10:38

Can you confirm whether the joint smart grid study is a stand-alone project, or does it fall within the renewable and alternate energy feasibility study? And the reason why we're asking that question is it appears on the GRA schedules, specifically, Schedule 8.8 -- and that's Exhibit BB-1(a), Schedule 8.8 -- that the joint smart grid costs at line 75 -- it's line 75, are separate from the renewable feasibility study. And the renewable feasibility study is at line 67. 10:39

A. MR. TENNEY: So I'll start, and Mr. Massie may have something to add, but certainly, in my mind, they're two separate studies. When we're looking at renewables and alternate energy study, that's separate from the smart grid study.

The renewables and alternative energy study is strictly ATCO Electric Yukon working on that project. The joint smart grid study is just that, joint. It's with Yukon Energy Corporation. So I see them as two totally separate projects.

I agree that, like many things that we do, the eventual outcome of both of them might be to help us reduce dependancy on diesel, but they're looked at differently.

Q. Okay. And why is ATCO Electric Yukon recommending the joint smart grid study be conducted in 2017 rather than '18 or '19? 10:40

A. MR. MASSIE: We -- basically, that year was a result of sitting down with Yukon Energy and coordinating our resources: Really, what is the best timeline to put it together. And that was the thought for '17 is where we ended up in for our joint discussions.

Q. Could it be deferred to '18?

A. MR. TENNEY: It's hard for us to say, speaking on behalf of both companies. What we had agreed on is we were going to move forward in '17, and we certainly want to do it in lockstep, since we're so tightly tied together. So if we say sure and we don't get costs included in revenue requirement and they say no, then 10:41

we're in a tough spot again.

Q. With respect to the renewable and alternate energy study, can you explain -- and Ms. Middler talked about this a little bit yesterday, and I think I understand -- I know what the answer to this is, but I'm going to ask it anyway because it wasn't clear to me.

So with respect to that study, why are renewable -- renewables and alternate energy being evaluated through both a pre-feasibility study and then a feasibility study? And I thought I would -- what I heard yesterday was is there wasn't a strong distinction between the two, but I'm not sure, so can you help me out with that? 10:42

A. MR. TENNEY: Yes. I get tripped up on what those titles exactly mean. But in my mind it's just, when we get some third-party help to guide us, I don't want to waste time on a detailed study if they know right away that there's no renewable resource in the area or if they know straight away that the economics or the technical or the environmental considerations are just going to result in a no chance for a project. I don't want to focus resources there. I'd rather focus them where there's more of a chance. 10:42

So that said, I still think they're probably the

same study. It's just a quick glance, and then let's get into it in more detail.

Q. Okay. So would it be fair to say, Mr. Tenney, that a pre-feasibility study, you would do some preliminary work, and then that work may be rolled into the final feasibility study?

A. MR. TENNEY: Or we stop on that community. Agreed.

Q. Okay. If it was not feasible.

A. MR. TENNEY: Correct. 10:43

Q. Are you aware, gentlemen, at this time of any further funding opportunities for projects stemming from the renewable study from either the Federal or Territorial Governments that may be known to you or have been -- become public since you filed your application and your IRs?

A. MR. TENNEY: Again, in one of the information responses, we did talk about the last -- the 2016 federal budget that they earmarked, I believe it was $10.6 million for renewable energy programs. We have 10:43 **been working with the Federal Government to see if we can access that.**

To date, the message -- and I think we -- in one of that -- October 24th, I believe it was, update that we did, we had originally said that we hadn't included

the watt -- we weren't seeking federal funding for the Watson Lake bi-fuel project, but we did through the Canadian Electrical Association. The ATCO Group of Companies was participating with them and did submit that project in looking for funding.

What we got back -- what I understand we got back from the Federal Government is right now they were looking for projects that were farther along. In fact, they were looking for projects that were shovel ready. So they weren't looking to fund more feasibility studies. They were looking to help make the project -- the economics work to get it under construction. 10:44

So, to date, we haven't found any funding, but that doesn't mean we're not going to continue to try and access some.

Q. Okay. And Yukon Conservation Society asked you yesterday about alternatives in order to deal with fuel concerns at Watson Lake other than what you've proposed with this project. We just wanted to know, have you ever looked at other alternatives to managing that site other than the move to biofuel? 10:45

A. MR. TENNEY: Well, we're obviously looking at some right now, which is the renewable and alternative energy study. As I mentioned to Ms. -- I believe it was to Ms. Middler, we were for sure involved with the

Liard First Nation and the Town of Watson Lake in looking at hydro -- we're looking at hydro sites in the area, and certainly have a report completed on that.

I know we've been in conversations with -- I'm going to say it's mostly with the Liard First Nation, but it might be with the Kaska in total, about looking at geothermal-type projects as well. We have had some consideration on others.

Right now what we're looking for moving forward with in the near term is taking a look specifically more at solar and wind generation. We're not ruling out anything, but in the early days, we want to first look at those two. 10:46

Q. Okay. So that's longer term? You would still need the business case as proposed in this application for the shorter term?

A. MR. TENNEY: If we moved forward on hydro or geothermal, we for sure would need to be coming back to this Board. Those are significant projects with significant upfront resources required to determine feasibility. 10:46

Q. Okay. Continuing on Watson Lake. And, Mr. Tenney, and the panel, I might be bouncing around a little bit I'm going to get into some more specifics and then go back to the high level, because there's a lot of information

throughout the file on this project, and the Board's just trying to get their head around the project in total.

So can you confirm for us if the Watson Lake biofuel costs for Phase 2 have been grouped together with some of the costs for Watson Lake Phase 1? And specifically, I could take you to Schedule 8.8, because it only appears on that schedule, that the study costs were identified in there. So I'm just trying to get an idea of that -- in that schedule, that's the total study costs for Phase 1 and Phase 2. 10:47

And that's Exhibit BB-1(a), Schedule 8.8, line 33, I believe.

A. MR. TENNEY: My reason for searching around a little bit is I see the numbers there, but I have a different number in my head, and I just want to quickly look at YUB-13.

Q. Thank you, Mr. Tenney. I'll pull that up as well.

A. MR. TENNEY: I'm not sure I'm going to get anything there, but that's where I... 10:49

Yeah. We identify on -- that's the revised economic -- that's the revised table showing the capital costs for Phase 1 and 2. So I'm not page 2 of 6 of that IR.

Q. Yes, I'm there, sir.

A. MR. TENNEY: You can see from there on the very left-hand side, we had study costs identified of 222,000, and then additional engineering design and permitting work done in -- between 2012 of '15 (verbatim) of 272.

And so I guess I'm going to need to just check. I thought the whole amount of 494,000 was what we had in study costs.

Q. Okay. If you could undertake to do that, Mr. Tenney, and just let us know what the Watson Lake study costs include and what the total amount should be in 8.8. And if you need to revise the table in the IR as well -- that's IR 13. 10:50

A. MR. TENNEY: I will do that. I was just hoping you were going to stay at a high level for a lot longer where I had a chance.

Q. That's fine, sir. Thank you.

UNDERTAKING - TO PROVIDE WHAT THE WATSON LAKE STUDY COSTS INCLUDE AND WHAT THE TOTAL AMOUNT SHOULD BE IN SCHEDULE 8.8 AND IF THE TABLE IN IR 13 NEEDS TO BE REVISED 10:48

Q. MS. SABO: In the previous GRA decision, Board Order 2014, can you confirm that the Board directed that all project costs related for Watson Lake

be removed from ATCO Electric's proposed 2013-'15 capital additions?

A. MR. TENNEY: Yes. I believe they told us to leave them in work in progress because -- I'm not exactly the exact words -- but I thought they seen some potential for this project.

Q. And in compliance with that decision, I also understand ATCO Electric Yukon is stating that they have applied for this project again in the current GRA because the contracting issue with affiliate services would be avoided. Yes? 10:51

A. MR. TENNEY: Well, we didn't just file for just that reason, but that was our interpretation of the Board decision and that was a major concern of the Board's during the last GRA. But we noted that the Board still thought the project had potential.

When we reviewed all of the economics, and, again, our obligation to serve with reliable, cost-effective service, together all of that brought us back to where we are again today with us asking for this project to be approved. 10:51

Q. Fair enough, Mr. Tenney.

How did ATCO Electric Yukon determine that the transfer of assets from ATCO Gas for the Watson Lake project would be the alternative that would best

support Phase 2 of the project and the project costs?

A. MR. TENNEY: So the question, again, if I understand it, how the purchase of the assets from ATCO Gas would benefit Phase 2 of the project?

Q. I'm just wondering why you chose that as the solution to resubmit the project to address the Board's concern in Board Order 2014-06?

A. MR. TENNEY: Okay. So I'll try. I think if I understand the question. In the last go-around of the project, we had ATCO Gas as the affiliate that we were going to lease a lot of the equipment from. And our understanding was the Board thought that there wasn't enough competitive pressures put on that lease arrangement. 10:52

What we do know is we participated with ATCO Gas when they selected the equipment that was designed specifically for Watson Lake, and they ran a competitive process.

So we knew that there was value there.

Subsequent to that, when we filed the R&V -- before we filed the review and variance of the 2014-06, trying to address some of the Board's concerns, we had a third-party help us conduct a competitive process where we went out to -- there were more players in the marketplace at that time than there were when we made 10:53

the original application. So we ran a competitive process looking for either a lease arrangement or an outright purchase. We had three bidders, including gas, and ATCO Gas still ended up with the lowest price.

Those things lead us to believe -- that and the fact that ATCO Gas is going to transfer those assets that they purchased back in 2014 at their net book value, so at cost, we felt that made sense to us. All of those things taken together lead us to believe that was a prudent decision. 10:54

Q. Okay. And that competitive process led you to the conclusion that the cost of the assets transferred was done at a fair price because it was net book value; yes?

A. MR. TENNEY: Well, they were the lowest bidder in the competitive process. So that's one. And we know they've shown us their books as to what the net book value is for those assets. So that's two. Those were the reasons.

Q. Did any of the other bidders also look at what those assets would cost if they were to be successful in the bid process -- excuse me -- in the bid process? 10:54

A. MR. TENNEY: I'm not -- so as Mr. Grattan is pointing out, the competitive process and the results thereof showed what the bids were. So the Board has

that information, and I'm pretty sure it's on the record here in one of the IRs, I think, to the City of Whitehorse. We filed that review and variance application.

So -- but I don't -- I still don't know if I'm answering your question, because other two bidders didn't have access to look at ATCO Gas's numbers or the other bidder.

Q. Yeah.

A. MR. TENNEY: They just knew they were in a competitive process, and they submitted their bid. 10:55

Q. Fair enough, Mr. Tenney.

What I was trying to get at is how do we know that the assets purchased are transferred at net book value from ATCO Gas is a representative or the best price or the best asset to be used for the project? So can you help me out there?

A. MR. TENNEY: So I'm -- we're probably missing each other, because I'm probably just going to repeat what I said. In the R&V -- just prior to us submitting the R&V, we ran a process said, here's our specific requirements for our Watson Lake bi-fuel project. Can you tell me what you would submit a bid for to supply those assets. 10:56

Q. Okay.

A. MR. TENNEY: And ATCO Gas was the winning bidder.

Q. Thank you, Mr. Tenney. I think I got there.

Are you able to specify exactly what ATCO Electric Yukon is seeking approval for with respect to the Phase 1 portion of the project? Are we looking at the business case, the capital expenditures, the capital additions, or all three?

I can maybe give you a reference, Mr. Tenney, on why we're asking this the question. It's -- the application Appendix 3, Exhibit BB-1. And, like I said, it's Appendix 3 of the business case, pdf page 243. 10:57

A. MR. TENNEY: Our trouble on this side is we have a different pdf.

Q. Oh, yeah.

A. MR. TENNEY: So our numbers aren't quite the same.

Q. I've seen that before.

So what I'm looking at, it's a passage that says: (as read) 10:58

"The Watson Lake bi-fuel project achieves the Federal and Yukon Governments' goals of displacing diesel and managing electricity costs by..."

And then there's two numbered items and after that it says: (as read)

"ATCO Electric Yukon estimates the total cost of the three-year project to be approximately 4.97 million; however, at this time, ATCO Electric Yukon is seeking approval for 3.26 million to implement Phase 1."

