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November 23, 2023

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

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

Re: FortisBC Energy Inc. (FEI)

2023 Cost of Service Allocation (COSA) Study and Application for Approval of Revenue Rebalancing (Application) ~ Project No. 1599563

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

On July 20, 2023, FEI filed the Application referenced above. In accordance with the regulatory timetable established in BCUC Order G-218-23 for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners

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A. REGULATORY CONTEXT AND BACKGROUND

1.0 Reference: REGULATORY CONTEXT AND BACKGROUND

FortisBC Energy Inc. (FEI) 2016 Rate Design Application dated December 19, 2016 (2016 Application), Section 4.1, p. 4-1

Stakeholder Engagement

On page 4-1 of the 2016 Application, FEI stated:

> Prior to filing this Application, FEI conducted a stakeholder engagement process consisting of information sessions, stakeholder workshops and a residential customer online survey.

1.1 Please identify any stakeholder engagement activities undertaken in relation to the current Application, and the rationale for the engagement approach.

1.1.1 Please provide the key issues and findings for each activity, any feedback and/or concerns provided and how this feedback informed the current Application.

1.1.2 Please discuss any differences between the engagement activities undertaken in relation to the current Application as compared to the 2016 Application and the reasons for these differences.

Response:

FEI has not undertaken any stakeholder engagement activities in relation to this Application.

There are a number of key differences between the 2016 COSA and RDA and this current Application which support FEI's different approach to engagement in this Application.

The 2016 COSA and RDA had many more proposed changes and customer impacts. FEI proposed much more extensive rebalancing and, importantly, proposed changes to its rate design and its General Terms and Conditions. Further, the 2016 COSA and RDA was the first to be submitted by FEI since the amalgamation of FEI, FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW). FEI also undertook a separate COSA study for FEI Fort Nelson and proposed adjustments to the Fort Nelson rate design (and therefore consultation specific to the Fort Nelson service area was undertaken).

In contrast, the current Application contains no rate design changes or changes to FEI's General Terms and Conditions. Further, the 2023 COSA study results demonstrate that FEI's existing rates and rate designs are largely working as intended; as a result, FEI is only proposing minor rate rebalancing for certain customer classes. As shown in Table 5-23 of the Application, the bill impacts of the proposed rate rebalancing for the average residential and small commercial customer are small at approximately 0.4 percent and 0.04 percent, respectively (while all other rate schedules will either see no change in their rates or a small rate reduction).

FEI also considered the potential costs for undertaking stakeholder consultation and engagement processes such as those referenced in the preamble to this IR and weighed those costs, which would be borne by FEI's customers, against the relatively small impact to FEI's customers of the proposed rate rebalancing in the Application. Based on the actual costs incurred by FEI on consultation and engagement activities for the 2016 COSA and RDA of approximately $200 thousand, FEI estimates that performing similar consultation and engagement activities for the current Application would cost in the range of $300 thousand to $350 thousand when including inflation and general cost increases. These costs do not include the significant internal costs for FEI staff to plan, coordinate, prepare, present and participate in all of the activities.

Finally, this Application is being filed in response to the BCUC's directive to file an updated COSA study within five years of the 2016 COSA and RDA Decision[1]. The Application is not triggered by a need, at this time, to propose rate design changes or other changes with significant impacts to customers. Had FEI intended to bring forward an application with comprehensive rate design changes or with changes that would result in significant impacts to customers, it would have conducted stakeholder consultation and engagement in advance of filing the application.

1 Order G-4-18, Directive 4.

2.0 Reference: REGULATORY CONTEXT AND BACKGROUND

Exhibit B-1 Application, Section 3.5, p. 13

Filing of the next Cost of Service Allocation (COSA)

On page 13 of the 2023 Cost of Service Allocation and Revenue Rebalancing Application (Application), FEI states:

> […] the directive in the 2016 COSA Decision, for FEI to file a comprehensive and updated COSA study for each of FEI and FEFN for review by the BCUC five years after the release of the 2016 RDA Decision (by July 20, 2023). [footnotes omitted]

2.1 Please explain how frequent FEI expects to update its COSA and why this scheduled timeframe is considered appropriate.

2.1.1 Please explain whether there are circumstances that would necessitate updating the COSA sooner than the scheduled timeframe and if so, please list the circumstances.

Response:

FEI does not consider it necessary to assign a specific timeframe or frequency to when COSA studies are filed. In fact, it is common for the frequency of utility COSA study (and rate design) applications to vary. For example, FortisBC Inc. (FBC) filed a COSA study in 2020 in compliance with Order G-40-19 regarding FBC's 2017 COSA and RDA. Prior to the 2020 and 2017 COSA studies, FBC had last filed a COSA study in 2009. With regard to the frequency of FEI's COSA filings, prior to the 2016 COSA and RDA, FEI had not filed a COSA study in approximately 15 years (i.e., in 2001, as explained on page 10 of the Application).

As explained in the 2017 FBC COSA and RDA, COSA studies and rate designs are completed in consideration of a variety of factors, both internal to the operation of a utility, and in the environment in which the utility operates. FEI generally considers it appropriate to review the COSA model following significant changes in circumstances. For example, FEI's 2016 COSA study was undertaken in compliance with a BCUC directive in its Decision and Order G-21-14 regarding the FEI Application for Reconsideration and Variance of Order G-26-13 on the FortisBC Energy Utilities' Common Rates, Amalgamation and Rate Design Application. The result of that decision was significant changes to the utility, including the amalgamation of FEI, FEVI and FEW, and the implementation of common rates.

While FEI does not consider it necessary for the BCUC to determine the frequency of COSA filings, FEI considers that there should be a minimum of five years between COSA studies. As evidenced by the results of the 2023 COSA study, in the absence of significant changes to the utility's operations or structure, the rates and rate designs generally continue to perform as intended.

B. FEI'S COSA METHODOLOGY

3.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Section 4.2.1, Table 4-1, p. 20

FEI's 2023 test year revenue requirements

On page 20 of the Application, FEI presents Table 4-1 which provides a summary of FEI's 2023 test year revenue requirement with an earned return of $370 million.

3.1 Please update Table 4-1 to account for any impact of the Generic Cost of Capital (GCOC) Stage 1 Decision on the 2023 test year revenue requirements.

<u>Response:</u>

Please refer to Table 1 below for an updated version of Table 4-1 of the Application which shows the components of FEI's 2023 Approved revenue requirement pursuant to Order G-275-23 (GCOC Compliance Filing), dated October 17, 2023, which includes the impact of the BCUC GCOC Stage 1 Decision and Order G-236-23.

As approved by Order G-275-23, approximately $63.994 million of the 2023 revenue deficiency is deferred and captured in the non-rate base 2023 Revenue Deficiency deferral account. As such, there is no change to FEI's 2023 revenue requirement of $2,249 million after the GCOC Stage 1 Decision.

Table 1: Updated Table 4-1 – Summary of FEI's 2023 Test Year Revenue Requirements ($ millions)

Revene Requirement Components	2023 Interim (G-352-22) As-Filed	2023 Approved (G-275-23) GCOC Compliance	Change	Reference FEI GCOC Compliance Filing (Appendix B-1)
Cost of Gas	1,171	1,171	-	Schedule 16, Line 13, Column 5
O&M Expense (Net)	292	292	-	Schedule 16, Line 18, Column 5
Depreciation	221	221	-	Schedule 21, Line 5, Column 3
Amortization(1)	106	106	0.2	Schedule 21, Line 13, Column 3
Property Taxes	79	79	-	Schedule 16, Line 20, Column 5
Other Revenue	(42)	(42)	-	Schedule 16, Line 21, Column 5
Income Tax	52	73	22	Schedule 16, Line 25, Column 5
Earned Return	370	412	42	Schedule 16, Line 27, Column 5
Deferred 2023 Deficiency	-	(64)	(64)	Schedule 16, Line 22, Column 5
Total	**2,249**	**2,249**	-	

<u>Note to Table:</u>

(1): Changes in amortization due to the inclusion of the 2023 Demand Side Management (DSM) Expenditures Plan Application Cost deferral account as a result of Decision and Order G-45-23, as well as changes in AFUDC rates resulting from the GCOC Decision.

However, for an evaluation of the full impact of the GCOC Decision on the 2023 COSA and the R:C ratios before the deferred deficiency, please refer to Table 2 below which provides the change in the R:C ratio (before rate rebalancing) of each rate schedule due to the GCOC Decision under a scenario where the impact of the GCOC Decision on the 2023 deficiency is not deferred.

Please also refer to Table 3 below which shows the updated revenue shift and the estimated bill impact in percentage under the same proposed rate rebalancing option proposed in this Application. As shown in Table 3, the estimated bill impacts for the average residential and small commercial customer remain the same at 0.4 percent and 0.04 percent, respectively.

FEI will incorporate the GCOC Decision into the final COSA results and rate rebalancing as part of the Compliance Filing to the BCUC's decision on this Application.

Table 2: 2023 COSA Results (Before Rebalancing) including GCOC Decision

	Initial COSA		
Rate Schedule	Original App. R:C	GCOC Update R:C	Change
Rate Schedule 1 *Residential Service*	97.3%	97.2%	-0.1%
Rate Schedule 2 *Small Commercial Service*	98.0%	98.0%	0.0%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	104.1%	0.2%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	107.2%	0.3%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	96.4%	0.2%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.1%	0.2%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.8%	0.0%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.4%	0.2%

Rate Schedule (Rates Not Set Using Allocated Costs)	Original App. R:C	GCOC Update R:C	Change
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	125.6%	1.5%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	122.4%	123.8%	1.4%

Table 3: Final 2023 COSA Results (including GCOC Decision) with Revenue Rebalancing

	Initial COSA		After GCOC Update		COSA after Rebalancing	
Rate Schedule	Original App. R:C	GCOC Update R:C	Revenue Shift ($000s)	Approx. Annual Bill	Original App. R:C	GCOC Update R:C
Rate Schedule 1 *Residential Service*	97.3%	97.2%	5,275	0.4%	97.7%	97.6%
Rate Schedule 2 *Small Commercial Service*	98.0%	98.0%	145	0.04%	98.1%	98.1%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	104.1%	(145)	(0.04%)	103.9%	104.1%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	107.2%	(3,887)	(2.0%)	105.0%	105.0%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	96.4%	-	-	96.2%	96.4%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.1%	(164)	(4.7%)	105.0%	105.0%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.8%	-	-	101.8%	101.8%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.4%	-	-	100.1%	100.4%

Rate Schedule (Rates Not Set Using Allocated Costs)	Original App. R:C	GCOC Update R:C	Revenue Shift ($000s)	Approx. Annual Bill	Original App. R:C	GCOC Update R:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	125.6%	(50)	(3.1%)	120.5%	121.7%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	122.4%	123.8%	(1,173)	(1.3%)	121.1%	122.2%

3.2 Please state whether the GCOC Stage 1 Decision and the resulting compliance filing to set 2023 permanent rates would have any impact on the 2023 COSA and Revenue-to-Cost (R:C) ratios. If yes, please provide any resulting updates to the Application.

Response:

Please refer to the response to BCUC IR1 3.1.

4.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Section 4.2.2, pp. 20 and 22

Key assumptions for test year revenues and costs

On page 20 of the Application, FEI states:

> Since the majority of FEI's gross [operation and maintenance] O&M is determined using a formula and not developed on an activity view (O&M at the activity view is only accounted for in actuals), FEI has split its 2023 gross O&M into an activity view using percentages derived from its 2022 actual activity view O&M so that it could be used for the purpose of allocating O&M expenses in the COSA model. This approach is consistent with the 2016 COSA study, in which FEI's O&M was also determined based on a formula under the 2014-2019 Performance Based Ratemaking (PBR) Plan at that time. [Emphasis added]

4.1 Please indicate whether the BCUC has previously reviewed and/or approved the 2022 actual activity view O&M, which FEI is now using to split its 2023 gross O&M into an activity view. If so, please provide the BCUC order and decision in which it was approved.

4.1.1 If not, please state whether the BCUC approved the approach of using the prior year actual activity view O&M for the purpose of allocating O&M expenses in the COSA model when reviewing the 2016 COSA.

Response:

The 2022 actual activity view O&M was provided to the BCUC as part of FEI's 2022 Annual Report (pages 20.3 to 20.5), submitted on April 28, 2023. FEI received a letter of acknowledgment from the BCUC on October 17, 2023 indicating that BCUC staff had reviewed the 2022 Annual Report and no further action is required. The activity view is simply a method of presenting the 2022 actual O&M at an activity-level of detail. FEI also provides its actual O&M results in a resource view as part of its Annual Reports to the BCUC (e.g., see page 20.2 of the 2022 Annual Report).

The BCUC does not approve FEI's actual O&M spending under either the 2020-2024 MRP or under the 2014-2019 PBR Plan. As explained on page 20 of the Application, the majority of FEI's O&M is determined annually based on an approved indexed-based formula. Non-formula O&M (i.e., forecast or flow-through O&M) is reviewed annually in the Annual Review rate-setting process; however, it is the forecasts, not the actual results, that are approved as part of the Annual Review process.

The treatment of O&M in the 2023 COSA study is consistent with the 2016 COSA study, i.e., using the prior year actual activity view O&M for the purposes of allocating O&M expenses in the COSA model. While the BCUC did not specifically refer to FEI's method of allocating gross O&M in Order G-4-18 and the accompanying Reasons for Decision, dated January 9, 2018, the BCUC did state the following on page 11:

Subject to the determinations on issues addressed in Section 4.3, the Panel finds FEI's COSA methodology generally follows standard practice, which both EES Consulting and Elenchus view as being reasonable and acceptable for setting just and reasonable rates.

FEI considers the approach used in both the current 2023 COSA study and the 2016 COSA study to be reasonable. Given the BCUC's acceptance of the approach in the 2016 COSA and RDA proceeding, FEI sees no basis for utilizing a different approach for the current COSA study. Further, since the 2023 approved gross O&M is predominantly determined based on formula (with some items being forecast), it is logical to use the 2022 actual activity view O&M results to split the 2023 O&M into an activity view for the purposes of the COSA model.

4.2 Considering that the net O&M expenses are included in FEI's 2023 test year revenue requirements as shown in Table 4-1, please clarify why FEI is splitting its 2023 gross O&M expenses into an activity view rather than its 2023 net O&M expenses.

Response:

It is important to note that there is no activity view of net O&M. The activity view of O&M is always on a gross basis with a single line item that removes capitalized overheads. For clarity, FEI does not remove capitalized overheads from each individual O&M activity view line item and it would be inconsistent with past practice to do so. The line items in the O&M activity view sum to yield gross O&M. The Overhead Capitalized credit, to go from the gross O&M to the net O&M, has its own specific allocation to the various COSA functions based on the total allocated Gas Plant in Service.

Additionally, to determine net O&M, biomethane O&M costs are reversed out as a single line item and accounted for in the Biomethane Variance Account (BVA). This is because there is a separate regulatory process for determining biomethane recoveries. Attempting to allocate the biomethane credit to all O&M activity view line items would be inconsistent with past practice and illogical because it would be impossible to track and see that biomethane O&M costs have in fact been reversed out for the COSA study.

Further, splitting the 2023 net O&M using a 2022 actual activity view net O&M, which does not exist, would result in incorrect amounts of 2023 biomethane costs being transferred to the BVA and an incorrect 2023 capitalized overhead being used for allocation purposes in the COSA study.

Table 1 below demonstrates that if FEI split the 2023 net O&M using a 2022 actual activity view net O&M, the biomethane costs transferred to the BVA would be $4.289 million for allocation purposes instead of the 2023 Approved amount of $5.237 million, the capitalized overhead would be $55.043 million for allocation purposes instead of the 2023 Approved amount of $56.744 million, and the 2023 gross O&M would be $351.998 million for allocation purposes instead of the 2023 Approved amount of $354.647 million. This would lead to an incorrect allocation of O&M in the COSA study, e.g., FEI would functionalize and allocate $351.998 million as part of the 2023 COSA rather than the approved amount of $354.647 million.

Table 1: Demonstration of the Error in Biomethane Costs Transferred to BVA and Capitalized Overhead if 2023 Net O&M is Split (instead of 2023 Gross O&M) using 2022 Actual O&M

	2022 Actual O&M ($000s)	2022 O&M %	2023 O&M Split Based on 2022 Actual % ($000s)	2023 BCUC Approved O&M ($000s)	Error introduced in 2023 O&M used for COSA Study ($000s)
Gross O&M	$341,030	120.3%	$351,998	$354,647	$2,679
Biomethane transferred to BVA	(4,156)	-1.5%	(4,289)	(5,237)	(948)
Capitalized Overhead	(53,328)	-18.8%	(55,043)	(56,744)	(1,701)
Net O&M	**$283,546**	**100.0%**	**$292,666**	**$292,666**	**$ -**

5.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Section 4.2.3, p. 26

Known and measurable changes to the test year revenues and costs

5.1 Please explain how FEI calculated the 2025 rate base of $165.603 million and the cost of service of $13.931 million related to the Inland Gas Upgrade Project Certificate of Public Convenience and Necessity, as referenced on page 26 of the Application.

Response:

As the components of the Inland Gas Upgrade (IGU) Project completed through to 2023 are already included in FEI's rate base and rates, only the incremental impact from 2023 to 2025 due to the remaining IGU Project components are known and measurable changes to the 2023 Approved revenue and costs.

As discussed in Section 4.2.3.2 of the Application, FEI already included approximately $192.2 million in rate base from 2021 to 2023 (actuals for 2021 and 2022, forecast for 2023). At the time of preparing the Application, the IGU Project was estimated to have a total capital cost of approximately $360 million and was expected to be complete with all remaining assets placed in-service by the end of 2024; as such, approximately $167.8 million of assets related to the IGU Project were expected to enter rate base on January 1st of 2025. Please refer to Table 1 below which provides a reconciliation of the estimated rate base of $165.603 million (Line 19) as well as the incremental cost of service of $13.931 million (Line 28) in 2025.

Table 1: Reconciliation of 2025 Estimated Rate Base and Cost of Service as Known and Measurable Changes related to the IGU Project ($ millions)

Line	Particular	Reference	2025
1	Gross Plant		
2	46500 Transmission Mains		
3	Opening	Line 8 (Prior Yr + Jan 1st Additions)	167.757
4	Additions		-
5	Closing	Line 3 + Line 4	167.757
6			
7	Accumulated Depreciation		
8	46500 Transmission Mains		
9	Opening	Line 11 (Prior Yr)	(0.448)
10	Depreciation Expense	-Line 3 x 1.46%	(2.449)
11	Closing	Line 9 + Line 10	(2.898)
12			
13	Deferral - Net Salvage		
14	46500 Transmission Mains		
15	Opening	Line 17 (Prior Yr)	(0.129)
16	Net Salvage Provision	-Line 3 x 0.42%	(0.705)
17	Closing	Line 15 + Line 16	(0.834)
18			
19	**Mid-Year Rate Base**	**Sum of Line (3, 5, 9, 11, 15, 17) / 2**	**165.603**
20			
21	**Cost of Service**		
22	O&M Expense	IGU CPCN, Evid Update, App N-1 (2025 O&M - 2023 O&M)	2.083
23	Property Tax	IGU CPCN, Evid Update, App N-1 (2025 P-Tax - 2023 P-Tax)	0.249
24	Depreciation Expense	-Line 10	2.449
25	Amortization	-Line 16	0.705
26	Income Tax	Line 38	(1.872)
27	Earned Return	Line 19 x 6.23%	10.317
28	**Total**	**Sum of Line 22 to 27**	**13.931**
29			
30	Income Tax		
31	Earned Return	Line 27	10.317
32	Less: Interest	-Line 19 x (LTD x LTD Rate + STD x STD Rate)	(4.734)
33	Add: Depreciation & Amortization	Line 24 + Line 25	3.154
34	Less: CCA	Line 43	(13.799)
35	Taxable Income After Tax	Sum of Line 31 to 34	(5.062)
36			
37	Current Tax Rate		27%
38	Income Tax Expense	Line 35 / (1 - Line 37) x Line 37	(1.872)
39			
40	CCA		
41	Opening	Line 44 (Prior Yr)	172.488
42	Additions	Line 4	-
43	CCA	Line 41 + Line 42 x 1.5) x CCA Rate @ 8.00%	(13.799)
44	Closing	Sum of Line 41 to 43	158.689

5.2 Please explain how FEI calculated the 2025 rate base of $102.850 million and the cost of service of $8.334 million related to the Coastal Transmission System Transmission Integrity Management Capabilities Project CPCN, as referenced on page 26 of the Application.

Response:

While responding to this IR, FEI discovered a typographical error on Line 23 of page 26 of the Application. As noted in Section 4.2.3.3 of the Application, FEI expects the CTS-TIMC Project to be completed by the end of 2025 with all related assets expected to enter FEI's rate base on January 1st of 2026, not 2025. As such, it is the calculated *2026* (not 2025) undepreciated mid-year rate base amount of approximately $102.850 million and the calculated cost of service amount of approximately $8.334 million added to the 2023 COSA as a known and measurable change[2]. FEI notes this does not change the amount added to the 2023 COSA and does not change the COSA study results.

The 2026 rate base of $102.850 million and the 2026 cost of service of $8.334 million related to the CTS-TIMC Project are calculated based on the information provided as part of the CTS-TIMC CPCN Application, Confidential Appendix G-2, Financial Schedules Preferred Alternative. Table 1 below provides a reconciliation of the 2026 rate base amount of $102.850 million, and Table 2 below provides a reconciliation of the 2026 cost of service impact of $8.334 million. FEI notes that the $102.850 million does not include the $13.271 million[3] of capitalized development costs that were already included in the 2023 revenue requirement and rates.[4]

[2] BCUC approved projects expected to be included in rate base by or soon after 2025.

[3] $13.877 million as forecast in the CTS-TIMC CPCN application financial schedules (Schedule 7, Line 8).

[4] FEI Annual Review for 2023 Delivery Rates, Section 7.2.3.2.1, page 73, lines 23 to 25.

Table 1: Reconciliation of the 2026 Rate Base as Known and Measurable Changes related to the CTS-TIMC Project ($ millions)

Line	Particular	Reference	2026
1	Gross Plant - Opening		
2	46500 Mains - Pipeline	CTS-TIMC CPCN, App G-2, Sch. 7, Line 4	54.811
3	46500 Mains - Stations	CTS-TIMC CPCN, App G-2, Sch. 7, Line 5	41.113
4	46710 Measuring & Regulating - Stations	CTS-TIMC CPCN, App G-2, Sch. 7, Line 6	5.385
5	46720 Telemetry - Stations	CTS-TIMC CPCN, App G-2, Sch. 7, Line 7	5.385
6	Total, Opening	Sum of Line 2 to 5	106.694
7			
8	Gross Plant - Ending		
9	46500 Mains - Pipeline	CTS-TIMC CPCN, App G-2, Sch. 7, Line 31	54.811
10	46500 Mains - Stations	CTS-TIMC CPCN, App G-2, Sch. 7, Line 32	41.113
11	46710 Measuring & Regulating - Stations	CTS-TIMC CPCN, App G-2, Sch. 7, Line 33	5.385
12	46720 Telemetry - Stations	CTS-TIMC CPCN, App G-2, Sch. 7, Line 34	5.385
13	Total, Ending	Sum of Line 9 to 12	106.694
14			
15	Accumulated Depreciation - Opening		
16	46500 Mains - Pipeline	CTS-TIMC CPCN, App G-2, Sch. 8, Line 4	(0.986)
17	46500 Mains - Stations	CTS-TIMC CPCN, App G-2, Sch. 8, Line 5	(0.671)
18	46710 Measuring & Regulating - Stations	CTS-TIMC CPCN, App G-2, Sch. 8, Line 6	(0.127)
19	46720 Telemetry - Stations	CTS-TIMC CPCN, App G-2, Sch. 8, Line 7	(0.537)
20	Total, Opening	Sum of Line 16 to 19	(2.320)
21			
22	Accumulated Depreciation - Ending		
23	46500 Mains - Pipeline	CTS-TIMC CPCN, App G-2, Sch. 8, Line 31	(1.786)
24	46500 Mains - Stations	CTS-TIMC CPCN, App G-2, Sch. 8, Line 32	(1.271)
25	46710 Measuring & Regulating - Stations	CTS-TIMC CPCN, App G-2, Sch. 8, Line 33	(0.241)
26	46720 Telemetry - Stations	CTS-TIMC CPCN, App G-2, Sch. 8, Line 34	(1.020)
27	Total, Ending	Sum of Line 23 to 26	(4.318)
28			
29	Net Plant Mid-Year	Sum of Line (6, 13, 20, 27) / 2	103.374
30			
31	Deferred Charges - Net Salvage		
32	Opening	CTS-TIMC CPCN, App G-2, Sch. 9, Line 12	(0.486)
33	Amortization	CTS-TIMC CPCN, App G-2, Sch. 9, Line 17	(0.411)
34	Ending	CTS-TIMC CPCN, App G-2, Sch. 9, Line 18	(0.898)
35			
36	Net Plant Mid-Year	Line 29	103.374
37	Unamortized Deferred Charges, Mid-Year	(Line 32 + Line 34) / 2	(0.692)
38	Cash Working Capital	CTS-TIMC CPCN, App G-2, Sch. 5, Line 18	0.168
39	**Total Mid-Year Rate Base**	**Sum of Line 36 to 38**	**102.850**

Table 2: Reconciliation of the 2026 Incremental Cost of Service as Known and Measurable Changes related to the CTS-TIMC Project ($ millions)

Line	Particular	Reference	2026
1	**Cost of Service**		
2	O&M Expense	CTS-TIMC CPCN, App G-2, Sch. 1, Line 3	-
3	Property Tax	CTS-TIMC CPCN, App G-2, Sch. 1, Line 4, See Note 1	0.085
4	Depreciation Expense	CTS-TIMC CPCN, App G-2, Sch. 1, Sum of Line 13 to 16	1.998
5	Amortization Expense	CTS-TIMC CPCN, App G-2, Sch. 9, Line 17	0.411
6	Income Tax	Line 20	(0.585)
7	Earned Return	Line 10 x CTS-TIMC CPCN, App G-2, Sch. 5, Line 25	6.425
8	**Total**	**Sum of Line 2 to 7**	**8.334**
9			
10	Mid-Year Rate Base	BCUC IR1 5.2, Table 1	102.850
11			
12	Income Tax		
13	Earned Return	Line 7	6.425
14	Less: Interest	-Line 10 x (LTD x LTD Rate + STD x STD Rate)	(2.961)
15	Add: Depreciation & Amortization	Line 4 + Line 5	2.409
16	Less: CCA		(7.455)
17	Taxable Income After Tax	Sum of Line 13 to 16	(1.581)
18			
19	Current Tax Rate		27%
20	Income Tax Expense	Line 17 / (1 - Line 19) x Line 19	(0.585)

Note to Table:

Note 1: Property Tax less the 1% in lieu portion related to the rate base additions in 2023 (i.e., already in 2023 revenue and rates).

5.3 Please explain how FEI calculated the 2025 rate base of $10.927 million and the cost of service of $1.150 million related to the Gibsons Capacity Upgrade Project, as referenced on page 26 of the Application.

Response:

The 2025 rate base of $10.927 million related to the Gibsons Capacity Upgrade (GCU) Project is calculated based on the estimated project capital cost of $11.216 million[5], which is expected to

[5] As discussed in Section 7.2.3.2.2 of FEI's Annual Review for 2023 Delivery Rates, the total GCU project cost of $12.194 million included approximately $0.978 million of deferred costs, with the remaining $11.216 million related to the project capital.

complete in 2023, entering FEI's rate base on January 1, 2024[6]. Please refer to Table 1 below for a reconciliation of the 2025 rate base amount of $10.927 million.

6 As part of FEI's Annual Review for 2024 Delivery Rates (page 65), submitted on July 28, 2023, FEI forecast a total final capital cost of $12.489 million, including AFUDC, which is included in the forecast 2024 rate base on January 1, 2024.

Table 1: Reconciliation of the 2025 Rate Base as Known and Measurable Changes related to the GCU Project ($ millions)

Line	Particular	Reference	2025
1	Gross Plant - Opening		
2	43000 Land		0.614
3	43200 Structures		0.707
4	47500 Distribution Mains		1.829
5	43710 Measuring & Regulating		1.988
6	43600 Compressors & Other		4.358
7	43400 Gas Holder		1.718
8	Total, Opening	Sum of Line 2 to 7	11.216
9			
10	Gross Plant - Ending		
11	43000 Land	Line 2	0.614
12	43200 Structures	Line 3	0.707
13	47500 Distribution Mains	Line 4	1.829
14	43710 Measuring & Regulating	Line 5	1.988
15	43600 Compressors & Other	Line 6	4.358
16	43400 Gas Holder	Line 7	1.718
17	Total, Ending	Sum of Line 11 to 16	11.216
18			
19	Accumulated Depreciation - Opening		
20	43000 Land	Ending Balance, 2024	-
21	43200 Structures	Ending Balance, 2024	(0.017)
22	47500 Distribution Mains	Ending Balance, 2024	(0.024)
23	43710 Measuring & Regulating	Ending Balance, 2024	(0.044)
24	43600 Compressors & Other	Ending Balance, 2024	(0.153)
25	43400 Gas Holder	Ending Balance, 2024	(0.040)
26	Total, Opening	Sum of Line 20 to 25	(0.278)
27			
28	Depreciation Expense		
29	43000 Land	Line 2 x 0.00%	-
30	43200 Structures	Line 3 x 2.5%	(0.018)
31	47500 Distribution Mains	Line 4 x 1.35%	(0.025)
32	43710 Measuring & Regulating	Line 5 x 2.34%	(0.047)
33	43600 Compressors & Other	Line 6 x 3.68%	(0.160)
34	43400 Gas Holder	Line 7 x 2.45%	(0.042)
35	Total, Depreciation Expense	Sum of Line 29 to 34	(0.291)
36			
37	Accumulated Depreciation - Ending		
38	43000 Land	Line 20 + Line 29	-
39	43200 Structures	Line 21 + Line 30	(0.035)
40	47500 Distribution Mains	Line 22 + Line 31	(0.048)
41	43710 Measuring & Regulating	Line 23 + Line 32	(0.091)
42	43600 Compressors & Other	Line 24 + Line 33	(0.313)
43	43400 Gas Holder	Line 25 + Line 34	(0.082)
44	Total, Ending	Sum of Line 38 to 43	(0.569)
45			
46	Net Plant Mid-Year	Sum of Line (8, 17, 26, 44) / 2	10.792
47			
48	Deferred Charges - Net Salvage		
49	Opening	Ending Balance, 2024	(0.008)
50	Amortization		(0.008)
51	Ending	Line 49 + Line 50	(0.015)
52			
53	Deferred Charges - Application and Development Cost		
54	Opening	Ending Balance, 2024	0.273
55	Amortization		(0.273)
56	Ending	Line 54 + Line 55	-
57			
58	Net Plant Mid-Year	Line 46	10.792
59	Unamortized Deferred Charges, Mid-Year	Sum of Line (49, 51, 54, 56) / 2	0.125
60	Cash Working Capital	Line 17 x FEI CWC/Ending GPIS %	0.010
61	**Total Mid-Year Rate Base**	**Sum of Line 58 to 60**	**10.927**

While responding to this IR, FEI discovered an excel error in calculating the income tax expense in 2025 due to the GCU Project. The 2025 cost of service impact should be $1.359 million, not $1.150 million. This small error of $209 thousand in the cost of service has no material impact (after rounding) on the 2023 COSA or the R:C ratios.

