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July 30, 2021

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

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Multi-Year Rate Plan for 2020 through 2024 approved by British Columbia Utilities Commission (BCUC) Order G-165-20 (MRP Plan)

Annual Review for 2022 Delivery Rates

In accordance with the MRP Plan and BCUC Order G-227-21 setting out the Regulatory Timetable for FEI's Annual Review, FEI hereby attaches its Annual Review for 2022 Delivery Rates Application materials.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties to the FEI Annual Review for 2020 and 2021 Delivery Rates

FORTISBC ENERGY INC.

Multi-Year Rate Plan for 2020 through 2024

Annual Review for 2022 Delivery Rates

July 30, 2021

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

1.1 *INTRODUCTION*

FortisBC Energy Inc. (FEI or the Company) files this Application in compliance with British Columbia Utilities Commission (BCUC) Order G-165-20, which approved a Multi-Year Rate Plan (MRP or the Plan) for FEI 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, the flexibility to innovate and adapt, and incentive to invest in the future, while maintaining service quality. The approved Earnings Sharing Mechanism (ESM), set out in Section 10, aligns the incentive properties of the Plan between customers and the Company.

As explained in Section 10.2 of the Application, FEI proposes to distribute $1.853 million[1] in earnings sharing to customers in 2022. For 2020, FEI 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 $2.3 million. Approximately $0.7 million in savings was due to lower 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. Approximately $0.8 million of O&M savings was due to the timing of expenditures, such as vacancies and consulting expenditures, and lower general and miscellaneous expenditures. Although there was an additional approximate $0.8 million in formula O&M savings due to the net incremental impact of the COVID-19 pandemic, after accounting for the offsetting reduction in Late Payment Charges revenue, there was no impact on earnings sharing for this item. Please refer to Section 12.2.1 for further details.

FEI 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. In 2021, FEI and FortisBC 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 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 as enablers. Additionally, the group is focused on fostering a sustained awareness amongst managers and employees of the importance of productivity during the MRP to help address cost pressure challenges. In next year's annual review, FEI will be in a position to report back to the BCUC on the success of some of its initiatives.

The proposed delivery rates for 2022 flowing from the approved formulas and forecasts set out in the Application, including returning the actual 2020 earnings sharing to customers, result in

[1] This amount is pre-tax and includes financing accrued on the MRP Earnings Sharing deferral account.

an 8.07 percent delivery rate increase from 2021 delivery rates. After consideration of the delivery rate riders, the annual bill impact is an increase of approximately $45.18 or 4.57 percent for a residential customer[2]. The increase is primarily due to increases in amortization of deferrals of $19.037 million when compared to 2021 Approved and the elimination of the accumulated revenue surplus of $35.287 million, which was fully utilized in 2021, as described in Section 1.4 below.

In the subsections below, FEI sets out the approvals it is seeking and provides an overview of the requirements for the annual review process. This is followed by a summary of FEI's proposed revenue requirements and rate changes for 2022 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, FEI requests BCUC approval for the following pursuant to sections 59 to 61 of the *Utilities Commission Act*:

1. Approval to recover the 2022 revenue requirement and resultant delivery rate change on a permanent basis, effective January 1, 2022, as filed in the Application and subject to any adjustments identified by FEI during the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application.
2. The following deferral account approvals as described in Sections 7.5 and 12.4:
   - Creation of rate base deferral accounts for the following regulatory proceedings:
     - Transportation Service Report, with the amortization period to be determined in a future proceeding;
     - 2021 Generic Cost of Capital Proceeding, with the amortization period to be determined in a future proceeding; and
     - 2021 Renewable Gas Program Comprehensive Review, with the amortization period to be determined in a future proceeding;
   - Creation of a non-rate base deferral account titled the Regional Gas Supply Diversity (RGSD) Project Development Costs deferral account, attracting a weighted average cost of capital (WACC) return, with the amortization period to be proposed in a future application;
   - Amortization of the residual balance in the Waste Connections Costs and Recoveries deferral account in 2022; and

[2] Average residential customer with consumption of 90 GJs per year. Annual bill impact before BVA rate rider and RSAM rate rider is $48.60 or 4.92 percent.

- Approval to transfer the existing non-rate base 2017 & 2018 Revenue Surplus deferral account to rate base in order to eliminate the potential for future variances between actual and projected/forecast AFUDC, and to amortize the remaining deferral account balance in 2022.

3. Approval to change the frequency of reporting on the COVID-19 Customer Recovery Fund Deferral Account from monthly to quarterly, as described in Section 7.5.2.1.
4. A Biomethane Variance Account (BVA) Rate Rider for 2022 in the amount of $0.059 per gigajoule (GJ) as calculated in Section 10.3.1.
5. Revenue Stabilization Adjustment Mechanism (RSAM) riders for 2022 in the amount of $0.012 per GJ as set out in Table 10-5 in Section 10.3.2.
6. The 2022 Core Market Administration Expense (CMAE) budget of $5.575 million, as set out in Appendix B, and the allocation of the CMAE between FEI's Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA) based on the allocation percentages of 30 percent and 70 percent, respectively.

A draft order is included in Appendix E.

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 FEI'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 with FEI's Growth capital determined by the indexing formula), 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

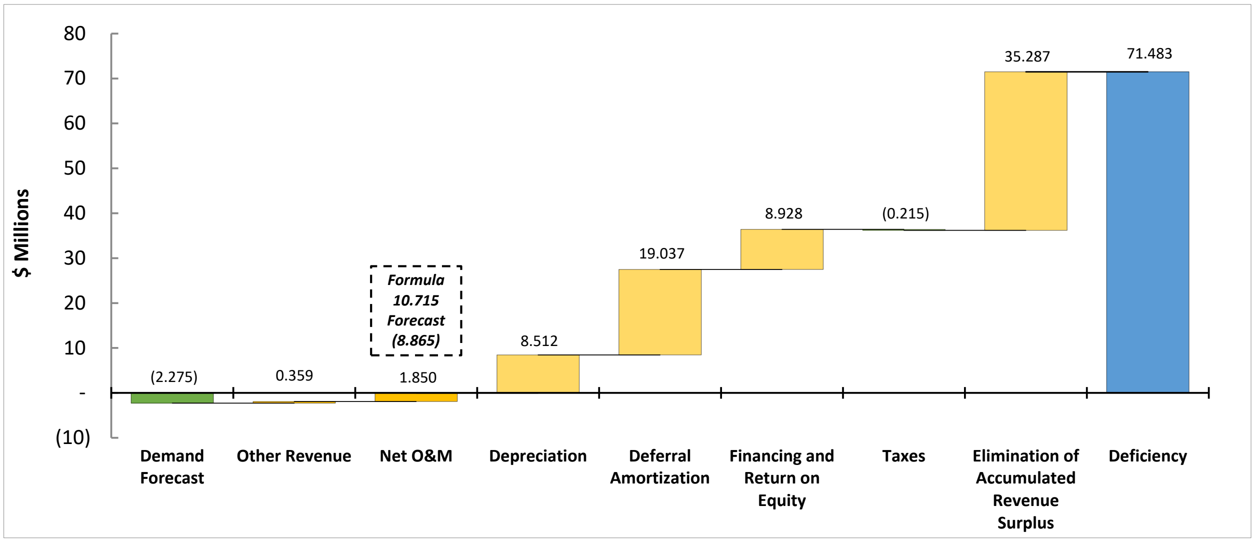
Item	Description	Response or Reference
2	Identification of any efficiency initiatives that the Utilities have undertaken, or intend to undertake, that require a payback period extending beyond the MRP period with recommendations to the BCUC with respect to the treatment of such initiatives.	FEI has not 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.	FEI does not have any recommendations at this time
6	Reporting on the Innovation Fund status.	Section 10.3.3
7	Assess and make recommendations to the BCUC on potential issues or topics for future Annual Reviews.	FEI does not have any recommendations at this time

1.4 *REVENUE REQUIREMENT AND RATE CHANGES FOR 2022*

The delivery rates for 2022 flowing from the revenue requirement components set out in the Application result in an 8.07 percent increase from 2021 delivery rates. The delivery rate increase results from a revenue deficiency of $71.483 million.

The following chart summarizes the items that contribute to the 2022 revenue deficiency. The chart shows each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The 2022 deficiency of $71.483 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: 2022 Delivery Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.4.1 Demand Forecast (Section 3)

In 2022, demand is forecast to increase by approximately 0.5 PJ compared to 2021 Approved due to increased Residential demand. The impact of this increase is a reduction to the 2022 deficiency of $2.275 million. FEI's 2022 Forecast revenue at 2021 approved rates is $1,579.745 million. FEI's 2022 Forecast gross delivery margin is $931.775 million.

1.4.2 Other Revenue (Section 5)

Other Revenue is forecast to increase the 2022 deficiency by approximately $0.359 million, mainly due to a decrease in SCP Third Party revenue.

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

FEI establishes the majority of its O&M costs by formula during the MRP term. For 2022, the formula incorporates a net inflation factor of 3.324 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,[3] for a total increase in formula O&M of $12.498 million[4] (4.6 percent) from 2021 formula O&M. O&M forecast outside of the formula is decreasing by $8.760 million[5] (15.4 percent) compared to 2021 Approved, primarily due to a decrease in pension and OPEB expense. The 2022 increase in total O&M expense net of capitalized overhead and Biomethane O&M transferred to the BVA is $1.850 million.

[3] Modified by 75 percent.
[4] Increase of formula O&M by $10.715 million net of capitalized overhead.
[5] Decrease of forecast O&M by $8.865 million net of capitalized overhead and biomethane O&M transferred to BVA.

1.4.4 Depreciation (Section 7)

FEI's 2022 depreciation expense increased by $8.607 million and CIAC from net additions decreased by $0.095 million compared to 2021 Approved, resulting in a net increase of $8.512 million. The increase in depreciation expense is primarily a result of CPCN additions to plant for the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) project, Tilbury 1A Expansion project and Inland Gas Upgrade (IGU) project, as discussed in Section 7.

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

Amortization of deferral accounts in 2022 increased by $19.037 million, primarily due to the increased amortization of the Demand-Side Management (DSM) deferral account by approximately $6.933 million and a debit amortization of $11.417 million for the 2020-2024 Flow-through non-rate base deferral account. As discussed in Section 12.4.2, the debit amortization of $11.417 million is primarily due to unfavourable commercial and industrial delivery margin in 2020 Actual and 2021 Projected totalling to $17.918 million, which is partially offset by favourable residential delivery margin and other revenues, as well as savings from interest, property tax, and income tax expenses.

1.4.6 Financing and Return on Equity (Section 8)

Financing and Return on Equity (ROE) increased FEI's 2022 deficiency by $8.928 million through changes in financing rates, the ratio of long-term debt vs. short-term debt, and changes in rate base.

For 2022, FEI has forecast a mid-year long-term debt issue of $200 million and is forecasting a short-term debt rate of 2.31 percent, which is an increase from the 2.19 percent short-term debt rate embedded in the 2021 Approved revenue requirement. Overall, FEI's deficiency is reduced by $4.054 million from financing rate changes and increased by $0.673 million from the ratio change between long-term and short-term debt. The increase in 2022 rate base has contributed $12.309 million to FEI's deficiency when compared to 2021 Approved due to a combination of CPCN additions and regular capital additions entering rate base, as discussed in Section 7.

In calculating its 2022 revenue deficiency, FEI has utilized its currently approved capital structure and ROE of 38.5 percent and 8.75 percent, respectively.

1.4.7 Taxes (Section 9)

FEI's 2022 property taxes are forecast to increase by 2.2 percent or $1.586 million from 2021 Approved. These increases are driven by construction activities, market value increases, changes in tax policies of local taxing authorities, and increased in-lieu taxes.

There has been no change in the income tax rate of 27 percent from 2021. Taxes are forecast to decrease in 2022 by 3.3 percent or $1.801 million from 2021 Approved primarily due to an increase in taxable income deductions resulting from higher CCA as well as lower pension and OPEB expenses.

1.4.8 Elimination of Prior Years' Accumulated Revenue Surplus

The largest driver of FEI's 2022 revenue deficiency is the elimination of the prior years' accumulated revenue surplus of $35.287 million before tax, which equates to approximately 3.98 percent of the total forecast delivery rate increase of 8.07 percent. Pursuant to Order G-319-20, FEI was approved to draw down the 2017 & 2018 Revenue Surplus deferral account to help mitigate the 2021 delivery rate increase. The draw-down of the revenue surplus approved for 2021 brought the deferral account balance to near zero[6] at the end of December 31, 2021, thus resulting in the 2022 deficiency increasing by $35.287 million compared to 2021 delivery rates. FEI notes this is a one-time impact isolated to 2022.

1.5 *SERVICE QUALITY INDICATORS (SECTION 13)*

FEI's 2020 and June 2021 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2020, for the nine SQIs with benchmarks, eight performed at or better than the approved benchmarks, with one, Meter Reading Accuracy, lower than the threshold due to the impact of the COVID-19 pandemic. For the four SQIs that are informational only, performance generally remains at a level consistent with prior years. In 2021 to date, performance for the metrics with benchmarks is trending towards meeting the benchmark or the threshold. Details of the SQIs are included in Section 13.

[6] As discussed in Section 7.5.2.3, a residual credit of $0.308 million resulting from the difference between actual and projected/forecast AFUDC amounts is proposed to be returned to customers in 2022 through a credit to amortization expense.

2. FORMULA DRIVERS

2.1 *INTRODUCTION AND OVERVIEW*

This section provides the calculation of the Inflation Factor (or I-Factor) used for calculating the 2022 O&M and Growth Capital amounts according to the MRP formula.

In the MRP Decision and Order G-165-20, 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[7].

The MRP Decision approved the use of a forecast of growth[8] to determine Formula O&M and Formula Growth Capital as well as a growth factor multiplier of 75 percent for Formula O&M.

The Inflation Factor and Growth Factor calculations utilize the above-described inputs and determinations. For 2022, FEI has used July 2019 through June 2021 inflation data for the 2022 revenue requirement calculations, using the Statistics Canada tables included in Appendix A1 of the Application.

Section 2.2 below determines the 2022 Inflation Factor based on prior year's BC-CPI and BC-AWE used to calculate Formula O&M discussed in Section 6 and Formula Growth Capital discussed in Section 7. Section 2.3 below determines the average customer count used to calculate the Formula O&M discussed in Section 6 and provides the gross customer additions forecast used to calculate the Formula Growth Capital discussed in Section 7.

2.2 *INFLATION FACTOR CALCULATION SUMMARY*

In the MRP Decision, the BCUC approved an Inflation Factor (I-Factor) using the actual CPI-BC and BC-AWE indices from the previous year and the actual labour weighting based on the most recent completed year of actuals. FEI 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 2021 for AWE-BC and May 2021 for CPI-BC has been used as a placeholder, as results to June 2021 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 2020 labour weighting of 51 percent, the calculation of the 2022 I-Factor is (1.237 percent x 49 percent) + (6.309 percent x 51 percent) = 3.824 percent.

[7] FEI's most recent year of completed actuals is 2020 so that ratio has been used for the 2022 I-Factor calculation. The 2023 I-Factor calculation will be based on the 2021 actual non-labour / labour split.

[8] Forecast of average customers for Formula O&M and a forecast of gross customer additions for Formula Growth Capital, both including a true-up to actual customers in the following years.

Table 2-1: I-Factor Calculation

		Table: 18-10-0004-01	*Table: 14-10-0223-01*	12 Mth Average				Last Completed Year			
Line No.	Date	BC CPI index	BC AWE $	CPI index	AWE $	CPI %	AWE %	Non Labour %	Labour %	I-Factor %	MRP Year
1	Jul-2019	132.4	995.70								
2	Aug-2019	132.2	1,003.20								
3	Sep-2019	132.0	1,007.69								
4	Oct-2019	132.2	1,015.61								
5	Nov-2019	131.8	1,012.26								
6	Dec-2019	131.7	1,014.87								
7	Jan-2020	132.1	1,025.98								
8	Feb-2020	132.9	1,024.80								
9	Mar-2020	132.3	1,029.14								
10	Apr-2020	131.2	1,105.84								
11	May-2020	131.5	1,127.73								
12	Jun-2020	132.6	1,097.00	132.1	1,038.32						
13	Jul-2020	132.6	1,095.17								
14	Aug-2020	132.4	1,089.30								
15	Sep-2020	132.5	1,092.97								
16	Oct-2020	132.9	1,093.25								
17	Nov-2020	133.3	1,098.85								
18	Dec-2020	132.8	1,109.54								
19	Jan-2021	133.6	1,115.13								
20	Feb-2021	134.1	1,114.34								
21	Mar-2021	134.9	1,104.90								
22	Apr-2021	135.2	1,110.80								
23	May-2021	135.1	1,110.80								
24	Jun-2021	135.1	1,110.80	133.7	1,103.82	1.237%	6.309%	49%	51%	3.824%	2022

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, and a forecast of gross customer additions to determine Formula Growth Capital.

The calculation of the average customers used to determine 2022 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 1,031,862 (shown on line 28 in Table 2-2 below). Starting with this 2019 average customers, the calculation adds 75 percent of cumulative average customer growth during the MRP term (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 2022 Average Customer (AC) Growth Factor

Line No.	Date	Actual 2020	Projected 2021	Forecast 2022	Total for 2022 Rate Setting	Reference
1	Prior Year Ending Customer Count	1,038,354	1,051,752	1,063,473		Appendix A2 Table A2-1 FEI Customers
2						
3	Additions:					
4	January	1,544	1,872	1,795		
5	February	1,028	883	840		
6	March	403	577	552		
7	April	722	358	329		
8	May	726	206	179		
9	June	921	172	143		
10	July	824	230	183		
11	August	848	655	609		
12	September	338	686	633		
13	October	2,006	2,213	2,092		
14	November	2,010	1,979	1,882		
15	December	2,028	1,890	1,800		
16	Total Additions	13,398	11,721	11,037		Appendix A2 Table A2-1 FEI Customer Additions
17	12-month Weighted Average Additions	6,268	5,326	5,017		
18						
19	Current Year Ending Customer Count	1,051,752	1,063,473	1,074,510		Line 1 + Line 16; Appendix A2 Table A2-1 FEI Customers
20						
21	Actual/Projected Prior Year Average Customers	1,031,862	1,044,622	1,057,078		2020: G-319-20; Sch 3, Line 13; 2021 and 2022: Prior Year Ending, Line 22
22	Average Customers for the Year	1,044,622	1,057,078	1,068,490		Line 1 + Line 17
23	Change in Average Customers	12,760	12,455	11,413	**36,628**	Sum of Annual Change in Average Customers on Line 23
24						
25	Growth Factor Multiplier				**75%**	G-165-20
26	Change in Average Customers for Rate Setting Purposes				**27,471**	Line 25 x Line 23
27						
28	Average Customers Used to Determine the Starting UCOM				**1,031,862**	Line 21, Yr 2020
29	**Average Customer Forecast for Rate Setting**				**1,059,333**	Line 28 + Line 26
30						
31	2020 Approved Average Customers for Rate Settin	1,040,410				2020: G-319-20; Sch 3, Line 22
32	2020 Actual Average Customers for Rate Setting	1,041,432				Line 21 Line 22 x 0.75
33	**2020 True Up**	**1,022**				Line 32 - Line 31

The forecast for FEI's Gross Customer Additions for determination of the Formula Growth Capital is provided in the table below.

Table 2-3: Forecast Gross Customer Additions (GCA)

Line No.	Gross Customer Additions		Reference
1	2020 Approved	18,000	
2	2020 Actual	18,980	
3	2020 True-up	980	Section 7, Table 7-2, line 14
4			
5	2021 Approved	16,000	
6			
7	2022 Forecast	20,000	Schedule 4, line 5

FEI is forecasting gross customer additions of 20,000 for 2022, which is higher than the 2021 Approved amount of 16,000 but is reflective of FEI's expectation of its 2021 customer growth, which is estimated at 20,500. As explained in Section 7.2.1, the true-up of formula growth capital is based on actual gross customer additions from two years prior (i.e., 2020); therefore, while the higher 2021 expected additions have informed FEI's forecast for 2022, they do not impact the calculation of formula growth capital in this annual review.

Gross customer additions is a forecast of new customers attaching to the gas distribution system. It comprises both new construction activity and conversions from other fuels to natural gas. In developing the forecast, FEI has assumed that the following activities remain at the same or similar levels to the prior years: the market capture rate for new construction at 81 percent, conversion activity comprises approximately 19 to 20 percent of the gross additions, and there are no further policy or building code impacts. The forecast for 2022 is undertaken by reviewing information contained in FEI's customer relationship management software (CRM) (leads, connection requests, timing of connection requests, etc.) along with interactions with builders, developers, and contractors. FEI uses market information such as building permits, forecast housing starts and completions as well as any knowledge of policy or building code changes that may affect specific municipalities. The impact of the COVID-19 pandemic continues to create greater uncertainty in the forecast of gross customer additions, which will be corrected in subsequent years with the BCUC approved true-up mechanism.

2.4 *INFLATION AND GROWTH CALCULATION SUMMARY*

A summary of the factors used to determine Formula O&M and Formula Growth Capital for 2022 is provided in Table 2-4, including the I-Factor calculated in Section 2.2, the approved X-Factor of 0.5 percent, and the forecast of customers determined in Section 2.3.

Table 2-4: Summary of Formula Drivers

Line No.	Particulars	2022	Reference
1	CPI	1.237%	Table 2-1, Line 24
2	AWE	6.309%	Table 2-1, Line 24
3			
4	Non Labour	49%	Table 2-1, Line 24
5	Labour	51%	Table 2-1, Line 24
6			
7	CPI/AWE Inflation	3.824%	(Line 1 x Line 4) + (Line 2 x Line 5)
8			
9	Productivity Factor	-0.500%	Order G-165-20
10			
11	Net Inflation Factor	3.324%	Line 7 + Line 9
12			
13	Average Customers for 2022 Formula O&M purposes	1,059,333	Table 2-2, Line 29
14			
15	Gross Customer Additions for 2022 Formula Growth Capital purposes	20,000	Table 2-3

In summary, the Net Inflation Factor for 2022 is 3.324 percent. Formula O&M for 2022 is determined using average customers of 1,059,333. Formula Growth Capital for 2022 is determined using gross customer additions of 20,000.

3. DEMAND FORECAST AND REVENUE AT EXISTING RATES

3.1 INTRODUCTION AND OVERVIEW

This section describes FEI's forecast of gas sales and transportation volumes. FEI's forecasting method remains consistent with prior years and the methods adopted in FEI's Forecasting Method Study in response to the forecasting directives in Order G-86-15. The total demand is a combination of energy demand from residential, commercial and industrial customers.

FEI is forecasting an increase in consumption in the 2022 Forecast (2022F) compared to the 2021 Approved. The 2022F normalized load is forecast to be approximately 234.1 PJs, which is an increase of 0.5 PJ compared to the 2021 Approved forecast. The increase in 2022F is due to increased load in the residential customer class.

Based on the 2021 Approved rates for each customer class, FEI's 2022 revenue forecast is $1,580 million and FEI's 2022 gross margin forecast is $932 million.

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

3.2 OVERVIEW OF FORECAST METHODS

FEI's demand forecast methods are consistent with prior years and the recommendations in the FEI Forecasting Method Study filed as Appendix B2 in FortisBC's 2020-2024 MRP Application. The Forecasting Method Study represented the culmination of a number of years of research and testing of alternative forecasting methods in response to the forecasting directives in Order G-86-15 and accompanying decision related to the FEI Annual Review for 2015 Rates Application. As a result of this study, FEI adopted the Exponential Smoothing method (ETS) for the purpose of forecasting residential and commercial use rates, as ETS proved to be the most accurate method for this purpose. See Appendix A3 for a detailed description of FEI's demand forecast methods.

The demand forecast relies on three components:

- the residential and commercial net customer additions forecast;[9]
- the residential and commercial use per customer (UPC) forecast; and
- the Industrial Forecast.

The demand forecast for residential and commercial customers is based on forecasts for the number of customers and UPC rates. Specifically, the monthly UPC is estimated for customers under Rate Schedules 1, 2, 3 and 23 and then multiplied by the corresponding monthly forecast

[9] The net customer additions are the year-over-year change in the total number of customers.

of the number of customers in these rate schedules. Monthly values are then aggregated for each year to derive the annual energy consumption.

The forecast of industrial energy demand is based upon customer-specific forecasts obtained through an Industrial Survey, as discussed in Section 3.3.3.

The forecast Natural Gas for Transportation (NGT) demand is for Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) volumes. The NGT demand and the LNG demand forecast is discussed is Section 3.3.4 below.

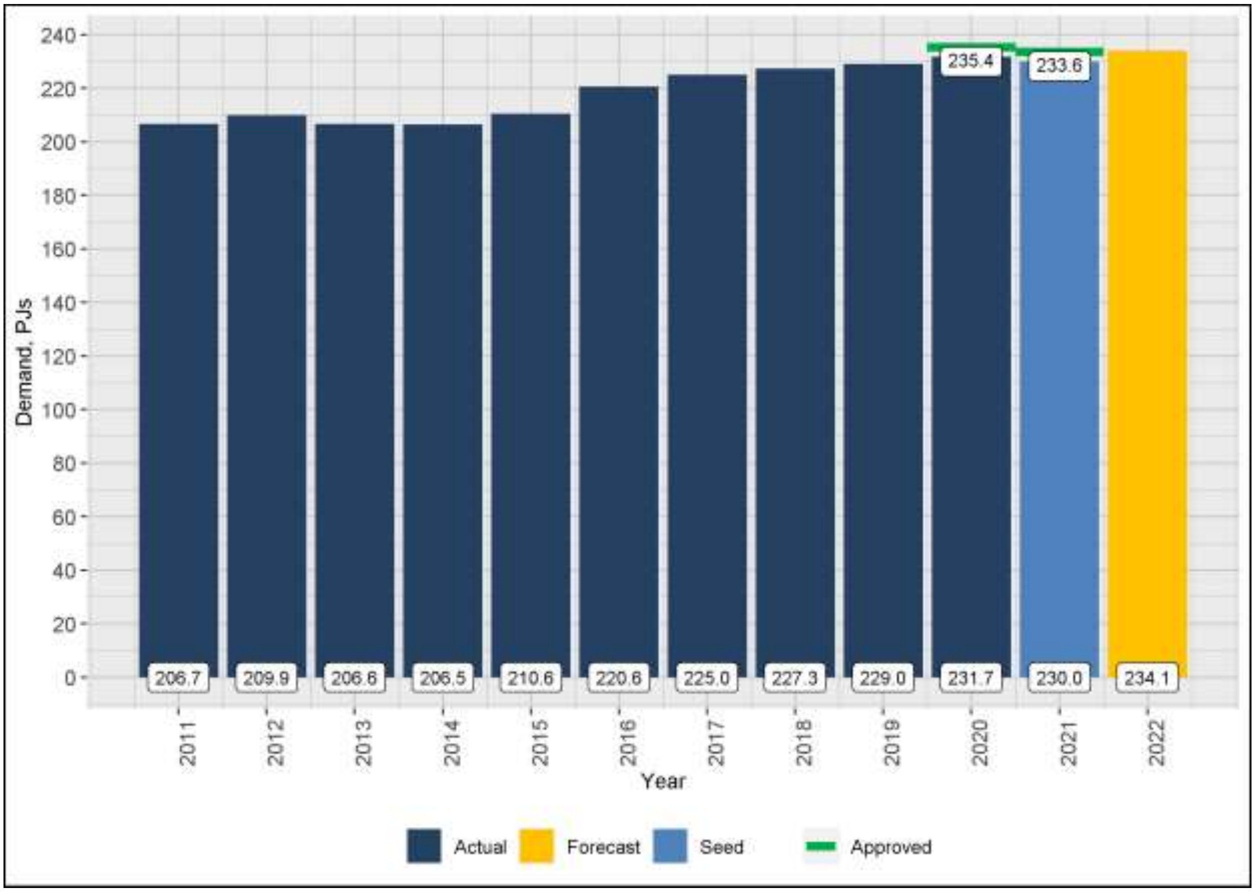
The following sections set out the results of the demand forecast. In the figures provided in the demand forecast sections, the following three time periods are shown:

- 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 2020 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 2021 (2021S) and the Seed Year forecast is based on the latest actual years, including 2020. As such, the 2021 Seed Year forecast in this Application will differ from the 2021 Forecast presented in the Annual Review for 2020 and 2021 Delivery Rates, for which 2020 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 2022 (2022F).
- 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 2020 and 2021 Delivery Rates.

3.3 *DEMAND FORECAST*

FEI's total energy demand consists of the weather normalized residential and commercial demand, and the customer-specific industrial, NGT, and non-NGT (LNG) demand. In aggregate, the absolute demand forecast variance in 2020 was 1.6 percent. As shown in Figure 3-1 below, the total load is forecast to be 234.1 PJs in 2022F, up 4.1 PJs from 2021S.

Figure 3-1: Total Energy Demand in PJs



The residential, commercial, industrial, and NGT and non-NGT (LNG) demand forecasts are provided separately in the following subsections.

3.3.1 Residential

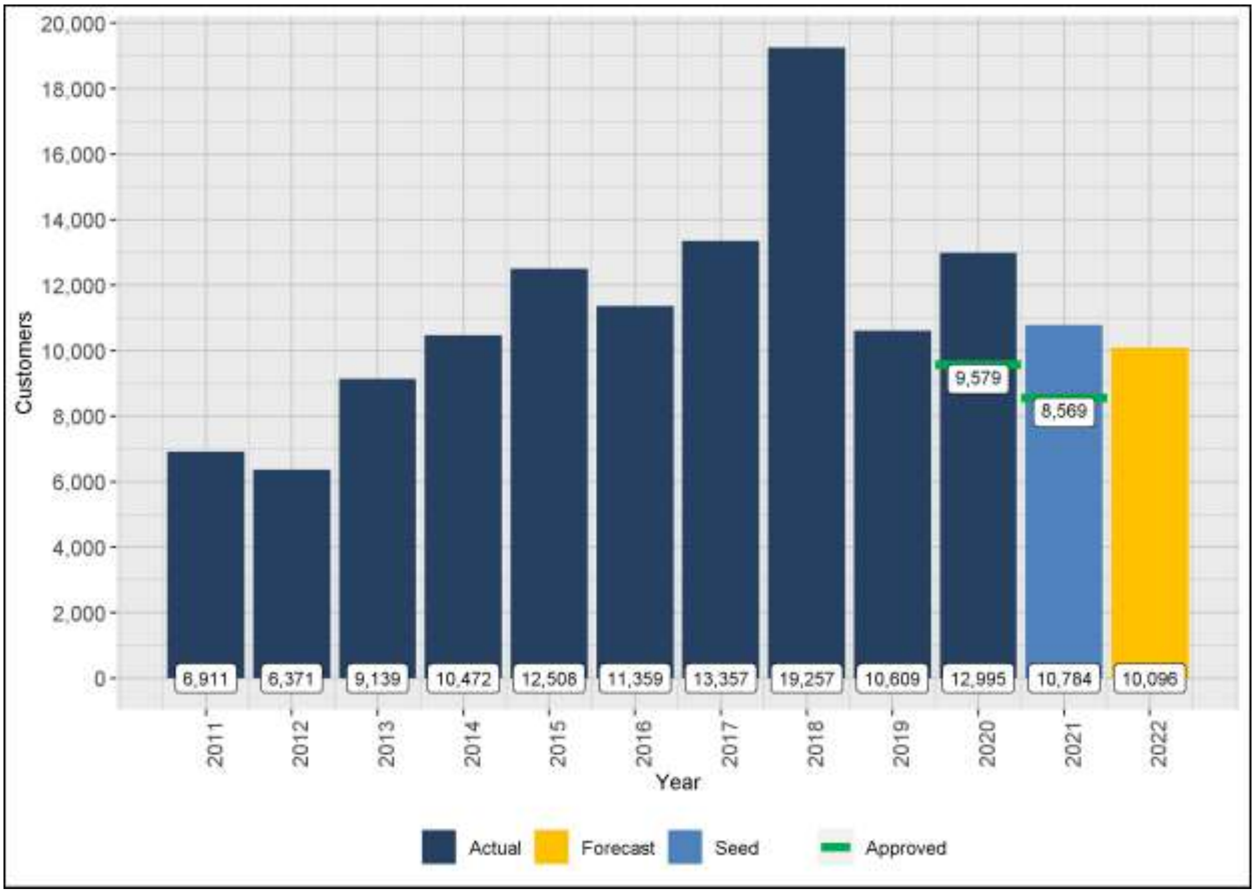
3.3.1.1 Residential Customer Additions

Consistent with past practice, FEI uses the Conference Board of Canada (CBOC) housing starts forecast as a proxy for residential net customer additions. The CBOC data used for the forecast, provided in Appendix A1, was issued in April 2021. The 2022 forecast of 10,096 additions reflects the actual residential additions recorded in 2020 and the single family and multi-family growth rate forecasts from the CBOC forecast.

As shown in Figure 3-2, residential customer additions are forecast to decrease by 688 additions in 2022F compared to 2021S. Figure 3-2 provides the residential net customer additions for 2011 through 2022.

FEI notes that there was a residential customer additions dip in early 2020 due to the COVID-19 pandemic; however, once the builder/developer community adjusted its operations for the pandemic, building activities accelerated to meet the new demand. This resulted in very robust growth in the second and third quarter of 2020 and contributed to the increased customer additions. In addition, with more customers working from home, it is likely that fewer customers chose to disconnect in 2020, which had the effect of contributing to the increase of net customer additions relative to forecast.

Figure 3-2: Residential Net Customer Additions

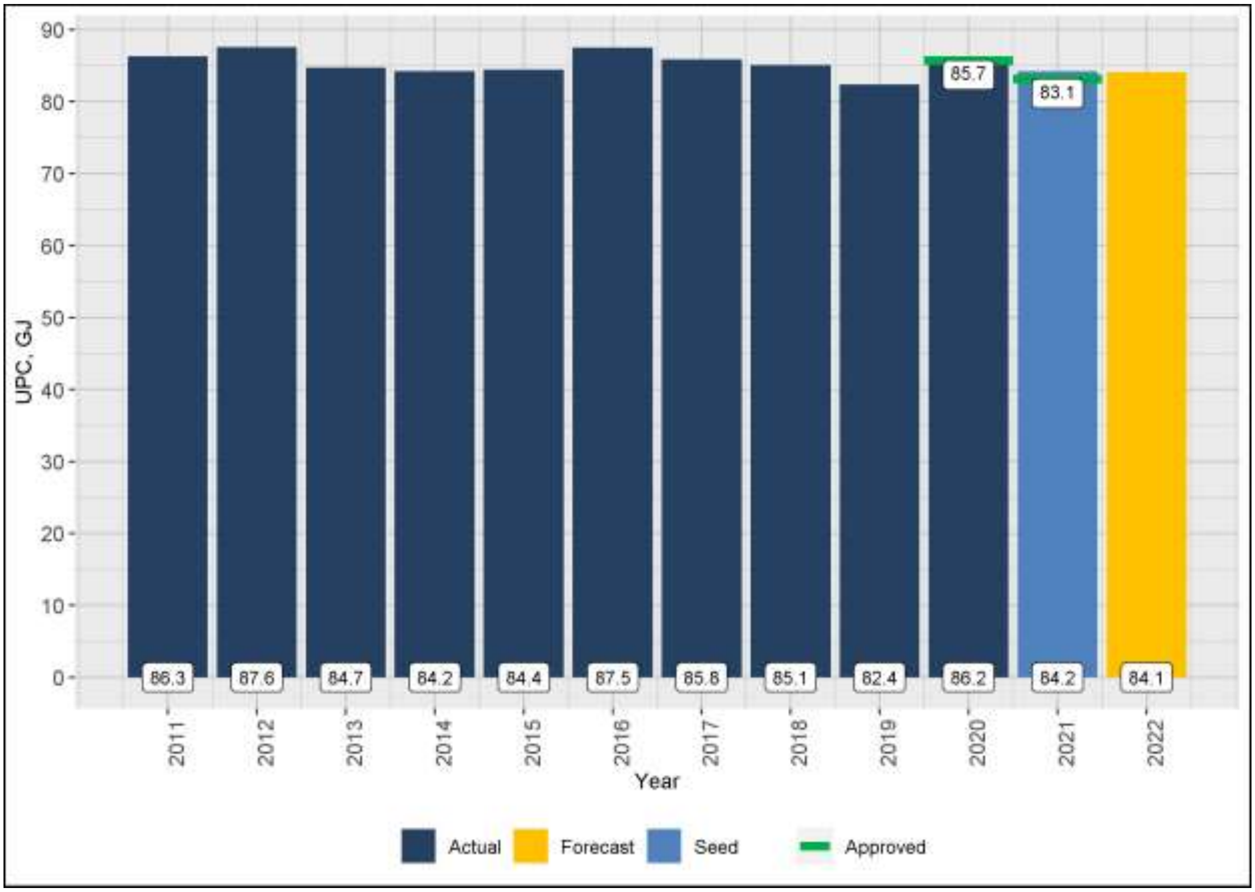


3.3.1.2 Residential UPC

The residential UPC forecast was developed using the ETS method with the most recent 10 years of historical weather-normalized UPC, described in Appendix A3.

As shown in Figure 3-3, the residential UPC is forecast to decrease by approximately 0.1 GJ in 2022F compared to 2021S.

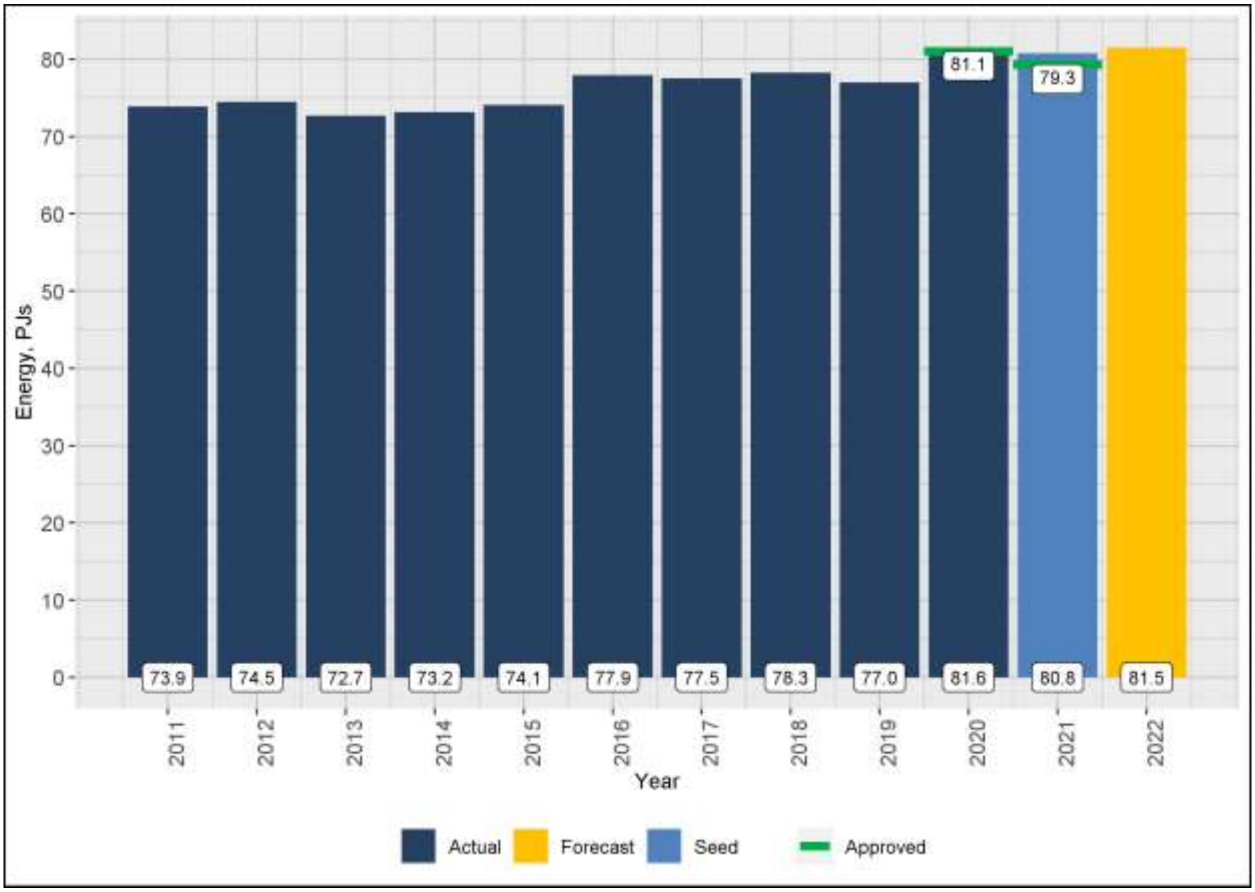
Figure 3-3: Rate Schedule 1 UPC



3.3.1.3 Residential Demand

Taking into account the customer additions and UPC forecasts described above, and as shown in Figure 3-4 below, residential demand is forecast to increase by 0.7 PJ in 2022F.

Figure 3-4: Normalized Residential Demand



3.3.2 Commercial

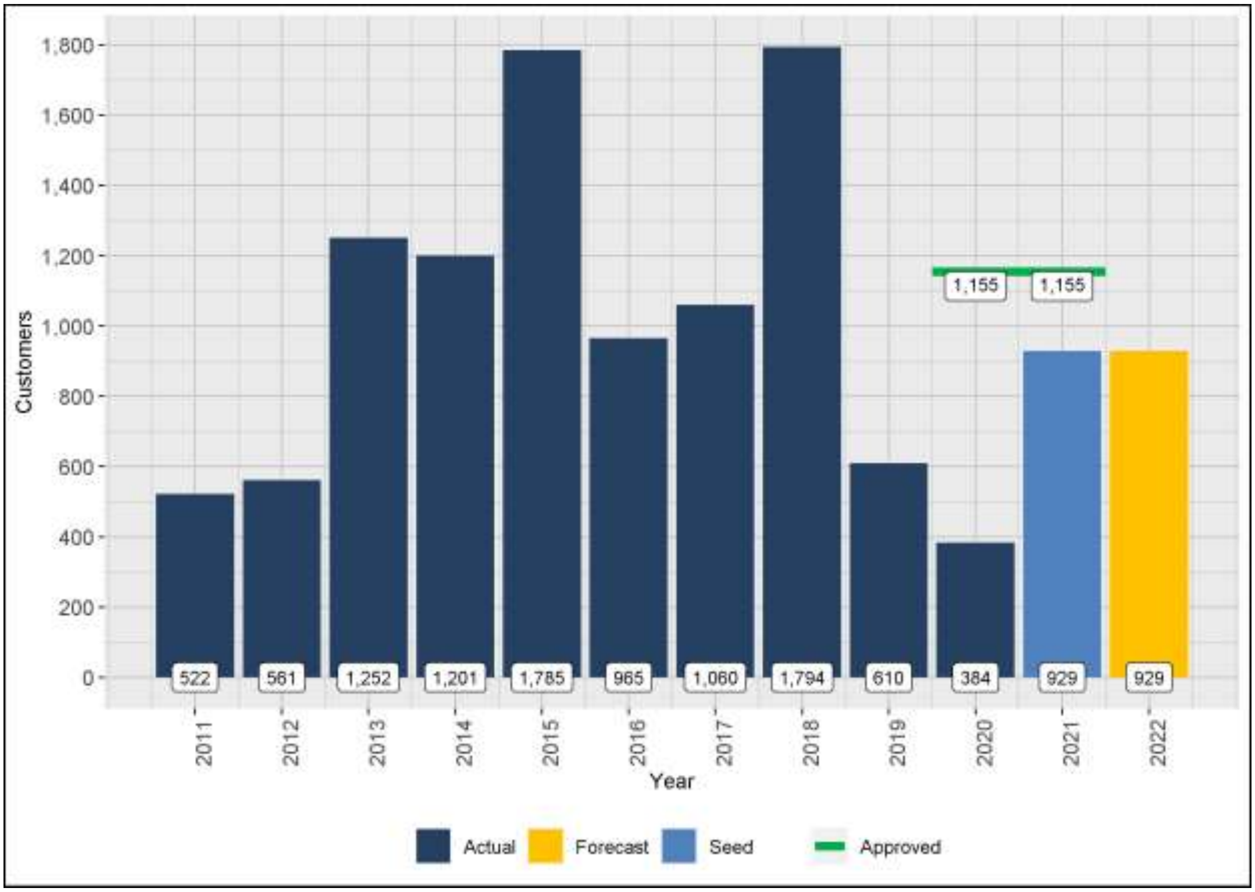
3.3.2.1 Commercial Customers

The commercial net customer additions forecast is based on the average of the actual net customer additions over the last three years for which a full year of actual data is available (i.e., 2018 to 2020). As there has been a relatively large migration of Rate Schedule 23 transportation customers to bundled service under Rate Schedule 3 since 2019, these two rate classes were forecast together as "large commercial" and the total allocated to the two rate classes proportional to the current composition.

With respect to the discrepancy between the 2020 Approved and 2020 Actual commercial customer additions, the commercial customer segment is very diverse and as a result it is difficult to pinpoint specific trends. However, the COVID-19 pandemic likely had impacts on many commercial segments that resulted in lower customer additions. For example, restrictions imposed by the pandemic adversely impacted the operation and viability of customers in the tourism, hotel and restaurant sectors.

As shown in Figure 3-5 below, commercial customer additions are forecast to remain flat in 2022F.

Figure 3-5: Commercial Net Customers Additions

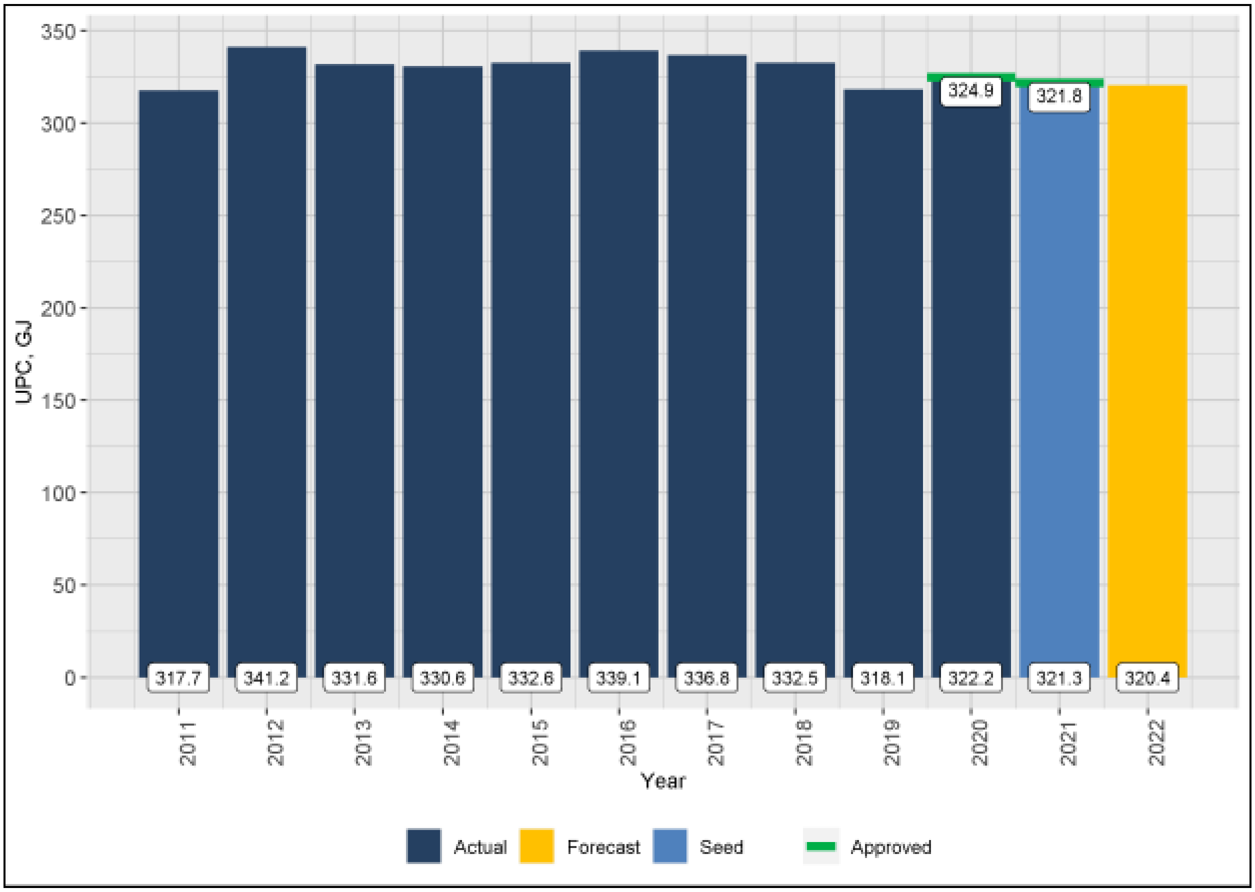


3.3.2.2 Commercial UPC

The commercial UPC forecast was developed using the ETS method, considering the most recent 10 years of historical weather-normalized UPC.

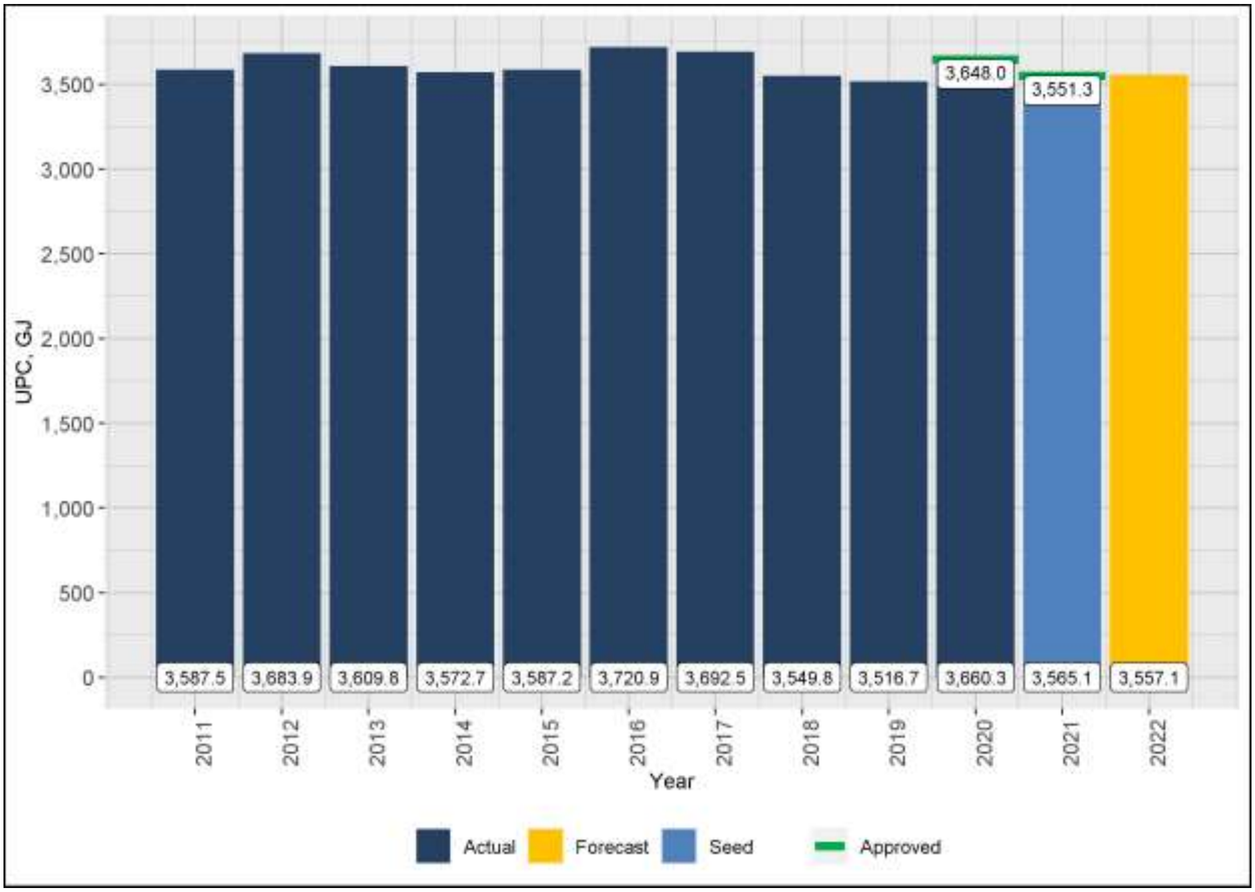
As shown in Figure 3-6, the Rate Schedule 2 UPC is forecast to decrease by 0.9 GJ in 2022F compared to 2021S.

Figure 3-6: Rate Schedule 2 UPC



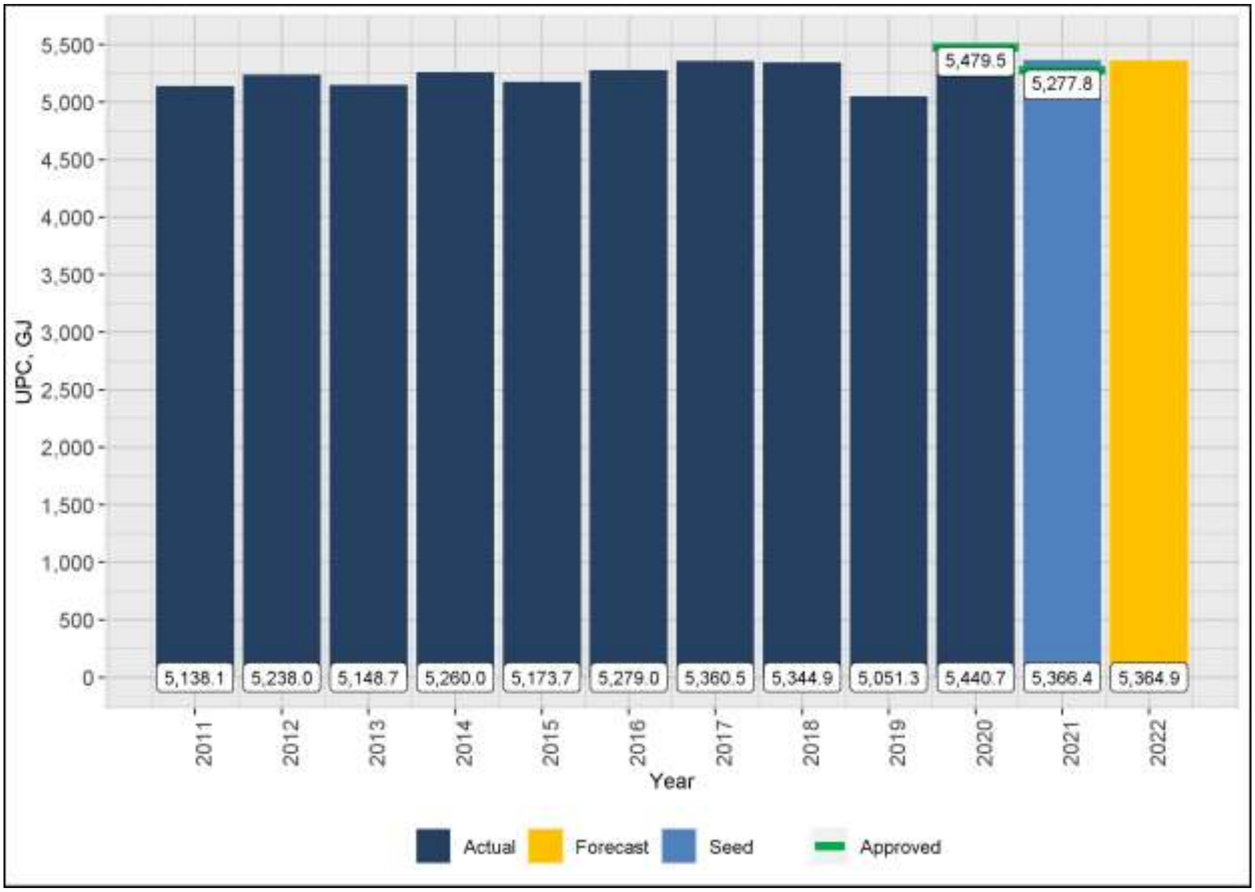
As shown in Figure 3-7, the Rate Schedule 3 UPC is forecast to decrease by approximately 8.0 GJs in 2022F compared to 2021S.