A. MR. TENNEY: Right. I see that. But I know there's an IR, and I probably should try and find this one. 10:58

Q. Is that the one with the table, sir?

A. MR. TENNEY: That's the one where we were asked the same question: What is it that we're asking the Board to approve?

Q. Yeah.

A. MR. TENNEY: We're asking the Board to approve the project. So I guess, in your words, that would be to approve the business case. At this time, we're asking the Board to approve our 2016 and 2017 revenue 10:59 **requirement, plus our capital additions for 2016 and '17. So under that words, we're asking them to approve the Phase 1 capital costs and associated O&M and fuel, and the 20 -- the Phase 2 part of the project which is to be built in 2018, that will have to come at a later**

time.

Q. Okay. And Phase 1 and 2, are these phases just for the conversion of the diesel units, or is there something else that's going to happen within those business cases -- or within those phases?

A. MR. TENNEY: So in Phase 1, we would have to move them -- move the majority of the equipment on site, and, you know, the LNG, the liquefaction, and the -- sorry, the storage, the large storage, and the regasification equipment. We would only convert one 10:59
engine to bi-fuel. Then we'd do the testing with Yukon Environment. And then on Phase 2, we talk about a second storage tank and some additional offloading facilities and the conversion of the other five units.

Q. Okay. And is there expected to be another phase after that work is complete? Just trying to get a sense of if the project costs we're seeing here for the test year is in -- understandably in 2018, because you've provided those as well. I'm just wondering if this is going to be a running cost, or there's going to be 11:00
another phase, or if you kind of expect this to be the end after Phase 1 and Phase 2 are completed.

A. MR. TENNEY: That's the end, as far as I see it. That would have all six of the existing units converted to bi-fuel mode.

Q. Okay. And I believe I saw in an IR -- and you can correct me if I'm wrong, because I didn't go back and pull it yesterday. In one of the IR responses, I thought you said in this proceeding you're looking for approval of both Phase 1 and Phase 2. Is that correct, or are we just looking at Phase 1 here?

A. MR. TENNEY: So that's, again, what I -- that's the same IR that I was referring to, and what my words are to one of your questions a few moments ago, we're essentially looking for the Board to approve the project, -- so, in your words, the "business case" -- which would mean they agree this makes sense in total. But we're just asking for the inclusion in revenue requirement of the equipment that's -- or the capital cost and the associated fuel and O&M costs for Phase 1. 11:01

Q. Okay. And if the Board were to approve the project in the decision that would, say, come out in Quarter 1 or Quarter 2 of 2017, would you -- when would Phase 1 expect to be completed if the project is approved?

A. MR. TENNEY: Depending exactly when the decision comes out, but what you kind of said there, I think we would expect it to be in service late in 2017. 11:02

Q. And the other thing, between Phase 1 and Phase 2, we notice that the majority of the costs, which are in 2017, the majority of the costs that make up the

$3 plus million for Phase 1 are basically related to Phase 1, which is one unit. And then we've got Phase 2, which is about 1.7 million, which is for the additional five units. And we were just looking at that and thinking the majority of the costs seem to be in Phase 1, so why is that the case, that it's so much more expensive for Phase 1 than Phase 2?

A. MR. TENNEY: Right. You're probably going to get me quickly over my head, but in terms of the storage of the actual LNG, you've got a large storage tank that's -- it's -- the size is bigger than just what's required for one engine. So -- and then the actual gasification, so when you take that LNG, the liquid natural gas, and heat it up and turn it back into gas, that's also included all in Phase 1.

Q. Okay.

A. MR. TENNEY: So there's a lot of costs that are common costs, but they're incurred upfront.

Q. Front. Okay. Yeah, and that's what we understood, because it's the LNG vaporizer and LNG storage tanks that are 1.47 million in Phase 1. 11:03

A. MR. TENNEY: Yeah. I think the only caution I have there is you're using the original numbers, the 1.47. That's been reduced to 11, 94. In that YUB-13 we --

Q. We were at.
A. MR. TENNEY: Right.
Q. Thank you. So if the Commission were to approve Phase 1 but did not determine Phase 2 in the decision that's going to come out as a result of this proceeding, what would be the response of ATCO Electric Yukon in types -- in terms of the decision-making on whether to go ahead in converting all units; right? If we only say, well, we'll look at Phase 1, but Phase 2, we'll see how Phase 1 goes first, and then we'll look at Phase 2 later. Can you give me an idea? I know it's speculative, but can you just give me a sense if that would be viable and why or why not? 11:04
A. MR. TENNEY: Well, I guess my first -- as you would guess, it really depends on what specifically the Board says. But it certainly gives us reason for some caution because a lot of the costs that are in Phase 1, in order to make this project economic, you need all six engines converted. And if we spend a significant chunk of capital and only have one engine converted, 11:05 **the economics aren't there for our customers. And so that's challenging -- I suspect challenging for not only ATCO Electric Yukon, its customers, but also the Board. Because we moved forward on this initiative because we felt it was an economic project. And if we**

didn't do both phases, we wouldn't have an economic project.

Q. Okay.

A. MR. TENNEY: So it does give us pause for caution.

Q. Okay. Thank you, Mr. Tenney.

Now, I've got some more accounting questions on Watson Lake, and, Mr. Grattan, or anyone on the panel, can you tell me what account number these diesel costs are recorded in? There was some testimony yesterday, 11:06
and we weren't sure if these were recorded in a generation account or somewhere separately. We think maybe Account 445, but if you could help us out and let us know what account the diesel units would be in, that's great.

A. MR. GRATTAN: I'm going to say, subject to check, the components that relate to the diesel generators tied to this project would be in 445, but I'll take that under subject to check.

Q. Thank you, sir. 11:07

A. MR. GRATTAN: Yeah. Mr. Tenney just reminded me that it could go to a number of different locations.

Q. Okay. And --

A. MR. GRATTAN: So that's why I was specific with respect to the pieces that are being added to the

diesel engines to facilitate LNG.

But if you're talking about the vaporizer and the infrastructure to get from the vaporizer into the Watson Lake plant, that would be potentially a different answer.

Q. Okay. I think it's sufficient if you can just take your subject to check, Mr. Grattan, rather than all the other components.

A. MR. GRATTAN: Fair enough.

Q. Thank you. 11:08

I'm going to take you to Exhibit B-9, and, again, that's the responses to the Board. And I'm looking at 29(g). And I'm looking at page 3 of 3 of the hard copy of that IR response.

And 24(g) asked about the original historical cost and accumulated depreciation related to the assets being purchased from ATCO Gas. And ATCO Electric Yukon responded on page 3 of 3, Part (g): (as read)

"This equipment has never been put into use, and as such, no depreciation has been accumulated. The original historical cost, accumulated depreciation, and net book value shown below." 11:09

And, again, that's the number that Mr. Tenney referred

me to of 1.194 million.

So can you confirm, were the assets purchased from ATCO in contemplation of the Watson Lake bio-fuel project?

A. MR. TENNEY: Were the assets purchased from ATCO?

Q. Gas, yeah. Or they're just being transferred.

A. MR. TENNEY: We have not purchased those assets yet from ATCO Gas.

Q. Mm-hmm. 11:09

A. MR. TENNEY: They're still ATCO Gas's assets.

Q. Okay. Thank you for that confirmation, Mr. Tenney.

Does ATCO Electric Yukon consider that facilities approval for the units in Phase 2 would be required because you're not just replacing one unit, you're replacing several? Do you think that that would require a facilities approval by this Board? Under Part 3 of the Act?

A. MR. TENNEY: I think I'm going to start, and Mr. Massie might chime in. 11:10

Q. Certainly.

A. MR. TENNEY: You said a couple things that -- just to make sure -- and maybe I didn't hear it quite correctly, but you said you're replacing all six units. We're not replacing any units. We're bolting on a

bi-fuel kit.

Q. Yeah. I'm sorry. I should have said "converting."

A. MR. TENNEY: Okay.

A. MR. MASSIE: And just in the relation to the Part 3 under the Act, it's our understanding that that -- the Part 3 is -- you need an order from the Minister. So that's our understanding in getting a Part 3 energy project certificate.

Q. Okay. And I'm sure your counsel will advice accordingly, I just wasn't sure if we maybe have -- have another wrinkle there. So I'll just leave it at that, gentlemen. Thank you. 11:11

Just one more question on the conversion of the diesel units. And, Mr. Massie, this is probably you because it's a fairly technical question.

A. MR. MASSIE: Oh, boy.

Q. How well is an engine designed to burn diesel versus natural gas once you do a conversion? Can you kind of give me a sense what that involves and how efficient that unit will be? 11:12

A. MR. MASSIE: So understanding for the bi-fuel kits that get bolted onto the existing units, it really is -- it introduces a mix of natural gas into the intake air of the unit. So the unit will still need diesel to burn or to operate. And it uses it primarily

for lubrication and cooling, but it's a combination of the both of the diesel and the natural gas.

And my understanding is that the natural gas can have as much as a 70 percent mixture in there. So it would be up to a maximum 70 percent of natural gas and 30 percent diesel. So there needs to be that diesel component still left in there for the proper operation of the unit.

Does that help?

Q. Yes. Thank you. 11:13

And when you put on the conversion kit -- I mean, the unit, I imagine, is modified by the conversion kit; yes?

A. MR. MASSIE: Yes. Yeah. That goes right on the unit.

Q. Okay. And does that affect the warranty or the service life of the unit?

A. MR. MASSIE: My understanding is that it does not modify the warranty. The -- our preliminary discussions are with the manufacturer of the units. 11:14 **And their technicians would be the ones that install it, the conversion kit, that is.**

Q. So would it be expected that the units would wear out quicker, or would they just be able to operate as before and have the same service life? Do you know?

A. MR. MASSIE: It's our expectation that it would not modify the service life of the unit. Yeah. Again, our expectation is that there will be no change in the life expectancy or the wear of the unit. The conversion kits are installed by their technicians. The technology is designed to work with those existing units.

Q. Okay. And if you were to have to replace a diesel unit, obviously -- I shouldn't say obviously -- would it be replaced with a new unit that would -- would be able to operate under both diesel and LNG, or would you also do what you're doing now and use a conversion kit? 11:15

A. MR. TENNEY: So, so far in my discussions and our group's discussions with the suppliers of these equipments, right now the bi-fuel equipment's direct from the factory without a bolt-on kit. So far they're only available in marine applications, and there's not one yet for use at a stationary power plant.

So in the near term, I suspect, we're looking at bolting on the bi-fuel kit. But I suspect if it's available in marine applications, as the demand for it grows, they'll likely make it available for stationary power plants. 11:16

Q. Thank you, Mr. Tenney. That's helpful because it's hard to compare units when they're not available.

I am going to move to the Fish Lake to headpond spillway replacement, which is Appendix 2 of the application at Exhibit BB-1. And I'm in Appendix 2, page 1 of the hard copy, pdf page 239.

A. MR. MASSIE: Page number, sorry, of the --

Q. Sorry. Hard copy is page 1.

A. MR. MASSIE: Okay, yeah, I'm there.

Q. Okay. And just a question general. I'm not going to refer you to anything quite yet, but ATCO Electric Yukon has stated: (as read) 11:17

"The main driver is aging infrastructure and that the project also complies with the recommendations of the dam safety report."

Yes?

A. MR. MASSIE: Yes, that's correct.

Q. Okay. And then on page 1 it also says: (as read)

"This project will ensure ATCO Electric complies with the recommendations of the dam safety report and Item 42 of the 11:17 water license HY12-065."

Yes?

A. MR. MASSIE: I'm just -- oh, there we go. At the bottom. HY12. Yes, I see that.

Q. Great. What was the recommendation of the 2014 dam

safety report and Item 2 of the water licence? Can you help us out?

A. MR. MASSIE: Sure, just give me one... Okay. So I'm looking at our -- the dam safety review in Attachment 1 of YUB-14. And the 2014-09 recommendation, as it states here, is: (as read)

"Replace the Dam Number 2 spillway with a new structure within the next three years, i.e., (by 2017)."

In brackets. 11:19

Q. Sorry, I missed that, Mr. Massie. Could you just repeat that?

A. MR. MASSIE: Of course. Let me just roll back. I'll... Do you need the reference page or the --

Q. No, that's fine.

A. MR. MASSIE: Just to read the actual recommendation again?

Q. Yes.

A. MR. MASSIE: Okay. So as read: (as read)

"Replace the Dam Number 2 spillway with 11:20
a new structure within the next three years."

And in brackets it has "(i.e., by 2017)."

Q. Okay. And Item 42 of the water licence, how does that factor in?

A. MR. MASSIE: So Item 42 of the water license is under Part (d) of the water license for monitoring, and, basically, it spells out that we will do a dam safety report on a yearly basis. And so, basically, the water licence dictates that we do these reports, and then the report has the recommendation.