Please refer to Table 2 below which provides a reconciliation of the 2025 cost of service impact of $1.359 million. The cost of service impact includes the following assumptions:

- Incremental O&M of approximately $43 thousand per year;
- Incremental property tax of approximately $13 thousand in 2025 related to the 1% in Lieu; and
- Return on rate base at 6.23 percent (Annual Review for 2023 Delivery Rates, Table 8-2)

Table 2: Reconciliation of the 2025 Incremental Cost of Service as Known and Measurable Changes related to the GCU Project ($ millions)

Line	Particular	Reference	2025
1	**Cost of Service**		
2	O&M Expense	BCUC IR1 5.3	0.043
3	Property Tax	BCUC IR1 5.3	0.013
4	Depreciation Expense	BCUC IR1 5.3; Table 1; Line 35	0.291
5	Amortization Expense	BCUC IR1 5.3; Table 1; -Line 50 - Line 55	0.281
6	Income Tax	Line 20	0.050
7	Earned Return	Line 10 x 6.23%	0.681
8	**Total**	**Sum of Line 2 to 7**	**1.359**
9			
10	Mid-Year Rate Base	BCUC IR1 5.3, Table 1, Line 61	10.927
11			
12	Income Tax		
13	Earned Return	Line 7	0.681
14	Less: Interest	-Line 10 x (LTD x LTD Rate + STD x STD Rate)	(0.312)
15	Add: Depreciation & Amortization	Line 4 + Line 5	0.572
16	Less: CCA		(0.806)
17	Taxable Income After Tax	Sum of Line 13 to 16	0.135
18			
19	Current Tax Rate		27%
20	Income Tax Expense	Line 17 / (1 - Line 19) x Line 19	0.050

6.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Section 4.2, Table 4-3, Table 4-4, Table 4-6, Table 4-7, pp. 21, 24, 27

Final revenue requirements and rate base for 2023 COSA

On page 27 of the Application, FEI states:

> Tables 4-6 and 4-7 below provide the final revenue requirement and rate base, respectively, that are used in the 2023 COSA for allocation, including all adjustments related to the assumptions discussed in Section 4.2.2 and all known and measurable changes discussed in Section 4.2.3.

On page 21 of the Application, FEI presents Table 4-3 and states:

> Consistent with FEI's approach in past COSA studies, including the 2016 COSA study, the revenues of bypass and large industrial contract customers are treated as credits to the cost of service and allocated to each of FEI's non-bypass rate schedules (RS) (i.e., sales and non-contract transportation service).

On page 24 of the Application, FEI states that Table 4-4 presents the 2023 forecast of RS 46 revenue as well as the cost of service of Tilbury 1A that is included in the 2023 COSA.

6.1 Considering that the sum of $1.357 million (Table 4-3) and $33.869 million (Table 4-4) is $35.226 million, please clarify how FEI arrives at a total credit of $47.3 million from Bypass, Contract Customers and RS46 in Table 4-6.

<u>Response:</u>

FEI clarifies that the $47.3 million shown in Table 4-6 is the 2023 delivery margin forecast to be recovered from Bypass, Contract Customers, and RS 46, not revenue which includes cost of gas. The sum of $1.357 million from Table 4-3 is revenue which includes cost of gas. Further, the $33.869 million from Table 4-4 is the deficiency from Tilbury 1A, not the delivery cost recovery from RS 46 customers.

Please refer to Table 1 below for a reconciliation of the $47.3 million shown in Table 4-6 of the Application. FEI also clarifies and shows in Table 1 below that the $47.3 million includes the 2023 Forecast delivery margin from RS 22 interruptible customers. As explained on page 25 of the Application (lines 23 to 26), consistent with the 2016 COSA study, the delivery margin (and revenue) from RS 22 interruptible customers is treated as credits to the cost of service and allocated to each of FEI's non-bypass rate schedules.

Table 1: Reconciliation of the $47.3 million of Delivery Margin Credit from Table 4-6 of the Application

Rate Schedules	Reference	2023 Approved Delivery Margin ($000s)
Bypass and Special Rates		
RS 22 - Firm Service	Appendix B, Schedule 19, Line 21	349
RS 25	Appendix B, Schedule 19, Line 22	388
RS 46	Appendix B, Schedule 19, Line 23	28,474
Byron Creek	Appendix B, Schedule 19, Line 24	134
VIGJV	Appendix B, Schedule 19, Line 26	4,896
Non-bypass		
RS 22 - Interruptible	See Note 1	15,784
RS 22 - Interruptible (Known and Measureable Changes)	See Note 2	(2,704)
Total		47,322

Notes to Table:

1) *RS 22 – interruptible only; does not include interruptible delivery margin from RS 22A and RS 22B customers.*

2) *10 fully interruptible RS 22 customers are reclassed to RS 22 – firm, which is equivalent to a shift in delivery margin of approximately $2.704 million. As explained in Section 4.2.3.1, reclassing existing interruptible demand to firm demand does not increase the overall revenue or cost of service in the 2023 COSA model since the interruptible charge under RS 22 is set to equal the effective charges for firm demand (i.e., Firm Demand Charge per Month plus the Firm MTQ Delivery Charge per GJ).*

6.2 Please explain how FEI calculates the $36.5 million credit to the cost of gas from Bypass, Contract Customers and RS46, as shown in Table 4-6 above.

Response:

Please refer to Table 1 below which provides the reconciliation of the $36.5 million credit related to the cost of gas from Bypass, Contract Customers and RS 46.

The cost of gas for RS 46 is recovered directly from the LNG sales customers, whereas the cost of gas for the bypass customers (i.e., RS 22 bypass and RS 25 bypass) and the transportation customers (i.e., RS 22 – interruptible) is related to their allocation of unaccounted-for (UAF) gas, which is gas that is not specifically accounted for in the balancing of receipts, deliveries, and operation use. The cost of UAF related to the bypass and transportation service customers is included in the determination of their delivery rates to facilitate the recovery of UAF costs, as these customers do not pay for midstream charges.

Table 1: Reconciliation of the $36.5 million Cost of Gas Credit from Table 4-6 of the Application

Rate Schedules	Reference	2023 Approved Cost of Gas ($000s)
Bypass and Special Rates		
RS 22 - Firm Service	Appendix B, Schedule 18, Line 18, Column 3	450
RS 25	Appendix B, Schedule 18, Line 19, Column 3	36
RS 46	Appendix B, Schedule 18, Line 20, Column 3	35,585
Non-bypass		
RS 22 - Interruptible	See Note 1	446
RS 22 - Interruptible (Known and Measureable Changes)	See Note 2	(60)
Total		36,457

<u>*Notes to Table:*</u>

1) *RS 22 – interruptible only; does not include interruptible cost of gas from RS 22A and RS 22B customers.*

2) *10 fully interruptible RS 22 customers are reclassed to RS 22 – firm, which is equivalent to shifting cost of gas of approximately $60 thousand. As explained in Section 4.2.3.1, reclassing existing interruptible demand to firm demand does not increase the overall revenue or cost of service in the 2023 COSA model since the interruptible charge under RS 22 is set to equal the effective charges for firm demand (i.e., Firm Demand Charge per Month plus the Firm MTQ Delivery Charge per GJ).*

6.3 Please explain how FEI calculated that an amount of $56.4 million (Table 4-7) of biomethane-related assets would be removed from its rate base.

<u>Response:</u>

Please refer to Table 1 below for the reconciliation of the $56.4 million of biomethane-related assets to be removed from rate base for the purposes of the 2023 COSA.

Table 1: Reconciliation of Biomethane-related Assets

Line	Particular	Reference	Amount ($000s)
1	Biogas Plant		
2	2023 Opening	Appendix B, Schedule 6.1, Line 49, Column 3	20,490
3	2023 Ending	Appendix B, Schedule 6.1, Line 49, Column 8	85,187
4			
5	Biogas Accumlated Depreciation		
6	2023 Opening	Appendix B, Schedule 7.2, Line 49, Column 5	(5,082)
7	2023 Ending	Appendix B, Schedule 7.2, Line 49, Column 11	(5,903)
8			
9	Biogas CIAC		
10	2023 Opening	Appendix B, Schedule 9, Line 5, Column 2	(566)
11	2023 Ending	Appendix B, Schedule 9, Line 5, Column 7	(566)
12			
13	Biogas CIAC Amortization		
14	2023 Opening	Appendix B, Schedule 9, Line 12, Column 2	301
15	2023 Ending	Appendix B, Schedule 9, Line 12, Column 7	329
16			
17	**Net Biogas Plant**	**Sum of Line (2 to 15) / 2**	**47,095**
18			
19	Deferral - Net Salvage		
20	2023 Opening	Appendix B, Schedule 10.1, Line 36, Column 5	(234)
21	2023 Ending	Appendix B, Schedule 10.1, Line 36, Column 8	(289)
22	**Mid-Year Average**	**(Line 20 + Line 21) / 2**	**(262)**
23			
24	Deferral - BVA Transfer		
25	**Mid-Year Average**	**Appendix B, Schedule 11.1, Line 22, Column 10**	**9,544**
26			
27	**Total Mid-Year Rate Base**	**Line 17 + Line 22 + Line 25**	**56,378**

7.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Section 4.3.1.7, Table 4-8, p. 31; Order G-4-18 with Reasons for Decision on FEI Cost of Service Allocation and Revenue to Cost Ratios (FEI 2016 COSA Decision)

Functionalization summary

7.1 For each of the following items included in Table 4-8 of the Application, please confirm, or explain otherwise, that FEI's functionalization treatment in the 2023 COSA is consistent with the 2016 COSA and was approved by the BCUC in the FEI 2016 COSA Decision:

- Gas supply operations costs
- Transmission assets and related costs
- Distribution assets and related costs
- Marketing costs
- Customer accounting costs

<u>Response:</u>

FEI confirms that for the functions listed in this IR, the treatment in the 2023 COSA is consistent with the 2016 COSA that was approved by the BCUC in the FEI 2016 COSA Decision.

8.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Section 4.3.2, p. 32

Classification

On page 32 of the Application, FEI states:

> As discussed in Section 4.3.1.2.2, the Tilbury 1A expansion has been in service since 2018 for supporting the growing LNG sales demand both domestically and internationally. The costs related to the Tilbury 1A expansion are functionalized separately from the Tilbury Base Plant. Since the sales of LNG through RS 46 are credited back to all non-bypass customers through the delivery rates of each rate schedule, FEI is also allocating the related costs of the Tilbury 1A expansion based on the delivery margin of each of these rate schedules in the 2023 COSA.

8.1 Please explain the method used by FEI to classify the Tilbury 1A expansion assets and related costs (e.g., demand-related, energy-related, or customer-related).

Response:

As noted on page 32 of the Application and referenced in the preamble above, the Tilbury 1A expansion is allocated based on the delivery margin of each rate schedule in the 2023 COSA, thus matching the allocation of the RS 46 LNG sales revenue. Technically speaking, the Tilbury 1A expansion assets and related costs (as well as the offsetting RS 46 revenue) are neither demand-related (e.g., peak demand), energy-related (e.g., volume), or customer-related (e.g., customer count). However, for the purposes of classification, and irrespective of the allocation based on delivery margin, the Tilbury 1A expansion assets and related costs (as well as the offsetting RS 46 revenue) are grouped as demand-related, which is reflected in Table 4-9 of the Application.

9.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Section 4.3.2, p. 33

Minimum System Study (MSS)

On page 33 of the Application, FEI states:

> FEI uses the MSS approach with PLCC adjustment to determine the split between the demand-related and customer-related classification for distribution related costs.
>
> In the Elenchus COSA Report on FEI's 2016 COSA study, Elenchus stated that the use of MSS with a PLCC adjustment is an accepted method for classifying distribution related assets and costs based on Elenchus' experience. […] In the 2016 COSA Decision, the BCUC determined the method to be reasonable for use in COSA studies.
>
> […]
>
> The results of the MSS for the 2023 COSA are based on actual 2022 data, with the customer-related component and the demand-related component each approximately 50 percent.

9.1 Please describe any material difference between the results of the MSS in the 2016 COSA and in the 2023 COSA.

Response:

There is no change to the methodology between the 2016 and 2023 COSA studies used in the minimum system study (MSS) to calculate the proportion of distribution costs that are customer-related versus demand-related. The only changes in the MSS between the two COSA studies are the underlying cost of steel and plastic pipe, the variations in total length of steel and plastic pipe between 2016 and 2023, and the valuation of 60 mm pipe in FEI's minimum system as described below. The 2023 MSS also included the Fort Nelson service area, as common rates were implemented on January 1, 2023.[7]

In the 2016 MSS, FEI valued its minimum system based on 60 mm plastic (PE) pipe, whereas in the 2023 MSS, the minimum system is now valued based on both 60 mm steel and 60 mm PE pipe. As such, the average unit cost of 60 mm pipe in the 2023 MSS included the average unit cost of 60 mm steel pipe and the average unit cost of 60 mm PE pipe. The implicit assumption of only valuing the minimum system with 60 mm PE pipe in the 2016 MSS was that, at that time, FEI considered that only PE pipe would be used if FEI had to build the minimum system again. However, in reality, FEI has continued to utilize distribution steel pipe since the 2016 MSS, such as for intermediate pressure (IP) distribution pipes. As such, in the 2023 MSS, FEI changed to

[7] BCUC Decision and Order G-278-22.

use both the unit cost of 60 mm steel and PE pipes, which is more reasonable and reflective of current practice.

Table 1 below summarizes the results of the 2016 and 2023 MSS. One material change in terms of the underlying costs between the 2016 and 2023 MSS is the increase in the average unit cost of steel pipe relative to the increase in the average unit cost of PE pipe. The average unit cost of all steel pipes has increased by approximately 93 percent (Line 12) since 2016 compared to approximately 18 percent for PE pipe. This was expected given the significant inflationary increases, especially in the price of steel, in recent years when compared to 2016.

The change to using both average unit costs of steel and PE for 60 mm or less and the increase in steel prices are the main drivers that led to the change from the 30/70 percent split between customer-related and demand-related in the 2016 MSS to the 50 percent split in the 2023 MSS.

Table 1: Comparison between 2023 MSS and 2016 MSS

Line	Particular		Steel Only Mains	Plastic Only Mains	Combined Steel and Plastic	Notes
1		2023	11,629	15,233	26,862	Total length for all diameter sized pipes
2	Length (km)	2016	11,650	13,832	25,482	
3		Change	(21.26)	1,401.27	1,380.01	Line 1 - Line 2
4		% Change	-0.2%	10%	5%	Line 3 / Line 2
5	Total Weighted Cost	2023	$ 7,179,522	$ 1,235,179	$ 8,414,701	2023 COSA: Appendix E, Table 1, Line 31
6	for all diameter sized	2016	3,735,438	950,556	4,685,994	2016 RDA: Appendix 6-5, Table 1, Line 32
7	pipes ($000s)	Change	$ 3,444,084	$ 284,623	$ 3,728,707	Line 5 - Line 6
8		% Change	92.2%	30%	80%	Line 7 / Line 6
9		2023	$ 617.4	$ 81.1	$ 313.3	Line 5 / Line 1
10	Average Total Unit	2016	320.6	68.7	183.9	Line 6 / Line 2
11	Cost ($/m)	Change	$ 296.8	$ 12.4	$ 129.4	Line 9 - Line 10
12		% Change	93%	18%	70%	Line 11 / Line 10
13		2023	$ 271.0	$ 69.5	$ 156.7	DP Weighted cost ≤ 60 mm pipe / length in meters
14	Average Unit Cost for	2016	55.7	55.7	55.7	(See Note 1)
15	<= 60 mm only ($/m)	Change	$ 215.4	$ 13.8	$ 101.1	Line 13 - Line 14
16		% Change	387%	25%	182%	Line 15 / Line 14
17	Minimum Size Cost (All	2023	$ 3,151,910	$ 1,058,587	$ 4,210,497	Line 13 x Line 1
18	Pipe Value at <=60 mm	2016	648,696	770,185	1,418,881	Line 14 x Line 2
19	Unit Costs) ($000s)	Change	2,503,214	288,402	2,791,616	Line 17 - Line 18
20		% Change	386%	37%	197%	Line 19 / Line 18
21	Customer-Related	2023			50.0%	Line 17 / Line 5
22		2016			30.3%	Line 18 / Line 6
23	Demand-Related	2023			50.0%	1 - Line 21
24		2016			69.7%	1 - Line 22

<u>*Note to Table:*</u>

(1) As discussed above, the 2016 MSS used the average unit cost of 60 mm or less PE pipe for the calculation of the minimum size cost (i.e., all pipe valued at 60 mm unit costs) for both steel and PE pipes. This has been changed to using the average unit cost of 60 mm or less steel pipe for steel and the average unit cost of 60 mm or less PE pipe for plastic, which is more reflective of FEI's current practice.

10.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Section 4.3.2, p. 34

Peak Load Carrying Capability (PLCC) adjustment

On page 34 of the Application, FEI states:

> Based on a minimum distribution system of 60 mm PE in diameter, as discussed in the MSS section above, the PLCC adjustment for the 2023 COSA is calculated to be 0.206 GJ [gigajoules] per day per customer.

10.1 Please describe any material difference between the calculation of the PLCC adjustment in the 2016 COSA and in the 2023 COSA.

<u>Response:</u>

There is no change to the methodology used to calculate the PLCC adjustment between the 2016 and 2023 COSA studies. Table 1 below summarizes the PLCC results in 2016 and 2023. As demonstrated below, there is no material change between the two COSA studies, i.e., an increase of 0.001 GJ/day per customer, from 0.205 (2016) to 0.206 (2023).

Table 1: Summary of PLCC Adjustment from 2016 COSA to 2023 COSA

	Total Consumption GJ/day	Total Customers Served from Distribution Networks	PLCC Adjustment – Average GJ/day per Customer
2016	206,360	1,004,925	0.205
2023	225,161	1,092,907	0.206
Change	**18,801**	**87,982**	**0.001**

11.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Section 4.3.1, Table 4-8, p. 31; Section 4.3.2, Table 4-9, p. 35

Functionalization and classification summaries

FEI summarizes the delivery cost of service functionalization in Table 4-8 and the delivery cost of service classification in Table 4-9.

11.1 Please revise Table 4-8 to include the delivery cost of service classification summary as contained in Table 4-9.

Response:

Please see Table 1 below for a revised version of Table 4-8 which includes the classification of the delivery cost of service between energy, demand, and customer in the 2023 COSA study.

Table 1: Breakdown of the 2023 COSA Delivery Cost of Service by Function and Classification

Function	Classification	($ millions)	Percentage of Total
Gas Supply Operations	Energy	11.0	1.0%
	Demand	-	-
	Customer	-	-
Tilbury Base LNG Storage	Energy	-	-
	Demand	17.9	1.7%
	Customer	-	-
Tilbury Phase 1A Expansion	Energy	-	-
	Demand	33.9	3.2%
	Customer	-	-
Mt. Hayes LNG Storage	Energy	-	-
	Demand	7.0	0.7%
	Customer	-	-
Transmission	Energy	-	-
	Demand	266.6	25.3%
	Customer	-	-
Distribution	Energy	-	-
	Demand	196.0	18.6%
	Customer	403.4	38.3%
Marketing	Energy	41.6	3.9%
	Demand	0.0	0.0%
	Customer	38.3	3.6%
Customer Accounting	Energy	-	-
	Demand	-	-
	Customer	38.8	3.7%
Total		**1,054.4**	**100.0%**

12.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Section 4.3.3, p. 35; Section 4.5, Table 4-16, p. 46

Allocation

On page 35 of the Application, FEI states:

> Within the 2023 COSA, there is approximately $52.6 million of costs that have been classified as energy-related. These costs include approximately $11.0 million of gas supply operations related costs such as company use gas and gas control, as discussed in Section 4.3.1.1. The remaining $41.6 million of costs are all related to the amortization of the [Demand Side Management] DSM deferral account in the 2023 test year.

On page 46 of the Application, FEI presents an extract of Table 4-16 below:

Table 4-16: Summary of Changes to COSA Study Methods from 2016

Application Section	Methodology Description	2016 COSA Method	2023 COSA Method	Comments
4.3.3	Allocation	Customer-related costs allocated based on average and weighted customers. Demand-related costs allocated to rate schedules based on coincident peak demand. Energy-related costs allocated based on sales volume.	No change from 2016 except that the costs of the Tilbury 1A expansion are classified as Energy-related and allocated based on the delivery cost of service of all non-bypass customers.	The RS 46 revenue associated with the Tilbury 1A expansion is an offsetting credit to all non-bypass customers, thus the associated costs should also be allocated to all non-bypass customers.

[Emphasis Added]

12.1 If, within the 2023 COSA, there is approximately $52.6 million of costs that have been classified as energy-related, and this includes $11 million of costs related to gas supply operations and $41.6 million related to the amortization of the DSM deferral account, please clarify why the costs of the Tilbury 1A expansion, which have also been classified as energy-related (per Line 4.3.3 in Table 4-16), are not included in the $52.6 million amount of energy-related costs.

<u>Response:</u>

The statement in Table 4-16 regarding the costs of the Tilbury 1A expansion being classified as Energy-related was a typographical error. The costs associated with the Tilbury 1A expansion are allocated based on the delivery margin of each rate schedule in the 2023 COSA and therefore the classification is neither demand-related nor energy-related.

As explained in the response to BCUC IR1 8.1, for the purpose of the classification, and irrespective of the allocation based on delivery margin, the Tilbury 1A expansion assets and related costs are grouped as demand-related and reflected in Table 4-9 of the Application. As such, the statement in Table 4-16 of the Application should have read "the costs of Tilbury 1A expansion are classified as *Demand-related* and allocated based on the delivery cost of service of all non-bypass customers".

On line 4.3.3 of Table 4-16, FEI states that energy-related costs are allocated based on sales volumes but also states that the costs of the Tilbury 1A expansion, which are classified as Energy-related, are allocated based on the delivery cost of service of all non-Bypass customers.

12.2 Please clarify why the Tilbury 1A expansion costs are not allocated based on sales volumes. Please also clarify the basis on which these costs are allocated.

Response:

As discussed in the response to BCUC IR1 8.1, the Tilbury 1A expansion costs are allocated based on the delivery margin of each non-bypass rate schedule which is consistent with the treatment of the offsetting revenues from RS 46 LNG sales.

FEI notes that RS 46 was authorized by Direction No. 5 to the BCUC. RS 46 is a rate schedule that is set separately from FEI's delivery rates. Therefore, as part of FEI's Annual Review process that sets the revenue requirement and delivery rates, the revenue from RS 46 LNG sales is treated as a credit to the delivery margin of all non-bypass customers. The result is that the credit is allocated to each non-bypass rate schedule based on each rate schedule's delivery margin.

Since delivery rates are set to recover the delivery margin of each rate schedule and include fixed charges, variable volumetric charges, demand charges, etc., a rate schedule's delivery margin is not directly proportional to its sales volume. As such, if the Tilbury 1A expansion costs were allocated based on sales volumes, there would be a misalignment between how the costs and the revenues (RS 46) are allocated to each non-bypass rate schedule. Table 1 below provides a comparison between sales volume and delivery margin in terms of the percentage breakdown by rate schedule.

Table 1: Comparison of Percentage Allocation between Sales Volume and Delivery Margin

Rate Schedule (Non-bypass)	Sales Volume (Table 4-10 of Application)		Delivery Margin (Table 4-14 of Application)	
	TJ	%	$000s	%
1	82,890	41.7%	693.5	65.8%
2	29,204	14.7%	176.4	16.7%
3/23	29,674	14.9%	119.0	11.3%
4	166	0.1%	0.1	0.0%
5/25	19,130	9.6%	45.0	4.3%
6	21	0.0%	0.1	0.0%
7/27	10,293	5.2%	3.1	0.3%
22	12,373	6.2%	3.0	0.3%
22A	7,669	3.9%	8.5	0.8%
22B	7,481	3.8%	5.9	0.6%
Total	**198,901**	**100.0%**	**1,054.4**	**100.0%**

If the Tilbury 1A Expansion costs were allocated based on sales volume instead of delivery margin, then RS 1 will be allocated 41.7 percent of the Tilbury 1A Expansion costs while benefiting from approximately 65.8 percent of the offsetting revenue from RS 46. Allocating Tilbury 1A Expansion costs based on delivery margin ensures there is no misalignment in the allocation between the costs and the revenues related to LNG sales.

13.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Section 4.3.3.2, pp. 36–37, Table 4-11, p.38

Demand-related allocation

On page 36 of the Application, FEI states:

> Consistent with FEI's 1993, 1996, 2001, 2012, and 2016 RDAs, FEI has used the coincident peak (CP) approach to allocate demand-related costs to each rate schedule. This reflects the fact that FEI's delivery system has generally been constructed to meet the peak day (coldest day) demand of all its firm service customers.

13.1 Please define coincident peak (CP) and non-coincident peak (NCP) and clarify why the CP approach is superior to the non-coincident peak (NCP) to allocate demand-related costs to each rate schedule.

Response:

The following descriptions/definitions are from Gas Rate Fundamentals, 4th Ed., American Gas Association, 1987, Arlington, Virginia.

Coincident Demand (CP)

> The CP method, also called peak responsibility, allocates capacity-related costs based on the demands of the various classes of service at the time of the system peak. The rationale for the CP method is that the utility's costs associated with its maximum load should be divided among the customers causing that peak. The magnitude of those customers' demands at other times of the day, month or year or the length of those demands is not a consideration. Under this method, the "allocator" for capacity costs is the ratio of the demand of the various classes of service at the time of the system peak to the total demand at that time. (Page 141)

Non-coincident Demand (NCP)

> This method, also called class demand, is based on the maximum demands of the individual classes of service regardless of when those demands occur. Under the NCP method, the effects of diversity are apportioned in equal proportions to each class. Thus, the allocator for capacity costs is the ratio of each of the class maximum demands to the sum of all the class maximum demands irrespective of time of occurrence. (Page 143)

For FEI, the appropriate allocator to use for allocating demand-related (capacity-related) costs is the CP method. This is because FEI's capacity infrastructure costs, such as the LNG storage facilities (Tilbury Base Plant and Mt. Hayes), transmission and distribution system assets, and their related costs are incurred to meet firm service peak demand requirements (i.e., they ultimately determine the size and capacity of FEI's system), which occurs during winter and corresponds with the coincident peak of FEI's system. If NCP is used to allocate demand-related costs, then the costs would be allocated based on the individual peak that might or might not be related to the costs incurred by FEI to meet the coincident system peak.

On page 37 of the Application, FEI states:

> The CP of each rate schedule for allocation purposes is calculated based on a three-year weighted-average load factor (LF) and the annual volume of each rate schedule as follows:
>
> CP (or Peak Day Demand) = Annual Consumption / (3-year w-avg. LF x 365 days)
>
> The three-year weighted average LF is calculated based on the annual LF by region and by rate schedule using the number of customers per rate schedule in each region. Furthermore, the annual LF by region and by rate schedule is calculated based on an estimate of the peak day demand for each rate schedule on a regional basis using the regional temperature and a regression analysis that uses average monthly temperature and actual demand data for 10 months (excludes July and August).
>
> […]
>
> Essentially, the sum of the heat sensitive rate schedules' peak day demand (i.e., RS 1, 2, 3, 23, 5, 25, and 6) and the firm contractual commitments (i.e., RS 22, 22A, and 22B) is equal to FEI's total peak day demand.

On page 38 of the Application, FEI presents Table 4-11.

13.2 Please provide the formula FEI uses to calculate the three-year weighted average load factor and provide a definition for load factor.

Response:

The load factor is a ratio of **Average Daily Weather Normalized Demand per Customer** divided by **Estimated Peak Daily Demand** and is intended to describe the utilization of the system at the region and rate class level.

$$Load\ Factor = \frac{\text{Average Daily Weather Normalized Demand per Customer}}{\text{Estimated Peak Daily Demand}}$$

The following example and explanation show how the Lower Mainland RS 1 (or Rate 1) load factor is calculated.

