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September 28, 2021

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

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Project No. 1599232

Annual Review for 2022 Delivery Rates (Application)

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

On July 30, 2021, FEI filed the Application referenced above. In accordance with the regulatory timetable established in BCUC Order G-277-21 for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

Table of Content **Page No.**

A. GENERAL

1.0 Reference: REVENUE REQUIREMENT AND RATE CHANGES FOR 2022

Exhibit B-2 (Application), Section 1.1, pp. 1, 2; Section 1.4, p. 7; FEI Annual Review for 2020 and 2021 Rates proceeding, Exhibit B-2, Section 12.4.1, p. 165

Delivery Rate Increase

On pages 1 and 2 of FortisBC Energy Inc.'s Annual Review for 2022 Delivery Rates (Application), FortisBC Energy Inc. (FEI) states:

> 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 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. [Footnote references removed]

1.1 Please provide the annual bill impact of the proposed 2022 delivery rate increase after consideration of delivery rate riders and commodity charges, in dollars and percent increase, for the average residential, commercial and industrial customer, respectively.

Response:

Please refer to the table below which provides the annual bill impact of the proposed 2022 delivery rate increase for FEI's residential (Rate Schedule 1), commercial (Rate Schedules 2 and 3) and industrial (Rate Schedules 4 – 7) customers. FEI has excluded transportation customers as FEI does not have insight into the commodity charge portion of their total bills. In addition to the basic charge and delivery charge, the annual bill impacts include all commodity related charges and all delivery rate riders as listed below:

- Commodity-related charges:
  - Cost of Gas (Commodity Cost Recovery Charge)
  - Storage & Transport Charge
  - Rate Rider 6 – MCRA per GJ
- Delivery Rate Riders:
  - Delivery Rider 2 – Clean Growth Innovation Fund
  - Delivery Rider 3 – BVA Rate Rider per GJ
  - Delivery Rider 5 – RSAM per GJ (applies to Rate Schedules 1, 2, 3, and 23 only)

Further, the average residential annual bill impact as referenced in the preamble was based on the cost of gas rates on July 2021 when the Application was filed. Pursuant to Order G-266-21, the BCUC approved the cost of gas rates for FEI's RS 1 to 7 and RS 46 customers to increase from \$2.844 per GJ to \$3.844 per GJ, effective October 1, 2021. FEI has also included the average annual bill impacts in percentages based on the new cost of gas rates effective October 1, 2021 in the table below. For clarity, the average annual bill impacts *in dollars* remain the same since in this Application FEI is requesting approval only of delivery rate increases.

Rate Schedule	Average UPC (GJ)	Annual Bill Impact, incl. all riders and Commodity Related Charges ($)	Annual Bill Impact, incl. all riders and Commodity Related Charges on July 2021 (%)	Annual Bill Impact, incl. all riders and Commodity Related Charges on October 2021 (%)
Residential				
Rate Schedule 1	90	$ 45.18	4.57%	4.19%
Commercial				
Rate Schedule 2	340	$ 120.36	3.86%	3.48%
Rate Schedule 3	3,770	$ 999.05	3.36%	2.98%
Industrial				
Rate Schedule 4	7,450	$ 1,668.80	3.95%	3.36%
Rate Schedule 5	15,040	$ 3,902.34	3.95%	3.43%
Rate Schedule 6	2,930	$ 811.61	4.10%	3.57%
Rate Schedule 7	128,790	$ 21,379.14	3.14%	2.64%

1.2 If possible, please provide a forecast of the annual delivery rate changes expected until the end of the current Multi-Year Rate Plan (MRP) period (i.e., 2023 and 2024). If not possible, please explain why not.

Response:

FEI has not prepared a forecast of the annual delivery rate changes expected for 2023 and 2024 at this time as they require detailed development of each component of the revenue requirement, including the demand forecast, taxes, O&M expenses, interest rates, and capital additions in those years. Further, as directed by the BCUC in the MRP Decision and Order G-165-20[1], FEI must file an updated forecast of its 2023 and 2024 regular sustainment and other capital expenditures as part of the 2023 Annual Review. This updated forecast will impact 2023 and 2024 delivery rates and has not yet been developed.

To provide the requested rate increases with the information known today, the table below provides a high level estimate of 2023 and 2024 delivery rate changes assuming no changes to any components of FEI's revenue requirement, including demand forecasts, from the 2022 forecast, except for the following:

- Adjustment to FEI's formula O&M for 2023 and 2024 based on the 2022 net inflation factor of 3.324 percent;
- Adjustment to FEI's formula growth capital for 2023 and 2024 based on the 2022 net inflation factor of 3.324 percent and 2022 gross customer additions of 20,000;
- Forecasts of sustainment and other capital for 2023 and 2024 based on the original forecasts provided in FEI's MRP Application. FEI notes that, as explained above, the sustainment and other capital forecasts for 2023 and 2024 will be updated as part of the 2023 Annual Review; and
- Rate base additions in 2023 and 2024 from approved CPCNs, which include the Lower Mainland Intermediate System Upgrade (LMIPSU) project, Inland Gas Upgrade (IGU) project, and the Pattullo Gasline Replacement (PGR) project.

	2023	2024
High Level Forecast Delivery Rate Change (%)	4.00%	4.14%

[1] MRP Decision, p. 131.

1.3 Please provide a table that compares FEI's approved and achieved annual return on equity (before and after earnings sharing), in dollars and percentage, for 2020 actual, 2021 projected and 2022 to 2024 forecast.

Response:

Please refer to the table below for FEI's approved and achieved return on equity (ROE), before and after earnings sharing, for 2020 Actual. For 2021 Projected and 2022 to 2024 Forecast, FEI does not have actual information and is therefore unable to forecast any variance from the currently approved ROE of 8.75 percent. Therefore, before and after sharing amounts are equal in each of these years.

As discussed in Section 10.2 of the Application, earnings sharing will have a two-year lag. For example, the 2020 actuals are trued-up in the proposed 2022 delivery rates. 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.

Line	Particular	Reference	2020	2021	2022	2023	2024
1	Approved/Forecast Equity Portion of Rate Base ($000s)	See Note 1	1,943,106	2,006,789	2,082,530	2,189,885	2,291,156
2	Approved/Forecast ROE ($000s)	Line 1 x Line 3	170,022	175,594	182,221	191,615	200,476
3	Approved ROE (%)	G-129-16	8.75%	8.75%	8.75%	8.75%	8.75%
4							
5	Actual Equity Portion of Rate Base ($000s)	See Note 2	1,929,848				
6	Actual ROE Before-Sharing ($000s)	See Note 2	171,135				
7	Actual ROE Before-Sharing (%)	Line 6 / Line 5	8.87%				
8							
9	Actual Earnings Sharing ($000s)	See Note 2	(1,137)				
10	Actual ROE After-Sharing ($000s)	Line 6 + Line 9	169,998				
11	Actual ROE After-Sharing (%)	Line 10 / Line 5	8.81%				

Notes to table:

1) Approved/Forecast Equity Portion of Rate Base:
   - For 2020 & 2021 – approved by Order G-319-20;
   - For 2022 – see Section 11 of the Application, Schedule 26; and
   - For 2023 & 2024 – rate base forecast based on assumptions as discussed in the response to BCUC IR1 1.2.
2) Actual Equity Portion of Rate Base, ROE Before-Sharing and Earnings Sharing for 2020 is from FEI's 2020 Annual Report, page 26.3.

On page 7 of the Application, FEI states:

> 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 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.

On page 165 of FEI's Annual Review for 2020 and 2021 Rates application, FEI stated:

> FEI is also requesting approval to draw down the remaining balance of the deferral account in 2021 rates, which equals $35.287 million pre-tax, which will result in a 6.59 percent 2021 delivery rate increase compared to 2020 delivery rates. Without returning a portion of the existing surplus in 2021, the 2021 delivery rate increase would be 10.87 percent compared to 2020 levels. [Footnote references removed]

1.4 Please provide a breakdown of the 8.07 percent forecast delivery rate increase for 2022, showing the percentage point impact (increase or decrease) attributable to each component of the revenue requirement.

Response:

Please refer to the table below for the breakdown of the 8.07 percent forecast delivery rate increase by each component of the revenue requirement.

Components	Figure 1-1 ($ millions)	%
Demand Forecast	(2.275)	(0.26%)
Other Revenue	0.359	0.04%
Net O&M	1.850	0.21%
Depreciation	8.512	0.96%
Deferral Amortization	19.037	2.15%
Financing and Return on Equity	8.928	1.01%
Taxes	(0.215)	(0.02%)
Elimination of Accumulated Revenue Surplus	35.287	3.98%
Total Deficiency	71.483	8.07%
Non-Bypass Margin at 2021 Approved Rates	885.532	

1.5 Please provide the delivery rate increase for 2022 under the scenario that the prior years' accumulated revenue surplus of $35.287 million was not applied to the 2021 delivery rates. In other words, what would the delivery rate increase for 2022 be if the 2021 approved rate increase had been 10.87 percent?

<u>Response:</u>

This response also addresses BCUC IR1 1.6.

Please refer to the table below for the annual delivery rate increases (Line 15) and revenue deficiencies/surpluses (Line 14) from 2017 to 2021 if FEI had not received approval to defer any revenue deficiencies/surpluses over those years. The delivery rate change shown for 2022 is accordingly based on the assumption that there were no deferred deficiencies/surpluses applied in the previous years.

As the table below shows, without the accumulation of the revenue deficiencies/surpluses in prior years and the use of the accumulated surplus balance in 2021, the 2022 delivery rate increase would be 3.93 percent.

The analysis below demonstrates the key benefit of FEI's approved approach of deferring the deficiencies/surpluses between 2017 and 2020, as it has resulted in smoother delivery rate changes than the alternative of not deferring the deficiencies/surpluses in those years. Line 15 below shows that, had FEI not received deferral treatment, the year-to-year delivery rate changes over the period from 2017 to 2022 would have been volatile, ranging from a rate <u>decrease</u> of 4.28 percent in 2017 to a rate <u>increase</u> of 11.17 percent in 2021. Conversely, by deferring and accumulating the deficiencies/surpluses over the same period, the delivery rates (as approved from 2017 to 2021, and proposed for 2022) were smoother, with gradual increases annually from zero percent to 8.07 percent, and a difference of 8.07 percent between the highest and lowest delivery rate change (as opposed to a difference of 15.45 percent between the highest and lowest delivery rate change under the alternative scenario of not deferring the deficiencies/surpluses).

Line	Particular	Reference	2017	2018	2019	2020	2021	2022
1	Non-Bypass Margin @ Existing Rate ($000s)	Prev Yr: Line 19 x Cur Yr: Line 17	747,902	767,070	812,048	804,581	822,867	920,842
2	Bypass and Special Rate Margin ($000s)	Schedule 19 (2017-2021: See Note 1; 2022: Section 11)	26,813	26,954	30,002	35,362	50,021	46,243
3	Total Margin @ Existing Rate	Line 1 + Line 2	774,715	794,024	842,050	839,943	872,888	967,085
4								
5	Revenue Requirement ($000s)							
6	O&M	Schedule 16 (2017-2021: See Note 1; 2022: Section 11)	236,050	241,481	246,088	262,297	274,770	276,620
7	Depreciation & Amortization	Schedule 16 (2017-2021: See Note 1; 2022: Section 11)	199,526	222,212	230,699	232,160	280,628	308,177
8	Property Tax	Schedule 16 (2017-2021: See Note 1; 2022: Section 11)	67,450	67,157	67,559	67,959	71,811	73,397
9	Other Revenue	Schedule 16 (2017-2021: See Note 1; 2022: Section 11)	(42,958)	(46,048)	(44,893)	(37,597)	(41,995)	(41,636)
10	Income Tax	Schedule 16 (2017-2021: See Note 1; 2022: Section 11)	35,651	50,137	52,972	35,844	54,012	52,211
11	Earned Return	Schedule 16 (2017-2021: See Note 1; 2022: Section 11)	246,984	281,696	291,732	315,305	325,561	334,489
12	Total Expenses ($000s)	Sum of Line 6 to 11	742,703	816,634	844,157	875,968	964,787	1,003,259
13								
14	**Deficiency/(Surplus) ($000s)**	**Line 3 - Line 12**	**(32,012)**	**22,611**	**2,107**	**36,025**	**91,899**	**36,174**
15	**Delivery Rate Increase (%)**	**Line 14 / Line 1**	**-4.28%**	**2.95%**	**0.26%**	**4.48%**	**11.17%**	**3.93%**
16								
17	Non-bypass Volume (TJ)	Schedule 19 (2017-2021: See Note 1; 2022: Section 11)	182,942	196,021	201,573	199,203	194,999	196,294
18	Non-bypass Margin Required ($000s)	Line 1 + Line 14	715,890	789,680	814,155	840,606	914,766	957,016
19	Effective Revised Rate ($/GJ)	Line 18 / Line 17	3.913	4.029	4.039	4.220	4.691	4.875
20								
21	**Approved Deficiency/(Surplus) ($000s)**	**Schedule 1 (2017-2021: See Note 1; 2022: Section 11)**	**-**	**-**	**8,679**	**16,300**	**54,582**	**71,483**
22	**Approved Delivery Rate Increase (%)**	**Schedule 1 (2017-2021: See Note 1; 2022: Section 11)**	**0.00%**	**0.00%**	**1.10%**	**2.00%**	**6.62%**	**8.07%**

Note 1: 2017: G-182-16; 2018: G-196-17; 2019: G-237-18 & G-10-19; 2020/2021: G-139-20

1.6 Please provide the respective annual delivery rate increases and revenue deficiencies/surpluses for the last 5 years (i.e. 2017 to 2021) in the absence of any application of the 2017 & 2018 Revenue Surplus deferral account to mitigate the rate increases in those years that had revenue deficiencies. In other words, what would have been the delivery rate increases or decreases and the revenue deficiencies/surpluses for 2017 to 2021 if there were no prior years' accumulated revenue surplus?

Response:

Please refer to the response to BCUC IR1 1.5.

2.0 Reference: REVENUE REQUIREMENT AND RATE CHANGES FOR 2022

Exhibit B-2, Section 1.4.5, p. 6; Section 12.4.2.2, pp. 145–147

Amortization of Deferral Accounts

On page 6 of the Application, FEI states:

> 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.

2.1 Please explain why amortization of the DSM deferral account has increased by $6.933 million compared to 2021. As part of the response, please provide a breakdown of the $6.933 million increase by each significant driver of the increase.

Response:

The increase in amortization of $6.933 million from 2021 to 2022 is primarily attributable to the 2021 Projected deferral account additions of $89.775 million ($65.852 million after tax), which are amortized over 10 years, and consist of the following:

Rate Base Deferral Account Additions	$29.932 million
Non-Rate Base Deferral Account Additions	58.672 million
Total Additions before AFUDC	88.604 million
AFUDC on Non-Rate Base Deferral Account	1.171 million
Total Additions	$89.775 million

The total 2021 Projected additions of $88.604 million (before AFUDC) shown above are equal to the 2021 forecast expenditures of $88.803 million (excluding the portion allocated to Fort Nelson) as shown in the 2019-2022 DSM expenditure schedule accepted by Order G-10-19, which details the significant drivers of these expenditures as follows:

Program Area	2021 Expenditures ($million)
Residential	28.476
Commercial	27.437
Industrial	3.644
Low Income	6.984

Program Area	2021 Expenditures ($million)
Conservation Education and Outreach	8.578
Innovative Technologies	2.631
Enabling Activities	9.231
Portfolio Level Activities	1.822
Total	**88.803**

2.2 Please provide a table showing the balance of the DSM deferral account, including the annual amortization expense of the DSM deferral account and the DSM deferral account additions from 2019 to 2022. Please also include the percentage year over year change in DSM amortization expense and DSM deferral account additions, respectively.

2.2.1 Please reconcile the annual DSM deferral account additions from the response above to the DSM expenditure schedule accepted by the BCUC by Order G-10-19.[2]

Response:

Please refer to the table below for balances in both the rate base and non-rate base DSM deferral accounts, including annual additions and amortization expense for the years 2019 to 2022. Also included below is the reconciliation of the DSM additions (Line 27) to the amounts accepted by Order G-10-19, in addition to Order G-135-21, which approved an additional $2.290 million of expenditures in 2022. Please also refer to Line 30 and Line 32 for the percentage year-over-year change in DSM deferral account additions and DSM amortization expense, respectively. FEI also notes the DSM additions for Fort Nelson (Line 19) in columns 5 and 6 are an allocation of the total DSM additions based on the average customer count between FEI and Fort Nelson.

[2] https://www.ordersdecisions.bcuc.com/bcuc/orders/en/item/361056/index.do?q=G-10-19, p. 5.

DSM Deferral Accounts Continuity
2019-2022

Line No	Particulars	Reference	Actual 2019	Actual 2020	Projected 2021	Forecasted 2022	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**Demand Side Management - Rate Base**						
2	Opening Balance		100,790	137,957	165,474	195,760	
3	Opening Balance Transfer from Non Rate Base		30,393	25,458	33,412	44,002	
4	Additions		29,969	29,940	29,932	29,935	
5	Tax		(8,092)	(8,084)	(8,082)	(8,082)	
6	Amortization		(15,103)	(19,797)	(24,976)	(31,910)	
7	Ending Balance		**137,957**	**165,474**	**195,760**	**229,705**	
8							
9	**Demand Side Management - Non Rate Base**						
10	Opening Balance		30,393	25,458	33,412	44,002	
11	Opening Balance Transfer to Rate Base		(30,393)	(25,458)	(33,412)	(44,002)	
12	Additions		34,575	45,366	58,672	67,798	
13	AFUDC		218	295	1,171	1,353	
14	Tax		(9,335)	(12,249)	(15,841)	(18,305)	
15	Ending Balance		**25,458**	**33,412**	**44,002**	**50,846**	
16							
17	**Total Additions**						
18	FEI (Total of RB and NRB)	Line 4 + 12	64,544	75,306	88,604	97,733	326,187
19	FN (Total of RB and NRB)		79	117	199	213	608
20			64,623	75,423	88,803	97,946	326,795
21							
22	**Total Approved**						
23	G-10-19		66,350	72,577	88,803	96,775	324,505
24	G-135-21		-	-	-	2,290	2,290
25			66,350	72,577	88,803	99,065	326,795
26							
27	**Reconciliation Over (Under)**	Line 20 - 25	(1,727)	2,846	-	(1,119)	-
28							
29							
30	**Year-over-Year % Change – DSM Additions**	Line 18		16.67%	17.66%	10.30%	
31							
32	**Year-over-Year % Change – DSM Amortization**	Line 6		31.08%	26.16%	27.76%	

On pages 145 to 147 of the Application, FEI explains the projected variances in delivery margin for 2021 and 2020, respectively, stating:

- 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.

2.3 Please explain whether the unfavourable industrial and commercial margins experienced in 2020 and 2021 were impacted by the COVID-19 pandemic. If so, please explain how. If not, please explain why not.

Response:

The unfavourable industrial margins in 2020 and 2021, as mentioned in the preamble, were a result of lower LNG demand from the non-NGT segment. As discussed in Section 3.3.4 of the Application, this was primarily due to the COVID-19 pandemic which led to limited availability of space on ships into and out of China, significantly increasing the cost of shipping LNG for FEI's non-NGT LNG customers. FEI's 2022 forecast for non-NGT LNG demand is more favourable, as reflected in Table 3-2 of the Application, based on discussions with customers and the expectation that restrictions due to the COVID-19 pandemic will start to lift. Please also refer to the responses to BCUC IR1 6.1 and 6.2 for further discussion on FEI's non-NGT LNG forecasts.

For the commercial segment, as mentioned in the preamble, the unfavourable margins in 2020 and 2021 were primarily a result of lower commercial customer additions than originally forecast, as reflected in Figure 3-5 of the Application. FEI notes the commercial customer segment is very diverse; therefore, it is difficult to pinpoint the specific factor(s) that might have led to the lower commercial customer additions than originally forecast. However, as discussed in Section 3.3.2.1 of the Application, FEI believes the COVID-19 pandemic likely had significant impacts on commercial sectors such as tourism, hotels and restaurants, as well as small businesses, due to various restrictions imposed during the pandemic. FEI is unable to predict if the COVID-19 pandemic will continue to impact the commercial segment in 2022 and beyond. As discussed in Appendix A3 of the Application, FEI's forecasting method for commercial customer additions is based on the average of net customer additions from the prior three years (i.e., from 2018 to 2020).

Any variances between forecast and actual/projected delivery margin are flowed through to customers.

2.4 Please explain whether the unfavourable industrial and commercial margins experienced in 2020 and 2021 are expected to continue in 2022 and beyond. Why or why not?

Response:

Please refer to the response to BCUC IR1 2.3.

B. FORMULA DRIVERS

3.0 Reference: FORMULA DRIVERS

Exhibit B-2, Section 2.2, Table 2-1, p. 9; Section 2.3, Table 2-2, p. 10; FEI Annual Review for 2020 and 2021 Rates proceeding, Exhibit B-2, Section 2.3, Table 2-2, p. 10; Exhibit A2-1, Compliance Filing to the BCUC's Decision and Order G-319-20 for FEI's Annual Review for 2020 and 2021 Delivery Rates dated December 11, 2020 (Compliance Filing), Table 2-1, p. 2

Inflation and Growth Factor Calculation

The following is an extract of Table-2-1 on page 9 of the Application:

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						

The following is an extract of Table 2-1 from FEI's Annual Review for 2020 and 2021 Delivery Rates Compliance Filing:

Table 2-1: Updated 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
25	Jul-2019	132.4	996.11								
26	Aug-2019	132.2	1,003.60								
27	Sep-2019	132.0	1,008.09								
28	Oct-2019	132.2	1,015.74								
29	Nov-2019	131.8	1,012.40								
30	Dec-2019	131.7	1,014.52								
31	Jan-2020	132.1	1,025.61								
32	Feb-2020	132.9	1,025.17								
33	Mar-2020	132.3	1,029.38								
34	Apr-2020	131.2	1,106.54								
35	May-2020	131.5	1,126.59								
36	Jun-2020	132.6	1,097.37	132.1	1,038.43	1.596%	5.745%	48%	52%	3.754%	2021

3.1 Please explain why the BC AWE data for July 2019 through June 2020, as provided in Table 2-1 of the Application, is different from the BC AWE data for the same period, as provided in FEI's 2020 and 2021 Annual Review Compliance Filing.