Q. Okay. Thank you. I want to go to the Watson Lake Unit 2 replacement business case at Appendix 4 of the application. And I have a pdf, so it's probably not going to help you, Mr. Massie, but it's pdf pages 251 to 254 where the business case is at. 11:21

A. MR. MASSIE: Yes, I have the business case --

Q. Okay.

A. MR. MASSIE: -- in front of me.

Q. And, actually, I do have the page. It's page 1. It says: (as read)

> "The original scope of the project in the 2013-'15 General Rate Application was to replace the unit with a similar-sized engine, 800 kilowatts. At 11:21 the time the unit tender and selection, capacity requirements were reviewed. This review determined that, in order to meet contingency handling requirements, a larger unit, 100 kilowatts, is

required."

Can you provide me with some detail on why the issue of requiring a larger unit was not known at the time that the Watson Lake business case was provided in the '13-'15 GRA? Why was it only identified at the time of tender and selection?

A. MR. MASSIE: Yeah, okay. So if -- recalling that the last business case we -- we identify the size of the unit that needs to be replaced. And usually that we'll recommend is that we're going to be 11:22
replacing the unit with a similarly-sized unit. The caveat that we have is that when it comes -- so when that business case was built back in late 2012, early 2013, it was forecast to be replaced in 2015. So what we do is when we get to the year that we are replacing a unit is we review the community load at that time.

After reviewing that community load, we -- we select the -- the engine that's going to provide the best -- best complement to the plant to continue to supply the load of the community, as well as that 11:23
combination of efficiency for heat rate.

Q. Okay.

A. MR. MASSIE: So, though we forecast at -- ahead of time what we think that unit will be, when it comes time to replace a unit, we do have to factor in what

we're -- what we're looking in front of us for a load on the community.

Q. Okay. And, similarly, for the Old Crow Unit 3 replacement, you would say the same thing. So that's a general policy?

A. MR. MASSIE: Yes, we do a -- that load analysis, and you'll see in the Old Crow 3 replacement there's a -- there's a community load duration curves. So understand, you know, throughout the year how much time a community spends at a certain amount of load. 11:24 **It will factor in the peak loads. So obviously we -- the peak load of the community can only be -- you know, that peak can be established in a one-minute interval in a year, but we'll still have to supply that peak, so that gets factored in as well. So not just -- not just the peak, but the dispersion of load throughout the year for that community.**

Q. And can you give me a sense -- I know you've provided a lot of information on, you know, the project steps you take when you're building a business case in your 11:24 forecasts, and I'd just like to know a little bit more about the planning phase, given what you've just responded to, you know, later you do an update to see where the load is at.

So when you're planning a project and looking at

your forecasts, what information or what steps are there in the planning phase that you use to develop that business case? Do you have kind of an internal checklist you follow? Is there kind of a standard list of things you look at to try and make your forecasts as accurate as possible?

A. MR. MASSIE: Yes. There is a standard checklist of what we look at. You know, we also factor in, especially in this last test period, you know, we look at the actuals from projects that have been completed. So our estimates at the time are based on what we think the community will need for a unit at that time, what we think the contractors' rates will be, what we think materials will cost at that time.

As we go ahead with projects, like in the later years of that test period, 14, '15, and including this year in '2016, we'll look at the costs that we've incurred in those projects. So we'll have a very informed understanding of what the actual costs were, not just based on a -- on our estimate. We'll look at our actual cost from previous projects that are similar.

The one thing that we've found quite interesting with these diesel generators, so when we tender for the supply of the units, it really -- in this last test

11:25

11:26

period, there was quite a variation in costs based on market demand.

So, for instance, this -- this unit, Watson Lake 2, you know, we knew we were replacing it this year for -- so in the first quarter, when we went to market to get a replacement engine -- and the replacement engine is actually 895 kilowatt engine. That's what's been selected and will be installed here shortly.

But when we got the tenders back, there was actually a unit that was 11 -- 1.4 megawatt. So 1450 kilowatt unit that was offered for purchase at a cost that was below the cost of this unit. And so that -- that surprised us. It was a much larger unit. 11:27

So we contact the manufacturer; but, you know, in that instance, the unit was going to be heading to a mine. That mine is no longer there. So they had a brand-new unit sitting on their floor that they want to do get rid of at a discount price.

At that time, you know, we reviewed that unit to our community load, and it just -- the efficiency wasn't there. You know, we could have, you know, got that bigger unit, but it wouldn't have been run in at a very efficient rate compared to this unit. 11:28

Q. Okay.

A. MR. MASSIE: So there are a number of factors that we put into our model to -- before we start looking at these. However, our -- the interesting part that we've found is that market, even now with the turndown in commodity prices and the mining sector that these contractors supply units for, they're phoning us to see if we need anything now. Whereas in the last couple years, it's been tough getting ahold of them.

So it's just one of those interesting things that we've learned as we've gone along and have been dealing with going forward. 11:29

Q. Okay. And any other checklist items? I mean, I imagine I don't need to get you to do an undertaking to provide the checklist to make sure it's complete.

Anything else you can think of?

A. MR. MASSIE: Well, you know, we look at the cost -- those material costs, our labour costs, what we think from the competitive bid will come in. As we've learned with the -- our Old Crow projects is looking at other community projects in the area that will affect the availability of resources for us. 11:29

So those items are the -- are the ones that we look at. Some of them.

Q. Okay. And do you also look at reliability standards in the area? We know you submit reports to the Board on

reliability and where you've had issues. Does that factor into your business case analysis?

A. MR. MASSIE: Are we still -- are we still talking specifically generation or broader?

Q. More broadly, yes.

A. MR. MASSIE: Okay. Yes. Yeah. The system performance, the plant performance, yes, we figure in -- that into the equation too. Very similar to this Watson Lake 2 unit, the performance of the unit was forecast to be replaced in 2015. The unit was 11:30
operating acceptability within its parameters. There was no issues with it or the community. So it would be replaced in 2016.

But on the distribution side, yes, we'll look at performing feeders, see if there are deficiencies in the system that are contributing to those outages, and that would factor into it also.

Q. Okay. Thank you.

And now back to Old Crow and the business case. I have a confirming question. Is it correct that 11:31
Old Crow's generation plant capacity will have grown from three units with an installed capacity of 1,170 kilowatt hours to four units with an installed capacity of 2,000 kilowatt hours?

A. MR. MASSIE: I can confirm that the new

installed capacity is 2,000 kilowatts. I'll take from the existing, subject to check. Just I don't have --

Q. That's fine, sir.

A. MR. MASSIE: -- the old unit numbers in front of me.

I may have them. Yes. 1,170 that's what --

Q. Correct.

A. MR. MASSIE: Yes. That is correct.

Q. So can you provide an explanation regarding the basis for the increased capacity in Old Crow? Is it just load-based or something else? 11:32

A. MR. MASSIE: So I think when we talk about Old Crow, the overall capacity of the community is -- of our power plant capacity in that community is 2,000 kilowatts now. It's important, though, to understand that these are two separate power plants. They're in the same -- our same lot up in Old Crow, very close to each other. And the new fuel depot really is what confines us to that area.

Q. Okay. 11:33

A. MR. MASSIE: But they're two separate power plants. So we look at them as two -- one power plant at 1,000 and another power plant at 1,000. And it was really one of the big business drivers for our last business case on the Old Crow plant expansion, was to

have full contingency in the event of a loss of a power plant in that community.

So, you know, it's -- it being a fly-in only isolated community north of the Arctic Circle, it definitely is a tough spot for us to have full contingency in our generation as we do in the other communities that we have road access to.

So we have some mobile generators that will provide contingency backup for a community like Destruction Bay or Beaver Creek. If there happened to be a catastrophe and we lose power plant, we're able to roll into that community and have a backup contingency for it. That contingency really wasn't available as readily for Old Crow. That was the business driver around having a second power plant. 11:34

So we do look at those power plants up there as being two separate power plants providing full backup for the other at 1,000 kilowatts.

Does that help at all?

So, yeah, I guess, just the fact that the two power plants there, at the 1,000 kilowatt, compared to the 1,170 that it was before, they do -- they do work in tandem. There is the ability, of course, for two engines in a power plant to be running and a third engine if the community load does grow, which it has in 11:35

the past number of years. And we do have that -- that -- no -- we've seen that peak loading grow and -- and that table is on page 1.

Q. Okay. And you've referred to mobile generators not being as feasible as an option. Is that geography or availability of transport?

A. MR. MASSIE: Availability of transport. We would have to obtain a Herc -- Hercules aircraft to get those units in there. As we've noted in -- or maybe we haven't noted, I've just -- know of it, that we -- for our project that we've completed, the projects we've completed in Old Crow, we've needed a -- to obtain an Herc airplane in the past couple years. When we originally put the estimate together and looked at it, there was a Canadian airline that had a couple that had since got out of that business, so now we had to get a lot of our equipment into Fairbanks, Alaska, to utilize the only Herc that we could find from that side. So the logistics of getting one of those here, get the unit loaded up and to Old Crow would be a matter of days to do. So that really was the drive for that contingency issue of the -- of the second power plant in Old Crow.

11:36

11:37

Q. Okay. What is the expected firm capacity of Old Crow? We're just wondering, for Watson Lake, you provided a

difference between installed capacity and firm capacity. Maybe you could just explain what those terms mean for me first.

A. MR. MASSIE: Fair enough. So the installed capacity is the total amount of our generation that is available on a site. And the firm capacity is -- is that total minus the largest unit. So it's called an N minus 1 criteria. So we're going to -- what we plan for is, if there's an issue and our largest unit is offline, not available, the firm capacity would -- is the capacity we need to ensure that we can supply the community. So in the -- in the example of Old Crow, it would be 1,400 kilowatts would be the firm capacity. Total capacity, again, is 2,000. 11:38

Q. Thank you. We'd like to follow up on the McIntyre subdivision replacement, Appendix 8. And I'm looking at hard copy page 3 of that business case in the application and, specifically, Table 1, when you get there, Mr. Massie.

A. MR. MASSIE: I am there. 11:39

Q. Okay. And I believe that this was with Mr. Rondeau or Mr. Maissan, but there was some discussion of this table. And we wanted to make sure that, when looking at 2013 actuals, there's a construction actual forecast amount of 656, and that's in hundred thousands. So we

wanted to know if that amount is being capitalized, and, if so, what is going into rate base. So it might Mr. Grattan rather than you on that question, but...

A. MR. MASSIE: Yeah, I would take a long time to answer that.

A. MR. GRATTAN: So, sorry, you're asking the question of whether the 656 was put into service? Capitalized?

Q. Whether it was capitalized, yes.

A. MR. GRATTAN: So Mr. Massie's confirmed that that line was in service in 2013, so it would have been capitalized. 11:40

Q. Okay. And what would be going into rate base, Mr. Grattan? Would it be that --

A. MR. GRATTAN: $656,000.

Q. Same amount. So it actually did take both of you to answer that question, so thank you.

A. MR. GRATTAN: Quickly.

Q. I'm going to move to the downtown Whitehorse business case at Appendix 9. And that's at pdf pages 273 to 282. And I'm actually going to just keep that open. I don't know if you'll need it or not. But I'm also going to take you to the response to YUB-YECL-17(g) at Exhibit B-9, page 4 for the hard copy. Again, that's 17(g), page 4, and pdf pages 210. 11:40

And in IR 17(g) it says: (as read)
"With respect to ATCO Electric's system -- sorry -- with respect to ATCO Electric Yukon's system performance optimizations alternative for the downtown Whitehorse capacity upgrade, ATCO Electric Yukon stated the following..."

So the sentence in that IR is: (as read)
"The options discussed under this alternative are still being investigated, as they would be able to provide a short-term solution as load grows in the future." 11:42

So is that still the case, Mr. Massie, or do we have a further update to where that's at?

A. MR. MASSIE: Mm-hmm. So in the items that were looked at for that, that Alternative 3, are on page 7 of that business case. I'm not sure what the pdf number is, and under there are the four bullets that were considered under that system performance optimization. 11:42

Q. I'm just getting there, sir.

A. MR. MASSIE: You bet.

Q. Proceed.

A. MR. MASSIE: Okay. So just walking through those, I guess at a high level, we did look at and consider all these individually in the context of how they could improve the capacity of our -- of delivering our power in the downtown core.

