Sarah Walsh
Director, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (778) 578-3861
Cell: (604) 230-7874
Fax: (604) 576-7074
www.fortisbc.com

November 23, 2023

Residential Consumer Intervener Association
c/o Midgard Consulting Inc.
Suite 828 – 1130 W Pender Street
Vancouver, B.C.
V6E 4A4

Attention: Peter Helland, Director

Dear Peter Helland:

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 Residential Consumer Intervener Association (RCIA) 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 RCIA IR No. 1.

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

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

1. Reference: Exhibit B-1 Application p.11; 2016 Rate Design Application Proceeding Exhibit B-1 Appendix 6-1

Elenchus and EES Reports

On page 11 of the Application, FEI states:

> *On February 21, 2017, the BCUC issued a letter explaining that the BCUC staff retained an independent consultant, Elenchus Research Associates Inc. (Elenchus) to independently review FEI's COSA study and rate design. Elenchus filed its COSA report on April 26, 2017, and its Rate Design Report on June 23, 2017.*

On page 9 of the Appendix to its Order G-4-18, the BCUC states:

> *FEI retained EES Consulting Inc. (EES Consulting), a third party expert in public utility rate design matters, to review and assist in developing the COSA study and rate design for FEI. EES Consulting assessed the appropriateness of the COSA methodology and rate design, made recommendations for changes it felt were warranted, and reviewed the COSA model created by FEI staff. EES Consulting also prepared a report, which is included in Appendix 6-1 of the Application.*

1.1 Please file the Elenchus COSA report and Elenchus Rate Design Report filed with the BCUC in the 2016 Rate Design Application proceeding.

<u>Response:</u>

Please refer to Attachment 1.1A for the Elenchus COSA Report and Attachment 1.1B for the Elenchus Rate Design Report filed with the BCUC as part of the 2016 COSA and RDA proceeding.

1.2 Please file the EES Report on FEI's cost of service allocation from the 2016 COSA proceeding.

<u>Response:</u>

Please refer to Attachment 1.2 for the EES COSA Report for FEI's 2016 COSA study filed as part of the 2016 COSA and RDA Proceeding.

2. Reference: Exhibit B-1 Application p.12

Daily Demand Formula

On page 12 of the Application, FEI states:

> *An adjustment to the multiplier in the Daily Demand formula in RS 5/25 general firm service from 1.25 to 1.10 and an increase to the Demand Charge of RS 5/25 such that the economic crossover point between RS 3/23 and RS 5/25 incented high load factor customers to take service under RS 5/25, which also generated revenues needed to recover the cost of service;*

2.1 Please explain the Daily Demand formula and how the multiplier works.

<u>Response:</u>

As stated in the currently approved tariffs for RS 5 and RS 25 customers:[1]

> Daily Demand is equal to 1.10 multiplied by the greater of:
>
> a) the Customer's highest average daily consumption of any month during the winter period (November 1 to March 31); or
>
> b) one half of the Customer's highest average daily consumption of any month during the summer period (April 1 to October 31).
>
> The calculation of Daily Demand will be based on the Customer's actual gas use during the preceding Contract Year.

---

[1] RS 5: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/rateschedule_5.pdf?sfvrsn=1b55c32f_31 (page R-5.21);
RS 25: https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/rateschedule_25.pdf?sfvrsn=2caeaafa_22 (R-25.35)

3. Reference: Exhibit B-1 Application p.12

Allocation to RS 4 and RS 7/27

On page 12 of the Application, FEI states:

> *The continuation of the existing discount between interruptible (RS 7/27) and firm service (RS 5/25), and also between seasonal firm service (RS 4) and firm service (RS 5/25);*

3.1 Please explain the rate design (i.e., how rates are established) for RS 4 and RS 7/27. Why are these classes not allocated costs reflecting their demand and consumption characteristics and numbers of customers in order to establish their rates?

Response:

Please refer to Attachment 3.1 which contains a discussion from the 2016 COSA and RDA of the rate design principles and reasoning for setting RS 4 and RS 7/27rates.

As part of the COSA study, interruptible (RS 7/27) and seasonal (RS 4) customers are allocated costs that reflect zero demand on the system design peak day since these customers are not consuming gas (are or will be interrupted) under the extreme peak weather conditions and therefore they do not contribute to peak demand nor require the utility to construct system capacity upgrades to serve them. If the rates of these customers were set based on their allocated costs, and because no demand-related costs are allocated to them in the COSA, their rates could become so low that they would essentially become "free-riders" on FEI's system. This would be unfair to firm (non-interruptible) customers for whom the system is designed to serve during the winter peak, and to whom the majority of demand related costs are allocated in the COSA study.

As such, and as explained in Attachment 3.1, the rates for RS 7/27 and RS 4 are set based on the value of the service that they receive as an interruptible customer as a discount to the service that they would receive as a General *Firm* Service (RS 5/25) customer. This way, the interruptible customers will be contributing to the recovery of FEI's transmission and distribution system costs when they are not interrupted during the non-peak day periods.

The BCUC supported the RS 7/27 and RS 4 rate design in the 2016 RDA Decision:[2]

> The Panel finds the following points support FEI's proposal to maintain the current discount:
>
> - Elenchus' analysis supports providing interruptible service at a discount to firm service. Elenchus states that "Conceptually, it is reasonable to provide a discount for interruptible service that results in the total annual lost revenue being no more than the annualized costs avoided as a result of the ability to curtail the interruptible customers."

[2] Decision and Order G-135-18, pages 23 to 24.

- Offering an interruptible service is beneficial to all FEI customers, as it allows FEI to defer the need for new infrastructure and the associated costs to its system. FEI calculates that the value to all customers of the avoided cost of service from RS 7/RS 27 customers is approximately $0.04 per GJ, or a net annual benefit of approximately $5 million;
- Interruptible service is not firm service at a discount. Customers can be interrupted if needed and will either incur cost to for backup systems or experience costs related to interrupted operations. Accordingly, a low discount may discourage new interruptible customers and may also cause existing interruptible customers to migrate to firm service; and
- The interruptible customer base is relatively stable which provides support for the current discount. If the discount was too large and the expected level of curtailment is very low, then there would more firm customers migrating to interruptible service.

4. Reference: Exhibit B-1 Application p.22

Natural Gas Transportation Costs and Revenues

On page 22 of the Application, FEI states:

> *Pursuant to Direction No. 5 to the BCUC, and approved by Order G-161-12, both the costs and revenues for FEI's NGT program (CNG and LNG service) are part of FEI's natural gas class of service and are included in the delivery charges for all non-bypass customers. As such, the recoveries of FEI's constructed fueling stations, i.e., capital, O&M, and Overhead & Management (OH&M) charges, are included as Other Revenue in FEI's revenue requirement and treated as an offset to the cost of service in the 2023 COSA. The related NGT plant-in-service and O&M expenses are included in FEI's natural gas class of service and functionalized as Distribution, and the costs are classified as part demand-related and part customer-related, as discussed in Section 4.1.1.2 above, and allocated to all non-bypass customers. This approach is consistent with the 2016 COSA study.*

4.1 Please explain the basis for allocating the revenues and costs of the natural gas transportation program.

Response:

The costs specific to FEI's NGT program are the assets, and operating and maintenance costs related to CNG and LNG fueling stations for use by local CNG and LNG vehicles. These stations are part of FEI's distribution system and as such, are functionalized as distribution.

As discussed in Section 4.3.2.4 of the Application, distribution functionalized costs are classified as 50 percent demand-related and 50 percent customer-related through the Minimum System Study (MSS) and are allocated to all non-bypass customers based on the gross plant of distribution costs. Allocating to all non-bypass customers is consistent with the treatment of all other distribution assets and with the allocation approach taken in the 2016 COSA study.

4.2 Which rate schedules serve natural gas transportation customers?

Response:

Natural Gas for Transportation customers receive their natural gas through Rate Schedules 3, 23, 5, 25, 6P and 46.

5. Reference: Exhibit B-1 Application pp.23,28,32; BCUC Order G-4-18 Appendix p.7

Tilbury Phase 1A Expansion Revenues/Costs and RS 45 and RS 50 Rates

On page 23 of the Application, FEI states:

The Tilbury 1A expansion has been in service since 2018. Therefore, as part of the 2023 COSA, FEI reverted to the standard approach for the Tilbury 1A expansion, which was supported by Elenchus in its 2016 COSA Report as the "standard practice". This standard approach is to use the 2023 forecast cost of service and RS 46 revenue that was included in FEI's approved 2023 delivery rates, with any surplus or deficit allocated to all of FEI's non-bypass customers.

5.1 Please provide the RS 46 revenues for each year from 2019 to 2022 and forecasted for 2023 through 2025.

Response:

Please refer to Table 1 below for the RS 46 revenue for each year from 2019 to 2022 Actual, and forecasts for 2023 and 2024 as provided in FEI's Annual Review for 2024 Delivery Rates. FEI does not have a forecast for RS 46 revenue for 2025 at this time.

	2019	2020	2021	2022	2023P	2024
RS 46 Revenue ($000s)	14,141	12,593	9,266	10,135	27,608	35,116

5.2 Please explain how RS 46 rates are set.

Response:

On November 28, 2013, FEI applied for approval of RS 46 pursuant to Order in Council (OIC) No. 557, dated November 27, 2013, B.C. Regulation 245/2013, Special Direction (SD) No. 5 to the BCUC and received approval with the issuance of BCUC Order G-211-13. RS 46 was included as Appendix 1 to OIC No. 557 and set the level and adjustment mechanisms of various charges. RS 46 was subsequently amended by OIC No. 749, dated December 19, 2014, B.C. Regulation 265/2014, SD No. 5 to the BCUC, adjusting certain charge adjustment mechanisms.

Please refer to the table below for the RS 46 charges and their escalation mechanisms related to the provision of LNG (dispensing) Service and LNG Transportation Service.

Table 1: RS 46 Charges related to LNG Transportation Service and LNG Service

Charge	Change Mechanism
LNG Transportation Service	
LNG Tanker Charge	Escalated annually at the greater of 2% or the BC CPI.
LNG Tanker Hauling Charge	FEI cost plus 15% Administration Charge
LNG Service	
LNG Facility Charge	Escalated annually at the greater of 2% or the BC CPI.
Electricity Surcharge	Adjusted by a 2% per year until after the Available LNG Capacity exceeds 20,000 GJ per Day, but thereafter shall be adjusted upon the estimated prior year electricity use per GJ of LNG Output of the LNG Facilities and approved interim or permanent BC Hydro rate increase incurred at the LNG Facilities.
LNG Spot Charge	Equal to $0.25 per GJ greater than the sum of the LNG Facility Charge and Electricity Surcharge, as adjusted, above.
Process Fuel Gas	Process Fuel Gas is deemed to be a quantity equal to 1% (one percent) of the LNG Dispensed to the Customer for this Rate Schedule after the Available LNG Capacity exceeds 20,000 Gigajoules per Day, but thereafter the Process Fuel Gas percentage will be updated annually based on the prior year's actual percentages of Gas consumed and losses of Gas at the LNG Facilities.

RS 46 includes other commodity related charges that are not exclusive to RS 46 and LNG service, are similar to other rate schedules and are cost based. These charges are related to the commodity and set out the prices for gas and biomethane, if elected, that an RS 46 customer would pay. RS 46 also includes charges that enable a customer to acquire and deliver their own commodity to FEI's interconnect (referred to as Transportation Service, or T-service).

FEI can apply to the BCUC to amend, cancel or add charges to RS 46.

5.3 Explain why RS 46 is not a cost-based rate based on the costs of the Tilbury Phase 1A facility along with an appropriate share of FEI's other costs (i.e. transmission to bring the gas to Tilbury, general administration, operating, and maintenance, marketing, etc.).

Response:

Please refer to the response to RCIA IR1 5.2.

On page 28 of the Application, FEI states:

> *As discussed in Section 4.2.2.5, the Tilbury 1A expansion has been in service since 2018 and the related costs were included in FEI's rate base on January 1, 2019. The Tilbury 1A expansion was included in the 2016 COSA study as a known and measurable change and at that time was functionalized in the same way as the Tilbury Base Plant, which was that the associated costs were allocated on a peak day demand basis to firm customers only (i.e., excludes RS 4, RS 7/27, and RS 22 Interruptible).*

On page 32 of the Application, FEI states:

> *Since the sales of LNG through RS 46 are credited back to all non-bypass customers through the delivery rates of each rate schedule, FEI is also allocating the related costs of the Tilbury 1A expansion based on the delivery margin of each of these rate schedules in the 2023 COSA.*

5.4 Please confirm or otherwise explain whether the Tilbury Phase 1A tank volume is fully reserved for NGT and LNG sales.

Response:

Except for the 5 mmcfd reserved for the Tilbury Base Plant (as discussed in Section 4.2.2.5), the Tilbury Phase 1A tank volume is reserved for LNG sales under RS 46, which includes FEI's NGT program and non-NGT sales (i.e., export).

5.5 Please identify the rate classes that make use of the Tilbury Phase 1A facility (other than the 5 TJ/d of liquefaction and interconnection).

Response:

FEI's LNG sales, which are served primarily from the Tilbury Phase 1A facility, are served with RS 46.

On page 7 of the Appendix to its Order G-4-18, the BCUC states:

> *FEI notes that RS 46 – LNG Sales, Dispensing and Transportation Service; and RS 50 – Large Industrial Transportation Service Rate Schedule, were established by Direction No. 5 to the Commission and are therefore not subject to change in this Application. FEI states that both costs and revenues for RS 46 are directly allocated to RS 46 with the net difference between the two being treated as a credit to the cost of service and allocated to all non-bypass customers.*

5.6 Please describe the circumstances under which RS 46 and RS 50 rates are subject to change.

Response:

Please refer to the response to RCIA IR1 5.2 for an explanation of the circumstances under which RS 46 rates would be subject to change.

RS 50 for Large Volume Industrial Transportation service has embedded in it the mechanisms by which it will be set and change over time. The RS 50 Table of Charges sets out those mechanisms and for ease of understanding FEI has summarized them below.

- The Initial Demand Toll for Firm Transportation Service is determined when FEI's first RS 50 customer commences taking service and will be based on the incremental cost to serve that customer plus a system contribution charge for the use of FEI's existing system.
- The Demand Toll for Firm Transportation Service (Firm Demand Toll) after the initial service period will escalate by FEI's General Rate Change[3] bound between 0 and 3 percent.
- The interruptible volume demand toll is set to 90% of the Firm Demand Toll if the interruptible gas is delivered between April 1 and October 31 inclusive, and 115% if the interruptible gas is delivered between November 1 and March 31 inclusive.
- If, at the time a new RS 50 customer enters into a transportation agreement with FEI, the forecast incremental cost of service associated with providing transportation service to such customer causes the Firm Demand Toll to increase by more than 5% above the Firm Demand Toll that would have applied if the customer had not entered into a transportation agreement, then FEI shall require the customer to:

  (a) provide a contribution in aid of construction; or

  (b) pay an additional toll or rate rider, that has the effect of limiting the increase in the Firm Demand Toll to 5% above the Firm Demand Toll that would have

[3] The General Rate Change is meant to reflect delivery rate changes.

applied if the customer had not entered into a transportation agreement under this rate schedule.

FEI can apply to the BCUC to amend, cancel or add charges to RS 50.

6. Reference: Exhibit B-1 Application p.18

Classification Methodology

On page 18 of the Application, FEI states:

> *Demand-related costs are those associated with plant that is designed, installed and operated to meet maximum daily gas flow requirements, such as transmission and distribution mains. Essentially, these are all costs associated with having peak capacity on standby and available upon peak customer demand. Given this, transmission and distribution capacity, compressor costs, and LNG storage are classified as demand-related costs with respect to FEI's requirement for serving peak demand at the winter peak.*

6.1 Is the apportionment between customer classes of peak demand in non-winter seasons (e.g., summer) meaningfully different than the apportionment for the annual (winter) peak? Please discuss.

6.2 Please discuss the pros and cons of using multiple peaks distributed across the year to apportion demand-related costs, versus only using a single annual peak.

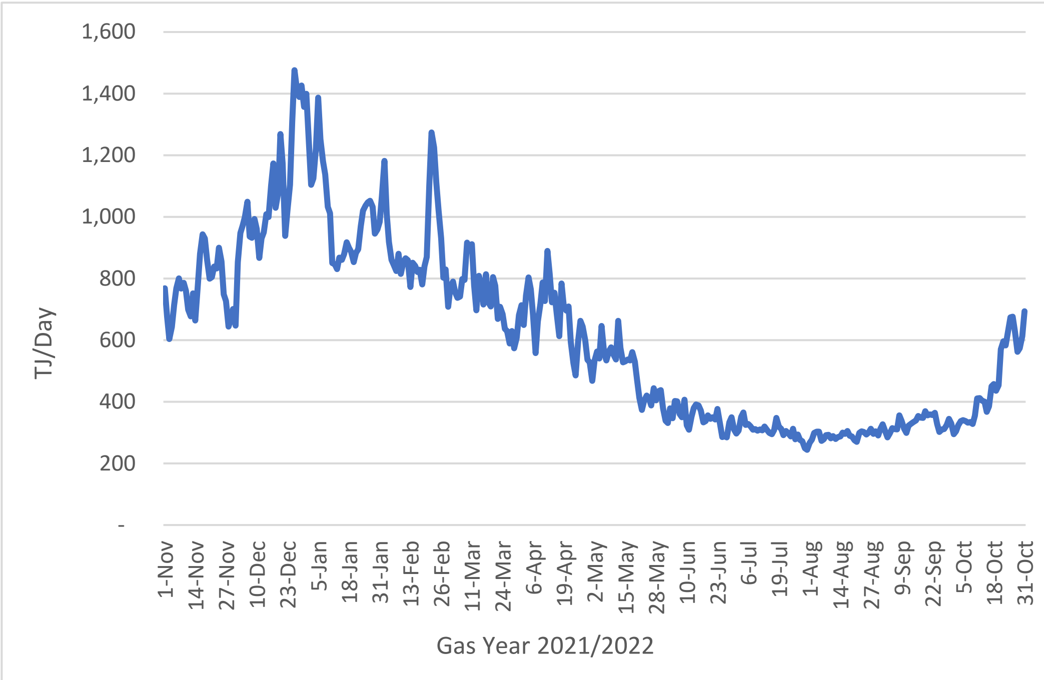
Response:

Most of FEI's customers are weather sensitive, which means they demand the majority of their natural gas when temperatures are at their lowest. FEI builds its system and secures gas supply resources to meet the winter (lowest) peak day design temperature. Consistent with FEI's history back to the 1970s, FEI has had a definite winter peak demand. FEI has not experienced a peak day demand outside of the winter period.

Figure 1 below shows the daily demand in TJ, for both sales and transportation customers, for the gas year November 1, 2021 to October 31, 2022, which clearly illustrates that FEI's peak demand occurs during winter, thereby driving FEI's transmission and distribution infrastructure. It would not be reasonable nor logical to use the summer demand for allocating FEI's transmission and distribution related costs.

As shown in Figure 1 below, FEI does not experience multiple design peak days throughout the year. There is a definite winter peak when extreme cold days occur and then the daily demands decline into the summer period and then start to increase in the fall period, ramping up to the winter peak demand.

Figure 1: FEI Daily Demand (TJ) from November 1, 2021 to October 31, 2022



The transmission, storage and distribution systems have been designed and built to provide firm service under design day conditions which occur in the winter. The demand-related costs have not been allocated on the basis of the number of days of peak, but on the basis of how each rate class contributes to peak demand on a design day event. It does not matter whether a design day event occurs multiple times or only one time during the year. FEI's allocation approach aligns with system design and cost causation.

7. Reference: Exhibit B-1 Application p.25

RS 22 Firm Revenue and Contract Demand Adjustments

On page 25 of the Application, FEI states:

> *For clarity, the additional RS 22 firm revenue has no overall impact to the cost of service in the 2023 COSA reflected in Table 4-5 above. The 10 additional RS 22 firm customers were previously fully interruptible customers under RS 22; therefore, reclassing existing interruptible demand to firm demand does not increase the overall revenue or cost of service in the 2023 COSA model since the interruptible charge under RS 22 is set to equal the effective charges for firm demand (i.e., Firm Demand Charge per Month plus the Firm MTQ Delivery Charge per GJ).*

7.1 Please explain why movement of customers from interruptible service to firm service does not increase the revenues received by FEI.

7.1.1 Why would interruptible service be priced the same as firm service, and if this is the case why would any customers elect interruptible service if it is the same price as firm service?

<u>Response:</u>

To be clear, the "movement" of customers from interruptible service to firm service as discussed on page 25 of the Application does not mean there is new volume or new customers. The movement is the result of existing RS 22 customers choosing to firm up some of their existing interruptible volume. The total volume of these RS 22 customers is the same before and after the move, the difference is that a portion of the existing customers' existing volume is now counted towards RS 22 firm and the remaining portion is counted towards RS 22 interruptible.

The rates for RS 22 interruptible service approved by the 2016 RDA Decision are set to equal the *<u>effective</u>* firm charges (i.e., the effective delivery charges per GJ are the same between RS 22 interruptible and firm service <u>at equal volumes</u>). As such, customers shifting their existing interruptible volume to firm volume (without adding new volume) do not have an impact on overall revenue. Please refer to the response to BCUC IR1 19.6 for the detailed calculations related to the split of the RS 22 effective firm charges between the Firm Demand Charge per month and Firm MTQ Delivery Charge per GJ.

Although there is no overall change in revenue, customers that decide to firm-up some, or all, of their volume, are required to pay for the firm volume of service (i.e., the portion paid under the Firm Demand Charge per month) regardless of whether they take the firm volume or not. Electing firm service ensures that some volume will be delivered to an RS 22 customer in a situation where interruptible customers are interrupted, with a trade-off that the firm volume must be paid for regardless of whether it is taken or not.

On page 25 of the Application, FEI states:

> *FEI also notes that, consistent with the 2016 COSA and as accepted by the BCUC in the 2016 COSA Decision, the R:C ratios for RS 22 firm customers are calculated and included in the 2023 COSA schedules while the revenues of RS 22 interruptible customers are treated as credits to the cost of service and allocated to each of FEI's non-bypass rate schedules.*

7.2 Please explain why the revenues of RS 22 interruptible customers are treated as credits to the cost of service and allocated to each of FEI's non-bypass rate schedules.

Response:

To be clear, it is the interruptible revenue (demand) of RS 22 customers that FEI treats as credits to the cost of service. Historically, all RS 22 customers were interruptible, but since the 2016 RDA Decision, RS 22 customers may firm-up some, or all, of their demand (within system capacity constraints). Therefore, an RS 22 customer could have some firm demand and some interruptible demand. Treating interruptible RS 22 revenue (demand) as credits to the cost of service and allocating to each of FEI's non-bypass rate schedules is consistent with past practice and the approach taken in the 2016 COSA and RDA (and approved in the 2016 RDA Decision).

To ensure that the costs allocated to RS 22 are limited to their firm (contract) demand[4], the interruptible revenue[5] is treated as a credit to the account of all other customers in the COSA study. If the RS 22 interruptible revenue was included together with the RS 22 firm revenue for setting rates, the R:C ratio for RS 22 would be extremely high because the costs allocated would be based only on the firm demand while the revenues would include both firm <u>and interruptible</u> revenue. Accounting for the interruptible revenue as a credit in the COSA study keeps it from distorting the R:C ratio for RS 22.

7.3 Please explain how the costs of serving RS 22 are allocated.

---

4 It is a rate schedule's firm demand for which FEI must construct its system to serve on the peak day, not interruptible demand.

5 Interruptible revenue is derived by multiplying interruptible demand by interruptible rates.

<u>Response:</u>

As explained in the response to RCIA IR1 7.2, the interruptible revenue from RS 22 is allocated as a credit to the other rate schedules in the COSA study.

Please refer to Table 1 below which shows the allocators for firm RS 22, including the relative percentages of the various costs classified as demand-related, energy-related or customer-related.

Table 1: Classification and Allocation of RS 22 Firm Costs

Allocation of	Classification	RS 22 # of Customers	Weighting Factor	Demand, Annual Energy, Weighted # of Customers	FEI Total	% of Total
Tilbury Base Plant, Tilbury 1A, Mt. Hayes LNG, Transmission	Demand			6 TJ	1,353 TJ	0.431%
Distribution Mains, Stations	Demand			6 TJ	1,092 TJ	0.534%
Distribution Mains, Stations	Customer	13	N/A	13	1,076,960	0.001%
DSM	Energy			2,128 TJ	188,656 TJ	1.128%
Distribution Meters & Services	Customer	13	97.8	1,272	1,269,006	0.100%
Customer Admim. & Billing	Customer	13	137.8	1,791	1,142,223	0.157%

8. Reference: Exhibit B-1 Application pp.29,32

Mount Hayes Functionalization and Classification

On page 29 of the Application, FEI states:

> *As the Mt. Hayes LNG facility has a different function than the Tilbury LNG facilities, its costs and revenues are allocated differently. The Mt. Hayes LNG facility went into service in 2011 and has a dual purpose of serving as 1) a gas supply storage facility and 2) a transmission facility which, similar to pipeline looping or compression, provides additional transmission system capacity.*
>
> *FEI currently credits approximately $18 million to Other Revenue in its revenue requirement while debiting the same amount to the midstream costs. This results in a transfer of costs from FEI's delivery cost of service, where the cost of transmission is accounted for, into FEI's midstream costs, where storage is accounted for. Under this treatment, all non-bypass customers receive an allocation of the Mt. Hayes facility through the delivery rates of each rate schedule to account for the transmission purpose of the Mt. Hayes facility, while only the sales customers will receive an allocation of the Mt. Hayes facility through their storage and transport charge for the storage purpose of the facility.*

On page 32 of the Application, FEI states:

> *Consistent with historical treatment, FEI has been classifying the delivery costs portion of the Mt. Hayes LNG facility as demand-related and the costs are allocated to all non-bypass customers on a peak day demand basis. For the storage component, sales customers receive an allocation of the Mt. Hayes facility through their storage and transport charge as part of FEI's gas costs.*

8.1 Please elaborate on the role of the Mount Hayes plant as a gas supply storage facility. Does FEI inject volumes in the summer and draw down in the winter in order to lower the cost of gas commodity? Does it lower the upstream transportation expense? Or is the Mount Hayes plant purely for peak shaving, reducing the amount of transmission plant needed to serve Vancouver Island?

<u>Response:</u>

The Mt. Hayes LNG storage facility serves several purposes for FEI. For example, the facility alleviates a capacity constraint between V1 and Victoria by providing supply during short periods of high demand during cold winter weather, as well as providing supply for peak shaving and providing operational or emergency support as needed. FEI confirms that supply is generally injected during the summer and withdrawn in the winter which can contribute to lowering the cost of gas; however, the plant does not impact FEI's upstream pipeline capacity holdings required to serve Vancouver Island, given its location and relatively small tank size. Further, since FEI generally refills the facility in the summer, FEI has upstream capacity to service this demand.

8.2 Please explain how FEI determines that $18 million is the correct amount to credit to Other Revenue and debit to the midstream costs.

Response:

The amount FEI credits Other Revenue and debits midstream costs reflects the storage value that Mt. Hayes provides. The quantification is based on the avoided cost of off-system storage and transportation.

In the 2016 COSA and RDA, FEI updated the avoided storage and transportation cost calculation for Mt. Hayes and included it as Appendix 6-11 to the application. At that time, FEI determined that $18 million was a reasonable estimate for the avoided cost of third-party storage and transportation and FEI was approved to continue to credit Other Revenue, thereby reclassifying $18 million of Mt. Hayes costs from delivery to midstream.

In the 2016 COSA Decision, the method for allocating the costs of the Mt. Hayes facility was approved by the BCUC (page 16):

> The Panel approves FEI's proposal regarding the treatment of the cost allocation for the Mt. Hayes LNG facility. FEI's proposal regarding the treatment of the cost allocation for the Mt. Hayes LNG facility is appropriate and reasonable since it reflects how FEI uses the facility in a dual-manner and the treatment is in alignment with cost causation principles. The Panel notes none of the interveners oppose FEI's treatment of costs associated with the Mt. Hayes LNG facility.

Since the Mt. Hayes facility is used in the same way as it was in 2016, FEI did not update the avoided storage cost calculation for this Application and has continued to treat $18 million of Mt. Hayes costs as midstream costs.

Please refer to Attachment 8.2, which is pages 6-14 to 6-16 from Exhibit B-1 of the 2016 COSA and RDA proceeding, setting out the updated calculation of avoided off-system storage and transportation costs.

8.3 Please explain how the Mount Hayes storage-functionalized costs are classified and why this is the appropriate classification.

Response:

As noted on page 29 of the Application, Mt. Hayes has a dual purpose. The $18 million serving as a credit for Mt. Hayes' storage purpose is effectively removed from the COSA study so that the only cost related to Mt. Hayes remaining in the COSA is the cost to serve the transmission purpose. Like FEI's other transmission costs, Mt. Hayes' transmission costs are classified as demand-related and allocated to rate schedules with firm demand based on the applicable rate schedules' contribution to peak day demand. FEI allocates transmission costs using peak day demand because FEI constructs its transmission and distribution systems to meet customer demand on the peak (coldest) day, which occurs in the winter.

8.4 Please explain the basis for the allocation of the Mount Hayes storage-functionalized costs are classified and why this is the appropriate allocation method.

Response:

Please refer to the response to RCIA IR1 8.3.

9. Reference: Exhibit B-1 Application p.30

Transmission Functionalization

On page 30 of the Application, FEI states:

> *FEI's Transmission function includes costs related to the transmission pipeline assets, compression, right of way and related maintenance, measurement control operations, and transmission supervision. It also includes an allocation of general and intangible plant costs and expenses. FEI is approved to credit Other Revenue for the Southern Crossing Pipeline (SCP) capacity from the Midstream Cost Reconciliation Account (MCRA). As such, the Transmission function also includes this credit related to the SCP capacity.*

9.1 Please explain whether any benefits accrue to FEI from accessing gas from TC Energy's Foothills pipeline as opposed to the Westcoast/Enbridge pipeline.

9.1.1 If there are benefits, such as reduced upstream transportation costs or lower commodity costs, should any of the SCP revenues be reflected in the Gas Supply function?

<u>Response:</u>

The main benefit to FEI from accessing gas from TC Energy's Nova Gas Transmission Ltd (NGTL) and Foothills pipelines is that it is the only way for FEI to diversify its dependence on the Westcoast/Enbridge T-South system. If FEI did not have access to this capacity, as well as the Southern Crossing Pipeline (SCP), FEI would need to contract additional capacity on the T-South system. Given the current market conditions, this would come at an increased cost compared to the existing tolls FEI pays for NGTL and Foothills capacity.

As FEI discussed in its 2020/21 Annual Contracting Plan (ACP)[6], FEI took back SCP capacity (FEI no longer contracts with external parties that wish to secure capacity on the SCP) effective November 1, 2020 to meet load requirements and provide supply diversity for its customers. Taking this capacity back was FEI's only opportunity in the marketplace to diversify its portfolio, which is vital in light of the October 9, 2018 rupture and capacity restrictions imposed thereafter on the Westcoast T-South pipeline. FEI now uses the SCP pipeline, in part, to transport gas to its various interconnects. Therefore, some of the costs of the SCP pipeline in FEI's delivery costs are moved to the Midstream portfolio (MCRA) so that only Sales customers, who receive the benefit of FEI's midstream contracting activities, bear those costs through Storage and Transport charges on their monthly bills. Moving the cost to the MCRA is achieved by crediting FEI's Other Revenue and debiting the MCRA in each Annual Review. This has the effect of transferring SCP costs from delivery to midstream.

[6] Accepted by BCUC Letter L-31-20, dated June 5, 2020.

The primary reason that the SCP revenues (the transfer of SCP costs to midstream) are functionalized as transmission is so that both the SCP costs and revenues are matched through the allocation process, leaving the net amount properly allocated in delivery rates.

10. Reference: Exhibit B-1 Application p.30

Distribution Functionalization

On page 30 of the Application, FEI states:

> *FEI's Distribution function includes costs related to the distribution pressure and intermediate pressure pipe assets, meter installation and exchange, service lines, preventative maintenance, field training, distribution pipe operations costs emergency management and an allocation of general costs and intangible plant costs and expenses.*

10.1 Please explain the rationale for functionalizing Intermediate Pressure mains as Distribution and not Transmission.

<u>Response:</u>

Prior to 1998, Inland Natural Gas Co. Ltd. (Inland) included Intermediate Pressure (IP) pipe as part of their distribution assets. When Inland acquired BC Gas Inc. (formerly the BC Hydro Gas Division) in 1988, discussions with the BCUC led to confirmation that IP pipe should be considered distribution assets. This is further supported by the following:

- The function and characteristics of an IP pipe are to distribute gas throughout an area, as opposed to transporting gas long distances; and
- Canadian Standards Association (CSA) Z662:23 Clause 12, and its previous editions, in consideration of the FEI IP operating pressures, define FEI's IP pipes as part of a gas distribution system.

There has been no separation of the cost details between IP lines and DP lines in FEI's asset accounting records.

10.2 Please explain how Intermediate Pressure mains are classified and why this is the appropriate classification.

<u>Response:</u>

IP lines are functionalized as Distribution mains and are included in the Minimum System Study (MSS) to determine how much of the cost is classified as Demand-related and as Customer-related. For the 2023 COSA study, the MSS resulted in the classification of 50 percent of the costs as demand-related and 50 percent as customer-related.

The minimum size pipe used to reach customers is the 60 mm pipe. This standard size has been in place since 2008 and it is only by exception that a smaller size pipe is used. The pipeline carrying capacity (PLCC) adjustment to each rate schedule's peak demand is based on the 60 mm pipe size capacity in each distribution network.

This approach of using the MSS to split the costs of distribution mains into demand-related and customer-related was supported by the BCUC in the 2016 COSA Decision (page 18):

> The Panel notes the acceptance of the parties and on its own review**, the Panel finds FEI's approach of using the MSS to split the costs of distribution mains between demand and customer related costs is reasonable for use in the COSA studies**.

11. Reference: Exhibit B-1 Application p.34,35

DSM Allocation Functionalization

On page 34 of the Application, FEI states:

The Marketing and Customer Accounting functions are generally classified as customer-related. This methodology is consistent with past practice and is appropriate, as the underlying cost causation for these functions is directly related to the customers served under each rate schedule and not based on their volumetric usage or demand. One exception is Demand Side Management (DSM) expenditures which are classified as energy-related since DSM programs reduce overall throughput via energy conservation. For the purposes of allocating costs to each customer class, FEI developed separate customer weighting factors for customer administration and billing, as described further in Section 4.3.3.3.

On page 35 of the Application, FEI states:

The remaining $41.6 million of costs are all related to the amortization of the DSM deferral account in the 2023 test year. All of these costs are allocated using the energy (volume in TJ) delivered by each rate schedule under the 2023 Test Year as provided in Table 4-10 below.

11.1 Please provide the rationale for allocating DSM costs based on each class' share of annual energy.

<u>Response:</u>

For clarity, all DSM related costs are classified as energy. The costs are first split between three subgroups of Residential, Commercial, and Industrial based on the average DSM expenditures distributed to those groups from 2016 to 2022. Residential and low-income programs are categorized as Residential, commercial-related programs are categorized as Commercial, industrial-related programs are categorized as Industrial, and all other program costs that are not specifically tied to Residential, Commercial, or Industrial are allocated to each subgroup based on the incentives categorized as Residential, Commercial, or Industrial. The DSM costs in each subgroup are then allocated to the rate schedules within each subgroup based on annual volume (energy consumption).

This approach of allocating the DSM costs using energy was reviewed[7] and agreed to by Elenchus[8] as part of their 2016 COSA Report. Although FEI's DSM allocation was not explicitly mentioned in the 2016 COSA Decision, FEI's 2016 COSA study was approved as filed, except for specific items (not related to DSM costs) that the BCUC identified.

---

7 Exhibit A2-2 of 2016 COSA and RDA proceeding, page 15, Lines 12 and 13, and also Line 16.

8 Exhibit A2-7 of 2016 COSA and RDA proceeding, Elenchus response to BCSEA IR1 1.1 and 1.1.1.

FEI considers that the DSM costs within each subgroup need to be allocated broadly using energy, as the intent of DSM is to achieve conservation of energy in alignment with government policy. The outcome of GHG reductions is also related to the annual energy reduction resulting from the DSM programs, not demand-related or customer-related. Using energy for allocation also ensures all natural gas customers are funding the DSM programs for the purpose of conservation as a whole. Using a demand classification would result in no costs being allocated to interruptible customers who are also benefiting from conservation and GHG reductions. Furthermore, the outcomes of FEI's natural gas DSM programs are mostly energy conservation/reduction, not peak demand reduction; therefore, it is reasonable to allocate using energy. Finally, if FEI were to use a customer classification, most DSM costs would be borne by residential customers since FEI's customer base is predominantly residential.

11.2 Please explain whether FEI has considered allocating DSM costs to each rate class according to each class' participation in DSM programming.

11.2.1 Please provide the pros and cons of such an approach.

Response:

This is effectively the approach that FEI has taken. Please refer to the response to RCIA IR1 11.1 for further explanation.

11.3 Please provide rationale for grouping amortization of the DSM deferral account costs within the Energy Classification rather than the Demand Classification.

Response:

Please refer to the response to RCIA IR1 11.1.

12. Reference: Exhibit B-1 Application p.37

RS 6 Natural Gas Vehicles Allocation

On page 37 of the Application, FEI states:

> *Consistent with past practice, RS 6 (Natural Gas Vehicles) has been assigned a 100 percent load factor for determination of its peak day demand since this class of customers is not heat sensitive.*

12.1 Please confirm whether the facilities that are used to fuel natural gas vehicles operate at a 100% load factor.

12.1.1 If not confirmed, please provide further rationale for the assumption of 100% load factor and why this is an appropriate assumption when determining the peak day demand for these customers.

<u>Response:</u>

FEI cannot confirm that all customers taking service under RS 6/6P are operating at a 100 percent load factor, as FEI only has monthly volume information (FEI's meters for this rate schedule do not measure daily volume). However, it is reasonable to believe that vehicle fueling is not heat sensitive and therefore does not coincide with FEI's winter peak demand. As such, consistent with past accepted practice, RS 6 has been assigned a 100 percent load factor for the determination of its peak demand for allocation purposes.

13. Reference: Exhibit B-1 Application p.37; Exhibit A-4 BCUC IR1 13

Load Factor

On page 37 of the Application, FEI states:

> *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).*

13.1 Please explain how FEI estimates the peak day demand for each rate schedule, particularly for customers/rate schedules that do not have demand meters.

Response:

Please refer to the responses to BCUC IR1 13.2 and 13.3.

In BCUC IR1 13.3, the BCUC requests:

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

13.2 Please confirm or otherwise explain whether FEI's formulas to calculate coincident peak from load factors are, essentially, a summation of individual rate class peak demands from several regions.

Response:

Please refer to the responses to BCUC IR1 13.2 and 13.3.