Figure 3-7: Rate Schedule 3 UPC



As shown in Figure 3-8, the Rate Schedule 23 UPC is forecast to decrease by 1.5 GJs in 2022F compared to 2021S.

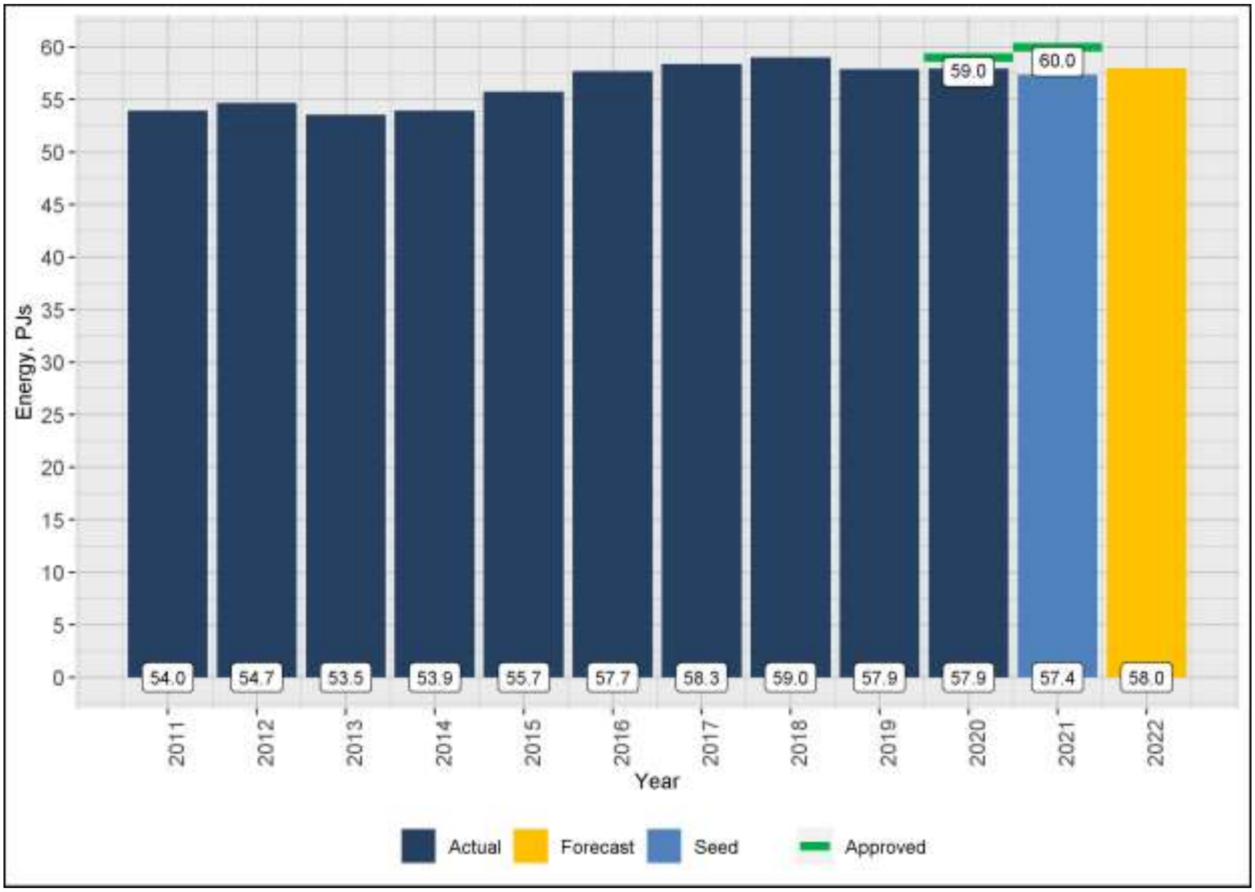
Figure 3-8: Rate Schedule 23 UPC



3.3.2.3 Commercial Demand

Taking into account the customer additions and UPC forecasts described above, and as seen in Figure 3-9 below, commercial demand is forecast to increase by 0.6 PJ in 2022F compared to 2021S.

Figure 3-9: Commercial Demand



3.3.3 Industrial Demand

The 2022F demand for industrial customers was forecast using the Industrial Survey.

For the 2022 Forecast, customers responded to the survey in June and July of 2021. The survey was launched as close as possible to the filing date to mitigate potential variances in the forecast, particularly from Rate Schedule 22 customers. The survey needed to be completed by July 5, 2021 to allow sufficient time for internal review of the results, loading of data in FEI's Forecasting Information System (FIS), preparing the forecast and drafting the Application. Since the survey requires approximately five weeks to complete, it was launched on May 28, 2021.

As shown in Table 3-1 below, the response rate achieved in 2021 was 47.9 percent of industrial customers, representing approximately 90.0 percent of industrial volumes. There was no reply from 47.1 percent of industrial customers, who received the survey and three reminder notifications; this group represents only 9.2 percent of the industrial demand. Surveys could not be delivered to 5.0 percent of the industrial customers due to issues such as incorrect email addresses; this group represents 0.8 percent of the total industrial load.

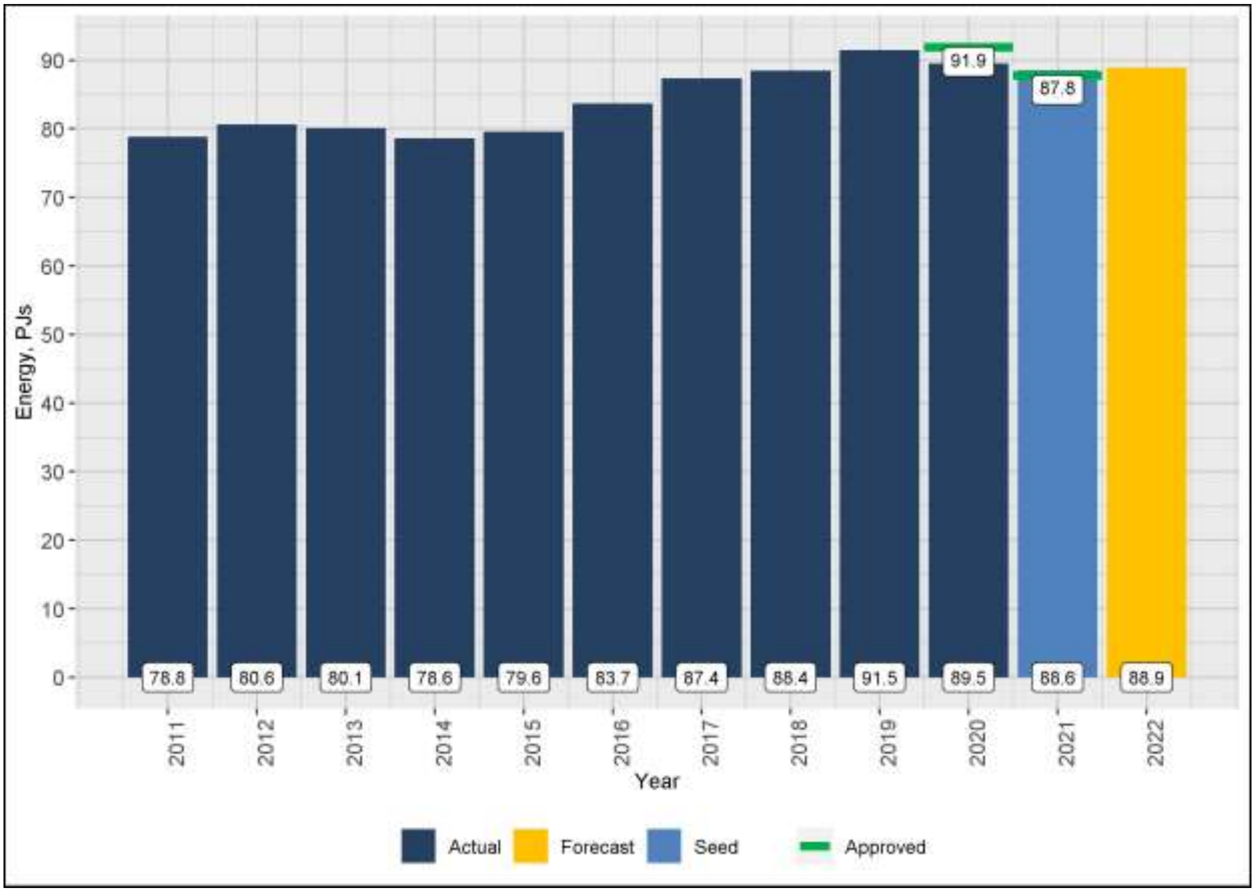
Table 3-1: Industrial Survey Response Rates

2021 Industrial Survey	Description	Customers	Demand
Survey Completed	The survey was delivered and completed.	47.9%	90.0%
Survey delivered but not completed	The survey was delivered, but after three follow-up emails was not completed.	47.1%	9.2%
Survey undeliverable	The survey was not deliverable. This can be a result of invalid email addresses, faulty email servers etc.	5.0%	0.8%
Total		100.0%	100.0%

The forecast of demand for customers that either chose not to reply to the survey or could not be contacted (representing 10 percent of the total industrial demand) was set to equal 2020 Actual consumption.

As seen in Figure 3-10 below, the demand from the industrial rate schedules is forecast to increase by 0.3 PJ in 2022F compared to 2021S.

Figure 3-10: Industrial Demand[10]



3.3.4 Natural Gas for Transportation and LNG Demand

This section summarizes the CNG and LNG demand forecasts related to demand from NGT customers and non-NGT related demand for LNG supplied under Rate Schedule 46, including power generation and export customers. Table 3-2 below provides the 2021 Approved, 2021 Projection and 2022 Forecast total NGT and non-NGT LNG demand. As directed in Order G-86-15, FEI has included the forecast of demand provided to customers under spot purchase agreements (i.e., not under firm take-or-pay commitments) in the total NGT and non-NGT LNG demand.

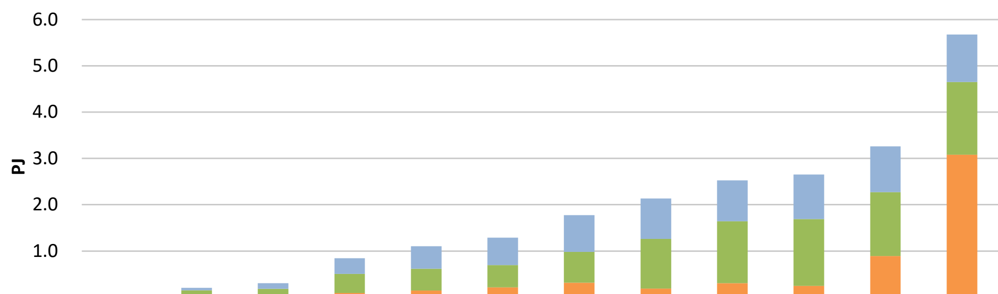
[10] Excludes NGT.

Table 3-2: FEI Total Natural Gas Demand for NGT and non-NGT LNG (GJs per year)

GJ	2021 Approved	2021 Projected	2022 Forecast
CNG	951,388	985,808	1,024,550
LNG	1,784,400	1,381,324	1,566,989
Total NGT Demand	**2,735,788**	**2,367,132**	**2,591,539**
LNG (Non-NGT) Demand	3,685,185	892,151	3,083,297
Total NGT and Non-NGT Demand	**6,420,973**	**3,259,283**	**5,674,836**

The following figure shows the composition of the 2011 to 2020 Actual, 2021 Projected and 2022 Forecast annual demand for CNG (RS 3/5/23/25/6P) and LNG (RS 46), including a breakdown of LNG demand between NGT and non-NGT.

Figure 3-11: Actual (A), Projected (P) and Forecast (F) Demand for CNG & LNG[11]



	2011 A	2012 A	2013 A	2014 A	2015 A	2016 A	2017 A	2018 A	2019 A	2020 A	2021 P	2022F
CNG (NGT) - RS 3/5/23/25/6P	0.0	0.1	0.1	0.3	0.5	0.6	0.8	0.9	0.9	1.0	1.0	1.0
LNG (NGT) - RS 46	0.0	0.2	0.2	0.4	0.5	0.5	0.7	1.1	1.3	1.4	1.4	1.6
LNG (Non-NGT) - RS 46	-	-	-	0.1	0.1	0.2	0.3	0.2	0.3	0.2	0.9	3.1
Total CNG & LNG	0.0	0.2	0.3	0.8	1.1	1.3	1.8	2.1	2.5	2.7	3.3	5.7

The 2021 Projected demand of 3.3 PJs is 0.6 PJ higher than the 2020 Actual demand of 2.7 PJs, as shown in Figure 3-11 above. This increase is primarily related to the projected increase in LNG (Non-NGT) export deliveries in 2021.

For 2022, there is a small forecast increase in CNG demand for NGT customers of approximately 0.04 PJ (approximately 3.9 percent) from the 2021 Projected level. This is primarily attributable to incremental load from existing customers and two new CNG stations projected to be in-service in late 2021. The 2022 Forecast LNG demand for NGT customers is forecast to increase by 0.2 PJ (13.4 percent) from the 2021 Projected level, primarily due to a an increase in LNG consumption from marine customers for 2022.

For non-NGT LNG demand, FEI expects the 2022 Forecast will increase as a result of expanded LNG exports as restrictions due to the COVID-19 pandemic continue to be lifted. The

[11] Forecast includes all NGT related CNG and LNG demand, and Other LNG demand, inclusive of contract and excess demand flowing through stations as well as spot volumes and third party station CNG/LNG volumes.

COVID-19 pandemic caused issues with the destination ports and international shipping which resulted in significant issues for FEI's customers, including significant increases to the cost of shipping and limited availability of space on ships into and out of China. The 2021 Projected and 2022 Forecast include volumes from three prospective export customers, and the 2022 Forecast represents an approximate 2.2 PJs increase from the 2021 Projected volume.

3.4 *REVENUE AND MARGIN FORECAST*

The forecast of revenues and margins has been developed by considering the total 2022 Forecast energy in GJs applied at 2021 Approved delivery rates and applicable 2021 Approved commodity and storage and transport rates (most recently approved commodity and storage and transport rates).

3.4.1 Revenue

Revenues are a function of both energy consumption and the rate applicable at the time the energy is consumed. FEI has developed its forecast of revenues by multiplying the energy forecast by the approved rates for each customer class.

Table 3-3 below summarizes the 2021 Approved, 2021 Projected and 2022 Forecast revenue, by customer segment, at currently approved 2021 rates.

Table 3-3: Forecast Sales Revenue at 2021 Approved Rates (Commodity, Midstream, and Delivery)

Revenue ($ millions)	Approved 2021	Projected 2021	Forecast 2022
Residential[1]	803.736	883.194	891.164
Commercial[2]	441.435	469.446	474.238
Industrial[3]	200.264	190.860	214.343
Total	**1,445.435**	**1,543.500**	**1,579.745**

Notes to table:

[1] Rate Schedule 1.

[2] Rate Schedules 2, 3, 23.

[3] Rate Schedules 4, 5, 6, 6P, 46, 7, 22, 25, 27, Joint Venture, BC Hydro Island Generation.

3.4.2 Margin

Margins are calculated by subtracting the cost of gas (discussed in Section 4) from the total revenues set out in Table 3-3 above.

Table 3-4 below summarizes the 2021 Approved, 2021 Projected and 2022 Forecast margin, by customer segment, at currently approved 2021 delivery rates.

Table 3-4: Forecast Gross Margin at 2021 Approved Delivery Rates

Margin ($ millions)	Approved 2021	Projected 2021	Forecast 2022
Residential[1]	532.207	540.064	545.063
Commercial[2]	257.025	247.063	249.684
Industrial[3]	140.268	125.401	137.028
Total	**929.500**	**912.528**	**931.775**

Notes to table:

[1] Rate Schedule 1.

[2] Rate Schedules 2, 3, 23.

[3] Rate Schedules 4, 5, 6, 6P, 46, 7, 22, 25, 27, Joint Venture, BC Hydro Island Generation.

Variances between the delivery margin forecast in this section and actual delivery margin are captured in either the Revenue Stabilization Adjustment Mechanism (RSAM) deferral account if they relate to use rate variances for residential and commercial customers, or the Flow-through deferral account for all other variances.

3.5 SUMMARY

FEI's forecast of demand for natural gas is based upon methods that are consistent with those used in prior years and FEI's adoption of the ETS method which has been demonstrated to be superior to past practice as reported previously to the BCUC. FEI's forecast provides a reasonable estimate of future natural gas demand for 2022. Based on these methods, FEI is forecasting an increase in consumption in 2022F of 0.5 PJ compared to the 2021 Approved level. Based on the 2021 Approved rates for each customer class, FEI's 2022 Forecast revenue is $1,580 million, which is an increase of approximately $134 million from the 2021 Approved amount.

4. COST OF GAS

The cost of gas includes the cost of the gas commodity, the cost of midstream resources (storage and transportation), and the Core Market Administration Expense (CMAE) costs associated with providing the gas supply function. With the exception of the CMAE costs, as further explained below and in Appendix B, the Company is not requesting approval of forecast gas costs within this Application. Instead, any rate changes related to the flow through of gas costs are dealt with in separate applications to the BCUC. Any variations between forecast and actual gas costs will continue to be returned to, or recovered from, customers through the existing deferral account mechanisms.

In compliance with the BCUC's determination in decision and Order G-79-14, FEI will be filing annually for approval of the CMAE budget as part of the Annual Review filings. Further, pursuant to the BCUC's direction in the FEI Annual Review for 2020 and 2021 Delivery Rates Decision and Order G-319-20, FEI will include a comprehensive review of the CMAE costs in its next revenue requirements or MRP application following the MRP term. Please see Appendix B for a detailed discussion of the CMAE budget. In summary, and as included in the Approvals Sought (Section 1.2) of the Application, FEI is requesting BCUC approval of the following related to CMAE, effective January 1, 2022:

- Approval of the 2022 CMAE Budget of $5.575 million, as set out in Schedule 1 of Appendix B; and
- Approval of the allocation of the 2022 CMAE between the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA) based on the allocation percentages of 30 percent and 70 percent, respectively.

While the Company is not requesting approval of forecast gas costs (other than CMAE) with this Application, the forecast cost of gas is required in the determination of a number of revenue requirement line items that form part of the forecasts included in this Application. The total cost of gas for the purposes of this Application has been determined by multiplying forecast sales volumes using the demand forecast described in Section 3, by the current unit gas cost recovery charges for each rate schedule.

The natural gas commodity cost recovery rate for the Mainland and Vancouver Island service area became effective October 1, 2020 pursuant to Order G-231-20, dated September 10, 2020. The natural gas storage and transport rates and riders, also known as the midstream cost recovery rates and MCRA rate riders, for the Mainland and Vancouver Island service area became effective January 1, 2021 pursuant to Order G-314-20, dated December 3, 2020.

The table below sets out the forecast cost of gas at existing rates, by rate schedule group.

Table 4-1: Forecast Cost of Gas at Existing Rates[12,13]

Cost of Gas ($ millions)	Approved 2021	Projected 2021	Forecast 2022
Residential[1]	271.529	343.130	346.101
Commercial[2]	184.410	222.383	224.554
Industrial[3]	59.996	65.459	77.315
Total	**515.935**	**630.972**	**647.970**

Notes to table:

1. Includes Rate Schedules 1 volumes
2. Includes Rate Schedules 2, 3, 23 volumes
3. Includes Rate Schedules 4, 5, 6, 6P, 46, 7, 22, 25, 27 volumes

The natural gas storage and transport, or midstream, component of the cost of gas includes the costs for the contracted third party pipeline and storage resources, seasonal and peaking supply, and also includes costs for unaccounted for gas (UAF).

UAF refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use. UAF includes measurement variances and line loss of gas that is flowing in the transmission and distribution systems. Sources of UAF comprise, but are not limited to, system leakage, lost gas (i.e., gas lost as a result of utility and third party activities, including gas theft), and measurement inaccuracies. The cost of UAF related to the Sales rate classes is included in the cost of gas and recovered from core customers[14] via the gas cost rates. The cost of UAF related to the Transportation Service rate classes is included in the determination of the delivery rates to facilitate recovery of UAF costs from Transportation Service customers, as they do not pay midstream charges.

12 Biomethane commodity costs are excluded from the table because they are allocated directly to the Biomethane Variance Account (BVA).

13 Cost of gas from transportation customers (i.e., RS 22, 23, 25 and 27) is resulting from UAF.

14 Core customers are those for whom FEI is obligated to ensure the purchase, transportation, and uninterrupted delivery of natural gas to their premises.

5. OTHER REVENUE

5.1 *INTRODUCTION AND OVERVIEW*

This section discusses FEI's forecasts of Other Revenue. In the MRP Decision (page 74), FEI was approved for forecast variances in certain components of Other Revenue to be subject to earnings sharing. These components include Late Payment Charges, Application Charges, NSF Returned Cheque Charges, Other Recoveries, and NGT Overhead and Marketing Recoveries. The remaining components of Other Revenue continue to receive flow-through treatment of variances between forecast and actual results, consistent with the treatment during the 2014-2019 PBR Plan term.

As shown in the table below, FEI is forecasting Other Revenue to decrease slightly from the amount approved for 2021, primarily due to a decrease in SCP Third Party revenue.

Table 5-1: Other Revenue Components ($ millions)

	Approved 2021	Projected 2021	Forecast 2022
Late Payment Charge	$ 2.954	$ 2.768	$ 2.704
Application Charge	1.984	1.990	2.013
NSF Returned Cheque Charges	0.028	0.028	0.028
Other Recoveries	0.288	0.288	0.288
NGT Related Recoveries	3.698	3.858	4.168
Biomethane Other Revenue	0.951	0.926	0.986
SCP Third Party Revenue	14.053	14.053	13.410
LNG Capacity Assignment	18.039	18.039	18.039
Total Other Operating Revenue	**$ 41.995**	**$ 41.950**	**$ 41.636**

In the following sections, FEI summarizes the methods used to forecast the line items included in the table above, and also addresses the largest components of Other Revenue, the SCP Third Party Revenue and the LNG Capacity Assignment.

5.2 *OTHER REVENUE COMPONENTS*

5.2.1 Late Payment Charge

Late Payment Charges are calculated based on the average of the most recent three years of Late Payment Charges earned. However, FEI implemented a number of customer relief measures in 2020 during the COVID-19 pandemic, including the suspension of Late Payment Charges. As a result, the 2022 Forecast for Late Payment Charges is based on the 2017 to 2019 average of Late Payment Charges earned.

5.2.2 Application Charge

Application Charges are calculated based on the application fees specified in FEI's rate schedules applied to new customer connections or current customer reconnections. The 2022 Forecast amounts are expected to be in line with 2021 levels.

5.2.3 NSF Returned Cheque Charges and Other Recoveries

The 2022 Forecast amounts for NSF Returned Cheque Charges and other miscellaneous income items are based on 2021 levels.

5.2.4 NGT Related Recoveries

FEI has forecast recoveries associated with the NGT program related to the overhead and marketing charge that is applied to FEI fuelling station customers, tanker rentals from LNG customers, and CNG and LNG fuelling stations (CNG & LNG Service Revenues) as shown in Table 5-2 below. Variances between forecast and actual NGT Overhead and Marketing Recoveries are subject to earnings sharing. Variances in the NGT Tanker Rental Revenue and CNG & LNG Service Revenues are treated as Flow-through with the variances being captured in the Flow-through deferral account and the CNG & LNG Service Revenues deferral account, respectively.

Table 5-2: 2021 and 2022 NGT Related Recoveries ($ millions)

	Approved 2021	Projected 2021	Forecast 2022
NGT Overhead and Marketing Recovery	$ 0.258	$ 0.277	$ 0.283
NGT Tanker Rental Revenue	0.774	0.810	0.928
CNG & LNG Service Revenues	2.666	2.771	2.958
Total NGT Related Recoveries	**$ 3.698**	**$ 3.858**	**$ 4.168**

The following subsections discuss each of the NGT related recoveries.

5.2.4.1 NGT Overhead and Marketing Recovery

Pursuant to Order G-78-13, FEI has included a forecast of overhead and marketing (OH&M) recovery from FEI's NGT fuelling station customers for 2022. As shown in Table 5-3 below, the forecast NGT OH&M revenue for 2022 is $0.283 million. This revenue is calculated by multiplying the approved OH&M rate of $0.52 per GJ by the applicable[15] 2022 Forecast CNG and LNG sales volumes.

[15] For host customers with CNG or LNG delivered through an FEI-owned CNG or LNG fueling station, the applicable volume for OH&M is limited to the contract minimum volume. For third-party fueling customers, all volume is applicable for OH&M.

Table 5-3: NGT Overhead and Marketing Revenue Forecast ($ millions)

	2021 Approved	2021 Projected	2022 Forecast
Applicable Volume (GJ)	495,745	532,738	543,622
Rate ($/GJ)	$ 0.52	$ 0.52	$ 0.52
Total NGT OH&M Revenue ($ millions)	**$ 0.258**	**$ 0.277**	**$ 0.283**

5.2.4.2 NGT Tanker Rental Revenue

Table 5-4 below shows the tanker rental revenue for each type of FEI-owned tanker based on the currently approved RS 46 tanker rental rates.

Table 5-4: LNG Tanker Rental Revenue ($ millions)

Tanker Rental Revenue	2021 Approved	2021 Projected	2022 Forecast
Standard Tanker Rental Deliveries	360	360	240
Rate ($/Delivery)	$ 295	$ 295	$ 301
Sub Total ($ millions)	$ 0.106	$ 0.106	$ 0.072
Tridem Tanker Rental Deliveries	-	-	-
Rate ($/Delivery)	$ 353	$ 353	$ 360
Sub Total ($ millions)	$ -	$ -	$ -
Marine Equipped Tridem Tanker Rental Deliveries	1,344	1,416	1,688
Rate ($/Delivery)	$ 497	$ 497	$ 507
Sub Total ($ millions)	$ 0.668	$ 0.704	$ 0.856
Total Tanker Rental Revenue ($ millions)	**$ 0.774**	**$ 0.810**	**$ 0.928**

For the Standard tankers, the 2021 Projected rental revenue is forecast to be the same as the 2021 Approved. For 2022, FEI is forecasting the Standard tanker rental revenue to be reduced from the 2021 level, primarily due to a reduction of high pressure direct injection (HPDI) LNG vehicles on the road, as no equivalent commercially available engine is available on the market today.

For Tridem tankers, the 2021 Approved rental revenue is zero since these tankers are primarily used for long haul deliveries in Canada, such as to the Yukon, and these tankers are not permitted in the US (due to weight restrictions in the US). FEI does not expect Canadian deliveries to occur outside of British Columbia and is therefore expecting the 2021 Projected and 2022 Forecast Tridem tanker rental revenue to be zero.

For the Marine tankers, the 2021 Projected rental revenue is forecast to be slightly higher than the 2021 Approved, as the number of rental deliveries increased by 72. For 2022, FEI forecasts 272 additional marine tanker deliveries due to increased vessel consumption and additional vessels put into service.

5.2.4.3 CNG and LNG Service Revenue Forecast

The CNG and LNG Service Other Revenue forecast includes the FEI-owned CNG and LNG fuelling station recoveries (i.e., capital, O&M, and short-term fuelling rates) at the contracted minimum take-or-pay volumes of each station. Table 5-5 below provides a breakdown of the CNG and LNG fuelling station recoveries. The forecast of station recoveries as Other Revenue does not include recoveries from spot volume and excess volume (i.e., fuelling customer uses more than their contracted minimum take-or-pay volume)[16].

Table 5-5: CNG and LNG Fuelling Service Station Revenue Forecast ($ millions)

CNG/LNG Service Revenue	2021 Approved	2021 Projected	2022 Forecast
CNG Station	$ 1.850	$ 1.877	$ 2.133
LNG Station	0.696	0.756	0.687
Subtotal - NGT Stations	**$ 2.545**	**$ 2.633**	**$ 2.820**
Surrey Ops CNG Pump	0.121	0.137	0.137
Total	**$ 2.666**	**$ 2.771**	**$ 2.958**

The 2021 Projected recoveries for CNG and LNG Stations are higher than the 2021 Approved levels by $0.088 million. This increase is primarily due to the projected increase in LNG revenue of $0.060 million related to the three-month contract extension to the Teck Coal Limited LNG Fuelling station and added volume commitments from FEI customers as a result of FEI adding new stations in 2021. CNG Station recoveries are forecast to increase in 2022 by $0.256 million compared to 2021 Projected due to anticipated new CNG stations being put into service in 2022 and a full year of volume commitment revenue from the CNG stations put into service in 2021. LNG Station revenues are forecast to decrease by $0.069 million in 2022 due to the expiry of the three-month Teck Coal Limited extension and the reduction of LNG volume commitments between the opening of the Port Kells Fuelling Station and the closure of the CUC LNG Station.

5.2.5 Biomethane Other Revenue

The Other Revenue amount of $0.986 million in 2022 shown in Table 5-1 above is the transfer from delivery margin to the Biomethane Variance Account (BVA) for the cost of service of the Biomethane capital assets.

In accordance with Order G-210-13, which approved the Biomethane Program on a permanent basis, the following delivery margin related costs must be included in the BVA:[17]

- Upgrading plant cost of service;
- Interconnection cost of service[18]; and
- Program overhead costs.[19]

[16] Station revenue recoveries from spot and excess volume are recorded in the CNG and LNG Recoveries deferral account. CNG and LNG Station recoveries under minimum take-or-pay contracts are recorded in Other Revenue.

[17] The cost of procuring Biomethane supply does not need to be transferred because it is accounted for directly in the BVA.

[18] Prior to Order G-165-20, the cost of service of Biomethane interconnection costs for projects introduced before Order G-210-13 were recorded in FEI's general cost of service.

[19] Program costs as defined in Order G-210-13 include education, marketing, direct administration, cost of enrollment and the cost of IT upgrades.

Commencing in 2020, the BCUC approved[20] the interconnection costs prior to Order G-210-13 to be recorded in the BVA consistent with costs incurred after Order G-210-13.

The 2022 Forecast amounts are consistent with 2021 because there are minimal amounts of plant additions scheduled for 2022.

5.3 Southern Crossing Pipeline (SCP) Third Party Revenue

The SCP Third Party Revenue includes the items shown in the table below.

Table 5-6: 2021 and 2022 SCP Revenue Components ($ millions)

	Approved 2021	Projected 2021	Forecast 2022
MCRA	$ 13.284	$ 13.284	$ 13.284
Net Other Mitigation - West to East Capacity	0.769	0.769	0.126
Total SCP Revenue	**$ 14.053**	**$ 14.053**	**$ 13.410**

The components of the SCP Third Party Revenues shown in Table 5-6 are discussed separately below. Any variance from the forecast SCP Third Party Revenues will continue to be recorded in the SCP Mitigation Revenues Variance Account and returned to or recovered from customers over a two-year period.

5.3.1 Midstream Cost Reconciliation Account (MCRA)

The Other Revenue of $13.284 million is related to the inclusion of the 105 MMcfd of SCP east to west capacity in the MCRA portfolio. As part of the FEI Annual Review for 2020 and 2021 Delivery Rates Decision and Order G-319-20, the BCUC approved, effective November 1, 2020, the debiting of the MCRA and crediting of Other Revenue in the amount of $346.617 per MMcfd. This treatment is approved to remain in effect for the remainder of the MRP term.

5.3.2 Net Other Mitigation Revenue

The Company has been seeking, and will continue to seek, opportunities to contract the west to east capacity on the SCP.

The forecast mitigation revenue for the SCP west to east capacity for 2022 is based on the current forward market price differentials for summer 2022. FEI forecasts generating net mitigation revenue in the amount of $0.126 million in 2022.

The mitigation revenue generated from the SCP west to east capacity ties to market price differentials during the summer months and reflects the existing pipeline capacity within the region. These market conditions will continue to change over time. The mitigation revenue forecast is net of the cost of using FEI gas supply resources, such as the Westcoast Energy Inc.

[20] Order G-165-20.

Kingsvale South transportation capacity held in the midstream portfolio, to connect with the SCP system. The mitigation revenue net of the gas supply resource costs is allocated to Other Revenue.

5.4 LNG CAPACITY ASSIGNMENT

The $18.039 million in LNG capacity assignment Other Revenue shown in Table 5-1 above represents a transfer of costs from the delivery margin to gas costs reflecting the allocation of a portion the Mt. Hayes LNG facility costs to gas costs.

The Mt. Hayes cost allocations were reviewed during the FEI 2016 Rate Design Application proceeding. The BCUC approved FEI's proposal to continue to allocate costs based on the Mt. Hayes LNG facility having a dual purpose serving as a gas supply storage facility and as a transmission facility providing additional transmission system capacity.[21]

5.5 SUMMARY

FEI has forecast the Other Revenue components for 2022 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 are recorded in the SCP Mitigation Revenues Variance Account (for variances in the items discussed in Section 5.3), the Biomethane Variance Account (for variances in the items discussed in Section 5.2.5), the CNG/LNG Recoveries deferral account (for excess revenue from the CNG & LNG Service Recoveries forecast discussed in Section 5.2.4.3), and the Flow-through deferral account (for any remaining variances from forecast in Section 5.2.4.3 and all variances from forecast in Sections 5.2.4.2 and 5.4), with variances in the remaining items being shared with customers through the earnings sharing mechanism.

[21] The cost allocation for the Mt. Hayes LNG facility was approved pursuant to Order G-4-18 and the Reasons for Decision attached as Appendix A, both dated January 9, 2018.

6. O&M EXPENSE

6.1 INTRODUCTION AND OVERVIEW

Under the MRP, FEI'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 2022, the Formula O&M is $284.961 million, representing a 4.6 percent increase from the 2021 Formula O&M, primarily due to the formula drivers. O&M expenses forecast outside the formula for 2022 are $48.084 million, representing a 15.4 percent decrease from the amount approved for 2021. Overall, the increase in Gross O&M Expense from 2021 Approved to 2022 Forecast is 1.2 percent.

The components of 2022 O&M expense are shown in Table 6-1 below.

Table 6-1: 2022 O&M Expense ($ millions)

Line No.	Description	Approved 2021	Projected 2021	Forecast 2022	Reference
1	Formula O&M	$ 272.463	$ 272.463	$ 284.961	Section 11, Schedule 20, Line 8
2	Forecast O&M	56.844	58.842	48.084	Section 11, Schedule 20, Lines 15 to 22
3	2020 O&M True-up			0.258	Section 11, Schedule 20, Line 10
4	Total Gross O&M	329.307	331.305	333.303	Line 1 + Line 2 + Line 3
5	Capitalized Overhead (16%)	(52.689)	(53.009)	(53.328)	Section 11, Schedule 20, Line 27
6	Biomethane O&M transferred to BVA	(1.848)	(2.668)	(3.355)	Section 11, Schedule 20, Line 26
7	Net O&M	$ 274.770	$ 275.628	$ 276.620	Line 4 through 6

In the sections below, FEI provides further details on its formula and forecast O&M expenses for 2022. Additionally, in compliance with the BCUC's directive in the MRP Decision[22], FEI 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 2022 inflation based on prior year's BC-CPI and BC-AWE, less the productivity improvement factor, is 3.324 percent.

For 2022, the annual operating and maintenance expense under the formula is calculated as:

[22] MRP Decision, 115.

2021 Approved formula UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)] + 2020 Formula O&M True-up

Table 6-2 below shows the calculation of the 2022 Formula O&M, including the calculation of the 2020 Formula O&M true-up. FEI notes the true-up of formula O&M is a two-year lag based on actual average customer counts from 2020.

Table 6-2: Calculation of 2022 Formula O&M ($ millions)

Line No.	Description	Forecast 2022	Reference
1	Prior Year Base Unit Cost O&M ($/customer)	$ 260	G-319-20 2021 FEI Annual Review Decision
2	I-Factor	3.324%	Section 2, Table 2-4
3	Current Year Unit Cost O&M ($/customer)	$ 269.0	
4	Average Customer Forecast	1,059,333	Section 2, Table 2-2
5	2022 Inflation-Indexed O&M before 2020 True-up	$ 284.961	Line 3 x Line 4
6	2020 True-up O&M	0.258	Line 16
7	Inflation-Indexed O&M	$ 285.219	Line 5 + Line 6
8			
9	2020 O&M True-up		
10	2020 Actual 12 month Average Customers	1,044,622	FEI 2020 Annual Report
11	2020 Forecast 12 month Average Customers	1,043,259	G-319-20 2020 FEI Annual Review Decision
12	Difference	1,363	Line 10 + Line 11
13	Growth Factor	75%	G-165-20 MRP Decision
14	Change in Customers - True-up	1,022	Line 12 x Line 13
15	2020 Unit Costs ($/customer)	$ 252.0	G-319-20 2020 FEI Annual Review Decision
16	O&M True-up for 2022	0.258	Line 14 x Line 15 / 1,000,000

6.2.1 New/Incremental System Operations, Integrity and Security Funding

In the MRP Decision (page 115), the BCUC directed FEI 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: integrity management; maintaining system infrastructure; operations, compliance and safety; cyber security; data analytics; gas control; Canadian Energy Pipeline Association (CEPA) participation; and any other significant factors or miscellaneous items.

The table below shows the requested information, including the new/incremental funding in each category in 2019 dollars (the Approved Base O&M), escalated by the annual formula factors to arrive at the formula O&M amounts (the 2020 Formula O&M). The table also shows the 2020 Actual O&M and the resulting variances to the 2020 Forecast (or Formula) O&M.

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

Line No.		Approved Base O&M	2020 Formula O&M[1]	Actual 2020 O&M	2020 Forecast/Actual Variance	Cumulative Forecast/Actual Variance[2]
1	Integrity Management	$ 1.350	$ 1.381	$ 1.147	$ (0.234)	$ (0.234)
2	Maintaining System Infrastructure	0.700	0.716	0.729	0.013	0.013
3	Operations, Compliance and Safety	0.600	0.614	0.704	0.090	0.090
4	Cyber Security	0.508	0.520	1.130	0.610	0.610
5	Data Analytics	0.300	0.307	-	(0.307)	(0.307)
6	Gas Control	0.650	0.665	-	(0.665)	(0.665)
7	CEPA Participation	0.700	0.716	0.475	(0.241)	(0.241)
8	Other	-	-	-	-	-
9	Total	$ 4.808	$ 4.918	$ 4.185	$ (0.733)	$ (0.733)

Notes to table:
(1) 2020 Formula O&M is the incremental funding with Net Inflation factor applied (2.290%).
(2) Cumulative Forecast/Actual variance is the same as the 2020 (first year of MRP) Forecast/Actual variance.

Overall, total actual spending in 2020 was approximately $4.185 million, which is approximately $0.733 million lower than the 2020 Formula O&M amount. Areas with notable variances include Cybersecurity, Data Analytics, Gas Control and CEPA Participation.

With regard to Cybersecurity, the additional $0.610 million in spending was for activities to enhance FEI's cybersecurity and business continuity programs. The funding was used to build out the governance and controls for operational technology in response to increasing cyber threats on operational systems, and to update the Company's business continuity plans for each business area in response to opportunities for improvement identified during the COVID-19 pandemic, as well as to improve overall resiliency.

Offsetting the increase in Cybersecurity were lower expenditures of approximately $0.906 million for Gas Control and CEPA participation. Contributing to the lower spend was the mid-year approval of the MRP, timing of the hiring of Gas Controllers, and timing of control room management improvements. The plan is to hire one net new Gas Controller per year and to coordinate the timing of the new hires with retirements of existing employees. FEI will proceed with implementing CEPA required control room management improvements in the coming months.

For the Data Analytics, the lower spending of approximately $0.307 million was primarily due to one-time labour savings from the timing of new hires. In 2021, new hires are expected that will reduce the variance.

As discussed in the FEI Annual Review for 2020 and 2021 Delivery Rates application (pages 41 and 42), the funding for the different categories of new/incremental O&M approved for System Operations, Integrity and Security was developed based on the anticipated requirements over the term of the MRP, recognizing that priorities may change and that the expenditures may vary from year to year depending upon factors such as the availability of resources (i.e., labour vacancies) and the timing of activities.

Over the term of the MRP, FEI anticipates that the total new/incremental spending required in the combined categories of System Operations, Integrity and Security will be relatively close to the cumulative approved formula amounts, and there will continue to be variations from year to year.

6.3 O&M EXPENSE FORECAST OUTSIDE THE FORMULA

In addition to FEI's Formula O&M, FEI forecasts a number of O&M items outside of the formula annually, including pension and OPEB expense, insurance, integrity digs, BCUC levies, and O&M supporting Clean Growth initiatives, as well as any exogenous factors. These amounts are shown in Table 6-4 below along with a comparison to 2021.

Table 6-4: 2022 Forecast O&M ($ millions)

Line No.	Description	Approved 2021	Projected 2021	Forecast 2022
1	Pension/OPEB (O&M Portion)	$ 22.354	$ 22.354	$ 9.537
2	Insurance	9.908	10.430	11.474
3	Integrity Digs	4.800	5.900	5.700
4	BCUC Levies	7.290	7.290	7.408
5	**Clean Growth Initiatives:**			
6	Biomethane O&M	1.848	2.668	3.355
7	Renewable Gas Development	0.750	1.000	1.000
8	NGT O&M	1.813	1.919	2.057
9	Variable LNG Production Costs	8.081	7.281	7.553
10	Forecast O&M	$ 56.844	$ 58.842	$ 48.084

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expenses are captured in the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by the BCUC in Order G-138-14. Variances in BCUC fees are captured in the BCUC Levies Variance deferral account and amortized into rates in the subsequent year. Variances in insurance, integrity digs, Clean Growth initiatives and exogenous factors are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expense for 2022 is based upon actuarial estimates using a range of assumptions as of December 31, 2020 with an update of discount rate estimates as of May 31, 2021 provided by the Company's external third party actuary, Willis Towers Watson. The discount rate determined as of May 31, 2021 reflects the market yields of high quality Canadian corporate bonds which have increased since 2020. In addition to O&M, pension and OPEB expense is embedded in Capital Expenditures, Asset Removal Costs, and Core Market Administration Expense (CMAE) categories, as shown in Table 6-5.

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

Line No.	Description	Approved 2021	Projected 2021	Forecast 2022
1	O&M	$ 22.354	$ 22.354	$ 9.537
2	Capital - Growth	1.832	1.832	1.693
3	Capital - Other (Approved)	3.317	3.317	3.275
4	Capital - Other (to Pension & OPEB Variance Deferral)[1]	2.079	2.079	1.712
5	Deferral - Asset Removal Costs	2.128	2.128	1.967
6	Deferral - CMAE	0.644	0.644	0.595
7	Total	$ 32.354	$ 32.354	$ 18.779

Notes to table:

[1] This line item represents the pension and OPEB expense difference between the estimates embedded in the Sustainment & Other Capital forecasts on Line 3 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 2022 rate-setting purposes.

The variance between the 2021 Approved and actual pension and OPEB expense, including the known capital variance on Line 4 of Table 6-5 above, and any variance between the 2022 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-138-14.

The 2022 Forecast pension and OPEB expense has decreased by $13.575 million compared to the 2021 Approved expense primarily due to the following factors:

- An approximate $19 million decrease in amortization of actuarial losses and increase in current service costs, which are primarily 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 2.5 percent, which was used to determine the 2021 Approved expense, to 3.5 percent, which is used to determine the 2022 Forecast expense; and
- An approximate $3 million decrease due to an increase in investment returns as a result of a higher balance of pension plan assets;

offset in part by:

- An approximate $9 million increase in interest costs due to an increase in the discount rate.

6.3.2 Insurance Expense

Insurance expense relates to the insurance premium expense allocated to FEI by Fortis Inc. as set out in Table 6-6 below.

Table 6-6: Insurance Expense ($ millions)

Line No.	Description	Approved 2021	Projected 2021	Forecast 2022	Reference
1	Insurance Premiums	$ 9.908	$ 10.430	$ 11.474	Section 11, Schedule 20, Line 16
2	Total	$ 9.908	$ 10.430	$ 11.474	

The 2021 Projected insurance premium expense of $10.430 million is $0.522 million higher than 2021 Approved, as it incorporates FEI's actual July 2021 to June 2022 insurance renewals of $11.194 million. The higher premiums experienced in 2021 are expected to continue into 2022. The forecast for 2022 insurance is $11.474 million, an increase of $1.044 million from 2021 Projected. The 2022 Forecast is calculated as the amount of the first six months of actual annual insurance premiums for January 2022 to June 2022 of $5.597 million and applying a 5 percent increase for the remaining six months.[23]

FEI has experienced significant increases in insurance expense in the last two renewals as a result of the following factors:

- Insurers reducing their insurance capacity, which means reducing the limit that an insurance company agrees to assume from underwriting a risk. This results in the need for other insurers of the existing policies to increase their capacity or the need to seek new insurers who are willing to participate in the existing insurance program, which can lead to changes in pricing philosophies and higher premiums being charged;
- Insurers limiting their risks by adding new exclusions to exclude or restrict coverages for a particular event; and
- Increases in policy deductibles or self-insured retentions, which raises the threshold of an insured event for indemnification under a policy.

6.3.3 Integrity Digs

In the MRP Decision and Order G-165-20,[24] the BCUC approved the treatment of integrity digs as a flow-through item and variances between forecast and actual amounts are captured in the Flow-through deferral account. In accordance with the approved deferral account treatment of integrity digs, FEI provides the following update and forecast of its integrity dig expenditures. Costs associated with integrity digs are primarily outside of FEI's control, and there can be considerable uncertainty related to scope, cost, timing and volume of expected digs.

[23] $11.194 million/2 = $5.597 million x 1.05 = $5.877 million. $5.597 million + $5.877 million = $11.474 million.
[24] MRP Decision, p. 74.

The following table provides the forecast with Reason for Dig categories adopted to provide long-term relevance to future reports. Footnotes to the table identify how these numbers can be compared to submissions prior to the establishment of the 2020-2024 MRP. FEI considers the Reason for Dig categories to be the significant drivers for uncertainty with respect to the number of integrity digs. Discussion of each category follows.

Table 6-7: Integrity Digs Activities and Expenditures

Line No.	Reason for Digs	Number of Digs per Year			
		2021 Approved	2021 Approved, corrected[4]	2021 Projected	2022 Forecast
1	**ILI Digs – New Tool(s):** ILI digs attributed or projected due to an inspection with an ILI technology or ILI tool that has not been previously run in a given pipeline segment[1]	80	41	20	40
2	**ILI Digs – New Practice(s):** ILI digs attributed or projected due to changes to industry practices or standards (e.g., strain-based criteria for dent digs) requiring a corresponding change from FEI's past integrity dig practices[2]	40	40	28	20
3	**ILI Digs – Established Tools and Practices:** ILI digs identified through previously established technologies, tools, and practices[3]	25	64	74	80
4	**Non-ILI Digs:** Digs identified through above-ground cathodic protection and coating surveys	10	10	17	15
5	**Total Integrity Digs**	**155**	**155**	**139**	**155**
6	Total Expenditures ($000s)	$4,800	$4,800	$5,900	$5,700
7	Cost per dig ($000s)	$31	$31	$42	$37

Notes to table:

[1] Previously reported as "Circumferential magnetic flux leakage in-line inspection digs", which is just one example of integrity digs due to a first-time inspection with an ILI technology or ILI tool in a given pipeline segment.

[2] Previously reported as "Dent digs (includes dig selections that were influenced by the strain-based criteria)". The intent of this Reason for Dig was to capture increasing numbers of integrity digs due to a change to an industry practice or industry standard. The current wording will facilitate FEI's future reporting of other potential changes to industry practices and standards that will require a corresponding change from FEI's past integrity dig practices.

[3] Previously reported as "Other ILI digs". These are digs resulting from FEI's routine and ongoing use of previously adopted ILI technology or ILI tools and in accordance with previously established practices.

[4] 39 digs pertaining to a re-run with Circumferential magnetic flux leakage technology were incorrectly included as attributable to a first-time inspection ("2021 Approved"). These 39 digs have been re-stated as "Ongoing ILI digs not covered by a category above" ("2021 Approved, corrected"). These are now digs resulting from FEI's routine and ongoing use of previously adopted ILI technology or ILI tools.

FEI's forecasts related to ILI Digs – New Tools are influenced by the following:

- EMAT tool runs are now complete in two pipeline segments, with digs estimated within FEI's forecasts for 2021 and 2022. Fewer digs than forecast have been required to date;
- FEI continues to run Circumferential MFL (Magnetic Flux Leakage) tools in its transmission pipelines, and has run these tools in all pipelines constructed in the 1970s or earlier. Baseline inspections with this technology in FEI's later-constructed pipelines are expected to be completed over the next 14 years. There were no baseline Circumferential MFL runs scheduled in 2021 and one is scheduled in 2022; and
- In 2020, FEI was granted a CPCN for its Inland Gas Upgrade project.[25] The 2022 Forecast includes FEI's estimate of integrity digs from first-time in-line inspections associated with this project.

FEI's forecasts related to ILI Digs – New Practices continue to be influenced by the required adoption of the strain-based criteria for dents in current industry practice and standards.

FEI's forecasts related to ILI Digs – Established Tools and Practices result from FEI's analysis of its MFL and geometry tool runs, which are scheduled on a maximum seven-year interval and will vary from year to year. As other tool technologies (e.g., CMFL, EMAT) become established on a similar re-run schedule, it is expected that FEI's estimates of ongoing ILI digs will also include integrity digs identified through those tools.

FEI's 2021 Projected Non-ILI Digs include five digs that were re-scheduled from 2020 to mitigate the impact of excavating in a public park.

FEI continues to experience a range of scope and costs associated with its 2021 year-to-date integrity digs. Cost drivers include site access, site management during the dig, site restoration, and repairs. The increase in FEI's 2021 Projected average cost per dig is primarily due to forecast costs associated with repairs. For 2022, FEI's average cost per dig is slightly lower than the 2021 Projected due to a higher proportion of digs being forecast in FEI's Interior Transmission System, where dig costs are typically lower than for digs in populated areas such as FEI's Coastal Transmission System (e.g., increased costs due to traffic control and site restoration).

6.3.4 BCUC Levies

FEI's 2022 Forecast for BCUC levies is based on two components: (i) the BCUC levy; and (ii) FEI's portion of funding for the BCUC hearing room facilities.[26]

The 2022 Forecast BCUC levies for FEI is $7.408 million and includes the following:

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[25] Order G-12-20.

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

- The forecast BCUC levy of $7.214 million based on Order G-180-21 for the BCUC's Fiscal 2021/22 year, which represents the best information available at this time. The BCUC levy calculation for Fiscal 2022/23 will not be available until early in 2022; and
- An estimate of $0.194 million for FEI's portion of the funding for the BCUC hearing room facilities.

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.

6.3.5 Clean Growth Initiative - Biomethane O&M

A summary of the Biomethane O&M, by project, is provided in Table 6-8 below:

Table 6-8: Biomethane O&M by Project ($ millions)

Line No.	Description	Approved 2021	Projected 2021	Forecast 2022	Reference
1	Program Overhead	1.079	1.920	2.617	
2	City of Surrey	0.010	0.006	0.010	
3	Kelowna	0.512	0.501	0.502	
4	Salmon Arm	0.204	0.211	0.196	
5	Fraser Valley Biogas	0.010	0.010	0.010	
6	Seabreeze Farms	0.010	0.010	0.010	
7	Lulu Island WWTP	0.010	0.010	0.010	
8	Dickland Farms	0.010	-	-	
9	Total Biomethane O&M	1.845	2.668	3.355	Section 11, Schedule 20, Line 17

The 2021 Projected Biomethane O&M is greater than approved as a result of increased resources to support existing and new project development. In addition, FEI will be restarting the customer education programs in Q4 of 2021. The Dickland Farms project has experienced a delay and has resulted in no O&M for 2021 and 2022.

The 2022 Forecast Biomethane O&M is $3.355 million. This increase is primarily a result of an expected increase of $1.538 million in program overhead for 2022 as compared to 2021 Approved. The increase is due to an increase in resources required to grow the renewable gas portfolio, as enabled by the amendment to the GGRR (see additional details of the GGRR amendment in Section 6.3.6 below). More specifically, the increased costs are primarily related to increased spending on new renewable gas supply project development, increased staff and full year continuation of customer education programs related to renewable gas customer enrolment.

6.3.6 Clean Growth Initiative – Renewable Gas Development

Table 6-9: Renewable Gas Development O&M ($ millions)

Line No.	Description	Approved 2021	Projected 2021	Forecast 2022	Reference
1	Renewable Gas Development	0.750	1.000	1.000	Section 11, Schedule 20, Line 21
2	Total	0.750	1.000	1.000	

In order to support the continued growth of the renewable gas portfolio, including the incorporation of other renewable gases such as hydrogen and synthetic methane, FEI requires resources within its Renewable Gas team to work on safety, codes and standards, and for feasibility work more generally. In May 2021, the Provincial government issued an amendment to the GGRR that forms the basis for FEI's acquisition of renewable gas. The amendment both expanded the amount of renewable gas that can be acquired from 5 to 15 percent and expanded the definition of renewable gas to include hydrogen, syngas and lignin, in addition to biomethane. In addition, the federal government has recently committed to increase carbon reduction targets from 30 percent to between 40 and 45 percent by 2030. The policy initiatives will expand the resources that are required to support renewable gas development. In addition to the work identified above, FEI is seeing the need to support Indigenous groups that are exploring the production of renewable gases in their communities.

As a result of this increased interest and support in advancing the development of renewable gas, FEI now expects to spend approximately $1 million in 2021, which is approximately $0.250 million higher than the 2021 Approved amount. Additional costs are for activities and feasibility work related to developing the supply of renewable gases and hydrogen into the program. Actual expenditures in 2021 may vary from that projected depending on the timing of the completion of work required and renewable gas development opportunities.

2022 Forecast O&M is approximately $1 million, consistent with the 2021 Projected amount, and is related to requirements to continue work on safety, codes and standards, feasibility, and business development, recognizing that developments in the renewable gas industry may require the Company to respond accordingly and incur more costs than currently forecast.

6.3.7 Clean Growth Initiative - NGT O&M

NGT O&M is comprised of O&M expenses related to the operation of the FEI-owned CNG and LNG fuelling stations and FEI-owned LNG tankers available for rental to LNG customers. Table 6-10 below summarizes the NGT O&M.

Table 6-10: NGT O&M ($ millions)

Line No.	Description	Approved 2021	Projected 2021	Forecast 2022	Reference
1	CNG Stations	0.856	0.983	1.090	
2	LNG Stations	0.311	0.291	0.282	
3	LNG Tankers	0.545	0.625	0.615	
4	Emergency Response and Preparedness (ERAP)	0.100	0.020	0.070	
5	**Total NGT O&M**	**1.813**	**1.919**	**2.057**	Section 11, Schedule 20, Line 18

The 2021 Projected O&M expense is approximately $0.106 million higher 2021 Approved. This is primarily due to land lease payments required during the construction of three FEI stations.

The 2022 Forecast NGT O&M is increasing by approximately $0.138 million from the 2021 Projected level. This is primarily due to the reduction of LNG station volume from the closure of an LNG station in 2021, as well as an increase in CNG volume from 2021 Projected to 2022 Forecast from two additional CNG stations in 2021 and one additional CNG station in 2022, as discussed in Section 3.3.4 of this Application.