So that first bullet about the optimized substation transformer tap settings and regulators, so the existing equipment there can really be -- we can go and make settings -- change the settings on it so that they will operate right at their maximum and push to 11:43
their limits. That would provide us with greater capacity.

However, we're operating equipment at its absolute limits there. So that -- that's really about as far as we've considered that option. You know, it really is an option for us in emergency situations, is how that works.

The dispatch interface, that's tied to the last bullet with SCADA, and that's about understanding our system, you know, in and a realtime fashion. So we'd 11:44
be able to sit there at the computer, see realtime loads, going in all different directions to understand where it's going. Our answer to any capacity or overload issues would be to switch the system around on a reactive basis.

So those are things we could still do, and we still consider; but, really, being reactive that way really wasn't considered on a go-forward, long-term basis.

The third bullet there, the installation of additional switches, that did happen. That is part of the proposed option that we've moved with. And I'd say -- and that's captured on page 5 of the business case. You'll see the -- there where we talk about the projects that we've completed in the '16 and '17 test years. 11:45

The main one at the top is the installation of the Selkirk substation, and then the reconductor in the river crossing, and then those bottom three projects are those projects. So we did -- we did move forward with those in -- as part of the solution.

Q. Okay. And given that response, Mr. Massie, do you have any updates to your forecasts costs or the forecast costs for this project still accurate?

A. MR. MASSIE: We've completed the installation of the Selkirk substation. I believe two of those three bullets in the bottom there, in the 2016 test period, for -- two of those are complete. The third one is scheduled to be complete. And they are all forecast to be on those budgets that they're -- in the 11:46

2016 test year.

Q. Thank you.

In terms of the Paint Mountain cable replacement at Appendix 10, if you could pull that up. And I have got a reference of pdf page 210 for those people who are following along.

The page that I was interested in was actually the last page of the business case that has the geographical map on it?

A. MR. MASSIE: I am there. 11:47

Q. And I'm just wondering, with running the cable for the alternate route in red, it kind of goes in a U-shape and up and across the hill and back down.

My question to you is, when preparing this business case for presentation to the Board, why was that the best route? Did you consider alternate routes, or was that the only one available?

A. MR. MASSIE: We did consider alternate routes, and I'm just -- apologize. I thought we had noted that here in this business case. 11:47

So the first one, route that we considered, was the existing one, replacing the cable as it is, in place.

Q. Yeah.

A. MR. MASSIE: We've noted, like -- that's --

basically runs up the rock face of the mountain. Very vertically challenging, I would say. We have no access -- ability to access most of that route, the existing route.

So it's very steep terrain. My guess is that it was installed with a helicopter. There would be no way else to do that. So just given the access issues that we had, that really took care of that concern, or that alternative, I guess.

We also considered an alternative, and it's not on this map, but on the opposite side of the mountain from where that -- the chosen alternative is. Unfortunately, there's no distribution line on that side of the mountain. Again, it's very similar terrain to our proposed route. So the proposed route we actually can access. We can hike that and be able to access that cable. 11:48

On the other side of that mountain, there's very similar terrain that we would be able to access; however, the distribution line is not at the bottom there. So we would have to build a couple kilometres of distribution line. So that put that out of the cost-effective range compared to the proposed route. 11:49

Because you'll see at the bottom there, the blue line, that's an existing power line that we would be

hooking into to go from there.

Q. Okay.

A. MR. MASSIE: So there were a number or a handful of other routes we did consider, but this chosen one was given -- was made just really on the access for -- that we'll have available to that cable going forward.

Q. And thank you, sir.

I think the first alternative to replace it as was -- definitely was in the business case, but the additional information about the other alternate route is helpful. 11:50

On the first day of the hearing in response to Mr. Marriott there was an exchange on whether capital additions for the streetlight conversion project would be a customer cost or a system cost. I think that was with you, Mr. Tenney, if you recall that.

The Board was wondering if this is going to be a system cost, could ATCO Electric Yukon undertake to provide the Board with a table showing the historical cost and accumulated depreciation and the resulting net book value that would be expected to be recovered for this project? 11:50

A. MR. TENNEY: Yes. We will undertake to do that.

Q. Thank you, Mr. Tenney.

UNDERTAKING - TO PROVIDE THE BOARD WITH A TABLE SHOWING THE HISTORICAL COST AND ACCUMULATED DEPRECIATION AND THE RESULTING NET BOOK VALUE THAT WOULD BE EXPECTED TO BE RECOVERED FOR THE CAPITAL ADDITIONS FOR THE STREETLIGHT CONVERSION PROJECT

Q. MS. SABO: I'd like now to move to one of the schedules. Actually, it's Attachment 9.2. So it's Exhibit BB-1. It's the YECL GRA application, Attachment 9.2, which is the 2017 capital expenditure information and page 2 of the hard copy. Page 189 pdf. 11:51

A. MR. MASSIE: That's the second page of generation appropriation is what I have. Is that correct?

Q. I've got it at the top. It's actually PLC replacement Stage 1, so it's Attachment 9.2, page 2.

A. MR. MASSIE: Sure, if you -- yeah, I think I'm there, if you just give me the -- oh, there. Okay. I went to the schedule. I am there. 11:52

Q. Thank you. I'm first of all going to look at the Teslin plant assessment where it says: (as read)

"The existing generating unit is contained in a trailered building on a

concrete foundation. During inspections, it was noted that there is considerable difference in elevation throughout the plant floor. The assessment will identify foundation and/or building deficiencies."

Our question is, since the problem in the floor and elevation been identified, could ATCO Electric Yukon go straight to bids from contractors to assess and fix the elevation problem versus doing an assessment? 11:53

A. MR. MASSIE: Yes, I think that is a possibility, be able to let them in there and assess the issue, I guess, and give us their recommendations to fix, and costs to fix, I suppose.

Q. Okay. And, Mr. Massie, would you expect that to be of similar cost to the 102,000, or would that reduce the costs required to fix this problem if you did it through bids rather than an assessment first?

A. MR. MASSIE: Sorry, can you repeat that?

Q. I'm just wondering if it's more cost effective to go straight to the bid tender process to look at getting it fixed rather than having an assessment cost included in your forecast. 11:54

A. MR. MASSIE: Mm-hmm. So I think one of the things we don't clearly detail in there is, you know,

the assessment is also going to give us an assessment of that -- of the plant overall health of the actual structure. But I don't think I would -- I would disagree. There's -- when we put it out for tender and for bid to fix it, there's just a few unknowns that we would -- we don't fully understand that could -- that I could give you any more detail, that the 102 could be high or lower than that.

Q. Thank you, Mr. Massie.

As an aside, I guess, with respect to capital projects ATCO Electric Yukon conducts, have you ever considered disclosing the results of bid tenders as part of a prudency review of the cost of the project? Now, I understand some of that information may be confidential, but to give you an example: In other jurisdictions, sometimes you'll see, you know, the ranking system, the final bids, maybe redacted copies of the bid tenders. Can you just give me a sense of -- of whether you've ever provided that information or would be willing to in the future? 11:55 11:56

A. MR. MASSIE: I don't know that we've provided that information in the past. You know, as we looked at the questions that we had on these projects and the variances and we went back and looked at the competitive processes that we put in place, I can tell

you we do have a very similar process in our tendering of our packages. There is a weighted score for each, you know, weighting of cost on the experience of the contractor, the references, timelines that they can meet. We do do all that in -- for our competitively tendered project.

A. MR. GRATTAN: And I'll just add to what Mr. Massie said is, is that there's a lot of what I would refer to as normal bread-and-butter-type utility construction work we do here in the Yukon. 11:57

In the past, where we do have something very unique -- and that was actually part of the 2008-2009 GRA where we were assessing moving to the next generation of billing systems, we went from an old billing engine to a more updated billing engine. And we did, as part of that proceeding, provide significant documentation on the record that evaluate the ratings and the rankings and the weightings of the various billing engine service providers that were out there.

So, in unique circumstances, we certainly have 11:58 done that in the past. When it comes to normal -- normal routine stuff, as Mr. Massie has pointed out, I would say we have not.

Q. Okay. And certainly if the Board were to request that information for projects, ATCO Electric Yukon could

provide some information at that time?

A. MR. GRATTAN: It is -- it is fair that the Board certainly can request that, and we would be certainly fine to provide in a way that maintains confidentiality.

Q. Okay. Thank you, Mr. Grattan.

Thank you for that foray. I'm going to take you back to Attachment 9.2 again looking at the PLC replacement, Stage 1. And we'd just like some more detail on what ATCO Electric Yukon is proposing to do with the $103,000 amount reflected there. 11:59

A. MR. MASSIE: Sure. So this PLC replacement, I guess it's important to note that there's two vintages as of now, two vintages of PLCs, control systems, that we utilize in our plants.

The ones that we've changed in Beaver Creek and Destruction Bay, they were -- I believe it's called an IDEC PLC. It was from a 1980s vintage, so there's that set of PLCs that we have out there. Then we have this newer -- as in from the '90s -- PLC system from GE. 12:00 **The difference and the benefit of the newer technology is that there is -- there is the ability to update and change these PLCs with the new upgraded hardware for the PLCs.**

It's not as in-depth as the older versions, the

IDEC versions, where basically all the hardware material, the whole system had to be decommissioned and removed and installed. This is more of a stepped process. It's my understanding that the majority of the hardware material that is out there in these PLCs will remain. It's more of electronics upgrades and a few small material items that need to be upgraded to -- to this PLC system.

So the Stage 1, really, we're looking at two -- two to three plants to go in there and put the -- install or look at the existing system, understand what it's going to take to replace it. Install possibly, if we can, the first stage of it. And that would really show us what we need to -- what we need to inform our future stages and future PLC replacements. We'll be able to understand fully the ramifications of changing out these older ones with the newer ones and apply that to our future PLCs.

Q. Okay. So there could be several stages depending on the results of the success per PLC replacement here? In Stage 1? 12:01 12:02

A. **MR. MASSIE: Yeah. I would say this is -- this is Stage 1. I don't know if there's going to be several. But there definitely will be later stages to replace our PLCs to bring them up to a more modern**

control system that can fully communicate with our SCADA systems and provide us some better data.

Q. Okay. And in terms of the Teslin plant assessment of 102,000, which we were discussing earlier, is that amount related to design only, or is it more encompassing to other items?

A. MR. MASSIE: No. It's not design only. And, I guess, I wasn't very clear there, and neither is the description. We based that amount on a past estimate we had for a new concrete pad in -- underneath this trailered unit. 12:03

Subsequent to that, it was thought that the actual trailer is what's the deficiency and not the concrete pad. So we've factored in some work on the concrete, but to look at the whole setup as a whole, the trailered unit and the concrete, to ensure that we get whichever deficiency -- whichever item is deficient fixed.

Q. And do you have the design for that project, how that's going to layout at this time, or is that still to be determined? 12:03

A. MR. MASSIE: Yeah. It's still to be determined. There's no finalized design yet or assessment.

Q. Okay. And the next item on there is the Watson Lake

plant fire alarm system for 102,000. Just had a question on whether there are fire alarm systems in other existing plants, or is this a unique item?

A. MR. MASSIE: Sorry. The question, are there any other fire systems --

Q. Alarm systems --

A. MR. MARTINO: -- in the plant?

Q. In your system. Like, are there other plants that ATCO Electric Yukon -- you have fire alarm systems for other plants in that -- not just Watson Lake? 12:04

A. MR. MASSIE: Yeah. Yeah. There would be an updated one in the new Old Crow plant. The older plant would have very basic ones, fire detection systems. This is really looking at -- there is a new design or new systems out there where the -- in the case of Watson Lake, if you look at the fire alarm system, instead of just heat and smoke detectors, as it mentions there, it will have individual sensors for each unit. So it will understand -- if the fire is contained to one unit, it will be able to shut off the 12:05 **fuel just to that unit.**

Then there's the -- the other systems will detect if it's a bit bigger and if the fuel system needs to be shut off for the whole plant or just one specific unit.

So, yeah, it's -- the system that we're looking at

here, and it's not -- again, we're just looking at the design of them, because there's a whole host of options that can be looked at for the system; but, as that system I just described, that isn't -- we don't have that system in place anywhere.

Q. Okay. So we don't know the expected total cost for that system as of yet? This is just the design cost?

A. MR. MASSIE: Yes. Again, there's a number of options, as we understand it, that there could be put in place for that power plant. We're going to look at the design. That will give us some informed costs for each one of those options. So we'll understand if -- be able to weigh the benefits of a better option or adding more options or not. 12:06

Q. Okay. Thank you, Mr. Massie.

MS. SABO: Mr. Chairman, I just have one more project to question on. I know we're a little bit over lunch, but I would appreciate your indulgence, if we could just finish off capital.