Response:

The monthly BC AWE amounts from July 2019 to June 2020 have changed because Statistics Canada periodically revises their AWE results. FEI uses the most current set of AWE results in each year's Annual Review filing.

On page 10 of the Application, FEI states: "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."

3.2 Please provide details on the source and how FEI forecasted gross customer additions of 20,000 for 2022. Please provide any calculations as necessary.

Response:

The 2022 Forecast of gross customer additions has been estimated based on the method described on page 11 of the Application. Please also refer to the response to BCUC IR1 3.3.

Generally, housing demand currently outstrips supply and this circumstance is expected to remain into 2022. The 2022 forecast gross customer additions are reasonable and supported by market conditions along with current interest in connecting to the gas system via leads and connection requests.

3.3 Please explain how and why FEI estimates 20,500 for its 2021 customer growth.

Response:

The forecast of 20,500 for 2021 is reflective of the current market for new homes and the increased demand for natural gas service to existing homes and is a 30 percent increase over the original forecast of 16,000. This is primarily driven by the COVID-19 pandemic which has had a significant and positive impact on the building, renovation and real estate markets. The building and real estate industry quickly adapted to the new reality of COVID-19 pandemic rules and protocols.

At the time that FEI filed its 2021 forecast in the Annual Review for 2020 and 2021 Delivery Rates Application, FEI did not foresee the positive impact that the COVID-19 pandemic would have on new builds and existing home renovations/upgrades in BC. Two factors are playing a significant role in accelerating the growth in new homes being built and existing homes being updated/upgraded (which often includes a new gas service):

1. **Increased demand for new homes during the COVID-19 pandemic.** The demand for new homes has increased as many people who are now working from home want larger homes in a more suburban surrounding. Continued low interest rates have added to this market demand.

2. **Available Cash.** For those still working, available disposable income savings began to increase significantly during the pandemic. This was primarily due to the lack of opportunity to spend on vacations, food and entertainment, etc. As a result, some found that they now had the down payment to qualify for a new home. For those who already owned their home, many opted to invest in home renovations and upgrades such as updating heating equipment.

FEI's expectations for the remainder of 2021 and for 2022 do not indicate that this demand for new homes will drop significantly over this period. Demand continues to outstrip supply throughout BC, and is forecast continue in this manner for at least the next year. Therefore, FEI believes that its 2021 projected and 2022 gross forecast gross customer additions are reasonable and supported by market conditions.

3.3.1 Please explain the reasons for the difference between the 2021 approved gross customer additions of 16,000 and FEI's expectation of 2021 customer growth of 20,500.

Response:

Please refer to the response to BCUC IR1 3.3.

3.3.2 Please explain whether the revised 2021 customer growth estimate (i.e., 20,500) impacts the proposed 2022 delivery rates. If so, how?

Response:

The higher projected 2021 customer growth does not impact the proposed 2022 delivery rates.

As explained in Section 7.2.1 of the Application, the true-up of formula growth capital requires the actual gross customer additions (GCA) for a full year be available. As such, the proposed 2022 delivery rates are only affected by the actual gross customer additions from 2020 (i.e., a two-year lag). The 2021 customer growth will affect 2023 and future delivery rates, once the actual 2021 GCAs are known.

FEI provides the following example of how the 2021 GCAs would impact future rates, based on its best estimates at this time.

Using the 20,500 projected GCAs, combined with FEI's knowledge of current results and capital cost projections for the remainder of 2021, the 2021 projected growth capital expenditure estimate is approximately $105 million. This estimate is approximately $40 million greater than the formula growth capital expenditure calculation of $64.8 million which was embedded in 2021 delivery rates. Of the $40 million, approximately half is a volume variance (due to the higher GCAs) and half is due to cost pressures, primarily from customer-driven system improvements and large mains extensions, as well as contractor price increases above what was embedded in the formula.

Under FEI's MRP, future delivery rates will be impacted in two ways. First, the volume variance (the capital expenditure variance due to the GCAs being higher than the number of GCAs that were included in the GCA formula) will be added to rate base in 2023, in the same way that the 2020 GCA true-up occurred in 2022 (see Table 7-2, row 16 of the Application). Second, the remaining capital expenditure variance will impact earnings sharing for 2021 and future years of the MRP term, although the delivery rate impacts will occur starting in 2023 due to the lag in calculating the earnings sharing results. As earnings sharing is calculated based on the variance in FEI's overall ROE, it will be impacted by the total variance in rate base which is impacted by FEI's total capital expenditures (growth, sustainment, and other), and many other items. But, for the purposes of illustrating the impact that the 2021 growth capital expenditures variance would have on future ROE, FEI has assumed all other items would be equal to the approved.

With these assumptions, FEI estimates that the delivery rate impact of the 2021 growth capital expenditure variance of $40 million would be an approximate 0.02 percent increase in 2023 and a further 0.35 percent increase in 2024 (once the full year of rate base impacts is included), when compared to the proposed 2022 forecast delivery margin.

The impacts described above are only the incremental delivery rate impacts of the 2021 growth capital expenditures themselves. These impacts will be offset by incremental revenues from the 2021 GCAs, which will be realized in delivery rates as early as 2022 through both higher forecast customers in 2022 and the flow-through of additional revenues from 2021. These incremental revenues are discussed in the response to BCOAPO IR1 14.1 in relation to the 2020 GCAs.

FEI presents following calculation of the 2022 Average Customer growth factor in Table-2-2 on page 10 of the Application:

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

On page 11 of the FEI Annual Review for 2020 and 2021 Delivery Rates application, FEI provided the following Average Customer growth factor calculation for 2020 and 2021:

Table 2-2: Average Customer (AC) Growth Factor Calculation[11]

Line No.		2020	2021	Reference
1	Average Customer Forecast - Prior Year	1,031,862	1,043,259	
2	Average Customer Forecast - Test Year	1,043,259	1,053,292	Schedule 19, Row 30
3	Average Customer Change	11,397	10,033	Line 2 - Line 1
4	Customer Growth Factor Multiplier	75%	75%	
5	Change in Customers - Rate Setting Purposes	8,548	7,525	Line 3 x Line 4
6				
7	*Average Customer Continuity for Rate Setting Purposes*			
8	Average Customer Forecast - Prior Year	1,031,862	1,040,410	Prior Year Line 10
9	Change in Customers - Rate Setting Purposes	8,548	7,525	Line 5
10	Average Customer Forecast - Rate Setting Purposes	1,040,410	1,047,935	Line 8 + Line 9

3.4 Please explain and provide the calculation for the 12-month weighted average additions shown in Line 17 in Table 2-2 of the Application.

Response:

Please refer to the table below for the calculation of the 12-month weighted average additions. Because the additions occur on a monthly basis, a 12-month weighted average is a more accurate reflection of the average number of customer additions over a year than a straight average. For example, the January additions are weighted for a full year (i.e., 12 months or a weighting of

12/12) while December additions are weighted for one month only (i.e., a weighting of 1/12). A weighted average is consistent with how FEI has calculated its average customer additions in its past annual review applications.

			2020 Actual			2021 Projected			2022 Forecast		
Line	Particular	Reference	Additions	Monthly Weighting	Weighted Additions	Additions	Monthly Weighting	Weighted Additions	Additions	Monthly Weighting	Weighted Additions
	(1)	(2)	(3)	(4)	(5) = (3) x (4)	(6)	(7)	(8) = (6) x (7)	(9)	(10)	(11) = (9) x (10)
1	January		1,544	12/12	1,544	1872	12/12	1,872	1795	12/12	1,795
2	February		1,028	11/12	942	883	11/12	809	840	11/12	770
3	March		403	10/12	336	577	10/12	481	552	10/12	460
4	April		722	9/12	542	358	9/12	269	329	9/12	247
5	May		726	8/12	484	206	8/12	137	179	8/12	119
6	June		921	7/12	537	172	7/12	100	143	7/12	83
7	July		824	6/12	412	230	6/12	115	183	6/12	92
8	August		848	5/12	353	655	5/12	273	609	5/12	254
9	September		338	4/12	113	686	4/12	229	633	4/12	211
10	October		2,006	3/12	502	2213	3/12	553	2092	3/12	523
11	November		2,010	2/12	335	1979	2/12	330	1882	2/12	314
12	December		2,028	1/12	169	1890	1/12	158	1800	1/12	150
13	**12-Mth Weighted Average**	**Sum of Ln 1 to 12**			**6,268**			**5,326**			**5,017**

3.5 Please clarify whether FEI has changed the average customer (AC) growth factor calculation methodology for 2022 compared to the methodology used for 2020 and 2021.

3.5.1 If so, please provide the following:

(i) The rationale for the change;

(ii) Why the "Change in Average Customers for Rate Setting Purposes" is based on a three-year average (i.e. Actual 2020 to Forecast 2022) for 2022 versus the difference in the average customer forecast between the prior year (2021) and test year (2022) as shown in the FEI Annual Review for 2020 and 2021 Delivery Rates;

(iii) The 2022 average customer forecast for rate setting and rate impact using the calculation methodology in the FEI Annual Review for 2020 and 2021 Delivery Rates.

3.5.2 If not, please explain how the two calculation methodologies are the same.

Response:

FEI has not changed the methodology for calculating the average customer (AC) growth factor in 2022. FEI has only changed the presentation of the calculation in Table 2-2.

Table 2-2 of the Application is an expanded version of Table 2-2 from the FEI Annual Review for 2020 and 2021 Delivery Rates Application (2020 and 2021 Annual Review). The purpose of the expanded version is to provide additional calculations and cross-referencing to Appendix A2 for the average customer forecast numbers (i.e., Line 22 of Table 2-2 of the Application vs. Line 2 of the 2020 and 2021 Annual Review version of the table). This was done to provide assurance to the BCUC that a consistent customer forecast was applied throughout the Application.

Please refer to Table 1 below for the AC growth factor calculation using the data from this Application presented in the format of Table 2-2 from the 2020 and 2021 Annual Review.

Both versions of the table produce the same average customer forecast for rate-setting purposes, which is 1,059,333, as shown in Line 29 of Table 2-2 of the Application and Line 10 in the table below.

Table 1: 2022 Data Presented in 2020 and 2021 Annual Review Table 2-2 Format

Line No.		Actual 2020	Projected 2021	Forecast 2022	Reference
1	Average Customer Forecast - Prior Year	1,031,862	1,044,622	1,057,078	
2	Average Customer Forecast - Test Year	1,044,622	1,057,078	1,068,490	Schedule 19, Line 37, Col 9
3	Average Customer Change	12,760	12,455	11,413	Line 2 - Line 1
4	Customer Growth Factor Multiplier	75%	75%	75%	
5	Change in Customers - 2022 Rate Setting Purposes	9,570	9,341	8,560	Line 3 x Line 4
6					
7	*Average Customer Continuity for 2022 Rate Setting Purposes*				
8	Average Customer Forecast - Prior Year	1,031,862	1,041,432	1,050,774	Prior Year Line 10
9	Change in Customers - 2022 Rate Setting Purposes	9,570	9,341	8,560	Line 5
10	Average Customer Forecast - 2022 Rate Setting Purposes	1,041,432	1,050,774	1,059,333	Line 8 + Line 9

The “change in average customers for rate setting purposes” in the expanded Table 2-2 of the Application is not based on a three-year average. It is still based on prior years and uses the same methodology that was used in Table 2-2 of the 2020 and 2021 Annual Review. However, instead of multiplying the individual year’s “change in customers” by the 75 percent growth factor multiplier and then presenting it as a cumulative continuity of “average customers for rate setting purposes”, as was done in the 2020/2021 version of Table 2-2, the new expanded Table 2-2 shown in this Application calculates the total average customer change over the three years from 2020 to 2022 first, before applying the 75 percent growth factor multiplier to the total. The end result is the same between the two formats; the difference is simply in the presentation of how the end result is derived.

C. DEMAND FORECAST AND REVENUE AT EXISTING RATES

4.0 Reference: LOAD FORECAST

Exhibit B-2, Section 3.3.3, pp. 22–24

Industrial Demand

On pages 22 to 23 the Application, FEI describes the customer survey used to forecast industrial demand. On page 22 of the Application, FEI states:

> […] 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.

4.1 Please compare the industrial customer survey response rate and the corresponding load that the respondents represented as a percentage of the total industrial load in the years 2016 to 2021 in a table format.

4.1.1 Please comment on the trend(s), if any, on the customer survey response rate.

Response:

The following table shows the industrial customer survey response rate and the corresponding load that the respondents represented as a percentage of the total industrial load in the years 2016 to 2021.

Industrial Survey Response Rate	2016	2017	2018	2019	2020	2021
Demand	89.0%	88.6%	89.4%	89.1%	89.3%	90.0%
Customers	51.0%	49.4%	49.4%	48.5%	46.7%	47.9%

As shown in the above table, the response rates by demand have been very consistent. The 2021 survey that was just completed achieved a demand response rate of 90 percent, which is the highest response rate achieved to date. While the response rate by customers has decreased slightly between 2016 and 2021, FEI does not consider this to be representative of a trend, particularly as the customer response rate for 2021 increased compared to 2020.

4.2 Please explain the measures that FEI has taken (or is undertaking) to improve the customer survey response rate.

Response:

The industrial forecast is based on the demand forecasts gathered from the industrial survey. As shown in the response to BCUC IR1 4.1, FEI achieved a demand response of 90 percent for the first time this year.

To support continuous improvement, each year FEI addresses any issues and implements any minor changes that it believes will enhance the ease of responding to the survey and/or will increase the usefulness and accuracy of the results. In 2020, some minor changes were made to the survey software to allow customers to provide comments about why their forecast was higher or lower than in the past. In addition, some minor formatting changes were made to the survey form itself to reduce the possibility of typographical errors. Further, the message sent in the introductory, survey and reminder email messages is reviewed each year for clarity and edited as needed.

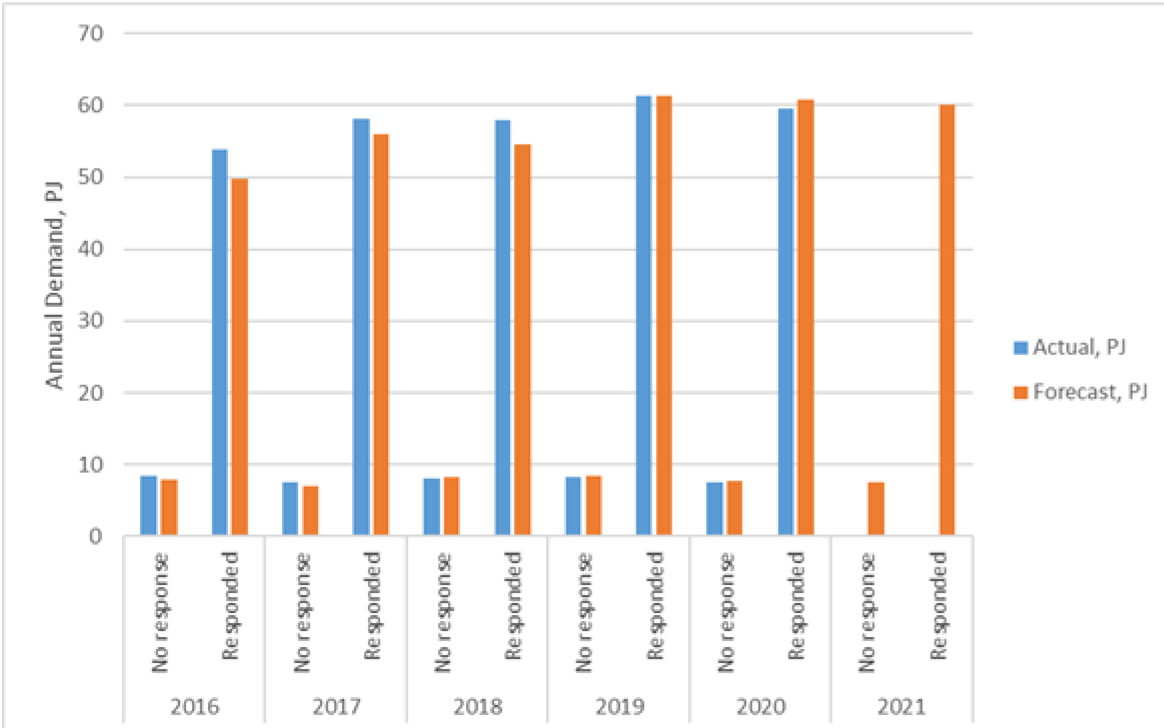
FEI considers a demand response rate of 90 percent to be very strong and, despite ongoing improvement efforts, FEI is cognizant that it is not reasonable to expect a 100 percent response rate. FEI believes the consistently high response rate for the industrial survey is a result of the ease of use of the Industrial Survey Web Site tool. Using this tool, customers can review their prior consumption and survey submissions online as they enter their future forecast.

4.3 Please compare the forecast and actual load among non-respondents and respondents, respectively, from 2016 to 2021 in a bar graph and table format. As part of the response, please include the forecast and actual load in PJ.

4.3.1 Based on the response above, please comment on the load forecast accuracy associated with respondents and non-respondents with an explanation of any variances between the two groups since 2016.

Response:

The following bar chart and table compare the forecast and actual load among non-respondents and respondents from 2016 through 2020. FEI has also provided the 2021 forecast load between non-respondents and respondents, but cannot provide the comparison for 2021 because the actual load will not be available until early 2022.



	Actual, PJ	Forecast, PJ
2016		
No response	8.4	7.9
Responded	53.8	49.7
2017		
No response	7.5	7.0
Responded	58.1	56.0
2018		
No response	8.0	8.3
Responded	58.0	54.6
2019		
No response	8.2	8.5
Responded	61.3	61.4
2020		
No response	7.5	7.7
Responded	59.5	60.8
2021		
No response		7.6
Responded		60.1

The chart shows that both the annual demand and the variance from the non-responding group of customers is very small, and in all cases the variance is smaller than the variance from the responders.

The five-year average variance for the non-responding customers was 0.9 percent. Many of the non-responding customers are strata corporations that have very consistent demand year over year which is reflected in these results.

The five-year average variance for the responding customers was -2.9 percent and is larger because demand for many of these customers depends on the demand for the goods and services they produce. In addition, other factors such as the cost of competing energy sources affects their consumption relative to the forecasts they provide.

On page 23 of the Application, FEI further explains that "the demand from the industrial rate schedules is forecast to increase by 0.3 PJ in 2022F as compared to the 2021S."

4.4 Please explain the factors that contribute to a higher industrial load forecast for 2022. If applicable, please explain if these new loads are expected to persist in future years.

Response:

The forecast increase in industrial demand from 88.6 PJs in 2021 to 88.9 PJs in 2022 is very minor, at 0.3 PJ or 0.34 percent. This is less than the absolute average year-over-year change in industrial demand since 2011 of 2.1 PJs, as shown in Table 2-1 in Appendix A2.

Given that the aggregate increase from 2021 to 2022 is only one third of one percent and represents industrial survey responses from over 1,000 customers in 81 different industry segments, FEI is unable to comment on the factors that caused survey participants to forecast this minor increase.

5.0 Reference: LOAD FORECAST

Exhibit B-2, Appendix A3, pp. 6–7

Forecast Methodologies: Commercial Customer Additions

On pages 6 to 7 of Appendix A3 to the Application, FEI explains how it calculates forecast commercial customer additions:

> The three-year average [net] additions […] is 433, 433 additions are forecast in each of 2021 and 2022.
>
> 2021$S\ Customers$ = 2020 $Customers$ + 3 $Yr\ Avg\ Additions$
>
> Using the data above:
>
> 2021S = 55,052 = 54,619 + 433

5.1 Please confirm, or explain otherwise, that the forecasting method for commercial customer additions has remained the same in the period between 2016 to 2020.

5.1.1 Please provide a table comparing the actual and the forecasted commercial customer additions for the period 2016 to 2020.

<u>Response:</u>

Confirmed. The basic three-year average method for forecasting commercial customer additions has not changed in the period from 2016 to 2020. However, as a result of a large migration of RS 23 customers back to bundled service, FEI started forecasting RS 3 and RS 23 customers together in the 2020 and 2021 Annual Review. Please also refer to Section 3.3.2.1 of the Application for additional discussion. Once the customers in RS 3 and RS 23 were combined, the resulting large commercial group was forecast using the same three-year average method.

The following table shows the forecast, actual and variance results for each commercial class, as well as the aggregate total.

Customer Additions	2016	2017	2018	2019	2020
Rate Schedule 2					
Forecast	1,026	1,318	1,210	1,115	872
Actual	998	899	1,271	442	677
Variance	-2.8%	-46.6%	4.8%	-152.3%	-28.8%

Customer Additions	2016	2017	2018	2019	2020
Rate Schedule 3					
Forecast	(51)	26	19	91	248
Actual	(112)	252	587	945	(168)
Variance	54.5%	89.7%	96.8%	90.4%	247.6%

Customer Additions	2016	2017	2018	2019	2020
Rate Schedule 23					
Forecast	30	18	66	16	35
Actual	79	(91)	(64)	(777)	(125)
Variance	62.0%	119.8%	203.1%	102.1%	128.0%

Commercial Customer Additions	2016	2017	2018	2019	2020
Forecast	1,005	1,362	1,294	1,222	1,155
Actual	965	1,060	1,794	610	384
Variance	-4.1%	-28.5%	27.9%	-100.3%	-200.8%

5.2 In light of the commercial uncertainty caused by the COVID-19 pandemic, please explain whether FEI has considered alternative forecast methodology to better reflect the immediate impact and the recovery year following the COVID-19 pandemic in its 2021 and 2022 load forecast.

