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November 23, 2023

British Columbia Public Interest Advocacy Centre
Suite 803 470 Granville Street
Vancouver, B.C.
V6C 1V5

Attention: Leigha Worth, Executive Director

Dear Leigha Worth:

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 Public Interest Advocacy Centre, representing the British Columbia Old Age Pensioners' Organization, Council of Senior Citizens' Organizations of BC, Active Support Against Poverty, Disability Alliance BC, Tenants Resource and Advisory Centre, and Together Against Poverty Society (BCOAPO) 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 BCOAPO IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

1.0 Reference: Exhibit B-1, Application, pages 1-2, 51

Order G-4-18, page 25

Topic: R:C and M:C ratios

Preamble:

FEI states:

Table 1-1 provides the Revenue-to-Cost (R:C) and Margin-to-Cost (M:C) ratios from the 2023 COSA. **(Application, page 1)**

Some revenue responsibility must be shifted to other rates schedules…."This is typically done by using the rate schedules currently with R:C ratios below 100 percent, but above the lower bound range of reasonableness of 95 percent." **(Application, page 51)**

Order G-4-18 finds:

"A rate schedule with an R:C ratio that falls within the range of reasonableness is deemed to be recovering its fair cost and indicates that no rebalancing may be required….FEI states achieving unity, an R:C ratio of 100 percent, implies a level of precision that does not exist with any COSA study due to the necessary assumptions, estimates, simplifications, judgements, and generalizations involved. As a result, a range of reasonableness is warranted and accepted when evaluating the appropriateness of the R:C ratios." **(Order G-4-18, page 25)**

"…the 2023 COSA shows that there are currently three rate schedules with an R:C ratio below 100 percent which, in theory, can be used to rebalance RS 5/25 and RS 22." **(Application, page 52)**

1.1 Please provide a version of Table 1-1 that also includes the most recent five years of R:C and M:C ratios by class, providing any commentary as necessary or appropriate.

<u>Response:</u>

FEI does not have R:C and M:C ratios by class for the last five years. COSA studies require extensive time and resources to complete, and FEI does not undertake a COSA study every year. The last COSA study was completed as part of the 2016 COSA and RDA; prior to that, a COSA study was completed as part of the 2001 RDA.

Please refer to Table 1 below for a comparison of the R:C and M:C ratios resulting from the 2016 COSA and RDA proceeding (i.e., after rebalancing and rate design changes) and the R:C and M:C ratios from the 2023 COSA study (before and after rebalancing).

Table 1: R:C and M:C Ratios from 2016 COSA and RDA (After Rate Design Changes and Rebalancing) and 2023 COSA (Before and After Rebalancing)

	2016 RDA Decision (After Rate Design Changes and Rebalancing)		2023 COSA (Before Rebalancing)		2023 COSA (After Rebalancing - Option 5)	
Rate Schedule	**R:C**	**M:C**	**R:C**	**M:C**	**R:C**	**M:C**
Rate Schedule 1 *Residential Service*	96.6%	94.6%	97.3%	95.0%	97.7%	95.6%
Rate Schedule 2 *Small Commercial Service*	102.2%	104.1%	98.0%	95.6%	98.1%	95.7%
Rate Schedule 3/23 *Large Commercial Sales and Transportation Service*	103.6%	107.6%	104.0%	111.2%	103.9%	111.0%
Rate Schedule 5/25 *General Firm Sales and Transportation Service*	105.0%	112.6%	106.9%	126.9%	105.0%	119.5%
Rate Schedule 6 *Natural Gas Vehicle Service*	105.0%	109.5%	96.2%	91.0%	96.2%	91.0%
Rate Schedule 22 *Large Volume Transportation Service*	113.0%	113.4%	110.0%	110.2%	105.0%	105.1%
Rate Schedule 22A Transportation Service (Closed) Inland Service Area	103.1%	103.1%	101.8%	101.9%	101.8%	101.9%
Rate Schedule 22B Transportation Service (Closed) Columbia Service Area	100.0%	100.0%	100.1%	100.1%	100.1%	100.1%
Rate Schedule (Not Set Using Allocated Costs)	**R:C**	**M:C**	**R:C**	**M:C**	**R:C**	**M:C**
Rate Schedule 4 *Seasonal Firm Gas Service*	150.2%	578.3%	124.1%	339.0%	120.5%	302.5%
Rate Schedule 7/27 *General Interruptible Sales and Transportation Service*	139.3%	713.6%	122.4%	628.0%	121.1%	596.6%

1.2 Please provide a separate pie chart for each of the following (excluding Rate Schedules 4 and 7/27): i) total revenue requirement allocated to each class as proposed in this Application; ii) total customer numbers by class; iii) total annual energy by class as reflected in this Application; and iv) total demand by class as reflected in this Application.

Response:

FEI provides the requested information as follows:

(i) Please see Figure 1 and Table 1 below for the breakdown of the total revenue requirement allocated in the 2023 COSA by rate schedule (excluding RS 4 and RS 7/27). The revenue requirement aligns with Appendix D, Schedule 1, Line 28.

Figure 1: Revenue Requirement for Allocation in 2023 COSA by Rate Class (Excluding RS 4 and RS 7/27)

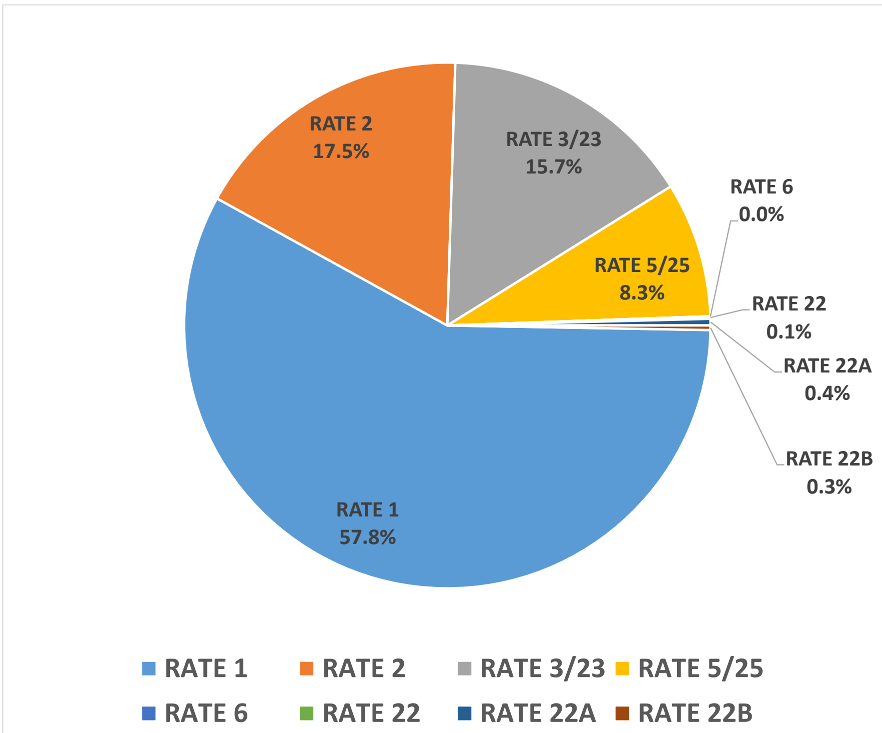


Table 1: Revenue Requirement for Allocation in 2023 COSA by Rate Class (Excluding RS 4 and RS 7/27)

Rate Schedule	Revenue Requirements ($000s)	%
RATE 1	$ 1,277,318	57.8%
RATE 2	386,041	17.5%
RATE 3/23	346,147	15.7%
RATE 5/25	183,712	8.3%
RATE 6	211	0.0%
RATE 22	3,187	0.1%
RATE 22A	8,923	0.4%
RATE 22B	6,176	0.3%
	$ 2,211,716	**100.0%**

(ii) Please see Figure 2 and Table 2 below for the breakdown of Average Customers by rate schedule (excluding RS 4 and RS 7/27) for the 2023 COSA. The average customer numbers in Table 2 below only include the 13 RS 22 firm service customers. As discussed in Section 4.2.3.1, the RS 22 fully interruptible customers and their associated revenue are treated as a credit to the delivery margin and allocated to all other non-bypass customers.

Figure 2: Average Customer Count in 2023 COSA by Rate Class (Excluding RS 4 and RS 7/27)

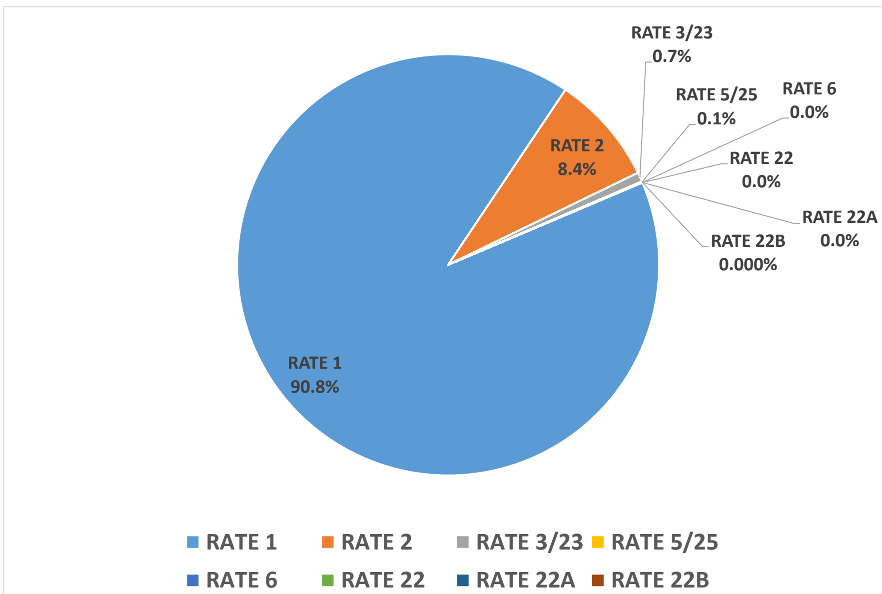


Table 2: Average Customer Count in 2023 COSA by Rate Class (Excluding RS 4 and RS 7/27)

Rate Schedule	Average Customers	%
RATE 1	977,501	90.8%
RATE 2	90,632	8.4%
RATE 3/23	7,750	0.7%
RATE 5/25	904	0.1%
RATE 6	13	0.0%
RATE 22	13	0.0%
RATE 22A	9	0.001%
RATE 22B	5	0.000%
	1,076,827	**100.0%**

(iii) Please see Figure 3 and Table 3 below for the breakdown of total annual energy by rate schedule (excluding RS 4 and RS 7/27) for the 2023 COSA. The annual energy in Table 3 below does not include the annual volume from the RS 22 fully interruptible customers.

Figure 3: Average Annual Energy Demand in 2023 COSA by Rate Class (Excluding RS 4 and RS 7/27)

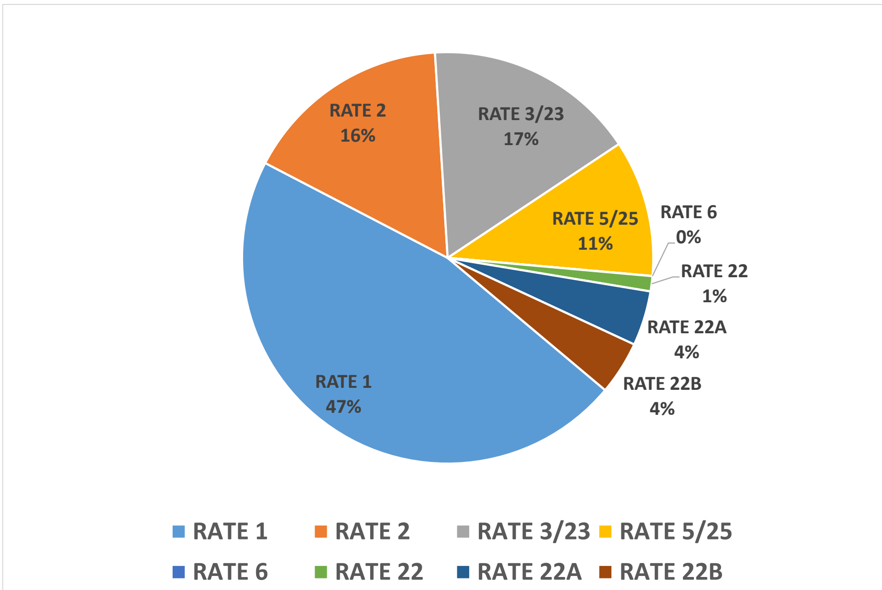


Table 3: Average Annual Energy Demand in 2023 COSA by Rate Class (Excluding RS 4 and RS 7/27)

Rate Schedule	Annual Volume (TJ)	%
RATE 1	82,890	46.5%
RATE 2	29,204	16.4%
RATE 3/23	29,674	16.7%
RATE 5/25	19,130	10.7%
RATE 6	21	0.0%
RATE 22	2,128	1.2%
RATE 22A	7,669	4.3%
RATE 22B	7,481	4.2%
	178,197	**100.0%**

(iv) Please see Figure 4 and Table 4 below for the breakdown of the total peak day demand or firm demand by rate schedule (excluding RS 4 and RS 7/27). The customer numbers align with Table 4-11 of Application.

Figure 4: Breakdown Peak Day or Firm Demand in 2023 COSA by Rate Class (Excluding RS 4 and RS 7/27)

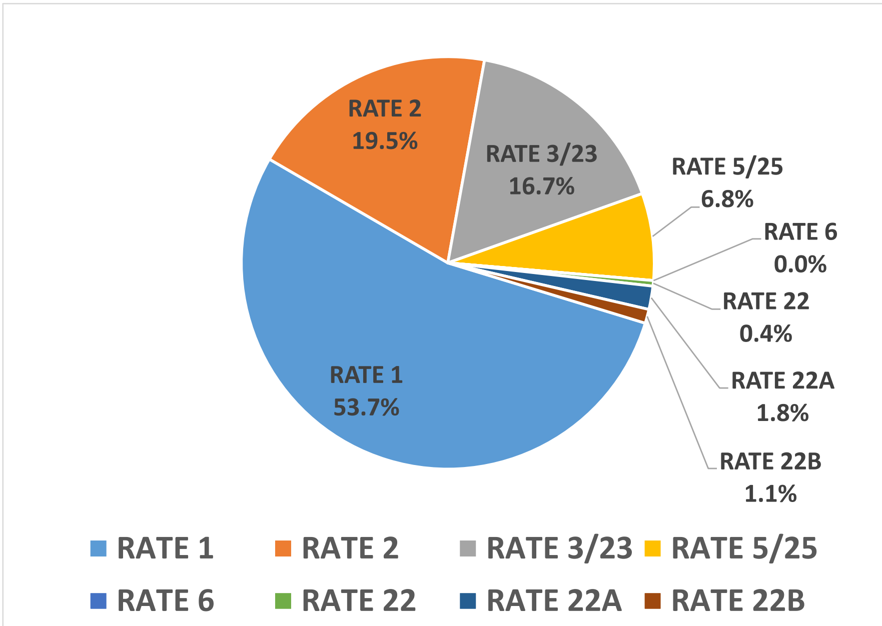


Figure 4: Breakdown Peak Day or Firm Demand in 2023 COSA by Rate Class (Excluding RS 4 and RS 7/27)

Rate Schedule	Peak Day or Firm Demand (TJ/day)	%
RATE 1	726.1	53.7%
RATE 2	263.3	19.5%
RATE 3/23	225.9	16.7%
RATE 5/25	92.3	6.8%
RATE 6	0.1	0.0%
RATE 22	5.8	0.4%
RATE 22A	24.7	1.8%
RATE 22B	14.9	1.1%
	1,353.0	**100.0%**

1.3 Please provide a table (excluding Rate Schedules 4 and 7/27) with the following: i) the total revenue requirement allocated to each class as reflected in current rates; ii) the total revenue requirement allocated to each class as proposed in this

Application; iii) the difference (both $ and %) between the current and proposed revenue requirement by class; iv) the current revenue requirement by class as a percentage of total current revenue requirement; v) the proposed revenue requirement by class as a percentage of total proposed revenue requirement; vi) the material drivers of the differences between the current and proposed revenue requirement by class; and vi) the material drivers of the change in each class's allocation of total revenue requirement between current and proposed.

