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September 21, 2022

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

Attention: Ms. Sara Hardgrave, Acting Commission Secretary

Dear Ms. Hardgrave:

Re: FortisBC Energy Inc. (FEI)

Annual Review for 2023 Delivery Rates (Application)

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

On July 29, 2022, FEI filed the Application referenced above. In accordance with the regulatory timetable established in BCUC Order G-240-22 for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

For convenience and efficiency, FEI has occasionally provided an internet address for referenced reports instead of attaching lengthy documents to its IR responses. FEI intends for the referenced documents to form part of its IR responses and the evidentiary record in this proceeding.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

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

1.0 Reference: INTRODUCTION

Exhibit B-2 (Application), Section 1.1, p. 1; FortisBC Energy Inc. (FEI) Annual Review for 2022 Delivery Rates (FEI 2022 Annual Review) proceeding; Exhibit B-3, British Columbia Utilities Commission (BCUC) Information Request (IR) 1.2; FEI Application for Common Rates and 2022 Revenue Requirements for the Fort Nelson Service Area (FEFN Common Rates) proceeding, Exhibit B-1, Section 7

2023 Delivery Rates Increase

On page 1 of the Application, FEI states:

> The proposed delivery rates for 2023 flowing from the approved formulas and forecasts set out in the Application, including returning the actual 2021 earnings sharing to customers, result in a 7.42 percent delivery rate increase from 2022 delivery rates. After consideration of the delivery rate riders, the annual bill impact is an increase of approximately $34.83 or 2.67 percent for a residential customer. [Footnote omitted]

1.1 Please provide the annual bill impact of the proposed 2023 delivery rate increase after consideration of all delivery rate riders and commodity charges, in dollars and percentage terms, for the average residential, commercial, and industrial customer, respectively. As part of the response, please provide a breakdown of the bill impacts by component.

Response:

Please refer to Attachment 1.1 for the annual bill impact including all rate riders and commodity charges (with a breakdown by component) of the proposed 2023 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. FEI notes the commodity related charge for Rate Schedules 1 to 7 customers included in the analysis is based on the currently approved cost of gas rates effective July 1, 2022 pursuant to Order G-154-22[1].

1.2 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 and 2021 actual, 2022 projected, and 2023 to 2024 forecast.

Response:

Please refer to Table 1 below for FEI's approved and achieved return on equity (ROE), before and after earnings sharing, for 2020 and 2021 Actual. For 2022 Projected and 2023 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. As a result, 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 2021 actuals are trued-up in the proposed 2023 delivery rates. This is consistent with the calculations for formula O&M and growth capital, where the true-up of the formula inputs happens only once actuals are known.

[1] Pursuant to Letter L-35-22, there is no change to the cost of gas rates on October 1, 2022; therefore, the rates remain at the level effective July 1, 2022 approved by Order G-154-22.

Table 1: Approved/Forecast and Actual ROE (Before and After Earnings Sharing) for 2020 to 2024

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	2,082,545	2,283,030	2,411,382
2	Approved/Forecast ROE ($000s)	Line 1 x Line 3	170,022	175,594	182,223	199,765	210,996
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	2,001,634			
6	Actual ROE Before-Sharing ($000s)	See Note 2	171,135	175,387			
7	Actual ROE Before-Sharing (%)	Line 6 / Line 5	8.87%	8.76%			
8							
9	Actual Earnings Sharing ($000s)	See Note 2	(1,137)	(122)			
10	Actual ROE After-Sharing ($000s)	Line 6 + Line 9	169,998	175,265			
11	Actual ROE After-Sharing (%)	Line 10 / Line 5	8.81%	8.76%			

Notes to Table:

1) Approved/Forecast Equity Portion of Rate Base:
   - For 2020 & 2021 – approved by Order G-319-20;
   - For 2022 – approved by Order G-366-21;
   - For 2023 – see Section 11 of the Application, Schedule 26, Line 3, Column 3; and
   - For 2024 – rate base forecast based on no change to capital additions from prior year except for sustainment and other capital forecast for 2024 as discussed in Section 7.2 of the Application.
2) Actual Equity Portion of Rate Base, ROE Before-Sharing and Earnings Sharing for 2020 and 2021 are from FEI's 2020 and 2021 Annual Reports, page 26.3.

In response to BCUC IR 1.2 in the FEI 2022 Annual Review proceeding, FEI provided the following high-level estimate for the 2023 and 2024 forecast delivery rate changes:

> 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%

1.3 Please reconcile FEI's forecasted delivery rate change of 4.00 percent for 2023, as provided in response to BCUC IR 1.2 in the FEI 2022 Annual Review, compared to the proposed 7.42 percent delivery rate increase in this Application. As part of the response, please provide a breakdown of the increase by component of FEI's revenue requirement (i.e. formula operations and maintenance (O&M), formula growth capital, forecast sustainment and other capital and rate base additions, other) which has changed.

Response:

As explained in the response to BCUC IR1 1.2 in the FEI Annual Review for 2022 Delivery Rates proceeding (and shown in the preamble to this IR), the 4 percent delivery rate increase was a very high-level estimate in which FEI assumed no changes to the majority of the revenue requirement components between 2022 and 2023. Further, even the items described in the bullet points in the preamble which were the drivers of the 4 percent increase were based on information that was expected to be updated in the 2023 Annual Review (i.e., this Application), such as the Net Inflation Factor and the Gross Customer Additions. FEI provided the high-level estimate of 4 percent to be responsive to the BCUC's IR, but FEI clearly stated in that response that it "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."

In contrast, the proposed 2023 delivery rate increase of 7.42 percent is based on actual and current information from the first half of 2022 when this Application was being developed. This includes demand forecasts, taxes (including property tax), interest rates, updated capital expenditure forecasts, and formula expenditures based on updated inflation and growth factors, among other items.

FEI respectfully declines to provide any further reconciliation, as performing such a detailed reconciliation would require significant effort and would not provide relevant information to evaluate the individual components of FEI's 2023 revenue requirement or to evaluate the reasonableness of the requested 7.42 percent delivery rate increase.

FEI considers the more relevant and appropriate reconciliation to be between the 2022 Approved revenue requirement components and the 2023 Forecast revenue requirement components, as these individual changes, along with the forecast demand, drive the requested 2023 delivery rate increase of 7.46 percent. FEI has provided a breakdown of the changes in each component of the revenue requirement between 2022 and 2023 in Section 1.5 as well as in Schedule 1, Section 11 of the Application. The Application also contains detailed breakdowns and explanations for the changes in each component of the revenue requirement between 2022 Approved, 2022 Projected, and 2023 Forecast in the various sections.

On page 10 of the Application, FEI clarifies that it is seeking interim approval of 2023 delivery rates only pending the outcome of Stage 1 of the BCUC's Generic Cost of Capital (GCOC) proceeding, as well as a decision on FEI's 2023 Demand Side Management (DSM) Expenditure Plan application. FEI states, "[w]hen a decision is reached on these proceedings, FEI will update its rate calculations and apply for permanent 2023 delivery rates."

In Section 7 of the FEI application for FEFN Common Rates, FEI explained that it proposes to implement the Proposed Common Rate Option for FEFN on January 1, 2023, stating that this date would allow FEI to incorporate the forecast 2023 revenue requirement impacts of FEFN in FEI's Annual Review for 2023 Delivery Rates, which will be filed mid-2022.

1.4 Please confirm, or explain otherwise, that the approval of permanent 2023 delivery rates is also pending a BCUC decision on FEI's application for FEFN Common Rates, effective January 1, 2023.

1.4.1 If confirmed, please provide FEI's proposed process and timing to incorporate the decision on FEI's application for FEFN Common Rates into the 2023 delivery rates if common rates are approved.

1.4.2 If not confirmed, please explain why not.

Response:

Not confirmed. FEI explained the process for incorporating FEFN's revenue requirement into FEI's revenue requirement if common rates are approved in its responses to BCUC IRs in the Common Rates proceeding. In particular, in response to BCUC IR2 32.1, FEI explained that depending on the timing of the Common Rates decision, if common rates were approved, FEI would have two options for incorporating FEFN into FEI's 2023 revenue requirement and delivery rates:

1. If a decision on common rates were received in September, FEI would likely file an evidentiary update in this Annual Review proceeding with the changes to FEI's financial schedules and the resulting (minor) change to the forecast 2023 delivery rates.
2. If a decision were received later than September, FEI would propose to incorporate FEFN's revenue requirement into FEI's revenue requirement as part of the compliance filing to the BCUC's decision on the 2023 Annual Review. This approach is similar to the approach that FortisBC Inc. (FBC) recently took with incorporating the Electric Vehicle Direct Current Fast Charging (EV DCFC) station-related revenues and expenses into FBC's 2022 rates.

Provided that a Common Rates decision is received within the current year (i.e., 2022), the approval of permanent 2023 delivery rates for FEI does not hinge on a determination on FEFN Common Rates. The impact of including FEFN into FEI's revenue requirement (as explained in the Common Rates proceeding) is negligible for FEI customers; therefore, inclusion of the changes in a compliance filing to the Annual Review Decision would be appropriate and consistent with past approaches. FEI notes that it is typical for minor changes to occur to the delivery rate and revenue requirement as part of the revenue requirement review process and as a result of the BCUC's decision on the revenue requirement application, and often to incorporate any impacts of the BCUC's decisions in other matters. This does not mean that interim rate approval is required.

1.5 Please explain why FEI does not request interim and permanent approval of 2023 delivery rates in this proceeding pending the outcoming of other concurrent BCUC and FEI proceedings, similar to the approach taken in the FortisBC Inc. (FBC) Annual Review for 2017 Rates or FEI Annual Review for 2018 Delivery Rates.

Response:

In both the FBC 2017 Annual Review and the FEI 2018 Annual Review (as referenced by the BCUC in this IR) only permanent rate approval was requested. However, due to circumstances which occurred subsequent to the filing of those applications, FEI/FBC filed for interim rate approval. FEI also notes that its approach to requesting interim rates in this Application is consistent with the approach taken in the FBC Annual Review for 2016 Rates proceeding, where FBC requested interim rates effective January 1, 2016 pending the outcome of the cost of capital proceeding in progress at that time (see page 2 of the application).

With regard to FBC's 2017 Annual Review, FBC requested a permanent rate increase **only** in the application (see pages 1 and 2 of the application). However, subsequent to filing the application, it became apparent that FBC's Application for Acceptance of Demand Side Management Expenditures for 2017 (DSM Application) would not be approved before the end of 2016. As stated in Order G-180-16 approving interim 2017 rates for FBC, "pursuant to section 44.2(2) of the UCA, the BCUC may not consent under section 61 of the UCA to an amendment to a schedule filed under section 61 to the extent that the amendment is for the purpose of, among other things, recovering expenditures on demand-side measures the public utility anticipates making during the period addressed by the schedule, unless the amendment is for the purpose of setting an interim rate". Therefore, FBC's 2017 rates were approved on an interim basis pending the outcome of the DSM Application so as not to be in contravention of the UCA. FEI notes that approval of the DSM Application had no impact on 2017 rates, and, by Order G-11-17, FBC's interim 2017 rates were made permanent with no change between interim and permanent rates.

With regard to FEI's 2018 Annual Review, FEI requested a permanent rate increase **only** in the application (see page 2 of the application). As explained in FEI's letter dated November 30, 2017, the only reason that FEI later applied for interim 2018 rates was because FEI was anticipating that the BCUC would not be able to issue its decision on the 2018 Annual Review in time for FEI to implement permanent delivery rates effective January 1, 2018. Thus, FEI applied for interim 2018 delivery rate approval.

The situation in this current Application is different primarily due to the potential impact of a decision in the Generic Cost of Capital (GCOC) proceeding. FEI does not know at this time what the effective date of the GCOC decision will be. If the effective date of the GCOC decision is January 1, 2023, and it is determined that changes are to be made to FEI's return on equity (ROE) and capital structure, this would have an impact on 2023 delivery rates. FEI has not incorporated any potential changes to its ROE and capital structure into its forecast 2023 revenue requirements in this Application (i.e., FEI's currently applied for delivery rate increase for 2023 is based on its existing ROE and capital structure); therefore, it would not be appropriate to request permanent 2023 delivery rate approval based on what has been filed in this Application.

2.0 Reference: REVENUE REQUIREMENT AND RATE CHANGES FOR 2023

Exhibit B-2, Section 1.5.5, p. 9, Section 12.4.2.12, p. 162

Amortization of Deferral Accounts

On page 9 of the Application, FEI states:

> Amortization of deferral accounts in 2023 increased by $3.679 million. This is primarily due to the increased amortization of the Demand-Side Management (DSM) deferral account by approximately $9.643 million, the amortization of $2.521 million of the TIMC deferral account starting in 2023, and a debit amortization of $19.512 million for the 2020-2024 Flow-through non rate base deferral account. These increases in amortization expense are mostly offset by a credit amortization of $28.848 million for the Emissions Regulations deferral account. […]

On page 162 of the Application, FEI provides a breakdown of the 2021 Flow-through deferral account true-up in the amount of a $10.491 million debit. The Flow-through deferral account true-up includes a variance related to the delivery margin for industrial customers in the amount of $10.619 million, which FEI explains is driven by lower liquified natural gas (LNG) demand.

2.1 Please provide a reconciliation of the $3.679 million increase in deferral accounts amortization for 2023 which is inclusive of all accounts.

Response:

Please refer to Attachment 2.1 for the reconciliation of the $3.679 million increase in the net amortization expense of all deferral accounts from 2022 to 2023.

2.2 Please explain why the amortization of the DSM deferral account has increased by $9.643 million as compared to 2022. As part of the response, please provide a breakdown of the $9.643 million increase by cost driver of the increase.

Response:

The increase in amortization of $9.643 million from 2022 to 2023 is primarily due to two parts:

1) The 2022 Projected deferral account additions are $112.831 million ($82.805 million after tax), which are amortized over 10 years at $8.280 million per year. Please refer to Table 1 below for the calculation of the deferral account additions and the amortization related to the 2022 Projected DSM expenditures.

Table 1: Calculation for the Amortization of the 2022 Projected DSM Deferral Account Additions

	$millions
Rate Base Deferral Account Additions	$ 29.933
Non-Rate Base Deferral Account Additions	81.275
Total Additions before AFUDC	$ 111.208
AFUDC on Non-Rate Base Deferral Account	1.623
Total Additions	$ 112.831
Tax	(30.026)
Total Additions After-Tax	$ 82.805
Amortization (10-year)	**$ 8.280**

The total 2022 Projected deferral account additions of $111.208 million (before AFUDC) shown in Table 1 above are the 2022 Forecast DSM expenditures for FEI (excluding the portion allocated to Fort Nelson) as approved by Orders G-10-19, G-135-21 and G-301-21 in relation to the 2019-2022 DSM Expenditure Plan, plus underspent amounts from prior years approved for rollover. Please refer to Table 2 below which details the significant drivers of the 2022 Approved DSM expenditures:

Table 2: Drivers of the 2022 Approved DSM Expenditures for FEI

Program Area	2022 Expenditures per Order G-10-19	2022 Expenditures per Order G-135-21	2022 Expenditures per Order G-301-21	Prior Year Expenditures Rolled Over to 2022	Total 2022 Expenditures
Residential	31.383	-	3.433	-	34.816
Commerical	31.074	(11.274)	-	-	19.800
Industrial	3.708	4.754	-	1.014	9.476
Low Income	7.217	-	3.767	1.269	12.253
Conservation Education and Outreach	9.433	-	-	1.752	11.185
Innovative Technologies	3.062	8.810	-	1.150	13.022
Enabling Activities	8.921	-	-	-	8.921
Portfolio Level Activities	1.979	-	-	-	1.979
Total 2022 DSM Expenditures	**96.777**	**2.290**	**7.200**	**5.185**	**111.452**
Less: Fort Nelson Allocation					(0.244)
Total FEI 2022 DSM Expenditures					**111.208**

2) The true-up of the deferral account additions, including AFUDC, between 2021 Projected and 2021 Actual, which total to $18.687 million ($13.642 million after tax) and are amortized over 10 years ($1.363 million). Please refer to Table 3 below for the calculation of the deferral account additions and the amortization related to the true-up of the 2021 DSM expenditures.

Table 3: Calculation for the True-up of the 2021 DSM Expenditures

		$millions
2021 Actual Deferral Account Additions	$	107.294
2021 Projected Deferral Account Additions		88.604
True-up of Additions before AFUDC	$	18.690
True-up of AFUDC on Non-Rate Base Deferral Account		(0.003)
Total True-up of Additions	$	18.687
Tax		(5.045)
Total Additions After-Tax	$	13.642
Amortization (10-year)	**$**	**1.363**

The true-up for the variance between the 2021 Projected and 2021 Actual DSM expenditures was $18.690 million (before AFUDC). Please refer to Table 4 below which details the significant drivers of the true-up of the 2021 DSM expenditures:

Table 4: Drivers of the True-up of the 2021 DSM Expenditures for FEI

Program Area	2021 Projected Expenditures	2021 Actual Expenditures	True-up Variance
Residential	28.476	51.487	(23.011)
Commerical	20.735	21.738	(1.003)
Industrial	7.913	6.095	1.818
Low Income	6.984	9.052	(2.068)
Conservation Education and Outreach	8.578	4.517	4.061
Innovative Technologies	5.064	3.913	1.151
Enabling Activities	9.231	9.199	0.032
Portfolio Level Activities	1.822	1.477	0.345
	88.803	**107.478**	**(18.675)**
Less: 2021 Fort Nelson Allocation	(0.199)	(0.184)	(0.015)
Total 2021 Non-Rate Base Expenditures	**88.604**	**107.294**	**(18.690)**

2.3 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 2023. Please also include the percentage year-over-year change in DSM amortization expense and DSM deferral account additions, respectively.

2.3.1 Please reconcile the annual DSM deferral account additions from the response above to the DSM expenditure schedule under review in the FBC 2023 DSM Plan proceeding.

Response:

Please refer to Table 1 below for the continuity of both the rate base and non-rate base DSM deferral accounts, including annual additions and amortization expense for the years 2019 to 2023. Please refer to Line 29 of Table 1 below for the reconciliation of the DSM additions to the amounts accepted by Orders G-10-19, G-135-21 and G-301-21 in relation to the 2019 to 2022 DSM Expenditure Plan as well as the amounts included in FEI's 2023 DSM Expenditure Plan Application. Please also refer to Line 32 and Line 34 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 6 and 8 are an allocation of the total DSM additions based on the average customer count between FEI and Fort Nelson.

Table 1: Continuity of the DSM Rate Base and Non-Rate Base Deferral Accounts

Line No	Particulars	Reference	Actual 2019	Actual 2020	Actual 2021	Projected 2022	Total DSM Plan 2019 -2022	Forecasted 2023	Total DSM Plan 2023	Notes
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
1	**Demand Side Management - Rate Base**									
2	Opening Balance		100,790	137,957	165,474	195,714		243,343		
3	Opening Balance Transfer from Non Rate Base		30,393	25,458	33,412	57,688		60,954		
4	Additions		29,969	29,940	29,869	29,933		59,870		
5	Tax		(8,092)	(8,084)	(8,065)	(8,082)		(16,165)		
6	Amortization		(15,103)	(19,797)	(24,976)	(31,910)		(41,553)		
7	Ending Balance		**137,957**	**165,474**	**195,714**	**243,343**		**306,449**		
8										
9	**Demand Side Management - Non Rate Base**									
10	Opening Balance		30,393	25,458	33,412	57,688		60,954		
11	Opening Balance Transfer to Rate Base		(30,393)	(25,458)	(33,412)	(57,688)		(60,954)		
12	Additions		34,575	45,366	77,425	81,275		80,827		
13	AFUDC		218	295	1,168	1,623		1,614		
14	Tax		(9,335)	(12,249)	(20,905)	(21,944)		(21,823)		
15	Ending Balance		**25,458**	**33,412**	**57,688**	**60,954**		**60,618**		
16										
17	**Total Additions**									
18	FEI (Total of RB and NRB)	Line 4 + 12	64,544	75,306	107,294	111,208	**358,352**	140,697	**140,697**	
19	FN (Total of RB and NRB)		79	118	184	244	**625**	306	**306**	
20			64,623	75,424	107,478	111,452	**358,977**	141,003	**141,003**	**[Note 2]**
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	G-301-21		-	-	24,982	7,200	**32,182**	-	-	
26	FEI 2023 DSM Expenditure Plan Application		-	-	-	-	**-**	141,077	**141,077**	
27			66,350	72,577	113,785	106,265	**358,977**	141,077	**141,077**	
28										
29	**Reconciliation Over (Under)**	Line 20 - 27	(1,727)	2,847	(6,307)	5,187	-	(74)	**(74)**	**[Note 1]**
30										
31										
32	**Year-over Year % Change - DSM Additions**	Line 18		16.67%	42.48%	3.65%		26.52%		
33										
34	**Year-over Year % Change - DSM Amortization**	Line 6		31.08%	26.16%	27.76%		30.22%		

Notes to Table:

1) At the time of responding to this IR, FEI noticed there is a small variance ($74 thousand) in the 2023 Additions between the 2023 Annual Review and the 2023 DSM Expenditure Plan Application. The variance is due to the timing of when the 2023 Annual Review was being developed versus when the 2023 DSM Expenditure Plan Application was filed. This variance will not change the proposed 2023 delivery rate increase as it only impacts the non-rate base deferral account. Furthermore, only the actual 2023 DSM expenditures will be recorded in the deferral accounts.
2) The total additions shown on Line 20 might vary slightly due to the timing of accruals between the actuals shown here (as per FEI's BCUC Annual Report) and the DSM Annual Report. FEI notes customer rates are based on the actuals shown in the BCUC Annual Report.

2.4 Please provide reasons for the lower 2021 Actual LNG demand as compared to 2021 Projected which contributes $10.619 million to the 2021 after-tax flow-through variance. As part of the response, please explain whether the lower LNG demand experienced in 2021 is expected to persist.

Response:

The lower demand is due to lower LNG exports as a result of restrictions due to the COVID-19 pandemic. 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 Asian Pacific ports. Based on ongoing discussions with potential customers, the easing of COVID-19 pandemic restrictions, and the continued high global demand for North American LNG, FEI expects increases in LNG demand; however, FEI expects that shipping congestion will persist in the short-term which may impact that demand.

B. FORMULA DRIVERS

3.0 Reference: FORMULA DRIVERS

Exhibit B-2, Section 2.2, p. 12; CBC News, "Inflation rises again to new 39-year high of 8.1%"[2] dated July 20, 2022; FEI and FBC Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024, Decision and Orders G-165-20 and G-166-20 (MRP Decision), Section 3.4, p. 101

Inflation Factor Calculation Summary

On page 12 of the Application, FEI states:

> […] FEI uses inflation data from July through June and Statistics Canada Table 18-10-0004-01 for CPI-BC and Table 14-10-0223-01 to determine AWE-BC. The supporting Statistics Canada tables are provided in Appendix A1. The latest available month of April 2022 for AWE-BC has been used as a placeholder, as results to June 2022 have not been released by Statistics Canada. […]

In the news article by CBC News dated July 20, 2022, it states:

> Canada's inflation rate rose to 8.1 per cent last month, Statistics Canada says, the fastest annual increase in the cost of living in decades.

Page 101 of the MRP Decision states:

> The Panel determines that for the Proposed MRPs, the off-ramp will be triggered if earnings in any one year vary from the approved ROE by more than +/- 150 basis points (post sharing).

3.1 Please discuss whether FEI anticipates rising inflation rates to have an impact on operations for the remainder of 2022 and into 2023.

3.1.1 If yes, please discuss how FEI intends to manage inflationary pressures and any risks that inflation may pose to the MRP plan off-ramp provision since formula O&M and growth capital are based on the previous years' inflation data.

3.1.2 If no, please explain why not.

Response:

Yes, FEI has seen recent rising inflationary rates drive up costs in its operations in 2022 and, if high inflation continues in 2023, FEI expects its costs to remain elevated.

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[2] Retrieved on August 31, 2022, from: https://www.cbc.ca/news/business/canada-inflation-rate-1.6526060#:~:text=Inflation%20in%20Canada%20hits%2039%2Dyear%20high&text=New%20numbers%20from%20Statistics%20Canada,fastest%20annual%20increase%20since%201983.

As discussed in Section 7.2.1 of the Application, FEI has experienced significant inflationary pressures in its Sustainment and Other capital portfolios. As Growth capital is determined using a formula-based approach which uses the prior year's inflation data, higher costs and resulting variances are expected. For example, 2022 Projected Growth capital is approximately $100 million, which is approximately $15 million higher than the 2022 Formula Growth capital amount of $85.6 million (before CIAC) which was embedded in 2022 delivery rates. These increases are partly driven by contractor price increases above what was embedded in the formula, and similar to Sustainment and Other capital spending, FEI is exploring strategies to mitigate increased Growth capital cost pressures. FEI also notes that the impact of the higher actual Growth capital expenditures compared to formula on delivery rates will be offset by the incremental revenue resulting from attaching new customers in 2022.

On the O&M side, FEI is also seeing rising inflationary rates impact costs in areas such as vehicle fuel and travel related expenditures for FEI's employees. While FEI anticipates that the approved Inflation Factor (I-Factor) will provide sufficient funding to meet its needs to operate and maintain it assets and provide service to customers, FEI is continuing to monitor the situation. In addition, as outlined in Section 1.4.2 of the Application, FEI is evaluating and implementing a number of initiatives to achieve savings beyond the productivity improvement factor to manage its business needs and help to address cost pressures resulting from its evolving and challenging operating environment.

Despite the above, FEI does not expect the MRP off-ramp will be triggered due to inflationary pressures in 2023 and 2024. For example, based on the 2023 Forecast rate base and assuming that inflation impacts O&M expenses only, in order to trigger the MRP off-ramp of 150 basis points less than the approved ROE of 8.75 percent post-earnings sharing, FEI's actual formula O&M would need increase by approximately $111.7 million from the 2023 forecast formula O&M level. This is equivalent to a Net Inflation Factor of approximately 43 percent annually. FEI has no evidence that would suggest the annual inflation could be as high as 43 percent in 2023 or 2024. This also assumes that FEI will take no action to manage its O&M expenses. In addition, the I-Factor calculation uses actual CPI data and as shown in Table 2-1 of the Application, the average CPI has increased to 4.940 percent, which partly reflects the inflationary increases being experienced. To the extent that further inflation is seen in actual data, the increases will be included in the I-Factor used in the 2024 rate-setting process.

3.2 Please discuss whether FEI anticipates that inflationary pressures will cause the MRP plan off-ramp provision to be triggered during the remainder of the MRP term. Please explain why or why not.

Response:

Please refer to the response to BCUC IR1 3.1.

3.3 Please discuss whether it would be appropriate to reassess the calculation of the inflation factor for 2023 and/or the remainder of the MRP term.

3.3.1 If yes, please explain why and provide the proposed timing and regulatory review process for such an assessment.

3.3.2 If no, please explain why not.

Response:

FEI does not believe the inflation factor calculation should be reassessed for 2023 or the remainder of the MRP term (2024). FEI's costs are subject to inflation, and the inflation factor uses the latest data from Statistics Canada and remains a valid and objective measure of the economy-wide inflation in BC. Further, as explained in the response to BCUC IR1 3.1, FEI does not expect that the off-ramp will be triggered in 2023 or 2024 due to inflationary pressures.

4.0 Reference: FORMULA DRIVERS

Exhibit B-2, Section 2.3, pp. 14–15

Growth Factor Calculation Summary

On page 14 of the Application, FEI states:

> FEI is forecasting gross customer additions of 16,000 for 2023, which is lower than the 2022 Approved amount of 20,000 but is reflective of FEI's expectation of its 2022 customer growth, which is projected at 16,000. […]

On page 15 of the Application, FEI states:

> […] In developing the forecast, FEI has assumed that the market capture rate for new construction is likely to retreat somewhat versus previous years due to the continued
>
> impacts of building policies, building codes, and strong financial incentives provided for home electrification. […]

4.1 Please explain why maintaining the 2023 forecast gross customer additions (GCA) at 2022 projected levels is appropriate given FEI's statement that "the market capture rate for new construction is likely to retreat" in 2023. As part of the response, please provide the 2023 forecast methodology for GCA.

<u>Response:</u>

FEI's statement that "the market capture rate for new construction is likely to retreat somewhat versus previous years" was referring to both the 2022 Projected and the 2023 Forecast GCAs. As noted in the preamble, the 2022 Approved GCAs were 20,000 but, at the time of preparing this Application in May of 2022, FEI projected the 2022 GCAs to be lower at 16,000. This lower projection was in part a reflection of the anticipated retreat in the market capture rate and FEI expects similar conditions in 2023, which is why the 2023 Forecast has been set at 16,000 as well. Therefore, the statement regarding the market capture rate is meant to indicate that gross customer additions are not expected to be as high as the actual GCAs experienced historically. Please refer to the response to BCUC IR1 4.2 for the 2017 to 2021 actual GCAs.

The forecast methodology for GCAs is described on page 15 of the Application, lines 10 to 14. Additionally, as explained in the Application, any variances between forecast and actual GCAs will be trued up in subsequent annual reviews. For example, the variance between 2022 Approved and 2022 Actual GCAs will be trued up when setting 2024 delivery rates.

4.2 Please provide the 2017 to 2022 approved and actual GCA.

Response:

Please refer to Table 1 below for the 2020 to 2022 Approved Gross Customer Additions (GCAs), 2017 to 2021 Actual GCAs, and 2022 Projected GCAs. FEI notes that under the 2014-2019 PBR Plan, the growth capital formula was based on a lagging 50 percent growth factor using actual service line additions, not based on a forecast of GCAs; therefore, there were no approved GCAs for 2017 to 2019. FEI also notes that, as discussed in Section 7.2.2 of the Application, FEI is approved to include a true-up of formula growth capital for the variance between actual and approved GCAs from two years prior, i.e., the 2022 formula growth capital included a true-up for the variance in 2020, and the 2023 formula growth capital included a true-up for the variance in 2021.

Table 1: 2017 to 2022 Approved/Actual/Projected GCAs

	2017	2018	2019	2020	2021	2022
Approved	n/a	n/a	n/a	18,000	16,000	20,000
Actual/Projected	20,825	22,439	18,993	18,980	20,294	16,000

C. DEMAND FORECAST AND REVENUE AT EXISTING RATES

5.0 Reference: DEMAND FORECAST

Exhibit B-2, Section 3.3.3, pp. 28–29

Industrial Demand – BC Hydro Island Generation (IG)

On page 28 of the Application, FEI explains the decrease in forecasted industrial demand, shown in Figure 3-10 as follows:

> […] This decrease in demand is primarily due to FEI's contract with BC Hydro Island Generation (IG) expiring in April 2022, which had a contract demand of approximately 16.4 PJ [petajoules]. BC Hydro IG is now included in the 2023F [2023 Forecast] as a fully interruptible RS 22 [Rate Schedule 22] customer with a forecast minimum contract demand of 12 TJ [terajoules] per month (or 1.2 PJ per year).

5.1 Please identify the customer rate class for BC Hydro IG prior to contract expiry in April 2022.

Response:

Prior to the contract expiry in April 2022, BC Hydro IG was a special contract and thus not part of any of FEI's non-bypass customer rate classes. It is displayed on its own under Bypass and Special Rates in FEI's financial schedules as "BC Hydro IG" (see Section 11, Schedules 17 to 19 of the Application).

5.2 Please explain FEI's rationale for including BC Hydro IG in the 2023F as a fully interruptible RS 22 customer.

Response:

FEI included BC Hydro IG in the 2023F as a fully interruptible RS 22 customer as that is the level of service that BC Hydro chose to sign up for effective May 1, 2022, and RS 22 is the appropriate rate schedule. RS 22 is typically 100 percent interruptible unless the customer chooses some level of firm service depending on capacity availability.

BC Hydro elected fully interruptible service under RS 22 as it plans to use Island Generation as a backup facility while BC Hydro performs repairs to transmission cables serving Vancouver Island over the next two to four years. FEI and BC Hydro discussed firm and interruptible service options; however, as BC Hydro plans to do the repairs during mild weather in spring/summer when the loads on the gas system are at their lowest, BC Hydro chose fully interruptible service, understanding the risks of selecting such a service. The RS 22 agreement, combined with a four and a half year short-term electricity agreement with Capital Power, were the agreements that BC

Hydro entered into to be able to provide back up electricity support for Vancouver Island while repairs are made to transmission cables that serve Vancouver Island. BC Hydro has indicated it will no longer require Island Generation once the repairs have been completed.

FEI notes, as discussed on page 28 of the Application, a minimum contract demand of 12 TJ per month and associated revenue is included in the 2023 revenue forecast. The minimum contract demand of 12 TJ per month is specified in Section 6 of FEI's RS 22 tariff.[3]

5.3 Please discuss whether FEI is aware of whether BC Hydro IG has made or intends to make a firm request for gas service.