14. Reference: Exhibit B-1 Application pp.25,40; AMI CPCN Proceeding Exhibit B-30 Evidentiary Update Appendix A p.7

Advanced Metering Infrastructure

On page 40 of the Application, FEI states:

> *The weighting factors for meters and services are based on the average value of meter and service assets associated with each specific rate schedule relative to RS 1. For example, industrial customers are installed with bigger rotary meters and service lines, while residential customers are installed with smaller diaphragm meters and service lines; therefore, the average cost (i.e., including meter, service line, regulators and customer service) for industrial customers under RS 5 (i.e., approximately $29,545 per customer in 2022) is higher than the average cost for residential customers (i.e., approximately $1,872 per customer in 2022). In order to reflect the fact that an industrial customer under RS 5 has higher meter and service-related costs than a residential customer, the average number of customers under RS 5 would be multiplied by 15.8 for the purpose of allocating meter and service-related costs in the COSA model (i.e., Customer Weighting Factor as per Table 4-13 above which is equal to $29,545 divided by $1,872).*

14.1 Please explain how the roll-out of AMI and meter bypasses will affect the average costs and weighting factors in the COSA model.

<u>Response:</u>

AMI meters will replace the 200-series and 400-series meters that are presently used by residential and commercial customers. The average cost (including meters, service lines, regulators, and customer service) for RS 1 and RS 2 customers is $1,872 and $3,943, respectively, in the Customer Weighting Factor study as part of the 2023 COSA. With AMI meters replacing the 200-series and 400-series meters, the average cost for RS 1 and RS 2 becomes $1,919 and $3,951, respectively. FEI notes the change in average cost for RS 3 large commercial customers is negligible since only a small amount of meter sets currently used for RS 3 customers are the 200-series and 400-series (i.e., 86 total 200-series and 400-series meters out of an overall total of 6,017 RS 3 customers). There is no change in the average cost for other rate schedules' meters since they are not installed with 200-series and 400-series meters.

Please refer to Table 1 which provides the weighting factor with and without the changes related to AMI meters.

Table 1: Customer Weighting Factors with and without AMI Meters

Rate Schedule	Customer Weighting Factor (As-Filed)	Customer Weighting Factor with AMI Meters (RCIA IR1 14.1)
1	1.0	1.0
2	2.1	2.1
3	9.1	8.9
4	15.4	15.0
5	15.8	15.4
6	19.3	18.8
7	48.7	47.5
22	97.8	95.4
22A	309.5	302.0
22B	669.6	653.3
23	11.7	11.4
25	20.8	20.3
27	38.5[1]	37.5

Note to Table:

[1] As corrected in the response to BCUC IR1 14.1, the Customer Weighting Factor for RS 27 should be 38.5, not 48.7.

Please refer to Table 2 below which provides the R:C and M:C ratios with and without AMI. Changes in the R:C and M:C ratios are minimal due to AMI.

Table 2: Changes in R:C and M:C Ratios with AMI Meters included in Customer Weighting Factors

	As-Filed (Before Rebalancing)		RCIA 14.1 - Customer Weighting Factor incl. AMI (Before Rebalancing)		Difference	
Rate Schedule	R:C	M:C	R:C	M:C	R:C	M:C
RS 1	97.3%	95.0%	97.3%	94.9%	0.0%	-0.1%
RS 2	98.0%	95.6%	98.0%	95.6%	0.0%	0.0%
RS 3/23	104.0%	111.2%	104.1%	111.5%	0.1%	0.3%
RS 5/25	106.9%	126.9%	107.0%	127.1%	0.1%	0.2%
RS 6	96.2%	91.0%	96.8%	92.4%	0.6%	1.4%
RS 22	110.0%	110.2%	110.2%	110.5%	0.2%	0.3%
RS 22A	101.8%	101.9%	102.0%	102.1%	0.2%	0.2%
RS 22B	100.1%	100.1%	100.4%	100.5%	0.3%	0.4%
Rate Schedule (Not Set Using Allocated Costs)						
RS 4	124.1%	338.9%	124.3%	343.4%	0.2%	4.5%
RS 7/27	122.4%	628.0%	122.4%	633.4%	0.0%	5.4%

On page 25 of the Application, FEI provides Table 4-5 showing the known changes in revenues and costs that are factored into the 2023 COSA study:

Table 4-5: Summary of Known and Measurable Changes Included in 2023 COSA Study

Adjustments or Major Projects	Expected In-effect or In-Service Date	Change in Mid-Year Rate Base in 2023 COSA ($ millions)	Change in Cost of Service in 2023 COSA ($ millions)	Change in Firm Contract Demand in 2023 COSA (TJ/day)
RS 22 Firm Revenue and Contract Demand	2023	-	-	4.3
Inland Gas Upgrade (IGU) CPCN	2024 (Remaining Phase Only)	165.603	13.931	n/a
Coastal Transmission System Integrity Management Capabilities (CTS-TIMC) CPCN	2023, 2024, and 2025 (Complete in phases)	102.850	8.334	n/a
Gibsons Capacity Upgrade Project	2024	10.927	1.150	n/a
Total		**279.380**	**23.415**	**4.3**

In Appendix A to the AMI CPCN Proceeding Evidentiary Update, FEI provides an updated schedule:

Table 1-2: Project Schedule

Activity	Date
CPCN Filing	May 2021
Prepare	Q2 2021 – Q3 2022
Define	Q2 2022 – Q2 2023
Design, Build, Integrate and Ready For Deployment	Q2 2022 – Q3 2024
Deploy AMI Technology / Billing System Integration	Q3 2022 – Q3 2023
Deployment Region 1: Lower Mainland South	Q4 2022 – Q2 2025
Deployment Region 2: Lower Mainland North	Q2 2024 – Q4 2026
Deployment Region 3: North Interior	Q2 2023 – Q3 2025
Deployment Region 4: South Interior	Q1 2023 – Q2 2026
Deployment Region 5: Vancouver Island	Q3 2023 – Q3 2026
Deployment Region 6: Kootenays	Q3 2024 – Q4 2026
Deploy Enterprise Data Repository, Customer Portal, Leak Detection	Q1 2024 – Q1 2025
Final Acceptance	Q3 2026
Close Out	Q3 2026 – Q4 2026

14.2 With AMI installations being completed in 2022 through 2024, please explain why AMI is not included in the list of Known and Measurable Changes Included in the 2023 COSA study.

<u>Response:</u>

FEI notes that Table 1-2 of the AMI CPCN Application was not updated as part of the Evidentiary Update because there were no changes to Table 1-2. Given that the BCUC issued the AMI Decision and Order C-2-23 on May 15, 2023, it is not possible to have the Deployment of AMI technology starting in Q3 of 2022, as shown in Table 1-2 and referenced in the preamble above.

As explained in Section 4.2.3 of this Application, the effective date sought for implementation of the rebalancing proposals in the Application, if approved, is January 1, 2025. Accordingly, the known and measurable changes included in the 2023 COSA study are those changes that are expected to be in-service <u>by or soon after</u> January 1, 2025. The current anticipated schedule for first deployment of AMI is late 2024 or early 2025, with full deployment of AMI not expected to complete until at least 2027; as such, FEI did not include the AMI CPCN Project as a known and measurable change in the 2023 COSA study.

15. Reference: Exhibit B-1 Application pp.44,85

Benefits to Transportation Service Customers

On page 44 of the Application, FEI states:

Although the Storage and Transport Charge only applies to sales customers, the resources are used each day to balance the system as a whole, which benefits both sales and transportation service customers.

On page 85 of the Application, FEI states:

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

15.1 Please explain how FEI's storage and transportation resources are used to benefit Transportation Service customers.

15.1.1 Please explain how Transportation Service customers reimburse FEI for this benefit.

<u>Response:</u>

FEI manages the Operational Balancing Agreement ("OBA") at the interconnect locations on the Westcoast T-South and TC Energy Foothills systems. Both FEI and shipper agents representing transportation customers deliver supply to these interconnect locations on a daily basis to serve the demand of their respective customer groups. As FEI manages the OBA as a whole for each cycle of the gas day, FEI may need to implement resources as provided for in the ACP to physically balance the supply and demand at a given interconnect location. When FEI uses Midstream resources to manage imbalances caused by either or both customer groups, Transportation customers inherently benefit from the resources used to balance the system.

The incremental balancing charge that was approved in the 2016 COSA and RDA for balancing beyond a 10 percent tolerance is designed to serve as an incentive to shipper agents to balance within the 10 percent tolerance. When shipper agents exceed this tolerance, the charges incurred are collected to compensate core customers for the costs of system balancing. The revenue from balancing service charges, as well as from all other charges included in the transportation tariffs, are credited to offset the midstream costs and serve to reduce the Storage and Transport Charge that core customers pay.

15.2 Please reconcile the statements on page 44 with respect to Transportation Service customers benefiting from storage and transportation resources with the statements on page 85 indicating that Transportation Service customers are not entitled to benefit from midstream resources.

Response:

To clarify, FEI stated in the Application that "Transportation Service customers do not pay for those midstream resources and are not entitled to benefit from them at the expense of core customers". [Emphasis added]

As part of its daily activities, FEI balances gas demand and supplies at each of its interconnects using the midstream resources it has acquired for sales customers. While Transportation service customers inherently benefit from these balancing activities, it is the responsibility of the Transportation service customer or its shipper agent to acquire the appropriate midstream resources to deliver the gas to FEI's interconnect with Westcoast or Trans Canada. In the event that shortfalls or imbalances occur, balancing charges as approved by the BCUC will apply to the Transportation service customers or their shipper agents. The revenues collected through these balancing charges are credited to the MCRA, which lowers the Storage and Transport Charge for sales customers in the following gas years from what they would be otherwise pay.

FEI's Transportation Services Model was extensively reviewed and updated as part of the 2016 COSA and RDA. Further, the BCUC recently reviewed FEI's balancing charges again as part of FEI's Transportation Service Report filed on June 15, 2022 pursuant to BCUC Decisions and Orders G-135-18 and G-210-20. The Transportation Service Report reviewed and assessed the performance of the Transportation Service Model under the new and updated customer-balancing tariff terms, conditions and charges which were approved in Order G-135-18 (New Rules). The Report shows that the New Rules are working as intended by incenting shipper agents to appropriately manage their supply and demand requirements daily on FEI's system on behalf of their customers. FEI's conclusions in the Report are supported by the detailed analysis and review conducted by an independent, third-party expert, Atrium Economics, LLC (Atrium Economics), including a benchmarking study comparing FEI's New Rules to local distribution companies (LDCs) across North America. The BCUC accepted the Transportation Service Report in Order G-372-22, dated December 16, 2022. Please refer to Attachment 15.2 for the 2022 Transportation Service Report which also included the Atrium's review in Appendix A of the report.

16. Reference: Exhibit B-1 Application p.45

Interruptible and Seasonal Customers

On page 45 of the Application, FEI states:

> *For Interruptible (RS 7) and Seasonal (RS 4) customers, the Storage and Transport Charge is set equal to the rate for RS 5. Interruptible and seasonal customers have a zero peak day value, as the interruptible customers would be curtailed on extreme cold weather days and the load from seasonal customers primarily occurs during the non-heating (off peak) months.*

16.1 Please explain why Interruptible and Seasonal customers pay the same Storage and Transport Charge as RS 5 customers if they do not receive the same benefits in terms of meeting winter peak demand as RS 5 customers receive.

Response:

FEI notes that the rate-setting approach for the Storage and Transport Charge to recover midstream costs is not in scope of this Application. Rates for the Storage and Transport Charge, and the Commodity Cost Recovery Charge are dealt with in FEI's quarterly gas cost reviews with rates approved by the BCUC.

In the quarterly gas cost reviews, there are no midstream costs allocated to RS 7 (fully interruptible) and RS 4 (seasonal) sales service. The storage and transport charges for RS 7 and RS 4 have been set to equal RS 5 (General Firm Service) since April 1, 2004, following Order G-25-04 as part of the FEI (TGI at that time) Cost Allocation Application for Commodity Unbundling and Customer Choice Phase 1 Application. Similar to pipelines, even though FEI must contract its midstream resources to meet peak winter requirements, these resources are used throughout the year to serve all sales service customers. Therefore, while these costs are allocated based on the load factor of FEI's winter peaking sales service customers, they are used to serve all sales service customers, including RS 4 and RS 7. Accordingly, since RS 7 and RS 4 customers are winter interruptible, their storage and transport charges are set based on the value of the service rather than the winter peak load factor. These customers should therefore be contributing to the recovery of FEI's midstream costs by paying the same storage and transport charge as RS 5 customers, which provides some recovery of these costs and benefits all other firm sales customers.

17. Reference: Exhibit B-1 Application p.47; Exhibit A-4 BCUC IR1 17.1

Revenue: Cost and Margin: Cost Ratios

On page 47 of the Application in footnote 75, FEI states:

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

In its IR 17.1, the BCUC requests:

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

17.1 Please confirm or otherwise explain that if FEI used M:C ratios, there would be no need to impute the cost of gas for transportation rate schedules.

Response:

Confirmed. If the M:C ratios were used, there would not be a need to impute the cost of gas for RS 23, 25 and 27. However, please refer to the response to BCUC IR1 15.1 for an explanation of the imputed cost of gas for RS 23, 25, and 27. Please also refer to the responses to BCUC IR1 15.2, 17.1, and 17.3 for a discussion of why M:C ratios are not used to inform FEI's revenue rebalancing proposals.

18. Reference: Exhibit B-1 Application p.52,54

Economic Crossover Point and RS 3/23 Consumption Threshold

On page 52 of the Application, 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).*

18.1 Please explain why FEI maintains a constant Basic Charge instead of increasing the Basic Charge by the same percentage as the delivery charge when rate changes are requested.

Response:

Basic charges have remained constant since 2009[9] with rate changes typically flowing to Delivery and Demand Charges.[10] The intent was that with rate increases only impacting the charges that varied with volume, customers would be encouraged to consume less, thereby conserving energy.

18.2 Please confirm or otherwise explain whether the economic crossover point is expected to remain stable if rate increases are applied equally to the Delivery Charge and the Basic Charge.

Response:

Please refer to the response to BCUC IR1 21.3.

On page 54 of the Application, FEI states:

9 With the exception of FEI's 2016 COSA and RDA, where some Basic Charges were amended.

10 Approved by Order G-141-09 following a Negotiated Settlement Agreement for the 2010 and 2011 RRA.

As shown in Figure 5-1 above, approximately 87,000 (or 99 percent) of RS 2 customers consumed less than 2,000 GJ in 2022 while only approximately 625 customers consumed more than the 2,000 GJ threshold.

For RS 3/23 customers, Figure 5-2 below shows that the majority consumed more than 2,000 GJ in 2022, with approximately 1,600 (or 20 percent) consuming less than 2,000 GJ in 2022. Many of these customers likely have reduced their operations during the year, have implemented energy efficiency measures, had business ownership changes, or only had a partial year of operations.

Based on the bill frequency of RS 2 and RS 3/23, the segmentation threshold of 2,000 GJ remains reasonable as almost all commercial customers approximately 98 percent) are correctly placed in either RS 2 or RS 3/23 in terms of the volume threshold of 2,000 GJ.

18.3 Please explain the origin or rationale for segmenting RS 2 and RS 3/23 customers at 2000 GJ/year as opposed to some other threshold.

Response:

The origin of the segmentation between RS 2 and RS 3/23 at 2,000 GJ was the 1993 Phase B Rate Design. Please refer to the response to BCUC IR1 21.4 for the rationale from the 1993 Phase B Rate Design Application and also a discussion of why FEI considers that the threshold between Small and Large Commercial customers should remain at 2,000 GJ.

18.4 Please provide the tariffs for RS 2, RS 3/23, and RS 5/25.

Response:

Please refer to the links below for the currently approved tariffs of each requested rate schedule:

- RS 2 Small Commercial;
- RS 3 Large Commercial;
- RS 23 Large Commercial Transportation Service;
- RS 5 General Firm Service; and
- RS 25 General Firm Transportation Service.

18.5 Please identify the number and percentage of RS 2 customers consuming less than i) 1000 GJ/year and ii) 1500 GJ/year.

Response:

Please refer to Table 1 below for the number and percentage of RS 2 customers consuming less than 1,000 GJ per year and 1,500 GJ per year. Overall, approximately 91 percent of RS 2 customers consumed less than 1,000 GJ per year and 97 percent of RS 2 customers consumed less than 1,500 GJ per year based on 2022 actuals.

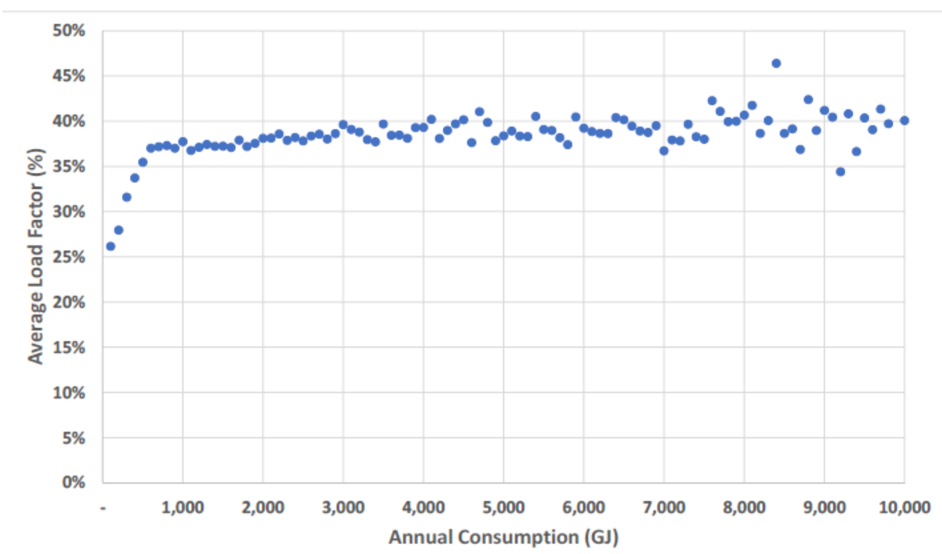
Table 1: Small Commercial (RS 2) Customer breakdown by Annual Volume

Annual Consumption	Number of RS 2 Customers	Percentage of Total RS 2 Customers
Less than 1,000 GJ/year	79,207	90.8%
Less than 1,500 GJ/year	84,421	96.7%

Please note that the number of RS 2 customers shown in Table 1 as consuming less than 1,500 GJ per year also includes those that consumed less than 1,000 GJ per year.

On page 57, FEI provides a graph of load factor versus consumption:

Figure 5-5: Average Commercial Customer (RS 2 and RS 3/23) Load Factor versus Annual Consumption Levels



18.6 Considering the only significant deviation from the 37% to 40% range of load factors occurs at consumption levels less than 600 GJ/year, please explain why the consumption threshold between RS 2 and RS 3/23 should be 2000 GJ/year and not 1000 GJ/year or even 600 GJ/year.

Response:

Figure 5-5 of the Application demonstrates that, based on 2022 actuals, there is no material change observed for the segmentation between RS 2 and RS 3/23 customers from what was observed in the 2016 COSA and RDA. The majority of commercial customers (including both RS 2 and RS 3/23 customers) that consumed more than 2,000 GJ continued to have load factors of approximately 40 percent as was seen in 2016, while customers that consumed less than 2,000 GJ have a wider range of load factors. As explained on page 57 of the Application, there needs to be a material shift away from this observation to warrant a move away from the existing threshold of 2,000 GJ.

Please refer to the response to BCUC IR1 21.4 which explains why there is no significant change that warrants a change to the 2,000 GJ segmentation between RS 2 and RS 3/23 customers.

On page 55 of the Application, FEI states:

> *The load factor of most RS 2 customers is between 20 percent and 30 percent while the load factor of most RS 3/23 customers is between 30 percent and 50 percent.*

18.7 Please provide a histogram of the load factors for those RS 2 customers with consumptions above 1500 GJ/yr in 100 GJ blocks similar to Figure 5-3.

Response:

FEI is unable to create a histogram for load factors while still showing consumption with increments of 100 GJ blocks (FEI is unable to illustrate both load factor and annual consumption on the x-axis of the histogram). Instead, FEI provides two histograms below: Figure 1 for load factors at 10 percent increments and Figure 2 for annual consumption at 100 GJ increments for those RS 2 customers with consumption above 1,500 GJ in 2022.

FEI notes that commercial customers in RS 2 and RS 3/23 are not mutually exclusive. It is expected that customers with annual volumes close to or exceeding 2,000 GJ would be similar in terms of load factor regardless of whether they are RS 2 or RS 3/23 customers. Based on 2022 actuals, the number of RS 2 customers with annual consumption above 1,500 GJ per year is small at 2,792, or about 3.2 percent of all RS 2 customers. Thus, it is not reasonable to assess the segmentation of two customer groups based on a small subset of customers within the rate schedule. Please refer to the response to BCUC IR1 21.4 for discussion on why FEI does not believe a change to the segmentation threshold of 2,000 GJ is warranted.

Figure 1: Small Commercial (RS 2) Customer Load Factor Distribution (Annual Consumption above 1,500 GJ only)

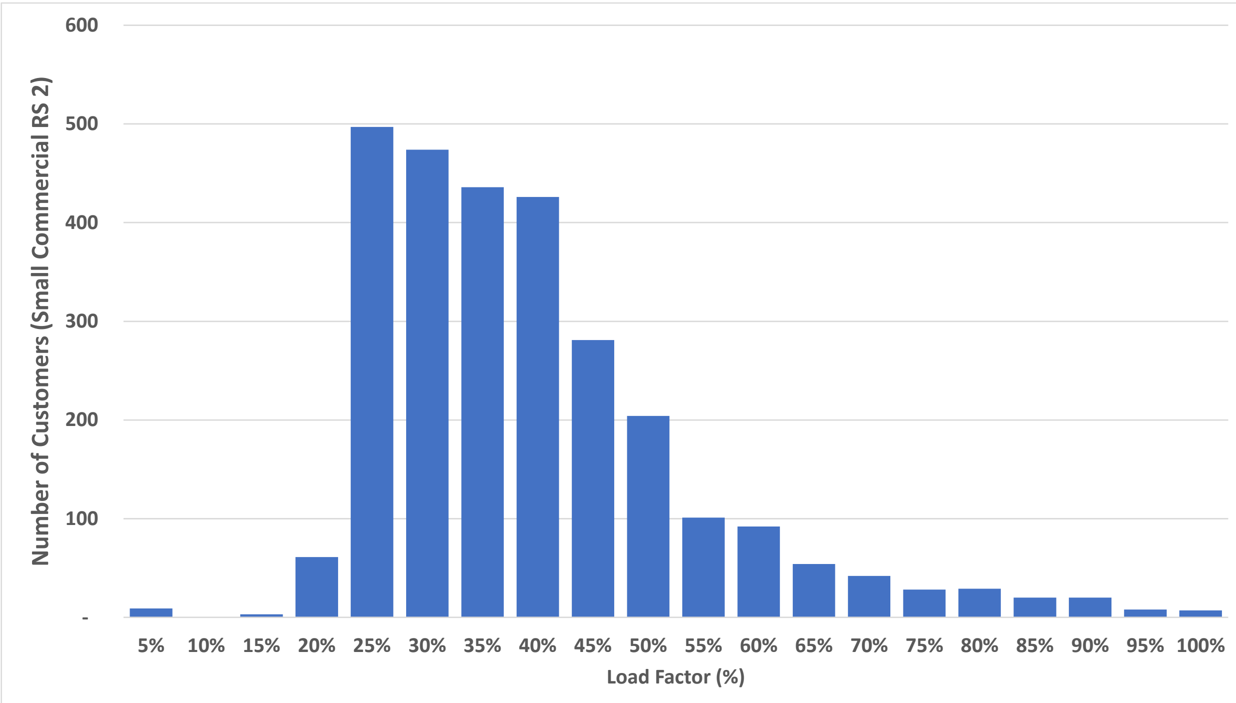
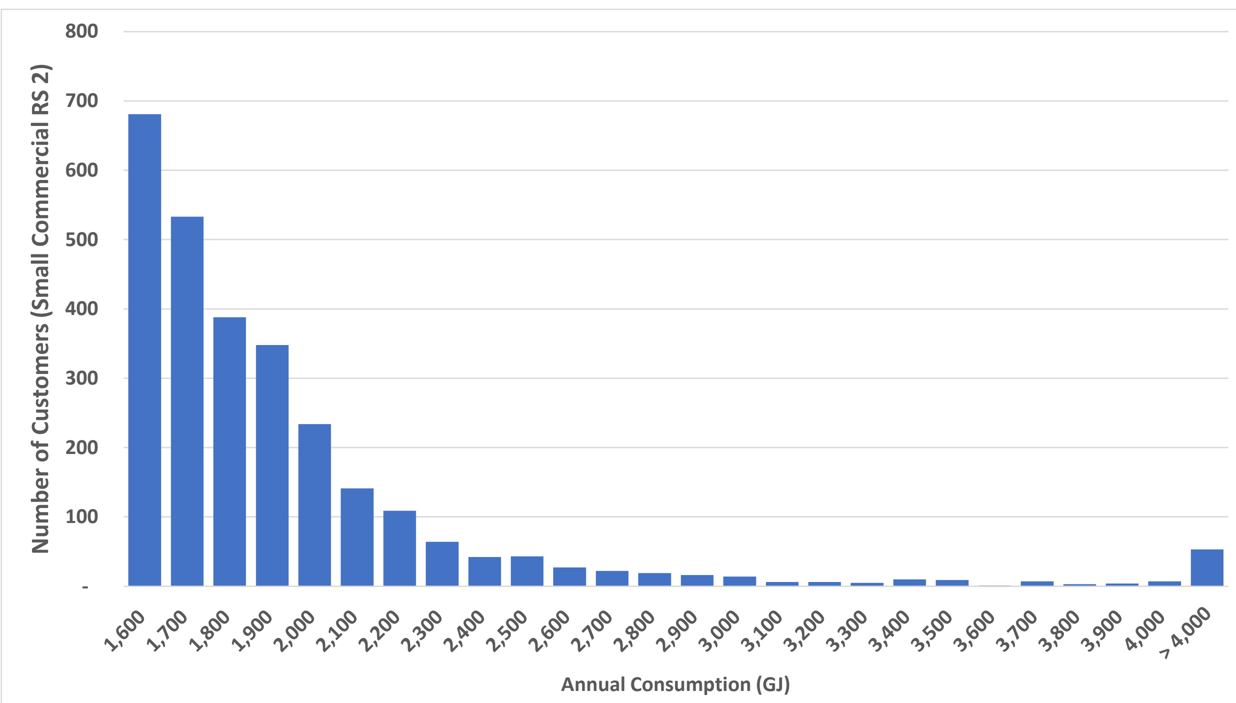


Figure 2: Small Commercial (RS 2) Customer Annual Consumption Distribution (Annual Consumption above 1,500 GJ only)



18.8 Please provide a histogram of load factors for RS 3/23 customers with consumptions less than 2000 GJ/yr in 100 GJ blocks, similar to Figure 5-3.

Response:

As explained in the response to RCIA IR1 18.7, FEI is unable to provide a histogram for both load factor and consumption on the x-axis. As such, FEI provides two histograms below: Figure 1 for load factors at 10 percent increments and Figure 2 for annual consumption at 100 GJ increments for those RS 3/23 customers that had consumption less than 2,000 GJ in 2022.

Also as explained in the response to RCIA IR1 18.7, it is unreasonable to assess the segmentation of two customer groups based on a very small subset of customers within the rate schedule. Please refer to the response to BCUC IR1 21.4 for a discussion on why FEI does not believe a change to the segmentation threshold of 2,000 GJ is warranted.

Figure 1: Large Commercial (RS 3/23) Customer Load Factor Distribution (Annual Consumption less than 2,000 GJ only)

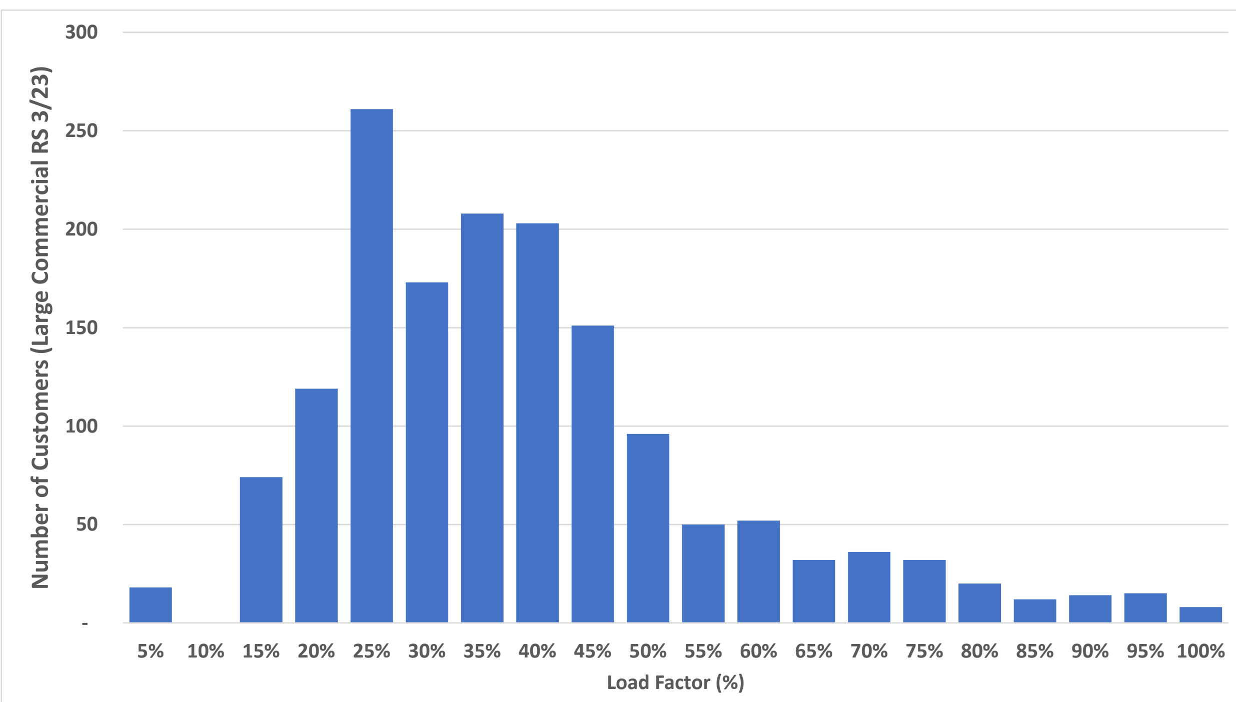
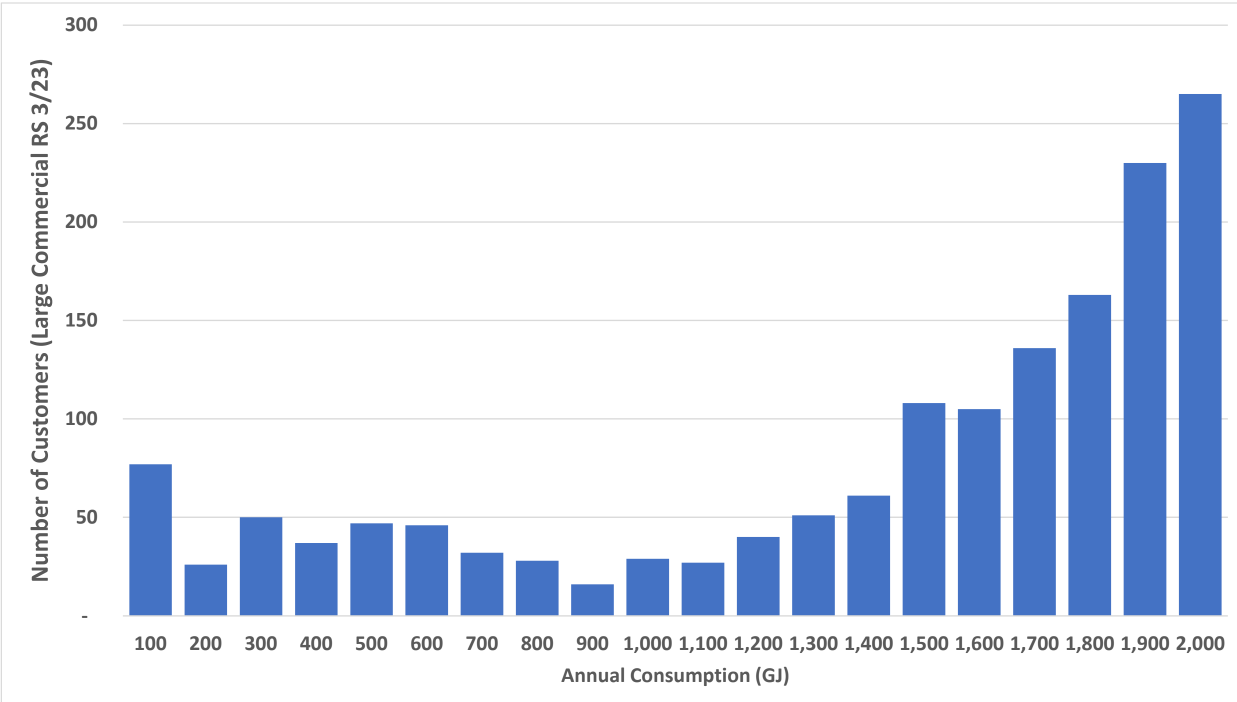


Figure 2: Large Commercial (RS 3/23) Customer Annual Consumption Distribution (Annual Consumption less than 2,000 GJ only)



On page 54 of the Application, FEI states:

> *It is FEI's practice to review the consumption history of RS 2 and RS 3/23 customers annually to ensure that commercial customers are served under the appropriate rate schedule based on their consumption meeting the tariff requirements. Based on this annual consumption review, FEI will transfer commercial customers to the appropriate rate schedule (between RS 2 and RS 3/23) as necessary.*

18.9 Please confirm whether customers can elect to pay RS 3/23 rates if they are above the economic crossover point but below the 2000 GJ/year RS 3/23 consumption threshold.

Response:

In accordance with FEI's Tariff, customers cannot elect to be served as an RS 3/23 customer if they are above the economic crossover point but below the 2,000 GJ per year consumption threshold. The criteria for which FEI determines which rate schedule a commercial customer is served is based on their normalized annual consumption. Customers with consumption less than

2,000 GJ are served using RS 2 and customers with consumption greater than 2,000 GJ are served by RS 3/23.

18.10 Please explain the implications of changing the consumption threshold for RS 3/23 to a lower value, such as to the current economic crossover point.

Response:

The implication would be that 2,734 customers would be moved from RS 2 to RS 3/23 and 707 customers would be moved from RS 3/23 to RS 2, with little difference in overall revenue and minimal cost allocation differences in the COSA study. This movement could cause confusion for these customers, and it would affect their energy bills. It is for these and other reasons why FEI does not believe that a change in threshold between RS 2 and RS 3/23 is warranted. Please also refer to the response to BCUC IR1 21.4.

18.11 Please confirm whether it is feasible for FEI to run a COSA scenario where customers are reassigned to classes depending on the most economic rate schedule (i.e., RS 2 customers consuming greater than 1515 GJ are moved to RS 3 and pay RS 3 rates).

18.11.1 If feasible, please re-run the COSA and provide the resulting R:C and M:C ratios.

Response:

Confirmed. Please refer to the response to BCUC IR1 21.4 which provides the R:C and M:C ratios when RS 2 and RS 3/23 reassignments are completed, and also a discussion on why changing the segmentation threshold to 1,515 is not reasonable or warranted.

19. Reference: Exhibit B-1 Application p.60

Rate Rebalancing

On page 60 of the Application, FEI states:

> *Option 2 involves revenue rebalancing only to ensure all R:C ratios are within the range of reasonableness of 95 percent and 105 percent, but does not include any adjustments regarding the economic crossover point between RS 2 and RS 3/23 or between RS 3/23 and RS 5/25. There are two possible options to absorb the revenue shifts from RS 22 and RS 5/25: (1) use RS 1; or (2) use RS 2.*

19.1 Please explain whether both RS1 and RS 2 could absorb the revenue shift, with RS 1 and RS 2 absorbing the revenue shift proportional to their delivery revenues.

19.1.1 If this is possible, please provide versions of Table 5-3 and 5-4 reflecting this option.

19.1.2 If this is possible, please comment on the impact to the economic crossover point between RS 2 and RS 3/23.

<u>Response:</u>

It is possible to use both RS 1 and RS 2 to absorb the revenue shift proportionally based on their revenue. FEI provides an assessment of this option below similar to the assessment completed on other options explored in this Application. Overall, the difference between this option (i.e., distributing the revenue rebalancing proportionally between RS 1 and RS 2 based on their delivery revenues) and FEI's proposed Option 5 (i.e., revenue rebalancing to RS 1 only) is small. As demonstrated by the analysis below, under this option the average bill impact to RS 1 customers would be slightly reduced by approximately $1.19 per year when compared to FEI's proposed Option 5 which is a trade-off with RS 2 and RS 3/23 having larger increases in their Basic Charge, i.e., approximately $82.50 per year and $191.30 per year more, respectively, when compared to FEI's proposed Option 5.

FEI considers smaller changes in the Basic Charges of RS 2 and RS 3/23 would be preferrable because an increase in the Basic Charges would mostly impact the smallest commercial customers who consume very little volumes. However, the difference between this option and FEI's proposed Option 5 is very small and FEI considers both options would be reasonable for revenue rebalancing.

Please refer to Tables 1 and 2 below (in a similar view as Tables 5-3 and 5-4 of the Application) for the R:C and M:C ratios and potential rate changes under this option (i.e., distributing the revenue rebalancing proportionally between RS 1 and RS 2 based on their delivery revenues).

Table 1: 2023 COSA R:C and M:C Results after Revenue Rebalancing (Using RS 1 and RS 2 for Rebalancing)

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%	3,466	0.3%	97.6%	95.5%
Rate Schedule 2 *Small Commercial Service*	98.0%	95.6%	1,053	0.3%	98.3%	96.2%
Rate Schedule 3/23 *Large Commercial Sales and Transportation*	104.0%	111.2%	0.0	0.0%	104.0%	111.2%
Rate Schedule 5/25 *General Firm Sales and Transportation*	106.9%	126.9%	(3,344)	(1.8%)	105.0%	119.5%
Rate Schedule 6 *Natural Gas Vehicle Service*	96.2%	91.0%	-	-	96.2%	91.0%
Rate Schedule 22 *Large Volume Transportation Service*	110.0%	110.2%	(151)	(4.5%)	105.0%	105.1%
Rate Schedule 22A *Transportation Service (Closed) Inland*	101.8%	101.9%	-	-	101.8%	101.9%
Rate Schedule 22B *Transportation Service (Closed) Columbia*	100.1%	100.1%	-	-	100.1%	100.1%

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

Table 2: Summary of Rate Changes (Using RS 1 and RS 2 for Rebalancing)

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	$ 0.042	$ 6.052
RS 2 - Small Commercial			
Basic Charge ($/Day)	$ 0.9485	$ 0.2260	$ 1.1745
Delivery Charge ($/GJ)	$ 4.568	$ (0.220)	$ 4.348
RS 3/23 Large Commercial			
Basic Charge ($/Day)	$ 4.7895	$ 0.5241	$ 5.3136
Delivery Charge ($/GJ)	$ 3.893	$ (0.050)	$ 3.843
RS 4 - Seasonal			
Basic Charge ($/Month)	$ 14.4230	$ -	$ 14.4230
Delivery Charge - Off-Peak ($/GJ)	$ 1.904	$ (0.309)	$ 1.595
Delivery Charge - Extended ($/GJ)	$ 2.549	$ (0.069)	$ 2.480
RS 5/25 - General Firm Service			
Basic Charge ($/Month)	$ 469.0000	$ -	$ 469.0000
Delivery Charge ($/GJ)	$ 1.085	$ (0.071)	$ 1.014
Demand Charge ($/GJ/Month)	$ 30.278	$ (1.989)	$ 28.2890
RS 7/27 - General Interruptible Service			
Basic Charge ($/Month)	$ 880.0000	$ -	$ 880.0000
Delivery Charge ($/GJ)	$ 1.748	$ (0.095)	$ 1.653
RS 22 - Large Volume Transportation			
Basic Charge ($/Month)	$ 3,664.0000	$ -	$ 3,664.0000
Firm Demand Charge ($/GJ/Month)	$ 32.199	$ (0.505)	$ 31.694
Firm MTQ ($/GJ)	$ 0.1930	$ (0.009)	$ 0.1840
Interruptible MTQ ($/GJ)	$ 1.2520	$ (0.026)	$ 1.2260

The differences in the R:C and M:C ratios are small under this option when compared to FEI's proposed Option 5. This is because, as set out in Table 1 above, the majority of the revenue rebalancing will continue to be absorbed by RS 1 because RS 1 is approximately 76 percent of the total revenue of RS 1 and RS 2.