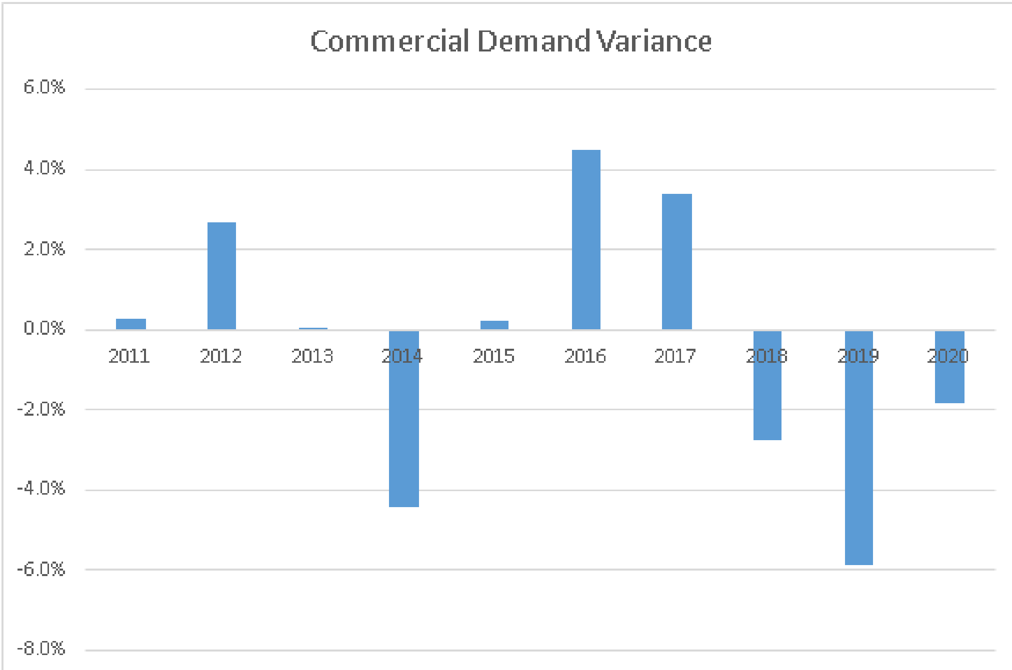
5.2.1 If so, please elaborate on what methodologies were considered and why they were not adopted for preparing the 2021 and 2022 load forecasts. If not, please explain why not.

Response:

FEI did not consider an alternative forecast method for commercial customer additions or use rates for 2021 or 2022. FEI cannot predict the trajectory of the COVID-19 pandemic and when recovery might occur.

The FEI commercial customer additions forecast method uses the most recent three-year average of actual customer additions by rate class and region and, by reforecasting each year, the actual impacts from the COVID-19 pandemic will be accounted for.

As shown in the figure below, the aggregate commercial demand variance for 2020 was better than any year since 2016, despite the COVID-19 pandemic.



When demand variances are low, potential method changes need to be considered very carefully, so that changes do not increase forecast variances. Potential new methods must be studied carefully, over a period of time. If methods are frequently changed (for example, in an attempt to capture current events), then forecasts and trends become difficult to compare over time and variances could increase.

FEI recently completed the 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 Delivery Rates Application. As a result of this study, FEI concluded that the existing three-year average method for forecasting commercial customer additions resulted in the lowest demand variance. FEI is not aware of any other methods that were not tested as part of the Forecasting Method Study that would be capable of accurately forecasting the trajectory of the COVID-19 pandemic and its impact on potential future commercial customers.

FEI also notes that load forecasting variances are recorded in either the Revenue Stabilization Adjustment Mechanism (RSAM) deferral account or the Flow-through deferral account, such that customers are kept whole from any variances in load that might be caused by factors such as the COVID-19 pandemic.

5.3 Please recalculate the forecast and the delivery rate impacts using the following alternative forecast methodologies. Please also discuss the likelihood of each of these scenarios occurring and why.

- Scenario 1 – Using the average net additions for the period between 2017 to 2019; and
- Scenario 2 – Using the 2019 customers as the base as opposed to the 2020 customers.

Response:

Please refer to Figure 1 below which shows the 2022 commercial customer count forecast as filed and the two alternative scenarios requested. Please also refer to Figure 2 for the 2022 commercial demand forecast as filed and the two alternative scenarios requested. As FEI does not have actual market data from the commercial sector that would support these alternative scenarios, FEI is not able to comment on the likelihood of either of these scenarios occurring.

As shown in the tables in Section 3.2 of Appendix A2, the variance in commercial demand between forecast and actual for 2020 using FEI's existing forecasting method was very low at just -1.9 percent, despite the fact the forecast was prepared entirely with pre-COVID-19 pandemic data. Given the low historical variance, it is not necessary to apply untested subjective adjustments to FEI's current forecasting methodology. Furthermore, FEI's view is that it is not appropriate to apply subjective changes to forecast methods each year without proper research and supporting market data testing. Without research and testing, there is no basis to conclude that such subjective changes would actually increase the accuracy of the forecast. Please also refer to the response to BCUC IR1 5.2.

Figure 1: Commercial Customer Count Forecast for Alternative Scenarios

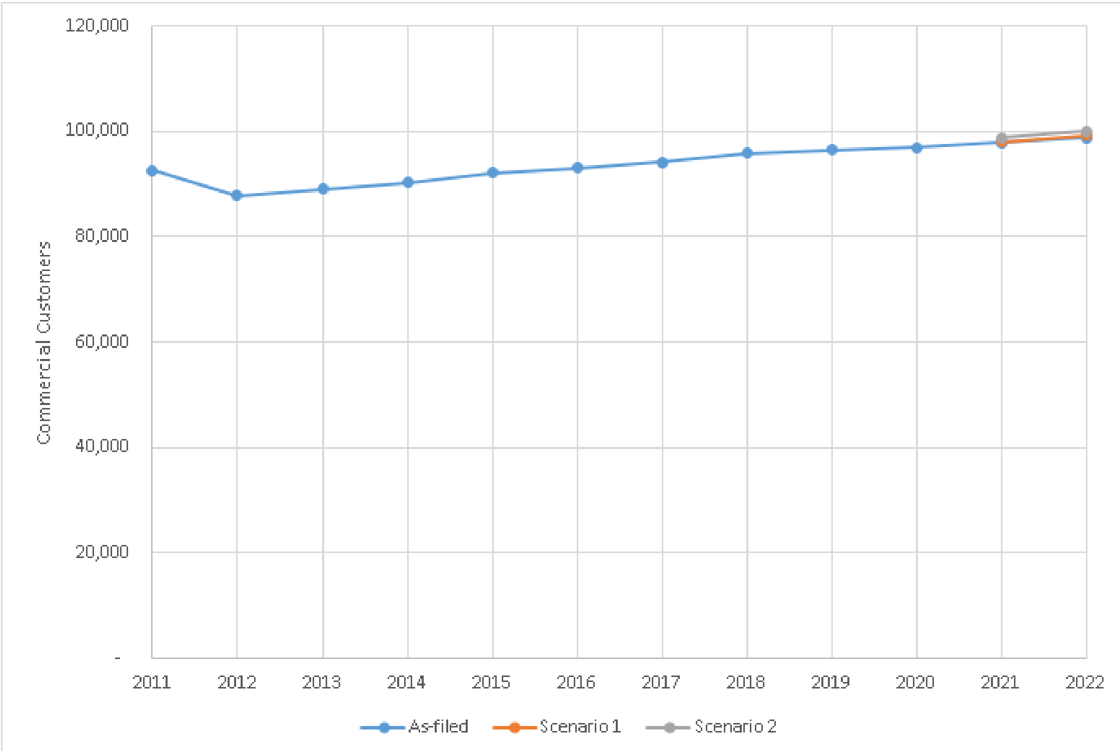


Figure 2 – Commercial Customer Demand Forecast for Alternative Scenarios

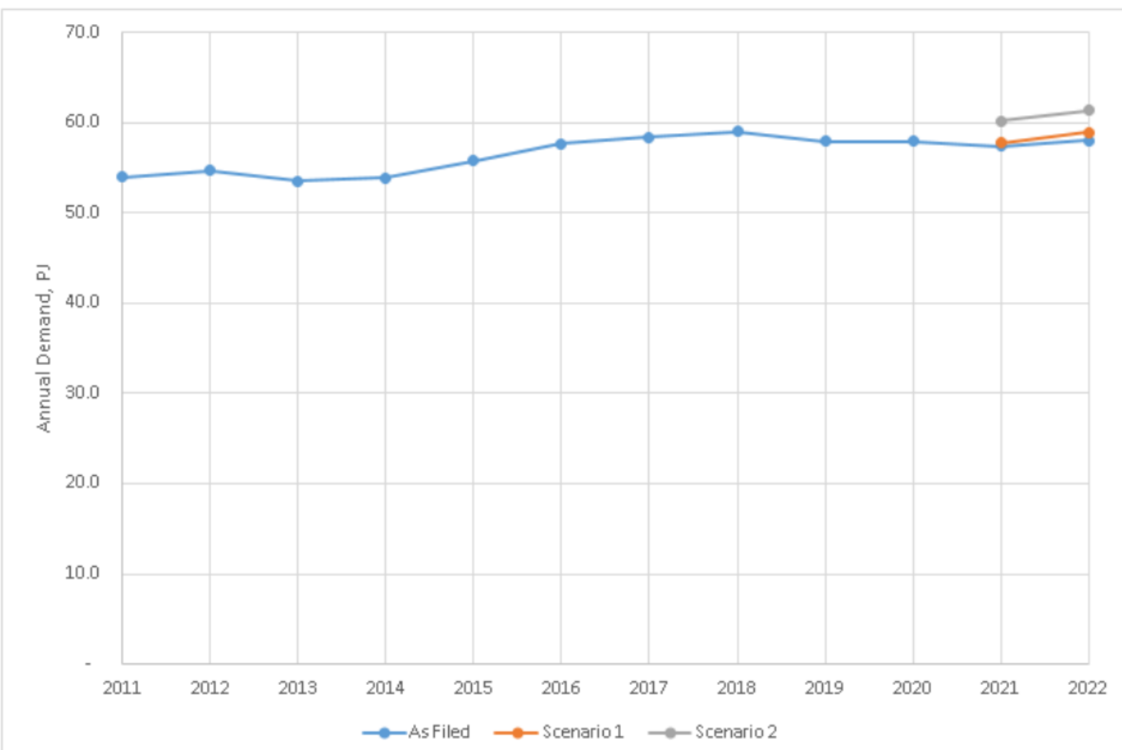


Table 1 below provides the delivery rate impact based on the two alternative scenarios and compared against the proposed 2022 delivery rate change of 8.07 percent.

Table 1: Forecast Delivery Rate Change for Alternative Commercial Customer Additions Scenarios

	As-Filed	Scenario 1	Scenario 2
2022 Forecast Delivery Rate Change (%)	8.07%	8.04%	7.96%

As Table 1 shows, the difference in the 2022 forecast delivery rate change amongst all scenarios (i.e., forecast as filed, Scenario 1 and Scenario 2) is small.

For the reasons provided above and in the response to BCUC IR1 5.2, FEI considers its current forecasting method to be the most appropriate approach.

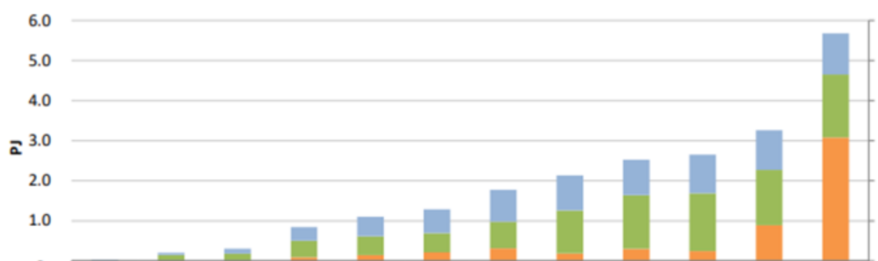
6.0 Reference: LOAD FORECAST

Exhibit B-2, Section 3.3.4, pp. 25-26

Natural Gas for Transportation and Liquefied Natural Gas (LNG) Demand

On page 25 of the Application, FEI provides Figure 3-11:

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

Further on pages 25 to 26 of the Application, FEI states that the 2022 LNG (non-NGT) load is forecast to:

> […] increase as a result of expanded LNG exports as restrictions due to the COVID-19 pandemic continue to be lifted. The 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.

6.1 Please explain whether the three prospective export customers mentioned in the preamble above represent firm loads.

<u>Response:</u>

The three prospective export customers are expected to represent firm loads, but are currently uncontracted.

6.2 Please discuss the level of certainty FEI has in its LNG (non-NGT) demand forecast for 2022 and why.

Response:

The 2022 Forecast demand is reflective of current discussions with customers and the best available market information at the time. FEI is aware of challenges in the current export market, as described in the preamble, which may cause further delays in providing LNG supply to these customers. Any variance from forecast and actual LNG (non-NGT) demand will be captured in the Flow-through deferral account and will be returned to or recovered from FEI's customers in subsequent years through amortization of the Flow-through deferral account.

6.3 Please provide a sensitivity analysis showing how a decrease in LNG (non-NGT) loads of -25%, -20%, -10% and -5% impacts the 2022 delivery rates.

Response:

The following table shows the impact of a 5%, 10%, 20% and 25% decrease in LNG (non-NGT) load on the 2022 delivery rates.

Sensitivity	2022 Forecast (PJ)	2022 Rate Change	Changes in Delivery Rate Increase (%)
Base	3.1	8.07%	0.00%
-5%	2.9	8.16%	0.09%
-10%	2.8	8.25%	0.18%
-20%	2.5	8.44%	0.36%
-25%	2.3	8.53%	0.46%

6.4 Please explain the reasons for the variance between 2021 projected and the 2020 actual results for the LNG (non-NGT) category.

Response:

The reason for the variance is due to a forecast increase in LNG (non-NGT) load from the three prospective LNG (Non-NGT) customers in 2021, which is based on discussions with customers and the best available market information at the time.

7.0 Reference: LOAD FORECAST

Exhibit B-2, Section 11, Schedules 1, 17 to 19, pp. 95, 118–120

Revenue Requirement and Rate Changes for 2022

FEI presents the summary of rate change for 2022 in Schedule 1 in Section 11. FEI provides further details regarding energy volume sold and revenue at existing rates for 2022 in Schedule 17; the revenue at existing and revised rates for the year ending December 31, 2022 in Schedule 19; and the cost of energy for 2022 in Schedule 18.

7.1 In table format, please provide the impact to FEI's revenue surplus/deficiency and requested rate change for 2022, if the gross load forecast is -10%, -5%, 0%, +5%, and +10% less/more than the forecast presented in the Application, respectively, assuming all else equal:

- Residential;
- Commercial;
- Industrial;
- Compressed Natural Gas (CNG) and LNG load; and,
- Equal adjustment to the demand across all rate classes.

Please provide all inputs and assumptions made.

7.1.1 Please also provide, if possible, a revised Schedule 1, and Schedules 17 through 19 for year 2022 respectively, in a functional excel spreadsheet with the above sensitivity analysis.

<u>Response:</u>

Please refer to the table below for the impact of varying load forecasts on FEI's revenue surplus/deficiency and the requested 2022 delivery rate change.

Variances between the forecast and actual delivery margin are captured in either the Revenue Stabilization Adjustment Mechanism (RSAM) deferral account or the Flow-through deferral account. The resulting revenue requirement impacts are returned to or recovered from customers through the amortization of these deferral accounts in subsequent years. In other words, customers are kept whole for any demand forecast variances with the respective deferral accounts.

With regard to the request for revised Schedules 1 and 17 through 19 for each scenario, FEI is unable to provide this information as it would require extensive effort to manually create the 80 individual schedules (5 customer scenarios times 4 sensitivity ranges times 4 financial schedules). As the financial schedules provided in Section 11 are system-generated, there is not a readily available working excel model to provide the requested information. However, in order to be responsive to this information request, FEI has created the attached excel spreadsheet (please refer to Attachment 7.1) which recreates the requested financial schedules from Section 11 and provides a drop-down list under the "Select Scenario" tab so that users can observe the impact of the various scenarios on the financial schedules. Please also refer to Attachment 7.1 for the excel spreadsheet of the below sensitivity analysis which provides all inputs and assumptions.

Scenarios	-10%	-5%	0%	5%	10%
Residential (RS 1)					
Revenue deficiency/(surplus) ($000s)	111,537	91,510	71,483	51,455	31,428
2022 Delivery Rate Change (%)	13.19%	10.57%	8.07%	5.68%	3.40%
Commercial (RS 2, 3, 23) - excl. CNG					
Revenue deficiency/(surplus) ($000s)	91,919	81,701	71,483	61,265	51,047
2022 Delivery Rate Change (%)	10.63%	9.33%	8.07%	6.84%	5.63%
Industrial (RS 4, 5, 6, 7, 22, 25, 27) - excl. CNG					
Revenue deficiency/(surplus) ($000s)	76,808	74,165	71,483	68,744	65,954
2022 Delivery Rate Change (%)	8.73%	8.40%	8.07%	7.74%	7.40%
CNG and LNG (RS 3, 23, 5, 25, 6P, 46)					
Revenue deficiency/(surplus) ($000s)	72,055	71,916	71,483	70,164	68,844
2022 Delivery Rate Change (%)	8.14%	8.12%	8.07%	7.92%	7.77%
All Rate Schedules & LNG RS 46					
Revenue deficiency/(surplus) ($000s)	137,872	104,844	71,483	37,181	2,827
2022 Delivery Rate Change (%)	16.82%	12.30%	8.07%	4.05%	0.30%

D. COST OF GAS

8.0 Reference: COST OF GAS

Exhibit B-2, Section 4, Table 4-1, p. 29

Cost of Gas Calculation

FEI sets out the forecast cost of gas at existing rates, by Rate Schedule group in Table 4-1 on page 29 of the Application.

8.1 Please provide a breakdown of the calculated cost of gas amount presented in Table 4-1, including the assumed load, corresponding cost of gas rates, and Unaccounted for Gas (UAF), for each rate class. Please provide all inputs and assumptions made.

Response:

As noted on page 28 of the Application, with the exception of the Core Market Administration Expense (CMAE) costs, FEI is not seeking approval of the forecast gas costs in this Application. The forecast cost of gas is required in the determination of FEI's forecast of the total revenue requirement included in the Application and is therefore provided in Section 4 for informational purposes. The total cost of gas has been determined by multiplying forecast sales volumes by the unit gas cost recovery charges for each rate schedule. The cost of gas rates were based on the following:

- the 2022 Forecast and 2021 Projected midstream $/GJ is based on the Q4, 2020 gas cost report[3];
- the 2022 Forecast and 2021 Projected commodity $/GJ is based on the Q2, 2021[4] gas cost report;
- the 2021 Approved midstream $/GJ is based on the Q4, 2019[5] gas cost report; and
- the 2021 Approved commodity $/GJ is based on the Q2, 2020[6] gas cost report.

FEI has provided the following three tables that show the individual detail used to calculate the cost of gas amounts included in Table 4-1 of the Application.

[3] Order G-314-20.
[4] Letter L-15-21.
[5] Order G-306-19.
[6] Letter L-35-20.

Forecast 2022	Commodity (TJ) (1)	UAF (TJ) (2)	Midstream ($/GJ) (3)	Commodity ($/GJ) (4)	UAF ($/GJ) (5)	Cost of Gas [1] ($/GJ) (6)	Cost of Gas [2] ($000's) (7)
Residential							
Rate Schedule 1 [3]	81,494	-	1.350	2.897	-	4.25	346,101
Commercial						-	-
Rate Schedule 2 [3]	29,000	-	1.373	2.897	-	4.27	123,827
Rate Schedule 3 [3]	24,885	-	1.148	2.897	-	4.04	100,657
Rate Schedule 23	-	25	-	-	2.832	2.83	70
Industrial						-	-
Rate Schedule 4	160	-	0.830	2.844	-	3.67	586
Rate Schedule 5	9,420	-	0.812	2.844	-	3.66	34,441
Rate Schedule 6	20	-	0.082	2.844	-	2.93	59
Rate Schedule 7	6,601	-	0.830	2.844	-	3.67	24,251
Rate Schedule 22	-	161	-	-	2.832	2.83	457
Rate Schedule 25	-	55	-	-	2.832	2.83	156
Rate Schedule 27	-	27	-	-	2.832	2.83	77
Bypass and Special Rates						-	-
Rate Schedule 22 - Firm Service	-	65	-	-	2.832	2.83	185
Rate Schedule 25	-	6	-	-	2.832	2.83	17
Rate Schedule 46	4,650	-	0.830	2.844	-	3.67	17,085
Total	**156,231**	**340**					**647,970**

Projection 2021	Commodity (TJ) (1)	UAF (TJ) (2)	Midstream ($/GJ) (3)	Commodity ($/GJ) (4)	UAF ($/GJ) (5)	Cost of Gas [1] ($/GJ) (6)	Cost of Gas [2] ($000's) (7)
Residential							
Rate Schedule 1 [3]	80,795	-	1.350	2.897	-	4.25	343,128
Commercial						-	-
Rate Schedule 2 [3]	28,829	-	1.373	2.897	-	4.27	123,095
Rate Schedule 3 [3]	24,532	-	1.148	2.897	-	4.04	99,229
Rate Schedule 23	-	28	-	-	2.087	2.09	59
Industrial						-	-
Rate Schedule 4	143	-	0.830	2.844	-	3.67	526
Rate Schedule 5	9,034	-	0.811	2.844	-	3.66	33,021
Rate Schedule 6	20	-	0.082	2.844	-	2.93	59
Rate Schedule 7	6,186	-	0.830	2.844	-	3.67	22,727
Rate Schedule 22	-	190	-	-	2.087	2.09	397
Rate Schedule 25	-	63	-	-	2.087	2.09	131
Rate Schedule 27	-	32	-	-	2.087	2.09	66
Bypass and Special Rates						-	-
Rate Schedule 22 - Firm Service	-	80	-	-	2.087	2.09	166
Rate Schedule 25	-	7	-	-	2.087	2.09	14
Rate Schedule 46	2,273	-	0.830	2.844	-	3.67	8,353
Total	**151,813**	**399**					**630,972**

Approved 2021	Commodity (TJ) (1)	UAF (TJ) (2)	Midstream ($/GJ) (3)	Commodity ($/GJ) (4)	UAF ($/GJ) (5)	Cost of Gas [1] ($/GJ) (6)	Cost of Gas [2] ($000's) (7)
Residential							
Rate Schedule 1 [3]	79,332	-	1.097	2.326	-	3.42	271,529
Commercial						-	-
Rate Schedule 2 [3]	28,937	-	1.123	2.326	-	3.45	99,816
Rate Schedule 3 [3]	26,204	-	0.946	2.279	-	3.23	84,511
Rate Schedule 23	-	34	-	-	2.421	2.42	83
Industrial						-	-
Rate Schedule 4	149	-	0.716	2.279	-	2.99	446
Rate Schedule 5	8,169	-	0.716	2.279	-	3.00	24,466
Rate Schedule 6	23	-	0.130	2.279	-	2.41	56
Rate Schedule 7	5,924	-	0.716	2.279	-	2.99	17,742
Rate Schedule 22	-	184	-	-	2.421	2.42	446
Rate Schedule 25	-	72	-	-	2.421	2.42	174
Rate Schedule 27	-	34	-	-	2.421	2.42	81
Bypass and Special Rates						-	-
Rate Schedule 22 - Firm Service	-	77	-	-	2.421	2.42	187
Rate Schedule 25	-	6	-	-	2.421	2.42	15
Rate Schedule 46	5,470	-	0.716	2.279	-	2.99	16,381
Total	**154,208**	**407**					**515,935**

Table Notes:

[1] Cost of Gas (Column 6) = Columns 3 + 4 + 5
[2] Cost of Gas (Column 7) = (Columns 1 + 2) X (Column 6)
[3] Rate Schedules (RS) 1 – 3 are based on a blended rate of FEI's current commodity cost recovery charge and average marketer rate for RS 1-3 for unbundled customers.