THE CHAIR: That's fine with everyone else, we'll just carry on. 12:06

MS. SABO: Thank you.

Q. Mr. Massie, I don't really want to pull up too many references here, but we just want to understand in terms of PLC controller upgrades, you've done one at

Destruction Bay for $307,000, and then we have the Beaver Creek programmable logic control PLC upgrade.

And just in terms of costing and lessons learned, we were -- we were wondering with respect to the Beaver Creek PLC controller upgrade project, did you apply any of the knowledge or the learnings from your Destruction Bay project to Beaver Creek? Or are they just -- you didn't -- they're not interrelatable? There was no sort of nexus between what occurred at both of those areas? 12:07

A. MR. MASSIE: No. It's a very fair question. Just -- the DB -- D Bay PLC project is forecast for 2017 for that -- the 307. We have incurred costs in '14 and '15.

But they are similar very similar systems for the Beaver Creek and Destruction Bay power plants.

We've looked at our project that we completed in Beaver Creek; and, really, the lessons learned -- again, we really underestimated the issues we were going to have in decommissioning the old PLC as we 12:08 **installed the new PLC while keeping the community's power on.**

As well as we ran into an issue in particular to that power plant that the Beaver Creek 2 replacement project was delayed, and it wasn't completed in '13.

So that -- we were expecting the new unit to show up already with that PLC system attached to it. So we wouldn't have to worry about that.

So there was definitely, as you say, some lessons to be learned from that one. They have been fully incorporated into our forecast for Destruction Bay. And I think that's why we see that number adjusted to 307 in 2017 compared to -- and, again, we already have -- and I think it's 109,000 in costs for that project. 12:09

But it's -- we've definitely informed ourselves and looked at that project in Beaver Creek, very similar one to D Bay, and what we'll need to complete that project incorporated in that forecast.

Q. And I don't have the numbers in front of me, Mr. Massie, but in terms of magnitude between those projects, is Beaver Creek a lot bigger or a lot smaller than the DB controller upgrade? Can you just give me a ratio show or a sense of the magnitude?

A. **MR. MASSIE: Again, they're very similar power plants. They're three-engine power plants. You know, they have this -- that -- that similar PLC that needs to be replaced.** 12:10

The difference I see for Destruction Bay is that we have two newer units in there that have been

recently replaced in '14 and in '15, with D Bay 2 being finished in '16. They would already have that updated PLC attached to that unit, and it would be -- right now, as it's running, it will be able to communicate with the old PLC of the power plant.

So each unit has its own separate controller, and then the power plant also has its central controller which controls, you know, the coordination of putting that generation onto the grid, the fuel system, and the -- a host of other power plant -- common power plant controls. That's what it does. 12:11

So very similar projects, very similar power plants, both in vintage and the setup of their units.

Q. Thank you, Mr. Massie. Those are my questions on capital.

MS. SABO: Mr. Chair?

THE CHAIR: All right. Does any Board member have any questions for the panel?

MS. SABO: Just lunch break we thought first.

THE CHAIR: Oh, just lunch break. Okay. No, 12:11
I thought you were saying --

MS. SABO: I still have a few more questions.

THE CHAIR: Okay. I wasn't sure about that, obviously. All right.

So it's 10 after 12, so why don't we convene at

20 minutes to 2, 90 minutes from now. Is that right?

A. MR. GRATTAN: Unless we were to go less than an hour. Subject to --

THE CHAIR: We can do that too. I'm --

MS. SABO: I know --

THE CHAIR: What works?

MS. SABO: Yeah, that's fine. I just note that a majority of the intervener groups had a lunch-hour conference, and they'll be back at 1:30, so I'm fine to keep -- 12:12

THE CHAIR: Well, let's go to 1:30 then. That weeks for everyone?

MS. SABO: Yes.

THE CHAIR: All right.

MS. SABO: Thank you.

(PROCEEDINGS ADJOURNED AT 12:12 P.M.)

PROCEEDINGS ADJOURNED TO 1:30 P.M.

Volume 3
November 3, 2016
P.M. Session

(PROCEEDINGS COMMENCED AT 1:32 P.M.)

UNDERTAKING RESPONSES:

THE CHAIR: Thank you, everyone.

So, Mr. Williams?

MR. WILLIAMS: Yes, sir. We have -- in order to be -- to be as efficient as possible here, we're going to try to respond to some of the undertakings from this morning just orally. The panel is prepared to deliver some of those answers. So if that's okay with the Panel and Board counsel, then we'll proceed in that manner. 13:33

MS. SABO: No objections from Board counsel.

THE CHAIR: Go ahead.

MR. WILLIAMS: Thank you, sir.

I'm going to turn things over to Mr. Grattan first, and he's going to respond to what I believe were the first and second undertakings taken this morning. He's also going to respond to one of his subject to check -- or his subject to check. So he'll be responding on three matters in total, sir. And then we'll turn things over to Mr. Massie, who will respond 13:33

to I believe what amounted to the fourth undertaking from this morning.

THE CHAIR: Go ahead.

A. MR. GRATTAN: Okay. So I'm going to hopefully clarify the discussion that was going on this morning about the amortization period of Demand Site Management costs. And we were trying to confirm where the five-year amortization period came, or the 20 percent amortization rate that's detailed on Schedule 7.3. And that comes from Board Order 2014-06, page 101, or 101, 13:34 **where the Board stated the Board orders that Yukon Electrical that capital the amounts of DSM spend in '2011, '12, and '13 relating to the development of the plan or policy paper and the pro rata amount of the costs already spent in 2011, '12, and '13 but not related to the development of the plan or policy paper and to amortize these costs over the 2014 to 2018 period.**

So that was -- that was what informed us as to amortize things as part of the 2014-06 decision. And 13:35 **we have used that same precedent for purposes of amortizing the DSM costs that were incurred in the years '14, '15, and '16 over a five-year period beginning in 2017. So I think if I've explained that correctly, we should be exactly the same as to how it**

was treated last time versus what we're proposing to treat it this time.

So that covers, I think, the two undertakings.

The subject to check, we were discussing the Watson Lake bi-fuel project and the addition of Watson Lake bi-fuel capital into Schedule 7.3. And I think the Board was asking for me to confirm that the Watson Lake bi-fuel was being added into Account 445, generating equipment and prime mover other.

And, yes, as I said, that was going to be the largest account that was used for purposes of the bi-fuel project. But there are also small amounts of Watson Lake bi-fuel that go into Account 444, which is fuel holders, producers, and accessory equipment; as well as Account 446, which is accessory, electrical equipment, other. 13:36

So between those three accounts, that's where the Watson bi-fuel capital is going. And as agreed by myself earlier, the majority of it goes into 445.

MS. SABO: Thank you, Mr. Grattan. If Board staff has any questions, we'll follow up with you in writing. 13:37

MR. WILLIAMS: Mr. Massie, we'll turn things over to you, sir.

A. MR. MASSIE: Yes. I was to provide the

year-to-date costs for new extensions, and as of October 31st, 2016, our actual costs are $2,116,000.

MS. SABO: Thank you, Mr. Massie.

MR. WILLIAMS: With that, Mr. Chairman, I believe we're done with what we're able to provide at this point in time.

THE CHAIR: Okay. Thank you.

Ms. Sabo.

MS. SABO: Thank you, Mr. Chairman.

Q. I do have a few follow-ups from this morning on capital. 13:38

Mr. Massie, you were talking about PLCs and DL -- diesel generation unit this is morning, and I have a high-level question. Generally, when you install a new diesel generation unit, would new PLCs come with the unit, or would you use existing PLC?

A. MR. MASSIE: A new -- a new unit would come with a new PLC already attached, yes.

Q. Okay.

A. MR. MASSIE: To be certain, there would be modifications that will need to ensure that it works. If we're putting it into an older plant that has an older PLC, there will be some modifications we will need to do, but the unit does come with an updated PLC. 13:39

Q. Okay. Thank you. I would like to take you back. We

were talking a little bit about manufacturing of generation and diesel engine units and warranties in terms of Watson Lake, and the Board has a few follow-ups. Is the manufacturer of the conversion kits for biofuel generation the same as the manufacturer of the generation engine? Do they come from the same manufacturer?

A. MR. MASSIE: Well, we are planning on competitively tendering the process. The manufacturer of the units does provide the bi-fuel kits, so we are assuming that they will be responding to that tender. 13:40

Q. So it's uncertain at this time whether they will be the same as the manufacturer of the diesel generation units.

A. MR. MASSIE: That's a fair assumption. It could be -- they could be, or it could be another third-party, yes.

Q. Okay. For example, for the diesel generation Unit Number 2 that you're replacing, what is the warranty for that unit? 13:40

A. MR. MASSIE: And to be specific, I would have to undertake to provide that, but generally the diesel units come with warranties of a certain time, whether it be six months or 12 months and operating hours. So usually there is one or the other that will have a

warranty unit -- a warranty timeframe for the unit.

Q. Okay.

A. MR. MASSIE: Could be a combination of the both or one or the other.

Q. Okay. And would that warranty be impacted by the addition of the conversion unit that you would be placing on these diesel generators?

A. MR. MASSIE: Again, we -- we're not expecting it to be impacted, but that would have to be determined at the time of the successful tender process, I suppose. 13:41

Q. And that would apply to both of the warranties you mentioned; right? You're uncertain on both the operating and the other warranty, how that would be impacted?

A. MR. MASSIE: Sorry. The -- the two warranties?

Q. Yeah. I'm just trying to make sure that we're talking about, if the warranty is impacted by the conversion unit, you mentioned two different types of warranties. So... 13:42

A. MR. MASSIE: Oh, sorry. Yeah. It's the same warranty. It's just the hours -- there's an hours demarcation, operating hours for the unit that's covered by warranty or time, whichever comes first. So it's not operating very much in the first 12 months,

then if it was a 12-month warranty, they would go with the 12 months.

Q. Okay. Thank you for that.

I would like to ask a question on cost of debt, and it's in the IR responses at Exhibit B-9, and it's the YUB-YECL-73.

A. MR. GRATTAN: Just one moment, please.

Q. No problem. And I've got a pdf page of 398, Mr. Grattan. So I don't know if that's close to where you need to be. 13:43

A. MR. GRATTAN: I'm there.

Q. Thank you.

And I've glad you got a hard copy, because we put together our compilation tables of the bond rates. So I'm going to walk through.

2011 bond spread, the 2011 actual we have at 1.637 from that IR. And it might be in (b) or (c).

A. MR. GRATTAN: Yes, I see it, yes.

Q. Or (a).

And 2012 actual is 1.533? 13:44

A. MR. GRATTAN: Yes.

Q. 2013 actual is 1.589?

A. MR. GRATTAN: Yes.

Q. 2014 actual, 1.475?

A. MR. GRATTAN: Yes.

Q. 2015 actual, 1.767?
A. MR. GRATTAN: Yes.
Q. And then 2016 forecast and '17 forecasts we have at 1.8.
A. MR. GRATTAN: Correct.
Q. Great. And we're just wondering, given that trend between the actuals and the forecasts, can you explain the trend in the actuals, why that change had occurred, that upward trend in '15?
A. MR. GRATTAN: No. I won't -- I'm not going to be able to explain it at any technical level, other than I can share that in the recent Alberta generic cost of capital decision, I have read that the Alberta Utilities Commission has noted recent spreads increasing. So that it was -- it was noted by the Alberta Utilities Commission. I presume it was also noted by the various parties in -- as part of the Alberta GCOC. 13:44
Q. Okay.
A. MR. GRATTAN: That's about all I can say about it. 13:45
Q. That's fine. Yeah. We were just noting that the variation in numbers, you know, it seems to be higher in '11, '12, '13 actual, and then you have a dip in '14, and then back up in '15.

So can you explain why the forecast years show a higher bond spread than those historicals? Why are you forecasting --

A. MR. GRATTAN: Sure. Well, the -- I think what our treasury department has based this forecast on is recent spreads, as is noted in this -- as is noted in 2015, the spread increased between '14 and '15 to a point of 1.67 -- 1.767 in 2015. And the treasury department has taken it up to 1.8 for forecast purposes for each of 2016 and '17. So I'm not sure I can add much more to it other than it's based on recent bond spreads. 13:46

Q. Okay. Thank you.

I have some questions about the deferral accounts applied for, and you provided a summary table in response to -- I believe, it was YEC, and it's the last page of their IRs at Exhibit B-8, pdf page 40 of 40.