Table 3 below confirms that under this option, the economic crossover point between RS 2 and RS 3/23 can be maintained at 2,000 GJ by increasing the Basic Charges for both RS 2 and RS 3/23 with a decrease in the Delivery charges. However, this option would require the Basic Charge for RS 2 to increase by $0.2260 per day, which is slightly higher than the increase in FEI's proposed Option 5.

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

Line	Rate Components	Reference	RS 2	RS 3/23	Diff.
1	Basic Charge (per day)		1.1745	5.3136	
2	Number of Days		365.25	365.25	
3	Basic Charge Revenue ($)	Line 1 x Line 2	429	1,941	1,512
4					
5	Delivery Charge ($/GJ)		4.348	3.843	
6	Cost of Gas ($/GJ)		6.750	6.499	
7	Total Variable Cost ($/GJ)	Line 5 + Line 6	11.098	10.342	0.756
8					
9	Volume Threshold (GJ)	Line 3 / Line 7	2,000	2,000	2,000

Tables 4 and 5 below provide an updated summary of the revenue shift between rate schedules and an updated summary of bill impacts amongst all rebalancing options considered, excluding Option 1 but including the scenario requested in this IR. Under the scenario requested in this IR (i.e., using both RS 1 and RS 2 to absorb the revenue rebalancing), the bill impact to RS 1 would be reduced slightly by $1.19 per year when compared to FEI's proposed Option 5 since a small portion of revenue rebalancing is shifted to RS 2. For RS 2 customers, because of the small revenue rebalancing shift, the bill impact to RS 2 customers would be increased slightly by approximately $10 per year when compared to Option 5 (i.e., approximately $11.67 per year instead of $1.65 per year for RS 2). And for RS 3/23 customers, the bill impact would be increased by approximately $19 per year when compared to Option 5 due to RS 2 absorbing the additional revenue shift, thus the Basic Charge of RS 3/23 would have to be adjusted upward to continue to maintain the segmentation threshold to 2,000 GJ (i.e., approximately an impact of $8.93 per year instead of a savings of $10 for RS 3/23).

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	RCIA IR1 19.1: Rebalancing to RS 1 and RS 2
RS 1	4,519	-	4,519	-	4,519	3,466
RS 2	-	4,519	4,071	4,075	145	1,053
RS 3/23	-	-	(4,071)	444	(145)	0
RS 5/25	(3,344)	(3,344)	(3,344)	(3,344)	(3,344)	(3,344)
RS 6	-	-	-	-	-	-
RS 22	(151)	(151)	(151)	(151)	(151)	(151)
RS 22A	-	-	-	-	-	-
RS 22B	-	-	-	-	-	-
RS 4	(46)	(46)	(46)	(46)	(46)	(46)
RS 7/27	(978)	(978)	(978)	(978)	(978)	(978)

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

	Option 2a		Option 2b		Option 3		Option 4		Option 5		RCIA IR1 19.1	
	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)	Avg. Bill Impact (%)	Avg. Bill Impact ($)
RS 1	0.4%	$ 4.95	-	$ -	0.4%	$ 4.95	-	$ -	0.4%	$ 4.95	0.3%	$ 3.76
RS 2	-	$ -	1.2%	$ 50	1.1%	$ 45	1.1%	$ 45	0.04%	$ 1.65	0.27%	$ 11.67
RS 3/23	-	$ -	-	$ -	(1.2%)	$ (469)	0.1%	$ 123	(0.04%)	$ (10)	0.00%	$ 8.94
RS 5/25	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)	(1.8%)	$ (2,942)
RS 6	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
RS 22	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)	(4.5%)	$ (29,978)
RS 22A	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
RS 22B	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -	-	$ -
RS 4	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)	(3.0%)	$ (2,843)
RS 7/27	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)	(1.1%)	$ (12,673)

20. Reference: Exhibit B-1 Application pp.68,69

Rate Rebalancing – Option 3

On pages 68 and 69 of the Application, FEI states:

> **Principle 3 – Price signals that encourage efficient use and discourage inefficient use (Partially)**
>
> *Under Option 3, the rates of RS 2 and RS 3/23 are adjusted to maintain the economic crossover points between RS 2 and RS 3/23 (as discussed in Section 5.2.2) and RS 3/23 and RS 5/25 (as discussed in Section 5.2.3). Table 5-11 below confirms that, under Option 3, the increase in the Basic Charge for both RS 2 and RS 3/23, plus the offset from the reduction of the variable delivery rates, will move the economic crossover point back to 2,000 GJ and realign it with the segmentation threshold between RS 2 and RS 3/23. Additionally, as shown in Table 5-12 below, the adjusted rates ensure the economic crossover point between RS 3/23 and RS 5/25 is maintained at a level similar to the current 2023 Approved rates.*
>
> *However, Option 3 represents only a partial improvement compared to Options 2a and 2b. As shown in Tables 5-11 and 5-12 below, the implications of maintaining the economic crossover points between RS 2 and RS 3/23, and between RS 3/23 and RS 5/25 are that the Basic Charges of RS 2 and RS 3/23 would have to be increased substantially from the current level. As shown in Table 5-10 above, under Option 3, the Basic Charge for RS 2 will have to be increased from $0.9485 per day to $1.3040 per day (an increase of approximately $130 per year) while the Basic Charge for RS 3/23 will have to be increased from $4.7895 per day to $6.6534 per day (an increase of approximately $680 per year). Since the potion of fixed charge is increased while the portion of variable charge is reduced under Option 3, the price signal for <u>efficient use</u> would be reduced, resulting in a misalignment with this rate design principle*. [underlining added]

20.1 Please provide FEI's definition of efficient use. Does FEI equate reduced use with efficient use?

<u>Response:</u>

FEI does not have a definition of efficient use. FEI notes that the statement, “the price signal for efficient use would be reduced” on page 69 of the Application and highlighted in the preamble above is referring to the fact that increased recovery through the fixed basic charge while reducing recovery from the variable volumetric charge should lessen the price signal for customer energy conservation.

As noted in the response to RCIA IR1 18.1, the original intent of keeping the basic charges constant while applying rate changes to the variable volumetric charges was to encourage customers to use less energy. As such, FEI agrees that reduced use through energy efficiency or conservation activities equate to efficient use of energy.

20.2 Please provide Bonbright's definition of efficient use.

Response:

Dr. Bonbright does not define efficient use but does speak to functions of public utility rates[11] in regard to economic function of price and to regulation in natural gas.

On page 97 of the 2nd Edition of Bonbright's book "Principles of Public Utility Rates", Bonbright stated the following:

> … the only real economic function of prices – regulated or unregulated – is to influence the behavior of economic agents. Here, the price is designed, not to induce production, but rather to restrict or influence demand. Thus, to be efficient, prices must be both supply-eliciting and demand-inhibiting.

Further, on pages 634 – 635, Bonbright stated the following:

> … What we propose is that the following checklist be used in assessing new regulatory initiatives.
>
> Efficiency. Any new rate or other socially optimal regulatory policy should:
>
> (1) Decrease the delay and distortion of market signals;
> (2) Accommodate changes in market conditions;
> (3) Maintain cost control for all commodities and services delivered; and,
> (4) Enhance open access of the gas transportation network.
>
> … Efficiency / Equity (combined). A proper regulatory policy should also strive to accomplish the following:
>
> (7) rewards should flow to those who act in concert with the above regulatory goals, while penalties should flow to those acting in opposition to them …; and
> (8) the price for each commodity or service should at least cover their incremental costs.

FEI considers its statement regarding price signals and efficient use in the context of increasing the basic charge while reducing variable volumetric charges on page 69 of the Application is generally in alignment with Bonbright's discussion in the above excerpts. For instance, increasing

---

11 Bonbright, James C., Danielsen, Albert L., and Kamerschen, David R., "Principles of Public Utility Rates", 2nd Edition, Public Utilities Report, Inc., Arlington, Va., 1988.

the basic charge would neither be supply-eliciting nor demand-inhibiting; it would also be increasing the distortion of market signals rather than decreasing it.

20.3 Please explain whether FEI considers that rates that reflect the underlying cost of service are efficient.

Response:

FEI notes the statement highlighted in the preamble above is referring to the fact that increasing fixed basic charges while reducing variable volumetric charges will reduce the price signal of efficiently using energy through conservation. The statement is not referring to whether FEI's rates are reflecting the underlying cost of service. Please refer to the response to RCIA IR1 20.1.

Generally, rates based on the long run marginal cost of providing a product or service would be considered most efficient. However, understanding that the utility is constrained to collecting its revenue requirement, which is based on embedded costs and not the marginal cost, the appropriate blend of both is to allocate a utility's embedded costs through the COSA and then to design rates that reflect marginal cost or provide the signal for efficient use. As such, FEI considers that rates reflecting the underlying cost of service are efficient.

20.4 Please provide the proportions of the allocated customer costs that each of the RS 2 and RS 3/23 Basic Charges recover.

Response:

Please refer to Table 1 below for the proportions of the allocated customer costs that each of the current 2023 Approved Basic Charges recover for RS 2 and RS 3/23. For comparison, FEI also included the proportion for RS 1.

Table 1: Allocated Customer-related Costs vs. Basic Charge Recovery for RS 1, RS 2, and RS 3/23

Line	Particular	Reference	Rate 1	Rate 2	Rate 3/23
1	Customer-related Costs ($000s)	Appendix D, Schedule 4, Line 52	386,419	63,531	20,035
2					
3	Average Number of Customers	Appendix D, Schedule 7, Line 5	977,501	90,632	7,750
4	Current Basic Charge Rate ($/Day)	Table 5-24 of Application	0.4085	0.9485	4.7895
5	Current Basic Charge Recovery ($000s)	Line 4 x 365.25 x Line 3 / 1,000	145,848	31,399	13,558
6					
7	% of Basic Charge Recovery over Customer-Related Costs	Line 5 / Line 1	37.7%	49.4%	67.7%

20.5 Please provide a table comparing existing Basic Charges, Delivery Charges, and Demand Charge for RS 2 and RS 3/23 with those charges adjusted assuming the Basic Charges recovered 100% of the allocated customer costs and the RS 3/23 Demand Charge recovered 100% of the allocated demand costs.

20.5.1 Please provide the annual revenues recovered from the Basic Charge, Delivery Charge, and Demand Charge for the existing rates compared with the above scenario for RS 2 and RS 3/23 customers

20.5.2 Please provide the economic crossover point based on these rates in a table similar to Table 5-12.

Response:

Please refer to Table 1 below which provides the Basic Charge and Delivery Charge for RS 2 and RS 3/23 calculated based on the Basic Charge recovering 100 percent of the customer-related margin and the Delivery Charge recovering 100 percent of the demand-related and energy-related margins. FEI notes that there is no demand charge for RS 2 or RS 3/23. FEI also includes the same calculation for RS 1 to demonstrate the impact if the same rate-setting approach is taken for residential customers. FEI also notes that there is no change to the total annual revenue from each rate schedule based on the recalculated rates, as the calculation is simply shifting the revenue recovered from the delivery charges to the basic charges.

Table 1: Basic Charge Recalculated at 100% Recovery of Customer-Related Costs and Delivery Charge Recalculated at 100% Recovery of Demand-Related and Energy-Related Costs for RS 1, 2, and 3/23

Line	Particular	Reference	Rate 1	Rate 2	Rate 3/23
1	Customer-related Margin ($000s)	Appendix D, Schedule 4, Line 52	386,419	63,531	20,035
2	Demand and Energy-related Margin ($000s)	Appendix D, Schedule 4, Line 50 + Line 51	307,072	112,856	98,924
3	Total Cost of Service Margin ($000s)	Line 1 + Line 2	693,491	176,387	118,959
4					
5	Average Number of Customers	Appendix D, Schedule 7, Line 5	977,501	90,632	7,750
6	Basic Charge @ 100% of Customer-Related Margin ($/Days)	Line 1 x 1,000 / Line 5 / 365.25	1.0823	1.9192	7.0778
7					
8	Volume (TJ)	Appendix D, Schedule 7, Line 2	82,890	29,204	29,674
9	Delivery Charge @ 100% Demand and Energy-Related ($/GJ)	Line 2 / Line 8	3.705	3.864	3.334
10					
11	Current Basic Charge ($/Days)	RCIA IR1 20.4	0.4085	0.9485	4.7895
12	**Different ($/Days)**	**Line 6 - Line 11**	**0.6738**	**0.9707**	**2.2883**
13	**Different (%)**	**Line 12 / Line 11**	**165%**	**102%**	**48%**
14					
15	Current Delivery Charge ($/GJ)	Table 5-24 of Application	6.010	4.568	3.893
16	**Different ($/GJ)**	**Line 9 - Line 15**	**(2.3054)**	**(0.7036)**	**(0.5593)**
17	**Different (%)**	**Line 16 / Line 15**	**-38%**	**-15%**	**-14%**

Table 2 below shows the economic crossover point between RS 2 and RS 3/23, which will increase to 2,410 GJ based on the recalculated rates under the rate-setting approach suggested by this IR. A higher economic crossover point means there will be more RS 3/23 customers moving to RS 2 at a higher rate.

Table 2: Economic Crossover Point between RS 2 and RS 3/23 Based on Recalculated Rates (RCIA IR1 20.5)

Line	Rate Components	Reference	RS 2	RS 3/23	Difff.
1	Basic Charge (per day)	RCIA IR1 20.5, Table 1, Line 6	1.9192	7.0778	
2	Nmber of Days		365.25	365.25	
3	Basic Charge Revenue ($)	Line 1 x Line 2	701	2,585	1,884
4					
5	Delivery Charge ($/GJ)	RCIA IR1 20.5, Table 1, Line 6	3.864	3.334	
6	Cost of Gas and Storage & Transport ($)	RCIA IR1 20.5, Table 3, Line 1 + Line 2	6.750	6.499	
7	Total Variable Cost ($/GJ)	Line 5 + Line 6	10.614	9.833	0.782
8					
9	**Volme Threshold (GJ)**	**Line 3 / Line 7**	**2,410**	**2,410**	**2,410**

The bill impact based on the recalculated rates will depend on the level of consumption of each customer; however, customers with zero or low volumes will be impacted the most with the significant increase in the Basic Charge. Table 3 below provides the estimated bill impact for RS 1, RS 2, and RS 3/23 based on three different assumed annual energy consumption levels, (zero volume, average volume, and high volume). Customers with zero volume will see the biggest bill impact: approximately 164.9 percent for RS 1 customers, 102.3 percent for RS 2 customers, and 47.8 percent for RS 3/23 customers if the Basic charge is set to recover 100 percent of the customer-related costs. For large volume customers, this rate-setting approach will result in savings of approximately 4.8 percent, 4.4 percent, and 4.0 percent for RS 1, RS 2, and RS 3/23 customers, respectively. FEI concludes that this rate-setting approach will primarily penalize low volume customers and will discourage the efficient use of energy given the reduced variable rates. This is contrary to the intent of holding Basic Charges constant thereby providing energy efficiency price signals, and when compared to existing rates, does not encourage energy conservation.

Table 3: Estimated Bill Impact to RS 1, RS 2, and RS 3/23 Customers Based on Recalculated Rates (RCIA IR1 20.5)

Line	Particular	Reference	Rate 1	Rate 2	Rate 3/23
1	Cost of Gas - 2023 COSA ($/GJ)		5.159	5.159	5.159
2	Storage & Transport - 2023 COSA ($/GJ)		1.543	1.591	1.340
3					
4	*Example of Bill Impact*				
5	**Volume - Zero (GJ)**		-	-	-
6	Current Rates				
7	Basic Charge Recovery ($)	RCIA IR1 20.5, Table 1, Line 11 x 365.25	149	346	1,749
8	Delivery Charge Recovery ($)	RCIA IR1 20.5, Table 1, Line 15 x Line 5	-	-	-
9	Cost of Gas and Storage & Transport ($)	(Line 1 + Line 2) x Line 5	-	-	-
10	Total	Sum of Line 7 to Line 9	149	346	1,749
11					
12	Alternative (RCIA IR1 20.5 Table 1)				
13	Basic Charge Recovery ($)	RCIA IR1 20.5, Table 1, Line 6 x 365.25	395	701	2,585
14	Delivery Charge Recovery ($)	RCIA IR1 20.5, Table 1, Line 9 x Line 11	-	-	-
15	Cost of Gas and Storage & Transport ($)	(Line 1 + Line 2) x Line 5	-	-	-
16	Total	Sum of Line 13 to Line 15	395	701	2,585
17					
18	**Different ($)**	**Line 16 - Line 10**	**246**	**355**	**836**
19	**Different (%)**	**Line 17 / Line 10**	**164.9%**	**102.3%**	**47.8%**
20					
21	**Volume - Avg (GJ)**		90	322	3,650
22	Current Rates				
23	Basic Charge Recovery ($)	RCIA IR1 20.5, Table 1, Line 11 x 365.25	149	346	1,749
24	Delivery Charge Recovery ($)	RCIA IR1 20.5, Table 1, Line 15 x Line 21	541	1,471	14,209
25	Cost of Gas and Storage & Transport ($)	(Line 17 + Line 18) x Line 21	603	2,174	23,721
26	Total	Sum of Line 23 to Line 25	1,293	3,991	39,680
27					
28	Alternative (RCIA IR1 20.5 Table 1)				
29	Basic Charge Recovery ($)	RCIA IR1 20.5, Table 1, Line 6 x 365.25	395	701	2,585
30	Delivery Charge Recovery ($)	RCIA IR1 20.5, Table 1, Line 9 x Line 27	333	1,244	12,168
31	Cost of Gas and Storage & Transport ($)	(Line 1 + Line 2) x Line 21	603	2,174	23,721
32	Total	Sum of Line 29 to Line 31	1,332	4,119	38,474
33					
34	**Different ($)**	**Line 32 - Line 26**	**39**	**128**	**(1,206)**
35	**Different (%)**	**Line 33 / Line 26**	**3.0%**	**3.2%**	**-3.0%**
36					
37	**Volume - High (GJ)**		150	1,800	6,500
38	Current Rates				
39	Basic Charge Recovery ($)	RCIA IR1 20.5, Table 1, Line 11 x 365.25	149	346	1,749
40	Delivery Charge Recovery ($)	RCIA IR1 20.5, Table 1, Line 15 x Line 37	902	8,222	25,305
41	Cost of Gas and Storage & Transport ($)	(Line 33 + Line 34) x Line 37	1,005	12,150	42,244
42	Total	Sum of Line 39 to Line 41	2,056	20,719	69,297
43					
44	Alternative (RCIA IR1 20.5 Table 1)				
45	Basic Charge Recovery ($)	RCIA IR1 20.5, Table 1, Line 6 x 365.25	395	701	2,585
46	Delivery Charge Recovery ($)	RCIA IR1 20.5, Table 1, Line 9 x Line 43	556	6,956	21,669
47	Cost of Gas and Storage & Transport ($)	(Line 1 + Line 2) x Line 37	1,005	12,150	42,244
48	Total	Sum of Line 45 to Line 47	1,956	19,807	66,498
49					
50	**Different ($)**	**Line 48 - Line 42**	**(100)**	**(912)**	**(2,800)**
51	**Different (%)**	**Line 49 / Line 42**	**-4.8%**	**-4.4%**	**-4.0%**

On page 70 of the Application, FEI states:

> ***Principle 4 – Customer understanding and acceptance***
>
> *Basic charges usually remain constant during FEI's annal [sic] rate changes. Therefore, if the Basic Charges of RS 2 and RS 3/23 are increased under Option 3 due to revenue rebalancing, it might lead to customer confusion and could impact customer acceptance (especially for small and large commercial customers).*

20.6 Please explain whether FEI has experience with customers expressing concerns or lack of acceptance of changes to the Basic Charge.

20.6.1 If so, please provide the circumstances when changes to the Basic Charge caused customer confusion and a lack of acceptance.

20.6.2 Please elaborate on the concerns expressed by customers.

Response:

The consistency of the Basic Charge has resulted in very few inquiries or concerns. Customer inquiries that FEI does receive are typically regarding a comparison between FEI's Basic Charges and other utilities or organizations that also have Basic Charges on their bills.

20.7 Please confirm whether FEI has engaged with stakeholders regarding changes to the Basic Charge.

Response:

FEI has not undertaken any stakeholder engagement activities in relation to this Application or regarding changes to the Basic Charge. Please refer to the response to BCUC IR1 1.1 for further explanation regarding stakeholder engagement and consultation, and also to the response to RCIA IR1 20.6 regarding customers' inquiries into the Basic Charge.

On page 70 of the Application, FEI states:

> *For example, assuming a particular commercial customer has no volumes (which could occur over time when a commercial property is under development/renovation, changing ownership/lease, or vacant) and pays for the Basic Charge only, they will experience the maximum bill impact of $130 per year under RS 2 or $680 per year under RS 3/23, since this customer would not be able to offset the increase through the reduced variable charges.*

20.8 Please explain whether FEI expects situations where an RS 3/23 customer has a high percentage bill impact due to a customer consuming few or no volumes to be temporary.

Response:

FEI expects that a situation where a commercial customer consumes zero or very small volumes would be temporary. However, FEI's practice is to review the consumption history of its commercial customers annually and, if warranted, FEI will transfer the commercial customer to the appropriate rate schedule (between RS 2 and RS 3/23) as necessary.

20.9 Please confirm whether any RS 3/23 customers whose circumstances have permanently changed can change to a rate schedule more in line with their consumption.

Response:

Please refer to the response to RCIA IR1 20.8.

Attachment 1.1A

British Columbia Utilities Commission

Patrick Wruck
Commission Secretary

Commission.Secretary@bcuc.com
Website: www.bcuc.com

Sixth Floor, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
TEL: (604) 660-4700
BC Toll Free: 1-800-663-1385
FAX: (604) 660-1102

Log No. 54361

VIA EFILE
gas.regulatory.affairs@fortisbc.com

April 26, 2017

FEI 2016 RATE DESIGN
EXHIBIT A2-2

Ms. Diane Roy
Vice President, Regulatory Affairs
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Ms. Roy:

Re: FortisBC Energy Inc.
2016 Rate Design Application

Commission staff submit the following independent consultant report for the record in this proceeding:

Elenchus Research Associates Inc. – Review of FortisBC Energy Inc. Cost of Service Allocation Studies for the 2016 Rate Design Application

Yours truly,

Original signed by:

Patrick Wruck

kbb

Enclosure

FEI 2016 RATE DESIGN
EXHIBIT A2-2

34 King Street East, Suite 600
Toronto, Ontario M5C 2X8
elenchus.ca

Review of FortisBC Energy Inc. Cost of Service Allocation Studies for the 2016 Rate Design Application

A Report Prepared by
John Todd and Michael Roger
Elenchus Research Associates, Inc.

Prepared for the British Columbia Utilities Commission

25 April 2017

Table of Contents

1 OVERVIEW

The British Columbia Utilities Commission (BCUC or Commission) issued on December 14, 2016 its Request for Proposal (RFP) 8103 regarding Independent Expert Consultant to Review Gas Utility Rate Design Application.

Elenchus Research Inc. (Elenchus) was selected by the BCUC to provide expert analysis in reviewing the Cost of Service Allocation (COSA) studies filed by FortisBC Energy Inc. (FEI). The two studies filed are:

1. COSA study included in FEI's 2016 Rate Design Application, dated December 19, 2016; and the
2. COSA study for the Fort Nelson service area, included in FEI's Supplemental Filing, filed with the Commission on February 2, 2017.

Some of the issues expected to be reviewed for reasonableness and appropriateness by Elenchus by the Commission include:

- FEI's objectives for the COSA studies
- FEI's COSA methodology(s)
- FEI's delivery and gas cost of service allocations, including the:
  - key assumptions and justifications;
  - treatment of existing major assets, such as Tilbury LNG Storage, Mt. Hayes LNG Storage and Southern Crossing Pipeline;
  - treatment of known and measurable changes, including the Tilbury Expansion Project and other such major capital projects;
  - functionalization of costs;
  - classification of costs;
  - allocation of costs; and
  - direct assignments.

- Revenue to Cost (R:C) ratio range and the R:C and margin to cost ratios resulting from the COSA studies
- Key changes in FEI's assumptions, justifications and methodologies from COSA studies previously approved by the Commission, including the 1993 BC Gas Rate Design Application
- The supporting studies and analyses that are inputs into FEI's COSA study, including the EES COSA Study Report; minimum system study; and customer weighting factor study, and
- Assessment of the impact of the omission of supporting studies and/or analyses that are typically included in a COSA study as standard industry practice[1]

This report consists of 6 additional sections, followed by Appendices.

Section 2 provides a brief overview of the standard approach to cost allocation that is widely accepted by regulators across Canada and internationally.

Section 3 extends the discussion of the principles on which the Elenchus review is based by summarizing generally accepted rate making (Bonbright) principles.

Section 4 provides an overview of FEI's cost of service allocation methodology and Elenchus views.

Section 5 provides an overview of Fort Nelson's cost of service allocation methodology and Elenchus views.

Section 6 provides the revenue to cost ratios and margin to cost ratios discussed in the application and summarizes Elenchus views on ratios.

Section 7 summarizes Elenchus work.

Appendix A includes responses from FEI to questions raised by Elenchus on FEI's evidence.

[1] Outlined in the Detailed Terms of Reference for the Cost of Service Allocation Report in Exhibit A-4.

Appendix B includes the qualifications of the Elenchus' team that conducted the study and prepared this report.

2 COST ALLOCATION THEORY/OVERVIEW

It is standard practice in Canada and in many jurisdictions internationally to rely on cost allocation studies, also referred to as COSA, or cost allocation method, to apportion utility assets and expenses to a utility's customer classes[2]. Because most of the assets and expenses of a utility are used jointly by multiple customer classes, cost of service allocation studies are used to apportion a utility's assets which form the utility's rate base and the utility's revenue requirement among customer classes on a fair and equitable basis as guided by the principle of cost causality.

A utility's rate base consists of the investments in assets approved by a regulator on which the utility is allowed to earn a fair return. The revenue requirement is the amount of the expenses incurred in the utility's operation and are also approved by the utility's regulator.

Cost causality refers to the principle of identifying the customer classes that "cause" particular expenses to be incurred by the utility. For example, if 50% of the capacity of a pipeline is needed to meet the peak demand of a particular customer class, then that class is deemed to have "caused" 50% of the costs associated with building and maintaining that capacity.

Each utility may use cost allocation methodologies differently in order to reflect its own particular circumstances, but in general, the same main concepts and principles are applied.

Traditionally there are three steps that are followed in a cost of service allocation study: Functionalization, Categorization or Classification, and Allocation.

---

[2] A standard reference document for cost allocation methodologies used by natural gas and electric utilities continues to be the "Electric Utility Cost Allocation Manual" published by the National Association of Regulatory Utility Commissioners (NARUC) in 1992. A subsequent NARUC publication, "Cost Allocation for Electric Utility Conservation and Load Management Programs" (1993) extends the application of the basic principles to conservation and demand side management (DSM) programs.

Functionalization of assets and expenses is the process of grouping assets and expenses of a similar nature, for example, generation, transmission, distribution, customer service, meter reading, etc. Hence, as a first step in a cost of service allocation study, each account in the utility's system of accounts is functionalized. That is, the function(s) served by the assets or expenses contained in each account is identified so that the costs can be attributed appropriately to the identified functions.

Categorization or Classification is the process by which the functionalized assets and expenses are classified as demand, energy and/or customer related. Hence, the costs associated with each function are attributed to these categories based on the principle that the quantum of costs is reflective of the quantum of system demand, energy throughput or the number of customers.

Allocation, which is the final step, is the process of attributing the demand, energy and customer related assets and expenses to the customer classes being served by the utility. This allocation is accomplished by identifying allocators related to demand, energy, or customer counts that are reflective of the relationship between different measures of these cost drivers and the costs that are deemed to be caused by each customer class. For example, if the necessary investment in a particular class of asset (e.g., certain transmission lines) is caused strictly by the single peak in annual demand, then the relevant costs would normally be allocated to each rate class using the 1-coincident peak (1-CP) method.

Direct Allocation, sometimes referred as Direct Assignment is used in some instances when assets and/or costs can be related directly to a particular customer class and are then directly assigned to that customer class. For example, if a lateral pipeline is used to transport natural gas exclusively to one customer or one class of customers then the costs associated with that lateral would normally be allocated directly to that customer class. When costs are directly allocated, they by-pass the functionalization and categorization step that are used to apportion shared assets and/or costs to the customer classes. Directly allocating assets and/or cost to a particular customer class means that no other customer class in the utility has caused the assets and/or costs to be incurred by the utility. The assets and/or costs are not shared among various customer classes, the assets and/or costs are specific to one customer class. If the other customer classes did not impose the identified assets and/or costs on the utility, in this example a lateral pipeline, based on cost causality principle, the other customer classes should not be responsible and should not be allocated the assets and/or costs of the lateral.

Data used in COSA Studies: Cost of service allocation studies can be done using historical actual data or using future test year data. The information needed is the utilities' financial data related to assets and expenses as well as sales data. The financial data are usually based on the accounting system used by the utility. The sales data used are by customer class and include for example number of customers, energy throughput (Gj) and peak day demand (Tj/day)[3].

Frequency of COSA Studies: Cost of service allocation studies are conducted periodically by utilities to compare the costs attributable to the various customer classes with the revenues being collected from the customer classes. The frequency with which COSA studies are updated varies across jurisdictions and is typically linked to the rate-setting process. Updates are typically expected at least every five years.

For example, natural gas utilities in Ontario have two options for rate-setting. One option is the price cap incentive rate-setting (Price Cap IR) plan of five years, which sets rates through a cost of service process for the first year and then adjusts in years two to five using a formula specific to each year. The other option is the custom incentive rate-setting (Custom IR) plan which sets rates for a minimum of five years using forecast of the utility's costs and sales volumes. Union Gas Limited (Union) chose the Price Cap IR plan and conducts a cost of service study every 5 years while Enbridge Gas Distribution (Enbridge) sets rates under the Custom IR plan and a cost of service study is conducted every year[4].

The most recent cost of service studies filed by ATCO Gas (ATCO) are from their 2008/2009 and 2011/2012 General Rate Application (GRA) – Phase II[5].

---

3 "Peak day demand" is used interchangeable with "demand".

4 The most recent cost of service application for Union is filed in 2011 for 2013 test year EB-2011-0210 The most recent cost allocation study for Enbridge is filed in 2016 for 2017 test year EB-2016-0215.

5 ATCO Gas 2011/2012 General Rate Application Phase II, Application 1608495-1.

Comparison of Cost and Revenues is done to determine to what extent the customer class is paying their fair share of the costs imposed on the utility. A revenue to cost ratio of 1.00 or above 1.00 means that the class is paying their fair share of costs or even more than their fair share. A revenue to cost ratio below 1.00 means that the class is not paying for their fair share of costs.

Since the allocation of shared costs amongst various customer classes can't be done in a perfectly accurate way and parameters or allocators are used to split shared costs, in many jurisdictions, a range of revenue to cost ratio is accepted as reflecting the fair allocation of costs to customer classes instead of thriving to achieve a revenue to cost ratio of 1.00 for all customer classes. Elenchus conducted a jurisdictional review and found that many jurisdiction use ranges of 0.95 to 1.05, or 0.90 to 1.10 as acceptable revenue to cost ratios when establishing revenue responsibilities by customer classes. Section 6 below discusses further revenue to cost and margin to cost ratios.

3 GENERALLY ACCEPTED RATE MAKING PRINCIPLES

It is generally accepted by regulators and regulated utilities that any utility's cost of service allocation methodology and approach to rate design should be based on a set of clearly enunciated principles. These principles then guide the work that is undertaken to allocate assets and expenses to customer groups appropriately and establish rates that recover those costs from customers in a manner that is consistent with the principles.

The most commonly used reference for defining the objectives in utilities' cost of service allocation and rate design is the seminal work of James Bonbright[6]. Chapter 16 (pages 383-384) of the Second Edition sets out ten "attributes of a sound rate structure":

Revenue-related Attributes:

1. *Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality or safety.*

---

[6] *The Principles of Public Utility Rates*, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen (Second Edition, 1988) Public Utilities Reports, pages 383-4.

> 2. *Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.*
>
> 3. *Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers, and with a sense of historical continuity.*
>
> *Cost-related Attributes:*
>
> 4. *Static efficiency of the rate classes and rate blocks in discouraging wasteful use of the service, while promoting all justified types and amounts of use:*
>
>   *(a) in the control of the total amounts of service supplied by the company;*
>
>   *(b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).*
>
> 5. *Reflections of all of the present and future private and social costs and benefits occasioned by the service's provision (i.e., all internalities and externalities).*
>
> 6. *Fairness of the specific rates in the apportionment of total cost of service among the different ratepayers, so as to avoid arbitrariness and capriciousness, and to attain equity in three dimensions: (1) horizontal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).*
>
> 7. *Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).*
>
> 8. *Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.*
>
> *Practical-related Attributes*
>
> 9. *The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.*

10. Freedom from controversies as to proper interpretation.

While there is no generally accepted hierarchy for these principles, the relevance and weight given to the principles will vary with the particular circumstance and context of a regulatory application.

It is inevitable that in applying these principles, conflicts arise in trying to apply all of the principles simultaneously. An allocation that is more equitable may well compromise economic efficiency or simplicity. Determining the optimal trade-offs between the principles in developing rates therefore requires judgment[7]. For this reason, cost of service allocation and rate design are often referred to as being as much art as science.

4 FEI'S COST ALLOCATION METHODOLOGY

FEI is guided by similar principles when undertaking cost of service allocation and rate design as the Bonbright principles outlined above in section 3 of this report. In addition to the Bonbright principles, FEI is guided by the legal context used to set customer rates and by energy policy documents reflecting the Government energy objectives.

FEI lists the principles it uses in Exhibit B-1, Section 5.3, page 5-2. The eight principles are:

1. Recovering the Cost of Service
2. Fair apportionment of costs amongst customers
3. Price signals that encourage efficient use
4. Customer understanding and acceptance
5. Practical and cost-effective to implement
6. Rate stability
7. Revenue stability

[7] An excellent restatement of the Bonbright Principles that emphasizes the need to balance the conflicting principles appears in Newfoundland and Labrador Board of Commissioners of Public Utilities, in the matter of an application by Newfoundland and Labrador Hydro for a General Rate Review, Decision and Order of the Board, Order No. P.U. 7 (2002-2003) June 7, 2002, at pages 27-30.

8 Avoidance of undue discrimination

FEI's eight cost of service allocation principles cover the same areas as the Bonbright principles listed above in Section 3 of this report. The revenue related attributes of Section 3 are included in FEI's principles # 1, #6 and # 7. The cost related attributes of Section 3 are included in FEI's principles # 2, # 3 and # 8. The practical related attributes of Section 3 are included in FEI's principles # 4 and # 5,

To establish a principled cost allocation approach consistent with Bonbright's principle #6, regulators generally adopt the view that the class that causes specific costs should be expected to pay those costs. This is referred to at the cost causation principle. For example, AUC noted in Decision 2007-026 that allocation of costs for ATCO Gas should be based on each rate group's respective proportion of such costs. In general, customer related costs are allocated to rate classes on the basis of number of customers, commodity related costs are allocated on the basis of throughput and demand related costs are allocated on the basis of coincident peak demands or non-coincident peak demands[8]. Enbridge also mentioned in its cost allocation studies that the overriding principle for proper classification and allocation of costs is to do so based on the causation of costs that are approved by the OEB[9].

FEI's cost of service allocation methodology, as described in its evidence in Section 6 of Exhibit B-1, follows the traditional approach to cost of service allocation study as described in Section 2 of this report. It includes the three steps of Functionalization, Classification and Allocation.

4.1 FUNCTIONALIZATION

The functions proposed by FEI include: Gas Supply Operations, Tilbury LNG Storage, Mt. Hayes LNG Storage, Transmission, Distribution, Marketing and Customer Accounting[10].

---

[8] EUB (now AUC) Decision 2007-026 (April 26, 2007), page 72.

[9] EB-2016-0215, Exhibit G2, Tab 1, Schedule 1, page 9 of 28.

[10] Exhibit B-1, Section 6.3.4, page 6-13, Table 6-8

4.1.1 Gas Supply

This function includes costs related to gas control, use of gas and allocation of general and intangible plant assets and expenses.

4.1.2 Tilbury LNG Storage

This function includes costs related to the operation and maintenance of the facility and allocation of general and intangible plant assets and expenses.

4.1.3 Mt. Hayes LNG Storage

This function includes costs related to the operation and maintenance of the facility and allocation of general and intangible plant assets and expenses.

This facility has a dual purpose of serving as a gas supply storage facility and a transmission facility which provides additional transmission system capacity to serve customers[11] and FEI in the COSA study reclassified a portion of Mt. Hayes costs to the transmission function. This treatment is unusual. Elenchus is not aware of analogous methodologies being used in Canada in allocating the costs of storage or LNG to customer classes. However, it is Elenchus understanding that this unique treatment reflects the unique role that Mt. Hayes LNG Storage serves in the FEI system. Storage is more typically a purely midstream asset, but Mt. Hayes LNG Storage also provides benefit to the downstream gas distribution system. Consequently, it is appropriate to reflect the multi-faceted role of the facility in the cost of service allocation methodology.

4.1.4 Transmission

This function includes costs related to the transmission pipe assets, compression, right of way and related maintenance, measurement control operations and transmission supervision. This function also includes an allocation of general and intangible plant assets and expenses. This function also includes Southern Crossing Pipeline (SCP) costs.

[11] Exhibit B-1, Section 6.3.4.4, page 6-14, lines 31 to 33

4.1.5 Distribution

This function includes assets and expenses related to the distribution pressure and intermediate pressure pipe assets, meter installation and exchange, service lines, maintenance, training, distribution pipe operations, emergency management and an allocation of general costs and intangible plant assets and expenses.

4.1.6 Marketing

This function includes costs related to energy solutions, energy efficiency, resource planning and market development and external relations. It also includes an allocation of general costs and intangible plant assets and expenses.

4.1.7 Customer Accounting

This function includes the costs of administering FEI's customers, computer hardware and software, leasehold improvements, furniture, equipment and structures, customer billing, customer assistance, credit and collections, customer service supervision and an allocation of general costs and intangible plant assets and expenses.