For current rates, please provide the revenue requirement data used to drive the R:C and M:C changes in this Application.

Response:

FEI provides the requested tables below. Regarding BCOAPO's request to provide, for current rates, the revenue requirement data used to drive the R:C and M:C ratio changes in the Application, the revenue requirement data is the 2023 Approved rates plus known and measurable changes (i.e., the current revenue requirement is reflected in Appendix D, Schedule 1, Line 18, and the proposed revenue requirement under revenue rebalancing Option 5 is reflected in Appendix D, Schedule 1, Line 28).

(i) *Current* revenue requirement for 2023 before revenue rebalancing by rate schedule:

Rate Schedule	2023 Revenue ($000s)
RATE 1	1,272,799
RATE 2	385,896
RATE 3/23	346,292
RATE 5/25	187,057
RATE 6	211
RATE 22	3,337
RATE 22A	8,923
RATE 22B	6,176

(ii) *Proposed* revenue requirement for 2023 by rate schedule after revenue rebalancing Option 5:

Rate Schedule	2023 Revenue ($000s)
RATE 1	1,277,318
RATE 2	386,041
RATE 3/23	346,147
RATE 5/25	183,712
RATE 6	211
RATE 22	3,187
RATE 22A	8,923
RATE 22B	6,176

(iii) Difference ($ and %) between Current (item (i) above) and Proposed (item (ii) above) revenue requirement for 2023 by rate schedule. FEI notes that this is equivalent to the amount of revenue rebalanced between rate schedules as reflected in Appendix D, Schedule 1, Line 21.

Rate Schedule	Difference ($000s)	Difference (%)
RATE 1	4,519	0.4%
RATE 2	145	0.04%
RATE 3/23	(145)	-0.04%
RATE 5/25	(3,344)	-1.8%
RATE 6	-	0.0%
RATE 22	(151)	-4.5%
RATE 22A	-	0.0%
RATE 22B	-	0.0%

(iv) Current revenue requirement (i.e., item (i) above) by rate schedule as a percentage of total current revenue requirement (i.e., total of item (i) above):

Rate Schedule	2023 Revenue (%)
RATE 1	57.6%
RATE 2	17.5%
RATE 3/23	15.7%
RATE 5/25	8.5%
RATE 6	0.0%
RATE 22	0.2%
RATE 22A	0.4%
RATE 22B	0.3%

(v) Proposed revenue requirement (i.e., item (ii) above) by rate schedule as a percentage of total proposed revenue requirement (i.e., sum of item (ii) above) after revenue rebalancing under proposed Option 5. FEI also included the change in percentage between this and item (iv) above.

Rate Schedule	2023 Revenue (%)	Change from Item (iv)
RATE 1	57.8%	0.2%
RATE 2	17.5%	0.0%
RATE 3/23	15.7%	0.0%
RATE 5/25	8.3%	-0.2%
RATE 6	0.0%	0.0%
RATE 22	0.1%	0.0%
RATE 22A	0.4%	0.0%
RATE 22B	0.3%	0.0%

(vi) As shown in the table in (iii) above, the material drivers of the difference between the current and proposed revenue requirements by rate schedule are:

- The increased allocation to RS 1 by approximately $4.519 million or 0.4 percent, which is a result of the revenue shift from RS 5/25 and RS 22 such that the R:C ratios of both rate schedules will move back within the range of reasonableness of 95 percent to 105 percent. As highlighted in Table 5-17 of the Application, the R:C ratio for RS 1 before rebalancing is 97.3 percent and is the most reasonable choice to absorb the revenue shift from RS 5/25 and RS 22. Using RS 1 to absorb the revenue shift results in relatively small bill impacts for both RS 1 and RS 2, and the R:C ratio for RS 1 after rebalancing will continue to be lower than RS 2.
- The shift between RS 2 and RS 3/23 is related to the adjustment to move the economic crossover point back to 2,000 GJ between these two rate schedules.

(vii) As shown in the table in (v) above, there is no material change in the allocation to each rate schedule compared to the total revenue requirement for each rate schedule. The allocation to RS 1 of the total revenue requirement before and after the proposed revenue rebalancing increases by 0.2 percent, while RS 5/25 decreases by 0.2 percent and RS 22 decreases by 0.01 percent. This is expected since the proposed rebalancing option is to shift revenue from RS 5/25 and RS 22 to RS 1. For all other rate schedules, there is no change in terms of the level of allocation of the total revenue requirement after rounding to 1 decimal place.

1.4 Please provide a summary table (excluding Rate Schedules 4 and 7/27) with the following: i) customer numbers by class reflected in current rates and as proposed in this Application; ii) total energy by class as reflected in current rates and as proposed in this Application; and iii) total demand by class as reflected in current rates and as proposed in this Application.

For current rates, please provide the load data used to drive the R:C and M:C changes in this Application.

Response:

The COSA study and the resulting revenue rebalancing proposals do not shift any customer, energy, or demand between rate schedules. Accordingly, the current customer counts, total energy and total demand remain unchanged after the proposed revenue rebalancing.

For the breakdowns of the customer count, total energy, and total demand by rate schedule that are used to drive the R:C and M:C ratios in the 2023 COSA study, please refer to the response to BCOAPO IR1 1.2 (Table 2 for customer count by rate schedule, Table 3 for total energy by rate schedule, and Table 4 for total demand by rate schedule).

1.5 Please explain FEI's views and understanding of the BCUC's findings that an R:C ratio that falls within the range of reasonableness is deemed to be recovering its fair cost.

Response:

In FEI's view, an R:C ratio that falls within the range of reasonableness is considered to be recovering its fair costs because a COSA study that produces any R:C ratio involves many assumptions, estimates, allocations, and judgements such that the level of precision required to reach unity of the R:C ratios for all customer groups does not exist. As the BCUC stated in the FEI 2016 RDA Decision:[1]

> 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, the

[1] Decision and Order G-135-18, page 41.

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

The BCUC's findings in the 2016 RDA Decision that an R:C ratio that falls within the range of reasonableness is deemed to be recovering its fair costs was based on evidence provided by Elenchus, who was engaged by the BCUC as part of the 2016 COSA and RDA proceeding to review FEI's 2016 COSA study. Elenchus stated the following in its responses to information requests on their assessment of FEI's 2016 COSA Study:

> **<u>CEC IR 18.4 to Elenchus</u>**
>
> Please confirm that an R:C ratio of 1 would be indicative of an equal (50:50) probability that a rate class is contributing more or less revenue than its costs of service.
>
> **RESPONSE:**
>
> Elenchus does not view it as appropriate to interpret an R:C ratio in this way. Cost allocation is not a statistical exercise that has a probabilistic interpretation.
>
> <u>Given the imprecision of COSA models, which derives in part from the fact that there are multiple legitimate methods that can be used to allocate costs, each one producing a different R:C ratio, Elenchus is of the view that any R:C ratio that is within the defined range of reasonableness can be considered to be full cost recovery</u>. An R:C ratio that is below the range is considered to indicate under-recovery of costs and any R:C ratio that is above the range indicates over-recovery of costs.
>
> In a probabilistic situation, such as a sample survey, there is a true value that is being estimated. <u>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</u>. In COSA work, rather than attempting to determine R:C ratios using multiple reasonable methods, a range of reasonableness is used. **[Emphasis Added]**

Please also refer to the responses to BCUC IR1 19.2 and 19.4.

1.6 Please explain why FEI did not develop a revenue rebalancing option that spreads the cost of rebalancing the two Rate Schedules (5/25 and 22) between the six Rate

Schedules (1, 2, 3/23, 6, 22A, and 22B) with R:C ratios within the range of reasonableness given that the BCUC has found that an R:C ratio that falls within the range of reasonableness is deemed to be recovering its fair cost.

Response:

FEI's proposal to shift revenue responsibility from RS 5/25 and RS 22 to RS 1 is consistent with past practice and was the same approach approved in the 2016 RDA Decision. Specifically, in the 2016 RDA Decision, the BCUC stated:

> The Panel finds that FEI has made a reasonable case for allocating the responsibility for the rate design revenue impacts and rate rebalancing to RS1. <u>FEI's approach is consistent with past practice and reflects standard utility practice. RS 1's R:C ratio is the only rate class below 100 percent and RS 1 customers have the capacity to absorb these amounts with the lowest bill impact to individual customers. All parties including BCOAPO accept that the allocation of the rate design revenue and rebalancing impacts to RS 1.</u> The only issue among the parties is the quantum of the rebalancing amount that should be allocated to RS 1. [Emphasis added]

An alternative approach for rebalancing is to shift revenues among all rate classes that are within the range of reasonableness. As set out in the response to BCOAPO IR1 1.8, such an approach would reduce the annual bill impact to the average RS 1 customer by 0.3 percent, from 0.4 percent to 0.1 percent, reducing the bill impact from approximately $4.95 per year to $1.42 per year. However, this alternative approach will cause larger bill impacts to all other customers, including an average bill impact to RS 6 customers of approximately 9.1 percent. This rebalancing approach is also less transparent and more difficult to understand. FEI's proposed approach of shifting revenue responsibility to RS 1 customers achieves the least overall bill impact to all customer classes.

1.7 Please provide FEI's views of whether rate rebalancing with classes that only fall below 100% (that is, between 95% to 100%) implicitly implies that class R:C ratios above unity (that is between 100% and 105%) are overpaying costs and thus FEI's range of reasonableness is actually 95% - 100%, rather than 95% - 105%.

Response:

Shifting revenue responsibility from rate schedules with R:C ratios greater than 100 percent to those with R:C ratios lower than 100 percent does *not* imply that customer classes in either situation are under- or over-paying.

As discussed in the response to BCOAPO IR1 1.5, R:C ratios that fall within the range of reasonableness are considered to be recovering their fair share of costs. Further, as explained in the response to BCOAPO IR1 1.6, using rate schedules with R:C ratios less than 100 percent for absorbing revenue shifts is consistent with past practice.

FEI also notes that by using rate schedules that have R:C ratios lower than 100 percent to absorb revenue shifts from rate schedules that are outside the upper bound of the range of reasonableness moves all rate schedules' R:C ratios closer together. Shifting more revenue responsibility to rate schedules that are above unity (but below the upper bound of the range of reasonableness) will push these rate schedules closer to the upper limit and result in a higher likelihood that they will need to be rebalanced when the next COSA study is undertaken. FEI considers such an approach impractical and unreasonable when other options (such as the option proposed by FEI) are available.

1.8 Please provide a scenario that equally spreads the rebalancing cost ($3.495 million[2]) to each of the classes within the range of reasonableness (excluding Rate Schedules 4 and 7/27), to the extent possible without allowing any class's R:C ratio to exceed the range of reasonableness boundaries (i.e. 95% and 105%). In the event that a class' R:C ratio will exceed 105%, please cap the rebalancing at 105% and allow the residual to be spread equally among the remaining classes within the 95% - 105%. As part of the response, please provide any commentary as necessary.

Response:

Please refer to the responses to BCOAPO IR1 1.6 and 1.7 for an explanation of why FEI does not consider the requested approach appropriate. However, to be responsive, FEI provides the resulting R:C and M:C ratios under the rebalancing approach set out in this question.

Tables 1 and 2 below provide a similar view as Tables 5-17 and 5-18 of the Application, but for the rebalancing approach requested in this IR. Under this approach, the revenue shift to RS 1

[2] FEI Application, page 51, line 36.

customers will be approximately $1.307 million with a bill impact of 0.1 percent (equivalent to $1.42 per year) for the average residential customer, which is a reduction from $4.5 million or a bill impact of 0.4 percent (equivalent to $4.95 per year).

As shown in Table 1 below, this approach effectively forces all rate schedules, except for RS 1 and RS 2, to be at the upper limit of the range of reasonableness and creates the risk that many rate schedules will fall outside of the range of reasonableness in the short term (i.e., as a result of the next quarterly gas cost change or next delivery rate change). This approach essentially creates a small, short-term benefit for RS 1 customers by reducing the bill impact by approximately $3.53 per year; however, due to the increased likelihood that more customer classes will need to be rebalanced back into the range of reasonableness as part of the next COSA review, the longer-term impact will likely be a larger (negative) bill impact to RS 1 customers. For example, if the majority of the other rate schedules (RS 3/23, 5/25, 6, 22, 22A, and 22B) fall outside of the range of reasonableness, the resulting revenue shift would need to be borne by the only remaining rate schedules within the range of reasonableness.

Table 1: 2023 COSA R:C and M:C Results after Revenue Rebalancing (Rebalancing RS 5/25 and RS 22 to all Rate Schedules)

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%	1,307	0.1%	97.4%	95.2%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%	1,308	0.3%	98.3%	96.3%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	111.2%	1,308	0.4%	104.4%	112.3%
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%	19	9.1%	105.0%	111.9%
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%	278	3.1%	105.0%	105.2%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.1%	300	4.9%	105.0%	105.2%

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 (Rebalancing RS 5/25 and RS 22 to all Rate Schedules)

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	$ 0.016	$ 6.026
RS 2 - Small Commercial			
Basic Charge ($/Day)	$ 0.9485	$ 0.0998	$ 1.0483
Delivery Charge ($/GJ)	$ 4.568	$ (0.068)	$ 4.500
RS 3/23 Large Commercial			
Basic Charge ($/Day)	$ 4.7895	$ 1.4941	$ 6.2836
Delivery Charge ($/GJ)	$ 3.893	$ (0.098)	$ 3.795
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 6 - Natural Gas Vehicle			
Basic Charge ($/Day)	$ 2.0041	$ -	$ 2.0041
Delivery Charge ($/GJ)	$ 3.733	$ 0.9212	$ 4.654
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

Tables 3 and 4 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 approach requested in this IR (similar to Tables 5-21 and 5-22 of the Application). It can be seen that FEI's proposed Option 5 results in a slightly higher bill impact (by approximately $3.53 per year) but that all other rate schedules are less impacted.

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	BCOAPO IR1 1.8: Spread Rebalancing to all Rate Schedules (Except RS 4 and 7/27)
RS 1	4,519	-	4,519	-	4,519	1,307
RS 2	-	4,519	4,071	4,075	145	1,308
RS 3/23	-	-	(4,071)	444	(145)	1,308
RS 5/25	(3,344)	(3,344)	(3,344)	(3,344)	(3,344)	(3,344)
RS 6	-	-	-	-	-	19
RS 22	(151)	(151)	(151)	(151)	(151)	(151)
RS 22A	-	-	-	-	-	278
RS 22B	-	-	-	-	-	300
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		BCOAPO IR1 1.8	
	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	0.1%	$ 1.42
RS 2	-	$ -	1.2%	$ 50	1.1%	$ 45	1.1%	$ 45	0.04%	$ 1.65	0.3%	$ 14
RS 3/23	-	$ -	-	$ -	(1.2%)	$ (469)	0.1%	$ 123	(0.04%)	$ (10)	0.38%	$ 186
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	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	9.1%	$ 1,474
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	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	3.1%	$ 30,207
RS 22B	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	4.9%	$ 58,628
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)

1.8.1 Please provide a table that includes i) the resulting class R:C and M:C ratios; ii) the total allocated class revenue requirement as proposed by FEI; iii) the total allocated class revenue requirement flowing from this scenario; iv) the total overall impact by class on a percentage basis; and v) the total bill impact ($ and %) for a typical residential customer.