6.3.8 Clean Growth Initiative - Variable LNG Production Costs

For the MRP, LNG O&M costs are allocated between formula and forecast (flow-through) O&M based on whether they are fixed or variable costs. Fixed costs represent the fixed costs to operate the LNG plant, regardless of its use (for peak shaving storage, or LNG production for sales). The remaining portion of total LNG O&M costs is treated as flow-through outside of formula O&M. These costs represent the variable costs for the production of LNG (liquefaction of natural gas, the dispensing of LNG, the handling and loading of tankers with LNG, etc.) where the costs fluctuate and are dependent on sales volumes.

A table breaking out the various components of the Variable LNG Production Costs is included below.

Table 6-11: Variable LNG Production O&M ($ millions)

Description	Approved 2021	Projected 2021	Forecast 2022
Tilbury Plant:			
Labour	1.650	1.350	1.706
Materials	0.540	0.740	0.765
Contractor	1.131	1.131	0.612
Power	3.813	3.113	3.492
Fees and Employee Expenses	0.308	0.308	0.319
Sub-total	7.443	6.643	6.893
Mt. Hayes Plant			
Labour	0.315	0.315	0.325
Materials	0.026	0.026	0.027
Contractor	0.056	0.056	0.057
Power	0.243	0.243	0.251
Fees and Employee Expenses	0.000	0.000	0.000
Sub-total	0.639	0.639	0.660
Total O&M	8.081	7.281	7.553

The Variable LNG Production O&M expense required for operation of the expanded Tilbury LNG facility[27] and the Mt. Hayes LNG facility consists of variable labour, materials, certain contractor costs, power to run the plants, and employee expenses for the employees included in variable labour, as set out in the MRP application (page C-25). The definition of variable costs was also outlined in the response to BCUC IR2 173.4 as part of the MRP proceeding.

Included in the variable labour is the labour for the following: LNG operators for truck loading and shunting of LNG; Millwrights and Electrical and Instrumentation Technicians to support production-related maintenance activities; and Operations Management personnel to oversee activities. In 2021, timing of new hires and vacancies are expected to contribute to lower labour costs compared to 2021 Approved. In 2022, labour costs are expected to increase reflecting the full complement of staffing and labour required.

The materials costs are for materials related to production and for freight for the shipping of LNG. In 2021, higher expenditures are projected reflecting a stable level of ongoing materials costs. In 2022, materials costs are forecast to be similar to 2021.

Contractor costs are for variable contractor services used for truck loading and sewer water treatment related to the production of LNG and for consultant services to optimize the production performance of the LNG Plant. No significant variance is anticipated in 2021. In 2022, a lower amount of contractor services is forecast and may vary as the Company starts to reach full time operations.

Other variable costs include power (i.e., electricity) costs, employee expenses and shunting truck costs. Electricity costs vary directly with production. In 2021, electricity costs are projected to be lower than 2021 Approved due to lower forecast sales volumes. Similarly for 2022, forecast electricity costs reflect anticipated sales volumes.

The overall 2022 Forecast Variable LNG Production O&M costs are estimated to be similar to the 2021 Projected amounts, with increases consistent with general inflation.

6.4 *NET O&M EXPENSE*

Net O&M expense is Gross O&M less capitalized overhead and Biomethane O&M transferred to the BVA. As approved by the BCUC in Order G-165-20, the capitalized overhead rate is set at 16 percent for FEI. After capitalized overhead and the transfer of $3.355 million of Biomethane O&M to the BVA, the net O&M expense for 2022 is $276.620 million.

6.5 *SUMMARY*

Overall, the increase in Gross O&M Expense from 2021 Approved to 2022 Forecast is 1.2 percent. The formula-driven O&M is increasing at a rate of 4.6 percent and the O&M

[27] The expanded LNG facility is the Phase 1A facilities defined in Direction No. 5 to the BCUC, B.C. Reg. 245/2013, as amended by B.C. Reg. 265/2014.

forecast outside of the formula is decreasing by 15.4 percent. The capitalized overhead rate of 16 percent remains unchanged from 2021, as approved by the BCUC in Order G-165-20.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

Rate Base for FEI is forecast to be $5.409 billion for 2022. Rate Base is comprised of mid-year net gas plant in service, construction advances, work-in-progress not attracting AFUDC, unamortized deferred charges, working capital, deferred income tax, and LILO benefit.

FEI's 2022 Rate Base includes the full-year impacts of the 2021 closing projected plant balances as well as the impact of the following amounts:

- Mid-year impact of capital additions, net of CIAC additions, resulting from regular capital expenditures of $308.662 million;
- Mid-year impact of plant depreciation, net of CIAC amortization of $202.343 million;
- Full-year impact of $28.186 million of capital expenditures and related AFUDC for the LMIPSU Project as discussed in Section 7.2.3.2 below;
- Mid-year impact of $1.668 million for the Tilbury 1A Expansion Project as discussed in Section 7.2.3.2 below; and
- Full-year impact of $69.990 million of capital expenditures and related AFUDC for the Inland Gas Upgrade (IGU) Project as discussed in Section 7.2.3.2 below.

In addition, various changes in deferred charges, working capital and other items increase Rate Base by a net amount of $4.101 million in 2022.

Details of the 2022 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-165-20, FEI received the following approvals for capital expenditures:

- Approval of FEI's forecasts submitted for regular sustainment and other capital expenditures for the years 2020 through 2022;
- Approval of growth capital to be set annually on a formula basis; and
- Approval of a number of items to be forecast outside the formula on an annual basis.

The components of 2022 regular capital expenditures are shown in Table 7-1 below.

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

Line No.	Description	Approved 2021	Projected 2021	Forecast 2022	Reference
1	Formula Growth Capex	64.844	64.844	87.501	Table 7-2, Line 9
2	Forecast Sustainment & Other Capex	162.860	162.860	163.580	Section 11, Schedule 4, Lines 16 + 17
3	Flow through Capex	27.012	26.553	50.619	Section 11, Schedule 4, Sum of Lines 13 through 15
4	Total Gross Regular Capex	254.716	254.257	301.700	
5	Less: Formula CIAC	(2.250)	(2.250)	(1.948)	Section 11, Schedule 9, Line 2
6	Less: Forecast CIAC	(3.755)	(3.755)	(3.901)	Section 11, Schedule 9, Line 3
7	Net Regular Capex	248.711	248.252	295.851	

In the subsections below, FEI provides further details on its regular capital expenditures for 2022.

7.2.1 Formula Growth Capital Expenditures

The formula-driven growth capital expenditures start from a base of the prior year's approved unit cost for growth capital (UCGC), escalated by the prior year's inflation, and multiplied by the forecast gross customer additions, resulting in the forecast inflation-indexed growth capital before the true-up of formula growth capital, the formulaic CIAC, and the forecast for the system extension fund (SEF). The true-up of formula growth capital is based on actual gross customer additions from two years prior (i.e., 2020).

As calculated in Section 2, the 2022 net inflation factor based on prior year's BC-CPI and BC-AWE is 3.324 percent. Forecast gross customer additions in 2022 of 20,000 are then multiplied by the unit cost for growth capital.

For 2022, the annual growth capital expenditures under the formula is calculated as:

2021 Approved formula UCGC x [1 + (I Factor – X Factor)] x Gross Customer Additions + 2020 Formula Growth Capital True-up + 2022 Formula CIAC + 2022 Forecast SEF

Table 7-2 below shows the calculation of the resulting 2022 Formula growth capital expenditures.

Table 7-2: Calculation of 2022 Formula Growth Capital ($ millions)

Line No.	Description	Forecast 2022	Reference
1	Prior Year Base Unit Cost Growth Capital ($/customer)	3,912	G-165-20 and Section 11, Schedule 4, Line 2
2	Net Inflation Factor	3.324%	Section 11, Schedule 3, Line 9
3	Current Year Unit Cost Growth Capital ($/customer)	4,042	Line 1 x (1 + Line 2)
4	Gross Customer Addition Forecast	20,000	Section 11, Schedule 4, Line 5
5	Inflation Indexed Growth Capital	80.840	Line 3 x Line 4 / 1,000,000
6	2020 Growth Capital True-up	3.713	Line 16
7	Formulaic CIAC	1.948	Section 11, Schedule 9, Line 2
8	System Extension Fund	1.000	G-338-20 SEF Decision
9	Gross Formula Growth Capex	87.501	Sum of Line 5 to Line 8
10			
11	2020 Growth Capital True-up		
12	2020 Actual Gross Customer Addition	18,980	Section 2, Table 2-3
13	2020 Forecast Gross Customer Addition	18,000	G-319-20 2020 FEI Annual Review Decision
14	Difference	980	Line 12 - Line 13
15	2020 Unit Cost Growth Capital ($/customer)	3,789	G-319-20 2020 FEI Annual Review Decision
16	Growth Capital True-up in 2022	3.713	Line 14 x Line 15 / 1,000,000

The 2022 Gross Formula Growth Capital amount is $87.501 million. This amount includes the 2020 growth capital true-up of $3.713 million, the formulaic CIAC amount of $1.948 million, and the forecast SEF amount for 2022 of $1 million[28].

7.2.2 Forecast Capital Expenditures

The level of forecast capital expenditures approved for 2022 by the MRP Decision and Order G-165-20 is shown in Table 7-3 below.

Table 7-3: Forecast Capital Expenditures ($ millions)

Line No.	Description	Approved 2021	Projected 2021	Forecast 2022	Reference
1	Sustainment Capital	112.944	112.944	117.106	Section 11, Schedule 4, Line 16
2	Other Capital	49.916	49.916	46.474	Section 11, Schedule 4, Line 17
3	Total	162.860	162.860	163.580	Line 1 + Line 2

7.2.3 Flow-Through Capital Expenditures

7.2.3.1 Regular Capital Expenditures

FEI 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 2022 are shown in Table 7-4 below along with a comparison to 2021.

[28] The SEF, up to $1 million per year, was approved on a permanent basis pursuant to Order G-338-20.

Table 7-4: Flow-Through Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2021	Projected 2021	Forecast 2022	Reference
1	Pension/OPEB (Growth Capital Portion)	1.832	1.832	1.693	Section 11, Schedule 4, Line 13
2	Biomethane Assets	20.150	8.044	40.255	Section 11, Schedule 4, Line 14
3	NGT Assets	5.030	16.677	8.671	Section 11, Schedule 4, Line 15
4	Forecast Regular Capex	27.012	26.553	50.619	Sum of Lines 1 through 3

Each of these items is described further below.

Pension/OPEB (Growth Capital Portion)

The 2022 Forecast Pension and OPEB capital expenditures of $1.693 million represent the forecast growth capital portion of the total Pension and OPEB costs for 2022. Pension and OPEB costs are described in Section 6.3.1.

Biomethane Capital

The following table provides the 2021 Approved, 2021 Projected and 2022 Forecast for Biomethane capital expenditures, including the Order approving each project.

Table 7-5: Biomethane Capital Expenditures ($ millions)

Line No.	Description	Order	Approved 2021	Projected 2021	Forecast 2022
1	City of Vancouver	G-235-19	17.300	3.800	24.000
2	Kelowna	E-19-12	0.120	1.168	0.005
3	Salmon Arm	G-194-10	-	0.241	-
4	Lulu Island WWTP	E-13-13	0.020	0.112	-
5	Dickland Farms	E-13-20	1.230	0.890	0.100
6	Ren Energy	G-60-20	1.480	0.850	0.150
7	Seabreeze Farms	E-11-19	-	0.277	-
8	Capital Regional District	E-15-21	-	0.350	7.000
9	City of Surrey	E-3-16	-	0.007	-
10	Net Zero Waste	To be filed	-	0.100	4.000
11	Delta RNG	To be filed	-	0.100	5.000
12	Misc Modifications	Misc.	-	0.150	-
13	Total Biomethane CAPEX		20.150	8.044	40.255

The 2021 Projected and 2022 Forecast Biomethane capital expenditures are $8.044 million and $40.255 million, respectively.

FEI's applications for each biomethane project are filed and approved individually by the BCUC; therefore, the capital estimates provided here are not being requested for approval as part of the annual review process, but are provided to include the current estimates for biomethane capital expenditures in customer rates.

The 2021 Projected capital expenditures are less than 2021 Approved by $12.106 million. The variance between 2021 Projected and Approved is primarily due to a delay in spending on the

City of Vancouver project. FEI has not been able to finalize a design-build contract with an appropriate party to execute the City of Vancouver landfill project. The selection process has been longer than expected and there is now a need to adjust the project execution approach which will delay the spending. FEI forecasts $24.000 million of capital expenditures in 2022 with the work to be completed in 2023, resulting in an expected in-service date of early 2024.

The lower 2021 Projected expenditures due to the previously mentioned City of Vancouver project delay are partially offset by higher spending on the Kelowna upgrader related to required improvements, and additional capital expenditures for the Salmon Arm, Lulu Island, Seabreeze and City of Surrey projects, as well as miscellaneous capital modifications, which are projected to be transferred to plant in service in the year of spend.

With regard to the 2022 Forecast capital expenditures of $40.255 million, over half of this forecast amount is related to the City of Vancouver project, with the remainder of the forecast expenditures related to five projects, including Dickland Farms, Ren Energy (REN), Capital Regional District (CRD), Net Zero Waste and Delta RNG.

The 2021 Projected and 2022 Forecast capital expenditures for Dickland Farms are expected to be transferred to plant in service in 2022.

The REN expenditures are expected to be transferred to plant in service in 2023. The expenditures for the FEI facilities align with the expected execution timeline provided by REN to FEI.

The CRD expenditures are expected to be transferred to plant in service in 2023 to align with the current CRD timeline for the execution of its project at the Hartland landfill.

The design and permitting processes for the Net Zero Waste and Delta RNG projects are underway and applications are expected to be filed before the end of 2021, with the assets expected to enter service in 2023.

Natural Gas for Transportation (NGT) Assets

The following table provides additional detail by project for the 2021 and 2022 NGT Assets capital expenditures.

Table 7-6: NGT Assets Capital Expenditures ($ millions)

Line No.	Description	BCUC Order	Approved 2021	Projected 2021	Forecast 2022
1	Cumberland (CNG)	N/A	0.950	-	-
2	Waste Connections Abbotsford (CNG)	G-25-21	0.080	0.279	-
3	Prince George (CNG)	N/A	1.000	-	-
4	District of Cowichan (CNG)	N/A	1.000	-	-
5	GFL Abbotsford (CNG)	To be filed	-	1.994	-
6	Annacis Island (CNG)	To be filed	-	1.136	-
7	Port Kells (LNG)	Filed	-	0.071	-
8	Waste Connections Expansion (CNG)	G-110-20	-	0.447	-
9	Waste Management Expansion (CNG)	To be filed	-	-	0.751
10	Surrey (CNG)	To be filed	-	-	1.500
11	LNG Tanker (LNG)	GGRR	2.000	-	2.000
12	T1A Truck Load-out	GGRR	-	12.750	4.420
13	**Total NGT Capital Expenditures**		**5.030**	**16.677**	**8.671**

The 2021 Projected and 2022 Forecast NGT Assets capital expenditures are $16.677 million and $8.671 million, respectively. The capital expenditures for NGT Assets listed in Table 7-6 above are Prescribed Undertakings under the GGRR, with station recovery rates (i.e., capital and O&M rates) approved individually by the BCUC for each CNG or LNG station. Therefore, the capital estimates provided here are not being requested for approval as part of the annual review process, but are provided to include the current estimates for NGT Assets capital expenditures in customer rates.

The inclusion of the Tilbury 1A (T1A) truck load-out project as an NGT Asset is the primary reason for the difference between the 2021 Projected and 2021 Approved amount of capital expenditures in Table 7-6 above. The Tilbury 1A truck load-out project, which involves two new LNG tanker truck load-outs at FEI's Tilbury facility for transferring LNG from the T1A storage tank to LNG tank trailers, is a prescribed undertaking under section (3)(a)(ii) of the GGRR.[29] The project began in 2019 and is expected to complete by 2023. FEI did not include this project in the table showing NGT Assets capital expenditures in the Annual Review for 2020 and 2021 Delivery Rates; however, since it has been in work-in-progress and not affecting rate base, this is a presentation issue only as it did not affect the rate calculations for either year.

The other differences between the 2021 Projected and 2021 Approved capital expenditures are due to the following:

- Negotiations for the CNG stations originally forecast for Prince George and District of Cowichan ($1.000 million each for 2021 Approved) are still ongoing, but FEI is currently not forecasting these two stations to be built in 2021 or 2022;

[29] Section (3)(a)(ii) – One or more tanker truck load-outs for the purposes of providing within British Columbia liquefied natural gas fuel and fueling services to owners of vehicles that operate on liquefied natural gas or to owners or operators of marine vehicles that operate on liquefied natural gas.

- The CNG station originally forecast for Cumberland ($0.950 million for 2021 Approved) has been cancelled;
- Waste Connections Abbotsford (Order G-25-21) is delayed from 2020 to 2021 which resulted in the increase in capital expenditures from 2021 Approved ($0.080 million) to 2021 Projected ($0.279 million);
- Construction of two new CNG stations at GFL Abbotsford and Annacis Island, and one new LNG station at Port Kells, projected to be $3.200 million in 2021;
- One CNG station expansion at Waste Connections, projected to be $0.447 million; and
- The one new LNG marine tank trailer, which is a prescribed undertaking under section (3)(a)(i) of the GGRR,[30] originally forecast for 2021 ($2.000 million) is now delayed to 2022.

The 2022 Forecast capital expenditures are related to the following:

- Construction of one new CNG station at Surrey, estimated to be $1.500 million;
- A CNG station expansion at Waste Management, estimated to be $0.751 million;
- A new LNG marine tank trailer, originally forecast for 2021, is now estimated to occur in 2022 for $2.000 million; and
- An estimated $4.420 million for the two truck load-outs at Tilbury 1A, as discussed above.

7.2.3.2 CPCN and Special Project Capital Expenditures

Also forecast outside of the formula are any capital expenditures related to approved CPCNs, and other projects that are proceeding as a result of an Order in Council (OIC). In 2022, FEI is forecasting capital expenditures related to the Tilbury 1A Expansion project, the LMIPSU project, the IGU project and the PGR project. Each project is discussed below.

Tilbury 1A Expansion Project

The cost recovery of expenditures associated with the Tilbury 1A Expansion Project is authorized by Direction No. 5 to the BCUC as amended by OIC Nos. 557 (2013), 749 (2014), and 162 (2017). Under Direction No. 5, FEI can spend up to $425 million, plus AFUDC and feasibility and development costs, to construct storage and liquefaction facilities. FEI is forecasting the cost of the Tilbury 1A Expansion Project to be within the authorized amount, at a total of $495.1 million ($425 million excluding AFUDC and feasibility and development costs). $467.3 million of the Tilbury 1A Expansion Project was added to rate base as of January 1, 2019 and $18.7 million was added to rate base as of January 1, 2020. FEI forecasts 2021

[30] Section (3)(a)(i) – One or more liquefied natural gas tank trailers or liquefied natural gas fueling stations for the purposes of providing within British Columbia liquefied natural gas fuel and fueling services to owners of vehicles that operate on liquefied natural gas.

expenditures of $7.4 million that will be added to rate base in 2021 and final 2022 expenditures of $1.7 million that will be added to rate base in 2022.

LMIPSU Project CPCN

The LMIPSU project CPCN application was filed with the BCUC in December 2014 and approved through Order C-11-15. The LMIPSU project includes work on the Coquitlam Gate IP project, which addresses an increasing number of gas leaks on the Coquitlam Gate IP line and restores operational flexibility and resiliency to the Metro Vancouver IP system, and the Fraser Gate IP project, which will provide required seismic upgrades to the Fraser Gate IP line. The Burnaby and Coquitlam IP sections of the Coquitlam Gate IP project and the Coquitlam gate station were placed in service in 2019 at a cost of $304.414 million and were added to rate base January 1, 2020. FEI forecasts expenditures of $21.498 million and $15.470 million (excluding AFUDC) in 2021 and 2022, respectively, to complete the Coquitlam Gate and Fraser Gate portions of the LMIPSU project, with $28.186 million projected to enter rate base on January 1, 2022. The total estimated capital cost for the LMIPSU project, including AFUDC and abandonment/demolition costs, is $446.142 million.

IGU Project CPCN

The IGU project CPCN application was filed with the BCUC in December 2018 and approved through Order G-12-20. The IGU project includes upgrades to 29 pipeline laterals in the Interior of British Columbia that currently do not accommodate in-line inspection. This project addresses pipeline integrity risk associated with pipelines that operate at a hoop stress that has the potential for pipeline rupture due to corrosion on these lines that cannot be detected using current pipeline integrity methods.

FEI upgraded the Mackenzie, Cranbrook and Fording Laterals in 2020 at a cost of $54.572 million. These expenditures were added to rate base on January 1, 2021. FEI is forecasting expenditures of $70.151 million and $78.811 million (excluding AFUDC) in 2021 and 2022, respectively, with $69.990 million being added into rate base on January 1, 2022. The estimated capital cost for the IGU Project, including AFUDC and abandonment/demolition costs, is approximately $360 million.

PGR Project CPCN

The PGR project CPCN application was filed with the BCUC in August 2020 and approved through Order C-2-21. The PGR project includes construction of a new NPS 20 (508 mm) gas line and associated facilities in the City of Burnaby to replace the distribution system capacity currently provided by FEI's distribution pressure gas line affixed on the Pattullo Bridge (Pattullo Gas Line), which must be decommissioned in 2023 prior to the demolition of the Pattullo Bridge by the Province. The project scope also includes the modification, decommissioning and/or abandonment of existing infrastructure no longer required due to the removal of the Pattullo Gas Line crossing of the Fraser River. FEI forecasts expenditures of $48.916 million and $105.976 million (excluding AFUDC) in 2021 and 2022, respectively, although there are no additions to rate base until after 2022. FEI has developed the AACE Class 3 cost estimate for the PGR Project to a total of $192.155 million in as-spent dollars, including AFUDC and decommissioning/abandonment costs.

7.3 2022 PLANT ADDITIONS

The 2022 Plant Additions are comprised of: (i) FEI's 2022 regular capital expenditures from Section 7.2 above, plus the Tilbury 1A Expansion project, LMIPSU project, and the IGU project; (ii) the change in work in progress which adjusts for capital expenditures for projects such as those listed in Section 7.2 that are in progress at year end; (iii) AFUDC; and (iv) 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 7-7: Reconciliation of 2022 Capital Expenditures to Plant Additions ($ millions)

Line No.	Description	Forecast	Reference
1	Formula Growth Capex	87.501	Section 11, Schedule 4, Line 10
2	Forecast Sustainment & Other Capex	163.580	Section 11, Schedule 4, Lines 16 + 17
3	Flow through Capex	50.619	Section 11, Schedule 4, Sum of Lines 13 through 15
4	Total Gross Regular Capex	301.700	Sum of Lines 1 through 3
5	Capitalized Overheads	53.328	Section 11, Schedule 5, Line 19
6	AFUDC	3.200	Section 11, Schedule 5, Line 20
7	Change in Work in Progress	(43.717)	Section 11, Schedule 5, Line 22
8	Total Regular Additions to Plant	**314.511**	Sum of Lines 4 through 7
9			
10	Special Projects and CPCN Capex		
11	Tilbury Expansion Project	1.668	Section 11, Schedule 5, Line 7
12	LMIPSU	15.470	Section 11, Schedule 5, Line 8
13	IGU	78.811	Section 11, Schedule 5, Line 9
14	Pattullo Gasline Replacement	105.976	Section 11, Schedule 5, Line 10
15	AFUDC	3.988	Section 11, Schedule 5, Line 26
16	Change in Special Projects and CPCN Work in Progress	(106.069)	Section 11, Schedule 5, Line 28
17	Total Special Projects and CPCN Additions to Plant	**99.844**	
18			
19	Total Plant Additions	**414.355**	

7.4 ACCUMULATED DEPRECIATION

FEI's 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 2022 were approved by Order G-165-20, and are based on FEI's most recent depreciation study. Depreciation is calculated beginning January 1 of the year after the assets are placed in service, which is the treatment approved by Order G-138-14.

Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance net of CIAC, the 2022 depreciation expense is calculated as $199.430 million.[31]

7.5 DEFERRED CHARGES

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[32] 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, Schedules 11 and 11.1, FEI has classified its existing rate base deferral accounts in accordance with this classification.

The 2022 Forecast mid-year balance of unamortized deferred charges in rate base for FEI is a credit of $32.829 million.

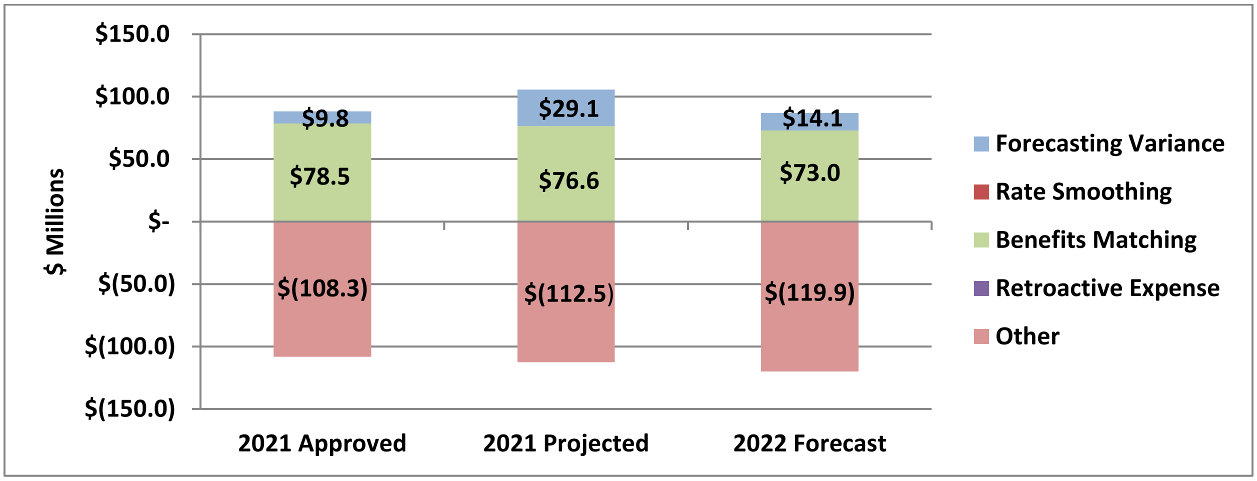
The 2022 credit balance is driven largely by the balances in several deferral accounts, including the Net Salvage Provision, the net variance between the Pension and OPEB Funding accounts, Emissions Regulations, MCRA, and Deferred Interest on MCRA / CCRA / RSAM / Gas in Storage accounts. The credit balance is partially offset by the Demand-Side Management, Greenhouse Gas Reductions Regulation Incentives, CCRA, Gains and Losses on Asset Disposition, Whistler Pipeline Conversion, BVA Balance Transfer, Pension and OPEB Variance, COVID-19 Customer Recovery Fund, and RSAM accounts.

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

[31] $208.030 million depreciation expense as calculated in Section 11, Schedule 21, Line 5 less $8.600 million amortization of CIAC as calculated in Section 11, Schedule 21, Lines 11 and 12.

[32] Log No. 53608, Appendix B.

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



Based on amortizing the opening deferral account balances using the approved amortization periods, the 2022 amortization expense is calculated as $108.747 million[33]. 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.

7.5.1 New Deferral Accounts

FEI is seeking approval of three new rate base deferral accounts to capture costs related to the following regulatory processes:

- Transportation Service Report;
- 2021 Generic Cost of Capital Proceeding; and
- 2021 Renewable Gas Program Comprehensive Review.

Table 7-8 below addresses the considerations identified in the Regulatory Account Filing Checklist, as they pertain to the deferral accounts requested in Section 7.5.1.1 to 7.5.1.3 below.

Table 7-8: Deferral Account Filing Considerations

Item	Consideration	Determination
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.	FEI requests the establishment of three new deferral accounts to capture costs related to the following regulatory processes: (i) Transportation Service Report; (ii) 2021 Generic Cost of Capital Proceeding; and (iii) 2021 Renewable Gas Program Comprehensive Review.

[33] Total of Section 11, Schedule 11.1, Line 29, Column 6 and Schedule 12, Line 25, Column 6.

Item	Consideration	Determination
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 requested accounts are regulatory proceeding cost accounts, which are routinely sought by utilities to capture external costs related to the preparation, filing, and regulatory review of applications.
II.	Propose a term (i.e., length of time) that the regulatory account should be approved for and explain why that term is appropriate.	The term of each account encompasses the preparation and filing of the relevant regulatory application and its review by the BCUC.
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 since regulatory proceeding costs are not included in Base O&M Expense) and trued up annually by way of the Flow-Through deferral account. FEI 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.

Item	Consideration	Determination
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.
b)	the degree of forecast uncertainty associated with the item;	Refer to IV. a). FEI forecasts additions to the deferral accounts based on the expected type of review process and degree of intervener involvement. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.
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 index-based O&M Expense under the MRP. See section 7.5.1.1 to 7.5.1.3.
d)	any impact on intergenerational equity	Generally, FEI recovers the costs of regulatory proceedings over the period of time related to the application, which serves to match the costs and benefits. See section 7.5.1.1 to 7.5.1.3. 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.	FEI classifies these 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.
VI.	Identify if the regulatory account is a cash or non-cash account.	Regulatory proceeding cost accounts are cash accounts.

Item	Consideration	Determination
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 index-based O&M Expense.
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.	Generally, FEI amortizes the costs of regulatory proceedings over the period of time related to the application, which serves to match the timing of costs and benefits. See section 7.5.1.1 to 7.5.1.3.
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).
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral accounts can be reviewed as part of the present proceeding. Deferral account approvals and disposition are generally determined in revenue requirements proceedings. Where requested within CPCNs or other applications, the regulatory process will be included within the draft timetable for each specific application.

7.5.1.1 Transportation Service Report

On July 20, 2018, the BCUC issued its Decision and Order G-135-18 in FEI's 2016 Rate Design Proceeding, approving a number of rate design changes to FEI's Transportation Service model. The decision directed FEI to file a report on the Transportation Service Model by June 1, 2022, assessing the impact of the approved rate design changes, and to engage with stakeholders to review the Transportation Service Model in the preparation of the report.

FEI is seeking a deferral account to capture costs associated with preparation of the report and the regulatory review proceeding which will follow. Consistent with other deferral accounts related to regulatory compliance filings, this deferral account will capture costs associated with stakeholder consultation, preparation of the report, and the regulatory review process. These costs include BCUC costs, intervener and participant funding costs, external legal fees, expert/consulting costs, and miscellaneous facilities, stationery and supplies costs. FEI forecasts additions of $0.100 million in 2021, $0.250 million in 2022 and $0.150 million in 2023. Actual costs will vary depending on how the proceeding progresses and will be confirmed after the regulatory process is completed.

FEI expects to apply for disposition of this account in the Annual Review for 2023 Delivery Rates application.

7.5.1.2 2021 Generic Cost of Capital Proceeding

On January 18, 2021, the BCUC issued a Notice of Initiating a Generic Cost of Capital (GCOC) proceeding to all regulated entities. In subsequent orders, the BCUC has determined the GCOC will proceed in two stages, and will determine, at a later date, the effective date to implement a new cost of capital, whether interim rates will be necessary or not, or whether a transition period will be required. The scope for Stages 1 and 2 has been determined, including the BCUC addressing deferral account financing costs after the completion of both Stages 1 and 2. Additionally, the BCUC advised parties that it has engaged an independent expert consultant for the GCOC proceeding, as well as an initial report on the pros and cons of using a Benchmark Utility in the determination of cost of capital, alternatives to using a Benchmark Utility, the practices in other jurisdictions, and the applicability of practices in other jurisdictions to BC. Participants will be filing submissions on the initial report as well as submissions on questions regarding the use of a Benchmark Utility.

FEI is seeking a deferral account to capture costs associated with its participation in the GCOC proceeding. These costs include BCUC costs, intervener and participant funding costs, external legal fees, expert/consulting costs, and miscellaneous facilities, stationery and supplies costs. While the regulatory timetable for the GCOC proceeding is not yet established, FEI expects that Stage 1 will commence later in 2021 and continue into 2022. At this time, FEI forecasts additions of $0.750 million in 2021, $0.750 million in 2022 and $0.350 million in 2023. Actual costs will vary depending on how the proceeding progresses and will be confirmed after the regulatory process is completed.

FEI will apply for disposition of the account in a future application following completion of the regulatory process for the GCOC proceeding.

7.5.1.3 2021 Renewable Gas Program Comprehensive Review

On August 12, 2020, FEI filed its Biomethane Energy Recovery Charge (BERC) Rate Methodology assessment report in compliance with Directive 16 of the BCUC's Decision and Order G-133-16. On January 29, 2021, the BCUC issued Order G-35-21, determining that a regulatory review process with two stages was warranted, with the first stage reviewing the BERC Rate assessment report and the second stage consisting of a comprehensive review of FEI's Renewable Gas (RG)[34] Program. As directed in Order G-35-21, on June 30, 2021 FEI

[34] Previously referred to as Renewable Natural Gas or RNG Program.

filed a status update letter setting out, among other things, the scope of the RG Program comprehensive review with anticipated filing of an application in the fourth quarter of 2021.

FEI is seeking approval to establish a deferral account to capture the costs related to development of the RG Program comprehensive review application and expected regulatory proceeding costs. These costs include BCUC costs, interveners and participant funding costs, external legal fees, expert/consulting costs, notice publication costs, and miscellaneous facilities, stationery and supplies costs. FEI forecasts additions of $0.330 million in 2021 and $0.435 million in 2022. Actual costs will vary depending on how the proceeding progresses and will be confirmed after the regulatory process is completed.

FEI will apply for disposition of this account in a future application following completion of the regulatory process for the RG comprehensive review proceeding.

7.5.2 Existing Deferral Accounts

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

7.5.2.1 COVID-19 Customer Recovery Fund Deferral Account

7.5.2.1.1 DESCRIPTION AND FINANCIAL ESTIMATES

In June 2020, FEI received approval through Order G-132-20 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 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 2021 and 2022 financial estimates and descriptions for each of the three items approved for inclusion in the COVID-19 Customer Recovery Fund Deferral Account.

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. Overall, the bill payment deferral program has been successful, providing easy to access bill payment support to those customers that need it most during the pandemic with minimal administrative burden. FEI has experienced high collection rates in regards to this program and is therefore expecting to recover approximately 90 percent of the outstanding balances through the regular monthly instalments. FEI will no longer be accepting new applications effective June 1, 2021.

Table 7-9: Bill Payment Deferral Amounts ($ millions)

	2020 Actual	2021 Projected	2022 Forecast
Opening Balance	-	1.952	0.280
Additions	2.837	-	-
Repayments	(0.885)	(1.672)	-
Transfers	-	-	(0.280)
Ending Balance	1.952	0.280	-

Although the program has been successful, FEI does not expect to recover the full amount of the deferred balances, as a small percentage of customers have not made their required instalment payments. Any of the customer balances that are ultimately deemed unrecoverable will be designated as unrecoverable revenue and as such, added to the COVID-19 Customer Recovery Fund Deferral Account. These additions to the deferral account are forecast in section (c), Table 7-11 *Unrecoverable Revenue Amounts*.

Based on the results of a small pilot customer contact approach (which is described further below) and current repayment trends, FEI expects approximately 90 percent of the required repayments under the deferral arrangement to be collected, resulting in approximately 10 percent of the amounts being considered unrecoverable. This results in $0.280 million of customer accounts being deemed unrecoverable and therefore reclassed within the COVID-19 Customer Recovery Fund Deferral Account to unrecoverable revenue additions in section (c).

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 $0.709 million as of May 2021. The credits provided through this program were well received by small commercial customers and supported them in the initial phase of the COVID-19 pandemic.

Table 7-10: Bill Credit Amounts ($ millions)

	2020 Actual	2021 Projected	2022 Forecast
Opening Balance	-	0.708	0.709
Additions	0.970	0.001	-
Tax	(0.262)	-	-
Ending Balance	0.708	0.709	0.709

Given the duration and period these credits were available for, as well as the June 1, 2021 closure of the program for new applications, FEI does not expect additional credits to be offered to customers throughout the remainder of 2021 or in 2022.

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 7-11: Unrecoverable Revenue Amounts ($ millions)

	2020 Actual	2021 Projected	2022 Forecast
Opening Balance	-	0.064	0.502
Transfers	-	-	0.280
Additions[35]	0.088	0.600	1.700
Tax	(0.024)	(0.162)	(0.535)
Ending Balance	0.064	0.502	1.947

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; and
- any unrecovered revenue from all customer classes due to COVID-19, including industrial and large commercial customers and those residential and small commercial customers that did not participate in the bill payment deferral or bill credit relief offerings.

To date, there has been a minimal amount of unrecoverable revenue relating to COVID-19 added to the Customer Recovery Fund Deferral Account. This is primarily due to FEI's temporary suspension of the debt collections program and related collections activities throughout 2020 and early 2021[36] as well as the timing of the Customer Recovery Fund repayment schedule.

To support the development of a consistent and appropriate approach for identifying amounts deemed unrecoverable due to COVID-19, FEI 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 COVID-19. 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 COVID-19.

[35] The 2020 unrecoverable revenue additions of $0.088 million consist of $0.084 million of residential customer balances and $0.004 million of small commercial customer balances.

[36] In response to the pandemic, FEI ceased late payment charges, disconnections for non-payment and collection agency referrals for the majority of 2020 and restarted these activities in March 2021.

FEI has recently conducted a pilot where a select amount of customers were contacted with the intent of measuring the success of the outreach plan and internal guidelines. The results from this pilot stage have been used to develop the unrecoverable revenue forecast additions to the Customer Recovery Fund Deferral Account provided in Table 7-11 above. During the pilot, 480 customers with past due balances were contacted to determine impacts of the pandemic. 15 percent of the customers with an average balance of $550 confirmed that they were financially impacted by COVID-19 and will require support to bring their accounts into good standing. This result was applied to the estimated 3,600 customers with outstanding balances as at June 1, 2021 to derive the forecast COVID-19 related unrecoverable revenue deferral account additions.

While the forecasts of the unrecovered revenue additions rely on estimates and broader macroeconomic factors, the actual amounts that accumulate in the deferral account are expected to be representative of balances that are attributable to specific customers that cannot make payment due to COVID-19. Further, due to the time between identifying these accounts as unrecoverable due to COVID-19 and the review process, which may include a payment commitment from the customer on a partial outstanding balance, FEI expects that additions to the account will extend to at least 2022.

7.5.2.1.2 DISPOSITION OF DEFERRAL ACCOUNT

As discussed above, 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 are expected to continue into 2022. As a result, the deferral account will be required to capture unrecovered revenues until at least the end of 2022.

After 2022, the need for the continuation of the COVID-19 Customer Recovery Fund Deferral Account is dependent on the continued impact of the COVID-19 pandemic on FEI's customers' ability to make payments on their utility bills. While the current outlook regarding the COVID-19 pandemic in BC is positive, with resumption of normal operating conditions expected later this year, coinciding with the Province achieving Step 4 of the Province of BC Four Step Restart Plan, the financial effects of the COVID-19 pandemic on customers' ability to make payments may remain for some time afterwards. During the pandemic, individuals and businesses alike have suffered, with some struggling to meet their financial obligations. Federal and provincial government support programs such as the Canada Recovery Benefit (CRB) for individuals, the Canada Emergency Wage Subsidy (CEWS) for businesses and other various financial assistance programs have helped individuals and businesses in BC. However, with the elimination of these financial assistance programs eventually expected, even though the pandemic may be declared over from a medical perspective, financially some consumers and businesses may not have recovered and may be unable to make bill payments.

Similarly, the general state of the economy may not have fully recovered from the impact of the COVID-19 pandemic by 2022. As FEI's unrecovered revenue additions are influenced by broader macroeconomic factors, and given the state of the economy at this time and the uncertainty as to the timing of recovery, FEI is not able to forecast by the end of 2022 that its unrecovered revenues will have normalized to that prior to the COVID-19 pandemic.

With the uncertainties described and recognizing the uncertainty around the duration and significance of the pandemic on customers' ability to pay their bills, with the potential for unrecoverable revenue to shift between periods or vary from the forecast, FEI will be in a better position to provide an update regarding the continued financial effects from the COVID-19 pandemic on its customers (homes and businesses) at the time of the Annual Review for 2023 Delivery Rates and will be able to provide a recommendation on whether the deferral account will be required past 2022. By this time next year, based on the current outlook, the general state of the economy post pandemic, and the status of the collectability of FEI's billed revenues will likely be clearer.

In consideration of the ongoing uncertainties and continued need for the COVID-19 Customer Recovery Fund Deferral Account discussed above, FEI is not proposing to commence recovery of the deferral account as part of this Application. Instead, FEI will request approval of an amortization period for this deferral account in the Annual Review for 2023 Delivery Rates application.

7.5.2.1.3 REQUEST TO CHANGE REPORTING FREQUENCY

FEI seeks approval to change the reporting requirements for the COVID-19 Customer Recovery Fund Deferral Account from filing monthly reports with the BCUC to filing quarterly reports.

As part of the approval in Order G-132-20 for the establishment of the deferral account, FEI was directed to file monthly reports with the BCUC detailing the status of the relief program as follows:

a) An assessment on the need for an extension or any other formal change to the customer relief measures beyond the July 1, 2020 date.

b) A report on the COVID-19 Customer Recovery Fund Deferral Account and customer relief measures. This report must include the number of customers that have been approved for each program, as well as the number of customers that have applied but have been rejected from participating in the program, in addition to reporting on the current balance in the deferral account.

FEI has filed monthly reports with the BCUC since May 15, 2020 and effective June 1, 2021, FEI closed the deferral and credit program components to new applicants.

With more than one full year of monthly reporting complete, the closure of the deferral and credit program to new applicants and the administrative efforts associated with monthly reporting, a change to the frequency of filing these reports with the BCUC from monthly to quarterly is appropriate at this time. In addition, quarterly data may better highlight material changes in the deferral account balance as repayments continue and unrecovered revenue amounts materialize. FEI will continue to provide the same level of deferral account detail in the quarterly reports as currently provided in the monthly reports and proposes to file the quarterly reports with the BCUC as follows each year as applicable: October 15th, January 15th, April 15th and July 15th.

7.5.2.2 BFI (presently "Waste Connections") Costs and Recoveries Deferral Account

Pursuant to Order C-6-12, FEI received approval to establish a rate base deferral account to capture the revenues associated with the volumes in excess of Waste Connections' take-or-pay commitment for CNG fuelling service (related to the capital component of excess recoveries only) which could be credited back to Waste Connections in the event that they were required to pay the un-depreciated capital cost of the fuelling station if the contract buyout provision was used.

Further, as described in the Waste Connections Application for Expansion and approved by Order G-85-20, FEI was able to apply the excess capital revenue within the five-year renewal term (i.e., to reduce the Capital Rate) or apply the excess capital revenue at the end of the renewal term (i.e., reducing the cost to buy out the station). Waste Connections agreed to have the actual excess capital component recoveries of $0.731 million as of December 31, 2019, and a further $0.033 million from January 1 to March 31, 2020, be returned by applying the recoveries to the beginning of the five-year renewal period commencing April 1, 2020, thereby reducing the Capital Rate. The resulting impact of this decision was to transfer the $0.764 million of excess recoveries to capital, as a reduction against the existing plant balance of the assets, thereby reducing rate base.

As a result of the above, a residual balance of $0.202 million remains in the BFI Costs and Recoveries deferral account related to the tax on the $0.764 million excess recoveries. Given there is not an approved recovery mechanism for the BFI Costs and Recoveries deferral account, FEI is requesting to amortize this deferral account over one year beginning January 1, 2022, after which time the account will be discontinued.

7.5.2.3 2017-2018 Revenue Surplus Deferral Account

In the Annual Review for 2020 and 2021 Delivery Rates Decision and Order G-319-20, FEI received approval to draw down the balance in the previously approved 2017 & 2018 Revenue Surplus deferral account to zero in order to mitigate delivery rate increases in 2020 and 2021. FEI projects a minor remaining credit balance in the 2017 & 2018 Revenue Surplus deferral account of approximately $0.308 million (after-tax) at the end of 2021. This balance is due to the difference between actual and projected/forecast AFUDC amounts.

FEI requests approval to transfer this deferral account from a non-rate base deferral account to a rate base deferral account, in order to eliminate the potential for future variances between actual and projected/forecast AFUDC, and to amortize the remaining December 31, 2021 balance in 2022, after which time the account will be discontinued.

7.6 *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-165-20.

Other working capital includes gas in storage, transmission line pack gas, inventory of materials and supplies, employee loans and withholdings and refundable contributions.

The main components of other working capital are gas in storage and transmission line pack, which are forecast on a 13-month average basis using the approved costs embedded in the 2021 Q2 gas cost report and historical volumes. All other 2022 amounts are forecast based on 2020 Actual levels.

7.7 *SUMMARY*

FEI's rate base includes the impact of formula-driven growth capital expenditures, regular capital expenditures that are forecast outside of the formula, and CPCNs and major projects, adjusted for work-in-progress, AFUDC and overheads capitalized. FEI has provided forecasts for all of its rate base deferral accounts in the financial schedules included in Section 11. In Section 7.5.1, FEI requested approval of three new deferral accounts and in Section 7.5.2, FEI discussed three existing accounts, including requesting amortization of two of these existing accounts. Finally, the rate base includes other working capital, composed of gas in storage and other smaller components that have been forecast consistent with prior years.

8. FINANCING AND RETURN ON EQUITY

8.1 INTRODUCTION AND OVERVIEW

FEI has prepared this Application using the benchmark capital structure of 61.5 percent debt and 38.5 percent equity and Return on Equity (ROE) of 8.75 percent approved by Order G-129-16. The 2022 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, FEI's AFUDC rate for 2022 (which is equal to its after-tax weighted average cost of capital) is 5.42 percent. Any variances from interest rates used to set delivery 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-129-16, the BCUC has approved a benchmark capital structure of 61.5 percent debt and 38.5 percent equity with an allowed ROE of 8.75 percent, effective January 1, 2016, which have been used to calculate rates in this Application. FEI notes that the BCUC has initiated a Generic Cost of Capital (GCOC) proceeding and, 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. If the BCUC determines later in 2021 that the effective date to implement a new cost of capital is January 1, 2022, FEI will file for interim rates and will update the 2022 revenue requirement once the GCOC decision is issued.

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

FEI is a public issuer of long-term debt. In April 2021, FEI issued long-term debt of $150 million at a rate of 2.42 percent[37] for a term of 30 years. The net proceeds were used to repay existing indebtedness and finance the Company's capital expenditure program. FEI plans to issue additional long-term debt of approximately $200 million in 2022 and will use the funds for the same purposes. The 2022 debt issuance is reflected in the financial schedules in July 2022 at a rate of 3.60 percent.[38] The exact timing, amount and rate of the 2022 issuance will depend on

[37] Section 11, Schedule 27, Line 17 (effective rate 2.482 percent).
[38] Section 11, Schedule 27, Line 18 (effective rate 3.655 percent).

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

FEI obtains short-term funding primarily through the issuance of commercial paper to Canadian institutional investors. FEI backstops the commercial paper issuances by maintaining a $700 million committed credit facility that matures in July 2026.[39] The credit facility provides FEI with short-term liquidity to fund its capital program and working capital requirements, and FEI issues letters of credit as part of this facility. FEI also maintains a $55 million letter of credit facility that matures in March 2023 to support its letters of credit.

8.3.3 Forecast of Interest Rates

FEI 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 FEI are maintained.

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

The 3-month T-Bill forecast for 2022 is 0.47 percent, which is a slight increase from the 0.45 percent approved in 2021. For 2022, FEI forecasts a similar level of other financing fees to the 2021 Approved amount. Other financing fees include the fees that FEI incurs for its letters of credit under the $700 million credit facility and the $55 million letter of credit facility discussed in Section 8.3.2, as well as interest paid on customer deposits. The short-term borrowing rate forecast is shown in Table 8-1 below.

[39] On July 14, 2021, the credit facility was extended to July 14, 2026.

Table 8-1: Short Term Interest Rate Forecast

FEI Short Term Interest Rate	Approved 2021	Projected 2021	Forecast 2022
3-Month T-Bill Rate [1]	0.45%	0.13%	0.47%
Spread to CDOR	0.44%	0.39%	0.39%
CDOR Rate	0.89%	0.52%	0.86%
Spread to CP	-0.22%	-0.32%	-0.32%
CP Dealer Commission	0.10%	0.10%	0.10%
ST Interest Rate on Credit Facilities	**0.77%**	**0.30%**	**0.64%**
Fixed Financing Fees [2]			
Standby fee on Undrawn Credit [3]	0.86%	0.90%	1.12%
Renewal Fee on Undrawn Credit	0.33%	0.32%	0.40%
Other Financing Fees [4]	0.23%	0.12%	0.15%
ST Interest Rate on Fixed Financing Fee	**1.42%**	**1.34%**	**1.67%**
FEI Short Term Rate	**2.19%**	**1.64%**	**2.31%**

Notes to table:

[1] 3-Month T-Bill Rate for 2022 is a weighted average rate based on forecasts provided by Canadian Chartered banks in June 2021.

[2] Fixed financing fees represent the costs of maintaining the $700 million credit facility and letter of credit facility, which are fixed fees regardless if FEI draws from the credit facility. The fees have been converted into a short-term rate for forecast purposes.

[3] A standby fee of 16 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 FEI will borrow through commercial paper and will not change the undrawn credit facility fee percentage.

8.3.4 Interest Expense Forecast

The interest expense forecast reflects FEI'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 effective interest method. For each long-term debt issue, the effective rate (forecast effective rate if it is a new issue) is multiplied by the average balance of that long-term debt for the year. The 2022 long-term debt schedule for FEI can be found in Section 11, Schedule 27.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FEI applies AFUDC to projects that are greater than three months in duration and greater than $100 thousand. Based on the above information, FEI's AFUDC rate for 2022 (which is equal to its after-tax weighted average cost of capital) is 5.42 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2022

	Weight	Pre Tax Rate	After Tax Rate	Earned Return
Short Term Debt	2.00%	2.31%	1.69%	2.31%
Long Term Debt	59.50%	4.65%	3.39%	4.65%
Common Equity	38.50%	11.99%	8.75%	8.75%
Weighted Average	100.00%	7.43%	5.42%	6.18%

8.4 SUMMARY

FEI's equity financing and ROE have been forecast for 2022 at the same percentages as approved by Order G-129-16. FEI'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 2022 as compared to 2021 Approved.

9. TAXES

9.1 *INTRODUCTION AND OVERVIEW*

This section discusses FEI's forecasts of property taxes and income tax which have been forecast on a basis consistent with prior years. In 2022, property taxes are forecast to increase by 2.2 percent from 2021 Approved, while income tax is forecast to decrease by 3.3 percent compared to 2021 Approved.

9.2 *PROPERTY TAXES*

Property taxes for 2022 of $73.397 million incorporate Company forecasts of assessed values of taxable assets, mill rates and taxes from revenues earned from gas consumed within municipalities. A breakdown of property taxes by asset type is provided in Table 9-1 below.

Table 9-1: Property Tax Forecasts ($ millions)

Line No.	Description	Approved 2021	Projected 2021	Forecast 2022
1	Distribution Assets	$ 25.473	$ 27.272	$ 28.360
2	Transmission Assets	21.012	18.847	19.209
3	Gas Storage Assets	8.185	6.949	7.118
4	Manufactured Gas Assets	0.037	0.035	0.036
5	General Assets	4.478	4.869	5.128
6	In-Lieu	12.423	12.693	13.368
7	OGC Fees	0.286	0.285	0.285
8	Total Property Taxes	$ 71.894	$ 70.950	$ 73.504
9	Less: Property Tax Transferred to BVA	(0.083)	(0.083)	(0.107)
10	Net Property Tax	$ 71.811	$ 70.867	$ 73.397
11				
12	Forecast Change from 2021 Approved			2.2%
13	Forecast Change from 2021 Projected			3.6%

As shown in the above table, in 2022 property taxes are forecast to increase by 2.2 percent from 2021 Approved and increase by 3.6 percent compared to 2021 Projected. The increase in the 2022 Forecast compared to 2021 Projected is due to construction activities, market value increases, changes in tax policies of local taxing authorities and increased in-lieu taxes. The most significant forecast drivers of the changes are as follows:

1. ***Changes in Tax Rates***. Tax Rates are expected to change for 2022 as follows:
    a) Municipal rates are expected to increase by 0.25 percent for Lower Mainland municipalities, and 0.50 percent for all other municipalities;
    b) School rates are expected to decrease by 1.0 percent;

   c) Rural rates are expected to decrease by 2.0 percent;

   d) Tax rates on First Nations are expected to increase by 0.25; and

   e) Other rates are not expected to change overall.

2. ***Changes in Revenues to Calculate Grants In-lieu of Taxes.*** Revenues reported to municipalities are expected to increase by 5.3 percent based on actual revenues. Grants in-lieu of taxes are based on a fixed percentage of revenues; the overall 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 FEI's property are based on expected inflationary increases. These include:

   a) A 3.0 percent increase in assessed values of distribution lines and services plus additional new construction;

   b) A 3.0 percent increase in assessed values of transmission lines. In consideration of the impacts of the COVID-19 pandemic, changes to linear rates from BC Assessment's systematic review that concluded in 2019 are expected to be delayed until 2023;

   c) A 2.0 percent increase in assessed values for LNG assets; and

   d) Land value changes which are expected to increase on average between 5.0 percent for right of ways and 7.0 to 8.0 percent for market value for properties owned in fee simple.

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

9.3 *INCOME TAX*

FEI 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 2022, which is unchanged from 2021. 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 2022 is forecast to decrease by $1.801 million or 3.3 percent compared to 2021 Approved. The 2022 decrease is primarily due to higher deductible temporary differences associated with property, plant and equipment and lower taxable temporary differences associated with pension and OPEB, partially offset by higher rate base and amortization of deferred charges.

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*

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

10. EARNING SHARING AND RATE RIDERS

10.1 INTRODUCTION AND OVERVIEW

In this section, FEI discusses earnings sharing and the calculation of its delivery rate riders. FEI proposes to distribute a $1.853 million pre-tax credit ($1.353 million after-tax) earnings sharing amount to customers as part of 2022 delivery rates. FEI has also set out the BVA, RSAM and Clean Growth Innovation Fund (CGIF) rate riders for 2022 and provides details on the CGIF, which is funded through the collection of the CGIF rate rider.

10.2 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 FEI 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 FEI distributes earnings sharing amounts. This is consistent with the calculations of formula O&M and growth capital, where the true-up of the formula inputs happens only once actuals are known. Thus, for 2022 delivery rates, it is the 2020 formula O&M, 2020 growth capital, and 2020 earnings sharing amounts that are calculated and impact rates in 2022.

For 2022, FEI proposes to distribute a $1.853 million pre-tax credit ($1.353 million after-tax) to customers, comprised of:

- The $1.250 million credit difference between the projected ending 2020 deferral account balance of zero,[40] embedded in 2021 delivery rates, and the actual ending 2020 deferral account credit balance of $1.250 million as provided in FEI's 2020 Annual Report to the BCUC;
- The $0.068 million credit difference between the forecast 2021 financing addition of zero,[41] embedded in 2021 delivery rates, and the projected 2021 financing addition of $0.068 million credit embedded in this Application; and
- 2022 forecast financing of a $0.035 million credit.[42]

After truing-up the 2020 earnings sharing balance to actual and including the financing adjustments described above, FEI proposes to distribute $1.853 million to customers in 2022 as a reduction in 2022 revenue requirements through amortization of the projected 2022 opening after-tax balance of $1.353 million in the MRP Earnings Sharing deferral account.

[40] Annual Review for 2020 and 2021 Delivery Rates Compliance Filing financial schedules, Schedule 12, Line 23, Column 2.
[41] Annual Review for 2020 and 2021 Delivery Rates Compliance Filing financial schedules, Schedule 12, Line 23, Column 4.
[42] Section 11, Schedule 12, Line 21, Column 4.

As part of future rate filings, the earnings sharing for 2021 will be subject to similar true-ups as described above, which will account for the actual 2021 ROE variance from approved.