4.1.8 Elenchus' Analysis of FEI's functions

Elenchus is of the view that the functions used by FEI are appropriate and reflect the various activities that FEI is involved in during the delivery of natural gas to its customers.

A proper functionalization of assets and costs in a cost of service allocation study reflecting the various utility's activities allow for a fair apportionment of assets and costs to customer classes using cost causality principle. If assets and costs are not broken down into proper functions, it could result in assets and/or costs being classified and allocated to customers that do not impose the assets and/or costs on the utility.

Elenchus is of the opinion that the Mt. Hayes facility treatment in FEI's cost allocation study is appropriate as it performs dual functions related to distribution (delivery margin) and midstream (storage and transmission). Separating the delivery function from the midstream function allows for the assets and costs of the Mt. Hayes facilities to be categorized and allocated in the cost of service allocation study to those customers that use these services from FEI.

As a comparison, Enbridge Gas Distribution Inc. in Ontario uses the following functions in its COSA study: Gas Supply, Storage, Sales Pressure Regulators, Distribution Pressure Regulators, Services, Mains, Meters, Rental Equipment, Sales/Marketing, Customer Accounting and Unidentifiable[12]. Union Gas in Ontario uses: Production and Gathering, Local Storage, Underground Storage, Transmission, Distribution (Southern Ontario), Distribution (Northern Ontario), Intangible Plant and General Plant[13]. ATCO in Alberta uses: Administration, Consumer education, Billing, Call Centre, Meter reading, Retailer service, Transmission, Distribution meters, Customer service, Distribution services and Distribution mains[14].

Table 1 compares the functions used in cost of service allocation studies by FEI, Enbridge, Union Gas and ATCO.

Table 1: Cost Allocation Functionalization

Functions	FEI	Enbridge	Union Gas	ATCO
Gas	Gas supply	Gas supply	Production and gathering	
Storage	Tilbury Storage	Storage	Local storage	
	Mt. Hayes Storage		Underground storage	
Transmission	Transmission	Sales pressure regulators	Transmission	Transmission
Distribution	Distribution	Distribution pressure regulators	Distribution (Southern Ontario)	Distribution meters
		Services Mains	Distribution (Northern Ontario)	Distribution Mains
		Meters	Intangible plant	Meter reading
		Rental Equipment	General Plant	Distribution Services
Marketing	Marketing	Sales/ Marketing		Consumer education Call Centre Retailer Service Customer Service
Accounting	Customer Accounting	Customer Accounting		Administration Billing
		Unidentifiable		

[12] Exhibit G2, Tab 1, Schedule 1, page 6, Table 2, Proceeding EB-2012-0459

[13] Proceeding EB-2011-0210, Exhibit G3, Tab 3, Schedule 1

[14] ATCO Gas 2011/2012 General Rate Application Phase II filing, Tab A, page 4/70 and 5/70, May 29, 2012

4.2 CLASSIFICATION

FEI's classifies the functionalized assets and expenses into Demand, Energy and Customer[15] related.

4.2.1 GAS SUPPLY

Gas supply is classified as energy related

4.2.2 LNG STORAGE

Tilbury and Mt. Hayes functions are classified as demand related. The Tilbury Expansion is allocated entirely to RS 46 customer class[16].

4.2.3 TRANSMISSION

This function is classified as 100% demand related.

4.2.4 DISTRIBUTION

To support the classification of some distribution assets and expenses, e.g. distribution mains, into customer and demand related, additional supporting studies are required. FEI conducted a Minimum System Study (MSS) and related Peak Load Carrying Capacity (PLCC) adjustment[17].

Based on Elenchus experience, in order to determine the proportion of distribution costs that are customer related and the proportion that are demand related, there are two generally accepted methodologies being used by utilities: Minimum System method and Zero Intercept method.

The Minimum System method calculates the proportion of distribution asset costs that are customer related by taking the ratio of the costs of the smallest distribution assets, e.g. smallest main, to the costs of all similar assets, e.g. all mains. This process is used

[15] Exhibit B-1, Section 6.2.1.2, page 6-4

[16] Exhibit B-1, Section 6.3.5.2, page 6-18, line 2, 3

[17] Exhibit B-1, Appendix 6-5

to determine the customer components for mains. A common critique of this method is that the customer related portion of the distribution system is able to carry some demand, therefore, some demand related costs would be included in the customer component. To address this concern an adjustment is made to take into consideration the demand that can be supplied through the minimum system. The adjustment is the PLCC.

The PLCC adjustment determines the theoretical capacity of the minimum system, that is, the capacity of the smallest distribution asset. The capacity of the smallest distribution asset is divided by the number of customers served by the distribution system and an average minimum system capacity per customer is calculated. This average minimum capacity is multiplied by the number of customers in each rate class and the corresponding amount is deducted from the peak demand for that rate class to derive the adjusted peak demand. The adjusted peak demand is used to allocate demand related distribution assets and costs.

The Zero Intercept method calculates the customer related component of a distribution asset type by plotting a graph of the unit costs of different size similar assets and using the value at the zero intercept in the graph to represent the customer component of the asset costs. A common critique of this method is that a utility may not have enough data to plot a proper graph, or the method may result in a negative value at zero intercept.

Union gas uses the minimum system method to classify mains into demand and customer related[18]. ATCO also uses minimum system method to classify costs of distribution mains. AUC approved ATCO to continue using the minimum plant method in Decision 2000-16 based on the rationale that the minimum plant method produced smoother results over time than the zero intercept method, and was not subject to the same data gathering problems[19]. Further, in Decision 2007-026[20], AUC discussed that the zero intercept method could produce statistically unreliable results if the extension of the regression equation beyond the boundaries of the data intercepted the Y axis at a negative value

[18] Proceeding EB- 2011-0210, Exhibit G3, Tab 1, Schedule 1, page 9, lines 13, 14

[19] EUB (now AUC) Decision 2000-16 (June 12, 2000), page 21.

[20] EUB (now AUC) Decision 2007-026 (April 26, 2007), page 59.

due to some abnormality in the data. AUC also noted that the determination of the zero intercept was not an exact science and required judgment. AUC approved ATCO to continue using the minimum plant method[21]. Enbridge uses the zero intercept method approved by the OEB in EBRO 487 Decision with Reasons and the proportions are updated every year along with its cost allocation study[22]. Elenchus reviewed the MSS and PLCC adjustment study done by FEI and agrees with how FEI has conducted the study and used the results. These studies are typical reviewed and updated periodically but typically not with every COSA update. MSS and PLCC reviews are only required when there is reason to believe that the latest study needs to be updated, for example if the distribution asset minimum standards change.

4.2.5 Marketing and Customer Accounting

These functions are classified by FEI as customer related with the exception of DSM funding which is classified as energy related.

4.2.6 Elenchus Analysis of FEI's Classification Methods

Demand, energy and customer are the standard classifications used in COSA studies and Elenchus agrees with the classifications used by FEI in the COSA studies. Elenchus is not aware of any other classification method used in cost of service allocation studies. Sometimes the term commodity is the term used instead of energy.

The use of minimum system with PLCC adjustment and/or the zero intercept method has been accepted as a classification methodology for distribution related assets and costs based on Elenchus experience.

Elenchus has seen the minimum system method applied more often by utilities than the zero intercept method.

---

[21] Note that the Negotiated Settlement from ATCO 2008-2009 GRA-Phase II resulted in a negotiated classification of costs (e.g. Distribution Service Function be classified 100% to the Customer component and then distributed to rate groups on the basis of Weighted Customers), rather than using the Minimum Plant Method, AUC directed ATCO to bring this topic forward at the next GRA Phase Application.

[22] EB-2016-0215, Exhibit G2, Tab 1, Schedule 1, page 12 of 28.

4.3 ALLOCATION

FEI allocates classified assets and expenses to each customer class in the COSA study as follows:

- Demand related using peak day estimated consumption
- Energy related using annual demand
- Customer related using number of customers or weighted number of customers[23].

4.3.1 DEMAND RELATED

FEI uses the coincident peak (CP) methodology to allocate demand related assets and expenses to rate schedules. FEI states in its evidence that: *FEI's delivery system has generally been constructed to meet the peak day (coldest day) demand of all its firm service customers[24].* FEI allocates demand related costs based on the rate schedule's contribution to the system peak.

The peak day demand estimate for each rate schedule uses regional temperatures data and is based on a regression analysis that uses average monthly temperature and actual demand data for ten months (excludes July and August). For heat sensitive loads, load factors are used in order to determine the peak day demand and data for three years are used and are averaged.

Elenchus agrees that demand related costs be allocated based on coincident peak allocator, but Elenchus experience is that Distribution demand related assets and expenses are allocated to rate classes using non-coincident peak allocators instead of using coincident peak allocators.

Traditionally in COSA studies, the closer the assets are to customers and further away from the generation source, it is the customers' individual demands that influence the size of the distribution assets required to satisfy customers' demand and not the size of the coincident demand imposed by customers on the entire system. Coincident demands

---

[23] Exhibit B-1, Section 6.3.6, page 6-20

[24] Exhibit B-1, Section 6.3.6, page 6-21, lines 15 to 16

have an impact in the sizing of generation and transmission assets, but not on the size of the distribution assets.

For example, ATCO uses non-coincident peak values[25] to distribute demand related distribution costs to each rate group as AUC approved in Decision 2007-026[26].

4.3.2 Energy Related

FEI uses annual demand (Tj) estimates in order to allocate energy related assets and expenses to each rate schedule.

4.3.3 Customer Related

Average number of customers and weighted number of customers are used to allocate customer related costs by FEI in the COSA study.

Weighted number of customers is used to allocate service lines and meters, customer billing and customer contact services. Weighting factors are used because not all customer classes impose the same costs on FEI for these services. The weighting factors developed are a comparison of the costs imposed by each customer class in relation to the costs imposed by the Residential customer class for a cost function.

4.3.4 Elenchus Analysis of FEI's Allocation Methods

Elenchus agrees with the allocators used by FEI in the COSA study and they are the standard allocators used by utilities in COSA studies. Elenchus experience is that non-coincident peak (NCP) is used to allocate distribution demand related assets and expenses by electric utilities.

In response to Elenchus question to FEI, (included as Appendix A to this report), on using non-coincident peak as an allocator for distribution demand related assets and expenses, FEI stated that:

---

25 ATCO Gas 2011/2012 General Rate Application Phase II, Attachment 2, page 2 of 8.

26 EUB (now AUC) Decision 2007-026 (April 26, 2007), page 92.

a) it does not have the necessary metering in place in order to calculate NCP by customer class,

b) approximately 80% of FEI's customers volumes are heat sensitive and the NCP would be the same as their coincident demand in the peak day and

c) that the FEI system is designed to satisfy the demand during the peak day.

FEI summarizes its response by stating that*: "while FEI refers to its Peak Day demand as a coincident peak, it is derived from the sum of the various customer class loads under a design day event, which is similar to the standard approach to developing an NCP based on a measurement of historic system peak day loads. As a result, there is very little difference between the FEI's CP demand and the NCP demand. FEI's method to calculate Peak Day and allocate costs based on the results is appropriate as it is aligned with the way in which FEI plans and builds its distribution system."*

Elenchus accepts FEI's explanation of the reasons for using CP as an allocator instead of NCP and that even if the data would be available, the results would be unchanged.

4.4 GAS COST ALLOCATION

Gas costs are incurred by FEI in order to meet peak customer demand for all sales customers only and have two components: (i) commodity and (ii) storage and transport. These costs are allocated to sales customers and are not allocated to transportation customers.

Commodity is charged as a flow through cost to sales customers by FEI without mark-up. It is classified as energy related and is allocated to customers based on throughput.

Storage and transport costs are incurred by FEI in order to satisfy sales customers demand on a daily basis and the pipeline system stays in balance on a daily basis. The storage and transport resources that FEI has in place are to meet design day and design year conditions, and are secured in an open and competitive marketplace. It is classified as demand related and is allocated to customers based on a load factor adjusted volumetric basis. Elenchus notes that this methodology is consistent with the treatment of storage and transport (i.e., midstream) costs for Fort Nelson, as discussed in section

5.5 below. It is also consistent with the peak and average method used by Enbridge Gas Distribution for its upstream transportation and Union transmission costs[27]. The comparable upstream commodity costs borne by other Canadian natural gas utilities are generally limited to transportation costs.

4.4.1 Elenchus Views on Gas Cost Allocation

Elenchus agrees with the allocation of commodity gas costs to FEI's customers. Commodity gas costs are a flow through cost for FEI sales customers and depend on the amount of natural gas used by sales customers, therefore energy is the allocator to use that reflects cost causality.

4.5 Assumptions and Adjustments

The following assumptions and adjustments were used by FEI in its COSA study. The adjustments to the data reflect changes that should be incorporated into the COSA study to reflect how FEI expects to operate in 2018.

4.5.1 Test Year

FEI used the approved costs for its 2016 test year in its COSA study. The approved revenue requirement is $1,237.5 million and the approved asset rate base is $3,692.7 million[28].

4.5.2 Operating and Maintenance (O&M) Expenses

FEI broke down its approved 2016 O&M expenses into functions using the same percentage of its actual 2015 O&M results.

[27] OEB files EB-2016-0215, Ex. G2, T1, S1 page 11 and EB-2011-0210, Ex. G3, T5, S22, page 1.

[28] Exhibit B-1, Section 6.3.1.1, Table 6-1, page 6-6

4.5.3 REVENUE ADJUSTMENT – RS 22 A

FEI found out that its approved 2016 revenues included a misclassification of RS 22A non-bypass customer revenues and has corrected the error in its application.

4.5.4 REVENUE ADJUSTMENT – BC HYDRO

FEI has adjusted the data in its COSA study to reflect changes in BC Hydro consumption and contract that occurred as of November 1, 2016[29]. BC Hydro increased its firm demand and the contract for Burrard Thermal expired

4.5.5 BYPASS AND LARGE INDUSTRIAL CONTRACT CUSTOMERS

FEI is not changing the terms and conditions applicable to bypass customers which have contractual obligations and rates that have been negotiated with the customers to maintain them connected to FEI's system. FEI also serves contract customers that have in the past negotiated their rates with FEI and the rates have been approved by the BCUC.

The revenues from bypass and contract customers are treated as a credit to the cost of service and the credit is allocated to each sales and non-contract transportation service rate schedule[30].

4.5.6 BIOMETHANE CUSTOMERS

FEI's biomethane service allows customers to allocate a portion of their natural gas as renewable natural gas. Biomethane is a renewable and carbon neutral energy source that reduces GHG emissions when replacing natural gas[31]. The biomethane related costs are generally included in a variance account to be recovered from biomethane customers consistent with an order from the Commission. The biomethane related costs that remain in the COSA study to be functionalized and allocated are the costs of six interconnections and these costs have been functionalized as distribution and are allocated to customers

[29] Exhibit B-1, Section 6.3.1.4, page 6-8, lines 8 to14

[30] Exhibit B-1, Section 6.3.1.5, page 6-9, lines 11 to 13

[31] Exhibit B-1, Section 6.3.1.5, page 6-9, lines 20 to 21

with access to the biomethane program[32]. Customers in rate schedules 1B (residential), 2B (small commercial), 3B (large commercial), 5B (general firm) and 11B (large volume interruptible) are eligible for this program

4.5.7 NATURAL GAS FOR TRANSPORTATION CUSTOMERS

FEI has a natural gas transportation program that provides incentives to customers to purchase vehicles or convert transportation equipment into using CNG and LNG. The treatment of the program, approved by the Commission based on a Government Directive, in the COSA study, has the costs included in the delivery charges for all non-bypass customers, the related revenues for the fueling stations included as Other Revenues and the assets and costs included in the distribution function. These costs are classified as demand and customer related and are allocated to all customers[33].

4.5.8 LOAD FACTOR ADJUSTMENT TO RS 5 CUSTOMERS

FEI is proposing to adjust the load factor adjustment for RS 5 customers to use the RS 5's three-year average instead of the 50% deemed load factor that was negotiated in the 1996 rate design application. The load factor is used to allocate midstream costs to RS 5 customers and FEI contracts for midstream resources based on a calculated load factor for RS 5 customers, not a deemed load factor[34].

4.5.9 KNOWN AND MEASURABLE CHANGES

There are three approved projects that FEI expects to have in service in 2018 for which their costs have been included in the COSA study:

- Lower Mainland Intermediate Pressure System Upgrade
- Coastal Transmission System Upgrade
- Tilbury Expansion

---

32 Exhibit B-1, Section 6.3.1.6, page 6-9, lines 19 to 28

33 Exhibit B-1, Section 6.3.1.7, page 6-10, lines 2 to 12

34 Exhibit B-1, Section 6.4.2.1, page 6-30, lines 6 to 11

Only the Tilbury project has associated revenues and FEI has used a ten year levelized margin approach to reflect the impact of the project on FEI's customers.

4.5.10 ELENCHUS ANALYSIS OF ASSUMPTIONS AND ADJUSTMENTS

Elenchus understands that the adjustments made by FEI in its COSA study reflect how FEI expects to operate in 2018 and Elenchus supports these adjustments as they reflect expected normal operating conditions for FEI in 2018.

The test year used in a cost of service allocation study, based on Elenchus experience, reflects the normal operating conditions for a utility and known changes from past operations should be incorporated in the test year data as known adjustments.

Similar to FEI's test year approach, AUC directed gas utilities to set going-in rates on the basis of a notional year revenue requirement using actual costs experienced during generation Performance Based Regulation (PBR) term with any necessary adjustments to reflect individual distribution utility known or anticipated anomalies[35]. There are also gas utilities in U.S. (e.g. Atmos Energy Corporation[36]) that use a historic test year adjusted for known and measurable changes.

The 10 year horizon used by FEI in its COSA study to reflect the impact of the Tilbury Expansion project is not consistent with standard practice. Utilities undertake new investments on an ongoing basis and as a result the revenue requirement in any year includes costs for older assets that have a diminished impact on the total revenue requirement as well as new assets that have a high initial impact. Except in extraordinary cases, it would be inconsistent to levelize the costs of a single project while not levelizing the costs associated with other investments. Elenchus is not aware of any unique aspects of the Tilbury Expansion Project that make its impact on customers generally, or any class of customers, that justify exceptional treatment of this project in the form of levelizing its costs for purposes of the COSA.

[35] AUC Errata to Decision 20414-D01-2016, page 11.

[36] Railroad Commission of Texas, Gas Utility Docket No. 10428, page 2 of 10.

5 FORT NELSON

As described in Exhibit B-1-1, Section 13 of FEI's evidence, the COSA study for Fort Nelson also follows the traditional three step approach of functionalization, classification and allocation. Part of the evidence was updated on April 7, 2017 in Exhibit B-1-1-1.

5.1 FUNCTIONALIZATION

The functions used for Fort Nelson COSA study are: Gas supply operations, Transmission, Distribution, Marketing and Customer Accounting. There are no FEI on-system storage facilities in Fort Nelson.

5.1.1 ELENCHUS ANALYSIS OF FORT NELSON FUNCTIONALIZATION

Elenchus opinion is that the functionalization proposed for Fort Nelson's cost allocation study is appropriate in order to be able to classify and allocate Fort Nelson's assets and costs to its customer classes based on cost causality principles.

5.2 CLASSIFICATION

The same three classifications are used in Fort Nelson's COSA study: demand, energy and customer related, as are used in FEI's cost of service allocation studies.

The minimum system method is used to classify some of Fort Nelson's distribution assets e.g. mains, into demand and customer related and a related PLCC adjustment is made to the results.

Fort Nelson's minimum system study results are different than the minimum system study results for FEI, but in the initial Application the same PLCC adjustment was used for Fort Nelson as it is used for FEI[37].

[37] Exhibit B-1-1, Appendix 13-1, Table 4, page 5

5.2.1 Elenchus Analysis of Fort Nelson Classification

Elenchus opinion is that the PLCC adjustment for Fort Nelson should be based on the characteristics for Fort Nelson, the same way as the results of the minimum system study reflects Fort Nelson's own circumstances and Fort Nelson's results are different than the minimum system results for FEI.

In response to Elenchus question to FEI, (included as Attachment A to this report), on using a PLCC that would be specific to Fort Nelson, FEI responded that after considering this issue, FEI intends to update the evidence filed for COSA for Fort Nelson and proposes to use a PLCC value that is specific to Fort Nelson. FEI's analysis shows that the difference is that the PLCC for Fort Nelson is 1.178 GJ per customer as compared to the 0.205 GJ per customer for FEI as a whole. The reason given by FEI for the higher PLCC value for Fort Nelson relates to lower density and fewer larger customers in Fort Nelson's system compared to the FEI system as a whole.

The evidence for Fort Nelson was updated on April 7, 2017 to reflect the impact of using a PLCC adjustment specific to Fort Nelson.

5.3 Allocation

The Fort Nelson COSA study uses the following allocators:

- Demand related using peak day estimated consumption;
- Energy related using annual demand; and
- Customer related using number of customers or weighted number of customers.

The peak day demand is used to allocated demand related assets and expenses. The customer load for the test year is adjusted by the load factor of each rate category to estimate the peak day demand for each rate class.

Energy related costs are allocated to rate classes based on forecast annual consumption.

Customer related costs are allocated to rate classes using number of customers in each rate category.

Weighted number of customers is used to allocate service lines and meters, customer billing and customer contact services. Weighting factors are used because not all customer classes impose the same costs for these services. The weighting factors developed for each customer class are in relation to the costs imposed by the Residential customer class for the service.

5.3.1 Direct Allocation

Direct allocation is used in COSA studies when there are assets and/or expenses that can be identified separately and are imposed on the utility by only one customer class, therefore there is no need to classify and allocate these costs to other customer classes. For Fort Nelson the cost of the industrial customer meter station has been directly assigned to the RS 25 General Firm Transportation customer class[38].

5.3.2 Gas Cost Allocation

Gas costs are classified as energy related and are allocated to sales customers using forecast annual consumption.

5.3.3 Midstream Costs

Midstream costs are classified as demand related and are allocated to all sales customers based on their load factor adjusted volumes.

5.3.4 Elenchus Analysis of Fort Nelson Allocation

Elenchus opinion is that the allocation method used in Fort Nelson's cost allocation study is appropriate and is consistent with the allocation used in FEI's cost allocation study.

[38] Exhibit B-1-1, Section 13.4, page 13-13, lines 15 to 18

5.4 ASSUMPTIONS AND ADJUSTMENTS

5.4.1 TEST YEAR

For Fort Nelson, approved costs for 2018 have been used in the COSA study. The approved revenue requirement is $3.162 million and the rate base is $11.2275 million[39].

5.4.2 OPERATING AND MAINTENANCE EXPENSES

FEI has a Shared Service Agreement with Fort Nelson. FEI provides functional support to Fort Nelson including Information Systems, Energy Supply and Resource Development, Transmission, Finance and Regulatory, Customer Service, Energy Solutions and External Relations, Engineering Services, Operations Support, Governance, Human Resources, Environment, Health and Safety and Corporate.

To functionalize the Shared Service costs, FEI had to split the Shared Services line item into components.

FEI used for Fort Nelson, the same proration method that was used to break O&M into activity, excluding FEI's Distribution or LNG O&M components as Fort Nelson has direct distribution costs and does not have any LNG activity.

Fort Nelson's 2017 and 2018 Revenue Requirement includes detailed O&M for Distribution Operations.

5.4.3 ADJUSTMENT TO TEST YEAR INPUTS

FEI adjusted the number of customers and revenue for one customer in the RS 25 customer class, since this customer moved to the Rate 2.1 customer class. The customer had no consumption, so only the fixed revenue was moved.

5.4.4 LOAD FACTOR ADJUSTMENT

Rate Schedule 25 in Fort Nelson is intended to serve process load customers that have higher annual throughput and are less heat sensitive than large commercial customers.

[39] Exhibit B-1-1, Section 13, page 13-14, Table 13-5

In its evidence for Fort Nelson, FEI states that customers with low factors below 40% are more heat sensitive than a typical process load customer and should be taking service under the large commercial rate. A 40% load factor has been used for RS 25 in the Fort Nelson COSA study in order to reflect the intended use of the rate schedule[40].

5.4.5 Elenchus Analysis of Fort Nelson Assumptions and Adjustments

Elenchus also supports the adjustments done to reflect how Fort Nelson is expected to operate in 2018. The test year used in a cost allocation study, based on Elenchus experience, reflects the normal operating conditions for a utility and known changes from past operations should be incorporated in the test year data as known adjustments.

6 Revenue to Cost Ratio and Margin to Cost Ratio

Revenues to cost ratios are the measure used in a COSA study to determine if a customer class is paying its fair share of costs.

Margin to cost ratio include only FEI's delivery revenues and costs. Revenue to cost ratio include also gas and storage and transport costs and revenues.

FEI uses a R:C ratio range of between 0.90 and 1.10 as an acceptable range of results for its COSA. If a customer class has a ratio within that range it is assumed that the customer class is recovering its fair share of costs and FEI does not propose to adjust its share of cost responsibility.

6.1 FEI R:C and M:C Ratios

The revenue to cost ratio, prior to rate design and rebalancing proposals by FEI, are within the range of 0.95 to 1.05 for all classes except for RS 6 and RS 22A[41]. Classes being served by interruptible service have been excluded from the analysis as interruptible

---

[40] Exhibit B-1-1, Section 13.4.1.4, page 13-15, lines 23 to 29

[41] Exhibit B-1, Section 6.5.2, page 6-35, Table 6-18

service does not drive system capacity needs and the charges applied to interruptible service are not based on the results of the cost allocation study.

RS 6 is the natural gas vehicle service rate category and RS 22A is a closed transportation service rate schedule in the Inland service area.

The margin to cost ratio prior to rate design and rebalancing proposal by FEI for all classes considered are within the 0.90 to 1.10 range with the exception of RS 6 and RS 5/25. RS 5/25 is the General Firm sales and transportation service rate schedule.

6.1.1 Elenchus Analysis of FEI Ratios

The revenue to cost ratio is calculated by dividing total revenue from the rate schedule by the total allocated cost of delivery plus storage and transport and gas. In FEI business models, commodity, storage and transport costs are incorporated into customer rates without a markup. The margin to cost ratio is calculated by excluding gas and storage and transport costs from both the numerator and denominator of the R:C ratio[42]. The definition of R:C and M:C ratios implies that the calculated R:C ratio range would always be less than the calculated M:C ratio range. Specifically, the M:C ratio would be less than the calculated R:C ratio for the same rate schedule if the R:C ratio is less than 1.00 and the M:C ratio would be greater than the calculated R:C ratio for the same rate schedule if the R:C ratio is greater than 1.00[43]. For transportation customers, the R:C ratio and M:C ratio are almost the same. They arrange their own commodity, storage and transport resources and delivery is the only service they buy from FEI[44]. Since there is a consistent relationship between R:C and M:C ratios, it is essentially no difference in using either of the ratios as the benchmark. However, to compare FEI with other gas utilities, it is better to use a ratio that is adopted by others[45].

---

[42] Exhibit B-1, Section 6, page 6-34, line 18-23.

[43] Exhibit B-1, Section 6.5.2, page 6-35, Table 6-18

[44] Exhibit B-1, Section 3, page 3-4, line 8-13.

[45] Nevertheless, providing M:C ratios as well as R:C ratios does provide additional information that may be helpful to parties. Elenchus notes that the Ontario Energy Board's (OEB) treatment of bill impacts from utility rate applications takes an analogous dual reporting approach. The OEB Handbook to Utility Rate Applications, dated October 12 2016, OEB states that for bill impacts, it will assess both "How the

By reviewing cost of service studies conducted by other major Canadian gas utilities, Elenchus found that R:C ratio is the typical ratio used in the industry although the accepted range of reasonableness is different for each utility. For ATCO, the Alberta Energy and Utilities Board (now AUC) noted that revenue to costs ratios within a target range of 0.95 to 1.05 are generally considered to be appropriate. The Board also noted that rates that vary from the target range after a consideration of other rate design criteria may be approved in order to take into account non-cost issues[46].

Based on Elenchus experience, revenue to cost ratios that are within a range of acceptable values are considered to indicate that the customer class is paying its fair share of costs and that there is no need to realign cost responsibility. The usual revenue to cost range of acceptable ratios that Elenchus has observed is between 0.90 and 1.10 or a narrower range of 0.95 to 1.05. A narrower range of 0.95 to 1.05 is usually used by regulators and utilities in instances when there is good load and costing data available to be used in a COSA study and the utility and regulator have had experience and history in using COSA studies in order to set rates.

Elenchus agrees with how FEI has calculated the revenue to cost ratios and margin to cost ratios results and agrees that no adjustment to rate classes' cost responsibility is required at this stage based on the R:C ratio range of reasonableness.

6.2 FORT NELSON R:C AND M:C RATIOS

The revenue to cost ratio and margin to cost ratio for Fort Nelson before rebalancing and rate design proposals were updated on April 7, 2017 to reflect the impact of using a PLCC adjustment specific to Fort Nelson. The revenue to cost ratios for rate 1 (residential) and rate 2.1 (small commercial) customers classes are within the range of 0.90 to 1.10 while the revenue to cost ratios for rate 2.2 (large commercial) and rate schedule 25 (general firm transportation) are outside the range of 0.90 to 1.10[47].

utility has considered total bill impacts in its planning" and "What the bill impacts are for only those components of the bill that are within the control of the utility (no pass-through items)".

[46] EUB Decision 2006-062 (June 27, 2006), page 3.

[47] Exhibit B-1-1-1, Section 13.4.3, page 13-20, Table 13-12

6.2.1 Elenchus Analysis of Fort Nelson Ratios

Elenchus notes that it is generally accepted practice to undertake rate design adjustments to reduce the revenue to cost ratios for rate classes that are above the range of 1.10 to bring them within the acceptable range of revenue to cost ratios. The resulting revenue shortfall is normally recovered from customer classes that have revenue to cost ratios that are below 1.00, often primarily from those below the lower end of the range i.e. 0.90.

In Fort Nelson's case, rate 2.2 with a revenue to cost ratio of 113.2 before rebalancing and rate design proposal and rate schedule 25 with a revenue to cost ratio of 112.1 before rebalancing and rate design proposal are above the upper range of 1.10. Rate I is the only customer class with a R:C ratio below 1.00 (0.905) before rebalancing.

7 Summary

Elenchus has reviewed FEI's application with respect to cost allocation methodologies and this report includes our views on FEI's proposals.

Appendix A Responses from FEI

Page Intentionally Blank

16705 Fraser Highway
Surrey, BC V4N 0Ei
Tel: (604) 576-7178
Fax: (604) 576-7000
fortisbc.com

MEMO

To	Mike Roger & John Todd	Date	March 30, 2017
	Elenchus	From	Richard Gosselin
Re	FEI 2016 Rate Design Application - Questions on Evidence Filed	CC	Doug Chong (BCUC); Errol South (BCUC)

Dear Mr. Roger and Mr. Todd:

Further to your questions dated March 24, 2017, the following are FortisBC Energy Inc.'s responses.

1. **Preamble:** Exhibit B-1, Appendix 6-1, page 24

   Question: What are FEI's views on EES recommending the use of Non-Coincident Peak (NCP) to allocate demand related distribution costs as opposed to using Coincident Peak (CP) as an allocator?

   Response:

   As explained below, there is very little difference between the Coincident Peak (CP) demand that FEI uses and the Non-Coincident Peak (NCP) demand that EES suggests that FEI should consider incorporating into its future COSA.

   First, it is important to note that FEI does not have demand meters in place to measure the CP and NCP for 99% of its customers.

   Coincident Peak, generally speaking, refers to demand among a group of customers that coincides with total demand on the system at that time. A customer's CP is usually calculated from meter readings taken at the time when the customer's demand is likely to be highest; however, 99 percent of FEI's customers do not have demand meters, meaning daily consumption data for these customers is unavailable.

   A customer's NCP would be calculated using several readings taken at different times to determine what their actual Peak Day demand may be. Again, a more sophisticated type of meter is required to calculate NCP and this data is unavailable for most of FEI's customers. FEI has not taken the steps to collect daily demand data for most of its customers because FEI plans and builds its distribution system based on a design day.

   Second, there is not likely to be a material difference between the CP and NCP on FEI's system since greater than 99 percent of FEI's customers are heat sensitive, these customers include FEI's Residential and Commercial Classes Rate Schedules (RS) 1, 2, 3 and 23 and they account for approximately 70% of FEI's total annual volume. FEI's larger industrial customers are less heat sensitive than its Residential and Commercial customers. However, FEI's Firm General Service RS 5 and RS 25, which are not included in the 99% or 70% referenced above are also fairly heat sensitive with consumption to temperature regression R squares of 0.88 and 0.71 respectively. Adding these two Rate Schedules volumes to the 70% above brings total annual volume that would be considered heat sensitive to approximately 80%. As the usage of these customers correlates well to temperature, it is very likely that these customers will require their Peak Day demand on the same day (coincidentally). Consequently, less than 1 percent of FEI's customers contribute to a difference between the system NCP and CP.

Third, FEI's approach to calculating its coincident peak is based on a design day and is similar to the standard approach to developing an NCP. The design day is an extreme weather condition (coldest day in 20 years). FEI build its system based on the design day so that it is able to serve its customers when a design day occurs. For its Peak Day demand, FEI calculates the demand that would come from each of its customer classes during a design day and then adds them together. Since greater than 99 percent of FEI's customers are heat sensitive and their consumption correlates well with temperature (high R squared results from regression analysis), FEI is able to calculate these customers' peak day demand during a design day event using the slope and intercept from the regression analysis.[1] For other customers, we use the firm contract demand that we are obligated to provide them on the design day. The sum of these Peak Day demands is considered the system Peak Day demand. FEI uses this Peak Day demand method along with firm demand of its less heat sensitive customers to plan and build its distribution system.

In summary, while FEI refers to its Peak Day demand as a coincident peak, it is derived from the sum of the various customer class loads under a design day event, which is similar to the standard approach to developing an NCP based on a measurement of historic system peak day loads. As a result, there is very little difference between the FEI's CP demand and the NCP demand. FEI's method to calculate Peak Day and allocate costs based on the results is appropriate as it is aligned with the way in which FEI plans and builds its distribution system.

2. **Preamble:** Exhibit B-1-1, Appendix 13-1, minimum system for Fort Nelson. The PLCC adjustment is the same as the FEI PLCC adjustment.

Question: Should a different PLCC value be used for Fort Nelson as a separate entity in order to reflect that it is in a different geographic location further north and using more natural gas than in the rest of FEI's territory? There are different minimum system results used for Fort Nelson and FEI, but the same PLCC is used.

Response:

The data used in developing the PLCC used in the COSA Study was an average over the entire system and included Fort Nelson. Because the same minimum size of 60mm is used for both FEI and Fort Nelson, FEI felt it was reasonable that the PLCC for the entire system be used.

However, the question of a Fort Nelson specific PLCC was posed at FEI's second workshop on COSA and Rate Design proposals on March 9, 2017 and by Elenchus in seeking clarification regarding Fort Nelson's COSA Study. After discussion both internally and with

[1] Appendix 6-7

EES, FEI considers that using a Fort Nelson specific PLCC would be more appropriate because it is a separate region for rate making purposes.

The data is available to calculate a unique PLCC for Fort Nelson and the result is 1.178 GJ per customer as compared to the 0.205 GJ per customer for FEI as a whole. The higher PLCC amount for Fort Nelson is likely a result of less density in customers and fewer large customers on the system. Using a higher Fort Nelson specific PLCC would have the impact of reducing costs allocated to the residential class and increasing costs allocated to the commercial classes.

FEI plans on filing an Evidentiary Update for Fort Nelson including updated COSA results and rate design proposals on or before April 14, 2017 but does not expect that an update will be required for FEI as removing Fort Nelson from FEI PLCC analysis should not materially affect the PLCC for the rest of the system.

Sincerely,

Richard Gosselin
Manager, Cost of Service
FortisBC Energy Inc.

Page Intentionally Blank

Appendix B Elenchus Team Qualifications

Page Intentionally Blank

JOHN D. TODD

34 King Street East, Suite 600 | Toronto, ON M5C 2X8 | 416 348 9910 | jtodd@elenchus.ca

---

PRESIDENT

John Todd has specialized in government regulation for over 35 years, addressing issues related to price regulation and deregulation, market restructuring to facilitate effective competition, and regulatory methodology. Sectors of primary interest in recent years have included electricity, natural gas and the telecommunications industry. John has assisted counsel in over 250 proceedings and provided expert evidence in over 100 hearings. His clients include regulated companies, producers and generators, competitors, customer groups, regulators and government.

PROFESSSIONAL OVERVIEW

Founder of Elenchus Research Associates Inc. (Elenchus) **2003**

- ERAI was spun off from ECS (see below) as an independent consulting firm in 2003. There are presently twenty-five ERAI Consultants and Associates. Web address: www.elenchus.ca

Founded the Canadian Energy Regulation Information Service (CERISE) **2002**

- CERISE is a web-based service providing a decision database, regulatory monitoring and analysis of current issues on a subscription basis. Staff are Rachel Chua and rotating co-op students. Web address: www.cerise.info

Founded Econalysis Consulting Services, Inc. (ECS) **1980**

- ECS was divested as a separate company in 2003
- There are presently four ECS consultants: Bill Harper, Mark Garner, Shelley Grice, and James Wightman. Web address: www.econalysis.ca

EDUCATION

1975 Masters in Business Administration in Economics and Management Service, University of Toronto

1972 Bachelors of Science in Electrical Engineering, University of Toronto

PRIOR EMPLOYMENT

Ontario Economic Council, Research Officer (Government Regulation) **1978 - 1980**

Research Assistant, Univ. of Toronto, Faculty of Management Studies **1973 - 1978**

Bell Canada, Western Area Engineering **1972 – 1973**

REGULATORY/LEGAL PROCEEDINGS

Provided expert evidence and/or assistance to the applicant or another participant:

Before the Ontario Energy Board

John Todd has provided expert assistance in a total of 62 proceedings before the Ontario Energy Board from 1991 to 2016. He has presented evidence in 25 of these cases. The most recent case he participated in was the *Independent Electricity System Operator, 2016 Usage Fee*. Evidence: Cost Allocation and Rate Design for the 2016 IESO Usage Fee.

Before the Public Utilities Board of Manitoba

John has provided expert assistance in a total of 46 proceedings before the Public Utilities Board of Manitoba from 1990 to 2015. He has presented evidence in 23 of these cases. The most recent case he participated in was the *City of Winnipeg: Manitoba Hydro 2015/16 GRA and Manitoba Hydro COSS Review.*

Before the British Columbia Utilities Commission

John has provided expert assistance in a total of 33 proceedings before the British Columbia Utilities Commission from 1993 to 2006. He has presented evidence in eight of these cases. The most recent case he participated in was the *British Columbia Transmission Corporation, 2006 Transmission Revenue Requirement.*

Before the Régie de l'énergie

John has provided expert assistance in a total of ten proceedings before the Régie de l'énergie from 1998 to 2014. He has presented evidence in nine of these cases. The most recent case he participated in was the *Report for the Régie de l'énergie, Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Quebec Distribution and Transmission Divisions.*

Before the Alberta Energy and Utilities Board

John has provided expert assistance in of two proceedings before the Alberta Energy and Utilities Board in 2001. He has presented evidence in one case. The second case of 2001 was in regards to the case of *Generic, Gas Rate Unbundling (2001-093)*. Evidence: Canadian Experience and Approaches.