As part of the response, please provide any commentary as necessary.

Response:

Please refer to the response to BCOAPO IR1 1.8.

2.0 Reference: Order G-4-18, pages 22-23

Exhibit A-4, BCUC IR 2.1

FEI Biomethane Energy Recovery Charge Rate Methodology and Comprehensive Review of a Revised Renewable Gas Program, Exhibit B-11, Comprehensive Review and Application for a Revised Renewable Gas Program, page 1

FEI 2022 Long Term Gas Resource Plan (LTGRP) Exhibit B-1, page ES-1

FEI 2024-2027 Demand Side Management (DSM) Plan, Exhibit B-1, page 1

Topic: Frequency of COSA Studies

Preamble:

"The Panel considers that the advantages of performing a COSA study every five years outweigh the potential disadvantages. Any supporting studies that inform the COSA should be updated and filed along with the COSA studies. If there are significant changes in circumstances or FEI's business, the Panel expects FEI to file its updated COSA studies earlier than five years in order to reflect these changes." **(Order G-4-18, pages 22-23)**

"…the Renewable Gas Program now needs to change in response to evolving government climate policies, customer needs for Renewable Gas, and the significant increase in Renewable Gas that FEI is acquiring pursuant to the GGRR. Without a response from FEI, federal, provincial and municipal regulations and policies focused on reducing GHG emissions threaten the long-term viability of the gas delivery system and energy choice for British Columbians." **(Comprehensive Review and Application for Approval of a Revised Renewable Gas Program, page 1)**

"The foundation for the 2022 LTGRP and this transformational reduction in GHG emissions is FEI's existing infrastructure, service offerings, workforce and logistics, as well as the regional gas supply infrastructure that is vital to serving the energy needs of British Columbians." **(LTGRP Application, page ES-1)**

"The DSM Plan continues many of the cost-effective programs previously accepted in FEI's 2023 DSM Plan but makes a significant transition away from conventional high-efficiency gas space and water heating equipment…to advanced DSM programming…The changes to FEI's DSM Plan reflect provincial government policy direction in the 2021 CleanBC Roadmap…and the recent amendments to the Demand-Side Measures Regulation (DSM Regulation), which became effective June 30, 2023." **(2024-2027 DSM Application, page 1)**

2.1 Further to BCUC IR 2.1, in light of the transformational changes challenging the viability of FEI's natural gas business along with rising customer costs, please provide FEI's views with supporting rationale on the appropriateness of preparing a COSA and Rate Design study more frequently than every five years.

Response:

Please refer to the response to BCUC IR1 2.1 for a discussion on why FEI does not consider it necessary for COSA studies to be completed within a defined timeframe or frequency.

If and/or when the transformational changes suggested in this IR materialize, the impact to the COSA and rate design would occur over the long term; therefore, undertaking more frequent COSA studies is not necessary at this time. In FEI's view, energy transformation in the natural gas business has been occurring since the last COSA study was completed in 2016. Further, many notable changes and external events occurred during these past five years, including FEI's implementation of common rates with Fort Nelson (effective January 1, 2023), the COVID-19 pandemic, and significant inflationary increases. However, despite all of these changes and impacts, and as evidenced by the results of the 2023 COSA study, the current rates and rate design are largely performing as intended and there have been limited shifts compared to the 2016 COSA study.

2.2 Please provide FEI's views along with its rationale as to whether the significant changes to FEI's business may warrant reconsideration of the 95% to 105% range of reasonableness to a broader range such as 90% to 110% as previously employed by FEI.

Response:

FEI does not believe there is a need to widen the range of reasonableness to 90 to 110 percent. As noted by the BCUC in Decision and Order G-4-18 (2016 COSA Decision), "the size of the range of reasonableness depends on the precision of the cost allocation estimates and stability of those estimates overtime."[3]

[3] Page 35.

There is no evidence to suggest the precision of the estimates used in the 2023 COSA study are worse than those used in the 2016 COSA study such that widening the range of reasonableness is warranted. The 2023 COSA study demonstrates that FEI's rates continue to perform as intended within the 95 to 105 percent range of reasonableness. Further, FEI does not consider that changes to the natural gas business would result in diminished precision of its assumptions or estimates such that a wider range of reasonableness would be required.

FEI notes that if the range of reasonableness was changed to 90 to 110 percent, no revenue rebalancing would be needed as part of this 2023 COSA study.

2.3 Please provide FEI's views as to whether a +/- 5% tolerance from unity is sufficient to support the multitude of assumptions, approximations and judgements that support FEI's COSA. As part of the response, please discuss what factors in the current transformational circumstances of FEI would result in the sustainment or improvement in accuracy and fairness/equity of its COSA.

Response:

The 2023 COSA study results show that a +/- 5 percent tolerance from unity is sufficient to support the assumptions, approximations, and judgements. This is demonstrated by the fact that only two rate schedules require minor revenue rebalancing despite the 95 to 105 percent range of reasonableness.

Please also refer to the response to BCOAPO IR1 2.2 explaining that there is no evidence to suggest the precision of FEI's estimates, assumptions, or judgements has diminished, requiring a wider range of reasonableness. Having a wider range such as +/- 10 percent only means that there is no revenue rebalancing needed as a result of the 2023 COSA study.

As noted by the BCUC in the 2016 COSA Decision: "A rate schedule with an R:C ratio that falls within the range of reasonableness is deemed to be recovering its fair cost and indicates that no rebalancing may be required".[4] [Emphasis Added]

Accordingly, FEI's rates and rate design, based on the defined +/- 5 percent tolerance, address the considerations of fairness and equality between rate classes.

4 Page 25.

2.3.1 Further to BCOAPO IR 2.3, please provide any quantitative analysis FEI has prepared to demonstrate that a +/- 5% band is sufficient to address the assumptions, approximations and judgements underpinning its COSA and provide sufficient latitude to address considerations of fairness and equality that extends beyond cost as well as other ratemaking principles.

Response:

Please refer to the response to BCOAPO IR1 2.3.

2.3.2 Further to BCOAPO IR 2.3, please provide FEI's views as to whether a broader range of reasonableness (such as 90% to 110%) would still give rise to the economic crossover matters raised in its COSA Application.

Response:

Broadening the range of reasonableness to 90 to 110 percent (or any other range) would not resolve the need to address the economic crossover issue. The economic crossover issue is related to the ratio between the basic and variable charges between RS 2 and RS 3/23, not the precision of FEI's estimates, approximations and judgments that underpin this COSA study.

3.0 Reference: Exhibit B-1, Application, pages 12, 47

Topic: Use of a Range of Reasonableness

Preamble: FEI states:

> "The BCUC also determined that the R:C ratios should be used to inform rate design and rate rebalancing proposals and directed FEI to use an R:C ratio range of reasonableness of 95 percent to 105 percent to inform rate design and rebalancing proposals." **(Application, page 12)**

> "The COSA study is one of the primary tools used to establish cost guidelines and to evaluate the reasonableness of the revenue of each rate schedule by determining whether the rates charged to each rate schedule adequately recover their allocated cost of service." **(Application, page 47)**

3.1 Please provide FEI's interpretation along with its rationale for what "inform" rate design and rebalancing means.

<u>Response:</u>

In the 2016 RDA Decision, the BCUC stated the following:[5]

> 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 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. [Emphasis Added]

Based on the above, FEI considers that using the range of reasonableness of 95 percent to 105 percent to inform rate design and rebalancing proposals means that if a rate schedule's R:C ratio is within the range of reasonableness, it is recovering its fair costs, and rebalancing is not required.

[5] FEI 2016 RDA Decision and Order G-135-18, page 42.

3.2 Please discuss what other tools FEI used to evaluate the reasonableness of the revenue of each rate schedule.

Response:

As explained in the Application, the results of the 2023 COSA study indicate that the existing rates and rate design are operating effectively and as intended. In consideration of the overall results of the 2023 COSA study, FEI's internal review of its rates and rate design, and the fact that the R:C ratios resulting from the 2023 COSA study show that only minor rebalancing is needed, FEI determined that overall, its rates and rate design are reasonable. While FEI exclusively used the R:C ratios and the defined range of reasonableness to evaluate the revenue responsibility of each rate schedule, once it was determined that rebalancing was needed for RS 5/25 and RS 22, FEI used Bonbright's Principles to guide the selection of the preferred rebalancing option.

3.3 Please provide a full discussion with supporting rationale as to how FEI defines the principle of fairness and equity.

Response:

FEI considers fairness and equity in the context of the BCUC's findings and determinations regarding the range of reasonableness and R:C ratios in the 2016 COSA Decision (in particular, page 25) and the 2016 RDA Decision (in particular, pages 41 and 42). For further explanation, please refer to the responses to BCOAPO IR1 2.3 and BCUC IR1 19.4.

FEI also considers fairness and equity in the context of Bonbright's Rate Design Principles. FEI assessed each of its rebalancing options against Bonbright's principle 2 (fair apportionment of costs among customers) as part of the Application. With regard to principle 8 (avoidance of undue discrimination), please refer to the responses to BCUC IR1 20.2 and 20.3.

4.0 Reference: Exhibit B-1, Application, page 17; Table 4-1, page 20; Table 4-8, page 31

Topic: Functionalized Costs by Class

4.1 Please provide a pie chart for each class/rate schedule (excluding Rate Schedules 4 and 7/27) that: i) identifies each class's current functional costs by each of the seven functions; and ii) identifies each class's proposed functional costs by each of the eight functions. As part of the response, please also provide the supporting numerical data in one table, along with the percentage change by functional category and the material drivers of the changes.

<u>Response:</u>

FEI notes that for the purposes of the COSA study, FEI functionalizes costs to determine revenue responsibility for each cost-based rate schedule. FEI's revenue rebalancing proposals do not change how costs are functionalized in the COSA study; only how much revenue should be collected from each rate schedule. As such, there is no percentage change by functional category and no material drivers of the changes between the "current" and "proposed" functional costs from revenue rebalancing.

Please refer to Table 1 below which breaks down the functional costs for each rate schedule, except RS 4 and RS 7/27. FEI has also provided pie graph figures below that graphically illustrate the breakdown of the functional costs for each rate schedule.

Table 1: 2023 COSA Functionalized Costs by Rate Schedule ($000s)

COSA Function	RS 1	RS 2	RS 6	RS 22	RS 22A	RS 22B	RS 3/23	RS 5/25
Gas Supply Operations	$ 5,915	$ 2,034	$ 2	$ -	$ -	$ -	$ 1,786	$ 795
Tilbury Base LNG Storage	9,883	3,584	1	79	-	-	3,075	1,256
Tilbury Phase 1A Expansior	22,275	5,666	3	95	272	189	3,821	1,444
Mt. Hayes LNG Storage	3,737	1,355	0	30	127	76	1,163	475
Transmission	140,780	52,388	10	1,178	5,055	3,027	45,528	18,666
Distribution	418,744	98,849	71	1,279	2,315	1,940	55,724	19,225
Marketing	58,946	9,133	5	232	663	629	6,869	2,318
Customer Accounting	33,211	3,380	0	61	42	23	994	779
Total	**$ 693,491**	**$ 165,104**	**$ 87**	**$ 2,780**	**$ 8,474**	**$ 5,886**	**$ 118,959**	**$ 44,958**