5.3.1 Please summarize any correspondence between FEI and BC Hydro IG regarding firm gas service requirements.

Response:

Please refer to the response to BCUC IR1 5.2.

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3 https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/rateschedule_22.pdf.

D. COST OF GAS

6.0 Reference: COST OF GAS

Exhibit B-2, Section 1.2, p. 2, Appendix B, p. 7; FEI Annual Review for 2020 and 2021 Delivery Rates Application Decision and Order G-319-20 dated December 8, 2020 (2020 and 2021 Annual Review Decision), p. 14

2023 Core Market Administration Expense (CMAE) Budget

On page 2 of the Application, FEI requests approval of the 2023 CMAE budget of $5.795 million, as set out in Appendix B, and the allocation of the CMAE between FEI's Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA) based on the allocation percentages of 30 percent and 70 percent, respectively.

On page 7 of the Appendix B to the Application, FEI explains that the methodology used for allocating CMAE costs to the gas supply commodity and midstream portfolios remains consistent with that of previous years.

Page 14 of the FEI 2020 and 2021 Annual Review Decision states:

In the Application, FEI is requesting the approval of the 2021 CMAE Budget of $5.524 million; and approval of the allocation of the 2021 CMAE between the Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA) based on the allocation percentages of 30 percent and 70 percent, respectively. <u>FEI states that this allocation reflects the level of work performed by employees in the Gas Supply area to support each of the portfolios</u>. [Emphasis added]

6.1 Please explain whether the level of work performed by employees in the Gas Supply area supports the proposed methodology for allocating CMAE costs between the CCRA and MCRA and if there have been any significant changes in this regard since 2021.

6.1.1 If there have been changes, please explain why the methodology used for allocating the CMAE costs should remain at 30 percent to the CCRA and 70 percent to the MCRA.

<u>Response:</u>

The proposed allocation assigning 30 percent of the CMAE costs to the CCRA and 70 percent of the CMAE costs to the MCRA, consistent with the currently approved allocation percentages, remains representative of the level of work performed within the Gas Supply area and required to support the commodity and midstream portfolios. To date, there have been no significant changes since the start of the MRP term.

FEI notes that, pursuant to Order G-319-20, a comprehensive review of the CMAE costs including consideration of whether these costs are conducive to a formulaic approach and whether they should continue to be forecast with flow-through treatment, and whether the current allocation percentages to the CCRA and MCRA remain appropriate, is to be completed and included in FEI's next revenue requirement or MRP application following the current MRP term.

E. OTHER REVENUE

7.0 Reference: OTHER REVENUE

Exhibit B-2, Section 5.2.1, pp. 35–36

Late Payment Charge

On page 35 of the Application, FEI provides Table 5-1 showing the 2022 Approved, 2022 Projected and 2022 Forecast for each component of Other Revenues, as reproduced in part below:

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

	Approved 2022	Projected 2022	Forecast 2023
Late Payment Charge	$ 2.704	$ 4.108	$ 3.364

On page 36 of the Application, FEI states that "the amount of Late Payment Charges being collected for 2022 has been influenced by the impacts of the higher cost of gas and carbon tax on customers' bills."

7.1 Please provide a breakdown of the increase in Late Payment Charge between 2022 Approved ($2.704 million) and 2022 Projected ($4.108 million) based on the factors discussed on page 36 of the Application (i.e. COVID-19 pandemic, higher cost of gas, and carbon tax).

Response:

FEI is unable to provide a breakdown of the increase in 2022 Projected Late Payment Charges by the factors requested. This is because the 2022 Projected amount was calculated based on the actuals to date with the remaining months forecast using a similar trend for the remainder of the year and was not projected on a per factor basis.

FEI notes that as at the end of August 2022, Actual Late Payment Charges are $2.899 million which is higher than the full year 2022 Approved amount of $2.704 million. Anecdotally, overall higher customer bills, driven by both usage and rates, as well as other general inflationary pressures customers may be experiencing would likely lead to an increase in Late Payment Charges.

7.2 Please provide in a summary table, the 2020 and 2021 Approved and Actual Late Payment Charges.

7.2.1 To the extent that there are also significant differences between 2020 and 2021 Approved versus Actual results, please discuss what changes, if any, FEI has made to its forecasting methodology for 2023 as compared to previous years.

Response:

Please see the table below providing the 2020 and 2021 Approved and Actual Late Payment Charges. As the table shows, the 2020 Actual Late Payment Charges were notably lower than 2020 Approved, with 2021 Actuals also coming in lower than approved but to a lesser degree. The lower Actual results in 2020 and 2021 were due to FEI suspending the collection of Late Payment Charges in early 2020 until March 2021 due to the COVID-19 pandemic. As discussed in Section 12.2.1 of the Application, the variances in 2020 and 2021 Late Payment Charges are included in the calculation of the exogenous factor impact related to the COVID-19 pandemic.

Table 1: 2020 and 2021 Approved and Actual Late Payment Charges

Year	Approved	Actual	Variance
2020	1.671	0.818	(0.853)
2021	2.954	2.622	(0.332)

As explained in Section 5.2.1 of the Application, FEI has adjusted its forecasting method for Late Payment Charges in this Application to exclude the impact of 2020 on the 2023 Forecast and to incorporate more recent results by factoring in the 2022 Projected Late Payment Charges. Historically, FEI has forecast Late Payment Charges based on the average of the most recent three years of actual Late Payment Charges earned. In recognition that this approach would likely result in an under-forecasting of Late Payment Charges for 2023, FEI determined that it would be more appropriate to calculate the 2023 Forecast using the average of the 2021 Actual and the 2022 Projected Late Payment Charges.

8.0 Reference: OTHER REVENUE

Exhibit B-2, Section 3.3.4, p. 29, Section 5.2.4, p. 37

Natural Gas for Transportation (NGT) Related Recoveries

On page 29 of the Application, FEI provides Table 3-2 as follows:

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

GJ	2022 Approved	2022 Projected	2023 Forecast
CNG	1,024,550	1,471,479	1,468,479
LNG	1,566,989	1,407,696	1,527,696
Total NGT Demand	**2,591,539**	**2,879,175**	**2,996,175**
Non-NGT Demand (export)	3,083,297	1,188,389	3,690,789
Total NGT and Non-NGT Demand	**5,674,836**	**4,067,564**	**6,686,964**

On page 37 of the Application, FEI provides Table 5-3 as follows:

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

	2022 Approved	2022 Projected	2023 Forecast
Applicable Volume (GJ)	543,622	559,773	525,898
Rate ($/GJ)	$ 0.52	$ 0.52	$ 0.52
Total NGT OH&M Revenue ($ millions)	**$ 0.283**	**$ 0.291**	**$ 0.273**

Further, on page 37 of the Application, in Footnote 18, FEI states:

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

8.1 Please confirm, or explain otherwise, that the difference in NGT volume in Table 3-2 and Table 5-3 is due to the applicable volume in Table 5-3 being limited to the contract minimum volume.

Response:

Not confirmed. FEI clarifies that the volumes shown in Table 3-2 represent the total from all NGT and non-NGT LNG customers, which includes contracted minimum, third-party demand, excess demand, and spot demand delivered through FEI-owned fueling stations, as well as any demand that is delivered through customer-owned stations and non-NGT RS 46 demand. As explained on page 37 of the Application and referenced in the preamble above, only the contracted demand <u>and</u> the third-party demand that are delivered through FEI-owned fueling stations are subject to the OH&M charge and, as such, only those volumes are included in Table 5-3.

On page 37 of the Application, FEI states that it is "forecasting the Standard tanker rental revenue to decrease from the 2022 level, primarily due to a reduction in LNG vehicles on the road, as the existing heavy duty LNG engines have been discontinued, and there is not expected to be a replacement until 2024-2025 at the earliest."

8.2 Please provide the reasons why existing heavy duty LNG engines have been discontinued and why there is not expected to be a replacement until 2024–2025 at the earliest.

Response:

The 15L LNG engines which provided the required horsepower for heavy-duty trucks carrying payloads of up to 120,000 lbs on mountainous terrain are no longer commercially available. These engines have historically been the primary driver of on-road LNG demand. Westport supplied the High-Pressure Direct Injection (HPDI) engines for nearly all of the existing LNG heavy duty trucks and stopped taking orders for these engines due to technology issues. However, there is currently a 12L LNG fueled engine available which has been adopted by one customer so far, and its performance is being evaluated. In October 2021, Cummins Inc., a global leader in manufacturing diesel and natural gas engines, announced their plans to bring a new 15L natural gas engine to market to support the industry's path to zero emissions.[4] FEI expects this engine, or an alternative, will be available in the Canadian marketplace by late 2024.

[4] https://investor.cummins.com/news/detail/530/moving-heavy-duty-trucking-down-the-path-to-zero-emissions.

9.0 Reference: OTHER REVENUE

Exhibit B-2, Section 5.3, pp. 39–40

Southern Crossing Pipeline (SCP) Third Party Revenue

On pages 39 to 40 of the Application, FEI states:

> The [SCP Third Party] Other Revenue of $13.284 million is related to the inclusion of the 105 MMcfd [million cubic feet per day] of SCP east to west capacity in the MCRA [Midstream Cost Reconciliation Account] portfolio. As part of the FEI Annual Review for 2020 and 2021 Delivery Rates Decision and Order G-319-20, the BCUC approved, effective November 1, 2020, the debiting of the MCRA and crediting of Other Revenue in the amount of $346.617 per MMcfd.

9.1 Please provide the calculation of the SCP Third Party Other Revenue amount of $13.284 million given the 105 MMcfd amount and $346.617 per MMcfd cost.

<u>Response:</u>

The 2023 Forecast for the 105 MMcfd (million cubic feet per day) of east to west SCP capacity included in the MCRA is calculated as follows:

(105 MMcfd) X ($346.617 per MMcfd) X (365 days) = $13,284,096.53

F. O&M EXPENSE

10.0 Reference: O&M EXPENSE

Exhibit B-2, Section 1.4.1, p. 4, Section 6.2.1, p. 43

Formula and Non-Formula O&M – Delayed Costs

On page 4 of the Application, FEI states:

> Additionally, approximately $3.3 million of [2021 Formula] O&M savings were due to the timing of expenditures, such as vacancies and consulting expenditures, and lower general and miscellaneous expenditures. While some of the savings are one-time in nature (e.g., delay in filling vacancies), some of the savings are expected to continue into the future, recognizing that cost pressures in the future may offset the savings.

10.1 Please provide a breakdown of the $3.3 million of O&M savings by each of the cited reasons for savings (i.e. vacancies, consulting expenditures, general and miscellaneous expenditures). Please also indicate what percentage of the savings in each of these categories is expected to be one-time and what percentage is expected to be recurring.

Response:

Contributing to the $3.3 million of net O&M savings are estimated savings of approximately $2.1 million from labour vacancies in various departments, including Customer Service, Energy Solutions, Information Systems, and Environmental and Safety. The remaining approximate $1.2 million is related to consulting, and general and miscellaneous expenditures, including $0.3 million for reduced printing and postage costs resulting from an increase in the number of customers on paperless billing. Please refer to page 7 of the Application for a discussion of the Paperless Billing Customer Campaigns.

The labour vacancies savings ($2.1 million or 64 percent of total O&M savings) and $0.9 million of the consulting expense savings (27 percent of total O&M savings) are considered one-time in nature as the positions and related funding are expected to be required in future years. The remaining $0.3 million of the general and miscellaneous expenditures (9 percent of total O&M savings) for the reduced postage and printing are considered permanent in nature and expected to carry into future years.

10.2 Please discuss the necessity of these $3.3 million in O&M savings to continue operations in 2022 and 2023.

Response:

As explained in the response to BCUC IR1 10.1, the majority of the savings are one-time in nature due to factors such as labour vacancies in various departments. These positions are important to continuing operations, including connecting new customers, providing high quality service to existing customers, and ensuring that FEI is meeting environmental and safety standards and regulations, among other goals. Based on historical experience, FEI expects the factors contributing to the $3.3 million of O&M savings realized in 2021 (or some portion of it) will likely continue into 2022 and 2023. For instance, the challenge of filling vacancies in the current labour market is an issue that the majority of organizations across all industries is facing.

FEI is currently evaluating and implementing opportunities (please refer to Section 1.4.2 of the Application) to generate efficiency savings to sustain the $3.3 million savings achieved in 2021 into 2022 and 2023, while maintaining overall operations and service quality levels. Such opportunities may result in an increased proportion of recurring savings compared to one-time savings. However, while O&M savings are likely to continue to be achieved, the reasons for the net overall savings realized in future years may be different as there may be cost pressures that offset the current overall level of savings achieved in future years.

10.3 Please discuss any impact delayed costs have had on operations in 2021.

Response:

In 2021, the $3.3 million of savings were realized for the reasons described in the response to BCUC IR1 10.1 and did not have a significant impact on FEI's overall operations. This was evidenced by service quality levels continuing to remain high overall. As explained in the response to BCUC IR1 10.2, filling vacancies in certain areas of the Company is continuing to be a challenge due to the tight labour market. This issue has to a certain extent impacted some areas of the organization, such as meter reading and customer service, which is discussed in Sections 13.2.2.3 and 13.2.2.4 of the Application.

On page 43 of the Application, FEI states:

> For gas control and CEPA [Canadian Energy Pipeline Association] participation, FEI spent $1.058 million less than the formula amount in 2021 due to the timing of hiring gas controllers and the timing of control room management improvements. One gas controller was hired in 2021 and the plan is to hire one net new gas controller per year and to coordinate the timing of the new hires with retirements of existing employees. Also in 2021, FEI proceeded with implementing CEPA

required control room management improvements and performed activities including CEPA assessments and other improvements due to non-CEPA drivers (e.g., regulatory requests, industry practice).

10.4 Please discuss any uncertainty or expected challenges anticipated to fill new roles, including the hiring of gas controllers with appropriate experience and skills, or to recruit consultants in 2023.

Response:

FEI experiences uncertainty and challenges when filling many new roles, including the hiring of gas controllers with appropriate experience and skills. A common challenge is locating candidates with appropriate experience and skills within British Columbia. An added complexity is that many of the other job markets typically have lower-cost housing markets than exist in FEI's operating territory, and especially in the Lower Mainland.

FEI's hiring of consultants typically has less uncertainty and fewer challenges than those that exist for internal hiring. As an example, consultants tend to have greater flexibility as to their work location. FEI seeks consulting services when specialized skill sets are needed and/or when workload is variable. Consultants are not suitable for the gas controller positions because, in addition to the specialized skill set required, these positions require Company-specific training (i.e., FEI-specific skills that are not available from consultants) and the positions are required over the long-term.

10.5 Related to gas control and CEPA participation, please discuss why one net new gas controller is required in each subsequent year (i.e. from 2022) and for how many years this additional hiring will occur.

Response:

In alignment with the response to BCUC IR1 33.1 in the 2020-2024 MRP proceeding, FEI continues to strive to increase its Gas Control Room staffing to 12 gas controllers to ensure the utility will be able to meet the requirements of its customers, align with industry standards, and continue to operate in a safe and reliable manner within a progressively complex and demanding operational environment.

One net new controller per year achieves FEI's goal for gas controller staffing by 2025 (i.e., one net new controller in each of 2022, 2023, and 2024, plus one year for training). FEI's hiring activities (i.e., actual numbers of new hires) and schedule will consider issues such as anticipated timing of retirements, experiences with other employee attrition, onboarding and training capacity, and the uncertainty and challenges associated with hiring this role as discussed in the response to BCUC IR1 10.4.

10.6 Please provide further details on the specific “industry practices” noted in relation to non-CEPA drivers.

Response:

Control room management, as with many practices of natural gas utilities and transmission pipeline operators, is influenced significantly by industry practice. Many of FEI’s peer companies operate pipeline systems in both Canada and the United States; as such, practices in these two countries tend to have the highest visibility and priority to FEI in its assessments of industry standard practice.

The primary example of a control room management “industry practice” noted in relation to non-CEPA drivers is with respect to alarm philosophies (e.g., definition of alarm criticality levels, formal alarm response protocols). Alarm management practices have tended to have greater definition and implementation by US operators, likely influenced by US federal regulations. Although this subject is considered a non-CEPA driver at the current time, FEI’s continual improvements are influenced by a range of drivers that may evolve.

11.0 Reference: O&M EXPENSE

Exhibit B-2, Section 6.3.3.1, p. 47

Forecast O&M – Integrity Dig Expenditures – First-time In-line Inspections (ILI)

On page 47 of the Application, FEI states:

> FEI's forecast related to ILI Digs – New Tools is primarily an estimate of the integrity digs resulting from first-time in-line inspections associated with the IGU [Inland Gas Upgrade] Project. FEI has reduced its 2022 Projection for number of digs in this area due to the timing of in-line inspections as well as FEI's expectations of pipeline conditions.

11.1 Please discuss FEI's methodology for estimating the number of integrity digs and associated cost per dig resulting from first-time in-line inspection associated with the IGU Project, detailing all assumptions made.

<u>Response:</u>

FEI's forecasts of the number of integrity digs are developed by technical staff within the System Integrity department. For dig projections that are prepared prior to the receipt of in-line inspection data or prior to ILI data analysis, there is no sufficient technical basis for estimating the number of digs from a first-time in-line inspection with definitive calculations and assumptions. As such, FEI's adopted methodology is to enable qualified staff to apply their engineering judgment for these projections. In their development of integrity dig forecasts, FEI staff's judgement is informed by various information sources, including:

- Knowledge of populations of imperfections from other in-line inspected pipelines, while recognizing that one pipeline's condition is not an accurate predictor of another pipeline's condition; and
- Knowledge of imperfections that the IGU project is endeavouring to locate and remove prior to in-line inspection.

FEI's forecasts of the associated cost per dig are developed by Transmission Operations staff, and consider the average cost to complete similar integrity digs, as well as utilizing knowledge and/or estimates of future costs, such as those associated with contractors and equipment. However, there are inherent challenges to forecasting the cost per dig, particularly when no historical data is available, as there can be considerable uncertainty due to dig-specific factors such as site access, dig scope, and local site remediation. Thus, when running an in-line inspection tool technology in a pipeline for the first time, predictions of the potential number of digs required are highly uncertain.

The uncertainty associated with forecasting integrity digs is why the BCUC approved flow-through treatment of all integrity dig expenditures as part of the MRP Decision and Order G-165-20.

11.2 Please discuss what FEI's expectations are with respect to pipeline conditions.

11.2.1 Please discuss any changes in FEI's expectations of pipeline conditions since the BCUC approved the IGU Project.

11.2.1.1 Please explain how such changes in FEI's expectations impact its 2022 projection for number of integrity digs.

Response:

The context of the statement in the preamble referring to "FEI's expectations of pipeline conditions" was referring to a learning that some imperfections originally estimated to be removed through integrity digs are being removed through IGU project activities. Please also refer to the response to BCUC IR1 11.1.

FEI does not formulate specific expectations of pipe conditions prior to running ILI tools, as there is insufficient information on which to base such an assessment. Broadly speaking, FEI expects that the IGU pipelines will warrant integrity digs based on evaluation of ILI-reported anomalies' failure potentials and the potential to exceed the criteria published in the CSA Z662 standard (Clause 10.10 "Evaluation of Imperfections"). These expectations of pipeline conditions associated with the IGU project have remain unchanged since the IGU project was approved.

12.0 Reference: O&M EXPENSE

Exhibit B-2, Section 6.3.3.2.1, p. 49

Integrity Dig Expenditures – Inland Gas Upgrade Project

On page 49 of the Application, FEI states:

> In 2022, FEI inspected two laterals using ILI, and although there remains some schedule uncertainty, FEI is projecting that approximately half of the 11 laterals where ILI capability will be provided will have their tool runs completed by 2023.

12.1 Please provide the estimated target dates for completing first-time ILI tool runs and associated integrity digs and the overall schedule for each of the 11 laterals where ILI capability will be provided with the IGU Project.

12.1.1 Please include any assumption FEI has made and the basis for the assumption.

Response:

FEI's ILI implementation schedule for those laterals selected for ILI as part of the IGU project remains consistent with the schedule described in the response to BCUC IR2 74.1 in the IGU project proceeding.

To provide an overall schedule, FEI has expanded on information provided in "Table 1-1: Pipeline Construction Schedule" from the IGU Project Semi-Annual Progress Report No. 5 filed with the BCUC on July 27, 2022. The table below provides pipeline-specific target dates for completing first-time ILI tool runs and associated integrity digs for each of the pipeline segments where ILI capability will be provided.

FEI requests that a portion of this response be held on a confidential basis pursuant to Section 19 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-178-22, as it contains security and commercially sensitive information regarding schedule and risks to the project which, if publicly disclosed, could potentially jeopardize the safety and security of FEI's system. FEI, therefore, requests that the redacted portions of this response on a confidential basis and that it only be made available to interveners upon executing a Confidentiality Declaration and Undertaking form acceptable to the BCUC.

[redacted]

Table 1: Pipeline Construction, ILI, and Integrity Digs Schedule

Note: The first 5 columns are for ILI-related pipelines, excerpted from the IGU Project Semi-Annual Progress Report No. 5, filed July 27, 2022					Note: The latter 3 columns are provided in response to BCUC IR1 12.1		
ID No.	**Lateral/Loop Name and Construction Activity**	**Construction Start**	**Construction Finish**	**Phase #**	**Pipeline Cleaning Target Start**	**First-time ILI Target Completion**	**Integrity Digs Forecast Schedule**
1	Mackenzie Lateral 168 (ILI – Field Bends)	[redacted]	[redacted]	[redacted]	2022	2023 (first ILI activities are currently scheduled Q3/Q4 2022)	2023+
2	Mackenzie Loop 168 (ILI – Field Bends)	[redacted]	[redacted]	[redacted]	2022	2023 (first ILI activities are currently scheduled Q3/Q4 2022)	2023+
7	Prince George 1 Lateral 168 (ILI)	[redacted]	[redacted]	[redacted]	2023	2024	2024+
14	Salmon Arm Loop 168 (ILI)	[redacted]	[redacted]	[redacted]	2024	2025	2025+
22.1	Fording Lateral 219 (ILI – Field Bends)	[redacted]	[redacted]	[redacted]	2023	2024	2024+
22.2	Fording Lateral 168 (ILI)	[redacted]	[redacted]	[redacted]	2023	2024	2024+
24	Cranbrook Lateral 168 (ILI)	[redacted]	[redacted]	[redacted]	2022	2023 (first ILI activities have been initiated in 2022)	2023+
25	Cranbrook Loop 219 (ILI)	[redacted]	[redacted]	[redacted]	2022	2023 (first ILI activities have been initiated in 2022)	2023+
26	Cranbrook Kimberley Loop 219 (ILI)	[redacted]	[redacted]	[redacted]	2023	2024	2024+
27	Cranbrook Kimberley Loop 273 (ILI)	[redacted]	[redacted]	[redacted]	2023	2024	2024+
28	Kimberley Lateral 168 (ILI)	[redacted]	[redacted]	[redacted]	2023	2024	2024+
29	Skookumchuck Lateral 219 (ILI)	[redacted]	[redacted]	[redacted]	2023	2024	2024+

The above schedule includes the following general assumptions:

- Construction Finish estimates provided in the latest IGU Project Semi-Annual Progress Report No. 5, filed July 27, 2022, will remain unchanged;

- Post-construction project work to remove any obstructions that may impede the clear passage of the ILI tool are complete prior to the Pipeline Cleaning Target start year;
- ILI vendor and tool availability in the year(s) estimated for in-line inspection; and
- First-time in-line inspection success (e.g., no further undetected obstructions in the pipeline that unexpectedly interfere with the ILI activities, no tool failure during the in-line inspection).

12.2 Please provide the reason(s) for the schedule uncertainty noted in the preamble above.

Response:

Please refer to Confidential Attachment 12.2 which provides excerpts of the following sections from the IGU Project Semi-Annual Progress Report No. 5, filed with the BCUC on a Confidential Basis on July 27, 2022:

- Section 1.4 “Project Issues and Challenges” describes the reason(s) for the schedule uncertainty noted in the preamble above to this IR.
- Section 4.1 “Significant Project Risks and Plans to Mitigate” describes how FEI is addressing project-related schedule uncertainty related to ILI tool runs.

FEI requests that Attachment 12.2 be held on a confidential basis pursuant to Section 19 of the BCUC’s Rules of Practice and Procedure regarding confidential documents as set out in Order G-178-22, as it contains security and commercially sensitive information regarding schedule and risks to the project which, if publicly disclosed, could potentially jeopardize the safety and security of FEI’s system. FEI, therefore, requests that the BCUC hold Attachment 12.2 on a confidential basis and that it only be made available to interveners upon executing a Confidentiality Declaration and Undertaking form acceptable to the BCUC.

Secondary reasons contributing to schedule uncertainty include the following:

- ILI vendor and tool availability in the year(s) estimated for in-line inspection; and
- First-time in-line inspection success (e.g., no further undetected obstructions in the pipeline that unexpectedly interfere with the ILI activities, no tool failure during the in-line inspection).

Other activities undertaken by FEI to mitigate the secondary reasons contributing to schedule uncertainty are as follows:

- To mitigate ILI vendor and tool availability in the year(s) estimated for in-line inspection, FEI undertakes advance communication and planning with ILI vendors; and

- To improve the potential of first-time in-line inspection success, ILI-related activities are planned to enable sufficient time for interpretation of and response to all available information (e.g., post-construction caliper tool run results, pipeline cleaning results, and geometry tool run results).

12.3 What alternatives has FEI considered or could consider to address schedule uncertainty related to ILI tool runs?

Response:

Please refer to the response to BCUC IR1 12.2.

13.0 Reference: O&M EXPENSE

Exhibit B-2, Section 6.3.6, pp. 51–52, Section 6.3.7, p. 52

Forecast O&M – Clean Growth Initiative – Renewable Gas Development

On page 51 of the Application, FEI provides the following table:

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

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Renewable Gas Development	1.000	1.750	2.000	Section 11, Schedule 20, Line 21
2	Total	1.000	1.750	2.000	

On page 52 of the Application, FEI states:

> […] The 2022 Projected O&M costs include the addition of two incremental labour resources and the increased use of external consultants to successfully execute on planned activities to meet business goals and objectives. […]
>
> The 2023 Forecast O&M is approximately $2.0 million, which is an increase from the 2022 Projected amount, and is related to requirements to continue work on project feasibility, safety, codes and standards, and business development. In addition to the work identified above, FEI is seeing the need to support Indigenous groups that are exploring the production of renewable gases in their communities. FEI requires funding to hire internal resources to work with Indigenous groups on the evaluation of opportunities.

13.1 Please explain and provide a breakdown of renewable gas development O&M for:

(i) 2022 Approved ($1.000 million) as compared to 2022 Projected ($1.750 million); and

(ii) 2023 Forecast ($2.000 million) as compared to 2022 Projected ($1.750 million).

13.1.1 Please provide the roles and salaries of the “two incremental labour resources.” Please indicate whether the roles are permanent or temporary positions.

13.1.2 Please provide the roles and costs of the “increased use of external consultants.”

<u>Response:</u>

The following table provides a breakdown of the 2022 Approved, 2022 Projected and 2023 Forecast Renewable Gas Development O&M.

Table 1: 2022 Approved, 2022 Projected and 2023 Forecast Renewable Gas Development O&M

	2022 Approved	2022 Projected	2023 Forecast
Labour ($ millions)			
Existing Labour Resources	0.878	0.878	0.901
New Engineering Resource		0.100	0.200
New Business Development Resource			0.200
Subtotal Labour ($ millions)	**0.878**	**0.978**	**1.301**
Non-Labour ($ millions)			
Total Employee Expenses, Fees and Admin Costs	0.032	0.141	0.063
Total Consultant Contractors Costs	0.090	0.631	0.636
Subtotal Non-Labour ($ millions)	**0.122**	**0.772**	**0.699**
Total ($ millions)	**1.000**	**1.750**	**2.000**

As shown in the above table, the increased spending between 2022 Approved and 2022 Projected is due to:

- hiring one incremental engineering labour resource (this resource was hired partway through 2022, which is why the labour cost increases for this new resource in 2023);
- costs for external consultants and professional services providers; and
- increased employee expenses (the increased employee expenses are primarily due to one-time employee relocation expenses as the new employee relocated from outside of BC).

While the Application (as referenced in the preamble to this IR) stated that FEI planned to hire two incremental labour resources in 2022, due to timing issues, FEI now expects to hire the second incremental labour resource in 2023. FEI notes that the 2022 Projected Renewable Gas O&M expenses are still expected to be approximately $1.750 million despite the delay in hiring the second resource as FEI anticipates utilizing more external consultant and contractor resources in 2022 to advance various activities, as further described below.

The largest driver of the increase between 2022 Approved and 2022 Projected is related to the use of external consultants and professional services providers to advance hydrogen, syngas, and lignin supply development, as follows:

- Multi-disciplinary professional engineering and project development services to explore the technical and economic feasibility and advance various hydrogen and lignin supply (production) project opportunities.
- Specialist technical and engineering services to advance various scopes of work related to the feasibility of different scenarios for the existing gas system to support the development of new forms of renewable gas in the market, such as blending hydrogen

with natural gas or conversion of segments of the gas system to operate on one hundred percent hydrogen.

- Professional services to assist with preparing multiple funding applications to various provincial and federal funding agencies to support supply projects and other market development activities for hydrogen, syngas, and lignin production and customer update of these new forms of renewable gas in BC.
- External legal counsel to assist and advise on various regulatory, legal, tax and commercial aspects of hydrogen and lignin acquisition opportunities.

The increased spending between 2022 Projected and 2023 Forecast is due to the full year salary of the incremental engineering resource hired in 2022 and the full year salary of a new business development professional which FEI expects to hire in 2023. The new business development professional will work on a range of activities, including providing support to Indigenous groups on the evaluation of new forms of renewable gas such as hydrogen. The salaries for these new resources are fully loaded salaries, which includes base salary, benefits, concessions, etc. based on an average salary within a specified band.

13.2 Please elaborate on how the internal resources will work with Indigenous groups on the evaluation of opportunities.

13.2.1 Please discuss the specific consultations FEI has already conducted with Indigenous groups as it relates to the production of renewable gases in their communities and the opportunities identified.

Response:

FEI has not yet commenced work with Indigenous groups as it relates to the production of other forms of renewable gases in their communities. As stated in the response to BCUC IR1 13.1, FEI intends to hire a qualified business development professional resource in 2023 that will work on a range of renewable gas development activities, including providing support to Indigenous groups on the evaluation of new forms of renewable gas such as hydrogen, syngas and lignin. FEI expects that up to 20 percent of this resource’s time will be committed to engaging in work with Indigenous groups and is expected to be similar to the engagement FEI’s Renewable Gas team currently undertakes with Indigenous groups related to RNG (biomethane) opportunities. These current engagement activities include:

- Providing expertise during initial feasibility and guidance on potential RNG opportunities;
- Assisting Indigenous development corporations to communicate the benefits of RNG projects to Chief, Council, and their communities; and
- Engaging in consultations for any permitting required for RNG project development.

G. RATE BASE

14.0 Reference: RATE BASE

Exhibit B-2, Section 7.2.1.1, pp. 58–59

Sustainment Capital

On page 58 of the Application, FEI states that its Updated Forecasts for sustainment capital have increased by $9.423 million in 2023 and $5.845 million in 2024 compared to the Original Forecasts. FEI explains that these increases are primarily in the Transmission System Reliability & Integrity portfolio and the Distribution System Integrity portfolio.

Further, on pages 58 and 59, FEI states that the drivers of the increases in 2023 and 2024 Sustainment Capital Expenditures in the Transmission System Reliability & Integrity and the Distribution System Integrity portfolios can be summarized as follows:

- Significant inflationary increases brought on by unanticipated events such as the COVID-19 pandemic and the war in Ukraine, which have resulted in large cost escalations in materials, labour and fuel;
- Alteration activities driven by various large third-party infrastructure upgrade projects that have received funding from various levels of government as part of the COVID-19 pandemic economic recovery efforts; and
- Additional reliability and integrity projects being required that were not anticipated at the time of the MRP proceeding.

14.1 Please provide a breakdown of the increases in FEI's 2023 and 2024 Sustainment Capital Expenditures in the Transmission System Reliability & Integrity and the Distribution System Integrity portfolios by each of the three major drivers listed in the preamble (inflationary pressures, increased alteration activities, new reliability and integrity projects).

<u>**Response:**</u>

FEI is unable to provide the requested breakdown, as these factors impact FEI's specific projects and programs differently and, due to the large number of individual projects which FEI undertakes annually (including the projects and activities within FEI's various sustainment programs), FEI is unable to specifically assign a value to each of the pressures described in the Application. FEI continually manages a portfolio of approximately 1,500 to 2,000 active sustainment capital projects at various stages of the project lifecycle (from initial development through to project closing). FEI provides below some discussion around each of the three drivers listed in the preamble.