E. OTHER REVENUE

9.0 Reference: OTHER REVENUE

Exhibit B-2, Section 3.3.4, p. 24; Section 5.2.4.3, p. 33

CNG and LNG Service Revenue Forecast

On page 33 of the Application, FEI states:

> […] 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.

Footnote 16 states:

> 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.

On page 24 of the Application, FEI states:

> […] 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 [Natural Gas for Transportation] and non-NGT LNG demand.

9.1 Please clarify whether FEI has included a forecast for spot and excess volumes in the NGT demand forecast. If not, please explain why not.

9.1.1 If so, please explain why a forecast for station revenue recoveries from spot and excess volumes is not included in Other Revenue when the forecast demand is included in the calculation of the delivery rate.

9.1.2 If so, please clarify whether FEI has included a forecast of the costs associated with spot and excess volumes in the calculation of the delivery rate.

<u>Response:</u>

The preamble refers to two separate and un-related spot and excess volumes related to LNG and CNG services. As explained below, FEI includes spot and excess LNG demand under RS 46 in its demand forecast, but does not include spot and excess volumes related to its LNG and CNG fueling stations.

Section 3.3.4 of the Application is specifically related to FEI's delivery demand forecast. The sentence referenced on page 24 of the Application is referring to LNG delivery demand under RS 46: "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 <u>LNG</u> demand." [Emphasis added.] For RS 46 LNG customers taking

LNG service without a Contract Demand as defined in the tariff for RS 46, the volumes are considered spot volume, and a spot premium of $0.25 per GJ is applied to these customers' RS 46 LNG Facility Charge. Additionally, for RS 46 LNG customers with a Contract Demand, the volume that exceeds the contract demand is considered excess volume and is also subject to the $0.25 per GJ spot premium. As stated on page 24 of the Application, these spot and excess delivery volumes are included in FEI's 2022 LNG demand forecast shown in Table 3-2 of the Application, and therefore, are included in the calculation of the 2022 delivery rates.

Section 5.2.4.2 of the Application is specifically related to revenues from FEI's CNG and LNG fueling stations. The referenced sentence on page 33 of the Application is referring to the spot and excess volumes of FEI's CNG and LNG fueling stations, and has no relation to the spot and excess volume under RS 46 delivery as discussed above: "The forecast of <u>station</u> recoveries as Other Revenue does not include recoveries from spot volume and excess volume (i.e., fueling customer uses more than their contracted minimum take-or-pay volume)". [Emphasis added.] For FEI's fueling station customers that do not have a minimum take-or-pay agreement, their volumes are considered spot volume to the station and their station rates include a $1 per GJ spot charge in addition to the capital and O&M station rates. Furthermore, for customers that have a minimum take-or-pay agreement, any volume that exceeds the minimum agreed level is considered excess volume for the fueling station. As stated in Section 5.2.4.3 of the Application as well as footnote 16 of the Application, station revenues recovered under the fueling stations' spot and excess volumes are not included in the forecast of FEI's other revenue, as they are captured in the CNG and LNG Recoveries deferral account. FEI does not forecast fueling station spot and excess volume; therefore, the 2022 spot and excess recoveries from fueling stations are not included in the calculation of the 2022 delivery rates.

F. O&M EXPENSE

10.0 Reference: FORMULA O&M EXPENSE

Exhibit B-2, Section 6.2.1, Table 6-3, p. 38

Integrity Management

The following is an extract of Table-6-3 on page 38 of the Application, showing FEI's System Operations, Integrity and Security New/Incremental Spending:

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)

10.1 Please explain why Actual 2020 O&M was $0.234 less than the 2020 Formula O&M ($1.147 million - $1.361 million) for Integrity Management.

Response:

The general timing of the expenditures for activities such as inspection of non-piggable transmission pipe (e.g., facilities piping in stations), and inspection and assessment of compressor stations contributed to the lower spending in 2020 for incremental funding approved for Integrity Management. The mid-year approval of the 2020-2024 MRP Application and the need to engage technical resources impacted FEI's ability to fully progress incremental integrity activities in 2020.

As noted in the Application, the funding for the 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 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.

G. RATE BASE

11.0 Reference: RATE BASE

Exhibit B-2, Section 7.2.3.1, Table 7-5, pp. 51–53

Flow-Through Capital Expenditures – Biomethane

On page 51 of the Application, FEI states:

> 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.

On page 52 of the Application, FEI states:

> The 2021 Projected and 2022 Forecast Biomethane capital expenditures are $8.044 million and $40.255 million, respectively […]. The 2021 Projected capital expenditures are less than 2021 Approved by $12.106 million.

Also, on page 52, FEI provides Table 7-5, showing a breakdown of Biomethane Capital Expenditures:

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

On page 53 of the Application, FEI states:

> 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.

11.1 Please explain what issues FEI has had in the tender and selection process in finalizing a design-build contract for the City of Vancouver landfill project in 2021. As part of the response, please explain how this impacts the project schedule.

Response:

FEI had encountered two main issues in the procurement process to tender and select a design-build contractor for the City of Vancouver landfill project.

The first issue was that the original design-build proposal prices were significantly higher than the original project cost estimate budget, despite having a competitive tender procurement process with multiple bidders. FEI opted to structure the RFP in a way that required the contractors to price more risk related to project delivery, compared to the allowances for project risk in the original budget, which pushed the bids higher. Further, FEI received feedback from bidders indicating that the COVID-19 pandemic negatively affected the supply chain for major equipment and materials that also increased prices. FEI spent several months with the preferred proponent to negotiate and allocate risk and cost savings for the project.

The second issue was that the proponents were not able to agree to commercial terms regarding performance security that FEI required for the project, to ensure the facility would perform as required to remain compliant with the Greenhouse Gas Reduction (Clean Energy) Regulation and previous BCUC decision regarding this project.

FEI originally selected the design-build project delivery method because this method was considered the most efficient in terms of cost and schedule; however, as a result of these unforeseen issues, FEI decided to cancel the design-build RFP and alter the project delivery method to a design-bid-build. Using this method, FEI believes that it can negotiate both a better performance guarantee (directly with equipment vendors) and reduce costs related to risk and equipment and materials procurement that was originally borne by the primary contractor.

Therefore, FEI anticipates that the revised project execution plan and overall cost of the project will allow FEI to remain compliant with the original BCUC decision and the Greenhouse Gas Reduction (Clean Energy) Regulation. The change in the project delivery method impacts the project schedule by delaying the completion date of the facility from Q1 2021 to Q4 2023.

11.2 Please explain any impacts, financial or otherwise, to the City of Vancouver project being behind schedule.

Response:

The financial impacts of the project being behind schedule are limited to a shift in the spend profile, as project expenditures will move to a future period. This delay in schedule will also shift when expected supply starts to be delivered. Other than a shift in the project schedule, FEI does not anticipate an increase in costs and does not anticipate any other impacts.

11.3 Please provide a project description for each of the "Net Zero Waste" and "Delta RNG" biomethane projects.

Response:

The following is a project description summary of the Net Zero Waste and Delta RNG projects.

Net Zero Waste (Supplier) will own and operate an anaerobic digester and upgrader facility capable of purifying raw biogas to Renewable Natural Gas (biomethane). The project will be constructed on an existing compost facility located in Abbotsford, BC. The facility currently receives municipal and commercial/industrial organic waste from the local area. FEI will own and operate interconnection facilities on site to monitor and inject RNG into the natural gas distribution system. The Supplier has agreed to pay a contribution in aid of construction for the full cost of FEI's interconnection facilities. FEI filed the biomethane purchase agreement (BPA) between FEI and Net Zero Waste with the BCUC on September 10, 2021. The project is anticipated to be operational by the end of 2022.

Delta RNG (Supplier) will own and operate a facility capable of purifying the remainder of the landfill gas produced at the City of Vancouver landfill, which is not contracted to FEI. This portion of landfill gas is sold to a greenhouse operator located near the City of Vancouver landfill in Delta, BC. The greenhouse operator has arranged to sell the landfill gas to the Supplier to be upgraded to RNG. The RNG will in turn be sold to FEI for use in the RNG program. FEI will own and operate interconnection facilities to monitor and inject the RNG into the natural gas distribution system. The Supplier will pay for the cost of FEI's interconnection facilities. FEI anticipates filing the BPA with Delta RNG by the end of 2021. The project is expected to be operational by the end of 2022 or early 2023.

11.4 Please explain why the Forecast 2022 capital expenditures are reasonable considering the Approved 2021 capital expenditure are projected to be underspent.

Response:

FEI provides the following table and explanations for the variances in the 2021 Approved and Projected capital expenditures.

	Approved 2021	Projected 2021	Variance 2021
City of Vancouver	17.300	3.800	**(13.500)**
Kelowna	0.120	1.168	
Lulu Island	0.020	0.112	
Dickland Farms	1.230	0.890	
Ren Energy	1.480	0.850	
Planned 2021 Capital	2.850	3.020	**0.170**
Salmon Arm	-	0.241	
Seabreeze	-	0.277	
City of Surrey	-	0.007	
Misc. Modifications	-	0.150	
Unplanned 2021 Capital	-	0.674	**0.674**
CRD	-	0.350	
Net Zero Waste	-	0.100	
Delta RNG	-	0.100	
New 2021 Projects	-	0.550	**0.550**
Total Biomethane Capital	20.150	8.044	**(12.106)**

The reason why the 2021 Projected capital is less than approved is due to the delay in the City of Vancouver project. Please refer to the response to BCUC IR1 11.1 for more information regarding this delay.

For the capital FEI originally forecast in 2021, the variance related to these projects is small.

The remaining spending was either unplanned spending on existing projects or new projects.

In 2021, FEI has experienced some unplanned repairs related to the Salmon Arm, Seabreeze, and City of Surrey facilities, resulting in some required capital expenditures for these projects.

In addition, new projects arose since FEI filed the 2020 and 2021 Annual Review that will require capital investment in 2021. Each of these project's Biomethane Purchase Agreements (BPAs) either have been or will be filed with the BCUC. To date, the CRD BPA has been accepted by the BCUC, the Net Zero Waste BPA has been filed, and the Delta RNG BPA is expected to be filed soon.

There will continue to be some variances between forecast and actual project spending, as new projects are developed and as unanticipated spending is required. The overall 2022 Forecast included in the Application is based on the best available information at this time; individual projects will be filed with the BCUC as they are finalized.

11.4.1 Please explain the impacts to the ratepayer and shareholder if projects are delayed and FEI underspends its biomethane capital expenditures budget for 2022.

Response:

Biomethane capital expenditures are part of FEI's Clean Growth Initiatives, and as discussed in Section 7.2.3.1 of the Application, FEI is approved to treat these expenditures as flow-through under the MRP. For biomethane-related projects, any variances in the cost of service resulting from over or underspending of capital forecasts (due to, for example, a delay in the project) will be captured by the BVA deferral account and will be recovered from or returned to customers through the BVA rate rider[7]. Therefore, both shareholders and customers will be held whole if the biomethane capital budget is over or underspent.

In general, if a project is delayed, meaning a delay in the start of the project, and no other factors have changed, shareholder and ratepayer impacts would be limited to timing differences. If the actual capital expenditures are lower than forecast due to reasons other than a delay (i.e., the spending itself is less), then the amount that is added to rate base will also be lower, resulting in lower depreciation expense and return on rate base.

However, as shown in the table below (shown in $ millions), except for the $5 thousand in upgrade work for Kelowna, none of the 2022 Forecast biomethane capital expenditures are expected to be added to rate base in 2022. As such, there would essentially be no impact to 2022 delivery rates due to variances in the forecast biomethane capital expenditures.

Line No.	Description	Order	Approved 2021	Projected 2021	Forecast 2022	Expected Rate Base Additions for 2022
1	City of Vancouver	G-235-19	17.300	3.800	24.000	2024
2	Kelowna	E-19-12	0.120	1.168	0.005	2022
3	Salmon Arm	G-194-10	-	0.241	-	n/a
4	Lulu Island WWTP	E-13-13	0.020	0.112	-	n/a
5	Dickland Farms	E-13-20	1.230	0.890	0.100	2023
6	Ren Energy	G-60-20	1.480	0.850	0.150	2023
7	Seabreeze Farms	E-11-19	-	0.277	-	n/a
8	Capital Regional District	E-15-21	-	0.350	7.000	2024
9	City of Surrey	E-3-16	-	0.007	-	n/a
10	Net Zero Waste	To be filed	-	0.100	4.000	2024
11	Delta RNG	To be filed	-	0.100	5.000	2024
12	Misc Modifications	Misc.	-	0.150	-	n/a
13	Total Biomethane CAPEX		20.150	8.044	40.255	

[7] The BVA rider is calculated based on the projected current year ending balance of the BVA non-rate base deferral account, transferred to the rate base BVA rate rider account for recovery through the BVA rider.

12.0 Reference: RATE BASE

Exhibit B-2, Section 7.2.3.1, Table 7-6, p. 54; Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR), Sections 1, 2(3)(a)(i), 2(3)(b.1)[8]

Flow-Through Capital Expenditures – NGT and Tilbury T1A truck load-out

On page 54 of the Application, FEI provides Table 7-6, showing a breakdown of the 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**

Further on page 54 of the Application, FEI states:

> 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

[8] https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/102_2012

> 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.

In footnote 29 on page 54 of the Application, FEI states:

> 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.

Section 2(3)(b.1) of the GGRR states: "expenditures, during the undertaking period, on a tanker truck load-out do not exceed $10 million, and on administration and marketing do not exceed $250 000;"

Section 1 of the GGRR defines "undertaking period" as "the period that ends on March 31, 2022.

Section 2(3)(a)(i) of the GGRR states:

> (3) A public utility's undertaking that is in the class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:
>
> (a) the public utility, before March 31, 2022, enters into a binding commitment to construct and operate, or purchase and operate, one or more of the following:
>
> (i) one or more liquefied natural gas tank trailers or liquefied natural gas fuelling stations for the purposes of providing within British Columbia liquefied natural gas fuel and fuelling services to owners of vehicles that operate on liquefied natural gas;

12.1 Please provide a project description for each of the following capital expenditures and the anticipated BCUC filing date for each project:

i. Waste Management Expansion (CNG);

ii. Surrey (CNG);

iii. GFL Abbotsford (CNG); and

iv. Annacis Island (CNG).

Response:

Below is a description of each project and the estimated BCUC filing date. Since the design specifics of the stations are confidential at this time, FEI is only able to provide limited details on the station specifics.

Waste Management Expansion (CNG): An expansion to their current CNG facility which includes additional fill posts. FEI expects to file an application by December 2021.

Surrey (CNG): This slow fill station will accommodate a fleet of CNG vehicles. FEI expects to file an application in Spring of 2022.

GFL Abbotsford (CNG): This fast fill station will accommodate GFL Environmental Inc. and other customers requiring CNG. FEI expects to file an application before the end of November 2021.

Annacis Island (CNG): This fast fill station will accommodate multiple customers requiring CNG. FEI expects to file an application before the end of November 2021.

12.2 Please discuss whether FEI expects to incur costs after March 31, 2022 with respect to any of the projects listed in Table 7-6. If so, please quantify and explain how FEI plans to request recovery of these costs.

<u>Response:</u>

FEI anticipates incurring costs of approximately $2.464 million after March 31, 2022 for the projects listed in Table 7-6. A breakdown of the forecast costs is below.

Project	Forecast Expenditures after March 31, 2022 ($ millions)
Waste Management Expansion (CNG)	0.563
Surrey (CNG)	1.500
T1A Truck Load-out	0.401
Total	**2.464**

FEI expects to include recovery of these costs in its annual review filings, as the 2022 forecast projects listed in Table 7-6, excluding the Waste Management Expansion (CNG), will be prescribed undertakings under the GGRR and will be subject to the applicable cost recovery requirements under the *Clean Energy Act*. The Waste Management CNG station was constructed under the General Terms and Conditions (GT&Cs), therefore the future expansion and cost recovery of the Waste Management CNG station will be completed under the GT&Cs and will not be affected by the GGRR.

Under Section 2(2) and (3) of the GGRR, FEI need only enter into a binding commitment before March 31, 2022 to construct and operate, or purchase and operate, CNG stations, LNG tanker trailers or tanker truck load-outs. The GGRR does not require the assets to be operational, or all expenditures to be made, before March 31, 2022.

The limits on “expenditures” during the undertaking period in section 2(2) and (3) of the GGRR must be read in conjunction with Section 2(4) of the GGRR, which defines these “expenditures” as including “binding commitments to incur expenditures in the future”. Therefore, it is sufficient for FEI to have made binding commitments during the undertaking period to incur the expenditures; FEI need not actually make the expenditures during the undertaking period.

Therefore, for the projects in Table 7-6 (excluding the Waste Management CNG station) to be a prescribed undertaking, FEI is required to enter into binding commitments prior to March 31, 2022 for the fueling stations, tanker trailers and tanker truck load-outs. Consistent with this criterion, FEI expects to have made the requisite binding commitments prior to March 31, 2022 and would only proceed with the investments if the binding commitments were in place.

Further, FEI is monitoring its expenditures under section 2(2) and (3) of the GGRR and will not exceed any of the applicable spending limits in the GGRR.

The 2022 Forecast projects listed in Table 7-6, excluding the Waste Management Expansion (CNG), are GGRR prescribed undertakings and are subject to the applicable GGRR cost recovery requirements. FEI expects to file an application for the Surrey CNG station, which will provide an opportunity for the BCUC to confirm that the station meets the GGRR requirements.

Please also refer to FEI's response to BCUC IR1 12.7 for further discussion on how the LNG tanker trailer and tanker truck load-outs meet the criteria for prescribed undertakings under the GGRR.

12.3 Please explain why FEI did not include the T1A Truck Load-Out project in the table showing NGT Assets capital expenditures in the FEI Annual Review for 2020 and 2021 Delivery Rates.

<u>Response:</u>

The exclusion of the T1A Truck Load-out project from Section 7 of the 2020 and 2021 Annual Review (either in the NGT Assets or the CPCN and Special Projects sections) was an oversight.

As mentioned in Section 7.2.3.1 of the Application, the T1A Truck Load-out project has been in FEI's work-in-progress since 2019 and was included for the first time in FEI's 2019 BCUC Annual Report under CPCNs and Special Projects[9]. FEI also notes that the project, while not specifically identified, was recorded as part of the "Change in Work in Progress" (Line 21) in Schedule 5, Section 11 – 2020 and 2021 in FEI's 2020 and 2021 Annual Review application.

While preparing the 2020 BCUC Annual Report in early 2021, FEI concluded that since the T1A Truck Load-out project is a prescribed undertaking under the GGRR, it would be more appropriate to list the capital expenditures related to this project with FEI's other NGT assets that are also

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9 Page 5.1– "Additions to Gas Plant in Service (CPCNs) and Special Projects" of the 2019 BCUC Annual Report, Line 18 – Capital Expenditures and Line 29 – Closing WIP.

GGRR prescribed undertakings. As such, in the 2020 BCUC Annual Report[10] and in this Application, FEI has included the T1A Truck Load-out project together with all other NGT assets, including all GGRR prescribed undertakings, under the NGT Assets flow-through capital expenditures.

Since the 2020 BCUC Annual Report was prepared and filed in 2021 (i.e., subsequent to the completion of FEI's 2020 and 2021 Annual Review proceeding), the omission of the T1A Truck Load-out project from Section 7 was not able to be corrected until the current Application.

As mentioned above, the T1A Truck Load-out project has been in FEI's work-in-progress since 2019; therefore, the omission of this project from the project descriptions in Section 7 of previous annual reviews has no implications to the delivery rate calculations.

12.4 Please further explain the scope and need for the T1A Truck Load-Out project.

<u>Response:</u>

The T1A Truck Load-out project consists of two additional LNG truck loading bays with dedicated weigh scales to be constructed adjacent to the existing truck load-out bays at the T1A plant. There are currently two truck load-out bays at Tilbury. The two additional truck load-outs that are included as part of the T1A Truck Load-out project are expected to be needed to serve growth in demand from the domestic marine, remote power generation, rail and mine haul markets.

12.4.1 Please provide a table that breaks down the cost estimate of the T1A Truck Load-Out project by tanker truck load out and by year. As part of the response, please identify the undertaking year of the expenditures for these tanker truck load outs, as defined in the GGRR.

<u>Response:</u>

Please refer to Table 1 below for the cost breakdown of the T1A Truck Load-out project by the number of load-outs and by year (i.e., 2019 and 2020 actuals, 2021 projected, and 2022 forecast). Please also refer to Table 2 below for the cost breakdown in terms of the GGRR undertaking years. FEI notes the capital expenditures shown in Table 1 are based on the calendar year while the GGRR undertaking years (Table 2) are based on a fiscal year of April 1 to March 31.