A. MR. GRATTAN: Sorry. Can you repeat which YEC response, please?

Q. Yes, I can. Move some notes around, Mr. Grattan. So I'm going to find it again here. It's YEC-16. 13:47

A. MR. GRATTAN: Thank you.

Q. And the very last page of those IRs.

A. MR. GRATTAN: I am there.

Q. Great. Thank you.

As you well know, there's a -- reflected in that table, there's a diesel fuel deferral account that's been previously approved by the Board. And we just wanted confirmation if the account -- only accounts for changes in the price of diesel, or is there more included in that account?

A. MR. GRATTAN: The -- it is a status quo. So the diesel fuel deferral account is strictly dealing with price variances tied to diesel fuel.

Q. Okay. 13:48

A. MR. GRATTAN: And then -- presumably you're going to go on to the next line, LNG fuel deferral account.

Q. Yeah. Again, yet does that only account for change in prices?

A. MR. GRATTAN: Yes. So it's just a different fuel. And we're certainly open to how the Board -- if the Board believes there's a better way of handling this, we're open; but our proposal is to have two separate deferral accounts, one for diesel fuel, and 13:48 **one for LNG fuel.**

Q. Thanks for getting ahead of me, Mr. Grattan.

The other -- I know we did recently for ATCO Pipelines in Alberta, we had one deferral account, but we had them account different types. So LNG, say,

in one line item and diesel fuel in the other, and then one account. So you wouldn't object to anything like that?

A. MR. GRATTAN: We would not.

Q. Thank you.

And moving back up to the purchase power flow-through, I want to take you to a different IR. It's a Commission IR, YUB-YECL-47(b).

A. MR. GRATTAN: Just one moment, please.

Q. That's fine. And it's hard copy page 3. 13:49

A. MR. GRATTAN: I am there.

Q. Thank you.

In that response, ATCO Electric was asked to comment on whether under a power purchase flow-through deferral account, it would be guaranteed a fixed margin, where the fixed margin was defined as incremental sales revenue less power purchase costs, as set out in the last GRA. And ATCO responded in part that it would assume risk associated with sales volume but would not assume risk associated with changes to 13:50 the wholesale purchase rate.

Can you explain what is meant by a "sales volume risk" in that context?

A. MR. GRATTAN: Sure. So as part of -- as part of this application, we have had significant discussions

with respect to how ATCO Electric Yukon's actual sales have turned out compared to what was awarded or approved. And over the last three years, for example, we have had actual sales come in lower than approved, and that has resulted in us having a lower margin, which is the delta between what was forecast for sales less us buying less electricity from Yukon Energy. So from a pure volume perspective, we have either a risk that we are going to have less margin, or we're going to -- if actual sales come in higher, we're going to have more margin. It's not much more complicated than that.

Q. Okay. And I'm sure the parties may to want to reply on this in argument and reply argument, but I would like some follow-up for you whether -- does that -- does it mean that there would be a guaranteed fixed margin on sales in excess of forecasts through the use of the power purchase flow-through deferral account as proposed by ATCO Electric Yukon?

13:51

A. MR. GRATTAN: I think you're going to -- I better let you repeat that, make sure that I got --

13:52

Q. Okay.

A. MR. GRATTAN: I got it. A guarantee fixed margin.

Q. On sales in excess of forecast.

A. MR. GRATTAN: So if -- maybe the easiest way to explain this would be to use a simple example.

Q. Great.

A. MR. GRATTAN: And -- let's see here. How can I go about this? Okay. So there's -- the current Block 1 energy rate, excluding riders for residential, customers is 12 cents. So if our actual sales are 1 kilowatt hour higher than what was forecast, we're going to have an additional 12 cents. And because we're buying in the hydro zone, our electricity from 13:53
Yukon Energy at -- is that 8.3 cents -- 8.3 cents, we're going to have to buy -- I'll just round it to 8 cents so I can get my math right here.

If we're -- given that we're going to have one additional kilowatt hour of sales to factor in line losses, which is at 6 percent or about that, we're going to have an additional 8 cents of purchase power cost. So the delta between those two at a real simplistic level is 4 cents. So our gross margin will go up 4 cents if we have an additional kilowatt hour of 13:54
sales higher than forecast.

Vice versa, it goes in the other direction if we are -- if our sales forecast is too high, which has been the case the last number of years.

Q. Okay.

A. MR. GRATTAN: Is that helpful?

Q. Thank you, Mr. Grattan.

A. MR. GRATTAN: And just one other thing. Mr. Tenney is also reminding me, and it's just to add a little more complexity to the equation here.

We also -- that's -- that 12 cents was based on the first block of rates. We also have a block between 1,000 and 2,500 kilowatt hours and over 2,500 kilowatt hour. And each one of those blocks has different rates. For example, the second block has a rate of 13:55
12.8 cents, and the third block has a rate of 13.99 cents. So depending on what goes on between actual and forecast, you could have margins bouncing around, either us having additional earnings or net earnings, net margin, or additional loss of margin.

Q. Okay. So by having that deferral account in place, does that result in a guaranteed fixed margin for ATCO Electric Yukon on sales in excess of the forecast?

A. MR. GRATTAN: I think it guarantees that there will be -- there will be an additional margin, whatever 13:56
it turns out to be, if sales are higher than forecast. And then I keep repeating. It's the same deal on the other side, so it's mirrored one way or the other.

Q. Okay. Thank you. I would like to move on to the pensions deferral account, and I just wanted -- I

understand that -- the matters before the Alberta Utilities Commission on the pensions for 2014 and '16. But are there any unique or special charges that may apply to ATCO Electric Yukon that would not apply to the other ATCO entities that we should consider in terms of pensions and pension deferrals?

A. MR. GRATTAN: If there are any, I am not aware of them.

Q. And given that proceeding is a 2014 to 2016 proceeding, how would you expect to adjust for the pension amount for '16 and '17 in this proceeding -- 13:57

A. MR. GRATTAN: So --

Q. -- or after?

A. MR. GRATTAN: Sure.

Q. Yes.

A. MR. GRATTAN: The pension application currently before the Alberta Utilities Commission covers the period '14, '15, and '16, and for the period 2016, ATCO -- the ATCO Utilities have requested the COLA to be 100 percent, as opposed to do the currently approved level of 50 percent. 13:58

For 2015, I believe they've -- ATCO Utilities has asked for 80 percent of COLA as opposed to the currently approved 50 percent. So I'm anticipating, if the world unfolds as we anticipate it, that the

Alberta Utilities Commission will either -- well, it's going to land on a number of possibilities, but we fully anticipate for 2016 forward whatever the Alberta Utilities lands on, that's what we will incorporate for our proposal in this application.

Q. Okay. Thank you, Mr. Grattan. I think the Alberta Utilities Commission is probably glad you didn't reference any numbers there, since I'm counsel on that proceeding.

For ATCO Electric Yukon's DB pension for placeholder amounts for the test years, do the amounts contain any provisions for special payments? 13:58

A. MR. GRATTAN: They do not.

Q. Well, I --

A. MR. GRATTAN: Sorry, and just -- sorry. That -- that was updated. In the latest numbers that we've provided, that there is no special payment for 2016.

Q. Thank you for that additional response.

And special payments, that's '16 and '17; right?

A. MR. GRATTAN: Correct. Based on the actuarial evaluation as of December 31st, 2015, and that is the latest forecast. There would be no special payments for the years '16 or '17. 13:59

Q. Okay. Will ATCO Electric Yukon's defined benefit pension be considered to be in a liability position for

either of the test years?

Yeah, I think you answered that. I just wanted to confirm.

A. MR. GRATTAN: That I'm going to have to -- when you say a "liability," like, the overall plan?

Q. Yeah. I was thinking on the higher level, rather than on the special payments.

A. MR. GRATTAN: Just one moment. I'm not sure. I've got to be careful here because you've asked -- you think that I've answered it, but I'm not sure I have. I don't know whether you can help me where you think that I've answered it. 14:01

Q. Well, we were just talking about how the special payments are one issue and the overall liability of the fund is a different issue.

A. MR. GRATTAN: Yes.

Q. So if you have any comments on the overall liability, that's fine. If you don't, that's fine as well, Mr. Grattan.

A. MR. GRATTAN: Okay. If you'll let me off the hook on that one, I would prefer not to speak to the overall plan. 14:01

Q. Yes. Thank you.

ATCO Electric Yukon is asking for a deferral account for regulatory changes and load changes due to

government programs, which has been discussed in previous days of this hearing.

The Board would like more detail on how this deferral account would work.

A. MR. TENNEY: So there is a response that I'm sure you're aware of, YUB-2(b).

Q. Yes.

A. MR. TENNEY: So it's my understanding that the one example that I'll use is the IPP policy that we talked about on Day 1 of the proceeding, where, if the government ends up with a policy that we have to purchase power from an IPP that's greater than what the costs would have been had we generated the power ourselves and if the government doesn't backstop that situation, we would propose to put that in a deferral account and come back before this Board in a subsequent GRA to look for collection if those costs are prudent.

14:03

Q. Okay. So would it be fair to say, Mr. Tenney, that the parameters for what you're expecting in this account would be sort of any sort of government policy? As it kind of arises within the test period, then you would put in those amounts, and then it would be up to the Board to determine whether those amounts were prudent after they were incurred?

14:03

A. MR. TENNEY: That would be how I would think it

would work.

Q. Okay. Thank you.

I have a few questions on errors and omissions, which is my final area. We notice that you put on -- and it's well-established on the record -- you put in an update of October 24th on errors and omissions that you corrected as of that date. We were just wondering, are there any other error and omissions that you're aware of as of today?

A. MR. GRATTAN: From a revenue-requirement perspective, we're not aware of any other changes. The only reason I was having this conversation is, is that one of the tables that was being referenced to yesterday, I believe -- it's an O&M table that determines O&M per customer, I believe. 14:05

Q. Yes.

A. MR. GRATTAN: There's a mathematical error on it that we are wanting to correct. We were going to put that in along with our remaining undertakings. And it's just a mathematical error in that table. 14:05

Q. Okay.

A. MR. GRATTAN: So that's -- it's something that we would just make sure that the record is as clear as possible.

Q. That would be appreciated, Mr. Grattan. I'll leave you

with that.

We also do have one that we noticed as well. It's not necessarily an error and omission, but in the October 24th, 2016, update, and it's -- for the Board's reference, it's Exhibit B-13.

And I'm going to take you to line 1 of Schedule 10.1, which is the utility EBT.

A. MR. GRATTAN: Just one moment, please. I'm there.

Q. Okay. And I've got a note here, the correction of that error resulted in an EBT for 2016 changing the amount from 3.2 million to 3.944 million, which is an increase of 661,000. And then for 2017, the resulting change for EBT was from 4.542 to 3.728, which was a decrease of 814. 14:07

Are you seeing that there, Mr. Grattan?

A. MR. GRATTAN: So I'm not sure I heard you correctly. It's my understanding that for 2016, the original schedules --

Q. Yes. 14:08

A. MR. GRATTAN: -- showed a utility earnings per tax -- or utility earnings before tax of 3,944,000, which was decreased to 3283.

Q. Okay. I think we have that backwards.

A. MR. GRATTAN: Yeah. And then for 2017, it was

originally stated that 3,728,000 and updated to 4,542,000.

Q. Okay. Thank you, Mr. Grattan. And just -- we noticed in our Excel versions of Schedule 10.2 there was no formula in the cells --

MR. GRATTAN: Yeah.

Q. -- for the test years.

A. MR. GRATTAN: Yes.

Q. Are you able to provide us an Excel version of the schedule with working formulas? 14:09

A. MR. GRATTAN: Of course.

Q. Thank you. And that --

A. MR. GRATTAN: I can undertake to do that.

Q. That is your final undertaking from me today, sir.

UNDERTAKING - TO PROVIDE AN EXCEL VERSION OF THE SCHEDULE 10.2 WITH WORKING FORMULAS

MS. SABO: Thank you, panel. We really appreciate you attending today, and we know it's been some long days, and we appreciate your responses. 14:09

A. MR. GRATTAN: Thank you.

A. MR. MASSIE: Thank you.

THE CHAIR: Thank you.

Did any Board members have any questions?