1. Calculation of the Average Daily Weather Normalized Demand per Customer

	A	B	C	D
	Month	**Days in Month**	**Monthly Weather Normalized Demand per Customer, GJ**	**Average Daily Weather Normalized Demand per Customer, GJ**
1	Jan	31	14.9	0.48
2	Feb	28	12.4	0.44
3	Mar	31	11.1	0.36
4	Apr	30	7.5	0.25
5	May	31	4.7	0.15
6	Jun	30	3.0	0.10
7	Jul	31	2.8	0.09
8	Aug	31	2.9	0.09
9	Sep	30	2.9	0.10
10	Oct	31	6.5	0.21
11	Nov	30	9.9	0.33
12	Dec	31	15.0	0.48
13	Average Daily Weather Normalized Demand per Customer, GJ			0.26

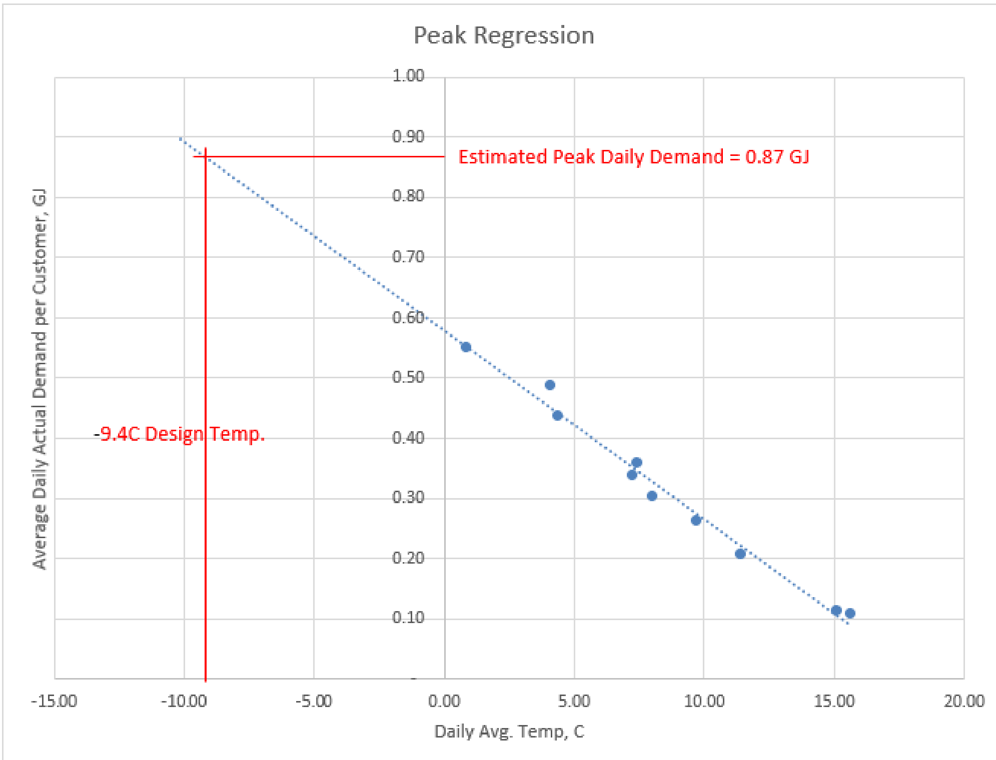
- Columns A and B record the months and days in the month.
- Column C is the monthly weather normalized demand per customer recorded per month for the region and rate class.
- Column D is the average daily weather normalized demand per customer calculated as Column C divided by Column B.
- Row 13 is the simple average of column D and is the numerator in the load factor calculation.

2. Calculation of Estimated Peak Daily Demand

	A	B	C	D	E	F
	Month	**Days in Month**	**Daily Average Temp. (C)**	**Monthly Actual Demand per Customer, GJ**	**Average Daily Actual Demand per Customer, GJ**	
1	Jan	31	4.1	15.1	0.49	
2	Feb	28	4.4	12.3	0.44	
3	Mar	31	7.2	10.5	0.34	
4	Apr	30	8.0	9.1	0.30	
5	May	31	11.4	6.4	0.21	
6	Jun	30	15.6	3.3	0.11	
7	Sep	30	15.1	3.5	0.12	
8	Oct	31	9.7	8.1	0.26	
9	Nov	30	7.4	10.8	0.36	
10	Dec	31	0.9	17.1	0.55	
11					Design Temp, C	-9.40
12					Slope	-0.03
13					Intercept	0.58
14					Estimated Peak Daily Demand , GJ	0.87

- Columns A and B record the months and days in the month.
- Column C is the daily average temperature for the month. This is the average of the set of average daily temperatures recorded in the month.
- Column D is the monthly actual demand per customer recorded per month for the region and rate class.
- Column E is the daily average actual demand per customer calculated as Column D divided by Column B.

The Estimated Peak Daily Demand is shown in row 14 and is calculated using a regression between the Average Daily Actual Demand per Customer (column E) and the Daily Average Temperature (column C). The regression is shown below:



The blue dots are from columns C and E of the table above. The regression line is extended to the Design Temperature (-9.4C for Lower Mainland).

3. Calculation of Load Factor

The load factor is then calculated as follows:

$$Load\ Factor = \frac{\text{Average Daily Weather Normalized Demand per Customer}}{\text{Estimated Peak Daily Demand}} = \frac{0.26}{0.87} = 0.29$$

The above calculation is repeated for each of the six regions[8] to determine first the regional load factors for each rate schedule, which will then be weighted based on the number of customers by region for each rate schedule for a regional weighted load factor. FEI completes a regional based load factor to ensure the influence of different weather patterns, building stock and customer preferences in each region are accounted for.

[8] The load factor calculation is weighted based on results from the following six regions: Lower Mainland, Inland, Columbia, Vancouver Island, Whistler and Fort Nelson.

Once the regional weighted average load factor by rate schedule is calculated, the process is then repeated such that a three-year weighted average load factor by region can be calculated. Please refer to item 5) below for further discussion on why a three-year average is used.

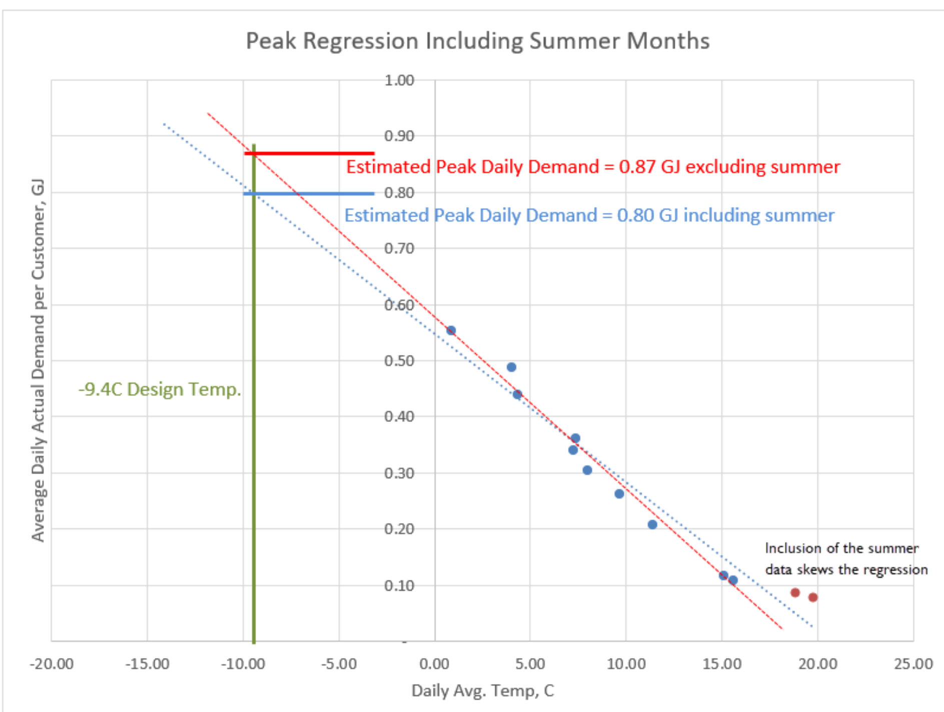
4. Exclusion of Summer Months from Peak Estimate for RS 1/2/3/23/5/25

The summer months (July and August) are omitted from the regression analysis for rate schedules 1, 2, 3, 23, 5 and 25 because the weather sensitive space heating load is not present in those months. If the summer months were included, the regression line would have a lower slope and underestimate the peak demand, which would over-estimate the load factor.

In the following figure, July and August data is shown as the two red dots in the bottom right corner of the plot.

The original regression line is shown in red, and at -9.4C results in an estimated peak of 0.87 GJ. When the summer months are included, the regression line flattens slightly and is shown as the blue dashed line. The resulting winter peak, which is under-estimated, is shown as the blue horizontal line at 0.80 GJ.

Including the summer data does not result in a reasonable estimate of the winter peak and therefore July and August data is not included in the regression analysis.



5. Rationalization of Three-Year Average

FEI's use of a three-year average to develop the load factors is consistent with past practice, and part of the methodology accepted by the BCUC in the 2016 COSA Decision. Using a three-year average strikes a reasonable balance between smoothing out recent fluctuations and being responsive to recent trends. Furthermore, it is preferable for the purposes of comparability and consistency over time to continue to apply the existing method, which remains reasonable and appropriate.

13.3 Please clarify how FEI addresses the circularity between the peak day demand and the load factor, as the peak day demand is dependent on the load factor and the load factor is based on an estimate of the peak day demand.

<u>Response:</u>

There is no circularity between the load factor and estimating the peak demand as used in the COSA study. Please refer to the response to BCUC IR1 13.2 for the derivation of the load factors for each rate schedule.

The peak day demand used to calculate the three-year weighted average load factor is the "estimated peak daily demand" as set out in the response to BCUC IR1 13.2 and is calculated based on the design day temperature with a linear regression between *<u>actual</u>* average daily demand per customer and *<u>actual</u>* daily average temperature. This is different than the peak day demand used to allocate demand-related costs, which is calculated based on the three-year weighted average load factor and the 2023 *<u>forecast</u>* volume of each rate schedule.

13.4 Please revise Table 4-11 to include the annual consumption of each rate schedule so that all the necessary data to calculate the peak day demand of each rate schedule is included in Table 4-11.

<u>Response:</u>

Please refer to Table 1 below for a revised version of Table 4-11 with the annual volumes from Table 4-10. The peak day demand equals to the annual volumes from Rate Schedules 1, 2, 3, 23, 5, 25 and 6 divided by the product of 365 days times the load factor[9]. FEI notes that the values for Rate Schedules 22, 22A, and 22B are based on the firm demand of these customers and not

9 For example, RS 1 is 82,890 TJ / (365 days x 0.31276) = 726.1 TJ/day.

calculated based on the load factor. There is no peak day or firm demand for Rate Schedules 4, 7 and 27 as these are seasonal customers or fully interruptible.

Table 1: Annual Volume, Load Factors, and Peak Day/Firm Demand by Rate Schedule for Allocation

Rate Schedule	Annual Volume (TJ)	Load Factor(1)	Peak Day or Firm Demand (TJ/Day)
1	82,890	31.3%	726.1
2	29,204	30.4%	263.3
3	25,770	36.0%	195.9
23	3,904	35.7%	30.0
4	166	n/a	-
5	10,827	53.6%	55.3
25	8,303	61.6%	37.0
6	21	100.0%	0.1
22	12,373	n/a	5.8
22A	7,669	n/a	24.7
22B	7,481	n/a	14.9
7	6,004	n/a	-
27	4,289	n/a	-
Total	**198,901**		**1,353.0**

Note to Table:

(1) Rounded to one decimal place.

13.5 Please confirm, or explain otherwise, that FEI's CP is 1,353.0 TJ/day in Table 4-11 on the coldest day and that each rate schedule is allocated FEI's demand-related costs on the basis of their respective contribution to FEI's CP.

Response:

Not confirmed.

The 1,353.0 TJ/day in Table 4-11 is simply the sum of CP peak day demand or firm demand of various rate schedules that will be allocated demand-related costs. It is for the purpose of each individual allocation and does not represent FEI's CP on the coldest day.

For clarity, the peak day demand shown for Rate Schedules 1, 2, 3, 23, 5, 25, and 6 represent the peak under extreme cold weather. For customers served under Rate Schedules 22, 22A and

22B, the values represent the sum of the firm contracted capacity of each customer in these rate schedules.

The Peak Day/Firm Demands are used to allocate the demand-related costs functionalized in Transmission and Mt. Hayes, while the Tilbury Base Plant is allocated only to core customers (Rate Schedules 1, 2, 3/23, 5/25, and 6) based on their respective Peak Day Demand. Demand-related costs under the Distribution Function are allocated based on the peak day demand of each rate schedule (as shown in Table 4-11) minus the PLCC adjustment factor (0.206 x the number of customers in the Rate Schedule).

FEI notes that Table 4-11 does not include the firm contract demand of each of the industrial bypass customers, the contract customer VIGJV, or RS 46 LNG customers. As discussed in Section 4.2.2.2, the revenue from these customers is treated as a credit to FEI’s revenue requirement and are not allocated with demand-related costs using the peak day/firm demand.

14.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Section 4.3.3.3, p. 39

Customer-related allocation

On page 39 of the Application, FEI states:

> For the purposes of the 2023 COSA, FEI developed two types of weighting factors for adjusting the average number of customers:
>
> - a weighting factor for costs related to Meters and Distribution Services; and
> - a weighting factor for costs related to Administration and Billing.
>
> Table 4-13 below shows the weighting factors for meters/services and for administration/billing, which are calculated for each rate schedule relative to the residential rate schedule.[70]
>
> Footnote 70: FEI's residential rate schedule (RS 1) is used as the base upon which to weight against other rate schedules because it is the least costly rate schedule to connect and administer. For this reason, the weighting study shows the residential rate schedule with a factor of 1.0. [*Emphasis added*]

14.1 Please provide the weighting study referenced in Footnote 70.

Response:

The weighting factor study referenced in Footnote 70 is referring to two weighting factor analyses, the Customer Weighting Factor and the Customer Admin & Billing Factor, presented in Table 4-13 of the Application.

The Customer Weighting Factor is used to adjust the number of customers when allocating the costs associated with meters and services, whereas the Customer Admin & Billing Factor is used to adjust the number of customers when allocating the costs related to customer administration and customer billing. Please refer to Attachment 14.1A for the Customer Weighting Factor and Attachment 14.1B for the Customer Admin & Billing Factor.

While responding to this IR, FEI noticed the Customer Weighting Factor for Rate Schedule 27 should be 38.5, not 48.7. This correction is reflected in Attachment 14.1A and does not affect the 2023 COSA study, allocated costs, or resulting R:C and M:C ratios.

14.2 Please describe any material difference between the 2016 COSA and the 2023 COSA as it relates to the number and type of weighting factors to adjust the average number of customers.

Response:

There is no change to the type and number of customer weighting factors between the 2016 and 2023 COSA studies. In both COSA studies there is one customer weighting factor related to meters and services and another customer weighting factor related to customer administration and billing. The changes in the weighting factors between the rate schedules are primarily due to the relative increases in the underlying costs between residential customers and other customers between 2016 and 2023. For example, FEI had experienced larger inflationary increases in the industrial meters and service costs relative to the inflationary increase in residential meters and service costs, which resulted in a higher weighting factor for the industrial rate schedules since all weighting factors are relative to residential customers.

On page 40 of the Application, FEI states:

> For example, industrial customers are installed with bigger rotary meters and service lines, while residential customers are installed with smaller diaphragm meters and service lines; therefore, the average cost (i.e., including meter, service line, regulators and customer service) for industrial customers under RS 5 (i.e., approximately $29,545 per customer in 2022) is higher than the average cost for residential customers (i.e., approximately $1,872 per customer in 2022).

14.3 Please list all the assets and related costs that are considered when calculating the customer weighting factor used for meters and services.

Response:

Please refer to Attachment 14.1A provided in the response to BCUC IR1 14.1 for the list of different meter types (including the component costs related to each meter type) as well as the related service lateral costs used to determine the Customer Weighting Factor.

14.4 Please explain how FEI determines the amount of “meter, service line, regulators and customer service” to include in the average cost to serve customers in each rate class. As an example, please explain how FEI arrived at an average cost of $29,545 to serve industrial customers under RS 5 as it relates to meters and services.

Response:

Please refer to Attachment 14.1A provided in the response to BCUC IR1 14.1 for the detailed calculations of the Customer Weighting Factor for each rate schedule.

The process for each rate schedule is the same, as follows:

1. For each rate schedule, the different types of meters as well as the number of meters for each meter type are identified based on available records.
2. For each meter type, the following are identified:
    a. The cost of the meter;
    b. The cost of the meter set excluding the meter itself (i.e., regulators, instrument drivers, piping that is added to the meter);
    c. The cost for electronic volume correctors (EVC) for larger commercial / industrial meter sets and telemetry costs;
    d. Customer service and the service lateral costs for each meter type;
    e. For large industrial customers such as RS 22, the cost of any customer station that houses all metering equipment as well as a provision for the service lateral;
    f. For large industrial customers to whom natural gas is supplied from FEI's high pressure pipeline, an engineering cost estimate is used to determine the customer station costs for reducing the pressure to a level that meets the customers' requirements; and
    g. For the residential 200-series meter sets, for which approximately 85 percent are connected to a single service lateral while the remaining 15 percent are meters that share a single service lateral, Table 1 below illustrates how the total cost is calculated for these residential customers with a 200-series meter (also see Attachment 14.1A, page 1, Rate 1 – Residential, Line 2, Column m).

Table 1: Calculation of Total Cost for Residential 200-Series Meter

	Single Meters to a Service Lateral	Meters Sharing a Service Lateral	Total
Proportion of 200 series meters	85.18%	14.82%	100.00%
Number of Meters	759,201	132,076	891,201
Total Cost of Meter, Meter Set w/o Meter & Service Lateral	$2,109[10]		
Total Cost of Meter, Meter Set w/o Meter		$207[11]	
Total Cost of 200-Series Meter & Lateral	$1,601 million	$27 million	$1,628 million

[10] Attachment 14.1A, page 1, Rate 1 – Residential, Line 2, Column i.

[11] Attachment 14.1A, page 1, Rate 1 – Residential, Line 2, Column b + Column c.

For each rate schedule listed in Attachment 14.1A, the total cost for meters and services (Column m) is calculated and then divided by the number of meters (or stations for large industrial rate schedules) to determine the Class Per Unit Cost (Column n). The Class per Unit Cost is then divided by the Rate 1 Residential Class Per Unit Cost to determine the Customer Weighting Factor of each Rate Schedule (Column o).

Using RS 5 as an example, Table 2 below provides the calculation of the $29,545 referenced in the preamble to this IR and the RS 5 Customer Weighting Factor of 15.8.

Table 2: Rate Schedule 5 Class per Unit Cost and Customer Weighting Factor

Line	Particulars	Amount	Reference
1	RS 5 Total Cost	$7,740,748	Attachment 14.1A, Page 3, Line 18, Column m
2	RS 5 Number of Meters	262	Attachment 14.1A, Page 3, Line 18, Column l
3	RS 5 Class per Unit Cost	$29,545	Line 1 / Line 2
4	RS 1 Class per Unit Cost	$1,872	Attachment 14.1A, Page 1, Line 16, Column n
5	RS 5 Customer Weighting Factor	15.8	Line 3 / Line 4

Table 3 below provides the Total Cost, Total Number of Meters or Customers or Stations, the Average Class Per Unit Cost, and the Customer Weighting Factor for all rate schedules.

Table 3: Summary of Customer Weighting Factor for all Rate Schedules

Rate Schedule	Total Cost	No. of Meters or Customers	Average Class Per Unit Cost	Residential Class Per Unit Cost	Weighting Factor
1	$1,755,256,795	937,401	$1,872	$1,872	1.0
2	$374,606,805	95,013	$3,943	$1,872	2.1
3	$102,336,308	6,017	$17,008	$1,872	9.1
4	$1,154,718	40	$28,868	$1,872	15.4
5	$7,740,748	262	$29,545	$1,872	15.8
6	361,181	10	$36,118	$1,872	19.3
7	$1,276,028	14	$91,145	$1,872	48.7
22	$4,213,351	23	$183,189	$1,872	97.8
22A	$5,796,000	10	$579,600	$1,872	309.5
22B	$6,269,000	5	$1,253,800	$1,872	669.6
23	$37,182,175	1,696	$21,923	$1,872	11.7
25	$20,212,484	520	$38,870	$1,872	20.8
27	$7,705,459	107	$72,014	$1,872	38.5

15.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Section 4.6.1, Table 4-17, pp. 43 and 47–48

2023 R:C ratios

On page 43 of the Application, FEI states:

> Transportation service customers do not pay FEI's commodity or storage and transport charges.

On page 47 of the Application, FEI states:

> For FEI's Transportation Service rate schedules that have companion sales rate schedules (i.e., RS 23, RS 25, and RS 27 are companions to RS 3, RS 5 and RS 7, respectively), FEI imputes a cost of gas so that, when the R:C ratios are calculated for these Transportation Service rate schedules, they are on the same basis (i.e., delivery margin plus cost of gas) as for the sales rate schedules.[75]

> Footnote 75: Order G-42-91, dated May 23, 1991, page 3. RS 23, RS 25, and RS 27 are transportation options for RS 3, 5, and RS 7 respectively. Since the allocated cost for RS 3, RS 5, and RS 7 includes cost of gas, a cost of gas is imputed for RS 23, RS 25, and RS 27 to ensure consistency and to show the R:C ratios on a combined basis for RS 3/23, RS 5/25, and RS 7/27. Without the imputed cost of gas for these transportation rate schedules, the comparison would be effectively between the [Margin-to-Cost] M:C ratios of the transportation rate schedule and the R:C ratios of the sales rate schedule, which is not a representative comparison.

On page 48 of the Application, FEI presents Table 4-17.

15.1 Considering that transportation service customers do not pay FEI's cost of gas, please clarify what FEI means by "imputing a cost of gas" for the Transportation Service rate schedules and describe the method used by FEI to impute this cost of gas.

<u>Response:</u>

As indicated in the preamble, RS 3/23, RS 5/25 and RS 7/27 are companion rate schedules where customers may switch[12] from Sales Service (purchasing gas from FEI) to Transportation Service (purchasing market gas). These companion rate schedules have the same basic charges, delivery charges and demand charges. As such, for the purposes of evaluating the performance of the rates, particularly the delivery rates, for these rate schedules, a combined R:C ratio is used.

---

[12] Switching from Transportation Service to Sales Service is only possible if FEI is able to acquire gas and upstream resources of the behalf of the customer.

To be able to present a combined R:C ratio, where the "R" in the R:C ratio includes gas costs, FEI must impute a cost of gas for RS 23, 25 and 27. As discussed on page 47 of the Application and referenced in the preamble above, without the imputed cost of gas for RS 23, 25, and 27, the comparison and evaluation would not be representative, as the transportation service rate schedules are being evaluated with the M:C ratios but have the same delivery rates as the sales service rate schedules which are being evaluated with the R:C ratios. Such a comparison would also be misleading for essentially the same group of customers, one with and one without cost of gas (i.e., RS 3 and 23, RS 5 and 25, and RS 7 and 27).

The imputed cost of gas for RS 23, 25, and 27 is calculated using the average cost of gas from the corresponding sales service RS 3, 5 and 7. Table 1 below provides the detailed calculations for the RS 23, 25, and 27 imputed cost of gas.

Table 1: Calculation of Imputed Cost of Gas for RS 23, 25, and 27

Line	Particulars	Amount	Reference
1	RS 3 Cost of Gas ($000s)	$ 185,898	
2	RS 3 Annual Sales Volume (TJ)	25,770	
3	RS 3 Average Cost of Gas ($ / GJ)	$ 7.214	Line 1 / Line 2
4			
5	RS 23 Annual T-Service Volume (TJ)	3,904	
6	Imputed RS 23 Cost of Gas	$ 28,161	Line 3 x Line 5
7			
8	**Total Cost of Gas for RS 3/23**	**$ 214,059**	**Line 1 + Line 6; Schedule 1, Line 3**
9			
10	RS 5 Cost of Gas ($000s)	$ 73,578	
11	RS 5 Annual Sales Volume (TJ)	10,827	
12	RS 5 Average Cost of Gas ($ / GJ)	$ 6.796	Line 10 / Line 11
13			
14	RS 25 Annual T-Service Volume (TJ)	8,303	
15	Imputed RS 25 Cost of Gas	$ 56,428	Line 12 x Line 14
16			
17	**Total Cost of Gas for RS 5/25**	**$ 130,006**	**Line 10 + Line 15; Schedule 1, Line 3**
18			
19	RS 7 Cost of Gas ($000s)	$ 40,943	
20	RS 7 Annual Sales Volume (TJ)	6,004	
21	RS 7 Average Cost of Gas ($ / GJ)	$ 6.819	Line 19 / Line 20
22			
23	RS 27 Annual T-Service Volume (TJ)	4,289	
24	Imputed RS 27 Cost of Gas	$ 29,248	Line 21 x Line 23
25			
26	**Total Cost of Gas for RS 7/27**	**$ 70,191**	**Line 19 + Line 24; Schedule 1, Line 3**

15.2 For Transportation Service rate schedules that do not have companion sales rate schedules, such as RS 22A and RS 22, please confirm, or explain otherwise, that the comparison is effectively between the M:C ratios of those transportation service rate schedules and the R:C ratios of the sales rate schedules. Please also explain whether this is a representative comparison.

Response:

Not confirmed.

Transportation service rate schedules do have a cost of gas component, which is related to their unaccounted-for (UAF) gas which is recovered through their delivery rates.

The UAF cost of gas for transportation service rate schedules such as RS 22, 22A, and 22B is set out in Appendix D, Line 3 of the Application, and also reflected in the financial schedules in FEI's Annual Review for 2023 Delivery Rates proceeding[13]. It would be inconsistent if the UAF of transportation service rate schedules are ignored and only evaluated based on their M:C ratios while sales service rate schedules are evaluated using the R:C ratios that include their cost of gas. FEI acknowledges that the UAF cost of gas is quite small in these transportation service rate schedules, resulting in an R:C ratio that is very close to the M:C ratio.

FEI notes that the primary purpose of the R:C ratios is to serve as a guide as to whether rate design or rebalancing is needed, while the M:C ratios provide additional information. The primary purpose of the R:C ratios is not for comparing against other rate schedules. Evaluating RS 22, 22A, and 22B using M:C ratios would have resulted in the same conclusion, i.e., revenue rebalancing should occur for RS 22 in order to bring the R:C ratio or M:C ratio within the range of reasonableness.

[13] Evidentiary Update to FEI Annual Review for 2023 Delivery Rates dated October 24, 2022, Appendix B, Schedule 18, Lines 13-19.

16.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Section 4.6.1, p. 48

2023 R:C ratios for RS 4 and RS 7/27

On page 48 of the Application, FEI states:

> FEI has excluded RS 4 and RS 7/27 from Table 4-17 above because RS 4 is a seasonal service (firm in the summer and interruptible in the winter) and RS 7/27 is a fully interruptible service. These rates do not drive system capacity additions, and consequently are not allocated any demand-related costs. The charges within these rate schedules are not set using their allocated costs from the 2023 COSA. Instead, the charges for these rate schedules are set based on a discount to the charges of RS 5/25, FEI's General Firm Service rate schedule. Nevertheless, FEI has calculated the ratios for these rate schedules, which are set out in Table 4-18 below. [footnote omitted]

16.1 Please clarify why FEI's energy-related costs and customer-related costs are not allocated to RS 4 and RS 7/27 in accordance with the allocators presented in Table 4-10 (annual volume), Table 4-12 (number of customers) and Table 4-13 (weighted number of customers).

Response:

FEI notes that the quoted paragraph in the preamble above from page 48 of the Application did not state that RS 4 and RS 7/27 are not allocated energy-related and customer-related costs. The quoted paragraph only highlights that RS 4 and RS 7/27 are not allocated demand-related costs. These rate schedules are either seasonal and winter interruptible or fully interruptible; therefore, they do not contribute to peak demand, which occurs in the winter. Please refer to Schedules 4 and 5 of Appendix D of the Application which show that energy-related and customer-related costs are allocated to RS 4 and RS 7/27.

The quoted paragraph is highlighting the fact that the rates for RS 4 and RS 7/27 are not set using their allocated costs from the COSA study. Instead, the rates for these rate schedules are set based on a discount to the rates of RS 5/25. As such, the R:C and M:C ratios for RS 4 and RS 7/27 are not included in Table 4-17 with the R:C and M:C ratios of other rate schedules (those with their rates set based on their allocated costs).

FEI notes that the demand-related costs shown in Schedules 4 and 5 of Appendix D for RS 4 and RS 7/27 are related to Tilbury 1A expansion costs. As discussed in the response to BCUC IR1 8.1, the Tilbury 1A expansion costs are allocated using the delivery margin cost of service but are grouped with the demand-related costs for presentation purposes.

Also, for clarity, Table 4-13 does not show the weighted number of customers as this IR suggests. Table 4-13 shows the weights (or weighting factor) that would be applied to the number of customers. The weighted number of customers is equal to the number of customers multiplied by the weighting factors.

17.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Section 4.6.1, pp. 48–49, Tables 4-17 and 4-18; FEI 2016 COSA Decision, p. 25

2023 R:C and M:C ratios

On pages 48 to 49 of the Application, FEI presents Table 4-17 and Table 4-18 which shows the R:C and M:C ratio results before rebalancing.

On page 25 of the FEI 2016 COSA Decision, the BCUC stated:

> […] FEI has already been using a range of reasonableness for its R:C ratio, but an equivalent range has not been determined for the M:C ratio. Since the M:C ratio would be applied in an equivalent manner once an appropriate range of reasonableness has been calculated, the Panel considers that consistency with past practice is appropriate. The Panel places weight on Elenchus' view that the most important consideration in choosing an approach is consistency and that the same ratio and the same range should be used as the primary reference point on an on-going basis. While consistency is an important factor in the Panel's decision, it does not preclude the Commission from considering alternatives to the R:C ratio in future applications.

17.1 Please discuss the pros and cons of using the M:C ratio to inform FEI's revenue rebalancing proposals and the impact this ratio may have on the appropriate range of reasonableness.

Response:

FEI's decision to use the R:C ratios as opposed to the M:C ratios to inform its revenue rebalancing proposals was guided by the BCUC's determination and findings on page 25 of the Reasons for Decision attached to Order G-4-18 (2016 COSA Decision). In that decision, the Panel found that "the R:C ratio should be used to inform rate design and rate rebalancing proposals". Further, while the Panel directed FEI to present both the R:C and M:C ratios for each rate schedule in the next COSA study filing, the Panel also stated: "While the R:C ratios will inform rate design and rate balancing, the M:C ratios will provide useful context for stakeholders."

The pros and cons of using R:C and/or M:C ratios to guide rate design and revenue rebalancing were discussed extensively as part of the 2016 COSA and RDA and were detailed in the 2016 COSA Decision. The considerations are as follows:[14]

1. Jurisdictional use;
2. Intervener preference;
3. Exclusion of flow-through costs; and

[14] Page 25 of 2016 COSA Decision.

4. Consistency of applying a method.

1. Jurisdictional Use

As part of Elenchus' jurisdictional review, it showed that of the six Canadian gas utilities surveyed, three used R:C ratios while the other three used M:C ratios.

2. Intervener Preference

In the 2016 COSA and RDA proceeding, two interveners stated a preference for the R:C ratios while two preferred the M:C ratios.

3. Exclusion of Flow-through Costs

As part of Elenchus' review of FEI's 2016 COSA study, Elenchus concluded that the "M:C ratio has merit as a primary reference since it excludes flow-through costs", i.e., gas costs are not being rebalanced and only the revenues less gas costs will recover the cost of service margin.