Before the Newfoundland & Labrador Board of Commissioners of Public Utilities

John has provided expert assistance in a total of nine proceedings from 2005 to 2015. He has presented evidence in three cases. The most recent proceeding he participated in was the *Newfoundland Power, 2016 Deferred Cost Recovery Application* case.

Before the New Brunswick Energy and Utilities Board

John has provided expert assistance in a total of nine proceedings before the New Brunswick Energy and Utilities Board from 2007 to 2016. He has presented evidence in three cases. The most recent proceeding he participated in was the *2015 New Brunswick Power Customer Cost Allocation Student Review.* Evidence: Cost Allocation Study Review.

Before the Nova Scotia Utility and Review Board

John has provided expert assistance in a total of nine proceedings before the Nova Scotia Utility and Review Board from 2008 to 2016. He has presented evidence in four cases. The most recent proceeding he participated in was *Efficiency One, Updated Cost Allocation Methodology.*

Before the National Energy Board (NEB)

John has provided expert assistance in one proceeding before the NEB, during 1999. The proceeding was in regards to *BC Gas, Southern Crossing Project.*

Before the Canadian Radio-television and Telecommunications Commission (CRTC)

John has provided expert assistance in 47 proceedings before the Canadian Radio-television and Telecommunications Commission from 1990 to 2016. He has presented evidence in 13 of these cases. The most recent proceeding he participated in was a *Review of Basic Telecommunications Services, Consultation CRTC 2015-134.*

Before the Ontario Telephone Services Commission (OTSC)

John has provided expert assistance in one proceeding before the Ontario Telephone Services Commission in 1992. The case was in regards to a *Review of Rate-of-Return Regulation for Public Utility Telephone Companies.* Evidence used: The need for OTSC regulation of municipal utility telcos.

Before the Ontario Securities Commission

John has provided expert assistance in four proceedings before the Ontario Securities Commission from 1981 to 1985. He presented evidence in each case. The most recent proceeding he participated in was a *Securities Industry Review.* Evidence: Industry structure and the form of regulation.

Before the Ontario Municipal Board

John has provided expert evidence and assistance in two proceedings before the Ontario Municipal Board in 1992 and 1995. In 1995, he assisted in a case regarding an *Appeal of Boundary Expansion by Lincoln Hydro and Electric Commission*, with an affidavit prepared on the tests for boundary expansions.

Before the Supreme Court of Ontario

John has presented evidence in one proceeding before the Supreme Court of Ontario, in 1990. The case related to the *Challenge of the Residential Rent Regulation Act (1986) under the Canadian Charter of Rights and Freedoms.* Evidence: The impact of rent regulation on Ontario's rental housing market.

Before the Saskatchewan Court of Queen's Bench

John has presented evidence in one proceeding before the Saskatchewan Court of Queen's Bench, in 1993. The evidence was regarding market dynamics and competition policy.

Non-Hearing Processes

John has provided expert assistance in 17 non-hearing processes since 1997 to the following Ontario Energy Board, British Columbia Gas, the British Columbia Utilities Commission, the New Brunswick Department of Energy, SaskPower, the Government of Vietnam, and more.

Commercial Arbitrations and Lawsuits

John has provided expert assistance in 6 commercial arbitrations and lawsuits between 2004 and 2015.

Facilitation Activities

- 5 Strategic Planning sessions with Executive and/or Board of Directors of regulated companies between 2000 and 2015
- 6 stakeholder processes for regulators and utilities from 2000 through 2016

Other Regulatory Issues Researched

- Over 20 studies completed for regulators, utilities and others outside of hearing processes

SELECTED PRESENTATIONS

- Productivity Benchmarking Panel at Canadian Electrical Association RITG CAMPUT Workshop (May 2016)
- Utility Cost Recovery in an Era of Ageing Infrastructure, Technological Change and Increasing Customer Service Expectation, CEA Legal Committee and Regulatory Innovations Task Group (June 2016)
- MEARIE Training Program, Regulatory Essentials for LDC Executives (2016)
- Issue in Regulatory Framework for Tenaga Nasional Berhad, Indonesia (with Cynthia Chaplin & London Economics) (2015)
- Witness Training for electric utilities 2014 - 2016
- "Innovations in Rate Design", CAMPUT Training Session, Annually 2010-2013
- "Cost of Service Filing Requirements" (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with the Ontario Energy Board
- "Green Energy Act" (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with Ontario Energy Board
- "Rate Design", CAMPUT Training Session, Annually 2009- 2013
- "How to Build Transmission and Distribution to Enable FiT: The Role of Distributors", EUCI Conference on Feed in Tariffs, Toronto, Sept. 2009
- "Distributor Mergers and Acquisitions: Potential Savings", 2007 Electricity Distributors Assoc.
- "Beyond Borders" Regulating the Transition to Competition in Energy Markets (with Fred Hassan), EnerCom Conference March 2006.

SELECTED OTHER ACTIVITIES

- Organizing Committee for the Concert for Inclusion in support of ParaSport Ontario
- Chairman of the Board of Directors of the Ontario Energy Marketers Association (formerly the Direct Purchase Industry Committee) and Executive Director of the Association.
- Invited participant in the Ontario Energy Board's External Advisory Committee.
- Panelist for "Administrative Tribunals and ADR", Osgoode Hall Law School, Professional Development Program, Continuing Legal Education, April 1997.
- Former Member of the Board of Directors of East Toronto Community Legal Services.
- Numerous appearances on CBC radio and television commenting on energy industry issues, competition, regulation and mergers in the Canadian economy.

CLIENTS

Over 70 private sector companies, including utilities

15 industry and other associations

Over 30 consumers' associations and legal clinics

Government

- 5 Regulatory Tribunals
- 6 Federal departments
- 14 Provincial departments, commissions and agencies
- 13 municipal and other departments/entities

For John Todd's complete curriculum vitae, please visit: www.elenchus.ca

Page Intentionally Blank

MICHAEL J. ROGER

34 King Street East, Suite 600 | Toronto, ON M5C 2X8 | 905 731 9322 | mroger@elenchus.ca

ASSOCIATE, RATES AND REGULATION

Michael has over 38 years of experience in the electricity industry dealing in areas of finance, cost allocation, rate design and regulatory environment. Michael has been an expert witness at numerous Ontario Energy Board proceedings and has participated in task forces dealing with his areas of expertise. Michael is a leader and team player that gets things done and gets along well with colleagues.

PROFESSIONAL OVERVIEW

Elenchus **2010 - Present**
Associate Consultant, Rates & Regulation

- Provide guidance on the Regulatory environment in Ontario for distributors and other stakeholders, with particular emphasis on electricity rates in Ontario and the regulatory review and approval process for cost allocation, rate design and special studies.
- Some of the clients that Michael provides advice include: Hydro Quebec Energy Marketing Inc., GTAA, Ontario Energy Board, City of Hamilton, Hydro One Transmission, Powerstream, Hydro Ottawa, Veridian and APPrO.

Hydro One Networks Inc. **2002 - 2010**
Manager, Pricing, Regulatory Affairs, Corporate and Regulatory Affairs

- In charge of Distribution and Transmission pricing for directly connected customers to Hydro One's Distribution system, embedded distributors and customers connected to Hydro One's Transmission system.
- Determine prices charged to customers that conform to guidelines and principles established by the Ontario Energy Board, (OEB).
- Provide expert testimony at OEB Hearings on behalf of Hydro One in the areas of Cost Allocation and Rate Design.
- Keep up to date on Cost Allocation and Rate Design issues in the industry.
- Ensure deliverables are of high quality, defensible and meet all deadlines.

- Keep staff focused and motivated and work as a team member of the Regulatory Affairs function. Provide support to other units as necessary.

Ontario Power Generation Inc. **1999 - 2002**
Manager, Management Reporting and Decision Support, Corporate Finance

- Produce weekly, monthly, quarterly and annual internal financial reporting products.
- Input to and coordination of senior management reporting and performance assessment activities.
- Expert line of business knowledge in support of financial and business planning processes.
- Coordination, execution of review, and assessment of business plans, business cases and proposals of an operational nature.
- Provide support to other units as necessary.
- Work as a team member of the Corporate Finance function.

Ontario Hydro **1998 - 1999**
Acting Director, Financial Planning and Reporting, Corporate Finance

- Responsible for the day to day operation of the division supporting the requirements of Ontario Hydro's Board of Directors, Chairman, President and CEO, and the Chief Financial Officer, to enable them to perform their due diligence role in running the company.
- Interact with business units to exchange financial information.

Financial Advisor, Financial Planning and Reporting, Corporate Finance **1997**

- Responsible for co-ordinating Retail, Transmission, and Central Market Operation divisions' support of Corporate Finance function of Ontario Hydro to ensure financial information consistency between business units and Corporate Office, review business units compliance with corporate strategy.
- Provide advice to Chief Financial Officer and Vice President of Finance on business unit issues subject to review by Corporate Officers.
- Participate or lead task team dealing with issues being evaluated in the company.
- Supervise professional staff supporting the function.
- Co-ordinate efforts with advisors for GENCO and Corporate Function divisions to ensure consistent treatment throughout the company.

Section Head, Pricing Implementation, Pricing **1986 - 1997**

- Responsible for pricing experiments, evaluation of marginal costs based prices, cost-of-service studies for municipal utilities, analysis and comparison of prices in the electric industry, rate structure reform evaluation, analysis of cost of servicing individual customers and support the cost allocation process used to determine prices to end users.
- Responsible for the derivation of wholesale prices charged to Municipal Electric Utilities and retail prices for Direct Industrial customers, preparation of Board Memos presented to Ontario

Hydro's Board of Directors and support the department's involvement at the Ontario Energy Board Hearings by providing expert witness testimony.

Section Head (acting), Power Costing, Financial Planning & Reporting, Corporate Finance **1994 - 1995**

- Responsible for the allocation of Ontario Hydro's costs among its customer groups and ensure that costs are tracked properly and are used to bill customers.
- Maintain the computer models used for cost allocation and update the models to reflect the structural changes at Ontario Hydro.
- Participate at the Ontario Energy Board Hearings providing support and expert testimony on the proposed cost allocation and rates.
- Provide cost allocation expertise to other functions in the company.

Additional Duties **1991**

- Manager (acting) Rate Structures Department.
- Review of utilities’ rates and finances for regulatory approval.
- Consultant: Sent by Ontario Hydro International to Estonia to provide consulting services on cost allocation and rate design issues to the country’s electric company.

Analyst, Rates **1983 - 1986**

- In charge of evaluating different marketing strategies to provide alternatives to customers for the efficient use of electricity.
- Co-ordinate and supervise efforts of a work group set up to develop a cost of service study methodology recommended for implementation by Municipal Electric Utilities and Ontario Hydro's Rural Retail System.
- Provide support data to Ontario Hydro's annual Rate Submission to the Ontario Energy Board.
- Participate in various studies analysing cost allocation areas and financial aspects of the company.

Forecast Analyst, Financial Forecasts **1980 – 1983**

- Evaluating cost data related to electricity production by nuclear plants and preparing short term forecasts of costs used by the company. Maintain and improve computer models used to analyse the data.
- Review Ontario Hydro's forecast of customer revenues, report actual monthly, quarterly and yearly results and explain variances from budget.
- Support the development of new computerized models to assist in the short-term forecast of revenues.

Project Development Analyst, Financial Forecasts **1979 - 1980**

- In charge of developing computerized financial models used by forecasting analysts planning Ontario Hydro's short term revenue and cost forecasts and also in the preparation of Statement of Operations and Balance Sheet for the Corporation.

Assistant Engineer – Reliability Statics, Hydroelectric Generations Services **1978 – 1979**

- In charge of analysing statistical data related to hydroelectric generating stations and producing periodic report on plants' performance.

ACADEMIC ACHIEVEMENTS

1977	Master of Business Administration, University of Toronto. Specialized in Management Science, Data Processing and Finance. Teaching Assistant in Statistics.
1975	Bachelor of Science in Industrial and Management Engineering, Technion, Israel Institute of Technology, Haifa, Israel.

Attachment 1.1B

Patrick Wruck
Commission Secretary

Suite 410, 900 Howe Street

Commission.Secretary@bcuc.com
bcuc.com

June 23, 2017

Sent via eFile

FEI 2016 RATE DESIGN
EXHIBIT A2-10

Ms. Diane Roy
Vice President, Regulatory Affairs
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8
gas.regulatory.affairs@fortisbc.com

Re: FortisBC Energy Inc. - 2016 Rate Design Application – Project Number 3698899
Elenchus Rate Design Report

Dear Ms. Roy:

Commission staff submit the following independent consultant report for the record in this proceeding:

> Elenchus Research Associates Inc. – Review of FortisBC Energy Inc. Rate Design Methodology for the 2016 Rate Design Application.

Sincerely,

Original signed by:

Patrick Wruck
Commission Secretary

ES/yl
Enclosure
cc: Registered Interveners

FEI 2016 RATE DESIGN
EXHIBIT A2-10

34 King Street East, Suite 600
Toronto, Ontario, M5C 2X8
elenchus.ca

Review of FortisBC Energy Inc. Rate Design Methodology for the 2016 Rate Design Application

Report prepared by
John Todd and Michael Roger
Elenchus Research Associates, Inc.

Prepared for:
British Columbia Utilities Commission

23 June 2017

Page Intentionally Blank

Table of Contents

EXECUTIVE SUMMARY

Elenchus Research Associates Inc. (Elenchus) was retained by the British Columbia Utilities Commission (Commission or BCUC) for the review of the FortisBC Energy Inc. (FEI) 2016 Rate Design Application. By letter dated April 26, 2017, the BCUC finalized the scope for the Rate Design Report. Attachment A to the letter itemized eleven topics that are to be addressed in the Elenchus report.

To assist in determining the reasonableness and appropriateness of FEI's rate design methodologies, Elenchus conducted a jurisdictional review of other gas utilities across Canada and in the Pacific Northwest U.S. See Appendix A.

A summary of the key conclusions and observation on the rate design topics are:

1. Rate shock
    - There are no generally accepted principles that provide clear guidance to regulators for defining rate increases that constitute rate shock.
    - Whenever a customer class is faced with a large rate increase, it is reasonable for a regulator to consider whether the increase will result in sufficient rate shock for customers in the class to warrant some form of mitigation.
    - While many utilities and regulatory agencies have no established method for quantifying rate shock, at least two Canadian regulators of natural gas utilities do address the issue of rate shock using an established and consistent methodology.
    - Elenchus has observed that a common threshold for defining a rate/bill increase that constitutes rate shock is a double-digit increase (i.e., greater than 10%).
2. FEI rate design for residential customers
    - The percentage of fixed costs recovered by utilities in their basic fixed charge varies from utility to utility and between jurisdictions.
    - There appears to be a trend toward recovering a larger proportion of customer-related costs through the monthly basic charge.

- Conceptually, cost allocation principles imply that in order to reflect cost causality the fixed charge should reflect customer-related costs as identified for purposes of the cost allocation model, while the variable charges should reflect energy and demand related costs.

3. FEI rate design for commercial customers

- Among the utilities reviewed by Elenchus, there is only one utility, AltaGas, that explicitly prepared the economic crossover volume analysis between rate classes in its rate design. AltaGas excluded the gas cost recovery charge when calculating the cross over point between small and large general service classes.

4. FEI rate design for industrial customers

- Higher load factor customers are less expensive to serve on a volumetric basis than lower load factor customers since they require less distribution capacity, less storage for load balancing and/or less upstream transportation.
- The customer's consumption characteristics, which are represented by the customer's load profile and load factor, are key factors in making customers eligible for service under various rate classes. Applying a minimum load factor requirement to a specific rate class or not depends on utility's specific load profile.
- Interruptible rates are designed with the primary purpose of controlling load factor for the utility. Customers who have the capability to maintain operations during gas service curtailments, or are prepared to discontinue operations, are provided the option of contracting for interruptible natural gas service. Interruptible gas services are provided at a lower rate than the equivalent firm service. By designing the system to meet only the lower firm design day requirements all utility customers benefit from the reduced capital cost and a more efficient system than if all customers were served on a firm basis.

5. Rate design for Fort Nelson

- All Canadian gas utilities in the review adopt unbundled rates where gas costs, delivery charges, and storage and transport charges are individually visible on consumers' bills.

- AltaGas, ATCO, Centra Gas and Puget Sound Energy have flat rate structures for most or all rate groups. Declining block rates are used for all customer groups by Union Gas and Enbridge. Puget Sound Energy and Avista add declining block rates just for industrial customers.
- Under any alternative used to develop Basic charge and volumetric charge there will be winners and losers.
- Acceptable levels of bill impacts will have to be determined and if any customer would have bill impacts exceeding acceptable levels as a result of the proposed rate structure changes, bill impact mitigation measures would need to be applied.

6. FEI's application of revenue to cost ratio range of reasonableness

- The revenue to cost ratios assist the rate design process by comparing revenues recovered from a rate class with the associated costs. It is also a tool to analyze the degree of cross-subsidization across rate classes.
- Elenchus' review did not identify any other Canadian utility using M:C ratios. The utilities surveyed use the R:C ratio and do not estimate a separate ratio for transportation customers as FEI uses.
- Elenchus views the M:C ratio as a reasonable alternative to the R:C ratio as a basis for determining whether the costs recovered in rates deviate from 100% recovery to justify rate rebalancing. Regulators typically accept rates within a range as constituting full recovery since it is recognized that cost allocation studies are not precise – unless the level of cost recovery is outside the specified range of reasonableness, differential rate increase would not be considered equitable since small deviations from 100% are as likely to be the results of the imprecision of the methodology as they are to be the results of true cost difference.
- It appears to Elenchus that one ratio must be accepted as the primary, or most relevant, basis for determining whether rate rebalancing is needed. The most important consideration is consistency.

7. Transportation Service review

   - The jurisdictional review indicates that daily balancing provision for transportation service is the industry practice.

8. Bypass customers and rates

   - The approach to determining bypass rates reflect operational and policy considerations in specific jurisdictions. For example, where bypass is not feasible due to the absence of alternate transportation systems that customers can connect to, consideration of bypass rates may be a moot point.
   - Where bypass is feasible, the primary purpose of bypass rates is to avoid uneconomic bypass. Uneconomic bypass occurs when the costs that must be incurred to enable a customer to bypass the utility exceed the incremental costs that must be incurred to connect the customer. However, impeding economic bypass is not normally in the public interest since, by definition, economic bypass implies that the incremental costs of bypass are less than the incremental cost of utility providing service.

9. Crisis Intervention Funds for residential customers

   - Crisis assistance programs are available in Ontario, Alberta, Manitoba and in the U.S. The programs are designed to help low-income families in a financial crisis pay their utility bills and sometimes also improve household energy efficiency through weatherization, thereby reducing energy costs.

10. Disconnection Policies for residential customers

    - The research indicates that regulators enforce strict rules about energy disconnection during winter to protect vulnerable energy consumers. However, Elenchus notes that these rules reflect social policy consideration and they are therefore normally based on legislated requirements.

1 OVERVIEW

Elenchus Research Associates Inc. (Elenchus) was retained by the British Columbia Utilities Commission (Commission or BCUC) for the review of the FortisBC Energy Inc. (FEI) 2016 Rate Design Application.

On April 26, 2017, the Commission received Elenchus's first report - Review of FortisBC Energy Inc. Cost of Service Allocation Studies for the 2016 Rate Design Application.

By Order G-30-17, the BCUC established the further regulatory process, which included a procedural conference to seek input from FEI and registered interveners on the key topics to be addressed by Elenchus in the second report – Review of FortisBC Energy Inc. Rate Design for the 2016 Rate Design Application. By letter dated April 26, 2017, the BCUC finalized the scope for the Rate Design Report. Attachment A to the letter itemized eleven topics that are to be addressed in the Elenchus report.

To assist in determining the reasonableness and appropriateness of FEI's rate design methodologies, Elenchus conducted a jurisdictional review of other gas utilities across Canada and in the Pacific Northwest U.S.

The utilities included in the review are:

- AltaGas (Alberta)
- ATCO (Alberta)
- Enbridge Gas Distribution (Ontario)
- Union Gas (Ontario)
- Centra Gas (Manitoba Hydro, Manitoba)
- SaskEnergy (Saskatchewan)
- Gaz Metro (Quebec)[1]

---

1 Rate design methodology for Gaz Metro and Gazifere are not reviewed in the report because documents related to their applications on Regie du lodgement website are only available in French. They are listed for the jurisdictional review of rates.

- Gazifere (Quebec)[1]
- Puget Sound Energy (Washington)
- Avista (Washington)

Appendix A summarizes the proceedings reviewed in the report.

This report contains twelve additional sections that correspond to the eleven topics, with a final section that summarizes the report's conclusions and observations. Hence:

- Section 2 reviews the topic of rate shock;
- Section 3 reviews rate design for residential customers;
- Section 4 reviews rate design for commercial customers;
- Section 5 reviews rate design for industrial customers;
- Section 6 reviews rate design for Fort Nelson;
- Section 7 extends the discussion of revenue to cost ratio and range of reasonableness from what was included in Elenchus' first report;
- Section 8 provides an overview of balancing provision for transportation service;
- Section 9 discusses bypass customers and rates;
- Section 10 reviews crisis intervention funds for residential customers;
- Section 11 provides an overview of disconnection policies for residential customers;
- Section 12 addresses other topics with significant impact to customer rates and/or customer classes; and
- Section 13 summarizes the conclusions and observations of the report.

Each section identifies and comments on the individual questions related to each topic that were identified by the BCUC in its April 26, 2017 letter.

Appendices are included at the end of the report providing additional details that may be of interest to some parties.

2 RATE SHOCK

2.1 FEI PROPOSAL

FEI's Application did not include a proposal regarding the mitigation of rate shock. In the Procedural Conference dated April 5, 2017, the company noted that "FEI generally uses a 10 percent increase as a general guideline for rate shock, but believes that each circumstance has to be looked at individually."[2]

2.2 INDUSTRY PRACTICE

There are no generally accepted principles that provide clear guidance to regulators for defining rate increases that constitute rate shock. In Elenchus view, the concept is best viewed in the context of the Bonbright principles[3] that are discussed at pages 6-7 of the first Elenchus report (Review of FortisBC Energy Inc. Cost of Service Allocation Studies for the 2016 Rate Design Application). The principles include:

> 3. *Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers, and with a sense of historical continuity.*

As the previous report observed, "the relevance and weight given to the principles will vary with the particular circumstance and context of a regulatory application" (page 8, lines 2-4). It follows that there can be no absolute definition of rate shock that will apply in all circumstances. Nevertheless, whenever a customer class is faced with a large rate increase, it is reasonable for a regulator to consider whether the increase will result in sufficient rate shock for customers in the class to warrant some form of mitigation. Elenchus recognizes the following considerations to be relevant to the assessment of whether a mitigation strategy is appropriate to avoid rate shock.

---

2 BCUC, Procedural Conference, Volume 3, page 306.

3 *The Principles of Public Utility Rates*, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen (Second Edition, 1988) Public Utilities Reports, pages 383-4.

- The determination of a “large” increase may be influenced by the general rate of inflation in other costs (i.e., is the increase large relative to the prevailing inflation rate?), the past trend in rate increases (i.e., is the prospective increase consistent with expectations?), and other factors that bear on the perceived reasonableness of the prospective increase.
- If the “large” rate increase is an across the board increase due to a large increase in costs or significant loss of customers or throughput, mitigation of rate shock for any class may not be practical while allowing the utility to recover its prudently incurred costs in full.
- Mitigation of rate shock for a customer class is normally limited to circumstances in which there are differential rate increases to address COSA results with some classes outside the acceptable range. Rate shock for the customer class(es) facing the largest increases can be mitigated by phasing in the adjustment needed to shift all classes within the acceptable range.
- Mitigation of rate shock for customers within a class due to a design of the rate structure (e.g., a change in the fixed variable split) can also take the form of a phase-in of the change in the rate structure.
- Since mitigation of rate shock will result in rates that may be considered inequitable in terms of the Bonbright principles taken as a whole, since R/C ratios will remain outside the accepted range, mitigation should take the form of a phase-in of the rate changes indicated by the cost allocation study that is completed as expeditiously as possible, while limiting the extent of rate shock. Judgment is required to determine a phase-in period that balances inter-class or inter-customer equity against the potential hardship of a sudden large increase in the bills of some customers.

The preceding list of considerations is not intended to be exhaustive, but is merely an indication of the types of considerations that may influence a regulator’s judgment in determining whether an increase is reasonable or constitutes rate shock that is large enough to warrant some form of mitigation.

- ***What method do utilities and regulatory agencies in other jurisdictions use to quantify rate shock?***

Many utilities and regulatory agencies have no established method for quantifying rate shock. In the absence of an established methodology, regulators are able to make rate decisions that implicitly mitigate the impact of rate adjustments on particular customers or customer classes to the extent they consider appropriate on a case-by-case basis. At least two Canadian regulators of natural gas utilities do address the issue of rate shock using an established and consistent methodology.

In Ontario, to quantify rate increases, natural gas distributors must provide bill impact information in both percentage and absolute dollar terms for all customer classes calculated at typical customer volumes[4]. For example, Enbridge uses a typical residential heating and water heating customer who consumes 3,064 m^3 (114 GJ[5]) per year and a typical commercial and industrial customer who consumes 22,606 m^3 (843 GJ) per year for the bill impact analysis[6]. The OEB requires natural gas utilities to file a mitigation plan if the total bill increase for any customer class is material[7].

In Alberta, the AUC has generally applied a threshold of 10% of the total bill as the potential indicator of rate shock[8].

- ***In assessing rate shock, is consideration given to the total customer bill, each component (commodity rate, delivery rate, fixed basic charge), or a combination of charges?***
- ***When commodity costs are flow-through to the commodity rate, are commodity costs typically included or excluded from rate shock considerations?***

In Ontario, gas distributors apply for a Quarterly Rate Adjustment Mechanism ("QRAM") every quarter, and the proposed gas supply price is based on the forecast market price

---

4 OEB, Filing Requirements For Natural Gas Rate Applications, page 36.

5 1 cubic meters (m^3) natural gas equal to 0.0373 gigajoules (GJ).

6 OEB EB-2014-0039, Final Rate Order.

7 OEB, Filing Requirements For Natural Gas Rate Applications, page 36.

8 AUC, Decision 21987-D01-2016, December 9, 2016, page 21.

for natural gas. The OEB requires natural gas distributors to file evidence that explains in detail the reasons for the large rate increase if a 25% increase is anticipated on the commodity portion of a typical residential customer's bill. Distributors are also required to include a plan for mitigation of the increase in their application[9]. When reviewing delivery rate application proposals, the OEB asks distributors to demonstrate total bill impacts as well as delivery-only components that are within the control of the utility[10]. The OEB expects utilities to mitigate bill impacts through the pacing and prioritizing of investments and activities.

For electricity distributors, the OEB has a policy requiring the filing of a mitigation plan when the total bill impact is 10% or more for any customer class. The OEB expects all other utilities to propose mitigation plans, or explain why a plan is not required, when their proposals result in material impacts to customers[11].

The AUC considers the overall change in total customer bills when applying the 10% threshold as the potential rate shock indicator[12].

- ***Does the assessment of rate shock differ for different types of customers?***

In Ontario, the bill impacts and mitigation requirement apply to all customer classes and in Alberta, the AUC uses the 10% bill increase threshold for all rate classes.

Other utilities included in the jurisdictional review did not specify their methods of quantifying and assessing rate shock in the proceedings listed in Appendix A. Elenchus notes, however, that since the mitigation of rate shock is essentially a public policy issue, each regulator's enabling legislation or other policy direction may provide important guidance on how the issue should be addressed in a specific jurisdiction. Elenchus also conducted a jurisdictional review on government legislations that provide a general guideline with respect to energy price. Please refer to Appendix B for the across Canada legislation review.

9 OEB, EB-2014-0199, Decision and Order, August 14, 2014, page 5.

10 OEB, Handbook to Utility Rate Application, October 13, 2016, page 20.

11 Ibid, page v.

12 AUC, Decision 21981-D01-2016, December 21, 2016, page 17.

2.3 ELENCHUS ANALYSIS

Rate shock is an important concept that constrains the pace at which the rates for specific classes, or specific customers within a class, are increasing in a single year. The definition of rate shock is a matter of judgment since it requires the balancing of two concepts of fairness:

- The first concept of fairness relates to the absolute level of rates. The rates implied by a regulator's analytic findings with respect to a utility's revenue requirement, cost allocation and rate design, taking into account all considerations other than rate shock will, by definition, be rates that are fair and equitable in terms of the share of costs recovered from each class and from individual customers within each class.
- The second concept of fairness relates to the rate of change in rates, or more importantly the change in a customer's average monthly bill[13], as a result of the justified rate changes. In many circumstances, a significant increase in customer bills can result in real or perceived hardship for customers that are sufficiently severe that the increase is considered inequitable. This inequity may justify moderating the impact on customers by reducing the increase that would otherwise be implemented, although the necessary consequence is that some other customers will have higher rates than would have been required in the absence of the mitigation of rate shock for the customers with the largest increases.

Due to these equity concerns, it is a common practice for regulators to require mitigation of rate changes in two circumstances, whether or not there is an explicit methodology for measuring rate shock:

1. When a cost allocation study indicates the need to rebalance between classes through differential rate increases, the full impact of the rebalancing may be spread over two or more years. Any class that would experience an unacceptably large rate/bill

[13] The average monthly bill is typically calculated as the average monthly volume (annual volume/12) multiplied by the old and new rates. The result is equal to the change in the average customer's annual cost at the new rate versus the old rate.

increase (rate shock) will receive a reduced rate increase in the first year and possible in subsequent years as well. Consequently, to allow the utility to recover its full revenue requirement, the rates for one or more other rate classes will be higher than they would otherwise have been.

2. When a cost allocation study, or other considerations, implies the need for changes in the rate structure (e.g., a change in the fixed variable split), the impact on the bills of different customers within a class will vary. For example, if the fixed charge is increased relative to the variable charge, lower volume customers within the class will experience larger percentage rate increases. This rate design change may be phased in so that the impact on customer bills will be mitigated. As a result, customer within a class that would otherwise have experienced very large increases, will have that impact reduced, while those that would have experienced smaller increases, or decreases, will instead have their rates adjusted slightly upwards.

   As an example, if the monthly fixed charge is proposed to be increased by 50% from $10 to $15 and the variable charge is proposed to be maintained at current levels, (0% change). Customers with minimal usage may experience an increase in their bills close to 50%. To mitigate the impact on low volume customers, the change in the fixed charge could be spread over two years resulting in the first-year fixed charge being $12.50. The target of $15 would not be reached until the second year. In order to recover the approved revenue requirement in the first year, the variable charge will need to be increased to recover the foregone $2.50 per month fixed charge not implemented in the first year.

Elenchus has observed that a common threshold for defining a rate/bill increase that constitutes rate shock is a double-digit increase (i.e., 10% or more). This view of rate shock appears to be more reflective of perceived societal values than any analytic basis for defining undue hardship resulting from a rate increase. Indeed, the hardship resulting from a rate increase is more closely correlated to income than the rate increase itself. Further, since customers tend to focus on the change in their total bills, rather than changes in individual components of the bill, it is typical, and in the view of Elenchus more appropriate, to define rate shock in terms of the increase in the total bill.

FEI's proposed rates for all rate classes are within the 10% rate increase threshold. Furthermore, FEI's approach as indicated in the Procedural Conference dated April 5, 2017, appears to be consistent with the approach that has been accepted in other jurisdictions.

3 FEI RATE DESIGN FOR RESIDENTIAL CUSTOMERS

3.1 FEI PROPOSAL

FEI is proposing to continue with its existing rate structure[14] for its residential customers which consists of a fixed daily basic charge[15] and a flat volumetric delivery charge. FEI states that the flat rate structure is preferred considering that residential customers are already familiar with this rate structure and it provides simplicity in administration and stability in revenues forecast.

FEI is proposing a one-time 5% increase to fixed daily basic charge and corresponding decrease in the volumetric delivery charge. This type of changes is typically referred to as a change in the fixed-variable split. As indicated in the delivery cost COSA model, about 98.6%[16] of the costs allocated to the residential rate schedule are fixed costs within the time frame of the test year (i.e., both customer and demand-related costs cannot be avoided in response to declining customer counts or volume). Furthermore, FEI calculates that the current basic charge of $11.84 per month recovers about 44% of the customer costs and about 27% of the total fixed costs allocated to the residential class[17]. Therefore, the proposed 5% increase in daily basic charge and corresponding decrease in the delivery charge will improve the alignment between fixed costs allocated to the residential class and the fixed charges applicable to residential customers.

[14] FEI defines the flat rate structure as the straight-line meter rate structure, where the volumetric charge is flat and does not vary with the customer's consumption. (Exhibit B-1, Section 7, page 7-11, line 2)

[15] Note that although the basic charge is referred to as a fixed daily basic charge, the quantum is the amount charged on a monthly basis.

[16] Exhibit B-1, Appendix 6-4, Schedule 7.

[17] Exhibit B-1, Section 7, page 7-17, line 5-9.

The proposed rate design has essentially no impact on customers with annual consumption within the 80 to 85 GJ range. The mean annual residential consumption based on 2015 data was estimated to be 81 GJ[18]. Customers with consumption above the 80 to 85 GJ range will experience reductions in their bills while customers with consumption below this range will experience increases in their bills. Lower volume customers with annual consumption less than 45 GJ will experience increases in their bills ranging from approximately $4 to $7 (approximate 0.7% to 5% of the annual bill) depending on the consumption level[19].

3.2 INDUSTRY PRACTICE

- ***A review of the different tools (example: basic charge, variable charge, demand charge) used in natural gas tariffs to recover fixed costs and variable costs and how these tools are used in the industry.***
    - ***What are acceptable practices for the recovery of fixed costs using the tools identified?***
- ***Is it acceptable practice to set the basic charge based on recovering a specific percentage or range of percentages of fixed costs?***

It is extremely rare for residential natural gas customers to have meters that record their daily demand due to the high cost of this type of meter. As a result, it is not practical to implement the conceptually optimal three-part tariff structure (fixed basic connection charge, variable volumetric charge and variable demand charge). Consistent with the perception that monthly volumetric consumption is a reasonable proxy for demand, it follows that it is reasonable to recover demand-related costs through the volumetric charge. It is common for utilities to also recover some portion of customer-related costs through the volumetric charge, presumably with the rationale that the volumetric charge is a proxy for the value of service to customers. Maintaining a low fixed basic monthly charge also serves to maintain customer connections even for customers with low

18 Exhibit B-1, Section 7, page 7-5, lines 6 to 8

19 Exhibit B-1, Section 7, page 7-25, Table 7-9.

demand. This approach is consistent with the marginal cost of serving connected customers (i.e., it is financially beneficial for a utility to encourage connected customers to continue to take service, even if their volume is minimal, and avoid having them discontinue natural gas service). Nevertheless, there appears to be a trend toward recovering a larger proportion of customer-related costs through the monthly basic charge, which improves equity as measured by fully allocated costs.

In its 2003-2004 and 2005-2007 General Rate Application Phase II Review, ATCO Gas suggested that the fixed charge for the Low Use rate group[20] should be moved from the existing level which recovers 73% of the customer classified costs allocated to the rate group to recovering 100% of such costs. ATCO Gas indicated that such treatment is required to ensure that higher-volume customers within the rate group are not cross subsidizing lower-volume customers within the same rate group. ATCO Gas also argued that a utility's ability to earn its approved revenue requirement should not be subject to weather related risk and recovering fixed costs in the variable charge leads to the potential of under or over recovering of those costs. The Alberta Energy and Utilities Board (EUB, now AUC) decided to limit the Low Use fixed charge to 90% of the customer classified costs in the COSS results. The EUB recognized the arguments for moving fixed charge more in line with the costs, including fairness within and between rate classes and predictability and stability in revenue requirement recovery. However, the decision was made in recognition of the affordability for the lowest use customers and fixed income customers, and the concern of potential rate shock[21].

Similarly, AltaGas proposed a directional move towards recovery of a greater proportion of fixed costs through fixed charges from the existing 66%[22] in its rate design proposal for small general service customers in 2013-2017 Performance Based Regulation Application Phase II.

---

[20] Low Use Delivery Service is applicable to all customers using 1,200 GJ per year or less. ATCO Gas 2011-2012 GRA Phase II Application, Tab D, page 9 of 13.

[21] EUB Decision 2007-026 (April 26, 2007), page 94-96.

[22] AltaGas 2013-2017 Performance Based Regulation Application Phase II, page 20.

For SaskEnergy, its long-term objective is to recover at least 75% of its customer care related costs through the Basic Monthly Charge[23].

In its 2015 General Rate Case, Avista applied to increase the customer charge for residential customers from $9.00 to $12.00 per month. It claims that the total customer allocated costs to residential customers are $27.07 per customer per month and $12.17 of the $27.07 total costs are related to the cost of the meter and service, billing, and providing customer service. It was stated that ideally the fixed costs for providing service would be recovered through a fixed monthly charge because a utility's facilities and support functions are made available to its customers irrespective of how much energy they use[24]. However, the Washington Utilities and Transportation Commission (UTC) directed Avista to retain the customer charge for residential natural gas customers at $9.00 per month[25]. The decision stated that this approach is consistent with the UTC's preference for basic charges to reflect only "direct customer costs"[26].

For other proceedings in the review, the percentage of recovery of fixed costs in the fixed charges was not specified.

3.3 ELENCHUS ANALYSIS

3.3.1 PERCENTAGE RECOVERY OF FIXED COSTS

As the Elenchus survey indicates, the percentage of fixed costs recovered by utilities in their basic fixed charge varies from utility to utility and between jurisdictions.

In Ontario, the OEB has mandated that electricity distributors transition to fully fixed rates for residential customers by 2019 to recover distribution costs. Commercial and industrial (C&I) customers continue to be billed on a combination of fixed and variable charges. The

---

23 SaskEnergy 2016 Commodity and Delivery Service Rate Application, page 27.

24 The Washington Utilities and Transportation Commission, Docket No. UE-150204/UG-150205, Direct Testimony of Patrick D. Ehrbar, page 26.

25 The Washington Utilities and Transportation Commission, Docket No. UE-150204/UG-150205, Order 05, page 9.

26 Ibid, page 10.

current split between fixed and variable charges differs dramatically across Ontario distributors, reflecting their historical billing practices. The split also varies significantly among customers within the C&I classed due to the wide range of volumetric consumption that is a characteristic of these classes.

The OEB's reasoning for the move to fully fixed residential distribution rates is that it helps ensure that electric distributors will recover their approved revenue requirement through a fixed charge and it will eliminate the disincentive to conservation program success since success inherently results in lower customer consumption and revenue under a variable distribution rate. Also, the OEB suggested that utilities will be able to do better long-term asset management planning knowing that there is more certainty in recovering their future capital and operating expenses.

Previously, the costs of Ontario electricity distributors were recovered from residential customers based on a combination of fixed and variable distribution charges and each utility determined the proportion of fixed costs recovered through the basic charge taking into consideration their previously approved fixed basic distribution charge and the results of the cost allocation study methodology. This has been the standard approach in other jurisdictions for distributors of both natural gas and electricity.

Conceptually, cost allocation principles imply that to reflect cost causality the fixed charge should mirror customer-related costs as identified in the cost allocation model, while variable energy and demand charges should reflect energy and demand-related costs. Nevertheless, rate-setting is also often influenced by value of service considerations that result in a lower fixed charge which keeps bills down for customers with below average demand. This approach can encourage increased penetration in terms of the number of customers connected although this is arguably accomplished by embedding a cross-subsidy of low-volume users by the higher volume users in the same rate class.