10.3 *RATE RIDERS*

There are two delivery rate riders that are set each year through the annual review process. These are the BVA Rate Rider and the RSAM Rate Riders. Additionally, pursuant to the MRP Decision, FEI was approved to collect a basic charge fixed rate rider of $0.40 per month from all non-bypass customers for the term of the MRP to support FEI's Clean Growth Innovation Fund (CGIF) activities.

10.3.1 BVA Rate Rider

The 2021 BVA rate rider was approved on a permanent basis by Order G-319-20. The following supports the BVA rate rider for 2022.

On August 12, 2016, the BCUC issued Order G-133-16 and the accompanying Decision in the matter of the Biomethane Energy Recovery Charge (BERC) Rate Methodology Application (2016 Biomethane Decision). The 2016 Biomethane Decision approved the Short Term BERC rate based on a premium of $7 per GJ above the Conventional Gas Cost (defined as the sum of the Commodity Cost Recovery Charge, the carbon tax and any other taxes applicable to conventional natural gas sales). The Long Term BERC rate is to be set at a $1 per GJ discount to the Short Term BERC rate.

FEI also received approval to amortize/transfer the net of tax year-end balance in the BVA, after adjustment for the value of unsold biomethane quantities, to a BVA Rate Rider Account for recovery from, or refund to, all non-bypass customers via a delivery rate rider effective January 1 of the subsequent year.

In the 2016 Biomethane Decision, FEI was directed to provide the following information:

- A continuity schedule showing the breakdown of the forecast December 31st balance in the BVA to be recovered by the BVA Rate Rider by year including sufficient supporting details.
- The calculation of the BVA Rate Rider by rate class.
- A continuity schedule showing the forecast, actual and variance (actual – forecast) biomethane revenues and volumes sold (GJ) by rate class, type of contract (short term/long term) and year.
- Number of customers in each rate class.

FEI provides the requested information below for the projected closing 2021 balance of the BVA rate rider account, and the calculation of the BVA Rate Riders for 2022.

10.3.1.1 BVA Rate Rider Account

The BVA balance at the end of December 31, 2021 is projected to be a debit of $11.293 million before-tax.[43] This balance consists of the projected $18.754 million in costs to acquire biomethane less $7.461 million of recoveries by way of the Biomethane Energy Recovery Charge (BERC). FEI projects 13.2 TJs of biomethane to remain in inventory for 2021.

The amount transferred from the BVA to the BVA rate rider account is determined on an after tax basis. The after tax balance in the BVA before transfer to the BVA rate rider account is projected to be $8.244 million.[44]

The following table summarizes the BVA rate rider account and shows both the projected after tax ending 2021 balance of $0.114 million[45] and the $8.130 million[46] transfer to the BVA rate rider account.

[43] Table 10-1, Line 16.
[44] Table 10-1, Line 25.
[45] Table 10-1, Line 29.
[46] Table 10-1, Line 27.

Table 10-1: BVA Rate Rider Account

Line No	BVA Continuity	Note	2021 Projected (a) ($000s)	Reference
1	**BVA Opening Balance**	(b)		
2	Pre-Tax Balance (Before Adjustment for Unsold Biomethane)		$ 0.0	
3	Pre-Tax Adjustment for Unsold Biomethane		(0.0)	
4	Pre-Tax Adjustment for Unsold Biomethane		$ -	Line 2 + Line 3
5				
6	Tax Recovery		-	- Line 4 x Line 18
7	Net of Tax Balance (After Adjustment for Unsold Biomethane)		$ -	Line 4 + Line 6
8				
9	**BVA Activities:**			
10	Biomethane Costs Incurred		$ 18,754.1	
11	Biomethane Costs Recovered		(7,460.9)	
12	Total Activities - Pre-Tax		**$ 11,293.1**	Line 10 + Line 11
13				
14	Pre-Tax Balance of Unsold Biomethane	(c)	$ 155.7	
15	Pre-Tax Balance After Adjustment for Unsold Biomethane		11,137.5	Line 12 - Line 14
16	**BVA Ending Balance**		**$ 11,293.1**	Line 14 + Line 15
17				
18	Tax Recovery Rate		27%	
19				
20	Tax Recovery on Balance of Unsold Biomethane		$ (42.0)	- Line 14 x Line 18
21	Tax Recovery on Balance after adjustment		(3,007.1)	- Line 15 x Line 18
22				
23	After-Tax Balance of Unsold Biomethane		113.6	Line 14 + Line 20
24	After-Tax Balance After adjustment for Unsold Biomethane		8,130.4	Line 15 + Line 21
25	**Net of Tax BVA Balance before Transfer to BVA Rider Account**		**$ 8,244.0**	Line 23 + Line 24
26				
27	**Transfer to BVA Rate Rider Account**	(d)	**$ (8,130.4)**	- Line 24
28				
29	**Net of Tax Balance (After transfer to BVA Rider Account)**		**$ 113.6**	Line 25 + Line 27

Notes

(a) The annual forecast is an updated 2021 forecast

(b) Recorded opening balance reconciles to the December 31, 2020 balance in the FortisBC Energy Inc. 2020 BVA Status Report.

(c)

		2020		2021
Calculation of Adjustment for Unsold Biomethane		Recorded		Projected
Beginning Quantity Unsold Biomethane (in TJ)		0.1		0.0
Biomethane Purchased (in TJ)		306.0		682.0
Biomethane Sold (in TJ)		(306.2)		(668.8)
Ending Total Biomethane Unsold (in TJ)		0.0		13.2
BERC rate in effect at forecast (in $/GJ)				
January 1st effective BERC rate (in $/GJ)	$	11.830	$	11.830
Value of Unsold Biomethane at December 31st	$	0.0	$	155.7

(d) Pursuant to Order G-133-16, and the Decision issued concurrently, the net of tax balance at December 31, 2021, after adjustment for the value of unsold biomethane quantities, was transferred to the BVA Rate Rider Account for recovery from / refund to all non-bypass customers.

10.3.1.2 BVA Rate Rider Calculation

The cumulative BVA rate rider for recovery in 2022 is forecast at $11.525 million and is recovered from non-bypass customers through a rate rider based on 2022 Forecast volumes. The $11.525 million to be collected consists of the projected 2020 recovery variance of $387.7 thousand[47] plus the $8.130 million after tax debit transferred from the BVA grossed up to a before tax debit value of $11.138 million.[48]

To calculate the BVA rate rider, the projected BVA rate rider account balance of $11.525 million is divided by the 2022 Forecast non-bypass customer volume of 196,294 TJs, which results in a BVA rate rider of $0.059 per GJ. Any difference between the actual and forecast BVA rate rider amount collected will be trued up in the subsequent year. Details of the BVA rate rider calculation are provided in Table 10-2 below.

[47] The $387.7 thousand represents a combined adjustment for the 2020 actual and projected BVA balance transfer variance and the 2021 recovery variance because of the 2021 volume projection variance.

[48] Table 10-2, Line 5.

Table 10-2: 2022 BVA Rate Rider Calculation

Line No	Particulars	BVA Rider Projected 2021 ($000s) Net of Tax	BVA Rider Projected 2021 ($000s) Grossed Up	Non-Bypass Forecast 2022 Vol (TJ)
1	**BVA Rider Account Balance**			
2	**BVA Balance Transfer Deferral Account Balance Dec 31, 2020 - Actual**	3,402.0	$ 4,660.3	
3	Less Projected 2021 BVA Rider recoveries for 2020 using 2021 Projected Non-bypass volumes	(3,119.0)	(4,272.6)	
4	**2021 projected true up adjustment - 2020 projected recovery variance**	283.0	387.7	
5	BVA Balance transferred to BVA Balance Transfer Deferral Account Dec 31, 2021 - Projected	8,130.4	$ 11,137.5	
6	**BVA Balance Transfer Deferral Account Balance Dec 31, 2021 - Projected**	**8,413.4**	**11,525.2**	**196,294.3**
7				
8	**Residential**			
9	Rate Schedule 1		$ 4,784.8	81,494.4
10	**Commercial**			
11	Rate Schedule 2		$ 1,702.7	29,000.0
12	Rate Schedule 3		$ 1,461.2	24,886.2
13	Rate Schedule 23		$ 242.2	4,125.4
14	**Industrial**			
15	Rate Schedule 4		$ 9.4	159.5
16	Rate Schedule 5		$ 553.1	9,420.4
17	Rate Schedule 6		$ 1.2	20.8
18	Rate Schedule 7		$ 387.6	6,601.1
19	Rate Schedule 22- Firm Service		$ 609.4	10,379.2
20	Rate Schedule 22- Interruptible Service		$ 970.7	16,533.0
21	Rate Schedule 25		$ 538.0	9,163.8
22	Rate Schedule 27		$ 264.8	4,510.5
23				
24	**Total BVA Rider (Non-Bypass)**		**$ 11,525.2**	**196,294.3**
25				
26	**Calculation BVA Rider Per ($/GJ) Flat Rate**		**$ 0.059**	
27	(Line 6 divided by Line 24) $11,525.2/196,294.3 TJ = $0.059 per GJ			

In the 2016 Biomethane Decision, FEI was directed to provide a continuity of forecast, actual and variance (actual - forecast) biomethane (BERC) revenues and volumes sold by rate schedule, and type of contract.

The following table breaks down the BERC revenues and volumes by rate schedule and by short-term and long-term contracts. In 2021, the projected recoveries are $7.461 million attributable to sales volumes of 668.8 TJs from 9,481 RNG customers. The expected sales volume from existing and projected long-term contracts is included in the 2021 Projected volume and revenue in Table 10-3 below.

Table 10-3: BERC Revenue and Volume

Line No	Volume and Revenue	2020 Actual	2020 Projected	2020 Variance	2021 Projected
1	**Volume (TJ)**				
2	**Short-term**				
3	Rate Schedule 1B	111.3	119.5	(8.2)	101.9
4	Rate Schedule 2B	21.4	16.9	4.5	21.2
5	Rate Schedule 3B	18.8	19.3	(0.5)	18.2
6	Rate Schedule 5B	15.0	89.5	(74.5)	116.3
7	Rate Schedule 11B	-	14.0	(14.0)	133.6
8	Rate Schedule 30	-	-	-	-
9	Sub-total	166.6	259.3	(92.7)	391.2
10					
11	**Long Term**				
12	Rate Schedule 11B	139.6	164.6	(25.0)	277.6
13	Sub-total	139.6	164.6	(25.0)	277.6
14					
15	**Total Sales Volume (TJ)**	306.2	423.8	(117.7)	668.8
16					
17	**Recoveries ($000s)**				
18	**Short-term**				
19	Rate Schedule 1B	$ 1,172.7	$ 1,259.1	$ (86.4)	$ 1,205.2
20	Rate Schedule 2B	225.8	178.1	47.7	250.5
21	Rate Schedule 3B	197.9	203.8	(5.9)	215.1
22	Rate Schedule 5B	160.5	942.6	(782.1)	1,376.2
23	Rate Schedule 11B	-	147.7	(147.7)	1,581.0
24	Rate Schedule 30		-	-	-
25	Sub-total	1,756.9	2,731.4	(974.5)	4,627.9
26					
27	**Long Term**				
28	Rate Schedule 11B	1,396.0	1,733.6	(337.6)	2,833.1
29	Sub-total	1,396.0	1,733.6	(337.6)	2,833.1
30				-	
31	**Total Sales**	$ 3,152.9	$ 4,465.0	$ (1,312.1)	$ 7,461.0

In the 2016 Biomethane Decision, FEI was also directed to provide the number of customers by rate schedule. The following table sets out the 2021 Projected number of renewable natural gas customers by rate schedule.

Table 10-4: RNG Customers by Rate Schedule

2021 RNG Projected Participation (Rate Schedule)	Customer Enrollment
Short Term	
Rate Schedule 1B	9,273
Rate Schedule 2B	183
Rate Schedule 3B	17
Rate Schedule 11B	2
Rate Schedule 5B	3
Rate Schedule 30 Off System	-
Long Term	
Rate Schedule 11B	3
Total	**9,481**

In summary, the 2022 BVA rate rider attributable to the cumulative December 31, 2021 transfers from the BVA is $0.059 per GJ recoverable from all non-bypass customers.

10.3.2 RSAM Rate Riders

The RSAM Rate Riders collect or refund the previous year's projected RSAM balance from Rate Schedule 1, 2, 3 and 23 customers over two years. The projected balance in the RSAM account at the end of 2021 is a debit of $2.473 million. The calculation of the 2022 RSAM riders is shown in Table 10-5.

Table 10-5: 2022 RSAM Riders

2021 RSAM + Interest Closing Balance ($000)	2,473
Amortization Period (Years)	2
2022 Amortization Post-Tax ($000)	1,237
Tax Rate	27%
2022 Amortization Pre-Tax ($000)	1,694

RSAM (Rider 5) Calculation

Rate Class	RSAM Amortization (S000)	2022 Volume (TJ)	Rider ($/GJ)
Rate 1/1BU/1U/1X		81,494.4	0.012
Rate 2/2BU/2U/2X		29,000.0	0.012
Rate 3/3BU/3U/3X		24,886.2	0.012
Rate 23		4,125.4	0.012
	1,694	139,506.0	0.012

The differences that result from the actual 2021 ending RSAM balance varying from the projection, and the actual 2022 volumes varying from the forecast set out in this filing, will be included in the calculation of the 2023 RSAM Riders and, in this way, refunded to or collected from customers.

10.3.3 Clean Growth Innovation Fund (CGIF)

The collection of the $0.40 per month innovation rider commenced on August 1, 2020 and is forecast to collect $5.1 million in 2022.

Actual expenditures for 2020 were $1.0 million and are forecast to be $1.7 million and $5.0 million in 2021 and 2022, respectively.

To date, just under $2.0 million in funding has been approved in two portfolios which is described below.

The Company has made good progress in establishing the CGIF governance processes and finding and approving project portfolios that meet the criteria established for the Clean Growth Innovation Fund. FEI has also rejected some proposals and has moved others to non-CGIF funding sources. In some cases, FEI is continuing to work with proponents of rejected projects to make them more relevant to the purpose of the CGIF.

Governance

FEI committed to and has established two employee groups with oversight of the CGIF. First, the Innovation Working Group (IWG) is responsible for the identification, evaluation, selection, and execution of projects. The IWG is comprised of FEI staff that provide subject matter expertise from a variety of departments key to assessing the technical and business proposals which are part of the portfolios.

Second, the Executive Steering Committee (ESC) has been established to provide strategic direction to the CGIF and to approve the funding for the portfolios recommended by the IWG and reviewed by the External Advisory Council (EAC).

The EAC is made up of a variety of FortisBC stakeholders to provide insight and feedback on the Companies' innovative initiatives on a periodic basis. The EAC includes the following stakeholders:

- BCOAPO;
- MoveUP;
- BCSEA;
- BC Ministry of Energy, Mines and Low-Carbon Innovation;
- Foresight Cleantech Accelerator Centre;
- BC Bioenergy Network
- University of British Columbia

- University of Victoria; and
- City of Kamloops.

The EAC has met three times. Two of the meetings were to review and advise on the two expenditure portfolios prior to approval by the ESC.

At the first meeting, the purpose and the five key criteria for evaluating innovative proposals were reviewed. The five key criteria were established during the MRP application regulatory process, and are:

1. Amount of co-funding secured (from applicant and third parties);
2. Estimated CO2e reduction in British Columbia;
3. Estimated non-CO2e emission reduction (NOx, SOx) in British Columbia;
4. Estimation of energy cost reductions for customers; and
5. Relevant experience of the applicant project team.

At both portfolio review meetings, the proposals that were recommended and rejected by the FEI Innovation Working Group were presented to the EAC. The EAC asked a number of questions regarding the proposals and the overall portfolio mix, and in the end agreed with the recommendations and rejections put forward by FEI.

In addition to the two portfolio review meetings, FEI representatives also presented to the EAC a summary of the key findings of a FortisBC-commissioned report that explores different low carbon pathways. The *Pathways for British Columbia to Achieve Its GHG Reduction Goals* assesses the implications of two alternative energy pathways to a low carbon future for BC and recommends a diversified pathway which utilizes and builds on both the electricity and gas infrastructure in the Province.

Spending Commitments

In total, $1.977 million has been approved for spending in two portfolios.

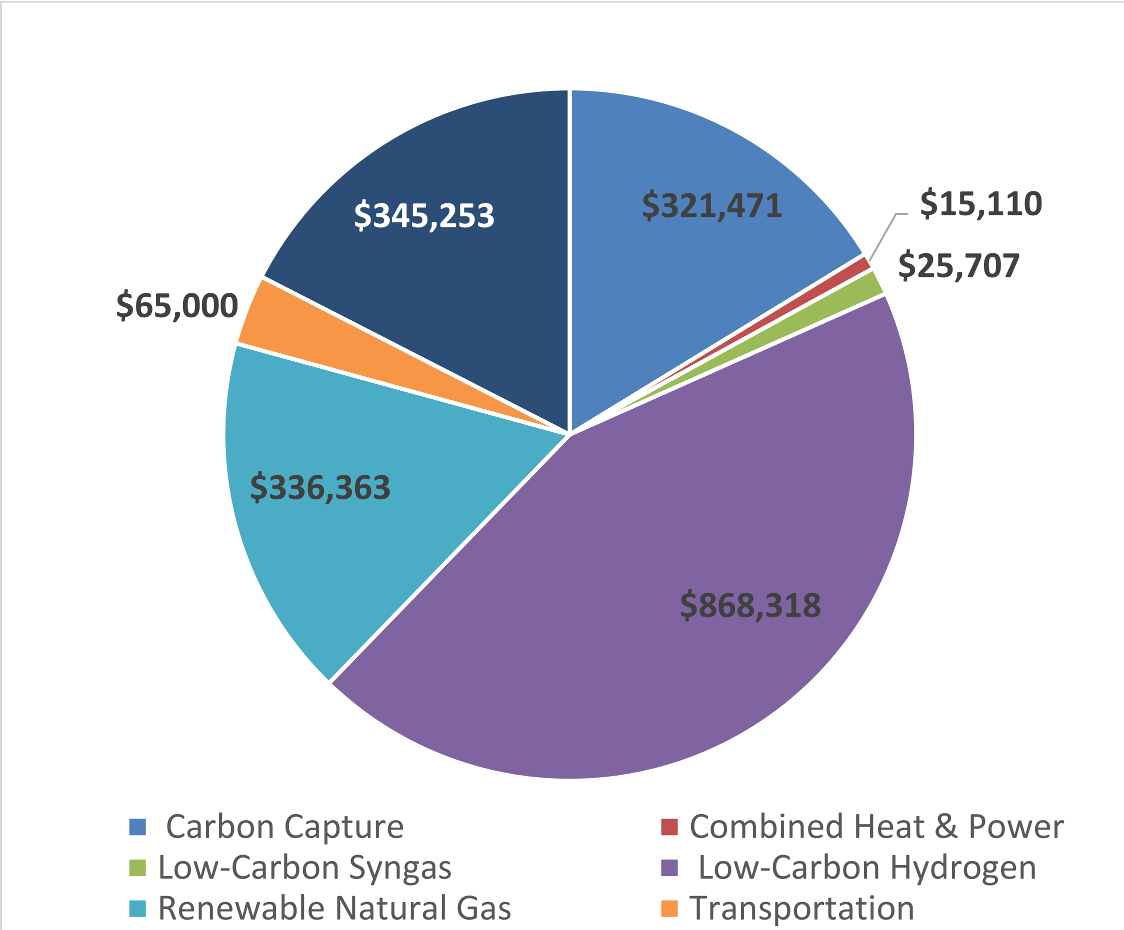
Table 10-6: Approved and Rejected Spending for Portfolios One and Two ($ millions)

	Portfolio One	Portfolio Two	Total
Approved	$1.450	$0.527	$1.977
Rejected	$0.231	$3.173	$3.404

In some cases, C&EM Innovative Technologies has funded CGIF proposals which were rejected for the CGIF, as the rejected proposals fit the C&EM Innovative Technologies funding criteria.

The approved spending is in a variety of areas, as shown in Figure 10-1 below.

Figure 10-1: CGIF Approved Spending by Category



The categories in the graph above encompass the following types of projects:

- **Renewable and Low-Carbon Gases.** There are 12 projects approved in this category. The majority of the projects are testing innovative processes for creating low-carbon gaseous fuels, particularly hydrogen and biomethane (renewable natural gas or RNG). Seven of the projects are creating low-carbon hydrogen, five are for improved processes for creating renewable natural gas and one for syngas. The single largest project that is part of this portfolio category is a $500 thousand funding commitment for a "hydrogen lab" at UBC Okanagan, which is co-funded by Natural Sciences and Engineering Research Council and one other private company. The hydrogen lab is a scalable and automated laboratory setup for conducting an integrated experimental study on the performance and feasibility of hydrogen-enriched natural gas - from injection (for a range of 5-20 percent hydrogen by volume), mixing quality, material exposure, separation and combustion, to emission.

- **Transportation.** This category comprises a single research project focused on reducing GHG emissions from natural gas engines using a combination of lab-based engine experiments, as well as field measurements of GHG emissions from in-use engines.
- **CHP or Combined Heat and Power.** This is a demonstration project in which a commercial building disconnected from the electrical grid was tested using natural gas-powered micro-CHPs, solar panels and a battery storage system. A CHP can produce both heat and electricity from natural gas.
- **Carbon Capture.** This CGIF category is funding four projects which capture carbon dioxide in some manner. In some cases, the carbon dioxide is converted into other marketable products and in others the carbon dioxide is being selectively captured from exhaust gases. The carbon capture processes being tested are generally suited for capturing smaller, customer-driven carbon emissions rather than large-scale industrial emissions.
- **Natural Gas Innovation Fund (NGIF) Operating Expenses.** These are FEI's share of the 2020 operating expenses of the Canadian Gas Association's (CGA) NGIF, of which FEI is a member with a number of other Canadian utilities and oil and gas producers. In total, 15 of the 19 proposals funded by the CGIF are NGIF projects that are co-funded by other Canadian utilities and oil and gas producers.
- **Natural Gas Futures (NGF) Small Projects**. This funding is for a number of smaller UBC NGF projects that are nearing completion and meet CGIF criteria. These include a fugitive methane emissions quantification system, a carbon capture system test, and a combustion emissions sensing system.

Details on each project with approved funding is set out in Table 10-7 below.

Table 10-7: CGIF Approved Project Funding

Primary Partner	Category	CGIF Funding Approved	Project Description
NGIF	Carbon Capture	$92,015	Field pilot of carbon recycling system designed to lower oil & gas emissions directly at source. The unit captures CO2 directly from any flue stack of sufficiently large volume, and converts it into marketable mineral feedstocks.
NGIF	Carbon Capture	$28,042	Testing of an adsorption technology using waste heat from a CHP that uses less electricity vs conventional chillers.
NGIF	Carbon Capture	$51,414	Demonstration of membrane-based carbon capture technology for flue emissions.
NGIF	Carbon Capture	$150,000	Retrofit of Once-Through Steam Generator with modular decarbonization systems reduce 90 percent of the carbon emissions. If successful, this technology has potential for carbon capture in marine natural gas transportation applications.
	Carbon Capture Total	**$321,471**	

Primary Partner	Category	CGIF Funding Approved	Project Description
NGIF	Combined Heat & Power	$15,110	Demonstration of a commercial building using natural gas, CHP's and solar panels disconnected from the electrical grid.
	Combined Heat & Power Total	**$15,110**	
NGIF	Low-Carbon Syngas	$25,707	Development of patented photocatalysts to convert carbon dioxide (CO2) and methane (CH4) simultaneously into low carbon-intensity synthesis gas.
	Low-Carbon Syngas Total	**$25,707**	
UBCO	Low-Carbon Hydrogen	$500,000	Development of a novel scalable and automated hydrogen-enriched natural gas (HENG) laboratory setup for conducting an integrated experimental studies on the performance and feasibility of HENG - from injection, mixing quality, material exposure, separation and combustion, to emission.
NGIF	Low-Carbon Hydrogen	$77,122	Prototype development and testing of novel methane pyrolysis process, with two end products, hydrogen and carbon black.
NGIF	Low-Carbon Hydrogen	$42,845	Prototype development and testing of novel methane pyrolysis process, with two end products, hydrogen and carbon black.
NGIF	Low-Carbon Hydrogen	$25,707	Testing of a patented nano-catalyst that can reduce cost of PEM electrolysers used in production of hydrogen by reducing the amount of platinum catalyst required.
NGIF	Low-Carbon Hydrogen	$114,084	This project will test technology that could reduce the cost of large-scale electrolysers. The testing will be in environments which will validate some of its key features, advantages, and benefits. This project will specifically test the ability to directly couple with solar and wind applications with variable load.
NGIF	Low-Carbon Hydrogen	$70,000	The project objective of this initiative is to demonstrate a novel process which uses renewable energy to split a mineral salt and water, producing hydrogen, hydroxide, sulfuric acid and oxygen. The hydroxide is combined with CO2 and then added to seawater, permanently sequestering CO2 as bicarbonate. This project will construct and operate a negative emissions hydrogen pilot plant.
NGIF	Low-Carbon Hydrogen	$38,560	Prototype development and testing of novel methane pyrolysis process, with two end products, hydrogen and carbon black.
	Low-Carbon Hydrogen Total	**$868,318**	
NGIF	Renewable Natural Gas	$77,121	Piloting the integration of technologies to improve RNG production by allowing the co-digestion of dairy, poultry and hog manure.
NGF (UBC)	Renewable Natural Gas	$105,000	Testing of an integrated pyrolysis system coupling pre-treatment, anaerobic digester and post-treatment to improving carbon conversion efficiency and lower the biogas and renewable natural gas production cost.

Primary Partner	Category	CGIF Funding Approved	Project Description
NGIF	Renewable Natural Gas	$77,121	Demonstration of the conversion of wood waste into both RNG and biocoal on a commercial scale. Biocoal would allow large industrial companies to reduce their reliance on fossil coal, while the natural gas distribution industry would benefit from additional access to lower-cost RNG.
NGIF	Renewable Natural Gas	$77,121	Developing of technology to convert forestry waste and agricultural crop waste into renewable natural gas (RNG). The proposed project will validate the design for scaling up existing technology. The project will include detailed design, construction, and testing of a system capable of processing 1 tonne of biomass per day. Supporting subsystems for surrogate methanation gas supply, instrumentation, controls, and data collection are also be included in the project.
	Renewable Natural Gas Total	**$336,363**	
NGF (UBC)	Transportation	$65,000	Experimental and field work to reduce the GHG emissions from natural gas engines using a combination of lab-based engine experiments, as well as field measurements of GHG emissions from in-use engines. The lab-based studies will develop methodologies for in-use emission characterization and strategies for emissions reductions, based on operating conditions of field engines. This will provide technologies for low GHG emission transportation systems and provide quantitative emission characterization for inventory and policy development purposes.
	Transportation Total	**$65,000**	
NGIF	Uncategorized	$215,253	NGIF operations and administration expenses per the NGIF/FortisBC Master Funding Agreement.
NGF (UBC)	Uncategorized	$130,000	• R&D on fugitive methane emissions quantification system • LNG transfer technology • Testing prototype micro-carbon capture and utilization system • R&D on combustion emissions sensing system • R&D on engine combustion emissions mitigation technologies (e.g. cylinder deactivation, air-fuel ratio optimization) • R&D on renewable energy (e.g. RNG) production and integration systems
	Uncategorized Total	**$345,253**	
	Grand Total	**$1,977,223**	

Results-to-Date

FEI receives regular updates from each funded project which has achieved one or more interim milestones. Generally speaking, there are specific interim milestones that must be achieved before more funding is released. To date, FEI has not withheld any progress payments based on the milestone reports.

One CGIF-funded project has been completed, which is the CHP project referenced above in which a micro-CHP unit (pictured below) was installed as part of an off-electrical-grid commercial building upgrade utilizing a number of innovative energy technologies.

Figure 10-2: Installed Micro-CHP unit

The installed unit is a CSA-certified Aisin Coremo micro-CHP unit which claims 90 percent efficiency and produces 1.5 kW of electrical power and 12,600 BTU/hour hydronic heat production. Also installed were solar panels and a battery storage system, with all of the energy systems tied together with a custom control system.

The following is a summary of the lessons learned from the project:

- Multiple control system tweaks are required to balance simultaneous production of heat and electricity when only one energy type is required;
- Selected mCHP units offer multiple engine speeds, but are most efficient at full throttle;
- Control system is much more complicated with battery storage system;
- Annual gas consumption will be reduced as system is optimized; and

- The sum of all energy used on site (delivered natural gas), minus all renewable energy generated on site, divided by the floor area of the building as built equalled 68.1kWh/m2, which was less than the estimated intensity of 76.7 kWh/m2.

Based on these results, FEI will continue to recommend micro-CHP units for customers that require the additional electricity production they offer as a way of increasing resiliency from electric system outages. However, due to the complexity and cost of an off-grid system such as the one piloted during this test, such a system would not be recommended except where electric grid services are not available or prohibitively expensive.

10.4 *SUMMARY*

As discussed in Section 10.2 above, FEI proposes to distribute a $1.853 million pre-tax credit ($1.353 million after-tax) earnings sharing amount to customers as part of 2022 delivery rates. In Section 10.3, FEI updated all of the 2022 delivery rate riders for 2021 Projected ending balances and 2022 Forecast volumes. Based on these updates, FEI has calculated a BVA rate rider of $0.059 per GJ and a RSAM rate rider of $0.012 per GJ for 2022. FEI has also provided details on the CGIF in Section 10.3, which is funded through the collection of the innovation rider.

11. FINANCIAL SCHEDULES

SUMMARY OF RATE CHANGE Schedule 1
FOR THE YEAR ENDING DECEMBER 31, 2022
($millions)

Line No.	Particulars	2022 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (2.275)		
3	Change in Other Revenue	0.359	(1.916)	
4				
5	**O&M CHANGES**			
6	Gross O&M Change	2.489		
7	Capitalized Overhead Change	(0.639)	1.850	
8				
9	**DEPRECIATION EXPENSE**			
10	Depreciation from Net Additions		8.607	
11				
12	**AMORTIZATION EXPENSE**			
13	CIAC from Net Additions	(0.095)		
14	Deferrals	19.037	18.942	
15				
16	**FINANCING AND RETURN ON EQUITY**			
17	Financing Rate Changes	(4.054)		
18	Financing Ratio Changes	0.673		
19	Rate Base Growth	12.309	8.928	
20				
21	**TAX EXPENSE**			
22	Property and Other Taxes	1.586		
23	Other Income Taxes Changes	(1.801)	(0.215)	
24				
25	**2021 Revenue Deficiency**		35.287	
26				
27	**REVENUE DEFICIENCY (SURPLUS)**		**$ 71.483**	Schedule 16, Line 11, Column 4
28				
29	Non-Bypass Margin at 2021 Approved Rates		885.532	Schedule 19, Line 17, Column 3
30	Rate Change		8.07%	

Schedule 2

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	2021 Approved	2022 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 7,565,637	$ 7,867,224	$ 301,587	Schedule 6.2, Line 35, Column 3
2	Opening Balance Adjustment	-	-	-	Schedule 6.2, Line 35, Column 4
3	Net Additions	310,033	355,732	45,699	Schedule 6.2, Line 35, Column 5+6+7
4	Plant in Service, Ending	7,875,670	8,222,956	347,286	
5					
6	Accumulated Depreciation Beginning	$ (2,284,843)	$ (2,423,184)	$ (138,341)	Schedule 7.2, Line 35, Column 5
7	Opening Balance Adjustment	-	-	-	Schedule 7.2, Line 35, Column 6
8	Net Additions	(137,439)	(152,348)	(14,909)	Schedule 7.2, Line 35, Column 7+8
9	Accumulated Depreciation Ending	(2,422,282)	(2,575,532)	(153,250)	
10					
11	CIAC, Beginning	$ (446,483)	$ (451,881)	$ (5,398)	Schedule 9, Line 6, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(6,005)	(5,849)	156	Schedule 9, Line 6, Column 5+6
14	CIAC, Ending	(452,488)	(457,730)	(5,242)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 178,851	$ 187,384	$ 8,533	Schedule 9, Line 13, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	8,533	8,628	95	Schedule 9, Line 13, Column 5+6
19	Accumulated Amortization Ending - CIAC	187,384	196,012	8,628	
20					
21	Net Plant in Service, Mid-Year	$ 5,100,723	$ 5,282,625	$ 181,902	
22					
23	Adjustment for timing of Capital additions	$ 38,361	$ 49,088	$ 10,727	
24	Capital Work in Progress, No AFUDC	36,412	42,035	5,623	
25	Unamortized Deferred Charges	(20,024)	(32,829)	(12,805)	Schedule 11.1, Line 27, Column 10
26	Working Capital	57,008	68,253	11,245	Schedule 13, Line 14, Column 3
27	Deferred Income Taxes Regulatory Asset	603,711	689,807	86,096	Schedule 15, Line 6, Column 3
28	Deferred Income Taxes Regulatory Liability	(603,711)	(689,807)	(86,096)	Schedule 15, Line 6, Column 3
29	LILO Benefit	(41)	(3)	38	
30					
31	Mid-Year Utility Rate Base	$ 5,212,439	$ 5,409,169	$ 196,730	

FORMULA INFLATION FACTORS
FOR THE YEARS ENDING DECEMBER 31, 2020 to 2022
($000s)

Line No.	Particulars	Reference	2020	2021	2022	Total for 2022 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Formula Cost Drivers**						
2	CPI		2.692%	1.596%	1.237%		
3	AWE		2.881%	5.745%	6.309%		
4	Labour Split						
5	Non Labour		48.000%	48.000%	49.000%		
6	Labour		52.000%	52.000%	51.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	2.790%	3.753%	3.824%		
8	Productivity Factor	G-165-20	-0.500%	-0.500%	-0.500%		
9	Net Inflation Factor	Line 7 + Line 8	2.290%	3.253%	3.324%		
10							
11							
12	**Growth in Average Customer Calculation**						
13	Actual/Projected Prior Year Average Customers		1,031,862	1,044,622	1,057,078		
14	Average Customers for the Year	Schedule 19, Line 30, Column 9	1,044,622	1,057,078	1,068,490		
15	Change in Average Customers	Line 14 - Line 13	12,760	12,456	11,412	36,628	
16	Customer Growth Factor Multiplier	G-165-20				75%	
17	Change in Customers - Rate Setting Purposes	Line 15 x Line 16				27,471	
18							
19	**Average Customer Continuity for Rate Setting Purposes**						
20	Average Customers Used to Determine Starting UCOM	Line 13 Yr 2020				1,031,862	
21							
22	Average Customer Forecast - Rate Setting Purposes	Line 17 + Line 20				1,059,333	

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 4

Line No.	Particulars	Growth CapEx	Other CapEx	Forecast CapEx	Total CapEx	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Inflation Indexed Capital Growth**					
2	2021 Unit Cost Growth Capital	$ 3,912				
3	2022 Net Inflation Factor	3.324%				Schedule 3, Line 9, Column 5
4	2022 Unit Cost Growth Capital	$ 4,042				
5	2022 Gross Customer Additions	20,000				
6	2022 Inflation Indexed Growth Capital	$ 80,840			$ 80,840	
7	2020 Growth Capital Customer True-Up				3,713	
8	2022 System Extension Fund				1,000	
9	2022 Growth CIAC				1,948	
10	2022 Inflation Indexed Gross Growth Capital				$ 87,501	
11						
12	**Capital Tracked Outside of Formula**					
13	Pension & OPEB (Growth Capital Portion)			$ 1,693		
14	Biomethane Assets			40,255		
15	NGT Assets			8,671		
16	Sustainment Capital			117,106		
17	Other Capital			46,474		
18	Sub-total			$ 214,199	214,199	
19						
20	**Total Capital Expenditures Before CIAC**				$ 301,700	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 5

Line No.	Particulars		2022 Formula	Cross Reference
	(1)		(2)	(3)
1	**CAPEX**			
2	Growth Capital Expenditures	$	87,501	Schedule 4, Line 10
3	Forecast Capital Expenditures		214,199	Schedule 4, Line 18
4	Total Capital Expenditures	$	301,700	
5				
6	**Special Projects and CPCN's**			
7	Tilbury Expansion Project	$	1,668	
8	LMIPSU		15,470	
9	IGU		78,811	
10	Pattullo Gasline Replacement		105,976	
11	Total Capital Expenditures	$	201,925	
12				
13	**Total Capital Expenditures**	$	503,625	
14				
15				
16	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
17				
18	Regular Capital Expenditures	$	301,700	Line 4
19	Add - Capitalized Overheads		53,328	Schedule 20, Line 27
20	Add - AFUDC		3,200	
21	Gross Capital Expenditures		358,228	
22	Change in Work in Progress		(43,717)	
23	**Total Regular Additions to Plant**	$	314,511	
24				
25	Special Projects and CPCN's Capital Expenditures	$	201,925	Line 11
26	Add - AFUDC		3,988	
27	Gross Capital Expenditures		205,913	
28	Change in Work in Progress		(106,069)	
29	**Total Special Projects and CPCN Additions to Plant**	$	99,844	
30				
31	**Grand Total Additions to Plant**	$	414,355	

PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Account	Particulars	12/31/2021	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2022	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	175-10	Unamortized Conversion Expense	$ 109	$ -	$ -	$ -	$ -	$ 109	
3	175-00	Unamortized Conversion Expense - Squamish	777	-	-	-	(777)	-	
4	178-00	Organization Expense	728	-	-	-	-	728	
5	401-01	Franchise and Consents	297	-	-	-	(100)	197	
6	402-11	Utility Plant Acquisition Adjustment	62	-	-	-	(62)	-	
7	402-03	Other Intangible Plant	1,907	-	-	-	-	1,907	
8	440-02	Water/Land Rights Tilbury	4,299	-	-	-	-	4,299	
9	461-01	Transmission Land Rights	51,622	-	-	-	-	51,622	
10	461-02	Transmission Land Rights - Mt. Hayes	609	-	-	-	-	609	
11	461-12	Transmission Land Rights - Byron Creek	16	-	-	-	-	16	
12	461-13	IP Land Rights Whistler	24	-	-	-	-	24	
13	471-01	Distribution Land Rights	3,469	-	-	-	-	3,469	
14	471-11	Distribution Land Rights - Byron Creek	1	-	-	-	-	1	
15	402-01	Application Software - 12.5%	67,350	-	-	11,249	(11,187)	67,412	
16	402-02	Application Software - 20%	32,383	-	-	10,984	(5,192)	38,175	
17			$ 163,653	$ -	$ -	$ 22,233	$ (17,318)	$ 168,568	
18									
19		**MANUFACTURED GAS / LOCAL STORAGE**							
20	430-00	Manufact'd Gas - Land	$ 31	$ -	$ -	$ -	$ -	$ 31	
21	432-00	Manufact'd Gas - Struct. & Improvements	1,199	-	-	-	-	1,199	
22	433-00	Manufact'd Gas - Equipment	610	-	-	-	-	610	
23	434-00	Manufact'd Gas - Gas Holders	2,955	-	-	-	-	2,955	
24	436-00	Manufact'd Gas - Compressor Equipment	367	-	-	-	-	367	
25	437-00	Manufact'd Gas - Measuring & Regulating Equipment	1,714	-	-	-	-	1,714	
26	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	15,164	
27	442-00	Structures & Improvements (Tilbury)	100,025	-	-	-	-	100,025	
28	443-00	Gas Holders - Storage (Tilbury)	183,719	-	-	-	-	183,719	
29	448-11	Piping (Tilbury)	48,427	-	1,668	-	-	50,095	
30	448-21	Pre-treatment (Tilbury)	38,003	-	-	-	-	38,003	
31	448-31	Liquefaction Equipment (Tilbury)	89,093	-	-	-	-	89,093	
32	449-00	Local Storage Equipment (Tilbury)	27,862	-	-	-	-	27,862	
33	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	-	-	-	-	1,083	
34	442-01	Structures & Improvements (Mount Hayes)	19,045	-	-	-	-	19,045	
35	443-05	Gas Holders - Storage (Mount Hayes)	61,774	-	-	-	-	61,774	
36	448-41	Send out Equipment(Tilbury)	7,690	-	-	-	-	7,690	
37	448-51	Sub-station and Electric (Tilbury)	36,847	-	-	-	-	36,847	
38	448-61	Control Room (Tilbury)	3,771	-	-	-	-	3,771	
39	448-10	Piping (Mount Hayes)	12,455	-	-	-	-	12,455	
40	448-20	Pre-treatment (Mount Hayes)	29,238	-	-	-	-	29,238	
41	448-30	Liquefaction Equipment (Mount Hayes)	28,880	-	-	-	-	28,880	
42	448-40	Send out Equipment (Mount Hayes)	23,552	-	-	-	-	23,552	
43	448-50	Sub-station and Electric (Mount Hayes)	21,788	-	-	-	-	21,788	
44	448-60	Control Room (Mount Hayes)	6,425	-	-	-	-	6,425	
45	448-65	MH Inspection (Mount Hayes)	-	-	-	-	-	-	
46	449-01	Local Storage Equipment (Mount Hayes)	5,727	-	-	-	-	5,727	
47			$ 767,444	$ -	$ 1,668	$ -	$ -	$ 769,112	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 6.1

Line No.	Account	Particulars	12/31/2021	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2022	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	460-00	Land in Fee Simple	$ 10,805	$ -	$ -	$ 331	$ -	$ 11,136	
3	461-00	Transmission Land Rights	-	-	-	-	-	-	
4	462-00	Compressor Structures	36,645	-	-	1,548	(241)	37,952	
5	463-00	Measuring Structures	20,210	-	-	4,049	(136)	24,123	
6	464-00	Other Structures & Improvements	10,610	-	-	-	-	10,610	
7	465-00	Mains	1,516,543	-	69,990	12,371	(1,063)	1,597,841	
8	465-20	Mains - INSPECTION	42,772	-	-	5,204	(3,630)	44,346	
9	465-11	IP Transmission Pipeline - Whistler	58,689	-	-	198	-	58,887	
10	465-30	Mt Hayes - Mains	6,307	-	-	-	-	6,307	
11	465-10	Mains - Byron Creek	1,371	-	-	-	-	1,371	
12	466-00	Compressor Equipment	200,312	-	-	1,825	(455)	201,682	
13	466-10	Compressor Equipment - OVERHAUL	8,195	-	-	604	-	8,799	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	7,239	-	-	-	-	7,239	
15	467-10	Measuring & Regulating Equipment	94,930	-	-	3,018	(115)	97,833	
16	467-20	Telemetering	18,289	-	-	479	(10)	18,758	
17	467-31	IP Intermediate Pressure Whistler	372	-	-	-	-	372	
18	467-30	Measuring & Regulating Equipment - Byron Creek	291	-	-	-	-	291	
19	468-00	Communication Structures & Equipment	10,095	-	-	-	-	10,095	
20			$ 2,043,675	$ -	$ 69,990	$ 29,627	$ (5,650)	$ 2,137,642	
21									
22		**DISTRIBUTION PLANT**							
23	470-00	Land in Fee Simple	$ 5,457	$ -	$ -	$ 85	$ -	$ 5,542	
24	472-00	Structures & Improvements	56,032	-	564	481	(16)	57,061	
25	472-10	Structures & Improvements - Byron Creek	124	-	-	-	-	124	
26	473-00	Services	1,427,229	-	-	84,531	(3,656)	1,508,104	
27	474-00	House Regulators & Meter Installations	164,362	-	-	23,790	(6,183)	181,969	
28	474-02	Meters/Regulators Installations	214,759	-	-	-	-	214,759	
29	475-00	Mains	1,997,628	-	26,777	77,307	(4,605)	2,097,107	
30	476-00	Compressor Equipment	614	-	-	-	-	614	
31	477-10	Measuring & Regulating Equipment	213,091	-	563	11,707	(670)	224,691	
32	477-20	Telemetering	22,800	-	282	1,364	(79)	24,367	
33	477-30	Measuring & Regulating Equipment - Byron Creek	153	-	-	-	-	153	
34	478-10	Meters	304,357	-	-	20,479	(5,873)	318,963	
35	478-20	Instruments	15,406	-	-	498	-	15,904	
36	479-00	Other Distribution Equipment	-	-	-	-	-	-	
37			$ 4,422,012	$ -	$ 28,186	$ 220,242	$ (21,082)	$ 4,649,358	
38									
39		**BIO GAS**							
40	472-20	Bio Gas Struct. & Improvements	$ 716	$ -	$ -	$ 218	$ -	$ 934	
41	475-10	Bio Gas Mains – Municipal Land	1,867	-	-	-	-	1,867	
42	475-20	Bio Gas Mains – Private Land	339	-	-	-	-	339	
43	418-10	Bio Gas Purification Overhaul	20	-	-	-	-	20	
44	418-20	Bio Gas Purification Upgrader	11,220	-	-	-	-	11,220	
45	477-40	Bio Gas Reg & Meter Equipment	3,349	-	-	693	-	4,042	
46	478-30	Bio Gas Meters	65	-	-	30	-	95	
47	474-10	Bio Gas Reg & Meter Installations	742	-	-	49	-	791	
48	483-25	RNG Comp S/W	138	-	-	-	(138)	-	
49			$ 18,456	$ -	$ -	$ 990	$ (138)	$ 19,308	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 6.2

Line No.	Account	Particulars	12/31/2021	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2022	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 18,916	$ -	$ -	$ 2,292	$ -	$ 21,208	
3	476-20	NG Transportation LNG Dispensing Equipment	14,175	-	-	2,000	-	16,175	
4	476-30	NG Transportation CNG Foundations	2,967	-	-	-	-	2,967	
5	476-40	NG Transportation LNG Foundations	1,311	-	-	-	-	1,311	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to LNG)	1,494	-	-	-	-	1,494	
7	476-60	NG Transportation CNG Dehydrator	708	-	-	-	-	708	
8	476-70	NG Transportation LNG Dehydrator	-	-	-	-	-	-	
9			$ 39,571	$ -	$ -	$ 4,292	$ -	$ 43,863	
10									
11		**GENERAL PLANT & EQUIPMENT**							
12	480-00	Land in Fee Simple	$ 31,306	$ -	$ -	$ -	$ -	$ 31,306	
13	482-10	Frame Buildings	24,658	-	-	670	-	25,328	
14	482-20	Masonry Buildings	126,489	-	-	4,595	(117)	130,967	
15	482-30	Leasehold Improvement	1,672	-	-	85	(65)	1,692	
16	483-30	GP Office Equipment	3,125	-	-	126	(163)	3,088	
17	483-40	GP Furniture	19,224	-	-	2,176	(461)	20,939	
18	483-10	GP Computer Hardware	46,501	-	-	11,019	(8,315)	49,205	
19	483-20	GP Computer Software	5,164	-	-	-	(1,021)	4,143	
20	484-00	Vehicles	51,891	-	-	8,682	-	60,573	
21	484-10	Vehicles - Leased	15,421	-	-	-	(1,458)	13,963	
22	485-10	Heavy Work Equipment	750	-	-	4	-	754	
23	485-20	Heavy Mobile Equipment	9,277	-	-	1,633	-	10,910	
24	486-00	Small Tools & Equipment	57,485	-	-	6,763	(2,237)	62,011	
25	487-20	Equipment on Customer's Premises	-	-	-	-	-	-	
26	488-10	Telephone	1,821	-	-	-	(598)	1,223	
27	488-20	Radio	17,629	-	-	1,374	-	19,003	
28	489-00	Other General Equipment	-	-	-	-	-	-	
29			$ 412,413	$ -	$ -	$ 37,127	$ (14,435)	$ 435,105	
30									
31		**UNCLASSIFIED PLANT**							
32	499-00	Plant Suspense	-	-	-	-	-	-	
33			$ -	$ -	$ -	$ -	$ -	$ -	
34									
35		**Total Plant in Service**	$ 7,867,224	$ -	$ 99,844	$ 314,511	$ (58,623)	$ 8,222,956	
36									
37		Cross Reference			Schedule 5, Line 29, Column 2	Schedule 5, Line 23, Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2021	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2022	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**INTANGIBLE PLANT**										
2	175-10	Unamortized Conversion Expense	$ 109	1.00%	$ 65	$ -	$ 1	$ -	$ -	$ -	$ 66	
3	175-00	Unamortized Conversion Expense - Squamish	777	10.00%	777	-	-	(777)	-	-	-	
4	178-00	Organization Expense	728	1.00%	457	-	7	-	-	-	464	
5	401-01	Franchise and Consents	297	1.08%	246	-	2	(100)	-	-	148	
6	402-11	Utility Plant Acquisition Adjustment	62	0.00%	62	-	-	(62)	-	-	-	
7	402-03	Other Intangible Plant	1,907	2.50%	1,246	-	48	-	-	-	1,294	
8	440-02	Water/Land Rights Tilbury	4,299	0.00%	-	-	-	-	-	-	-	
9	461-01	Transmission Land Rights	51,622	0.00%	1,766	-	-	-	-	-	1,766	
10	461-02	Transmission Land Rights - Mt. Hayes	609	0.00%	-	-	-	-	-	-	-	
11	461-12	Transmission Land Rights - Byron Creek	16	0.00%	19	-	-	-	-	-	19	
12	461-13	IP Land Rights Whistler	24	0.00%	-	-	-	-	-	-	-	
13	471-01	Distribution Land Rights	3,469	0.00%	248	-	-	-	-	-	248	
14	471-11	Distribution Land Rights - Byron Creek	1	0.00%	1	-	-	-	-	-	1	
15	402-01	Application Software - 12.5%	67,350	12.50%	29,812	-	8,419	(11,187)	-	-	27,044	
16	402-02	Application Software - 20%	32,383	20.00%	9,435	-	6,477	(5,192)	-	-	10,720	
17			$ 163,653		$ 44,134	$ -	$ 14,954	$ (17,318)	$ -	$ -	$ 41,770	
18												
19		**MANUFACTURED GAS / LOCAL STORAGE**										
20	430-00	Manufact'd Gas - Land	$ 31	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
21	432-00	Manufact'd Gas - Struct. & Improvements	1,199	2.50%	425	-	30	-	-	-	455	
22	433-00	Manufact'd Gas - Equipment	610	5.00%	345	-	30	-	-	-	375	
23	434-00	Manufact'd Gas - Gas Holders	2,955	2.50%	877	-	74	-	-	-	951	
24	436-00	Manufact'd Gas - Compressor Equipment	367	4.00%	184	-	15	-	-	-	199	
25	437-00	Manufact'd Gas - Measuring & Regulating Equipment	1,714	5.00%	1,244	-	86	-	-	-	1,330	
26	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	1	-	-	-	-	-	1	
27	442-00	Structures & Improvements (Tilbury)	100,025	2.20%	11,090	-	2,201	-	-	-	13,291	
28	443-00	Gas Holders - Storage (Tilbury)	183,719	1.23%	20,603	-	2,260	-	-	-	22,863	
29	448-11	Piping (Tilbury)	50,095	2.45%	3,092	-	1,186	-	-	-	4,278	
30	448-21	Pre-treatment (Tilbury)	38,003	3.84%	3,744	-	1,459	-	-	-	5,203	
31	448-31	Liquefaction Equipment (Tilbury)	89,093	2.45%	6,359	-	2,183	-	-	-	8,542	
32	449-00	Local Storage Equipment (Tilbury)	27,862	2.77%	19,722	-	772	-	-	-	20,494	
33	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	0.00%	-	-	-	-	-	-	-	
34	442-01	Structures & Improvements (Mount Hayes)	19,045	3.85%	7,561	-	733	-	-	-	8,294	
35	443-05	Gas Holders - Storage (Mount Hayes)	61,774	1.65%	10,637	-	1,019	-	-	-	11,656	
36	448-41	Send out Equipment(Tilbury)	7,690	2.41%	509	-	185	-	-	-	694	
37	448-51	Sub-station and Electric (Tilbury)	36,847	2.41%	2,637	-	888	-	-	-	3,525	
38	448-61	Control Room (Tilbury)	3,771	6.09%	679	-	230	-	-	-	909	
39	448-10	Piping (Mount Hayes)	12,455	2.45%	3,110	-	305	-	-	-	3,415	
40	448-20	Pre-treatment (Mount Hayes)	29,238	3.84%	12,069	-	1,123	-	-	-	13,192	
41	448-30	Liquefaction Equipment (Mount Hayes)	28,880	2.45%	7,554	-	708	-	-	-	8,262	
42	448-40	Send out Equipment (Mount Hayes)	23,552	2.41%	6,067	-	568	-	-	-	6,635	
43	448-50	Sub-station and Electric (Mount Hayes)	21,788	2.41%	5,666	-	525	-	-	-	6,191	
44	448-60	Control Room (Mount Hayes)	6,425	6.09%	4,196	-	391	-	-	-	4,587	
45	448-65	MH Inspection (Mount Hayes)	-	20.00%	(1)	-	-	-	-	-	(1)	
46	449-01	Local Storage Equipment (Mount Hayes)	5,727	3.08%	996	-	176	-	-	-	1,172	
47			$ 769,112		$ 129,366	$ -	$ 17,147	$ -	$ -	$ -	$ 146,513	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7.1
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2021	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2022	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**TRANSMISSION PLANT**										
2	460-00	Land in Fee Simple	$ 10,805	0.00%	$ 503	$ -	$ -	$ -	$ -	$ -	$ 503	
3	461-00	Transmission Land Rights	-	0.00%	-	-	-	-	-	-	-	
4	462-00	Compressor Structures	36,645	3.32%	20,504	-	1,217	(241)	-	-	21,480	
5	463-00	Measuring Structures	20,210	2.13%	8,664	-	430	(136)	-	-	8,958	
6	464-00	Other Structures & Improvements	10,610	3.62%	3,954	-	384	-	-	-	4,338	
7	465-00	Mains	1,586,533	1.46%	472,689	-	23,163	(1,063)	-	-	494,789	
8	465-20	Mains - INSPECTION	42,772	15.20%	14,548	-	6,501	(3,630)	-	-	17,419	
9	465-11	IP Transmission Pipeline - Whistler	58,689	1.54%	8,239	-	904	-	-	-	9,143	
10	465-30	Mt Hayes - Mains	6,307	1.54%	1,078	-	97	-	-	-	1,175	
11	465-10	Mains - Byron Creek	1,371	5.03%	1,566	-	69	-	-	-	1,635	
12	466-00	Compressor Equipment	200,312	2.42%	106,420	-	4,848	(455)	-	-	110,813	
13	466-10	Compressor Equipment - OVERHAUL	8,195	10.19%	5,046	-	835	-	-	-	5,881	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	7,239	2.34%	1,861	-	169	-	-	-	2,030	
15	467-10	Measuring & Regulating Equipment	94,930	2.12%	30,778	-	2,013	(115)	-	-	32,676	
16	467-20	Telemetering	18,289	8.97%	14,869	-	1,640	(10)	-	-	16,499	
17	467-31	IP Intermediate Pressure Whistler	372	2.26%	128	-	8	-	-	-	136	
18	467-30	Measuring & Regulating Equipment - Byron Creek	291	2.41%	45	-	7	-	-	-	52	
19	468-00	Communication Structures & Equipment	10,095	0.00%	4,393	-	-	-	-	-	4,393	
20			$ 2,113,665		$ 695,285	$ -	$ 42,285	$ (5,650)	$ -	$ -	$ 731,920	
21												
22		**DISTRIBUTION PLANT**										
23	470-00	Land in Fee Simple	$ 5,457	0.00%	$ (13)	$ -	$ -	$ -	$ -	$ -	$ (13)	
24	472-00	Structures & Improvements	56,596	2.15%	12,279	-	1,217	(16)	-	-	13,480	
25	472-10	Structures & Improvements - Byron Creek	124	4.67%	83	-	6	-	-	-	89	
26	473-00	Services	1,427,229	2.18%	391,165	-	31,114	(3,656)	-	-	418,623	
27	474-00	House Regulators & Meter Installations	164,362	7.45%	106,529	-	12,245	(6,183)	-	-	112,591	
28	474-02	Meters/Regulators Installations	214,759	4.55%	45,426	-	9,772	-	-	-	55,198	
29	475-00	Mains	2,024,405	1.35%	563,208	-	27,329	(4,605)	-	-	585,932	
30	476-00	Compressor Equipment	614	0.00%	1,444	-	-	-	-	-	1,444	
31	477-10	Measuring & Regulating Equipment	213,654	2.51%	66,041	-	5,363	(670)	-	-	70,734	
32	477-20	Telemetering	23,082	3.59%	7,655	-	829	(79)	-	-	8,405	
33	477-30	Measuring & Regulating Equipment - Byron Creek	153	0.00%	210	-	-	-	-	-	210	
34	478-10	Meters	304,357	6.06%	183,131	-	18,444	(5,873)	-	-	195,702	
35	478-20	Instruments	15,406	2.92%	7,673	-	450	-	-	-	8,123	
36	479-00	Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-	
37			$ 4,450,198		$ 1,384,831	$ -	$ 106,769	$ (21,082)	$ -	$ -	$ 1,470,518	
38												
39		**BIO GAS**										
40	472-20	Bio Gas Struct. & Improvements	$ 716	2.69%	$ 147	$ -	$ 19	$ -	$ -	$ -	$ 166	
41	475-10	Bio Gas Mains – Municipal Land	1,867	1.56%	168	-	29	-	-	-	197	
42	475-20	Bio Gas Mains – Private Land	339	1.56%	13	-	5	-	-	-	18	
43	418-10	Bio Gas Purification Overhaul	20	5.00%	8	-	1	-	-	-	9	
44	418-20	Bio Gas Purification Upgrader	11,220	5.00%	3,345	-	561	-	-	-	3,906	
45	477-40	Bio Gas Reg & Meter Equipment	3,349	3.22%	601	-	108	-	-	-	709	
46	478-30	Bio Gas Meters	65	4.89%	16	-	3	-	-	-	19	
47	474-10	Bio Gas Reg & Meter Installations	742	5.32%	77	-	39	-	-	-	116	
48	483-25	RNG Comp S/W	138	20.00%	139	-	-	(138)	-	-	1	
49			$ 18,456		$ 4,514	$ -	$ 765	$ (138)	$ -	$ -	$ 5,141	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 7.2