However, it is important to note that, assuming all things being equal, the equivalent range of reasonableness for the M:C ratios would need to be wider than the range of reasonableness set for the R:C ratios. The BCUC included this point in the 2016 COSA Decision (page 24):

> Elenchus elaborated that for the range of reasonableness of the R:C ratio to be applied in a manner equivalent to a range of reasonableness for the M:C ratio, the R:C ratio range would have to be narrower than the equivalent M:C ratio range.

Table 1 below provides an illustrative example of this point. As Table 1 shows, depending on the portion of cost of gas relative to the total cost of service, the equivalent range of reasonableness for the M:C ratios will have to be wider than the accepted range of 95 percent to 105 percent for R:C ratios. Given the cost of gas portion of FEI's total cost of service varies year-over-year, the advantage of using the R:C ratios is that it avoids the need to vary the range of reasonableness depending on the portion of cost of gas relative to the total cost of service, i.e., the range of reasonableness for R:C ratios would not change regardless of the proportion of gas costs over the total cost of service.

Table 1: Illustration of Wider M:C Ratio for the Equivalent R:C Ratio Range of Reasonableness

Line	Particular	Reference					
1	**Scenario 1:**						
2	**Cost of Gas Ratio to Total Cost of Service @ 45%**						
3	Delivery Margin	$100 x (1 - 45%)	$ 55	$ 55	$ 55	$ 55	$ 55
4	Cost of Gas	$100 x 45%	45	45	45	45	45
5	Total Cost of Service	Line 3 + Line 4	$ 100	$ 100	$ 100	$ 100	$ 100
6							
7	Delivery Rate Recovery	Line 9 - Line 8	$ 45	$ 50	$ 55	$ 60	$ 65
8	Cost of Gas	Line 4	45	45	45	45	45
9	Total Revenue	Line 5 x Line 11	$ 90	$ 95	$ 100	$ 105	$ 110
10							
11	R:C Ratio (Set)		90%	95%	100%	105%	110%
12	M:C Ratio (Equivalent)	Line 7 / Line 3	82%	91%	100%	109%	118%
13							
14	**Scenario 2:**						
15	**Cost of Gas Ratio to Total Cost of Service @ 50%**						
16	Delivery Margin	$100 x (1 - 50%)	$ 50	$ 50	$ 50	$ 50	$ 50
17	Cost of Gas	$100 x 50%	50	50	50	50	50
18	Total Cost of Service	Line 16 + Line 17	$ 100	$ 100	$ 100	$ 100	$ 100
19							
20	Delivery Rate Recovery	Line 22 - Line 21	$ 40	$ 45	$ 50	$ 55	$ 60
21	Cost of Gas	Line 17	50	50	50	50	50
22	Total Revenue	Line 18 x Line 24	$ 90	$ 95	$ 100	$ 105	$ 110
23							
24	R:C Ratio (Set)		90%	95%	100%	105%	110%
25	M:C Ratio (Equivalent)	Line 20 / Line 16	80%	90%	100%	110%	120%
26							
27	**Scenario 3:**						
28	**Cost of Gas Ratio to Total Cost of Service @ 55%**						
29	Delivery Margin	$100 x (1 - 55%)	$ 45	$ 45	$ 45	$ 45	$ 45
30	Cost of Gas	$100 x 55%	55	55	55	55	55
31	Total Cost of Service	Line 29 + Line 30	$ 100	$ 100	$ 100	$ 100	$ 100
32							
33	Delivery Rate Recovery	Line 35 - Line 34	$ 35	$ 40	$ 45	$ 50	$ 55
34	Cost of Gas	Line 30	55	55	55	55	55
35	Total Revenue	Line 31 x Line 37	$ 90	$ 95	$ 100	$ 105	$ 110
36							
37	R:C Ratio (Set)		90%	95%	100%	105%	110%
38	M:C Ratio (Equivalent)	Line 33 / Line 29	78%	89%	100%	111%	122%
39							
40	**Scenario 4:**						
41	**Cost of Gas Ratio to Total Cost of Service @ 60%**						
42	Delivery Margin	$100 x (1 - 60%)	$ 40	$ 40	$ 40	$ 40	$ 40
43	Cost of Gas	$100 x 60%	60	60	60	60	60
44	Total Cost of Service	Line 42 + Line 43	$ 100	$ 100	$ 100	$ 100	$ 100
45							
46	Delivery Rate Recovery	Line 48 - Line 47	$ 30	$ 35	$ 40	$ 45	$ 50
47	Cost of Gas	Line 43	60	60	60	60	60
48	Total Revenue	Line 44 x Line 50	$ 90	$ 95	$ 100	$ 105	$ 110
49							
50	R:C Ratio (Set)		90%	95%	100%	105%	110%
51	M:C Ratio (Equivalent)	Line 46 / Line 42	75%	88%	100%	113%	125%

4. Consistency of Method

In the 2016 COSA Decision (page 24), the BCUC noted the following:

> Elenchus stated that one measure should be considered to be the primary basis for determining when rate rebalancing is to be considered and the second measure, if used, would be considered for informational purposes only.

The BCUC then stated the following as part of its determination (page 25):

> The Panel places weight on Elenchus' view that that the most important consideration in choosing an approach is consistency and that the same ratio and the same range should be used as the primary reference point on an on-going basis.

Continuing to use the R:C ratios to inform FEI's rate design and rebalancing proposals is therefore preferable because it is consistent with previous applications, including the 2016 COSA and RDA.

17.2 Please explain whether FEI used the M:C ratios in any way to inform the revenue rebalancing proposals in the Application and if so, how. If not, why not.

Response:

FEI did not use the M:C ratios to inform the revenue rebalancing proposals for the reasons explained in the response to BCUC IR1 17.1.

17.3 Please discuss the impact on FEI's revenue rebalancing proposals put forward in the Application if M:C ratios were used to inform rate design and revenue rebalancing, and whether this would change FEI's statement that "The 2023 COSA results demonstrate that a comprehensive redesign of FEI's existing rates is not warranted at this time."

Response:

If the BCUC directed or ordered FEI to use the M:C ratios to guide and inform revenue rebalancing, the 2023 COSA results would still demonstrate that a comprehensive redesign of FEI's existing rates is not warranted at this time.

As discussed in the response to BCUC IR1 17.1, the equivalent range of reasonableness for the M:C ratios would need to be wider than the range of reasonableness set for the R:C ratios. Based on the 2023 COSA study, the total cost of gas is close to 55 percent of the total allocated cost of service.[15] Based on the illustrative example shown in Table 1 in the response to BCUC IR1 17.1, the range of reasonableness for the M:C ratios would be 89 percent to 111 percent in order to be equivalent to the 95 percent to 105 percent range of reasonableness for the R:C ratios.

Based on an M:C ratio range of reasonableness of 89 percent to 111 percent, Table 1 below (which is a copy of Table 4-17 from the Application) shows that only RS 3/23 and RS 5/25 would be outside of the upper bound of the range of reasonableness, with RS 3/23 only outside by 0.2 percent. All other rate schedules would remain within the range of reasonableness. As such, if FEI were to use the M:C ratios to guide and inform revenue rebalancing, the 2023 COSA results would still demonstrate that a comprehensive redesign of FEI's existing rates is not warranted at this time.

Table 1: R:C and M:C Ratio Results before Rebalancing

Rate Schedule	R:C	M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%
Rate Schedule 3/23 *Large Commercial Sales and Transportation Service*	104.0%	111.2%
Rate Schedule 5/25 *General Firm Sales and Transportation Service*	106.9%	126.9%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%
Rate Schedule 22A Transportation Service (Closed) Inland Service Area	101.8%	101.9%
Rate Schedule 22B Transportation Service (Closed) Columbia Service Area	100.1%	100.1%

Page 25 of the FEI 2016 COSA Decision also stated:

> […] ICG submits that flow-through cost items should be excluded since they do not reflect the cost of serving a customer […] and cites Elenchus statement that "The

[15] Appendix D, Schedule 1, Line 8: Total Cost of Gas (incl. imputed amount for RS 23, 25, and 27) is $1.247 million, while the total utility allocated cost of service is $2.301 million (Schedule 1, Line 9). $1.247 million / $2.301 million = 54.2%.

advantage of that, as pointed out in the report, is one, the margin – the pass-throughs vary across different classes. So using an M:C ratio for all the classes as the primary measure, in a sense, makes more sense when you're comparing classes.

17.4 Please explain the significance of being able to compare classes when addressing revenue rebalancing.

Response:

If the results of the COSA study indicate that one or more classes of customers' revenue responsibility should be decreased, then the next step is to examine what other class(es) should have their revenue responsibility increased such that the total revenues to the utility remain unchanged. This requires being able to compare the various classes as to whether they could bear some, or all, of the revenue shift. Consideration should go beyond the R:C ratios as there may be other economic factors that impact a certain customer group's ability to absorb some, or all, of the revenue shift.

FEI notes that since the 1993 Phase B rate design, the shift of revenue responsibility has been to the residential customer class because it consistently has the lowest R:C ratio. The residential customer class also has the most customers and revenue base to absorb revenue shifts. Even if another class of customer is now shown to have an R:C ratio below 100 percent, due to its relatively small size (e.g., RS 6), the majority of the revenue shift would still need to be made to the residential rate class.

17.5 Given that pass-through costs vary across different classes, please explain the rationale for using R:C ratios to determine the revenue rebalancing proposals put forward in the Application.

Response:

FEI used the R:C ratios to inform its revenue rebalancing proposals for the reasons described in the response to BCUC IR1 17.1. The rebalancing being put forward by FEI has no impact on the cost of gas, as the proposals in this Application only impact the delivery margin.

18.0 Reference: FEI'S COSA METHODOLOGY

Exhibit B-1, Appendix E, Table 4, pp. 4–6

MSS and PLCC study results

On page 4 of Appendix E to the Application, FEI states:

> The capacities of the minimum sized distribution systems are then divided by the number of customers served by each distribution system and an average minimum system capacity per customer (the PLCC Adjustment) is calculated. <u>This PLCC Adjustment is then multiplied by the number of customers in each rate class, and the corresponding amount is subtracted from the peak demand for that rate class to get the PLCC adjusted peak demand. This PLCC adjusted peak demand is then used to allocate the demand related costs for the Distribution function</u>. [*Emphasis added*]

18.1 Please confirm, or explain otherwise, that the capacities of the minimum-sized distribution systems are shown in the 6th column of Table 4 on p. 6 of Appendix E, under the header "total consumption (GJ/d)."

<u>Response:</u>

Confirmed.

18.2 Please clarify how the variables "design degree day," "heating value (MJ/m3)," and "load for PLCC (m3/h)" enter into the calculation of the PLCC adjustment.

<u>Response:</u>

For each distribution network, FEI establishes a Design Degree Day based on historical weather data that represents a 1-in-20 years extreme cold weather event. Distribution systems are designed to meet the peak hour load that is expected to occur on the Design Degree Day. If all distribution mains were 60 mm pipe, there is a load capacity that is associated with it. For example, in the case of 100 Mile – Clinton, that capacity is 3,458 cubic meters / hour in the column titled "Load for PLCC m^3/hr".

Associated with each distribution network is an average heat content of gas. For 100 Mile – Clinton it is 39.132 MJ per cubic meter. To convert the capacity from cubic meters per hour to GJ per day, the following formula is used for each network:

Load for PLCC m^3/hr. x Heating value MJ/m^3 x 24 hours / 1000 = Total Consumption GJ/d

The "Total Consumption GJ/d" for all distribution networks divided by the total number of customers equals the PLCC adjustment, i.e., Average GJ per day per Customer.

18.3 Please revise Table 4-11 to include the PLCC adjustment, as described in the underlined portion of the preamble. Please also include in the revised table the PLCC adjusted peak demand by rate schedule.

Response:

Table 1 below provides the requested revised version of Table 4-11 of the Application. Customers in RS 4 and 7/27 have zero firm demand.

Table 1: PLCC Adjusted Peak Demand by Rate Schedule

Rate Schedule	Load Factor	Peak Day or Firm Demand (TJ/Day)	Number of Customers	PLCC Adjustment	PLCC Adjusted Peak Demand (For Distribution Function) (TJ/Day)
PLCC Factor				0.206	
1	31.3%	726.1	977,501	201.4	524.7
2	30.4%	263.3	90,632	18.7	244.6
3	36.0%	195.9	7,049	1.5	194.5
23	35.7%	30.0	701	0.1	29.8
4	n/a	-	18	n/a	-
5	53.6%	55.3	632	0.1	55.2
25	61.6%	37.0	272	0.1	36.9
6	100.0%	0.1	13	0.0	0.1
22	n/a	5.8	24	0.0	5.8
22A	n/a	24.7	9	0.0	24.7
22B	n/a	14.9	5	0.0	14.8
7	n/a	-	45	n/a	-
27	n/a	-	70	n/a	-
Total		**1,353.0**	**1,076,971**	**221.8**	**1,131.2**

C. REVENUE REBALANCING

19.0 Reference: REVENUE REBALANCING

Exhibit B-1, Section 1, p. 2, Section 5.3, Tables 5-4, 5-7, 5-10, 5-14, 5-15 and 5-18, pp. 62, 65, 68, 72–73 and 76, Section 5.3.6, Tables 5-21 and 5-22, p. 79, Section 5.4, Table 5-23, p. 83

Revenue Rebalancing Options

19.1 Please explain whether FEI considered the revenue rebalancing option of using RS 2 with adjustments for maintaining economic crossover between RS 2 and RS 3/23 only.

19.1.1 Please provide an assessment of this revenue rebalancing option against Bonbright's rate design principles, similar to that provided for revenue rebalancing options 1 to 5 in Section 5.3 of the Application.

19.1.2 In a similar format to Table 5-15 in the Application, please provide a table showing the economic crossover volume between RS 2 and RS 3/23 of 2,000 GJ that will be maintained under this revenue rebalancing option.

19.1.3 In a similar format to Table 5-18 in the Application, please provide a table showing the rate changes to each affected rate schedule under this revenue rebalancing option. Please specify assumptions used.

19.1.4 Please expand Tables 5-21 and 5-22 to include this revenue rebalancing option, while excluding Option 1 (Status Quo). Please specify assumptions used.

Response:

FEI did not consider using RS 2 for revenue rebalancing with adjustments for maintaining the economic crossover between RS 2 and RS 3/23 only (i.e., the option proposed in this IR). As explained on page 75 of the Application, FEI's proposed rebalancing Option 5 was developed based on the results observed from Options 1 to 4. One of the learnings from Option 4 was that if RS 2 is used to absorb the revenue rebalancing from RS 5/25 and RS 22, there will be no bill impact to RS 1 customers, but RS 2 customers will experience the highest bill impact out of all options explored. In contrast, the proposed Option 5, which is to use RS 1 to absorb the revenue rebalancing while adjusting RS 2 to maintain the economic crossover between RS 2 and RS 3/23, will result in a better balance between RS 1 and RS 2 customers, with both seeing only small bill impacts (i.e., 0.4 percent and 0.04 percent, respectively).

However, FEI provides an assessment of this option below using the same approach as the options assessed in Section 5.3 of the Application.

Tables 1 and 2 below provide a similar view as Tables 5-17 and 5-18 of the Application based on the option requested in this IR (using RS 2 for revenue rebalancing with adjustments for the maintaining economic crossover between RS 2 and RS 3/23). As demonstrated below, there will be no impact to RS 1 customers under this option; however, the bill impact for RS 2 customers will become 1.21 percent, which is the highest out of all options explored. For the average RS 2 customer with 322 GJ of consumption annually, this is equivalent to an annual bill impact of approximately $52.

Table 1: 2023 COSA R:C and M:C Results after Revenue Rebalancing (Using RS 2 for Revenue Rebalancing and Maintaining Economic Crossover between RS 2 and RS 3/23)

Rate Schedule	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%	-	-	97.3%	95.0%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%	4,664	1.21%	99.2%	98.2%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	111.2%	(145)	(0.04%)	103.9%	111.0%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	126.9%	(3,344)	(1.8%)	105.0%	119.5%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%	-	-	96.2%	91.0%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%	(151)	(4.5%)	105.0%	105.1%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.9%	-	-	101.8%	101.9%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.1%	-	-	100.1%	100.1%

Rate Schedule (Rates Not Set Using Allocated Costs)	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	339.0%	(46)	(3.0%)	120.5%	302.5%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	122.4%	628.0%	(978)	(1.1%)	121.1%	596.6%

Table 2: Summary of Rate Changes (Using RS 2 for Revenue Rebalancing and Maintaining Economic Crossover between RS 2 and RS 3/23)

Rate Schedule	Current 2023 Approved Rates	Changes	Option (BCUC IR1 19.1)
RS 1 - Residential			
Basic Charge ($/Day)	$ 0.4085	$ -	$ 0.4085
Delivery Charge ($/GJ)	$ 6.010	$ -	$ 6.010
RS 2 - Small Commercial			
Basic Charge ($/Day)	$ 0.9485	$ 0.3658	$ 1.3143
Delivery Charge ($/GJ)	$ 4.568	$ (0.255)	$ 4.313
RS 3/23 Large Commercial			
Basic Charge ($/Day)	$ 4.7895	$ 0.4730	$ 5.2625
Delivery Charge ($/GJ)	$ 3.893	$ (0.050)	$ 3.843
RS 4 - Seasonal			
Basic Charge ($/Month)	$ 14.4230	$ -	$ 14.4230
Delivery Charge - Off-Peak ($/GJ)	$ 1.904	$ (0.309)	$ 1.595
Delivery Charge - Extended ($/GJ)	$ 2.549	$ (0.069)	$ 2.480
RS 5/25 - General Firm Service			
Basic Charge ($/Month)	$ 469.0000	$ -	$ 469.0000
Delivery Charge ($/GJ)	$ 1.085	$ (0.071)	$ 1.014
Demand Charge ($/GJ/Month)	$ 30.278	$ (1.989)	$ 28.2890
RS 7/27 - General Interruptible Service			
Basic Charge ($/Month)	$ 880.0000	$ -	$ 880.0000
Delivery Charge ($/GJ)	$ 1.748	$ (0.095)	$ 1.653
RS 22 - Large Volume Transportation			
Basic Charge ($/Month)	$ 3,664.0000	$ -	$ 3,664.0000
Firm Demand Charge ($/GJ/Month)	$ 32.199	$ (0.505)	$ 31.694
Firm MTQ ($/GJ)	$ 0.1930	$ (0.009)	$ 0.1840
Interruptible MTQ ($/GJ)	$ 1.2520	$ (0.026)	$ 1.2260

When assessed against the Bonbright rate design principles, this option aligns with principle 2 by bringing the R:C ratios within the range of reasonableness:

- **Principle 2 – Fair appointment of costs among customers**

  All R:C ratios of the applicable rate schedules fall within the range of reasonableness. Therefore, the cost recovery through each rate schedule closely reflects the fair appointment of costs from each customer group.

However, this option offers no improvement to principle 3, and is not as well aligned with principles 4 and 6 when compared to all other options explored:

- **Principle 3 – Price signals that encourage efficient use and discourage inefficient use**

  Under this option, the changes in the Basic Charges for RS 2 and RS 3/23, plus the offset from the reduction in the variable delivery rates of both rate schedules, will move the economic crossover point back to 2,000 GJ and realign it with the segmentation threshold between RS 2 and RS 3/23. This is confirmed in Table 3 below.

However, since this option uses RS 2 to absorb all revenue shifts from RS 5/25 and RS 22 as well as to maintain the economic crossover point between RS 2 and RS 3/23 rate schedules to 2,000 GJ, the Basic Charge of RS 2 will have to be increased significantly as shown in Table 2 above which will result in the highest bill impact to RS 2 customers out of all options explored. The increase in the RS 2 Basic Charge under this option is $0.3658 per day (an approximate increase of $134 per year) versus an increase of $0.2026 per day under the proposed Option 5 (an approximate increase of $74 per year). This level of increase to the Basic Charge would impact the price signal for small commercial customers under RS 2 and would discourage the efficient use of energy, contrary to Bonbright's rate design principle 3.

Table 3: Economic Crossover Volume between RS 2 and RS 3/23 (Using RS 2 for Revenue Rebalancing and Maintaining Economic Crossover between RS 2 and RS 3/23)

Line	Rate Components	Reference	RS 2	RS 3/23	Diff.
1	Basic Charge (per day)		1.3143	5.2625	
2	Number of Days		365.25	365.25	
3	Basic Charge Revenue ($)	Line 1 x Line 2	480	1,922	1,442
4					
5	Delivery Charge ($/GJ)		4.313	3.843	
6	Cost of Gas ($/GJ)		6.750	6.499	
7	Total Variable Cost ($/GJ)	Line 5 + Line 6	11.063	10.342	0.721
8					
9	Volume Threshold (GJ)	Line 3 / Line 7	2,000	2,000	2,000

- **<u>Principle 4 – Customer understanding and acceptance</u>**

  As basic charges usually remain constant during FEI's annal rate changes, significantly increasing the RS 2 Basic Charge under this option will likely lead to customer confusion and could impact customer acceptance (especially Small Commercial customer acceptance) of FEI's rates.

- **<u>Principle 6 – Rate stability (Customer rate impact should be managed)</u>**

  Under this option, there will be no bill impact to RS 1 customers, and the bill impact to the average RS 2 customer will remain relatively small at 1.21 percent or $52 per year. However, it is still the largest impact to RS 2 customers out of all options explored and the large increase in the Basic Charge of RS 2 will have a significant impact on those customers that have small or minimal volumes. This is because customers that have small or minimal volumes would have limited opportunity to offset the increased Basic Charge through decreased consumption (as shown in Table 2 above, the variable charges of RS 2 will be reduced under this option to offset some of the increase in the Basic Charge). For example, assuming a particular Small Commercial customer has no volumes (which could occur over time when the commercial property is under development/renovation, changing ownership/lease, or vacant) and pays the Basic Charge only, they will experience the maximum bill impact of $134 per year since this customer would not be able to offset the increase through the reduced variable charges.

This level of bill impact is worse than all other options explored and is therefore less aligned with the rate design principle of rate stability.

Tables 4 and 5 below provide an updated summary of the revenue shift between rate schedules and an updated summary of bill impacts amongst all rebalancing options considered, removing Option 1 and including the option requested in this IR. The proposed Option 5 continues to result in the least bill impact to both RS 1 and RS 2 customers while still maintaining the economic crossover point between RS 2 and RS 3/23 at 2,000 GJ.

Table 4: Summary of Revenue Shift between Rate Schedules for all Rebalancing Options ($000s)

	Revenue Shift ($000s)					
	Option 2a: Revenue Rebalancing Only Using RS 1	Option 2b: Revenue Rebalancing Only Using RS 2	Option 3: Revenue Rebalancing Using RS 1 plus Maintaining Economic Crossover between RS 2 and RS 3/23, and between RS 3/23 and RS 5/25	Option 4: Revenue Rebalancing Using RS 2 plus Maintaining Economic Crossover between RS 2 and RS 3/23, and between RS 3/23 and 5/25	Option 5: Revenue Rebalancing Using RS 1 plus Maintaining Economic Crossover between RS 2 and RS 3/23 Only	BCUC IR1 19.1: Revenue Rebalancing Using RS 2 plus Maintaining Economic Crossover between RS 2 and RS 3/23 Only
RS 1	4,519	-	4,519	-	4,519	-
RS 2	-	4,519	4,071	4,075	145	4,664
RS 3/23	-	-	(4,071)	444	(145)	(145)
RS 5/25	(3,344)	(3,344)	(3,344)	(3,344)	(3,344)	(3,344)
RS 6	-	-	-	-	-	-
RS 22	(151)	(151)	(151)	(151)	(151)	(151)
RS 22A	-	-	-	-	-	-
RS 22B	-	-	-	-	-	-
RS 4	(46)	(46)	(46)	(46)	(46)	(46)
RS 7/27	(978)	(978)	(978)	(978)	(978)	(978)

Table 5: Summary of Bill Impact in % and $ for an Average Customer in each Rate Schedule for all Rebalancing Options

	Option 2a		Option 2b		Option 3		Option 4		Option 5		BCUC IR1 19.1	
	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)
RS 1	0.4%	$ 4.95	-	$ -	0.4%	$ 4.95	-	$ -	0.4%	$ 4.95	-	$ -
RS 2	-	$ -	1.2%	$ 50	1.1%	$ 45	1.1%	$ 45	0.04%	$ 1.65	1.21%	$ 52
RS 3/23	-	$ -	-	$ -	(1.2%)	$ (469)	0.1%	$ 123	(0.04%)	$ (10)	(0.04%)	$ (10)
RS 5/25	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)
RS 6	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
RS 22	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)
RS 22A	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
RS 22B	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
RS 4	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)
RS 7/27	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)

On page 83 of the Application, FEI provides Table 5-23 which shows the R:C ratios after the preferred revenue rebalancing option (Option 5) for RS 5/25 and RS 22 are both 105.0 percent.

19.2 Please explain why FEI proposes to move RS 5/25 and RS 22 to the upper bound of the range of reasonableness as opposed to moving these two rate schedules closer to the center of the range (i.e. 100 percent).

Response:

There is no requirement to rebalance back to unity, and FEI considers its proposed rebalancing approach to be the best approach for all customer classes because it minimizes rate impacts for all the customer classes used to rebalance RS 5/25 and RS 22 back to the range of reasonableness.

The main impact of rebalancing the R:C ratios of RS 5/25 and RS 22 to unity will be additional bill impacts to RS 1 customers, which will have to absorb a larger revenue shift. The revenue shift to RS 1 under this approach will increase the revenue shift to be absorbed by RS 1 under Option 5 from approximately $4.5 million to $16.6 million, which is an additional $12.1 million. Please refer to the response to BCUC IR1 19.3 for a detailed assessment of this option (rebalancing RS 5/25 and RS 22 to unity).

As was discussed in the 2016 COSA and RDA, including by the BCUC in the 2016 COSA Decision, due to the assumptions, estimates and judgements involved in a COSA study, it is appropriate to use a range of reasonableness. Accordingly, FEI considers that as long as the R:C ratio of each rate schedule (except for RS 4 and RS 7/27) is within the range of reasonableness, the rates are sufficient to recover the fair or full costs to serve that rate schedule.

FEI's view is also shared by Elenchus. In response to CEC IR1 2.2 in the 2016 COSA and RDA proceeding, Elenchus stated:[16]

> If one or more ratios fall outside the accepted range, then rebalancing should be undertaken. Rebalancing should be undertaken to move all classes that are outside the approved range to the nearest boundary.

This view was also supported by the BCUC in their determination on the appropriateness of rebalancing to unity in the 2016 RDA Decision and Order G-135-18 (2016 RDA Decision):[17]

> In this decision, the Panel places weight on the evidence provided by Elenchus that:
>
> - Any R:C ratio that is within the defined range of reasonableness can be <u>considered to be full cost recovery</u>;

[16] Exhibit A2-8, Elenchus response to CEC IR1 2.2.
[17] Page 42.

- Rebalancing should be undertaken to move all classes that are outside the approved range to the nearest boundary;
- It is not appropriate to periodically rebalance to R:C ratios of 1.00; and
- Elenchus is not aware of any jurisdiction that periodically rebalances rates so that all R:C ratios are 1.00. [Emphasis Added]

There have been no changes in circumstances between the BCUC's determinations in the 2016 COSA and RDA and the current Application which would suggest that a change in the approach to rebalancing is necessary or warranted.

Ultimately, as unity does not necessarily measure the true cost to serve a particular customer class, FEI does not consider it appropriate to place additional bill impacts on RS 1 customers simply to achieve unity for RS 5/25 and RS 22 customers when the rates already recover the fairly allocated cost of service at the nearest boundary.

19.3 Please explain whether FEI considered rebalancing RS 5/25 and RS 22 to an R:C ratio of 100 percent.

19.3.1 Please discuss how this alternative could be implemented and explain whether it could be achieved while maintaining the economic crossover between: (i) RS 2 and RS 3/23 only, and (ii) RS 2 and RS 3/23, and between RS 3/23 and RS 5/25.

19.3.2 Please provide an assessment of this revenue rebalancing option against Bonbright's rate design principles. Please specify assumptions used.

19.3.3 In a similar format to Table 5-18 in the Application, please provide a table showing the rate changes to each affected rate schedule under this revenue rebalancing option. Please specify assumptions used.

19.3.4 Please expand Tables 5-21 and 5-22 to include this revenue rebalancing option, while excluding revenue rebalancing Option 1 (Status Quo). Please specify assumptions used.

Response:

Please refer to the response to BCUC IR1 19.2 for the reasons why FEI did not consider rebalancing RS 5/25 and RS 22 to an R:C ratio of 100 percent.

However, to be responsive, FEI provides an assessment of this option below using the same approach as the other options assessed in Section 5.3 of the Application.

Tables 1 and 2 below provide a similar view as Tables 5-17 and 5-18 of the Application, but for the option described in this IR, using RS 1 to rebalance the R:C ratios of RS 5/25 and RS 22 to unity plus adjustments to RS 2 and RS 3/23 to maintain the economic crossover between RS 2 and RS 3/23. Under this option, the revenue shift to RS 1 customers will become approximately $16.6 million with a bill impact of 1.3 percent (equivalent to approximately $18 per year) for the average residential customer. In comparison, under FEI's proposed rebalancing Option 5, the revenue shift to RS 1 customers is approximately $4.5 million and the average bill impact is 0.4 percent (equivalent to approximately $4.95 per year).