<u>Item #1: Inflationary Increases</u>

The 2023 and 2024 Updated Forecasts were not developed by applying a blanket escalation factor from the Original Forecasts or from prior years' capital expenditure levels to account for inflationary pressures. The 2023 and 2024 Updated Forecasts, which include individual projects (single-year and multi-year projects) as well as ongoing programs, were developed using the most recent pricing that is available to FEI, such as current contractor pricing or recent bid pricing for similar work. The prices received for projects vary depending on the scope and project category. Additionally, while the prices include consideration of current inflationary pressures, FEI does not have visibility into the extent that inflationary pressures have impacted the overall pricing. For instance, the contractor hourly rates or the recent bid pricings would not normally have a separate line item for inflationary pressures. Inflationary pressure is also not tracked separately for projects that are currently in execution. For example, project managers are required to submit change controls throughout the execution stage of individual projects such that the most recent information is available for the purpose of forecasting future costs; however, these change controls are not categorized for inflation.

Item #2: Alteration Activities and Item #3: New Reliability and Integrity Projects

Table 1 below shows the increases due to (1) increased alteration activities driven by third-party infrastructure projects and (2) new reliability and integrity projects (i.e., projects that were not included in the Original Forecasts) that have an estimated cost of $2 million or above. FEI notes that, as highlighted above, the cost estimates for these new alterations or new projects would have the increases due to inflationary pressures embedded and FEI is unable to provide a further breakdown of these new alteration/projects for inflation. In contrast, the cost estimates of sustainment capital projects in the Original Forecasts provided in the 2020-2024 MRP Application included an annual inflation of two percent. As these forecasts were developed in 2019 (i.e., at the time of the MRP Application), FEI did not have information to develop individual project-specific inflationary increases for projects anticipated in the 2023-2024 timeframe; therefore, FEI applied a two percent inflation factor to its overall sustainment capital portfolio for 2023 and 2024. However, for the new and updated sustainment capital projects in this Application, inflationary pressures have been incorporated at a project specific level using the most recent pricing such as current contractor rates as well as recent bid results for similar work, as explained above.

Table 1: 2023 and 2024 Forecast Increases to Sustainment Capital due to Alteration Activities and New Reliability and Integrity Projects

	2023 Forecast	2024 Forecast
1) Increase due to Alteration by Third-Party Infrastructure Activities[1, 2]	$9.690 million	$11.902 million
2) Increase due to New Projects (i.e., not part of the original forecast) that are over $2 million[3]	$9.920 million	$16.217 million

Notes to Table:

1. The increases shown above do not include the offset/savings in costs due to deferred or cancelled projects, or changes in scope in other categories of work throughout the sustainment capital portfolio.
2. Includes two third-party alteration projects that are over $2 million, both of which are also listed in Appendix C2 of the Application:
   - Highway 97 Quesnel River Bridge Crossing; and
   - Highway 11 Main Alteration – 3rd Party Alteration.

3. Please refer to Appendix C2 of the Application for the list of individual new projects that are over $2 million. Please also refer to Table 2 below for additional detail on these individual projects that are considered "New" (i.e., not part of the Original Forecasts) and over $2 million.

Table 2 below provides further details for the projects listed in Appendix C2 of the Application, including a comparison between the Original Forecasts provided in the 2020-2024 MRP Application and the Updated Forecasts, with identification of whether the project was new (not included in the 2020-2024 MRP Application) or deferred, as well as the percentage increase in costs by project.

Table 2: Summary of Sustainment Capital by Project Basis (Over $2 million) between the Original Forecast (MRP Application) and the Updated Forecast (2023 Annual Review)

	Portfolio	Forecast	2020	2021	2022	2023	2024	Total	Change
Transmission System Reliability & Integrity									
Grand Forks to Trail 273 Pipeline Alteration	Pipeline Alterations	MRP	3,480	109	-	-	-	3,589	54% Increase
		2023 AR	350	5,094	70	-	-	5,514	
V1 Compressor Unit 1, 2 & 3 Engine Overhaul	Compressor Unit Overhauls	MRP	-	278	2,468	2,435	2,708	7,889	Deferred
		2023 AR	-	-	-	-	-	-	
TIlbury LNG Air Cooler Upgrade	LNG Plant Alterations	MRP	-	-	-	3,184	-	3,184	Cancelled
		2023 AR	-	-	-	-	-	-	
5 Year Turnaround at Tilbury LNG Expansion	LNG Plant Alterations	MRP	-	-	612	1,873	-	2,485	75% Increase
		2023 AR	-	120	4,194	50	-	4,364	
Huntingdon to Nichol In Line Inspection	Pipeline Inspections	MRP	-	-	-	2,760	-	2,760	65% Decrease
		2023 AR	-	-	-	940	-	940	
V1 Compressor Unit 1, 2 & 3 Emissions Reduction to 15 PPM	Compressor Unit Overhauls	MRP	-	-	-	-	-	-	New
		2023 AR	-	10	70	2,090	10	2,180	
V3 Compressor Engine Overhaul	Compressor Unit Overhauls	MRP	-	-	-	-	-	-	New
		2023 AR	-	-	5	2,023	12	2,040	
Savona Compressor Fire Protection	Compressor Station Alterations	MRP	-	-	-	-	-	-	New
		2023 AR	-	15	51	51	1,968	2,085	
River Road Valve Assembly - New Valve & Automation	Pipeline Alterations	MRP	-	-	-	-	-	-	New
		2023 AR	70	240	45	615	3,325	4,295	
Savona to Vernon 323 Pipeline SN-1-1 Valve Assembly Upgrade	Pipeline Alterations	MRP	-	-	-	-	-	-	New
		2023 AR	-	50	5	520	1,763	2,338	
Lantzville New TP / DP Station	Pipeline Station Alterations	MRP	-	-	-	-	-	-	New
		2023 AR	-	115	900	1,401	3,480	5,896	
Distribution System Reliability									
240 St & 102 Ave Station - Insufficient Capacity	Distribution Station Alterations	MRP	260	2,184	78	-	-	2,522	Deferred
		2023 AR	-	-	-	-	-	-	
		MRP	-	53	2,351	-	-	2,404	Deferred

	Portfolio	Forecast	2020	2021	2022	2023	2024	Total	Change
SI - 1850m x 168 IPST McLeod	Distribution System Capacity Alterations	2023 AR	-	-	-	-	-	-	
SI - 1300m x 323 IPST Riverside	Distribution System Capacity Alterations	MRP	-	-	-	51	3,536	3,587	Deferred
		2023 AR	-	-	-	-	-	-	
Penticton Second Supply	Distribution Stations NEW	MRP	2,100	-	-	-	-	2,100	148% Increase
		2023 AR	12	6	130	300	4,750	5,198	
Bradner & Downes New District Station	Distribution Stations NEW	MRP	-	-	-	-	-	-	New
		2023 AR	-	65	130	200	2,429	2,824	
Richmond IP River Road to Cambie Rd Capacity Upgrade	Distribution System Capacity Alterations	MRP	-	-	-	-	-	-	New
		2023 AR	280	33	115	200	3,200	3,828	
Distribution System Integrity									
NW Kamloops Secondary Supply	Distribution Main Alterations	MRP	-	-	542	3,315	11	3,868	Deferred
		2023 AR	-	-	-	-	-	-	
Main Renewal - Moncton Street, Richmond	Distribution Mains Renewal	MRP	-	-	-	-	-	-	New
		2023 AR	24	240	2,260	140	-	2,664	
Second Narrows Shorted Flange Upgrade	Distribution System Cathodic Protection	MRP	-	-	-	-	-	-	New
		2023 AR	27	212	655	2,680	30	3,604	
Highway 97 Quesnel River Bridge Crossing Replacement	Distribution Mains Alterations	MRP	-	-	-	-	-	-	New
		2023 AR	-	10	255	104	2,784	3,153	
Highway 11 Main Alteration - 3rd Party Alteration	Distribution Main Alterations	MRP	-	-	-	-	-	-	New
		2023 AR	-	42	4,044	10	-	4,096	

15.0 Reference: RATE BASE

Exhibit B-2, Appendix C2, Section 3, pp. 1–4

Sustainment Capital – Transmission System Reliability & Integrity – Lantzville New TP / DP Station

On page 1 of Appendix C2 to the Application, FEI states:

> The Transmission System Reliability & Integrity capital category includes activities related to the ongoing safe and reliable operation of the transmission system. The main areas of expenditure under this category include:
>
> - Pipeline alterations to mitigate the threat of natural hazards, comply with codes and standards, and facilitate maintenance and inspections;
> - Alterations to transmission facilities, including pressure control, compression, and LNG to ensure safe, reliable, and efficient operation; and
> - Pipeline major inspections including inline inspections and marine crossing inspections.

Table C2-2 on page 2 of Appendix C2 to the Application, titled "Updated FEI Transmission System Reliability & Integrity Capital Expenditures on Projects Greater than $2 million ($000s)," includes the Lantzville New TP / DP Station project.

On page 4 of Appendix C2 to the Application, FEI provides the following description of the Lantzville New TP / DP Station project:

> **Lantzville New TP / DP Station**: Development within the Lantzville area of Nanaimo is currently expanding, and developers have plans to install a total of 750 residential units. FEI has determined that a new TP/DP station is required to supply the community due to additional loads. The new station will also address tail end pressure on the Northwest side of Nanaimo, provide alternative pressure sources to the system, and reduce the need for IP [Intermediate Pressure] looping within Nanaimo. The estimated cost of this project is $6 million with spending primarily in 2023 and 2024.

15.1 Please provide FEI's rationale for including the Lantzville TP / DP Station project under the Transmission System Reliability & Integrity capital category given the preamble above that the new TP/DP station is required to supply new load.

15.1.1 Please explain how this project relates to the ongoing safe and reliable operation of FEI's transmission system.

Response:

The Lantzville TP / DP Station project is a sustainment capital project, and it would not be appropriate to include the project within growth capital. As described in the 2020-2024 MRP Application (pages C-56 and C-57), FEI's growth capital includes four categories: (1) New

Customer Mains, (2) New Customer Services, (3) New Customer Meters, and (4) System Improvements (DP). These categories of growth capital (and the associated capital expenditures) were approved to form the Base Growth Capital for the MRP term[5]. The Lantzville project does not fall under any of the four growth capital categories and is therefore appropriately considered a sustainment capital project, despite it supporting additional load.

This project relates to the ongoing safe and reliable operation of FEI's transmission system as it requires the installation of significant, additional pressure control equipment and facilities that are necessitated by the Vancouver Island high-pressure transmission system.

Historically, when there were separate transmission and distribution companies operating on Vancouver Island, the transmission company would install a custody transfer/pressure control station as part of its transmission system. Then, downstream of that station, the distribution company would install a second pressure control station as part of its distribution system.

Now, with only one company operating the natural gas system, a single station is proposed with the two pressure reductions being on the same site. The installation of the Lantzville TP/DP Station is proposed as one project for efficiency; however, the expenditures will settle to different asset classes based on their location within the station. Since the project involves pressure control equipment to address the high-pressure transmission system it was decided to locate the project within Transmission System Reliability & Integrity capital.

[5] MRP Decision and Order G-165-20, p. 122.

16.0 Reference: RATE BASE

Exhibit B-2, Appendix C2, Section 5, pp. 6–7

Sustainment Capital – Distribution System Integrity – Second Narrows Shorted Flange Upgrade

On page 6 of Appendix C2 to the Application, FEI states: "Distribution System Integrity expenditures consist primarily of main and service alterations and replacements due to condition or at the request of third parties."

Table C2-7 on page 7 of Appendix C2 to the Application, titled "Updated FEI Distribution System Integrity Capital Expenditures on Projects Greater than $2 Million ($000s)," includes the Second Narrows Shorted Flange Upgrade project.

On page 7 of Appendix C2 to the Application, FEI provides the following description of the Second Narrows Shorted Flange Upgrade project:

> **Second Narrows Shorted Flange Upgrade**: A pair of isolating flanges on the IP pipeline feeding North Vancouver and West Vancouver at the south abutment of the Second Narrows Bridge have shorted, resulting in a section of pipeline no longer receiving adequate cathodic protection. This IP pipeline is the sole gas supply to customers on the North Shore. The recommended solution is to remove and replace a short spool of piping at the south abutment. Cathodic protection will be reinstalled. Due to suspected corrosion issues at the existing anchor block at the location, the construction work will additionally install a new anchor block downstream of the current location. Significant site preparation will be required to provide adequate site access for the personnel and equipment required to complete mechanical construction activities. The IP pipeline will be locally isolated, and a bypass tool will be installed to maintain gas flow during construction. The estimated cost of this project is approximately $3.6 million, with the majority of expenditures occurring in 2023.

16.1 Please provide details of the condition of the section of pipe that FEI intends to remove and replace.

<u>Response:</u>

The Second Narrows Shorted Flange Upgrade will remove and replace approximately 9 metres of pipe to reinstate adequate cathodic protection (CP) on the IP pipeline feeding North Vancouver and West Vancouver. The 9 metres of pipe slotted for replacement includes a failed isolating flange, as well as a concrete anchor block.

The isolating flange is used to isolate the above ground piping from the below ground piping by stopping the CP current from crossing the flange. Since it has shorted, CP is being drained to the bridge, leaving the below ground pipe with inadequate CP. The anchor block contains rebar that is suspected to be in contact with the pipe, which is permitting the CP current to drain from the pipe to the bridge. The 9-metre replacement pipe will include a new monolithic isolation joint in place of the failed isolating flange and a new anchor block reinstating adequate CP to the IP pipeline.

FEI discovered the short in the CP system in 2015 through the annual CP survey. In this survey, inadequate CP levels were measured in the west IP lateral that runs along Kootenay Street from East Pender Street to the Second Narrows Bridge in the City of Vancouver. FEI determined the CP deficiency to be a result of a short in the isolation flanges at the Second Narrows Bridge. It was suspected this short was accompanied by other shorted locations, including the concrete anchor block at the south abutment, which is causing the pipeline CP to drain to the bridge, causing inadequate levels of CP.

In the intervening period to the implementation of this project, the following mitigation efforts have been implemented:

- In 2017, FEI installed an Anode Bed on the IP lateral to assist in the protection of this section of pipeline. This aided but did not fully repair the low CP levels.
- In December 2021, FEI Corrosion Control undertook a close interval survey (CIS) along the impacted length of the IP pipeline between the Second Narrows Bridge and East Pender Street. The CIS data showed that protection improved in the immediate area around the CP rectifier. The remainder of pipeline is shown to have marginal protection with some extremely low sections. The most severe section is at the north section near the Second Narrows Bridge and towards the south near Hastings Street.
- Following the CIS in December 2021, to rectify the low reading in the south, the CP system of the IP pipeline was tied to another CP system.
- In June 2022, once the adjusted CP system stabilized, FEI Corrosion Control performed another CIS. The CP improved in the IP pipeline, though extremely low sections still remain at the north end near the Second Narrows Bridge.

With all the above mitigations, the short at the bridge is still active.

Also, in 2018, FEI completed a detailed visual inspection of the pipe and crossing in accordance with FEI's five-year bridge crossing maintenance plan. In this 9-metre section of pipe, the report observed localized blistering of the paint indicating corrosion, some surface corrosion of pipe splice welds and surface corrosion on the flanges at ground entry. The 2018 inspection also concluded that the pipeline and supports are in generally good condition with coating deterioration in line with expected rates between inspections. Coating failure is occurring locally with some localized minor corrosion. The pipe is well-aligned on its supports and no adjustments are required. No bridge deficiencies that would compromise the pipe or its supports were identified.

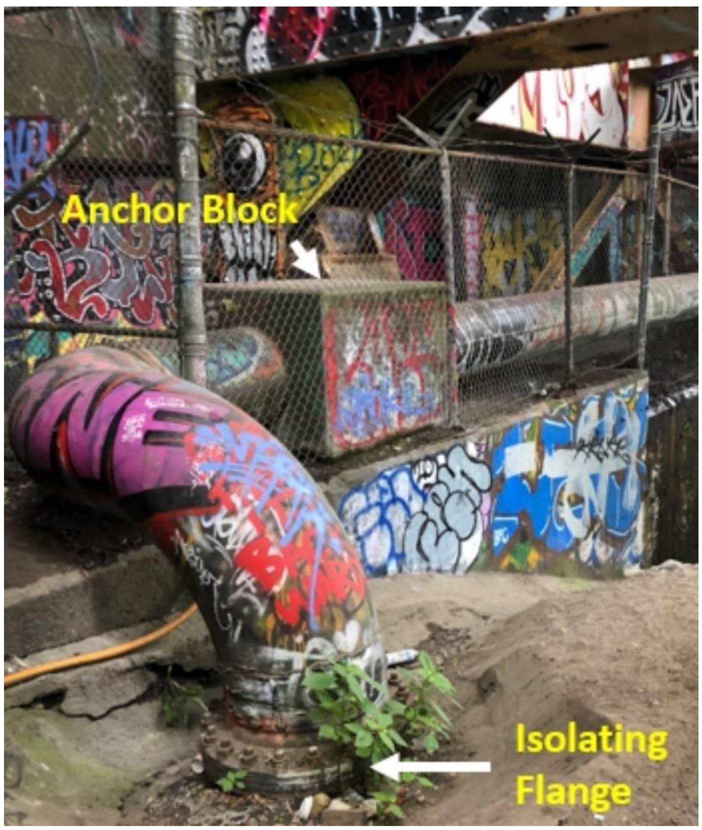
FEI is uncertain of the condition of pipe under the anchor block as this pipeline was not designed to allow the use of ILI tools, and the pipe cannot be visually inspected beneath the concrete. It is highly likely there is a short in the concrete anchor block at the south-east bridge abutment due to a diminishing radio-detection signal at this location. For this to have occurred, either the anchor flange or the pipe must have come into contact with the rebar in the anchor block.

To gain better insight into whether there is a contact path between the pipe and the anchor block rebar, a structural scan was completed in February 2021. The scan was performed on the top, ends and sides of the concrete block and detected the depth and location of the steel rebar, the anchor flange, and the pipe. The scan concluded there is a high probability that rebar is in contact with the pipe.

It was also concluded that if electrical isolation is reinstated prior to the anchor block, either by repairing or replacing the isolating flanges or installing a monolithic isolation joint, there are still potential corrosion issues for the pipeline due to the pipe-rebar contact. The pipe may experience local corrosion if the metals are dissimilar, the environment is corrosive, or there is a grounding path through the abutment. Therefore, the anchor block requires replacement alongside the isolating flange to address the short.

Figure 1 below provides a photograph of the pipe section requiring replacement.

Figure 1: Second Narrows Shorted Flange and Anchor Block Slotted for Replacement



16.1.1 Please explain when and how FEI discovered that this section of pipeline was no longer receiving adequate cathodic protection.

Response:

Please refer to the response to BCUC IR1 16.1.

16.1.2 Please explain why the recommended solution is to remove and replace this segment.

Response:

FEI investigated multiple different repair solutions to remediate the cathodic protection issue at the Second Narrows Bridge, but concluded the only way to ensure adequate CP is to remove the short.

As part of the formal repair investigation, FEI completed a Front-End Engineering & Design (FEED) study which evaluated solutions to remediate the shorted flanges. The recommended solution from the study involves removing and replacing a short spool of piping at the south abutment. FEI concluded that the replacement spool will include the installation of an above-grade monolithic isolation joint (MIJ) as the preferred method of reinstating CP isolation. Due to suspected touch point and corrosion issues at the existing anchor block at the location, it was determined the construction work will remove the existing anchor block and install a new one. Please refer to the response to BCUC IR1 16.1 for details on the investigations completed on the anchor block.

As this IP pipeline is the only source of supply to the North Shore, care was taken during the preliminary design work to ensure any corrective actions would not inadvertently take the pipeline out of service. Repair work on the isolation flange while the pipeline was still in operation was considered, but was ultimately determined to be too risky. If a leak were to occur during the repair operation, the pipeline would need to be shut-in to stop the leak, and supply to the North Shore would be lost. A double stop-off and bypass operation was determined to be necessary to repair the CP short while still ensuring supply to the North Shore. The double stop-off and bypass operation makes up a large portion of the cost and complexity of the project. Since this section of the pipeline is to be isolated, it is prudent to choose the repair method that provides the best long-term protection to the pipeline. Replacing the isolating flanges with a MIJ was preferred as MIJ fittings are less likely to short than isolating flanges. This decreases the likelihood that FEI will need to perform a similar replacement operation again in the future.

Leaving the CP short in place while mitigating its impact was also considered, but was ultimately rejected, as mitigation methods cannot adequately protect the pipeline. The only way to ensure adequate CP is to remove the short.

16.2 Please confirm whether a recent inspection on the pipeline under the Second Narrows Bridge, including the bridge and pipe hangers, has been conducted.

16.2.1 If confirmed, please discuss the overall condition of the pipeline based on recent inspection results.

16.2.2 If not confirmed, please explain when the pipeline was last inspected.

Response:

Please refer to the response to BCUC IR1 16.1.

16.3 Please provide details of the corrosion issue at the existing anchor block, including when and how FEI discovered this issue.

Response:

Please refer to the response to BCUC IR1 16.1.

16.4 Please describe the site preparation required to provide adequate site access for the personnel and equipment to complete the Second Narrows Shorted Flange Upgrade project.

Response:

Due to the presence of a steep slope, the existing site is not suitable to provide access for the personnel and equipment required to complete the mechanical scope, necessitating civil works to safely access the work location. FEI engaged a qualified engineering firm to complete a feasibility study for the civil design. A geotechnical study was completed at the same time to better understand the anticipated ground conditions at the site in support of the civil design of the site access works.

The key objectives of the civil design are to: provide an access road and safe working area for an excavator and personnel at the existing flanges location, provide a work pad for laydown of the equipment, and provide a crane pad for placement of the crane and outriggers for installation of the isolation device. The design must also accommodate many constraints, including avoidance of third-party infrastructure such as the Second Narrows Bridge itself, avoidance of construction within City of Vancouver Parks Land and CP Railway Statutory Right of Way (SRW), and minimizing cut and fill quantities.

The selected option involves widening the existing access path leading from the Bridgeway Access Road up to the flange location. A double level working area will be constructed adjacent to the flange, designed to minimize excavated material; the upper level will create the work pad, and the lower level will provide an area for an excavator to be positioned to assist in the installation of the replacement spool. The elevation of the lower level has been optimized to allow the crane arm sufficient clearance to work under the lowest bridge chord. The placement of the crane outriggers identified in the conceptual lifting plan has been optimized in conjunction with the civil design.

A large overhanging tree close to the work site will be removed and the embankment cut back for the safety of personnel. Simple retaining structures such as lock-block walls are proposed to be utilized in areas for slope stability. This work will allow personnel and equipment access to the south abutment at ground level on the seaward side of the abutment. Current access from above is via a walking path while access from the bottom is via a condemned access road.

16.5 Please provide details of any other integrity projects or system improvements related to the Second Narrows Bridge pipeline segment currently being considered by FEI, including project overview, timing, anticipated cost and impact or implications on the Second Narrows Shorted Flange Upgrade project.

Response:

FEI currently has one project related to the Second Narrows Shorted Flange upgrade, called the “Second Narrows Bridge - Remove Insertion Meter”. FEI plans to complete this project at the same time as the Second Narrows Shorted Flange Upgrade project to utilize equipment, material and labour already on site.

The scope of the “Second Narrows Bridge - Remove Insertion Meter” includes the removal of the old meter and platform, as well as installing an encirclement fitting over the insertion meter valve body. When FEI relocated the telemetry equipment away from this location, an insertion meter, platform, and cage were left behind due to difficulties mobilizing equipment to site. When the insertion meter is removed, the valve body remains as a potential leak point. To permanently remove the potential leak point, an encirclement tee is required to encase the insertion meter valve.

In order to install an encirclement fitting over the insertion meter valve body, FEI will utilize the heavy equipment that will be in place for the shorted flange work. The total project costs for the “Second Narrows Bridge - Remove Insertion Meter” are estimated at $288 thousand, with $100 thousand forecast for 2023 and the remainder forecast for 2024.

16.6 Please provide FEI's rationale for including the Second Narrows Shorted Flange Upgrade project under the Distribution System Integrity capital category and not the Transmission System Reliability & Integrity capital category.

Response:

The pipeline that the isolating flanges are located on is designated as an Intermediate Pressure pipeline or IP pipeline. CSA Z662:19 oil and gas pipeline systems requirements classify a distribution pipeline as "main and service lines, and their associated control devices, through which gas is conveyed from transmission lines or from local sources of supply to the termination of the operating company installation." As well, these lines must operate at a hoop stress of less than 30 percent of the specified minimum yield strength of the pipe.

Since this IP pipeline meets the above-described requirements, it is appropriately classified as a distribution line and the project is appropriately included under the Distribution System Integrity capital category.

17.0 Reference: RATE BASE

Exhibit B-2, Appendix C2, Section 5, p. 7

Sustainment Capital – Distribution System Integrity – Highway 97 Quesnel River Bridge Crossing Replacement

On page 7 of Appendix C2 to the Application, FEI provides the following description of the Highway 97 Quesnel River Bridge Crossing Replacement project:

> **Highway 97 Quesnel River Bridge Crossing Replacement**: The Ministry of Transportation and Infrastructure has informed FEI that the Quesnel River Bridge on Highway 97 will be replaced. A 2020 inspection of the bridge has identified that the pipe wall thickness is deteriorating rapidly, and that the pipe hangers are in poor condition. FEI is planning to replace the existing bridge crossing with a horizontal directional drill crossing. The estimated cost of this project is approximately $3.2 million, with the majority of expenditures forecast in 2024.

17.1 Please explain why FEI is planning to replace the existing bridge crossing with a horizontal directional crossing instead of a replacement bridge crossing.

<u>Response:</u>

The Ministry of Transportation and Infrastructure (MOTI) Utility Policy Manual states that pipeline installations will only be allowed on new MOTI structures with approval of the chief engineer, when alternative crossing methods such as the horizontal directional drill (HDD) method are proven to not be feasible. In order to install a new on-bridge crossing in the future, FEI would need to conduct an analysis of an HDD crossing to demonstrate to MOTI that alternative crossing methods (including HDD) have been properly explored and deemed infeasible. If an HDD crossing is deemed feasible, FEI expects that MOTI would not approve a new on-bridge crossing. FEI has not ruled out the feasibility of an HDD crossing, and therefore has assumed (in the absence of information indicating otherwise) that an HDD crossing would be the method of construction for this project. As further geotechnical and feasibility assessments are completed, FEI will update the construction plan and forecasts accordingly.

In August of 2022, after this Application was submitted, MOTI provided an update to FEI that the Quesnel North-South Interconnector project, including replacement of the Quesnel River Bridge, had been placed on hold as the Province works to address infrastructure projects stemming from the fall 2021 floods. At this time, FEI does not have a firm date from MOTI for the replacement of the Quesnel River Bridge. In light of this recent development, FEI is reassessing the plans for replacing this crossing, and investigating a number of options for this location including rehabilitation options that may extend the life of the pipe on the bridge until such a time that MOTI is able to complete the Quesnel North-South Interconnector project. Recent assessments have identified that the pipe wall thickness is deteriorating rapidly, and the existing pipe hangers are in poor condition. It is expected that the existing crossing will require an intervention in the near future, and FEI cannot wait until such a time that MOTI is able to complete their project. As part of this reassessment, FEI will look to select a preferred alternative that minimizes the overall project cost.

Should the sustainment funding requirements for this project change during the remainder of the MRP term (either an increase or decrease in funding requirements) FEI will manage these changes within its overall sustainment capital budget in accordance with FEI's Asset Investment Planning (AIP) process. FEI allocates its limited sustainment capital funds in an optimized, risk-informed manner and would re-allocate funds to or from this project based on FEI's process and Value Framework (outlined in Section 3.2 of the 2020-2024 MRP Application). Please also refer to the response to RCIA IR1 5.1 for additional details on this process.

17.2 Please discuss the Ministry of Transportation and Infrastructure's target date for replacement of the Quesnel River Bridge on Highway 97.

Response:

Please refer to the response to BCUC IR1 17.1.

17.2.1 Please discuss the timing for the removal of the gas line from the existing Highway 97 Quesnel River Bridge.

Response:

If FEI proceeds with an HDD, the existing line will be removed from service when the new line is commissioned in 2024 or 2025. As explained in the response to BCUC IR1 17.1, FEI does not have a firm date from MOTI for the replacement of the Quesnel River Bridge. FEI has not yet clarified with MOTI whether the decommissioned line will be required to be removed from the bridge. FEI will confirm removal scope requirements with MOTI as the project progresses.

17.2.2 Please explain whether FEI is responsible for the cost to remove the gas line.

17.2.2.1 If yes, please clarify whether the cost to remove the gas line is included in the estimated $3.2 million project cost.

Response:

Based on other comparable bridge removal scopes, FEI currently estimates that if the existing line is removed from the bridge the removal costs that FEI would be responsible for would be around $500 thousand. These costs are not included in the $3.2 million project cost because the removal costs are charged to FEI's Net Salvage Provision (deferred charges) and not to sustainment capital.

17.3 Please explain whether FEI engaged an independent engineering firm to assess the feasibility of a horizontal drill crossing.

17.3.1 If yes, please describe the engineering firm's relevant qualifications and experience. Please also provide the independent engineer's scope of work on this project.

17.3.2 If not, please explain why not.

Response:

Yes, FEI has engaged CCI Solutions, an independent engineering firm, to assess the feasibility of HDD. Please refer to the response to BCUC IR1 17.1 for information on the necessity of the geotechnical investigations. CCI Solutions is conducting an independent review of the feasibility of the HDD crossing. The timeline of this review is uncertain in light of MOTI's Quesnel North-South Interconnector project being placed on hold (please refer to the response to BCUC IR1 17.1). CCI's scope of work includes drilling, sampling, and lab testing of four borehole locations supporting two separate HDD alignment options, as well as a summary report that provides recommendations for HDD design and construction.

CCI is a leading expert in HDD, Open-Cut, and Micro-Tunnelling methods. Since 2004, CCI has been a driving force in the continued advancement of trenchless pipeline systems and employs proven methods for tackling difficult river, road, and utility crossings. CCI provides award winning, highly technical services to the pipeline, oil & gas, and municipal infrastructure sectors, including Engineering Solutions, Construction Management, Environmental and Geotechnical Services, and Forestry Services. CCI has assisted FEI with the design of many trenchless crossings on similar project scopes in recent years.

18.0 Reference: RATE BASE

Exhibit B-2, Section 7.2.1.2, p. 64, Section 12.2.1, p. 150

Other Capital – Kelowna Space Project

On page 64 of the Application, FEI states:

> FEI continues to experience capacity challenges at numerous locations […] Identifying solutions to address the space constraints has been very challenging, particularly due to the significant escalation in real estate costs to acquire new industrial land in the Kelowna area. However, the companies have now finalized a solution which leverages the use of FEI's and FBC's existing sites and results in the leasing of a new site for FEI's and FBC's Shared Services Departments. […]

On page 150 of the Application, FEI states that "[a]s of July 4, 2022, employees have returned to a primarily office-based work model. Employee-related activities and expenses for business purposes (i.e., travel, accommodation, etc.) have also returned to normal."

18.1 Please clarify whether the lease for the Kelowna Space Project has been signed and the term of the lease.

<u>Response:</u>

Yes, a lease agreement has been executed for the new leased facility that is currently under construction, and that will be the new location for the Kelowna-based Support Services groups. The term of the lease is 10 years and the currently targeted date for commencement of the lease is in the fourth quarter of 2023 based on the current construction schedule.

18.2 Given FEI's statement with respect to the significant escalation in real estate costs in the Kelowna area, please discuss any other alternatives considered by FEI to leasing a new site for FEI's and FBC's Shared Services Departments, such as deferring the solution to address the space constraints to a future time or considering alternatives to employees returning to a primarily office-based work model (e.g. remote or hybrid work models). Please discuss the pros and cons of any alternatives considered and why they were rejected.

<u>Response:</u>

FortisBC considered multiple options to address the space constraints faced by both FEI and FBC in the Kelowna region. The options developed considered the needs of each utility separately as well as the two utilities combined. Upon completion of each area's space program requirements in 2020 (i.e., Gas Operations, Electric Operations and the Shared Services Department), it became clear the office growth for all groups had impacted the ability for the Shared Services Department to remain combined with Operations at one of the existing facilities.

FortisBC has been employing a number of short-term measures to address the space constraints experienced in Kelowna. These measures include removing collaborative spaces like meeting and lunchrooms, and removing closets and storage rooms to create space for workstations. In addition, some employees were relocated to other facilities where possible and appropriate.

These measures are now exhausted as there are no further spaces which can be reallocated to workstations required for further growth. Moreover, the space which has been reallocated is both temporary and suboptimal with regard to working conditions. There is little or no access to natural light and a complete lack of collaborative workspaces critical to employees working on multi-faceted projects. This situation is substandard and is not beneficial to the Company or to customers as it promotes inefficiency, hinders collaborative work, negatively impacts the work culture, and can be challenging for employee recruitment and retention.