[10] Page 4, Line 11 – NGT Assets in the 2020 BCUC Annual Report.

Please refer to the response to BCUC IR1 12.2 for discussion of how the prescribed undertaking for LNG tanker truck load-outs in section 2(3) of the GGRR is not limited to expenditures made during the undertaking period (as defined in the GGRR), but also includes binding commitments to incur expenditures in the future. Please also refer to the response to BCUC IR1 12.7 for how the tanker truck load-outs meet the criteria for a prescribed undertaking as defined in section 2(3) of the GGRR.

Table 1: Annual Cost Breakdown by Calendar Year ($)

FEI CapEx Calendar Year	2019 Actual	2020 Actual	2021 Projected	2022 Forecast	Total
Truck Load-out Bay 1	352,911	762,060	6,465,295	1,697,893	9,278,158
Truck Load-out Bay 2	352,911	762,060	6,465,295	1,697,893	9,278,158
Contingency			585,219	258,465	843,684
Total	705,821	1,524,119	13,515,810	3,654,250	19,400,000

Table 2: Annual Cost Breakdown by GGRR Undertaking Year ($)

GGRR Undertaking Year	Apr 2019 - Mar 2020 Actual	Apr 2020 - Mar 2021 Actual	Apr 2021 - Mar 2022 Projected	Apr 2022 - Mar 2023 Forecast	Total
Truck Load-out Bay 1	466,142	2,053,029	6,558,537	200,450	9,278,158
Truck Load-out Bay 2	466,142	2,053,029	6,558,537	200,450	9,278,158
Contingency	-	-	843,684	-	843,684
Total	932,283	4,106,058	13,960,757	400,901	19,400,000

12.4.2 Please provide the total administration and marketing costs on tanker truck load-outs during the undertaking period.

Response:

FEI has not incurred any administration and marketing costs to date under the GGRR for tanker truck load-outs.

12.5 Please confirm, or explain otherwise, that FEI has entered a binding commitment before March 31, 2022 to construct and operate, or purchase and operate, the LNG tanker(s) in Table 7-6 (line 11).

12.5.1 If confirmed, please provide further details of the binding commitment.

Response:

FEI expects to purchase an additional LNG tanker (i.e., tank trailer) in early 2022, as reflected in Table 7-6 of the Application, but has not yet entered into a binding contract to purchase the LNG tanker. Consistent with the requirements of the GGRR, FEI will only purchase the LNG tanker if it enters into a binding commitment to purchase and operate the LNG tanker before March 31, 2022 and the expenditure is within the GGRR spending limit.

12.6 Please explain why the Forecast 2022 capital expenditures are reasonable considering the Approved 2021 capital expenditures (excluding the T1A Truck Load-out) are projected to be underspent.

Response:

FEI's NGT station capital expenditure forecasts are reasonable as they are based on current discussions with customers and the best available market information at the time.

The 2021 Approved capital expenditures included the purchase of a specialized marine LNG tanker which will not occur in 2021. This purchase was to support two marine vessels that were expected to be in-service in early 2021 and are now expected to be operational in late 2021 and early 2022. As such, FEI has delayed the marine LNG tanker purchase to 2022. Excluding that LNG tanker (and the T1A Truck Load-out), FEI's 2021 Projected expenditures are $897 thousand higher than Approved.

The 2021 forecast CNG stations at Cumberland, Prince George and District of Cowichan were not constructed. Instead, stations at Annacis Island, (GFL) Abbotsford, Waste Connections Abbotsford and Port Kells were constructed, along with an expansion to an existing Waste Connections station. There will continue to be some variability in the locations of and expenditures for fueling stations between forecast and actual.

12.6.1 Please explain the impacts to the ratepayer and shareholder if FEI over or underspends its NGT capital expenditures budget for 2022.

Response:

NGT capital expenditures are part of FEI's Clean Growth Initiatives, and as discussed in Section 7.2.3.1 in the Application, FEI is approved to treat these expenditures as flow-through under the MRP. For NGT related projects, any variances in the cost of service resulting from over or underspending of capital forecasts (due to for example, a delay in the project), will be captured in the Flow-through deferral account and will be recovered from or returned to customers through amortization of the Flow-through deferral account in delivery rates. Therefore, both shareholders and customers will be held whole if the NGT capital budget is over or underspent.

Please refer to the response to BCUC IR1 11.4.1, which provides further explanation in the event that a project is delayed, or if the actual capital expenditures are lower than forecast.

Additionally, for NGT projects related to fueling stations, the Capital Rate charged to the fueling station customer is designed based on the capital expenditures of the station. Per the agreements with all fueling customers, if the actual capital expenditures are over or under by more than 2 percent, the Capital Rate will be amended to ensure recovery from the fueling customers[11], which further protects non-bypass customers from large variances in NGT capital expenditures.

FEI notes that the majority of the 2022 Forecast for NGT assets is related to the T1A truck load-outs, which are expected to be completed in 2022, as discussed in the response to BCUC IR1 12.4.1. As such, they will not enter FEI's rate base until January 1, 2023 and there will not be an impact to the 2022 rates if there is any variance in spending due to the truck load-outs.

12.7 Please confirm, or explain otherwise, that FEI plans to file a separate application for the BCUC to determine whether its LNG Tanker and T1A Truck Load-out projects listed in Table 7-6 meet the criteria to be a prescribed undertaking under the GGRR.

12.7.1 If confirmed, please discuss when FEI plans to file this application(s).

12.7.2 If not confirmed, please discuss whether FEI is requesting the BCUC, in this current proceeding, to make a determination on whether these projects meet the criteria to be a prescribed undertaking. Why or why not? Please discuss whether there is inconsistency between this approach and FEI's usual practice with respect to other prescribed undertakings.

<u>Response:</u>

FEI is not planning to file a separate application to determine if the LNG tanker (tank trailer) and the T1A Truck Load-out projects listed in Table 7-6 are prescribed undertakings under the GGRR. FEI submits that this determination is relatively straightforward and should be made in the context of this proceeding, as the only BCUC approval triggered by these undertakings is the recovery of the costs in rates, which is properly the subject of FEI's Annual Reviews.

[11] For CNG and LNG stations that are prescribed undertakings under the GGRR, recovery of the stations' cost of service is based on a minimum recovery of 80 percent for a 5-year term or 60 percent for a 7-year term.

FEI clarifies there is no inconsistency with FEI's usual practice with respect to other prescribed undertakings. For example, FEI's applications for approval of fueling service agreements for CNG and LNG fueling stations are driven by the requirement of sections 2(2)(c) and 2(3)(c) of the GGRR to recover at least 80 percent or 60 percent of the station's forecast operating costs from the fueling customers with a take-or-pay agreement with minimum terms of 5 or 7 years, respectively. This requires FEI to apply for BCUC approval of station recovery rates for the individual fueling customers. However, there is no similar requirement for LNG tank trailers or LNG tanker truck load-outs as there is no specific rate or other approval required for FEI to proceed with these expenditures. Although FEI is not required to seek approval for these expenditures or to set any specific rates, approval is required for the recovery of the costs through FEI's delivery rates. As such, FEI's Annual Review or revenue requirements applications are the appropriate proceeding for the BCUC to review these expenditures.

The following describes how FEI's tanker trailer and the T1A truck load-outs meet the criteria for a prescribed undertaking under section 2(3) of the GGRR.

Section 2(3)(a)(i): Binding Commitment before March 31, 2022 for Tank Trailer

As discussed in the response to BCUC IR1 12.5, FEI expects to make a binding commitment before March 31, 2022 to purchase and operate the LNG tank trailer listed in Table 7-6, and will only proceed with the purchase if such a binding commitment is in place. There is no ambiguity about what an LNG tank trailer is. It is simply a trailer that has a storage tank for LNG. A picture of the type of LNG tank trailer that FEI intends to purchase is provided below.

The purpose of purchasing the tank trailer is to provide, within BC, LNG and LNG fueling service to owners of vehicles including marine vehicles that operate on LNG. Specifically, as part of FEI's NGT program, FEI will use the tank trailer to transport LNG from FEI's Tilbury and Mount Hayes LNG facilities to customer locations.

Section 2(3)(a)(ii): Binding Commitment before March 31, 2022 for Tanker Truck Load-Outs

FEI made binding commitments with a design-build-contract in October 2020 to construct and operate the Tilbury 1A tanker truck load-outs. As defined in the GGRR, a "tanker truck load-out" means equipment for transferring liquefied natural gas from a storage tank to a liquefied natural gas tank trailer. The tanker truck load-outs at Tilbury 1A consist of equipment used to transfer LNG from the Tilbury 1A tank to an LNG tank trailer. A picture of a tanker truck load-out is provided below (with an LNG tanker being loaded with LNG as shown).

As with FEI's tank trailers, the purpose of purchasing and operating the tanker truck load-outs is to provide, within BC, LNG and LNG fueling service to owners of vehicles including marine vehicles that operate on LNG. The tanker truck load-outs enable FEI to transfer LNG from its Tilbury facility to LNG tank trailers, which can then be transported to customer locations.

Section 2(3)(b.1) and (3.01): Maximum Spending Limits Not Exceeded

FEI monitors its spending on prescribed undertakings to ensure that none of the maximum spending limits will be exceeded. None of the spending limits applicable to LNG tank trailers and LNG tanker truck load-outs have been or will be exceeded:

- ***2(3)(b.1):*** The only requirements specific to LNG truck load-outs is a maximum of $10 million per load-out. The current capital expenditure forecasts for the proposed two LNG truck load-outs are less than $10 million each. Please refer to the responses to BCUC IR1 12.4.1 and 12.4.2.

- ***2(3)(b.1):*** FEI's administration and marketing costs to date related to the prescribed undertaking in section 2(3) (i.e., LNG tank trailers, LNG stations and tanker truck load-outs) are less than $250,000.
- **2(3.01):** FEI's total expenditures to date under the prescribed undertakings in section 2(2) and 2(3) are less than $62.5 million, which is the maximum spending allowed under Section 2(3.01) of the GGRR.

13.0 Reference: RATE BASE

Exhibit B-2, Section 7.3, Table 7-7, pp. 57

Plant Additions

On page 57 of the Application, FEI provides Table 7-7, showing a Reconciliation of 202 Capital Expenditures to Plant Additions:

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**	

13.1 Please provide a breakdown, by project, of the work in progress amounts from Table 7-7 (lines 7 and 16).

<u>Response:</u>

A breakdown by project of the work in progress amounts shown on Lines 7 and 16 in Table 7-7 in the Application is provided in the tables below.

Line 7: Change in Regular Capital Work in Progress ($ millions)

Project name	2022 Forecast
City of Vancouver Biomethane Project	(24.000)
Tilbury 1A Truck Load-out (GGRR)	(4.420)
Other RNG	(15.297)
Total	**(43.717)**

Line 16: Change in Special Projects and CPCN Work in Progress ($ millions)

Project name	2022 Forecast
LMIPSU	12.716
IGU	(12.809)
PGR	(105.976)
Total	**(106.069)**

13.2 Please explain how FEI determines the work in progress amounts from Table 7-7 (lines 7 and 16).

Response:

The change in work in progress amounts shown on Lines 7 and 16 in Table 7-7 in the Application represent the difference between the closing and opening work in progress balances, which is equivalent to the net amount of total plant additions less capital expenditures, AFUDC and capitalized overheads.

FEI assumes all regular capital expenditures will be added to plant in the same year, while only Flow-through and Major Project capital expenditures are evaluated for timing differences and recognized in the Change in Work in Progress forecasts.

14.0 Reference: DEFERRED CHARGES

Exhibit B-2, Section 7.5.1, Table 7-8, pp. 59–64

New Deferral Accounts

On page 59 of the Application, FEI states:

> 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.

In Table 7-8 on pages 59 to 64 of the Application, FEI addresses the considerations identified in the BCUC's Regulatory Account Filing Checklist with respect to these deferral accounts.

On pages 63 and 64 of the Application, FEI provides the forecast additions to the requested new rate base deferral account as follows:

- Transportation Service Report: 2021 = 0.100 million, 2022 = $0.250 million and 2023 = $0.150 million
- 2021 Generic Cost of Capital Proceeding: 2021 = $0.750 million, 2022 = $0.750 million and 2023 = $0.350 million
- 2021 Renewable Gas Program Comprehensive Review: 2021 = $0.330 million and 2022 = $0.435 million

14.1 Please discuss whether FEI has a quantitative threshold (e.g. anticipated regulatory costs > $X) or qualitative considerations when determining whether to request establishment of a new deferral account to capture regulatory proceeding costs. If so, please provide the quantitative threshold or qualitative considerations.

Response:

FEI does not have a specific quantitative threshold for determining whether to request establishment of a new regulatory proceeding cost deferral account, as it is accepted practice that regulated utilities should be provided the opportunity to recover their prudently incurred costs. For clarity, the costs recorded in the regulatory proceeding cost deferral accounts are not included within FEI's formula O&M under the MRP. The regulatory costs included within FEI's formula O&M are FEI's internal labour (i.e., the FTEs) within the applicable FEI departments to support the utility's applications, in particular, the Regulatory department, though resources from other departments are also required. The costs included within the applied for regulatory cost deferral accounts are primarily related to BCUC costs and PACA costs, and any costs for FEI's external counsel and external consultants or experts. These costs are driven by the regulatory process established for the application, and as such are largely outside of FEI's control and vary considerably depending on the nature/size of the application, the regulatory process established by the BCUC, and the number of interveners that participate.

While FEI does not have a quantitative threshold in place for determining whether to request establishment of a new deferral account to capture regulatory proceeding costs, FEI does consider qualitative factors. The qualitative factors that FEI considers include the nature of the filing or application, the potential review process the BCUC may initiate, the likely duration of the proceeding, the extent of involvement of other parties in the process, and the potential for interveners to claim participant cost awards. FEI typically requests new deferral accounts to capture regulatory proceeding costs when it is anticipated that there will be a public hearing process with intervener participation.

Further, on pages 63 and 64 of the Application, with respect to the 2021 Renewable Gas Program Comprehensive Review, FEI states:

> 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 [Biomethane Energy Recovery Charge] Rate assessment report and the second stage consisting of a comprehensive review of FEIs Renewable Gas (RG) Program. […] [Footnote references removed]
>
> 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.

14.2 Please discuss whether FEI captures the regulatory costs associated with the regulatory review of the BERC Rate assessment report (i.e. Stage 1) in a deferral account. If so, please identify the deferral account, the amounts captured by year, and the BCUC order that approved the establishment of the account.

14.2.1 If not, please explain why a deferral account should be established to capture the regulatory costs associated with the comprehensive review of FEI's Renewable Gas Program (i.e. Stage 2). Please also explain how the BERC Rate assessment report (i.e. Stage 1) costs were recovered from FEI's ratepayers.

<u>Response:</u>

FEI captured the costs associated with the regulatory review of the BERC Rate Assessment Report (i.e., Stage 1 costs) in the Biomethane Variance Account (BVA) deferral account. To date, the amount recorded is approximately $31 thousand ($7 thousand in 2020 and approximately $24 thousand to date in 2021) pre-tax. This deferral account was approved by Order G-194-10, which allows for direct administrative costs related to the Biomethane Program to be recorded to the BVA deferral account. Given that the BERC Rate Assessment Report was a compliance filing[12], FEI did not expect significant costs associated with the BCUC's review of the compliance filing. As such, a separate deferral account for the Stage 1 proceeding costs was not sought.

A separate deferral account is being requested to capture the costs associated with the comprehensive review of FEI's Renewable Gas Program (i.e., Stage 2 costs) as the costs are forecast to be much more substantial compared to Stage 1 costs. As stated in FEI's Annual Review for 2022 Delivery Rates, additions to the 2021 RG Program Comprehensive Review deferral account are forecast to be $0.330 million in 2021 and $0.435 million in 2022.

[12] Directed by the BCUC in the Decision and Order G-133-16 in the matter of *FEI's 2015 Application for Approval of Biomethane Energy Recovery Charge Rate Methodology* (2015 BERC Proceeding).

15.0 Reference: DEFERRED CHARGES

Exhibit B-2, Section 7.5.2.1, Table 7-11, pp. 66–67

COVID-19 Customer Recovery Fund Deferral Account

On page 66 of the Application, FEI provides the following table that shows the account receivables that are considered unrecoverable due to the COVID-19 pandemic, which have been added to the COVID-19 Customer Recovery Fund deferral account. FEI also states that "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

Further on page 66 of the Application, FEI states:

> 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.

On page 67 of the Application, FEI states:

> 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.

15.1 Please discuss how the 2022 forecast additions of $1.7 million was calculated given that 15 percent of the 480 customers contacted (out of an estimated 3,600 total customers with outstanding balances) confirmed that they were financially impacted by COVID-19, and the average balance was $550. If the $1.7 million is derived from a calculation, please provide the calculation.

Response:

The forecast addition of $1.7 million for 2022 to the COVID-19 Customer Recovery Fund deferral account was based on findings from the pilot project and adjusted to reflect bill payment deferral amounts already accounted for.

Please refer to the table below for the detailed calculation:

Line	Particulars			Notes
1	Total Customers Past Due as at June 2, 2021		24,000	
2	Estimated Percentage Unrecoverable		15%	As determined based on pilot program customer contacts
3	Estimated Number of Customers		3,600	Line 1 x Line 2
4				
5	Average Outstanding Balance	*$*	$ 550	Average outstanding account balance for customers in pilot group
6	Estimated Total Balance	*$ 000s*	$ 1,980	(Line 3 x Line 5) / 1,000
7	Less: Bill Payment Deferrals	*$ 000s*	$ 280	Embedded in Line 6; however, already accounted for in the deferral account
8	Estimated Unrecovered Revenue Addition	*$ 000s*	**$ 1,700**	Line 6 - Line 7

The average outstanding balance per customer inherently includes bill payment deferral amounts; however, this amount has been added as transfers to the deferral account (please refer to the Transfers line identified in Table 7-11 of the Application). As such, an adjustment is required to remove the bill payment deferral amount from the calculation to avoid double counting in the forecast balance of the deferral account.

15.2 Please provide the actual or projected annual bad debt expense for 2018 to 2021 and the forecast for 2022 that are deemed unrecoverable in the normal course of business (i.e. not deemed unrecoverable due to COVID-19).

15.2.1 If there is more than a 10 percent difference between the 2022 and the pre-pandemic (i.e. 2018 and 2019) non-COVID-19 related bad debt expense provided in the response to the preceding information request (IR), please explain the cause of the differences.

Response:

Please refer to the table below for the actual, projected and forecast bad debt expense amounts for the years requested.

Table 1 - FEI Bad Debt Expense ($ million) – 2018 through 2022

	2018 Actual	2019 Actual	2020 Actual	2021 Projected	2022 Forecast
Bad Debt Expense	0.891[1]	1.646	1.565	1.600	2.055

Note:

[1] In 2018, bad debt expense was very low relative to the previous five years. From 2014 to 2018, the average bad debt expense was approximately $1.8 million per year compared to the 2018 bad debt expense of $0.9 million.

At this time, the 2022 forecast bad debt expense recognized in O&M is estimated to be in line with the average bad debt expense from 2014 to 2018 of $1.8 million per year[13] and higher than the pre-pandemic (i.e., 2018 and 2019) non-COVID-19 related bad debt expense by more than a 10 percent difference, primarily due to higher overall revenue from increases in cost of gas and delivery rates since 2019. The COVID-19 related bad debt expense is accounted for in the COVID-19 deferral account and is not included in the numbers provided in this response.

[13] MRP Application, p. C-20.

16.0 Reference: DEFERRED CHARGES

Exhibit B-2, Section 7.5.2.2, p. 69; Order G-128-11 dated July 19, 2022, Appendix A to G-128-11, Reasons for Decision, pp. 17–18

BFI (presently "Waste Connections") Costs and Recoveries deferral account

On page 69 of the Application, FEI states:

> […] 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.

On pages 17 and 18 of the BCUC's Reasons for Decision with respect to FEI's Application for approval of a Service Agreement for Compressed Natural Gas Service with Waste Management of Canada Corporation and General Terms and conditions for Compressed Natural Gas and Liquified Natural Gas Service, the BCUC stated:

> The Panel questions whether it is in the interests of FEI's existing ratepayers to bear the costs or risks associated with reducing carbon emissions for the transportation sector when FEI ratepayers represent only a portion of the province's population and, generally speaking, are not directly responsible for those emissions. We are of the opinion that they should not. In our view, it is more appropriate that these costs be borne either by the owners of the vehicles, as they are the emitters, or by the people of the province as a whole, as they are the beneficiaries. […]
>
> Thus, the Panel agrees with FEI's approach that the ratepayers be "kept whole," and throughout this decision, we discuss the reasons for our agreement. Consistent with this approach, the Panel finds that while the benefits of GHG emission reduction provides a justification for FEI's proposed NGV [Natural Gas Vehicle] program, FEI's ratepayers must be insulated, to the greatest extent possible, from the costs and risks of the program. [Emphasis removed]

16.1 Given the BCUC's previous statement that FEI's ratepayers should be "kept whole" and "insulated, to the greatest extent possible, from the costs and risks of the [NGV] program," please explain why the $0.202 residual balance in the BFI Costs and Recoveries deferral account should be recovered from FEI's ratepayers.

Response:

FEI notes that the referenced BCUC Order G-128-11 was dated July 19, 2011, not July 19, 2022 as indicated in the reference to the IR. Order G-128-11 preceded both the *Greenhouse Gas Reduction (Clean Energy) Regulation,* under which NGT stations can be prescribed undertakings pursuant to section 18 of the *Clean Energy Act*, and Direction No. 5 to the BCUC, section 3 of which requires the BCUC to "treat CNG service and LNG service, and all costs and revenues related to those services, as part of the utility's natural gas class of service" and "allocate all costs and revenues related to CNG service and LNG service to all applicable customers".

The $0.202 million residual balance in the BFI Costs and Recoveries deferral account is not a cost to Waste Connections (formerly BFI) and recovering the amount from FEI's ratepayers will keep both FEI and customers whole.