Figure 1: RS 1 Functionalized Costs

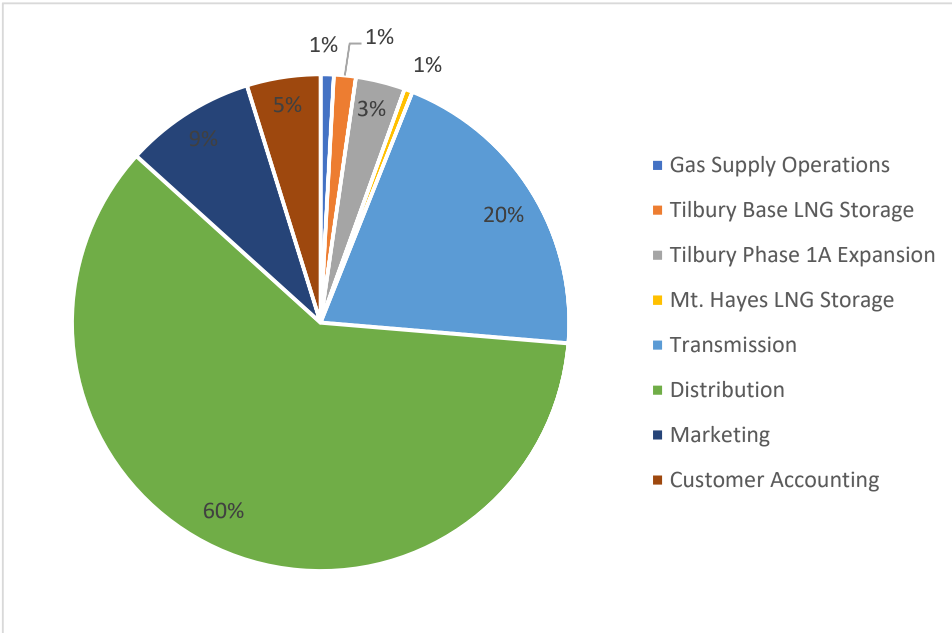


Figure 2: RS 2 Functionalized Costs

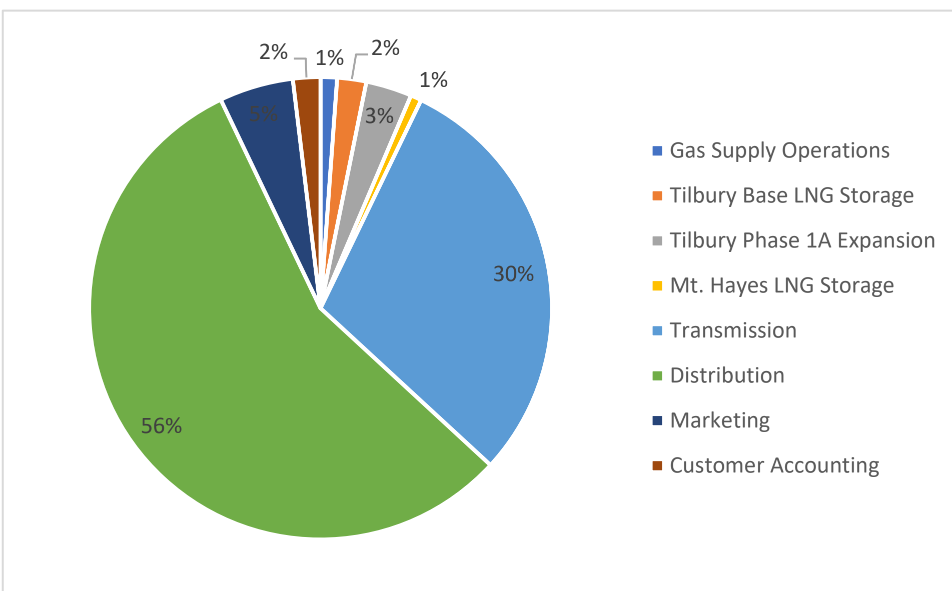


Figure 3: RS 3/23 Functionalized Costs

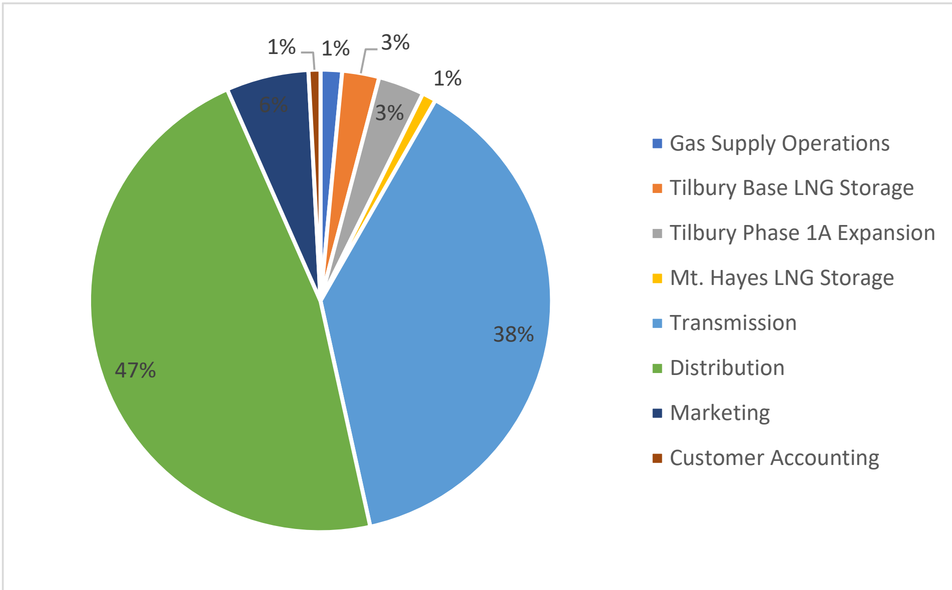


Figure 4: RS 5/25 Functionalized Costs

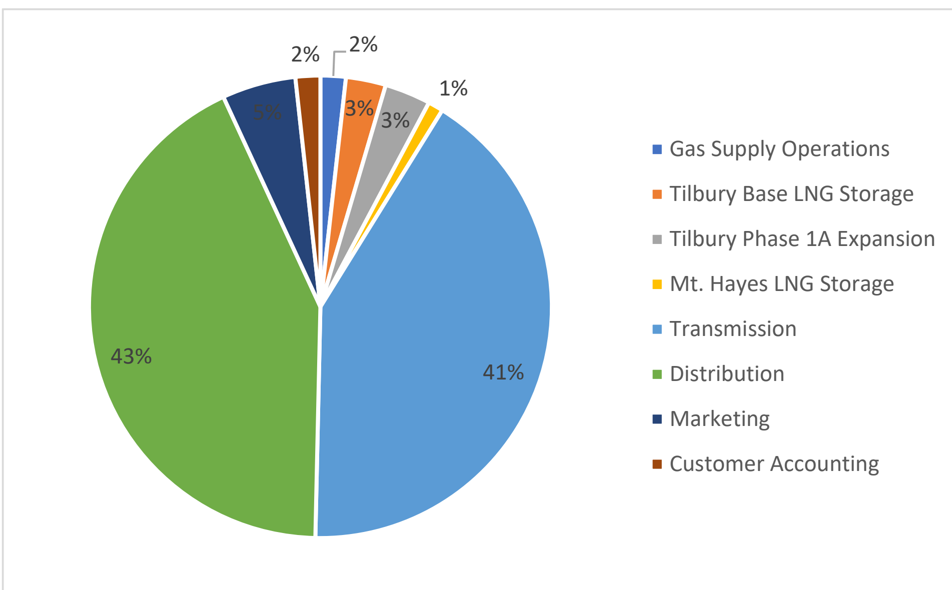


Figure 5: RS 6 Functionalized Costs

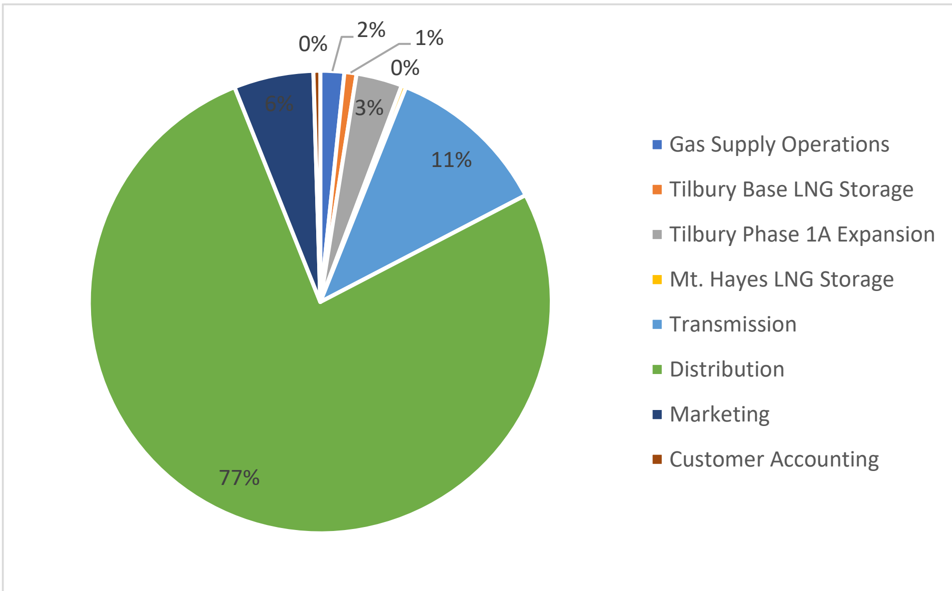


Figure 6: RS 22 Functionalized Costs

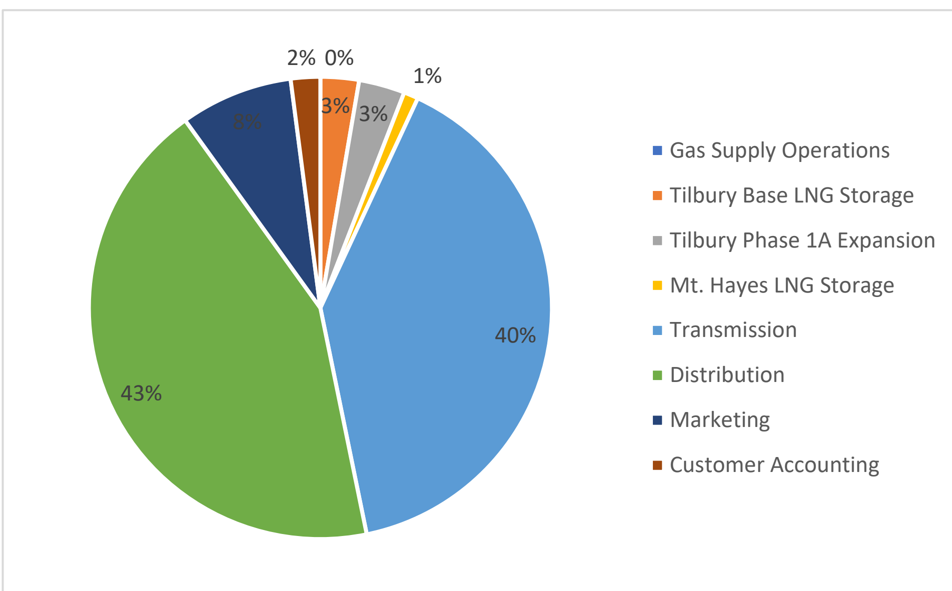


Figure 7: RS 22A Functionalized Costs

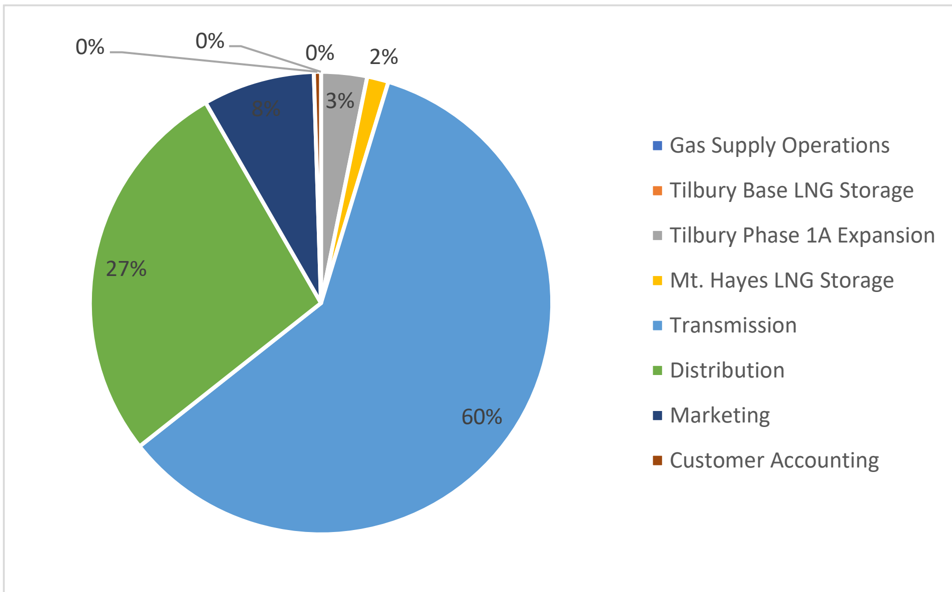
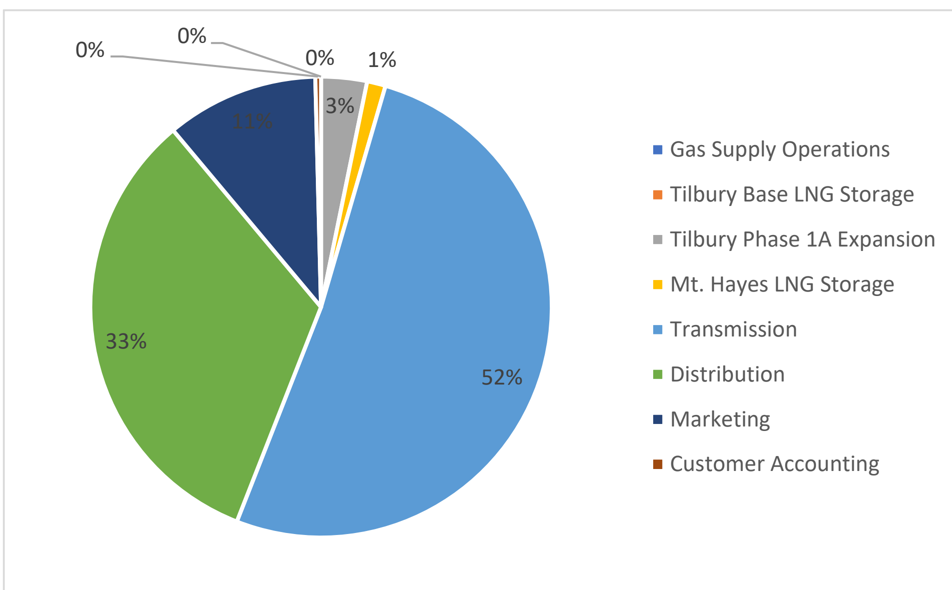


Figure 8: RS 22B Functionalized Costs



4.2 Please reconcile FEI's 2023 Test Year Revenue Requirement of $2,249 million (Table 4-1) with total functionalized costs of $1,054.4 million (Table 4-8).

Response:

The $2,249 million shown in Table 4-1 is the 2023 revenue requirement, inclusive of cost of gas, but excluding the known and measurable changes discussed in Section 4.2.3. Additionally, the $2,249 million includes an offsetting credit from bypass customers, large industrial contract customers and RS 46 LNG customers. The $1,054.4 million shown in Table 4-8 is FEI's delivery margin, which excludes cost of gas. The $1,054.4 million is functionalized in the 2023 COSA and is based on the 2023 Approved delivery margin and the known and measurable changes, less the offsetting credits from bypass customers, large contract demand customers and RS 46 LNG customers.

Table 4-6 of the Application (copied below) provides a reconciliation of the $2,249 million and the $1,054.4 million. The sum of the 2023 Approved delivery costs of $1,078.3 million (i.e., Line 1) and the 2023 Approved cost of gas of $1,170.8 million (i.e., Line 6) equal to the $2,249 million from Table 4-1. The $1,054.4 million of delivery costs is equal to the 2023 Approved delivery costs of $1,078.3 million (i.e., Line 1), less the offsetting bypass, contract, and RS 46 credit of $47.3 million (i.e., Line 2), plus the known and measurable changes of $23.4 million (i.e., Line 3).

Table 4-6: Final Delivery and Gas Costs used in 2023 COSA

Line	Particular	Reference		Amount ($millions)
1	Delivery Costs	Table 4-1 (excl. Cost of Gas)	$	1,078.3
2	Less: Bypass, Contract Customers and RS 46	Section 4.2.2.2 and 4.2.2.5	$	(47.3)
3	Add: Known and Measureable Changes	Table 4-5	$	23.4
4	**Final Delivery Costs for 2023 COSA**	**Table 4-8**	**$**	**1,054.4**
5				
6	Cost of Gas	Table 4-1	$	1,170.8
7	Less: Bypass, Contract Customers and RS 46	Section 4.2.2.2 and 4.2.2.5	$	(36.5)
8	**Final Gas Costs for 2023 COSA**	**Table 4-15**	**$**	**1,134.3**

4.3 Please fully discuss how FEI functionalizes plant as Transmission vs. Distribution. As part of the response, please explain i) how pressure factors into the decision to functionalize assets as Transmission or Distribution; ii) the number of border assets (and total investment as a % of total Transmission and Distribution investment) that provide both Transmission and Distribution infrastructure support and how FEI functionalizes these assets between the functions; and iii) the role of and frequency cost allocation staff review the functionalization of Transmission and Distribution plant.

Response:

Since FEI's inception, the functionalization between transmission and distribution has been based on the Canadian Standards Association (CSA) Z662:23, and its previous editions. Furthermore, distribution is comprised of assets whose purpose is distributing gas within an area, as opposed to transporting gas over long distances.

Operating pressure is not a factor that determines the functionality of a particular main or lateral. However, mains operating at higher pressures (for example, greater than 300 psi) are typically transmission assets, whereas mains operating at lower pressures are typically distribution assets.

FEI interprets "border assets" as the utility's intangible and general plant assets, which are used not only to support transmission and distribution functions but also to support FEI's other functions including storage. Examples are customer administration, customer contact, billing and administrative and general operations. Consistent with past COSA studies from 1993, 1996, 2001, and 2016, the intangible and general plant has been functionalized based on the functionalized direct gross plant costs that include storage (Tilbury Base Plant, Tilbury Phase 1A, and Mt Hayes), transmission, and distribution assets. Table 1 below provides the breakdown of the functionalized direct gross plant in percentages, which is then used to functionalize the intangible and general plant related costs.

Table 1: Breakdown of Functionalized Intangible and General Plant related Costs in Dollars ($000s) and Percentage

Functions	Direct Gross Plant	%	Intangible Plant	General Plant	Total	%
Gas Supply Operations	$ -	0%	$ -	$ -	$ -	0%
Tilbury LNG: Base Plant	92,025	1%	1,277	4,931	6,209	1%
Mt. Hayes LNG	209,967	3%	2,914	11,251	14,166	3%
Tilbury 1A	476,771	6%	6,618	25,548	32,166	6%
Transmission	2,571,951	31%	35,700	137,818	173,518	31%
Distribution	4,856,522	59%	67,412	260,236	327,648	59%
Marketing	-	0%	-	-	-	0%
Customer Accounting	-	0%	-	-	-	0%
Total	**$ 8,207,236**	**100%**	**$ 113,922**	**$ 439,784**	**$ 553,706**	**100%**

The review of the asset costs and O&M expenses, including the separation between transmission and distribution occur regularly as part of FEI's operations and is also subject to the BCUC's review during rate-setting proceedings. Asset classifications are also reviewed as part of FEI's depreciation studies, which are typically completed every five years and are subject to BCUC review and approval, as well as part of COSA studies.

5.0 Reference: Exhibit B-1, Application, page 32

Topic: Gas Supply Operations

Preamble: FEI states:

> "…the delivery costs that are functionalized as Gas Supply are primarily related to gas control and company use gas. These costs are classified as Energy related as they vary by the volume of gas delivered to customers." **(Application, page 32)**

5.1 Please provide a table that identifies all the rate base (including, for example, working capital) and revenue requirement expenditures functionalized to Gas Supply as reflected in the 2023 COSA. As part of the response, please provide the delivery-related Gas Supply costs as a percentage of total commodity costs.