With regard to alternatives to employees returning to a primarily office-based work model, such as remote or hybrid models, FortisBC has introduced some flexibility into its working arrangements where appropriate; however, the Company continues to support an office-centric approach to work and places a high value and priority on in-person collaboration. FortisBC realizes that with the shift in the employee market, some flexibility in work arrangements is important, but this flexibility needs to be balanced with the Company's operational requirements and with a focus on enhancing the organizational culture.

The Kelowna Space Project has already factored in the assumption of this flexibility in work arrangements with employees. The Company completed an exercise to understand the impact to the required space program for the selected final solution if a hybrid work program was introduced. Specifically, the hybrid model assumed desk sharing and applied two different ratios of seats to employees (with the exception of field employees) to see the impact on the required seat numbers in correlation to reduced square footage. Providing workstation seats based on a 1:1.2 and 1:1.5 ratio was used to calculate how the workstation count could be decreased.

The prevailing industry recommendation is to increase meeting room ratios when hybrid desk sharing is introduced as the expectation is the employees will be coming into the office to meet with others. Pre-pandemic recommendations were for a meeting room to staff ratio between 1:8 and 1:10. For hybrid work environments, the recommendation has increased to a ratio of 1:6. This increase in meeting room requirements cuts into the square footage that is able to be saved by providing fewer workstations.

The findings from the exercise for the Shared Services Department was a reduction of 500 sq. ft. based on a 1:1.2 ratio and 2,157 sq. ft. for a 1:1.5 ratio. As a result of this exercise, FortisBC reduced the allowed growth space in the space program model which in turn reduced the amount of lease space for the Shared Services Support Hub.

Further, on page 64 of the Application, FEI states:

> […] the Kelowna Space Project is a combined project for FEI and FBC, and the cost of the project has therefore been allocated between the two utilities accordingly. The total cost of the Kelowna Space Project is $13.996 million. Of this total, approximately $10.996 million is allocated to FEI based on employee count, with $6.083 million and $3.913 million reflected in FEI's Updated Forecasts for 2023 and 2024, respectively.
>
> As part of the Kelowna Space Project, both FEI and FBC Shared Services Departments (Support Services) located in Kelowna will relocate to a new office lease facility approximately 25,000 ft2 in size. Tenant improvements will be completed in 2023 […]

18.3 Please confirm whether tenant improvement costs are included in the total cost of $13.996 million for the Kelowna Space Project.

18.3.1 If no, please provide the 2023 forecast tenant improvement costs and clarify how they are captured in the 2023 forecast revenue requirement and the impact on the proposed 2023 delivery rates.

Response:

FEI discovered a typo while responding to this IR. The correct total cost of the Kelowna Space Project is $13.930 million, not $13.996 million. This is only a typo, there is no change to the portion of the project cost allocated to FEI, which remains at $10.996 million, and no impact to the proposed 2023 delivery rate increase.

FEI confirms the tenant improvements costs are included in the total cost of $13.930 million for the Kelowna Space Project.

18.4 Please describe the nature of the tenant improvements, including a breakdown of the costs which are one-time in nature and costs which are expected to continue into the future, if any.

Response:

The tenant improvements to be completed in 2023 as referenced in the preamble above are related to the new leased facility in Kelowna. FEI's portion of the tenant improvement costs are estimated to be $3.25 million, where $2.86 million is estimated for leasehold improvements and $0.385 million for furniture and equipment. FEI notes that, although not identified in the preamble above, there is also approximately $3.06 million of leasehold improvement costs to be incurred by FEI in 2024 for the move to the FBC-owned Benvoulin property. The tenant improvements (including both leasehold improvements and new furniture/equipment) are specific to meeting the space programming requirements of the multiple departments and include, but are not limited to:

- Design and engineering consulting and permitting fees;
- Additions of wall partitions;
- Painting;
- Flooring, lighting, electrical, data and mechanical improvements to suit floor plan layouts;
- Structural improvements for the file room; and
- Furniture and equipment acquisition and installation.

All of the above costs are considered one-time in nature.

While responding to this IR, FEI identified that the $2.86 million of leasehold improvements were incorrectly shown as additions to the asset class 482-20 Masonry Buildings (i.e., Section 11 – Schedule 6.2, Line 14) instead of asset class 482-30 Leasehold Improvement (i.e., Section 11 – Schedule 6.2, Line 15). FEI determined the impact of this change to the proposed 2023 delivery rate increase would be a change from 7.42 percent to 7.43 percent. Given the small impact to the proposed 2023 delivery rate increase, FEI will correct this as part of its Compliance Filing.

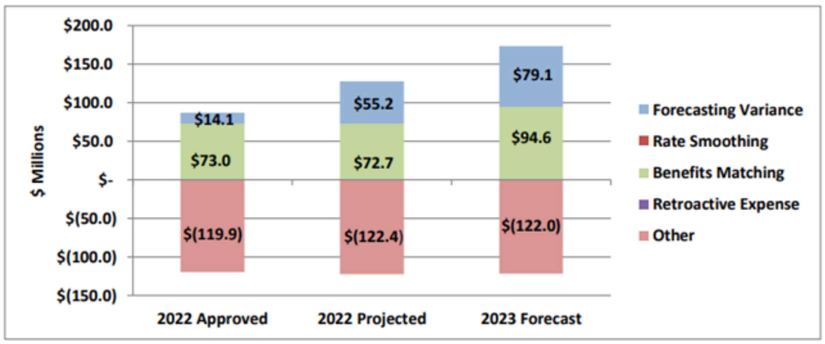
19.0 Reference: RATE BASE

Exhibit B-2, Section 7.5, p. 76

Deferral Account Balances

On page 76 of the Application, FEI provides the following table:

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



19.1 Please provide a breakdown of the Forecasting Variance deferral accounts mid-year balances in Figure 7-1 by account for 2022 Approved and 2022 Projected.

19.1.1 Please explain and provide reasons for the following:

(i) The change in the 2022 Projected Forecasting Variance deferral accounts mid-year balance ($55.2 million) as compared to the 2022 Approved mid-year balance ($14.1 million); and

(ii) The change in the 2023 Forecasting Variance deferral accounts mid-year balance ($79.1 million) as compared to the 2022 Projected mid-year balance ($55.2 million).

Response:

Please refer to the table below for a breakdown of the Forecasting Variance deferral accounts' mid-year balances as included in Figure 7-1 by account for 2022 Approved, 2022 Projected and 2023 Forecast.

Line No.	Particulars	Mid Year Balance ($000s) 2022 Approved	2022 Projected	2023 Forecast	Change 2022 Projected vs 2022 Approved	2023 Forecast vs 2022 Projected
	(1)	(2)	(3)	(4)	(3) - (2)	(4) - (3)
1	Midstream Cost Reconciliation Account (MCRA)	$ (1,796)	$ (39,533)	$ (37,187)	$ (37,737)	$ 2,346
2	Commodity Cost Reconciliation Account (CCRA)	11,780	112,568	135,100	100,788	22,532
3	Revenue Stabilization Adjustment Mechanism (RSAM)	1,922	(25,834)	(31,689)	(27,756)	(5,855)
4	Interest on CCRA / MCRA / RSAM / Gas Storage	(1,542)	(1,184)	859	358	2,043
5	SCP Mitigation Revenues Variance Account	(151)	229	269	380	40
6	Pension & OPEB Variance	3,860	8,600	11,441	4,740	2,841
7	BCUC Levies Variance	19	359	343	340	(16)
8	**Total Forecasting Variance Deferral Accounts**	**$ 14,092**	**$ 55,205**	**$ 79,136**	**$ 41,113**	**$ 23,931**

Explanations for the 2022 Projected versus 2022 Approved and 2023 Forecast versus 2022 Projected balances are as follows:

2022 Projected vs 2022 Approved:

The increase from the $14.092 million 2022 Approved mid-year balance to the $55.205 million 2022 Projected mid-year balance is primarily attributable to the following variances:

- $100.788 million increase in the Commodity Cost Reconciliation Account (CCRA) deferral account mid-year balance. The CCRA deferral account captures the variance between actual gas commodity costs and approved gas commodity costs (i.e., those recovered from customers in rates). The increase is attributable to the following:
  - $26.152 million increase from the 2021 Projected ending CCRA balance to the 2021 Actual ending CCRA balance. At the time of filing the 2022 Annual Review, the 2021 Projected variance additions of actual gas commodity costs to be recovered from customers were $21.839 million before-tax ($15.942 million after-tax) based on the Q2 2021 Gas Cost Report filed with the BCUC. In contrast, the 2021 Actual variance additions of actual gas commodity costs to be recovered from customers were $57.663 million before-tax ($42.094 million after-tax) for the full year 2021; and
  - $74.636 million difference between the mid-year 2022 Approved CCRA after-tax activity of $(23.559) million and the 2022 Projected CCRA after-tax activity of $125.713 million. The net difference in the approved and projected activity is $149.272 million ($23.559 million + $125.713 million), which has an impact of $74.636 million on a mid-year basis ($149.272 million / 2). The increase in the current 2022 Projected ending CCRA activity is mainly attributable to the projected gas commodity costs under-recovery of $172.210 million (before-tax) based on the Q2 2022 Gas Cost Report filed with the BCUC.
- $37.737 million credit increase in the Midstream Cost Reconciliation Account (MCRA) deferral account mid-year balance. The MCRA deferral account captures the variance between actual midstream costs and approved midstream recovery costs (i.e., those recovered from customers in rates). The increase is attributable to the following:
  - $27.090 million credit increase from the 2021 Projected ending MCRA balance to the 2021 Actual ending MCRA balance. At the time of filing the 2022 Annual Review, the 2021 Projected variance additions of actual midstream costs to be returned to customers were $13.345 million before-tax ($9.742 million after-tax) based on the Q2 2021 Gas Cost Report filed with the BCUC. In contrast, the 2021 Actual variance additions of actual midstream costs to be returned to customers were $51.363 million before-tax ($37.495 million after-tax) for the full year 2021. The variance between the 2021 Projected and 2021 Actual related to rider recovery was a minimal amount of $0.909 million debit before-tax ($0.663 million after-tax) to be collected from customers; and

  - $10.647 million credit difference between the mid-year 2022 Approved MCRA after-tax debit activity of $1.197 million and the 2022 Projected MCRA after-tax credit activity of $(20.098) million. The net difference in the approved and projected activity is $21.295 million ($20.098 million + $1.197 million), which has an impact of $10.647 million on a mid-year basis ($21.295 million / 2). The increase in the current 2022 Projected ending MCRA activity is mainly attributable to the projected midstream costs over-recovery of $47.229 million (before-tax) and the current 2022 Projected rider additions of $19.697 million based on the Q2 2022 Gas Cost Report filed with the BCUC.

- $27.755 million credit increase in the Rate Stabilization Adjustment Mechanism (RSAM) deferral account mid-year balance. The RSAM deferral account captures the variances in use rate (GJ per customer) between actual/projected and approved for RS 1, 2, 3, and 23 with the balance being amortized through the RSAM rider recovery. The increase is attributable to the following:

  - $11.977 million credit increase from the 2021 Projected ending RSAM balance to the 2021 Actual ending MCRA balance. Please refer to the response to BCUC IR1 28.3 for the explanation of this change; and

  - $15.778 million credit difference between the mid-year 2022 Approved RSAM after-tax credit activity of $(32.837) million and the 2022 Projected RSAM after-tax credit activity of $(1.281 million). The net difference in the approved and projected activity is $31.556 million ($32.837 million - $1.281 million), which has an impact of $15.778 million on a mid-year basis ($31.556 million / 2). The 2022 gross credit additions of $(43.160) million were projected using actual monthly variances in use rates of RS 1, 2, 3, and 23 up to May 2022 only. The practice of using year-to-date actuals of use rate variances for projecting the current year additions is consistent with past annual reviews. The 2022 Projected RSAM rider recovery of $1.822 million, excluding RSAM interest, was based on a RSAM rate rider of $0.012 per GJ (approved by Order G-366-21) and a projected 2022 demand with actuals up to May 2022 for RS 1, 2, 3, and 23.

2023 Forecast vs 2022 Projected:

The increase from the $55.205 million 2022 Projected mid-year balance to the $79.136 million 2023 Forecast mid-year balance is primarily attributable to the $22.532 million increase in the CCRA deferral account mid-year balance:

The full year impact of the 2022 Projected gross rate base additions to the CCRA. These additions were projected as $172.210 million in the 2022 Projected continuity ($125.713 million after-tax) and the mid-year impact in 2022 is $62.857 million ($125.713 million / 2) compared to the full-year impact of $125.713 million in 2023; partially offset by

The mid-year impact of the 2023 Forecast gross rate base credit additions to the CCRA of $110.478 million ($80.649 million after-tax). The mid-year impact in 2023 is $40.325 million ($80.649 million / 2). The 2023 Forecast variance additions of actual gas commodity costs over-recovery of $110.478 million (before-tax) is based on the Q2 2022 Gas Cost Report filed with the BCUC.

19.2 Please provide a breakdown of the Benefits Matching deferral accounts mid-year balances in Figure 7-1 by account for 2022 Approved and 2022 Projected.

19.2.1 Please explain and provide reasons for the change in the 2023 Benefits Matching deferral accounts mid-year balance ($94.6 million) as compared to the 2022 Projected mid-year balance ($71.7 million).

Response:

Please refer to the table below for a breakdown of the Benefits Matching deferral accounts' mid-year balances, as included in Figure 7-1, by account for 2022 Approved, 2022 Projected and 2023 Forecast.

		Mid Year Balance ($000s)			Change	
Line No.	Particulars	2022 Approved	2022 Projected	2023 Forecast	2022 Projected vs 2022 Approved	2023 Forecast vs 2022 Projected
	(1)	(2)	(3)	(4)	(3) - (2)	(4) - (3)
1	Demand-Side Management (DSM)	$ 234,734	$ 248,373	$ 305,373	$ 13,639	$ 57,000
2	NGV Conversion Grants	6	8	7	2	(1)
3	Emissions Regulations	(2,042)	(15,713)	(14,424)	(13,671)	1,289
4	On-Bill Financing Pilot Program	2	1	1	(1)	-
5	Greenhouse Gas Reduction Regulation Incentives	25,401	24,970	23,330	(431)	(1,640)
6	CNG and LNG Recoveries	(508)	(469)	(593)	39	(124)
7	BCUC Initiated Inquiry Costs	72	120	97	48	(23)
8	2017 Rate Design Application	395	395	132	-	(263)
9	2017 Long Term Resource Plan Application	21	21	-	-	(21)
10	PGR Application and Preliminary Stage Development Costs	479	357	186	(122)	(171)
11	Transportation Service Report	165	121	198	(44)	77
12	2021 Generic Cost of Capital Proceeding	822	421	895	(401)	474
13	2019-2022 DSM Expenditures Application Costs	13	13	-	-	(13)
14	City of Coquitlam Application Proceeding	179	260	65	81	(195)
15	Whistler Pipeline Conversion	5,345	5,344	4,606	(1)	(738)
16	Gas Asset Records Project	728	728	411	-	(317)
17	BC OneCall Project	4	4	-	-	(4)
18	Gains and Losses on Asset Disposition	6,492	6,492	2,505	-	(3,987)
19	Net Salvage Provision/Cost	(201,274)	(201,749)	(243,662)	(475)	(41,913)
20	PCEC Start Up Costs	590	590	546	-	(44)
21	2022 Long Term Gas Resource Plan Application	684	611	950	(73)	339
22	2020–2024 MRP Application	339	339	204	-	(135)
23	City of Surrey Operating Terms Application Costs	17	17	-	-	(17)
24	2021 Renewable Gas Program Comprehensive Review	400	696	1,627	296	931
25	IGU Application and Preliminary Stage Development Costs	(194)	(194)	-	-	194
26	GCU Preliminary Stage Development Costs	-	776	647	776	(129)
27	Transmission Integrity Management Capabilities	-	-	11,344	-	11,344
28	Annual Review of 2020-2024 Rates	152	126	108	(26)	(18)
29	**Total Benefits Matching Deferral Accounts**	**$ 73,022**	**$ 72,658**	**$ 94,553**	**$ (364)**	**$ 21,895**

The increase from $72.658 million in the 2022 Projected mid-year balance to $94.553 million in the 2023 Forecast mid-year balance for the Benefits Matching deferral accounts is primarily attributable to the following variances:

- $57.000 million increase in the Demand Side Management (DSM) deferral account mid-year balance due to:
  - The full year impact of the 2022 Projected gross rate base additions. These additions were projected as $29.933 million in the 2022 Projected continuity ($21.851 million after-tax) and the mid-year impact in 2022 is $10.925 million ($21.851 million / 2) compared to the full-year impact of $21.851 million in 2023;
  - The mid-year impact of the 2023 Forecast gross rate base additions of $59.870 million ($43.705 million after-tax). The mid-year impact in 2023 is $21.853 million ($43.705 million / 2);
  - The 2023 opening balance transfer of $60.954 million from non-rate base to rate base for prior year expenditures has a full year impact on 2023 with no corresponding impact on 2022;
  - The mid-year impact of the 2022 amortization expense of $(31.910) million. The mid-year impact in 2022 is $(15.955) million ($31.910 million / 2) compared to the full-year impact of $(31.910) million in 2023; and
  - The mid-year impact of the 2023 amortization expense of $(41.553) million. The mid-year impact in 2023 is $(20.777) million ($41.553 million / 2).
- $11.344 million increase in the Transmission Integrity Management Capabilities (TIMC) deferral account mid-year balance mainly due to the full-year impact of the $12.604 million transfer of the Coastal Transmission System (CTS) TIMC Project CPCN pre-development and application costs from non-rate base to rate base in the 2023 Forecast, as approved by Order C-3-22;

Partially offset by:

- $41.913 million increase in the Net Salvage Provision/Cost deferral account mid-year balance due to:
  - The full year impact of the 2022 net salvage provision. The net provision was projected as $(57.288) million in the 2022 Projected continuity and the mid-year impact in 2022 is $(28.644) million ($57.288 million / 2) compared to the full-year impact of $(57.288) million in 2023;
  - The mid-year impact of the 2023 Forecast net salvage provision of $(59.870) million. The mid-year impact in 2023 is $(29.935) million ($59.870 million / 2);
  - The mid-year impact of the 2022 Projected removal costs of $16.157 million. The mid-year impact in 2022 is $8.079 million ($16.157 million / 2) compared to the full-year impact of $16.157 million in 2023; and

- The mid-year impact of the 2023 Forecast removal costs of $17.174 million. The mid-year impact in 2023 is $8.587 million ($17.174 million / 2).

20.0 Reference: NEW DEFERRAL ACCOUNTS

Exhibit B-2, Section 7.5.1, pp. 77–78

Gibsons Capacity Upgrade (GCU) Preliminary Stage Development Costs Deferral Account

On page 77 of the Application, FEI states that it has incurred preliminary stage development costs that total $0.978 million pre-tax for the GCU project. FEI states:

> FEI is now seeking approval within this Annual Review, the proceeding where approval of the project is being requested, for the rate base GCU Preliminary Stage Development Costs deferral account with a three-year amortization period. FEI believes a three-year amortization period is appropriate <u>as it is consistent with the recovery period of other similar preliminary stage development cost deferrals</u> and serves to mitigate the rate impact to customers. [Emphasis added]

On page 78 of the Application, FEI states, "[t]he term of the account encompasses the preliminary stage and subsequent amortization period, equivalent to the term of the benefit."

20.1 Please provide a breakdown of the $0.978 million preliminary stage development costs for the GCU Project.

<u>Response:</u>

Please refer to the table below for the breakdown of the $0.978 million preliminary stage development costs for the GCU Project.

Preliminary Stage Development Costs	$000s
Engineering	
Design	$ 427
Geotechnical	82
Project Services	
Archaeological & Environmental	$ 99
Communications & Relations	25
Project Management	278
Property Services	15
Regulatory & Permitting	49
Other	3
Total	**$ 978**

20.2 Please explain why a three-year amortization period for the proposed GCU Project Preliminary Stage Development Costs Deferral Account is appropriate within the context of the GCU project and the term of the benefit.

Response:

FEI considered amortization periods ranging from one year to five years, but ultimately determined that three years was the most reasonable. As Table 1 below shows, the only amortization period with a noticeable rate impact is one year, so that option was rejected. FEI also rejected amortization periods of greater than three years as, given the size of the deferral account balance and the impact of the resulting annual amortization expense on the annual delivery rates, a longer amortization period was deemed unnecessary.

FEI further considered the construction timeline of the GCU project and determined that an amortization period of three years aligns well with the remaining three-year construction period of the project from 2022 to 2024 as shown in Table 7-13 of the Application. This consideration was noted as important by the BCUC in its recent decision on FEI's Coastal Transmission System – Transmission Integrity Management Capabilities (CTS TIMC) project. As part of Decision and Order C-3-22, the BCUC directed FEI to amortize the balance of the TIMC Development Cost deferral account, which captured the application and preliminary stage development costs of the CTS TIMC Project, over a five-year period. On page 46 of the decision, the BCUC stated:

> "Based on the evidence provided, the Panel finds that the levelized annual impact over five-years is reasonable as it more closely matches to FEI's EMAT ILI run interval period, <u>aligns with the five-year construction period of the Project</u>, and <u>allows for a smoothing of rates</u>." [Emphasis added.]

The proposed three-year amortization period for the GCU Preliminary Stage Development Costs deferral account achieves both alignment with the GCU project's construction period and some degree of rate smoothing.

Please refer to Table 1 below which shows the delivery rate impact as well as the changes to the proposed 2023 delivery rate increase of 7.42 percent if the amortization period for the GCU Preliminary Stage Development Costs deferral account is changed to one year, two years, four years, or five years.

Table 1: Delivery Rate Impact and Changes to Proposed 2023 Delivery Rates for One to Five Year Amortization Periods for the GCU Preliminary Stage Development Costs Deferral Account

	Amortization Period				
	1 Year	2 Years	3 Years	4 Years	5 Years
Annual Delivery Rate Impact to 2022 Approved (%)	0.113%	0.060%	0.042%	0.033%	0.027%
Changes to Proposed 2023 Delivery Rate Increase (%)	0.071%	0.018%	0.000%	-0.009%	-0.014%
Proposed 2023 Delivery Rate Increase (%)	7.49%	7.44%	7.42%	7.41%	7.40%

20.3 Please discuss whether any alternative amortization periods were considered by FEI.

20.3.1 If yes, please discuss these the pros/cons of the alternatives, including why they were rejected.

20.3.2 If no alternatives were considered, please discuss why not.

Response:

Please refer to the response to BCUC IR1 20.2.

20.4 Please provide the delivery rate impact and pros/cons of the GCU Preliminary Stage Development Costs deferral account for the following amortization periods: (i) one year; (ii) two years; and (iii) five years.

Response:

Please refer to the response to BCUC IR1 20.2.

21.0 Reference: RATE BASE

Exhibit B-2, Section 7.5.2.1, pp. 80–81, 83

COVID-19 Customer Recovery Fund Deferral Account

On pages 80 to 81 of the Application, FEI provides continuity schedules for the 2020 and 2021 Actual, 2022 Projected and 2023 Forecast for each of the three items approved by Order G-132-20 for inclusion in the COVID-19 Customer Recovery Fund Deferral Account:

(i) Bill payment deferral amounts (Table 7-16);

(ii) Bill credits amounts (Table 7-17); and

(iii) Unrecoverable revenue amounts (Table 7-18).

On page 81 of the Application, FEI explains that the unrecoverable revenue portion of the COVID-19 Customer Recovery Fund Deferral Account "represents the amount of customer balances owing (i.e., accounts receivables) that are recognized as unrecoverable due to the COVID-19 pandemic. As such, these amounts are in excess of the normal course forecast bad debt expense that is recognized in index-based O&M."

Related to unrecoverable revenues, in Footnote 57 on page 81 of the Application, FEI states:

> The actual 2020 unrecoverable revenue additions of $0.088 million consist of $0.004 million of small commercial customer balances and $0.084 million of residential customer balances. The actual 2021 unrecoverable revenue additions of $0.196 million consist of $0.009 million of small commercial customer balances and $0.187 million of residential customer balances.

21.1 Please explain and provide a breakdown of the 2022 Projected unrecoverable revenue additions ($0.975 million in Table 7-18) similar to that provided in Footnote 57 on page 81 of the Application. As part of the response, please discuss the driver(s) related to each of the small commercial customer and residential customer additions and explain FEI's forecast methodology for each.

<u>Response:</u>

The 2022 Projected unrecoverable revenue additions of $0.975 million consist of $0.097 million of small commercial customer forecast balances and $0.878 million of residential customer forecast balances.

The forecast addition of $0.975 million for 2022 to the COVID-19 Customer Recovery Fund Deferral Account was based on the number of total customers with past due balances as of March 1, 2022, and findings from the pilot project completed in 2021. During the pilot, customers with past-due balances were contacted to determine whether the COVID-19 pandemic had influenced their ability to pay their outstanding balances. Of the customers contacted, 15 percent confirmed that they were financially impacted by COVID-19 and will require support to bring their accounts into good standing. These customers, of which approximately 90 percent are residential customers, had an average outstanding balance of $550.

Please refer to the table below for the detailed calculation:

Line	Particulars			Notes
1	Total Customers Past Due at March 1, 2022		12,400	
2	Estimated Percentage Unrecoverable		15%	As determined based on pilot program customers contacts
3	Estimated Number of Customers		1,800	Line 1 x Line 2, rounded down to nearest hundred
4				
5	Average Outstanding Balance	$	550	Average outstanding account balance for customers in pilot group
6	Estimated Total Balance	$000s	990	(Line 3 x Line 5) / 1,000
7	Less: Bill Payment Deferrals	$000s	13	Embedded in Line 6; however, already accounted for in the deferral account
8	Less: Rounding	$000s	2	
9	Estimated Unrecoverable Revenue Addition	$000s	975	Line 6 - Line 7 - Line 8
10				
11	Breakdown by Rate Class:			
12	Residential	$000s	878	Allocation is equivalent to 90% residential and 10% small commercial based
13	Small Commercial	$000s	97	on responses from the pilot program.

21.2 Please provide FEI's 2019 to 2021 Actual, 2022 Projected and 2023 Forecast bad debt expense as is relates to unrecoverable revenue from customers in the normal course of business (i.e. not deemed unrecoverable due to COVID-19).

Response:

Please refer to the table below for the actual, projected and forecast bad debt expense amounts for the years requested. These amounts do not include unrecoverable revenue due to the COVID-19 pandemic as those amounts are included in the COVID-19 Customer Recovery Fund Deferral Account.

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

	2019 Actual	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Bad Debt Expense	1.646	1.565	1.983	2.312	2.149

On page 83 of the Application, FEI states:

> FEI does not anticipate any further additions to the [COVID-19 Customer Recovery Fund] deferral account after 2022 and proposes to commence amortization of the balance in the deferral account on January 1, 2023 using a three-year amortization period. FEI considers a three-year amortization period to be appropriate because it matches the number of years during which the COVID-19 Customer Recovery

Fund Deferral Account was active (i.e., 2020 through 2022). Should public health and economic conditions deteriorate significantly due to the resurgence of the COVID-19 pandemic later this year or in the future[…] FEI may seek BCUC approval again for deferral account treatment for the same purpose and reasons set out in the 2020 application.

21.3 Please discuss whether any alternative amortization periods for the COVID-19 Customer Recovery Fund Deferral Account were considered by FEI.

21.3.1 If yes, please discuss the pros/cons of the alternatives considered, including why they were rejected.

21.3.2 If no, please explain why not.

Response:

FEI considered amortization periods ranging from one year to five years, but ultimately determined that three years was the most reasonable. As Table 1 below shows, all of the amortization periods have a similar impact on rates, with the exception of the one-year period which is greater. FEI concluded that a three-year period achieved a good balance between minimizing 2023 rate pressure and requesting an overly long amortization period. Additionally, a three-year amortization period aligns well with the length of time the deferral account was active (i.e., the number of years that additions were recorded in the deferral account, which was 2020 through 2022).

Please refer to Table 1 below which shows the delivery rate impact as well as changes to the proposed 2023 delivery rate of 7.42 percent if the amortization period for the COVID-19 Customer Recovery Fund Deferral Account is one, two, four, or five years.

Table 1: Delivery Rate Impact and Changes to Proposed 2023 Delivery Rates of One to Five Year Amortization Periods for the COVID-19 Customer Recovery Fund Deferral Account

	Amortization Period				
	1 Year	2 Years	3 Years	4 Years	5 Years
Annual Delivery Rate Impact to 2022 Approved (%)	0.252%	0.133%	0.093%	0.073%	0.061%
Changes to Proposed 2023 Delivery Rate Increase (%)	0.159%	0.040%	0.000%	-0.020%	-0.032%
Proposed 2023 Delivery Rate Increase (%)	7.58%	7.46%	7.42%	7.40%	7.39%

21.4 Please provide the 2023 delivery rate impact and pros/cons of the COVID-19 Customer Recovery Fund Deferral Account deferral account for each of the following amortization periods: (i) one-year; and (ii) two-years.

Response:

Please refer to the response to BCUC IR1 21.3.

21.5 Please confirm, or explain otherwise, that FEI is not requesting closure of the COVID-19 Customer Recovery Fund Deferral Account.

21.5.1 If confirmed, please clarify whether FEI will seek BCUC approval again for deferral account treatment should further additions related to the three items approved for inclusion in the COVID-19 Customer Recovery Fund Deferral Account be needed.

21.5.2 If not confirmed, please explain why not.

<u>Response:</u>

Confirmed. Due to the uncertainty related to the potential for a deterioration in public health or economic conditions due to a resurgence in COVID-19, FEI is not requesting closure of the COVID-19 Customer Recovery Fund Deferral Account in this Application. FEI confirms that, if in the future this deferral account is once again required to record the three items approved by Order G-132-19 (i.e., unrecovered revenue, bill payment deferrals and bill credits due to the COVID-19 pandemic), FEI would seek approval from the BCUC to recover any amounts recorded in the account.

22.0 Reference: EXISTING DEFERRAL ACCOUNTS

Exhibit B-2, Section 1.5.5, p. 9, Section 7.5.2.2, p. 84

Emissions Regulations Deferral Account

On page 84 of the Application, FEI states:

> In the FEI Annual Review for 2017 Delivery Rates Application, FEI requested and received approval through Order G-182-16 to amortize any additions to the [Emissions Regulations deferral] account over a period of five years. In that Application, FEI stated "This amortization period is appropriate given that FEI expects to continue to receive revenues which will vary depending on the number of credits FEI earns under the RLCFRR and the price at which FEI is able to sell those credits. The longer recovery period of five years will help smooth the rate impact on customers as these revenues are received from time to time."

Further, on page 84, FEI states:

> In this Application, FEI is requesting approval to change the amortization period of this deferral account from five years to one year. As of the end of the first quarter of 2022, the British Columbia Low Carbon Fuel Standard (BC-LCFS) has validated approximately 80,149 in carbon credits for FEI that have accumulated since 2019, with an approximate market value of $37.5 million. FEI anticipates monetizing those amounts through the sale of credits prior to the end of 2022. Given the significant dollar amount expected to be received and the time period that has already elapsed between when the credits were earned and validated, accelerating the return of these credits to customers is the appropriate measure to take and may serve to mitigate other rate pressures in the short-term, which will be beneficial to customers in the current market environment.

On page 9 of the Application, FEI states that the "increases in amortization expense are mostly offset by a credit amortization of $28.848 million for the Emissions Regulations deferral account."

22.1 Please confirm whether the carbon credits that FEI has accumulated since 2019 represent the entirety of FEI's credit balance.

<u>Response:</u>

Confirmed. Please refer to the response to BCUC IR1 22.2 which shows that the total number of credits accumulated since 2019 is 80,149.

22.2 Please provide the following information for 2017 to 2021 Actuals, 2022 Projected and 2023 Forecast:

(i) The number and $-value of credits FEI has earned under the Renewable Carbon Fuel Requirements Regulation (RLCFRR) before 2019 and accumulated since 2019;

(ii) The number of credits, price per credit and $-value of credits FEI has sold; and

(iii) The number and $-value of credits FEI has amortized.

<u>Response:</u>

Please refer to Table 1 below which shows the number of credits validated and the dollar value of the validated credits that FEI sold between 2017 to 2021 Actual and 2022 Projected. FEI notes that the credit validation and credit sale (i.e., transfer) do not always happen within the same year, as such, FEI included 2015 and 2016 in Table 1 to show the matching validated credits to those that were transferred in 2017. All credits as well as the transfer of the credits (i.e., sold at fair market value) are approved by the British Columbia Low Carbon Fuel Standard (BC-LCFS). FEI expects to sell all credits accumulated since 2019 (i.e., 80,149) in 2022 and currently does not have a forecast of credits that might be validated by BC-LCFS in 2023; as such, FEI does not have a forecast of credit transfers and the dollar value of the transfers for 2023.