THE CHAIR QUESTIONS THE PANEL:

Q. So I had one. And yesterday I think it was Mr. Tenney was having a discussion with Mr. Rondeau from UCG, and it was talking about consultations with the public and those sorts of things. And I note that YCL or AEY was in attendance at the recent LNG facility proceeding that the Board conducted. And I'm not sure if any of you attended the -- there was an evening session that the Board scheduled there in which the public had an opportunity to address the Board. 14:10

These proceedings are necessarily formal and often intimidating and aren't really a very good vehicle for people to do that. And -- but you had indicated some thoughts about the Board doing things like that. And I wondered if you had any comments on the -- on any benefit that you may have seen coming from that. I mean, recognizing that the Board is an evidentiary-based thing, and panels come and provide evidence, which is tested, and that kind of material is not. But do you think it informs the process in any way? 14:10

A. MR. TENNEY: So I wasn't at that myself. I don't know if my colleagues were. But I would suggest anything that allows the public to participate -- I would think if I was coming into this room to make a

presentation, it looks rather intimidating, and I can't even keep up with the volume of data that's in here. So it's a difficult task.

So if there's a more informal way to engage our customers about what we're doing, I don't think we would be opposed to any of that. But it's hard sometimes to translate what they exactly say to us and whether we actually took action or whether they perceive that we took any action that could be a challenge. But we're open to any of those forums. 14:11

As -- as Mr. Rondeau suggested, it's probably unlikely that a lot of our customers are looking in the newspaper to see that we're planning a rate application, and then whether they would attend an event like this.

So we're open to it. We don't have any earth-shattering suggestions here about what that could look like and how it would be benefit -- or how you could structure it to make sure it was most beneficial. But we're open to that. 14:12

Q. Yes. It's not likely -- the general public doesn't always read the legal notices in the paper, and so -- but I'm wondering how you think, maybe, that those sorts of comments that come to people if, say, at that event we scheduled, I don't know, two or three hours

and gave people five minutes or whatever, and they had to register in advance, but really the information that they gave was only of value to interveners or panelists who might incorporate that into what they were doing. It's not something that really can enter into the Board's deliberations. So I wonder if you see a way to get that information and use it with the public?

A. MR. TENNEY: So if I understood you -- and again, I apologize that I'm not familiar with what happened in that evening event at the LNG facility proceeding, but if you're suggesting customers, residents in the Yukon can attend an informal session with intervener groups, and intervener groups can utilize those thinking into the process, that's your question: Would that be beneficial? 14:12

Q. Yes.

A. MR. TENNEY: Well, I think it is, but if somehow it would be -- there's a part of me -- and I know we always like to think we're going to do a great job educating staff but -- or our customers, I'm not sure most customers understand how we go about -- all of us go about setting rates, what makes up revenue requirement after you get revenue requirement, how does it get allocated to customer class, and then how do you ultimately design rates. 14:13

That's probably the biggest barrier to everybody participating fully is they don't quite understand how all that works. So we'd love to say, well, let's just educate them, but how do you get them to come out to get educated? And it might not be -- surprise to some of us, but it might not be the most exciting subject matter.

So I'm not sure -- again, I'm not sure I'm giving you anything, but the more we can do, the better off we're going to be, because if we don't have public participation in front of the Yukon Utilities Board, we don't really have a great rate-setting mechanism. 14:14

Q. Okay. Thank you for that. And at that event, of course, we recorded that stuff. It formed part of the transcript, although it didn't really enter into the decisions. But if people took some of those concerns and incorporated them into their questions or their answers, that would be useful.

Okay. Thank you for that. And that's all that I have. 14:14

THE CHAIR: Anybody else? No.

Then subject to the panel finishing up with the odd little undertaking or subject to check that they need to report on, I think that we can release this panel.

MR. WILLIAMS: Yes, sir. I just have a couple -- couple hours of redirect maybe.

THE CHAIR: Okay. Only two? Sorry, I forgot to ask you about that.

MR. WILLIAMS: No, I'm good, sir. We can release this panel.

THE CHAIR: You don't have anything for them?

MR. WILLIAMS: No.

THE CHAIR: Okay. So, panel, thank you for your time and your patience. 14:15

A. MR. TENNEY: Thank you very much.

THE CHAIR: And Godspeed.

A. MR. MASSIE: Thank you.

(PANEL STANDS DOWN)

MS. SABO: Do we want to maybe take a ten-minute break to switch out the panels?

THE CHAIR: Okay. We'll do that so that the panel can pack themselves up, and then we'll put the other panel on. So where are we at here? So say 25 past we'll reconvene. Thank you. 14:15

(ADJOURNMENT)

THE CHAIR: So good afternoon again.

And are we ready to proceed with the City of Whitehorse panel, Mr. Marriott?

MR. MARRIOTT: Yes, sir, we are.

THE CHAIR: Would you like to introduce your panel.

MR. MARRIOTT: Good afternoon, Mr. Chairman, Board members. It's my pleasure at this time to introduce to you the witness for the City of Whitehorse. Mr. Russ Bell.

Mr. Bell prepared the evidence that is marked as Exhibit C3-3. And his responses to information requests from the Board are marked as Exhibit C3-4.

Mr. Bell is a chartered professional accountant. 14:39
And his experience and training are outlined in Appendix A of his evidence. And with that, by way of brief introduction, I would ask that Mr. Bell be sworn, please.

R. BELL (For City of Whitehorse), sworn

MR. MARRIOTT EXAMINES THE WITNESS:

MR. MARRIOTT: Okay. Thank you.

Now, Mr. Chairman, what I propose is that I'm going to move to the formal introduction -- sorry -- 14:40
formal adoption of evidence by Mr. Bell, and then I'll have him say a few things to the Board about his training and experience.

Q. So, Mr. Bell, a few moments ago I mentioned Exhibits C3-3 and C3-4. Were those documents prepared

by you or under your direction and control?
A. Yes, they were.
Q. Do you have any corrections to make to any of that material?
A. No, I do not.
Q. Are those Exhibits C3-3 and C3-4 true and accurate to the best of your knowledge and belief?
A. They are.
Q. Do you adopt those exhibits as your evidence on behalf of the City of Whitehorse in this proceeding? 14:41
A. I do.
Q. Now, Mr. Bell, as I mentioned, before I turn you over for questioning, I would ask that you outline for the Board's benefit your qualifications, training, and experience relevant to your testimony, and feel free, in doing so, to refer to Appendix A in Exhibit C3-3 as you do so, sir.
A. Thank you. I hold a Bachelor of Commerce agree from the University of Alberta. I received that in 1981. I'm also a professional accountant, a CPA, formerly a 14:41
CMA or certified management accountant. I have over 35 years' experience in the utility industry, starting my career at Canadian Western Natural Gas in Calgary, which is the local gas transmission and distribution company, as well as providing retail.

In that, I've done work in accounting, business planning, budgeting, rate applications, and in IT. I ended my career with ATCO as controller of their IT division, ATCO I-Tek.

Since leaving ATCO, I have been a consultant representing the interests of customers, largely working on a number of files for General Rate Applications, specialized applications regarding income tax, smart metering. As well, recently I've been involved heavily involved in the recent performance-based regulation initiatives in Alberta representing customer interests in the first and now second-generation PBR proceedings.

Q. Thank you, Mr. Bell.

MR. MARRIOTT: Mr. Chairman, Mr. Bell is available for questions.

THE CHAIR: Thank you.

So, Mr. Williams, YECL, will you be asking any questions?

MR. WILLIAMS: Sir, I would ask that you maybe canvas the other interveners first. I understand that one of them may have some questions, and if it would please you, I would like the opportunity to go last, if possible.

THE CHAIR: That's fine.

14:42

14:42

So UCG, Mr. Rondeau.

MR. RONDEAU CROSS-EXAMINES THE WITNESS:

Q. Good day, Mr. Bell.

A. Good afternoon, sir.

Q. My first question would be that you summarize a bit of the evidence that you've presented to us on the functional review of YECL's cost and showing that you believe there's a consistent pattern for YECL or AEY to overforecast its costs that are being used to establish rates. 14:44

THE CHAIR: Mr. Williams.

MR. WILLIAMS: Sir, this is -- Ms. Sabo and I discussed this briefly. I'm certainly happy to have interveners question Mr. Bell, but obviously there's a fine line between relevant questions from interveners and what would -- what I would term as sweetheart cross here. And I'm hesitant to give Mr. Bell another opportunity to elaborate on his evidence as a result of questions from Mr. Rondeau.

MR. RONDEAU: I'm simply asking for a summary. 14:44 Either way, it doesn't matter that much.

THE CHAIR: Why don't we try it this way: Do you have questions about some areas that he's asked, and would you like to --

MR. RONDEAU: I certainly do.

THE CHAIR: Okay. Would you -- why don't we try it that way.

Q. MR. RONDEAU: Is it fair to say, Mr. Bell, that based on your analysis, AEY's rates over the last several years have resulted in recoveries from ratepayers that are significantly -- significantly above the required levels?

THE CHAIR: Mr. Williams.

MR. WILLIAMS: Sir, I -- I'm not trying to be difficult, and I do hate to take this position at this point, but this is clearly sweetheart cross, and I need to object to it, sir. 14:45

MR. RONDEAU: I'm not trying to sweetheart cross, I'm just trying to get at the meat of the matter here.

THE CHAIR: Maybe you could rephrase that question in a way where you're asking him -- I'm not going to tell you how to ask the question, but I think there's another way to ask it.

MR. RONDEAU: Okay. 14:46

Q. Is it fair to say that, based on your analysis, that AEY's rates have been overforecasted?

MR. WILLIAMS: Sir, I'm not -- again, I'm not sure there is a way for him to ask this question that wouldn't amount to sweetheart cross. Either way,

Mr. Bell's evidence stands for itself.

I think the only -- the only party here that is adverse in interest in a strict legal sense to Mr. Bell would be YECL, so I think unless Mr. Rondeau has questions about Mr. Bell's experience or something like that, I'm not really sure where we can go with this line of questioning.

THE CHAIR: Well, Mr. Rondeau -- well, just let me hear from our counsel first.

MR. RONDEAU: Yes. 14:47

MS. SABO: Mr. Chairman, I just thought from -- I can give legal advice from legal counsel for the Board's perspective. And Mr. Williams is correct. I informed parties yesterday that, if they have a specific question on a specific portion of Mr. Bell's evidence, that they're all welcome to ask those questions. And certainly, as you have pointed out, the Board certainly doesn't want to direct the questions people ask; but if Mr. Rondeau is able to point to a certain portion of Mr. Bell's evidence or an IR 14:47 response in framing a question, that would probably be helpful without us foraying into sweetheart cross.

MR. MARRIOTT: Maybe a comment from me might be of some assistance. I would just say this from the City of Whitehorse's perspective: Mr. Bell's here to

answer any questions the Board considers relevant and appropriate. We're not here to do anything that would be contrary to practice or what has been built up as sort of the rules relating to this issue.

So, in Alberta, certainly where I do most of my work, there is a rule against sweetheart cross-examination, which essentially means a party essentially on the same side as Mr. Bell is using the examination to emphasize or reiterate a position that they already agree with. 14:48

Where I've seen other tribunals allow examination by an intervener that looks to be aligned in interest would be on true matters of clarification where something was unclear, and they're trying to elicit clarity.

MR. RONDEAU: I think I understand that.

THE CHAIR: Okay. Thank you for that. I just need a second, please.

Yes. So I think Mr. Bell's evidence is on the record, and it's been accessible to everyone. So if 14:49 you have a question about a specific conclusion or about how he arrived at that conclusion that you could ask him or that you wanted to shed some light on, that I think would be an appropriate area. But these other kinds of questions I think are not.

Proceed.

MR. RONDEAU: I'll try this one, and we'll see where it goes.

Q. Do you have any recommendations on how applications by the Yukon utilities could be improved to present a more useful picture of past performances versus the test year forecast?

A. In my evidence, I have done an analysis that is not different than I have done in other jurisdictions where I've compared forecast accuracy over a recent historical period to assess whether the utility has a history of overforecasting or underforecasting in a specific area. 14:50

In my analysis, I have derived the results I have in my evidence based on that experience and that practice.

In terms of how a utility could improve its forecasting, I think it's up to the utility to develop a forecasting methodology that it thinks is reasonable and produce evidence that it asserts supports that methodology. 14:51

In my evidence, I've identified several areas where I do not believe the historical trends demonstrate an accurate level of forecasting.

Q. Okay. I'm sure you've heard in the last few days that

some of the controversy is non-controllable costs and -- as well as capital project costs.