Response:

FEI notes the breakdown of the revenue requirements and rate base functionalized to Gas Supply Operations is shown in Schedule 2 and Schedule 3, respectively, of Appendix D. Please refer to Table 1 below which provides a summary of the revenue requirements and rate base related to Gas Supply Operations. As shown in the table below, the cost of service margin allocated to Gas Supply is approximately 0.96 percent of the total commodity costs (i.e., Line 24).

Table 1: Summary of Gas Supply Operation Costs in Rate Base and Revenue Requirements

Line	Gas Supply Operations Function	Amount ($000s)	Reference
1	**Rate Base Costs**		
2	Deferred Charges		
3	Commodity Cost Reconciliation Account (CCRA)	$ 135,100	
4	Midstream Cost Reconciliation Account (MCRA)	(37,154)	
5	total Deferred Charges	97,946	Appendix D, Schedule 3, Line 13
6			
7	Cash Working Capital	10,522	Appendix D, Schedule 3, Line 14
8			
9	**Total Rate Base**	$ 108,468	Appendix D, Schedule 3, Line 15
10			
11	**Cost of Service**		
16	O&M Expenses	4,042	Appendix D, Schedule 2, Line 1
18	Income Tax	820	Appendix D, Schedule 2, Line 6
19	Earned Return	6,122	Appendix D, Schedule 2, Line 7
20	**Total Cost of Service Margin**	10,984	Appendix D, Schedule 2, Line 8
21	Cost of Gas (excl. Imputed CoG for RS 23/25/27)	1,134,316	Appendix D, Schedule 2, Line 10
22	**Total Revenue Requirement**	$ 1,145,300	Appendix D, Schedule 2, Line 11
23			
24	Cost of Service Margin as a % of the Cost of Gas	0.96%	Line 20 / Line 21

5.2 Please explain when and how delivery-related Gas Supply costs will be incorporated into commodity rates and whether FEI is seeking approval of such rates as part of this Application or a future commodity rate application.

Response:

As stated on page 32 of the Application, the costs that are functionalized as Gas Supply are related to gas control and company use gas, as well as the financing costs and associated income tax expense related to the rate base CCRA and MCRA deferral accounts, as set out in the response to BCOAPO IR1 5.1. The costs are not related to the purchasing of gas or the commodity costs of gas consumed by FEI's customers.

FEI is not seeking in this Application, nor does FEI intend to seek in any future application, approval to have these costs charged to either the CCRA or MCRA for recovery through commodity related charges (cost of gas and/or storage and transport charges).

6.0 Reference: Exhibit B-1, Application, page 19; Table 4-1, page 20

FEI 2022 LTGRP, Exhibit B-1, page ES-1

Topic: 2023 COSA Assumptions

Preamble: FEI states:

"For the 2023 COSA model, FEI used the 2023 approved costs from its Annual Review for 2023 Delivery Rates proceeding as the test year for the basis of cost allocation. FEI chose the 2023 approved costs because they reflect the most current operating conditions, include both FEI and FEFN under common delivery rates as discussed in Section 3.6, and were the most recently available approved costs at the time the 2023 COSA was prepared." **(Application, page 19)**

Footnote 41: "The 2023 delivery rates were approved on an interim basis pursuant to Order G-352-22, pending the outcomes of Stage 1 of the BCUC's Generic Cost of Capital (GCOC) proceeding (not yet issued) and FEI's Application for Acceptance of Demand Side Management (DSM) Expenditures Plan for 2023 proceeding (Decision and Order G-45-23, dated March 6, 2023)." **(Application, page 19)**

"The foundation for the 2022 LTGRP and this transformational reduction in GHG emissions is FEI's existing infrastructure, service offerings, workforce and logistics, as well as the regional gas supply infrastructure that is vital to serving the energy needs of British Columbians. Table ES-1 provides a summary of FEI customer, demand and pipeline characteristics. Table ES-2 presents the renewable and low-carbon gas resources included in the 2022 LTGRP that, over the planning horizon, along with increased DSM and growth in fuel service for the low-carbon transportation (LCT) sector, are pivotal in reaching BC's GHG emission reduction goals." **(2022 LTGRP, page ES-1)**

6.1 Please clarify the load forecast basis (including customer numbers, demand and energy) underpinning the 2023 COSA. To the extent that the load forecast underpinning 2023 Delivery Rates was not used, please identify the load forecast underpinning the 2023 COSA along with FEI's rationale.

Response:

The Test Year revenue requirement for the 2023 COSA study is 2023, as such the load forecast underpinning the 2023 COSA study is the load forecast from FEI's Annual Review for 2023 Delivery Rates (2023 Annual Review), approved by Order G-352-22. Please refer to Appendix B of the Evidentiary Update to the 2023 Annual Review, Schedule 19, Lines 9 and 10 for the 2023 forecast customer numbers and energy, respectively. For the peak day demand used as part of the 2023 Annual Review (but not shown in Appendix B of the Evidentiary Update), please refer to the response to BCOAPO IR1 1.2, Table 4. Please also refer to the 2023 Annual Review Application for further details of the 2023 demand forecast.

6.2 Please clarify the basis of the Cost of Gas forecast underpinning the 2023 COSA.

<u>Response:</u>

The cost of gas that underpins the 2023 COSA study is the cost of gas included as part of the 2023 Annual Review. Please refer to Section 4 of the 2023 Annual Review Application for a detailed discussion on the cost of gas forecast.

6.3 Please explain how FEI functionalizes, classifies, and allocates working capital. As part of the response, please identify the total gas costs assumed for purposes of allocating working capital in the 2023 COSA.

<u>Response:</u>

The treatment of working capital in the 2023 COSA study is consistent with the approach taken in the 2016 COSA and RDA. There are four items that make up the working capital: 1) inventories of materials and supplies; 2) transmission line pack / gas in storage; 3) refundable contributions; and 4) cash working capital. The total working capital is approximately $113.639 million (Appendix D, Schedule 3, Line 14), which is approximately 1.8 percent of FEI's total rate base of $6.166 billion in the 2023 COSA study.

Inventories (item 1) and refundable contributions (item 4) have been functionalized to Distribution.

Transmission line pack / gas in storage (item 3) has been functionalized to Transmission.

Cash working capital (item 4) is essentially the timing difference between accounts payable and accounts receivable for FEI's daily operations. Accordingly, this item has been functionalized based on the sum total of the functionalized O&M expense, property taxes, income tax and the cost of gas, as these costs would have an impact on the timing difference between accounts payable and receivable. Please refer to Table 1 below which provides the percentages used to functionalize the cash working capital. The total gas costs used as part of this functionalization are approximately $1,134 million, which is the total gas cost for the 2023 COSA as shown in Table 4-6 of the Application.

Table 1: Functionalization of Cash Working Capital ($000s)

Particulars	Reference	Total	Gas Supply Operations	Tilbury LNG Base Plant	Mt. Hayes LNG	Tilbury 1A LNG	Transmission	Distribution	Marketing	Customer Accounting
Cash Working Capital		$ 14,934	$ 10,522	$ 115	$ 81	$ 190	$ 1,084	$ 2,106	$ 432	$ 403
Functionalization for Cash Working Capital										
O&M Expenses	Appendix D, Schedule 2, Line 1	$ 351,536	$ 4,042	$ 11,558	$ 6,499	$ 13,440	$ 75,050	$ 152,723	$ 44,322	$ 43,902
Property & Sundry Taxes	Appendix D, Schedule 2, Line 2	79,490	-	492	1,077	3,418	26,425	48,078	-	-
Income Tax	Appendix D, Schedule 2, Line 6	51,486	820	403	1,245	3,746	15,855	27,228	2,448	(259)
Cost of Gas	Appendix D, Schedule 2, Line 10	1,134,316	1,134,316	-	-	-	-	-	-	-
Total		$ 1,616,829	$1,139,178	$ 12,453	$ 8,821	$ 20,604	$ 117,330	$ 228,030	$ 46,770	$ 43,643
Percentage of Total		**100%**	**70.46%**	**0.77%**	**0.55%**	**1.27%**	**7.26%**	**14.10%**	**2.89%**	**2.70%**

6.4 Please explain and provide FEI's rationale for its functionalization, classification and allocation of DSM costs underpinning its 2023 COSA. As part of the response, please explain whether FEI has made any changes to its overall allocation methodology associated with DSM expenditures, compared to current treatment.

Response:

There is no change in the treatment of DSM costs from the 2016 COSA and RDA. The costs are functionalized to Marketing, classified as Energy, and allocated to all rate schedules based on their annual energy demand.

Please refer to the responses to RCIA IR1 11.1 and 11.2 for the rationale of the treatment of DSM costs in the COSA study.

6.5 Please confirm, or otherwise explain, whether FEI views DSM as being integral to meeting mandated environmental targets and why.

Response:

Based on the above preamble, FEI interprets the phrase "mandated environmental targets" in BCOAPO IRs 6.5 through 6.7 as referring specifically to provincially mandated GHG reduction targets. As such, confirmed. As one of the pillars of FortisBC's Clean Growth Pathway as presented in the 2022 LTGRP[6], FEI views its DSM activities as integral to the Province meeting its GHG reduction targets.

6.6 Please confirm or otherwise explain whether FEI views RNG as being integral to meeting mandated environmental targets and why.

Response:

Confirmed. As another pillar in its Clean Growth Pathway, FEI views its acquisition and delivery of RNG and other low-carbon and renewable gases as a vital resource in overcoming the challenges presented by the need to decarbonize BC's energy system and economy.

6.7 Does FEI foresee any future challenges to its reliance upon RNG in light of evolving environmental targets? Please explain why or why not.

Response:

As long as FEI has a clear mandate from the Province to pursue the acquisition and delivery of RNG to its current and future customers, FEI does not see any insurmountable challenges to the contribution of RNG to meeting provincial GHG reduction targets. All utilities will experience substantial challenges over the energy transition, and it is only by working together and maintaining the health and viability of the gas and electric utilities that BC will be able to meet its carbon reduction goals. It is also FEI's view that a diversified energy future that includes a mandate for FEI to pursue the acquisition and delivery of RNG is the lowest cost pathway to decarbonize BC's energy system and economy.

6.8 Please explain FEI's overall RNG-related allocation methodology.

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[6] https://www.bcuc.com/OurWork/ViewProceeding?applicationid=1000, Exhibit B-1.

Response:

As explained in Section 4.2.2.4 of the Application, the current cost recovery mechanisms were approved by Orders G-133-16 and G-165-20.[7] All biomethane (RNG) related costs and revenues are transferred to the Biomethane Variance Account (BVA) with the balance recovered through the Biomethane Energy Recovery Charge (BERC) and the BVA Rate Rider. As such, there are no RNG-related costs that are recovered through FEI's delivery rates. All related costs as well as any offsetting revenue related to RNG are removed from the 2023 COSA for allocation purposes.

6.9 To the extent that there are currently differing allocation methodologies associated with DSM and RNG, please provide FEI's views as to the appropriateness of differing methodologies of these resource expenditures.

Response:

As explained in the response to BCOAPO IR1 6.8, all RNG costs are removed from the COSA and are therefore not allocated in the COSA study. Regardless, FEI does not consider the costs associated with DSM and RNG to be comparable when considering cost allocation. RNG costs include physical assets as well as the supply costs of RNG while the DSM expenditures are incentives offered to customers for energy efficiency measures which involve no physical assets or commodity costs incurred by FEI.

6.10 Please provide a pie chart that: i) identifies the proposed allocation of DSM expenditures by class in this Application; and ii) identifies the allocated costs of DSM expenditures by class as reflected in current rates.

Response:

FEI interprets BCOAPO's reference to the "proposed" allocation of DSM expenditures (item i) as referring to the allocation of DSM expenditures after FEI's proposed revenue rebalancing and interprets BCOAPO's reference to "current" (item ii) as referring to the allocation of DSM expenditures before the proposed revenue rebalancing. FEI confirms that there is no change to

[7] MRP Decision, pages 75-76.

the allocation of DSM expenditures before and after the proposed revenue rebalancing, as rebalancing does not change the underlying cost allocation methods.

Please refer to Figure 1 and Table 1 below for the breakdown of the cost of service in the 2023 COSA related to DSM expenditures allocated to each rate schedule. FEI notes the cost of service items related to DSM expenditures include the amortization of the DSM expenditure rate base deferral account and the associated earned return and income tax expense of the DSM expenditure rate base deferral account.

Figure 1: Breakdown of Cost of Service in 2023 COSA related to DSM Expenditures by Rate Schedule

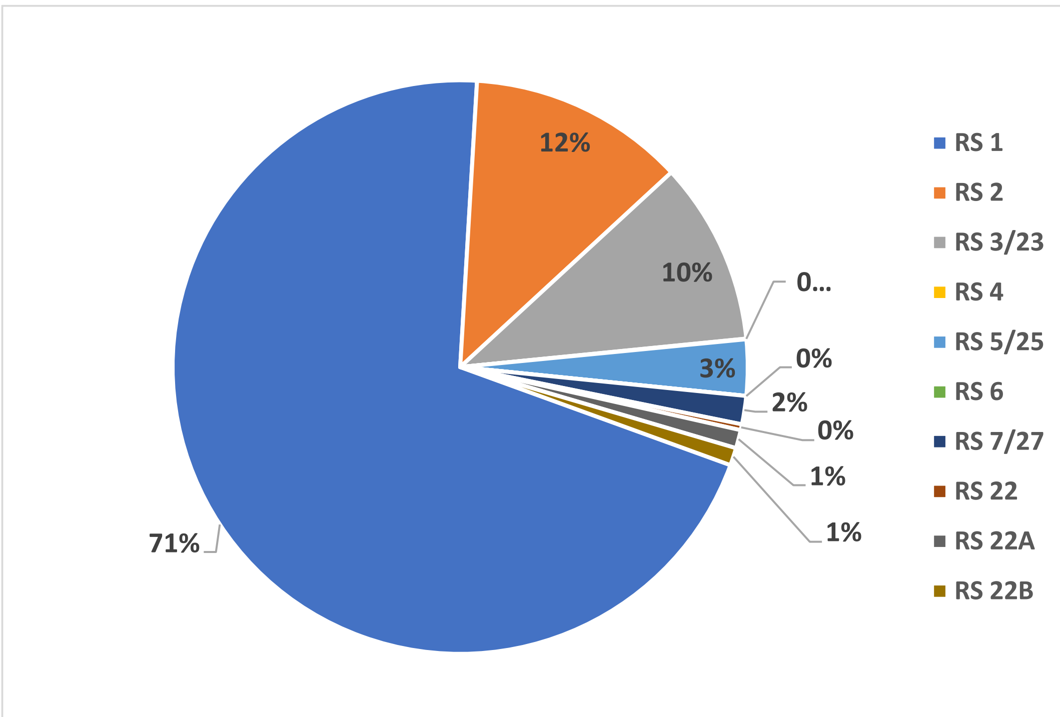


Table 1: Breakdown of Cost of Service in 2023 COSA related to DSM Expenditures by Rate Schedule

Rate Schedule	DSM Amortization ($000s)	Income Tax ($000s)	Earned Return ($000s)	Total ($000s)	Total (%)
RS 1	26,132	2,095	15,646	43,873	70%
RS 2	5,793	213	1,592	7,599	12%
RS 3/23	5,887	63	468	6,418	10%
RS 4	13	1	7	22	0%
RS 5/25	1,549	49	367	1,965	3%
RS 6	2	0	0	2	0%
RS 7/27	833	19	142	994	2%
RS 22	172	4	29	205	0%
RS 22A	621	3	20	643	1%
RS 22B	606	1	11	618	1%
Total	**41,608**	**2,448**	**18,283**	**62,339**	**100%**

6.11 Please provide a table with columns (excluding Rate Schedules 4 and 7/27) that: i) identifies the DSM expenditures allocation by class as reflected in current rates; ii) identifies DSM expenditures allocation by class as reflected in the 2023 COSA as proposed; iii) the DSM expenditures by class as a percentage of total DSM expenditures both currently and as proposed in the 2023 COSA; and iv) identifies the material drivers of the change by class relative to total DSM expenditures.