Table 1: Number of Credits and $-value of Credits Sold from 2017 to 2022

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Projected
Year of Compliance Period (Credit Reported to)	2013-2014	2015	2013-2016[1]	2017	2018			2019-2020
Carbon Credits (Validated)	14,349	12,893	12,809	17,323	26,521	-	-	53,628
Credit Transfer (Sold)		(14,349)	(12,893)	(30,132)	-	-	-	(80,149)
Annual Net Credit Additions	14,349	(1,456)	(84)	(12,809)	26,521	-	-	(26,521)
Cumulative Credit Balance	14,349	12,893	12,809	-	26,521	26,521	26,521	-
Value per Credit of Transfer	n/a	$ 170	$ 170	$ 170	n/a	n/a	n/a	$ 467
$ value of Credit ($000s)[2,3]	$ -	$ 2,439	$ 2,191	$ 5,122	$ -	$ -	$ -	$ 37,455

<u>Notes to Table:</u>

1) The 2013-14 and 2015 BC-LCFS Compliance Reports were revised in 2016 with adjustments to the credits validated;

2) The dollar value of the credits sold in 2016, 2017, and 2018 Actuals were recorded (pre-tax) in the Emissions Regulations deferral account in each of those years[6] with amortization over a five-year period starting in the subsequent year (i.e., the credits sold in 2016, net of tax, are amortized over five years from 2017 to 2021); and

3) The dollar value of the credits expected to be sold in 2022 (i.e., $37.455 million, pre-tax) will be captured in the Emissions Regulations deferral account and are proposed to be amortized over a one-year period in 2023. The value of the credit is estimated based on the average Q1-2022 sales price listed in the BC Low Carbon Fuel Credit Market Report[7]. The actual revenue received from

6 2016: FEI's 2016 BCUC Annual Report, p. 11, Line 15, Column 5; 2017: FEI's 2017 BCUC Annual Report, p. 11, Line 22, Column 5; and 2018: FEI's 2018 BCUC Annual Report, p. 11, Line 21, Column 5.

7 https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf-017.pdf

the sale of the accumulated carbon credits will be dependent on the market conditions at the time of the sale and actual offers received from potential buyers.

22.3 Please explain why FEI plans to monetize all of the carbon credits and why it is not proposing to hold on to any credits to smooth rates over a longer period of time.

Response:

FEI generally monetizes all credits within a year from the date that the credits are validated. At the time of FEI's 2017 Annual Review when the amortization period for the Emissions Regulations deferral account was approved, credits were validated by BC-LCFS on an annual basis allowing FEI to monetize the credits in each year at that time. However, as shown in the response to BCUC IR1 22.2, there has been a lapse in credit validation by BC-LCFS since 2019 which has resulted in the credits from the 2019 and 2020 compliance periods not being validated until 2022. As such, FEI was not able to monetize the accumulated credits until now.

As a result of this delayed monetization, the total accumulated validated credits of 80,149 which FEI expects to monetize in 2022 are comprised of the credits earned from the 2018, 2019 and 2020 compliance periods. Had the credits been validated sooner, FEI would have been able to monetize the credits in previous years and customers would have started receiving the benefits through reduced delivery rate impacts in previous years. In order to make up for this delay, FEI considers it more beneficial to customers to amortize the deferral account balance immediately so that the benefits are not further delayed into future years. Due to the time that has already elapsed since these credits were first earned (i.e., five years from 2018 to 2023 when the dollar values of the credit are amortized into customer rates), FEI believes it is most appropriate to return the credit to customers as soon as possible. If the amortization period were to remain at five years, then it would be almost 10 years until the credits earned from 2018 would be returned to customers.

Furthermore, monetizing all the validated credits now will have the biggest effect on smoothing the 2023 delivery rate increase. At the time that the five-year amortization period for the Emissions Regulations deferral account was approved (i.e., in the 2017 Annual Review Decision), FEI's annual delivery rate increases were relatively small, ranging from 0 percent to 1.79 percent from 2015 to 2019. Rate smoothing considerations at that time were different, with the focus being more on avoiding rate decreases as a result of setting amortization periods over too short a time period for deferral accounts with large credit balances.

In the current situation, FEI's focus is on reducing the impacts of large rate increases. As demonstrated in Table 1 below, changing the amortization period from five years to one year significantly reduces the 2023 delivery rate increase, from 10.60 percent to 7.42 percent, achieving the biggest effect of rate smoothing.

Table 1: Delivery Rate Impact and Changes to Proposed 2023 Delivery Rates of One to Five Year Amortization Periods for the Emissions Regulations Deferral Account

	Amortization Period				
	1 Year	2 Years	3 Years	4 Years	5 Years
Annual Delivery Rate Impact to 2022 Approved (%)	-4.199%	-2.211%	-1.548%	-1.217%	-1.018%
Changes to Proposed 2023 Delivery Rate Increase (%)	-2.651%	-0.663%	0.000%	0.331%	0.530%
Proposed 2023 Delivery Rate Increase (%)	7.42%	9.41%	10.07%	10.40%	10.60%

Ultimately, FEI considers returning the credits that were first earned five years ago to customers as soon as possible and achieving the most rate smoothing for the 2023 delivery rate increase are important and compelling reasons to change the amortization period to one year.

22.3.1 Please explain whether there is a time limit or expiration by which FEI is allowed to validate and monetize credits.

Response:

The deadline for FEI to submit the annual Compliance Report to BC-LCFS for validation of the credits earned over the previous calendar year is March 31st (i.e., the 2020 Compliance Report for the period from January 1, 2020 to December 31, 2020 is March 31, 2021). FEI does not know the time it takes BC-LCFS to validate the credits. As shown in the table in the response to BCUC IR1 22.2, it could take multiple years until the credits are validated.

Currently, once the credits are validated by BC-LCFS, there is no expiration date by which FEI is allowed to monetize the credits.

22.3.2 Please confirm whether FEI anticipates monetizing the entire accumulated carbon credits in 2022.

22.3.2.1 If yes, please reconcile the following two statements: (i) "increases in amortization expense are mostly offset by a credit amortization of $28.848 million for the Emissions Regulations deferral account" as stated on page 9 of the Application; and (ii) FEI's carbon credits have a market value of approximately $37.5 million (pre-tax) as stated on page 84 of the Application.

22.3.2.2 If no, please explain the difference between the two FEI statements included in the IR above.

Response:

Confirmed, FEI anticipates monetizing the entire accumulated carbon credits in 2022. FEI clarifies that the estimated $37.5 million dollar value of the credits accumulated since 2019 is the pre-tax dollars and is based on 80,149 credits sold at $467.32 per credit (as explained in the response to BCUC IR1 22.2). FEI notes that the actual revenue received from the sale of the accumulated carbon credits will be dependent on market conditions at the time of the sale and actual offers received from potential buyers. In contrast, the $28.848 million is the forecast 2022 ending balance of the Emission Regulations deferral account, which FEI is proposing to fully amortize in 2023.

Please refer to Table 1 below for the continuity of the Emission Regulations deferral account for 2022 and 2023, which shows the $37.455 million as gross additions to the deferral account in 2022 and the $28.848 million as the ending balance in 2022, as well as the amortization in 2023.

Table 1: Continuity of the Emissions Regulations Deferral Account for 2022 Projected and 2023 Forecast ($000s)

Line	Particular	Reference	2022	2023
1	Opening Balance	Prior Year Ending Balance	(2,578)	(28,848)
2	Gross Additions		(37,455)	-
3	Tax	-Line 2 x 27%	10,113	-
4	Net Additions	Line 2 + Line 3	(27,342)	-
5	Amortization	See Note 1	1,072	28,848
6	Ending Balance	Line 1 + Line 4 + Line 5	(28,848)	-

Note to Table:

1) The 2022 amortization is for the credits that were sold in 2017 and 2018, which were amortized over a five-year period.

22.4 Please elaborate on the justifications to change the amortization period of the Emissions Regulations deferral account from five years to one year as it relates to any change in circumstances since the FEI Annual Review for 2017 Delivery Rates.

22.4.1 Please discuss whether any alternative amortization periods were considered by FEI.

22.4.1.1 If yes, please discuss these alternatives, including why they were not chosen.

22.4.1.2 If no alternatives were considered, please discuss why not.

22.4.2 Please provide the delivery rate impact of the Emissions Regulations deferral account if it were to be amortized over (i) a three-year period and (ii) a five-year period.

Response:

Please refer to the response to BCUC IR1 22.3.

22.5 Please explain whether FEI expects to continue to earn credits in the future.

22.5.1 If yes, please confirm that all amortization of this deferral account would be one year go-forward and explain why the amortization period of one year would be justified.

22.5.2 If no, please explain FEI's intention regarding the closure of the Emissions Regulations deferral account.

Response:

FEI expects to continue to earn credits in the future. FEI has submitted its 2021 Compliance Report to BC-LCFS but has not yet received validation of the credits. All future credits monetized will continue to be captured in the Emissions Regulations deferral account and amortized over a one-year period going forward.

However, FEI does not anticipate stable annual revenues from the sale of credits under the BC-LCFS in the upcoming years. This is primarily because customers under RS 46 are able to claim the carbon credits for themselves by switching to transportation agreements, as opposed to taking delivery of gas from FEI as a sales customer. FEI anticipates more of these customers will switch to transportation agreements such that they are able to receive the credits themselves, reducing the number of carbon credits for FEI going forward.

FEI considers that changing the amortization period to one year going forward is appropriate, as the annual balance in the deferral account (i.e., the number of credits available to be monetized annually) is not expected to be significant enough in the future to require a longer amortization period to smooth potential delivery rate impacts. First, FEI expects the validation of credits by the BC-LCFS will be more timely going forward, such that the credits will not accumulate to a similar scale as they have currently. Second, as mentioned above, FEI anticipates less annual revenue from the sale of credits in the future due to RS 46 customers switching to transportation agreements and thus receiving the credits themselves instead of FEI.

H. FINANCING AND RETURN ON EQUITY

23.0 Reference: FINANCING AND RETURN ON EQUITY

Exhibit B-2, Section 8.3, pp. 86–88, Section 11, Schedule 27

Long-Term Debt

On page 86 of the Application, FEI states, "[t]he 2023 Forecast for financing costs, including the interest expense on issued long- and short-term debt and on new issuances that are forecast, has been updated as described in Section 8.3 below."

On pages 86 and 87 of the Application, FEI states that it plans to issue long-term debt of approximately $200 million in 2022 and $300 million in 2023, whereby the funds will be used to repay existing indebtedness and finance the Company's capital expenditure program.

On pages 87 and 88 of the Application, FEI states:

> […] FEI is in a rising interest rate environment due to high inflation, Russia's invasion in Ukraine, and the removal of monetary policy actions that were prevalent during the initial years of the COVID-19 pandemic (i.e., 2020 and 2021). In addition, on July 13, 2022 the Bank of Canada completed its fourth rate hike of the year, raising the benchmark interest rate to 2.5 percent from 0.25 percent at the beginning of 2022 and signalling that more rate hikes will be announced in 2022. […]

23.1 Given the rising interest rate environment, please discuss the alternatives available, if any, to manage interest expense and financing costs in consideration of FEI's plans to issue long-term debt of approximately $200 million in 2022 and $300 million in 2023. Are there options available to FEI which would allow the utility to forgo issuing the long-term debt or to issue smaller amounts?

Response:

Broadly speaking, FEI has two ways to mitigate the impact of a rising interest rate environment: greater reliance on its low-cost commercial paper program and, under certain circumstances, issuing long-term debt at shorter tenors.

FEI's last long-term debt issuance was completed in April 2021 and since then FEI has been utilizing its Credit Facility to support its commercial paper program, which is a low-cost and flexible approach to raising financing. While FEI's Credit Facility's available capacity is adequate at this time, FEI's funding needs are expected to increase significantly over the next several months and drawings will likely exceed $500 million by the end of November. That provides limited cushion in FEI's $700 million Credit Facility and will require FEI to issue long-term debt in order to be able to finance its capital expenditures and other operational expenses. An expansion of FEI's credit facilities would provide greater flexibility in timing of issuances as it would expand the amount of low-cost commercial paper that could be issued.

In circumstances where the issuance rate of long-term debt at shorter tenors is markedly lower than rates at longer tenors, it may be favorable to issue shorter tenor bonds such as 5-, 7- and 10-year maturities compared to 30 years to mitigate the impact of higher borrowing rates.

23.2 Please provide the sensitivity of the 2023 forecast financing costs and proposed 2023 delivery rates to a +1 percent to +3 percent rise in interest rates.

Response:

FEI has interpreted this question as asking for the impact of a 1 percent, 2 percent, and 3 percent rise in both the 2023 short-term debt rate and the 2022 and 2023 forecast long-term debt issuance rates.

Financing costs are currently forecast to increase by $34.617 million and the proposed delivery rate increase is 7.42 percent.

1. An increase of 1 percent would increase 2023 financing costs to $39.913 million and increase the proposed delivery rate to 7.97 percent.
2. An increase of 2 percent would increase 2023 financing costs to $45.211 million and increase the proposed delivery rate to 8.51 percent.
3. An increase of 3 percent would increase 2023 financing costs to $50.510 million and increase the proposed delivery rate to 9.06 percent.

In Section 11 of the Application, FEI shows Schedule 27 – Embedded Cost of Long-Term Debt, which has been reproduced in part below:

FORTISBC ENERGY INC. — FEI Annual Review for 2023 Rates - July 29, 2022 — Section 11

EMBEDDED COST OF LONG TERM DEBT — Schedule 27
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars (1)	Issue Date (2)	Maturity Date (3)	Net Proceeds of Issue (4)	Average Principal Outstanding (5)	Interest * Rate (6)	Interest Expense (7)	Cross Ref (8)
17	2021 Medium Term Debt Issue - Series 34	April 14, 2021	July 18, 2031	148,984	150,000	2.495%	3,743	
18	2022 Medium Term Debt Issue	October 1, 2022	October 1, 2052	198,000	200,000	4.864%	9,728	
19	2023 Medium Term Debt Issue	October 1, 2023	October 1, 2053	297,000	75,616	4.763%	3,602	

23.3 Please confirm whether FEI plans to issue long-term debt of approximately $200 million in 2022 and $300 million in 2023 as discussed on pages 86 to 87 of the Application, or $200 million in 2022 and $75,616 in 2023 as reflected in Lines 18 and 19, respectively, in Schedule 27.

Response:

FEI plans to issue long-term debt of $200 million in 2022 and $300 million in 2023, either of which may be designated as a green bond. The $75,616 reflected for 2023 on Line 19 of Schedule 27 is the average balance outstanding for the year. If the debt is issued on October 1, 2023, the average balance is calculated as ((365 days – 273 days) / 365 days) * $300 million = $75,616 thousand.

24.0 Reference: FINANCING AND RETURN ON EQUITY

Exhibit B-2, Section 8.3, pp. 87, 89

Short-Term Debt

On page 87 of the Application, FEI states that it currently maintains a $55 million letter of credit facility to support its letters of credit which matures in March 2023.

24.1 Please discuss whether FEI intends to renew the letter of credit facility.

24.1.1 If not, please explain why not and discuss any risk to FEI of not renewing the letter of credit facility.

24.1.2 If yes, please discuss the expected timing of the renewal.

<u>Response:</u>

Yes, FEI is currently in the process of extending the $55 million letter of credit facility for another year.

On page 89 of the Application, FEI states that its interest rate forecasts are based in part on the Canadian Deposit Overnight Right (CDOR). FEI further states the following:

> CDOR's regulated administrator, announced that CDOR will cease to be published after June 28, 2024. The Canadian Alternative Reference Rate Working Group (CARR) was established to coordinate the transition to a new risk-free rate benchmark. It is anticipated that CDOR will transition to the Canadian Overnight Repo Rate Average (CORRA), a transaction-based overnight risk-free interest rate benchmark in existence since 1997. FEI will work with its banking syndicate members to transition its credit facility agreements to CORRA and will revisit the methodology for short-term interest rate forecasting when such a transition is complete.

24.2 Please explain if there are any expected costs to FEI associated with the transition from CDOR to CORRA and if so, please provide an estimate of the expected cost and impact on rates.

<u>Response:</u>

FEI does not expect any material costs related to transitioning from CDOR to CORRA. While FEI will need to incur legal fees to amend the credit facility agreement to incorporate CORRA, FEI would plan to group that amendment with other regularly scheduled amendments to the agreement, which should result in no material incremental legal costs as a result of the transition.

However, there are still some uncertainties with the new benchmark, such as whether the CORRA rate is needed in Canada. If the results of the public consultation show a strong need for such a rate, and the creation of a 1- and 3-month term CORRA is determined to be feasible, the rate could begin to be published by the end of Q3 2023.[8] While FEI expects that the transition to a new benchmark will not result in any material cost, some of the intricacies of the new benchmark are still being worked through by the Bank of Canada and CARR. As discussed in the Application, CDOR rates will be calculated and published until June 28, 2024, at which point all loan agreements in Canada will transition to the new benchmark.

8 Recommended fallback language for loans referencing CDOR (bankofcanada.ca).

I. TAXES

25.0 Reference: TAXES

Exhibit B-2, Section 9.2, p. 92

Property Taxes

On page 92 of the Application, FEI outlines that tax rates pertaining to municipal, school, rural and other rates are expected to change in 2023 (e.g. percentage increase or decrease).

25.1 Please provide the rationale for each of the expected percentage increases and decreases in tax rates which are described on page 92 of the Application.

Response:

The 2023 Forecast changes in tax rates are determined based on the following:

- Municipal tax rates are set by individual municipalities on an annual basis. Changes to the municipal tax base, changes in the classification of actual properties, and/or budget requirements can drive changes to municipal tax rates. FEI used the compounded average annual growth rate (CAGR) from 2016 to 2022 to forecast the percentage changes in municipal tax rates.
- School tax rates and rural general tax rates are set annually by the provincial government. FEI used the CAGR from 2016 to 2022 to forecast the percentage changes in school tax and rural general tax rates.
- First Nations tax rates are set by each First Nation Band Council and approved by the First Nations Tax Commission. Generally, First Nations base their general tax rate on the rate charged by a neighbouring municipality. FEI used the CAGR from 2016 to 2022 to forecast the percentage changes in First Nations tax rates.
- Other tax rates are an amalgamation of six or more tax rates that are set by varying authorities with taxation powers including, but not limited to, regional districts, hospital districts, transit, BC Assessment, the Municipal Finance Authority, Police taxes, special benefiting areas, parcel taxes, etc., that may be levied on a property tax folio.

Further, on page 92 of the Application, FEI provides the 2023 forecast changes in the assessed values of FEI's property (e.g. percentage increase or decrease).

25.2 Please provide the rationale for each of the expected percentage increases and decreases in assessed values which are described on page 92 of the Application.

Response:

FEI's expectations for the forecast increases and decreases in assessed values are based on the compounded average annual growth rate (CAGR) over the period from 2016 to 2022 (with the exception of LNG property, as further described below). FEI further breaks down and describes the changes in annual assessed values for each property category below.

Distribution Lines and Services

Distribution lines and service improvements have increased from a total of $1,237.9 million in 2016 to a total of $1,404.8 million in 2022, or 13.5 percent. The compounded average growth rate (CAGR) over this period was an increase of 2.13 percent.

Year	Total Assessment Improvements	% Change
2022	1,404,815,100	-2.8%
2021	1,445,315,500	3.7%
2020	1,394,068,400	5.1%
2019	1,326,167,600	11.1%
2018	1,193,871,900	-0.6%
2017	1,200,960,800	-3.0%
2016	1,237,695,500	

Land represents a very small portion of the value associated with distribution lines. In 2022, Land represented 0.03 percent of the total value of distribution assets assessed. Land associated with distribution lines and services is made up of distribution right of ways over crown lands only. From the table below, the total value of land associated with distribution lines increased from $184,700 in 2016 to $390,800 in 2022, or 111.6 percent, resulting in a CAGR increase of 13.3 percent over this six-year period. Land values for the 2023 assessment are to reflect the market value at July 1, 2022.

Year	Total Assessed Land	% Change
2022	390,800	17.8%
2021	331,800	29.0%
2020	257,300	23.4%
2019	208,500	-8.2%
2018	227,100	19.3%
2017	190,300	3.0%
2016	184,700	

Transmission Lines

Transmission line improvements have increased from a total of $570.8 million to $686.2 million, or 20.2 percent, from 2016 to 2022. The CAGR over this period was an increase of 3.1 percent.

Year	Total Assessed Improvements	% Change
2022	686,162,800	5.6%
2021	649,952,800	2.3%
2020	635,607,600	6.1%
2019	599,000,394	4.4%
2018	573,586,500	0.1%
2017	573,017,000	0.4%
2016	570,753,000	

Land associated with transmission lines, as with distribution lines, are right of ways located on Crown land, but are still a minor portion of the value of total transmission lines; approximately 1.4 percent of the total value of transmission lines. In 2016, the land value associated with transmission lines was $4.5 million, compared to $9.5 million in 2022, an increase of 111.7 percent from 2016 to 2022. This equates to a 13.3 percent CAGR increase over this six-year period.

Year	Total Assessed Land	% Change
2022	9,534,064	19.5%
2021	7,979,548	3.7%
2020	7,694,559	4.4%
2019	7,371,857	33.6%
2018	5,517,606	7.7%
2017	5,123,758	13.8%
2016	4,502,617	

LNG

LNG improvements have experienced some significant assessment value changes since 2016 from new construction in LNG assets. In this case, FEI relied on the changes in 2021 and 2022, as they are more representative of the current market environment.

Year	Total Assessed Improvements	% Change
2022	221,585,400	-1.3%
2021	224,527,300	-0.9%
2020	226,600,100	4.1%
2019	217,571,600	9.8%
2018	198,216,600	13.0%
2017	175,444,600	77.9%
2016	98,643,300	

Land changes associated with the LNG plants reflect the six-year CAGR of land for LNG improvements, which increased in value from $34.9 million in 2016 to $101.9 million in 2022, or 192.1 percent. The CAGR over this period was an increase of 19.5 percent.

Year	Total Assessed Land	% Change
2022	101,856,000	23.2%
2021	82,701,000	13.5%
2020	72,854,000	22.6%
2019	59,437,000	32.5%
2018	44,846,000	16.3%
2017	38,560,000	10.6%
2016	34,865,000	

Office Improvements

Overall, office improvement values have decreased from $69.2 million in 2016 to $68.0 million in 2022, or 1.8 percent. The CAGR over this period was a decrease of 0.3 percent.

Year	Total Assessed Improvements	% Change
2022	67,961,100	7.9%
2021	62,987,600	-2.6%
2020	64,699,500	-4.0%
2019	67,405,600	-8.9%
2018	74,023,400	-0.9%
2017	74,717,300	8.0%
2016	69,187,500	

Land values associated with offices has increased from $69.4 million in 2016 to $197.8 million in 2022, or 185.0 percent. The CAGR over this six-year period was an increase of 19.0 percent.

Year	Total Assessed Land	% Change
2022	197,792,700	23.8%
2021	159,765,800	7.8%
2020	148,189,900	10.0%
2019	134,722,900	22.6%
2018	109,912,300	18.7%
2017	92,622,200	33.5%
2016	69,403,500	

25.3 Please provide the sensitivity of the assessed values of FEI's property to: (i) a +/- 1 percent change in interest rates; and (ii) general real estate market conditions.

Response:

FEI land and property assessments are subject to changes that affect the local real estate market in the areas they are located. As such, as interest rate changes affect the value of property in a given taxing jurisdiction, FEI's valuations would likewise be affected. For example, if a 1 percent decrease in interest rates increases demand for real estate in a market segment, FEI would expect prices in that segment to increase. This increase in prices will increase assessments (since assessment data is based, in part, on market transaction data) in that segment. Similarly, FEI would expect that a 1 percent increase in interest rates would have the effect of reducing demand and putting downward pressure on prices, therefore decreasing assessed values. If FEI has assessable property in that segment, it is expected that FEI's assessments would be reflected accordingly. However, FEI cannot provide a direct correlation between a specific change in interest rates (i.e., +/- 1 percent) to a specific change in the assessed values of FEI's property.

26.0 Reference: TAXES

Exhibit B-2, Section 11, Schedule 22

Property and Sundry Taxes

In Schedule 22 of the Application, FEI shows:

FORTISBC ENERGY INC. — FEI Annual Review for 2023 Rates - July 29, 2022 — Section 11

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s) — Schedule 22

Line No.	Particulars (1)	2022 Approved (2)	2023 Forecast (3)	Change (4)	Cross Reference (5)
1	General School and Other	$ 60,136	$ 62,788	$ 2,652	
2	1% In-Lieu of Municipal Taxes	13,368	16,289	2,921	
3					
4	Total	$ 73,504	$ 79,077	$ 5,573	
5					
6	Total Property Tax Expense per Line 4	$ 73,504	$ 79,077		
7	Less: Property Tax Transferred to Biomethane BVA	(107)	(92)		
8	**Net Property Tax Expense**	$ 73,397	$ 78,985		

26.1 Please explain why the 2023 Forecast “Property Tax Transferred to Biomethane BVA” in line 7 of Schedule 22 ($92,000) is less than the 2022 Approved amount of $107,000 despite a higher property tax expense (line 6) in the 2023 Forecast as compared to the 2022 Approved.

Response:

The two lines (i.e., Lines 6 and 7) in Schedule 22 are not directly comparable. The Total Property Tax Expense shown on Line 6 of Schedule 22 is for all of FEI’s assets, which include pipelines, stations, facilities, etc., across many municipalities across FEI’s entire service area; whereas, the Property Tax Transferred to Biomethane BVA shown on Line 7 is specific to FEI’s biomethane assets only. The Biomethane assets are only a small subset of FEI’s assets and these assets are located in only a small number of municipalities. As described in Section 9.2 of the Application, changes in tax rates and assessed values vary depending on the municipality and the type of asset.

FEI also notes that the 2022 Approved numbers shown in Schedule 22 were forecasts that were completed in mid-2021 during the preparation of the Annual Review for 2022 Delivery Rates. Please refer to Table 1 below (also shown in Table 9-1 of the Application) for the 2022 Approved, 2022 Projected and 2023 Forecast property tax for biomethane assets transferred to the BVA. As the table shows, the 2022 Projected property tax for biomethane assets is approximately $75 thousand, which is lower than the 2022 Approved level. The 2023 Forecast was based on the 2022 Projected level, which FEI forecasts to increase from the 2022 Projected level.

Table 1: Property Tax Transferred to BVA for 2022 Approved, 2022 Projected and 2023 Forecast

	Approved 2022	Projected 2022	Forecast 2023
Property Tax Transferred to BVA ($000s)	$ 107	$ 75	$ 92

J. EARNING SHARING AND RATE RIDERS

27.0 Reference: EARNINGS SHARING AND RATE RIDERS

Exhibit B-2, Section 10.3.1, pp. 96, 98–99; FEI 2022 Annual Review proceeding, Exhibit B-2, pp. 81–82, Exhibit B-3, BCUC IR 18.6

Biomethane Variance Account (BVA) Rate Rider

On page 96 of the Application, FEI states:

> The BVA balance at the end of December 31, 2022 is projected to be a debit of $34.596 million before-tax. This balance consists of the 2021 ending inventory balance of $2.881 million plus a projected $52.484 million in costs to acquire biomethane less $20.769 million of recoveries by way of the Biomethane Energy Recovery Charge (BERC). […]

On page 81 of Exhibit B-2 in the FEI 2022 Annual Review proceeding, FEI projected 2021 biomethane costs incurred of $18.7541 million and biomethane costs recovered of $7.4609 million.

27.1 Please provide the actual 2021 biomethane costs and explain the change from the 2021 Actual costs to the 2022 Projected costs.

Response:

The 2021 Actual biomethane costs were $21.5 million, which includes the cost to acquire 790 TJ of biomethane, biomethane production O&M, and the cost to contract for acquisitions. As set out in the preamble, the 2022 Projected cost to acquire biomethane included in this Application is $52.5 million which includes the cost to acquire 2,187 TJ of biomethane, biomethane production O&M and the cost to contract for acquisitions. The difference between 2022 Projected and 2021 Actual is $31.0 million of which 99 percent, or $30 million, is due to the volume difference between 2022 Projected and 2021 Actual.

Please see Table 1 below setting out the difference between 2021 Actual and 2022 Projected and the percent of total.

Table 1: Difference between 2021 Actual and 2022 Projected Biomethane Costs

Item	Difference ($000)	Percent of total
Volume	30,673	99%
Price per GJ	(789)	-3%
O&M	1,127	4%
Property Tax	(39)	0%
Other	(15)	0%
Total	30,957	100%

27.2 Please explain why biomethane costs incurred are expected to increase from $18.7541 million projected in 2021 to $52.484 million projected in 2022. As part of the response, please discuss the purchase price of biomethane in 2021 and 2022, and whether the projected increase is primarily driven by price, volumes, or both.

Response:

The projected increase in biomethane costs is due to the increased volume of biomethane that FEI is projecting to acquire in 2022. FEI projects to acquire 2.2 PJ of biomethane in 2022 compared to 0.7 PJ in 2021. The cost to acquire biomethane in 2022 is projected to be $24.00 per GJ compared to $27.50 per GJ in 2021. FEI has quantified the difference between 2021 and 2022 biomethane costs in the table below.

Table 1: Difference in Biomethane Costs between 2022 and 2021

Line No.	Particulars	Total Biomethane Acquisition Cost ($000)	Total Biomethane Volume (TJ)	Avg Biomethane Acquisition Cost ($/GJ)
		[1]	[2]	[3]
1	2022	52,484	2,187	24.00
2	2021	18,754	682	27.50
3	Difference	33,730	1,505	(3.50)
4				
5	Variances		Reference	
6	Volume	41,377	(Line 3, Column [2]) x (Line 2, Column [3])	
7	Price	(7,646)	(Line 3, Column [3]) x (Line 1, Column [2])	
8	Total	33,730	Line 6 + Line 7	

On page 98 of the Application, FEI states:

> To calculate the BVA rate rider, the projected BVA rate rider account balance of $26.146 million is divided by the 2023 Forecast non-bypass customer volume of 198,408 TJ, which results in a BVA rate rider of $0.132 per GJ. […]

On page 82 of Exhibit B-2 in the FEI 2022 Annual Review proceeding, FEI stated:

> To calculate the BVA rate rider, the projected BVA rate rider account balance of $11.525 million is divided by the 2022 Forecast non-bypass customer volume of 196,294 TJs, which results in a BVA rate rider of $0.059 per GJ.

27.3 Please provide the bill impact, in dollars and percent terms, for the average customer as a result of increasing the BVA rate rider from $0.059 per gigajoule (GJ) to $0.132 per GJ.

Response:

Please refer to Table 1 below which shows the annual bill impact, in dollars and percentage terms, for the average customer (RS 1 to 7) as a result of the BVA rider increasing from $0.059 per GJ to $0.132 per GJ. FEI has excluded transportation customers as FEI does not have insight into the commodity charge portion of their total bills.

Table 1: Bill Impact Due to BVA Rider Increasing from $0.059 per GJ (2022) to $0.132 per GJ (2023)

Rate Schedule (RS)	Avg. UPC (GJ)	Annual Bill Impact due to BVA Rider (2022 to 2023) $	%
RS 1 Residential	90	$ 6.57	0.50%
RS 2 Small Commercial	322	$ 23.51	0.58%
RS 3 Large Commercial	3,650	$ 266.45	0.65%
RS 4 Seasonal	9,200	$ 671.60	0.83%
RS 5 Gernal Firm Service	17,100	$ 1,248.30	0.77%
RS 6 Natural Gas Vehicle Service	1,600	$ 116.80	0.71%
RS 7 General Interruptible Service	133,400	$ 9,738.20	0.86%

Table 10-4 on page 100 of the Application shows the renewable natural gas (RNG) customer enrollment projection for 2022 by rate schedule, and Table 10-3 on page 99 of the Application shows the expected sales volume from existing and projected long-term contracts.

In responses to BCUC IR 18.6 in the FEI 2022 Annual Review proceeding, FEI explained the approaches taken to project the 2021 demand for RNG.

27.4 Please expand Table 10-4 in the Application to include the 2021 actual RNG customer enrollment by rate schedule.

Response:

Please see the revised Table 10-4 below.

Revised Table 10-4: RNG Customers by Rate Schedule

RNG Participation (Rate Schedule)	Customer Enrollment 2021 Actual	Customer Enrollment 2022 Projected
Short Term		
Rate Schedule 1B	9,353	9,647
Rate Schedule 2B	189	221
Rate Schedule 3B	16	25
Rate Schedule 11B	3	2
Rate Schedule 5B	3	15
Rate Schedule 30 Off System		
Long Term		
Rate Schedule 11B	2	3
Total	**9,566**	**9,913**

27.5 Please explain how FEI projects the sales volume for 2022 shown in Table 10-3, including how the approach taken to projecting demand for RNG remains the same or is different from that of 2021 (as provided in BCUC IR 18.6) and the reason(s) why.