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2021	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2022	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Natural Gas for Transportation**										
2	476-10	NG Transportation CNG Dispensing Equipment	18,916	5.00%	$ 4,370	-	946	-	-	-	$ 5,316	
3	476-20	NG Transportation LNG Dispensing Equipment	14,175	5.00%	4,328	-	709	-	-	-	5,037	
4	476-30	NG Transportation CNG Foundations	2,967	5.00%	792	-	148	-	-	-	940	
5	476-40	NG Transportation LNG Foundations	1,311	5.00%	494	-	66	-	-	-	560	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to LNG)	1,494	10.00%	916	-	149	-	-	-	1,065	
7	476-60	NG Transportation CNG Dehydrator	708	5.00%	188	-	35	-	-	-	223	
8	476-70	NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-	-	-	
9			$ 39,571		$ 11,088	$ -	$ 2,053	$ -	$ -	$ -	$ 13,141	
10												
11		**GENERAL PLANT & EQUIPMENT**										
12	480-00	Land in Fee Simple	$ 31,306	0.00%	$ 17	$ -	$ -	$ -	$ -	$ -	$ 17	
13	482-10	Frame Buildings	24,658	3.17%	13,326	-	782	-	-	-	14,108	
14	482-20	Masonry Buildings	126,489	1.52%	34,913	-	1,923	(117)	-	-	36,719	
15	482-30	Leasehold Improvement	1,672	9.49%	1,062	-	198	(65)	-	-	1,195	
16	483-30	GP Office Equipment	3,125	6.67%	1,344	-	208	(163)	-	-	1,389	
17	483-40	GP Furniture	19,224	5.00%	5,587	-	961	(461)	-	-	6,087	
18	483-10	GP Computer Hardware	46,501	25.00%	21,969	-	11,625	(8,315)	-	-	25,279	
19	483-20	GP Computer Software	5,164	12.50%	3,018	-	645	(1,021)	-	-	2,642	
20	484-00	Vehicles	51,891	11.07%	20,270	-	5,744	-	-	-	26,014	
21	484-10	Vehicles - Leased	15,421	9.44%	15,105	-	137	(1,458)	-	-	13,784	
22	485-10	Heavy Work Equipment	750	5.14%	488	-	39	-	-	-	527	
23	485-20	Heavy Mobile Equipment	9,277	6.09%	4,718	-	565	-	-	-	5,283	
24	486-00	Small Tools & Equipment	57,485	5.00%	24,976	-	2,874	(2,237)	-	-	25,613	
25	487-20	Equipment on Customer's Premises	-	6.67%	-	-	-	-	-	-	-	
26	488-10	Telephone	1,821	6.67%	1,557	-	121	(598)	-	-	1,080	
27	488-20	Radio	17,629	6.67%	5,616	-	1,176	-	-	-	6,792	
28	489-00	Other General Equipment	-	0.00%	-	-	-	-	-	-	-	
29			$ 412,413		$ 153,966	$ -	$ 26,998	$ (14,435)	$ -	$ -	$ 166,529	
30												
31		**UNCLASSIFIED PLANT**										
32	499-00	Plant Suspense	-	0.00%	-	-	-	-	-	-	-	
33			$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	
34												
35		**Total**	$ 7,967,068		$ 2,423,184	$ -	$ 210,971	$ (58,623)	$ -	$ -	$ 2,575,532	
36		Less: Depreciation & Amortization Transferred to Biomethane BVA					(765)					
37		Less: Vehicle Depreciation Allocated To Capital Projects					(2,176)					
38		**Net Depreciation Expense**					$ 208,030					
39												
40		Cross Reference	Schedule 6.2, Line 35, Column 3+4+5									

NON-REG PLANT CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 8

Line No.	Particulars			12/31/2021	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2022	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Non-Regulated Plant**									
2	NRB Depreciation @ 0%			$ 1,054	$ -	$ -	$ -	$ -	$ 1,054	
3	NRB Depreciation @ 2.4%			176,594	-	-	-	-	176,594	
4									-	
5	**Total**			$ 177,648	$ -	$ -	$ -	$ -	$ 177,648	
6										
7										
8										

9 **NON-REG PLANT ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE**
10 **FOR THE YEAR ENDING DECEMBER 31, 2022**
11 **($000s)**

Line No.	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2021	Opening Bal Adjustment	Depreciation Expense	Depreciation Retirements	Cost of Removal	12/31/2022	Cross Reference
12										
13										
16	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
17										
18	**Non-Regulated Plant Depreciation**									
19	NRB Depreciation @ 0%	$ 1,054	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	
20	NRB Depreciation @ 2.4%	176,594	2.40%	138,414	-	4,238	-	-	142,652	
21									-	
22	**Total**	$ 177,648		$ 138,414	$ -	$ 4,238	$ -	$ -	$ 142,652	

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	12/31/2021	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2022	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	Distribution Contributions	$ 296,154	$ -	$ -	$ 1,948	$ -	$ 298,102	
3	Transmission Contributions	152,762	-	-	3,901	-	156,663	
4	Others	2,399	-	-	-	-	2,399	
5	Biomethane	566	-	-	-	-	566	
6	**Total**	$ 451,881	$ -	$ -	$ 5,849	$ -	$ 457,730	
7								
8	**Amortization**							
9	Distribution Contributions	$ (127,385)	$ -	$ -	$ (6,250)	$ -	$ (133,635)	
10	Transmission Contributions	(58,737)	-	-	(2,230)	-	(60,967)	
11	Others	(990)	-	-	(120)	-	(1,110)	
12	Biomethane	(272)	-	-	(28)	-	(300)	
13	**Total**	$ (187,384)	$ -	$ -	$ (8,628)	$ -	$ (196,012)	
14								
15	**Net CIAC**	$ 264,497	$ -	$ -	$ (2,779)	$ -	$ 261,718	
16								
17								
18	Total CIAC Amortization Expense per Line 13				$ (8,628)			
19	Less: CIAC Amortization Transferred to Biomethane BVA				28			
20	**Net CIAC Amortization Expense**				$ (8,600)			

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2021	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2022	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**MANUFACTURED GAS / LOCAL STORAGE**							
2	437-00	Manufact'd Gas - Measuring & Regulating Equipment	$ 1,714	0.00%	$ (22)	$ -	$ -	$ (22)	
3	442-00	Structures & Improvements (Tilbury)	100,025	0.68%	2,179	680	-	2,859	
4	443-00	Gas Holders - Storage (Tilbury)	183,719	1.12%	5,533	2,058	-	7,591	
5	448-11	Piping (Tilbury)	50,095	0.28%	571	136	-	707	
6	448-21	Pre-treatment (Tilbury)	38,003	0.50%	755	190	-	945	
7	448-31	Liquefaction Equipment (Tilbury)	89,093	0.57%	2,345	508	-	2,853	
8	449-00	Local Storage Equipment (Tilbury)	27,862	0.82%	1,350	229	-	1,579	
9	442-01	Structures & Improvements (Mount Hayes)	19,045	0.49%	420	93	-	513	
10	443-05	Gas Holders - Storage (Mount Hayes)	61,774	0.36%	1,076	222	-	1,298	
11	448-41	Send out Equipment(Tilbury)	7,690	0.28%	63	22	-	85	
12	448-51	Sub-station and Electric (Tilbury)	36,847	0.56%	860	206	-	1,066	
13	448-10	Piping (Mount Hayes)	12,455	0.28%	163	35	-	198	
14	448-20	Pre-treatment (Mount Hayes)	29,238	0.50%	689	146	-	835	
15	448-30	Liquefaction Equipment (Mount Hayes)	28,880	0.57%	795	165	-	960	
16	448-40	Send out Equipment (Mount Hayes)	23,552	0.28%	318	66	-	384	
17	448-50	Sub-station and Electric (Mount Hayes)	21,788	0.56%	595	122	-	717	
18	449-01	Local Storage Equipment (Mount Hayes)	5,727	0.32%	90	18	-	108	
19			$ 737,507		$ 17,780	$ 4,896	$ -	$ 22,676	

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2021	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2022	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	462-00	Compressor Structures	$ 36,645	0.11%	$ 522	$ 41	$ -	$ 563	
3	463-00	Measuring Structures	20,210	0.62%	631	125	-	756	
4	464-00	Other Structures & Improvements	10,610	0.29%	117	31	-	148	
5	465-00	Mains	1,586,533	0.42%	32,746	6,663	-	39,409	
6	465-11	IP Transmission Pipeline - Whistler	58,689	0.34%	831	200	-	1,031	
7	465-30	Mt Hayes - Mains	6,307	0.30%	98	19	-	117	
8	466-00	Compressor Equipment	200,312	0.07%	2,457	140	-	2,597	
9	467-00	Mt. Hayes - Measuring and Regulating Equipment	7,239	0.21%	58	15	-	73	
10	467-10	Measuring & Regulating Equipment	94,930	0.16%	1,012	152	-	1,164	
11	467-20	Telemetering	18,289	0.00%	(26)	-	-	(26)	
12	467-31	IP Intermediate Pressure Whistler	372	0.35%	4	1	-	5	
13	468-00	Communication Structures & Equipment	10,095	0.00%	401	-	-	401	
14			$ 2,050,231		$ 38,851	$ 7,387	$ -	$ 46,238	
15									
16		**DISTRIBUTION PLANT**							
17	470-00	Land in Fee Simple	$ 5,457	0.00%	$ (1,393)	$ -	$ -	$ (1,393)	
18	472-00	Structures & Improvements	56,596	0.52%	578	295	-	873	
19	473-00	Services	1,427,229	2.09%	63,910	29,829	(16,386)	77,353	
20	474-00	House Regulators & Meter Installations	164,362	3.37%	3,695	5,539	-	9,234	
21	474-02	Meters/Regulators Installations	214,759	0.00%	748	-	-	748	
22	475-00	Mains	2,024,405	0.50%	52,291	10,122	(8,267)	54,146	
23	476-00	Compressor Equipment	614	0.00%	706	-	-	706	
24	477-10	Measuring & Regulating Equipment	213,654	0.45%	4,634	961	-	5,595	
25	477-20	Telemetering	23,082	0.48%	216	111	-	327	
26	478-10	Meters	304,357	0.00%	2,874	-	-	2,874	
27			$ 4,434,515		$ 128,259	$ 46,857	$ (24,653)	$ 150,463	
28									
29		**BIO GAS**							
30	472-20	Bio Gas Struct. & Improvements	$ 716	0.29%	$ 10	$ 2	$ -	$ 12	
31	475-10	Bio Gas Mains – Municipal Land	1,867	0.39%	43	7	-	50	
32	475-20	Bio Gas Mains – Private Land	339	0.39%	3	1	-	4	
33	418-20	Bio Gas Purification Upgrader	11,220	0.24%	119	27	-	146	
34	477-40	Bio Gas Reg & Meter Equipment	3,349	0.00%	(6)	-	-	(6)	
35	474-10	Bio Gas Reg & Meter Installations	742	1.44%	16	11	-	27	
36			$ 18,233		$ 185	$ 48	$ -	$ 233	

Schedule 10.2

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2021	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2022	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 18,916	0.00%	$ (1)	$ -	$ -	$ (1)	
3			$ 18,916		$ (1)	$ -	$ -	$ (1)	
4									
5		**GENERAL PLANT & EQUIPMENT**							
6	482-10	Frame Buildings	$ 24,658	0.37%	$ (189)	$ 91	$ -	$ (98)	
7	482-20	Masonry Buildings	126,489	0.08%	1,116	101	-	1,217	
8	482-30	Leasehold Improvement	1,672	0.00%	(46)	-	-	(46)	
9	483-30	GP Office Equipment	3,125	0.00%	1	-	-	1	
10	483-40	GP Furniture	19,224	0.00%	(67)	-	-	(67)	
11	484-00	Vehicles	51,891	-3.70%	(1,923)	(1,920)	-	(3,843)	
12	485-10	Heavy Work Equipment	750	-0.67%	(21)	(5)	-	(26)	
13	485-20	Heavy Mobile Equipment	9,277	-1.80%	(842)	(167)	-	(1,009)	
14	486-00	Small Tools & Equipment	57,485	0.00%	36	-	-	36	
15	487-20	Equipment on Customer's Premises	-	0.00%	(2)	-	-	(2)	
16	488-20	Radio	17,629	0.00%	(7)	-	-	(7)	
17			$ 312,200		$ (1,944)	$ (1,900)	$ -	$ (3,844)	
18									
19		**Total**	$ 7,571,602		$ 183,130	$ 57,288	$ (24,653)	$ 215,765	
20		Less: Depreciation & Amortization Transferred to Biomethane BVA				(48)			
21		**Net Salvage Depreciation Expense**				$ 57,240			
22		Cross Reference	Schedule 6.2, Column 3+4+5						

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	12/31/2021	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2022	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Midstream Cost Reconciliation Account (MCRA)	$ (2,394)	$ -	$ -	$ -	$ -	$ 1,640	$ (443)	$ (1,197)	$ (1,796)	
3	Commodity Cost Reconciliation Account (CCRA)	23,559	-	(32,273)	8,714	-	-	-	-	11,780	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	2,562	-	-	-	-	(1,755)	474	1,281	1,922	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(1,918)	-	(563)	152	12	1,578	(426)	(1,165)	(1,542)	
6	SCP Mitigation Revenues Variance Account	(201)	-	-	-	101	-	-	(100)	(151)	
7	Pension & OPEB Variance	3,119	-	1,712	-	(230)	-	-	4,601	3,860	
8	BCUC Levies Variance	37	-	-	-	(37)	-	-	-	19	
9		$ 24,764	$ -	$ (31,124)	$ 8,866	$ (154)	$ 1,463	$ (395)	$ 3,420	$ 14,092	
10											
11	**2. Rate Smoothing Accounts**										
12											
13	**3. Benefits Matching Accounts**										
14	Demand-Side Management (DSM)	$ 195,760	$ 44,002	$ 29,935	$ (8,082)	$ (31,910)	$ -	$ -	$ 229,705	$ 234,734	
15	NGV Conversion Grants	8	-	-	-	(4)	-	-	4	6	
16	Emissions Regulations	(2,578)	-	-	-	1,072	-	-	(1,506)	(2,042)	
17	On-Bill Financing Pilot Program	2	-	(1)	-	-	-	-	1	2	
18	Greenhouse Gas Reduction Regulation Incentives	25,552	-	6,450	(1,742)	(5,010)	-	-	25,250	25,401	
19	CNG and LNG Recoveries	(435)	-	(795)	215	434	-	-	(581)	(508)	
20	BCUC Initiated Inquiry Costs	71	-	100	(27)	(71)	-	-	73	72	
21	2017 Rate Design Application	526	-	-	-	(263)	-	-	263	395	
22	2017 Long Term Resource Plan Application	41	-	-	-	(41)	-	-	-	21	
23	PGR Application and Preliminary Stage Development Costs	-	575	-	-	(192)	-	-	383	479	
24	Transportation Service Report	73	-	250	(67)	-	-	-	256	165	
25	2021 Generic Cost of Capital Proceeding	548	-	750	(203)	-	-	-	1,095	822	
26	2019-2022 DSM Expenditures Application Costs	25	-	-	-	(25)	-	-	-	13	
27	City of Coquitlam Application Proceeding	284	-	100	(27)	(284)	-	-	73	179	
28		$ 219,877	$ 44,577	$ 36,789	$ (9,933)	$ (36,294)	$ -	$ -	$ 255,016	$ 259,739	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 11.1

Line No.	Particulars	12/31/2021	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2022	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**3. Benefits Matching Accounts (cont'd)**										
2	Whistler Pipeline Conversion	5,714	-	-	-	(739)	-	-	4,975	5,345	
3	Gas Asset Records Project	912	-	-	-	(368)	-	-	544	728	
4	BC OneCall Project	8	-	-	-	(8)	-	-	-	4	
5	Gains and Losses on Asset Disposition	8,485	-	-	-	(3,987)	-	-	4,498	6,492	
6	Net Salvage Provision/Cost	(184,956)	-	24,653	-	(57,288)	-	-	(217,591)	(201,274)	
7	PCEC Start Up Costs	612	-	-	-	(44)	-	-	568	590	
8	2022 Long Term Gas Resource Plan Application	565	-	325	(87)	-	-	-	803	684	
9	2020–2024 MRP Application	407	-	-	-	(136)	-	-	271	339	
10	City of Surrey Operating Terms Application Costs	34	-	-	-	(34)	-	-	-	17	
11	2021 Renewable Gas Program Comprehensive Review	241	-	435	(118)	-	-	-	558	400	
12	IGU Application and Preliminary Stage Development Costs	(387)	-	-	-	387	-	-	-	(194)	
13	Annual Review of 2020-2024 Rates	172	-	180	(49)	(172)	-	-	131	152	
14		$ (168,193)	$ -	$ 25,593	$ (254)	$ (62,389)	$ -	$ -	$ (205,243)	$ (186,717)	
15											
16	**4. Retroactive Expense Accounts**										
17											
18	**5.Other Accounts**										
19	Pension & OPEB Funding	$ (282,139)	$ -	$ (1,839)	$ -	$ -	$ -	$ -	$ (283,978)	$ (283,059)	
20	US GAAP Pension & OPEB Funded Status	156,888	-	-	-	-	-	-	156,888	156,888	
21	BFI Costs and Recoveries	202	-	-	-	(202)	-	-	-	101	
22	BVA Balance Transfer	283	8,130	-	-	-	(11,525)	3,112	-	4,207	
23	COVID-19 Customer Recovery Fund	1,491	-	1,700	(535)	-	-	-	2,656	2,074	
24	2017 & 2018 Revenue Surplus Account	-	(308)	-	-	308	-	-	-	(154)	
25		$ (123,275)	$ 7,822	$ (139)	$ (535)	$ 106	$ (11,525)	$ 3,112	$ (124,434)	$ (119,943)	
26											
27	**Total**	$ (46,827)	$ 52,399	$ 31,119	$ (1,856)	$ (98,731)	$ (10,062)	$ 2,717	$ (71,241)	$ (32,829)	
28	Less: Net Salvage Amortization Transferred to Biomethane BVA					48					
29	**Net Rate Base Deferred Amortization Expense**					$ (98,683)					

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 12

Line No.	Particulars	12/31/2021	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2022	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**<u>1. Forecasting Variance Accounts</u>**										
2	Biomethane Variance Account	$ 8,244	$ (8,130)	$ -	$ -	$ -	$ -	$ -	$ 114	$ 114	
3	Flowthrough (2020-2024)	11,121	-	296	-	(11,417)	-	-	-	5,561	
4	Marketer Cost Variance	15	-	(20)	5	-	-	-	-	8	
5		$ 19,380	$ (8,130)	$ 276	$ 5	$ (11,417)	$ -	$ -	$ 114	$ 5,683	
6	**<u>2. Rate Smoothing Accounts</u>**										
7	2017 & 2018 Revenue Surplus Account	$ (308)	$ 308	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
8											
9	**<u>3. Benefits Matching Accounts</u>**										
10	Demand-Side Management (DSM) - Non Rate Base	$ 44,002	$ (44,002)	$ 69,151	$ (18,305)	$ -	$ -	$ -	$ 50,846	$ 25,423	
11	PEC Pipeline Development Costs and Commitment Fees	(2,398)	-	-	-	-	-	-	(2,398)	(2,398)	
12	PGR Application and Preliminary Stage Development Costs	575	(575)	-	-	-	-	-	-	-	
13	Transmission Integrity Management Capabilities	14,804	-	1,593	(207)	-	-	-	16,190	15,497	
14	Regional Gas Supply Diversity (RGSD) Project Development Costs	1,533	-	38,200	(10,314)	-	-	-	29,419	15,476	
15	Clean Growth Innovation Fund	(3,384)	-	4,813	(1,350)	-	(5,100)	1,377	(3,644)	(3,514)	
16		$ 55,132	$ (44,577)	$ 113,757	$ (30,176)	$ -	$ (5,100)	$ 1,377	$ 90,413	$ 50,484	
17	**<u>4. Retroactive Expense Accounts</u>**										
18											
19	**<u>5.Other Accounts</u>**										
20	Mark to Market - Hedging Transactions	$ (1,940)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,940)	$ (1,940)	
21	MRP Earnings Sharing Account	(1,318)	-	(35)	-	1,353	-	-	-	(659)	
22		$ (3,258)	$ -	$ (35)	$ -	$ 1,353	$ -	$ -	$ (1,940)	$ (2,599)	
23											
24											
25	**Total Non Rate Base Deferral Accounts**	$ 70,946	$ (52,399)	$ 113,998	$ (30,171)	$ (10,064)	$ (5,100)	$ 1,377	$ 88,587	$ 53,568	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 13

Line No.	Particulars	2021 Approved	2022 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 17,474	$ 19,040	$ 1,566	Schedule 14, Line 30, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Employee Loans	1,368	1,559	191	
6	Employee Withholdings	(6,444)	(6,367)	77	
7					
8	**Other Working Capital Items**				
9	Transmission Line Pack Gas	2,103	1,725	(378)	
10	Gas In Storage	40,786	50,364	9,578	
11	Inventory - Materials and Supplies	2,041	2,250	209	
12	Refundable Contributions	(320)	(318)	2	
13					
14	Total	$ 57,008	$ 68,253	$ 11,245	

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 14

Line No.	Particulars	2022 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	$ 935,162	40.3	$ 37,687,029		
4	Commercial Tariff Revenue	494,394	37.8	18,688,093		
5	Industrial Tariff Revenue	158,142	47.7	7,543,370		
6	Bypass and Special Rates	63,530	37.6	2,388,728		
7						
8	**Other Revenue**					
9	Late Payment Charges	2,704	53.8	145,475		
10	Application Charges	2,013	39.0	78,507		
11	Other Utility Income	36,919	39.0	1,439,841		
12						
13	Total	$ 1,692,864		$ 67,971,043	40.2	
14						
15	**EXPENSES**					
16	Energy Purchases	$ 647,970	(40.0)	$ (25,918,800)		
17	Operating and Maintenance	276,620	(31.8)	(8,796,516)		
18	Property Taxes	73,397	(1.3)	(95,416)		
19	Operating Fees	10,472	(352.9)	(3,695,583)		
20	Carbon Tax	389,866	(30.7)	(11,968,886)		
21	GST	31,885	(39.7)	(1,265,828)		
22	PST	28,339	(45.8)	(1,297,918)		
23	Income Tax	52,211	(15.2)	(793,607)		
24						
25	Total	$ 1,510,759		$ (53,832,554)	(35.6)	
26						
27	Net Lag (Lead) Days				4.6	
28	Total Expenses				$ 1,510,759	
29						
30	Cash Working Capital				$ 19,040	

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 15

Line No.	Particulars	2021 Approved	2022 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Total DIT Liability- After Tax	$ (454,945)	$ (520,816)	$ (65,871)	
2	Tax Gross Up	(168,267)	(192,631)	(24,364)	
3	DIT Liability/Asset - End of Year	$ (623,212)	$ (713,447)	$ (90,235)	
4	DIT Liability/Asset - Opening Balance	(584,209)	(666,166)	(81,957)	
5					
6	DIT Liability/Asset - Mid Year	$ (603,711)	$ (689,807)	$ (86,096)	

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	2021 Approved	2022 Forecast at 2021 Approved Rates	2022 Forecast Revised Revenue	2022 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	154,208	156,232		156,232	2,024	
3	Transportation Volume (TJ)	79,366	77,825		77,825	(1,541)	
4		233,574	234,057	-	234,057	483	Schedule 17, Line 24, Column 3
5							
6	**REVENUE AT EXISTING RATES**						
7	Sales	$ 1,347,141	$ 1,486,769	$ -	$ 1,486,769	$ 139,628	
8	Deficiency (Surplus)	-	-	65,805	65,805	65,805	
9	Transportation	98,294	92,976	-	92,976	(5,318)	
10	Deficiency (Surplus)	-		5,678	5,678	5,678	
11	Total	1,445,435	1,579,745	71,483	1,651,228	205,793	Schedule 19, Line 30, Column 8
12				-			
13	**COST OF ENERGY**	515,935	647,970	-	647,970	132,035	Schedule 18, Line 24, Column 3
14							
15	**MARGIN**	929,500	931,775	71,483	1,003,258	73,758	
16							
17	**EXPENSES**						
18	O&M Expense (net)	274,770	276,620	-	276,620	1,850	Schedule 20, Line 28, Column 4
19	Depreciation & Amortization	280,628	308,177	-	308,177	27,549	Schedule 21, Line 15, Column 3
20	Property Taxes	71,811	73,397	-	73,397	1,586	Schedule 22, Line 8, Column 3
21	Other Revenue	(41,995)	(41,636)	-	(41,636)	359	Schedule 23, Line 12, Column 3
22	Deferred 2021 Revenue Deficiency	(35,287)	-	-	-	35,287	Schedule 1, Line 25, Column 3
23	Utility Income Before Income Taxes	379,573	315,217	71,483	386,700	7,127	
24							
25	Income Taxes	54,012	32,916	19,295	52,211	(1,801)	Schedule 24, Line 13, Column 3
26							
27	**EARNED RETURN**	$ 325,561	$ 282,301	$ 52,188	$ 334,489	$ 8,928	Schedule 26, Line 5, Column 7
28							
29	**UTILITY RATE BASE**	$ 5,212,439	$ 5,407,694		$ 5,409,169	$ 196,730	Schedule 2, Line 31, Column 3
30	**RATE OF RETURN ON UTILITY RATE BASE**	6.25%	5.22%		6.18%	-0.06%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 17

Line No.	Particulars	2021 Approved	2022 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**				
2	Residential				
3	Rate Schedule 1	79,332.3	81,494.4	2,162.1	
4	Commercial				
5	Rate Schedule 2	28,937.2	29,000.0	62.8	
6	Rate Schedule 3	26,203.9	24,886.2	(1,317.7)	
7	Rate Schedule 23	4,877.8	4,125.4	(752.4)	
8	Industrial				
9	Rate Schedule 4	148.9	159.5	10.6	
10	Rate Schedule 5	8,168.9	9,420.4	1,251.5	
11	Rate Schedule 6	23.4	20.8	(2.6)	
12	Rate Schedule 7	5,924.2	6,601.1	676.9	
13	Rate Schedule 22 - Firm Service	10,434.2	10,379.2	(55.0)	
14	Rate Schedule 22 - Interruptible Service	15,899.6	16,533.0	633.4	
15	Rate Schedule 25	10,252.7	9,163.8	(1,088.9)	
16	Rate Schedule 27	4,796.0	4,510.5	(285.5)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	11,030.7	10,916.5	(114.2)	
19	Rate Schedule 25	893.6	1,017.5	123.9	
20	Rate Schedule 46	5,469.6	4,650.0	(819.6)	
21	Byron Creek	11.0	8.7	(2.3)	
22	BC Hydro IG	16,425.0	16,425.0	-	
23	VIGJV	4,745.0	4,745.0	-	
24	Total	233,574.0	234,057.0	483.0	
25					
26	**REVENUE AT EXISTING RATES**				
27	Residential				
28	Rate Schedule 1	$ 803,736	$ 891,164	$ 87,428	
29	Commercial				
30	Rate Schedule 2	240,070	264,539	24,469	
31	Rate Schedule 3	183,348	194,471	11,123	
32	Rate Schedule 23	18,017	15,228	(2,789)	
33	Industrial				
34	Rate Schedule 4	788	955	167	
35	Rate Schedule 5	47,303	59,326	12,023	
36	Rate Schedule 6	135	126	(9)	
37	Rate Schedule 7	27,027	34,542	7,515	
38	Rate Schedule 22 - Firm Service	7,317	7,326	9	
39	Rate Schedule 22 - Interruptible Service	18,026	18,624	598	
40	Rate Schedule 25	25,123	22,424	(2,699)	
41	Rate Schedule 27	7,940	7,490	(450)	
42	Bypass and Special Rates				
43	Rate Schedule 22 - Firm Service	802	794	(8)	
44	Rate Schedule 25	418	426	8	
45	Rate Schedule 46	44,734	41,646	(3,088)	
46	Byron Creek	109	119	10	
47	BC Hydro IG	15,735	15,735	-	
48	VIGJV	4,807	4,810	3	
49	Total	$ 1,445,435	$ 1,579,745	$ 134,310	

COST OF ENERGY
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 18

Line No.	Particulars	2021 Approved	2022 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 271,529	$ 346,101	$ 74,572	
4	Commercial				
5	Rate Schedule 2	99,816	123,827	24,011	
6	Rate Schedule 3	84,511	100,657	16,146	
7	Rate Schedule 23	83	70	(13)	
8	Industrial				
9	Rate Schedule 4	446	586	140	
10	Rate Schedule 5	24,466	34,441	9,975	
11	Rate Schedule 6	56	59	3	
12	Rate Schedule 7	17,743	24,251	6,508	
13	Rate Schedule 22 - Firm Service	259	258	(1)	
14	Rate Schedule 22 - Interruptible Service	188	200	12	
15	Rate Schedule 25	173	156	(17)	
16	Rate Schedule 27	81	77	(4)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	187	185	(2)	
19	Rate Schedule 25	15	17	2	
20	Rate Schedule 46	16,382	17,085	703	
21	Byron Creek	-	-	-	
22	BC Hydro IG	-	-	-	
23	VIGJV	-	-	-	
24	Total	$ 515,935	$ 647,970	$ 132,035	

MARGIN AND REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 19

			2022 Forecast			2022 Forecast					
Line No.	Particulars	2021 Approved Margin	Margin at 2021 Approved Rates	Effective Increase	Margin at Revised Rates	Revenue at 2021 Approved Rates	Effective Increase	Revenue at Revised Rates	Average Number of Customers	Terajoules	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON - BYPASS**										
2	Residential										
3	Rate Schedule 1	$ 532,207	$ 545,063	$ 43,998	$ 589,061	$ 891,164	$ 43,998	$ 935,162	969,238	81,494.4	
4	Commercial										
5	Rate Schedule 2	140,254	140,712	11,359	152,071	264,539	11,359	275,898	90,390	29,000.0	
6	Rate Schedule 3	98,837	93,814	7,573	101,387	194,471	7,573	202,044	6,988	24,886.2	
7	Rate Schedule 23	17,934	15,158	1,224	16,382	15,228	1,224	16,452	768	4,125.4	
8	Industrial										
9	Rate Schedule 4	342	369	30	399	955	30	985	20	159.5	
10	Rate Schedule 5	22,837	24,885	2,009	26,894	59,326	2,009	61,335	591	9,420.4	
11	Rate Schedule 6	79	67	5	72	126	5	131	12	20.8	
12	Rate Schedule 7	9,284	10,291	831	11,122	34,542	831	35,373	45	6,601.1	
13	Rate Schedule 22 - Firm Service	7,058	7,068	571	7,639	7,326	571	7,897	9	10,379.2	
14	Rate Schedule 22 - Interruptible Service	17,838	18,424	1,487	19,911	18,624	1,487	20,111	28	16,533.0	
15	Rate Schedule 25	24,950	22,268	1,798	24,066	22,424	1,798	24,222	298	9,163.8	
16	Rate Schedule 27	7,859	7,413	598	8,011	7,490	598	8,088	71	4,510.5	
17	Total Non-Bypass	$ 879,479	$ 885,532	$ 71,483	$ 957,015	$ 1,516,215	$ 71,483	$ 1,587,698	1,068,458	196,294.3	
18											
19											
20	**Bypass and Special Rates**										
21	Rate Schedule 22 - Firm Service	$ 615	$ 609		$ 609	$ 794		$ 794	6	10,916.5	
22	Rate Schedule 25	403	409		409	426		426	3	1,017.5	
23	Rate Schedule 46	28,352	24,561		24,561	41,646		41,646	20	4,650.0	
24	Byron Creek	109	119		119	119		119	1	8.7	
25	BC Hydro IG	15,735	15,735		15,735	15,735		15,735	1	16,425.0	
26	VIGJV	4,807	4,810		4,810	4,810		4,810	1	4,745.0	
27	Total Bypass & Special	$ 50,021	$ 46,243	$ -	$ 46,243	$ 63,530	$ -	$ 63,530	32	37,762.7	
28											
29											
30	Total	$ 929,500	$ 931,775	$ 71,483	$ 1,003,258	$ 1,579,745	$ 71,483	$ 1,651,228	1,068,490	234,057.0	
31											
32	**Effective Increase**			8.07%			4.71%				

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2022
($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	2021 Base Unit Cost O&M	$ 260			
3	2022 Net Inflation Factor	3.324%			Schedule 3, Line 9, Column 5
4	2022 Base Unit Cost O&M	$ 269			Line 2 x (1 + Line 3)
5					
6	2022 Average Customer Forecast - Rate Setting Purpose	1,059,333			Schedule 3, Line 22, Column 6
7					
8	2022 Inflation Indexed O&M before prior year True-up	$ 284,961			Line 4 x Line 6 / 1000
9					
10	2020 Average Customer True-up	258			
11					
12	2022 Inflation Indexed O&M	$ 285,219		$ 285,219	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ 9,537		
16	Insurance		11,474		
17	Biomethane O&M		3,355		
18	NGT O&M		2,057		
19	Variable LNG Production		7,553		
20	Integrity Digs		5,700		
21	Renewable Gas Development		1,000		
22	BCUC fees		7,408		
23	Sub-total		$ 48,084	48,084	Sum of Lines 15 through 22
24					
25	**Total Gross O&M**			$ 333,303	Line 12 + Line 23
26	O&M Transferred to Biomethane BVA			(3,355)	
27	Capitalized Overhead			(53,328)	-16 % x Line 25
28	**Net O&M Expense**			$ 276,620	Sum of Lines 25 through 27

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 21

Line No.	Particulars	2021 Approved	2022 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 202,032	$ 210,971	$ 8,939	Schedule 7.2, Line 35, Column 7
3	Depreciation & Amortization Transferred to Biomethane BVA	(726)	(765)	(39)	Schedule 7.2, Line 36, Column 7
4	Vehicle Depreciation Allocated To Capital Projects	(1,883)	(2,176)	(293)	Schedule 7.2, Line 37, Column 7
5		199,423	208,030	8,607	
6					
7	**Amortization**				
8	Rate Base Deferrals	$ 89,748	$ 98,731	$ 8,983	Schedule 11.1, Line 27, Column 6
9	Rate Base Deferrals - Net Salvage Amortization Transferred to Biomethane BVA	(38)	(48)	(10)	Schedule 11.1, Line 28, Column 6
10	Non-Rate Base Deferrals	-	10,064	10,064	Schedule 12, Line 25, Column 6
11	CIAC	(8,533)	(8,628)	(95)	Schedule 9, Line 13, Column 5
12	CIAC Amortization Transferred to Biomethane BVA	28	28	-	Schedule 9, Line 19, Column 5
13		81,205	100,147	18,942	
14					
15	Total	$ 280,628	$ 308,177	$ 27,549	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 22

Line No.	Particulars	2021 Approved	2022 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 59,471	$ 60,136	$ 665	
2	1% In-Lieu of Municipal Taxes	12,423	13,368	945	
3					
4	Total	$ 71,894	$ 73,504	$ 1,610	
5					
6	Total Property Tax Expense per Line 4	$ 71,894	$ 73,504		
7	Less: Property Tax Transferred to Biomethane BVA	(83)	(107)		
8	**Net Property Tax Expense**	$ 71,811	$ 73,397		

OTHER REVENUE Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	2021 Approved	2022 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 2,954	$ 2,704	$ (250)	
2	Application Charge	1,984	2,013	29	
3	NSF Returned Cheque Charges	28	28	-	
4	Other Recoveries	288	288	-	
5	SCP Third Party Revenue	14,053	13,410	(643)	
6	NGT Tanker Rental Revenue	774	928	154	
7	NGT Overhead and Marketing Recovery	258	283	25	
8	Biomethane Other Revenue	951	986	35	
9	LNG Capacity Assignment	18,039	18,039	-	
10	CNG & LNG Service Revenues	2,666	2,957	291	
11					
12	Total	$ 41,995	$ 41,636	$ (359)	

INCOME TAXES Schedule 24
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	2021 Approved	2022 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 325,561	$ 334,489	$ 8,928	Schedule 16, Line 27, Column 5
2	Deduct: Interest on Debt	(149,967)	(152,268)	(2,301)	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	(29,562)	(41,057)	(11,495)	Line 36
4	Accounting Income After Tax	$ 146,032	$ 141,164	$ (4,868)	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 200,044	$ 193,375	$ (6,669)	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 54,012	$ 52,211	$ (1,801)	
11					
12	Previous Year Adjustment	-	-	-	
13	**Total Income Tax**	$ 54,012	$ 52,211	$ (1,801)	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Non-tax Deductible Expenses	$ 1,200	$ 1,200	$ -	
19	Depreciation	199,423	208,030	8,607	Schedule 21, Line 5, Column 3
20	Amortization of Deferred Charges	89,710	108,747	19,037	Schedule 21, Line 8+9+10, Column 3
21	Amortization of Debt Issue Expenses	1,202	1,259	57	
22	Vehicles: Interest & Capitalized Depreciation	1,894	2,181	287	
23	Pension Expense	23,385	11,137	(12,248)	
24	OPEB Expense	8,969	7,642	(1,327)	
25					
26	Deductions:				
27	Capital Cost Allowance	(278,899)	(298,674)	(19,775)	Schedule 25, Line 26, Column 6
28	CIAC Amortization	(8,505)	(8,600)	(95)	Schedule 21, Line 11+12, Column 3
29	Debt Issue Costs	(1,816)	(1,816)	-	
30	Vehicle Lease Payment	(234)	(142)	92	
31	Pension Contributions	(13,038)	(13,739)	(701)	
32	OPEB Contributions	(2,971)	(3,206)	(235)	
33	Overheads Capitalized Expensed for Tax Purposes	(26,345)	(26,664)	(319)	
34	Removal Costs	(16,064)	(24,653)	(8,589)	Schedule 11.1, Line 6, Column 4
35	Major Inspection Costs	(7,473)	(3,759)	3,714	
36	Total	$ (29,562)	$ (41,057)	$ (11,495)	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 25

Line No.	Class	CCA Rate	12/31/2021 UCC Balance	2022 Additions	UCC Adjustment for AIIP *	2022 CCA	Forecast 12/31/2022 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 940,716	$ 4,853	$ 2,426	$ (37,920)	$ 907,649
2	1 (LNG Plant - post Feb 2015)	4%	15,219	-	-	(609)	14,610
3	1(b)	6%	98,802	11,112	5,556	(6,928)	102,986
4	2	6%	81,661	-	-	(4,900)	76,761
5	3	5%	1,605	-	-	(80)	1,525
6	6	10%	238	-	-	(23)	215
7	7	15%	20,705	1,453	727	(3,432)	18,726
8	8	20%	28,735	10,057	5,029	(8,764)	30,028
9	10	30%	14,897	8,390	4,195	(8,245)	15,042
10	10.1	30%	129	-	-	(39)	90
11	12	100%	-	21,096	-	(21,096)	-
12	13	manual	1,687	82	41	(478)	1,291
13	14	manual	25	-	-	(25)	-
14	14.1 (pre 2017)	7%	15,250	-	-	(1,067)	14,183
15	14.1 (post 2016)	5%	5,315	-	-	(266)	5,049
16	17	8%	962	-	-	(77)	885
17	38	30%	1,500	1,578	789	(1,160)	1,918
18	43.2	50%	196	-	-	(98)	98
19	45	45%	1	-	-	-	1
20	47	8%	152,972	-	-	(12,238)	140,734
21	47 (LNG Plant - post Feb 2015)	8%	161,123	-	-	(12,890)	148,233
22	49	8%	432,445	91,805	45,902	(45,612)	478,638
23	50	55%	3,770	10,548	5,274	(10,776)	3,542
24	51	6%	1,493,771	359,151	179,575	(121,951)	1,730,971
25							
26	Total		$ 3,471,724	$ 520,125	$ 249,514	$ (298,674)	$ 3,693,175
27							
28	* Note - Accelerated Investment Incentive Property						

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Schedule 26

Line No.	Particulars	2021 Approved Earned Return	Amount	Ratio	2022 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	$ 147,276	$ 3,218,288	59.50%	4.65%	2.77%	$ 149,765	$ 2,489	Schedule 27, Line 29&31, Column 5&6&7
2	Short Term Debt	2,691	108,351	2.00%	2.31%	0.05%	2,503	(188)	
3	Common Equity	175,594	2,082,530	38.50%	8.75%	3.37%	182,221	6,627	
4									
5	Total	$ 325,561	$ 5,409,169	100.00%		6.18%	$ 334,489	$ 8,928	
6									
7	Cross Reference		Schedule 2, Line 31, Column 3						

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Net Proceeds of Issue	Average Principal Outstanding	Interest * Rate	Interest Expense	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Medium Term Note - Series 11	September 21, 1999	September 21, 2029	$ 147,710	$ 150,000	7.073%	$ 10,610	
2	2004 Long Term Debt Issue - Series 18	April 29, 2004	May 1, 2034	148,085	150,000	6.598%	9,897	
3	2005 Long Term Debt Issue - Series 19	February 25, 2005	February 25, 2035	148,337	150,000	5.980%	8,970	
4	2006 Long Term Debt Issue - Series 21	September 25, 2006	September 25, 2036	119,216	120,000	5.595%	6,714	
5	2007 Medium Term Debt Issue - Series 22	October 2, 2007	October 2, 2037	247,697	250,000	6.067%	15,168	
6	2008 Medium Term Debt Issue - Series 23	May 13, 2008	May 13, 2038	247,588	250,000	5.869%	14,673	
7	2009 Med.Term Debt Issue- Series 24	February 24, 2009	February 24, 2039	98,766	100,000	6.645%	6,645	
8	2011 Medium Term Debt Issue - Series 25	December 9, 2011	December 9, 2041	98,590	100,000	4.334%	4,334	
9	2015 Medium Term Debt Issue - Series 26 (Series A Renewal)	April 13, 2015	April 13, 2045	148,938	150,000	3.413%	5,120	
10	2016 Medium Term Debt Issue - Series 27 (Series B Renewal)	April 8, 2016	April 8, 2026	127,704	128,545	2.644%	3,399	
11	2016 Medium Term Debt Issue - Series 28	April 8, 2016	April 9, 2046	148,746	150,000	3.716%	5,574	
12	2016 Medium Term Debt Issue - Series 29	December 13, 2016	March 6, 2047	148,865	150,000	3.822%	5,733	
13	2017 Medium Term Debt Issue - Series 30	October 30, 2017	October 30, 2047	173,584	175,000	3.735%	6,536	
14	2018 Medium Term Debt Issue - Series 31	December 7, 2018	December 7, 2048	198,351	200,000	3.897%	7,794	
15	2019 Medium Term Debt Issue - Series 32	August 9, 2019	August 9, 2049	198,500	200,000	2.857%	5,714	
16	2020 Medium Term Debt Issue - Series 33	July 13, 2020	July 13, 2050	198,392	200,000	2.579%	5,158	
17	2021 Medium Term Debt Issue - Series 34	April 14, 2021	July 18, 2031	149,162	150,000	2.482%	3,723	
18	2022 Medium Term Debt Issue	July 1, 2022	July 1, 2052	198,000	100,822	3.655%	3,685	
19								
20	FEVI L/T Debt Issue - 2008	February 16, 2008	February 15, 2038	247,999	250,000	6.109%	15,273	
21	FEVI L/T Debt Issue - 2010	December 6, 2010	December 6, 2040	98,836	100,000	5.278%	5,278	
22								
23	LILO Obligations - Creston	November 1, 2005	October 31, 2022		1,518	8.366%	127	
24								
25	Vehicle Lease Obligation				247	2.024%	5	
26								
27	Sub-Total				$ 3,226,132		$ 150,130	
28	Less: Fort Nelson Division Portion of Long Term Debt				(7,844)		(365)	
29	Total				$ 3,218,288		$ 149,765	
30								
31	Average Embedded Cost					4.65%		
32								
33	* Interest Rate is Effective Interest Rate as it includes amortization of debt issue costs							

12. ACCOUNTING MATTERS AND EXOGENOUS FACTORS

12.1 *INTRODUCTION AND OVERVIEW*

In this section, FEI discusses “Exogenous Factors” under its MRP, including an update on the exogenous factor treatment for the impacts of the COVID-19 pandemic, emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FEI requests approval of one new deferral account and provides information on the Transmission Integrity Management Capabilities (TIMC) Development Costs and Flow-through deferral accounts.

12.2 *EXOGENOUS (Z) FACTORS*

FEI 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 FEI has been established at $0.500 million, as approved in the MRP Decision.

In the Annual Review for 2020 and 2021 Delivery Rates, FEI identified the COVID-19 pandemic as a potential exogenous factor affecting 2020 and future years, and the BCUC approved FEI’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[49]. FEI also stated in the Annual Review for 2020 and 2021 Delivery 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. FEI provides an update on the COVID-19 pandemic net incremental costs (costs less cost reductions) including reduced late payment revenues in the following section.

[49] FEI Annual Review for 2020 and 2021 Delivery Rates Decision and Order G-319-20.

12.2.1 COVID-19 Pandemic

During the COVID-19 pandemic, FEI 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 delivery system safely and reliably. This has to date resulted in net incremental O&M impacts and a reduction in late payment charge revenues.

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

Consistent with the MRP, FEI'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.

Recognizing the above circumstances, FEI 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. FEI has included in this section 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) discussed below.

However, the COVID-19 pandemic, unlike other events experienced by the Company (e.g. responding to an emergency situation affecting delivery of energy), has a broader 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, affecting the determination of the costs that are attributable to the pandemic. For example, there may be incremental costs such as 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. While acknowledging these uncertainties, the following summary of net incremental costs provides a reasonable representation of the overall COVID-19 pandemic impact on the Company.

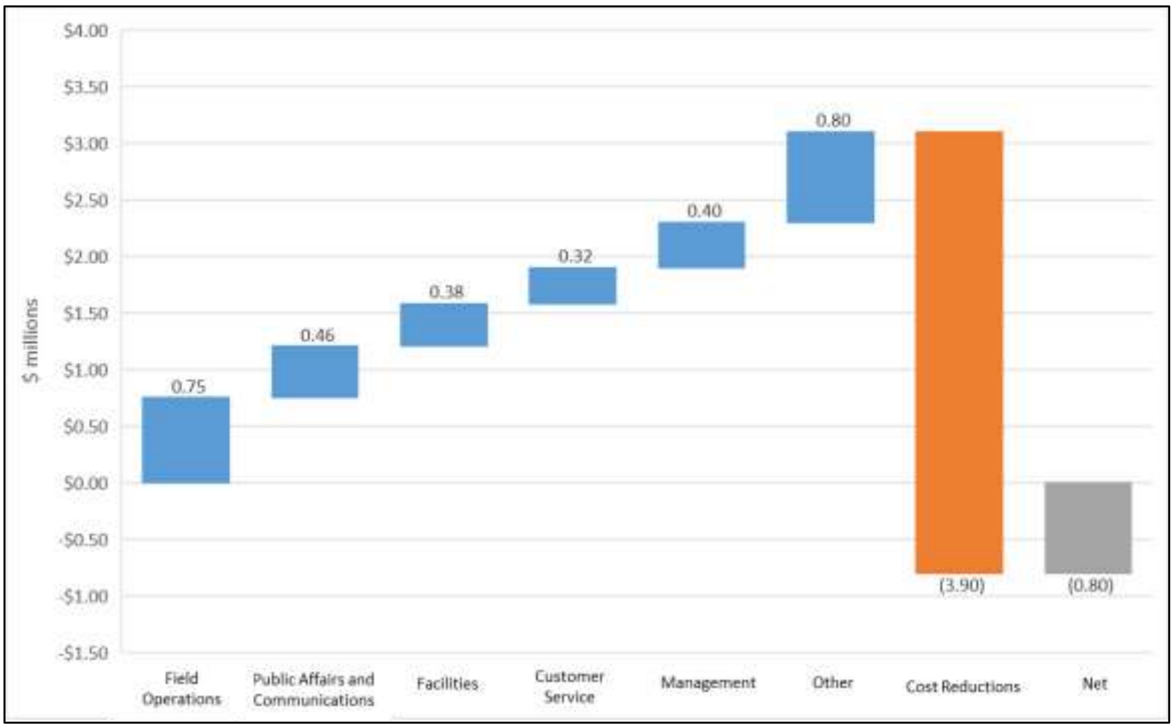
12.2.1.2 Summary of Net Incremental Costs

Overall, in 2020, as a result of the COVID-19 pandemic, the Company's net incremental O&M (costs less cost reductions) decreased by approximately \$0.8 million. However, this net O&M decrease was offset by a shortfall in Late Payment Charge revenues of approximately \$0.9 million, resulting from the discontinuation of customer collection activities during the pandemic. When combined, the total impact of the COVID-19 pandemic in 2020, including reduced late payment revenues, was an incremental increase in net costs of \$0.1 million.

12.2.1.3 2020 COVID-19 Pandemic Impact

While the COVID-19 pandemic increased O&M costs in 2020, these costs were offset by lower employee related expenses. As of December 2020, FEI incurred approximately $3.1 million in O&M costs related to the COVID-19 pandemic. These costs were primarily to ensure the health, safety and well-being of FEI's customers, employees, and their communities, and to continue to operate the delivery system safely and reliably. The incremental costs were offset by approximately $3.9 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: FEI COVID-19 Pandemic 2020 Net O&M Costs



12.2.1.3.1 <u>INCREASED O&M EXPENDITURES DUE TO THE COVID-19 PANDEMIC</u>

In the Field Operations area, FEI incurred approximately $0.75 million related to the COVID-19 pandemic. Of this amount, approximately $0.50 million was related to personal protective equipment (i.e., mask, gloves and sanitizers), with the remaining costs related to lower system damage claims recoveries due to the suspension of the provincial court system early in 2020 at the onset of the COVID-19 pandemic, which impacted the Company's ability to collect on damage claims.

In the Public Affairs and Communications area, FEI incurred approximately $0.46 million for activities to keep customers and key stakeholders informed of the Company's assistance available during the COVID-19 pandemic. 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.

FEI incurred approximately $0.38 million for Facilities-related resources and activities including safety supplies, furniture storage, additional cleaning, first aid coverage, and signage.

For the Customer Service area, FEI incurred approximately $0.32 million, primarily for expanded hours to operate the Willingdon Park facility to accommodate the after-hours group and support appropriate social distancing in the work environment.

Under the category of Management, approximately $0.40 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 $0.80 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 FEI 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 include course fees, travel, meals and accommodation, company function expenses, and employee hiring and relocation expenses.

As at December 2020, the reduced employee expenses identified and reprioritized by departments for addressing COVID-19 pandemic costs were estimated at approximately $3.7 million. In addition to reduced employee expenses, there was an estimated $0.2 million reduction in employee health benefits (dental, employee health spending, etc.) used by employees, bringing the total cost reductions to approximately $3.9 million in 2020.

12.2.1.3.3 REDUCED REVENUE FROM LATE PAYMENT CHARGES

In the Annual Review for 2020 and 2021 Delivery Rates Application (pages 30-31), FEI explained that the calculation of 2020 Projected Late Payment Charges included six months of actual results, with the remaining six months projected based on the prorated average of the actual 2017 to 2019 Late Payment Charges. FEI was expecting to resume its collection activities during the latter part of 2020 when the impact of the COVID-19 pandemic subsided. However, the COVID-19 pandemic continued, leading FEI to not resume its customer collection activities until 2021. As a result of the COVID-19 pandemic, 2020 Actual Late Payment Charges were lower than 2020 Approved by approximately $0.9 million. It is appropriate to consider this variance as part of the COVID-19 pandemic exogenous factor determination, similar to that being considered for O&M expenses, as the shortfall in Late Payment Charges is directly linked to the discontinuation of customer collection activities during the COVID-19 pandemic.

12.2.1.3.4 NET IMPACT IN 2020 IS NOT MATERIAL

When the variances for the net incremental O&M (costs less cost reductions) and the Late Payment Charges are aggregated, the net variance of the two factors is approximately $0.1 million, consisting of a $0.8 million decrease in net incremental O&M costs and a shortfall of $0.9 million in Late Payment Charges.

12.2.1.4 2021 COVID-19 Pandemic Impact

Based on the current outlook regarding the COVID-19 pandemic in BC, FEI expects the impact on the Company's operating costs to decline in the coming months and eventually end. FEI's current plans are to resume normal operations coinciding with the Province achieving Step 4 of the Province of BC Four Step Restart Plan, currently planned for September 7, 2021. Step 4 includes the lifting of restrictions with normal social contact allowed and workplaces fully reopened.

To date in 2021, FEI is continuing to incur additional expenditures to manage the impact of the COVID-19 pandemic. The nature of the costs being incurred is similar to that observed in 2020 and includes costs for activities in Field Operations, Public Affairs Emergency Team and Communications and Facilities. FEI expects to continue to incur additional expenditures to approximately when Step 4 of the Province of BC Four Step Restart Plan begins, at which time the majority of incremental expenditures related to the COVID-19 pandemic, except for expenditures related to the Company's reintegration efforts, will have occurred. FEI is also monitoring for any significant cost reductions related to COVID-19 such as a continued temporary reduction in employee-related expenses that may help to offset the incremental expenditures. Additionally, FEI is continuing to track the reduction in Late Payment Charges due to the COVID-19 pandemic.

Upon resumption of normal operating conditions expected later this year, FEI will no longer be tracking COVID-19 pandemic related net incremental O&M costs.

12.2.1.5 Conclusion

FEI will report to the BCUC on the final 2021 estimated net incremental O&M costs and any reduced revenues from Late Payment Charges in the Annual Review for 2023 Delivery Rates application. At that time, when the total of the 2020 and 2021 net incremental O&M costs and reduced Late Payment Charges will be available, FEI can make a final recommendation on whether or not the amounts exceed the materiality threshold.

12.3 ACCOUNTING MATTERS

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

12.3.1 Emerging Accounting Guidance

In the PBR Plan decision, the BCUC directed FEI 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, FEI will continue to provide accounting policy changes and updates as part of the Annual Review materials.