Response:

Please refer to the response to BCOAPO IR1 6.10.

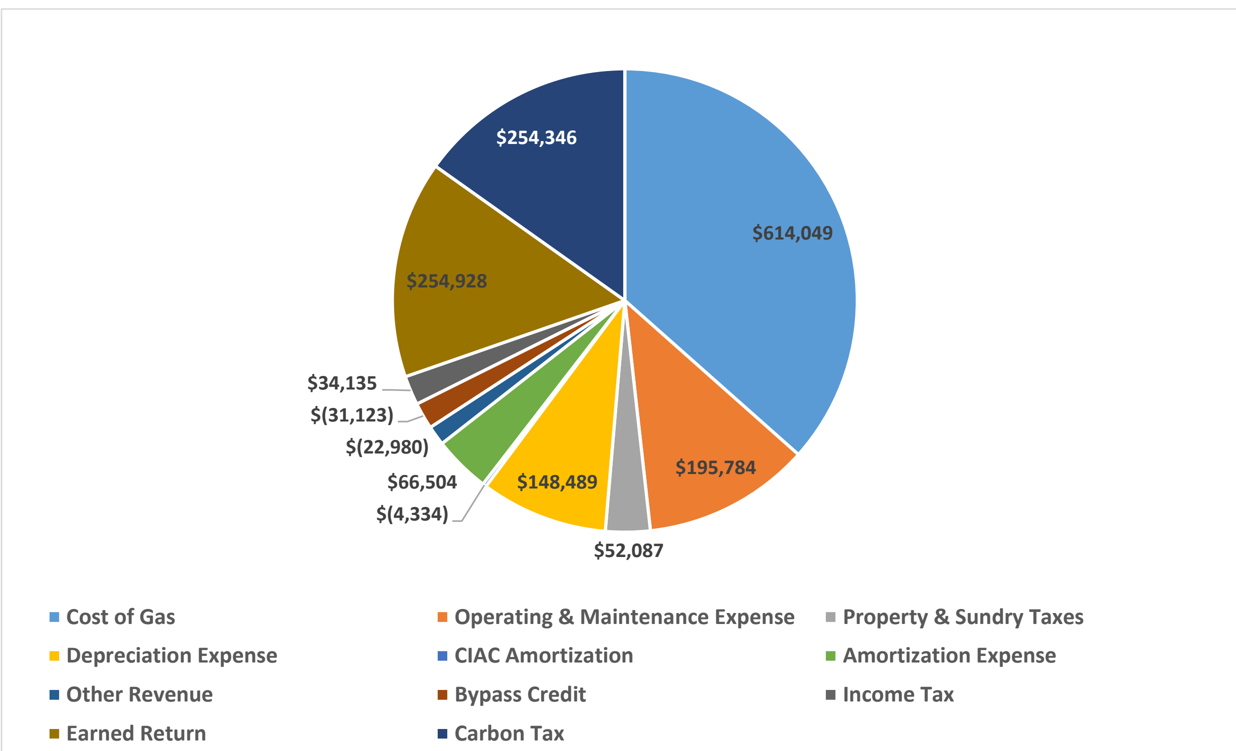
6.12 Please provide a pie chart for each customer class (excluding Rate Schedules 4 and 7/27) that reflects the allocation of each Revenue Requirement component (for example, O&M, Depreciation/Amortization, Income, Taxes, Gas Costs, etc.) along with each class's current total carbon tax paid.

Response:

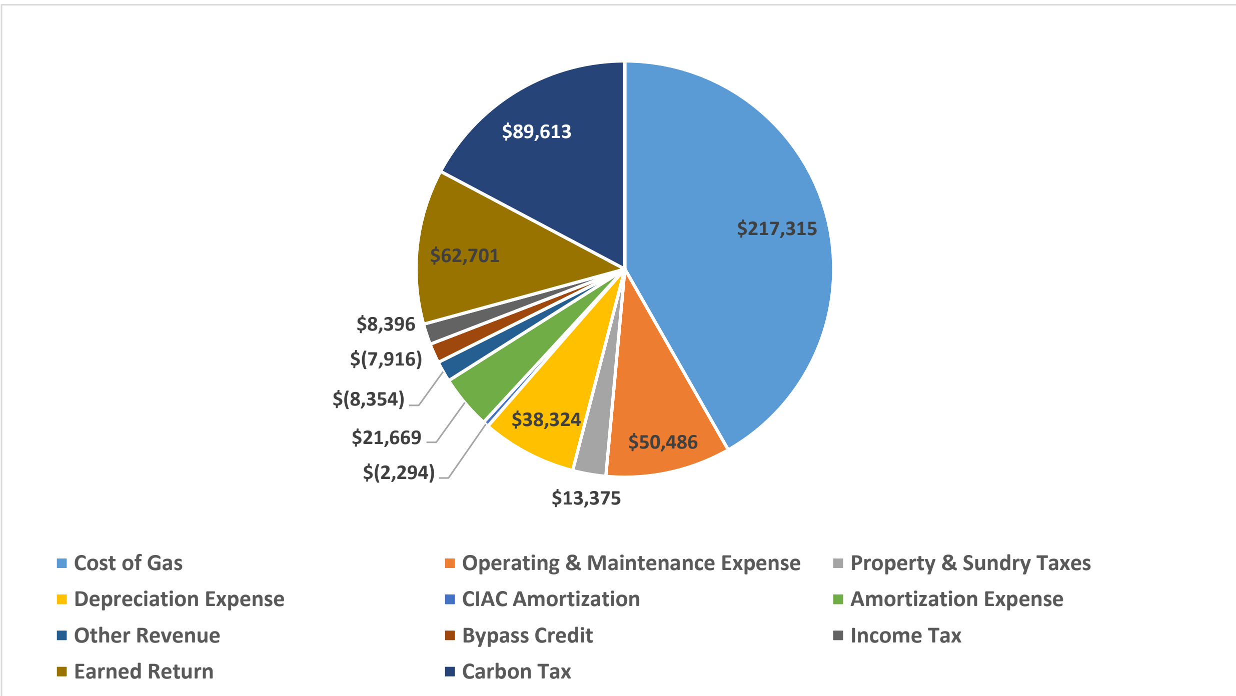
Please refer to the pie charts below for a breakdown of the revenue requirement components allocated to each rate schedule (excluding RS 4 and RS 7/27) in the 2023 COSA plus the estimated carbon tax paid by customers in each rate schedule based on volumes in the 2023 COSA. FEI notes that the carbon tax is *not* part of FEI's revenue requirement and therefore not part of the COSA study. The carbon tax value in each pie chart is an estimate based on the volumes included in the 2023 COSA for each rate schedule multiplied by the carbon tax rate at $2.5588 per GJ for January 1, 2023 to March 31, 2023, and at $3.2384 per GJ for April 1, 2023 to December 31, 2023.

FEI does not have any information regarding the cost of gas paid by RS 22, 22A, and 22B customers. The cost of gas included in the COSA for these customers is only their Unaccounted for Gas allocation; therefore, for the purposes of responding to this IR, FEI has determined the carbon tax by multiplying the customers' delivery volume by the BC carbon tax rates.

Figure 1: RS 1 Breakdown of Revenue Requirement Allocation in 2023 COSA plus Carbon Tax Payable by the Customer



1 **Figure 2: RS 2 Breakdown of Revenue Requirement Allocation in 2023 COSA plus Carbon Tax**
2 **Payable by the Customer**



3

Figure 3: RS 3/23 Breakdown of Revenue Requirement Allocation in 2023 COSA plus Carbon Tax Payable by the Customer

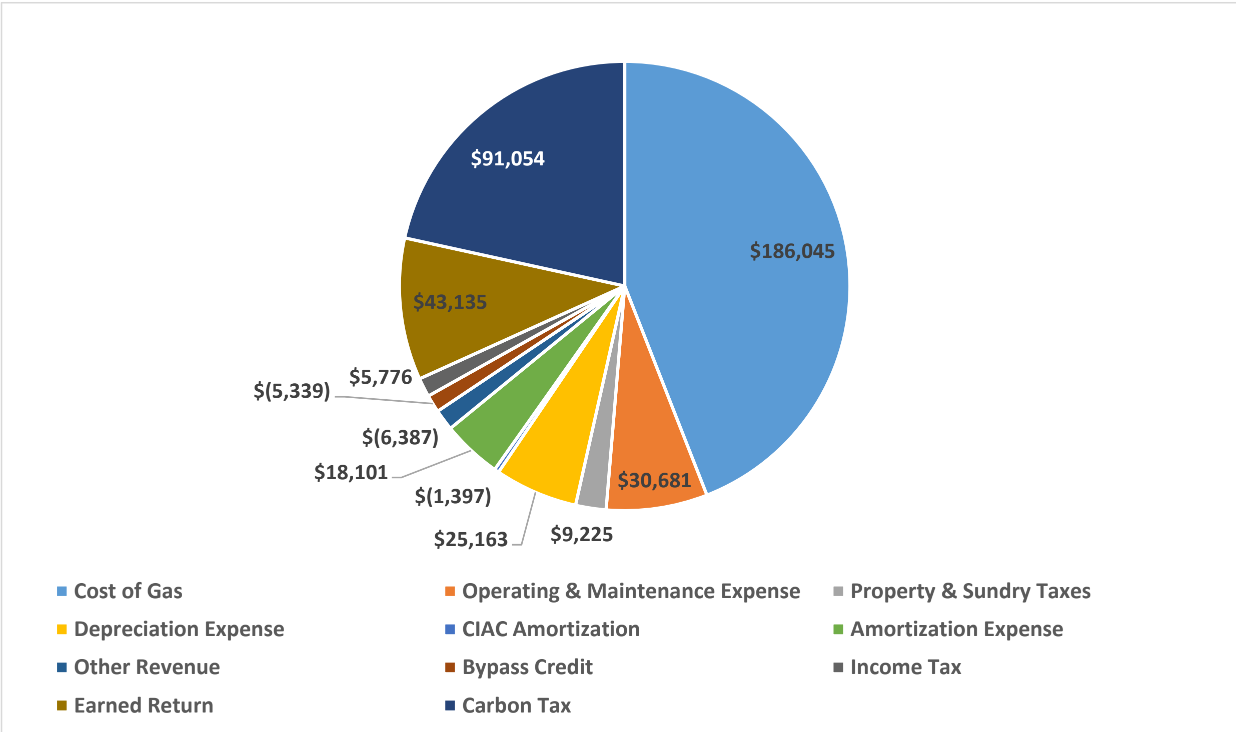


Figure 4: RS 5/25 Breakdown of Revenue Requirement Allocation in 2023 COSA plus Carbon Tax Payable by the Customer

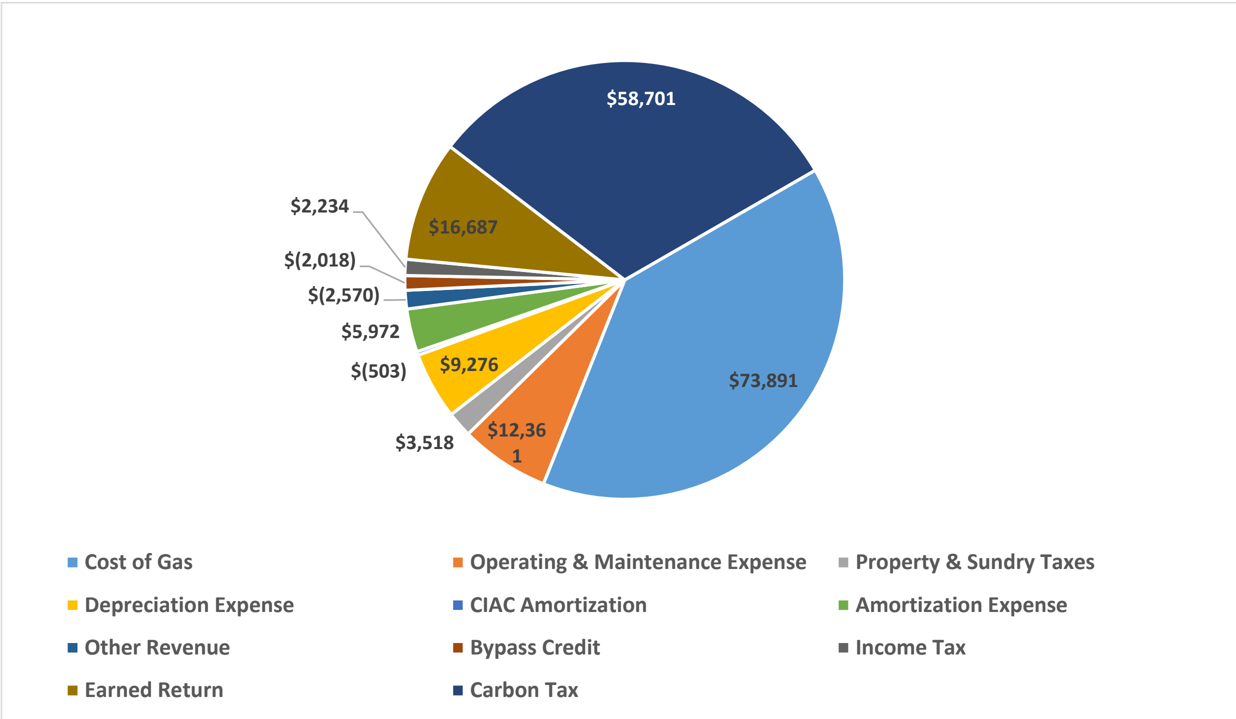


Figure 5: RS 6 Breakdown of Revenue Requirement Allocation in 2023 COSA plus Carbon Tax Payable by the Customer

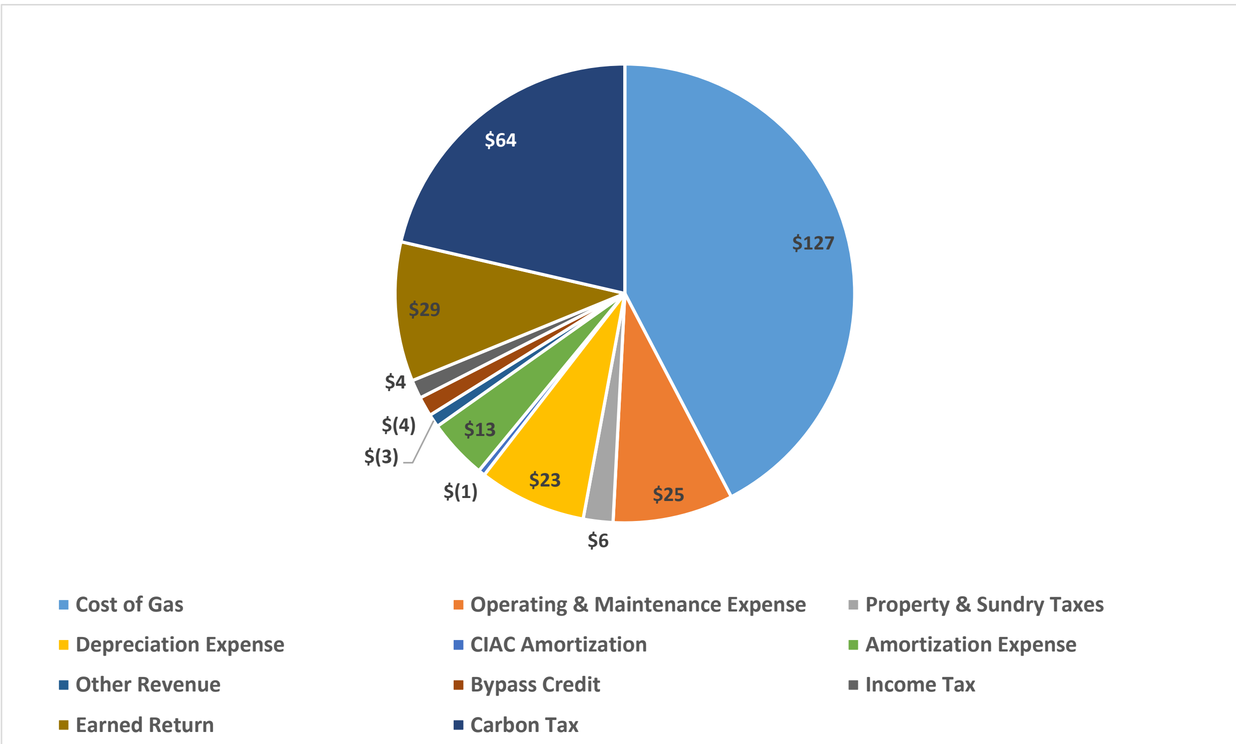


Figure 6: RS 22 Breakdown of Revenue Requirement Allocation in 2023 COSA plus Carbon Tax Payable by the Customer