Response:

FEI uses the same methodology as described in the response to BCUC IR1 18.6 in the 2022 Annual Review proceeding. That response is reproduced below for reference:

> 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.

Projecting the sales volume for 2022 is more challenging than for 2021. This is because in 2021 the program remained closed to new enrollment until mid-October. There was therefore comparatively little uncertainty as to how many new customers may enroll by December 31, 2021. In contrast, the program has been open to new enrollments for the entirety of 2022, and FEI has had discussions with larger volume consumers who have expressed interest in enrolling in the RNG Program. Whether or not these customers enroll in 2022 can create significant variation between projected and actual volumes sold by year end.

27.6 Please provide the reason(s) for the 2021 variances in RNG sale volumes between 2021 Actual and 2022 Projected for each of the following rate schedules and short- or long-term contracts: (i) Rate Schedule 5B (Short-term); (ii) Rate Schedule 11B (Short-term); and (iii) Rate Schedule 11B (Long-term).

Response:

In all cases, the difference between the volume of RNG sold in 2021 and the volume of RNG projected to be sold in 2022 is attributable primarily to increased customer enrollment in the program, across all rate classes.

28.0 Reference: EARNINGS SHARING AND RATE RIDERS

Exhibit B-2, Section 10.3.2, p. 100, Section 11, Schedule 11; FEI 2022 Annual Review proceeding, Exhibit B-2, p. 111

Revenue Stabilization Adjustment Mechanism (RSAM)

On page 100 of the Application, FEI states that the projected balance in the RSAM account at the end of 2022 is a credit of $43.112 million.

In Section 11 of the Application, FEI provides the following information in Schedule 11 – Unamortized Deferred Charge and Amortization – Rate Base:

FORTISBC ENERGY INC. — FEI Annual Review for 2023 Rates - July 29, 2022 — Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE — Schedule 11
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars (1)	12/31/2022 (2)	Opening Bal./ Transfer/Adj. (3)	Gross Additions (4)	Less Taxes (5)	Amortization Expense (6)	Rider (7)	Tax on Rider (8)	12/31/2023 (9)	Mid-Year Average (10)	Cross Ref (11)
1	1. Forecasting Variance Accounts										
2	Midstream Cost Reconciliation Account (MCRA)	$ (49,582)	$ -	$ -	$ -	$ -	$ 33,960	$ (9,169)	$ (24,791)	$ (37,187)	
3	Commodity Cost Reconciliation Account (CCRA)	175,424	-	(110,478)	29,829	-	-	-	94,775	135,100	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(42,252)	-	-	-	-	28,940	(7,814)	(21,126)	(31,689)	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(82)	-	1,459	(394)	(483)	1,781	(481)	1,800	859	
6	SCP Mitigation Revenues Variance Account	325	-	-	-	(112)	-	-	213	269	
7	Pension & OPEB Variance	14,018	-	-	-	(5,154)	-	-	8,864	11,441	
8	BCUC Levies Variance	685	-	-	-	(685)	-	-	-	343	
9		$ 98,536	$ -	$ (109,019)	$ 29,435	$ (6,434)	$ 64,681	$ (17,464)	$ 59,735	$ 79,136	
10											

On page 111 of Exhibit B-2 in the FEI 2022 Annual Review, FEI provides Schedule 11, which has been reproduced in part below:

FORTISBC ENERGY INC. — FEI Annual Review for 2022 Rates - July 30, 2021 — Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE — Schedule 11
FOR THE YEAR ENDING DECEMBER 31, 2022
($000s)

Line No.	Particulars (1)	12/31/2021 (2)	Opening Bal./ Transfer/Adj. (3)	Gross Additions (4)	Less Taxes (5)	Amortization Expense (6)	Rider (7)	Tax on Rider (8)	12/31/2022 (9)	Mid-Year Average (10)	Cross Ref (11)
1	1. Forecasting Variance Accounts										
2	Midstream Cost Reconciliation Account (MCRA)	$ (2,394)	$ -	$ -	$ -	$ -	$ 1,640	$ (443)	$ (1,197)	$ (1,796)	
3	Commodity Cost Reconciliation Account (CCRA)	23,550		(32,273)	8,714					11,780	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	2,562	-	-	-	-	(1,755)	474	1,281	1,922	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(1,918)	-	(563)	152	12	1,578	(426)	(1,165)	(1,542)	
6	SCP Mitigation Revenues Variance Account	(201)	-	-	-	101	-	-	(100)	(151)	
7	Pension & OPEB Variance	3,119	-	1,712	-	(230)	-	-	4,601	3,860	
8	BCUC Levies Variance	37	-	-	-	(37)	-	-	-	19	
9		$ 24,764	$ -	$ (31,124)	$ 8,866	$ (154)	$ 1,463	$ (395)	$ 3,420	$ 14,092	
10											

28.1 Please reconcile the projected balance in the RSAM account at the end of 2022 of $43.112 million as discussed on page 100 of the Application and the credit balance of $42.252 million shown in Schedule 11.

Response:

The difference between the 2022 Projected ending credit balance in the RSAM account of $43.112 million, shown in Table 10-5 of the Application, and the 2022 Projected ending credit balance in the RSAM account of $42.252 million, shown in Section 11, Schedule 11 of the Application, is the 2022 Projected ending credit balance in the RSAM Interest account of $0.860 million. The RSAM Interest account balance is included within the Interest on CCRA /MCRA / RSAM / Gas Storage deferral account shown on Line 5 of Schedule 11 in Section 11 of the

Application. That amount is also included in Line 1 of Table 10-5 in the Application where the line description refers to "2022 RSAM + Interest Closing Balance $000)."

28.2 Please provide a continuity schedule that shows the change from the 2020 actual RSAM balance to the actual 2021 ending balance and to the projected 2022 ending balance.

Response:

Please refer to the requested continuity schedule below, which shows the change from the 2020 Actual ending RSAM balance to the 2022 Projected ending RSAM balance. As discussed in the response to BCUC IR1 28.1, the 2022 Projected ending RSAM balance of $43.112 million shown in Table 10-5 of the Application includes RSAM Interest, which is recorded separately in the Interest on CCRA/MCRA/RSAM/Gas Storage rate base deferral account. Therefore, FEI has included the RSAM Interest deferral account within the continuity schedule below.

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

Line No.	Particulars	**Actual 12/31/2020**	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	**Actual 12/31/2021**	Mid-Year Average
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	RSAM	17,970	-	(24,985)	6,746	-	(12,528)	3,383	(9,415)	4,278
2	RSAM Interest	(33)	-	(106)	29	-	23	(6)	(93)	(63)
	Total	**17,937**	**-**	**(25,091)**	**6,775**	**-**	**(12,505)**	**3,376**	**(9,508)**	**4,215**

Line No.	Particulars	**Actual 12/31/2021**	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	**Projected 12/31/2022**	Mid-Year Average
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	RSAM	(9,415)	-	(43,160)	11,653	-	(1,822)	492	(42,252)	(25,833)
2	RSAM Interest	(93)	-	(1,015)	274		(36)	10	(860)	(477)
	Total	**(9,508)**	**-**	**(44,175)**	**11,927**	**-**	**(1,858)**	**502**	**(43,112)**	**(26,310)**

28.3 Please explain the driver(s) behind the increase in the RSAM balance from 2021 projected of $2.562 million to the 2022 projected value.

Response:

To explain the drivers behind the net change of $44.814 million from the 2021 Projected ending RSAM balance of $2.562 million receivable from customers to the 2022 Projected ending RSAM balance of $42.252 million owing to customers, FEI has divided the response into two steps:

1. 2021 Projected vs. 2021 Actual: The 2021 Projected ending balance of the RSAM account, excluding RSAM interest, was $2.562 million receivable from customers, whereas the 2021 Actual ending balance of the RSAM account, excluding interest, was $9.415 million owing to customers, resulting in a variance of $11.977 million between the 2021 Projected and the 2021 Actual ending balance of the RSAM account.

2. 2021 Actual vs. 2022 Projected: While the 2021 Actual ending balance of the RSAM account, excluding interest, was $9.415 million owing to customers, the 2022 Projected activity in the RSAM account, excluding RSAM interest, is $32.837 owing to customers, resulting in an 2022 Projected ending balance of $42.252 million.

To assist in explaining variances between 2021 Projected and 2021 Actual, the tables below provide the continuity for the RSAM deferral account and RSAM interest deferral account for the 2021 Projected ending balance as included in FEI's 2022 Annual Review, and for the 2021 Actual ending balance.

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. The variance of $11.977 million between the 2021 Projected and the 2021 Actual ending balance of the RSAM account is due to the following:

- At the time of filing FEI's 2022 Annual Review, the gross credit additions of $8.869 million, excluding RSAM interest, were projected using actual monthly variances in use rates of RS 1, 2, 3, and 23 up to May 2021 only[9]. 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 2021, were $24.985 million, excluding RSAM interest; and

- At the time of filing the 2022 Annual Review, the projected RSAM rider recovery was $12.238 million, excluding RSAM interest, which was based on an RSAM rate rider of $0.087 per GJ (approved by Order G-319-20) and a projected demand with actuals up to May 2021 for RS 1, 2, 3, and 23. However, the actual 2021 full year demand for RS 1, 2, 3, and 23 combined was higher than projected, resulting in an increased actual RSAM recovery of $12.528 million, excluding RSAM interest.

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

Table 1: 2021 Projected RSAM Deferral Continuity (As Filed in FEI's 2022 Annual Review)

Line No.	Particulars	**Actual 12/31/2020**	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	**Projected 12/31/2021**	Mid-Year Average
1	RSAM	17,970	(8,869)	2,395	-	(12,238)	3,304	2,562	10,266
2	RSAM Interest	(33)	(99)	27	-	23	(6)	(88)	(61)
	Total	**17,937**	**(8,968)**	**2,421**	**-**	**(12,215)**	**3,298**	**2,474**	**10,205**

Table 2: 2021 Actual RSAM Deferral Continuity

Line No.	Particulars	**Actual 12/31/2020**	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	**Actual 12/31/2021**	Mid-Year Average
1	RSAM	17,970	(24,985)	6,746	-	(12,528)	3,383	(9,415)	4,277
2	RSAM Interest	(33)	(106)	29	-	23	(6)	(93)	(63)
	Total	**17,937**	**(25,091)**	**6,775**	**-**	**(12,505)**	**3,376**	**(9,508)**	**4,214**

To assist in explaining variances between 2021 Actual and 2022 Projected, the table below provides the continuity for the RSAM deferral account and RSAM interest deferral account for the 2022 Projected ending balance as included in this Application.

The 2022 gross credit additions of $43.160 million, excluding RSAM interest, were projected using actual monthly variances in use rates of RS 1, 2, 3, and 23 up to May 2022 only. The practice of using year-to-date actuals of use rate variances for projecting the current year additions is consistent with past annual reviews.

The 2022 Projected RSAM rider recovery of $1.822 million, excluding RSAM interest, was based on an RSAM rate rider of $0.012 per GJ (approved by Order G-366-21) and a projected 2022 demand with actuals up to May 2022 for RS 1, 2, 3, and 23.

Table 3: 2022 Projected RSAM Deferral Continuity (As Filed in FEI's 2022 Annual Review)

Line No.	Particulars	**Actual 12/31/2021**	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	**Projected 12/31/2022**	Mid-Year Average
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	RSAM	(9,415)	-	(43,160)	11,653	-	(1,822)	492	(42,252)	(25,833)
2	RSAM Interest	(93)	-	(1,015)	274		(36)	10	(860)	(477)
	Total	**(9,508)**	**-**	**(44,175)**	**11,927**	**-**	**(1,858)**	**502**	**(43,112)**	**(26,310)**

K. ACCOUNTING MATTERS AND EXOGENOUS FACTORS

29.0 Reference: ACCOUNTING MATTERS AND EXOGENOUS FACTORS

Exhibit B-2, Section 12.2.1, pp. 83, 149–151; FEI Annual Review for 2020 and 2021 Delivery Rates, Order G-319-20 dated December 8, 2020

COVID-19 Pandemic

On pages 150 to 151 of the Application, FEI seeks a variance to Directive 10 of Order G-319-20 for the following reasons:

1. It is consistent with the treatment of other exogenous items;
2. It will allow the O&M and Late Payment Charge Revenue reported in the Annual Reports to be more reflective of the actual amounts incurred, as using the Flow-through deferral account does not result in direct adjustments to O&M or Late Payment Charge Revenue, but rather one catch-all account for all flow-through adjustments. Alternatively, transferring the actual O&M savings or Late Payment Charge shortfall directly to the COVID-19 Customer Recovery Fund Deferral Account would result in those respective O&M and Other Revenue actual amounts being effectively booked back to the forecast amounts; and
3. The COVID-19 incremental savings will be returned to customers immediately in 2023.

On page 149 of the Application, FEI states, "[w]hen the 2020 and 2021 variances for the net incremental O&M (costs less cost reductions) and the Late Payment Charges are aggregated, the net variance of the two factors is approximately $2.68 million […]"

On page 83 of the Application, FEI proposes a three-year amortization period for the COVID-19 Customer Recovery Fund Deferral Account.

29.1 With reference to the two approaches in the statements below, please provide sample journal entries in 2020, 2021 and 2023 for each approach as it relates to the 2020 and 2021 direct costs, cost reductions, and late payment charges. Please specify what accounts (i.e. the COVID-19 Customer Recovery Fund Deferral Account, Flow-through deferral account or other) are debited and credited in each journal entry in order to explain the difference between the two approaches.

(i) "Using the Flow-through deferral account does not result in direct adjustment to O&M or Late Payment Charge Revenue, but rather one catch-all account for all flow-through adjustments"; and

(ii) "Alternatively, transferring the actual O&M savings or Late Payment Charge shortfall directly to the COVID-19 Customer Recovery Fund Deferral Account would result in those respective O&M and Other Revenue actual amounts being effectively booked back to the forecast amounts."

29.1.1 Please explain why the respective O&M and Other Revenue actual amounts would not need to be adjusted with the Flow-through deferral account approach.

Response:

Please see the requested journal entries below, including the journal entries for 2022 to show the full continuity of the actual and expected adjustments. FEI has also included the related tax and earnings sharing journal entries to demonstrate how customers are held whole under either scenario.

As the two scenarios demonstrate, the journal entries for 2020 and 2021 are the same, and only begin to deviate in 2022 as a result of either using the Flow-through deferral account or the COVID-19 Customer Recovery Fund Deferral Account. In reviewing the summary account balances at the end of each scenario, specifically for O&M and Other Revenue – Late Payment Charges, it is evident that in Scenario 1, the cumulative balances from 2020-2023 reflect the actual O&M cost reductions and reduced Late Payment Charges (shown in Table 12-1 in the Application) while in Scenario 2, the actual cumulative balances are zero, effectively meaning the O&M and Other Revenue-Late Payment Charges accounts would be booked back to the cumulative approved amounts for these exogenous items.

FEI believes using the Flow-through deferral account approach is more advantageous as the accounts will reflect actual activity over the years, rather than approved, which provides a more accurate basis for future rate-setting applications.

($millions)	Scenario 1 - Using the Flowthrough Deferral Account		Scenario 2 - Using the COVID-19 Customer Recovery Fund Deferral Account	
2020 Journal Entries	DR Formula O&M Expense (shared)	$ 2.840	DR Formula O&M Expense (shared)	$ 2.840
	CR Cash	$ (2.840)	CR Cash	$ (2.840)
	To record actual direct O&M costs		*To record actual direct O&M costs*	
	DR Cash	$ 4.510	DR Cash	$ 4.510
	CR Formula O&M Expense (shared)	$ (4.510)	CR Formula O&M Expense (shared)	$ (4.510)
	To recognize O&M cost reductions		*To recognize O&M cost reductions*	
	DR Other Revenue-Late Payment Charges (shared)	$ 0.853	DR Other Revenue-Late Payment Charges (shared)	$ 0.853
	CR Cash	$ (0.853)	CR Cash	$ (0.853)
	To recognize lower late payment charge revenues received		*To recognize lower late payment charge revenues received*	
	DR Tax Expense (shared)	$ 0.220	DR Tax Expense (shared)	$ 0.220
	CR Taxes Payable	$ (0.220)	CR Taxes Payable	$ (0.220)
	To record tax @ 27% on the three entries above		*To record tax @ 27% on the three entries above*	
	DR Other Revenue-Earnings Sharing	$ 0.299	DR Other Revenue-Earnings Sharing	$ 0.299
	CR Earnings Sharing Deferral	$ (0.299)	CR Earnings Sharing Deferral	$ (0.299)
	To record earnings sharing on the four entries above		*To record earnings sharing on the four entries above*	
	DR Earnings Sharing Deferral	$ 0.081	DR Earnings Sharing Deferral	$ 0.081
	CR Taxes Payable	$ (0.081)	CR Taxes Payable	$ (0.081)
	To record the Earnings Sharing Deferral net-of-tax		*To record the Earnings Sharing Deferral net-of-tax*	

2021 Journal Entries	DR Formula O&M Expense (shared)	$ 1.550	DR Formula O&M Expense (shared)	$ 1.550
	CR Cash	$ (1.550)	CR Cash	$ (1.550)
	To record actual direct O&M costs		*To record actual direct O&M costs*	
	DR Cash	$ 3.740	DR Cash	$ 3.740
	CR Formula O&M Expense (shared)	$ (3.740)	CR Formula O&M Expense (shared)	$ (3.740)
	To recognize O&M cost reductions		*To recognize O&M cost reductions*	
	DR Other Revenue-Late Payment Charges (shared)	$ 0.332	DR Other Revenue-Late Payment Charges (shared)	$ 0.332
	CR Cash	$ (0.332)	CR Cash	$ (0.332)
	To recognize lower late payment charge revenues received		*To recognize lower late payment charge revenues received*	
	DR Tax Expense (shared)	$ 0.502	DR Tax Expense (shared)	$ 0.502
	CR Taxes Payable	$ (0.502)	CR Taxes Payable	$ (0.502)
	To record tax @ 27% on the three entries above		*To record tax @ 27% on the three entries above*	
	DR Other Revenue-Earnings Sharing	$ 0.678	DR Other Revenue-Earnings Sharing	$ 0.678
	CR Earnings Sharing Deferral	$ (0.678)	CR Earnings Sharing Deferral	$ (0.678)
	To record earnings sharing on the four entries above		*To record earnings sharing on the four entries above*	
	DR Earnings Sharing Deferral	$ 0.183	DR Earnings Sharing Deferral	$ 0.183
	CR Taxes Payable	$ (0.183)	CR Taxes Payable	$ (0.183)
	To record the Earnings Sharing Deferral net-of-tax		*To record the Earnings Sharing Deferral net-of-tax*	

2022 Journal Entries	DR Formula O&M Expense (shared)	$ 3.860	DR Formula O&M Expense (shared)	$ 3.860
	CR Flow-through O&M Expense	$ (3.860)	CR COVID-19 Customer Recovery Fund Deferral	$ (3.860)
	To reclass 2020/2021 O&M direct costs and cost reductions from formula to flow-through		*To reclass 2020/2021 O&M direct costs and cost reductions from formula to deferral*	
	DR Other Revenue-Late Payment Charges (exogenous flow-through)	$ 1.185	DR COVID-19 Customer Recovery Fund Deferral	$ 1.185
	CR Other Revenue-Late Payment Charges (shared)	$ (1.185)	CR Other Revenue-Late Payment Charges (shared)	$ (1.185)
	To reclass 2020/2021 late payment charge reductions from sharing to flow-through		*To reclass 2020/2021 late payment charge reductions from sharing to deferral*	
	DR Tax Expense (flow-through)	$ 0.722	DR Taxes Payable	$ 0.722
	CR Tax Expense (shared)	$ (0.722)	CR Tax Expense (shared)	$ (0.722)
	To reclass tax @ 27% on the two entries above from sharing to flow-through		*To record tax @ 27% on the two entries above*	
	DR Other Revenue-Flowthrough Costs	$ 1.953	DR COVID-19 Customer Recovery Fund Deferral	$ 0.722
	CR Flowthrough Deferral	$ (1.953)	CR Taxes Payable	$ (0.722)
	To recognize the flow-through items in the three entries above in the Flowthrough Deferral		*To record the COVID-19 Customer Recovery Fund Deferral net-of-tax*	
	DR Earnings Sharing Deferral	$ 0.977	DR Earnings Sharing Deferral	$ 0.977
	CR Other Revenue-Earnings Sharing	$ (0.977)	CR Other Revenue-Earnings Sharing	$ (0.977)
	To record earnings sharing on the 2022 items subject to sharing in the entries above		*To record earnings sharing on the 2022 items subject to sharing in the entries above*	
	DR Taxes Payable	$ 0.264	DR Taxes Payable	$ 0.264
	CR Earnings Sharing Deferral	$ (0.264)	CR Earnings Sharing Deferral	$ (0.264)
	To record the Earnings Sharing Deferral net-of-tax		*To record the Earnings Sharing Deferral net-of-tax*	
2023 Journal Entries	DR Flowthrough Deferral	$ 1.953	DR COVID-19 Customer Recovery Fund Deferral	$ 1.953
	CR Amortization Expense	$ (1.953)	CR Amortization Expense	$ (1.953)
	To amortize the balance in the Flowthrough Deferral into customer rates		*To amortize the balance in the COVID-19 Customer Recovery Fund Deferral into customer rates*	
	DR Revenue	$ 2.675	DR Revenue	$ 2.675
	CR Cash	$ (2.675)	CR Cash	$ (2.675)
	To return amortization in customer rates, grossed-up for tax		*To return amortization in customer rates, grossed-up for tax*	
	DR Taxes Payable	$ 0.722	DR Taxes Payable	$ 0.722
	CR Tax Expense	$ (0.722)	CR Tax Expense	$ (0.722)
	To record tax @ 27% on the entry above		*To record tax @ 27% on the entry above*	

Summary of Balances	Cash	$ -	$ -
	Taxes Payable	-	-
	Earnings Sharing Deferral	-	-
	Flowthrough Deferral	-	N/A
	COVID-19 Customer Recovery Fund Deferral	N/A	-
	Revenue	2.675	2.675
	Other Revenue-Late Payment Charges	1.185	-
	Other Revenue-Earnings Sharing	-	-
	Other Revenue-Flowthrough Costs	1.953	N/A
	O&M Expense	(3.860)	-
	Amortization Expense	(1.953)	(1.953)
	Tax Expense	-	(0.722)
1	Total	$ -	$ -

2

29.2 Please explain why FEI considers COVID-19 incremental savings should be returned to customers immediately in 2023, whereas amounts recorded in the COVID-19 Customer Recovery Fund Deferral Account should be recovered over three years.

Response:

There is no inconsistency between the two proposals. With regard to the COVID-19 Customer Recovery Fund Deferral Account, FEI is proposing an amortization period for an account which currently does not have an amortization period, and the rationale for the proposed three years is described in the response to BCUC IR1 21.3. With regard to the COVID-19 exogenous factor savings, FEI is not proposing an amortization period for a deferral account, but is proposing to change where the exogenous factor savings are recorded (i.e., the Flow-through deferral account instead of the COVID-19 Customer Recovery Fund Deferral Account). The rationale for doing so is not based on whether a one- or three-year amortization period is more appropriate; rather, it is related to the most reasonable approach for recording these savings from a regulatory accounting perspective and consistency with the treatment of all other exogenous factor events. The fact that the exogenous factor savings will be returned to customers immediately is a benefit which indirectly results from the inclusion of the savings in the Flow-through deferral account, which has an existing amortization period of one year. FEI notes that while the resulting benefit is indirect, in light of the requested delivery rate increase for 2023, the additional rate mitigation that results from the exogenous factor savings being returned to customers in 2023 is an important consideration.

29.3 In the event that FEI's request to vary Order G-319-20 is denied, please provide the 2023 delivery rate impact if the $2.68 million net incremental O&M and Late Payment Charges was to be amortized over each of the following amortization periods: (i) one-year; (ii) two-years; and (iii) three-years.

Response:

Please refer to Table 1 below which shows the changes to the proposed 2023 delivery rate if the $2.68 million net incremental O&M and Late Payment Charges were to be returned to customers over an amortization period of one, two or three years. FEI notes there is no change to the 2023 delivery rate increase if the net incremental O&M and Late Payment Charges are amortized over a one-year period instead of captured in the Flow-through deferral account as proposed. Both approaches will return the full amount to customers in 2023. If the net amount is directed to be amortized over a two-year period or three-year period, the 2023 delivery rate impact will increase from 7.42 percent to 7.61 percent or 7.67 percent, respectively.

Table 1: Changes to 2023 Delivery Rate Increase if Net incremental O&M and Late Payment Charges are Amortized over One, Two or Three Years

	Amortization Period		
	1 Year	2 Years	3 Years
Changes to Proposed 2023 Delivery Rate Increase (%)	0.00%	0.19%	0.25%
Proposed 2023 Delivery Rate Increase (%)	**7.42%**	**7.61%**	**7.67%**

On page 149 of the Application, FEI states:

> The cost reductions that FEI achieved consist primarily of lower employee expenses, in part as a response to the travel restrictions, including in and out of Province travel, and the effect that the COVID-19 pandemic has had on social interactions. Employee expenses that were not incurred due to the COVID-19 pandemic include course fees, travel, meals and accommodation, Company function expenses, and employee hiring and relocation expenses.
>
> For the years 2020 and 2021, the reduced employee expenses were estimated at approximately $8.25 million.

29.4 Please explain how FEI tracked and quantified the cost reductions related to the COVID-19 pandemic for 2020 and 2021.

Response:

For estimating the employee expense O&M cost reductions related to the COVID-19 pandemic, FEI compared the actual O&M employee expenses in 2020 and 2021 to the average of the actual O&M employee expenses observed for the three years prior to the start of the pandemic, including years 2017, 2018 and 2019. This provided a reasonable basis to estimate the approximate amount of O&M employee related cost reductions during the COVID-19 pandemic, as using the most recent three years of data prior to the COVID-19 pandemic smooths out the fluctuations of employee expenses that may occur from year to year, providing a representative baseline for comparison.

The following table provides the breakdown of 2020 and 2021 cost reductions by the categories referenced in the above preamble.

Table 1: Employee Expense Cost Reductions by Category for 2020 and 2021

	$millions	
	2020 Reductions	2021 Reductions
Course Fees	(0.46)	(0.31)
Travel	(2.04)	(2.27)
Meals and Accommodation	(1.90)	(1.33)
Company Function	(0.00)	0.13
Employee Hiring and Relocation	(0.11)	0.04
Total	(4.51)	(3.74)
Sum of 2020 and 2021 Reductions	(8.25)	

29.5 Please provide a breakdown of the cost reductions that FEI achieved by each of the categories noted on page 149 of the Application (i.e. course fees, travel, meals and accommodation, Company function expenses, and employee hiring and relocation expenses).

Response:

Please refer to the response to BCUC IR1 29.4.

Directive 10 of Order G-319-20 states: “FEI is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the previously approved COVID-19 Customer Recovery Fund Deferral Account as discussed in Section 12.2.1 of the Application.” [Emphasis added]

29.6 Please confirm, or explain otherwise, that the requested variance to Order G-319-20 should be as follows: “FEI is approved to record COVID-19 incremental costs and related savings from 2020 and 2021, as discussed in Section 12.2.1 of the Application, into the Flow-through deferral account.”

29.6.1 If confirmed, please explain whether FEI seeks to amend either of the 2021 or 2022 permanent delivery rates approved by Orders G-319-20 and G-366-21, respectively, given that amounts captured in the Flow-through deferral account are typically recovered from/returned to customers in rates by way of a projected variance in the prior year’s ending deferral account balance and a true-up of the projected variances from two years prior. Please explain why or why not.

29.6.2 If not confirmed, please provide FEI's proposed wording for the approval sought in this Application.

Response:

The suggested wording for the variance to Order G-319-20 is confirmed.

FEI is not seeking to amend 2021 or 2022 permanent delivery rates, nor is there any reason to do so. As shown in the journal entries provided in the response to BCUC IR1 29.1, no amounts have been recorded in either the Flow-through deferral account or the COVID-19 Customer Recovery Fund Deferral Account in 2020 or 2021 related to these exogenous items, with the actual amounts to be recorded in 2022, pending the BCUC's decision on this Application. These amounts were not recorded in either of the deferral accounts in 2020 or 2021 as FEI was unsure whether the cumulative amounts would exceed the exogenous factor materiality threshold. It is only in this Application, now that actuals are known, that FEI is confirming the cumulative combined amounts exceed the threshold and should be returned to customers. Therefore, FEI will reflect the adjustment in the 2022 financial statements and, given these amounts will be recorded in 2022 and are projected in the 2022 Flow-through deferral account calculation in Table 12-5 of the Application, they will be returned to customers in 2023 rates.

29.7 Please discuss whether FEI considered alternatives to varying Directive 10 of Order G-319-20, such as requesting approval to transfer the ending balance at December 31, 2022 of COVID-19 incremental costs and related savings in the COVID-19 Customer Recovery Fund Deferral Account to the Flow-through deferral account as a January 1, 2023 opening balance adjustment. Please explain why or why not.

Response:

To clarify, as demonstrated in the response to BCUC IR1 29.1, the 2020 and 2021 net savings amounts are not currently recorded in the COVID-19 Customer Recovery Fund Deferral Account, and instead remained in the respective income statement accounts in those years.

While FEI did consider making the adjustment to move the income statement amounts to the Flow-through deferral account in 2023 instead of 2022, FEI did not believe such an approach was necessary and would only have served to delay the return of the exogenous amounts to customers by another year (i.e., the Flow-through deferral account 2023 opening balance adjustment would have been projected in 2023 in the Annual Review for 2024 Delivery Rates and returned to customers in 2024 via amortization of the Flow-through deferral account). Given the final amount of net savings is known in 2022, FEI believes it is most appropriate and beneficial to customers to include the net savings in the Flow-through deferral account in 2022 and return the savings to customers in 2023.

30.0 Reference: EXOGENOUS FACTORS

Exhibit B-2, Section 12.2.2, pp. 151–155

Flooding Damage

On page 151 of the Application, regarding flooding damage incurred in November 2021, FEI states:

> […] FEI estimates the total costs associated with repairing damage to its facilities and restoring service to affected customers are approximately $3.3 million. At the time of this Application, the Company is working with its insurance company to determine the expenditures eligible for recovery. Any insurance recoveries would be used to offset the costs incurred. Given that the outcome of FEI's insurance claim is unknown at this time, FEI has identified the costs related to the 2021 flooding event as a potential exogenous factor but is not requesting recovery of the costs in this proceeding.

On pages 153 and 154 of the Application, in Table 12-2: O&M Costs and Table 12-3: Capital Costs, FEI shows the following actual and forecast costs related to the 2021 flooding event:

- 2021 Actual O&M costs of $1.253 million and total O&M forecast of $1.540 million; and
- 2021 Actual capital cost of $0.631 million and total capital forecast cost of $1.761 million.

30.1 For any natural disaster events in the last five years for which FEI has filed an insurance claim, please provide the following details:

(i) Whether any insurance claims have been denied;

(ii) The total O&M and capital dollar value of costs claimed and recovered;

(iii) The percentage of costs recovered;

(iv) The timeline for the insurance claims process; and

(v) The subsequent effect on insurance premiums after the claim was resolved.

Response:

FEI has not filed an insurance claim for any natural disaster event within the five years prior to 2022.

30.2 Please clarify how the costs associated with repairing flooding damage to FEI's facilities and restoring service to affected customers, as outlined in Table 12-2 and Table 12-3 of the Application, have been accounted for in FEI's financial statements for accounting purposes for the following periods:

(i) the year ended December 31, 2021; and

(ii) the six-months ended June 30, 2022.

Response:

The O&M and capital costs related to repairing flooding damage to FEI's facilities and restoring service to affected customers are being reported as they normally would, consistent with US GAAP, with no different treatment or disclosure.

For the year ended December 31, 2021, the 2021 Actual O&M costs of $1.253 million have been accounted for as part of Operations and Maintenance expense on the Consolidated Statement of Earnings of FEI's financial statements. For the capital expenditures, the 2021 Actual Capital costs of $0.631 million have been accounted for as part of Property, Plant, and Equipment on the Consolidated Balance Sheet of FEI's financial statements. For the six months ended June 30, 2022, the 2022 Actual O&M and Capital costs have been accounted for in the same manner, and presented as part of the same line items in FEI's financial statements.

At this time, FEI is unable to predict when the insurance claim is likely to be settled. However, once the insurance claim has been settled, FEI will follow appropriate accounting treatment in accordance with US GAAP at that time.

30.3 Please discuss FEI's balance sheet and note disclosure considerations regarding the 2021 flooding event in the context of US GAAP ASC 410[10] , 420[11] , and 450[12] or any other relevant sections which are related to contingencies and provisions for the following periods:

(i) the year ended December 31, 2021; and

(ii) the six-months ended June 30, 2022.