There are no new accounting policy changes that FEI is proposing, or that are required to be implemented under US GAAP, that result in a change in accounting for 2022.

12.4 NON-RATE BASE DEFERRAL ACCOUNTS

FEI 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, subject to BCUC approval, attract a weighted average cost of capital (WACC) return (which is equal to a rate base return).

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist[50]. The purpose of this checklist is to facilitate an efficient review of applications for deferral accounts. The checklist classifies deferral accounts as either: (a) forecast variance accounts; (b) rate smoothing accounts; (c) benefit matching accounts; (d) retroactive expense accounts; or (e) other.

In the following sections, FEI requests approval of one new deferral account. FEI also provides information on the Transmission Integrity Management Capabilities (TIMC) Development Costs and Flow-through deferral accounts. Information on FEI's non-rate base earnings sharing, BVA and CGIF deferral accounts is included in Section 10.

12.4.1 New Deferral Accounts

12.4.1.1 Regional Gas Supply Diversity (RGSD) Project Development Costs Deferral Account

FEI is seeking approval of one new non-rate base deferral account to capture costs related to activities associated with developing a project in consultation with Indigenous groups and other stakeholders from concept through to CPCN filing. The concept is an extension of the FEI Southern Crossing Pipeline (SCP) from Oliver to Huntingdon. The extension will significantly strengthen FEI's gas system resiliency. Additionally, it will position FEI for a lower carbon future

[50] Letter Log No. 53608, Appendix B.

by improving access to renewable and low carbon gaseous energy supply (hydrogen and RNG). FEI considers meaningful Indigenous participation to be foundational.

With this Application, FEI requests BCUC approval for a non-rate base deferral account, called the RGSD Project Development Costs deferral account, attracting a WACC return, for the Pre-Phase 1 and Phase 1 preliminary stage development costs related to the assessment of the RGSD Project[51]. FEI will propose an appropriate cost recovery method and period in its CPCN application for the RGSD Project or in another application if the project does not proceed to a CPCN application.

In the sections below, FEI provides supporting information for the RGSD Project Development Costs deferral account, including:

- A discussion of regional gas supply diversity;
- A description of development activities and costs proposed to be recorded in the deferral account; and
- How the deferral account complies with the BCUC's deferral account filing checklist.

12.4.1.1.1 REGIONAL GAS SUPPLY DIVERSITY

FEI has been assessing optimal solutions to provide gas supply resiliency for its customers, as discussed in its 2020/21 Annual Contracting Plan (ACP). FEI filed a confidential Compliance Report on August 31, 2020, in compliance with BCUC Letter L-31-20, regarding resiliency (Compliance Report). As stated in the Compliance Report, FEI's gas system resiliency depends on a combination of pipeline diversity, ample storage and the ability to manage load. Access to multiple regional pipelines, preferably separated geographically, to serve the distribution system improves a utility's ability to dependably collect and deliver gas supply to consumers.

In the Compliance Report, FEI discussed that an SCP expansion to Huntingdon would be FEI's preferred choice of pipeline development from a resiliency standpoint, given that this solution would entail an entirely different path from the Enbridge T-South system. Subsequent to the Compliance Report, FEI filed its 2021/22 ACP with the BCUC on May 3, 2021. In the 2021/22 ACP, FEI stated that it is completing initial scoping work and plans to proceed with developing a RGSD Project solution which would entail building a new pipeline to the Lower Mainland connecting to the SCP in the BC interior[52]. FEI expects that new compressor stations will also be required along the existing SCP system in order to deliver the incremental gas supply to Huntingdon.

The RGSD Project will provide significant benefits with respect to system resiliency, gas supply, decarbonization, and Indigenous reconciliation, as follows:

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[51] FEI is in the process of determining a project name to be used for future regulatory and public communication; however, "RGSD Project" has been adopted for the purposes of this Application.

[52] As discussed in the confidentially filed 2021/22 ACP in Appendix B, Section 6.1.4.

- FEI's Lower Mainland customers will benefit from increased resiliency due to the RGSD Project, as the pipeline will be built on a path that is entirely different than the existing T-South system, thereby accessing supply from a different supply hub. During the outage on Enbridge's T-South system, the SCP was critical for delivering supply to FEI's load centres. The extension of the SCP would allow FEI to split and diversify its supply sourcing more evenly between the Station 2 and AECO/NIT market hubs, which would put FEI in the strongest position to respond to supply disruptions relative to other regional pipeline expansion options. Consistent with the Compliance Report and FEI's Tilbury LNG Storage Expansion (TLSE) Project CPCN Application, FEI has determined that the optimal resiliency solution is to proceed with the TLSE Project to address short-term disruptions and an optimally sized pipeline for mid- and long-term disruptions. Subsequent events, such as industry cybersecurity breaches, wildfire events, and additional T-South disruptions only highlight the need for additional resiliency.
- With the RGSD Project, FEI will be able to realize additional gas supply benefits. For example, the AECO/NIT market is the most liquid and largest gas trading hub in western Canada. Increased access to this trading hub will provide FEI with access to a larger number of suppliers, increased intraday buying and selling flexibility, and likely lower priced storage capacity contracting. These market features at the AECO/NIT hub would allow FEI to greatly enhance and further optimize its ACP portfolio. Having two diverse pipelines would significantly strengthen security of daily gas supply for customers and provide increased diversity of resources. Further, since additional regional infrastructure is needed in the region, the RGSD Project would provide a better supply alternative compared to other expansion options. The RGSD Project has the ability to deliver AECO/NIT gas directly to Huntingdon via a new pipeline route that can serve customers of FEI and neighbouring US Pacific Northwest utilities that rely greatly on the Sumas market.
- The RGSD Project will also support FEI's decarbonization initiatives. FEI is a critical partner in implementing the federal and provincial governments' GHG reduction objectives. To demonstrate FEI's commitment to BC's climate goals, FEI developed the Clean Growth Pathway to 2050, which is a public response to the provincial government's consultation period on CleanBC. One of the key initiatives identified in the study is to reduce the carbon intensity of FEI's gas supply portfolio. FEI will achieve this by increasing the proportion of Renewable Gases (RG) in its portfolio, including hydrogen and RNG. In order to achieve the CleanBC targets, FEI will need close to 75 percent low carbon fuel by 2050. RG supply is a key component of FEI's Clean Growth Pathway, and will require pipeline transportation capacity. The RGSD Project will create the pipeline infrastructure required to transport physical RG to FEI's load centres. The RGSD Project presents an opportunity to build a pipeline to transport cost-effective hydrogen blends in the future. To be hydrogen compatible, as envisioned by the BC Hydrogen Strategy[53], a critical component of the analysis in the development

[53] BC Hydrogen Strategy, https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bc_hydrogen_strategy_final.pdf

phases will be to determine the metallurgical composition of the pipe and levels of compression required that would enable the flow of RG, specifically hydrogen, effectively and safely through the pipeline system.

- Foundational to the RGSD Project is the opportunity for meaningful collaboration with Indigenous nations along the project corridor. The RGSD Project represents a significant opportunity to advance Indigenous reconciliation through the potential for Indigenous ownership in the pipeline and facilities, by providing employment and training, and by enabling other beneficial initiatives within the various communities.

12.4.1.1.2 PROJECT DEVELOPMENT ACTIVITIES AND COSTS

The magnitude and scope of the RGSD Project is such that FEI requires approval of a project development cost deferral account in order to conduct Pre-Phase 1 and Phase 1 project assessment activities (outlined in Table 12-1 below) that will provide FEI with the detailed information necessary to prepare and file a CPCN application with the BCUC.

In order to prepare the project development cost estimate for this complex undertaking, FEI sourced services from a number of external consulting firms regarded as experts in their respective fields in conjunction with key technical personnel from FEI in order to prepare tasks and cost estimates that underpin this budget. The following is a summary of resources that have been engaged to plan the key activities and derive cost estimates required in the assessment phase of this project:

- FEI System Capacity Planning – to determine optimal pipe sizing and compression horsepower requirements;
- Innovative Pipeline Projects Limited – technical expertise for pipeline design, constructability and routing;
- Thurber Engineering Ltd. – geotechnical activities related to the terrain and constructability of the new pipeline along potential routes;
- Solaris Management Consultants Inc. – expertise on compressor stations, locations and unit configuration;
- Jacobs Engineering Group – environmental activities and the development of an Environmental Application (EA) that will be required for this project;
- Terra Archaeology Limited – Indigenous and archaeological activities;
- FEI / Fasken – external communication and Indigenous consultation strategy;
- FEI Property Services – lands and rights of way for the routing of the pipeline; and
- Det Norske Veritas (DNV) – hydrogen and de-carbonization initiatives that will influence the design and composition of the new pipeline.

Based on the information provided by these resources, FEI has prepared a project development cost budget for planned activities that are expected to culminate in the preparation and filing of a CPCN application. The estimated development costs for these preliminary stage activities are summarized in the table below:

Table 12-1: Estimated RGSD Project Development Costs ($ millions)

Major Category	Pre-Phase 1	Phase 1	Total
Pipeline Engineering	$ -	$ 4.1	**$ 4.1**
Compressor Engineering	-	8.9	**8.9**
Geotechnical Engineering	0.3	2.1	**2.4**
Environmental Application	-	2.3	**2.3**
Land and Right-of-Way	-	7.5	**7.5**
Indigenous & External Relations	1.5	9.5	**11.0**
Legal	0.3	2.0	**2.3**
Contingency	-	7.2	**7.2**
Management Cost	-	3.6	**3.6**
Total Costs	**$ 2.1**	**$ 47.2**	**$ 49.3**

As shown in Table 12-1 above, the project development costs have been broken down into Pre-Phase 1 and Phase 1 costs. The Pre-Phase 1 costs of $2.1 million are largely to engage in initial consultation activities with Indigenous communities in 2021. The balance ($47.2 million) for Phase 1 activities is planned to be spent in 2022 and 2023, leading to the preparation of a CPCN. Based on initial estimated timelines, FEI anticipates that the earliest possible date for a CPCN filing would be Q1 2023. However, the project development schedule will be largely influenced and driven by the Indigenous engagement discussions and will be adjusted as needed to meet the expectations and support required from Indigenous groups and other stakeholders.

In addition to Indigenous engagement, the project development activities encompass environmental, technical and engineering studies, and establishing route certainty. The development activities are further explained below.

Pipeline Engineering: Route development and preparation of cost estimates for a CPCN application.

Geotechnical assessment: Geotechnical work will form a component of the pre Front End Engineering Design (FEED) to produce a cost estimate. Work will include hazard identification, Light Detection and Ranging (LIDAR) acquisition, air photo acquisition, terrain mapping, alternate route assessments, geo hazard assessments, preliminary seismic assessments, and hydro technical assessments.

Compression Engineering: Site selection, design and preparation of cost estimates for four new compressor stations.

EA and Archeology: Develop the Initial Project Description (IPD), initiate the BC EA early engagement process, and develop the draft Application Information Requirements for the EA.

External Relations: Undertake meaningful consultation and opportunity development with Indigenous Nations. This includes consultation and relationship building, developing an engagement plan, and revisions to the IPD and engagement plan based on feedback from Indigenous Nations. The early engagement phase also includes consultation and relationship building with local governments, regulatory agencies, and other stakeholders.

Land and Right of Way: Establish contact with landowners, negotiate access agreements, and conduct preliminary area appraisals.

12.4.1.1.3 THE BCUC'S DEFERRAL ACCOUNT CHECKLIST

Table 12-2 below addresses the considerations identified in the Regulatory Account Filing Checklist, as they pertain to this deferral account request.

Table 12-2: Deferral Account Filing Considerations

Item	Consideration	Determination
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.	FEI requests the establishment of one new deferral account to capture the development costs related to the RGSD Project.
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 requested account will capture RGSD Project development costs, mainly related to external consulting costs, data assessment and front-end engineering and design (FEED).
II.	Propose a term (i.e. length of time) that the regulatory account should be approved for and explain why that term is appropriate.	This account will capture costs during the development phase of the project. It is anticipated costs for this phase will be incurred from 2021 until the CPCN filing.

Item	Consideration	Determination
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 this deferral account, costs would have been forecast as a combination of O&M and capital expenses outside of the formula.
IV a)	Address: whether, or to what extent, the item is outside of management's control;	The CPCN development costs are generally within FEI's control; however, it is accepted regulatory practice to defer development costs and recover them in a future period. This allows the costs of the complete project to be matched against when the benefits are realized, as well as to smooth the rate impact to customers from the recovery of the deferred costs.
b)	the degree of forecast uncertainty associated with the item;	During the project development phase, leading up to the CPCN application, the costs are fairly certain, as laid out in Table 12-1. A key component of the pre-CPCN project development phase will be developing forward costs. As further information becomes known, FEI will provide updates to the BCUC as required through future rate filings. FEI forecasts additions to the deferral account based on the best estimate of costs at this time. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.
c)	the materiality of the costs	The development costs are material at an estimate of $49.3 million. See Table 12-1 for further details.
d)	any impact on intergenerational equity	FEI will propose a recovery period that will match the costs and benefits of RGSD Project development to avoid concerns over intergenerational equity.
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.	FEI classifies development cost accounts as benefit matching accounts since the costs are recovered over the period of time the benefits are generally realized.
VI.	Identify if the regulatory account is a cash or non-cash account.	Development cost accounts are cash accounts.

Item	Consideration	Determination
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 are described in the Project Development Activity and Costs section and shown in Table 12-1. They will include required CPCN development costs such as environmental assessments, and detailed Indigenous and stakeholder consultation. Eligible costs also include FEI's incremental internal costs to provide required direction, inputs, technical analyses, and other contributions to the work above. Additions will be captured during the development phase of the project only.
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.	FEI will propose an appropriate recovery mechanism in its CPCN application for the pipeline project, which is expected to be filed in 2023.
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.	FEI will propose an appropriate recovery period in its CPCN application for the pipeline project.
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	FEI is requesting carrying costs based on its weighted average cost of capital (WACC). Non-rate base deferral accounts are generally financed using WACC.
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The BCUC's review of the pipeline development costs deferral account can occur as part of this annual review process. Approval of the pipeline project itself will be requested through a CPCN application, where the regulatory process will be included within the draft timetable.

12.4.2 Existing Deferral Accounts

In the sections below, FEI discusses two existing deferral accounts.

12.4.2.1 Transmission Integrity Management Capabilities (TIMC) Development Costs

In the decision accompanying Order G-237-18, which approved the creation of a non-rate base deferral account to collect development costs related to the TIMC project, FEI was directed to provide the following information:

1) Updated actual and forecast project development costs compared to budget with explanations for variances;

2) Updated timeline for when FEI anticipates filing the CPCN with explanations for changes; and

3) Details on project scope and deliverables, including any changes thereto from what was provided in the current annual review proceeding.

On February 11, 2021, FEI filed the Coastal Transmission System (CTS) TIMC Project CPCN (CTS TIMC CPCN) with the BCUC. In the CTS TIMC CPCN, FEI provides a detailed breakdown and description of the TIMC Development Costs deferral account and requests approval to recover the balance in this deferral account for the development costs incurred related to the CTS TIMC Project. FEI has attached the relevant sections of the CPCN application as Appendix C to this Application. As described in the CPCN application, FEI will continue to record costs in the TIMC Development Costs deferral account related to the development of the Interior Transmission System (ITS) TIMC Project CPCN, which is expected to be filed in 2022.

FEI notes that in the CTS TIMC CPCN application, it seeks approval to commence amortizing the deferral account balance in 2022. As FEI does not anticipate receiving approval of the CTS TIMC CPCN prior to 2022, FEI has revised this request in the CPCN application to commence amortization in 2023. Accordingly, there is no delivery rate impact associated with the TIMC Development Costs deferral account in 2022.

Given that FEI has now filed for recovery of the CTS project development-related costs as part of the CTS TIMC CPCN application and that FEI will be filing for recovery of the ITS project development-related costs as part of the upcoming ITS TIMC CPCN application in 2022, FEI will no longer be filing updates on this deferral account in future annual reviews.

12.4.2.2 Flow-Through Deferral Account (2020-2024)

As approved through Order G-165-20, 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.

1 **Table 12-3: 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

2

In accordance with the method set out in the table above, the calculation of the 2021 Projected Flow-through amount of $6.225 million debit is shown in Table 12-4 below. To calculate the amount to be collected from customers, FEI has also included the following adjustments:

- The $4.481 debit difference between the projected ending 2020 deferral account balance of zero,[54] embedded in 2021 delivery rates, and the actual ending 2020 deferral account debit balance of $4.481 million. A more detailed breakout of the 2020 variance is provided in Table 12-5 below;
- The $0.415 million debit difference between the forecast 2021 financing addition of zero[55] embedded in 2021 delivery rates, and the projected 2021 financing addition of $0.415 million debit embedded in this Application; and
- 2022 forecast financing of a $0.296 million debit.[56]

[54] Annual Review for 2020 and 2021 Delivery Rates Compliance Filing financial schedules, Schedule 12, Line 3, Column 2.
[55] Annual Review for 2020 and 2021 Delivery Rates Compliance Filing financial schedules, Schedule 12, Line 3, Column 4.
[56] Section 11, Schedule 12, Line 3, Column 4.

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

Line No.	Particulars	2021 Approved	2021 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Delivery Margin**			
2	Residential (Rate 1)	$ (532.207)	$ (533.413)	$ (1.206)
3	Commercial (Rate 2, 3, 23)	(257.025)	(252.746)	4.279
4	Industrial (All Others)	(140.268)	(133.392)	6.876
5				
6	**Net O&M Expense**			
7	Pension & OPEB	22.354	22.354	-
8	Insurance	9.908	10.430	0.522
9	Biomethane	1.848	2.668	0.820
10	NGT	1.813	1.919	0.106
11	Variable LNG Production Costs	8.081	7.281	(0.800)
12	Integrity Digs	4.800	5.900	1.100
13	Renewable Gas Development	0.750	1.000	0.250
14	BCUC Levies	7.290	7.290	-
15	Biomethane O&M transferred to BVA	(1.848)	(2.668)	(0.820)
16	Capitalized Overhead	(52.689)	(52.689)	-
17				
18	**Depreciation and Amortization**			
19	Amortization of Deferrals	89.710	89.710	-
20	Depreciation variance on Clean Growth Projects/CPCNs	-	-	-
21	CIAC Amortization variance on Clean Growth Projects/CPCNs	-	-	-
22				
23	**Total Property Taxes**	71.811	70.867	(0.944)
24				
25	**Other Revenues**			
26	SCP Third Party Revenue	(14.053)	(14.053)	-
27	NGT Tanker Rental Revenue	(0.774)	(0.810)	(0.036)
28	Biomethane Other Revenue	(0.951)	(0.926)	0.025
29	LNG Capacity Assignment	(18.039)	(18.039)	-
30	CNG & LNG Service Revenues	(2.666)	(2.771)	(0.105)
31				
32	**Interest Expense**			
33	Long-term debt interest expense variance	147.276	146.605	(0.671)
34	Interest variance on Clean Growth Projects/CPCNs	-	-	-
35	Short-term debt rate variance	-	(0.676)	(0.676)
36	Short-term debt volume variance from long-term debt issue variance	-	0.603	0.603
37	Short-term debt timing variance from long-term debt issue timing	-	(0.796)	(0.796)
38				
39	**Income Tax Expense**			
40	Income tax variance on Clean Growth Projects/CPCNs	-	-	-
41	Income tax/CCA rate changes	-	-	-
42	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs)	-	(2.302)	(2.302)
43				
44	**2021 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**6.225**
45				
46	2020 Ending Deferral Account Balance True-up			4.481
47	2021 Financing True-up			0.415
48	2022 Financing Addition to Deferral Account			0.296
49				
50	**2022 After-Tax Amortization**			**11.417**

As shown in Table 12-4 above, the 2021 Projected flow-through variance is $6.225 million. The variances in each flow-through category are described below.

The projected variances in delivery margin are due to the following:

- unfavourable industrial margin as a result of lower LNG demand, partially offset by favourable interruptible volumes for the Vancouver Island Joint Venture; and

- unfavourable commercial margin mainly as a result of lower customers than forecast, partially offset by favourable residential margin mainly as a result of higher customers than forecast.

Flow-through O&M amounts are provided in Section 6. Amortization expense is equal to the approved value. Variances in property taxes are provided in Section 9. Variances in Other Revenue are provided in Section 5. The projected interest expense variances are derived from FEI issuing long-term debt earlier in 2021 than forecast, but at a lower amount and lower rate than forecast, and FEI projecting a lower short-term interest rate than the approved short-term interest rate, as discussed in Section 8. 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 2021 subject to flow-through will be recorded in the deferral account in 2021 and amortized in 2023 rates.

As mentioned above, FEI is also providing a breakout of the 2020 true-up amount of $4.481 million debit in Table 12-5 below, along with an explanation of the variances.

Table 12-5: 2020 Actual vs. Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2020 Projected	2020 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Delivery Margin**			
2	Residential (Rate 1)	$ (506.021)	$ (506.947)	$ (0.927)
3	Commercial (Rate 2, 3, 23)	(236.975)	(234.091)	2.885
4	Industrial (All Others)	(122.634)	(118.756)	3.878
5				
6	**Net O&M Expense**			
7	Pension & OPEB	21.147	21.147	-
8	Insurance	8.521	8.457	(0.064)
9	Biomethane	1.807	2.354	0.547
10	NGT	1.694	2.076	0.382
11	Variable LNG Production Costs	7.861	7.250	(0.611)
12	Integrity Digs	4.400	5.915	1.515
13	Renewable Gas Development	0.400	0.340	(0.060)
14	BCUC Levies	6.782	6.782	-
15	Biomethane O&M transferred to BVA	(1.807)	(2.354)	(0.547)
16	Capitalized Overhead	(50.306)	(50.306)	-
17				
18	**Depreciation and Amortization**			
19	Amortization of Deferrals	51.033	51.033	-
20	Depreciation variance on Clean Growth Projects/CPCNs	-	(0.162)	(0.162)
21	CIAC Amortization variance on Clean Growth Projects/CPCNs	-	-	-
22				
23	**Total Property Taxes**	67.959	68.225	0.266
24				
25	**Other Revenues**			
26	SCP Third Party Revenue	(10.877)	(10.877)	-
27	NGT Tanker Rental Revenue	(0.569)	(0.686)	(0.117)
28	Biomethane Other Revenue	(0.937)	(0.937)	-
29	LNG Capacity Assignment	(18.039)	(18.039)	-
30	CNG & LNG Service Revenues	(2.939)	(3.274)	(0.335)
31				
32	**Interest Expense**			
33	Long-term debt interest expense variance	141.614	141.605	(0.009)
34	Interest variance on Clean Growth Projects/CPCNs	-	(0.186)	(0.186)
35	Short-term debt rate variance	-	0.292	0.292
36	Short-term debt volume variance from long-term debt issue variance	-	-	-
37	Short-term debt timing variance from long-term debt issue timing	-	-	-
38				
39	**Income Tax Expense**			
40	Income tax variance on Clean Growth Projects/CPCNs	-	(0.287)	(0.287)
41	Income tax/CCA rate changes	-	-	-
42	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs)	-	(1.916)	(1.916)
43				
44	**2020 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**4.544**
45				
46	2020 Financing True-up			(0.063)
47				
48	**2020 Ending Deferral Account Balance True-up**			**4.481**

The variances in delivery margin are due to the following:

- unfavourable industrial margin as a result of lower LNG demand, partially offset by favourable interruptible volumes for the Vancouver Island Joint Venture; and
- unfavourable commercial margin mainly as a result of lower customer additions than forecast, partially offset by favourable residential margin mainly as a result of higher customer additions than forecast.

Actual O&M expense was $1.162 million higher than approved, with the main variance related to integrity digs, which was $1.515 million higher than approved. The variance in integrity digs was due to more digs and repairs, and higher contractor costs than projected.

Actual property tax expenses were relatively consistent with the approved amount.

The flow-through components of Other Revenue were $0.452 million higher than approved, with the main variance related to CNG & LNG Service Revenues, which was $0.335 million higher than approved. The variance in CNG & LNG Service Revenues was mainly due to higher CNG Station demand than forecast.

The variance between the actual (1.78 percent) and approved (1.65 percent) short-term debt interest rates results in an amount recoverable from customers of $0.292 million,[57] shown on Line 35 of Table 12-5 above. The long-term debt interest expense variance of $0.009 million to be returned to customers is due to lower issue costs than forecast on the 2020 long-term debt issuance.

The favourable income tax variance of $1.916 million is calculated as 27 percent of the aforementioned variances.

The combined favourable variance of $0.635 million related to depreciation/CIAC amortization, interest and tax variances on Clean Growth/CPCN amounts, shown on Lines 20, 21, 34 and 40, respectively, in the table above, were derived for 2020 by comparing the actual 2020 cost of service impacts of the NGT Assets and the Tilbury 1A Expansion, Lower Mainland Intermediate Pressure System Upgrade and Coastal Transmission System projects to the amounts forecast for those same projects.

12.5 *SUMMARY*

FEI has discussed why it is not seeking exogenous factor treatment for the impacts of the COVID-pandemic, has provided an update on certain accounting related matters, requested one new non-rate base deferral account and included information on the TIMC Development Costs and Flow-through deferral accounts.

[57] (1.78% - 1.65%) x $222.345 million forecasted 2020 short-term debt in Schedule 26 of August 12, 2020 Annual Review for 2020 and 2021 Delivery Rates 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-165-20, the BCUC approved a balanced set of SQIs for FEI, covering safety, responsiveness to customer needs, and reliability. Nine 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, FEI reports on its 2020 and June 2021 year-to-date performance as measured against the SQI benchmarks and thresholds. The 2020 and June 2021 year-to-date SQI results indicate that the Company's overall performance to date meets service quality requirements. In 2020, for the nine SQIs with benchmarks, eight performed at or better than the approved benchmarks, with one, Meter Reading Accuracy, lower than the threshold due to the impact of the COVID-19 pandemic.[58] For the four SQIs that are informational only, performance generally remains at a level consistent with prior years. In 2021 to date, performance for the metrics with benchmarks is trending towards meeting the benchmark or the threshold.

Consistent with how SQIs were reviewed during the 2014-2019 PBR Plan term,[59] FEI has provided 2020 and year-to-date 2021 SQI results in this annual review. In accordance with Order G-44-16, the BCUC will evaluate FEI's actual 2021 SQI performance in the Annual Review for 2023 Delivery Rates when actual SQI results are known. FEI also notes that it will provide information on the 2022 year-to-date SQI results in the Annual Review for 2023 Delivery Rates.

13.2 *REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS*

For each SQI, Table 13-1 provides a comparison of FEI's 2020 and June year-to-date performance for 2021 to the proposed benchmarks and thresholds approved as part of the MRP. Actual 2020 and June year-to-date results for 2021 are also provided for the four informational SQIs.

[58] In Letter L-20-20, dated March 31, 2020, the BCUC granted public utilities relief from meter reading, when necessary, for the duration of the State of Emergency in the Province of British Columbia and while social distancing practices remain in place.

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

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

Performance Measure	Description	Benchmark	Threshold	2020 Results	2021 June YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within one hour	>= 97.7%	96.2%	97.7%	98.0%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	>= 95%	92.8%	96.9%	97.0%
All Injury frequency rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	<= 2.08	2.95	1.66	1.78
Public Contacts with Gas Lines	Current year average of number of line damages per 1,000 BC One calls received	<= 8	12	7	6
Responsiveness to the Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	>= 78%	74%	81%[60]	79%
Billing Index	Measure of customer bills produced meeting performance criteria	<= 3.0	5.0	0.6	1.0
Meter Reading Accuracy	Number of scheduled meters that were read	>= 95%	92%	89%	91%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>= 70%	68%	70%	66%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	>= 95%	93.8%	98.1%	98.4%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.7	8.7
Average Speed of Answer	Informational indicator – amount of time it takes to answer a call (seconds)	-	-	72	80
Reliability SQIs					
Transmission Reportable Incidents	Informational indicator – number of reportable incidents to outside agencies	-	-	1	0

[60] First Contact Resolution surveying was suspended from March 23 - May 3, 2020 as a result of the COVID-19 pandemic, thus the 2020 results do not contain data for the period that surveys were suspended.

Performance Measure	Description	Benchmark	Threshold	2020 Results	2021 June YTD Results
Leaks per KM of Distribution System Mains	Informational indicator - measures the number of leaks on the distribution system per KM of distribution system mains	-	-	0.0065	0.0030

In the following sections, FEI reviews each SQI's year-to-date individual performance in 2020 and 2021. Discussion is also provided for the informational SQIs.

13.2.1 Safety Service Quality Indicators

Emergency Response Time

This SQI measures the utility's responsiveness to on average 24,000 annual emergency events that include gas odour calls, carbon monoxide calls, house fires and hit lines. It is calculated as:

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

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, available resources, location (i.e., travel times and traffic congestion) and weather conditions.

The 2020 result was 97.7 percent which met the benchmark of 97.7 percent and was better than the threshold of 96.2 percent. In 2020, the Company performed slightly lower than the previous three years (2017-2019) and higher than the three years previous to that (2014-2016). The June 2021 year-to-date performance is 98.0 percent, which is better than the benchmark.

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

Table 13-2: Historical Emergency Response Time

Description	2014	2015	2016	2017	2018	2019	2020	June 2021 YTD
Results	96.7%	97.3%	97.4%	97.8%	97.8%	97.9%	97.7%	98.0%
Benchmark	97.7%							
Threshold	96.2%							

Telephone Service Factor (Emergency)

This indicator measures the percentage of emergency calls answered within 30 seconds and is calculated as:

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

The telephone service factor (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 the volume of inbound calls received and the resources available to answer those calls. Staffing is matched to the calls forecast based on historical data in order to reach the service level benchmark desired.

The 2020 result was 96.9 percent which was better than the benchmark of 95 percent. The June 2021 year-to-date performance is 97.0 percent which is also better than the benchmark.

For comparison, the Company's annual results under the 2014 to 2019 PBR Plan, the 2020 results and the June 2021 year-to-date for TSF (Emergency) are provided below:

Table 13-3: Historical TSF (Emergency) Results

Description	2014	2015	2016	2017	2018	2019	2020	June 2021 YTD
Results	95.8%	97.6%	98.5%	97.6%	97.9%	97.2%	96.9%	97.0%
Benchmark	95.0%							
Threshold	92.8%							

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 2020 (three-year rolling average) result was 1.66 which was better than the benchmark of 2.08. The 2020 annual AIFR was 1.43 which reflected 9 Medical Treatments and 15 Lost Time Injuries.

The June 2021 year-to-date performance (three-year rolling average) result is 1.78 which is better than the benchmark. The June 2021 year-to-date performance (annual) is 2.87 and reflects 8 Medical Treatments and 18 Lost Time Injuries.

Strengthening the safety culture continues to be a key driver for FEI, 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.

While the 2021 year-to-date injury rate is trending above previous years, the majority of the injuries experienced in 2021 are low severity in nature (ergonomic related strains and sprains), and mitigation measures have been taken to address the causes of these injuries. Aspiring to create a safe workplace, where all employees go home healthy and safe each day, continues to be the main organizational goal. This includes reducing the number of relatively low consequence accidents, like those that feature in the AIFR metric, in a proportionate and effective manner. However, the number of low consequence accidents are not in themselves predictors of the likelihood that high severity injuries will be experienced. For this reason, FEI continues to dedicate proportionate focus on high risk activities, ensuring that finite resources are applied cost effectively to build sufficient safety capacity and resilience in the Company's systems and that robust critical controls have been identified, implemented and sustained to avoid serious life altering injuries or fatalities.

The 2021 worker injury sprains and strains experienced are mainly attributable to the gas distribution workforce. The corresponding mitigation measures adopted have included additional ergonomic assessments, safe design of worker/task interface, focus on preparing the mind and body for the task in hand, equipment suitability review, and renewed emphasis on achieving effective job planning and hazard identification and risk control.

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

Table 13-4: Historical All Injury Frequency Rate Results

Description	2014	2015	2016	2017	2018	2019	2020	June 2021 YTD
Annual Results	1.73	2.52	2.13	1.36	1.74	1.82	1.43	2.87
Three year rolling average	2.22	2.42	2.13	2.00	1.74	1.64	1.66	1.78
Benchmark	2.08							
Threshold	2.95							

Public Contact with Gas Lines

This metric measures the overall effectiveness of the Company's efforts to minimize damage to the gas system through public awareness, which is designed to reduce interruptions and the associated public safety and service issues to customers.

This indicator is calculated as:

Number of Line Damages per 1,000 BC One Calls received

For the purpose of this service quality indicator, the measurement of performance is based on the annual results. The new benchmark and threshold approved in the MRP are 8 and 12, respectively.

In its Decision on FEI's Annual Review of 2015 Delivery Rates, the BCUC directed FEI to provide the number of line damages and the number of calls to BC One Call in future annual reviews. Therefore, the number of line damages and number of calls to BC One Call are provided in Table 13-5 below.

The 2020 result was 7, which is better than the benchmark. The June 2021 year-to-date performance is 6, which is also better than the benchmark.

Principal factors influencing results for this metric include economic growth (i.e., construction activity), damage prevention awareness programs, and heightened public awareness created by the BC One Call program. The current year result reflects an ongoing positive trend for this metric. Increased awareness through targeted workshops with municipalities and excavating contractors, together with the ongoing execution of the Damage Investigation Program have contributed to the improved performance.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 results, and June 2021 year-to-date results are provided below. The annual result has been trending downward. This is due to the historical upward trend in BC One Call ticket volume (increased awareness and increased construction activity) up until 2018, which was offset by an increase in the number of line damages resulting from increased construction activities. The Company is taking steps to continue to address line damages. FEI continues to have Damage Prevention Investigators focus on repeat damagers, and is working with Technical Safety BC to reduce line hits. In addition, FEI recently implemented the installation of marker tape above new underground gas assets. While BC One Call ticket volume once again decreased in 2020, mainly due to efficiency gains realized through new software introduced by BC One call, line damages also decreased. For 2021, BC One Call ticket volume is trending upward year-to-date as a result of improved awareness and higher than expected construction activities.

Table 13-5: Historical Public Contact with Gas Lines Results

Description	2014	2015	2016	2017	2018	2019	2020	June 2021 YTD
Annual Results	9	8	8	9	8	7	7	6
Benchmark	16						8	
Threshold	16						12	
BC One Call Ticket Volume	107,509	122,627	129,645	146,868	157,708	144,413	141,262	86,673
Line Damages	954	1,035	1,086	1,247	1,201	1,069	973	484

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

First Contact Resolution

First Contact Resolution (FCR) measures the percentage of customers who receive resolution to their issue in one contact with FEI. 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 2020 result was 81 percent which was better than the benchmark of 78 percent. This result excludes surveys from March 23 to May 3, 2020, as all Service Quality Measurement (SQM) surveys were suspended during that time due to the COVID-19 pandemic. The June 2021 year-to-date performance is 79 percent, which is slightly above the benchmark.

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

Table 13-6: Historical First Contact Resolution Levels

Description	2014	2015	2016	2017	2018	2019	2020	June 2021 YTD
Annual Results	80%	81%	81%	80%	83%	81%	81%	79%
Benchmark	78%							
Threshold	74%							

Billing Index

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

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

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

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

The 2020 result was 0.62 which was better than the benchmark of 3.0. No significant billing issues occurred in 2020. The June 2021 year-to-date result is 1.04 which is also better than the benchmark.

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

Table 13-7: Calculation of 2020 Billing Index

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Accuracy (Percent of bills without a Production Issue, based on input data); Target - 99.9%	99.9988%	If (PA≥99.9%,5000*(1 - PA),100*(1.05-PA))	=5000*(1-99.9988%)	0.06
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%	98.21%	(100%-PA)*100	=(100%-98.21%)*100	1.79
Billing Service Quality Indicator; Target < 3		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0.06 +0+1.79) / 3	0.62

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

Table 13-8: Historical Billing Index Results

Description	2014	2015	2016	2017	2018	2019	2020	June 2021 YTD
Annual Results	0.89	1.06	0.57	0.75	2.63	0.44	0.62	1.04
Benchmark	5.0						3.0	
Threshold	5.0							

Meter Reading Accuracy

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

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

Factors influencing this SQI's performance include the resources available, system issues impacting the Company's billing or reading collections systems, weather conditions including road and highway conditions, and traffic related issues.

The 2020 result was 89.2 percent which was lower than the benchmark and threshold. The impact of the COVID-19 pandemic and the need for physical distancing and enhanced hygiene practices by meter readers has resulted in a larger percentage of estimated reads in both 2020 and 2021 year-to-date. The BCUC anticipated this impact in Letter L-20-20, which granted public utilities relief from meter reading, when necessary, for the duration of the State of Emergency in the Province of BC and while social distancing practices remain in place.[61]

FEI continues to work closely with its meter reading service provider, Olameter, to achieve as many actual meter reads as safely possible during the pandemic. In addition to using the best available historical billing information to estimate reads for billing purposes, FEI is working with some customers to acquire additional information to support minimizing the variance between estimated and actual reads.[62]

The June 2021 year-to-date performance is 90.7 percent which is close to the threshold.

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

Table 13-9: Historical Meter Reading Accuracy Results

Description	2014	2015	2016	2017	2018	2019	2020	June 2021 YTD
Annual Results	97.0%	97.5%	96.9%	96.2%	95.4%	95.2%	89.2%	90.7%
Benchmark	95.0%							
Threshold	92.0%							

61 In BCUC Letter L-20-20, dated March 31, 2020, the BCUC stated:

The BCUC recognizes that this Pandemic greatly impacts utilities and utility customers across British Columbia as many businesses and individuals adjust to working from home, social distancing, and self-isolation. Given these difficult circumstances, the BCUC understands that utilities may not be able to conduct in-person meter reading for all customers at this time due to safety and operational concerns. As such, any public utilities regulated by the British Columbia Utilities Commission (BCUC) that are unable to estimate billings within their endorsed tariff Terms and Conditions are granted relief from meter reading, when necessary, for the duration of the State of Emergency in the Province of British Columbia and while social distancing practices remain in place.

In place of meter readings, when necessary, energy consumption may be estimated from best available sources and evidence for billing purposes. When the next actual meter reading is completed, customers' bills must then be adjusted for the difference between estimated and actual use over the interval between meter readings.

62 For example, where capacity is available, FEI is proactively contacting customers with multiple estimates in a row to determine if a customer provided read is possible to support the estimation.

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:

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

Similar to the TSF (Emergency), this 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 non-emergency 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 2020 result was 70 percent which meets the benchmark of 70 percent. The June 2021 year-to-date performance is 66 percent which is lower than the threshold.

In January and the early part of February 2021, the contact centres experienced a challenging mix of call volumes and high average handle time that resulted in non-emergency telephone service factors for each month being below threshold levels. Opportunities to enhance operational activities and processes were identified and performance returned to above threshold levels in March, with performance at or above threshold levels being sustained since that time. Due to the large volume experienced in the first quarter of the year compared to the rest of the year, the year-to-date performance as at June remains below threshold; however, FEI expects that the annual performance threshold will be met should the current performance levels continue as expected. Despite challenges with the telephone service factor and average speed of answer in the early part of the year, the overall impact on customer experience and service quality has been mitigated by continued strong performance with first contact resolution. As such, the customer service index has remained high throughout the period.

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

Table 13-10: Historical TSF (Non-Emergency) Results

Description	2014	2015	2016	2017	2018	2019	2020	June 2021 YTD
Annual Results	75%	71%	71%	71%	71%	71%	70%	66%
Benchmark[63]	75%	70%						
Threshold	68%							

Meter Exchange Appointments

The Meter Exchange Appointments SQI measures FEI's performance in meeting appointments for meter exchanges (excluding industrial meters). The calculation for percentage meter exchange appointments met is calculated as:

$$\frac{\text{Number of meter exchange appointments met}}{\text{Number of meter exchange appointments made}}$$

Factors influencing results include processes, number of emergencies, weather, and traffic conditions. The processes require the contact centre and operations departments to work closely together in order to better meet the needs of customers and match resources to appointments while maintaining emergency response capabilities.

The 2020 result was 98.1 percent which was better than the benchmark of 95 percent.[64] The June 2021 year-to-date performance is 98.4 percent, which is also better than the benchmark.

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

Table 13-11: Historical Meter Exchange Appointment Results

Description	2014	2015	2016	2017	2018	2019	2020	June 2021 YTD
Annual Results	95.5%	96.6%	96.9%	97.0%	96.3%	96.0%	98.1%	98.4%
Benchmark	95.0%							
Threshold	93.8%							

[63] The 2014 result was achieved with the Company targeting 75 percent as the benchmark. The BCUC approved the revised target of 70 percent in mid-September 2014. In 2015 and subsequent years, actual results were reflective of the revised target of 70 percent.

[64] The Meter Exchange program was suspended in April and May due to the COVID-19 pandemic with limited resumption of meter exchange activities in June. The Meter Exchange program ramped up July through October and resumed normal operation in November, completing 26,000 meter exchanges by year end.

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 mass market commercial customers. The survey is conducted quarterly and results are presented as a score out of ten.

The annual CSI score for 2020 was 8.7, the same as that obtained in 2019. There were no statistically significant shifts from 2019 to 2020 in the five measures that make up the overall customer satisfaction score. The scores for overall satisfaction, satisfaction with the accuracy of meter reading, and energy conservation metrics were static at 8.7, 8.5, and 7.9 respectively. The score for satisfaction with the contact centre decreased from 8.8 in 2019 to 8.7 in 2020, while the score for the satisfaction with field services metric increased from 9.0 in 2019 to 9.2 in 2020. None of these changes are statistically significant.

The score for 2021 year-to-date is 8.7 and the same as the 8.7 annual score recorded for 2020. Of the five measures that make up the overall customer satisfaction score, the results for June 2021 year-to-date were higher in one area, static in two and lower in two when compared to the annual 2020 scores. The score for satisfaction with field services increased from 9.2 in 2020 to 9.4 in 2021. The scores for satisfaction with the accuracy of meter reading and energy conservation information decreased from 8.5 to 8.4 and 7.9 to 7.7, respectively. The scores for overall satisfaction and for satisfaction with the contact centre remained static at 8.7. None of these changes are statistically significant.

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

Table 13-12: Historical Customer Satisfaction Results

Description	2014	2015	2016	2017	2018	2019	2020	June 2021 YTD
Annual Results	8.5	8.6	8.8	8.4	8.7	8.7	8.7	8.7
Benchmark	n/a							
Threshold	n/a							

Average Speed of Answer

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

The 2020 result was 72 seconds and was affected by the COVID-19 pandemic. The June 2021 year-to-date performance is 80 seconds. As described above, challenges experienced in the contact centre in January and February of 2021 resulted in monthly non-emergency TSF performance levels below the threshold. Comparatively, the ASA also experienced challenges during January and February and, aligned with the recovery to threshold levels of TSF, the monthly ASA also returned to typical levels of less than one minute beginning in March. Relative to previous years, both 2020 and 2021 are higher; however, they remain within a reasonable range from a customer experience perspective in that, on average for the year, calls to the contact centre were answered in just over one minute in 2020 and currently approximately one minute and thirty seconds in 2021.

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

Table 13-13: Average Speed of Answer

Description	2014	2015	2016	2017	2018	2019	2020	June 2021 YTD
Annual Results	34	37	40	34	35	39	72	80
Benchmark	n/a							
Threshold	n/a							

13.2.3 Reliability Service Quality Indicators

Transmission Reportable Incidents

The Transmission Reportable Incidents metric is an informational indicator that measures the number of reportable incidents to outside agencies for transmission assets as defined by the Oil and Gas Commission (OGC). The metric is intended to be an indicator of the integrity of the transmission system.

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

The incident in 2020 was a very minor leak found on a dent during an integrity dig. It was temporarily repaired at the time of discovery by installing a sleeve over the dent. The dented pipe is scheduled to be replaced in 2021.

Table 13-14: Historical Transmission Reportable Incidents

Description	2014	2015	2016	2017	2018	2019	2020	June 2021 YTD
Annual Results – Level 1	1	3	3	4	2	0	1	0
Annual Results – Level 2	1	0	0	0	0	0	0	0
Annual Results – Level 3	0	0	0	0	0	0	0	0
Benchmark	n/a							
Threshold	n/a							

Leaks per KM of Distribution System Mains

The Leaks per KM of Distribution System Mains metric is an informational indicator that measures the number of leaks on the distribution system per KM of distribution system mains. The metric is intended to be an indicator of the integrity of the distribution system. Each year, approximately one fifth of the distribution system is surveyed for leaks, with the number of leaks varying from year to year, depending on the condition of the pipe surveyed.

Variability in the number of leaks detected is influenced by the timing of the leak survey program as well as the condition of the distribution system, as some sections of the pipeline system are more prone to leaks depending on soil conditions, age of the pipelines, pipeline material and the location of the pipeline. As the distribution system ages, the expected number of leaks may increase depending on the Company's pipeline renewal/replacement activities. Increases in leak survey activity levels will generally also result in a higher number of leaks detected.

In its Decision on FEI's Annual Review of 2015 Delivery Rates, the BCUC directed FEI to provide a five-year rolling average as follows:

> The Panel agrees with BCSEA that a five-year rolling average of Leaks per KM of Distribution System Mains would be helpful information and directs FEI to provide this information in future annual reviews.

Table 13-15 below provides the historical data for the calculation of the June 2021 year-to-date five-year rolling average result of 0.0053 calculated using data from July 2016 to June 2021.

Table 13-15: June 2021 Year-to-Date Five Year Rolling Average

Period	Metric
July – December 2016	0.0022
January – December 2017	0.0047
January – December 2018	0.0047
January – December 2019	0.0061
January – December 2020	0.0060
January – June 2021	0.0030
Five Year Rolling Average	0.0053

The Company's 2014 to 2020 annual results are provided below. The five-year average for each year shown is calculated by taking the average of the results of the stated year and the four years prior (e.g. the 2020 five-year average is calculated using 2016 to 2020 annual data). The June 2021 year-to-date result is 0.0030, which is based on 70 leaks detected year-to-date, which is equal to the 2020 and 2019 results for the similar time period.

Table 13-16: Historical Leaks per KM of Distribution System Mains

Leaks per KM of Distribution System Mains	2014	2015	2016	2017	2018	2019	2020	June 2021 YTD
Leaks	114	102	107	108	140	139	152	70
Total km	19,172	22,602	22,813	22,951	23,060	23,268	23,460	23,707
Leaks per km	0.0059	0.0045	0.0047	0.0047	0.0061	0.0060	0.0065	0.0030
5 year average	0.0077	0.0071	0.0063	0.0055	0.0052	0.0051	0.0056	0.0053

The number of leaks on DP mains will vary from year to year. FEI does not expect the number of leaks to be a continuing trend.

13.3 *SUMMARY*

In summary, FEI's 2020 results and June 2021 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2020, for those SQIs with benchmarks, eight performed at or better than the approved benchmarks with the Meter Reading Accuracy metric performance lower than the threshold due to the impact of the COVID-19 pandemic. For the four SQIs that are informational only, performance generally remains at a level consistent with prior years.

Appendix A

DEMAND FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: Consumer Price Index (CPI)

Products and product groups[3, 4]	Reference period	British Columbia(map)
		2002=100
All-items	July 2019	132.4
	August 2019	132.2
	September 2019	132.0
	October 2019	132.2
	November 2019	131.8
	December 2019	131.7
	January 2020	132.1
	February 2020	132.9
	March 2020	132.3
	April 2020	131.2
	May 2020	131.5
	June 2020	132.6
	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

Table A1-2: Average Weekly Earnings (AWE)

		Average weekly earnings including overtime for all employees[6]
Geography	Reference period	Industrial aggregate excluding unclassified businesses[6, 7]
		Dollars
British Columbia(map)	July 2019	995.70[A]
	August 2019	1,003.20[A]
	September 2019	1,007.69[B]
	October 2019	1,015.61[B]
	November 2019	1,012.26[B]
	December 2019	1,014.87[B]
	January 2020	1,025.98[B]
	February 2020	1,024.80[B]
	March 2020	1,029.14[B]
	April 2020	1,105.84[B]
	May 2020	1,127.73[B]
	June 2020	1,097.00[B]
	July 2020	1,095.17[B]
	August 2020	1,089.30[B]
	September 2020	1,092.97[B]
	October 2020	1,093.25[B]
	November 2020	1,098.85[B]
	December 2020	1,109.54[B]
	January 2021	1,115.13[B]
	February 2021	1,114.34[B]
	March 2021	1,104.90[B]
	April 2021	1,110.80[B]

Table A1-3: Provincial Outlook Long-Term Economic Forecast 2021

Housing Type	**2018**	**2019**	**2020**	**2021**	**2022**
Housing Starts, Singles, British Columbia	11,163	8,792	8,519	6,823	6,099
SFD Forecast Percent Change		**-21.2%**	**-3.1%**	**-19.9%**	**-10.6%**
Housing Starts, Multiples, British Columbia	29,694	36,140	29,215	25,565	25,466
MFD Forecast Percent Change		**21.7%**	**-19.2%**	**-12.5%**	**-0.4%**
Total	40,857	44,932	37,734	32,388	31,566

Source:
The Conference Board of Canada
Provincial Outlook Long-Term Economic Forecast 2021
April 29th, 2021

Appendix A-2

Historical Forecast and Consolidated Tables

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List of Appendices

1. INTRODUCTION

This appendix presents two data sets as follows:

1. Historical and Forecast Data
    a. 2011 – 2020 Actual data
    b. 2021 Seed data
    c. 2022 Forecast data
2. Percent Error
    a. 2011 - 2020 Forecast, Actual and percent error

2. HISTORICAL AND FORECAST DATA TABLES

Table A2-1: FEI Customer Counts, Customer Additions, Use per Customer, and Energy[1]

FEI Customer Counts

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021S	2022F
RS 1	860,403	854,050	863,189	873,661	886,169	897,528	910,885	930,142	940,751	953,746	964,530	974,625
RS 2	85,704	81,123	82,452	83,625	85,076	86,074	86,973	88,244	88,686	89,363	90,160	90,956
RS 3	5,451	5,220	5,134	5,169	5,301	5,189	5,441	6,028	6,973	6,805	6,920	7,034
RS 23	1,433	1,520	1,529	1,522	1,724	1,803	1,712	1,648	871	746	764	782
Industrial	951	954	981	977	976	955	976	989	1,020	1,023	1,017	1,029
NGT	2	5	10	18	31	42	56	41	53	69	83	83
Total	953,943	942,872	953,295	964,971	979,277	991,591	1,006,043	1,027,092	1,038,354	1,051,752	1,063,473	1,074,510

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021S	2022F
RS 1	6,911	6,371	9,139	10,472	12,508	11,359	13,357	19,257	10,609	12,995	10,784	10,096
RS 2	511	577	1,329	1,173	1,450	998	899	1,271	442	677	797	797
RS 3	-16	-104	-86	35	132	-112	252	587	945	-168	115	115
RS 23	27	88	9	-7	202	79	-91	-64	-777	-125	18	18
Industrial	-66	8	27	-4	-1	-21	21	13	31	3	-6	12
NGT	2	3	5	8	13	11	14	-15	12	16	14	0
Total	7,369	6,943	10,423	11,676	14,305	12,314	14,452	21,049	11,262	13,398	11,721	11,037

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021S	2022F
RS 1	86.3	87.6	84.7	84.2	84.4	87.5	85.8	85.1	82.4	86.2	84.2	84.1
RS 2	317.7	341.2	331.6	330.6	332.6	339.1	336.8	332.5	318.1	322.2	321.3	320.4
RS 3	3,588	3,684	3,610	3,573	3,587	3,721	3,692	3,550	3,517	3,660	3,565	3,557
RS 23	5,138	5,238	5,149	5,260	5,174	5,279	5,361	5,345	5,051	5,441	5,366	5,365

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021S	2022F
RS 1	73.9	74.5	72.7	73.2	74.1	77.9	77.5	78.3	77.0	81.6	80.8	81.5
RS 2	27.1	27.6	27.0	27.5	28.0	29.0	29.1	29.1	28.1	28.7	28.8	29.0
RS 3	19.5	19.3	18.7	18.5	19.2	19.4	19.7	20.9	22.5	24.6	24.5	24.9
RS 23	7.4	7.8	7.9	8.0	8.6	9.3	9.5	9.0	7.3	4.6	4.0	4.1
Industrial	78.8	80.6	80.1	78.6	79.6	83.7	87.4	88.4	91.5	89.5	88.6	88.9
Sub-Total	206.6	209.7	206.3	205.7	209.5	219.3	223.3	225.8	226.4	229.0	226.7	228.4
NGT	0.1	0.2	0.3	0.8	1.1	1.3	1.8	1.6	2.6	2.6	3.3	5.7
Total	206.7	209.9	206.6	206.5	210.6	220.6	225.0	227.3	229.0	231.7	230.0	234.1

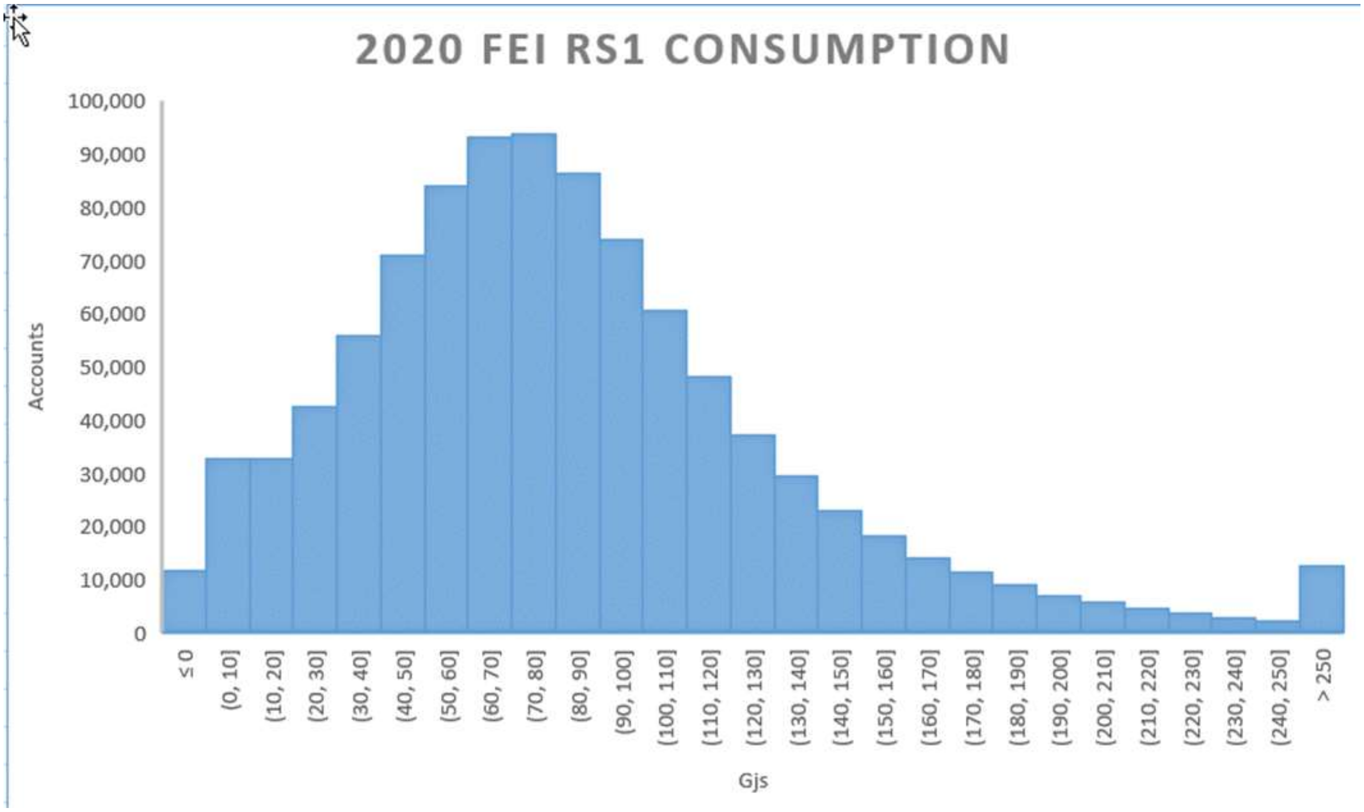
(1) Historical industrial tables do not include Burrard Thermal demand.