Table 1: 2023 COSA R:C and M:C Results after Revenue Rebalancing (Rebalancing RS 5/25 and RS 22 to Unity using RS 1 and Maintaining Economic Crossover between RS 2 and RS 3/23)

Rate Schedule	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%	16,609	1.3%	98.6%	97.4%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%	145	0.04%	98.1%	95.7%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	111.2%	(145)	(0.04%)	103.9%	111.0%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	126.9%	(12,101)	(6.5%)	100.0%	100.0%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%	-	-	96.2%	91.0%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%	(303)	(9.1%)	100.0%	100.0%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.9%	-	-	101.8%	101.9%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.1%	-	-	100.1%	100.1%

Rate Schedule (Rates Not Set Using Allocated Costs)	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	339.0%	(99)	(6.3%)	116.3%	261.7%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	122.4%	628.0%	(4,107)	(4.6%)	116.8%	496.0%

Table 2: Summary of Rate Changes (Rebalancing RS 5/25 and RS 22 to Unity using RS 1 and Maintaining Economic Crossover between RS 2 and RS 3/23)

Rate Schedule	Current 2023 Approved Rates	Changes	Option (BCUC IR1 19.3)
RS 1 - Residential			
Basic Charge ($/Day)	$ 0.4085	$ -	$ 0.4085
Delivery Charge ($/GJ)	$ 6.010	$ 0.200	$ 6.210
RS 2 - Small Commercial			
Basic Charge ($/Day)	$ 0.9485	$ 0.2026	$ 1.1511
Delivery Charge ($/GJ)	$ 4.568	$ (0.225)	$ 4.343
RS 3/23 Large Commercial			
Basic Charge ($/Day)	$ 4.7895	$ 0.4730	$ 5.2625
Delivery Charge ($/GJ)	$ 3.893	$ (0.050)	$ 3.843
RS 4 - Seasonal			
Basic Charge ($/Month)	$ 14.4230	$ -	$ 14.4230
Delivery Charge - Off-Peak ($/GJ)	$ 1.904	$ (0.603)	$ 1.301
Delivery Charge - Extended ($/GJ)	$ 2.549	$ (0.525)	$ 2.024
RS 5/25 - General Firm Service			
Basic Charge ($/Month)	$ 469.0000	$ -	$ 469.0000
Delivery Charge ($/GJ)	$ 1.085	$ (0.258)	$ 0.827
Demand Charge ($/GJ/Month)	$ 30.278	$ (7.198)	$ 23.0800
RS 7/27 - General Interruptible Service			
Basic Charge ($/Month)	$ 880.0000	$ -	$ 880.0000
Delivery Charge ($/GJ)	$ 1.748	$ (0.399)	$ 1.349
RS 22 - Large Volume Transportation			
Basic Charge ($/Month)	$ 3,664.0000	$ -	$ 3,664.0000
Firm Demand Charge ($/GJ/Month)	$ 32.199	$ (2.330)	$ 29.869
Firm MTQ ($/GJ)	$ 0.1930	$ (0.020)	$ 0.1730
Interruptible MTQ ($/GJ)	$ 1.2520	$ (0.097)	$ 1.1550

The following is the assessment of this option against the Bonbright rate design principles.

- **<u>Principle 2 – Fair appointment of costs among customers</u>**

  All R:C ratios of the applicable rate schedules fall within the range of reasonableness. Therefore, the cost recovery through each rate schedule closely reflects the fair appointment of costs from each customer group. However, under this option, RS 1 customers would have higher R:C and M:C ratios than RS 2 small commercial customers as shown in Table 1 above.

- **<u>Principle 3 – Price signals that encourage efficient use and discourage inefficient use</u>**

  Table 3 below confirms that, under this option, the increase in the Basic Charge for both RS 2 and RS 3/23, plus the offset from the reduction of the variable charges, would move the economic crossover point back to 2,000 GJ and realign it with the segmentation threshold between RS 2 and RS 3/23. FEI notes that the basic and variable charges for RS 2 and RS 3/23 under this option would be identical to the proposed Option 5. The only change would be the rate impact to RS 1 customers.

As part of this response, FEI did not develop a separate scenario that would also maintain the economic crossover between RS 3/23 and RS 5/25 as requested in BCUC IR1 19.3.1(ii). This is because the impact with or without maintaining the economic crossover between RS 3/23 and RS 5/25 would be identical to the changes between Option 3 and Option 5 as presented in Table 5-22 of the Application. I.e., the bill impact to RS 2 customers will increase from 0.04 percent (or average approximately $1.65 per year) to 1.1 percent (or average approximately $45 per year) while the bill credit to RS 3/23 customers would increase from 0.04 percent (or average savings of $10 per year) to 1.2 percent (or average savings of $469 per year) if the economic crossover between RS 3/23 and RS 5/25 is also maintained.

Table 3: Economic Crossover Volume between RS 2 and RS 3/23 (Rebalancing RS 5/25 and RS 22 to Unity using RS 1 and Maintaining Economic Crossover between RS 2 and RS 3/23)

Line	Rate Components	Reference	RS 2	RS 3/23	Diff.
1	Basic Charge (per day)		1.1511	5.2625	
2	Number of Days		365.25	365.25	
3	Basic Charge Revenue ($)	Line 1 x Line 2	420	1,922	1,502
4					
5	Delivery Charge ($/GJ)		4.343	3.843	
6	Cost of Gas ($/GJ)		6.750	6.499	
7	Total Variable Cost ($/GJ)	Line 5 + Line 6	11.093	10.342	0.751
8					
9	Volume Threshold (GJ)	Line 3 / Line 7	2,000	2,000	2,000

- **<u>Principle 4 – Customer understanding and acceptance</u>**

  The changes in the Basic Charges for RS 2 and RS 3/23 are identical to FEI's proposed Option 5, for which the increases are much smaller than under Options 3 and 4. As such, while this option (and also Option 5) might still lead to customer confusion and could impact customer acceptance due to the change in the Basic Charges, it is an improvement from Options 3 and 4 given that the impact is much smaller.

- **<u>Principle 6 – Rate stability (Customer rate impact should be managed)</u>**

  The bill impacts to the average RS 1 customer under this option are significantly higher than FEI's proposed Option 5, increased from 0.4 percent (or an average of approximately $4.95 per year) to 1.3 percent (or an average of approximately $18 per year), as shown in Table 1 above.

  In addition, rebalancing RS 5/25 and RS 22 customers to unity would result in a significant reduction in these customers' bills, as shown in Table 1 above. An average RS 5/25 customer would see savings of 6.5 percent on their bill (average approximately $10.7 thousand per year) and an average RS 22 customer would see savings of 9.1 percent on their bill (or average approximately $111.8 thousand per year), both at the expense of a significant increase for RS 1 customers.

Tables 4 and 5 below provide an updated summary of the revenue shift between rate schedules and an updated summary of bill impacts amongst all rebalancing options considered, excluding Option 1 but including the scenario requested in this IR (similar to Tables 5-21 and 5-22 of the Application). FEI's proposed Option 5 would result in significantly less bill impacts to RS 1 customers than the scenario requested in this IR.

Table 4: Summary of Revenue Shift between Rate Schedules for all Rebalancing Options ($000s)

	Revenue Shift ($000s)					
	Option 2a: Revenue Rebalancing Only Using RS 1	Option 2b: Revenue Rebalancing Only Using RS 2	Option 3: Revenue Rebalancing Using RS 1 plus Maintaining Economic Crossover between RS 2 and RS 3/23, and between RS 3/23 and RS 5/25	Option 4: Revenue Rebalancing Using RS 2 plus Maintaining Economic Crossover between RS 2 and RS 3/23, and between RS 3/23 and 5/25	Option 5: Revenue Rebalancing Using RS 1 plus Maintaining Economic Crossover between RS 2 and RS 3/23 Only	BCUC IR1 19.3: Revenue Rebalancing RS 5/25 and 22 to Unity plus Maintaining Economic Crossover between RS 2 and RS 3/23 Only
RS 1	4,519	-	4,519	-	4,519	16,609
RS 2	-	4,519	4,071	4,075	145	145
RS 3/23	-	-	(4,071)	444	(145)	(145)
RS 5/25	(3,344)	(3,344)	(3,344)	(3,344)	(3,344)	(12,101)
RS 6	-	-	-	-	-	-
RS 22	(151)	(151)	(151)	(151)	(151)	(303)
RS 22A	-	-	-	-	-	-
RS 22B	-	-	-	-	-	-
RS 4	(46)	(46)	(46)	(46)	(46)	(99)
RS 7/27	(978)	(978)	(978)	(978)	(978)	(4,107)

Table 5: Summary of Bill Impact in % and $ for an Average Customer in each Rate Schedule for all Rebalancing Options

	Option 2a		Option 2b		Option 3		Option 4		Option 5		BCUC IR1 19.3	
	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)
RS 1	0.4%	$ 4.95	-	$ -	0.4%	$ 4.95	-	$ -	0.4%	$ 4.95	1.3%	$ 18
RS 2	-	$ -	1.2%	$ 50	1.1%	$ 45	1.1%	$ 45	0.04%	$ 1.65	0.04%	$ 2
RS 3/23	-	$ -	-	$ -	(1.2%)	$ (469)	0.1%	$ 123	(0.04%)	$ (10)	(0.04%)	$ (10)
RS 5/25	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(6.5%)	$ (10,665)
RS 6	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
RS 22	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(9.1%)	$ (111,841)
RS 22A	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
RS 22B	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
RS 4	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(6.3%)	$ (5,548)
RS 7/27	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(4.6%)	$ (53,227)

19.4 Please explain whether FEI considered rebalancing all rate schedules to an R:C ratio of 100 percent and provide the pros and cons of this revenue rebalancing option.

Response:

FEI does not see any advantage of rebalancing all rate schedules to an R:C ratio of 100 percent.

FEI has not considered rebalancing all rate schedules to an R:C ratio of 100 percent for the following reasons:

1. In the 2016 RDA Decision,[18] the BCUC found that an R:C range of reasonableness of 95 to 105 percent was appropriate and directed FEI to use this R:C range of reasonableness to inform its rate design and rebalancing proposals in the 2016 COSA and RDA. Specifically, the Panel placed weight on the evidence provided by Elenchus that:

    - Any R:C ratio that is within the defined range of reasonableness can be considered to be full cost recovery;
    - Rebalancing should be undertaken to move all classes that are outside the approved range to the nearest boundary;
    - It is not appropriate to periodically rebalance to R:C ratios of 1.00; and
    - Elenchus is not aware of any jurisdiction that periodically rebalances rates so that all R:C ratios are 1.00.

    As Elenchus noted, and the BCUC Panel accepted, any R:C ratio that is within the defined range of reasonableness can be considered full cost recovery, or in other words, the fair cost by each rate schedule is recovered through their individual rates. Specifically, in response to CEC IR 18.4 on its assessment of FEI's 2016 COSA study, Elenchus stated:

    > In the case of cost allocation there is no underlying true value that is being estimated. There are multiple possible ways of defining cost causality, each of which is equally valid, which implies that is a range of values that could each be considered to be the true value.[19]

    In consideration of the above, FEI does not consider it necessary or preferable to rebalance all rate schedules to unity.

2. Due to the many assumptions, estimates, and judgements made to produce a COSA study, the level of precision implying that balancing to unity equals the true cost to serve a rate schedule does not exist. This was recognized by the BCUC Panel in the 2016 RDA Decision:[20]

    > While the BCUC, in its COSA and R:C Ratios Decision, accepted that in theory an R:C ratio of 100 percent for each rate schedule would indicate that the revenues recovered from each rate schedule are equal to the cost to serve them, <u>the</u>

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[18] Decision and Order G-135-18, pages 41 to 42.
[19] Exhibit A2-8, Elenchus response to CEC IR 18.4.
[20] Page 41.

assumptions, estimates and judgements involved in a COSA study, make it appropriate to use a range of reasonableness. [Emphasis added]

3. Rebalancing all rate schedules to unity creates unnecessary additional rate impacts and could result in rate volatility. As demonstrated in the response to BCUC IR1 19.4.1, rebalancing all rate schedules to unity means RS 1 customers will experience more significant bill impacts. In comparison to FEI's proposed Option 5, rebalancing all rate schedules to unity means that the increase to a residential customer's bill would be 630 percent greater.

4. The rates of RS 4 (seasonal) and RS 7/27 (fully interruptible) are not cost-based. Currently, the rates for these customers are set at a discount from RS 5/25 on a value-of-service basis. It is not possible to set these rates such that the R:C ratios for these rate schedules are equal to unity because their rates would become so low as to make them "free riders" on FEI's transmission and distribution systems, which would be unfair to other customers.

19.4.1 Please discuss how this alternative could be implemented and explain whether it could be achieved while maintaining the economic crossover between: (i) RS 2 and RS 3/23, and (ii) RS 2 and RS 3/23, and between RS 3/23 and RS 5/25.

Response:

Please refer to the response to BCUC IR1 19.4 for the reasons why FEI has not considered rebalancing all rate schedules to achieve an R:C ratio of 100 percent.

However, to be responsive, FEI provides Tables 1 and 2 below (in a similar view as Tables 5-17 and 5-18 of the Application) to illustrate the implementation of a scenario in which all rate schedules (except RS 4 and RS 7/27) are rebalanced to achieve an R:C ratio of 100 percent. FEI notes that this scenario assumes the rates for RS 4 (Seasonal) and RS 7/27 (Fully Interruptible) would continue to be set at a discount to RS 5/25.

Table 1: 2023 COSA R:C and M:C Results after Revenue Rebalancing (All R:C Ratios, except RS 4 and RS 7/27, to 100 percent)

Rate Schedule	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%	34,765	2.7%	100.0%	100.0%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%	7,812	2.0%	100.0%	100.0%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	111.2%	(13,283)	(3.8%)	100.0%	100.0%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	126.9%	(12,101)	(6.5%)	100.0%	100.0%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%	8	3.9%	100.0%	100.0%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%	(303)	(9.1%)	100.0%	100.0%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.9%	(160)	(1.8%)	100.0%	100.0%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.1%	(9)	(0.1%)	100.0%	100.0%

Rate Schedule (Rates Not Set Using Allocated Costs)	Initial COSA R:C	Initial COSA M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	COSA after Rebalancing M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	339.0%	(99)	(6.3%)	116.3%	261.7%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	122.4%	628.0%	(4,107)	(4.6%)	116.8%	496.0%

Table 2: Summary of Rate Changes (All R:C Ratios, except RS 4 and RS 7/27, to 100 percent)

Rate Schedule	Current 2023 Approved Rates	Changes	Option (BCUC IR1 19.4.1)
RS 1 - Residential			
Basic Charge ($/Day)	$ 0.4085	$ -	$ 0.4085
Delivery Charge ($/GJ)	$ 6.010	$ 0.419	$ 6.429
RS 2 - Small Commercial			
Basic Charge ($/Day)	$ 0.9485	$ 0.7383	$ 1.6868
Delivery Charge ($/GJ)	$ 4.568	$ (0.569)	$ 3.999
RS 3/23 Large Commercial			
Basic Charge ($/Day)	$ 4.7895	$ 2.7240	$ 7.5135
Delivery Charge ($/GJ)	$ 3.893	$ (0.707)	$ 3.186
RS 4 - Seasonal			
Basic Charge ($/Month)	$ 14.4230	$ -	$ 14.4230
Delivery Charge - Off-Peak ($/GJ)	$ 1.904	$ (0.603)	$ 1.301
Delivery Charge - Extended ($/GJ)	$ 2.549	$ (0.525)	$ 2.024
RS 5/25 - General Firm Service			
Basic Charge ($/Month)	$ 469.0000	$ -	$ 469.0000
Delivery Charge ($/GJ)	$ 1.085	$ (0.258)	$ 0.827
Demand Charge ($/GJ/Month)	$ 30.278	$ (7.198)	$ 23.0800
RS 6 - Natural Gas Vehicle			
Basic Charge ($/Day)	$ 2.0041	$ -	$ 2.0041
Delivery Charge ($/GJ)	$ 3.733	$ 0.3971	$ 4.130
RS 7/27 - General Interruptible Service			
Basic Charge ($/Month)	$ 880.0000	$ -	$ 880.0000
Delivery Charge ($/GJ)	$ 1.748	$ (0.399)	$ 1.349
RS 22 - Large Volume Transportation			
Basic Charge ($/Month)	$ 3,664.0000	$ -	$ 3,664.0000
Firm Demand Charge ($/GJ/Month)	$ 32.199	$ (2.330)	$ 29.869
Firm MTQ ($/GJ)	$ 0.1930	$ (0.020)	$ 0.1730
Interruptible MTQ ($/GJ)	$ 1.2520	$ (0.097)	$ 1.1550

If all rate schedules, except RS 4 and RS 7/27, are rebalanced to unity, then the revenue required from residential customers will increase from approximately $4.5 million (FEI's proposed Option 5) to approximately $34.8 million. For the average residential customer, the bill impact due to rebalancing to unity would be approximately 2.7 percent (or $38 per year). The average RS 2 customer would also see a bill impact of approximately 2.0 percent (or $86 per year), compared to 0.04 percent (or $1.65 per year) under FEI's proposed Option 5. The average RS 3/23 customer would see bill savings of approximately 3.8 percent (or savings of $1,587 per year); however, as further discussed below, this scenario would result in a significant increase in the Basic Charge for RS 3/23 customers.

Table 3 below also confirms that by increasing the Basic Charges for both RS 2 and RS 3/23, plus an offset from the reduction in variable charges, the economic crossover point between RS 2 and RS 3/23 can be maintained at 2,000 GJ. However, this would require the Basic Charge for RS 2 to increase from $0.9485 per day to $1.6868 per day, an increase of approximately 78 percent or $270 per year, and the Basic Charge for RS 3/23 to increase from $4.7895 per day to $7.5135 per day, which is an increase of approximately 57 percent or $995 per year.

Table 3: Economic Crossover Volume between RS 2 and RS 3/23 (All R:C Ratios, except RS 4 and RS 7/27, to 100 percent)

Line	Rate Components	Reference	RS 2	RS 3/23	Diff.
1	Basic Charge (per day)		1.6868	7.5135	
2	Number of Days		365.25	365.25	
3	Basic Charge Revenue ($)	Line 1 x Line 2	616	2,744	2,128
4					
5	Delivery Charge ($/GJ)		3.999	3.186	
6	Cost of Gas ($/GJ)		6.750	6.499	
7	Total Variable Cost ($/GJ)	Line 5 + Line 6	10.749	9.685	1.064
8					
9	Volume Threshold (GJ)	Line 3 / Line 7	2,000	2,000	2,000

FEI notes that it did not analyze a separate scenario that would maintain the economic crossover between RS 3/23 and RS 5/25. As discussed in the response to BCUC IR1 19.3, maintaining the economic crossover between RS 3/23 and RS 5/25 would only serve to further increase RS 2 customers' Basic Charge.

Tables 4 and below provide an updated summary of the revenue shift between rate schedules and an updated summary of bill impacts amongst all rebalancing options considered, excluding Option 1 but including the scenario requested in this IR, where all rate schedules are rebalanced to unity. This scenario would result in a significant impact to RS 1 and RS 2 customers when compared to FEI's proposed Option 5.

Table 4: Summary of Revenue Shift between Rate Schedules for all Rebalancing Options ($000s)

	Revenue Shift ($000s)					
	Option 2a: Revenue Rebalancing Only Using RS 1	Option 2b: Revenue Rebalancing Only Using RS 2	Option 3: Revenue Rebalancing Using RS 1 plus Maintaining Economic Crossover between RS 2 and RS 3/23, and between RS 3/23 and RS 5/25	Option 4: Revenue Rebalancing Using RS 2 plus Maintaining Economic Crossover between RS 2 and RS 3/23, and between RS 3/23 and 5/25	Option 5: Revenue Rebalancing Using RS 1 plus Maintaining Economic Crossover between RS 2 and RS 3/23 Only	BCUC IR1 19.4.1: Rebalancing all R:C Ratio to 100% (Except RS 4 and 7/27)
RS 1	4,519	-	4,519	-	4,519	34,765
RS 2	-	4,519	4,071	4,075	145	7,812
RS 3/23	-	-	(4,071)	444	(145)	(13,283)
RS 5/25	(3,344)	(3,344)	(3,344)	(3,344)	(3,344)	(12,101)
RS 6	-	-	-	-	-	8
RS 22	(151)	(151)	(151)	(151)	(151)	(303)
RS 22A	-	-	-	-	-	(160)
RS 22B	-	-	-	-	-	(9)
RS 4	(46)	(46)	(46)	(46)	(46)	(99)
RS 7/27	(978)	(978)	(978)	(978)	(978)	(4,107)

Table 5: Summary of Bill Impact in % and $ for an Average Customer in each Rate Schedule for all Rebalancing Options

	Option 2a		Option 2b		Option 3		Option 4		Option 5		BCUC IR1 19.4.1	
	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)
RS 1	0.4%	$ 4.95	-	$ -	0.4%	$ 4.95	-	$ -	0.4%	$ 4.95	2.7%	$ 38
RS 2	-	$ -	1.2%	$ 50	1.1%	$ 45	1.1%	$ 45	0.04%	$ 1.65	2.0%	$ 86
RS 3/23	-	$ -	-	$ -	(1.2%)	$ (469)	0.1%	$ 123	(0.04%)	$ (10)	(3.83%)	$ (1,587)
RS 5/25	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(6.5%)	$ (10,665)
RS 6	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	3.9%	$ 635
RS 22	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(9.1%)	$ (111,841)
RS 22A	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	(1.8%)	$ -
RS 22B	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	(0.1%)	$ -
RS 4	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(6.3%)	$ (5,548)
RS 7/27	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(4.6%)	$ (53,227)

On page 2 of the Application, FEI states:

> […] The results of the 2023 COSA therefore confirm that FEI's existing rates and rate designs are working well and as intended.

19.5 Please discuss what impact, if any, rebalancing all rate schedules to an R:C ratio of 100 percent would have on the existing rate design and whether it would lead to required rate design changes. If so, what would be the required rate design changes?

Response:

For the reasons explained in the responses to BCUC IR1 19.4 and 19.4.1, FEI does not consider rebalancing all customer classes to be necessary or preferable. However, despite the resulting large bill impacts to RS 1 and RS 2 customers in order to reach unity (shown in the response to BCUC IR1 19.4.1), the current rate designs will continue to be operable. No rate design changes would be required to achieve unity for all rate schedules (except for RS 4 and RS 7/27).

On pages 62, 65, 68, 72 and 76 of the Application, FEI provides Tables 5-4, 5-7, 5-10, 5-14 and 5-18, respectively, which summarize the rate changes to affected rate schedules under each of the revenue rebalancing options presented in the Application.

19.6 Please explain, with rationale and an illustrative example(s), how FEI allocated the rate changes to the various rate elements (e.g. RS 22 firm demand charge, firm monthly transportation quantity (MTQ) delivery charge and Interruptible MTQ delivery charge).

Response:

FEI provides the rationale for the changes to the various rate elements in each rate schedule using the proposed rebalancing Option 5 of the Application as example. The rationale for other options is the same.

Residential RS 1

The change in the RS 1 delivery rate is based on the increase in delivery margin. There is no change to the Basic Charge. Please see Table 1 below for the calculation:

Table 1: Calculation of the RS 1 Delivery Rate under the Rebalancing Proposal (Option 5)

Line	Particular	Reference	Amount
1	RS 1 Delivery Margin Rebalancing ($000s)	Schedule 1, Line 24	4,519.247
2			
3	Existing RS 1 Delivery Rate ($/GJ)	2023 Approved	6.010
4	RS 1 Volume (TJ)	2023 Approved	82,890
5			
6	Change in RS 1 Delivery Rate ($/GJ)	Line 1 / Line 4	0.055
7	**Rebalanced in RS 1 Delivery Rate ($/GJ)**	**Line 3 + Line 6**	**6.065**

Small Commercial RS 2 and Large Commercial RS 3/23

In order to satisfy the following requirements:

a) Shifting the crossover point between RS 2 and RS 3/23 back to 2,000 GJ;

b) Depending on the rebalancing option, additional changes are required for RS 2 to absorb the revenue shift; and

c) Maintaining the R:C ratios of both rate schedules within the range of reasonableness of 95 percent to 105 percent,

FEI used the Excel Solver functions to find the optimal values for the Basic Charges and Delivery Rates for both RS 2 and RS 3/23. Table 5-19 of the Application confirms the Excel Solver functions satisfy item a) above, and Table 5-17 of the Application confirms the Excel Solver functions satisfy items b) and c) above. The same approach was used for all other rebalancing options explored as part of the Application as well as in response to the scenarios requested in these IRs.

General Firm Service RS 5/25

For RS 5/25, there is no change to the monthly Basic Charge or Administration Charge. Both the delivery rate and demand charge are adjusted for the revenue rebalancing proportionally based on the 2023 forecast of recovery from delivery rates and from the demand charges. Table 2 below provides the calculations.

Table 2: Calculation of the RS 5/25 Delivery and Demand Rates under the Rebalancing Proposal (Option 5)

Line	Particular	Reference	Amount
1	RS 5/25 Delivery Margin Rebalancing ($000s)	Schedule 1, Line 24	$ (3,344.259)
2			
3	Total Delivery Volume (TJ)	2023 Approved	19,130
4	Total Demand (TJ)	2023 Approved	996
5			
6	Existing RS 5/25 Delivery Rate ($/GJ)	2023 Approved	1.085
7	Existing RS 5/25 Demand Rate ($/GJ/Mth)	2023 Approved	30.278
8			
9	Delivery Rate Revenue ($000s)	Line 3 x Line 6	20,756.267
10	Demand Charge Revenue ($000s)	Line 4 x Line 7	30,147.961
11	Total Delivery Margin Recovery ($000s)	Line 3 + Line 4	50,904.228
12			
13	% Rebalancing to Delivery Rate	Line 3 / Line 5	40.8%
14	% Rebalancing to Demand Charge	1 - Line 7	59.2%
15			
16	Change in RS 5/25 Delivery Rate ($/GJ)	Line 1 x Line 13 / Line 3	(0.071)
17	**Rebalanced in RS 5/25 Delivery Rate ($/GJ)**	**Line 6 + Line 16**	**1.014**
18			
19	Change in RS 5/25 Demand Charge ($/GJ/Mth)	Line 1 x Line 14 / Line 4	(1.989)
20	**Rebalanced in RS 5/25 Demand Charge ($/GJ/Mth)**	**Line 7 + Line 19**	**28.289**

RS 22 Large Volume Transportation Service

FEI used the same underlying calculations as were used in Table 9-26 of the FEI 2016 COSA and RDA for the RS 22 Firm Service in this Application. These calculations include setting the interruptible service equal to the <u>effective</u> firm rates and setting the Firm Monthly Transportation Quantity (MTQ) rate at approximately 15 percent of the effective firm rate, while the remaining 85 percent was used to set the Firm Daily Transportation Quantity (DTQ) rate. Table 3 below provides the calculations of the changes in each rate component of RS 22 based on a revenue rebalancing amount of $151 thousand (as shown in Table 5-21 of the Application).

Table 3: Calculation of the Rate Components of RS 22 under the Rebalancing Proposal (Option 5)

Line	Particular	Reference	Amount
1	RS 22 Delivery Margin Rebalancing	Schedule 1, Line 24	(150.726)
2	Current RS 22 Delivery Margin at 2023 Rates	Schedule 1, Line 16	3,257.118
3	Proposed Rebalanced RS 22 Delivery Margin ($000s)	Line 1 + Line 3	3,106.391
4	*(Incl. Known and Measureable Changes)*		
5			
6	Less: Basic Charge Collected Under RS 22	-Line 16	(571.584)
7	Less: Admin Charge Collected Under RS 22	-Line 17	(6.084)
8	Add: UAF Gas Costs	Schedule 1, Line 17	80.184
9	**Total Delivery Margin to be Collected thru Delivery Rates ($000s)**	**Sum of Line 3 to Line 8**	**2,608.908**
10			
11	RS 22 Basic Charge ($/Mth)		$ 3,664.000
12	RS 22 Admin Charge ($/Mth)		$ 39.000
13			
14	Number of RS 22 Firm Customer	Schedule 7, Line 5	13
15	Total RS 22 Basic Charge Recovery ($000s)	Line 11 x Line 14 x 12 / 1,000	571.584
16	Total RS 22 Admin Charge Recovery ($000s)	Line 12 x Line 14 x 12 / 1,000	6.084
17			
18	RS 22 Firm Volume (TJ)	Schedule 7, Line 2	2,128
19	**New RS 22 Effective Firm Rate ($/GJ)**	**Line 9 / Line 18 (Rounded to 3 Decimal Places)**	**$ 1.226**
20			
21	**<u>Proposed RS 22 Rates</u>**		
22	**Firm DTQ Charge ($/GJ/Mth)**	**(Line 19 - Line 23) x 365 days / 12 Mth (See Note 1)**	**$ 31.694**
23	**Firm MTQ Charge ($/GJ)**	**Line 19 x 15%**	**$ 0.184**
24	**Interruptible MTQ ($/GJ)**	**Line 19 (Equal to Firm Effective Rate in $/GJ)**	**$ 1.226**

<u>Note to Table</u>:

Note 1): Firm DTQ (Daily Transportation Quantity) equals to MTQ x 12 Months / 365 Days. The Firm MTQ Charge in $/GJ recovers 15% of the total effective firm rate (Line 19) with the remaining balance recovered through the Firm DTQ Rate.

RS 4 Seasonal and RS 7/27 Interruptible

FEI used the same underlying calculations as were used in Table 9-20 of the FEI 2016 COSA and RDA for the RS 7/27 Fully Interruptible Service in this Application and Table 9-21 of the FEI 2016 COSA and RDA for the RS 4 Seasonal Service.

For the RS 7/27 Fully Interruptible customers, a discount of approximately 18 percent was maintained from the effective rates of RS 5 General Firm Service based on an effective RS 5 load factor of 90.9 percent[21]. For RS 4 Seasonal customers, as explained in Section 9.7.5 of the 2016 COSA and RDA, the delivery rates during the off-peak were set equal to the Demand Charge of RS 5/25 at a 100 percent load factor plus the Delivery Charge for RS 5/25, and during the Extension Period, the rate is set to equal 1.5 times the Delivery Charge of RS 7/27. Table 4 below provides a reconciliation of the RS 7/27 rates and RS 4 rates as set out in Section 5-24 of the Application (i.e., as proposed for Option 5).

[21] As part of the tariff for RS 5, the daily demand per GJ includes a multiplier of 1.1, thus the effective load factor for RS 5 would be 100 percent divided by 1.1 = 90.9 percent, which is then used to convert the demand charge under RS 5 in $/Peak GJ/Mth to the effective demand charge in $/GJ.