Response:

There were no specific disclosures related to the 2021 flooding event required in FEI's financial statements and notes for either the year ended December 31, 2021 or the six-months ended June 30, 2022.

[10] US GAAP ASC 410: Asset Retirement and Environmental Obligations.
[11] US GAAP ASC 420: Exit or Disposal Cost Obligations.
[12] US GAAP ASC 450: Contingencies.

With respect to ASC 450 and recognition of gain contingencies such as insurance proceeds, the guidance indicates it is dependent on the level of certainty associated with realizing a gain in order to ensure entities are not providing misleading information. If a contingent gain is not recognized, it would not be disclosed. As discussed in the response to BCUC IR1 30.2 and Section 12.2.2.3 of the Application, the outcome of the insurance claim associated with the 2021 flooding event is uncertain both in terms of timelines for resolving the claim and estimating the amount. Given the unresolved uncertainties, for the periods ended December 31, 2021 and June 30, 2022, proceeds associated with insurance claims have not been recognized in FEI's financial statements.

With respect to ASC 450 and recognition or disclosure of loss contingencies, the guidance indicates that either recognition or disclosure could be required when there are existing conditions involving uncertainty as to a possible loss that will ultimately be resolved when one or more future events occur. Loss contingencies are recognized when the likelihood of a future event that will confirm the loss is probable and the amount of the loss can be reasonably estimated, otherwise they are only disclosed if the information would be of significance to a financial statement user. Since the majority of the costs related to the 2021 flooding event have been incurred and recognized appropriately, and future costs to be incurred are not dependent on a future event to occur for either the December 31, 2021 or the June 30, 2022 periods, the 2021 flooding event does not meet the definition of a loss contingency. Given this, for the periods ended December 31, 2021 and June 30, 2022, the estimated future costs associated with the 2021 flooding event have been appropriately recognized in FEI's financial statements as costs that have been incurred, and no additional disclosure is necessary.

The 2021 flooding event did not give rise to any obligations associated with future retirements of a long-lived asset (i.e., asset retirement obligation) or further environmental obligations and, as such, ASC 410 (Asset Retirement and Environmental Obligations) is not applicable. The nature of costs associated with the 2021 flooding event are also not within the scope of ASC 420 (Exit or Disposal Cost Obligations) which is limited to transactions and activities associated with terminating contracts, discontinued operations, and other exit activities associated with business combinations.

30.4 Please explain whether FEI considered requesting BCUC approval of a new deferral account to record the costs associated with repairing the flooding damage, with the amount and amortization period pending the final determination of the amount eligible for recovery from FEI's insurance company. If no, please explain why not.

<u>Response:</u>

FEI did not consider requesting a new deferral account to record the costs associated with repairing the flooding damage, as it is inconsistent with the typical approach for recording exogenous costs/savings in the Flow-through deferral account. The Flow-through deferral account is an established mechanism for recording variances between actual and approved amounts that are intended to be fully returned to or recovered from customers. Similar to the responses to the BCUC IR1 29 series, using the Flow-through deferral account instead of another deferral account allows historical O&M expenses to reflect the actual flooding remediation amounts, rather than having them cleared to a separate deferral account. For clarity, the existing O&M and capital costs are currently recorded as O&M and capital, respectively, and a move from those accounts would only be required if a new deferral account was created to reclassify those amounts to. With the mechanics of the Flow-through deferral, those amounts would not require reclassification directly to the Flow-through deferral to recover the respective amounts from customers.

On page 155 of the Application, FEI states:

> […] If FEI's insurance claim is successful, FEI's net incremental costs would be limited to the $1 million insurance deductible. However, until the insurance claim has been settled, FEI will not know the total cost related to the flooding, as FEI may receive all, partial or no reimbursement.

30.5 In the event that FEI's insurance company determines that no amount is eligible for recovery, please provide the estimated impact of the cost associated with the 2021 flooding event (i.e. $3.3 million incurred costs) on the proposed 2023 delivery rates.

Response:

Regardless of the outcome of the insurance claim, there would be no impact on 2023 delivery rates. This is because if the incremental capital and O&M costs related to the 2021 flooding event are ultimately approved for exogenous factor treatment, then these costs (i.e., O&M and the cost of service related to the capital) will be captured by the Flow-through deferral account and recovered from customers in the subsequent year. As FEI did not include an estimate of these costs in the 2022 Projected Flow-through deferral account additions, even if the insurance decision occurs before the end of 2022, the actual costs will only be included as a true-up to the 2022 ending balance of the Flow-through deferral account (i.e., variance between the 2022 Actual costs and the 2022 Projected costs of zero) as part of the Annual Review for 2024 Delivery Rates, and recovered from customers in 2024 delivery rates.

If the insurance decision occurs in 2023, depending on the timing, FEI may be able to include the costs as part of the 2023 Projected balance of the Flow-through deferral account during the 2024 Annual Review in which case they would be recovered from customers in 2024 delivery rates. If the insurance decision occurs late in 2023 or in a future year, FEI may include the costs as part of the 2023 ending balance true-up of the Flow-through deferral account, which would result in the amounts being recovered from customers in 2025 delivery rates.

30.6 In the event that FEI's insurance company determines that the full amount is eligible for recovery, please provide the estimated impact of the cost associated with the 2021 flooding event (i.e. $1 million insurance deductible) on the proposed 2023 delivery rates.

Response:

Please refer to the response to BCUC IR1 30.5.

L. APPENDIX C3 – GIBSONS CAPACITY UPGRADE BUSINESS CASE

31.0 Reference: GCU BUSINESS CASE

Exhibit B-2, Section 7.2.3.2.2, p. 74, Appendix C3, p. 1

Project Need

On page 74 of the Application, FEI states:

> The community of Gibsons is supplied with natural gas by a 19-kilometre IP pipeline from the Sechelt Gate Station which is in turn served by the Vancouver Island Transmission System (VITS). The capacity of the IP pipeline is insufficient to meet current peak demand such that FEI is currently unable to supply sufficient capacity to the community during design conditions without the support of a temporary contracted CNG trailer on site during winter months. […]

31.1 Please explain the extent to which the capacity of the IP pipeline from the Sechelt Gate Station is affected by (i) the peak demand on the entirety of the VITS system, and (ii) the peak demand in the localized area supplied by the Sechelt Gate Station.

31.1.1 Please discuss whether the capacity of the IP pipeline from the Sechelt Gate Station may be affected by future increases or decreases in demand.

Response:

The capacity of the IP pipeline from Sechelt serving Roberts Creek and Gibsons is unaffected by the peak demand on the entirety of the VITS and independent of the capacity and demand on the VITS, which is the upstream transmission system. Similarly, the peak demand of the localized area served by the Sechelt Gate Station, served directly by the VITS to a separate TP/DP Gate Station and not through the IP pipeline, does not impact the capacity of the IP pipeline.

The capacity of the IP pipeline is determined by the discharge pressure of the Sechelt TP/IP Gate Station supplying the IP pipeline, currently set to the maximum allowable for the pipeline of 3100 kPa, the pipe size and length, and the minimum allowable pressure at the far end of the IP pipeline at Gibsons. That minimum pressure is the pressure that will allow the Gibsons District Station to reliably discharge into that system at the maximum allowable DP pressure of 552 kPa under peak demand flow. Currently, that minimum pressure at Gibsons is 900 kPa to serve a peak demand of 3710 standard cubic metre per hour. Currently, without mitigating actions such as CNG supplementation, the pressure at Gibsons will fall well below 900 kPa under peak demand. This indicates that the pipeline does not have the capacity to provide sufficient pressure to allow the station to meet the peak demand supply.

Increases in peak demand without mitigation will cause further degradation in the pressure at Gibsons, further reducing the capacity of the IP pipeline and Gibsons District Station and increasing the need for supplementation of the pipeline supply with CNG. Decreases in demand would similarly reduce that need for supplementation.

On page 1 of Appendix C3 to the Application, FEI states: "[t]he purpose of the GCU project is to provide a cost-effective long-term capacity solution to address the current capacity shortfall in the Gibsons community."

31.2 Please provide FEI's 20-year demand forecast for the Gibsons community.

31.2.1 Please explain FEI's methodology for developing its 20-year demand forecast, detailing all assumptions made

.

Response:

The table below provides the current 20-year peak demand forecast for the Gibsons distribution system served by the Gibsons District Station. The results are based on FEI's 2022 account forecast and peak demand determined from customer consumption in the Gibsons area from the two-year period between January 1, 2020 and December 31, 2021.

Gibsons 20-year Peak Demand Forecast

Forecast year	Gibson Peak Demand (m^3/hour)
2022	3711
2023	3742
2024	3758
2025	3778
2026	3783
2027	3788
2028	3790
2029	3794
2030	3796
2031	3797
2032	3792
2033	3790
2034	3787
2035	3786
2036	3788
2037	3789
2038	3788
2039	3787
2040	3785
2041	3783
2042	3784

FEI's peak demand forecast is based on the same methodology described in recent applications and is described in greater detail in Section 7.3.2.1 of its 2022 Long Term Gas Resource Plan (LTGRP). The demand forecast is derived from the account forecast for the local area that is prepared annually that provides a 20-year forecast of residential, small commercial and large commercial customers (rate schedules 1,2, 3 and 23).

In order to create the incremental load each year added to the demand forecast, FEI multiplies the accounts in each rate class added each year by the average use per customer under peak demand (UPC_{peak}) for existing customers in that rate class in the local area (Gibsons Roberts Creek and Sechelt). UPC_{peak} for each existing customer is determined annually from a demand versus temperature regression of the most recent two years of billed consumption and local weather observed during that two-year period and by then extrapolating demand to the regional design temperature (a very cold average daily temperature expected to occur statistically approximately once every 20 years). In the forecast, FEI does not provide any adjustments for future changes in customer consumption but assumes the current UPC_{peak} remains constant throughout the forecast. For large industrial customers FEI does not forecast increases or decreases in accounts or demand but considers the level of industrial peak demand fixed at current levels throughout the forecast.

31.3 Please explain whether FEI applied any scenario modelling to its 20-year demand forecast.

31.3.1 If yes, please provide details of any scenarios assessed and discuss the results with respect to FEI's assessment of the impact for long-term capacity needs.

31.3.2 If no, please explain why not.

Response:

FEI does not apply any scenario modelling to its 20-year demand forecast for assessing infrastructure. FEI's approach is to use the current traditional peak demand forecast to identify future system upgrade needs. FEI then refreshes the demand forecasts on an annual basis to adjust timing and scope of previously identified projects within the forecast period until such time that detailed planning must begin to execute the project in time to meet the projected capacity deficit. At that future point, the most recent demand forecast derived from the calculated peak demand requirements of the connected customers is used to refine the project scope.

FEI does explore a range of peak demand forecasts in the LTGRP to study a range of possibilities that may develop over time. However, as stated above, FEI relies on the traditional forecast, that represents peak demand consumption occurring at the time, when planning and initiating the execution of projects imminently required. To apply scenarios to the forecast when decisions about initiating projects are made and that depend on factors that may or may not develop over time could unreasonably delay project execution if considered in decision making.

31.4 Please discuss whether FEI uses peak-day or peak-hour demand as a design basis for its transmission system supplying Gibsons and explain the reasons for this design basis.

Response:

FEI uses a peak day approach for the Vancouver Island Transmission System (VITS) (that supplies the Sechelt to Gibsons IP pipeline). A peak day design basis allows for the beneficial effects of line pack (the gas inventory contained within the pipeline) to supplement the impacts of peak hour demand by, for short periods, drawing on that inventory when demand out of the system exceeds the flow into the system. By accounting for the available line pack, the transmission system has a higher capacity to serve peak demand than if the same pipeline used peak hour demand as a design basis.

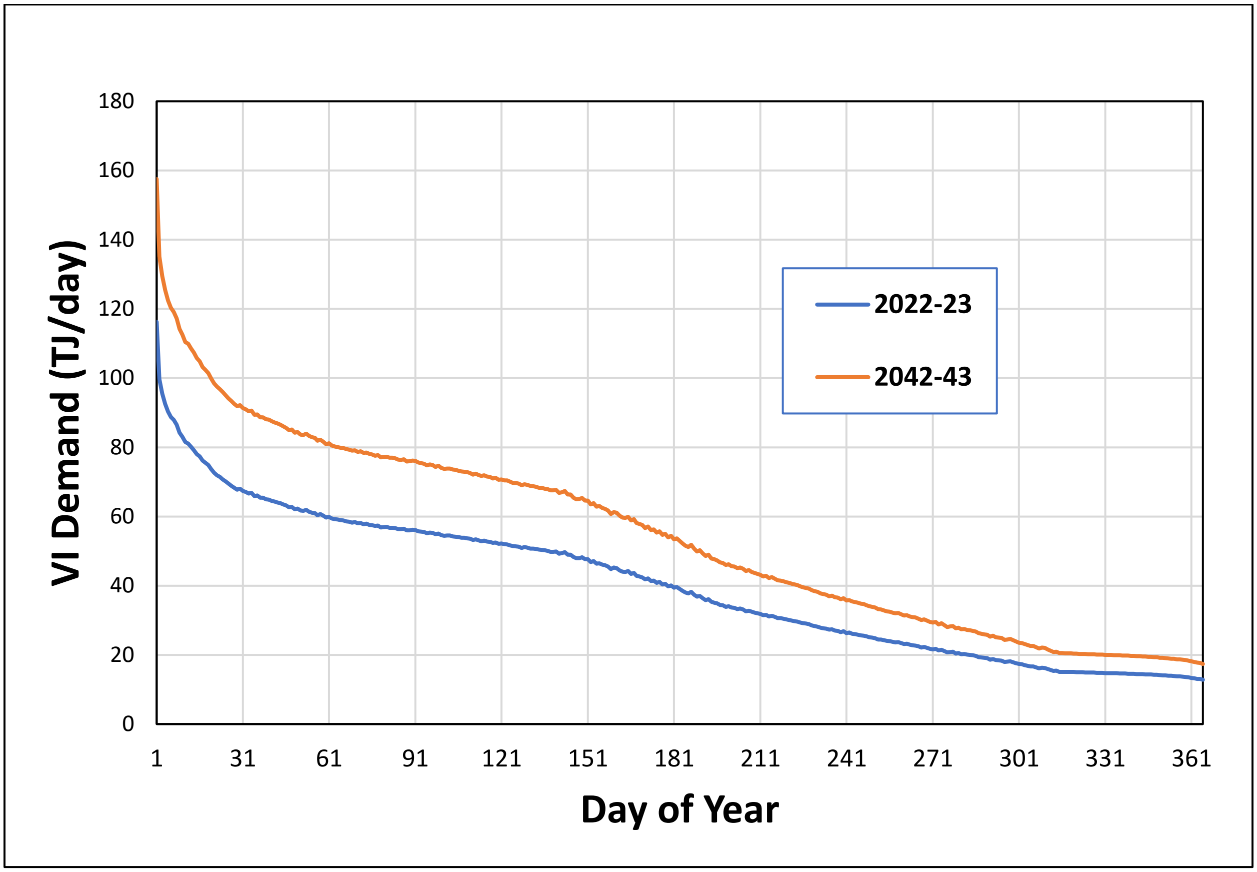
However, the beneficial effect of line pack within the VITS is unavailable to the IP pipeline serving Gibsons and cannot mitigate the capacity shortfall addressed by the GCU project because the pressure regulation at the Sechelt TP/IP Gate Station prevents line pack changes in the VITS from translating into corresponding changes in line pack in the downstream IP and DP systems. The IP pipeline and the Gibsons distribution system have insufficient line pack on their own to offset peak demand adequately; as a result, FEI uses peak hour demand as a design basis for all IP and DP systems because of that lack of available line pack.

31.5 Please provide Load Duration Curves for the current transmission system supplying Gibsons and at the end of the 20-year planning period which shows the peak demand for each day of a design year.

Response:

The following figure shows the most recent gas supply load duration curves for the VITS in 2022 and for 2042.

Figure 1: VITS Load Duration Curves

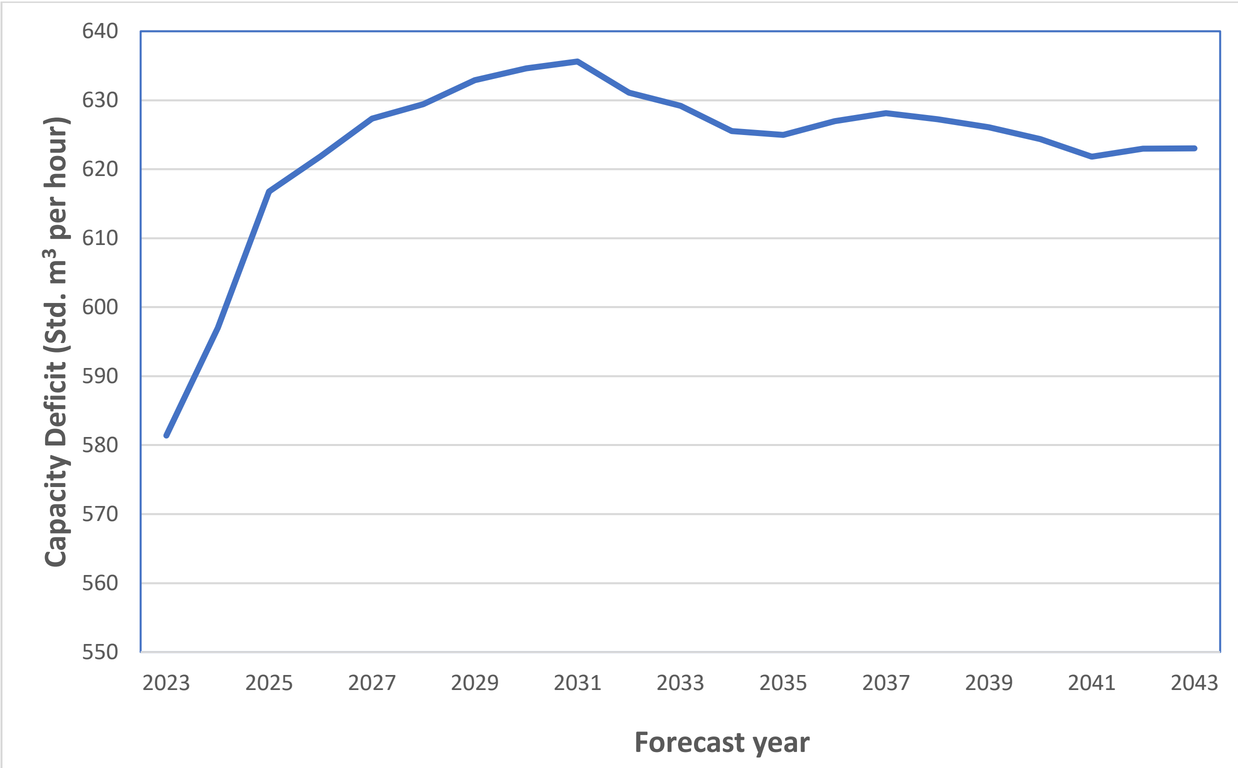


31.6 Please provide a graph for the Gibsons community which shows from 2023 to 2043 the anticipated capacity shortfall under forecasted peak demand conditions in the absence of the GCU Project.

Response:

The figure below provides the forecast capacity deficit each year through the forecast period.

Figure 1: Forecast Capacity Deficit for Gibsons in Absence of GCU Project



31.7 Please provide a table summarizing the following for each year from 2023 to 2043: (i) the forecast peak demand; (ii) the available capacity without supplement from a CNG trailer; (iii) the projected capacity shortfall; and (iv) the number of customers that would experience service disruptions.

<u>Response:</u>

The following table summarizes the requested information for the forecast period using FEI's most recent demand forecast for Gibsons.

Table 1: Forecast Capacity Shortfall and Number of Customers Disrupted without GCU Project

Forecast year	Gibson Peak Demand (m^3/hour)	Current Capacity to Serve Gibsons (m3/hour)	Capacity Shortfall (m3/hr)	Estimated Customers disrupted*
2023	3742	3161	581	681
2024	3758	3161	597	699
2025	3778	3161	617	722
2026	3783	3161	622	728
2027	3788	3161	627	735

Forecast year	Gibson Peak Demand (m^3/hour)	Current Capacity to Serve Gibsons (m3/hour)	Capacity Shortfall (m3/hr)	Estimated Customers disrupted*
2028	3790	3161	629	737
2029	3794	3161	633	741
2030	3796	3161	635	743
2031	3797	3161	636	744
2032	3792	3161	631	739
2033	3790	3161	629	737
2034	3787	3161	626	732
2035	3786	3161	625	732
2036	3788	3161	627	734
2037	3789	3161	628	736
2038	3788	3161	627	734
2039	3787	3161	626	733
2040	3785	3161	624	731
2041	3783	3161	622	728
2042	3784	3161	623	729
2043	3784	3161	623	730

* Customer disruption estimated using residential UPC_{peak} for Gibson area

31.8 Please explain whether FEI supplies any customers in the Gibsons community under an interruptible service rate.

31.8.1 If yes, please explain whether FEI has accounted for these customers' demand in its demand forecast.

31.8.2 If no, please update the demand forecast provided in response to IR 31.7 to show demand from firm and interruptible rate customers.

Response:

No. The Gibsons distribution system does not have customers with an interruptible rate schedule. FEI does not include interruptible demand in any peak demand forecasts so the demand forecast provided in the response to BCUC IR1 31.7 would not change whether interruptible customers exist currently or if they might connect in the future.

32.0 Reference: GCU BUSINESS CASE

Exhibit B-2, Appendix C3, Section 2.3, p. 11

Project Description

On page 11 of Appendix C3 to the Application, FEI states:

> As demand in Gibsons increases, additional storage capacity would be required. Two storage vessels would be installed initially with additions tentatively planned in 2037 and 2042 based on current projections. At this stage, the design does not include commercial CNG supply or truck filling capability.

Further on page 11, FEI includes a “4 x 1,945 Sm3 (standard cube metre) CNG storage vessels with gas management panel” as a key feature of the proposed CNG peak shaving station.

32.1 Please explain FEI’s methodology for determining the required storage capacity (initial and planned in 2037 and 2042) for the CNG peak shaving station, detailing all assumptions made.

Response:

FEI’s System Capacity Planning department used flow data from the Gibsons District Station to create a typical daily flow profile for the Gibsons system. This flow profile, along with the peak hour demand forecast for any year, is used to create an hour-by-hour representation of flow on a peak day for that chosen year. FEI used these peak day flow profiles, along with the calculated capacity of the existing IP pipeline and the Gibsons District Station to determine which hours of the day the existing pipeline and station needed supplementation to meet the hour’s demand and which hours of the day the pipeline and station could deliver more than the hour’s demand. FEI could then determine the cumulative amount of stored CNG required to supplement demand in the peak hour(s) on a peak day in any year and could also confirm that sufficient pipeline/station capacity existed in the off-peak hours to replenish the stored CNG.

FEI used the results to determine the peak CNG send out capacity that the facility would require and that two CNG tanks would be sufficient to supplement the peak demand requirements until at least 2037, at which point additional storage may be required if demand continued to grow. The predicted cumulative amount of stored CNG required until 2037 is 3,890 Sm3 which corresponds to two CNG vessels. In the early years of usage of the CNG vessels, a safety margin up to 90 percent is present, but this margin will erode as additional demands on the Gibsons system materialize and is expected to be at about 15 percent by 2037.

32.2 Please clarify whether FEI’s project cost estimate is based on two or four CNG storage vessels.

32.2.1 If the cost estimate is based on two CNG storage vessels, please provide a revised project cost estimate to install all four CNG storage vessels.

Response:

FEI's project cost estimate is based on two CNG storage vessels.

The incremental cost to install the additional two storage vessels is estimated to be approximately $477 thousand in 2022 dollars, inclusive of purchasing, shipping, lifting equipment, construction, and labour costs.

32.3 Please describe the "commercial CNG supply" and "truck filling capability" components of the future design, including the expected costs. As part of the response, please explain why the current design does not include commercial CNG supply or truck filling capability.

Response:

FEI has made provisions in the current design to minimize future costs where practical. However, as stated on page 17 of Appendix C3, the design does not include commercial CNG supply or truck filling capability as there is no current commercial demand for such facilities in the Gibsons area. If at a later date FEI determines there is interest in commercial CNG or truck filling capability, modifications can be made to the existing site to accommodate the request to include a CNG fueling station.

If future commercial CNG fueling station demand materializes, it will be part of FEI's Clean Growth Initiatives under the NGT program, with expenditures either being classified as a prescribed undertaking under the GGRR or FEI's GT&C 12B. In both cases, any incremental costs required to install the potential fueling station will be recovered from the fueling customers, similar to FEI's existing agreements for FEI-owned CNG & LNG fueling stations.

32.4 Please provide a cost estimate of the GCU project if it were to include the two additional storage vessels planned in 2037 and 2042, commercial CNG supply, and truck filling capability.

32.4.1 If the cost estimate in the preceding IR is above $15 million, please explain why FEI is not filing the GCU project as a Certificate of Public Convenience and Necessity (CPCN) application. As part of the response, please discuss any considerations FEI will make if the actual GCU project costs exceed $15 million.

Response:

With regard to commercial CNG supply and truck filling capability, please refer to the response to BCUC IR1 32.3 which explains why these costs would not be recovered from FEI's core customers.

With regard to the two additional storage vessels, the inclusion of these additional costs (estimated to be $477 thousand in 2022 dollars as described in the response BCUC IR1 32.2) would not result in the GCU project costs exceeding the $15 million materiality threshold.

However, it would not be appropriate to include the additional two storage vessels when assessing whether the GCU project exceeds the materiality threshold. Consistent with FEI's approach to CPCN applications, FEI provides information regarding future incremental capital and O&M expenses that could occur over the life of the assets; however, these costs are not part of the "project costs." The CPCN threshold is applied to the expected costs of the project. It is not based on all future capital costs that may be incurred subsequent to the project's completion, or the present value of all capital costs over the lifetime of the assets. As provided in the preamble, the two additional storage vessels are not needed until at least 2037 and 2042.

FEI does not expect that the GCU project will exceed the $15 million threshold. As demonstrated in the response to BCUC IR1 34.2, the P10 to P90 range of the GCU project cost is $10.446 million (with AFUDC) to $13.927 million (with AFUDC), with the expected P50 project cost at $12.194 million. FEI will actively manage the budget, scope of work, and schedule for all projects, and all changes to the project budget will be handled through change controls that are reviewed and approved internally.

33.0 Reference: GCU BUSINESS CASE

Exhibit B-2, Appendix C3, Section 1.2, p. 2

CNG Trailer

On page 2 of Appendix C3 to the Application, FEI states:

> […] Currently there is insufficient inlet pressure available to the Gibsons District Station during FEI design conditions. FEI has been managing this shortfall through the current availability of higher than contracted heating values present in the natural gas network, and by contracting a CNG trailer to be available on short notice during winter months to supplement low inlet pressures at the Gibsons District Station.

33.1 With reference to the statement, "there is insufficient inlet pressure available to the Gibsons District Station during FEI design conditions," please quantify and explain what is meant by "insufficient inlet pressure".

Response:

In stating that there is insufficient inlet pressure available to the Gibsons District Station, FEI means that with the IP pipeline operating at its maximum operating pressure at Sechelt, the pressure drop along the pipeline under peak demand flow would result in a pressure at the inlet to the Gibsons District Station that is too low for the primary regulating run on the station to deliver the required flow into the Gibsons distribution system at the required operating pressure (for the Gibsons system) of 552 kPa. This would create a supply shortfall in the system, would result in a degradation of pressure within the distribution system, and ultimately result in customer outages.

In the response to BCUC IR1 31.7, FEI indicated the current capacity to serve Gibsons is 3,161 m^3 per hour. At that rate of flow through the IP pipeline, the resulting pressure at the inlet to the Gibsons District Station would be 819 kPa. Peak flow higher than 3,161 m^3 per hour will result in pressure lower than 819 kPa at the inlet to the Gibson District Station and result in a degradation in pressure in the Gibsons distribution system.

Gibsons peak demand is currently estimated to be higher than 3,161 m^3 per hour should a design day occur (see the forecast provided in the response to BCUC IR1 31.7). As a result, there is insufficient inlet pressure for the Gibson District Station to deliver higher flow. FEI is therefore relying on the currently higher than typical heating value of the gas currently received from Enbridge and some supplementation with portable CNG to meet peak demand conditions should they occur before the GCU project is completed and in service.

33.2 Please explain FEI's methodology for determining the temporary CNG capacity needed to sustain gas supply to customers in Gibsons, detailing all assumptions made.

Response:

Please refer to the response to BCUC IR1 32.1.

33.3 Please discuss whether FEI could continue to manage this shortfall through an alternative involving temporary CNG trailers.

33.3.1 If yes, please provide an alternative assessment, including reasons why this alternative was rejected.

33.4 If no, please explain why not.

Response:

No. FEI notes that there are currently no CNG stations on the Sunshine Coast; therefore, any supply of CNG would have to be delivered from the Mainland, thus requiring some form of marine transport (barges), or requiring FEI to construct a permanent CNG fueling station on the Sunshine Coast. As such, due to the logistical complexity of arranging marine transport (barges) to deliver the filled CNG trailers (and any resupply required through the winter) or the additional costs to build a permanent compressor and refilling station solely for the purpose of refilling the temporary CNG trailers, FEI discounted the supply of portable CNG as a permanent solution.

33.5 Please explain the extent to which FEI's ability to manage shortfalls at the Gibsons District Gate Station is affected by heating values present in the gas network.

33.5.1 Please discuss whether FEI's ability to mange shortfalls at the Gibsons District Gate Station may be affected by future increases or decreases in heating values of the gas.

Response:

The current heating value present in the gas supply to the VITS and Gibsons is higher than that historically received and higher than the heating value that would be present in gas that meets the minimum gas quality specification used in gas supply contracts. This situation is currently beneficial in managing the capacity shortfall in the IP pipeline serving the community.

For capacity planning in the Gibsons region, FEI uses a 20-year average heating value equivalent to 38.82 MJ/m^3. Currently the area is receiving gas with a heating value of 41.01 MJ/m^3. While FEI has a minimum gas quality specification, FEI is not able to dictate a specific elevated gas energy content be provided by suppliers. Therefore, when preparing peak demand forecasts and in planning for capacity upgrades like the GCU project, FEI uses the lower 20-year average value to provide some allowance for variation in the heating value of the gas supply. At present, with the current above-average heating value, each standard cubic meter of natural gas currently delivers 5.6 percent more energy that FEI typically plans for.

Changes in heating value will have some effect on the capacity benefit the GCU project provides to supplement peak demand. If future heating values remain above the 20-year average, the GCU project will support a greater increased peak demand than it is currently designed to supplement; however, if heating values fall to a point where they remain below FEI's 20-year average used to design the facility, the GCU project will have a slightly lower capability to support peak demand. This circumstance might, for example, require storage expansion a year or two earlier than currently forecast at the CNG site.

34.0 Reference: GCU BUSINESS CASE

Exhibit B-2, Section 7.2.3.2.2, pp. 73–74, Appendix C3, Section 2.4, p. 12, Section 4.0

p. 20

Project Cost Estimate

On pages 73 and 74 of the Application, FEI states:

> In the MRP Application (Section 3.3.3, page C-77), FEI identified the GCU project as a Major Project (the GCU project was referred to as the FEI Sunshine Coast Capacity Upgrade project in the MRP Application). At the time of filing the MRP Application, FEI had anticipated that the GCU project would exceed the $15 million materiality threshold and would therefore be filed as a CPCN application at some point during the MRP term. However, through further refinement of the preliminary project scope and associated cost estimate, FEI was able to arrive at a lower cost solution […]

34.1 Please provide the estimated cost of the GCU project at the time of filing the MRP Application.

34.1.1 Please compare the cost of the GCU project at the time of filing the MRP Application to the cost of the GCU project presented in the Application. As part of the response, please explain the change(s) in the project scope and associated cost estimate such that the project cost is now below FEI's CPCN materiality threshold of $15 million.

<u>Response:</u>

At the time of filing the 2020-2024 MRP Application, FEI had not yet completed any AACE cost estimates for the GCU project. The alternatives being considered, which included three pipeline and control station alternatives, were only in the very early stages of investigation. However, based on an initial overview of the scope, and considering the required length and diameter of the pipelines as well as the expected challenges with routing, each of these alternatives were expected to well exceed the $15 million CPCN materiality threshold.

Since the time of the MRP filing, FEI has developed each of the alternatives to an AACE Class 4 level of definition. These resulted in a range of P50 cost estimates between $35.2 million and $48.3 million, as shown in Section 2.4 of Appendix C3. This work validated FEI's expectation as it pertained to the scope identified at the time of filing the 2020-2024 MRP Application.