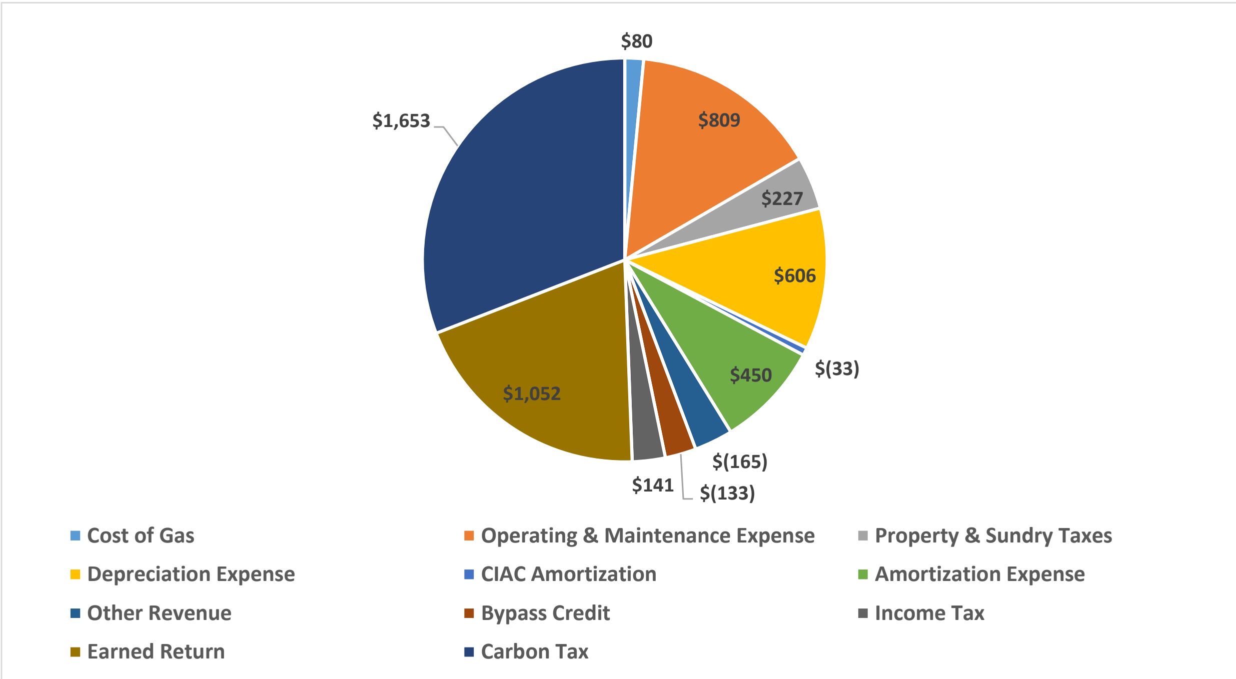


Figure 7: RS 22A Breakdown of Revenue Requirement Allocation in 2023 COSA plus Carbon Tax Payable by the Customer

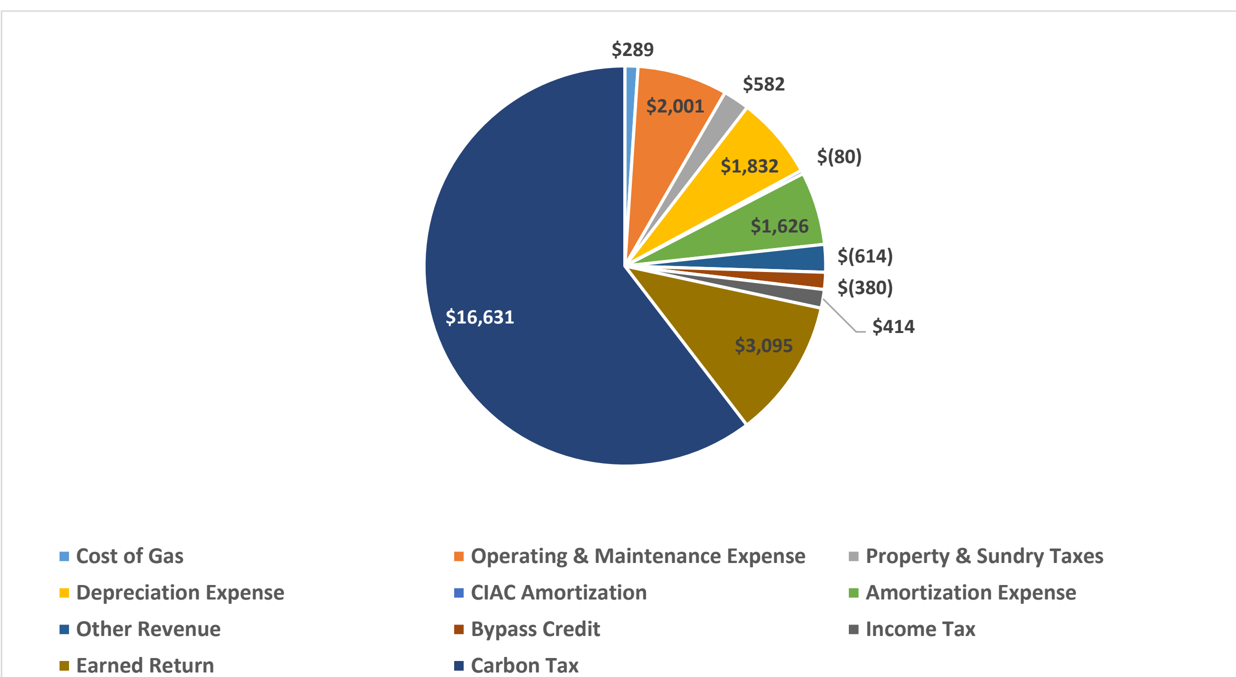
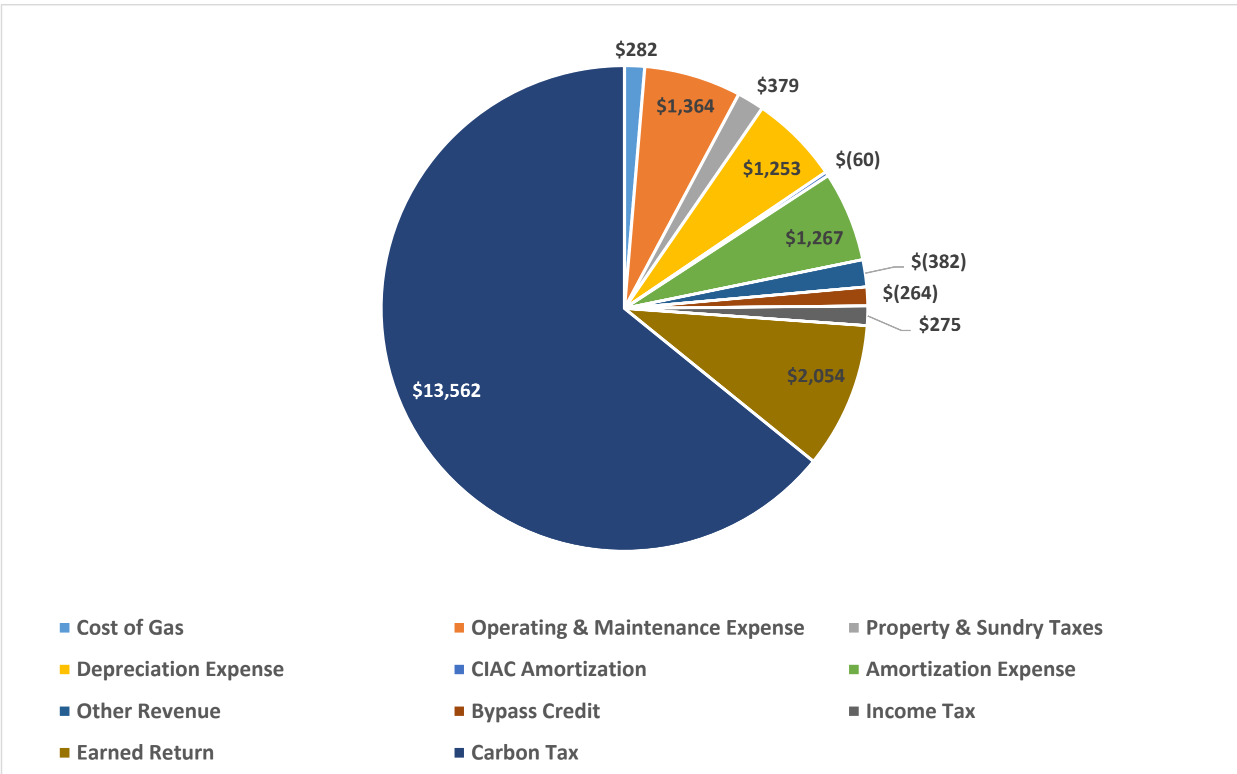


Figure 8: RS 22B Breakdown of Revenue Requirement Allocation in 2023 COSA plus Carbon Tax Payable by the Customer



7.0 Reference: Exhibit B-1, Application, page; Table 4-3, page 21

Topic: Allocation of Bypass credits to Non-bypass Rate Schedules

Preamble: FEI states:

> "…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 (i.e., sales and non-contract transportation service)." **(Application, page 21)**

> "Bypass industrial customers are in close proximity to upstream transmission pipelines and these customers have negotiated with FEI for delivery rates that are based on the customer's estimated cost of constructing and operating its own hypothetical pipeline to bypass FEI's system." **(Application, page 21)**

7.1 Please explain how bypass credits are allocated (i.e. functionalized, classified and allocated) to each customer class/rate schedule.

Response:

Consistent with the treatment from the 2016 COSA and RDA, the bypass and special contract revenues are functionalized as credits to transmission as these customers are generally in close proximity to the upstream transmission pipeline. The credits are allocated to all rate schedules based on the 2023 non-bypass delivery margin of each non-bypass rate schedule, and for presentation purposes, are grouped as demand-related classification.

Please refer to Table 1 below for the total bypass and Special Contract credits and the allocation to each rate schedule by the delivery margin of each rate schedule. The $12.909 million shown in Table 4-3 of the Application is revenue which includes cost of gas. FEI notes that it is the delivery margin recoveries (revenue less cost of gas) from the bypass and special contract customers that is being credited back to each rate schedule. FEI also notes the following:

- Table 4-3 of the Application did not include the recovery from the Vancouver Island Gas Joint Venture (VIGJV) which is also treated as a credit to FEI's non-bypass delivery margin. This is included in Table 1 below.
- Table 4-3 of the Application did not include the delivery margin from the RS 22 interruptible customers which, as discussed in Section 4.2.3.1, is also treated as an offsetting credit to FEI's other non-bypass customers.

Table 1: Summary of Bypass & Special Contract Offsetting Credits and Allocation to all Non-bypass Rate Schedules

Rate Schedule	Non-bypass Delivery Margin ($000's)	%	Bypass & Special Contract Margin ($000's)
RS 22 - Bypass			$ 349
RS 25 - Bypass			388
Byron Creek			134
VIGJV			4,896
Total Offsdetting Credit			$ 5,767
RS 1	$ 693,491	65.77%	$ (3,793)
RS 2	176,387	16.73%	(965)
RS 4	127	0.01%	(1)
RS 6	92	0.01%	(1)
RS 22	2,955	0.28%	(16)
RS 22A	8,474	0.80%	(46)
RS 22B	5,886	0.56%	(32)
RS 3/23	118,959	11.28%	(651)
RS 5/25	44,958	4.26%	(246)
RS 7/27	3,108	0.29%	(17)
Total	$ 1,054,438	100.00%	$ (5,767)

7.2 Further to Table 4-3, please provide a table that includes the total bypass credits and each class's/rate schedules allocated portion.

Response:

Please refer to the response to BCOAPO IR1 7.1.

7.3 Please explain the historical rationale of why FEI did not directly assign costs to industrial customers in close proximity to upstream transmission pipelines but rather based on an estimated cost of constructing and operating its own hypothetical pipeline.

Response:

The bypass rates were negotiated with individual customers, and approved by the BCUC, in the 1980s and 1990s. At that time, a bypass rate was based on what it would have cost the industrial customer to construct and operate a hypothetical pipeline connected to an upstream transmission system, thereby "bypassing" the utility. Since the construction and operation of a natural gas pipeline was not the industrial customer's core business, it was determined that it would be better for FEI to instead connect that customer to its distribution grid but charge the customer based on the cost of the hypothetical pipeline. These customers were not served with any existing rate schedules, nor were their rates based on an internal cost allocation. The hypothetical pipeline was never constructed or capitalized as an FEI asset, and the embedded cost of FEI's pipeline and facilities, from which the customer was served, was not considered when negotiating each bypass rate. Hence there is no direct assignment to be done. Ultimately, these customers are treated as offsetting revenues for the benefit of all non-bypass customers.

8.0 Reference: Exhibit B-1, Application, page 22

Topic: Biomethane Costs

Preamble: FEI states:

> "pursuant to the 2020-2024 MRP Decision for FEI, all biomethane related costs and revenues, including the original seven interconnections that were previously accounted for in FEI's delivery margin revenue requirement, are now included in the Biomethane Variance Account (BVA) with the balance to be recovered from customers through the Biomethane Energy Recovery Charge (BERC) and the BVA Rate Rider. As such, there are no biomethane costs and revenues accounted for in the 2023 COSA (i.e., all biomethane related assets or costs as well as any offsetting revenues such as the BVA Rate Rider are removed from FEI's rate base or cost of service for allocation purposes)." **(Application, page 22)**

8.1 Please confirm, or otherwise explain, whether the costs associated with biomethane, including both rate base/plant and revenue requirement expenditures are classified volumetrically and flow through to customers on an equivalent per/GJ basis.

Response:

Not confirmed. All biomethane related costs are removed from the 2023 COSA and are not recovered through the delivery rates. Instead, all biomethane costs as well as the offsetting revenues are recovered through the BERC and BVA rate rider. Please also refer to the response to BCOAPO IR1 6.8.