3.3.2 ALTERNATIVE TO FEI'S PROPOSAL OF ONE TIME 5% INCREASE

- ***A review of acceptable alternatives to FEI's proposal for a one-time 5% increase in the residential fixed charge in order to improve the alignment between the***

fixed costs allocated to the residential rate schedule and the fixed charges recovered from residential customers as explained by FEI.

Elenchus' opinion is that rates to customers should reflect the costs customers impose on the utility based on the cost causality principle. To the extent feasible and taking into consideration customers' bill impacts, fixed charges should recover the fixed costs imposed by customers on the utility and variable charges should recover variable costs.

There appears to be two primary reasons for utilities not recovering their fixed costs through fixed charges:

1. Doing so may result in rate shock to customers' bills.
2. This approach may run counter to a Government policy objective of encouraging conservation.

Alternatives to FEI's one time 5% increase proposals could include:

- No one-time increase
- One time 5% increase and subsequent annual adjustments to the fixed charge(s)
- One time increase greater than 5%

These are commented on in the following subsections.

3.3.2.1 No one- time increase

The benefits of no one-time increase are that it would eliminate potential bill impacts for low-use customers and it would be consistent with Government policy of encouraging customers to reduce their consumption of natural gas.

When a customer undertakes conservation and reduces consumption, the customer expects that its bill will be lower reflecting lower consumption. The fixed charge in the bill is unaffected by consumption changes, therefore, the larger the proportion of fixed charge in a bill, the less benefit that the customer will see as a result of conservation.

The disadvantages of no one-time increase are that fixed charges billed to customers will deviate further from the fixed costs imposed by customers on the utility and a larger proportion of fixed costs would be recovered through the variable charge resulting in more uncertainty to the utility of recovering its approved revenue requirement. In addition, keeping a higher variable charge is a disincentive for the utility to maximize the effectiveness of its conservation programs.

3.3.2.2 ONE TIME 5% INCREASE AND SUBSEQUENT ANNUAL ADJUSTMENTS

The benefits of FEI's proposal of a one time 5% increase to better align fixed charges with recovering fixed costs would start to dissipate if in subsequent years approved revenue requirement increases are recovered only by way of the variable charge. Depending on the level of increases, over time FEI may be recovering the same percentage of fixed costs through the fixed charge as it currently recovers and it could even deteriorate further and FEI may eventually recover a lower percentage of fixed costs through the fixed charge. In this case a future one-time adjustment would be necessary to again better align fixed charges with recovering fixed costs.

An alternative to FEI's proposal is to apply the one time 5% increase, but in subsequent years increase both the fixed and variable charges by the same proportion as the approved revenue requirement increase. This approach would better align rates with cost imposed by customers on the utility and maintain the alignment between the proportion of fixed costs recovered through the fixed charge.

The benefit of this alternative is that fixed charges would continue to recover a similar proportion of fixed costs in subsequent years and there would be limited future deviation in the proportion of fixed costs recovered though the fixed charges.

The disadvantage of this alternative is that it runs counter to the Government objective of encouraging conservation by continuously increasing the fixed charge in subsequent years in the same proportion as the approved revenue requirement for the utility increases. Continuously increasing fixed charges would tend to discourage reducing energy consumption from the customers' perspective.

3.3.2.3 MORE THAN 5% ONE TIME INCREASE

Taking into consideration potential rate shock to customers, especially low use customers, another alternative to FEI's one time 5% increase is to increase the fixed charge by more than 5% based on what is considered to be the maximum tolerable bill impact for low use customers. Low use customer could be a customer that used natural gas only for cooking, for example. A 5% increase in the fixed distribution charge will result in a smaller percentage increase in total customer bills after commodity and transportation charges are taking into consideration.

The benefit of this alternative is that it will allow the utility to recover a larger proportion of its fixed costs from the fixed charge and better align fixed charges with fixed costs.

The disadvantage of this alternative is that it runs counter to Government objective of encouraging conservation by increasing fixed charges and reducing variable charges sending the opposite price signal to customers that reduced energy consumption results in lower customer bills.

Elenchus notes that increases in the fixed monthly charge in excess of 5% have been common in the Ontario electricity sector; however, these increases have been the direct result of the OEB’s policy decision to require all distributors to transition to a fully fixed distribution charge. In addition, large percentage increases in fixed charges are common in cases where utilities have a relatively low basic monthly charge and increase the charge by a relatively small dollar amount, especially in cases where the utility maintains a rounded amount (for example, an increase from $20 to $25 would constitute a 25% increase but would typically not be considered to result in rate shock).

- ***A jurisdictional review of how low-volume residential customers are treated with regards to tariff charges or customer segmentation.***

Elenchus’ survey did not identify any natural gas utilities with low-volume residential customer rates. Low volume residential customers pay the same rates as larger volume residential customers. Some utilities such AltaGas and ATCO have general service rates that apply not only to residential customers but also to commercial customers with demand below a specified volumetric threshold.

The rationale for this approach is that the causal costs (essentially the costs associated with connecting a customer) below an identified modest volume are the same for most residential customer, whether small volume or larger volume, and for small commercial customers; hence, it is appropriate to group them together as small general service customers for rate design purposes.

Table 1 provides the jurisdictional review of the treatment of residential customers with regards to tariff charges and customer segmentation.

Table 1: Jurisdictional Review of Residential Customers Tariff and Customer Segmentation

Utility	Tariff for Residential Customers	Customer Segmentation
AltaGas Utilities[27]	Fixed charge: \$37.83/Month Variable charge: \$2.084/GJ	For residences and small businesses who consume up to 7,226 gigajoules (GJ)/year.
ATCO Gas[28]	North Fixed charge: \$29.19/Month Variable charge: \$1.830/GJ South Fixed charge: \$24.69/Month Variable charge: \$1.731/GJ	For customers that use less than 1,200 GJs annually, including residential, small apartment, small commercial and small industrial customers.
Centra Gas[29]	Fixed charge: \$14.00/Month Variable charge: \$2.489/GJ	For residential customers.
SaskEnergy[30]	Fixed charge: \$22.45/Month Fixed charge: \$3.65/GJ	For residential customers.
Enbridge Gas Distribution[31]	Fixed charge: \$20/Month Variable charge: First 30 m^3 (1.137 GJ): \$2.673/GJ Next 55 m^3 (2.084 GJ): \$2.528/GJ Next 85 m^3 (3.221 GJ): \$2.415/GJ Over 170 m^3 (6.441 GJ): \$2.33/GJ	For residential customers.

27 AltaGas, Rates & Rules, Accessible online: http://www.altagasutilities.com/general-services

28 ATCO Gas, Current Rates, Accessible online: http://www.atcogas.com/Rates/Current_Rates/

29 Manitoba Hydro, Current Natural Gas Rates, Accessible online: https://www.hydro.mb.ca/regulatory_affairs/energy_rates/natural_gas/current_rates.shtml

30 SaskEnergy, Residential Rates Effective November 1, 2016, Accessible online: http://www.saskenergy.com/residential/resrates_curr.asp

31 Enbridge Gas, Residential Customers – Rate 1, Accessible online: https://www.enbridgegas.com/homes/accounts-billing/residential-gas-rates/purchasing-gas-from-enbridge.aspx

Utility	Tariff for Residential Customers	Customer Segmentation
Union Gas[32]	North East and North West Fixed charge: $21.00/Month Variable charge: First 100 m³ (3.789 GJ): $3.309/GJ Next 200 m³ (7.578 GJ): $3.247/GJ Next 200 m³ (7.578 GJ): $3.15/GJ Next 500 m³ (18.945 GJ): $3.061/GJ All Over 1,000 m³ (37.89 GJ): $2.987/GJ	For residential customers.
Gazifere[33]	Fixed charge: $10.05/Month Variable charge: First 50 m³ (1.895 GJ): $7.068/GJ Next 50 m³ (1.895 GJ): $6.865/GJ Next 220 m³ (8.336 GJ): $6.667/GJ Next 680 m³ (25.765 GJ): $6.471/GJ Excess of 1,000 m³ (37.89 GJ): $6.268	For residential service.
Puget Sound Energy[34]	Fixed charge: $10.34/Month (USD) Variable charge: $3.45/GJ (USD)[35]	For residential customers.
Avista (Washington)[36]	Fixed charge: $9/Month (USD) Variable charge: First 70 Therms (7.3 GJ): $7.5/GJ (USD) Over 70 Therms: $8.6/GJ (USD)	For general service (Firm).

32 Union Gas, Current Natural Gas Rates, Accessible online: https://www.uniongas.com/residential/rates/current-rates

33 Gazifere, Conditions of Service and Tariff, Effective April 1st 2017.

34 Puget Sound Energy, Inc., Natural Gas Shedule NO. 23 Residential General Service (https://pse.com/aboutpse/Rates/Documents/gas_sch_023.pdf)

35 Converted from therms to gigajoule using 1 thm=0.105587 GJ.

36 Avista, Washington – Natural Gas Resources, 101 General Service – Firm – Washington (https://www.myavista.com/about-us/our-rates-and-tariffs/washington-natural-gas-resources)

4 FEI RATE DESIGN FOR COMMERCIAL CUSTOMERS

4.1 FEI PROPOSAL

FEI's rate design proposal for commercial customers includes two issues as follows:

- FEI proposed to maintain the threshold between small (RS 2) and large (RS 3 and RS 23) commercial customers at the existing level of 2,000 GJ per year.
- FEI proposed to increase the Basic Charge for RS 2, RS 3 and RS 23 and adjust the Delivery Charge to ensure that the economic crossover point for small and large commercial customers occurs at the threshold of 2,000 GJ per year.

FEI reviewed the relationship between commercial customer annual consumption and load factor and concluded that the existing threshold remains reasonable because the load factor flattens out after the 2,000 GJ/year consumption level.

It is calculated that the economic crossover between RS 2 and RS 3 at the current rates is at an annual consumption level of 1,457 GJ, which means that a customer who consumes more than 1,457 GJ and less than 2,000 GJ is better off financially as a RS 3 customer. Three options were evaluated to address this misalignment, including moving the threshold to 1,000 GJ, moving the threshold to 1,400 GJ, and adjusting the basic and delivery charges. Of these three options, FEI chose the third option on the basis that this option would cause the least disruption or impact on customers[37].

4.2 INDUSTRY PRACTICE

- ***When commodity costs are flow-through to the commodity rate, does the calculation of an economic crossover volume between two rate classes typically include the commodity rate?***

Among the utilities reviewed by Elenchus, there is only one utility, AltaGas, that explicitly prepared the economic crossover volume analysis between rate classes in its rate design.

[37] Exhibit B-1, Section 8, page 8-21, lines 16-22.

Specifically, AltaGas excluded the gas cost recovery charge when calculating the cross over point between small and large general service classes[38], which is different from the method used by FEI.

4.3 ELENCHUS ANALYSIS

It is noted that the gas cost recovery charge is collected through a rider at the same rate for small and large general service customers served by AltaGas, which means that the economic crossover volume is the same whether the commodity cost is included in or excluded from the calculation. However, this is not the case for FEI where different commodity costs exist for small and large commercial customers. The difference is due to the different method of regulating gas costs. For AltaGas, gas costs are excluded from the cost of service study and are recovered by a monthly rider applied to all sales service rates unless otherwise specified to ensure that customers pay neither more nor less than the actual costs[39]. For FEI, the commodity component of the gas cost is allocated to customers based on throughput while storage and transport components are allocated using the load factor adjusted volumetric basis.

It is common practice to recover commodity costs in a separate commodity rate; hence, commodity costs will not have an impact on the cross-over volume. Excluding commodity costs therefore simplifies the calculation with no loss of information.

---

[38] AltaGas 2013-2017 Performance Based Regulation Application Phase II, June 28, 2013, Appendix 3, Schedule 2.0.

[39] AltaGas 2013-2017 Performance Based Regulation Application Phase II, June 28, 2013, Appendix 4, Rate Rider “D”.

5 FEI RATE DESIGN FOR INDUSTRIAL CUSTOMERS

5.1 FEI PROPOSAL

FEI is proposing to maintain the current customer segmentation for industrial customers where rates are segmented into different rate groups based on service type (i.e., sales and transportation service with further segmentation into firm or interruptible services).

With respect to interruptible rates, FEI is proposing to maintain the existing methodology for setting interruptible service at a discount to firm service. Specifically, the delivery charge for interruptible service is based on the demand charge[40] and the delivery charge for firm service[41].

5.2 INDUSTRY PRACTICE

- ***A review of the benefits/disadvantages of requiring a minimum load factor to qualify for a specific rate for industrial rate classes***
    - ***What is a typical minimum load factor used in other jurisdictions, if any?***
    - ***An explanation of the benefits/disadvantages of different load factor levels.***

FEI does not have a minimum load factor requirement for the industrial rate classes and it is not proposing to introduce a minimum load factor although many other natural gas distributors do have a minimum load factor.

There are four utilities in the jurisdictional review that require a minimum load factor to qualify for specified industrial rate, which is one method that can be used to provide high load factor customers with lower rates that are reflective of their lower causal costs relative to volume. Table 2 below summaries the load factors requirements.

---

40 General Firm Service RS 5/RS 25 Demand Charge based on 90.9% adjusted load factor as proposed in this current proceeding due to the proposed decrease in the multiplier in Daily Demand formula for firm service.

41 Exhibit B-1, Section 9, page 9-32, Table 9-20.

Table 2: Minimum Load Factor Requirement

Utility	Rate Class	Minimum Load Factor Requirement
Enbridge Gas[42]	Large Volume Load Factor Large Volume High Load Factor	40% 80%
Union Gas[43]	Large Volume High Load Factor Firm	70%
Gaz Metro[44]	Stable Load Service	60%
Gazifere[45]	Moderate Volume Firm Large Volume Firm Very Large Volume Firm	50% 50% 50%

Higher load factor customers are less expensive to serve on a volumetric basis than lower load factor customers since they require less distribution capacity, less storage for load balancing and/or less upstream transportation for a given volume of natural gas. Consequently, lower rates are justified for higher load factor customers unless the rate structure consists of customer, demand and energy rates that correspond closely to the corresponding costs drivers.

- ***A jurisdictional review of how the rates for interruptible customers are typically determined, considering things such as cost causation, the risk of interruption, the benefits/disadvantages of having interruptible customers, and the benefits/disadvantages of having only firm customers.***

Interruptible rates are generally set at a lower rate than the equivalent firm service as interruptible customers cause lower costs that firm customers. In Ontario, the OEB approved interruptible rates for large contract customers who have the capacity to maintain operations during gas service curtailments using traditional cost allocation methods. Union and Enbridge use cost causality principle to establish interruptible rates. For example, no capacity related costs for peak transportation and storage deliverability

42 OEB EB-2016-0215, Rates Effective July 1st 2016.

43 OEB EB-2016-0245, Rates Effective January 1st 2017.

44 Gaz Metro, Conditions of Service and Tariff, Effective March 31st 2017.

45 Gazifere, Conditions of Service and Tariff, Effective April 1st 2017.

are allocated to Enbridge's Interruptible Rates 145 and 170. The bulk of the allocated costs are related to gas commodity and upstream transportation[46]. Table 3 present as comparison of the Enbridge and Union Interruptible Rates.

Table 3. Comparison of Firm and Interruptible Rates

Utility	Firm and Interruptible Rates	Average Unit Price (cents/m^3)	Interruptible Discount from Firm Rate (%)
Enbridge[47]	Rate 100 Average Commercial Firm	18.39	
	Rate 145 Average Commercial Interruptible	8.47	53.9
	Rate 110 Average Industrial Firm	7.72	
	Rate 170 Average Industrial Interruptible	5.44	29.5
Union[48]	**Union South**		
	Firm Contract Commercial / Industrial M5 (F)	2.7592	
	Interruptible Contract Commercial / Industrial M5 (I)	1.6298	40.9
	Firm Special Large Volume Contract M7 (F)	2.7417	
	Interruptible Special Large Volume Contract M7 (I)	0.9551	65.2
	Union North and East		
	Large Volume Firm Rate 10	5.2606	
	Large Volume Interruptible 25	1.8052	65.7

For Manitoba Hydro[49], interruptible customers are billed using a three-component rate structure, including a basic monthly charge, a monthly demand charge and a volumetric (commodity) charge. The basic monthly charge recovers 100% of the customer related costs determined in the cost allocation study. The monthly demand charge recovers 65% of the capacity/demand related costs from the COSA and the remaining 35% of the demand related costs are recovered through volumetric charge.

[46] OEB EB-2016-0215, Exhibit G2, Tab 5, Schedule 3, page 1 of 2.

[47] OEB EB-2016-0215, Exhibit H2, Tab 7, Schedule 1, page 5-8 of 8.

[48] OEB EB-2011-0210, Exhibit H3, Tab 1, Schedule 3, Page 1 & 2 of 2.

[49] Centra Gas Manitoba Inc. 2013/14 General Rate Application, Tab 11, page 16 of 17.

5.3 ELENCHUS ANALYSIS

5.3.1 MINIMUM LOAD FACTOR

The customer's consumption characteristics, which are represented by the customer's load profile and load factor, are key factors in making customers eligible for service under various rate classes. The appropriateness of applying a minimum load factor requirement to a specific rate class depends on utility's load profile and the structure of its rates. Providing lower rates for high load factor customers serves as an incentive (price signal) for customers in that rate class to improve their load factor. In cases where the improved load profile will reduce the utility's cost, the incentive is reasonable. In cases where the rate structure closely aligns with causal costs, the rate structure will normally provide the appropriate incentive for customers to optimize their load factor.

However, Elenchus notes that the effects of a minimum load factor can be quite complex. For example, Enbridge proposed to lower the load factor requirement from 50% to 40% under Large Volume Load Factor in proceeding EB-2012-0459[50]. It was stated that the reason for lowering the load factor requirement was based on two concerns:

- To facilitate continuity of service under this rate for customers who implement energy efficiency measures; and
- To provide a choice for general service customers with load factors greater than 40% to take service under this rate.

It was explained that when implementing energy efficiency measures, customer's annual consumption declines proportionally more than their peak consumption, thereby, resulting in a decline in load factor. Lowering the load factor requirement keeps those customers under this rate class. For those customers who have the choice to change from general service rate to this rate class, Enbridge evaluated the rate option with customers based on their specific needs and consumption characteristics. The OEB accepted Enbridge's proposed changes in Decision with Reasons for proceeding EB-2012-0459.

---

[50] OEB EB-2012-0459, Exhibit H1, Tab 2, Schedule 3.

It is noted that EES Consulting supported FEI's current segmentation of industrial rates because these rates include a demand charge[51] that already takes into account differing load factors by rate group and as a result, load factor is not necessary to segment customers even further in the industrial rate groups.

5.3.2 INTERRUPTIBLE SERVICE

Interruptible rates are designed with the primary purpose of controlling load factor for the utility. Customers who have the capability to maintain operations during gas service curtailments, or are prepared to discontinue operations, may be provided the option of contracting for interruptible natural gas service. Interruptible gas services are provided at a lower rate than the equivalent firm service. This service allows for the gas system to be designed to meet a lower peak day capacity thereby avoiding capital costs associated with a system that would be designed to meet the full peak day design had all customers' peak requirements been firm. This higher peak day firm design is typically only required a few days each year, even under extreme weather conditions. By designing the system to meet only the lower firm design day requirements, all utility customers benefit from lower capital costs and a more efficient distribution system.

Conceptually, it is reasonable to provide a discount for interruptible service that results in the total annual lost revenue being no more than the annualized costs avoided as a result of the ability to curtail the interruptible customers. At the same time, it benefits other customer classes to charge the highest rate for interruptible service that results in the optimal volumes being contracted as interruptible service. The value of interruptible service for both the utility and the customer depends on the detailed terms and conditions.

Interruptible service can also permit interruptions for economic reasons: the customer's service may be interrupted if the value of the resources that are made available to the utility due to the interruption (possible including diverted gas supply) are more valuable

[51] Utilities listed in Table 1 that require a minimum load factor do not include a demand charge in their rate schedules.

than the revenue that would be received for the interruptible service. For example, service curtailments may enable the utility to engage in spot transactions at a high market price.

6 Rate Design for Fort Nelson

6.1 FEI Proposal

6.1.1 Unbundled Rates

FEI is proposing to unbundle Fort Nelson's rates. That is, Fort Nelson's customers would see a separate volumetric Commodity Cost Recovery Charge per GJ, Storage and Transport Charge per GJ, Basic charge per day and Delivery charge per GJ[52]. Currently Fort Nelson's customers are billed based on bundled charges.

The benefits of moving Fort Nelson's customers to unbundled charges, as stated by FEI in its evidence in Section 13.5.2, are that the unbundled rate structure would be consistent with the rate structure in the rest of British Columbia, it would provide customers with transparency into the different components of customers' bills and eventually it would allow customers to participate in other services that require unbundled rates, such as the Renewable Natural Gas program.

The disadvantage of unbundling rates is that some customers may prefer bundled rates and may find unbundled bills to be complicated to understand.

6.1.2 Flat Rate Structure

FEI is proposing to change the current declining block structure used in Fort Nelson to a flat rate structure. For Fort Nelson's residential customers, rates decline for consumption in excess of 30 GJ per month. For commercial customers, rates decline for consumption in excess of 300 GJ per month[53].

---

[52] Exhibit B-1-1, Section 13, page 13-20, lines 25 to 27.

[53] Exhibit B-1-1, Section 13.5.3, page 13-22, lines 17 to 20

FEI states that the benefits of moving to a flat rate structure are that it is a common rate structure used in Canada, it would be more consistent with Government policy of encouraging conservation, and based on the residential customer research survey conducted by FEI the flat rate structure, it would be preferred by most Fort Nelson customers. Furthermore, most Fort Nelson's customers do not reach the declining consumption block. Moving to a flat rate structure would also eliminate the fluctuation in the minimum charge that is currently used with the declining block rate structure[54].

The disadvantage of changing from a declining block rate structure to a flat rate structure is that there may be customers that would have adverse bill impacts from the rate structure change given their own consumption characteristics.

FEI's evidence is that the bill impact for residential customers of moving from a bundled declining block rate structure with a minimum charge to an unbundled flat rate structure with a daily Basic charge is favourable to customers with the most number of months of consumption of less than 2 GJ and no monthly consumption in excess of 30 GJ. Residential customers with monthly consumption above 2 GJ and the highest number of months of consumption above 30 GJ would have less favourable bill impacts[55].

6.2 Industry Practice

- ***A jurisdictional review of the use of bundled and unbundled rates in natural gas utilities***

6.2.1 Bundled and Unbundled Rates

All Canadian gas utilities in the Elenchus review have unbundled rates where gas costs, delivery charges, and storage and transport charges are shown on consumers' bills. This approach provides greater transparency of the cost drivers since the line items are consistent with the costs of the various services provided by the utility to their customers.

[54] Exhibit B-1-1, Section 13.5.3, pages13-22 line 29 to page 13-24 line14

[55] Exhibit B-1-1, Section 13.5.4.4, page 13-22, lines 17 to 23

6.2.2 FLAT RATE AND DECLINING BLOCK RATE

AltaGas, ATCO, Centra Gas (Manitoba Hydro), and Puget Sound Energy utilize flat rates for most or all rate groups. Declining block rates are used for all customer groups by Union Gas and Enbridge. Puget Sound Energy and Avista have declining block rates only for their industrial customers[56].

6.3 ELENCHUS ANALYSIS

- ***A review of the benefits/disadvantages of FEI's proposal to move to unbundled rates***
- ***A discussion of the considerations that are typically made when changing rate structure for different rate classes in the context of FEI's rate design proposals for Fort Nelson***
- ***A review of the benefits/disadvantages of FEI's proposal for removing a declining block rate structure and adopting a flat rate structure***

Elenchus agrees with the advantages and disadvantages that are identified by FEI that are summarized in the preceding sections. An approach that is more consistent with standard practice will align the billing of Fort Nelson customers more closely with contemporary customer expectations which include a bill that provides more information on the factors that drive their energy costs and in doing so provide better price signals for customers that wish to manage their natural gas bills more effectively by investing in more efficient appliances and managing their use more prudently.

Customers whose energy consumption never exceeds the first block would be indifferent to a flat rate structure since they already have what amounts to a flat rate structure. Larger volume customers, who may have the greatest opportunity to reduce their consumption through improved conservation, will have increased information on the financial value to them of reducing their consumption.

---

[56] Exhibit B-1, Appendix 6-1, page 28.

On the other hand, customers may be accustomed to the situation that more consumption results in lower unit costs and would not easily accept giving up this benefit. They may perceive that their higher consumption, which may reflect higher need, is being unfairly penalized. Appropriate customer education, however, can focus on the reality that unbundled rates result in a more equitable sharing of costs.

Depending on the rate design of the flat rate structure, based on consumption levels, some customers may end up paying more and some customers may end up paying less than under a declining block rate structure. Change always results in resistance among some of the customers that pay more, especially if customer communications about the reasons for the change are not communicated effectively.

Abandoning the declining block rate structure in favour of a flat rate structure would align the Fort Nelson rates with standard practice and all customers in FEI's service territory would be under the same rate structure. Consistency across FEI's service areas should enhance the ability of FEI to educate its customers about the drivers of their energy costs and to manage their natural gas bills by adopting better conservation practices and investing in more efficiency appliances.

In addition, from the FEI perspective, given that most distribution expenses are fixed, having a fixed rate structure would better align with the nature of their operating costs. Also, in promoting conservation consistent with Government objectives, a flat rate structure sends a better price signal for conservation than a declining block rate structure.

On the downside, there will be changes to billing procedures that the utility will have to introduce to implement the flat rate structure and customer service will have to be enhanced to deal with the expected increase in customer enquiries once customers start receiving bills based on the new rate structure. The transition to a flat rate structure may result in significant bill increases for some customers.

Any change in a utility's rate structure results in some degree of customer confusion until customers understand and accept the new rate structure. The utility will have to make an extra effort in communicating the change and reasoning behind the change to customers. FEI may also want to equip its staff to respond to complaints with information on ways that customers can reduce their consumption and bills most effectively.

6.3.1 FEI's Methodology for Moving to a Flat Rate Structure

- ***A review of FEI's methodology used to calculate fixed (basic) and variable charges in a flat rate structure when moving from a declining block structure***

FEI states that the Basic charge and volumetric Delivery charge were developed in a way that achieves the lowest maximum dollar amount bill increase for any individual residential customer[57].

Alternatives to develop the Basic charge and volumetric charge when changing rate structure from declining block to flat rate structure are approaches that would result in:

1. the Basic charge being set equal to the current Minimum bill excluding non-distribution components currently included in the Minimum bill,
2. no bill impact for customers consuming the average monthly class consumption,
3. setting the Basic charge similar to the Basic charge used by FEI for its Residential customers in other service territories, or
4. setting the Basic charge based on the results of the COSA study for Fort Nelson.

The approach that is most consistent with the principle of designing rates so that they correspond to the relevant costs drivers is the fourth option. The rationales supporting the first three options are various pragmatic considerations that may be relevant to the degree of initial customer acceptance that is achieved.

Under any alternative used to develop Basic charge and volumetric charge there will be winners and losers. Customers have different levels of monthly consumption and will be impacted differently when implementing rate structure changes.

Acceptable levels of bill impacts will have to be determined and if any customer would have bill impacts exceeding acceptable levels as a result of the proposed rate structure changes, bill impact mitigation measures can be used to minimize negative reactions.

Nevertheless, the transition to a more equitable and more transparent rate design is a progressive step. The inevitable resistance to change by customers that are negatively impact should not be viewed as a justification for not proceeding with charges that

[57] Exhibit B-1-1, Section 13.5.4.3, page 13-31 lines 12 to 14

improve equity, provide greater transparency, and in doing so should reinforce public policy objectives such as encouraging conservation. Rather than avoiding change it makes more sense to complement progressive changes with effective communications and appropriate conservation programs, as well as giving due consideration of programs that provide financial assistance to customers that may face the greatest hardship as a result of the changes.

7 FEI'S APPLICATION OF REVENUE TO COST RATIO RANGE OF REASONABLENESS

7.1 FEI PROPOSAL

FEI applied a range of reasonableness of 90% to 110% for the revenue to cost ratios for all rate schedules to evaluate the appropriateness of R:C ratios. The R:C ratios include gas and transportation costs.

7.2 INDUSTRY PRACTICE

- ***A discussion of how the concept of range of reasonableness is dealt with in other jurisdictions in relation to revenue to cost ratios and their application to rate design and rebalancing.***

The calculation of revenue to cost ratios by customer class is a primary purpose of cost allocation studies and the use of a range of reasonable is the most common approach to relating proposed rates to the allocated costs.

Revenue to cost ratios assist the rate design process by comparing revenues recovered from a rate class with the associated allocated costs by customer class. They are also a tool for analyzing the degree of cross-subsidization across rate classes. While also taking other rate design principles into consideration, utilities use revenue to cost ratios as a tool to show whether the rates charged to each rate class adequately recover the costs they cause as determined by the utility's cost allocation study.

Union Gas noted that revenue to cost ratios are the outcome of the rate design application and acceptable ratios must satisfy rate design principles as well as bear a reasonable relationship to previously approved revenue to cost ratios. In Union's 2011 Cost of Service review, the OEB found that the proposed revenue to cost ratios were further away from unity than previous approved ones for some rate classes and concluded that the proposed ratios were not appropriate[58].

AltaGas stated that revenue to cost ratios are designed to mitigate the rate impacts and maintain reasonable continuity of rates for all classes[59]. In one of ATCO's Application, the EUB noted that rates that vary from the target revenue to cost ratios after a consideration of other rate design criteria may be approved in order to take into account non-cost issues[60].

Table 4 summarizes the R:C ratio range of reasonableness accepted by other regulators.

58 OEB EB-2011-0210, Decision and Order, page 85.

59 AltaGas 2013-2017 Performance Based Regulation Application Phase II, June 28, 2013, page 20.

60 EUB (now AUC) Decision 2006-062 (June 27, 2006), page 3.

Table 4: R:C Ratio Range of Reasonableness

Utility	Range of Reasonableness
AltaGas[61]	95% to 105%
ATCO[62]	95% to 105%
Union Gas[63]	Close to unity[64]
Enbridge[65]	Close to unity
Centra Gas[66]	100%
SaskEnergy[67]	95% to 105%

7.3 ELENCHUS ANALYSIS

- ***A discussion regarding the use of FEI's margin to cost ratio, instead of the revenue to cost ratio, to assess transportation customers' rate design, since these customers do not incur gas costs.***

Transportation customers arrange their own commodity, storage and transport resources; hence delivery is the only service they buy from FEI. As such, the R:C ratio and M:C ratio are almost the same for this class. Commodity, storage and transport costs are excluded from both the numerator and denominator when calculating the M:C ratios[68].

Elenchus' review did not identify any other Canadian utility using M:C ratios. The utilities surveyed use the R:C ratio and do not estimate a separate ratio for transportation customers as FEI uses.

---

61 AUC Decision 2014-139 (May 23, 2014), page 17.

62 EUB Decision 2006-062 (June 27, 2006), page 3.

63 OEB EB-2011-0210, Decision and Order, page 81.

64 Elenchus interprets "Close to unity" as a smaller range than 95% to 105%.

65 OEB Order EB-2012-0459, page 6 of 63.

66 Centra Gas Manitoba Inc. 2013/14 General Rate Application, Appendix 15.2, page 2 of 5.

67 SaskEnergy Incorporated Rate Application - 2016, slide 19.

68 Exhibit B-1. Section 6, page 6.34, lines 22 to 23

Elenchus nevertheless views the M:C ratio as a reasonable alternative to the R:C ratio as a basis for determining whether the costs recovered in rates deviate from 100% recovery to justify rate rebalancing. Regulators typically accept rates within a range as constituting full recovery since it is recognized that cost allocation studies are not precise. Hence, unless the level of cost recovery is outside the specified range of reasonableness, differential rate increase would not be considered equitable since small deviations from 100% are as likely to be the results of the imprecision of the methodology as they are to be the results of true cost difference.

For example, if the range of acceptable R:C ratios in a jurisdiction is between 0.90 and 1.10 and customer class A has a ratio of 0.91 and customer class B has a ratio of 1.11, rebalancing in order to bring the ratios to within the acceptable range would require that the R:C ratio for customer class B be reduced to 1.10 and customer class A would have to have its rates increased to absorb the reduction in revenues from customer class B, probably resulting in a ratio for customer class A that would be higher than 0.91. There is no requirement to bring the R:C ratios for either customer class to be equal to 1.00.

Rebalancing is done to bring all customer classes within the accepted range of R:C ratios. Any resulting shortfall in revenue requirement resulting from reducing rates to customer classes that have R:C ratios that are above the upper end of the accepted range, would be recovered from customer classes that have R:C ratios below 1.00 and/or that have the lowest R:C ratios. The exact steps used to rebalance rates vary across jurisdictions with no approach being analytically superior to any other. The preferred methodology is a matter of judgment.

The reverse scenario also applies. If a customer class has a R:C ratio below the lower end of the accepted range, its rates would be increased to bring the R:C ratio within the range. The additional revenue requirement received from this increase is offset by rate reductions for customer classes that have R:C ratios above 1.00 and/or have the highest R:C ratios.

The M:C ratio is a reasonable alternative to the R:C ratio because the uncertainty that is being addressed through the adoption of a range of reasonableness for the R:C (or M:C) ratio corresponds to the inherent imprecision in using cost allocation as a measure of causal costs is associated primarily with the allocation of common costs to rate classes. The commodity, storage and transport costs that are not included in the M:C ratio, are directly assignable to classes, although the rates may be based on the allocation of common costs in the cost allocation studies of the external suppliers.

While providing two sets of ratios has the benefit of providing more information to the Commission and stakeholders, it appears to Elenchus that as a practical consideration one ratio must be used as the primary basis for determining whether rate rebalancing is appropriate. The most important consideration in choosing an approach is consistency. That is, the same ratio and the same range should be used as the primary reference point on an on-going basis. Furthermore, the range that is used for a ratio should be consistent with the confidence that can reasonably be placed in the COSA results. This confidence is a matter of judgment, since there is no methodology, analogous to that used for some types of statistical analysis, for quantifying a confidence interval.

Elenchus sees merit in using the M:C ratio as the primary reference frame for determining whether rate rebalancing is appropriate since it excludes pass through costs. However, the R/C is so widely accepted that it would not be inappropriate as the primary reference.

8 TRANSPORTATION SERVICE REVIEW

8.1 FEI PROPOSAL

FEI proposed to eliminate monthly balancing and to require all transportation customers in all service areas to balance daily.

FEI also proposed to amend the balancing tolerance from 20% to 10%, coupled with a tiered charge approach under which charges increase as tolerance ranges are exceeded[69].

---

[69] Exhibit B-1, Section 10, page 10-1.

8.2 Industry Practice

- ***A discussion of the use of daily balancing versus monthly balancing for transportation service.***
    - ***A discussion of the range of balancing tolerances used within the industry.***

Table 5 provides a review by jurisdiction of the balancing requirements for transportation service.

Table 5: Balancing Provisions for Transportation Service

Utility	Daily or Monthly Balancing	Range of Balancing Tolerance
AltaGas[70]	Daily	4%
ATCO[71]	Daily	5%
Union Gas[72]	Daily	Maximum daily requirement for firm service is 100,000 m^3 (3,730 GJ) or more
Enbridge[73]	Daily	Maximum daily volume not less than 10,000 m^3 (373 GJ) and not more than 150,000 m^3 (5,595 GJ).
Avista[74]	Daily	3% (Aug-Feb); 5% (Mar-Jul)
Puget Sound[75] Energy	Daily	5%

---

70 AUC Decision 2014-139 (May 23, 2014), Appendix 3, page 218 of 266.

71 ATCO Gas 2011/2012 General Rate Application Phase II, Tab E, page 74 of 75.

72 OEB EB-2011-0210, Decision and Rate Order, January 17, 2013.

73 OEB EB-2016-0215, Draft Rate Order, Exhibit H2, Tab 6, Schedule 1.

74 Exhibit B-1, Appendix 10-1, page 4 of 20.

75 Exhibit B-1, Appendix 10-1, page 4 of 20.

8.3 ELENCHUS ANALYSIS

The jurisdictional review indicates that daily balancing provision for transportation service is the standard industry practice.

Daily balancing is consistent with the normal operating parameters of natural gas distribution systems. Natural gas distribution systems are capable of managing typical demand variances within a day through variances in pressure without requiring significant storage. In essence, natural gas storage is not required to accommodate the typical intra-day variances in customer consumption rates. Day-to-day variances on the other hand typically require storage, including variances within the permitted tolerance level.

Transportation customers arrange for their own supply of natural gas. To do so they must either be sophisticated customers or utilize external gas supply experts. As a result, it is reasonable to include relatively stringent balancing requirements (i.e., daily balancing); however, it will also be appropriate for the utility to make available to these customers the other services that may be required to meet those requirements in a cost-effective way unless alternatives for those services are readily available in the service area. For example, transportation customers may have access to market-based storage services from the utility on a competitive basis. More flexible load balancing requirement will inevitably facilitate gaming of the system by sophisticated customers so as to maximize their access to “free” storage and minimize their total commodity costs.

9 BYPASS CUSTOMERS AND RATES

9.1 FEI PROPOSAL

Bypass customers are on a negotiated rate which is not set as part of the rate design application process. Those customers are typically within close proximity to connect directly to the upstream pipeline system if they so choose. Bypass rates are derived from a discounted cash flow analysis based on the estimated cost of constructing and operating a hypothetical pipeline to bypass FEI’s system. Agreements are reviewed and approved by the BCUC with a typical initial term of 10 years. Extension of the contracts is subject to the BCUC approval[76]. Bypass customers are not allocated any costs in the COSA model and revenues from these customers are credited back to all other customers. A negotiated inflation rate is applied to the bypass rate each year to account for changes in operating costs over time[77]. FEI is not proposing any changes to the existing bypass agreements.

9.2 INDUSTRY PRACTICE

- ***A discussion of how bypass rates are determined in other jurisdictions.***
- ***A review of how other jurisdictions review bypass rates in an ongoing way.***

The treatment of bypass varies across jurisdictions in part due to differing policies with respect to whether bypass is permitted and whether bypass opportunities are available (i.e., if bypass is not permitted or available, bypass rates may not be necessary).

In New Brunswick, bypass is only available to major natural gas users that have been granted single end use franchises (SEUFs), by the Province. No other bypass is permitted.

In Ontario, gas distributors offer a form of bypass competitive rates to avoid potential bypass applications. For example, Rate 125 – Extra Large Volume Firm Distribution Service in Enbridge's rate schedule was designed to introduce a rate that would be robust against bypass[78]. In proceeding EB-2005-0551, Enbridge developed rates for Rate 125 based on its fully allocated cost study. It was stated that the costs associated with providing the service have been identified as the cost of providing incremental assets to serve new customers, the cost for system implementation, and the cost of providing load balancing service. The proposed rate structure includes a monthly customer charge, a delivery demand charge and a load balancing charge[79]. The OEB approved Enbridge's proposed rates for Rate 125 with the adjustments of lowering the monthly customer

---

[76] Exhibit B-1, Stakeholder Consultation, Information Session #2, May 19, 2016, page 110.

[77] Exhibit B-1, Section 6, page 6-9.

[78] OEB EB-2005-0551, Technical Conference Transcript, April 27, 2006, page 113.