The change in the project scope and cost estimate was a shift from a traditional pipeline-and-control-station alternative to an innovative CNG peak shaving facility that was able to meet the needs of the community in a more cost-effective manner. This alternative was a fundamentally different solution than those identified at the time of the 2020-2024 MRP Application and has resulted in a solution with a cost estimate below the CPCN materiality threshold of $15 million (please see the response to BCUC IR1 34.2). Once FEI determined that this innovative solution to the capacity issue was both feasible and resulted in the lowest rate impact, FEI determined that it was the best solution to proceed with for customers.

On page 20 of Appendix C3 to the Application, FEI states:

> The estimate is a Class 3, as defined by the AACE International Estimate Classification. This Class of estimate is considered a study or feasibility cost estimate with an expected level of accuracy of -20% to +30% for feasibility. […]

The GCU project capital cost estimate is summarized in Table C3-4, as reproduced below:

Table C3-4: Class 3 Capital Cost Estimate ($ millions)[2]

Particular	$ millions
Project Development	1.600
Project Management	1.218
Engineering	1.089
Pipeline Construction	0.247
Facilities Construction	5.986
Project Capital Costs	**$ 10.140**
Contingency	0.832
Escalation	0.320
AFUDC	0.902
Total Project Costs	**$ 12.194**

34.2 Please confirm, or explain otherwise, that the GCU project's lower and upper bound capital cost estimate are $9.7552 million and $15.8522 million, respectively[13].

34.2.1 If confirmed, please discuss whether it would be appropriate for FEI to file a CPCN application for the GCU project considering that the upper bound capital cost exceeds $15 million. Please explain why or why not.

34.2.2 If not confirmed, please provide the correct lower and upper bound capital cost estimate of the GCU project.

Response:

Not confirmed. Per Table 1 of AACE RP 18R-97, the Expected Accuracy Range is a Secondary Characteristic, driven by the Primary Characteristic of Maturity Level of Project Definition Deliverables. The accuracy range is not described by bounds but rather by +/- values which represent typical percentage variation at an 80 percent confidence interval. The target range of an estimate is a characteristic of the class of estimate and Table 1 in AACE 18R provides the

[13] Lower bound calculated as: Total Project Costs $12.194 million x (1 – 20%) = $9.7552 million; Upper bound calculated as: Total Project Costs $12.194 million x (1 + 30%) = $15.8522 million.

typical variation in low and high ranges at an 80 percent confidence interval. For example, a Class 3 estimate has a target range of -20% to +30%. As stated on page 5 of AACE RP 18R-97:

> While a target range may be expected for a particular estimate, the accuracy range should always be determined through risk analysis of the specific project and should never be pre-determined.

As such, and in alignment with AACE RP 42R-08 Risk Analysis and Contingency using Parametric Estimating, FEI calculated that, based on the level of definition and maturity of the associated deliverables, the total Project cost with an 80 percent confidence interval range on the base cost estimate at P10 is $10.446 million (with AFUDC) and at P90 is $13.927 million (with AFUDC). The Total Project Cost reported at $12.194 million in Table C3-4 represents the P50 value.

However, regardless of what might be the upper bound P90 estimate of the GCU Project, the CPCN threshold should be compared against the expected capital cost of the project, which in the case of the GCU, is $12.194 million. There is no requirement or mention of the CPCN threshold being held against the upper bound of the project capital cost estimate in the BCUC's Decision and Order G-120-15, which set the original $15 million CPCN threshold during FEI's 2014-2019 PBR term, or in the BCUC's Decision and Order G-165-20, which approved the continuation of the current $15 million CPCN threshold over the current 2020-2024 MRP term. Historically, except for specific projects/programs that were directed by the BCUC to apply for a CPCN (e.g., NGT fueling stations under FEI's GT&C 12B and biomethane capital projects which have a CPCN threshold of $5 million) or new extensions to FEI's system (e.g., Stargas transfer of assets to FEI), FEI has consistently applied the CPCN threshold of $15 million against its expected capital cost estimates. FEI considers that this is the most reasonable approach, as the expected estimate is the most likely one, whereas the P10 or P90 estimates are less likely.

34.3 Please provide a rate impact analysis for the GCU project over the life of the project for each of the lower, expected, and upper bound capital cost estimate.

<u>Response:</u>

Please refer to Table 1 below for the levelized delivery rate impact in percentage and in $ per GJ for the P10 (lower bound), P50 (expected), and P90 (upper bound) project cost estimates as discussed in the response to BCUC IR1 34.2. For the average residential (RS 1) customer with demand of 90 GJ per year, the levelized bill impact over the 62-year analysis period ranges from 41 cents to 53 cents. FEI notes the 62-year analysis period is based on 60 years of estimated service life for the station plus two prior years for construction (i.e., 2022 and 2023).

Table 1: Delivery Rate Impact for the GCU Project over the Life of the Project

	P10	P50	P90
Total Project Costs ($millions)	10.446	12.194	13.927
Levelized Delivery Rate Impact over 62 yrs (%)	0.09%	0.10%	0.11%
Levelized Delivery Rate Impact over 62 yrs ($/GJ)	$ 0.005	$ 0.005	$ 0.006
Levelized RS 1 Bill Impact ($)	$ 0.41	$ 0.47	$ 0.53

34.4 Please provide further information regarding the $12.194 million project cost estimate, including but not limited to, the following:

(i) A breakdown of each line item provided in Table C3-4 including a description of the line item;

(ii) When the project cost estimate was finalized; and

(iii) Considerations made for rising inflation, interest and commodity prices and any revised cost estimates as appropriate.

Response:

The following provides a breakdown and description of the items included in Table C3-4. The project cost estimate was finalized in the fourth quarter of 2021. At that time, FEI utilized market pricing and current bid information as much as possible to inform the cost estimate. As the estimate considers recent pricing, some of the material and labour cost pressures have been accounted for in the current cost estimates. FEI expects to manage the cost pressures within the existing contingency and escalation allowances for the GCU project.

Table 1: GCU Project Costs Breakdown and Description

Particular	Breakdown	Cost ($000)	Description
Project Development		1,600	
	Class 4	933	Costs associated with developing 4 alternatives to a Class 4 level of definition
	Class 3	667	Costs associated with developing the preferred alternative to a Class 3 level of definition
Project Management		1,218	
	Project Management	294	FEI oversight
	Community Relations	13	FEI internal resource support
	Indigenous Relations	43	FEI internal resource support
	Communications	5	FEI internal resource support
	Env/Arch	93	Environmental and Archaeological support and oversight

Particular	Breakdown	Cost ($000)	Description
	Property Services	614	FEI internal resource support and cost to purchase land
	Legal	2	FEI internal resource support
	Operations Support	61	FEI internal resource support for construction activities
	Health and Safety	18	FEI internal resource support
	Procurement	75	FEI internal resource support
Engineering		1,089	
	Design	913	Detailed design of the facility and associated new gas main to connect facility to existing DP system
	Geotechnical	73	Geotechnical investigation to inform design of the facility and new gas main
	Construction Management	103	Oversight of construction activities
Pipeline Construction		247	
	DP Main Open Trench Installation	217	Installation of the new gas main connecting the new station to the DP system
	DP Main Tie In	30	Tie-ins for the new main connection
Facilities Construction		5,986	
	CNG Station	5,157	On-site permitting, materials, fabrication, construction
	CNG Station Indirect	606	Temporary facilities and utilities, commissioning services.
	PST on Materials	223	
Project Capital Cost		**10,140**	
Contingency		832	Contingency allowance
Escalation		320	Allowance for escalation on labour and materials
AFUDC		902	
Total		**12,194**	

In Table C3-1 on page 12 of Appendix C3 of the Application, FEI provides a summary of the Class 4 capital cost estimates of the GCU project alternatives.

34.5 Please explain whether FEI engaged an independent engineering firm to estimate the capital cost of the GCU project, including the project alternatives.

34.5.1 If yes, please describe the engineering firm's relevant qualifications and experience. Please also provide the independent engineer's scope of work on this project.

34.5.2 If not, please explain why not.

Response:

FEI engaged two independent engineering firms (Tetra Tech and Jenmar Concepts) to estimate the capital cost of each of the GCU project alternatives considered at a Class 4 level of definition and to continue the development through to a Class 3 level of development for the preferred alternative.

Tetra Tech was retained to develop the engineering deliverables to AACE RP97-18 requirements, cost estimate and schedule at an AACE Class 4 level of definition for the two intermediate pressure pipeline alternatives. Tetra Tech has provided similar services as well as detailed engineering to FEI for various sustainment capital and major projects, including the Inland Gas Upgrade CPCN project. Tetra Tech's relevant qualifications and experience include providing engineering design services for the following pipeline projects:

- Pre-FEED, FEED and detailed engineering design of a new natural gas gathering system, including NPS 4 laterals, NPS 8 hot tap and facility components in Central Alberta;
- Detailed engineering design of a new NPS 10, 8.2 km long natural gas pipeline system, including a meter station facility and tie in to and existing NPS 10 pipeline in Alberta;
- Detailed engineering design of a new NPS 48, 3.2 km long natural gas pipeline system, including launcher and receivers in a mountainous area of British Columbia; and
- Detailed engineering design of a new NPS 20, 10 km long natural gas pipeline system, including a meter station facility in a mountainous area of British Columbia.

Jenmar Concepts was retained to develop the engineering deliverables to AACE RP18-97 requirements, cost estimate and schedule at an AACE Class 4 level of definition for the CNG peak shaving alternative. Jenmar Concepts has provided services to FEI for numerous CNG refueling station for transportation projects. Jenmar Concepts' relevant qualifications and experience include providing engineering design services for the following CNG projects:

- Detailed engineering design of a new CNG bulk trailer decanting system, including injection into a gas transmission pipeline;
- Detailed engineering design of a new heavy-duty CNG vehicle refuelling facility in British Columbia; and
- Detailed engineering design of a new CNG bulk loading facility, including gas dryer, CNG compressors, and CNG storage vessels.

Attachment 1.1

RATE SCHEDULE 1 - RESIDENTIAL SERVICE

Line No.	Particular	EXISTING RATES JULY 1, 2022				PROPOSED JANUARY 1, 2023 RATES				Annual Increase/Decrease		
		Quantity		Rate	Annual $	Quantity		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**MAINLAND AND VANCOUVER ISLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge per Day	365.25	days x	$0.4085 =	$149.20	365.25	days x	$0.4085 =	$149.20	$0.0000	$0.0000	0.00%
4	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	365.25	days x	$0.0131 =	4.78	365.25	days x	$0.0131 =	4.78	0.00	0.00	0.00%
5	Subtotal of per Day Delivery Margin Related Charges				**$153.98**				**$153.98**		**$0.00**	**0.00%**
6												
7	Delivery Charge per GJ	90.0	GJ x	$5.455 =	490.9500	90.0	GJ x	$5.990 =	539.1000	$0.535	$48.1500	3.69%
8	Rider 3 BVA Rate Rider per GJ	90.0	GJ x	$0.059 =	5.3100	90.0	GJ x	$0.132 =	11.8800	$0.073	6.5700	0.50%
9	Rider 5 RSAM per GJ	90.0	GJ x	$0.012 =	1.0800	90.0	GJ x	($0.209) =	(18.8100)	($0.221)	(19.8900)	-1.52%
10	Subtotal of Per GJ Delivery Margin Related Charges				**$497.34**				**$532.17**		**$34.83**	**2.67%**
11												
12	Commodity Related Charges											
13	Storage and Transport Charge per GJ	90.0	GJ x	$1.505 =	$135.4500	90.0	GJ x	$1.505 =	$135.4500	$0.000	$0.0000	0.00%
14	Rider 6 MCRA per GJ	90.0	GJ x	($0.154) =	(13.8600)	90.0	GJ x	($0.154) =	(13.8600)	$0.000	0.0000	0.00%
15	Subtotal Storage and Transport Related Charges per GJ				$121.59				$121.59		$0.00	0.00%
16												
17	Cost of Gas (Commodity Cost Recovery Charge) per GJ	90.0	GJ x	$5.907 =	$531.63	90.0	GJ x	$5.907 =	$531.63	$0.000	$0.0000	0.00%
18	Subtotal Commodity Related Charges per GJ				**$653.22**				**$653.22**		**$0.00**	**0.00%**
19												
20	Total *(with effective $/GJ rate)*	90.0		*$14.495*	**$1,304.54**	90.0		*$14.882*	**$1,339.37**	*$0.387*	**$34.83**	**2.67%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.
Slight differences in totals due to rounding

RATE SCHEDULE 2 - SMALL COMMERCIAL SERVICE

Line No.	Particular	EXISTING RATES JULY 1, 2022 Quantity	Rate	Annual $	PROPOSED JANUARY 1, 2023 RATES Quantity	Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**MAINLAND AND VANCOUVER ISLAND SERVICE AREA**									
2	Delivery Margin Related Charges									
3	Basic Charge per Day	365.25 days x	$0.9485 =	$346.44	365.25 days x	$0.9485 =	$346.44	$0.0000	$0.00	0.00%
4	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	365.25 days x	$0.0131 =	4.78	365.25 days x	$0.0131 =	4.78	$0.000	0.00	0.00%
5	Subtotal of per Day Delivery Margin Related Charges			**$351.22**			**$351.22**		**$0.00**	**0.00%**
6										
7	Delivery Charge per GJ	322.0 GJ x	$4.165 =	1,341.1300	322.0 GJ x	$4.554 =	1,466.3880	$0.389	125.2580	3.08%
8	Rider 3 BVA Rate Rider per GJ	322.0 GJ x	$0.059 =	18.9980	322.0 GJ x	$0.132 =	42.5040	$0.073	23.5060	0.58%
9	Rider 5 RSAM per GJ	322.0 GJ x	$0.012 =	3.8640	322.0 GJ x	($0.209) =	(67.2980)	($0.221)	(71.1620)	-1.75%
10	Subtotal of Per GJ Delivery Margin Related Charges			**$1,363.99**			**$1,441.59**		**$77.60**	**1.91%**
11										
12	Commodity Related Charges									
13	Storage and Transport Charge per GJ	322.0 GJ x	$1.542 =	$496.5240	322.0 GJ x	$1.542 =	$496.5240	$0.000	$0.0000	0.00%
14	Rider 6 MCRA per GJ	322.0 GJ x	($0.158) =	(50.8760)	322.0 GJ x	($0.158) =	(50.8760)	$0.000	0.0000	0.00%
15	Subtotal Storage and Transport Related Charges per GJ			$445.65			$445.65		$0.00	0.00%
16										
17	Cost of Gas (Commodity Cost Recovery Charge) per GJ	322.0 GJ x	$5.907 =	$1,902.05	322.0 GJ x	$5.907 =	$1,902.05	$0.000	$0.00	0.00%
18	Subtotal Commodity Related Charges per GJ			**$2,347.70**			**$2,347.70**		**$0.00**	**0.00%**
19										
20	Total *(with effective $/GJ rate)*	322.0	*$12.618*	**$4,062.91**	322.0	*$12.859*	**$4,140.51**	*$0.241*	**$77.60**	**1.91%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.
Slight differences in totals due to rounding

RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE

Line No.	Particular	EXISTING RATES JULY 1, 2022				PROPOSED JANUARY 1, 2023 RATES				Annual Increase/Decrease		
		Quantity		Rate	Annual $	Quantity		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**MAINLAND AND VANCOUVER ISLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge per Day	365.25	days x	$4.7895 =	$1,749.36	365.25	days x	$4.7895 =	$1,749.36	$0.0000	$0.00	0.00%
4	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	365.25	days x	$0.0131 =	4.78	365.25	days x	$0.0131 =	4.78	$0.000	0.00	0.00%
5	Subtotal of per Day Delivery Margin Related Charges				**$1,754.14**				**$1,754.14**		**$0.00**	**0.00%**
6												
7	Delivery Charge per GJ	3,650.0	GJ x	$3.582 =	13,074.3000	3,650.0	GJ x	$3.882 =	14,169.3000	$0.300	1,095.0000	2.67%
8	Rider 3 BVA Rate Rider per GJ	3,650.0	GJ x	$0.059 =	215.3500	3,650.0	GJ x	$0.132 =	481.8000	$0.073	266.4500	0.65%
9	Rider 5 RSAM per GJ	3,650.0	GJ x	$0.012 =	43.8000	3,650.0	GJ x	($0.209) =	(762.8500)	($0.221)	(806.6500)	-1.97%
10	Subtotal of Per GJ Delivery Margin Related Charges				**$13,333.45**				**$13,888.25**		**$554.80**	**1.36%**
11												
12	Commodity Related Charges											
13	Storage and Transport Charge per GJ	3,650.0	GJ x	$1.312 =	$4,788.8000	3,650.0	GJ x	$1.312 =	$4,788.8000	$0.000	$0.0000	0.00%
14	Rider 6 MCRA per GJ	3,650.0	GJ x	($0.135) =	(492.7500)	3,650.0	GJ x	($0.135) =	(492.7500)	$0.000	0.0000	0.00%
15	Subtotal Storage and Transport Related Charges per GJ				$4,296.05				$4,296.05		$0.00	0.00%
16												
17	Cost of Gas (Commodity Cost Recovery Charge) per GJ	3,650.0	GJ x	$5.907 =	$21,560.55	3,650.0	GJ x	$5.907 =	$21,560.55	$0.000	$0.00	0.00%
18	Subtotal Commodity Related Charges per GJ				**$25,856.60**				**$25,856.60**		**$0.00**	**0.00%**
19												
20	Total *(with effective $/GJ rate)*	3,650.0		*$11.218*	**$40,944.19**	3,650.0		*$11.370*	**$41,498.99**	*$0.152*	**$554.80**	**1.36%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.

Slight differences in totals due to rounding

RATE SCHEDULE 4 - SEASONAL FIRM GAS SERVICE

Line No.	Particular	EXISTING RATES JULY 1, 2022					PROPOSED JANUARY 1, 2023 RATES					Annual Increase/Decrease		
1		Quantity		Rate		Annual $	Quantity		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
2	**MAINLAND AND VANCOUVER ISLAND SERVICE AREA**													
3	Delivery Margin Related Charges													
4	Basic Charge per Day	214	days x	$14.4230	=	$3,086.52	214	days x	$14.4230	=	$3,086.52	$0.0000	$0.00	0.00%
5	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	214	days x	$0.0131	=	2.80	214	days x	$0.0131	=	2.80	$0.000	0.00	0.00%
6	Subtotal of per Day Delivery Margin Related Charges					**$3,089.32**					**$3,089.32**		**$0.00**	**0.00%**
7														
8	Delivery Charge per GJ													
9	(a) Off-Peak Period	9,200.0	GJ x	$1.723	=	15,851.6000	9,200.0	GJ x	$1.898	=	17,461.6000	$0.175	1,610.0000	1.98%
10	(b) Extension Period	0.0	GJ x	$2.368	=	0.0000	0.0	GJ x	$2.543	=	0.0000	$0.175	0.0000	0.00%
11	Rider 3 BVA Rate Rider per GJ	9,200.0	GJ x	$0.059	=	542.8000	9,200.0	GJ x	$0.132	=	1,214.4000	$0.073	671.6000	0.83%
12	Subtotal of Per GJ Delivery Margin Related Charges					**$16,394.40**					**$18,676.00**		**$2,281.60**	**2.80%**
13														
14	Commodity Related Charges													
15	Storage and Transport Charge per GJ													
16	(a) Off-Peak Period	9,200.0	GJ x	$0.912	=	$8,390.4000	9,200.0	GJ x	$0.912	=	$8,390.4000	$0.000	0.0000	0.00%
17	(b) Extension Period	0.0	GJ x	$0.912	=	0.0000	0.0	GJ x	$0.912	=	0.0000	$0.000	0.0000	0.00%
18	Rider 6 MCRA per GJ	9,200.0	GJ x	($0.094)	=	(864.8000)	9,200.0	GJ x	($0.094)	=	(864.8000)	$0.000	0.0000	0.00%
19	Commodity Cost Recovery Charge per GJ													
20	(a) Off-Peak Period	9,200.0	GJ x	$5.907	=	54,344.4000	9,200.0	GJ x	$5.907	=	54,344.4000	$0.000	0.0000	0.00%
21	(b) Extension Period	0.0	GJ x	$5.907	=	0.0000	0.0	GJ x	$5.907	=	0.0000	$0.000	0.0000	0.00%
22														
23	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak					**$61,870.00**					**$61,870.00**		**$0.00**	**0.00%**
24														
25	Unauthorized Gas Charge During Peak Period (not forecast)													
26														
27	Total during Off-Peak Period	9,200.0				**$81,353.72**	9,200.0				**$83,635.32**		**$2,281.60**	**2.80%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.
Slight differences in totals due to rounding

RATE SCHEDULE 5 - GENERAL FIRM SERVICE

Line No.	Particular	EXISTING RATES JULY 1, 2022					PROPOSED JANUARY 1, 2023 RATES					Annual Increase/Decrease		
1		Quantity		Rate		Annual $	Quantity		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
2	**MAINLAND AND VANCOUVER ISLAND SERVICE AREA**													
3	Delivery Margin Related Charges													
4	Basic Charge per Month	12	months x	$469.00	=	$5,628.00	12	months x	$469.00	=	$5,628.00	$0.00	$0.00	**0.00%**
5	Rider 2 Clean Growth Innovation Fund Rate Rider per Month	12	months x	$0.40	=	4.80	12	months x	$0.40	=	4.80	$0.00	0.00	0.00%
6	Subtotal of per Month Delivery Margin Related Charges					**$5,632.80**					**$5,632.80**		**$0.00**	**0.00%**
7														
8	Demand Charge per Month per GJ of Daily Demand	72.4	GJ x	$27.911	=	**$24,249.08**	72.4	GJ x	$30.194	=	**$26,232.55**	$2.283	**$1,983.47**	**1.22%**
9														
10	Delivery Charge per GJ	17,100.0	GJ x	$1.000	=	$17,100.0000	17,100.0	GJ x	$1.082	=	$18,502.2000	$0.082	$1,402.2000	0.86%
11	Rider 3 BVA Rate Rider per GJ	17,100.0	GJ x	$0.059	=	1,008.9000	17,100.0	GJ x	$0.132	=	2,257.2000	$0.073	1,248.3000	0.77%
12	Subtotal of Per GJ Delivery Margin Related Charges					**$18,108.90**					**$20,759.40**		**$2,650.50**	**1.63%**
13														
14	Commodity Related Charges													
15	Storage and Transport Charge per GJ	17,100.0	GJ x	$0.912	=	$15,595.2000	17,100.0	GJ x	$0.912	=	$15,595.2000	$0.000	$0.0000	0.00%
16	Rider 6 MCRA per GJ	17,100.0	GJ x	($0.094)	=	(1,607.4000)	17,100.0	GJ x	($0.094)	=	(1,607.4000)	$0.000	0.0000	0.00%
17	Commodity Cost Recovery Charge per GJ	17,100.0	GJ x	$5.907	=	101,009.7000	17,100.0	GJ x	$5.907	=	101,009.7000	$0.000	0.0000	0.00%
18	Subtotal Gas Commodity Cost (Commodity Related Charge)					**$114,997.50**					**$114,997.50**		**$0.00**	**0.00%**
19														
20	Total *(with effective $/GJ rate)*	17,100.0		*$9.531*		**$162,988.28**	17,100.0		*$9.802*		**$167,622.25**	*$0.271*	**$4,633.97**	**2.84%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.
Slight differences in totals due to rounding

RATE SCHEDULE 6 - NATURAL GAS VEHICLE SERVICE

Line No.	Particular	EXISTING RATES JULY 1, 2022			PROPOSED JANUARY 1, 2023 RATES			Annual Increase/Decrease		
1		Quantity	Rate	Annual $	Quantity	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**MAINLAND AND VANCOUVER ISLAND SERVICE AREA**									
3	Delivery Margin Related Charges									
4	Basic Charge per Day	365.25 days x	$2.0041 =	$732.00	365.25 days x	$2.0041 =	$732.00	$0.0000	$0.00	0.00%
5	Rider 2 Clean Growth Innovation Fund Rate Rider per Day	365.25 days x	$0.0131 =	4.7848	365.25 days x	$0.0131 =	4.7848	$0.000	0.0000	0.00%
6	Subtotal of per Day Delivery Margin Related Charges			**$736.78**			**$736.78**		**$0.00**	**0.00%**
7										
8	Delivery Charge per GJ	1,600.0 GJ x	$3.446 =	5,513.6000	1,600.0 GJ x	$3.733 =	5,972.8000	$0.287	459.2000	2.79%
9	Rider 3 BVA Rate Rider per GJ	1,600.0 GJ x	$0.059 =	94.4000	1,600.0 GJ x	$0.132 =	211.2000	$0.073	116.8000	0.71%
10	Subtotal of Per GJ Delivery Margin Related Charges			**$5,608.00**			**$6,184.00**		**$576.00**	**3.50%**
11										
12	Commodity Related Charges									
13	Storage and Transport Charge per GJ	1,600.0 GJ x	$0.470 =	$752.0000	1,600.0 GJ x	$0.470 =	$752.0000	$0.000	$0.0000	0.00%
14	Rider 6 MCRA per GJ	1,600.0 GJ x	($0.048) =	(76.8000)	1,600.0 GJ x	($0.048) =	(76.8000)	$0.000	0.0000	0.00%
15	Commodity Cost Recovery Charge per GJ	1,600.0 GJ x	$5.907 =	9,451.2000	1,600.0 GJ x	$5.907 =	9,451.2000	$0.000	0.0000	0.00%
16	Subtotal Cost of Gas (Commodity Related Charge)			**$10,126.40**			**$10,126.40**		**$0.00**	**0.00%**
17										
18	Total *(with effective $/GJ rate)*	1,600.0	*$10.294*	**$16,471.18**	1,600.0	*$10.654*	**$17,047.18**	*$0.360*	**$576.00**	**3.50%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.

Slight differences in totals due to rounding

RATE SCHEDULE 7 - GENERAL INTERRUPTIBLE SERVICE

Line No.	Particular	EXISTING RATES JULY 1, 2022				PROPOSED JANUARY 1, 2023 RATES				Annual Increase/Decrease		
1		Quantity		Rate	Annual $	Quantity		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**MAINLAND AND VANCOUVER ISLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge per Month	12	months x	$880.00 =	$10,560.00	12	months x	$880.00 =	$10,560.00	$0.00	$0.00	0.00%
5	Rider 2 Clean Growth Innovation Fund Rate Rider per Month	12	months x	$0.40 =	4.80	12	months x	$0.40 =	4.80	$0.00	0.00	0.00%
6	Subtotal of per Month Delivery Margin Related Charges				**$10,564.80**				**$10,564.80**		**$0.00**	**0.00%**
7												
8	Delivery Charge per GJ	133,400.0	GJ x	$1.616 =	$215,574.4000	133,400.0	GJ x	$1.744 =	$232,649.6000	$0.128	$17,075.2000	1.51%
9	Rider 3 BVA Rate Rider per GJ	133,400.0	GJ x	$0.059 =	7,870.6000	133,400.0	GJ x	$0.132 =	17,608.8000	$0.073	9,738.2000	0.86%
10	Subtotal of Per GJ Delivery Margin Related Charges				**$223,445.00**				**$250,258.40**		**$26,813.40**	**2.37%**
11												
12	Commodity Related Charges											
13	Storage and Transport Charge per GJ	133,400.0	GJ x	$0.912 =	$121,660.8000	133,400.0	GJ x	$0.912 =	$121,660.8000	$0.000	$0.0000	0.00%
14	Rider 6 MCRA per GJ	133,400.0	GJ x	($0.094) =	(12,539.6000)	133,400.0	GJ x	($0.094) =	(12,539.6000)	$0.000	0.0000	0.00%
15	Commodity Cost Recovery Charge per GJ	133,400.0	GJ x	$5.907 =	787,993.8000	133,400.0	GJ x	$5.907 =	787,993.8000	$0.000	0.0000	0.00%
16	Subtotal Cost of Gas (Commodity Related Charge)				**$897,115.00**				**$897,115.00**		**$0.00**	**0.00%**
17												
18	Total *(with effective $/GJ rate)*	133,400.0		*$8.479*	**$1,131,124.80**	133,400.0		*$8.680*	**$1,157,938.20**	*$0.201*	**$26,813.40**	**2.37%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations.
Slight differences in totals due to rounding

Attachment 2.1

FortisBC Energy Inc.
Reconciliation of Deferral Accounts Amortization

	2022 Deferral Amortization	2023 Deferral Amortization	Change
	(1)	(2)	(1) - (2)
RATE BASE			
1. Forecasting Variance Accounts			
Midstream Cost Reconciliation Account (MCRA)	-	-	-
Commodity Cost Reconciliation Account (CCRA)	-	-	-
Revenue Stabilization Adjustment Mechanism (RSAM)	-	-	-
Interest on CCRA / MCRA / RSAM / Gas Storage	12	(483)	495
SCP Mitigation Revenues Variance Account	101	(112)	213
Pension & OPEB Variance	(230)	(5,154)	4,924
BCUC Levies Variance	(37)	(685)	648
	(154)	**(6,434)**	**6,280**
2. Rate Smoothing Accounts	-	-	-
3. Benefits Matching Accounts			
Demand-Side Management (DSM)	(31,910)	(41,553)	9,643
NGV Conversion Grants	(4)	(3)	(1)
Emissions Regulations	1,072	28,848	(27,776)
On-Bill Financing Pilot Program	-	-	-
Greenhouse Gas Reduction Regulation Incentives	(5,010)	(5,387)	377
CNG and LNG Recoveries	434	548	(114)
BCUC Initiated Inquiry Costs	(71)	(121)	50
2017 Rate Design Application	(263)	(263)	-
2017 Long Term Resource Plan Application	(41)	-	(41)
PGR Application and Preliminary Stage Development Costs	(192)	(151)	(41)
Transportation Service Report	-	-	-
2021 Generic Cost of Capital Proceeding	-	-	-
2019-2022 DSM Expenditures Application Costs	(25)	-	(25)
City of Coquitlam Application Proceeding	(284)	(129)	(155)
Whistler Pipeline Conversion	(739)	(737)	(2)
Gas Asset Records Project	(368)	(266)	(102)
BC OneCall Project	(8)	-	(8)
Gains and Losses on Asset Disposition	(3,987)	(3,986)	(1)
Net Salvage Provision/Cost	(57,288)	(59,870)	2,582
PCEC Start Up Costs	(44)	(44)	-
2022 Long Term Gas Resource Plan Application	-	-	-
2020–2024 MRP Application	(136)	(135)	(1)
City of Surrey Operating Terms Application Costs	(34)	-	(34)
2021 Renewable Gas Program Comprehensive Review	-	-	-
IGU Application and Preliminary Stage Development Costs	387	-	387
GCU Preliminary Stage Development Costs	-	(259)	259
Transmission Integrity Management Capabilities	-	(2,521)	2,521
Annual Review of 2020-2024 Rates	(172)	(98)	(74)
	(98,683)	**(86,127)**	**(12,556)**
4. Retroactive Expense Accounts	-	-	-
5.Other Accounts			
Pension & OPEB Funding	-	-	-
US GAAP Pension & OPEB Funded Status	-	-	-
BFI Costs and Recoveries	(202)	-	(202)
Residual Delivery Rate Riders	-	-	-
BVA Balance Transfer	-	-	-
COVID-19 Customer Recovery Fund	-	(577)	577
Stargas Assets Acquisition Deferral Account	-	(106)	106
2017 & 2018 Revenue Surplus Account	308	-	308
	106	**(683)**	789
			-
TOTAL RATE BASE	**(98,731)**	**(93,244)**	**(5,487)**
Less: Net Salvage Amortization Transferred to Biomethane BVA	48	55	(7)
TOTAL NET RATE BASE	**(98,683)**	**(93,189)**	**(5,494)**
NON RATE BASE			
1. Forecasting Variance Accounts			
Biomethane Variance Account	-	-	-
Flowthrough (2020-2024)	(11,417)	(19,512)	8,095
Marketer Cost Variance	-	-	-
	(11,417)	**(19,512)**	**8,095**
2. Rate Smoothing Accounts			
2017 & 2018 Revenue Surplus Account	-	-	-
City of Vancouver Biomethane Purchase Agreement	-	-	-
	-	-	-
3. Benefits Matching Accounts			
Demand-Side Management (DSM) - Non Rate Base	-	-	-
PEC Pipeline Development Costs and Commitment Fees	-	-	-
PGR Application and Preliminary Stage Development Costs	-	-	-
Transmission Integrity Management Capabilities	-	-	-
Clean Growth Innovation Fund	-	-	-
	-	-	-
4. Retroactive Expense Accounts	-	-	-
5.Other Accounts			
Mark to Market - Hedging Transactions	-	-	-
US GAAP Uncertain Tax Positions	-	-	-
MRP Earnings Sharing Account	1,353	275	1,078
Stargas Assets Acquisition Deferral Account	-	-	-
	1,353	**275**	**1,078**
TOTAL NON RATE BASE	**(10,064)**	**(19,237)**	**9,173**
TOTAL RATE BASE AND NON RATE BASE	**(108,747)**	**(112,426)**	**3,679**

Attachment 12.2

FILED CONFIDENTIALLY