9.0 Reference: Exhibit B-1, Application, page 24

Topic: Known and Measurable Changes

Preamble: FEI states:

> "Table 4-5 below summarizes the known and measurable changes, which include adjustments to the RS 22 firm revenue and contract demand as well as three large major projects that have been approved by the BCUC which are expected to be in-service or close to their in-service dates by the effective date sought for implementation of the proposals in this Application, if approved, which is January 1, 2025. The rate base and cost of service of these known and measurable changes are included in the 2023 COSA and functionalized, classified, and allocated with existing costs as required." **(Application, page 24)**

9.1 Please provide a scenario of the 2023 COSA that removes revenues and costs (and other assumptions as necessary) associated with known and measurable changes to Test Year Revenues and Costs and provide all schedules. As part of the response, please provide a table that compares the allocated costs by class/rate schedule as proposed with the allocated costs by class/rate schedule that reflects the results of the scenario posed along with the drivers of material difference between the proposed allocation and the requested scenario.

<u>Response:</u>

FEI notes that, as discussed in Section 4.2.3 of the Application, known and measurable changes are typically large major CPCN projects that are already approved by the BCUC and are included in the COSA study such that the costs of these projects are reflected in the expected operating conditions for FEI in the near future. Including known and measurable changes in the 2023 COSA study is consistent with the methodology from past COSA studies, and this approach was supported by Elenchus as part of their review of FEI's 2016 COSA study.

Removing the costs related to the known and measurable changes identified in Table 4-5 of the Application, i.e., the incremental cost of service due to the IGU CPCN Project, the CTS-TIMC CPCN Project and the GCU Project, as well as the additional RS 22 firm demand revenue, will reduce the total costs that are functionalized, classified, and allocated. The removal of these items will also change the R:C and M:C ratios and will therefore change the revenue rebalancing.

FEI does not consider it appropriate to exclude known and measurable changes, as the rates resulting from any rebalancing will not reflect FEI's expected cost of service in the near future.

However, to be responsive, FEI provides the following tables comparing the impacts on the 2023 COSA with and without all known and measurable changes.

Table 1 below provides the R:C and M:C ratios (before rebalancing) with and without the known and measurable changes. Without the inclusion of known and measurable changes, in addition to RS 5/25 and RS 22, RS 22A will also need rebalancing as its R:C ratio is now 106.6 percent, which is over the upper bound of the range of reasonableness.

Table 1: R:C and M:C Ratios (before Rebalancing) with and without Known and Measurable Changes

Rate Schedule	As-Filed (Incl. Known & Measureable Changes) Before Rebalancing R:C	M:C	BCOAPO IR1 9.1 (Excl. Known & Measureable Changes) Before Rebalancing R:C	M:C
Rate Schedule 1 *Residential Service*	97.3%	95.0%	97.0%	94.4%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%	98.3%	96.2%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	111.2%	104.6%	113.2%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	126.9%	107.4%	129.6%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%	95.5%	89.4%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%	113.7%	114.1%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.9%	106.6%	106.8%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.1%	103.5%	103.7%

Rate Schedule (Rates Not Set Using Allocated Costs)	Before Rebalancing R:C	M:C	Before Rebalancing R:C	M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	124.1%	339.0%	123.2%	327.2%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	122.4%	628.0%	121.7%	604.0%

Table 2 below provides the rebalancing for the scenario where known and measurable changes are excluded from the 2023 COSA. Without the inclusion of known and measurable changes, the revenue shift to RS 1 customers will be slightly higher at $5.586 million, compared to approximately $4.5 million based on FEI's proposed rebalancing Option 5.

Table 2: R:C and M:C Ratios after Revenue Rebalancing (without Known and Measurable Changes)

Rate Schedule	Initial COSA (Excl. Known and Measurable Changes) R:C	M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing (Excl. Known & Measurable Changes) R:C	M:C
Rate Schedule 1 *Residential Service*	97.0%	94.4%	5,586	0.5%	97.5%	95.2%
Rate Schedule 2 *Small Commercial Service*	98.3%	96.2%	145	0.0%	98.4%	96.3%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.6%	113.2%	(145)	(0.0%)	104.5%	113.1%
Rate Schedule 5/25 *General Firm Sales and Transportation*	107.4%	129.6%	(4,095)	(2.2%)	105.0%	120.1%
Rate Schedule 6 *Natural Gas Vehicle Service*	95.5%	89.4%	-	-	95.5%	89.4%
Rate Schedule 22 *Large Volume Transportation Service*	113.7%	114.1%	(64)	(7.7%)	105.0%	105.1%
Rate Schedule 22A *Transportation Service (Closed) Inland*	106.6%	106.8%	(131)	(1.5%)	105.0%	105.2%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	103.5%	103.7%	-	-	103.5%	103.7%

Rate Schedule (Rates Not Set Using Allocated Costs)	Initial COSA R:C	M:C	Revenue Shift ($000s)	Approx. Annual Bill Impact (%)	COSA after Rebalancing R:C	M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	123.2%	327.2%	(51)	(3.3%)	119.2%	287.8%
Rate Schedule 7/27 *General Interruptible Sales and Transportation*	121.7%	604.0%	(1,245)	(1.4%)	120.0%	564.6%

The reason for the increased revenue shift to RS 1, when known and measurable changes are excluded, is because the known and measurable changes identified in Table 4-5 of the Application are major projects related to FEI's transmission system such as the IGU and CTS-TIMC CPCN projects. Transmission costs are classified as demand-related, which are allocated to all rate schedules (except for RS 4 and RS 7/27) based on peak demand. As such, with the costs removed, the "C" (cost) in the R:C ratio decreases, thereby increasing the R:C ratio if it was originally over 100 percent or reducing the R:C ratio if it was originally less than 100 percent. This effect is demonstrated by Table 1 above which shows the R:C ratios for RS 3/23, 5/25, 22, 22A and 22B all increasing, with RS 22A being pushed above the 105 percent upper limit of the range of reasonableness.

Tables 3, 4, and 5 below provide the change in functionalization, classification, and allocation to each rate schedule with and without known and measurable changes. By removing the known and measurable changes, the transmission functionalized costs are reduced, which leads to a reduction in demand-related costs.

Table 3: Functionalization of 2023 COSA with and without Known and Measurable Changes

Functionalization	Incl. Known & Measureable Changes (As-Filed) ($000s)	(%)	Excl. Known & Measureable Changes (BCOAPO IR1 9.1) ($000s)	(%)	Change ($000s)	(%)
Gas Supply Operations	$ 1,145,300	52.33%	$ 1,145,331	52.96%	$ 31	0.63%
LNG Storage Tilbury Base	17,878	0.82%	18,003	0.83%	125	0.02%
LNG Storage Mt. Hayes	6,963	0.32%	7,240	0.33%	277	0.02%
LNG Tilbury 1A	33,869	1.55%	34,607	1.60%	738	0.05%
Transmission	266,575	12.18%	232,470	10.75%	(34,106)	-1.43%
Distribution	599,406	27.39%	605,766	28.01%	6,360	0.63%
Marketing	79,955	3.65%	80,290	3.71%	335	0.06%
Customer Accounting	38,808	1.77%	38,868	1.80%	60	0.02%
Total	**$ 2,188,754**	**100.00%**	**$ 2,162,575**	**100.00%**	**$ (26,179)**	**0.00%**

Table 4: Classification of 2023 COSA with and without Known and Measurable Changes

Classification	Incl. Known & Measureable Changes (As-Filed) ($000s)	(%)	Excl. Known & Measureable Changes (BCOAPO IR1 9.1) ($000s)	(%)	Change ($000s)	(%)
Energy	$ 1,186,908	54%	$ 1,186,939	55%	$ 31	0.7%
Demand	521,250	24%	488,391	23%	(32,859)	-1.2%
Customer	480,595	22%	487,244	23%	6,649	0.6%
Total	**$ 2,188,754**	**100%**	**$ 2,162,575**	**100%**	**$ (26,179)**	**0.0%**

1 **Table 5: Allocation by Rate Class of 2023 COSA with and without Known and Measurable**
2 **Changes**

Cost of Service Margin Allocation	Incl. Known & Measureable Changes (As-Filed) ($000s)	(%)	Excl. Known & Measureable Changes (BCOAPO IR1 9.1) ($000s)	(%)	Change ($000s)	(%)
RS 1	$ 1,307,540	59.74%	$ 1,296,336	59.94%	$ (11,204)	0.21%
RS 2	393,702	17.99%	388,606	17.97%	(5,096)	-0.02%
RS 3/23	305,004	13.94%	300,222	13.88%	(4,781)	-0.05%
RS 4	1,260	0.06%	1,262	0.06%	2	0.00%
RS 5/25	118,849	5.43%	116,911	5.41%	(1,939)	-0.02%
RS 6	219	0.01%	219	0.01%	(0)	0.00%
RS 7/27	44,213	2.02%	44,264	2.05%	51	0.03%
RS 22	3,035	0.14%	729	0.03%	(2,305)	-0.10%
RS 22A	8,763	0.40%	8,189	0.38%	(574)	-0.02%
RS 22B	6,168	0.28%	5,837	0.27%	(330)	-0.01%
Total	**$ 2,188,754**	**100.00%**	**$ 2,162,575**	**100.00%**	**$ (26,179)**	**0.00%**

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10.0 Reference: Exhibit B-1, Application, pages 36, 37, 38, 44

Topic: CP Allocator

Preamble: 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." **(Application, page 36)**

> "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..." **(Application, page 37)**

> "The resources that FEI has in place are to meet design day and design year conditions." **(Application, page 44)**

> "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)….Table 4-11 below provides the load factors and peak day demand of each rate schedule used in the 2023 COSA." (**Application, page 37)**

10.1 Please discuss the factors other than peak day demand that drive the construction of FEI's delivery system and how factors other than peak day demand are addressed (other explicitly or implicitly) in the allocation of costs. If other factors are not addressed, please explain why.

Response:

As explained in Section 4.1.1.2, FEI's system and its associated costs can be classified into demand-related, energy-related, and customer-related. The development or construction of the delivery system can be driven by each of these classifications. For example, demand-related costs would be factors such as peak day demand and the maximum capacity of FEI's transmission and distribution system. Energy-related costs are costs that are impacted by the level of energy consumption, while customer-related costs are related to costs incurred for customer attachments to the distribution system.

As shown in Table 4-9 of the Application, in the 2023 COSA study, approximately 49.4 percent of FEI's delivery cost of service is demand-related (such as peak day demand), approximately 45.6 percent is customer-related (such as costs for customer attachments) and approximately 5 percent is energy-related (such as gas supply and DSM incentive costs).

10.2 Please confirm, or otherwise explain, that the CP allocator is based on the weighting of the most recent three-year average (of load factor and annual consumption). If not, please provide which three years of load factor and annual consumption data has been used for purposes of deriving the CP allocation for each class in the 2023 COSA with FEI's rationale.

Response:

Confirmed.

10.3 Please explain with supporting rationale, the basis of the use of three years in the derivation of the CP allocator.

Response:

Please refer to the response to BCUC IR1 13.2.

10.4 Please provide a fulsome conceptual discussion of how the three-year weighted average LF is derived. As part of the response please identify: i) the number of regions used; ii) the weighting and derivation for the average LF; and iii) whether each class/rate schedule is derived based on a straight average (which may implicitly reflect a weighting based on number of customers, for example).

Response:

Please refer to the response to BCUC IR1 13.2.

10.5 Please discuss FEI's views as to the purpose of deriving class CP based on a three-year average that considers regions, temperatures, and customer numbers by region.

Response:

Please refer to the response to BCUC IR1 13.2.

10.6 Please explain whether demand rates are derived and billed based on the same derivation of class CP as that derived for cost allocation purposes. If not, please explain the differences and provide the rationale for the difference between the allocation of costs, the design of rates, and billing.

Response:

FEI notes that only RS 5/25 and RS 22/22A/22B have demand charges as part of their total delivery charges. No other rate schedules have a demand charge.

The average demand cost for an RS 5/25 customer would be dependent on the customer's individual load factor such that customers with higher load factors, i.e., more efficient utilization of the system, would have lower average rates than those customers with lower load factors. The Demand Charge is not based just on the class load factor or class coincident peak (CP) of RS 5/25. The development of the RS 5/25 monthly Basic Charge, Demand Charge and Delivery Charge is explained in the 2016 COSA and RDA. The development of the rates took into consideration the economic crossover between a Large Commercial customer and a General Firm Service customer whose load profile had a higher load factor and a larger annual volume than a Large Commercial customer. All three charges, when applied to the billing determinants, resulted in revenues that were within the upper bound of the range of reasonableness.

For RS 22/22A/22B customers, their demand charges are based on their firm contracted demand which is used in the COSA study for allocating costs to these three rate schedules. The development of the RS 22 Demand Charge rate is explained in the 2016 COSA and RDA. Please also refer to the response to BCUC IR1 19.6 which provides the calculation of the Demand Charge (i.e., firm DTQ rate) for RS 22. RS 22A and 22B are closed service offerings pursuant to the BCUC's Decision regarding FEI's 1993 Phase B Rate Design; therefore, no customers can be added to these rate schedules. Since the 1996 negotiated settlement of FEI's 1996 Rate Design Application, the applicable Basic Charge, Demand Charge, and Delivery Charges have been increased by the rate changes approved through FEI's revenue requirement processes. The R:C ratios for RS 22A and 22B indicate that no changes to these rate schedules need to be made.

For all other rate schedules, there is no specific demand charge. The allocated demand-related costs (such as those allocated based on the peak-day demand or CP) are recovered through the fixed basic charge and the variable volumetric charge based on consumption. In other words, for these rate schedules, the demand-related costs are allocated based on the class CP and recovered through the basic and delivery charges.

11.0 Reference: Exhibit B-1, Application, page 50

Topic: Rate Design Principles

Preamble: FEI states:

> "Principle 5: Practical and cost-effective to implement (sustainable and meet long-term objectives)" **(Application, page 50)**

11.1 Please discuss FEI's long-term rate design objectives and how its COSA and Rate Design proposals reflect these objectives.

<u>Response:</u>

FEI's rate design objectives, both short-term and long-term, are to ensure that its rates continue to be just and reasonable, taking into consideration relevant Bonbright principles and standard utility practice.

FEI's 2023 COSA study was conducted in accordance with standard utility practice and demonstrates that FEI's current rates are performing as intended. FEI's rebalancing proposals are consistent with relevant Bonbright principles and, with all R:C ratios falling within the range of reasonableness after rebalancing, indicate that FEI's proposed rates will be just and reasonable, as they will recover a fair allocation of costs for the service that each rate schedule is receiving.

12.0 Reference: Exhibit B-1, Application, pages 52 and 58

Topic: Cost Allocation & Economic Crossover Volume (Rate Design)

Preamble: FEI states:

> "Table 5-1 below shows that 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). Therefore, it is mathematically certain that the economic crossover point between RS 2 and RS 3/23 will deviate over time from the segmentation threshold of 2,000 GJ per year." **(Application, page 52)**

> "As the R:C ratio for RS 5/25 is currently above the upper range of reasonableness of 105 percent, RS 5/25 could be rebalanced and, as discussed in Section 5.2.2 above, there is also a possible adjustment to RS 3/23 to address the economic crossover point between RS 2 and RS 3/23. Both of these adjustments could impact the economic crossover point between RS 3/23 and RS 5/25." **(Application, page 58)**

12.1 Please explain conceptually why it is appropriate to restrict inter-class rebalancing (that is between classes) in order to address an intra-class (rate design) matter.

<u>Response:</u>

There is no restriction on inter-class rebalancing to address an intra-class matter related to the economic crossover point between RS 2 and RS 3/23 customers, or the economic crossover point between RS 3/23 and RS 5/25 customers.

These are two separate issues that are being addressed through this Application. For the rebalancing matter, the objective is to move the R:C ratios of all rate schedules (except RS 4 and RS 7/27) within the range of reasonableness. To address the economic crossover, the objective is to adjust the basic charges and variable charges accordingly to move the economic crossover back to 2,000 GJ. To balance the impacts of the two separate issues, FEI explored various options as discussed in Section 5.3 of the Application (as well as additional options explored in various information requests as part of this proceeding) and evaluated each option based on the resulting rate impacts to each rate schedule, guided by Bonbright's principles.