Table A2-2: FEI 2022F Industrial Forecast Demand by Region[2]

Industrial	Demand (Pjs)
Mainland	66.1
Vancouver Island	22.7
Whistler	0.1
Total	88.9

[1] Historical industrial tables do not include Burrard Thermal demand.
[2] Does not include NGT forecast demand.

1 **Figure A2-1: FEI Residential Customers Normalized UPC in 2020**



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3. PERCENT ERROR DATA TABLES

In the data tables presented below, FEI provides 10 years of historical actual demand, forecast demand and percent error for each customer class and service area and on a consolidated (or amalgamated) basis, for total demand, total net customers, net customer additions and use per customer. The data tables are also provided as fully-functional Excel file in Appendix A2-1.

Percent error is the difference between the actual demand and the forecast demand, divided by the actual demand in a given year, or stated as a formula:

$$PE_t = \left(\frac{Y_t - F_t}{Y_t}\right) \times 100$$

Where F_t is the forecast at time t and Y_t is the actual value at time t.

The tables provided below present the historical data in amalgamated form, unless specifically identified for a particular region. In order to provide historical amalgamated data, FEI mapped the Vancouver Island and Whistler customers to FEI rate schedules for periods prior to 2015. This mapping was completed using the mapping approved for the purposes of amalgamation presented in FEI's Common Rates Methodology Application, Section 4.2, as approved by BCUC Order G-131-14.

3.1 *AMALGAMATED NET CUSTOMERS*

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1										
Forecast	857,592	870,980	880,331	866,852	883,371	892,830	909,727	916,365	934,804	950,330
Actual	860,403	854,050	863,189	873,661	886,169	897,528	910,885	930,142	940,751	953,746
Error = (ACT-FCST)	2,811	(16,930)	(17,142)	6,809	2,798	4,698	1,158	13,777	5,947	3,416
Percent Error = (Error/ACT)	0.3%	-2.0%	-2.0%	0.8%	0.3%	0.5%	0.1%	1.5%	0.6%	0.4%

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2										
Forecast	87,262	85,482	85,627	81,923	84,651	85,667	87,712	88,494	89,203	89,558
Actual	85,704	81,123	82,452	83,625	85,076	86,074	86,973	88,244	88,686	89,363
Error = (ACT-FCST)	(1,558)	(4,359)	(3,175)	1,702	425	407	(739)	(250)	(517)	(195)
Percent Error = (Error/ACT)	-1.8%	-5.4%	-3.9%	2.0%	0.5%	0.5%	-0.8%	-0.3%	-0.6%	-0.2%

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3										
Forecast	5,785	5,553	5,597	5,147	5,117	5,035	5,354	5,223	5,623	7,221
Actual	5,451	5,220	5,134	5,169	5,301	5,189	5,441	6,028	6,973	6,805
Error = (ACT-FCST)	(334)	(333)	(463)	22	184	154	87	805	1,350	(416)
Percent Error = (Error/ACT)	-6.1%	-6.4%	-9.0%	0.4%	3.5%	3.0%	1.6%	13.4%	19.4%	-6.1%

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23										
Forecast	1,328	1,526	1,586	1,634	1,552	1,670	1,760	1,934	1,744	906
Actual	1,433	1,520	1,529	1,522	1,724	1,803	1,712	1,648	871	746
Error = (ACT-FCST)	105	(6)	(57)	(112)	172	133	(48)	(286)	(873)	(160)
Percent Error = (Error/ACT)	7.3%	-0.4%	-3.7%	-7.4%	10.0%	7.4%	-2.8%	-17.4%	-100.2%	-21.4%

3.2 *AMALGAMATED NET CUSTOMER ADDITIONS*

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1										
Forecast	7,724	8,984	9,352	6,647	9,710	9,461	11,522	9,141	10,724	9,579
Actual	6,911	6,371	9,139	10,472	12,508	11,359	13,357	19,257	10,609	12,995
Error = (ACT-FCST)	(813)	(2,613)	(213)	3,825	2,798	1,898	1,835	10,116	(115)	3,416
Percent Error = (Error/ACT)	-11.8%	-41.0%	-2.3%	36.5%	22.4%	16.7%	13.7%	52.5%	-1.1%	26.3%

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2										
Forecast	877	145	145	411	1,026	1,026	1,318	1,210	1,115	872
Actual	511	577	1,329	1,173	1,450	998	899	1,271	442	677
Error = (ACT-FCST)	(366)	432	1,184	762	424	(28)	(419)	61	(673)	(195)
Percent Error = (Error/ACT)	-71.6%	74.9%	89.1%	65.0%	29.2%	-2.8%	-46.6%	4.8%	-152.3%	-28.8%

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3										
Forecast	114	44	44	4	(52)	(51)	26	19	91	248
Actual	(16)	(104)	(86)	35	132	(112)	252	587	945	(168)
Error = (ACT-FCST)	(130)	(148)	(130)	31	184	(61)	226	568	854	(416)
Percent Error = (Error/ACT)	812.5%	142.3%	151.2%	88.6%	139.4%	54.5%	89.7%	96.8%	90.4%	247.6%

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23										
Forecast	9	60	60	57	30	30	18	66	16	35
Actual	27	88	9	(7)	202	79	(91)	(64)	(777)	(125)
Error = (ACT-FCST)	18	28	(51)	(64)	172	49	(109)	(130)	(793)	(160)
Percent Error = (Error/ACT)	66.7%	31.8%	-566.7%	914.3%	85.1%	62.0%	119.8%	203.1%	102.1%	128.0%

3.3 AMALGAMATED NORMALIZED USE PER CUSTOMER

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1										
Forecast	86.5	86.3	85.2	86.0	83.1	81.6	82.2	89.1	87.0	85.7
Actual	86.3	87.6	84.7	84.2	84.4	87.5	85.8	85.1	82.4	86.2
Error = (ACT-FCST)	(0.2)	1.3	(0.5)	(1.8)	1.3	5.9	3.7	(4.0)	(4.6)	0.4
Percent Error = (Error/ACT)	-0.2%	1.5%	-0.6%	-2.1%	1.5%	6.7%	4.3%	-4.7%	-5.6%	0.5%

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2										
Forecast	320.2	315.0	314.5	340.0	333.7	329.5	328.4	345.2	341.3	324.9
Actual	317.7	341.2	331.6	330.6	332.6	339.1	336.8	332.5	318.1	322.2
Error = (ACT-FCST)	(2.5)	26.2	17.1	(9.4)	(1.1)	9.6	8.3	(12.7)	(23.2)	(2.7)
Percent Error = (Error/ACT)	-0.8%	7.7%	5.2%	-2.8%	-0.3%	2.8%	2.5%	-3.8%	-7.3%	-0.8%

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3										
Forecast	3,487	3,450	3,435	3,872	3,754	3,593	3,488	3,842	3,831	3,648
Actual	3,588	3,684	3,610	3,573	3,587	3,721	3,692	3,550	3,517	3,660
Error = (ACT-FCST)	101	234	175	(299)	(167)	128	205	(292)	(314)	12
Percent Error = (Error/ACT)	2.8%	6.4%	4.8%	-8.4%	-4.7%	3.4%	5.5%	-8.2%	-8.9%	0.3%

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23										
Forecast	4,680	4,901	4,927	5,546	5,309	5,382	5,227	5,399	5,492	5,480
Actual	5,138	5,238	5,149	5,260	5,174	5,279	5,361	5,345	5,051	5,441
Error = (ACT-FCST)	458	337	222	(286)	(135)	(103)	133	(54)	(440)	(39)
Percent Error = (Error/ACT)	8.9%	6.4%	4.3%	-5.4%	-2.6%	-2.0%	2.5%	-1.0%	-8.7%	-0.7%

3.4 AMALGAMATED DEMAND

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1										
Forecast	73.8	74.7	74.6	74.2	73.1	72.5	74.3	81.2	80.8	81.1
Actual	73.9	74.5	72.7	73.2	74.1	77.9	77.5	78.3	77.0	81.6
Error = (ACT-FCST)	0.1	(0.2)	(1.9)	(1.0)	1.0	5.4	3.3	(2.9)	(3.7)	0.5
Percent Error = (Error/ACT)	0.1%	-0.3%	-2.6%	-1.4%	1.3%	6.9%	4.2%	-3.7%	-4.9%	0.6%

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2										
Forecast	27.7	26.9	26.9	27.7	28.1	28.0	28.5	30.3	30.2	28.9
Actual	27.1	27.6	27.0	27.5	28.0	29.0	29.1	29.1	28.1	28.7
Error = (ACT-FCST)	(0.6)	0.7	0.1	(0.2)	(0.1)	1.0	0.6	(1.2)	(2.1)	(0.2)
Percent Error = (Error/ACT)	-2.2%	2.5%	0.4%	-0.7%	-0.4%	3.4%	2.0%	-4.3%	-7.4%	-0.8%

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3										
Forecast	19.9	19.1	19.1	19.9	19.2	18.1	18.7	20.1	21.5	25.2
Actual	19.5	19.3	18.7	18.5	19.2	19.4	19.7	20.9	22.5	24.6
Error = (ACT-FCST)	(0.4)	0.2	(0.4)	(1.4)	(0.0)	1.3	1.0	0.9	1.0	(0.6)
Percent Error = (Error/ACT)	-2.1%	1.0%	-2.1%	-7.6%	-0.2%	6.7%	5.2%	4.1%	4.3%	-2.4%

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23										
Forecast	6.2	7.2	7.5	8.7	8.3	9.0	9.2	10.3	9.6	4.8
Actual	7.4	7.8	7.9	8.0	8.6	9.3	9.5	9.0	7.3	4.6
Error = (ACT-FCST)	1.2	0.6	0.4	(0.7)	0.3	0.3	0.4	(1.3)	(2.3)	(0.2)
Percent Error = (Error/ACT)	16.2%	7.7%	5.1%	-8.7%	3.5%	3.2%	3.9%	-13.9%	-31.3%	-5.2%

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Commercial										
Forecast	53.8	53.2	53.5	56.3	55.6	55.1	56.4	60.7	61.3	59.0
Actual	54.0	54.7	53.6	54.0	55.8	57.7	58.3	59.0	57.9	57.9
Error = (ACT-FCST)	0.2	1.5	0.1	(2.3)	0.2	2.6	2.0	(1.6)	(3.4)	(1.1)
Percent Error = (Error/ACT)	0.4%	2.7%	0.2%	-4.3%	0.3%	4.5%	3.4%	-2.8%	-5.9%	-1.9%

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate 5										
Forecast	5.2	4.0	4.0	3.9	3.5	2.2	2.2	2.5	2.9	7.6
Actual	4.3	4.0	3.8	3.4	2.3	2.4	2.8	3.8	4.8	8.1
Error = (ACT-FCST)	(0.9)	0.0	(0.2)	(0.5)	(1.2)	0.3	0.7	1.3	1.9	0.5
Percent Error = (Error/ACT)	-21%	0%	-5%	-15%	-52%	11%	23%	34%	40%	6%

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate 25										
Forecast	13.8	13.4	13.5	13.3	13.9	13.8	13.8	14.4	14.8	10.3
Actual	13.2	12.9	13.1	13.4	13.7	13.9	14.5	13.9	13.2	9.9
Error = (ACT-FCST)	(0.6)	(0.5)	(0.4)	0.1	(0.2)	0.1	0.7	(0.5)	(1.7)	(0.4)
Percent Error = (Error/ACT)	-5%	-4%	-3%	1%	-1%	1%	5%	-3%	-13%	-4%

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate 22										
Forecast	27.1	29.7	29.6	43.2	33.2	36.3	38.2	38.5	43.3	41.0
Actual	34.9	38.0	36.4	36.0	37.0	40.5	40.9	42.0	43.3	39.0
Error = (ACT-FCST)	7.8	8.3	6.8	(7.2)	3.8	4.2	2.6	3.5	0.1	(2.0)
Percent Error = (Error/ACT)	22%	22%	19%	-20%	10%	10%	6%	8%	0%	-5%

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate 27										
Forecast	5.6	5.8	5.8	6.5	6.6	6.5	6.4	7.3	7.9	4.7
Actual	6.6	6.4	7.5	6.6	7.2	6.8	7.5	6.2	5.9	4.6
Error = (ACT-FCST)	1.0	0.6	1.7	0.1	0.5	0.3	1.1	(1.1)	(2.0)	(0.1)
Percent Error = (Error/ACT)	15%	9%	23%	2%	7%	4%	14%	-17%	-34%	-1%

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Industrial*										
Forecast	71.3	72.1	72.1	86.2	76.4	78.1	82.1	84.3	90.6	91.9
Actual	78.8	80.6	80.1	78.6	79.6	83.7	87.4	88.4	91.5	89.5
Error = (ACT-FCST)	7.5	8.5	8.0	(7.6)	3.2	5.6	5.3	4.2	0.9	(2.4)
Percent Error = (Error/ACT)	9.5%	10.5%	10.0%	-9.7%	4.0%	6.7%	6.0%	4.7%	1.0%	-2.7%

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
FEI										
Forecast	198.9	200.0	200.2	216.7	205.2	205.7	212.8	226.2	232.6	232.0
Actual	206.7	209.8	206.4	205.8	209.5	219.3	223.3	225.8	226.4	229.0
Error = (ACT-FCST)	7.8	9.8	6.2	(10.9)	4.3	13.6	10.5	(0.4)	(6.2)	(2.9)
Percent Error = (Error/ACT)	3.8%	4.7%	3.0%	-5.3%	2.1%	6.2%	4.7%	-0.2%	-2.7%	-1.3%

*Excld NGT and Burrard

3.5 MAINLAND NET CUSTOMERS

Mainland Customers	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1										
Forecast	762,460	773,231	780,005	768,622	780,972	787,836	799,732	803,319	813,959	823,255
Actual	765,553	759,712	766,668	774,083	782,914	790,562	798,917	811,696	817,817	826,142
Error = (ACT-FCST)	3,093	(13,519)	(13,337)	5,461	1,942	2,726	(815)	8,377	3,858	2,887
Percent Error = (Error/ACT	0.4%	-1.8%	-1.7%	0.7%	0.2%	0.3%	-0.1%	1.0%	0.5%	0.3%

Mainland Customers	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2										
Forecast	77,954	76,126	76,175	72,922	75,315	76,166	77,597	78,228	78,767	79,027
Actual	76,437	72,235	73,480	74,464	75,451	76,326	77,047	78,044	78,351	78,941
Error = (ACT-FCST)	(1,517)	(3,891)	(2,695)	1,542	136	160	(550)	(184)	(416)	(86)
Percent Error = (Error/ACT	-2.0%	-5.4%	-3.7%	2.1%	0.2%	0.2%	-0.7%	-0.2%	-0.5%	-0.1%

Mainland Customers	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3										
Forecast	5,191	4,962	5,002	4,577	4,560	4,497	4,667	4,608	5,029	6,545
Actual	4,863	4,675	4,598	4,625	4,671	4,605	4,867	5,478	6,291	6,046
Error = (ACT-FCST)	(328)	(287)	(404)	48	111	108	200	870	1,262	(499)
Percent Error = (Error/ACT	-6.7%	-6.1%	-8.8%	1.0%	2.4%	2.3%	4.1%	15.9%	20.1%	-8.3%

Mainland Customers	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23										
Forecast	1,328	1,526	1,586	1,634	1,552	1,582	1,609	1,669	1,562	836
Actual	1,433	1,520	1,529	1,522	1,573	1,614	1,546	1,458	800	708
Error = (ACT-FCST)	105	(6)	(57)	(112)	21	32	(63)	(211)	(762)	(128)
Percent Error = (Error/ACT	7.3%	-0.4%	-3.7%	-7.4%	1.3%	2.0%	-4.1%	-14.5%	-95.3%	-18.1%

3.6 *MAINLAND NET CUSTOMER ADDITIONS*

Mainland Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1											
Forecast	4,777	4,983	6,507	6,774	4,594	6,889	6,863	8,250	6,203	6,756	5,438
Actual	6,824	4,994	4,475	6,956	7,415	8,831	7,648	8,355	12,779	6,121	8,325
Error = (ACT-FCST)	2,047	11	(2,032)	182	2,821	1,942	785	105	6,576	(635)	2,887
Percent Error = (Error/ACT)	30.0%	0.2%	-45.4%	2.6%	38.0%	22.0%	10.3%	1.3%	51.5%	-10.4%	34.7%

Mainland Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2											
Forecast	713	750	49	49	331	851	851	1,072	951	860	676
Actual	42	409	325	1,245	984	987	875	721	997	307	590
Error = (ACT-FCST)	(671)	(341)	276	1,196	653	136	24	(351)	46	(553)	(86)
Percent Error = (Error/ACT)	-1597.6%	-83.4%	84.9%	96.1%	66.4%	13.7%	2.7%	-48.7%	4.6%	-180.1%	-14.6%

Mainland Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3											
Forecast	101	108	40	40	-	(65)	(64)	(1)	2	81	254
Actual	41	(19)	(144)	(77)	27	46	(66)	262	611	813	(245)
Error = (ACT-FCST)	(60)	(127)	(184)	(117)	27	111	(2)	263	609	732	(499)
Percent Error = (Error/ACT)	-146.3%	668.4%	127.8%	151.9%	100.0%	241.3%	3.0%	100.4%	99.7%	90.0%	203.7%

Mainland Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23											
Forecast	9	9	60	60	57	30	30	18	28	8	36
Actual	58	27	88	9	(7)	51	41	(68)	(88)	(658)	(92)
Error = (ACT-FCST)	49	18	28	(51)	(64)	21	11	(86)	(116)	(666)	(128)
Percent Error = (Error/ACT)	84.5%	66.7%	31.8%	-566.7%	914.3%	41.2%	26.8%	126.5%	131.8%	101.2%	139.1%

3.7 MAINLAND NORMALIZED USE PER CUSTOMER

Mainland UPC GJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1										
Forecast	90.3	90.8	89.9	90.7	88.1	86.3	86.2	93.5	91.5	90.8
Actual	90.4	92.2	89.3	88.8	88.7	92.0	90.4	89.7	87.1	91.1
Error = (ACT-FCST)	0.1	1.4	(0.6)	(1.9)	0.6	5.7	4.2	(3.8)	(4.5)	0.3
Percent Error = (Error/ACT)	0.1%	1.5%	-0.7%	-2.1%	0.7%	6.2%	4.6%	-4.2%	-5.1%	0.4%

Mainland UPC GJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2										
Forecast	318	308	306	334	329	329	327	345	339	324
Actual	314	338	330	330	330	338	335	329	316	322
Error = (ACT-FCST)	(4)	30	23	(3)	1	10	8	(15)	(23)	(2)
Percent Error = (Error/ACT)	-1.3%	8.8%	7.0%	-1.0%	0.2%	2.8%	2.4%	-4.6%	-7.3%	-0.6%

Mainland UPC GJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3										
Forecast	3,347	3,334	3,316	3,769	3,599	3,537	3,517	3,770	3,746	3,640
Actual	3,484	3,566	3,517	3,529	3,524	3,658	3,625	3,477	3,468	3,682
Error = (ACT-FCST)	137	232	201	(240)	(75)	121	108	(293)	(278)	42
Percent Error = (Error/ACT)	3.9%	6.5%	5.7%	-6.8%	-2.1%	3.3%	3.0%	-8.4%	-8.0%	1.1%

Mainland UPC GJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23										
Forecast	4,680	4,901	4,927	5,546	5,309	5,348	5,197	5,416	5,521	5,537
Actual	5,138	5,238	5,149	5,260	5,157	5,304	5,388	5,357	5,127	5,497
Error = (ACT-FCST)	458	337	222	(286)	(152)	(44)	191	(59)	(394)	(41)
Percent Error = (Error/ACT)	8.9%	6.4%	4.3%	-5.4%	-2.9%	-0.8%	3.5%	-1.1%	-7.7%	-0.7%

3.8 MAINLAND NORMALIZED DEMAND

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1										
Forecast	68.6	69.9	69.8	69.5	68.5	67.7	68.6	74.8	74.2	74.5
Actual	68.9	69.8	68.1	68.5	68.9	72.3	71.8	72.2	70.9	74.9
Error = (ACT-FCST)	0.4	(0.1)	(1.7)	(1.0)	0.4	4.6	3.2	(2.6)	(3.2)	0.4
Percent Error = (Error/ACT)	0.5%	-0.2%	-2.5%	-1.5%	0.5%	6.4%	4.5%	-3.6%	-4.6%	0.5%
ABS	0.5%	0.2%	2.5%	1.5%	0.5%	6.4%	4.5%	3.6%	4.6%	0.5%

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2										
Forecast	24.6	23.4	23.3	24.2	24.7	24.9	25.2	26.7	26.5	25.5
Actual	23.9	24.3	23.9	24.5	24.6	25.6	25.7	25.5	24.7	25.3
Error = (ACT-FCST)	(0.7)	0.9	0.6	0.2	(0.0)	0.7	0.5	(1.3)	(1.8)	(0.1)
Percent Error = (Error/ACT)	-3.0%	3.6%	2.5%	0.9%	-0.2%	2.7%	2.0%	-5.0%	-7.3%	-0.5%

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3										
Forecast	17.2	16.5	16.5	17.3	16.4	16.0	16.4	17.4	18.8	22.6
Actual	16.9	16.7	16.3	16.3	16.5	16.8	17.3	18.5	20.1	22.1
Error = (ACT-FCST)	(0.3)	0.2	(0.2)	(1.0)	0.0	0.8	0.9	1.2	1.3	(0.5)
Percent Error = (Error/ACT)	-1.8%	1.2%	-1.2%	-6.1%	0.3%	5.0%	5.4%	6.3%	6.4%	-2.4%

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23										
Forecast	6.2	7.2	7.5	8.7	8.3	8.4	8.3	9.0	8.6	4.5
Actual	7.4	7.8	7.9	8.0	8.0	8.4	8.6	8.1	6.6	4.3
Error = (ACT-FCST)	1.2	0.6	0.4	(0.7)	(0.3)	-	0.3	(0.8)	(2.0)	(0.2)
Percent Error = (Error/ACT)	16.2%	7.7%	5.1%	-8.7%	-3.3%	0.0%	3.1%	-10.4%	-30.8%	-4.8%

Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Commercial										
Forecast	48.0	47.1	47.3	50.2	49.3	49.3	49.9	53.1	53.9	52.6
Actual	48.2	48.8	48.1	48.8	49.1	50.8	51.6	52.2	51.3	51.7
Error = (ACT-FCST)	0.2	1.7	0.8	(1.5)	(0.3)	1.5	1.7	(0.9)	(2.5)	(0.9)
Percent Error = (Error/ACT)	0.4%	3.4%	1.6%	-3.0%	-0.5%	3.0%	3.3%	-1.8%	-5.0%	-1.6%

3.9 VANCOUVER ISLAND AND WHISTLER AMALGAMATED DATA

In order to provide historical amalgamated data, FEI mapped the Vancouver Island and Whistler customers to FEI rate schedules for periods prior to 2015. This mapping was completed using the mapping approved for the purposes of amalgamation presented in FEI's Common Rates

Methodology Application, Section 4.2 as approved by Order G-131-14. Tables in Sections 3.10 through 3.17 use this mapped data for historical calculations.

3.10 VANCOUVER ISLAND NET CUSTOMERS

FEVI Customers	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1										
Forecast	92,811	95,460	98,023	95,858	99,921	102,458	107,314	110,270	117,957	124,041
Actual	92,554	92,067	94,173	97,162	100,747	104,358	109,259	115,618	119,998	124,627
Error = (ACT-FCST)	(257)	(3,393)	(3,850)	1,304	826	1,900	1,945	5,348	2,041	586
Percent Error = (Error/ACT)	-0.3%	-3.7%	-4.1%	1.3%	0.8%	1.8%	1.8%	4.6%	1.7%	0.5%

FEVI Customers	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2										
Forecast	9,042	9,081	9,172	8,710	9,047	9,209	9,808	9,971	10,131	10,218
Actual	8,981	8,613	8,691	8,875	9,330	9,459	9,629	9,891	10,028	10,117
Error = (ACT-FCST)	(61)	(468)	(481)	165	283	250	(179)	(80)	(103)	(101)
Percent Error = (Error/ACT)	-0.68%	-5.43%	-5.53%	1.86%	3.03%	2.64%	-1.86%	-0.81%	-1.03%	-1.00%

FEVI Customers	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3										
Forecast	532	532	536	509	497	479	647	567	539	605
Actual	527	484	476	484	582	531	517	492	613	686
Error = (ACT-FCST)	(5)	(48)	(60)	(25)	85	52	(130)	(75)	74	81
Percent Error = (Error/ACT)	-0.95%	-9.92%	-12.61%	-5.17%	14.60%	9.79%	-25.15%	-15.24%	12.06%	11.81%

FEVI Customers	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23										
Forecast						83	141	243	164	66
Actual					141	175	152	179	67	37
Error = (ACT-FCST)					141	92	11	(64)	(97)	(29)
Percent Error = (Error/ACT)						52.57%	7.24%	-35.75%	-144.78%	-78.38%

1 ## 3.11 VANCOUVER ISLAND NET CUSTOMER ADDITIONS

FEVI Customer Additions	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1										
Forecast	2,705	2,463	2,564	2,001	2,759	2,537	3,188	2,857	3,888	4,043
Actual	1,883	1,845	2,106	2,989	3,583	3,611	4,901	6,359	4,380	4,629
Error = (ACT-FCST)	(822)	(618)	(458)	988	824	1074	1713	3502	492	586
Percent Error = (Error/ACT)	-43.7%	-33.5%	-21.7%	33.1%	23.0%	29.8%	35.0%	55.1%	11.2%	12.7%

FEVI Customer Additions	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2										
Forecast	125	91	91	71	171	171	239	256	251	190
Actual	81	251	78	184	453	129	170	262	137	89
Error = (ACT-FCST)	(44)	160	(13)	113	282	(42)	(69)	6	(114)	(101)
Percent Error = (Error/ACT)	-54.1%	63.8%	-16.4%	61.1%	62.2%	-32.6%	-40.6%	2.3%	-83.2%	-113.5%

FEVI Customer Additions	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3										
Forecast	5	4	4	4	13	13	32	19	11	(8)
Actual	2	39	(8)	8	98	(51)	(14)	(25)	121	73
Error = (ACT-FCST)	(3)	35	(12)	4	85	(64)	(46)	(44)	110	81
Percent Error = (Error/ACT)	-150.0%	89.7%	150.0%	50.0%	86.6%	125.5%	328.6%	176.0%	90.9%	111.0%

FEVI Customer Additions	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23										
Forecast						-	-	34	6	(1)
Actual					141	34	(23)	27	(112)	(30)
Error = (ACT-FCST)					141	34	(23)	(7)	(118)	(29)
Percent Error = (Error/ACT)						100.0%	100.0%	-25.9%	105.4%	96.7%

2

3.12 *VANCOUVER ISLAND NORMALIZED USE PER CUSTOMER*

FEVI UPC GJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1										
Forecast	54.9	48.6	46.9	45.0	44.0	45.1	51.3	56.3	54.7	51.2
Actual	51.8	49.5	47.3	47.1	50.5	52.6	51.5	51.6	49.7	52.3
Error = (ACT-FCST)	(3.1)	0.9	0.4	2.1	6.5	7.5	0.3	(4.7)	(5.0)	1.1
Percent Error = (Error/ACT)	-6.0%	1.8%	0.8%	4.5%	12.9%	14.3%	0.5%	-9.1%	-10.1%	2.1%

FEVI UPC GJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2										
Forecast	337	365	372	390	372	334	323	343	357	332
Actual	345	369	344	328	346	343	345	351	333	322
Error = (ACT-FCST)	8.0	4.0	(28.0)	(62.0)	(26.0)	9.0	22.0	8.7	(24.3)	(9.7)
Percent Error = (Error/ACT)	2.3%	1.1%	-8.1%	-18.9%	-7.5%	2.6%	6.4%	2.5%	-7.3%	-3.0%

FEVI UPC GJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3										
Forecast	6,349	6,351	6,398	5,896	5,187	4,031	3,069	4,171	4,411	3,629
Actual	4,460	4,820	4,431	3,901	3,894	4,060	4,181	4,074	3,827	3,404
Error = (ACT-FCST)	(1889)	(1531)	(1967)	(1995)	(1293)	29	1112	(97)	(584)	(225)
Percent Error = (Error/ACT)	-42.4%	-31.8%	-44.4%	-51.1%	-33.2%	0.7%	26.6%	-2.4%	-15.3%	-6.6%

FEVI UPC GJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23										
Forecast						5,996.2	5,635.7	5,343.6	5,281.6	4,799.8
Actual					5,636.0	5,052.0	5,157.5	5,260.4	4,368.5	4,726.7
Error = (ACT-FCST)						(944.2)	(478.2)	(83.3)	(913.1)	(73.1)
Percent Error = (Error/ACT)						-18.7%	-9.3%	-1.6%	-20.9%	-1.5%

1 ## 3.13 VANCOUVER ISLAND NORMALIZED DEMAND

FEVI Energy PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1										
Forecast	5.0	4.6	4.5	4.3	4.3	4.6	5.4	6.1	6.3	6.2
Actual	4.7	4.5	4.4	4.5	5.0	5.4	5.5	5.8	5.9	6.4
Error = (ACT-FCST)	(0.3)	(0.1)	(0.1)	0.2	0.6	0.8	0.1	(0.3)	(0.5)	0.1
Percent Error = (Error/ACT)	-6.4%	-2.2%	-2.3%	4.4%	12.9%	15.6%	1.5%	-5.6%	-8.3%	2.3%

FEVI Energy PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2										
Forecast	3.0	3.3	3.4	3.3	3.3	3.0	3.1	3.4	3.6	3.4
Actual	3.1	3.1	3.0	2.9	3.2	3.2	3.3	3.4	3.3	3.2
Error = (ACT-FCST)	0.1	(0.2)	(0.4)	(0.5)	(0.2)	0.2	0.2	0.0	(0.3)	(0.1)
Percent Error = (Error/ACT)	1.6%	-5.1%	-14.9%	-16.0%	-4.7%	6.3%	5.4%	1.4%	-8.0%	-3.4%

FEVI Energy PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3										
Forecast	2.5	2.4	2.4	2.4	2.5	1.9	2.0	2.4	2.4	2.3
Actual	2.3	2.3	2.1	1.9	2.4	2.2	2.1	2.1	2.0	2.2
Error = (ACT-FCST)	(0.2)	(0.1)	(0.3)	(0.5)	(0.1)	0.3	0.1	(0.3)	(0.3)	(0.0)
Percent Error = (Error/ACT)	-8.1%	-2.6%	-13.7%	-28.3%	-5.0%	13.6%	6.5%	-14.6%	-16.8%	-1.9%

FEVI Energy PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23										
Forecast						0.5	0.8	1.2	0.8	0.3
Actual					0.5	0.8	0.9	0.8	0.6	0.3
Error = (ACT-FCST)					(0.5)	(0.3)	(0.1)	0.4	0.2	0.0
Percent Error = (Error/ACT)						-37.50%	-9.16%	44.93%	32.22%	10.99%

FEVI Energy PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Commercial										
Forecast	5.6	5.7	5.8	5.7	5.9	5.4	5.9	7.0	6.8	5.9
Actual	5.4	5.5	5.1	4.8	6.2	6.2	6.3	6.3	6.0	5.8
Error = (ACT-FCST)	(0.1)	(0.2)	(0.7)	(1.0)	0.3	0.8	0.4	(0.6)	(0.8)	(0.2)
Percent Error = (Error/ACT)	-2.6%	-4.0%	-14.4%	-20.8%	4.4%	12.9%	6.3%	-10.0%	-13.6%	-3.2%

2

3.14 WHISTLER NET CUSTOMERS

WH Customers	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1										
Forecast	2,321	2,289	2,303	2,372	2,478	2,536	2,681	2,775	2,889	3,034
Actual	2,296	2,271	2,348	2,416	2,508	2,608	2,709	2,828	2,936	2,965
Error = (ACT-FCST)	(25)	(18)	45	44	30	72	28	53	47	(69)
Percent Error = (Error/ACT)	-1.1%	-0.8%	1.9%	1.8%	1.2%	2.8%	1.0%	1.9%	1.6%	-2.3%

WH Customers	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2										
Forecast	267	275	280	291	289	292	309	294	305	313
Actual	286	274	281	285	295	289	297	309	307	305
Error = (ACT-FCST)	19	(1)	1	(6)	6	(3)	(12)	15	2	(8)
Percent Error = (Error/ACT)	6.6%	-0.4%	0.4%	-2.1%	2.0%	-1.0%	-4.0%	4.7%	0.7%	-2.6%

WH Customers	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3										
Forecast	62	59	59	61	60	59	39	48	55	71
Actual	61	61	60	60	48	53	57	58	69	73
Error = (ACT-FCST)	(1)	2	1	(1)	(12)	(6)	18	10	14	2
Percent Error = (Error/ACT)	-1.6%	3.3%	1.7%	-1.7%	-25.0%	-11.3%	31.6%	16.9%	20.2%	2.7%

WH Customers	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23										
Forecast						5	10	22	18	4
Actual					10	14	14	11	4	1
Error = (ACT-FCST)					10	9	4	(11)	(14)	(3)
Percent Error = (Error/ACT)						64.3%	28.6%	-100.0%	-350.0%	-300.0%

3.15 *WHISTLER NET CUSTOMER ADDITIONS*

WH Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1											
Forecast	35	36	14	14	52	62	61	84	81	81	98
Actual	12	34	51	77	68	92	100	101	119	108	41
Error = (ACT-FCST)	(23)	(2)	37	63	16	30	39	17	38	27	(57)
Percent Error = (Error/ACT)	-191.7%	-5.9%	72.5%	81.8%	23.5%	32.6%	39.0%	16.8%	31.8%	25.4%	-139.5%

WH Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2											
Forecast	1	2	5	5	9	4	4	7	3	4	6
Actual	2	21	-	7	5	10	(6)	8	12	(2)	(2)
Error = (ACT-FCST)	1	19	(5)	2	(4)	6	(10)	1	9	(6)	(8)
Percent Error = (Error/ACT)	50.0%	90.5%		28.6%	-80.0%	60.0%	166.7%	11.9%	77.4%	300.0%	400.0%

WH Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3											
Forecast		1				-	-	(5)	(2)	(1)	2
Actual		2	(0)	(1)	(0)	(12)	5	4	1	11	4
Error = (ACT-FCST)		1				(12)	5	9	3	12	2
Percent Error = (Error/ACT)		41.1%				100.0%	100.0%	225.0%	339.0%	109.1%	50.0%

WH Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23											
Forecast							-	-	4	2	-
Actual						10	4	-	(3)	(7)	(3)
Error = (ACT-FCST)						10	4	0	(7)	(9)	(3)
Percent Error = (Error/ACT)						100.0%	100.0%		233.3%	128.6%	100.0%

3.16 WHISTLER NORMALIZED USE PER CUSTOMER

WH UPC GJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1										
Forecast	82.3	104.0	106.3	90.6	79.7	85.1	97.9	102.1	99.5	99.0
Actual	94.7	89.4	87.3	87.6	91.3	97.7	93.5	96.3	94.2	101.5
Error = (ACT-FCST)	12	(15)	(19)	(3)	12	13	(4)	(6)	(5)	2
Percent Error = (Error/ACT)	13.1%	-16.3%	-21.8%	-3.4%	12.7%	12.9%	-4.7%	-6.1%	-5.6%	2.4%

WH UPC GJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2										
Forecast	430.0	610.0	637.0	464.0	408.0	465.0	792.9	592.7	515.5	419.5
Actual	506.0	429.0	465.0	471.0	660.0	520.2	479.4	511.8	465.8	417.5
Error = (ACT-FCST)	76	(181)	(172)	7	252	55	(314)	(81)	(50)	(2)
Percent Error = (Error/ACT)	15.0%	-42.2%	-37.0%	1.5%	38.2%	10.6%	-65.4%	-15.8%	-10.7%	-0.5%

WH UPC GJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3										
Forecast	4,114.0	3,876.0	3,630.0	3,595.0	3,822.0	4,326.0	6,706.9	6,824.3	5,886.5	4,737.2
Actual	4,271.0	3,822.0	4,213.0	4,285.0	5,618.0	5,638.0	5,107.9	5,747.4	5,392.0	4,220.8
Error = (ACT-FCST)	157	(54)	583	690	1,796	1,312	(1,599)	(1,077)	(495)	(516)
Percent Error = (Error/ACT)	3.7%	-1.4%	13.8%	16.1%	32.0%	23.3%	-31.3%	-18.7%	-9.2%	-12.2%

WH UPC GJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23										
Forecast						5,888.0	4,328.3	4,702.9	4,654.3	5,121.0
Actual					4,328.0	5,078.0	4,557.0	4,860.0	5,045.3	5,929.5
Error = (ACT-FCST)						(810)	229	157	391	808
Percent Error = (Error/ACT)						-16.0%	5.0%	3.2%	7.7%	13.6%

1 ## 3.17 *WHISTLER NORMALIZED DEMAND*

WH Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 1										
Forecast	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3
Actual	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3
Error = (ACT-FCST)	0.0	(0.0)	(0.0)	(0.0)	0.0	0.0	(0.0)	(0.0)	(0.0)	0.0
Percent Error = (Error/ACT	12.0%	-14.2%	-21.5%	-1.4%	0.0%	14.6%	-4.1%	-5.3%	-4.6%	1.8%

WH Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 2										
Forecast	0.1	0.2	0.2	0.1	0.1	0.1	0.2	0.2	0.2	0.1
Actual	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.2	0.1	0.1
Error = (ACT-FCST)	0.0	(0.0)	(0.0)	0.0	0.1	0.0	(0.1)	(0.0)	(0.0)	(0.0)
Percent Error = (Error/ACT	21.4%	-33.3%	-30.8%	0.0%	36.8%	10.0%	-75.0%	-12.1%	-9.6%	-1.6%

WH Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 3										
Forecast	0.3	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Actual	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Error = (ACT-FCST)	0.0	0.0	0.0	0.0	0.1	0.0	0.0	(0.0)	0.0	(0.0)
Percent Error = (Error/ACT	3.8%	0.0%	15.4%	15.4%	17.9%	13.3%	3.5%	-3.8%	5.5%	-11.5%

WH Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rate Schedule 23										
Forecast						0.03	0.04	0.09	0.08	0.02
Actual					0.03	0.06	0.06	0.06	0.05	0.02
Error = (ACT-FCST)						0.03	0.02	-0.03	-0.03	0.00
Percent Error = (Error/ACT)						50.9%	32.2%	-44.7%	-73.7%	-7.7%

WH Demand, PJs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Commercial										
Forecast	0.4	0.4	0.4	0.4	0.4	0.4	0.6	0.6	0.6	0.5
Actual	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.4
Error = (ACT-FCST)	0.0	(0.0)	0.0	0.0	0.2	0.1	(0.1)	(0.1)	(0.0)	(0.0)
Percent Error = (Error/ACT	10.0%	-11.4%	0.0%	10.3%	30.0%	16.8%	-15.0%	-11.1%	-5.4%	-8.5%

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Appendix A3

Demand Forecast Methods

Table of Contents

List of Tables and Figures

1. INTRODUCTION

In this appendix, FEI provides a detailed description of its demand forecast method.

The following table shows the high level method used for each component of FEI's demand forecast.

Table A3-1: Summary of FEI Forecast Methods

Rate Group	Customer Additions	Customers	Use Rate	Demand
Residential	CBOC forecast by dwelling type	Prior year customers + customer adds	Exponential Smoothing method, using normalized historical UPC	Product of Customers and Use Rates
Commercial	3 Yr. Avg. historical additions	Prior year customers + customer adds	Exponential Smoothing method, using normalized historical UPC	Product of Customers and Use Rates
Industrial				Annual survey of industrial customers

FEI's demand forecast methods are consistent with the recommendations in the FEI Forecasting Method Study filed as Appendix B2 in FortisBC's 2020-2024 MRP Application. The Forecasting Method Study represented the culmination of a number of years of research and testing of alternative forecasting methods in response to the forecasting directives in Order G-86-15 and accompanying decision related to the FEI Annual Review for 2015 Rates Application. As a result of this study, FEI adopted the Exponential Smoothing method (ETS) for the purpose of forecasting residential and commercial use rates, as ETS proved to be the most accurate method for this purpose.

In the following sections, FEI provides background information, including a description of FEI's regions and rate classes, the time periods used in the forecast, and the weather normalization process, and then describes each of FEI's forecast methods used to derive the 2022 demand forecast, in the following order:

- Residential Customer Additions;
- Commercial Customer Additions;
- Residential and Commercial Use Rates;
- Residential and Commercial Demand Forecast; and
- Industrial Demand Forecast.

2. BACKGROUND INFORMATION

2.1 *FEI REGIONS*

FEI is divided into three regions as shown in Figure A3-1.

Figure A3-1: FEI Regions

The Mainland region is further divided into the following sub-regions:

- Lower Mainland
- Inland
- Columbia
- Revelstoke

Forecasting is performed at the sub-regional level for each rate schedule in the Mainland region and summed up to derive the Mainland region forecast, which is then added to the forecast for the Vancouver Island and Whistler regions to derive the total forecast for each rate schedule within FEI.

2.2 *ACTUAL, PROJECTED AND FORECAST YEARS*

FEI's demand forecasts contain data from three time frames:

- **Actual Years:** Actual years are those for which actual data exists for the full calendar year.
- **Forecast Year(s)**: This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or two or more years depending on the filing.
- **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 2021 and the Seed Year forecast is based on the latest actual years, including 2020. As such, the 2021 Seed Year forecast in this Application will differ from the 2021 Forecast presented in the Annual Review for 2020 and 2021 Delivery Rates, for which 2020 year-end actual data was not available.

2.3 RATE CLASSES

The following residential, commercial and industrial rate classes are included in the annual demand forecast:

Table A3-2: Rate Classes

Residential	
Rate Schedule 1 - Residential	This rate schedule is applicable to firm gas supplied at one premise for use in approved appliances for all residential applications in single-family residences, separately metered single family townhouses, row houses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments.
Commercial	
Rate Schedule 2 - Small Commercial	This rate schedule is applicable to customers with a normalized annual consumption at one premise of less than 2,000 gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
Rate Schedule 3 - Large Commercial	This rate schedule is applicable to customers with a normalized annual consumption at one premise of greater than 2,000 gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
Rate Schedule 23 - Commercial Transportation	This rate schedule is applicable to shippers with a normalized annual consumption at one premise of greater than 2,000 gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.

Industrial	
Rate Schedule 4 – Seasonal	This rate schedule applies to the sale of gas to one customer who, pursuant to this Rate Schedule, consumes gas during the off-peak period.
Rate Schedule 5 - General Firm	This rate schedule applies to the sale of firm gas through one meter station to a customer. Firm gas service under this Rate Schedule means the gas FEI is obligated to sell to a customer on a firm basis subject to interruption or curtailment.
Rate Schedule 7 - General Interruptible Sales	This rate schedule applies to the provision of a bundled interruptible transportation service and the sale of firm gas through one meter station to a customer.
Rate Schedule 22/22A/22B - Large Volume Transportation	This rate schedule applies to the provision of firm and/or interruptible transportation service (subject to a minimum of 12,000 gigajoules per month) through the FEI system and through one meter station to one shipper except as previously agreed upon.
Rate Schedule 25 - General Firm Transportation	This rate schedule applies to the provision of firm transportation service through the FEI system and through one meter station to one shipper.
Rate Schedule 27 - General Interruptible Transportation	This rate schedule applies to the provision of interruptible transportation service through the FEI system and through one meter station to one shipper.

2.4 WEATHER NORMALIZATION OF RESIDENTIAL AND COMMERCIAL USE RATES

Residential and commercial rate schedules (Rate Schedules (RS) 1, 2, 3 and 23) are weather sensitive. A weather normalization process is applied to all actual use rates for these rate schedules as described in this section. Separate normalization factors are developed for each region, rate schedule and month.

Actual UPC is weather normalized on a monthly basis for each region and rate class by dividing the actual UPC by a normalization factor. The normalization factor is derived from a non-linear regression model that estimates the impact of the monthly weather variation on the load. As the relationship between weather and the usage is not linear, FEI considers three non-linear models that are often used when modeling weather impact. One is based on the Gompertz distribution (the "Gompertz" model). The other two methods are variants based on the logit formulation with one (Logit-4) allowing for an additional parameter for optimal fitting. The models are:

- Gompertz

$$Estimated\ Monthly\ UPC = A\ \times\ e^{\left(-e^{-B\ \times(Avg.Monthly\ Temp.-C)}\right)}$$

- Logit-3

$$Estimated\ Monthly\ UPC = \frac{A}{1 + B \times e^{(-C\times Temp)}}$$

- Logit-4

$$Estimated\ Monthly\ UPC = \frac{(D + (A - D))}{1 + B \times e^{(-C \times Temp)}}$$

The A/B/C/D parameters are estimated through a least squares method to minimize the sum of squared errors (SSE). The optimization process to minimize the SSE is done using the Solver tool in Microsoft Excel.

The heat sensitivity estimated from the model assumes that the sensitivity varies not only depending on the weather but also on the rate class. For example, the residential rate schedule shows higher sensitivity to weather compared to the commercial rate schedules, and FEI's normalization factors account for the difference.

3. RESIDENTIAL CUSTOMER ADDITIONS

The residential net customer additions forecast was developed based on housing starts data from the CBOC forecast of April 29th, 2021, Provincial Outlook Long-Term Economic Forecast 2021. The housing starts data was as follows:

Table A3-3: BC Housing Starts Data

Housing Type	2019	2020	2021	2022
Housing Starts, Singles, British Columbia	8,792	8,519	6,823	6,099
Housing Starts, Multiples, British Columbia	36,140	29,215	25,565	25,466
Total	44,932	37,734	32,388	31,566

From the above housing starts forecast, the 2022F SFD growth rate is calculated as follows:

$$2022F\ SFD\ Growth\ Rate = \left(\frac{6{,}099}{6{,}823}\right) - 1 = -10.6\%$$

The remainder of the growth rates are calculated the same way and the results are shown in the following table:

Table A3-4: Growth Rates

Housing Type	2021	2022
SFD Forecast Percent Change	**-19.9%**	**-10.6%**
MFD Forecast Percent Change	**-12.5%**	**-0.4%**

The following table incorporates the FEI proportions of the actual account additions by single family dwelling (SFD) and multi-family (MFD) based on historical percentages from internal data in columns A and B. The 2020 actual total additions are shown in column C, followed by the SFD and MFD proportions in columns D and E. Finally the CBOC growth rates for 2021 are applied to the SFD and MFD proportions for 2021 in column F and G and for 2022 in column I and J.

Table A3-5: FEI Proportions of Actual Account Additions by SFD and MFD

	Internal Split		Actual Adds 2020			2021S			2022F		
	SFD	MFD	Total	SFD	MFD	SFD	MFD	Total	SFD	MFD	Total
	A	B	C	D	E	F	G	H	I	J	K
Mainland											
Lower Mainland	35%	65%	4,831	1,693	3,138	1,356	2,746	4,102	1,212	2,735	3,947
Inland	68%	32%	3,183	2,158	1,025	1,728	897	2,625	1,545	894	2,439
Columbia	67%	33%	249	168	81	134	71	205	120	71	191
Revelstoke	99%	1%	62	61	1	49	1	50	44	1	45
Whistler	76%	24%	41	31	10	25	9	34	22	9	31
Vancouver Island	82%	18%	4,629	3,803	826	3,045	723	3,768	2,723	720	3,443
Total			**12,995**	**7,913**	**5,082**	**6,337**	**4,447**	**10,784**	**5,666**	**4,430**	**10,096**

For example, the Lower Mainland 2022F SFD value of 1,212 (column I) is derived as follows:

- Lower Mainland 2020 Internal Split – SFD percentage = 35% (column A);
- Lower Mainland 2020 Actual additions = 4,831 (column C)

$$LML\ 2020 Actual\ SFD = 35\%\ \times 4{,}831 = 1{,}693\ (column\ D)$$

$$LML\ 2021\ Seed\ SFD = \ -19.9\% \times 1{,}693 = 1{,}356\ (column\ F)$$

$$LML\ 2022\ Forecast\ SFD = -10.6\% \times 1{,}356 = 1{,}212 (column\ I)$$

4. COMMERCIAL CUSTOMER ADDITIONS

Commercial customer additions are calculated as an average of the net customer additions by region and rate class from the prior three years.

The following table shows the customer additions for Lower Mainland RS 2.

Table A3-6: Customer Additions for Lower Mainland RS 2

	Year	Customers	Customer Additions	Average 2018-2020
		A	B	C
1	2017	53,320		
2	2018	54,055	735	
3	2019	54,211	156	
4	2020	54,619	408	433
5	2021S	55,052		
6	2022F	55,485		

Customer additions are calculated in column B. The three-year average of additions is shown in C4 and is 433, 433 additions are forecast in each of 2021 and 2022.

$$2021S\ Customers = 2020\ Customers\ + 3\ Yr\ Avg\ Additions$$

Using the data above:

$$2021S = 55{,}052 = 54{,}619 + 433$$

Identical calculations are completed for all regions and all small commercial rate schedules.

However, due to rate switching between the large commercial rate schedules (specifically RS 3 and RS 23), forecasting for these two classes was done as a group and then proportioned per 2020 customers distribution.

The following table shows how the Lower Mainland large commercial customer additions forecast was developed. Other regions are similar.

Table A3-7: Lower Mainland Large Commercial Customer Additions Forecast Development

		Customers					Proportion	
		RS 3	RS 23	Total	Total	3 Yr. Average	RS 3	RS 23
		A	B	C	D	E	F	G
1	2017	4,111	1,225	5,336				
2	2018	4,575	1,144	5,719	383			
3	2019	5,347	505	5,852	133			
4	2020	5,075	430	5,505	- 347	56	52	4
5	2021S	5,127	434				52	4
6	2022F	5,179	439				52	4

For each actual year (rows 1-4) the rate class customers from columns A and B are summed in column C.

Aggregate customer additions are shown in column D.

The three year average customer addiitons is 56 and shown in column E, row 4.

The 2020 proportion is calculated from columns A-C on row 4.

For example, the RS 3 proportion is:

$$RS\ 3\ Proportion = \frac{5{,}075}{5{,}505} = 0.92$$

The proportion of the aggregate customer additions (56) assigned to RS 3 is then:

$$RS\ 3\ Customer\ Additions = 0.92\ \times 56 = 52$$

A similar calculation is performed for RS 23 to arrive at 4 customer additions.

On row 5 the 2021S customer additions for RS 3 are shown in column A and calculated as:

$$2021S = 5{,}127 = 5{,}075 + 52$$

The remaining calculations are similar.

5. RESIDENTIAL AND COMMERCIAL USE RATES

5.1 *THE EXPONENTIAL SMOOTHING METHOD*

FEI develops its use rate forecasts based on ten years of annual use rates by region and rate class. The UPC values are weather-normalized using the process set out in section 2 above.

The ten years of data is used to calculate the UPC forecast using ETS, as implemented in Microsoft Excel.

ETS is implemented as both a formula and "wizard" in Excel 2016. Intermediate calculations and steps are not exposed or reproducible. Microsoft has not published, and is unlikely to publish, the specific algorithms and procedures used in its software.

The UPC method for Lower Mainland RS 1 (residential) is demonstrated below. All residential and commercial use rate forecasts in all regions are developed using the same method.

5.1.1 Lower Mainland RS 1 UPC Example

The forecast UPCs for Lower Mainland RS 1 were calculated as follows:

Start with ten years of weather normalized annual UPCs:

LOWER MAINLAND	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
RATE1	97.1	98.6	96.0	94.7	94.2	98.2	96.4	95.8	92.1	97.3

In Excel, the "forecast.ets()" function is used to calculate the 2021 and 2022 forecasts.

LOWER MAINLAND	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021S	2022F
RATE1	97.1	98.6	96.0	94.7	94.2	98.2	96.4	95.8	92.1	97.3	=FORECAST.ETS(T$7,$I67:$S67,$I$7:$S$7,0,0,1)	

The resulting forecasts for 2021 and 2022 are shown:

LOWER MAINLAND	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021S	2022F
RATE1	97.1	98.6	96.0	94.7	94.2	98.2	96.4	95.8	92.1	97.3	95.0	94.7

These annual UPCs must be converted to monthly values for input into FIS and this is accomplished by considering actual monthly proportions from the past three years.

LOWER MAINLAND													
UPC Rs1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2018	15.80	11.87	10.72	7.98	4.50	3.47	2.96	2.54	3.09	6.29	10.86	15.70	95.80
2019	14.47	11.54	9.80	7.08	4.38	3.20	2.67	2.60	3.41	6.79	10.29	15.89	92.13
2020	14.95	13.12	10.37	7.54	4.73	3.64	2.75	2.52	3.57	7.34	11.67	15.12	97.32
UPC Rs1													
2018	16%	12%	11%	8%	5%	4%	3%	3%	3%	7%	11%	16%	100%
2019	16%	13%	11%	8%	5%	3%	3%	3%	4%	7%	11%	17%	100%
2020	15%	13%	11%	8%	5%	4%	3%	3%	4%	8%	12%	16%	100%
Average	16%	13%	11%	8%	5%	4%	3%	3%	4%	7%	11%	16%	100%

In the preceeding table the first three rows show the actual weather normalized monthly UPC values. The second three rows show the proportions for each year along with the average proportion in the final row.

The average proportion is applied to the ETS forecast to establish the monthly forecast, as follows:

	LML Rs1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2021S UPC Forecast	95.0	15.1	12.2	10.3	7.5	4.5	3.4	2.8	2.6	3.4	6.8	10.9	15.6	95.0
2022F UPC Forecast	94.7	15.0	12.1	10.3	7.5	4.5	3.4	2.8	2.5	3.3	6.8	10.9	15.5	94.7

Note that the total of 95.0 and 94.7 matches the 2021S and 2022F ETS forecast, respectively, above.

Identical calculations are completed for all residential and commercial rate classes in all regions. The resulting monthly values are entered into FIS.

5.2 AMALGAMATION OF UPCS IN FIS

Once the use rates are seasonalized and developed for each region and each rate schedule (RS 1, RS 2, RS 3 and RS 23), they are entered into FIS. The amalgamated use rates are calculated using the following relationship:

$$Use\ Rate = \frac{\sum Volume}{\sum Accounts}$$

FIS calculates both the monthly volume and accounts by region and rate class. In an external spreadsheet the volumes and accounts are summed by month and by rate class for all regions.