Table 4: Reconciliation of RS 7/27 and RS 4 Delivery Rates Calculation (Proposed Option 5)

Line	Particular	Reference		Estimated Final Rates (Option 5)
1	RS 5/25 Effective Load Factor	100% / 1.1		0.909
2	RS 5/25 Demand Charge ($/GJ/Day)	Table 5-24 of Application	$	28.289
3				
4	Effective RS 5/25 Demand Charge ($/GJ)	Line 2 x (12 Mth/365) / Line 1		1.023
5	RS 5/25 Delivery Rate ($/GJ)	Table 5-24 of Application		1.014
6	Total RS 5/25 Effective Rate ($/GJ)	Line 4 + Line 5	$	2.037
7				
8	***RS 7/27***			
9	Effective RS 7/27 Load Factor	2016 RDA (Table 9-20)		0.625
10	**RS 7/27 Delivery Rate**	**Line 4 x Line 9 + Line 5**	**$**	**1.653**
11				
12	Discount as a percentage of Total RS 5/25 Firm (%)	1 - (Line 10 / Line 6)		18.8%
13				
14	***RS 4***			
15	Effective RS 4 Load Factor	2016 RDA (Footnote 159)		0.625
16	**RS 4 Off-Peak Delivery Rate ($/GJ)**	**Line 2 x (12 Mth/365) x Line 14 + Line 5**	**$**	**1.595**
17	**RS 4 Extension Period ($/GJ)**	**Line 10 x 1.5**	**$**	**2.480**

20.0 Reference: REVENUE REBALANCING

Exhibit B-1, Section 5.1, p. 51, Section 5.3, p. 59

Bonbright Rate Design Principles

On page 51 of the Application, regarding the Bonbright rate design principles, FEI states that it "does not apply all eight principles, and also not in any priority or with any particular weighting."

On page 59 of the Application, FEI states that it "assesses each revenue rebalancing option against Bonbright's rate design principles and identifies the preferred rebalancing option." FEI does not comment on principle 1: "Recovering the Cost of Service", principle 5: "Practical and cost-effective to implement", principle 7: "Revenue stability" and principle 8: "Avoidance of undue discrimination" when evaluating the revenue rebalancing options in the Application.

20.1 Please explain whether all revenue rebalancing options assessed in the Application and explored in these information requests would align with Bonbright's rate design principles 1, 5 and 7.

Response:

FEI did not comment on principles 1, 5, and 7 in its assessment of the different rebalancing options because these principles are generally not impacted or are minimally impacted by the various options. However, in order to be responsive, FEI provides the following table of its assessment of Bonbright's rate design principles 1, 5, and 7 for the rebalancing options explored in the Application as well as the options/scenarios requested by the BCUC and interveners in these IRs.

Rate Rebalancing Option	Rate Design Principles	Assessment
Option 1 Status Quo	Principle 1: Recovering the Cost of Service	There is generally no impact to FEI recovering its cost of service under this option. Rate schedules (i.e., RS 5/25 and RS 22) having R:C ratios higher than the upper bound range of reasonableness do not impact FEI's ability to recover its cost of service. Without addressing the economic crossover points, the number of customers that could be impacted is small and under normal circumstances, this revenue deficiency will be made up with rate increases to all non-bypass customers in the subsequent years through FEI's rate setting applications. Thus, this option does not impact FEI's ability to recover its cost of service.
	Principle 5 Practical and Cost-Effective to Implement	There is no impact. It involves no change to existing rates.
	Principle 7: Revenue Stability	The number of customers impacted by the economic crossover points between RS 2 and RS 3/23, and between

Rate Rebalancing Option	Rate Design Principles	Assessment
		RS 3/23 and RS 5/25 are small. Therefore, there is no material impact to the stability of FEI's revenue.
Option 2a Revenue Rebalancing Using Only RS 1, Without Adjustment for Economic Crossover Between RS 2 & 3/23, and Between RS 3/23 & 5/25	Principle 1: Recovering the Cost of Service	Same as Option 1 above. There is generally no impact to FEI recovering its cost of service under this option. Any change in revenue due to customer switching will be made up with delivery rate changes through FEI's rate setting applications.
	Principle 5 Practical and Cost-Effective to Implement	There is no impact. This option is easy to administer. The change in rates is no different than annual delivery rate changes or quarterly rate changes and is therefore practical to implement. There are no incremental costs to adjust the rates for all rate schedules.
	Principle 7: Revenue Stability	Same as Option 1. The number of customers impacted by the economic crossover points between RS 2 and RS 3/23, and between RS 3/23 and RS 5/25 is small. Thus, there is no material impact to the stability of FEI's revenue.
Option 2b Revenue Rebalancing Using Only RS 2, Without Adjustment for Economic Crossover Between RS 2 & 3/23, and Between RS 3/23 & 5/25	Principle 1: Recovering the Cost of Service	Same as Option 1 above. There is generally no impact to FEI recovering its cost of service under this option. Any change in revenue due to customer switching will be made up with delivery rate changes through FEI's rate setting applications.
	Principle 5 Practical and Cost-Effective to Implement	There is no impact. This option is easy to administer. The change in rates is no different from the annual delivery rate changes or quarterly rate changes and is therefore practical to implement. There are no incremental costs to adjust the rates for all rate schedules.
	Principle 7: Revenue Stability	Same as Option 1, the number of customers impacted by the economic crossover points between RS 2 and RS 3/23, and between RS 3/23 and RS 5/25 is small. Thus, there is no material impact to the stability of FEI's revenue.
Option 3 Revenue Rebalancing Using RS 1 Plus Adjustment to RS 2 & RS 3/23 For Maintaining Economic Crossover Between RS 2 & RS 3/23; & Between RS 3/23 & RS 5/25	Principle 1: Recovering the Cost of Service	There is essentially no impact to FEI recovering its cost of service under this option as the economic crossover points between RS 2 and RS 3/23, and between RS 3/23 and RS 5/25 are addressed.
	Principle 5 Practical and Cost-Effective to Implement	There is no impact. This option is easy to administer. The change in rates is no different from the annual delivery rate changes or quarterly rate changes and is therefore practical to implement. There are no incremental costs to adjust the rates for all rate schedules.
	Principle 7: Revenue Stability	There is no impact to the stability of FEI's revenue. Additionally, both economic crossover points are addressed.

Rate Rebalancing Option	Rate Design Principles	Assessment
Option 4 Revenue Rebalancing Using RS 2 Plus Adjustment to RS 2 & RS 3/23 For Maintaining Economic Crossover Between RS 2 & RS 3/23; & Between RS 3/23 & RS 5/25	Principle 1: Recovering the Cost of Service	Same as Option 3 above. There is essentially no impact to FEI recovering its cost of service under this option as the economic crossover points between RS 2 and RS 3/23, and between RS 3/23 and RS 5/25 are addressed.
	Principle 5 Practical and Cost-Effective to Implement	There is no impact. This option is easy to administer. The change in rates is no different from the annual delivery rate changes or quarterly rate changes and is therefore practical to implement. There are no incremental costs to adjust the rates for all rate schedules.
	Principle 7: Revenue Stability	There is no impact to the stability of FEI's revenue. Additionally, both economic crossover points are addressed.
Option 5 Revenue Rebalancing Using RS 1 Plus Adjustment to RS 2 & RS 3/23 For Maintaining Economic Crossover Between RS 2 & RS 3/23	Principle 1: Recovering the Cost of Service	Same or slightly better than Option 1 above; however, the economic crossover point between RS 3/23 and RS 5/25 is not addressed. There is generally no impact to FEI recovering its cost of service under this option. Any change in revenue due to customer switching between RS 3/23 and RS 5/25 will be small and will be made up with delivery rate increases during FEI's next rate setting application.
	Principle 5 Practical and Cost-Effective to Implement	There is no impact. This option is easy to administer. The change in rates is no different from the annual delivery rate changes or quarterly rate changes and is therefore practical to implement. There are no incremental costs to adjust the rates for all rate schedules.
	Principle 7: Revenue Stability	There is no impact to the stability of FEI's revenue. The variance in revenue due to the economic crossover point between RS 3/23 and RS 5/25 is small.
BCUC IR1 19.2 & 19.3: RS 5/25 & 22 R:C Ratios at Unity	Principle 1: Recovering the Cost of Service	No change to FEI's ability to recover its cost of service. Having R:C ratios at unity or at 105% for RS 5/25 and RS 22 will not change FEI's ability to recover its cost of service.
	Principle 5 Practical and Cost-Effective to Implement	There is no impact. This option is easy to administer. The change in rates is no different from the annual delivery rate changes or quarterly rate changes and is therefore practical to implement. There are no incremental costs to adjust the rates for all rate schedules.
	Principle 7: Revenue Stability	Same as Option 5 above. There is no impact to the stability of FEI's revenue. The variance in revenue due to the economic crossover point between RS 3/23 and RS 5/25 is small.
BCUC IR1 19.4 & 19.4.1: All R:C Ratios at Unity	Principle 1: Recovering the Cost of Service	In the absence of setting RS 4 and 7/27 to unity which would make them "free riders" on FEI's system, this option would result in FEI revenues being greater than the cost of service. See Table 1 of the response to BCUC IR1 19.4 where all firm service R:C ratios equal 100%, but RS 4 & 7/27 equal 116%.

Rate Rebalancing Option	Rate Design Principles	Assessment
	Principle 5 Practical and Cost-Effective to Implement	There is no impact. This option is easy to administer. The change in rates is no different from the annual delivery rate changes or quarterly rate changes and is therefore practical to implement. There are no incremental costs to adjust the rates for all rate schedules.
	Principle 7: Revenue Stability	In the absence of setting RS 4 and RS 7/27 to unity, this option would increase FEI's revenue by approximately $12.5 million (see Table 1 of BCUC IR1 19.4.1), and so can be considered as reducing FEI's revenue stability.
BCOAPO IR1 1.8: Reallocate Revenue Shift to all Rate Schedules (excluding RS 4 & 7/27) with R:C Ratios capped at 105%	Principle 1: Recovering the Cost of Service	No change to FEI's ability to recover its cost of service. Having R:C ratios at 105% for most rate schedules will not change FEI's ability to recover its cost of service.
	Principle 5 Practical and Cost-Effective to Implement	There is no impact. This option is easy to administer. The change in rates is no different from the annual delivery rate changes or quarterly rate changes and is therefore practical to implement. There are no incremental costs to adjust the rates for all rate schedules.
	Principle 7: Revenue Stability	Since all rate schedules, with the exception of RS 1 and RS 2, would have their R:C ratio sitting at the upper limit of range of reasonableness of 105%, it would be likely that most, if not all, of these rate schedules' revenues would exceed their costs by more than 105% in the near future. This would mean rebalancing in the opposite direction would be required and will reduce FEI's revenue from these rate schedules. The increase in FEI's revenue and the subsequent opposite rebalancing would reduce revenue stability.
RCIA IR1 19.1: Revenue Shift Reallocated to RS 1 & RS 2 Proportional to Delivery Revenue	Principle 1: Recovering the Cost of Service	This option is similar to the proposed Option 5 (except a small portion of revenue rebalancing will be absorbed by RS 2), but generally has no impact to FEI recovering its cost of service. Any change in revenue due to customer switching between RS 3/23 and RS 5/25 will be small and will be made up with delivery rate increases during the next rate setting application.
	Principle 5 Practical and Cost-Effective to Implement	There is no impact. This option is easy to administer. The change in rates is no different to the annual delivery rate changes or quarterly rate changes and is therefore practical to implement. There are no incremental costs to adjust the rates for all rate schedules.
	Principle 7: Revenue Stability	Similar to Option 5. There is no impact to the stability of FEI's revenue. The variance in revenue due to the economic crossover point between RS 3/23 and RS 5/25 is small.

20.2 Please explain whether all revenue rebalancing options that result in all R:C ratios of the applicable rate schedules being brought into the range of reasonableness would align with principle 8.

Response:

Options that result in all R:C ratios of the applicable rate schedules being brought into the range of reasonableness would partially align with principle 8. To improve the alignment with principle 8, the BCUC should also consider the options that deal with the economic crossover between RS 2 and 3/23. The rates applicable to RS 2 and RS 3/23 should result in approximately the same cost to customers who consume approximately 2,000 GJ annually.

20.3 Please discuss how FEI's preferred rebalancing option aligns with Bonbright's rate design principle 8 in the context of using RS 1 to absorb all revenue shifts from RS 5/25 and RS 22.

Response:

Using RS 1 to absorb all revenue shifts from RS 5/25 and RS 22 aligns with Principle 8, i.e., is not unduly discriminatory, as similarly situated customers continue to be treated similarly, consistent with the rate classes and rate design established and approved by the BCUC in 2016 and in previous years.

Further, using the residential rate class, which has had the lowest R:C ratio, to bear the revenue shift is the best option available for the reasons discussed in Section 5 of the Application, and is consistent with past FEI rate design applications approved by the BCUC. In addition, the revenue shift has a minimal impact on rates and, even after the revenue shift, the residential rate class will continue to have an R:C ratio within the lower end of the range of reasonableness.

In short, the revenue shift to RS 1 from RS 5/25 and RS 22 does not result in any change that engages Principle 8, as FEI's rates remain not unduly discriminatory.

21.0 Reference: REVENUE REBALANCING

Exhibit B-1, Section 5.2.2, p. 52, 57, Figures 5-3 and 5-4, p. 56, Section 5.2.3, Table 5-2, p. 59, Section 5.3.3, Table 5-12, pp. 68–70, Section 5.3.4, p. 72, Table 5-16, p. 74, Section 5.3.5, Table 5-20, pp. 77–78; Decision and Order G-135-18 on FEI 2016 Rate Design Application (2016 RDA Decision)

Economic Crossover Between Rate Schedules

On page 52 of the Application, FEI states:

> […] the current economic crossover volume between RS 2 and RS 3/23 at the 2023 Approved rates is approximately 1,515 GJ per year, which is already below the segmentation volume threshold of 2,000 GJ per year that is set out in the tariffs for these two customer groups. This deviation occurs because the Basic Charges for both RS 2 and RS 3/23 remain constant over time while the variable delivery charges are subject to change each year from FEI's rate-setting proceedings (annual reviews during FEI's current 2020-2024 MRP or revenue requirement applications).

21.1 Please explain how FEI mitigates the deviation of the economic crossover point between RS 2 and RS 3/23 over time from the threshold of 2,000 GJ per year.

Response:

Since the 1993 Phase B Rate Design Decision, FEI has been addressing the crossover point at 2,000 GJ per year between RS 2 and RS 3/23 customers as part of each COSA and Rate Design application. This was done in the 1996, 2001, and 2016 applications, and is included as part of the current Application under the proposed Option 5.

21.2 Please discuss whether FEI considered rate design changes to address the deviation of the economic crossover point between RS 2 and RS 3/23, and between RS 3/23 and RS 5/25 if applicable, over time. If so, what rate design changes were considered? And if not, why not?

Response:

FEI completed a major review of the crossover points between RS 2 and RS 3/23, and between RS 3/23 and RS 5/25 as part of the 2016 COSA and RDA. Adjustments were made to the Basic Charges of RS 2 and RS 3/23 as well as to the Demand Charge of RS 5/25 to address the deviation of the economic crossover points between the rate schedules. However, FEI determined that no major rate design changes were needed. Prior to the 2016 COSA and RDA, the crossover points were reviewed during the 2001 RDA.

In the 2016 COSA and RDA, FEI examined the customer/class load profiles and load factors between RS 2 and RS 3/23[22] to see if changes might warrant resetting the threshold at a different annual volume and if the pricing levels applied to the billing determinants would sufficiently recover the allocated cost. The results were no change to the annual volume threshold between RS 2 and RS 3/23 of 2,000 GJ; however, the Basic Charge and Delivery Charge for these two rate schedules were changed to be in alignment with the 2,000 GJ threshold, yielding the same cost for a customer consuming 2,000 GJ. This was reviewed again in this Application (i.e., Section 5.2.2) and FEI came to a similar conclusion as in the 2016 COSA and RDA, i.e., proposing in this Application to make no change to the annual volume threshold but proposing adjustments to the Basic Charges of both RS 2 and RS 3/23 to move the crossover point back to 2,000 GJ.

FEI also completed a similar review of the economic crossover point between RS 3/23 and RS 5/25 in both the 2016 COSA and RDA[23] and in this Application (Section 5.2.3). In the 2016 COSA and RDA, no rate design changes were required for RS 3/23 and RS 5/25 except for a small adjustment to the RS 5/25 Demand Charge for the economic crossover point between RS 3/23 and RS 5/25. In the current Application, FEI explored in Options 3 and 4 maintaining the crossover point between RS 3/23 and RS 5/25; however, to achieve a balance between rate impacts to RS 3/23 customers and the economic crossover for RS 3/23 and RS 5/25 customers, no adjustments were ultimately proposed in the proposed Option 5.

21.2.1 At what point in the deviation does FEI consider that rate design changes are needed?

Response:

There would need to be a clear and definite shift or change in the customer load profile in terms of annual use and load factor to segregate these rate schedules at different annual consumption levels. For example, as demonstrated throughout Section 5.2.2 of the Application, the customer load profiles in terms of annual use and load factors remain largely the same as load profiles in the 2016 COSA and RDA, and the small deviation in the economic crossover point between rate classes can be easily addressed by small adjustments to the basic charges without a comprehensive rate design change. FEI considers it inefficient and unnecessary as part of this Application to undergo a comprehensive rate design review when the customer load profiles are

[22] Section 8.3.3 of the 2016 COSA and RDA.
[23] Section 9.5.6 of the 2016 COSA and RDA.

largely the same and the deviation in the economic crossover point can be easily resolved through adjustments to the basic and variable charges.

21.3 Please explain whether the economic crossover point between RS 2 and RS 3/23 would be maintained or whether the deviation would be reduced over time if both the basic charges and delivery charges were subject to change each year by the same percentage from FEI's rate-setting proceedings.

21.3.1 If yes, please discuss whether FEI considers this an appropriate revenue rebalancing option to reduce the complexity of future revenue rebalancing.

Response:

Flowing through rate changes from the Annual Reviews to both the Basic Charge and the Delivery Charge will not reduce the complexity of future revenue rebalancing because of the gas cost recovery charges.

The economic crossover point between RS 2 and RS 3/23 is determined by: (i) the Basic Charge, (ii) the Delivery Charge, (iii) the Commodity Cost Recovery Charge, and (iv) the Storage and Transport Charge in each of the rate schedules. Applying delivery rate changes to both the Basic Charge and Delivery Charge would not prevent deviations from the 2,000 GJ crossover point.

Prior to the 2001 RDA, changes in rates from the Annual Reviews / Revenue Requirements processes were flowed to both the Basic Charge and the Delivery Charge, but the crossover point between RS 2 and RS 3/23 still needed to be reset to 2,000 GJ during the 2001 RDA.

On page 57 of the Application, FEI states:

> While differences can also be found at other threshold levels, the threshold and the relationship between load factor and consumption would need to be significantly different than 2,000 GJ as well as the trend shown in Figure 5-5 above to support moving away from the existing threshold of 2,000 GJ.

21.4 Please define "significantly different than 2,000 GJ as well as the trend shown in Figure 5-5 " in the context of the above preamble.

Response:

The following four factors were considered by FEI to determine that there was no significant difference observed to support moving away from the existing threshold of 2,000 GJ:

1) FEI conducted the same analysis in terms of actual average load factor versus annual consumption of commercial customers (including RS 2 and RS 3/23 customers) in both the 2016 COSA study (Figure 8-10 of the 2016 COSA and RDA) and in this 2023 COSA study (Figure 5-5 of this Application). FEI has provided a copy of both figures in Figures 1 and 2 below for comparison. While small variations between 2016 and 2023 are to be expected, there is no material change in terms of the general trend. The majority of commercial customers (including both RS 2 and RS 3/23) shown in the 2023 COSA that consume more than 2,000 GJ continue to have load factors at around 40 percent, similar to what was observed in 2016. Commercial customers that consume less than 2,000 GJ, while having a wider range, have load factors generally less than 40 percent in both the 2016 and 2023 COSA studies. As such, FEI concluded there is no material change regarding the load factor of its commercial customers since 2016 that warrant a move away from the existing threshold of 2,000 GJ.

Figure 1: RS 2 and RS 3/23 Load Factor vs. Annual Consumption in GJ (2016 COSA)

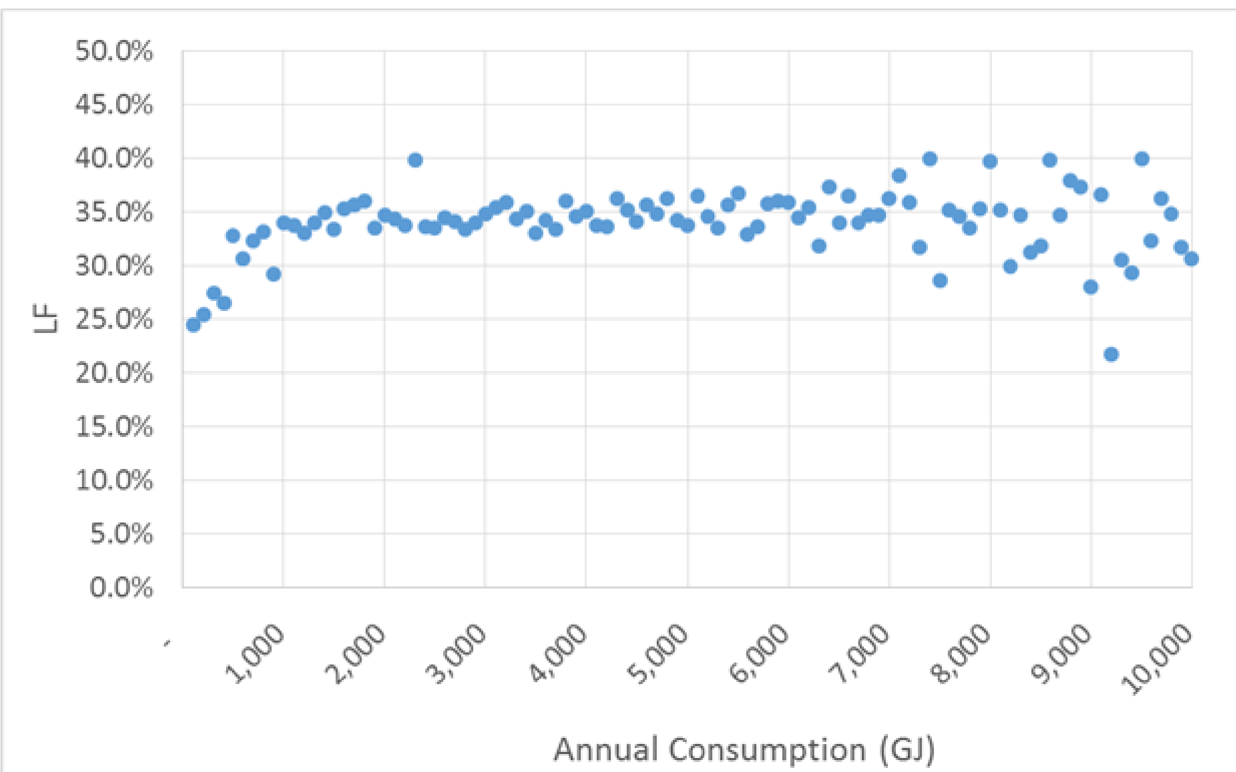
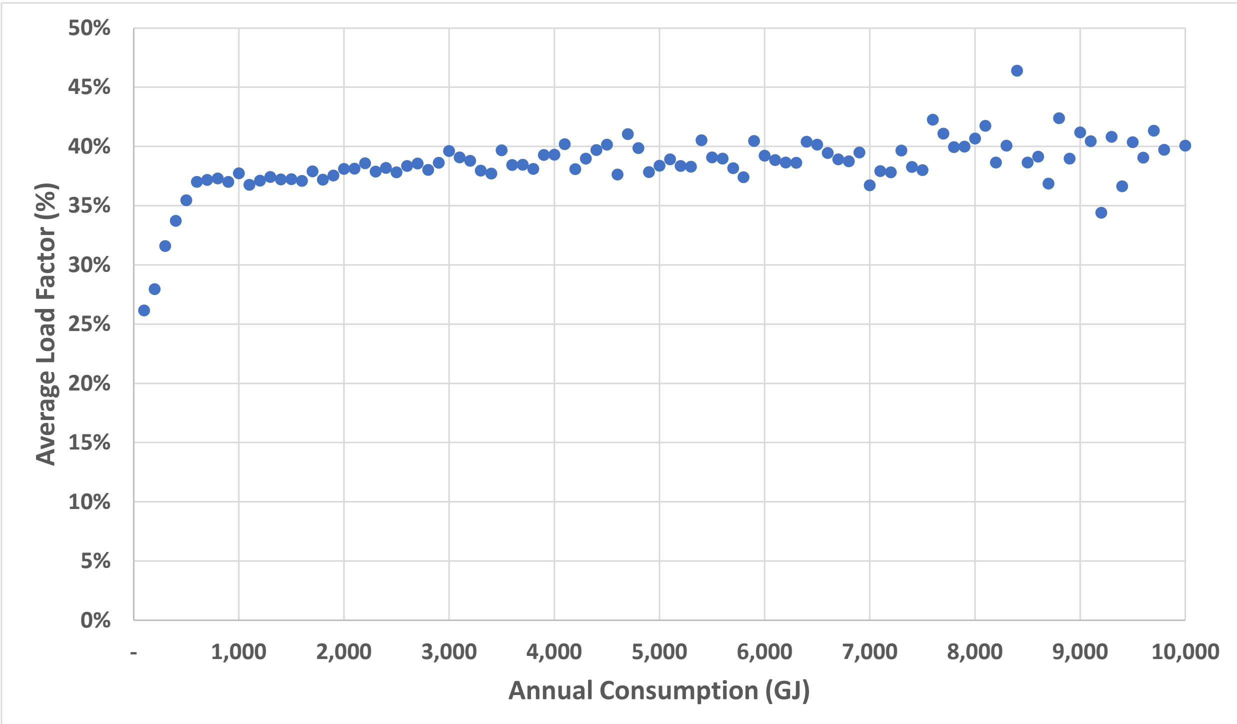


Figure 2: RS 2 and RS 3/23 Load Factor vs. Annual Consumption in GJ (2023 COSA)



2) The current crossover point between RS 2 and RS 3/23 is 1,515 GJ, as shown in Table 5-1 of the Application. Based on 2022 actuals, there are a total of 2,734 RS 2 customers that are above this crossover point and a total of 707 RS 3/23 customers below this crossover point, which is approximately 3.6 percent of total RS 2 and RS 3/23 customers. FEI does not consider the number of customers that currently fall between the current financial crossover point of 1,515 GJ and the threshold of 2,000 GJ to be significant enough to warrant a change from the existing crossover point of 2,000 GJ.

3) There is essentially no change from the 2023 COSA study even if FEI were to reassign the revenue and costs of those RS 2 customers currently consuming above 1,515 GJ to RS 3/23, and the revenue and costs of those RS 3/23 customers currently consuming below 1,515 GJ to RS 2. Table 1 below provides the R:C and M:C ratios (before rebalancing) with and without the reassignment. Even with the reassignment, the need to rebalance RS 22 and RS 5/25 remains the same before the reassignment.

Table 1: R:C and M:C ratios (before Rebalancing) with and without RS 2 and RS 3/23 Reassignments

Rate Schedule	As-Filed Before Rebalancing R:C	As-Filed Before Rebalancing M:C	BCUC IR1 21.4 (RS 2 and RS 3/23 Reassigned) Before Rebalancing R:C	BCUC IR1 21.4 (RS 2 and RS 3/23 Reassigned) Before Rebalancing M:C	Change Before Rebalancing R:C	Change Before Rebalancing M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%	97.6%	95.4%	0.3%	0.4%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%	97.0%	93.4%	-1.0%	-2.2%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	111.2%	103.3%	108.9%	-0.7%	-2.3%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	126.9%	106.9%	127.1%	0.0%	0.2%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%	96.5%	91.7%	0.3%	0.7%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%	110.3%	110.6%	0.3%	0.4%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.9%	102.1%	102.2%	0.3%	0.3%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.1%	100.5%	100.5%	0.4%	0.4%

Rate Schedule (Rates Not Set Using Allocated Costs)	Before Rebalancing R:C	Before Rebalancing M:C	Before Rebalancing R:C	Before Rebalancing M:C	Before Rebalancing R:C	Before Rebalancing M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	339.0%	124.2%	340.8%	124.2%	340.8%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	122.4%	629.0%	122.4%	630.6%	122.4%	630.6%

4) The separation of commercial customers between RS 2 and RS 3/23 started in the 1993 Phase B Rate Design, with the threshold between the two rate schedules set at 2,000 GJ. The following is copied from the 1993 Phase B Rate Design Application, Volume 1, Tab 7:

> In this application, BC Gas is proposing to introduce three sales service to non-residential:
>
> 1) Small commercial service;
> 2) Large commercial service;
> 3) General Firm service.
>
> The distinction between small and large commercial customers is drawn at consumption under and over at 2,000 gigajoules per year. The distinction is based on a number of factors with the most important being:

(a) The similarity of annual gas consumption profiles between the small commercial and residential customers.

(b) The similar load factors exhibited by the small commercial and residential customers; and

(c) Similarity in metering and pressure regulating equipment used by small commercial and residential customers.

FEI's view is that, specifically for item (c) above, one of the differentiating factors between Small and Large Commercial customers was the point at which the customer's metering equipment stopped having similar characteristics to Residential customers, with the assumption that Large Commercial customers would be typically using larger meter types. Table 2 below provides the data from the 2023 Customer Weighting Factor for Meters and Services (see Attachment 14.1A to BCUC IR1 14.1) which shows the number of 200, 400, and all other larger-sized meters as a percentage of the total number of meters for Residential, Small Commercial, and Large Commercial customers. It can be seen that approximately 99 percent of Large Commercial customers use larger meter types instead (not 200 and 400 series meters), whereas approximately 76 precent of Small Commercial customers use 200 and 400 series meters, with Residential customers almost exclusively using the 200 and 400 series meters. Based on this information, FEI concluded there is no significant change in the metering equipment used to serve Small Commercial customers that would precipitate a change to the segmentation threshold of 2,000 GJ.

Table 2: Meter Types used for Residential, Small Commercial, and Large Commercial Customers (2023 COSA)

Customer Classes	200 Meter Type	400 Meter Type	All Other Types
Residential RS 1			
No. of Meters	891,201	43,105	3,095
Total RS 1 Meters	937,401	937,401	937,401
% of Meter Type	95.1%	4.6%	0.3%
Small Commercial RS 2			
No. of Meters	48,413	23,511	23,089
Total RS 2 Meters	95,013	95,013	95,013
% of Meter Type	51.0%	24.7%	24.3%
Large Commercial RS 3			
No. of Meters	11	75	5,931
Total RS 3 Meters	6,017	6,017	6,017
% of Meter Type	0.2%	1.2%	98.6%

Based on the four factors discussed above, changing the current threshold of 2,000 GJ for segmenting RS 2 and RS 3/23 is not warranted.