The $0.202 million is related to income taxes paid[14] for the excess capital recoveries received of $0.764 million from Waste Connections since 2012, which have been captured in the BFI Costs and Recoveries deferral account. It is FEI's standard regulatory practice to record the tax effect in a net-of-tax deferral account. This enables matching of the taxes or tax benefits to the associated costs. This practice was confirmed in Order G-53-94, page 2:

> Deferred Account Balances in Rate Base
>
> If deferred expenses or credits are included in the utility's actual tax calculation in the year they are first recorded, then the amounts shall be recorded in rate base on a net of tax basis. If such expenses or credits are not included in the utility's tax calculation then the amounts shall be on a before tax basis.

As Waste Connections elected to have the total excess recoveries of $0.764 million returned by lowering their Capital Rate effective April 1, 2020, this effectively meant transferring a credit of $0.764 million to FEI's plant-in-service against the existing balance for the assets of the Waste Connections station, thereby reducing FEI's rate base. The $0.764 million will be fully returned to customers in future years through depreciation of the plant-in-service balance. Further, since the $0.764 million was treated as income for tax purposes in each of the years it was received, and the associated tax cost was included in the deferral, FEI has not included the $0.764 million as a credit to its Undepreciated Capital Cost (UCC) pool.

Amortizing the $0.202 million residual balance of tax in the deferral account for recovery from FEI's customers aligns with transferring the $0.764 million to FEI's plant-in-service. The $0.202

[14] The effective rate ranged from 25 percent to 27 percent from 2012 to 2020, resulting in a net effective tax rate of 26.4 percent on the deferral account additions.

million will be recovered in future customer delivery rates via amortization expense, resulting in a net after-tax amount of $0.562 million returned to customers via delivery rates. This is consistent with the regular net of tax deferral treatment where the entire after-tax amount in the deferral is recovered from or returned to customers through the amortization of the deferral included in the utility's revenue requirements. The amortization expense/depreciation expense is then added back on the tax schedule in the financial schedules, resulting in the full pre-tax amount being returned to or recovered from customers.

In summary, if the tax balance in the deferral were not recovered from FEI's customers, customers would actually over-benefit from these transactions. The amount returned to customers would be the $0.764 million in depreciation credits, grossed up for tax purposes via the add-back on the tax schedule, for a total benefit of $1.047 million ($0.764 million / (1-27%)). Therefore, amortizing the net of tax balance in the deferral as proposed is the correct approach and will keep both customers and FEI whole.

16.2 Please discuss whether the $0.202 million residual balance in the BFI Costs and Recoveries deferral account can be recovered from Waste Connections. For example, can Waste Connections' Capital Rate be adjusted to take into account the residual balance (e.g. apply $0.764 million less $0.202 million to reduce the Capital Rate)? If this is possible, please explain why this is not FEI's preferred treatment for the residual balance.

Response:

Please refer to the response to BCUC IR1 16.1. FEI does not believe it is appropriate to recover the residual balance from Waste Connections as it is not a cost of Waste Connections. Doing so will also result in disconnecting the associated tax from the $0.764 million excess capital revenue which was transferred to FEI's plant-in-service.

17.0 Reference: DEFERRED CHARGES

Exhibit B-2, Section 7.5.2.3, p. 69; Section 8.1, p. 71; Section 12.4, p. 134

2017-2018 Revenue Surplus Deferral Account

On page 69 of the Application, FEI states:

> […] 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.

On page 71 of the Application, FEI explains that its AFUDC rate is equal to its after-tax weighted average cost of capital.

On page 134 of the Application, FEI states:

> 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).

17.1 Given that the carrying costs on a non-rate base deferral account are equal to the return earned on a rate base deferral account, please explain how transferring the 2017 & 2018 Revenue Surplus deferral account to a rate base deferral account would eliminate the potential for future variances being captured in this account.

Response:

While FEI agrees that the carrying costs and earned return are generally equal whether the account is rate base or non-rate base attracting a WACC return, the calculation and accounting of the return is fundamentally different.

The return on a rate base deferral account is ultimately embedded in the earned return portion of the current year revenue requirements, with no additional adjustment required to the deferral account balance itself. With no actual or forecast additions to the deferral account, there is no potential for variances.

In contrast, the WACC return on a non-rate base deferral account is calculated and recorded monthly using the actual deferral balance and approved AFUDC rate. The amount is recorded directly in the deferral account itself, thereby resulting in current year additions to the deferral account. This creates the potential for variances to exist between the actual and forecast deferral additions, which may occur if the forecast was not produced using the same level of precision as actuals are recorded. Any variance between the forecast and actual additions would leave a residual balance in the deferral that is recovered from/returned to customers in a future year, where that amount may then also be subject to future variances that may occur.

Therefore, transferring these types of residual balances to rate base will ensure the balances are fully depleted in the forecast test year, while having no adverse impact on customers.

H. EARNINGS SHARING AND RATE RIDERS

18.0 Reference: EARNING SHARING AND RATE RIDERS

Exhibit B-2, Section 10.3.1, Tables 10-1, 10-3, 10-4, pp. 81–82, 84–85; FEI Annual Review for 2020 and 2021 Rates proceeding, Exhibit B-2, Section 10.2.1, Tables 10-1, 10-4, pp. 85, 89

BVA Rate Rider

Table 10-1, on pages 81 and 82, in the Application shows projected 2021 biomethane costs incurred of $18.754 million (line 10) and biomethane costs recovered of $7.461 million (line 11). Table 10-1 in the FEI Annual Review for 2020 and 2021 Delivery Rates application shows projected 2020 biomethane costs incurred of $9.167 million and biomethane costs recovered of $4.465 million.

18.1 Please explain why the 2021 biomethane costs are projected to be approximately twice as much as the costs projected for 2020.

__Response:__

There are two main drivers of the increase in 2021 projected biomethane costs in this Application compared to the 2020 projected costs included in FEI's 2020 and 2021 Annual Review. The primary driver of the increase is related to RNG purchase costs. The secondary driver is related to O&M costs.

RNG purchase costs have increased by $8.7 million due to an increase in volume and an increase in the average purchase cost. Projected volumes increased by 61 percent from approximately 424 TJs to approximately 682 TJs. The increased volumes also resulted in an increase to the average projected RNG purchase price by 57 percent due to the new supply projects.

O&M costs are projected to increase by 9 percent or $863 thousand in 2021, as additional resources are required to support existing and new project development. FEI has also restarted the RNG customer education programs in 2021.

18.2 Please provide the actual 2020 biomethane costs and explain the change from the actual 2020 costs to the projected 2021 costs.

__Response:__

The actual 2020 biomethane costs incurred were $8.167 million for approximately 306 TJs, compared to the 2021 projected biomethane costs of $18.754 million for approximately 682 TJs.

The primary reason for the increase in costs is the increased volume, as the current 2021 projected volume is approximately 2.23 times the 2020 actual volume.

As discussed in the response to BCUC IR1 18.1, the 2021 projected biomethane costs also include amounts for additional resources to support existing and new project development as well as the restarting of customer education programs. These additional O&M costs contribute to the increased biomethane costs projected for 2021.

18.3 Please explain why biomethane costs have increased at a faster rate than the biomethane cost recovery in 2021 compared to 2020.[15]

Response:

There are two main reasons why biomethane costs have increased at a faster rate than the biomethane cost recovery in 2021 compared to 2020:

1. FEI has projected 13.2 TJs of purchased RNG remaining as inventory by the end of 2021, and there is no cost recovery associated with these RNG volumes in 2021.

2. The biomethane cost recovery is limited to the BERC rate, with any increases disconnected from the cost of biomethane. The increase in the BERC rate is subject to the increase in FEI's cost of gas rates, which for 2021 resulted in an increase to the BERC rate by approximately 12 percent from $10.535 per GJ to $11.830 per GJ. In contrast, as discussed in the response to BCUC IR1 18.2, the biomethane costs are projected to increase by approximately 130 percent (from a 2020 actual amount of $8.167 million to a 2021 projected amount of $18.754 million), primarily due to the increase in volumes and O&M costs.

In note (c) of Table 10-1, FEI provides a continuity schedule of the total unsold biomethane for 2020 and 2021.

18.4 Please expand this continuity schedule to include the forecast amounts for the remainder of the MRP term (i.e. 2022 to 2024).

[15] Increase in biomethane cost recovery is approximately 67% = ($7.461M/$4.465M – 1) x 100; Increase in biomethane costs is approximately = 105% = ($18.754M/$9.167M – 1) x 100.

Response:

FEI cannot provide an accurate forecast of the amount of unsold biomethane for the remainder of the MRP term at this time. FEI is currently reviewing the Renewable Gas Program and expects to file a Renewable Gas Comprehensive Review application in late 2021. FEI anticipates that the results of the Renewable Gas Comprehensive Review will materially change the demand for biomethane, as service offerings may change in response to government policy, markets, and the increased supply of RNG.

FEI has, however, provided the following continuity schedule which expands note (c) in Table 10-1 of the Application to 2022, but notes that the embedded assumptions are unlikely to materialize. For the purpose of this table, FEI has used the expected volumes of all currently approved supply projects as the forecast for 2022. Any additional biomethane purchase agreements that are approved will impact the biomethane purchased volumes. FEI has assumed that the 2022 forecast volumes sold are equal to the 2022 forecast from the Q4, 2020 gas cost report, which is based on the current state of the Renewable Gas program.

Calculation of Adjustment for Unsold Biomethane	2020 Recorded	2021 Projected	2022 Forecast
Beginning Quantity Unsold Biomethane (in TJ)	0.1	-	13.2
Biomethane Purchased (in TJ)	306.0	682.0	3,179.2
Biomethane Sold (in TJ)	(306.2)	(668.8)	(2,685.7)
Ending Total Biomethane Unsold (in TJ)	-	13.2	506.7
BERC rate in effect at forecast (in $/GJ)			
January 1st effective BERC rate (in $/GJ)	11.83	11.83	11.83
Value of Unsold Biomethane at December 31st	-	155.7	5,994.3

Table 10-4 on page 85 of the Application shows the renewable natural gas (RNG) customer enrollment projected for 2021 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**

On page 89 of the FEI Annual Review for 2020 and 2021 Delivery Rates application, FEI provided the following table that shows the RNG customer enrollment projected for 2020.

Table 10-4: RNG Customers by Rate Schedule

2020 RNG Projected Participation (Rate Schedule)	Customer Enrollment
Short Term	
Rate Schedule 1B	10,273
Rate Schedule 2B	198
Rate Schedule 3B	15
Rate Schedule 11B	2
Rate Schedule 5B	2
Rate Schedule 30 Off System	-
Long Term	
Rate Schedule 11B	3
Total	**10,493**

The following is an extract of Table 10-3 on page 84 of the Application:

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

18.5 Please expand Table 10-4 in the Application to include the actual RNG customer enrollment for 2020 broken down by rate schedule.

<u>Response:</u>

FEI provides the following expanded Table 10-4, which also amends the projected customers for 2021 to align with the 2021 volumes projected in Table 10-3.

2020 RNG Projected Participation (Rate Schedule)	2020		2021	
	Projected	Actual	Original	Amended
Short Term				
Rate Schedule 1B	10,273	10,115	9,273	9,722
Rate Schedule 2B	198	194	183	191
Rate Schedule 3B	15	17	17	17
Rate Schedule 5B	2	2	3	12
Rate Schedule 11B	2	2	2	6
Rate Schedule 30B Off System	-	-	0	0
Long Term				
Rate Schedule 11B	3	3	3	3
Total	**10,493**	**10,333**	**9,481**	**9,951**

The table includes the following updates:

1. The actual customer enrolment for 2020 broken down by rate schedule as requested. In preparing the requested information, FEI noted that the actual 2020 customer enrolment indicated there were two additional participants in Rate Schedule 3B over the projected result, which appeared to be inconsistent with the fact that the RNG program was closed to new participants in 2020. FEI has reviewed the program data and determined that no new customers were admitted to the program during the closure period. The difference is attributable to the following:

    a. At the time that FEI prepared the projected numbers for the Annual Review for 2020 and 2021 Delivery Rates Application, one existing program participant had elected to change the percentage of RNG received. FEI's information system accomplished this by dropping the customer from the program temporarily, and subsequently re-enrolling the customer at the new desired percentage. When FEI prepared the projected numbers, the program data did not include this participant. In the end of year actual number presented in the table above, this participant is now included.

    b. Subsequent to when FEI prepared the 2020 projected customer enrolment numbers, one premise was migrated from Rate Schedule 2 to Rate Schedule 3. This participant's enrolment in the RNG program likewise migrated from Rate Schedule 2B to Rate Schedule 3B.

2. The projected enrolment for 2021 has been amended to include new participation. FEI now anticipates reopening the RNG program to new participants in the latter part of 2021. The projected participation for 2021 provided in the Application did not include new customer additions post program reopening.

With regard to the 2021 Amended Projected Participation provided in the above table, FEI notes that this updated customer enrolment count has no impact on the BVA rider calculated in Table 10-2 of the Application. The volumes as originally reported in Table 10-3 of the Application already included volumes projected from reopening the RNG program, thus the impact of the increased customer enrolment was already included in the BVA rider calculation.

18.6 Please explain how FEI projects the RNG volume for 2021 that is shown in Table 10-3.

Response:

FEI projects the demand for RNG using several approaches based on how customers are enrolled in the program.

For large volume customers under Rate Schedule (RS) 11B, a demand schedule is required outlining the customer's desired RNG volumes on a monthly basis. Schedules for short-term RS 11B customers cover a one-year period while long-term customers cover a 5-year contract period.

For mass-market customers (currently RS 1B, 2B and 3B), FEI uses the customer counts per rate class multiplied by the historical average consumption of RNG per customer. FEI updates the historical average consumption of RNG per customer annually to include the previous year's results.

Currently, there are only a few RS 5B customers. As such, FEI forecasts the consumption of these customers individually based on their consumption history plus any information they have provided to FEI about their desired volumes.

FEI updates the forecast on a monthly basis to include the actual customer and consumption numbers from the previous month. In this way, the accuracy of the year-end projection continues to improve as the year progresses.

18.7 Please explain why the 2021 projected volume for Rate Schedule 2B has increased from 16.9 TJ to 21.2 TJ when the number of projected customers enrolled has decreased from 198 to 183.

Response:

FEI notes the 16.9 TJ was a 2020 projected volume for Rate Schedule (RS) 2B from FEI's 2020 and 2021 Annual Review application filed in August 2020. FEI believes it is more appropriate to compare the 2021 projected volume with the 2020 actual, which was 21.4 TJs with actual customer enrollment of 194, as shown in the response to BCUC IR1 18.5. The minor volume reduction from the 2020 actual to 2021 projected level is consistent with the reduction of enrolled customers from 194 to 191. Please refer to the response to BCUC IR1 18.5 which shows that the amended 2021 projected customer enrollment for RS 2B is 191. Please also refer to the response to BCUC IR1 18.6 for a description of the forecasting methodology.

18.8 Please explain why the 2021 projected volume for Rate Schedule 3B has decreased from 19.3 TJ to 18.2 TJ when the number of projected customers enrolled has increased from 15 to 17.

Response:

FEI notes the 19.3 TJ was a 2020 projected volume for Rate Schedule (RS) 3B from FEI's 2020 and 2021 Annual Review application filed in August 2020. FEI believes it is more appropriate to compare the 2021 projected volume with the 2020 actual, which was 18.8 TJs with actual customer enrollment of 17, as shown in the response to BCUC IR1 18.5. There is no anticipated change in customer enrollment in RS 3B and the minor variance in volume of 0.3 TJ is likely attributable to small variances in the customer use rate. Please refer to the response to BCUC IR1 18.6 for a description of the forecasting methodology and BCUC IR1 18.5 for a discussion on the customer count for RS 3B.

18.9 Please explain why the 2021 projected volume for Rate Schedule 5B has increased to 116.3 TJ from the actual 2020 volume of 15 TJ.

Response:

The increase is attributable to two developments. First, in 2021 the City of Surrey nominated a larger portion of the RNG produced at its Surrey Biofuels facility for its own use, resulting in an increase to the 2021 projection. FEI notes the City of Surrey originally planned this to occur in 2020, and FEI adjusted its 2020 projected numbers upwards as part of its 2020 and 2021 Annual Review application accordingly, which led to the large variance between the 2020 projected and 2020 actual demand from RS 5B. Second, FEI plans to reopen the RNG program to new participants in the latter part of 2021. An allowance for new customers and load has been included under the 2021 RS 5B projected demand to account for new enrolment.

18.10 Please explain why the 2021 projected short-term and long-term volume for Rate Schedule 11B has increased when the number of projected short-term and long-term customers enrolled has stayed at 2 and 3, respectively.

Response:

The increase in projected volumes in 2021 compared to 2020 is due to FEI's improved ability to provide RNG to customers. The RNG program has been closed to new participants since August of 2019. During this period, service to existing Rate Schedule (RS) 11B customers has been curtailed. In the meantime FEI has successfully entered into new supply contracts. Beginning in late 2020, and continuing through 2021, several of these new suppliers began providing FEI with RNG. As 2021 progressed, and the new suppliers demonstrated their ability to reliably supply RNG, it became apparent that FEI was in a position to end the curtailment of RNG service to existing customers. Further, FEI was in a position to plan to reopen the program to new participants in late 2021. FEI factored the above developments into the projected sales volumes for 2021. In summary, the increase for RS 11B customers in 2021 is due to:

1. Ending the curtailment of service to existing RS 11B customers;
2. Providing additional volumes to existing RS 11B customers to offset the supply deficit incurred during the curtailment period. These volumes ensure that FEI will have delivered the contracted minimum supply volumes to the RS 11B customers; and
3. Providing an allowance for new RS 11B customer enrollment assuming a program reopening in the latter part of 2021.

FEI now believes that the projections above understate the volume of demand from RS 11B long-term customers, and overstates the volume of demand for RS 11B short-term customers. FEI's current 2021 projected demand for RS 11B long-term and short-term customers is approximately 365 TJs and 46 TJs, respectively. FEI notes the updated forecast only shifts projected volumes between short-term and long-term RS 11B customers; the total sales volume remains the same at 668.8 TJs. FEI also notes this shift does not impact the biomethane costs recovered in the BVA rider calculation[16].

[16] FEI projects Biomethane costs recovered in Table 10-1, Line 11 of the Application based on the total sales volume from Table 10-3, Line 15 times the actual weighted BERC recovery rate experienced in YTD actuals up to the time of filing the Application.

19.0 Reference: EARNING SHARING AND RATE RIDERS

Exhibit B-2, Section 10.3.2, Table 10-5, p. 85; Section 11, Schedule 11; FEI Annual Review for 2020 and 2021 Rates proceeding, Exhibit B-2, Section 11, Schedule 11,

pp. 109, 143

Revenue Stabilization Adjustment Mechanism

On page 85 of the Application, FEI states that the projected balance in the Rate Stabilization Adjustment Mechanism (RSAM) is a debit of $2.473 million.

On pages 109 and 146 of the FEI Annual Review for 2020 and 2021 Delivery Rates application, the projected RSAM balance at the end of 2021 and 2020 was a debit of $8.836 million and a debit of $17.667 million, respectively, and the actual RSAM balance at the end of 2019 was a debit of $26.353 million.

19.1 Please provide a continuity schedule that shows the change from the 2019 actual RSAM balance of $26.353 million to the actual 2020 ending balance and to the projected 2021 ending balance of $2.473 million.

Response:

Please refer to the table below for the requested continuity schedule from 2019 actual to 2021 projected for the RSAM balance. Note the 2021 ending balance of $2.473 million shown on page 85 of the Application includes RSAM interest, which is recorded separately in the Interest on CCRA/MCRA/RSAM/Gas Storage rate base deferral account. FEI has included the RSAM interest deferral account within the continuity schedule below.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RSAM
($000s)

Line No.	Particulars	Actual 12/31/2019	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	Actual 12/31/2020	Mid-Year Average
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	RSAM	26,353	-	(657)	177	-	(10,827)	2,923	17,970	22,162
2	RSAM Interest	8	-	(53)	14		(3)	1	(33)	(13)
	Total	**26,361**	**-**	**(710)**	**191**	**-**	**(10,830)**	**2,924**	**17,937**	**22,149**

Line No.	Particulars	Actual 12/31/2020	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	Projected 12/31/2021	Mid-Year Average
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	RSAM	17,970	-	(8,869)	2,395	-	(12,238)	3,304	2,562	10,266
2	RSAM Interest	(33)	-	(100)	27		23	(6)	(89)	(61)
	Total	**17,937**	**-**	**(8,969)**	**2,422**	**-**	**(12,215)**	**3,298**	**2,473**	**10,205**

19.2 Please explain the driver(s) behind the decrease in the RSAM balance from 2020 projected of $17.667 million to 2021 projected of $8.836 million.

Response:

The 2020 projected ending balance of $17.667 million shown in Table 10-5 of the Annual Review for 2020 and 2021 Delivery Rates Application is comprised of the projected debit ending balance of the RSAM deferral account of $17.673 million (Section 11, Schedule 11 - 2020, Line 4, Column 9) and the RSAM interest projected credit ending balance of $0.006 million. The RSAM interest is recorded separately and grouped in the Interest on CCRA/MCRA/RSAM/Gas Storage deferral account line in the financial schedules (Section 11, Schedule 11 - 2020, Line 5, Column 9). The 2021 forecast ending balance for the RSAM deferral account, as filed in the Annual Review for 2020 and 2021 Delivery Rates Application, is $8.836 million (Section 11, Schedule 11 – 2021, Line 4, Column 9).

FEI does not forecast additions to the RSAM account, as it is assumed that there will be no variance from the use rates that have been forecast. As a result, the reason for the decrease in the RSAM deferral account balance from the 2020 projected ending balance of $17.673 million to the 2021 forecast ending balance of $8.836 million is primarily due to the forecast 2021 RSAM rider recovery of $12.106 million. This is based on the 2021 RSAM rate rider of $0.087 per GJ and the 2021 forecast demand for RS 1, 2, 3, and 23. To further clarify, the table below shows the continuity from the projected ending balance of 2020 to the forecast ending balance of 2021 for the RSAM deferral account from FEI's 2020 and 2021 Annual Review application, using the various references described in the paragraph above. A breakout of the rider and the applicable volumes is also available in Table 10-5 of the 2020 and 2021 Annual Review application.