[79] OEB EB-2005-0551, Exhibit C, Tab 2, Schedule 4, page 2-4.

charge from $550 to $500 and ensuring that “the only aspect of Rate 125 that will be restricted to new customers is the billing contract demand feature”[80]. The OEB reviews rates for Rate 125 in each cost of service application in an ongoing way and the OEB found that Rate 125 customers should not be allocated the costs of transmission pressure pipelines less than 6” in diameter in the Decision to EB-2012-0459.

9.3 ELENCHUS ANALYSIS

The approach to determining bypass rates reflect operational and policy considerations in specific jurisdictions. For example, where bypass is not feasible due to the absence of alternate transportation systems that customers can connect to legally, consideration of bypass rates may be a moot point.

Where bypass is feasible, the primary purpose of bypass rates is to avoid uneconomic bypass. Uneconomic bypass occurs when the costs that must be incurred to enable a customer to bypass the utility exceed the incremental costs that must be incurred to connect the customer. However, impeding economic bypass is not normally in the public interest since, by definition, economic bypass implies that the incremental costs of bypass are less than the incremental cost of utility providing service.

Bypass rates are typically designed in a manner that is consistent with the principle that a bypass rate should be granted when the rate recovers the utility’s costs in full, preferably with a contribution to fixed costs, while being less than the utility’s standard rates for the class of customer receiving the bypass rate. When this test is met, uneconomic bypass is avoided. Uneconomic bypass may occur if bypass is permitted and the utility is required to charge a rate based on average fully allocated costs rather than serving customers that have the opportunity to bypass at a rate that reflects marginal cost.

80 OEB EB-2005-0551, Rate Order for Enbridge Gas Distribution, December 20, 2006, page 3.

10 CRISIS INTERVENTION FUNDS FOR RESIDENTIAL CUSTOMERS

In the Application FEI states that it “has developed and implemented a number of low income programs that are of no cost or low cost to low income participants. These programs are part of FEI’s annual natural gas DSM program. In 2015, FEI’s DSM program included three major low-income programs with a total expenditure of $1.55 million” (p. 7-28) It goes on to note that “FEI’s view is that the Commission does not have the jurisdiction to set rates based on the financial circumstances of FEI’s customers. FEI has, therefore, not addressed this matter further in this Application.” (p. 7-29)

Elenchus cannot comment on the legal issues related to the jurisdiction of the Commission; however, Elenchus is aware that public policy mandates generally do derive from government legislation, regulations or specific directives. The issue of the OEB’s jurisdiction to establish programs that assist low-income households with the cost borne by ratepayers (as opposed to taxpayer funded programs) was addressed by a court case which found that the OEB did have the jurisdiction to order utilities to undertake this type of program, although it was not obliged to do so. It is Elenchus understanding that the jurisdictional issue is determined by the specific legislation in each jurisdiction.

10.1 CRISIS ASSISTANCE PROGRAMS IN BC

The Ministry of Social Development and Social Innovations (the Ministry) runs crisis assistance programs that are designed to help low income customers. Under the Essential Utilities Supplement Program, a crisis supplement for essential utilities may be provided if recipients have reached their monthly or annual limit for crisis supplements, exhausted all resources, and do not have the ability to maintain essential utilities for their home when served with a disconnection notice or faced with the inability to re-establish essential utilities. The essential utilities supplement counts towards a recipient’s cumulative annual limit for crisis supplements. Another program administered under the Ministry’s supervision is the Utility Security Deposit program under which a supplement may be provided to assist recipients of income, hardship, and disability assistance with the cost of securing service for electricity or natural gas[81].

10.2 JURISDICTIONAL REVIEW

- ***A review of other jurisdictions that have a crisis intervention fund or similar program to assist ratepayers who are unable to pay their bills and are facing disconnection.***
    - ***A discussion of how the program is funded, designed, and administered.***

In Ontario, low income customers can apply for the Low-income Energy Assistance Program (LEAP) which provides a maximum $500 one-time assistance for their natural gas bills. The program is available to customers who are behind in their bill payments or may face having their service disconnected[82]. It is designed to provide emergency relief to eligible low-income consumers and is not intended to provide regular or ongoing bill payment assistance. The LEAP is funded by all ratepayers through each distributor's rates and the funds must be used only for that distributor's customers. OEB developed the program and one agency or a network of agencies (i.e. intake agency, distributors, lead agency, unit sub-meter provider) are responsible for the delivery of the program[83].

In Alberta, an one-time financial assistance to low income individuals or families facing utility disconnection is provided by Alberta Works/Alberta Supports or Canadian Red Cross[84]. For Manitobans, the Employment and Income Assistance Program (EIA) provide low-income consumers help with their utility costs[85].

---

81 Exhibit B-1, Section 7, page 7-28.

82 OEB, Low-income Energy Assistance Program, Accessible online: https://www.oeb.ca/rates-and-your-bill/help-low-income-consumers/low-income-energy-assistance-program

83 OEB OESP & LEAP Program Manual, Effective October 2015, Accessible online: https://www.oeb.ca/oeb/_Documents/Documents/OESP_LEAP_Program_Manual.pdf

84 Utilities Consumer Advocate, Financial Assistance, Accessible online: https://ucahelps.alberta.ca/financial-assistance.aspx

85 Government of Manitoba, Employment and Income Assistance (EIA), Accessible online: http://www.gov.mb.ca/fs/eia/

Crisis assistance programs have been available in U.S. for many years. For example, the federally-funded Low-Income Home Energy Assistance Program (LIHEAP) is designed to help low-income families in a financial crisis pay their utility bills and improve household energy efficiency through weatherization, thereby reducing energy costs. In California, the LIHEAP is administered by the department of Community Service & Development[86]. Since the U.S. programs are federally funded they are offered widely, but they are not ratepayer funded.

11 DISCONNECTION POLICIES FOR RESIDENTIAL CUSTOMERS

11.1 FEI PROPOSAL

FEI's current disconnection policies are set out in section 23, Discontinuance od Service and Refusal of Service in its General Terms and Conditions. The current online version had an effective date of January 1, 2015. It was approved by Order No. G-21-14, with the original being signed by the BCUC Secretary (Erica Hamilton).

Section 23.1 states that "FortisBC Energy may discontinue Service to a Customer with at least 48 Hours written notice to the Customer or Customer's Premises, or may refuse Service for any of the following reasons." The reasons include the standard reasons that appear in most utilities terms and conditions such as non-payment of the customer's account.

These General Terms and Conditions do not mention any standard practice for dealing with arrears in a manner that avoids disconnection. Many natural gas and electric utilities have processes for negotiating a payment schedule that addresses arrears in a manner that is financial manageable for the customer and is sufficient to avoid disconnection. Some utilities also assist customers faced with disconnection due to financial hardship by

[86] California Department of Community Service & Development, LIHEAP, Accessible online: http://www.csd.ca.gov/services/helppayingutilitybills.aspx

connecting them with government or non-profit organizations that provide financial assistance, or ratepayer programs that assist customers that cannot pay their utility bills.

The Application does not discuss provisions for mitigating the harm to customers associated with disconnections in FEI's Application policy other than the Provincially funded Crisis Assistance Program discussed above in section 10.1.

11.2 INDUSTRY PRACTICE

- ***A review of natural gas utility disconnection policies that are designed to mitigate any harm associated with disconnections, including winter shut-off restrictions and special circumstances with associated with medical issues.***

In Alberta, natural gas providers are compelled to include in their terms and conditions agreements the condition that they may not disconnect natural gas service between the dates of November 1st and April 14th, or at any time when the forecast for the next 24 hours indicates temperatures below 0 degrees. After April 14th, natural gas providers may disconnect gas service at their own discretion[87].

The OEB has also issued a Decision and Order[88] amending the licences of all Ontario electricity and natural gas distributors to ban the disconnection of residential consumers for the period commencing February 24, 2017 and ending April 30, 2017[89], and to require that disconnected homes be reconnected as soon as possible at no charge.

11.3 ELENCHUS ANALYSIS

The research indicates that some regulators enforce strict rules about disconnection during winter to protect vulnerable energy consumers. Elenchus notes that these rules reflect social policy consideration and they are therefore normally based on legislated

---

87 Utilities Consumer Advocate, Utilities Disconnection, Accessible online: https://ucahelps.alberta.ca/utilities-disconnection-and-load-limiters.aspx

88 OEB EB-2017-0101, Decision and Order, February 23, 2017, Attachment A.

89 The ban applies to the specified winter period. The OEB is launching a comprehensive review of the customer service rules that apply to all distributors and customer service rules relating to disconnection will be a key part of that review.

requirements. Social policy guidance is required since limitations on disconnections can result in higher costs for the utility due to increased bad debt, which are ultimately borne by other customers. The actual loss to the utility resulting from a restriction on disconnection will only equal the lost revenue in cases where the threat of disconnection would result in full payment. In cases where a customer would not be able to pay the arrears to maintain the connection or be reconnected, the loss to the utility will be only the costs that would be avoided due to the disconnection, which normally will be limited to the cost of the commodity being supplied to the customer since other costs are fixed.

Disconnection can result in increased charges to the customers since the amount owning can escalate significantly, especially if there are late payment charges that accumulate and compound. For this reason, there is merit in integrating policies that limit disconnection with programs that provide financial assistance to customers that fail to pay their bills due to low income problems.

12 Other Topics with Significant Impact to Customer Rates and/or Customer Classes

Elenchus did not find any additional rate design topics with significant impact on customer rates or customer classes to include in this report.

13 Summary of Key Conclusions and Observations

A summary of the key conclusions and observation on the rate topics discussed above are:

1. Rate shock
   - There are no generally accepted principles that provide clear guidance to regulators for defining rate increases that constitute rate shock.
   - Whenever a customer class is faced with a large rate increase, it is reasonable for a regulator to consider whether the increase will result in sufficient rate shock for customers in the class to warrant some form of mitigation.

- Many utilities and regulatory agencies have no established method for quantifying rate shock. In the absence of an established methodology, regulators are able to make rate decisions that implicitly mitigate the impact of rate adjustments on particular customers or customer classes as they consider appropriate on a case-by-case basis. At least two Canadian regulators of natural gas utilities do address the issue of rate shock using an established and consistent methodology.
- In Ontario, to quantify rate increases, natural gas distributors must provide bill impact information in both percentage and absolute dollar terms for all customer classes at the rate class level calculated at typical customer volumes. Natural gas utilities must file a mitigation plan if the total bill increase for any customer class is material.
- In Alberta, the AUC has generally applied a threshold of 10% of the total bill as the potential indicator of rate shock.
- Elenchus has observed that a common threshold for defining a rate/bill increase that constitutes rate shock is a double-digit increase (i.e., greater than 10%).

2. FEI rate design for residential customers
    - The percentage of fixed costs recovered by utilities in their basic fixed charge varies from utility to utility and between jurisdictions.
    - There appears to be a trend toward recovering a larger proportion of customer-related costs through the monthly basic charge, which typically improves equity as measured by fully allocated costs.
    - Conceptually, cost allocation principles imply that in order to reflect cost causality the fixed charge should reflect customer-related costs as identified for purposes of the cost allocation model, while the variable charges should reflect energy and demand related costs.
3. FEI rate design for commercial customers
    - Among the utilities reviewed by Elenchus, there is only one utility, AltaGas, that explicitly prepared the economic crossover volume analysis between rate classes

in its rate design. AltaGas excluded the gas cost recovery charge when calculating the cross over point between small and large general service classes.

- Gas cost recovery charge is collected through a rider at the same rate for small and large general service customers served by AltaGas, which means that the economic crossover volume is the same whether the commodity cost is included in or excluded from the calculation.
- The treatment of commodity costs in a cost of service study in AltaGas and FEI is different and is due to the different method of regulating gas costs. For AltaGas, gas costs are excluded from the cost of service study and are recovered by a monthly rider applied to all sales service rates unless otherwise specified to ensure that customers pay neither more nor less than the actual costs. For FEI, the commodity component of the gas cost is allocated to customers based on throughput while storage and transport components are allocated using the load factor adjusted volumetric basis.

4. FEI rate design for industrial customers

- Higher load factor customers are less expensive to serve on a volumetric basis than lower load factor customers since they require less distribution capacity, less storage for load balancing and/or less upstream transportation. Consequently, lower rates are justified for higher load factor customers unless the rate structure consists of customer, demand and energy rates that correspond very closely to the corresponding costs drivers.
- The customer's consumption characteristics, which are represented by the customer's load profile and load factor, are key factors in making customers eligible for service under various rate classes. Applying a minimum load factor requirement to a specific rate class or not depends on utility's specific load profile.
- Interruptible rates are designed with the primary purpose of controlling load factor for the utility. Customers who have the capability to maintain operations during gas service curtailments, or are prepared to discontinue operations, are provided the option of contracting for interruptible natural gas service. Interruptible gas services

are provided at a lower rate than the equivalent firm service. This service allows for the gas system to be designed to meet a lower peak day capacity thereby avoiding capital costs associated with a system that would be designed to meet the full peak day design had all customers' peak requirements been firm. This higher peak day firm design are typically only required a few days each year, even under extreme weather conditions. By designing the system to meet only the lower firm design day requirements all utility customers benefit from the reduced capital cost and a more efficient system than if all customers were served on a firm basis.

5. Rate design for Fort Nelson

- All Canadian gas utilities in the review adopt unbundled rates where gas costs, delivery charges, and storage and transport charges are individually visible on consumers' bills.
- AltaGas, ATCO, Centra Gas and Puget Sound Energy have flat rate structures for most or all rate groups. Declining block rates are used for all customer groups by Union Gas and Enbridge. Puget Sound Energy and Avista add declining block rates just for industrial customers.
- Under any alternative used to develop Basic charge and volumetric charge there will be winners and losers. Customers have different levels of monthly consumption and will be impacted differently when implementing rate structure changes.
- Acceptable levels of bill impacts will have to be determined and if any customer would have bill impacts exceeding acceptable levels as a result of the proposed rate structure changes, bill impact mitigation measures would need to be applied.

6. FEI's application of revenue to cost ratio range of reasonableness

- The revenue to cost ratios assist the rate design process by comparing revenues recovered from a rate class with the associated costs. It is also a tool to analyze the degree of cross-subsidization across rate classes.

- Elenchus' review did not identify any other Canadian utility using M:C ratios. The utilities surveyed use the R:C ratio and do not estimate a separate ratio for transportation customers as FEI uses.

- Elenchus views the M:C ratio as a reasonable alternative to the R:C ratio as a basis for determining whether the costs recovered in rates deviate from 100% recovery to justify rate rebalancing. Regulators typically accept rates within a range as constituting full recovery since it is recognized that cost allocation studies are not precise – unless the level of cost recovery is outside the specified range of reasonableness, differential rate increase would not be considered equitable since small deviations from 100% are as likely to be the results of the imprecision of the methodology as they are to be the results of true cost difference.

- While providing two sets of ratios has the benefit of providing more information to the Commission and stakeholders, it appears to Elenchus that one ratio must be accepted as the primary, or most relevant, basis for determining whether rate rebalancing is needed. The most important consideration is consistency.

- Elenchus sees merit in using the M:C ratio as the primary reference frame for determining whether rate rebalancing is appropriate, since it excludes pass through costs. Nevertheless, the R/C is so widely accepted that it cannot be deemed inappropriate as the primary reference.

7. Transportation Service review

   - The jurisdictional review indicates that daily balancing provision for transportation service is the industry practice.

8. Bypass customers and rates

   - The approach to determining bypass rates reflect operational and policy considerations in specific jurisdictions. For example, where bypass is not feasible due to the absence of alternate transportation systems that customers can connect to, consideration of bypass rates may be a moot point.

   - Where bypass is feasible, the primary purpose of bypass rates is to avoid uneconomic bypass. Uneconomic bypass occurs when the costs that must be incurred to enable a customer to bypass the utility exceed the incremental costs that must be incurred to connect the customer. However, impeding economic bypass is not normally in the public interest since, by definition, economic bypass implies that the incremental costs of bypass are less than the incremental cost of utility providing service.

9. Crisis Intervention Funds for residential customers

   - Crisis assistance programs are available in Ontario, Alberta, Manitoba and in the U.S. The programs are designed to help low-income families in a financial crisis pay their utility bills and sometimes also improve household energy efficiency through weatherization, thereby reducing energy costs.
   - In Ontario, low income customers can apply for the Low-income Energy Assistance Program (LEAP) which provides a maximum $500 one-time assistance for their natural gas bills. The program is available to customers who are behind in their bill payments or may face having their service disconnected. It is designed to provide emergency relief to eligible low-income consumers and is not intended to provide regular or ongoing bill payment assistance. The LEAP is funded by all ratepayers through each distributor's rates and the funds must be used only for that distributor's customers.
   - In Alberta, a one-time financial assistance to low income individuals or families facing utility disconnection is provided by Alberta Works/Alberta Supports or Canadian Red Cross.
   - For Manitobans, the Employment and Income Assistance Program (EIA) provide low-income consumers help with their utility costs.

10. Disconnection Policies for residential customers

    - The research indicates that regulators enforce strict rules about energy disconnection during winter to protect vulnerable energy consumers. However, Elenchus notes that these rules reflect social policy consideration and they are therefore normally based on legislated requirements.

APPENDIX A: UTILITIES REVIEWED

Utility	Proceeding	Decision
AltaGas[90] Number of Customers: 570,000 Annual Throughput: 730 Bcf Annual Revenue: $1,049.9 Million	2013-2017 Performance Based Regulation Application Phase II	AUC Decision 2014-139 (May 23, 2014)
ATCO[91] [92] Number of Customers: 1.1 million Annual Throughput: 237,734,785 GJ[93] (225.3 Bcf) Annual Revenue: $1,496 Million[94]	ATCO Gas 2011/2012 General Rate Application Phase II	AUC Decision 2013-035 (February 14, 2013)
Enbridge Gas Distribution Number of Customers: 2,158,000 Annual Throughput: 559.18 Bcf Annual Revenue: $2,486 Million (via Gas distribution sales) $34,560 Million (via Commodity sales, Gas distribution sales, and transportation and other services)	Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application	EB-2012-0459 (August 22, 2014)
Union Gas[95] Number of Customers: 1,400,000 Annual Throughput: 1,205 Bcf (Distribution volume – 472 Bcf; Storage and Transmission activity – 733 Bcf) Annual Revenue: $1.8 Billion	Union Gas Limited 2013 Rebasing Application	EB-2011-0210 (October 24, 2012)

[90] AltaGas, 2016 Annual Report, 2016, pp. 1, 66, Accessible Online: https://www.altagas.ca/sites/default/files/quarterly_reports/2016%20Anual%20Report%20web_0.pdf

[91] ATCO Gas, Corporate Profile, Accessible Online: http://www.atcogas.com/About_Us/About_ATCO_Gas/Corporate-Profile

[92] ATCO, Annual Report, 2016, pp. 123, Accessible Online: https://www.atco.com/Investors/Documents/Annual-Reports/ATCO_2016_YE_AR.pdf

[93] AUC Decision 21981-D01-2016 (December 21, 2016), page 16.

Utility	Proceeding	Decision
Centra Gas[96] Number of Customers: 276,858 Annual Throughput: 1,846 million m^3 (65.19 Bcf) Annual Revenue: $356 Million	Centra Gas 2013/2014 General Rate Application	PUB Order No. 85/13 (July 26, 2013)
SaskEnergy[97] Number of Customers: 387,019 Annual Throughput: 6,382 million m^3 (225.38 Bcf) Annual Revenue: $586 Million	2016 Commodity and Delivery Service Rate Application effective November 1, 2016	Saskatchewan Rate Review Panel Report submitted September 14, 2016
Puget Sound Energy[98] Number of Customers: 807,586 Annual Throughput: 1,058,398 Therms Annual Revenue: $1.181 Million[99]	2011 PSE General Rate Case	Docket UE-111048/UG-111049 Order 08 (May 7, 2012)
Avista[100] Number of Customers: 340,131 Annual Throughput: 1,173,257 Therms Annual Revenue: $1,913 Million $628,192 in Natural Gas Revenue[101]	General rate increase for natural gas services, effective March 12, 2015.	Docket No. UG-150205 Order 05 (January 6, 2016)

94 This number includes ATCO Gas, ATCO Pipelines, ATCO Gas Australia, ATCO Energy Solutions and ATCO Pipelines Mexico.

95 Union Gas, Union Gas at a Glance, 2016, Accessible Online: https://www.uniongas.com/about-us/at-a-glance

96 Manitoba Hydro, Manitoba Hydro-Electric Board 65th Annual Report, 2016, pp. 4, 21, 113, Accessible Online: https://www.hydro.mb.ca/corporate/ar/pdf/annual_report_2015_16.pdf

97 SaskEnergy, 2015-16 Annual Report, 2016, pp. 13-14, Accessible Online: http://www.saskenergy.com/about_saskenergy/annual_report/documents/2015-16/2015-16_Annual%20Report-web.pdf

98 United States Securities and Exchange Commission, Puget Sound Energy Annual Report, December 31, 2016, p. 19, Accessible Online: http://phx.corporate-ir.net/phoenix.zhtml%3Fc%3D63643%26p%3Dirol-sec

99 Converted with currency rate of USD $1 = CAD $1.32669

100 Avista, 2016 Annual Report, 2016, p. 13/160

101 Converted with currency rate of USD $1 = CAD $1.32669

APPENDIX B JURISDICTIONAL REVIEW OF GOVERNMENT LEGISLATIONS

Jurisdiction	Government Legislation	Description/Relevant Content
Ontario	*Electricity Act, 1998*[102]	The purposes of this Act include the following: (f) to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service;
	Ontario Energy Board Act, 1998[103]	Board objectives, gas The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives: 2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.
	Fair Hydro Act, 2017 (Bill 132)[104]	The Fair Hydro Act, 2017 would lower electricity bills by 25 per cent on average for all residential consumers and hold increases to the rate of inflation for four years.
Alberta	*An Act to Cap Regulated Electricity Rates (Bill 16)*[105]	Bill 16 will impose a maximum rate of 6.8 cents per kilowatt hour (kWh) for electricity consumers on the regulated rate option or RRO (a government-regulated rate that fluctuates monthly).

[102] Accessible online: https://www.ontario.ca/laws/statute/98e15

[103] Accessible online: https://www.ontario.ca/laws/statute/98o15

[104] Accessible online: http://www.ontla.on.ca/web/bills/bills_detail.do?locale=en&Intranet=&BillID=4875

[105] Accessible online: http://www.assembly.ab.ca/ISYS/LADDAR_files/docs/bills/bill/legislature_29/session_3/20170302_bill-016.pdf

Jurisdiction	Government Legislation	Description/Relevant Content
Manitoba	*The Affordable Utility Rate Accountability Act (Bill 18)*[106]	The act required the province to enlist an independent accounting firm to prepare a report each year[107] comparing the cost in each province of a bundle including home electricity, home heating and car insurance. Under the act, if the report shows the cost of the utility bundle in any province to be lower than in Manitoba, the finance minister must prepare a plan to return the province to the lowest-cost position.
New Brunswick	*Electricity Act*[108]	The act requires that rates charged for sales of electricity within the province shall be maintained as low as possible and changes in rates shall be stable and predictable from year to year.
British Columbia	*Utilities Commission Act*[109]	The act requires the Commission to set a rate that is not unjust or unreasonable.

[106] Accessible online: http://web2.gov.mb.ca/bills/40-1/b018e.php

[107] The 2017 Manitoba budget report indicated that the act will be repealed and no report will be prepared in 2017-18.

[108] Accessible online: http://laws.gnb.ca/en/ShowPdf/cs/2013-c.7.pdf

[109] Accessible online: https://web.archive.org/web/20060209000159/http://www.qp.gov.bc.ca:80/statreg/stat/U/96473_01.htm#section60

Appendix C: CVs

JOHN D. TODD

34 King Street East, Suite 600 | Toronto, ON M5C 2X8 | 416 348 9910 | jtodd@elenchus.ca

---

PRESIDENT

John Todd has specialized in government regulation for 40 years, addressing issues related to price regulation and deregulation, market restructuring to facilitate effective competition, and regulatory methodology. Sectors of primary interest in recent years have included electricity, natural gas and the telecommunications industry. John has assisted counsel in over 250 regulatory proceedings and provided expert evidence in over 125 hearings. His clients include regulated companies, producers and generators, competitors, customer groups, regulators and government.

PROFESSSIONAL OVERVIEW

Founder of Elenchus Research Associates Inc. (Elenchus) **2003**

- ERAI was spun off from ECS (see below) as an independent consulting firm in 2003. There are presently twenty-five ERAI Consultants and Associates. Web address: www.elenchus.ca

Founded the Canadian Energy Regulation Information Service (CERISE) **2002**

- CERISE is a web-based service providing a decision database, regulatory monitoring and analysis of current issues on a subscription basis. Staff are Rachel Chua and rotating co-op students. Web address: www.cerise.info

Founded Econalysis Consulting Services, Inc. (ECS) **1980**

- ECS was divested as a separate company in 2003
- There are presently four ECS consultants: Bill Harper, Mark Garner, Shelley Grice, and James Wightman. Web address: www.econalysis.ca

EDUCATION

1975 Masters in Business Administration in Economics and Management Service, University of Toronto

1972 Bachelors of Science in Electrical Engineering, University of Toronto

PRIOR EMPLOYMENT

Ontario Economic Council, Research Officer (Government Regulation) **1978 - 1980**

Research Assistant, Univ. of Toronto, Faculty of Management Studies **1973 - 1978**

Bell Canada, Western Area Engineering **1972 – 1973**

REGULATORY/LEGAL PROCEEDINGS

Provided expert evidence and/or assistance to the applicant or another participant:

Before the Ontario Energy Board

John Todd has provided expert assistance in a total of 62 proceedings before the Ontario Energy Board from 1991 to 2016. He has presented evidence in 25 of these cases. The most recent case he participated in was the *Independent Electricity System Operator, 2016 Usage Fee*. Evidence: Cost Allocation and Rate Design for the 2016 IESO Usage Fee.

Before the Public Utilities Board of Manitoba

John has provided expert assistance in a total of 46 proceedings before the Public Utilities Board of Manitoba from 1990 to 2015. He has presented evidence in 23 of these cases. The most recent case he participated in was the *City of Winnipeg: Manitoba Hydro 2015/16 GRA and Manitoba Hydro COSS Review.*

Before the British Columbia Utilities Commission

John has provided expert assistance in a total of 33 proceedings before the British Columbia Utilities Commission from 1993 to 2006. He has presented evidence in eight of these cases. The most recent case he participated in was the *British Columbia Transmission Corporation, 2006 Transmission Revenue Requirement.*

Before the Régie de l'énergie

John has provided expert assistance in a total of ten proceedings before the Régie de l'énergie from 1998 to 2014. He has presented evidence in nine of these cases. The most recent case he participated in was the *Report for the Régie de l'énergie, Performance Based Regulation: A Review of Design Options as Background for the Review of PBR for Hydro Quebec Distribution and Transmission Divisions.*

Before the Alberta Energy and Utilities Board

John has provided expert assistance in of two proceedings before the Alberta Energy and Utilities Board in 2001. He has presented evidence in one case. The second case of 2001 was in regards to the case of *Generic, Gas Rate Unbundling (2001-093)*. Evidence: Canadian Experience and Approaches.

Before the Newfoundland & Labrador Board of Commissioners of Public Utilities

John has provided expert assistance in a total of nine proceedings from 2005 to 2015. He has presented evidence in three cases. The most recent proceeding he participated in was the *Newfoundland Power, 2016 Deferred Cost Recovery Application* case.

Before the New Brunswick Energy and Utilities Board

John has provided expert assistance in a total of nine proceedings before the New Brunswick Energy and Utilities Board from 2007 to 2016. He has presented evidence in three cases. The most recent proceeding he participated in was the *2015 New Brunswick Power Customer Cost Allocation Student Review.* Evidence: Cost Allocation Study Review.

Before the Nova Scotia Utility and Review Board

John has provided expert assistance in a total of nine proceedings before the Nova Scotia Utility and Review Board from 2008 to 2016. He has presented evidence in four cases. The most recent proceeding he participated in was *Efficiency One, Updated Cost Allocation Methodology.*

Before the National Energy Board (NEB)

John has provided expert assistance in one proceeding before the NEB, during 1999. The proceeding was in regards to *BC Gas, Southern Crossing Project.*

Before the Canadian Radio-television and Telecommunications Commission (CRTC)

John has provided expert assistance in 47 proceedings before the Canadian Radio-television and Telecommunications Commission from 1990 to 2016. He has presented evidence in 13 of these cases. The most recent proceeding he participated in was a *Review of Basic Telecommunications Services, Consultation CRTC 2015-134.*

Before the Ontario Telephone Services Commission (OTSC)

John has provided expert assistance in one proceeding before the Ontario Telephone Services Commission in 1992. The case was in regards to a *Review of Rate-of-Return Regulation for Public Utility Telephone Companies.* Evidence used: The need for OTSC regulation of municipal utility telcos.

Before the Ontario Securities Commission

John has provided expert assistance in four proceedings before the Ontario Securities Commission from 1981 to 1985. He presented evidence in each case. The most recent proceeding he participated in was a *Securities Industry Review.* Evidence: Industry structure and the form of regulation.

Before the Ontario Municipal Board

John has provided expert evidence and assistance in two proceedings before the Ontario Municipal Board in 1992 and 1995. In 1995, he assisted in a case regarding an *Appeal of Boundary Expansion by Lincoln Hydro and Electric Commission*, with an affidavit prepared on the tests for boundary expansions.

Before the Supreme Court of Ontario

John has presented evidence in one proceeding before the Supreme Court of Ontario, in 1990. The case related to the *Challenge of the Residential Rent Regulation Act (1986) under the Canadian Charter of Rights and Freedoms.* Evidence: The impact of rent regulation on Ontario's rental housing market.

Before the Saskatchewan Court of Queen's Bench

John has presented evidence in one proceeding before the Saskatchewan Court of Queen's Bench, in 1993. The evidence was regarding market dynamics and competition policy.

Non-Hearing Processes

John has provided expert assistance in 17 non-hearing processes since 1997 to the following Ontario Energy Board, British Columbia Gas, the British Columbia Utilities Commission, the New Brunswick Department of Energy, SaskPower, the Government of Vietnam, and more.

Commercial Arbitrations and Lawsuits

John has provided expert assistance in 6 commercial arbitrations and lawsuits between 2004 and 2015.

Facilitation Activities

- 5 Strategic Planning sessions with Executive and/or Board of Directors of regulated companies between 2000 and 2015
- 6 stakeholder processes for regulators and utilities from 2000 through 2016

Other Regulatory Issues Researched

- Over 20 studies completed for regulators, utilities and others outside of hearing processes

SELECTED PRESENTATIONS

- Productivity Benchmarking Panel at Canadian Electrical Association RITG CAMPUT Workshop (May 2016)
- Utility Cost Recovery in an Era of Ageing Infrastructure, Technological Change and Increasing Customer Service Expectation, CEA Legal Committee and Regulatory Innovations Task Group (June 2016)
- MEARIE Training Program, Regulatory Essentials for LDC Executives (2016)
- Issue in Regulatory Framework for Tenaga Nasional Berhad, Indonesia (with Cynthia Chaplin & London Economics) (2015)
- Witness Training for electric utilities 2014 - 2016
- "Innovations in Rate Design", CAMPUT Training Session, Annually 2010-2013
- "Cost of Service Filing Requirements" (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with the Ontario Energy Board
- "Green Energy Act" (2010) 2nd Annual Applications Training for Electricity Distributors, Society of Ontario Adjudicators and Regulators in cooperation with Ontario Energy Board
- "Rate Design", CAMPUT Training Session, Annually 2009- 2013
- "How to Build Transmission and Distribution to Enable FiT: The Role of Distributors", EUCI Conference on Feed in Tariffs, Toronto, Sept. 2009
- "Distributor Mergers and Acquisitions: Potential Savings", 2007 Electricity Distributors Assoc.
- "Beyond Borders" Regulating the Transition to Competition in Energy Markets (with Fred Hassan), EnerCom Conference March 2006.

SELECTED OTHER ACTIVITIES

- Organizing Committee for the Concert for Inclusion in support of ParaSport Ontario
- Chairman of the Board of Directors of the Ontario Energy Marketers Association (formerly the Direct Purchase Industry Committee) and Executive Director of the Association.
- Invited participant in the Ontario Energy Board's External Advisory Committee.
- Panelist for "Administrative Tribunals and ADR", Osgoode Hall Law School, Professional Development Program, Continuing Legal Education, April 1997.
- Former Member of the Board of Directors of East Toronto Community Legal Services.
- Numerous appearances on CBC radio and television commenting on energy industry issues, competition, regulation and mergers in the Canadian economy.

CLIENTS

Over 70 private sector companies, including utilities

15 industry and other associations

Over 30 consumers' associations and legal clinics

Government

- 5 Regulatory Tribunals
- 6 Federal departments
- 14 Provincial departments, commissions and agencies
- 13 municipal and other departments/entities

For John Todd's complete curriculum vitae, please visit: www.elenchus.ca

MICHAEL J. ROGER

34 King Street East, Suite 600 | Toronto, ON M5C 2X8 | 905 731 9322 | mroger@elenchus.ca

---

ASSOCIATE, RATES AND REGULATION

Michael has over 38 years of experience in the electricity industry dealing in areas of finance, cost allocation, rate design and regulatory environment. Michael has been an expert witness at numerous Ontario Energy Board proceedings and has participated in task forces dealing with his areas of expertise. Michael is a leader and team player that gets things done and gets along well with colleagues.

PROFESSIONAL OVERVIEW

Elenchus **2010 - Present**
Associate Consultant, Rates & Regulation

- Provide guidance on the Regulatory environment in Ontario for distributors and other stakeholders, with particular emphasis on electricity rates in Ontario and the regulatory review and approval process for cost allocation, rate design and special studies.
- Some of the clients that Michael provides advice include: Hydro Quebec Energy Marketing Inc., GTAA, Ontario Energy Board, City of Hamilton, Hydro One Transmission, Powerstream, Hydro Ottawa, Veridian and APPrO.

Hydro One Networks Inc. **2002 - 2010**
Manager, Pricing, Regulatory Affairs, Corporate and Regulatory Affairs

- In charge of Distribution and Transmission pricing for directly connected customers to Hydro One's Distribution system, embedded distributors and customers connected to Hydro One's Transmission system.
- Determine prices charged to customers that conform to guidelines and principles established by the Ontario Energy Board, (OEB).
- Provide expert testimony at OEB Hearings on behalf of Hydro One in the areas of Cost Allocation and Rate Design.
- Keep up to date on Cost Allocation and Rate Design issues in the industry.
- Ensure deliverables are of high quality, defensible and meet all deadlines.

- Keep staff focused and motivated and work as a team member of the Regulatory Affairs function. Provide support to other units as necessary.

Ontario Power Generation Inc. **1999 - 2002**
Manager, Management Reporting and Decision Support, Corporate Finance

- Produce weekly, monthly, quarterly and annual internal financial reporting products.
- Input to and coordination of senior management reporting and performance assessment activities.
- Expert line of business knowledge in support of financial and business planning processes.
- Coordination, execution of review, and assessment of business plans, business cases and proposals of an operational nature.
- Provide support to other units as necessary.
- Work as a team member of the Corporate Finance function.

Ontario Hydro **1998 - 1999**
Acting Director, Financial Planning and Reporting, Corporate Finance

- Responsible for the day to day operation of the division supporting the requirements of Ontario Hydro's Board of Directors, Chairman, President and CEO, and the Chief Financial Officer, to enable them to perform their due diligence role in running the company.
- Interact with business units to exchange financial information.

Financial Advisor, Financial Planning and Reporting, Corporate Finance **1997**

- Responsible for co-ordinating Retail, Transmission, and Central Market Operation divisions' support of Corporate Finance function of Ontario Hydro to ensure financial information consistency between business units and Corporate Office, review business units compliance with corporate strategy.
- Provide advice to Chief Financial Officer and Vice President of Finance on business unit issues subject to review by Corporate Officers.
- Participate or lead task team dealing with issues being evaluated in the company.
- Supervise professional staff supporting the function.
- Co-ordinate efforts with advisors for GENCO and Corporate Function divisions to ensure consistent treatment throughout the company.

Section Head, Pricing Implementation, Pricing **1986 - 1997**

- Responsible for pricing experiments, evaluation of marginal costs based prices, cost-of-service studies for municipal utilities, analysis and comparison of prices in the electric industry, rate structure reform evaluation, analysis of cost of servicing individual customers and support the cost allocation process used to determine prices to end users.
- Responsible for the derivation of wholesale prices charged to Municipal Electric Utilities and retail prices for Direct Industrial customers, preparation of Board Memos presented to Ontario

Hydro's Board of Directors and support the department's involvement at the Ontario Energy Board Hearings by providing expert witness testimony.

Section Head (acting), Power Costing, Financial Planning & Reporting, Corporate Finance **1994 - 1995**

- Responsible for the allocation of Ontario Hydro's costs among its customer groups and ensure that costs are tracked properly and are used to bill customers.
- Maintain the computer models used for cost allocation and update the models to reflect the structural changes at Ontario Hydro.
- Participate at the Ontario Energy Board Hearings providing support and expert testimony on the proposed cost allocation and rates.
- Provide cost allocation expertise to other functions in the company.

Additional Duties **1991**

- Manager (acting) Rate Structures Department.
- Review of utilities' rates and finances for regulatory approval.
- Consultant: Sent by Ontario Hydro International to Estonia to provide consulting services on cost allocation and rate design issues to the country's electric company.

Analyst, Rates **1983 - 1986**

- In charge of evaluating different marketing strategies to provide alternatives to customers for the efficient use of electricity.
- Co-ordinate and supervise efforts of a work group set up to develop a cost of service study methodology recommended for implementation by Municipal Electric Utilities and Ontario Hydro's Rural Retail System.
- Provide support data to Ontario Hydro's annual Rate Submission to the Ontario Energy Board.
- Participate in various studies analysing cost allocation areas and financial aspects of the company.

Forecast Analyst, Financial Forecasts **1980 – 1983**

- Evaluating cost data related to electricity production by nuclear plants and preparing short term forecasts of costs used by the company. Maintain and improve computer models used to analyse the data.
- Review Ontario Hydro's forecast of customer revenues, report actual monthly, quarterly and yearly results and explain variances from budget.
- Support the development of new computerized models to assist in the short-term forecast of revenues.

Project Development Analyst, Financial Forecasts **1979 - 1980**

- In charge of developing computerized financial models used by forecasting analysts planning Ontario Hydro's short term revenue and cost forecasts and also in the preparation of Statement of Operations and Balance Sheet for the Corporation.

Assistant Engineer – Reliability Statics, Hydroelectric Generations Services **1978 – 1979**

- In charge of analysing statistical data related to hydroelectric generating stations and producing periodic report on plants' performance.

ACADEMIC ACHIEVEMENTS

1977	Master of Business Administration, University of Toronto. Specialized in Management Science, Data Processing and Finance. Teaching Assistant in Statistics.
1975	Bachelor of Science in Industrial and Management Engineering, Technion, Israel Institute of Technology, Haifa, Israel.