On page 59 of the Application, FEI provides Table 5-2, which shows the economic crossover volumes, before any revenue rebalancing, at varying load factors for RS 3/23 and RS 5/25 at the time of implementing the 2016 RDA Decision and at the current 2023 Approved rates, and states that "[i]f a customer's volume for a given load factor is greater than the economic crossover volume shown in the table below [Table 5-2], then the customer would receive a lower annual bill under RS 5/25 than under RS 3/23."

21.5 Before any revenue rebalancing, please confirm how many, if any, customers at each given load factor have 2022 actual volume greater than the economic crossover volume shown in Table 5-2 at the current 2023 approved rates.

Response:

Please refer to Table 1 below which provides the number of customers at each load factor (in the same range as provided in Table 5-2 of the Application) that have 2022 actual volumes greater than the economic crossover volume before any rebalancing at the current 2023 Approved rates. Table 1 also provides the number of customers at each load factor that have 2022 actual volumes greater than the economic crossover volume after rebalancing under Options 2a/2b, 3, 4, and 5.

Table 1: Number of Customers Exceeding Economic Crossover Volume at a Given Load Factor

	2023 Approved Rates		Option 2a / 2b		Option 3		Option 4		Option 5	
Load Factor	Economic Crossover (GJ)	Number of Customer Exceed	Economic Crossover (GJ)	Number of Customer Exceed	Economic Crossover (GJ)	Number of Customer Exceed	Economic Crossover (GJ)	Number of Customer Exceed	Economic Crossover (GJ)	Number of Customer Exceed
50%	4,747	46	3,807	79	4,543	49	3,706	83	3,825	79
49%	4,995	40	3,954	68	4,802	48	3,936	68	3,981	66
48%	5,283	40	4,120	63	5,105	43	4,207	60	4,157	61
47%	5,621	42	4,309	75	5,465	44	4,533	67	4,359	73
46%	6,023	20	4,525	43	5,898	23	4,932	38	4,591	41
45%	6,509	17	4,775	38	6,431	17	5,430	28	4,862	38
44%	7,108	11	5,068	29	7,102	11	6,073	20	5,181	27
43%	7,867	10	5,416	32	7,973	10	6,930	17	5,564	28
42%	8,857	16	5,836	38	9,147	13	8,133	19	6,030	34
41%	10,204	11	6,352	22	10,819	11	9,944	11	6,611	21
40%	12,144	3	7,003	19	13,387	3	12,978	3	7,355	17
39%	15,175	1	7,847	12	17,839	1	19,106	1	8,342	10
38%	20,585	2	8,989	8	27,449	-	37,989	-	9,714	8
37%	32,976	1	10,616	7	63,508	1	(911,418)	-	11,751	7
36%	90,441	-	13,124	3	(164,242)	-	(33,287)	-	15,093	2
Total		**260**		**536**		**274**		**415**		**512**

On pages 68 to 69 of the Application, regarding revenue rebalancing option 3, FEI states:

> […] as shown in Table 5-12 below, the adjusted rates ensure the economic crossover point between RS 3/23 and RS 5/25 is maintained at a level similar to the current 2023 Approved rates.

On page 69 of the Application, FEI provides Table 5-12.

21.6 Please confirm how many, if any, customers at each given load factor have 2022 actual volume greater than the economic crossover volume shown in Table 5-12 under revenue rebalancing option 3.

Response:

Please refer to the response to BCUC IR1 21.5.

On page 72 of the Application, regarding revenue rebalancing option 4, FEI states:

> […] as shown in Table 5-16 below, the adjusted rates ensure the economic crossover point between RS 3/23 and RS 5/25 is maintained at a level similar to 2023 Approved rates.

On page 74 of the Application, FEI provides Table 5-16.

21.7 Please confirm how many, if any, customers at each given load factor (except for the 37 percent load factor which is explained in footnote 87 of the Application) have 2022 actual volume greater than the economic crossover volume shown in Table 5-16 under revenue rebalancing option 4.

Response:

Please refer to the response to BCUC IR1 21.5.

On page 77 of the Application, FEI states:

> Based on actual 2022 annual consumption, FEI estimates that, under the rates for Option 5, approximately 734 more RS 3/23 customers could receive a lower annual bill with RS 5/25 […]

On page 78 of the Application, FEI provides Table 5-20.

21.8 Please confirm how many customers at each given load factor have 2022 actual volume greater than the economic crossover volume shown in Table 5-20 under revenue rebalancing option 5.

Response:

Please refer to the response to BCUC IR1 21.5.

On page 56 of the Application, FEI provides Figures 5-3 and 5-4 showing the load factors for RS 2 and RS 3/23 customers in 2022.

21.9 Please provide a table showing the annual bill impacts (in dollars and percentage) under revenue rebalancing option 5 and the number of customers at each load factor from 5 percent to 100 percent in intervals of 5 percent for an average customer in: (i) RS 2; and (ii) RS 3/23.

Response:

Please refer to Table 1 below for the annual bill impact (in dollars and in percentage) for RS 2 customers under FEI's proposed Option 5, summarized by load factor from 5 percent to 100 percent. FEI notes that the annual bill impact is calculated based on the average volume of each interval (total volume in each interval divided by number of customers at each interval).

Table 1: Average RS 2 Bill Impact at Each Load Factor from 5% to 100% under Option 5

Load Factor	No. of Customer	Avg. Volume (GJ)	Option 5 - Bill Impact ($)	(%)
5%	871	195	30	1.2%
10%	2	13	71	14.4%
15%	1,919	53	62	6.6%
20%	11,163	140	43	2.2%
25%	29,380	256	16	0.5%
30%	16,285	344	(3)	-0.1%
35%	7,245	497	(38)	-0.6%
40%	4,129	670	(77)	-1.0%
45%	2,581	717	(87)	-1.0%
50%	1,811	710	(86)	-1.0%
55%	1,424	628	(67)	-0.9%
60%	1,179	598	(61)	-0.9%
65%	1,147	513	(41)	-0.7%
70%	1,247	512	(41)	-0.7%
75%	1,043	446	(26)	-0.5%
80%	900	419	(20)	-0.4%
85%	743	413	(19)	-0.4%
90%	672	429	(22)	-0.4%
95%	640	350	(5)	-0.1%
100%	616	339	(2)	-0.1%

Please refer to Table 2 below for the annual bill impact (in dollars and in percentage) for RS 3/23 customers under FEI's proposed Option 5, summarized by load factor from 5 percent to 100 percent.

Table 1: Average RS 3/23 Bill Impact at Each Load Factor from 5% to 100% under Option 5

Load Factor	No. of Customer	Avg. Volume (GJ)	Option 5 - Bill Impact ($)	(%)
5%	28	2,976	24	0.1%
10%	-	-	173	9.9%
15%	83	1,510	97	0.6%
20%	149	1,730	86	0.4%
25%	809	3,101	18	0.1%
30%	999	4,047	(30)	-0.1%
35%	1,223	3,787	(17)	0.0%
40%	1,539	3,836	(19)	0.0%
45%	1,099	3,924	(23)	-0.1%
50%	639	3,977	(26)	-0.1%
55%	371	4,246	(40)	-0.1%
60%	247	4,096	(32)	-0.1%
65%	170	3,704	(12)	0.0%
70%	133	3,475	(1)	0.0%
75%	115	3,900	(22)	-0.1%
80%	89	4,100	(32)	-0.1%
85%	46	3,768	(16)	0.0%
90%	58	3,907	(23)	-0.1%
95%	45	4,488	(52)	-0.1%
100%	39	3,183	14	0.0%

D. TRANSPORTATION SERVICE REPORT

22.0 Reference: BALANCING COSTS AND REVENUES

Exhibit B-1, Section 6.1, pp. 87–88; FEI Transportation Service Report Compliance Filing in Accordance with BCUC Order G-135-18 and Order G-210-20 dated June 15, 2022 (Transportation Service Report), Table 5-3

Balancing Charges and Midstream Costs for Transportation Service Customers

On page 87 of the Application, FEI states:

> Although the balancing charges are not intended to be revenue generating or revenue neutral, as was presented in the Transportation Service Report (Section 5.5 and Table 5-3), the balancing charge of $0.25 per GJ when balancing in the 10 percent to 20 percent tolerance range is currently at a level that is recovering revenue which is reasonably close to the incremental variable costs required to balance the system as a whole. Thus, in most cases, the costs of the incremental midstream resources needed to balance the system as a whole will be offset by the recoveries from the balancing charge.

On page 34 of FEI's Transportation Service Report, FEI provides Table 5-3.

22.1 Please provide an update to Table 5-3 from the Transportation Service Report showing incremental variable costs for system balancing during winter 2022/23.

Response:

The following table shows the incremental variable costs for system balancing for the winter of 2022/23.

	Sumas Price (CAD$/GJ)	NWP Commodity Charge	NWP Fuel	Storage Fuel	Incremental Variable Costs (CAD$/GJ)
2018/19	$15.05	$0.01	$0.42	$0.17	**$0.60**
2019/20	$3.25	$0.01	$0.07	$0.04	**$0.12**
2020/21	$4.11	$0.01	$0.07	$0.05	**$0.13**
2021/22	$5.76	$0.01	$0.10	$0.07	**$0.18**
2022/23	$16.05	$0.01	$0.34	$0.19	**$0.54**
Winter Average (CAD$/GJ)					**$0.31**

Due to colder than normal temperatures and increased demand during the 2022/23 winter, Sumas prices were elevated and as shown, the average price over that period was $16.05 CAD/GJ. The NWP and Storage fuel were also elevated as compared to previous winters due to colder temperatures and higher load factor. The incremental NWP Commodity Charge remained the same over each winter. While the increase in the Sumas price and related fuel and charges resulted in a higher incremental variable cost during the 2022/23 winter of $0.54 CAD/GJ, the average over the four winter periods is $0.31 CAD/GJ, and the $0.25 CAD/GJ variable charge remains reasonable to recover system balancing within the 10 – 20 percent range.

For additional evaluation to validate if the $0.25 CAD/GJ charge is reasonably close to the incremental variable costs to balance the system as a whole, FEI calculated the incremental variable costs on an average annual basis. As the table shows, the average incremental variable cost from 2018 to September 2023 is $0.26 CAD/GJ.

	Sumas Price (CAD$/GJ)	NWP Commodity Charge	NWP Fuel	Storage Fuel	Incremental Variable Costs (CAD$/GJ)
2018	$4.34	$0.01	$0.10	$0.11	**$0.22**
2019	$6.72	$0.01	$0.20	$0.15	**$0.37**
2020	$2.69	$0.01	$0.05	$0.06	**$0.12**
2021	$4.73	$0.01	$0.08	$0.11	**$0.21**
2022	$10.09	$0.01	$0.20	$0.24	**$0.46**
2023 (Jan-Sep)	$5.80	$0.01	$0.09	$0.11	**$0.21**
Average (CAD$/GJ)					**$0.26**

The above annual analysis shows that the $0.25 CAD/GJ reasonably recovers the incremental variable costs incurred by FEI to provide system balancing as a whole.

22.2 Please discuss whether incremental variable costs for winter 2022/23 are consistent with FEI's statement that, "the balancing charge of $0.25 per GJ when balancing in the 10 percent to 20 percent tolerance range is currently at a level that is recovering revenue which is reasonably close to the incremental variable costs required to balance the system as a whole."

Response:

Please refer to the response to BCUC IR1 22.1.

On page 85 of the Application, FEI states:

> The fixed costs of FEI's midstream resources are recovered from FEI's core customers through the applicable Storage and Transport Charge per GJ applicable

to FEI's core sales service rate schedules. The Storage and Transport Charge is not applicable to FEI's Transportation Service rate schedules and, as such, Transportation Service customers do not pay for those midstream resources and are not entitled to benefit from them at the expense of core customers.

On page 88 of the Application, FEI presents Table 6-1: Total Transportation Service Balancing Charges vs. FEI's Total Midstream Costs (2018 to 2022 Actual) and states:

The five-year average of total balancing charges recovered from 2018 to 2022 was approximately $1.754 million, which is approximately 1.1 percent of FEI's average total midstream costs per year over the same period, or approximately 0.08 percent of FEI's total allocated cost of service included in the 2023 COSA.

22.3 Please explain how the variance of daily demand needs from FEI core customers compares to the variance of imbalances caused by transportation service customers.

Response:

The variance in daily demand needs of FEI's core customers and transportation service customers are relatively the same. Both FEI and Shipper Agents manage customers with similar demand patterns and load requirements, including customers that are heat sensitive, seasonal, or volatile throughout the year. FEI responds to the changes in daily demand requirements through midstream resources under the Annual Contracting Plan; similarly, Shipper Agents respond through their individual supply and market portfolios.

22.4 Please discuss whether it would be appropriate to allocate a portion of FEI's midstream resource costs to transportation customers based on their annual usage of midstream resources from 2018 to 2022.

Response:

FEI does not consider it appropriate to allocate a portion of FEI's midstream resource costs to transportation customers and considers that doing so would be detrimental to incenting Shipper Agents to balance their customer's supply and demand.

The option of a balancing fee was presented as an option in the stakeholder sessions in 2016 in advance of the 2016 COSA and RDA to account for the use of Core customer midstream resources by Transportation Service customers. In Exhibit B-4 of the 2022 Transportation Service Report proceeding, FEI provided the response to CEC IR 3.4 explaining why it did not propose allocating midstream costs to Transportation Service customers. FEI provides the excerpt below.

3.4. Would there be any justification for having shipper agents pay a fee such that they would be paying their appropriate portion of the midstream resources? Please explain why or why not.

Response:

The option of a balancing fee was explored in the 2016 RDA[3] to account for the use of core customer midstream resources by Transportation Service customers. In the 2016 RDA, FEI provided a summary of the replacement cost study, conducted by consultant Black & Veatch, of the market value of the balancing services provided by FEI.[4] The replacement cost, as detailed in the 2016 RDA, Table 10-7, provided the total replacement cost of balancing services, at the time, by tolerance, and the resulting per GJ cost or fee that would apply to the throughput for all Transportation Service customers. For the following reasons which continue to remain valid, FEI did not propose a fee-based approach.

[3] Section 10.7.5 Balancing Tolerance and Charges, Option 1 – Balancing Fee (service offering), page 10-33, 2016 RDA.

[4] FEI 2016 RDA, Section 10.7.4.

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- A charge applied to all throughput for all shipper agents would penalize the Transportation Service customers of shipper agents that are more proactively and closely managing balancing on FEI's system;
- A fee-based approach does not provide an incentive to balance more closely and effectively removes the obligation for shipper agents to manage matching supply and demand, which is a fundamental change to the Transportation Service Model and may result in unintended consequences for shipper agents, FEI and its core customers;
- Shipper agents raised concerns during the 2016 RDA workshops about the methodology and inputs to calculate the value of the balancing fees; and
- Shipper agents were of the view that applying a tighter tolerance would provide a better incentive to improve balancing behaviour versus applying a fee or charge.

In the 2016 RDA Decision, the Panel did not direct the imposition of a balancing fee or charge. Instead, the Panel stated:

> The Panel finds the resulting tiered structure of the balancing charges to be just, reasonable and not unduly discriminatory in that this rate structure is consistent with rate design principles of fair apportionment of costs among customers and price signals that encourage efficient use of resources. [5]

22.5 If FEI were to allocate a portion of FEI's midstream resource costs to transportation customers based on their use of midstream resources, please discuss what the appropriate basis for cost allocation would be.

Response:

Please refer to the response to BCUC IR1 22.4 where FEI explains that it does not consider such an approach reasonable or appropriate.

To be clear, FEI does not hold/contract for midstream resources to serve Transportation Service (T-service) customers. FEI expects that T-service customers are already paying their gas marketer to bring gas to FEI's interconnection points. If FEI were directed by the BCUC to allocate a portion of its midstream costs that are held/contracted for to serve Sales Service customers to T-service customers, FEI would need to re-evaluate the entire T-service model to determine what the services would be, whether midstream resources could in fact be acquired to serve them, and how the charges should be set.

In the Annual Contracting Plan, the midstream resources and associated costs are only for FEI's core sales customers, and from a cost causation view, T-service customers do not cause the costs and would not be allocated any of the midstream costs. It is the responsibility of the Shipper Agents on behalf of their transportation customers to secure their own midstream resources to bring the gas to the FEI interconnect with Enbridge or Trans Canada. When system imbalances occur within the gas day that require FEI to take action and use core market midstream resources, FEI does not know if the imbalances are caused by transportation or core customers. Once the gas day is complete, the supply and demand records calculate imbalances by the Shipper Agents to determine if they have exceeded the balancing tolerance, and charges are applied back to the midstream costs.

Changing to having a midstream fee charged to all T-service customers would be a step away from cost causation / cost recovery principles. Not all Shipper Agents cause incremental midstream costs, nor should they be responsible for the incremental cost recovery. The existing framework of the Transportation Model incents customers through pricing for imbalances, and when marketer group(s) exceed the 10 percent tolerance limit, the marketer then bears the charges and has to deal with its customers that caused the charges from FEI.

22.5.1 Please provide a calculation illustrating how costs would be allocated to FEI's transportation service customers on this basis, and explain how costs allocated to transportation service customers would compare to amounts recovered through balancing charges.

Response:

FEI is unable to provide the information requested in these IRs.

There is no rational basis for allocating FEI's midstream costs to T-service customers. FEI does not acquire midstream resources through the Annual Contracting Plan for T-service customers. Shipper Agents are responsible for acquiring their own midstream resources for their customers in their groups to deliver the gas to the interconnect points to FEI's system. Imbalances do not occur with T-service customers, imbalances occur with Shippers and their groups. FEI does not have detailed information at the customer level or by transportation service rate schedule to determine how much of the core market midstream resource is being used.

As explained in the response to BCUC IR1 22.4, FEI does not intend to apply a Midstream Fee for balancing services and therefore has not undertaken a calculation to determine how this fee or costs could be allocated across transportation service customers or how the costs would compare to the amounts recovered through balancing charges. Further, and in the absence of a rational basis for allocating midstream costs to T-service customers, FEI cannot comment on a different rebalancing option and cannot provide the rate impact of making any adjustments.

22.5.2 Please explain how this cost allocation would impact the proposed approvals sought and whether this would lead FEI to recommend a different revenue rebalancing option.

22.5.2.1 Please provide the rate impact, if any, of making such adjustments.

Response:

Please refer to the response to BCUC IR1 25.5.1.

22.6 If FEI were to recover a portion of midstream resource costs from transportation customers, please discuss what the appropriate recovery mechanism would be.

Response:

Please refer to the responses to BCUC IR1 22.4 and 22.5.

On page 88 of the Application, FEI states:

> Given the relatively small amount of revenue related to the balancing of FEI's Transportation
>
> Service Model when compared to FEI's total allocated cost of service, Table 6-2 below confirms that there is no material change to the R:C or M:C ratios even if FEI were to include the balancing revenues in the 2023 COSA model. As such, the balancing revenues will have no material impact to the allocation of costs between each rate schedule or change the results of the 2023 COSA.

22.7 Please provide the impact on the R:C or M:C ratios if FEI allocated midstream costs to transportation customers based on their usage of midstream resources in the 2023 COSA model.

Response:

Please refer to the responses to BCUC IR1 22.4 and 22.5.

Attachment 14.1A

FortisBC Energy Inc.

2023 Cost of Service Allocation (COSA)

Customer Weighting Factor Study

Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters	(Col. (i) + (e)) * Col. (j)	Class Per Unit Cost	Weighting Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**RATE 1 - RESIDENTIAL**														
2	200	$ 122	$ 85			$ -		$ 1,902	$ 2,109			891,201	$ 1,628,420,960		
3	400	$ 252	$ 139			$ -		$ 1,902	$ 2,292			43,090	98,773,248		
4	400 25#	$ 625	$ 1,778			$ -		$ 1,902	$ 4,304			15	64,563		
5	600	$ 625	$ 2,125			$ 2,240		$ 3,325	$ 8,315			1,481	12,314,515		
6	880 SONIX	$ 625	$ 3,292			$ 2,240		$ 3,325	$ 9,482			460	4,361,720		
7	1000	$ 810	$ 3,292			$ 2,240		$ 3,325	$ 9,667			1,102	10,653,034		
8	2M	$ 2,290	$ 3,703			$ 2,240		$ 3,325	$ 11,558			9	104,022		
9	3M	$ 2,638	$ 3,703			$ 2,240		$ 3,325	$ 11,906			31	369,086		
10	3M ID	$ 1,576	$ 12,180			$ 2,240		$ 3,325	$ 19,321			1	19,321		
11	5M	$ 3,240	$ 5,897			$ 2,240		$ 3,325	$ 14,702			7	102,914		
12	11M	$ 3,902	$ 7,836			$ 4,480		$ 3,325	$ 19,543			1	19,543		
13	7M	$ 3,750	$ 5,847			$ 2,240		$ 3,325	$ 15,162			3	45,486		
14	Rate 1 AMRs & EVCs			$ 4,191					$ 4,191	-	2		8,382		
15															
16	**Total**									**-**	**2**	**937,401**	**$ 1,755,256,795**	**$ 1,872**	**1.0**

Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters	(Col. (i) + (e)) * Col. (j)	Class Per Unit Cost	Weighting Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**RATE 2 - SMALL COMMERCIAL**														
2	200	$ 122	$ 85			$ -		$ 1,902	$ 2,109			48,413	$ 88,461,238		
3	400	$ 252	$ 139			$ -		$ 1,902	$ 2,292			23,498	$ 53,863,397		
4	400 25#	$ 625	$ 1,778			$ -		$ 1,902	$ 4,304			13	$ 55,955		
5	600	$ 625	$ 2,125			$ 2,240		$ 3,325	$ 8,315			2,467	$ 20,513,105		
6	880 SONIX	$ 625	$ 3,292			$ 2,240		$ 3,325	$ 9,482			862	$ 8,173,484		
7	1000	$ 810	$ 3,292			$ 2,240		$ 3,325	$ 9,667			16,518	$ 159,679,506		
8	1.5M	$ 2,310	$ 3,703			$ 2,240		$ 3,325	$ 11,578			20	$ 231,560		
9	2M	$ 2,290	$ 3,703			$ 2,240		$ 3,325	$ 11,558			458	$ 5,293,564		
10	3M	$ 2,638	$ 3,703			$ 2,240		$ 3,325	$ 11,906			1,751	$ 20,847,406		
11	5M	$ 3,240	$ 5,897			$ 2,240		$ 3,325	$ 14,702			708	$ 10,409,016		
12	7M	$ 3,750	$ 5,847			$ 2,240		$ 3,325	$ 15,162			165	$ 2,501,745		
13	3M ID	$ 1,576	$ 12,180			$ 2,240		$ 3,325	$ 19,321			27	$ 521,667		
14	5M ID	$ 2,022	$ 23,330			$ 2,240		$ 3,325	$ 30,917			33	$ 1,020,261		
15	7M ID	$ 2,457	$ 22,300			$ 2,240		$ 3,325	$ 30,322			19	$ 576,118		
16	11M	$ 3,902	$ 7,836			$ 4,480		$ 3,325	$ 19,543			34	$ 664,454		
17	11M ID	$ 2,736	$ 24,600			$ 4,480		$ 3,325	$ 35,141			12	$ 421,692		
18	16M ID	$ 3,801	$ 35,650			$ 4,480		$ 3,325	$ 47,256			8	$ 378,048		
19	23M ID	$ 3,221	$ 41,250			$ 4,480		$ 3,325	$ 52,276			2	$ 104,552		
20	DATTUS	$ 1,576	$ 12,180			$ 2,240		$ 3,325	$ 19,321			1	$ 19,321		
21	AAT 18 1440 ID	$ 54,720	$ 43,950			$ 4,480		$ 3,325	$ 106,475			1	$ 106,475		
22	AAT 90 175# IDTC	$ 64,528	$ 47,650			$ 4,480		$ 3,325	$ 119,983			1	$ 119,983		
23	T30 175# ID	$ 16,798	$ 34,650			$ 4,480		$ 3,325	$ 59,253			1	$ 59,253		
24	T57 175# ID AMR	$ 18,675	$ 34,650			$ 4,480		$ 3,325	$ 61,130			1	$ 61,130		
25	Rate 2 AMRs & EVCs			$ 4,191					$ 4,191	-	125		523,875		
26															
27	**Total**									**-**	**125**	**95,013**	**$ 374,606,805**	**$ 3,943**	**2.1**

FortisBC Energy Inc.
2023 Cost of Service Allocation (COSA)
Customer Weighting Factor Study

Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters	(Col. (i) + (e)) * Col. (j)	Class Per Unit Cost	Weighting Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**RATE 3 - LARGE COMMERCIAL**														
2	200	$ 122	$ 85			$ -		$ 1,902	$ 2,109			11	$ 23,199		
3	400	$ 252	$ 139			$ -		$ 1,902	$ 2,292			75	$ 171,919		
4	600	$ 625	$ 2,125			$ 2,240		$ 7,714	$ 12,704			40	$ 508,141		
5	880 SONIX	$ 625	$ 3,292			$ 2,240		$ 7,714	$ 13,871			28	$ 388,375		
6	1000	$ 810	$ 3,292			$ 2,240		$ 7,714	$ 14,056			2,450	$ 34,436,024		
7	1.5M	$ 2,310	$ 3,703			$ 2,240		$ 6,892	$ 15,145			2	$ 30,291		
8	2M	$ 2,290	$ 3,703			$ 2,240		$ 6,892	$ 15,125			179	$ 2,707,435		
9	3M	$ 2,638	$ 3,703			$ 2,240		$ 6,892	$ 15,473			1,310	$ 20,270,067		
10	3M ID	$ 1,576	$ 12,180			$ 2,240		$ 6,892	$ 22,888			51	$ 1,167,305		
11	5M	$ 3,240	$ 5,897			$ 2,240		$ 6,892	$ 18,269			1,049	$ 19,164,531		
12	5M ID	$ 2,022	$ 23,330			$ 2,240		$ 6,892	$ 34,484			85	$ 3,627,684		
13	7M	$ 3,750	$ 5,847			$ 2,240		$ 6,892	$ 18,729			459	$ 8,596,805		
14	7M ID	$ 2,457	$ 22,300			$ 2,240		$ 6,892	$ 33,889			71	$ 2,406,143		
15	11M	$ 3,902	$ 7,836			$ 4,480		$ 12,584	$ 28,802			129	$ 3,715,452		
16	11M ID	$ 2,736	$ 24,600			$ 4,480		$ 12,584	$ 44,400			48	$ 2,131,209		
17	16M ID	$ 3,801	$ 35,650			$ 4,480		$ 12,584	$ 56,515			16	$ 904,243		
18	20M/23M ID	$ 3,221	$ 41,250			$ 4,480		$ 12,584	$ 61,535			6	$ 369,211		
19	DATTUS	$ 1,576	$ 12,180			$ 2,240		$ 6,892	$ 22,888			-	$ -		
20	T18 175# ID	$ 15,132	$ 28,950			$ 4,480		$ 12,584	$ 61,146			5	$ 305,731		
21	T18 175#	$ 15,132	$ 28,950			$ 4,480		$ 12,584	$ 61,146			-	$ -		
22	T30 175# ID	$ 16,798	$ 34,650			$ 4,480		$ 12,584	$ 68,512			3	$ 205,537		
23	T27 175# ID AMR	$ 16,643	$ 28,950			$ 4,480		$ 12,584	$ 62,657			-	$ -		
24	Rate 3 AMRs & EVCs			$ 4,191					$ 4,191	-	288		1,207,008		
25															
26	**Total**									**-**	**288**	**6,017**	**$ 102,336,308**	**$ 17,008**	**9.1**

Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters	(Col. (i) + (e)) * Col. (j)	Class Per Unit Cost	Weighting Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**RATE 4 - SEASONAL**														
2	1000	$ 810	$ 3,292			$ 2,240		$ 7,714	$ 14,056			19	267,055		
3	2M	$ 2,290	$ 3,703			$ 2,240		$ 6,892	$ 15,125			2	30,251		
4	3M	$ 2,638	$ 3,703			$ 2,240		$ 6,892	$ 15,473			3	46,420		
5	5M	$ 3,240	$ 5,897			$ 2,240		$ 6,892	$ 18,269			2	36,539		
6	7M	$ 3,750	$ 5,847			$ 2,240		$ 6,892	$ 18,729			3	56,188		
7	11M ID	$ 2,736	$ 24,600			$ 4,480		$ 12,584	$ 44,400			2	88,800		
8	16M ID	$ 3,801	$ 35,650			$ 4,480		$ 12,584	$ 56,515			3	169,546		
9	23M ID	$ 3,221	$ 41,250			$ 4,480		$ 12,584	$ 61,535			3	184,606		
10	T30 175# ID	$ 16,798	$ 34,650			$ 4,480		$ 12,584	$ 68,512			2	137,024		
11	T60 175# ID	$ 27,475	$ 47,650			$ 4,480		$ 12,584	$ 92,189			1	92,189		
12	Rate 4 AMRs & EVCs			$ 4,191					$ 4,191	-	11		46,101		
13															
14	**Total**									**-**	**11**	**40**	**$ 1,154,718**	**$ 28,868**	**15.4**

FortisBC Energy Inc.
2023 Cost of Service Allocation (COSA)
Customer Weighting Factor Study

Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters	(Col. (i) + (e)) * Col. (j)	Class Per Unit Cost	Weighting Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**RATE 5 - GENERAL FIRM**														
2	1000	$ 810	$ 3,292			$ 2,240		$ 7,714	$ 14,056			7	$ 98,389		
3	3M	$ 2,638	$ 3,703			$ 2,240		$ 6,892	$ 15,473			34	$ 526,093		
4	5M	$ 3,240	$ 5,897			$ 2,240		$ 6,892	$ 18,269			89	$ 1,625,971		
5	3M ID	$ 1,576	$ 12,180			$ 2,240		$ 6,892	$ 22,888			11	$ 251,772		
6	5M ID	$ 2,022	$ 23,330			$ 2,240		$ 6,892	$ 34,484			22	$ 758,655		
7	7M	$ 3,750	$ 5,847			$ 2,240		$ 6,892	$ 18,729			57	$ 1,067,577		
8	7M ID	$ 2,457	$ 22,300			$ 2,240		$ 6,892	$ 33,889			12	$ 406,672		
9	11M ID	$ 2,736	$ 24,600			$ 4,480		$ 12,584	$ 44,400			11	$ 1,175,002		
10	11M	$ 3,902	$ 7,836			$ 4,480		$ 12,584	$ 28,802			8	$ 230,416		
11	16M ID	$ 3,801	$ 35,650			$ 4,480		$ 12,584	$ 56,515			5	$ 282,576		
12	23M ID	$ 3,221	$ 41,250			$ 4,480		$ 12,584	$ 61,535			2	$ 123,070		
13	T18 175#	$ 15,132	$ 28,950			$ 4,480		$ 12,584	$ 61,146			2	$ 122,292		
14	T27 175#	$ 16,643	$ 28,950			$ 4,480		$ 12,584	$ 62,657			1	$ 62,657		
15	AAT 60 175#											1	$ 209,000		
16	Rate 5 AMRs & EVCs			$ 4,191			$2,000		$ 6,191	262	66		$ 800,606		
17															
18	Total									**262**	**66**	**262**	**$ 7,740,748**	**$ 29,545**	**15.8**

Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters	(Col. (i) + (e)) * Col. (j)	Class Per Unit Cost	Weighting Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**RATE 6 - NGV SERVICES**														
2	1000	$ 810	$ 3,292			$ 2,240		$ 7,714	$ 14,056			-	$ -		
3	3M	$ 2,638	$ 3,703			$ 2,240		$ 6,892	$ 15,473			-	$ -		
4	3M ID	$ 1,576	$ 12,180			$ 2,240		$ 6,892	$ 22,888			2	$ 45,777		
5	5M ID	$ 2,022	$ 23,330			$ 2,240		$ 6,892	$ 34,484			4	$ 137,937		
6	7M ID	$ 2,457	$ 22,300			$ 2,240		$ 6,892	$ 33,889			4	$ 135,557		
7	Rate 6 AMRs & EVCs			$ 4,191					$ 4,191	-	10		41,910		
8															
9	**Total**									**-**	**10**	**10**	**$ 361,181**	**$ 36,118**	**19.3**

Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters	(Col. (i) + (e)) * Col. (j)	Class Per Unit Cost	Weighting Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**RATE 7 - GENERAL INTERRUPTIBLE**														
2	7M ID	$ 2,457	$ 22,300			$ 2,240		$ 6,892	$ 33,889			1	$ 33,889		
3	11M ID	$ 2,736	$ 24,600			$ 4,480		$ 12,584	$ 44,400			1	$ 44,400		
4	16M ID	$ 3,801	$ 35,650			$ 4,480		$ 12,584	$ 56,515			1	$ 56,515		
5	38M ID AMR	$ 9,400	$ 35,650		$ 15,000	$ 4,480		$ 12,584	$ 62,114			1	$ 77,114		
6	AAT 60 175# ID AMR	$ 58,663	$ 47,650		$ 15,000	$ 4,480		$ 12,584	$ 123,377			1	$ 138,377		
7	T18 175#								$ -			1	$ 104,000		
8	T30 175#	$ 16,978	$ 34,650			$ 4,480		$ 12,584	$ 68,692			4	$ 274,769		
9	T60 175# ID AMR	$ 27,475	$ 47,650			$ 4,480		$ 12,584	$ 92,189			2	$ 184,378		
10	AAT 90 175# IDTC AMR	$ 64,528	$ 47,650		$ 15,000	$ 4,480		$ 12,584	$ 129,242			2	$ 288,484		
11	Rate 7 AMRs & EVCs			$ 4,191			$2,000		$ 6,191	14	11		74,101		
12															
13	**Total**									**14**	**11**	**14**	**$ 1,276,028**	**$ 91,145**	**48.7**

FortisBC Energy Inc.
2023 Cost of Service Allocation (COSA)
Customer Weighting Factor Study

Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters / Stations	(Col. (i) + (e)) * Col. (j)	Class Per Unit Cost	Weighting Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**RATE 22 - LARGE INDUSTRIAL INTERRUPTIBLE**														
2	AAT 140 220# ID AMR (Customer Station)								$ 731,000			1	$ 731,000		
3	T60 175# ID AMR (Customer Station)								$ 1,045,000			1	$ 1,045,000		
4	T60 275# ID AMR (Customer Station)								$ 522,000			1	$ 522,000		
5	23M ID (Customer Station)								$ 104,000			1	$ 104,000		
6	T60 175# ID AMR	$ 27,475	$ 47,650			$ 4,480		$ 12,584	$ 92,189			1	$ 92,189		
7	T30 175#	$ 16,978	$ 34,650		$ 15,000	$ 4,480		$ 12,584	$ 68,692			1	$ 83,692		
8	AAT 57 175# ID AMR	$ 43,000	$ 34,650			$ 4,480		$ 12,584	$ 94,714			1	$ 94,714		
9	T18 175# ID AMR	$ 15,132	$ 28,950			$ 4,480		$ 12,584	$ 61,146			1	$ 61,146		
10	23M ID	$ 3,221	$ 41,250			$ 4,480		$ 12,584	$ 61,535			1	$ 61,535		
11	T18 175# ID AMR	$ 15,132	$ 28,950			$ 4,480		$ 12,584	$ 61,146			1	$ 61,146		
12	T60 175# ID AMR	$ 27,475	$ 47,650			$ 4,480		$ 12,584	$ 92,189			1	$ 92,189		
13	AAT 60 175# ID AMR	$ 58,663	$ 47,650		$ 15,000	$ 4,480		$ 12,584	$ 123,377			1	$ 138,377		
14	T140 220# ID AMR	$ 80,009	$ 100,650		$ 15,000	$ 4,480		$ 12,584	$ 197,723			1	$ 212,723		
15	T60 175# ID AMR	$ 27,475	$ 47,650		$ 15,000	$ 4,480		$ 12,584	$ 92,189			1	$ 107,189		
16	AAT 18 175# ID AMR	$ 30,199	$ 28,950			$ 4,480		$ 12,584	$ 76,213			1	$ 76,213		
17	T30 175#	$ 16,978	$ 34,650			$ 4,480		$ 12,584	$ 68,692			1	$ 68,692		
18	Q8.8 3" 1440#	$ 12,000	$ 28,950			$ 4,480		$ 12,584	$ 58,014			1	$ 58,014		
19	T60 175# ID AMR	$ 27,475	$ 47,650			$ 4,480		$ 12,584	$ 92,189			1	$ 92,189		
20	T30 175#	$ 16,978	$ 34,650			$ 4,480		$ 12,584	$ 68,692			1	$ 68,692		
21	16M ID AMR	$ 3,801	$ 35,650			$ 4,480		$ 12,584	$ 56,515			1	$ 56,515		
22	AAT 35 175# ID AMR	$ 39,088	$ 28,950			$ 4,480		$ 12,584	$ 85,102			1	$ 85,102		
23	T60 175# ID AMR	$ 27,475	$ 47,650		$ 15,000	$ 4,480		$ 12,584	$ 92,189			1	$ 107,189		
24	AAT 18 175# ID AMR	$ 30,199	$ 28,950			$ 4,480		$ 12,584	$ 76,213			1	$ 76,213		
25	Rate 22 AMRs & EVCs			$ 4,191			$ 2,000		$ 6,191	19	19		117,629		
26															
27	**Total**									**19**	**19**	**19**	**$ 4,213,351**	**$ 183,189**	**97.8**

Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Customer Station Cost	No. of AMR	No. of EVC	No. of Stations	Col. (j)	Class Per Unit Cost	Weighting Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**RATE 22A - LARGE INDUSTRIAL**														
2	5M ID											-	$ -		
3	16M ID											-	$ -		
4	AAT 18 1440 IDTC AMR								$ 783,000			1	$ 783,000		
5	AAT 35 1440# IDTC											-	$ -		
6	AAT 35 175# ID AMR								$ 313,000			1	$ 313,000		
7	AAT 60 1440# IDTC								$ 2,194,000			3	$ 2,194,000		
8	T18 175# ID AMR								$ 313,000			1	$ 313,000		
9	T27 175# ID AMR								$ 783,000			1	$ 783,000		
10	T30 175# ID AMR								$ 1,410,000			3	$ 1,410,000		
11	T60 175# ID AMR											-	$ -		
12	Rate 22A AMRs & EVCs			$ 4,191			########		$ 6,191	10	15				
13															
14	**Total**									**10**	**15**	**10**	**$ 5,796,000**	**$ 579,600**	**309.5**

FortisBC Energy Inc.
2023 Cost of Service Allocation (COSA)
Customer Weighting Factor Study

Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Customer Station	No. of AMR	No. of EVC	No. of Station	Col. (j)	Class Per Unit Cost	Weighting Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**RATE 22B - LARGE INDUSTRIAL**														
2	1,000														
3	AAT 60 1440# IDTC AM								$ 1,045,000			1	$ 1,045,000		
4	T18 175# ID AMR								1,045,000			1	$ 1,045,000		
5	T60 175# ID AMR								3,134,000			2	$ 3,134,000		
6	5M								1,045,000			1	$ 1,045,000		
7	Rate 22B AMRs & EVCs			$ 4,191			########			9	7				
8															
9	**Total**									**9**	**7**	**5**	**$ 6,269,000**	**$ 1,253,800**	**669.6**

Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters	(Col. (i) + (e)) * Col. (j)	Class Per Unit Cost	Weighting Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**RATE 23 - LARGE COMMERCIAL TRANSPORTATION**														
2	400	$ 252.00	$ 139			$ -		$ 1,902	$ 2,292			7	$ 16,046		
3	600	$ 625.00	$ 2,125			$ 2,240		$ 7,714	$ 12,704			1	$ 12,704		
4	880 SONIX	$ 625.00	$ 3,292			$ 2,240		$ 7,714	$ 13,871			1	$ 13,871		
5	1000	$ 810.00	$ 3,292			$ 2,240		$ 7,714	$ 14,056			373	$ 5,242,709		
6	2M	$ 2,290.00	$ 3,703			$ 2,240		$ 6,892	$ 15,125			43	$ 650,389		
7	3M	$ 2,638.00	$ 3,703			$ 2,240		$ 6,892	$ 15,473			381	$ 5,895,340		
8	3M ID	$ 1,576.00	$ 12,180			$ 2,240		$ 6,892	$ 22,888			25	$ 1,071,320		
9	5M	$ 3,240.00	$ 5,897			$ 2,240		$ 6,892	$ 18,269			440	$ 8,038,507		
10	5M ID	$ 2,022.00	$ 23,330			$ 2,240		$ 6,892	$ 34,484			70	$ 2,413,903		
11	7M	$ 3,750.00	$ 5,847			$ 2,240		$ 6,892	$ 18,729			206	$ 3,858,261		
12	7M ID	$ 2,457.00	$ 22,300			$ 2,240		$ 6,892	$ 33,889			55	$ 1,863,913		
13	11M	$ 3,902.00	$ 7,836			$ 4,480		$ 12,584	$ 28,802			44	$ 1,267,286		
14	11M ID	$ 2,736.00	$ 24,600			$ 4,480		$ 12,584	$ 44,400			30	$ 1,332,005		
15	16M ID	$ 3,801.00	$ 35,650			$ 4,480		$ 12,584	$ 56,515			12	$ 678,182		
16	23M ID	$ 3,221.00	$ 41,250			$ 4,480		$ 12,584	$ 61,535			3	$ 184,606		
17	T18 175# ID	$ 15,132.00	$ 28,950			$ 4,480		$ 12,584	$ 61,146			2	$ 122,292		
18	AAT 60 175# ID AMR	$ 58,663.00	$ 47,650			$ 4,480		$ 12,584	$ 123,377			1	$ 123,377		
19	T30 175# ID AMR	$ 16,978.00	$ 34,650			$ 4,480		$ 12,584	$ 68,692			1	$ 68,692		
20	T60 175# ID AMR	$ 27,475.00	$ 47,650			$ 4,480		$ 12,584	$ 92,189			1	$ 92,189		
21	Rate 23 AMRs & EVCs			$ 4,191			$2,000		$ 6,191	1,696	203		4,236,582		
22															
23	**Total**									**1,696**	**203**	**1,696**	**$ 37,182,175**	**$ 21,923**	**11.7**

FortisBC Energy Inc.
2023 Cost of Service Allocation (COSA)
Customer Weighting Factor Study

Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters	(Col. (i) + (e)) * Col. (j)	Class Per Unit Cost	Weighting Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**RATE 25 - GENERAL FIRM TRANSPORTATION**														
2	1000	$ 810.00	$ 3,292			$ 2,240		$ 7,714	$ 14,056			3	$ 42,167		
3	3M	$ 2,638.00	$ 3,703			$ 2,240		$ 6,892	$ 15,473			23	$ 355,887		
4	5M	$ 3,240.00	$ 5,897			$ 2,240		$ 6,892	$ 18,269			91	$ 1,662,509		
5	7M	$ 3,750.00	$ 5,847			$ 2,240		$ 6,892	$ 18,729			91	$ 1,704,378		
6	11M	$ 3,902.00	$ 7,836			$ 4,480		$ 12,584	$ 28,802			40	$ 1,152,078		
7	11M ID	$ 2,736.00	$ 24,600			$ 4,480		$ 12,584	$ 44,400			48	$ 2,190,808		
8	16M ID	$ 3,801.00	$ 35,650			$ 4,480		$ 12,584	$ 56,515			32	$ 2,482,971		
9	23M ID	$ 3,221.00	$ 41,250			$ 4,480		$ 12,584	$ 61,535			10	$ 615,352		
10	3M ID	$ 1,576.00	$ 12,180			$ 2,240		$ 6,892	$ 22,888			24	$ 549,320		
11	5M ID	$ 2,022.00	$ 23,330			$ 2,240		$ 6,892	$ 34,484			56	$ 1,931,123		
12	7M ID	$ 2,457.00	$ 22,300			$ 2,240		$ 6,892	$ 33,889			79	$ 2,677,257		
13	T30 175# ID AMR	$ 16,978.00	$ 34,650			$ 4,480		$ 12,584	$ 68,692			-	$ -		
14	AAT 35 1440#	$ 62,208.00	$ 64,650			$ 4,480		$ 12,584	$ 143,922			1	$ 313,000		
15	T18 175# ID AMR	$ 15,132.00	$ 28,950			$ 4,480		$ 12,584	$ 61,146			-	$ -		
16	T60 175# ID AMR	$ 27,475.00	$ 47,650			$ 4,480		$ 12,584	$ 92,189			4	$ 368,757		
17	AAT 18 175# ID AMR	$ 30,199.00	$ 28,950			$ 4,480		$ 12,584	$ 76,213			2	$ 152,426		
18	AAT 35 175# ID AMR	$ 39,088.00	$ 28,950			$ 4,480		$ 12,584	$ 85,102			1	$ 85,102		
19	T18 1440# ID AMR	$ 38,802.00	$ 43,950			$ 4,480		$ 12,584	$ 99,816			1	$ 99,816		
20	T18 175# ID	$ 15,132.00	$ 28,950			$ 4,480		$ 12,584	$ 61,146			5	$ 766,585		
21	T30 175# ID	$ 16,798.00	$ 34,650			$ 4,480		$ 12,584	$ 68,512			7	$ 724,073		
22	T90 175# ID	$ 30,225.00	$ 47,650			$ 4,480		$ 12,584	$ 94,939			2	$ 189,878		
23	T30 175# IDTC	$ 16,978.00	$ 34,650			$ 4,480		$ 12,584	$ 68,692				$ -		
24	Rate 25 AMRs & EVCs			$ 4,191			$2,000		$ 6,191	520	272		$ 2,148,997		
25															
26	**Total**									**520**	**272**	**520**	**$ 20,212,484**	**$ 38,870**	**20.8**

Line No.	Meter Type	Meter Cost	Meter Set w/o Meter	EVC (corrector)	Telecount / Telemetry	Customer Service	A.M.R.	Service Lateral	Total Cost	No. of AMR	No. of EVC	No. of Meters	(Col. (i) + (e)) * Col. (j)	Class Per Unit Cost	Weighting Factor
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	**RATE 27 - GENERAL INTERRUPTIBLE**														
2	5M	$ 3,240.00	$ 5,897			$ 2,240		$ 6,892	$ 18,269			1	$ 18,269		
3	5M ID	$ 2,022.00	$ 23,330			$ 2,240		$ 6,892	$ 34,484			7	$ 241,390		
4	7M ID	$ 2,457.00	$ 22,300			$ 2,240		$ 6,892	$ 33,889			13	$ 440,561		
5	11M	$ 3,902.00	$ 7,836			$ 4,480		$ 12,584	$ 28,802			1	$ 28,802		
6	11M ID	$ 2,736.00	$ 24,600			$ 4,480		$ 12,584	$ 44,400			15	$ 666,003		
7	16M ID	$ 3,801.00	$ 35,650			$ 4,480		$ 12,584	$ 56,515			21	$ 1,852,273		
8	23M ID	$ 3,221.00	$ 41,250			$ 4,480		$ 12,584	$ 61,535			12	$ 738,422		
9	AAT 18 1440 ID AMR	$ 54,720.00	$ 43,950		$ 15,000	$ 4,480		$ 12,584	$ 115,734			2	$ 246,468		
10	AAT 35 175# ID AMR	$ 39,088.00	$ 28,950			$ 4,480		$ 12,584	$ 85,102			1	$ 85,102		
11	AAT 140 220# ID AMR	$ 117,949.00	$ 100,650			$ 4,480		$ 12,584	$ 235,663			1	$ 235,663		
12	AAT 60 175# ID AMR	$ 58,663.00	$ 47,650			$ 4,480		$ 12,584	$ 123,377			1	$ 123,377		
13	Q8.8 3" 1440# ID AMR	$ 12,000.00	$ 28,950			$ 4,480		$ 12,584	$ 58,014			1	$ 58,014		
14	T18 175# ID AMR	$ 15,132.00	$ 28,950			$ 4,480		$ 12,584	$ 61,146			5	$ 305,731		
15	T27 175# ID AMR	$ 16,643.00	$ 28,950			$ 4,480		$ 12,584	$ 62,657			2	$ 125,314		
16	T30 175# ID AMR	$ 16,978.00	$ 34,650			$ 4,480		$ 12,584	$ 68,692			12	$ 824,306		
17	T57 175# ID AMR	$ 18,675.00	$ 34,650			$ 4,480		$ 12,584	$ 70,389			1	$ 70,389		
18	T60 175# ID	$ 27,475.00	$ 47,650			$ 4,480		$ 12,584	$ 92,189			11	$ 1,014,081		
19	Rate 27 AMRs & EVCs			$ 4,191			$2,000		$ 6,191	107	104		631,291		
19															
20	**Total**									**107**	**104**	**107**	**$ 7,705,459**	**$ 72,014**	**38.5**
21															

Attachment 14.1B

Customer Administration and Billing Weighting Factors
Department Survey of Resource allocation

Energy Solutions - Small Volume customers

	2022 O&M Budget	Rate 1 - Residential	Rate 2 - Small Commercial	Rate 3 - Large Commercial	Rate 23 - Large Commercial Transportation	Rate 4 - Seasonal	Rate 5 - General Firm	Rate 25 - General Firm Transportation	Rate 6 - NGV	Rate 7 - General Interruptible	Rate 22 (22 A/B) - Large Industrial Interruptible	Rate 27 - General Interruptible	Rate 22 - Bypass	Rate 25 - Bypass	Byron Creek	BCHydro ICP	VIGJV	Total
Estimated % allocation of all labour		5.45%	32.64%	24.27%	10.55%	0.00%	17.18%	2.73%	0.00%	4.64%	1.18%	1.36%	0.00%	0.00%	0.00%	0.00%	0.00%	100.0%
Labour	$ 980,540	$ 53,484	$ 320,013	$ 238,004	$ 103,402	$ -	$ 168,475	$ 26,742	$ -	$ 45,461	$ 11,588	$ 13,371	$ -	$ -	$ -	$ -	$ -	$ 980,540
Estimated % allocation of all non-labour		5.45%	32.64%	24.27%	10.55%	0.00%	17.18%	2.73%	0.00%	4.64%	1.18%	1.36%	0.00%	0.00%	0.00%	0.00%	0.00%	100.0%
Non Labour	$ 126,633	$ 6,907	$ 41,328	$ 30,737	$ 13,354	$ -	$ 21,758	$ 3,454	$ -	$ 5,871	$ 1,497	$ 1,727	$ -	$ -	$ -	$ -	$ -	$ 126,633
Total	$ 1,107,173	$ 60,391	$ 361,341	$ 268,741	$ 116,756	$ -	$ 190,232	$ 30,196	$ -	$ 51,333	$ 13,085	$ 15,098	$ -	$ -	$ -	$ -	$ -	$ 1,107,173
Number of customers		958,952	89,336	6,960	736	18	603	295	10	46	37	70	6	3	1	1	1	1,057,075
Cost per customer		$ 0.06	$ 4.04	$ 38.61	$ 158.74	$ -	$ 315.35	$ 102.21	$ -	$ 1,126.13	$ 358.49	$ 215.68	$ -	$ -	$ -	$ -	$ -	$ 1.05

Energy Solutions - Large Volume customers

	2022 O&M Budget	Rate 1 - Residential	Rate 2 - Small Commercial	Rate 3 - Large Commercial	Rate 23 - Large Commercial Transportation	Rate 4 - Seasonal	Rate 5 - General Firm	Rate 25 - General Firm Transportation	Rate 6 - NGV	Rate 7 - General Interruptible	Rate 22 (22 A/B) - Large Industrial Interruptible	Rate 27 - General Interruptible	Rate 22 - Bypass	Rate 25 - Bypass	Byron Creek	BCHydro ICP	VIGJV	Total
Estimated % allocation of all labour - Industrial Account Mgrs		0.00%	0.00%	3.00%	4.00%	1.00%	10.00%	14.00%	0.00%	10.00%	23.00%	23.00%	6.00%	2.00%	1.00%	1.00%	2.00%	100.0%
Estimated % allocation of all labour - Industrial Billing and Measurement		0.00%	0.00%	0.00%	40.00%	1.00%	29.00%	15.00%	0.00%	2.00%	3.00%	5.00%	1.00%	1.00%	1.00%	1.00%	1.00%	100.0%
Labour - Industrial Acct Mgrs	$ 536,113	$ -	$ -	$ 16,083	$ 21,445	$ 5,361	$ 53,611	$ 75,056	$ -	$ 53,611	$ 123,306	$ 123,306	$ 32,167	$ 10,722	$ 5,361	$ 5,361	$ 10,722	$ 536,113
Labour - Industrial Billing and Measurement	$ 898,628	$ -	$ -	$ -	$ 359,451	$ 8,986	$ 260,602	$ 134,794	$ -	$ 17,973	$ 26,959	$ 44,931	$ 8,986	$ 8,986	$ 8,986	$ 8,986	$ 8,986	$ 898,628
Estimated % allocation of all non-labour - Industrial Account Mgrs		0.00%	0.00%	3.00%	4.00%	1.00%	10.00%	14.00%	0.00%	10.00%	23.00%	23.00%	6.00%	2.00%	1.00%	1.00%	2.00%	100.0%
Estimated % allocation of all labour - Industrial Billing and Measurement		0.00%	0.00%	0.00%	40.00%	1.00%	29.00%	15.00%	0.00%	2.00%	3.00%	5.00%	1.00%	1.00%	1.00%	1.00%	1.00%	100.0%
Non Labour - Industrial Acct Mgrs	$ 98,900	$ -	$ -	$ 2,967	$ 3,956	$ 989	$ 9,890	$ 13,846	$ -	$ 9,890	$ 22,747	$ 22,747	$ 5,934	$ 1,978	$ 989	$ 989	$ 1,978	$ 98,900
Non Labour - Industrial Billing and Measurement	$ 284,366	$ -	$ -	$ -	$ 113,746	$ 2,844	$ 82,466	$ 42,655	$ -	$ 5,687	$ 8,531	$ 14,218	$ 2,844	$ 2,844	$ 2,844	$ 2,844	$ 2,844	$ 284,366
Total	$ 1,818,007	$ -	$ -	$ 19,050	$ 498,598	$ 18,180	$ 406,570	$ 266,351	$ -	$ 87,161	$ 181,543	$ 205,203	$ 49,931	$ 24,530	$ 18,180	$ 18,180	$ 24,530	$ 1,818,007
Number of customers		958,952	89,336	6,960	736	18	603	295	10	46	37	70	6	3	1	1	1	1,057,075
Cost per customer		$ -	$ -	$ 2.74	$ 677.90	$ 1,019.44	$ 673.97	$ 901.61	$ -	$ 1,912.13	$ 4,973.78	$ 2,931.47	$ 8,321.79	$ 8,176.73	$ 18,180.07	$ 18,180.07	$ 24,530.20	$ 1.72

Customer Administration and Billing Weighting Factors
Department Survey of Resource allocation

Customer Services - Billing and Adminstration

	2022 O&M Budget	Rate 1 - Residential	Rate 2 - Small Commercial	Rate 3 - Large Commercial	Rate 23 - Large Commercial Transportation	Rate 4 - Seasonal	Rate 5 - General Firm	Rate 25 - General Firm Transportation	Rate 6 - NGV	Rate 7 - General Interruptible	Rate 22 (22 A/B) - Large Industrial Interruptible	Rate 27 - General Interruptible	Rate 22 - Bypass	Rate 25 - Bypass	Byron Creek	BCHydro ICP	VIGJV	Total
Labour	$ 3,792,186	$ 3,440,201	$ 320,490	$ 24,969	$ 2,639	$ 37	$ 2,164	$ 1,060	$ 37	$ 164	$ 131	$ 251	$ 22	$ 11	$ 4	$ 4	$ 4	$ 3,792,186
Estimated % allocation of all labour		90.72%	8.45%	0.66%	0.07%	0.00%	0.06%	0.03%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	100.0%
Non Labour	$ 23,824,903	$ 21,613,513	$ 2,013,520	$ 156,871	$ 16,577	$ 234	$ 13,596	$ 6,658	$ 235	$ 1,027	$ 823	$ 1,578	$ 135	$ 68	$ 23	$ 23	$ 23	$ 23,824,903
Estimated % allocation of all non-labour		90.72%	8.45%	0.66%	0.07%	0.00%	0.06%	0.03%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	100.0%
Total	$ 27,617,089	$ 25,053,714	$ 2,334,009	$ 181,840	$ 19,216	$ 272	$ 15,761	$ 7,718	$ 272	$ 1,191	$ 954	$ 1,829	$ 157	$ 78	$ 26	$ 26	$ 26	$ 27,617,089
Number of customers		958,952	89,336	6,960	736	10	603	295	10	46	37	70	6	3	1	1	1	1,057,067
Cost per customer		$ 26.13	$ 26.13	$ 26.13	$ 26.13	$ 26.13	$ 26.13	$ 26.13	$ 26.13	$ 26.13	$ 26.13	$ 26.13	$ 26.13	$ 26.13	$ 26.13	$ 26.13	$ 26.13	$ 26.13

Customer Services - Contact Centres

	2022 O&M Budget	Rate 1 - Residential	Rate 2 - Small Commercial	Rate 3 - Large Commercial	Rate 23 - Large Commercial Transportation	Rate 4 - Seasonal	Rate 5 - General Firm	Rate 25 - General Firm Transportation	Rate 6 - NGV	Rate 7 - General Interruptible	Rate 22 (22 A/B) - Large Industrial Interruptible	Rate 27 - General Interruptible	Rate 22 - Bypass	Rate 25 - Bypass	Byron Creek	BCHydro IG	VIGJV	Total
Labour	$ 13,609,165	$ 12,345,984	$ 1,150,154	$ 89,607	$ 9,469	$ 134	$ 7,767	$ 3,803	$ 134	$ 587	$ 470	$ 901	$ 77	$ 39	$ 13	$ 13	$ 13	$ 13,609,165
Estimated % allocation of all labour		90.72%	8.45%	0.66%	0.07%	0.00%	0.06%	0.03%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	100.0%
Non Labour	$ 1,828,746	$ 1,659,005	$ 154,553	$ 12,041	$ 1,272	$ 18	$ 1,044	$ 511	$ 18	$ 79	$ 63	$ 121	$ 10	$ 5	$ 2	$ 2	$ 2	$ 1,828,746
Estimated % allocation of all non-labour		90.72%	8.45%	0.66%	0.07%	0.00%	0.06%	0.03%	0.00%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	100.0%
Total	$ 15,437,911	$ 14,004,988	$ 1,304,708	$ 101,648	$ 10,742	$ 152	$ 8,810	$ 4,314	$ 152	$ 666	$ 533	$ 1,022	$ 88	$ 44	$ 15	$ 15	$ 15	$ 15,437,911
Number of customers		958,952	89,336	6,960	736	10	603	295	10	46	37	70	6	3	1	1	1	1,057,067
Cost per customer		$ 14.60	$ 14.60	$ 14.60	$ 14.60	$ 14.60	$ 14.60	$ 14.60	$ 14.60	$ 14.60	$ 14.60	$ 14.60	$ 14.60	$ 14.60	$ 14.60	$ 14.60	$ 14.60	$ 14.60

	Rate 1 - Residential	Rate 2 - Small Commercial	Rate 3 - Large Commercial	Rate 23 - Large Commercial Transportation	Rate 4 - Seasonal	Rate 5 - General Firm	Rate 25 - General Firm Transportation	Rate 6 - NGV	Rate 7 - General Interruptible	Rate 22 (22 A/B) - Large Industrial Interruptible	Rate 27 - General Interruptible	Rate 22 - Bypass	Rate 25 - Bypass	Byron Creek	BCHydro ICP	VIGJV	Total
Number of customers	958,952	89,336	6,960	736	18	603	295	10	46	37	70	6	3	1	1	1	1,057,075
<u>Consolidated</u>																	
Total labour	15,839,669	1,790,657	368,663	496,406	14,519	492,619	241,455	171	117,796	162,454	182,761	41,252	19,758	14,364	14,364	19,725	19,816,632
Total non-labour	23,279,425	2,209,401	202,616	148,906	4,085	128,754	67,124	253	22,555	33,660	40,391	8,923	4,894	3,857	3,857	4,846	26,163,548
Total labour and non-labour	39,119,094	4,000,058	571,280	645,312	18,604	621,373	308,579	424	140,350	196,114	223,152	50,175	24,652	18,221	18,221	24,571	45,980,180
Total Cost per customer	$ 40.79	$ 44.78	$ 82.08	$ 877.38	$ 1,043.20	$ 1,030.04	$ 1,044.56	$ 40.73	$ 3,078.98	$ 5,621.32	$ 3,187.88	$ 8,362.52	$ 8,217.46	$ 18,220.80	$ 5,621.32	$ 5,621.32	$ 43.50
Weighting Factor (2022)	1.0	1.1	2.0	21.5	25.6	25.3	25.6	1.0	75.5	137.8	78.1	205.0	201.4	446.7	137.8	137.8	