Line	Particular	Projected 12/31/2020	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	Forecasted 12/31/2021
1	RSAM	17,673				(12,106)	3,269	8,836
2	RSAM Interest	(6)	(7)	2		5	(2)	(8)
3	Total	17,667	(7)	2	-	(12,101)	3,267	8,828

19.3 Please explain the driver(s) behind any change between the actual and projected ending 2020 account balance.

Response:

There is only a small variance between the 2020 Projected and 2020 Actual RSAM deferral account balance (of $270 thousand).

The tables below provide the continuity for the RSAM deferral account and RSAM interest deferral account for the 2020 projected ending balance as included in FEI's 2020 and 2021 Annual Review application, and for 2020 actuals as included in FEI's 2020 BCUC Annual Report.

The RSAM deferral account captures the variances in use rate (GJ per customer) between actual/projected and approved for rate schedules (RS) 1, 2, 3, and 23 with the balance being amortized through the RSAM rider recovery. The small variance of $270 thousand between the actual ending balance of 2020 and the projected ending balance of 2020 is primarily due to the following:

- At the time of filing the 2020 and 2021 Annual Review application, the gross credit additions of $982 thousand (before interest) were projected using actual monthly variances in use rates of RS 1, 2, 3, and 23 up to June 2020 only[17]. In contrast, the actual gross credit additions, due to variances in use rates of RS 1, 2, 3, and 23 for the full year of 2020, were $657 thousand; and
- At the time of filing the 2020 and 2021 Annual Review application, the projected RSAM rider recovery was $10.908 million, which was based on a RSAM rate rider of $0.078 per GJ (approved by Order G-307-19) and a projected demand with actuals up to June 2020 for RS 1, 2, 3, and 23. However, the actual 2020 full year demand for RS 1, 2, 3, and 23 combined was lower than projected, resulting in a reduced actual RSAM recovery of $10.827 million.

2020 Projected RSAM Deferral Continuity (As filed in FEI's Annual Review for 2020 and 2021 Delivery Rates)

Line	Particular	Actual 12/31/2019	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	Projected 12/31/2020
1	RSAM	26,353	(982)	265		(10,908)	2,945	17,673
2	RSAM Interest	8	(17)	5		(3)	1	(6)
3	Total	26,361	(999)	270	-	(10,911)	2,946	17,667

2020 Actual RSAM Deferral Continuity (As filed in FEI's 2020 BCUC Annual Report)

Line	Particular	Actual 12/31/2019	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	Actual 12/31/2020
1	RSAM	26,353	(657)	177		(10,827)	2,923	17,970
2	RSAM Interest	8	(53)	14		(3)	1	(33)
3	Total	26,361	(710)	191	-	(10,830)	2,924	17,937

19.4 Please explain the driver(s) behind the change in the ending 2021 account balance from $8.836 million projected in the previous annual review to the $2.473 million currently projected.

[17] Actual variance in use rates of RS 1, 2, 3, and 23 multiplied by the actual customer counts in the same month.

Response:

FEI notes the 2021 forecast ending debit balance of $8.836 million for the RSAM deferral account *excludes* RSAM interest and was based on the forecast provided in the 2020 and 2021 Annual Review application, which was filed in August 2020. It was based on the 2021 demand forecast and a forecast of zero use rate variances for RS 1, 2, 3, and 23 at that time. The current 2021 projected ending debit balance of $2.473 million *includes* RSAM interest and was projected based on an updated 2021 demand forecast and use rates variance for RS 1, 2, 3, and 23 with actuals up to May 2021. The practice of using year-to-date actuals of use rate variances for projecting the current year additions, but not forecasting future years' use rate variances, is consistent with past annual reviews.

Please refer to the response to BCUC IR1 19.1 for the continuity of the RSAM deferral which shows the current 2021 projected ending debit balance of $2.473 million (including RSAM interest) as included in the Application. Please also refer to BCUC IR1 19.2 for the continuity of the RSAM deferral which shows the initial 2021 forecast ending debit balance of $8.836 million (excluding RSAM interest) as included in FEI's 2020 and 2021 Annual Review application.

When comparing the original 2021 forecast continuity included in the 2020 and 2021 Annual Review application to the 2021 projected continuity shown in the response to BCUC IR1 19.1 and embedded in this Application, it can be seen that the current 2021 projected RSAM deferral balance continuity includes credit additions of $8.869 million related to 2021 actual use rate variances up to May 2021 (use rates were higher than approved). These additions account for the majority of the variance between the two continuity schedules.

Table 10-5 on page 85 of the Application shows 2022 amortization post-tax and pre-tax amounts of the RSAM of $1.237 million and $1.694 million, respectively.

Schedule 11 in Section 11 of the Application shows the following for the RSAM account:

- Balance at the end of 2021 of $2.562 million (line 4, column 2) and
- Rider of $1.755 million for 2022 (line 4, column 7)

19.5 Please reconcile the 2021 ending balance of $2.473 million with the $2.562 million in Schedule 11.

Response:

The difference between the 2021 ending debit RSAM balance of $2.473 million shown in Table 10-5 of the Application and the 2021 ending debit RSAM balance of $2.562 million shown in Schedule 11, Section 11 of the Application is the credit RSAM Interest ending balance of $0.089 million. The RSAM Interest deferral account balance is included within the Interest on CCRA /

MCRA / RSAM / Gas Storage deferral account line shown on Line 5 of Schedule 11, Section 11 of the Application. Please refer to the table below for the reconciliation:

	$ millions
RSAM ending 2021 balance per Schedule 11	$ 2.562
RSAM Interest ending 2021 balance included within Interest on CCRA / MCRA / RSAM / Gas Storage deferral account line on Schedule 11	($ 0.089)
RSAM balance per Table 10-5	$ 2.473

19.6 Please reconcile the 2022 amortization of the RSAM in Table 10-5 with the $1.755 million in Schedule 11.

Response:

The difference between the 2022 total RSAM rider recoveries of $1.694 million shown in Table 10-5 of the Application and the 2022 total RSAM rider recoveries of $1.755 million shown in Schedule 11, Section 11 of the Application is the 2022 total RSAM Interest rider refunds of $0.061 million. The RSAM Interest rider is included within the Interest on CCRA / MCRA / RSAM / Gas Storage deferral account line shown on Line 5 of Schedule 11, Section 11 of the Application. Please refer to the table below for the reconciliation.

	$ millions
RSAM riders per Schedule 11	$ 1.755
RSAM Interest riders included within the Interest on CCRA / MCRA / RSAM / Gas Storage deferral account line on Schedule 11	($ 0.061)
RSAM rider recoveries per Table 10-5	$ 1.694

20.0 Reference: EARNING SHARING AND RATE RIDERS

Exhibit B-2, Section 10.3.3, p. 86

Clean Growth Innovation Fund

On page 86 of the Application, FEI states:

> 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.

20.1 Please explain what the actual expenditures for 2020 to 2022 are for and provide a table with a breakdown by major cost category of the expenditures for 2020 actual, and 2021 and 2022 forecasts, respectively. As part of the response, please identify whether there are any expenditures that are considered one-time costs (e.g. start-up costs).

Response:

The forecast for 2021 expenditures of $1.7 million provided in the Application was an error. The $1.7 million figure is actually the projected *cumulative* expenditures in 2020 and 2021. Therefore, the projection for 2021 should have been $0.6 million. FEI will update the 2022 financial schedules in the compliance filing to the decision on the Application to reflect the revised 2021 projected amount. Given the Clean Growth Innovation Fund is a non-rate base deferral account, the revised 2021 projection will have no impact on the requested or final approved delivery rate increase; thus FEI does not consider it necessary to file an evidentiary update for this error.

FEI is unable to provide a categorized forecast for 2022 as the expenditure categories will depend on individually approved projects achieving certain milestones on the dates expected. The nature of the work being undertaken does not lend itself well to forecasting even on a high-level annual basis.

The breakdown by major categories for actual and projected 2020-2021 expenditures is provided below. FEI notes that none of the costs incurred are start-up costs.

2020 and 2021 CGIF Expenditures ($ thousands)

Category	2020 Actual	2021 Projected	Total
Renewable and Low-carbon Gases	454.6	340.1	794.6
Carbon Capture	143.4	52.3	195.7
Transportation	60.3	-	60.3
Combined Heat and Power	88.2	-	88.2
Natural Gas Innovation Fund	215.3	155.9	371.2
Natural Gas Futures	100.0	100.0	200.0
Total	1,061.7	648.3	1,710.0

Further on page 86 of the Application, FEI states:

> 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).

20.2 Please discuss who the members of the ESC are and explain whether they work independently from the IWG.

Response:

There are currently three members of the ESC:

- Vice-President, External and Indigenous Relations
- Vice-President, Energy Supply and Resource Development
- Vice-President, Regulatory Affairs

The ESC make their decisions independently of the IWG, but consider the recommendations of both the IWG and EAC.

I. ACCOUNTING MATTERS AND EXOGENOUS FACTORS

21.0 Reference: NEW DEFERRAL ACCOUNTS

Exhibit B-2, Section 12.4.1, Tables 12-1, 12-2, pp. 134, 137–1340; Utilities Commission Act (UCA), Section 44.2 (1)

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

On page 134 of the Application, FEI states:

> 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.

21.1 Please provide the current estimated Certificate of Public Convenience and Necessity (CPCN) capital cost for the above-noted RGSD Project.

Response:

A CPCN capital cost has not yet been prepared. The estimated $49.3 million of project development costs which FEI is requesting deferral account treatment for in this Application will capture the costs for the development and filing of the RGSD Project's CPCN application, including the development of the capital cost estimate. In the interim, based on unit cost data from other projects, conceptually the cost is anticipated to be in the range of $4 billion.

FEI further states on page 137 of the Application:

> 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) that will provide FEI with the detailed information necessary to prepare and file a CPCN application with the BCUC.

21.2 Please discuss the likelihood that, based on the development work performed in Pre-Phase 1 and Phase 1 project assessment activities, FEI would decide not to proceed with the RGSD Project.

21.2.1 Please discuss the implications to ratepayers if this situation were to occur.

Response:

An outcome of the work performed during Pre-Phase 1 and Phase 1 is to inform FEI of the feasibility of this project. As a result, the likelihood of successfully developing the RGSD Project will be identified with the work performed within these two phases.

If the RGSD Project is deemed to be not feasible during the work performed in Pre-Phase 1 or Phase 1, FEI would apply for recovery of the deferral account balance as part of a future revenue requirement application. As explained in the response to BCUC IR1 21.5, FEI expects that it would receive approval to recover its prudently incurred costs related to conducting the assessment phase of the RGSD Project, regardless of whether the project is ultimately deemed feasible. As part of the future revenue requirement application, FEI would propose an amortization period for recovery of the deferred project development costs. The delivery rate impact of these deferred costs would be dependent on the deferral account balance and the proposed amortization period, both of which would be examined as part of the future revenue requirement proceeding.

On page 138 of the Application, FEI provides the following table that shows the estimated RGSD Project development costs that FEI proposes to defer.

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**

Further on page 138 of the Application, FEI states:

> 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.

In Table 12-2 on page 140 of the Application, FEI states:

> 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.

21.3 Please explain the basis and estimating accuracy of each major category of RGSD Project development costs in Table 12-1.

Response:

The development of the RGSD Project Development Costs deferral account budget (as explained in Section 12.4.1.1.2 of the Application) was derived using a combination of internal FEI personnel and external consultants and firms and was based on a conceptual alignment of the pipeline, compressor station locations and schedule. Based on this information, each consultant and internal FEI employee developed budget estimates. Based on FEI's current understanding of the route alignment, FEI has assigned the category cost level estimates to be approximately Class 4. The Company has developed an overall contingency estimate to address risk and uncertainty, and plans to manage within the overall budget estimate of $49.3 million. Should the scope of work increase beyond the aggregate estimate and contingency, such work would be included in a CPCN application. The details for each of the major categories of RGSD Project development costs are summarized in the table below:

Cost Category	Cost Basis
Pipeline Engineering	Consultant used a ratio of Development Costs to Capital Costs that is typical of similar projects. Work incorporated information from other similar projects that have been completed.
Compressor Engineering	Consultant used ratios of Development Costs to Capital Costs based on historical project information.
Geotechnical Engineering	Consultant used professional experience to identify tasks required for pipeline design. These tasks were coupled with the resources required to complete them.
Environmental Application	Consultant used the following methodology to calculate approximate costs for the Project: Using historical knowledge of the level of support required for various office-based tasks and a conceptual schedule, costs were estimated and included. A high-level review of the discipline specific requirements related to expected constraints was included to capture various survey and permitting requirements. Using historical actuals from similar projects, actual cost per km of length of pipeline was calculated for several key tasks, compared between projects and used to estimate overall costs for this Project.
Land and Right-of-Way	FEI internal estimate is based on estimated length of new ROW, number of individual properties requiring assessments and agreements, statutory Right-of-Ways, material laydown areas as well as other land related costs.
Indigenous and External Relations	FEI internal estimate is based on the number of Indigenous consultations as identified by an external consultant and resources required to complete this work.
Legal	Consultant's estimate is based on historical experience as it relates to legal activities for conceptual scope.
Contingency	Based on component uncertainties, contingency of twenty percent was applied.
Management Cost	Management costs of ten percent were used to cover off a typical requirement for internal resources to manage a major project.

21.4 Please confirm, or explain otherwise, that the pre-phase 1 project development costs are the projected actual costs for 2021.

21.4.1 If not confirmed, please provide the projected actual costs and explain any differences from the $2.1 million presented in Table 12-1.

Response:

The Pre-Phase 1 development costs of $2.1 million were projected to be spent in 2021 at the time the Application was developed and, as explained in Section 12.4.1.1.2, the majority of these costs are for Indigenous engagement work. However, based on more recent information, FEI is now projecting 2021 spending to be approximately $1.0 million. The large-scale wildfire situation that occurred during the summer of 2021 in the BC interior, combined with the evolving COVID-19 pandemic, have negatively affected the timing of Indigenous engagement activities planned for 2021.

The balance of the $2.1 million originally projected for 2021 will be spent over the course of 2022, as FEI increases its Indigenous engagement and other activities. Thus, the overall total project development cost estimate remains at $49.3 million; it is only the timing of when the activities are undertaken and associated costs are incurred that has changed.

FEI will update the 2022 financial schedules in the compliance filing to the decision on the Application to reflect the revised 2021 projected ending balance in the RGSD Project Development Costs deferral account, if approved. Given the requested deferral account is a non-rate base deferral account, the revised 2021 projection will have no impact on the requested or final approved delivery rate increase for 2022.

21.5 In the event that that the Project Development Costs Deferral Account is approved, please clarify whether FEI understands this to mean that any costs captured in the deferral account will be recoverable or if the recovery of the costs will remain subject to future BCUC determination.

Response:

FEI confirms that it will apply for recovery of the RGSD Project Development Costs deferral account as part of a future application (i.e., either as part of a future CPCN for the RGSD project or as part of a future revenue requirement application if the RGSD project does not proceed to the CPCN filing stage). As part of the future application, the BCUC and interveners will have an opportunity to examine the actual costs recorded in the deferral account and, based on the evidence, the BCUC Panel appointed to that application will be able to make a determination on the recoverability of the deferred costs (as well as determining the appropriate amortization period for recovering the costs). This approach is consistent with how the costs recorded in the Transmission Integrity Management Capabilities (TIMC) Development Costs deferral account are being reviewed (please see Section 12.4.2.1 of the Application for more details on the TIMC Development Costs deferral account).

FEI expects that as part of a future application it would receive approval to recover its prudently incurred costs related to conducting the assessment phase of the RGSD project (as described in this Application).

21.6 In the absence of a BCUC-approved deferral account, please identify which of the Pre-Phase 1 and Phase 1 costs would be classified as O&M and which would be classified as capital in accordance with US Generally Accepted Accounting Principles (US GAAP) and why.

<u>Response:</u>

As described in Section 12.4.1.1.2 of the Application, the costs for Pre-Phase 1 are primarily to engage in initial consultation activities with Indigenous communities. In the absence of a regulatory approved deferral account for a rate-regulated entity such as FEI, the costs incurred during Pre-Phase 1 of the RGSD Project would generally be expected to be classified as O&M as the project is not considered probable of being constructed at this point. This is representative of the preliminary phase of construction for capital projects which are generally expensed under US GAAP, including ASC 360 Property, Plant and Equipment and ASC 970-340 Real Estate Other Assets and Deferred Costs.

The classification of Phase 1 costs between O&M and capital requires a degree of professional judgement when applying the accounting guidance. When construction of the RGSD Project is deemed probable of being constructed, the project is considered as part of the pre-construction phase for capital projects under US GAAP, which in turn permits the capitalization of various directly identifiable project costs. At this point, which could occur during Phase 1, an assessment would be performed to determine which costs would be considered eligible for capitalization outside of a regulatory approved deferral account under US GAAP. Generally speaking, costs to develop the CPCN application would be classified as O&M in the absence of a regulatory approved deferral account; however, certain Phase 1 geotechnical assessments, environmental application, right-of-way, and engineering costs are likely to meet the capitalization criteria as part of the pre-construction phase of capital projects under US GAAP.

In the absence of a BCUC-approved deferral account, any O&M costs incurred would have to be forecast outside of formula O&M expense (since the project development costs for future CPCN applications are not included in FEI's Base O&M) and trued-up annually by way of the Flow-through deferral account. However, consistent with past requests and approvals to capture the O&M portion of development costs in a deferral, such as the Pattullo Gas Replacement CPCN development costs, the O&M portion of development costs more appropriately belong in a deferral account, given the extended time period over which the costs are incurred. O&M costs are meant to reflect period costs, whereas costs recorded in a deferral account allow for a recovery of the costs incurred over a longer timeframe. Deferral treatment allows for O&M costs related to project development to be spread out in delivery rates over multiple years, as opposed to O&M costs which are embedded in the current year rates on a forecast basis.

21.6.1 Please provide the impact to each of 2022 and 2023 delivery rates under the scenario that the proposed deferral account is not approved.

Response:

As discussed in the response to BCUC IR1 21.6, FEI will not be able to determine with certainty what expenses should be classified as capital until it has determined that the project has entered the pre-construction phase under US GAAP. Since FEI cannot make that determination at this time, FEI has calculated the rate impacts for 2022 and 2023 below assuming the total Pre-Phase 1 and Phase 1 expenses are classified as O&M expenses. FEI cautions that classifying all of the Pre-Phase 1 and Phase 1 expenses as O&M is conservative and demonstrates the highest potential delivery rate impact. The cumulative delivery rate impact for the Pre-Phase 1 and Phase 1 expenses is 1.02 percent.

Please refer to the table below for the 2022 and 2023 delivery rate impacts under the scenario that the proposed deferral account is not approved. As discussed in the response to BCUC IR1 21.6, these costs would be outside of formula O&M, with any variances between actual and forecast captured in the Flow-through deferral account.

Rate Impacts of RGSD Project Development Costs ($ Millions)

Line	Particular	Reference	2022	2023
1	Pre-Phase 1 Costs	Application, Table 12-1, Pre-Phase 1	$ 2.1	$ -
2	Forecasted Phase 1 Costs	Application, Table 12-1, Phase 2	38.2	9.0
3	Revenue Deficiency	Line 1 + Line 2	$ 40.3	$ 9.0
4				
5	Non-Bypass Margin at 2021 Approved Rates	Schedule 1, Line 29	885.532	885.532
6				
7	Rate Change	Line 3 / Line 5	4.55%	1.02%
8				
9	Year Over Year Rate Change	PY Line 7 - CY Line 7	4.55%	-3.53%
10				
11	**Cumulative Rate Impact**	**Sum of Line 9**	**1.02%**	

According to section 44.2 (1) of the UCA, "A public utility may file with the commission an expenditure schedule containing one or more of the following:

a) statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;

b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;

c) a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.

21.7 Please discuss whether FEI considered filing an application for approval in accordance with Section 44.2 of the UCA for the estimated RGSD project development costs and why this approach was rejected.

<u>Response:</u>

FEI did not consider filing for approval of the estimated RGSD Project development costs under section 44.2 of the UCA because, as explained in the response to BCUC IR1 21.6, FEI does not know at this time how much of the estimated $49.3 million project development costs will be considered eligible for capitalization under US GAAP. As provided in the above preamble, a utility may file for approval with the BCUC under section 44.2(1) of the UCA for (a) DSM expenditures, (b) capital expenditures, or (c) expenditures to acquire energy. Given that FEI does not know at this time the amount of project development costs that will be considered eligible capital expenditures under US GAAP, in the absence of a BCUC-approved deferral account, and under a scenario where some or all of the costs are deemed to be O&M under US GAAP, FEI would have to expense these costs in the year they are incurred. Please see the response to BCUC

IR1 21.6.1 for the implications to customers if a deferral account is not approved and the costs are instead required to be expensed in the year incurred.

FEI also notes that approval of project development cost deferral accounts is the standard treatment for costs of this nature. While the project development cost deferral accounts are typically approved as part of the CPCN application, deferral account approval has been received in the past in advance of the CPCN application. A recent example of this is the TIMC Development Costs Deferral Account, which was approved as part of FEI's Annual Review for 2019 Delivery Rates. Approval of the regulatory treatment in advance of filing a CPCN application is appropriate when costs are to be incurred a number of years prior to a CPCN application being filed, as is the case with the RGSD Project.

J. SERVICE QUALITY INDICATORS

22.0 Reference: SERVICE QUALITY INDICATORS

Exhibit B-2, Section 13.2, Table 13-1, pp. 150, 157; BCUC Decision to FEI and FortisBC Inc.'s (FBC) Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024, dated June 22, 2020, pp. 87–88, 99

Meter Reading Accuracy

The following is an extract of Table 13-1 in the Application:

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

Performance Measure	Description	Benchmark	Threshold	2020 Results	2021 June YTD Results
Meter Reading Accuracy	Number of scheduled meters that were read	>= 95%	92%	89%	91%

On page 157 of the Application, FEI states:

> 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. [Footnote references removed]

22.1 Please explain whether FEI considers below-threshold results for meter reading accuracy for 2020 and 2021 YTD represent a "sustained degradation of service." Why or why not?