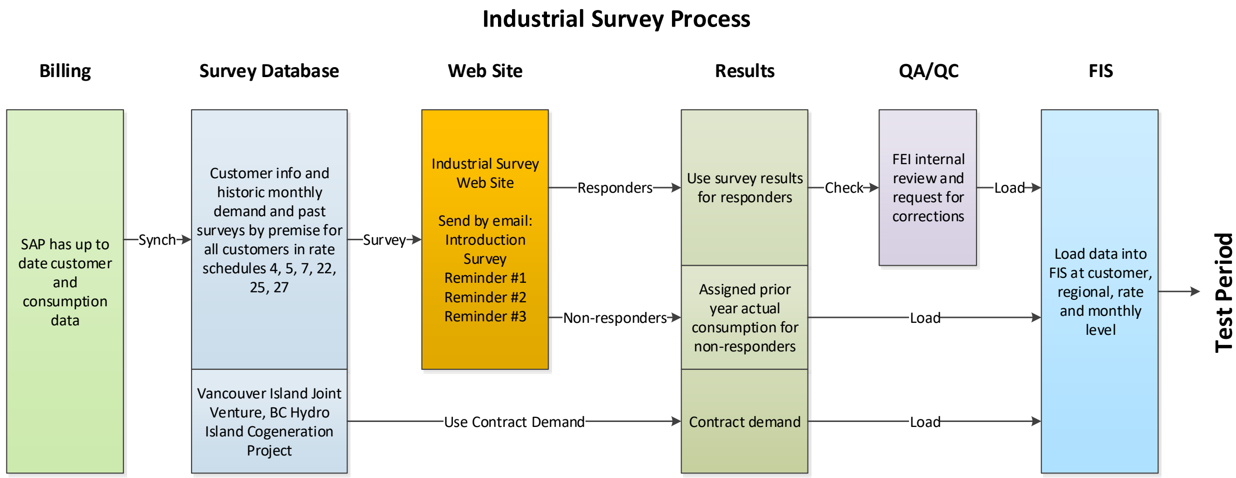
6. RESIDENTIAL AND COMMERCIAL DEMAND FORECAST

The residential and commercial demand forecasts are the products of the monthly customer forecast and the corresponding monthly use rates forecast at the sub-regional level. The sub-regions, regions and months are then summed to arrive at the amalgamated demand forecast.

7. INDUSTRIAL DEMAND FORECAST

The industrial demand is forecast using a web-based survey system. The following diagram shows the main steps of process.

Figure A3-2: Industrial Forecast Process



Each customer in each industrial class receives a customized email message with a secure link to their individual survey. The customer then uses the web based survey to complete their forecast of demand for the next five years and submits it to FEI. Once the survey is closed (typically after six weeks duration), the survey responses are checked and then the data is loaded into the FIS system. The following sections describe the process in detail.

7.1 CREATE THE SURVEY

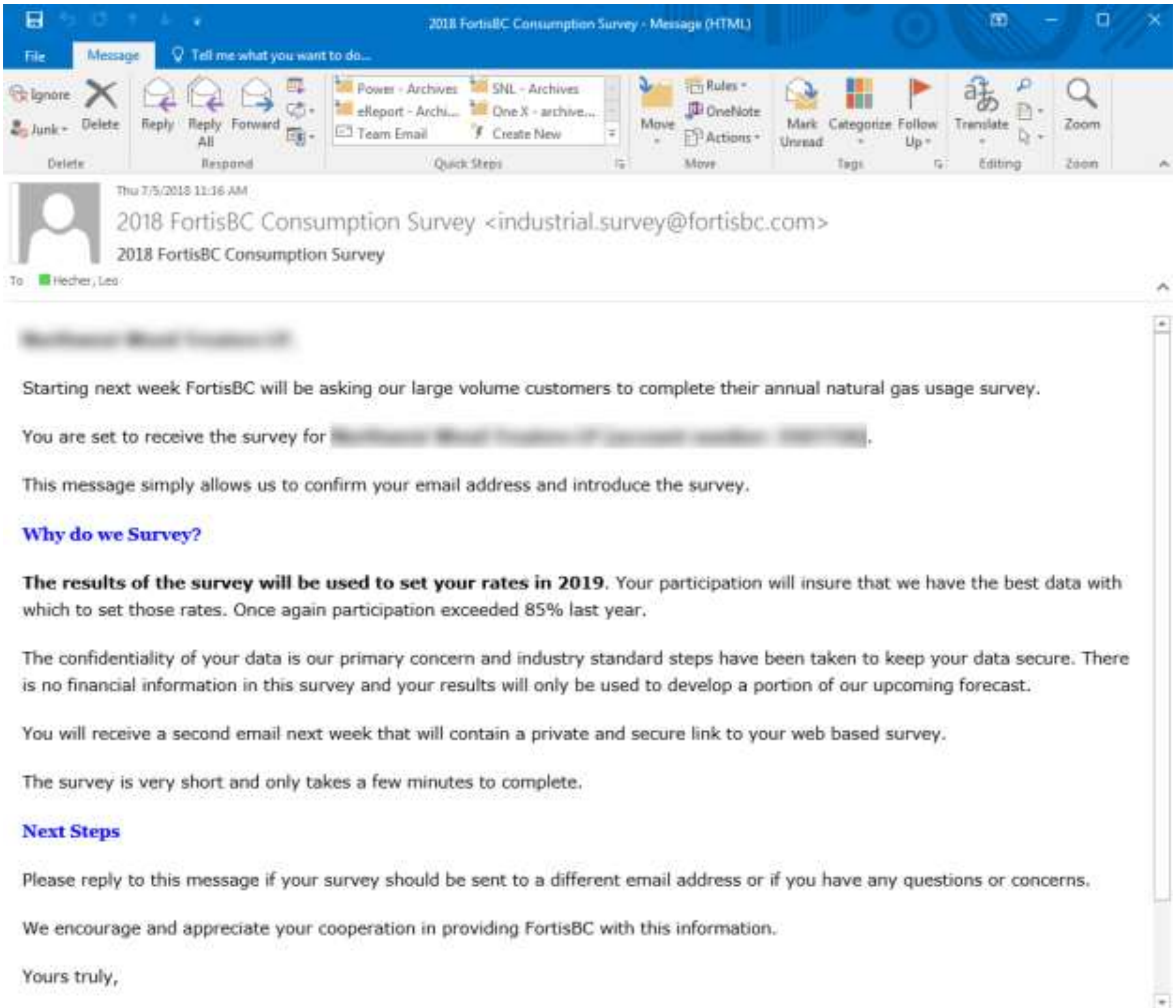
Prior to the start of the survey FEI creates a new survey using a web-based application. For the annual survey all industrial classes are selected. Commercial and residential customers are not surveyed.

7.2 SEND OUT THE INTRODUCTION EMAIL

The customer is introduced to the survey several days before the actual surveys are sent out. This allows the customer time to update their contact information and possibly to assign the survey to a different employee if there have been staffing changes. FEI has found this to be an important step and contributes to the high success rate because a minimal number of surveys are sent to the wrong person.

The survey web site creates the form letters and manages the send out. The following is an example of the introductory email.

Figure A3-3: Survey Introductory Email Example



2018 FortisBC Consumption Survey - Message (HTML)

Thu 7/5/2018 11:16 AM

2018 FortisBC Consumption Survey <industrial.survey@fortisbc.com>

2018 FortisBC Consumption Survey

To Hecher, Leo

[redacted]

Starting next week FortisBC will be asking our large volume customers to complete their annual natural gas usage survey.

You are set to receive the survey for [redacted].

This message simply allows us to confirm your email address and introduce the survey.

Why do we Survey?

The results of the survey will be used to set your rates in 2019. Your participation will insure that we have the best data with which to set those rates. Once again participation exceeded 85% last year.

The confidentiality of your data is our primary concern and industry standard steps have been taken to keep your data secure. There is no financial information in this survey and your results will only be used to develop a portion of our upcoming forecast.

You will receive a second email next week that will contain a private and secure link to your web based survey.

The survey is very short and only takes a few minutes to complete.

Next Steps

Please reply to this message if your survey should be sent to a different email address or if you have any questions or concerns.

We encourage and appreciate your cooperation in providing FortisBC with this information.

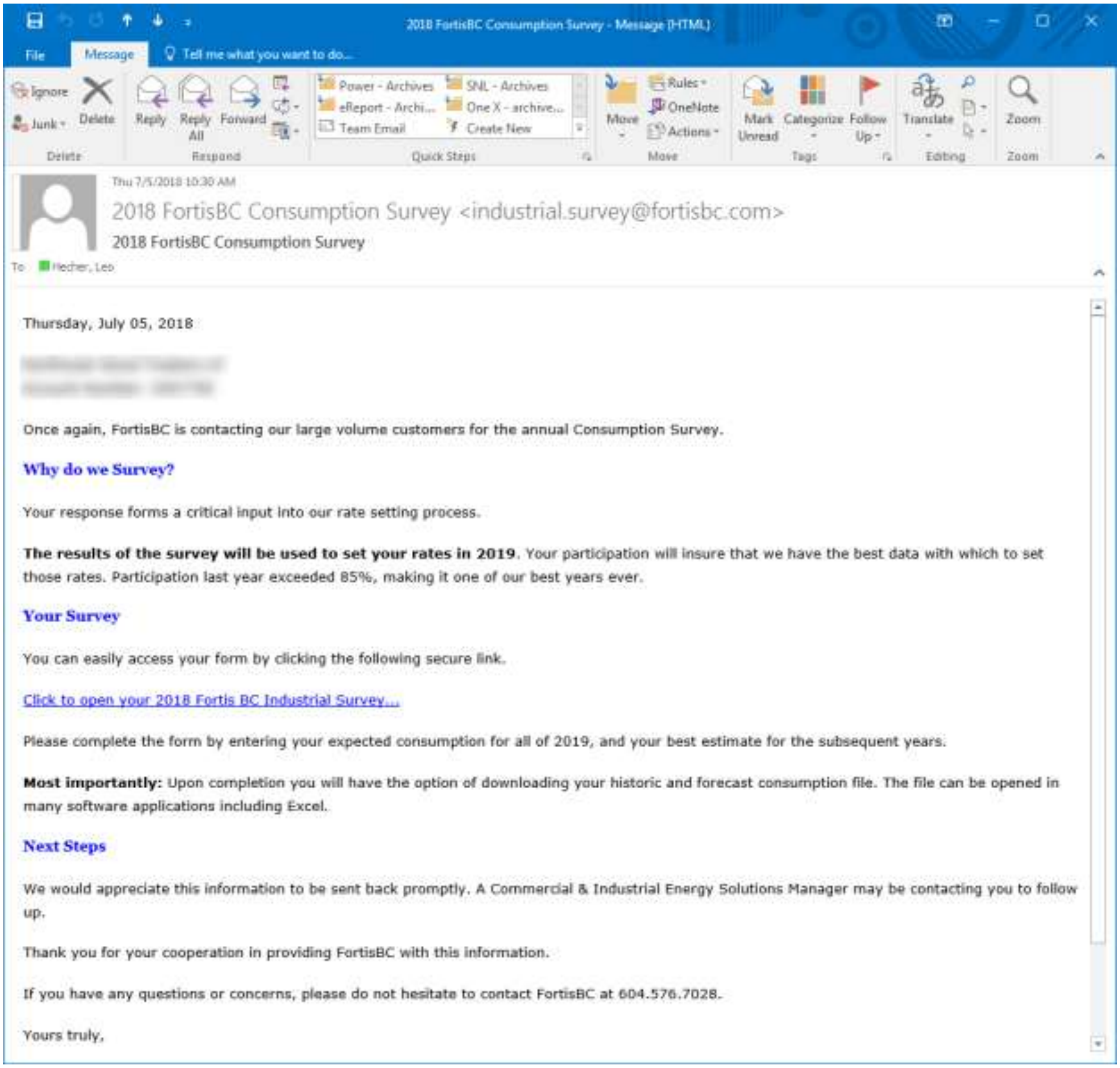
Yours truly,

Replies to these emails are used to update the contact and other information in the survey web site.

7.3 *SEND OUT THE SURVEY EMAIL*

An email with a customized link to the survey is sent out several days after the reminder. The survey is not sent until all the changes that resulted from the introductory email have been processed. As in the following sample email, each customer is sent an HTML link to the survey. An encrypted globally unique identifier in the link insures that customers cannot access surveys from other customers.

Figure A3-4: Survey Email Example


2018 FortisBC Consumption Survey - Message (HTML)

Thu 7/5/2018 10:30 AM

2018 FortisBC Consumption Survey <industrial.survey@fortisbc.com>

2018 FortisBC Consumption Survey

Thursday, July 05, 2018

Once again, FortisBC is contacting our large volume customers for the annual Consumption Survey.

Why do we Survey?

Your response forms a critical input into our rate setting process.

The results of the survey will be used to set your rates in 2019. Your participation will insure that we have the best data with which to set those rates. Participation last year exceeded 85%, making it one of our best years ever.

Your Survey

You can easily access your form by clicking the following secure link.

Click to open your 2018 Fortis BC Industrial Survey...

Please complete the form by entering your expected consumption for all of 2019, and your best estimate for the subsequent years.

Most importantly: Upon completion you will have the option of downloading your historic and forecast consumption file. The file can be opened in many software applications including Excel.

Next Steps

We would appreciate this information to be sent back promptly. A Commercial & Industrial Energy Solutions Manager may be contacting you to follow up.

Thank you for your cooperation in providing FortisBC with this information.

If you have any questions or concerns, please do not hesitate to contact FortisBC at 604.576.7028.

Yours truly,

7.4 SURVEY FORM

The following web form is displayed to the user after the link in the email has been clicked.

1

Figure A3-5: Survey (Web) Form Example

FORTIS BC INDUSTRIAL SURVEY

Industrial Survey -

Please note that the results of the survey will be used to set your 2019 rates. The secure link to your survey is below.

Account Number

Premise Number

Rate Class RATE7

Premise Address

Contact Form

1

Name Test Canada Ltd.

Email leo.necher@fortisbc.com

Phone

May we contact you about our rebate programs? Yes No

FortisBC has a number of Energy Efficiency and Conservation programs available to our industrial customers.

Historic Consumption Chart

2

Select Chart Type Historic Consumption

Historic Consumption Data

3

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2014	42	105	152	55	0	92	120	0	0	0	97	290	953
2015	152	101	61	53	201	247	137	25	0	384	1,311	1,056	3,729
2016	1,367	3,001	2,999	2,102	1,619	1,292	1,262	1,073	1,705	2,241	2,563	3,396	24,613
2017	3,956	3,622	3,672	3,029	2,529	2,957	2,198	1,561	1,613	3,180	3,375	4,071	35,753
2018	4,166	4,099	3,575	2,994	0	0	0	0	0	0	0	0	14,836

Projected Monthly Consumption Data (Ple… estimated monthly GJ's below)

4

Same as Last Year

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2019													0

Projected Annual Consumption Data (Please enter estimated annual GJ's below)

5

2020	2021	2022	2023

6

Submit Survey

2

Notes:

1) The user can change the contact name (normally a person's name), email and phone number. It is saved and will be used in subsequent years. This allows the recipient to redirect next year's survey.

2) A line chart showing the customer's actual historic consumption is shown for the prior 5 years. The customer can use the pick list to show a chart that shows last year's actual consumption and last year's survey. This allows the customer to see any variance in their survey from last year.

3) A table of historical consumption is shown for the prior five years. Zeroes are shown in this example because the survey database is not updated until the start of a real survey.

4) The customer is asked for monthly consumption for the coming year. The total at the right side is automatically updated to reduce typing errors. If the customer believes that its consumption is not changing they can use the "Same as last year" button as a fast alternative to typing in the same values.

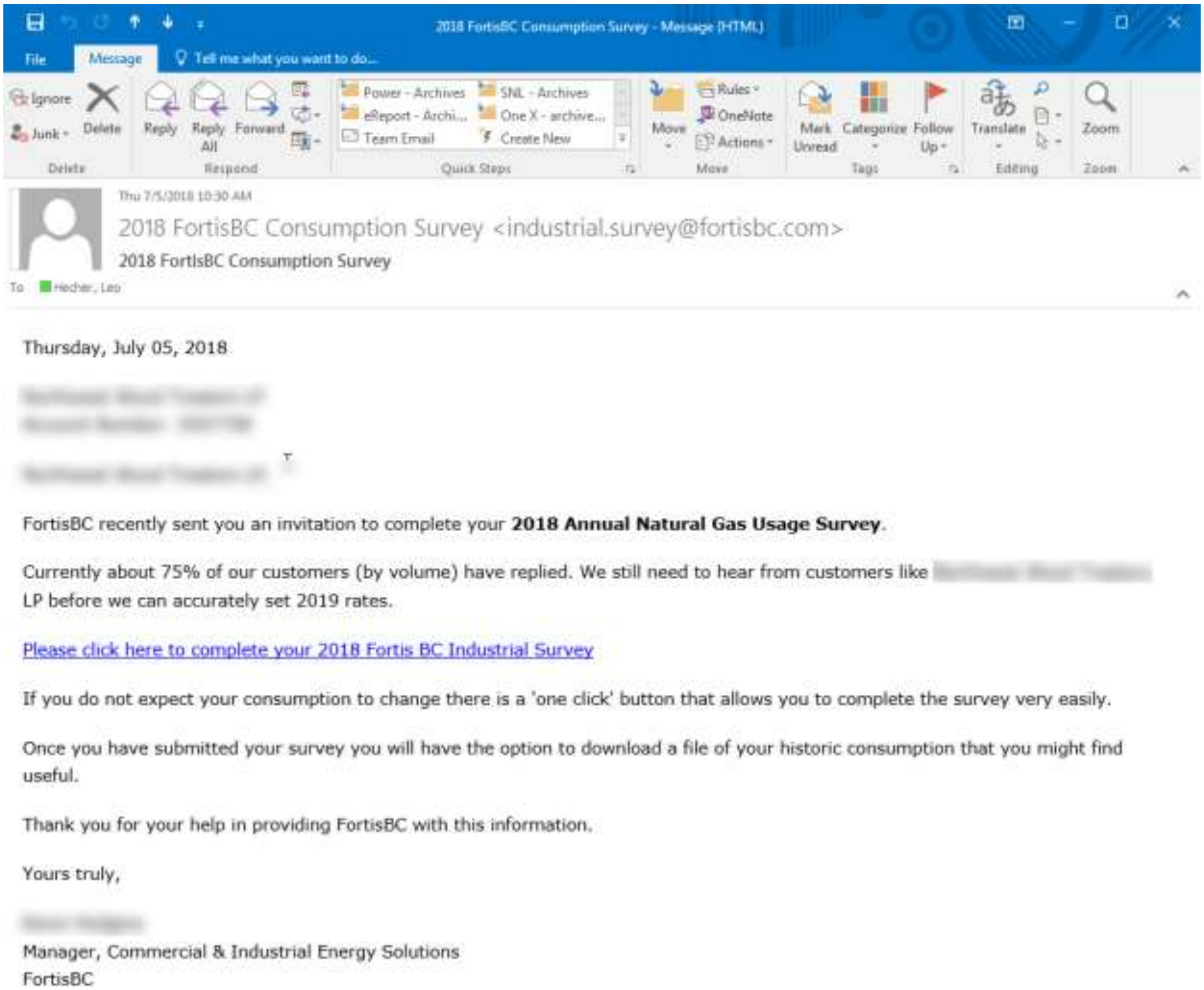
5) Annual forecasts are requested for the remaining 4 years of the survey.

6) Once the data has been entered the user clicks the Submit button to save the survey. Upon submitting the survey the user will be able to download a Microsoft Excel file containing the data from Step 3 above.

7.5 NON RESPONDERS AND THE REMINDER EMAIL

Once the survey is started, responses start coming in within the hour. A steady response rate normally continues for several days, but eventually slows. The survey system tracks the status of each survey and at all times FEI knows the response rate. Until the target response rate is reached, FEI sends out a weekly reminder email to those customers that have not yet responded. The reminder email contains the same link to the survey. The reminder step enhances the response rate of the survey. A sample is shown below:

Figure A3-6: Example of Survey Reminder Email



2018 FortisBC Consumption Survey - Message (HTML)

Thu 7/5/2018 10:30 AM

2018 FortisBC Consumption Survey <industrial.survey@fortisbc.com>

2018 FortisBC Consumption Survey

Thursday, July 05, 2018

FortisBC recently sent you an invitation to complete your **2018 Annual Natural Gas Usage Survey**.

Currently about 75% of our customers (by volume) have replied. We still need to hear from customers like LP before we can accurately set 2019 rates.

Please click here to complete your 2018 Fortis BC Industrial Survey

If you do not expect your consumption to change there is a 'one click' button that allows you to complete the survey very easily.

Once you have submitted your survey you will have the option to download a file of your historic consumption that you might find useful.

Thank you for your help in providing FortisBC with this information.

Yours truly,

Manager, Commercial & Industrial Energy Solutions
FortisBC

7.6 MONITORING THE RESPONSE RATE

The response rate for the survey is measured in terms of number of respondents and the volume from those respondents. FEI is not only concerned with the number of customers that reply but also the volume those customers represent. The response rate from a volumetric perspective is always higher than the customer count response rate because large customers (for example those in RS 22) are more likely to reply to the survey.

The response rate is measured by counting the number of responses vs the number of customers in the survey. Some customers will not respond because the survey has been sent to an invalid email address and in these cases FEI attempts to correct the address so that a survey can be completed. FEI notes that if an address cannot be corrected during the time of the survey, then the customer remains in the denominator of the response calculation ratio.

The following screen shot is for demonstration purposes only.

Figure A3-7: Example of Survey Results Dashboard

7.7 REVIEWING THE SURVEYS

Surveys from large volume customers are reviewed by the Forecast Manager and one or more Commercial and Industrial Energy Solutions Managers. The Commercial and Industrial Energy Solutions Managers are well informed about the issues with each individual customer and are able to rationalize the survey received from the customer. Where surveys are contrary to the information the Commercial and Industrial Energy Solutions Managers have, a follow up call is made and the survey is adjusted if required.

7.8 CLOSING OFF THE SURVEY AND LOADING FIS

Once the target response rate has been achieved in early July, the survey is closed. The data in the survey web site is then transferred automatically to the current forecast in FIS. Industrial rate classes are forecast by individual customer so the data for each customer is copied.

Checks are completed to make sure that that data was copied properly and that the survey web site and that the current FIS forecast are in sync.

Customers that do not respond to the survey are assigned their prior year's consumption.

FIS then sums the individual customer demand forecasts by rate class and region to develop the industrial demand forecast.

8. SUMMARY OF DEMAND FORECAST

Once the customer additions, use rates and industrial demand calculations and data have been completed, they are entered into FIS. FIS then aggregates the demand by month, region and rate class to prepare the overall forecast of demand.

Appendix B

FEI 2022 CMAE BUDGET REVIEW

FEI 2022 CORE MARKET ADMINISTRATION EXPENSE (CMAE) BUDGET REVIEW

1.1 *INTRODUCTION*

The CMAE budget funds the costs that FEI's Gas Supply Department incurs to plan, manage and optimize the commodity and midstream gas supply portfolios, mitigate unneeded resources, manage the credit exposure to counterparties, and minimize the impact of unfavourable upstream regulatory developments. As these activities serve core market customers and directly impact commodity and midstream costs, the CMAE budget is recovered separately from delivery costs through gas cost recovery rates.[1] FEI's 2017-2020 Actual, 2021 Approved, 2021 Projected, and 2022 Forecast CMAE budget is set out in Schedule 1 to this appendix, in the format prescribed in Appendix B to Order G-23-15.

As set out in the Approvals Sought (Section 1.2 of the Application), FEI requests BCUC approval of the following, effective January 1, 2022:

- approval of the 2022 forecast CMAE budget of $5.575 million, as set out in Schedule 1; and
- approval of the allocation of the 2022 forecast CMAE budget and actual costs between the Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA) based on the allocation percentages of 30 percent and 70 percent, respectively.

In compliance with the BCUC's Decision and Order G-79-14, FEI will continue to seek annual approval of the CMAE budget as part of the Annual Review filings.

Further, pursuant to the BCUC's direction in the FEI Annual Review for 2020 and 2021 Delivery Rates Decision and Order G-319-20, FEI will include a comprehensive review of the CMAE (Comprehensive CMAE Review) in its next revenue requirements or multi-year rate plan (MRP) application following the MRP term.

The following describes the 2022 Forecast CMAE budget.

[1] The Gas Supply department is primarily funded through the CMAE budget. However, activities not directly related to the commodity and midstream portfolio functions, such as the on-system transportation work supporting the transportation services business, are included in O&M costs and recovered in delivery rates from all non-bypass customers.

1.2 *DESCRIPTION OF CMAE BUDGET*

The principal purpose of activities funded by CMAE is to identify and secure safe, reliable and cost effective gas supply resources that are required to meet the demand for natural gas by core customers.

The CMAE budget is required for FEI staff and resources that are necessary:

- to plan and optimize gas supply requirements and to prepare FEI's Annual Contracting Plans;
- to secure and manage the gas supply resources on a daily basis and mitigate any unneeded resources;
- to establish appropriate contracts with counterparties and manage any associated credit exposure;
- to manage upstream regulatory developments in order to protect the interests of customers, including minimizing unfavourable outcomes and identifying and supporting opportunities that are beneficial to customers; and
- to complete the support activities related to regulatory and financial reporting and other compliance requirements.

Carrying out these responsibilities is critical given that the gross cost of the commodity and midstream gas supply portfolios is currently in excess of $750 million per year. These costs can change dramatically given commodity price volatility and changes in transportation and storage costs.

Developing and maintaining effective gas supply portfolios requires the evaluation of resources available to meet normal and peak day core load requirements. This work includes:

- support activities such as portfolio modelling and resource assessment;
- regional supply and demand analysis; discussions and meetings with pipeline and storage operators; maintaining strong relationships with gas producers and marketers;
- negotiation and administration of commodity, pipeline and storage contracts;
- staying on top of new regional infrastructure developments; and
- seeking opportunities for contracting resources related to cost-effective pipeline or storage capacity expansions or additions.

The general availability of these resources is influenced by the upstream regulatory framework that underpins the investment in regional infrastructure and supports commercial activity. Successful mitigation activities performed by gas supply, for which specialized expertise is needed, enables earning incremental revenue that offsets the overall cost of gas for the benefit of customers. Depending on market conditions, this effort can result in substantial revenue that reduces the cost of gas.

The level of the CMAE budget is determined by the scope of work required to meet the responsibilities described above, components of which are typically variable year-over-year. For example, the CMAE budget may need to increase in a year when significant upstream regulatory developments require intervention in proceedings to ensure the interests of customers are protected. The budget requirement typically decreases when there are fewer proceedings requiring intervention.

The CMAE activities are provided on the basis of a common administrative function and their cost are allocated to the gas supply commodity and midstream portfolios. This allocation assigns 30 percent of CMAE costs to the CCRA and 70 percent to the MCRA. Consistent with previous years, this allocation reflects the work performed by employees in the Gas Supply area to support each of the portfolios. While there has been little historical variability in the degree of work required to support the respective portfolios, the allocation percentages will be reviewed as part the scope of the Comprehensive CMAE Review.

The table below provides a summary of the 2021 Approved, 2021 Projected and 2022 Forecast CMAE amounts; Schedule 1 included in this appendix provides further details.

Table B-1: CMAE Summary ($ millions)

	Approved 2021	Projected 2021	Forecast 2022
Labour	**$ 3.041**	**$ 2.892**	**$ 3.038**
Non-Labour	**1.797**	**1.585**	**1.851**
Shared Services	**0.686**	**0.686**	**0.686**
Total CMAE	**$ 5.524**	**$ 5.163**	**$ 5.575**

1.3 *REGULATORY TREATMENT OF CMAE*

The forecast CMAE costs are included as a component of the forecast gas costs for the purposes of determining the commodity and midstream (storage and transport) cost recovery charges.

Variances between the actual gas costs incurred and the forecast gas costs embedded in recovery rates are captured in the gas cost deferral accounts and, subject to BCUC approval, these variances are refunded to or recovered from customers as part of future commodity and midstream rates.

At the end of each year, the Company files its gas cost status report with the BCUC, which provides a summary of the cost and recovery variances and provides explanations for any material variances. The actual year-end 2021 CMAE costs and variances to the approved budget will be submitted, in the format prescribed by the BCUC, as part of the FEI 2021 CCRA and MCRA Status Report due to be filed by April 30, 2022.

1.4 *PROJECTED 2021 CMAE COSTS*

Schedule 1 has been prepared in the prescribed format of Appendix B to Order G-23-15. The schedule presents the 2021 Approved and 2021 Projected CMAE amounts, including variances and explanations. As well, Schedule 1 provides a summary of the Actual 2017-2020 CMAE costs, and the 2022 Forecast CMAE budget.

The year-end costs shown in the 2021 Projected column in Schedule 1 are based on the actual costs incurred to May 31, 2021 and the projected costs for the remainder of the year. The Company projects that overall the 2021 CMAE costs will total $5.163 million, which is lower than the 2021 Approved amount. Schedule 1 provides a breakdown of the variances, including explanations, between 2021 Approved and 2021 Projected CMAE amounts at the individual cost component level.

The year-end 2021 Projected CMAE costs, including all variances at the cost component level from the 2021 Approved CMAE budget, reflect the prudent and effective management of commodity and midstream gas supply costs. Consistent with past practice, the actual costs will flow through to customers as part of future commodity and midstream rates.

1.5 *FORECAST 2022 CMAE COSTS*

As reflected in Schedule 1 in the 2022 Budget Request column, the Company is seeking approval of the 2022 CMAE budget in the amount of $5.575 million, which is $0.051 million higher than 2021 Approved. The increase from 2021 Approved is primarily related to inflation based on the forecast labour and non-labour inflation factors. As well, the forecast includes changes in the service level related to various non-labour components that have been identified. Explanations of the 2022 CMAE budget by cost component are set out below.

1.5.1 Information Systems (IS)

The 2022 Forecast Information Systems (IS) budget of $0.322 million is $0.192 million lower than 2021 Approved. As indicated in Schedule 1, 2021 continues to be a transition year related to the replacement of the current Entegrate deal capture system with a new Energy Trading and Risk Management (ETRM) system. During the transition period, software maintenance and support costs have been incurred on both systems and were anticipated to continue until the new system is fully functional and the Entegrate system can be retired. Although FEI is not expected to complete its transition to the new ETRM system until late 2021 and retire the

Entegrate system in 2022, FEI has been able to reduce the level and cost of support related to the Entegrate system earlier than anticipated. The lower cost forecasts related to the cancellation of the Entegrate software support contract are embedded in both the 2021 Projected and the 2022 Budget Request amounts.

1.5.2 Consulting and Legal

The 2022 Forecast Consulting and Legal budget of $0.750 million is based on the forecast of upstream regulatory work anticipated to occur in 2022; it also includes a forecast of the consulting and legal work required to support a review of gas supply market conditions related to the Annual Contracting Plan, and to support the review/renewal of the Gas Supply Mitigation Incentive Program (GSMIP).

Upstream regulatory matters engage FEI's interest in maintaining its ability to transact for gas supply at fair market prices, as well as reviewing costs that are reflected in fixed transportation tolls. The Company's participation in such proceedings, either directly or as a member of the Western Export Group (WEG), provides significant benefit to customers, as commodity purchases at fair market prices and increases to the upstream pipeline tolls and tariffs directly impact FEI's rates.

The degree of involvement in upstream regulatory matters that may be required in any given year is typically difficult to foresee with accuracy as it is driven by third party applications to national regulators (the Canada Energy Regulator (CER) in Canada and the Federal Energy Regulatory Commission (FERC) in the United States), who determine the scope and timeline of any review. The nature of these applications, and issues they potentially create, drives the scope of FEI's involvement, ranging from simple monitoring to full participation in oral hearings. The costs incurred by this involvement are, as a result, highly variable. To help manage the costs of this involvement, FEI is a member of the WEG, which shares costs relating to matters concerning TC Energy's NOVA Gas Transmission Ltd. (NGTL) and FoothillsBC systems.

1.5.3 Subscriptions & Memberships

The 2022 Forecast for Subscriptions & Memberships of $0.629 million has increased compared to 2021 Approved. The budget is based on the forecast costs for the required service levels and continues to include savings related to sharing the costs of some subscriptions with Aitken Creek Gas Storage ULC (ACGS). The 2022 Forecast includes inflationary increases to the various subscriptions and membership dues, as well as the contractual increases that are related to sole source subscriptions for commodity price services.

1.5.4 Sundries

The 2022 Forecast for Sundries of $0.060 million has increased from the 2021 Approved amount. The budget is based on the forecast regulatory proceeding costs related to BCUC gas supply applications during the year, including the upcoming GSMIP renewal, as well as the recurring expenditures for facilities communications and data charges, and other miscellaneous costs.

1.5.5 Training & Travel

The 2022 Forecast for Training & Travel of $0.090 million has increased from the 2021 Approved and is based on a measured resumption of travel activity as restrictions related to the COVID-19 pandemic are lifted.

1.5.6 MoveUP Labour

The 2022 Forecast for MoveUP Labour of $0.638 million has increased slightly compared to the 2021 Approved amount. The 2022 Forecast is based on the forecast of labour, including cross-charging, inflation, and benefits loadings.

1.5.7 M&E Labour

The 2022 Forecast for M&E Labour of $2.400 million has decreased slightly compared to the 2021 Approved amount. The 2022 Forecast is based on the forecast of labour, including cross-charging, inflation, and benefits loadings.

1.5.8 Shared Services

The 2022 Forecast for Shared Services of $0.686 million has remained unchanged from the 2021 Approved and reflects the 2022 service level requirements. The Shared Services charge relates to the transfer of costs for services provided to Gas Supply from other areas of the business. The Shared Services include the provision of management oversight, core customer load forecasting, office workspace and technology requirements, and internal legal, tax and treasury support for counterparty contracts and credit analysis.

1.6 *SUMMARY*

The Company has reviewed its requirements for 2022 and forecast its CMAE costs accordingly. The level of the 2022 Forecast CMAE budget is required to ensure that the Company is able to prudently and effectively manage commodity and midstream gas supply costs for the benefit of customers. Finally, the methodology used for allocating CMAE costs to the gas supply commodity and midstream portfolios remains appropriate.

Schedule 1

Line #											
1	**CMAE Cost Component**	**2017**	**2018**	**2019**	**2020**	**2021**					**2022**
2	**($000, unless specified otherwise)**	**Actual**	**Actual**	**Actual**	**Actual**	**Approved**	**Projected**	**Variance**	**Variance %**	**Variance Explanation**	**Budget Request**
3	IS (Information Systems)	274	311	342	482	514	320	(194)	-38%	IS costs lower than budget due to the earlier than forecast cancellation of the Entegrate system support service; significantly reducing the 2021 overlap of systems support costs during the ongoing transition phase to the new Energy Trading and Risk Management (ETRM) system.	322
4	Consulting & Legal	305	363	523	424	625	621	(4)	-1%		750
5	Subscriptions & Memberships	305	287	395	595	558	569	11	2%		629
6	Sundries	31	1,432	110	119	40	40	-	0%		60
7	Training & Travel	95	119	125	34	60	35	(25)	-42%	Training & Travel lower than budget as result of prolonged travel restrictions related to COVID-19 situation.	90
8	MoveUP Salaries before Benefits & Incentives	463	445	445	493	451	425	(26)	-6%	MoveUP Salaries lower due to temporarily unfilled position. Benefits lower due to lower salary costs.	457
9	MoveUP Benefits [3]	143	152	166	180	176	158	(18)	-10%		181
10	MoveUP Incentives [3] [4]	-	-	-	-						
11	M&E Salaries before Benefits & Incentives	1,213	1,349	1,268	1,350	1,569	1,550	(19)	-1%	M&E Salaries lower due to temporarily unfilled positions during the year, partially offset by reduced cross-charging. Benefits lower due to lower salary costs and lower than budgeted loadings.	1,598
12	M&E Benefits [3]	425	463	469	478	845	759	(86)	-10%		802
13	M&E Incentives [3]	208	215	289	234						
14	Energy Management Service Revenue	-	-	-	-	-	-	-			-
15	Shared Services	758	632	686	686	686	686	-	0%		686
16	**Total**	4,220	5,768	4,818	5,075	5,524	5,163	(361)	-7%		5,575
17											
18	**CMAE FTE**	**2017**	**2018**	**2019**	**2020**	**2021**					**2022**
19	**(Number)**	**Actual**	**Actual**	**Actual**	**Actual**	**Approved**	**Projected**	**Variance**	**Variance %**	**Variance Explanation**	**Budget Request**
20	MoveUP	5.3	4.9	4.9	4.9	5.0	4.4	(0.6)	-12%	Due to temporarily unfilled MoveUP position during the year.	5.0
21	M&E	13.5	13.8	14.4	13.7	15.0	14.4	(0.6)	-4%	Due to temporarily unfilled M&E positions during the year.	15.0
22	**Total**	18.8	18.7	19.3	18.6	20.0	18.8	(1.2)	-6%		20.0
23											
24	**Comparative Labour Loading**	**2017**	**2018**	**2019**	**2020**	**2021**					**2022**
25	**(percentages, except for salaries which is $000)**	**Actual**	**Actual**	**Actual**	**Actual**	**Approved**	**Projected**	**Variance**	**Variance %**	**Variance Explanation**	**Budget Request**
26	**Company-wide MoveUP Benefits as percentage of salaries** [1]	33%	30%	38%	40%						
27	**Company-wide MoveUP Incentives as percentage of salaries** [1] [4]	0%	0%	0%	0%						
28	**Subtotal Company-wide MoveUP Benefits & Incentives as percentage of salaries** [1] [3]	33%	30%	38%	40%	40%	40%				40%
29	**Company-wide M&E Benefits as percentage of salaries** [1]	31%	34%	32%	33%						
30	**Company-wide M&E Incentives as percentage of salaries** [1] [4]	15%	15%	17%	15%						
31	**Subtotal Company-wide M&E Benefits & Incentives as percentage of salaries** [1] [3]	46%	49%	49%	49%	51%	49%			Benefits & Incentives loading percentages in Approved based on 2020 inputs, as 2021 inputs were not available at time 2021 CMAE budget was developed.	49%
32	**CMAE MoveUP Salaries before cross-charging** [2]	$ 431	$ 428	$ 437	$ 445	$ 446	$ 397				$ 457
33	**CMAE MoveUP Benefits as percentage of salaries before cross-charging** [2]	33%	35%	38%	41%						
34	**CMAE MoveUP Incentives as percentage of salaries before cross-charging** [2] [4]	0%	0%	0%	0%						
35	**Subtotal CMAE MoveUP Benefits & Incentives as percentage of salaries** [2] [3]	33%	35%	38%	41%	40%	40%				40%
36	**CMAE M&E Salaries before cross-charging** [2]	$ 1,358	$ 1,435	$ 1,513	$ 1,462	$ 1,667	$ 1,554				$ 1,647
37	**CMAE M&E Benefits as percentage of salaries before cross-charging** [2]	31%	32%	31%	33%						
38	**CMAE M&E Incentives as percentage of salaries before cross-charging** [2] [4]	15%	15%	19%	16%						
39	**Subtotal CMAE M&E Benefits & Incentives as percentage of salaries** [2] [3]	47%	47%	50%	49%	51%	49%			Benefits & Incentives loading percentages in Approved based on 2020 inputs, as 2021 inputs were not available at time 2021 CMAE budget was developed.	49%

Notes: Canadian Office and Professional Employees Union, Local 378 (COPE) known as Movement of United Professionals (MoveUP).

(1) Company-wide Salaries have been adjusted for items not attracting benefit loading such as overtime, premiums, retiring allowance, temporary MoveUP employee salary, and other adjustments.

(2) CMAE Salaries before cross-charging have been adjusted for items not attracting benefit loading such as overtime, premiums, retiring allowance, temporary MoveUP employee salary, and other adjustments.

(3) Approved, Projected, and Budgeted Benefits & Incentives are included in a single labour loading rate based on budgeted amounts; breakdown is not available until after year-end.

(4) Data shown reflects incentive payments are made in the following fiscal year (e.g. 2018 payment amounts based on 2017 performance results). Effective April 1, 2015 MoveUP Gas employees no longer receive incentives.

Appendix C

EXCERPT FROM FEI CTS TIMC CPCN APPLICATION

[redacted]

5.3.2 Project Development Costs Were Necessary and Are Consistent with Original Forecasts

Table 12-1 from the Annual Review for 2019 Delivery Rates application (reproduced below), provided a forecast of development cost expenditures related to Phases 1 and 2:

Table 12-1: CPCN Development Costs ($000s)

Line No.	Phase	2018	2019	2020	Total
1	Phase 1	$ 5,680	$ 5,710	$ 230	$ 11,620
2	Phase 2	-	19,000	11,000	30,000
3					
4	Total	**$ 5,680**	**$ 24,710**	**$ 11,230**	**$ 41,620**

As FEI progressed with the Project development, the activities within each phase were further defined and consisted primarily of five categories:

1. The QRA needed to inform the Project, including priority and urgency (as described in Section 3.4.4);
2. Records and data refinement to provide the needed inputs for the QRA, and technical analysis and review of the QRA outputs;
3. A pilot project to test EMAT ILI tool behaviour in FEI pipelines (as described below in Section 5.3.3);
4. Scope development, FEED level engineering, and cost estimating required to define the Project to an appropriate level for this Application;
5. Application costs associated with the regulatory development and review of the submission to the BCUC.

Item 1 in the list above corresponds to the Phase 1 activities. Items 2 through 5 correspond to work associated with Phase 2.

As discussed in Section 6.2, the cost of these activities has been recorded in the approved TIMC Project Development deferral account. The costs are a combination of capital expenditures to be added to rate base, and one-time expenses supporting the development that FEI is proposing to amortize into rates over a three-year period. Further details for each item are provided in Table 5-3 below.

Table 5-3: Development Costs and Proposed Treatment

Item	Description	Phase	Proposed Treatment	Total Cost ($000s)
Initial QRA development	The costs for FEI's external consultant (JANA) to conduct a baseline system-level QRA. This work was required to meet previous commitments to the BCOGC to support the development of a segment-by-segment risk assessment process, as well as to confirm that SCC and cracking threats present a credible risk to FEI transmission pipelines.	Phase 1	Amortized expenses	10,552
QRA support costs	These are costs associated with collecting the necessary data (e.g., pipeline attributes, operating conditions, etc.) required as inputs for the QRA risk models. Additionally, this includes the internal and external costs associated with FEI's review and assessment of the QRA outputs. This was required to confirm the detailed scope and prioritization of work to be included in the CTS TIMC Project versus future TIMC projects.	Phase 2	Amortized expenses / Rate Base Capital	8,491
EMAT ILI Pilot Project	These costs are associated with retrofitting two pipelines in the FEI transmission system to accommodate running EMAT ILI tools. Also included are the costs of the tool runs themselves. Further information is provided in section 5.3.3 below.	Phase 2	Amortized expenses / Rate Base Capital	6,748
CTS TIMC Project Development	Costs associated with scope development, FEED level engineering, cost estimating, environmental investigations, and project management required to define the Project to an appropriate level for this Application. Also included are public consultation and Indigenous engagement costs.	Phase 2	Rate Base Capital	4,523
Application Costs	Costs associated with the preparation of the application, including external legal and regulatory reviews.	Phase 2	Amortized Expenses	510
			Total Costs	**30,824**

The total actual and projected development costs for the CTS TIMC project are $30.824 million to be incurred to the end of 2021, compared to the original estimated CPCN application development costs of $41.620 million for the entire TIMC project, as shown in Table 12-1 above. FEI notes, however, that the development costs for the future ITS TIMC CPCN application will continue to be collected in the deferral account until submission and a decision from the BCUC on that application. The costs for the ITS TIMC are expected to be substantially lower than those recorded to date, as the only items that will be incurred for this future application will be those associated with the scope development, FEED level engineering, cost estimating, environmental, project management, and consultation and engagement costs, shown in Table 5-3 above, as well as some incremental QRA refinement costs as it pertains to the ITS pipeline system.

[redacted]

6. PROJECT COSTS, FINANCIAL ANALYSIS, ACCOUNTING TREATMENT AND RATE IMPACT

[redacted]

6.2 *TIMC DEVELOPMENT COST DEFERRAL ACCOUNT*

As discussed in sections 1.2.2 and 5.3, FEI received BCUC approval with Order G-237-18, granting the creation of the non-rate base TIMC Development Cost deferral account. The deferral account was approved to attract a WACC return, with disposition to be proposed in a future application.

Costs captured in the TIMC deferral account include Preliminary Stage Development Costs, Pre-Construction Development Costs, and Application Costs:

- Preliminary Stage Development Costs consist of the QRA of FEI's transmission pipeline assets and the EMAT ILI Pilot project costs as discussed in Section 5.3.2.
- The Pre-Construction Development Costs include the costs related to front-end engineering and design, CPCN development costs including environmental assessments, First Nations and stakeholder consultations.
- CPCN application costs consist of costs for the regulatory process to review the Application. The cost estimate is based on a written process with two rounds of IRs and one workshop. The forecast application costs included are in line with the final costs for the IGU CPCN Application, adjusted to include the new Residential Consumers Intervener Group.

As set out in the Table 6-1 below, the December 31, 2020 ending balance in the TIMC deferral account is $9.2 million, based on gross costs of $23.7 million and $1.2 million of WACC return, less $9.3 million transferred to construction work-in-progress, less tax recovery of $6.4 million. The $9.3 million of construction work-in-progress that will be part of the Project capital cost was based on a year-end financial review of the deferral costs to determine which ones would be eligible for capitalization.

In 2021, FEI forecasts to spend $9.5 million on the last stages of Pre-Construction Development and $0.5 million on Application Costs. The $9.5 million of Pre-Construction Development Costs includes $3.9 million of costs related to QRA sustainment and EMAT inspections that will be capitalized. The forecast costs related to project scoping, planning, development, and regulatory proceeding costs will remain in the deferral.

Table 6-1: TIMC Development and Deferral Costs ($000s)

		Actual Costs ending December 31, 2020			2021 - Estimated Costs			
Line	Particular	Preliminary Stage Development Costs (1)	Pre-Construction Development Costs (2)	Total Pre-2021 Costs (3)	Pre-Construction Development Costs (4)	CPCN Application Costs (5)	Total 2021 Estimated Costs (6)	Total Column 3 + 6 (7)
1	Pre-Tax Costs [1]	14,641	9,100	23,741	6,573	510	7,083	30,824
2	Contingency [2]				2,900	41	2,941	2,941
3	**Subtotal: Development Costs**	**14,641**	**9,100**	**23,741**	**9,473**	**551**	**10,024**	**33,765**
4	Income Tax Recovery	(3,953)	(2,457)	(6,410)	(2,558)	(149)	(2,707)	(9,117)
5	Financing, WACC after tax	1,004	240	1,244	587	11	598	1,842
6	**Subtotal: Costs after tax and AFUDC**	**11,691**	**6,883**	**18,574**	**7,503**	**413**	**7,916**	**26,490**
7	Cost Capitalized[3]		(9,340)	(9,340)	(3,907)	-	(3,907)	(13,247)
8	**Total Deferral Costs**	**11,691**	**(2,457)**	**9,234**	**3,596**	**413**	**4,009**	**13,243**

Notes:

[1] *Column 7 agrees to Table 5-3.*

[2] *A portion of total project contingency seen in row 5 in table 6-2 has been allocated to the forecast development costs.*

[3] *Cost Capitalized include Pre-Tax Costs, Contingency, and Financing WACC.*

In total, FEI forecasts $33.8 million in gross development costs including contingency, less $9.1 million in income tax recovery, plus $1.8 million in financing costs, resulting in $26.5 million in development costs. FEI will capitalize $13.2 million of development costs related to the base line QRA, QRA sustainment, and EMAT inspections. This results in $13.2 million in development costs remaining in the deferral account at December 31, 2021.

FEI proposes to recover the balance of costs in the deferral account associated with the development of the CTS TIMC Application estimated at $13.2 million by amortizing the December 31, 2021 actual balance of those costs over 3 years commencing in 2022. The capitalized development costs, also estimated at $13.2 million, will enter rate base at January 1, 2022.

Note that FEI will continue to record costs associated with the future ITS TIMC application in the same deferral account, but these costs will be tracked and recorded separately from the CTS TIMC development costs and disposition will be requested as part of the ITS TIMC CPCN application.

[redacted]

Appendix D

PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-79-14 – FEI 2014 Core Market Administration Expense (CMAE) Budget						
1.	10	2	CMAE Budget Review	The Panel finds that the appropriate review process for the CMAE Budget is as part of the FEI revenue requirements applications. Therefore, until such time as FEI files its next revenue requirements application, the Panel directs FEI to submit future CMAE budgets separately to the Commission at least two weeks prior to the fourth quarter gas cost report to allow the Commission sufficient time to review the CMAE Budget, and to determine if there are sufficient variances from the previous CMAE Budget to warrant a more fulsome review. The Panel directs that the CMAE Budget review and approval process be included within the FEI revenue requirements application starting with the next such application by FEI.	Ongoing	Appendix B
G-237-18 – FEI Annual Review for 2019 Delivery Rates						
2.	8-9		TIMC Project	The Panel directs FEI to file the following information in its next revenue requirement application, which is expected to be filed sometime in 2019: 1. Updated actual and forecast project development costs compared to budget with explanations for variances; 2. Updated timeline for when FEI anticipates filing the CPCN with explanations for changes; and 3. Details on project scope and deliverables, including any changes thereto from what was provided in the current annual review proceeding.	Ongoing	Section 12.4.2.1
G-165-20 – FEI Multi-Year Rate Plan for 2020 through 2024						
3.	75	24	General Flow-through Deferral Account	The Panel directs FEI 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 12.4.2.2

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
4.	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 Initiative to report on	n/a
5.	99-100	37	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. • Transmission Reportable Incidents (number of reportable incidents to outside agencies) – FEI only. • Leaks per KM of Distribution System Mains (number of leaks on the distribution system per KM of distribution system mains) – FEI 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.	115	40	Systems Operations, Integrity and Security Expenditures	The Panel directs FEI 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: • Integrity management; • Maintaining system infrastructure; • Operations compliance and safety; • Cyber security; • Data analytics; • Gas control; • Canadian Energy Pipelines Association (CEPA) participation; and • Any other significant factors or miscellaneous items. 2. A description of how FEI 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.	Will be filed in FEI's Annual Review for 2023 Delivery Rates	n/a
8.	157	62	Innovation Fund	The Panel further directs FEI to include progress preports on the operation of FEI's Innovation Fund and projects funded thereby.	Ongoing during the MRP term	Section 10.3.3.
G-319-20 – FEI ANNUAL REVIEW FOR 2020 AND 2021 DELIVERY RATES						
9.	11		Revenue Deficiency	The Panel directs FEI to present the amortization of flow-through and other deferral accounts separately from depreciation and amortization in future Annual Reviews.	Ongoing during the MRP term	Section 1.4
10.	16	9	CMAE Budget	The Panel directs FEI to include, in it next revenue requirements or MRP application following the MRP term, a comprehensive review of the CMAE costs including consideration of whether these costs are conducive to a formulaic approach or whether they should continue to be forecast with flow-through treatment, and whether the current allocation percentages to the CCRA and MCRA remain appropriate.	Will be reviewed in FEI's next Revenue Requirements or MRP application	n/a

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
11.	17	10	COVID-19 Customer Recovery Fund Deferral Account	FEI is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the previously approved COVID-19 Customer Recovery Fund Deferral Account as discussed in Section 12.2.1 of the Application.	Status of COVID-19 exogenous factor treatment provided in this Application	Section 12.2.1
12.	17		2022 Long-Term Gas Resource Plan Deferral Account	The Panel approves…Creation of a rate base deferral account for the 2022 Long-Term Gas Resource Plan, with the amortization period to be determined in a future proceeding;	Amortization request will be filed in FEI's Annual Review for 2023 Delivery Rates	n/a
13.	17		MCRA and Other Revenue	The Panel approves…Effective November 1, 2020 and for the duration of the MRP term, to debit the MCRA and credit Other Revenue in the amount of $346.617 per MMcfd, as described in Section 5.3.2 of the Application.	Ongoing during the MRP term	Section 5.3.1

Appendix E

DRAFT ORDER

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ORDER NUMBER
G-xx-xx

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

and

FortisBC Energy Inc.
Annual Review for 2022 Delivery 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 Orders G-165-20 and G-166-20 approving a Multi-Year Rate Plan (MRP) for 2020 through 2024 (2020-2024 MRP Decision) for FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC), respectively. In accordance with the 2020-2024 MRP Decision, FEI is to conduct an annual review (Annual Review) process to set the delivery rates for each year;

B. By letter dated July 13, 2021, FEI proposed a regulatory timetable for the Annual Review of its 2022 delivery rates;

C. By Order G-227-21 dated July 27, 2021, the BCUC established the regulatory timetable for the Annual Review for FEI's 2022 delivery rates, which included FEI filing its Annual Review materials, intervener registration, one round of information requests, a workshop, FEI's response to undertakings at the workshop, and written final and reply arguments;

D. On July 30, 2021, FEI submitted its materials for the Annual Review for 2022 Delivery Rates Application (Application). In the Application, FEI forecasts an 8.07 percent delivery rate increase over the 2021 delivery rates, effective January 1, 2022;

E. The Application also requests the following deferral account approvals as described in Sections 7.5 and 12.4 of the Application:

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

      i. Transportation Service Report, with the amortization period to be determined in a future proceeding;

   ii. 2021 Generic Cost of Capital Proceeding, with the amortization period to be determined in a future proceeding; and

   iii. 2021 Renewable Gas Program Comprehensive Review, with the amortization period to be determined in a future proceeding;

2. Creation of a non-rate base deferral account titled the Regional Gas Supply Diversity (RGSD) Project Development Costs deferral account, attracting a weighted average cost of capital (WACC) return, with the amortization period to be proposed in a future application;

3. Amortization of the residual balance in the Waste Connections Costs and Recoveries deferral account in 2022; and

4. Approval to transfer the existing non-rate base 2017 & 2018 Revenue Surplus deferral account to rate base in order to eliminate the potential for future variances between actual and projected/forecast allowance for funds used during construction (AFUDC), and to amortize the remaining deferral account balance in 2022;

F. The Application also requests approval of the following:

   1. Approval to change the frequency of reporting on the COVID-19 Customer Recovery Fund Deferral Account from monthly to quarterly, as described in Section 7.5.2.1;

   2. A Biomethane Variance Account (BVA) Rate Rider for 2022 in the amount of $0.059 per gigajoule (GJ) as calculated in Section 10.3.1;

   3. Revenue Stabilization Adjustment Mechanism (RSAM) riders for 2022 in the amounts set out in Table 10-5 in Section 10.3.2; and

   4. The 2022 Core Market Administration Expense (CMAE) budget of $5.575 million, as set out in Appendix B, and the allocation of the CMAE between FEI's Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA) based on the existing allocation percentages of 30 percent and 70 percent, respectively; and

G. The BCUC has reviewed the Application and makes the following determinations.

NOW THEREFORE pursuant to sections 59 to 61 of the UCA, the BCUC orders as follows:

1. FEI is approved to recover the 2022 revenue requirement and the resultant delivery rate changes on a permanent basis, effective January 1, 2022, as filed in the Application, subject to any adjustments identified by FEI during the regulatory process and from any directives or determinations made in the reasons for decision issued concurrently with this order.

2. The following FEI deferral account treatments are approved:

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

      i. Transportation Service Report, with the amortization period to be determined in a future proceeding;

   ii. 2021 Generic Cost of Capital Proceeding, with the amortization period to be determined in a future proceeding; and

   iii. 2021 Renewable Gas Program Comprehensive Review, with the amortization period to be determined in a future proceeding;

  b. Creation of a non-rate base deferral account titled the Regional Gas Supply Diversity (RGSD) Project Development Costs deferral account, attracting a weighted average cost of capital (WACC) return, with the amortization period to be proposed in a future application;

  c. Amortization of the residual balance in the Waste Connections Costs and Recoveries deferral account in 2022; and

  d. Approval to transfer the existing non-rate base 2017 & 2018 Revenue Surplus deferral account to rate base, and to amortize the remaining deferral account balance in 2022.

3. FEI is approved to change the frequency of reporting on the COVID-19 Customer Recovery Fund Deferral Account from monthly to quarterly, as described in Section 7.5.2.1 of the Application;

4. A BVA Rate Rider for 2022 in the amount of $0.059 per GJ as calculated in Section 10.3.1 of the Application is approved.

5. RSAM riders for 2022 in the amounts set out in Table 10-5 in Section 10.3.2 of the Application are approved.

6. The 2022 CMAE budget of $5.575 million, as set out in Appendix B to the Application, and the allocation of the CMAE between FEI’s CCRA and MCRA based on the existing allocation percentages of 30 percent and 70 percent, respectively, are approved; and

7. FEI is directed to file with the BCUC, within 30 days of the issuance of this order, amended tariff pages 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