Are you aware of ways that other jurisdictions handle these type of things to be sure that overforecasting does not take place?

A. Any forecast by its very nature will not be exactly what you see in the actuals. My concern arises when there's a consistent pattern of overforecasting. When a utility has a reasonable methodology, my expectation is you would see variances because by the very nature forecasts are not precise. 14:52

But one would expect those variances to fluctuate on either side of the forecast.

In other jurisdictions, there are things that are done to try and mitigate that. In Alberta, we have gone through an extensive PBR methodology to try and change the way utilities behave. That's another discussion.

There are opportunities to test on a hearing basis like is done here. But, really, you know, in terms of preventing overforecasting, that's really in the hands of the Commission or the Board here as it assesses the record, looks at the history of the utility, and it comes up with what it thinks result in just and reasonable rates. And that's why I'm here presenting 14:52

my evidence, to provide a view of what I think has happened.

And this Board will then take that evidence, weigh it with the evidence of the utility, and come up with what it views as just and reasonable rates for utility customers in the Yukon to pay.

Q. Okay. Thank you.

Would you agree that such a thing as WIP, which is used in many jurisdictions, work in progress, would be useful deferral account to put these non-controllable costs into and as well as capital projects, until they are deemed used and useful? 14:53

A. **Well, work in progress or construction work in progress is an accounting construct. It's not a deferral account. When a project is initiated, the costs are gathered in work in progress. When the project is complete and put into service, it is moved from work in progress to plant in service.**

And so I believe YECL already uses work in progress as an accounting construct because it operates under Generally Accepted Accounting Principles and that is one of them, or one of the constructs that would be used. So I'm not really sure what you're asking, sir. I suspect YECL already uses work in progress as it's intended. 14:54

There are other constructs. In Alberta, the large transmission companies have a deferral account for projects that are directly assigned from the Independent System Operator or ISO. But those are very large projects that are not forecastable at all because they're based on the ISO long-term plan, which changes from time to time. And the utility really has no choice but to comply with the ISO plan.

There isn't really anything like that here. So I'm really not sure how you would do it. You could introduce more deferral accounts, yes; but that shifts risks from the utility onto customer, and I'm sure that's always a good thing either. 14:55

Q. Okay. Thank you.

That's what I was looking for, was maybe some type of remedy that other areas use to fix these problems that we're having here.

Basically the only other thing I have is that, in looking at your CV, that's the appendix of your evidence, you indicate that you have a lot of 14:56 experience in reviewing and testifying in other jurisdictions on rate applications.

So perhaps you could provide a specific reference to a regulatory proceeding where a utility has been found to overforecast its revenue requirement and maybe

remedies that the regulator used.

A. Well, each of the appearances, when it relates to a general tariff application, a portion of my evidence may have focussed on overforecasting. The remedy is -- in the jurisdictions I've dealt with -- and I believe this to be the same -- on a prospective-ratemaking basis, the remedy is to -- for the regulator to adjust the forecasts, to reduce the forecasts.

I don't believe there is a remedy that can go back and claw back or recoup any overforecasting. By the very nature of a future test period jurisdiction, once the revenue requirement is set, my understanding is that the utility then is -- is to operate its utility to create efficiencies and to benefit from those efficiencies. 14:57

That is one of the benefits of a future test period, is that the utility is incented to find efficiencies. The issue is were there's consistent overforecasting, then one has to question whether the utility is finding true efficiencies or is, in fact, using forecasting methodologies that should be changed. 14:57

So the remedy is for this Board to take note of the areas of overforecasting and adjust those portions of revenue requirement where it finds that, in fact, has been a systemic overforecasting.

Q. Very good.
MR. RONDEAU: Thank you so much.
THE CHAIR: Thank you.
Mr. Maissan.
MR. MARRIOTT: Mr. Chair, I think given the previous discussion and the questions that Roger asked, I don't think I have any questions that would be fruitful. Thank you.
THE CHAIR: Thank you.
Yukon Conservation Society? They have no questions? 14:58
MS. MIDDLER: No.
THE CHAIR: No.
And that's it, Mr. Williams. Would you like to...
MR. WILLIAMS: Sir, ATCO Electric Yukon has no questions for this witness.
THE CHAIR: Thank you.
Ms. Sabo.
MS. SABO: Thank you, Mr. Chair.
MS. SABO QUESTIONS THE WITNESS: 14:59
Q. Mr. Bell, I have a couple of questions to follow up with. I would like to take you to your IR responses to the Board. And it's Exhibit C-4. And I'm looking at IR Response 4 and -- 4(b). And the last paragraph of IR 4(b) on page 5.

A. I'm there, ma'am.

Q. Okay. And I was particularly interested in the first sentence you have there, which says: (as read)

> "If the Board wants to access the forecast costs, it could examine the forecast costs per new extension and compare that to historic actual costs per new extension."

A. I'm sorry, I'm not following. I thought I was there.

Q. Okay. It's your IR Response 4(b). 15:00

A. 4(b), as in Bob, yes.

Q. Yes. Last paragraph. And it's on its own on page 5.

A. That's my problem. I didn't go down one page far enough. Okay. I am there now.

Q. Okay. So in terms of that first sentence, sir, I thought this was an interesting concept, but I wondered how practical it would be to do that. Would you suggest that we do that on a one-time basis, or should we do that in each application, to look at the forecast cost per new extension and compare it to the historical 15:00 actual cost per new extension?

A. When I was writing this, I was thinking on an average. So it shouldn't be that onerous. It would be taking forecast capital additions and actual capital additions, looking at total new extensions in each

year, coming up with a cost per unit, and looking at the trend and the forecast as a way of assessing whether or not the forecast costs were within a reasonable range. I recognize that in any utility from one year to the next there can be a mix of different kinds of extensions, commercial, residential, multi-family, and things like that, so it's an indicator that allows you to get a sense of whether the forecast is in a realm of reasonableness.

Q. Okay. So we would still have the forecast as proposed. This additional component that you're recommending here would just be a reasonability check compared to that forecast? 15:01

A. Exactly.

Q. Okay. Thank you.

And my second question, Mr. Bell, relates to the question I asked ATCO Electric Yukon earlier today about forecasting accuracy and, given your evidence, what factors they would recommend in terms of looking at general forecasting accuracy or whether we should be looking at a more incremental level line-by-line analysis. 15:02

Were you in the room for that, sir?

A. Yes, I was.

Q. Okay. And I would ask you the same question. What

factors should we take into consideration looking at general forecasting accuracy or looking at line-by-line forecasting accuracy, for example, the new extensions that you've identified here? Can you help us how we should weigh those?

A. Absolutely. When a utility files an application, it files a detailed budget, if you will, or business plan for its test period. It uses a number of forecast methodologies and a number of ways to forecast different components of it. Some are based on average of historical costs. Others are based on expected workloads. And each utility does it differently.

If one were to just take the overall level of revenue requirement or forecast cost in the various components, you miss the subtleties of the different methodologies and you miss the fact that there may be a methodology that's producing an anomalous result, as I've identified in my evidence. And the utility should be incented to find better ways to produce forecasts. If a utility is constantly overforecasting in a certain area, it shouldn't be using that to offset bad forecasting on the other side in another area. It should be finding ways to forecast more accurately for each component.

That becomes even more important when you get into

15:03

15:03

Phase 2, where the different costs are charged to different customer classes, where you want accurate forecasts at an account level so that when you do do a Phase 2 application and you're developing rates for the various customer classes, each customer class is paying it's fair share of the costs.

If you just test forecast accuracy at a global level, you miss that nuance and aren't able to in fact derive fair rates on a customer-class-by-customer-class basis in a Phase 2 application. 15:04

Q. Okay. Any other considerations we should take into account when looking at general forecasting accuracy versus the line by line --

A. Well, in my mind, whenever I've read a regulatory decision, it's not a bucket-of-costs approach that has used. It's being a line-by-line approval thing, saying we agree with the FTEs, we agree with these capital projects, that you have evidence that you need to do them. We agree that the increases in costs for vegetation management should go up because of these considerations. 15:05

And so the decisions are rendered at a line by line -- or close to a line-by-line item. And so you're testing the forecast at a line-by-line basis at a reasonableness level anyways. And so it makes more

sense, then, to rule on that. And where there's a forecast that's off, adjust the forecast in your decision.

Q. Thank you, Mr. Bell. Those are my questions. We appreciate you attending today.

A. Thank you, ma'am.

THE CHAIR: Do any members have any questions? Mr. Marriott, do you have anything for your panel?

MR. MARRIOTT: No, thank you, sir.

THE CHAIR: Then this panel is -- we thank you for your attendance and... 15:05

A. Thank you, sir.

THE CHAIR: You're free to go.

A. Thank you, sir.

(WITNESS STANDS DOWN)

THE CHAIR: So where are we at now, Ms. Sabo?

MS. SABO: If I could get my mic on, maybe we could adjourn for the day. Chairman Laking, I don't have anything further. I think we just need to thank everybody for attending and if you have anything to add to that. We appreciate everybody's time over the past weeks of preparation the last few days in the hearing room. 15:06

MR. MARRIOTT: Sir, there is one thing, and I don't know that I would necessarily exercise this

right, but Mr. Coyne gave some undertakings and provided those answers after he left. If anybody had any follow-up in writing, maybe you could set a date for that. For me, Monday would be fine. I'm not sure I'm going to have any, but I would like an opportunity to kind of go over what he did say and see if there's anything arising. And then there would be, if you're going to do that, another date for him to respond, which Mr. -- ATCO Electric's counsel could speak to what would be reasonable. Maybe he hasn't spoken to Mr. Coyne, I don't know. 15:07

THE CHAIR: Well, there's a couple of other undertakings I think as well. Maybe the -- there might be some follow-on things on those, so maybe we could set a window for those written things.

MS. SABO: I think Mr. Marriott is right. Maybe Mr. Williams can give us an idea on timing, and we can set some dates.

THE CHAIR: Please.

MR. WILLIAMS: I think sometime next week should be fine. I think any time after about -- 15:07

Mid next week?

-- about mid next week we should be able to have all of our undertakings in, and then maybe it makes sense to set a date, maybe the start of the following

week, for any additional questions to be provided, if there are any.

THE CHAIR: So suggesting the 9th to get all of the material in. That's Wednesday?

MR. WILLIAMS: Yes, sir. That sounds about right.

THE CHAIR: And then questions from that by the following Monday, the 7th? Does that work?

MS. SABO: The 14th.

THE CHAIR: 14th. Yes, sorry. I'm going backwards. 14th. 15:08

And then responses to that? What are we thinking, two, three days?

MR. WILLIAMS: Sorry, sir. We're saying Monday the following week, so the 14th?

THE CHAIR: Yes. So 9th would be to get the material in. 14th would be the questions. That's a Monday.

MR. WILLIAMS: I think one week from there would be more than sufficient. 15:09

THE CHAIR: The 21st?

MR. WILLIAMS: Yes, sir.

MS. SABO: Argument's due to the 24th. So parties might need a little extra time to review that. So maybe instead of the 21st, we could pick the

Thursday or the Friday before.
THE CHAIR: Can we live with the 17th, which is --
MR. WILLIAMS: Why don't we go with that for now, and if something arises that's a significant question that we may need a bit more time, we can deal with that at that point in time.
THE CHAIR: We're looking for all of those materials to come in by the 9th. And questions on the 14th, and answers for the 17th. And then we have argument on the 24th, is -- according to the schedule now. 15:09
MR. MARRIOTT: I think that schedule works for the City.
MR. WILLIAMS: No issues with that, sir.
THE CHAIR: Okay. Any other parties have an issue with that schedule?
MR. RONDEAU: No problem.
THE CHAIR: Okay. Seeing none, then I thank everyone for their attendance at this proceeding, and we'll see you in the write-ups. 15:10
MR. MARRIOTT: Thank you very much.
MR. WILLIAMS: Thank you.
THE CHAIR: Thank you.
(PROCEEDINGS ADJOURNED AT 3:10 P.M.)

PROCEEDINGS CONCLUDED

Certificate of Transcript

We, the undersigned, hereby certify that the foregoing pages 393 to 554 are a complete and accurate transcript of the proceedings taken down by us in shorthand and transcribed from our shorthand notes to the best of our skill and ability.

Dated at the City of Whitehorse, Province of Yukon, on November 3, 2016.

"Danielle Harmata"
Danielle Harmata, CSR(A)
Official Court Reporter

"Adele Jones"
Adele Jones, CSR(A)
Official Court Reporter

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