<u>Response:</u>

The meter reading accuracy for 2020 and 2021 YTD below the approved threshold does not represent a serious degradation of service and does not warrant any financial penalty under the MRP. FEI's meter accuracy results for 2020 and 2021 YTD are attributable to the COVID-19 pandemic, rather than any action or inaction of FEI. The BCUC anticipated this impact when it relieved public utilities of their meter reading obligations where necessary due to the state of emergency and social distancing practices. FEI has taken steps to mitigate the impacts to service quality such that FEI does not consider there has been any serious degradation of service. FEI expects that 2021 actual results will reach the threshold level, although there remains considerable uncertainty due to the ongoing pandemic.

In the remainder of this response, FEI first summarizes the process and past BCUC guidance on interpreting SQI performance, and then applies that guidance to its meter reading performance in 2020 and 2021 YTD.

Process for Interpreting SQI Performance

The process for interpreting SQI performance was the product of a consensus recommendation in 2014 approved by BCUC Order G-14-15, dated February 4, 2015. The consensus recommendation indicates that performance below the threshold is not sufficient in itself to determine if there is a serious degradation of service:

> Based on how the Parties have established the thresholds and performance ranges, the Parties do not consider performance inferior to a threshold to necessarily
>
> - represent a "serious degradation of service", or
> - warrant adverse financial consequences for FortisBC
>
> but rather they consider that this circumstance warrants examination at an Annual Review to determine whether further action is warranted. However, performance inferior to a threshold is a factor the Commission may consider in determining whether there has been a "serious degradation of service" and whether adverse financial consequences for FortisBC are warranted.

In its Decision accompanying Order G-107-15, the BCUC provided the following guidance on how to follow the consensus recommendation (at pages 18-19):

> In determining whether financial consequences are in order, the Panel interprets the Consensus Recommendation as asking two fundamental questions: Has a serious degradation of service occurred? To what extent are the performance results attributable to the actions or inactions of the Company?
>
> The answer to whether a serious degradation has occurred is largely guided by key points set out in the Consensus Recommendation:
>
> - SQI performance below threshold does not necessarily mean that a serious degradation of service has occurred, but is a factor to consider in that determination.
> - Two of the four "other factors" noted are also relevant to a determination of whether or not any degradation of service is "serious":
>   - The impact on the delivery of safe, reliable and adequate service; and
>   - Whether the impact is seen to be transitory or of a sustained nature.
>
> In determining the extent to which the performance results are attributable to the actions or inactions of the Company, the remaining two "other factors" need to be considered:

- Any economic gain made by each Company in allowing service levels to deteriorate; and
- Whether each Company has taken measures to ameliorate the deterioration in service.

The BCUC also provided direction in Order G-44-16 that in each annual review the BCUC will review actual SQI results from the prior year. This avoids the difficulty and unfairness of evaluating year-to-date results, when thresholds and benchmarks are based on a full calendar year of performance, and performance may change by the end of the year. Thus, while 2021 YTD information is something the BCUC can consider, it should be recognized that the year is not yet complete, and 2021 actual results will be evaluated in the next annual review.

In the remainder of this response below, FEI follows this guidance to interpreting its meter reading performance, although FEI addresses the questions and factors in a different sequence than in the quote above.

Meter Reading Performance Results below Threshold are Due to Pandemic, Not the Actions or Inactions of the Company

FEI's meter reading accuracy results for 2020 and 2021 YTD are below the BCUC threshold level primarily due to the safety guidelines introduced in response to the ongoing COVID-19 pandemic and reduced staffing levels of FEI's meter reading service provider, Olameter, needing to isolate due to COVID-19 exposure or symptoms. This resulted in a reduced number of meters being read and an increased number of estimated reads.

The BCUC explicitly anticipated this impact of the pandemic and relieved utilities from the meter reading obligations in their tariff terms and conditions. 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.

Therefore, it is clear that FEI's meter reading performance was due to impacts of the COVID-19 pandemic, not any of its own actions or inactions. As discussed further below, FEI has worked diligently with its meter reading service provider to improve performance where possible, and these efforts have resulted in improved performance in 2021.

Meter Reading Performance Results below Threshold are Transitory in Nature

As the meter reading is due to the ongoing COVID-19 pandemic, FEI's meter reading performance is transitory in nature, rather than sustained. FEI has been working closely with Olameter to improve the accuracy rate to the extent possible and has taken measures that have improved metering accuracy in 2021 YTD. Based on year-to-date numbers, FEI expects to meet the 2021 year-end meter reading accuracy threshold, although there is uncertainty, as discussed further in BCUC IR1 22.4.

With physical distancing restrictions currently still in place, and periods of reduced Olameter staffing due to employee isolation as a result of symptoms, FEI expects continued pressure on this metric to remain throughout the pandemic. When the COVID-19 pandemic comes to end in the future with the lifting of all restrictions and the resumption of normal operation conditions, FEI expects Meter Reading Accuracy performance to once again meet or exceed the benchmark of 95 percent, an achievement it has successfully reached for many years prior to the start of the COVID-19 pandemic in 2020.

FEI Has Effectively Mitigated Impact on the Delivery of Safe, Reliable and Adequate Service

While customers have been impacted by the lower than threshold performance in meter reading accuracy due to the COVID-19 related safety protocols for meter readers, these impacts have been largely mitigated as explained further below.

In evaluating customer impacts of the lower 2020 and 2021 year-to-date meter reading accuracy results, FEI considers the number of customers impacted and the extent of those impacts, mitigating measures put in place and overall satisfaction related metrics.

<u>Volume of Customers and Impacts of Estimated Reads</u>

When an actual read is not available, FEI's billing system estimates the read based on historical consumption. The threshold and benchmark meter reading accuracy reflect that in the normal course of operations FEI will use estimations instead of actual meter reads for various reasons, such as when an actual read is not available due to uncontrollable weather impacts and site access issues. It is expected that estimations would be limited to 5-8 percent of total monthly meter reads, or approximately 50 to 85 thousand customer bills each month.[18]

There are two direct impacts of estimated reads, the first is that the billed amount may require a true-up once an actual read occurs, which can lead to payment challenges and dissatisfaction for

[18] High level calculation based on nearly 13 million meter reads each year.

customers. The second impact is that customers may not have accurate consumption information to support informed energy decisions over the short-term.

By default, historical consumption is used to estimate consumption and, as a result, is typically reasonably accurate. However, there are instances where estimations could lead to a larger variance due to factors that may have changed, such as the number or type of customer appliances or usage patterns.

On average each month in 2020, approximately 115 thousand bills were estimated and in 2021, on average, 112 thousand bills per month have been estimated. While some customers may have only experienced one estimated bill in this period, others may have had multiple estimated bills which could have a larger and compounding impact on the potential buildup of any amounts owing to or from the customer to FEI.

As a result of the potential inconvenience, bill payment challenges and energy use information available to customers as a result of estimation, FEI concludes that, absent effective mitigation measures, there would be moderate impacts to a larger group of customers than the number of customers that would be impacted by estimated reads even if meter reading accuracy met the threshold or benchmark.

<u>Mitigating Measures Have Been Effective</u>

In order to mitigate the impacts to customers of this temporary circumstance, FEI continues to work closely with its meter reading service provider to improve performance for meter reading accuracy to the extent possible, while supporting the safety protocols in place. These efforts include frequent information sharing and identification of areas that FEI can support, such as proactive outreach and analysis of premises that have an impediment to access, such as a locked gate or animal presence.

FEI is also proactively contacting customers with multiple estimates in a row to determine if a customer-provided read is possible to support the estimation. In addition, FEI proactively reaches out to customers with meters that have been identified as hard to access to arrange for a special read and to work with the customer for future access to the meter. These two measures support both an improved accuracy of the estimated bill as well as improved accuracy to support informed energy use decisions and behaviour.

Finally, to the extent that a customer has received a higher than expected bill, either as a result of the estimated consumption or any true-up once the actual read is available, FEI works with the customer on a one-on-one basis, providing flexible payment arrangements where appropriate. Specific to the 2020 period, FEI also had several additional measures that supported challenges with bill payments and the circumstances associated with COVID-19. This included the waiving of any late payment charges and the pausing of disconnections for non-payment until early 2021.

With the flexibility in payment arrangements, including the one-on-one focus on customers that have been impacted and the proactive approach taken to minimize variances between estimated and actual reads, FEI concludes that the mitigating measures have been successful in addressing the customer impacts noted above.

<u>Overall Customer Satisfaction Remains Positive</u>

Throughout 2020 and 2021, FEI has not seen any indications that the meter reading challenges faced have had a measurable impact on overall customer satisfaction and service quality. For example, the informational Customer Service Index SQI did not show any statistically significant changes in the accuracy of meter reading component of the index in 2020 or 2021 year-to-date. FEI believes that this is most likely due to both the volume of customers impacted representing a relatively small portion of customers overall and the success of the mitigating measures that have been put in place. In addition, the Billing Index SQI has remained at benchmark, indicating that any challenges to the Billing Index as a result of meter reading inputs have not materialized to date and billing metrics have remained aligned with customer expectations.

Overall, FEI's considers that the quality of service being provided to customers is high and customers are understanding and supportive of the steps being taken by FEI to mitigate the impacts and challenges associated with meter reading as a result of the COVID-19 pandemic.

22.2 Please explain any customer impacts of the lower 2020 and 2021 June YTD meter reading accuracy results. In the response, please explain the methods used to assess customer impact or experience.

<u>Response:</u>

Please refer to the response to BCUC IR1 22.1.

22.3 Please explain the reasons for the improved results for meter reading accuracy from 2020 to 2021 June YTD.

<u>Response:</u>

The improvement in the accuracy rate in 2021 is attributable to the following:

- increased communication and metrics reporting between Olameter and FEI;
- the identification of areas that FEI can support, such as customer outreach to improve access to sites with locked gates; and

- a reduced number of Olameter staff that have had to isolate due to COVID-19 exposure or symptoms in 2021 as compared to 2020.

22.4 Please explain whether the 2021 year-end results for meter reading accuracy are expected to be on-track to meet or exceed the threshold. Why or why not?

Response:

Based on year-to-date numbers, FEI expects to meet the 2021 year-end meter reading accuracy threshold; however, there is always an element of uncertainty as the impacts of the new variants of COVID-19 are still ongoing which could have unanticipated impacts in the later part of 2021. FEI continues to work closely with its meter reading service provider to improve the performance of this metric through regular meetings to review results and expectations, and by reaching out to customers to improve access to properties with locked gates. FEI expects to see further improvements as the year progresses.

22.5 Please explain whether FEI has resumed its pre-COVID-19 pandemic schedule for meter readings. If so, please explain when. If not, please explain why not.

Response:

FEI did not make any changes to the meter reading schedule during the pandemic, and the number of meter reads requested from FEI's meter reading service provider has always been based on the number of meters maintained by FEI. The number of actual reads obtained varied due to safety guidelines introduced in response to the ongoing COVID-19 pandemic and reduced staffing levels due to Olameter staff needing to isolate due to COVID-19 exposure or symptoms.

22.6 Please explain the results and accuracy of meter reading after: a) the State of Emergency in the Province of BC; and b) social distancing practices, were lifted.

Response:

British Columbia was under the provincial state of emergency from March 18, 2020 until the end of day on June 22, 2021. However, social and physical distancing practices are still in place and recommended by the BC Centre for Disease Control.

The meter reading accuracy rate has improved from 2020 and, as reported in the Application, the accuracy rate as at the end of June 2021 was at 90.7 percent with the threshold being 92 percent. FEI did not see a noticeable impact on results following the lifting of the provincial state of emergency. With physical distancing and other public health measures remaining in place, meter reading accuracy results may not return to benchmark levels until normal operating conditions can resume.

On pages 87 to 88 of the BCUC's Decision to FEI and FBC's Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024 (MRP Decision), it stated:

> […] In addition, the BCUC determined that failure to meet an SQI could result in a penalty where the BCUC may reduce the share of earnings above the allowed rate of return that would otherwise flow to the Utilities. In such instance, the maximum reduction to incentive earnings could result in a 60 percent ESM share to the customer rather than the standard 50 percent.
>
> […]
>
> In general, a threshold is the minimum performance required, and failure to meet a threshold could result in penalties being assessed during the Annual Review proceedings. A benchmark is considered a target, based on industry standard or best practice, and there is no penalty if it is not achieved. […] FortisBC confirms that it is proposing no changes to the existing approved process for interpreting metric performance where one or more of the Utilities SQIs do not meet the benchmark and falls outside of the threshold. [Footnote references removed]

On page 99 of the MRP Decision, it stated:

> FortisBC has confirmed that it is proposing no changes to the existing approved process for interpreting metric performance where one or more of the Utilities' SQIs do not meet the benchmark and fall outside of the threshold. The Panel is in agreement and finds provisions outlined in the Current PBR Plan Decisions continue to be reasonable. Therefore, the Panel determines that the existing approved process for interpreting metric performance is to remain in effect over the term of the MRPs. [Footnote references removed]

22.7 Please discuss whether any penalty should be levied by the BCUC for the below-threshold results for meter reading accuracy. If so, please quantify the penalty and explain how this was determined.

Response:

For the reasons explained in the response to BCUC IR1 22.1, no penalty should be levied.

23.0 Reference: SERVICE QUALITY INDICATORS

Exhibit B-2, Section 13.2, Table 13-1, pp. 150, 158, 161

Telephone Service Factor (Non-Emergency) and Average Speed to Answer

The following is an extract of Table 13-1 in the Application:

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

Performance Measure	Description	Benchmark	Threshold	2020 Results	2021 June YTD Results
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>= 70%	68%	70%	66%
Average Speed of Answer	Informational indicator – amount of time it takes to answer a call (seconds)	-	-	72	80

On page 158 of the Application, FEI states:

> 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.

On page 161 of the Application, FEI states:

> Comparatively, the ASA [average speed of answer] 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.

23.1 Please discuss any customer impacts of the lower 2021 June YTD telephone service factor (non-emergency) results and the higher average speed to answer. As part of the response, please explain the methods used to assess customer impact or experience.

Response:

FEI reiterates that, in accordance with Order G-44-16, the BCUC will evaluate FEI's 2021 SQI performance in the Annual Review for 2023 Delivery Rates when actual SQI results are known.

FEI assesses customer impact by considering the TSF along with First Contact Resolution (FCR) results as well as the informational indicators of Average Speed of Answer (ASA) and the Customer Service Index (CSI). In addition, FEI reviews after-call survey results to further validate and understand impacts.

In this regard, despite the TSF not meeting the threshold on a monthly basis for January and February 2021 and the ASA being longer than typical for customers of FEI, feedback from customers indicated that resolution remained high with the FCR achieving the benchmark on a YTD basis. Further, the CSI results for the first two quarters were aligned with the strong performance in this metric from previous years, the call back feature appeared to largely mitigate dissatisfaction with wait times and after-call survey results remained largely in line with average monthly results. As such, FEI has concluded that the customer impacts of the lower June YTD TSF and higher ASA have been largely limited to longer wait times at the start of the year and have not had an impact on overall service quality in 2021.

23.2 Please explain any measures FEI has taken or will take to improve its performance in telephone service factor (non-emergency) and average speed of answer for the remainder of 2021 and for 2022.

Response:

FEI has taken measures to improve its performance to address the increase in call volumes and average handle time experienced in the early part of 2021. While the telephone service factor (TSF) is impacted by several variables, the increase experienced was largely due to an increase in certain types of calls related to construction and new attachments, rebates and high bill inquiries (please refer to the response to BCUC IR1 23.4 for a detailed description of these call types). Once FEI identified the challenges being faced with these call types and overall handle time, FEI identified opportunities for learning and development, refocused efforts on identifying efficiencies in call handling and the work completed after calls, and reviewed workforce scheduling and new hire training and forecasting to respond to the latest trends. For example, FEI:

- put in place changes to the order of new hire training modules to support specific queues;

- prioritized more detailed and frequent coaching sessions for employees and managers;
- enhanced communication regarding the service level targets and departmental and individual performance; and
- improved access to individual performance metrics through dashboards.

Performance stabilized and FEI achieved TSF (non-emergency) results above threshold levels (on a monthly basis) in March as well as reductions in the average speed of answer (ASA).

As shown in the table below, the monthly TSF performance has been above threshold since March of 2021. FEI expects this SQI to meet threshold levels for 2021 overall and as at August 31, 2021 the year-to-date (YTD) result is above threshold at 69 percent.

Monthly 2021 Telephone Service Factor (Non-Emergency)

Month	Monthly Service Level
January	34%
February	59%
March	79%
April	68%
May	71%
June	80%
July	76%
August	83%
Year to Date	**69%**

The average speed of answer has also consistently declined such that the YTD result as of August 31 is approximately 69 seconds. See the table below for the monthly ASA for 2021:

Monthly 2021 Average Speed of Answer (Seconds)

Month	ASA
January	250.03
February	96.51
March	35.62
April	47.19
May	44.81
June	27.23
July	36.23
August	25.52
Year to Date	**68.88**

23.3 Please clarify what FEI considers to be "a reasonable range from a customer experience perspective" (e.g. calls answered within 1.5 minutes) and why.

Response:

FEI does not have a specific range that it considers reasonable; rather, FEI relies on customer feedback and after-call survey results to determine whether wait times may be challenging for customers and whether further action or alternatives are required. Anecdotally, and based on FEI's participation in industry related events, FEI is aware that some utilities in Canada have varying ranges of ASA, from under one minute to four minutes.

The call back feature, chat functionality and self-service options are all available to customers to mitigate some of the challenges of longer than expected wait times that may occur from time to time.

23.3.1 Please discuss whether FEI has compared its ASA with other utilities of similar size in North America. If so, please discuss how FEI compares with these other utilities.

Response:

Please refer to the response to BCUC IR1 23.3.

23.4 Please explain why there was an increase in call volumes and average handle time in January and the early part of February 2021. As part of the response, please provide a high-level summary of the subject matter(s) of these calls.

Response:

In the early part of 2021 FEI experienced a mix of high interaction volumes along with a mix of call types that typically take longer than average to respond to. These types of calls include construction and new attachments, rebates and high bill inquiries. While FEI does forecast for an overall increase in call volume during these months, particularly high bill inquiries, the actual volume and mix of calls was different than expected. This impacted the overall average handle time during this period and created significant pressure on meeting service level targets during January and February. Each of these three call types is described further below.

With respect to construction and customer attachment related calls, FEI saw a reduction for most of 2020 as compared to forecast; however, there was a resurgence in the first two months of 2021 and calls exceeded what had been forecast. Due to the nature of a construction call and new attachment, they can be lengthy calls that may require nearly double the amount of time of a typical call. As such, even smaller unexpected volumes of these types of calls can have significant impacts on overall handle time, as well as an impact on the timing of response to other types of calls in the various queues.

Rebate-related calls are relatively new to FEI contact centre support, with these types of gas calls having been repatriated from an outsourced provider in the Fall of 2020. As such, average handle time for the latter part of 2020 and through 2021 was high relative to other call types due to contact centre representatives getting more familiar and proficient with this call type, in addition to longer conversations with customers regarding their unique energy efficiency needs and one-on-one customer support in completing rebate-related applications. Similar to construction related calls described above, rebate-related calls tend to have longer handle times than an average call due to the nature of the conversations relative to other call types. Further, the success of the Double the Rebates energy efficiency campaign in the Fall of 2020 contributed to a significant volume of calls as a result of customer applications for this program extending into 2021.

High bill inquiries are a frequent call type during the early part of the year and also tend to have a longer handle time. They can be lengthy conversations involving comparisons to historical averages for the customer and exploring potential reasons that the customer is experiencing a higher bill than expected, often resulting in working together to find bill payment solutions. While fluctuations from forecast are not uncommon with this call type, the compounding impacts of the higher volume with this call type and the impacts noted above with construction and rebates calls led to overall significant increases in handle time as compared to expected average handle time for the period.

23.5 Please provide a table that shows by year, the number of employees and total FTEs in the contact centre and the number of non-emergency calls and other types of calls received by the contact centre, respectively, for 2016 to June 2021 YTD. An example table is provided below:

Contact Center	**2016**	**2017**	**2018**	**2019**	**2020**	**June 2021 YTD**
Number of employees						
FTE						
Number of non-emergency calls						
Number of other calls (please describe)						
Total number of calls						

Response:

Please note that FEI has interpreted the question to be seeking inbound calls only and has provided data as such. Furthermore, by reference to contact centres, FEI has interpreted the question to be referring to employees that are intended to regularly support inbound queues. As such, FEI has not included billing related roles in the number of employees as these employees are not intended to be regularly supporting inbound queues.

Please refer to the table below.

Contact Center	**2016**	**2017**	**2018**	**2019**	**2020**	**June 2021 YTD**
Number of employees[1]	148	160	151	141	146	157
FTE[1]	130.4	140.3	134.0	123.2	124.8	133.5
Number of non-emergency calls	681,814	661,031	595,951	548,345	518,769	313,754
Number of emergency calls	56,823	58,746	45,295	45,789	42,569	21,555
Number of other calls[2]	-	537	444	318	621	77
Total number of inbound calls	738,637	650,065	584,680	535,735	511,303	305,531

Notes to table:

[1] Based on monthly average and excludes employees in billing related roles.

[2] FEI major project and external support that occurs from time to time, such as that provided to the BCEDA (both during natural disaster response and the COVID-19 pandemic).

24.0 Reference: SERVICE QUALITY INDICATORS

Exhibit B-2, Section 13.2.3, Table 13-16, p. 163

Leaks per KM of Distribution System Mains

On page 163 of the Application, FEI provides Table 13-16:

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

Further on page 163, FEI states that it does not expect the number of leaks to be a continuing trend.

24.1 Please explain why FEI does not expect the number of leaks to be a continuing trend. Please also explain what steps, if any, FEI has taken to mitigate the incidence of leaks.

<u>Response:</u>

FEI does not expect the number of leaks to be a continuing trend because the variation shown in Table 13-16 of the Application falls within normal longer-term leak history variation. The following table provides the leak history from 2010 – 2020 showing periods where both increases and decreases in the number of leaks occurred.

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Leaks	140	166	169	143	114	102	107	108	140	139	152

FEI has robust leak management processes in place, including leak surveys and asset assessments to monitor leaks and the condition of the system as it ages, as well as programs to repair or replace aging assets to mitigate the frequency of leaks.

Attachment 7.1

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)