Attachment 1.2

FortisBC Energy, Inc.
Natural Gas Cost of Service and Rate Review
December 12, 2016

Prepared by:

EES Consulting

570 Kirkland Way, Suite 100
Kirkland, Washington 98033

A registered professional engineering corporation with offices in
Kirkland, WA and Portland, OR

Telephone: (425) 889-2700   Facsimile: (425) 889-2725

December 12, 2016

Mr. Atul Toky
Manager, Tariffs, Rate Design and Special Contracts
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, B.C. V4N 0E8

SUBJECT: Natural Gas Cost of Service Review

Dear Mr. Toky:

Please find attached the Natural Gas Cost of Service Review prepared by EES Consulting, Inc. (EES). The conclusions and recommendations contained within this report are based upon industry practice and generally accepted rate setting principles.

This study has been developed independently by EES Consulting, with information provided by FEI staff, as needed. The findings, conclusions and recommendations of this report provide the basis for the development of fair and equitable rates for FEI.

Thank you for the opportunity to assist FEI in this rate setting process. Please contact me directly if there are any questions about the subject analyses.

Very truly yours,

Gary S. Saleba
President

570 Kirkland Way, Suite 100
Kirkland, Washington 98033

Telephone: 425 889-2700 Facsimile: 425 889-2725

A registered professional engineering corporation with offices in
Kirkland, WA and Portland, OR

Contents

Executive Summary

This report is provided to FortisBC Energy, Inc. (FEI) in support of its 2016 Rate Design Application (RDA). EES Consulting has provided assistance to FEI throughout the process by providing a review of standard and alternative COSA methodologies, input as to the appropriate methodology to use given the unique circumstance of the utility, review of the COSA model, and recommendations on setting appropriate rates.

The COSA developed by FEI is based on appropriate methodologies and takes into account standard practice, past precedent and cost causation. The COSA is based on the 2016 revenue requirement approved by the Commission, adjusted for certain expected capital projects.

The FEI COSA contains the following functions:

- Gas Supply Operations
- Tilbury LNG Storage
- Mt. Hayes LNG Storage
- Transmission
- Distribution
- Marketing
- Customer Accounting

The three primary classifiers in the COSA are:

- Demand
- Energy
- Customer

Once costs were functionalized and classified using these categories, costs were then allocated across customer groups based on the appropriate allocation factors.

We have reviewed both the COSA methodology and the COSA model itself to determine whether it is correct and appropriate. We find that the COSA follows standard utility practice, is generally consistent with past practice for the utility and the results are acceptable for purposes of setting just and reasonable rates for the utility. There are a few items where it may be beneficial to consider a change in the methodology in future proceedings, which are addressed within this report.

The COSA is intended to provide findings on whether any rebalancing should occur between customer groups and to assist in rate design matters. As the proposed implementation date for new rates is June 2018, it is expected that actual rate levels will be based on the revenue requirement established under the PBR for 2018. The rate design changes proposed in the Application, including rebalancing between various customer groups, will be applied to the rates that are applicable at that time. However, for purposes of the application, the rate adjustments contained in the various sections of the rate application are shown as if they apply to current rate levels.

For the cost of gas the actual rate levels are reviewed and set quarterly based on the actual and projected costs of gas purchases. Midstream rates are generally updated on an annual basis outside of the revenue requirements process. For delivery rates, the actual rate levels are updated annually on the basis of the PBR methodology.

FEI has proposed using a 90% to 110% revenue to cost ratio range of reasonableness for setting proposed rates. We consider this to be a reasonable range for use when considering the revenue to cost ratios for FEI. While this is a broader range than what is currently accepted by the Commission for the electric utilities in B.C., it is consistent with the range previously accepted for gas utilities in the Province and the larger range is appropriate in this particular case. Generally, the greater the level of uncertainty that exists within the COSA, the greater the acceptable revenue to cost range should be. In this particular case, uncertainty exists due to the peak day demand allocators and the uncertainty inherent to the allocation of costs using any selected methodology.

Ratemaking principals are based on many factors besides the COSA results, and rate changes based on COSA results are best made during a time of relative stability. FEI has considered the standard Bonbright principles in proposing the rates contained in the application. We believe that these principles are adequately maintained with the current FEI rate proposal.

FEI has proposed some relatively minor changes in its rate design for the Residential, Commercial and Industrial groups. All of the changes proposed reflect a move towards cost-causation, as demonstrated in the COSA while balancing the other rate design principles. For this reason we conclude that the proposed changes are appropriate.

COSA Overview

EES Consulting was retained by FEI to review and assist the utility in developing its comprehensive cost of service allocation (COSA) and rate design for the natural gas utility. The COSA is one of the major inputs that is used in developing proposed rates for FEI. Basically the COSA takes the revenue requirements established for the utility and allocates costs across the various customer groups, with the results used to ensure that proposed rates are fair, equitable and not unduly discriminatory. EES Consulting worked with FEI staff in assessing the appropriateness of the COSA methodology and rate design, making recommendations for changes where warranted, and reviewing the COSA model created by FEI staff.

In 2012 FEI filed a consolidated COSA as part of its request for Amalgamation of the three separate natural gas utilities. While that COSA was used in support of the Amalgamation, it was not used to make changes in the COSA methodology or specific rate design changes. Since the Amalgamation was approved, FEI has been phasing in the postage stamping of rates with all customers (except Fort Nelson) migrating to the FEI rate schedules.

Prior to Amalgamation, FEI last filed a comprehensive COSA in 2001 and this methodology was considered as the starting point when performing the Amalgamated COSA.

Report Organization

This report is designed as a review of the appropriateness of the proposed COSA methodology for use in the Rate Design Application. Determining the appropriateness of the methodology was based on the specific circumstance of the utility, past practices of the utility, and a review of the methodologies used in other jurisdictions.

This report is organized such that it follows the steps taken in analyzing and developing FEI's COSA. Contained in this section is an overview of the COSA process. This is followed by a jurisdictional review of COSA methods used by gas utilities across Canada and in the Pacific Northwest U.S. The next two sections discuss the functionalization, classification and allocation of costs within the COSA. Next, a jurisdictional review of rates in place is provided. This is followed by a review of the proposed rate design for the utility. The final section provides the summary and recommendations for the COSA and Rate Design.

Overview of the COSA

The setting of natural gas delivery rates that achieve the standard Bonbright principles of fairness and avoidance of undue discrimination is a complex process. This process is directed, however, by generally accepted methodologies that can be used as a guide in developing FEI's natural gas rates. The COSA is the second step in a traditional three-step process for developing service rates. The first step is the development of the test period revenue requirement for the utility, which is the starting input for the COSA. The COSA spreads the revenue requirement across the various customer groups, creating per unit costs by group. In the third step, rates are designed for each rate schedule, with revenue to cost ratios and per unit costs being considered in setting the appropriate rate levels.

As part of the Amalgamation, the Fort Nelson service area was excluded from postage stamped rates. This means that a separate COSA is needed to develop rates for the Fort Nelson service area. Throughout this report the methodology used for the COSA is discussed and the methods apply equally to the FEI COSA and the Fort Nelson COSA, although they are not discussed individually.

The COSA analysis takes the revenue requirement for the utility and attempts to equitably allocate those costs to the various customer groups (e.g., residential, commercial). This analysis provides a determination of the level of revenue responsibility of each customer group and the adjustments required to meet the cost of service.

Because the majority of costs are not incurred by any one type of customer, the COSA becomes an exercise in spreading joint and common costs among the various groups using factors appropriate to each type of expense. The founding principle of cost allocation is the concept of cost-causation. Cost-causation evaluates which customer or group of customers causes the utility to incur certain costs by linking system facility investments and operating costs to serve certain facilities to the services used by different customers.

A COSA can be performed using embedded costs or marginal costs. An Embedded COSA generally reflects the actual costs incurred by the utility, including costs associated with the historical rate base, and closely track the costs kept in its accounting records. A Marginal COSA reflects the costs associated with adding a new customer, and are based on costs of facilities and services as if incurred at the present time. A Marginal COSA often results in costs per customer group that are higher than embedded costs. Therefore, the use of a Marginal COSA usually requires that all costs be scaled back to a level equal to the Embedded revenue requirement established using actual or projected costs from an “accounting” perspective. Note that a Marginal COSA is different than calculating the marginal costs for the utility overall. A Marginal COSA would determine revenue to cost ratios by customer group and the need for rebalancing between groups, while an overall marginal cost is often used as a potential factor in developing rate design. EES has prepared a separate report that addresses marginal delivery costs for FEI but a Marginal COSA has not been completed by either FEI or by EES Consulting.

FEI COSA uses an embedded approach, which is consistent with the accepted practice for the past 20 years. We believe this is the most appropriate methodology. Therefore, FEI’s embedded cost revenue requirement and existing rate base investment are used in developing the COSA results.

There are three basic steps to follow in developing a COSA, namely:

- Functionalization
- Classification
- Allocation

Functionalization separates costs into major categories that reflect the utility's plant investment and different services provided to customers. The primary functional categories are gas supply, transmission and distribution. In the case of FEI, additional functions are used to represent storage, marketing and customer accounting.

Classification determines the portion of the cost that is related to specific cost-causal factors, such as those that are demand-related, energy-related, or customer-related. Gas supply costs are related to supplying gas to core customers throughout the year. Storage and transmission costs are related to the bulk transfer of gas to load centers on the system. These storage and transmission facilities are typically designed and operated to meet system peak demand requirement. The distribution system is designed to extend service to all customers attached to the system and to meet the peak load capacity requirement of each customer. Customer accounting and marketing costs are more closely related to the number of customers on the system.

Allocation of costs to specific customer groups is based on the customer's contribution to the specific classifier selected. For instance, demand-related costs are allocated to a customer group using that customer group's contribution to the particular measurement of system demand. An analysis of customer requirements, loads, and usage characteristics is completed to develop allocation factors reflecting each of the classifiers employed within the COSA. The analysis may include an evaluation of the system design and operations, its accounting and physical asset records, customer load data, and special studies.

The overall COSA approach used for FEI COSA follows the standard three-step process that is generally accepted for embedded costs studies.

Overview of Rate Design

While the COSA is complex analysis of various line item expenses and various methodologies to allocate costs among the customer groups, rate design is less driven by detailed analysis. In designing rates the utility must take into account many different factors, of which the COSA results are just one. Rate design is just as complex as the COSA, however the complexity is related to more qualitative issues than quantitative issues.

The first issue in designing rates is to determine the appropriate segmentation of customers into customer groups. While this needs to be decided prior to carrying out the COSA, it is one of the factors in designing rates. In deciding what customer groups are most important the utility must consider factors that impact the costs developed in the COSA, as well as those factors that are more logistical in nature. The following is a list of factors to consider when developing the appropriate rates groups:

- Load Characteristics and Homogeneity
- Ability to Identify Customers Belonging to Each Group
- Different Levels of Service (e.g. sales vs. transport service, firm vs. interruptible)
- Different Uses of Gas Impacting Service Levels
- Ability for Customer to Understand and Accept the Customer Groups
- Ability to Administer the Customer Groups
- Benefits Associated with Attracting and Retaining Customers (e.g. bypass rates)

While the Revenue Requirements establishes the overall rate increase that is needed by the utility, the COSA is used to determine equity among the various customer groups. Within the COSA, revenue to cost ratios are developed to see which customer groups are paying more than their share of costs, and which customer groups are paying less than their share of costs. Because of the inherent uncertainty in any COSA, both because of differences in methodology and uncertainty in load factors and peak demands by rate group, a range of reasonableness is generally applied to determine whether a group is paying its fair share. In the past, a 90% to 110% percent range of reasonableness was applied to the revenue to cost ratios for FEI. Customer groups within that range do not need an adjustment in the overall rate level. Customer groups outside of that range should generally have rebalancing adjustments with a shift in revenues between groups such that revenue to cost ratios move towards the range of reasonableness. For rate schedules that require a rebalancing adjustment, gradualism is often applied rather than making a large adjustment at one time to avoid rate shock to any given customer groups

Once overall revenues for each rate group are established, the rate structure needs to be developed for each customer group. The rate structure needs to take into account the cost causation determined in the COSA, the price signals desired by the utility to promote economic efficiency, the ease of understanding by customers, the ability to administer the rates, rate stability and practices by neighboring and competing utilities. The rate structure includes the following types of factors, although not all of them may apply for any given utility:

- Inclusion of a Customer Charge
- Inclusion of a Minimum Bill
- Inclusion of a Demand Charge
- Inclusion of an Energy Charge
- Whether Rates Differ by Block (Inclining or Declining)

- Whether Demand Charges are Based on Contract Demand, Metered Demand or Demand Ratchet
- Whether the Cost of Gas and Delivery Charges are Separate

Based on the selected rate structure, the level of the rate components can be set. Setting specific rate components are generally driven by current rate components, the unit costs resulting from the COSA, rates for neighboring or competing utilities, acceptability from customers, rate stability and desired price signals.

Jurisdictional Review of COSA Methodology

To assist in determining whether FEI is using accepted methods within its COSA, EES Consulting reviewed the methods used by various other gas utilities across Canada and in the Pacific Northwest U.S. While physical circumstances, intervenor positions, Commission approvals and history all play a role in approved COSA methods for different utilities, it is useful to review what other utilities are using. The review of the methods used by other large gas utilities is based primarily on the Commission Decisions in the most recently approved rate cases. In some cases the Decision is still pending or a settlement was reached among the parties and the methods contained in the rate application were included.

The utilities included in the review are:

- ATCO (Alberta)
- Union Gas (Ontario)
- Enbridge (Ontario)
- Gaz Metro (Quebec)
- Puget Sound Energy (Washington)
- Avista (Washington)
- Northwest Natural Gas (Oregon)

We also spoke to a representative at SaskEnergy, however, they are not regulated in the traditional sense and their COSA is not publicly available.

While we were able to compare specific methods used in the COSA, in some cases it would be difficult to say that there was a true precedent as the Decision is still pending or the results were based on a negotiated settlement.

Table 1 summarizes the status of each rate proceeding and the related dates associated with the Application and Decision.

Table 1 Status of Most Recent Rate Application			
Name of Utility	**Timeline**	**Docket**	**Status**
ATCO	2012 Actuals	Decision 2013-035	Based on COSA method from 2010 settlement, COSA accepted as filed
Union Gas	Uses 2013 Forecast Year	EB-2011-0210	No changes in methodology from 2007, settlement/acceptance on most COSA issues
Enbridge	2014 Forecast	EB-2012-0459	Decision provided July 2014
Gaz Metro	Filed in 2013	R-3867-2013	Black & Veatch provided recommendations to COSA method in Application, no decision as of June 2016
Puget Sound Energy	Filed June 2011	UG-111049	Settlement in January 2012 – settled on rates and specified that they did not all agree on the COSA methodology
Avista	Filed in 2015 using 2014 Actuals	UG-15025	Settlement in January 2016 with no agreement specified on actual COSA
Northwest Natural Gas	Filed December 2011	UG-221	Settlement in October 2012 - COSA based on marginal cost rather than embedded cost

Because the Northwest Natural Gas rates are based on a marginal cost study, they are excluded in the comparison of the COSA methodologies used. They are, however, included in terms of the rate structure comparison included in a later section of this report.

Cost of Gas and Wholesale Transportation

Like FEI, most of the utilities exclude the cost of gas in their COSA and have a separate gas cost recovery mechanism to provide more frequent updates based on the actual cost of gas purchased. The exception to this is Union Gas and Avista where the cost of gas is still included in a combined rate. Union Gas allocated gas costs on the basis of annual energy.

Similarly, the cost of wholesale transportation service was often excluded from the COSA. For Union Gas transportation purchases were included and the base load costs were allocated on average day while remaining costs were allocated on the excess over the average day. Enbridge also included wholesale transportation purchases. For upstream transmission contracted on a 100% load factor basis the costs were allocated on the basis of annual demand. For purchased transportation from Union Gas to move gas into and out of storage the costs were split 40% based on average storage amount and 60% based on the peak day excess over average storage.

Storage

None of the utilities reviewed has internal storage similar to FEI's situation. Storage service was generally purchased on a wholesale basis. Even those utilities that owned storage facilities kept those facilities in their unregulated business. Table 2 summarizes the treatment of storage costs in the COSA of the utilities reviewed.

Table 2
Treatment of Storage

Name of Utility	Method Used
ATCO	Excluded from the delivery COSA.
Union Gas	Took out portion of costs related to unregulated side- only system integrity portion remains in the COSA. Remaining portion classified as peak demand (design day) and allocated based on excess demand over average demand
Enbridge	Develop storage costs and then charge for in-franchise use vs outside use. Three components include annual component for volume (space), variable amount per m3 for injections and withdrawals (space) and peak component for max daily rate (deliverability).
Gaz Metro	Not applicable
Puget Sound Energy	Allocated on Seasonal Demand
Avista	Noted that Commodity storage benefits for gas customers and balancing for all customers

Transmission

Not all of the utilities have facilities that were considered to be transmission. Table 3 summarizes the treatment of transmission costs in the COSA of the utilities reviewed. Because the inclusion of transmission varied so much between the utilities, it is difficult to reach any conclusions about a standard approach.

Table 3
Treatment of Transmission

Name of Utility	Method Used
ATCO	Not included.
Union Gas	Classified as demand-related using design day demand to allocate– except compressor fuel as energy related.
Enbridge	Transmission and high pressure system allocated on peak demand. (considered distribution mains)
Gaz Metro	Was average and excess method. Black & Veatch recommend 100% design day
Puget Sound Energy	Peak and average method
Avista	Not included.

Distribution Mains

Table 4 summarizes the treatment of distribution mains in the COSA of the utilities reviewed. In most cases there was a split of distribution mains between demand and customer, using either a minimum system approach or a fixed percentage split. While Gaz Metro previously used an average and excess method, their COSA consultant recommended a move to a minimum system approach. In Washington, the WUTC generally does not allow the use of the minimum system approach and therefore a peak and average method was used by the two utilities in Washington. However, by exempting large users from an allocation of the small mains, the treatment has some of the same impacts as a minimum system approach.

Table 4
Treatment of Distribution Mains

Name of Utility	Method Used
ATCO	Split 35% customer and 65% non-coincident demand
Union Gas	Minimum System – Demand and Customer
Enbridge	Large customer class excluded from pipes under 6" ordered by the OEB. Low pressure mains use minimum system, with 34% customer-related and 66% demand-related.
Gaz Metro	Was average and excess. Black & Veatch recommended minimum system with NCP demand & customer
Puget Sound Energy	Peak and average method – split by system load factor (33% load factor meant 33% on average demand and 67% on peak demand). Small mains less than 2" not allocated to large commercial or industrial. Medium means of 2" to 3" allocated with one-third allocated to all customers and two-thirds allocated to all but industrial customers.
Avista	CP and Commodity based on peak and average ratio (load factor with 60% peak, 40% commodity) – Commodity Portion segregated into small 2", medium 4"and large 6" with large users getting 0% of small mains and 33% of medium mains. Previously small and large (4") then used peak and average ratio. Only took out usage of large customers not served at all by small mains. Note that WUTC does not allow minimum system.

Compressor/Measuring/Regulating Equipment

Table 5 summarizes the treatment of compressor/measuring and regulating equipment in the COSA of the utilities reviewed. Generally these costs were treated in the same manner as distribution mains.

Table 5 Treatment of Compressor/Measuring/Regulating Equipment	
Name of Utility	**Method Used**
ATCO	Same as distribution mains
Union Gas	Classified as 100% Demand
Enbridge	Same as mains
Gaz Metro	Not discussed.
Puget Sound Energy	Peak and average method
Avista	Peak and average ratio method

Services and Meters

Table 6 summarizes the treatment of services and meters in the COSA of the utilities reviewed. In all cases the costs were classified as customer-related and some form of weighting of customer was used to develop the allocation factor.

Table 6 Treatment of Services and Meters	
Name of Utility	**Method Used**
ATCO	Customer or weighted customers (different for meters and services)- Does have meter reading, billing, customer service.
Union Gas	Classified as 100% Customer (use average customers, service replacement costs and service calls)
Enbridge	Customer-related, meter reading classified to Readings Processed
Gaz Metro	Not discussed.
Puget Sound Energy	Customer-related weighted on cost of installed meters.
Avista	Meters & services based on weighted customer

General Plant

Table 7 summarizes the treatment of general plant in the COSA of the utilities reviewed. There was a wide variation in the treatment of general plant facilities. In some cases specific studies were made for space utilization while in other cases a combination of plant, O&M expenses and labor were used.

Table 7 Treatment of General Plant	
Name of Utility	**Method Used**
ATCO	General Structures based on total space study, tools and equipment – capital and O&M use by function
Union Gas	Functionalize using indirect rate base functionalization factor (50% weighted net plant/50% O&M) or using indirect O&M functionalization factor (O&M less compressor fuel). and service calls)
Enbridge	Structures based on space utilization analysis and office equip follows, tools, computers etc. all have analysis of use.
Gaz Metro	Was based on other distribution plant, recommend some costs be based on labor ratios
Puget Sound Energy	Some based on plant, some based on labor
Avista	4-part allocator- 25% each Direct O&M without resources and labor, direct O&M labor, Customers, Net Plant). Used to be 50% other O&M and 50% throughput

A&G

Table 8 summarizes the Administrative and General (A&G) costs in the COSA of the utilities reviewed. In all cases O&M expenses were used for all or some of the allocation of costs. For the two utilities in Washington, a combination of O&M, plant, revenue and labor was used to allocate the A&G costs.

Table 8 Treatment of A&G	
Name of Utility	**Method Used**
ATCO	Customer and Non-Coincident Demand – based on distribution service costs before billing and call center
Union Gas	Functionalize on the basis of all other O&M – except labor benefits on basis of direct labor.
Enbridge	On the basis of O&M costs – includes 3% of the cost of gas and classified to Distribution
Gaz Metro	
Puget Sound Energy	Some on labor costs, some on plant, some revenue-related and the rest based on all other O&M expenses
Avista	4-part allocator

Sales & Marketing

Table 9 summarizes the treatment of sales and marketing in the COSA of the utilities reviewed. In all cases sales and marketing expenses were assigned as customer-related.

Table 9 Treatment of Sales and Marketing	
Name of Utility	**Method Used**
ATCO	100% Customer
Union Gas	Customer Related
Enbridge	NGV-related costs assigned, rest equally split between distribution costs and number of customers, general promotion used to increase gas utilization so classified as demand-related.
Gaz Metro	
Puget Sound Energy	Customer-related
Avista	Unweighted customers

Customer Accounting

Table 10 summarizes the treatment of customer accounting in the COSA of the utilities reviewed. Customer accounting costs were considered customer-related in all cases.

Table 10 Treatment of Customer Accounting	
Name of Utility	**Method Used**
ATCO	100% Customer
Union Gas	Customer Related
Enbridge	Number of Customers
Gaz Metro	
Puget Sound Energy	Customer-related
Avista	Acctg, customer care, meter reading allocated to unweighted customers

Demand Side Management/Conservation

Table 11 summarizes the treatment of demand side management (DSM) or conservation in the COSA of the utilities reviewed. Not all of the utilities had specific costs related to DSM.

Table 11 Treatment of Demand Side Management/Conservation	
Name of Utility	**Method Used**
ATCO	None
Union Gas	Classified as 100% Demand
Enbridge	Was not discussed – classified as distribution DSM and allocation method is not listed in table with others, less to Rate 1 than both customer, peak or commodity
Gaz Metro	
Puget Sound Energy	No costs identified
Avista	DSM Investment and amortization based on Peak and Average Method

Losses

Table 12 summarizes the treatment of losses in the COSA of the utilities reviewed. In most cases the treatment of losses was not specifically identified in the Application/Decision and was not specified in the tables.

Table 12 Treatment of Losses	
Name of Utility	**Method Used**
ATCO	Not discussed/included in tables.
Union Gas	Commodity related.
Enbridge	Commodity losses classified based on gas costs, storage losses follow storage treatment
Gaz Metro	Should be recovered in transport rates for transporters (by actual delivery after losses) and in cost of gas for purchasers
Puget Sound Energy	Not discussed or shown in COSA
Avista	Not discussed or shown in COSA

Review of COSA Functionalization and Classification Methods

The Adjusted 2016 COSA reflects the revenue requirements and rate base approved by the Commission in the Annual Rate Review. Adjustments have been made to reflect new large projects expected over the next few years so that the COSA can be representative of the utility's costs over the next several years. All items in the revenue requirement are then allocated across the various customer groups. As discussed previously, a separate COSA was performed for Fort Nelson and the methods used apply to both FEI and Fort Nelson.

Both the rate base and revenue requirements for FEI are functionalized and classified within the COSA. The methodology used for these first two steps are discussed in greater detail in this section. All of the functionalization and classification methods used in the COSA reflect both past practices and the specific circumstances of the utility. It is our opinion that they also fall within the range of accepted utility practice and are appropriate for the Adjusted 2016 COSA.

Functionalization

The first step in the COSA is the functionalization of costs. Generally, functionalization follows the various cost categories of items found in the rate base. For FEI, the COSA contains the following functions:

- Gas Supply Operations
- Tilbury LNG Storage
- Mt. Hayes LNG Storage
- Transmission
- Distribution
- Marketing
- Customer Accounting

The functions defined by FEI and the costs that were assigned to each function are appropriate given that they reflect the historic functions and follow the standard system of accounts of the utility. The functions generally differ in terms of usage, cost causation and which customer groups use the function. While Marketing and Customer Accounting are separate categories within the standard system of accounts, and have been treated as separate functions in the past, the current methodology is appropriate. However, they could potentially be combined as they are classified and allocated in the same manner, with no impact on the COSA results.

Costs that are directly related to the defined functions are assigned to those functions. For General plant accounts, facilities related to the Customer Information/Service system have been functionalized to the Customer Accounting function. The remaining assets are functionalized across all of the functions on the basis of the gross plant in service prior to intangible and general plant. Administrative and general (A&G) expenses are functionalized on the basis of all gross O&M before Administrative and General costs. This approach is consistent with standard practice in the industry.

An alternative approach sometimes used for functionalizing A&G, as well as general plant and the associated operating and maintenance (O&M) expense, is to use labor ratios to account for the number of staff assigned to each function. In the case of FEI, staff time is not always easily assigned to the various functions and does not necessarily best represent the level of effort and costs for some of the functions. The decision to use gross plant in service and O&M expense is appropriate at the present time as it spreads the costs among all of the functions and reflects past practice.

Classification of Costs

The second step in performing a COSA is to classify the functionalized expenses to traditional cost-causation categories. These cost-causation categories can be directly related to specific consumption behavior or system configuration measurements including peak day demand, energy, or number of customers. Each classification category will have a specific allocator that, when applied, will distribute those costs among the appropriate customer classes during the allocation phase of the analysis.

The three primary classifiers are:

- Demand
- Energy
- Customer

These three classifiers are standard for both gas and electric utilities and have consistently been used by FEI in past COSAs and best reflect the different cost causation factors. Therefore the classifiers are appropriate for the Adjusted 2016 COSA. Functionalized gas supply costs are generally classified and allocated on the basis of energy. Transmission system costs are generally classified as demand-related. Distribution costs are generally split between demand-related and customer-related components, or directly assigned to a specific customer group.

Within the three categories, there are multiple ways of defining each option as well as varying ways to split costs between two or more classifiers. Customer-related categories can distinguish between actual customer and weighted customer characteristics. Other classifiers sometimes used in the process include revenue-related and direct assignment. In addition, there are many instances where certain expense accounts are not specifically classified to a particular category but rather follow the spilt used for a related rate base account or subtotal of specific expenses or rate base accounts. For example, the depreciation expense associated with distribution is generally classified to demand and customer on the basis of the classification of the total distribution plant.

Classification of Gas Supply, Storage and Transmission Rate Base

FEI has a limited amount of rate base for gas supply, which has been classified as energy-related, consistent with all other gas supply accounts.

Storage facilities include the Tilbury and Mt. Hayes facilities. A portion of the costs for Mt. Hayes are assigned to the midstream portion of the cost of gas, with the residual included in the delivery component of the COSA. This is consistent with previous practice. For Tilbury, 100 percent is included in the delivery component. Those costs are then included in rate base and have all been classified as demand-related. FEI storage facilities differ from upstream and market area storage facilities that are available on a wholesale basis to gas purchasers and are generally considered part of the cost of gas. These wholesale storage options are generally used to provide seasonal storage to take advantage of cost differentials and availability of gas supply by season and require the purchase of additional wholesale transportation to access the facilities. FEI's storage facilities are integrated with the transmission system and are not available to other providers on a wholesale basis. The underlying cost causation for Tilbury and Mt. Hayes differs from wholesale storage as they are used to provide storage to meet short-term peaking needs, to provide reliability in the event of transmission outages, to offset the need for additional transmission facilities, and to assist with balancing daily customer needs of natural gas. These functions are available for both the core sales and transportation customers of FEI and are therefore appropriate to include in the delivery margin for all customers, with the exception of the portion of Mt. Hayes assigned to the midstream function. For that reason, the costs are classified on the basis of demand, consistent with past practice. Because the storage in place at FEI is unique to the system, reliance on the specific cost causation is used rather than widespread industry practice. The bulk of storage facilities in North America are wholesale facilities and their treatment is not relevant in this case.

The cost of providing transmission service to a customer is considered to be directly proportional to the contribution to system peak demand that a customer imposes on the system. All transmission rate base accounts are classified 100 percent demand-related. This is appropriate because it is consistent with past practice and industry standards.

Classification of Distribution Rate Base

Generally, there are two methodologies that can be used to classify distribution costs: 100% demand and minimum system. The 100% demand methodology assumes that the distribution system is built only to meet the peak day demand and are therefore all assigned on the basis of demand. In some cases, while the cost is considered demand-related, the allocator is a peak and average demand number or average and excess number rather than just based on peak day demand. We do not believe that the 100% demand approach is appropriate as the FEI system is built in part to reflect the fact that each customer is connected to the system, regardless of usage level.

Distribution costs can also be split between demand and customer according to a minimum system approach. This approach reflects the philosophy that the system is in place in part because there are customers to serve throughout the service territory expanse, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 joule of energy per year. The concept follows that any costs associated with a system larger than this minimum size are due to the fact that customers "demand" a delivery quantity greater than the minimum unit of gas supply and that therefore, those costs should be treated as demand-related. Because the residential group tends to have a higher share of the number of customers as compared to the share of peak demand, the minimum system methodology tends to allocate more costs to the residential customer group and customer-related unit costs tend to be higher than with the 100% demand methodology.

Distribution facilities include all equipment required to get gas supply from the transmission system to the end user of the natural gas. Classifying distribution costs under the minimum system method requires a special analysis of the nature of the costs. Most distribution costs are appropriately split between demand and customer components. Different accounts within the distribution function are treated separately. For purposes of the COSA, a specialized study termed a "minimum system analysis" was used, which is a theoretical analysis using both engineering and accounting inputs to develop a split of the distribution costs between demand and customer components. The minimum system study was updated by FEI staff to reflect the most current information to be consistent with the COSA test year.

The minimum system analysis is used to theoretically determine the lowest level of plant investment required to serve a utility's customers compared to the actual facilities in place to meet varying customer demands. FEI staff completed the minimum system study using current 2015 year data. For the consolidated COSA filed in the Amalgamation Proceeding, FEI engineers determined that the minimum size pipe should be 2 inches rather than the 1.25 inches that was used in the past. To better reflect this larger minimum size pipe, an offset to account for the peak load carrying capability (PLCC) of the minimum system was incorporated into the analysis. The PLCC adjustment is discussed in the following section.

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the length of distribution mains in place segregated by size of the pipe. The cost associated with these facilities are then determined. The costs associated with the minimum size facilities were classified as customer-related while the remaining facilities were classified as demand-related.

The result of the minimum system study for FEI was 70% demand-related and 30% customer-related. The result differs from studies prior to this time, in large part because of the change in the minimum size pipe. The calculations and data used in developing the minimum system were reviewed and have been done appropriately and provided reasonable results for the FEI system. The resulting demand/customer split was used for the majority of distribution accounts, including mains, structures and regulating equipment.

Costs associated with Services and Meters differ within the minimum system approach. These costs are directly associated with the number of customers, i.e. there is generally one service and meter per customer. Costs have therefore been classified as 100% customer-related.

The minimum system approach is consistent with past practice of the utility and is generally accepted in the utility industry.

Peak Load Carrying Capability Adjustment (PLCC)

While the minimum system is, in theory, designed to carry only a minimal amount of load, the actual facilities designated as the minimal size are capable of carrying some amount of demand, therefore overstating the level of the customer-related component. The actual amount of demand capability within the minimum system is a function of load density, minimum equipment standards, and other engineering considerations. Under traditional cost allocation techniques, each customer/connection attracts an equal allocation of the minimum system, plus each customer group is allocated demand costs based on the total customer group's peak demand. As such, it has been argued that a customer group peak demand allocator is too large, because a portion of these peak demand-related costs are being covered through the per customer/connection minimum system allocation.

The correction of the problem of over allocating demand can be achieved by the application of a PLCC adjustment. This adjustment recognizes that the minimum sized pipe assigned to the customer-related component has a peak load carrying capability, that is, it is large enough to carry more than just the minimal amount of gas associated with having a customer on the system. The PLCC adjustment is made to the allocation of demand-related costs among customers. Use of the PLCC adjustment has already been approved by the Commission for the FortisBC electric COSA and was included in the COSA for the Amalgamation Proceeding. This adjustment is particularly warranted in light of the change in the minimum size pipe to 2 inches as the new size allows an even greater amount of gas beyond the minimum requirement to flow to the customer.

The precise amount of a PLCC adjustment should match the definition of the minimum system adopted. In FEI's case, it was determined that the average PLCC is 0.205 GJ per customer. The use of the PLCC credit is an enhancement over what was done for COSAs prior to the Amalgamation Proceeding. EES Consulting reviewed the PLCC calculations and concur with the results.

The PLCC adjustment will determine how much demand for a customer group can be met by the minimum system (number of customers/connections x PLCC for minimum system) and will credit this amount against the peak demands by customer group used for determining demand allocators. The adjusted customer group peak demand amounts can then be used to allocate the distribution demand-related costs, eliminating the double-counting.

Other Rate Base Items

The Customer Accounting and Marketing functions were both classified as customer-related as the costs are not based on the usage of each customer. This is appropriate as it reflects cost causation, is consistent with past practice and is the industry standard. In the case of the accounts for Energy Efficiency & Conservation (EEC), currently included in the Marketing function, there is some question as to whether these costs are more closely aligned with customers or if they are in place to avoid gas and transmission facilities. FEI first split the costs by Residential, Commercial and Industrial groups based on the amounts spent for each customer group, similar to a direct assignment. Within each broad customer group, costs were classified as energy-related to allow allocation to specific rate schedule. This reflects both the benefits to the various customer groups as well as the impact of reducing energy use.

General plant was first functionalized to the various functions and then classified using the resulting assignments of gross plant prior to general plant. For example, the portion of general plant assigned to distribution was based on the gross plant functionalized as distribution and then was split between demand and customer in the same manner as the general gross plant amount. Accumulated depreciation accounts and working capital accounts were classified in the same fashion as the corresponding gross plant accounts. Customer contributions were tracked separately for the transmission and distribution functions and then each was classified in the same manner as gross plant for the function. This is appropriate because it allows the customer contributions to be a direct reduction in plant in the same manner it is ultimately allocated to customers.

Classification of Expenses

Gas Supply expenses within the COSA are relatively minor with the exception of the cost of gas and midstream costs. The cost of gas, and other minor gas supply expenses are classified as energy-related, consistent with the Gas Supply rate base accounts. This is consistent with past practice. While rates for the cost of gas are updated more frequently than the costs for gas delivery, they are included within the COSA for comparison purposes.

Midstream costs are updated annually along with the quarter four cost of gas. Midstream costs include charges for the use of upstream pipeline and storage facilities not owned by FEI. Charges for those services are primarily tied to contracted capacity, which is set to cover forecasted peak day demands. The annual midstream cost filings allocate costs by rate group and the results are included in the COSA to allow FEI to calculate revenue to cost ratios and bill comparisons that reflect the entire cost to the customer.

Expenses associated with storage facilities are treated in the same fashion as the storage rate base accounts, with all expenses classified as demand-related. Transmission expenses similarly follow the transmission rate base and are also classified as demand-related.

Some of the distribution expense accounts correspond to a rate base account and follow the treatment of that rate base item. For some items, this means a split between demand and customer using the minimum system split. For other items, rate base accounts are 100% customer-related and therefore the corresponding expenses are classified as customer-related. For more general distribution expenses, the costs are classified on the same basis as the total distribution rate base.

Marketing and Customer Accounting expenses are classified as customer-related. The exception is the expense associated with EEC programs, which is treated in the same manner described above.

A&G was first assigned to each function on the basis of gross plant. These amounts were then classified on the same basis as the plant associated with each of the various functions.

Treatment of Bypass, Interruptible and Other Revenues

In addition to revenues from core and transportation customers subject to tariffs, FEI also receives revenues from customers with bypass and other dedicated contracts as well as other activities. Because the COSA is concerned with collecting revenues from rates for the tariffed customer groups, these other revenues are treated as an offset to the revenue requirement. Specific items within other revenues are treated individually to best reflect the appropriate cost causation, as described below.

Revenues collected from late payment fees are functionalized to the Customer Accounting function and classified as customer-related. Connection fees are functionalized to the distribution function as they are charged in order to offset the cost of new customers hooked up to the distribution system. Other Revenues are then classified in the same manner as all distribution rate base.

A large portion of other revenue comes from customer revenues that are set at negotiated rates. FEI has customers on contract rates that have been negotiated due to the ability of the customer to bypass the system. For bypass customers, rates are set outside of the COSA because the COSA does not capture the benefits these customers provide to the system. For bypass customers, those customers could economically bypass the system when compared to full cost-based rates and they are provided a negotiated discount to connect/retain them as a customer. By continuing to collect revenues from these customers, they are contributing to the fixed cost of the system that is already in place. This is preferable to collecting no revenues from them and means that other customers will not have to make up for the revenues associated with their lost sales. The Commission has approved this rate-setting approach for bypass customers, and once the discount is negotiated, FEI is contractually obligated to sell at the specified rate.

Within the COSA, if bypass customers were allocated a full share of costs based on their peak demand, the revenue to cost ratio would be below 100%. That result would be acceptable given the circumstances, however, it would not recognize the impact on other rate groups. If there is a shortfall in revenues within the COSA from one group that will not be changed through rebalancing, all of the other rate groups will see revenue to cost ratios that are too high. The treatment in the COSA is to place the bypass revenue in the other revenue category, and classify and allocate those revenues in a manner to offset the fixed cost of the system and credit all other classes. This approach is consistent with past practice and follows cost-causation. As the discount for bypass customers is provided because the revenues benefit all other customers by retaining the bypass customer, it is appropriate that those revenues are used as a credit to benefit all other customers.

Bypass revenues are classified as demand, like the transmission and distribution rate base and expenses they offset. Revenues are then allocated to customer groups on the basis of the delivery margin so that the revenues offset the costs assigned to each group.

A similar issue exists for interruptible customers as for bypass customers. For interruptible customers, past studies included them as separate customer groups in the COSA but assigned them zero peak load. As with bypass customers, the COSA results were not used when setting the interruptible rates and instead rates were based on a market driven discount relative to firm rates. This discounting approach was approved by the Commission in its Phase B Rate Design Application Decision from October 1993, and subsequently continued to be used in later negotiated settlement agreements.

The past COSA treatment leads to interruptible customer groups seeing very high revenue to cost ratios, and reflect little or no contribution to the fixed system by interruptible customers as the costs assigned to them generally reflect only those costs that are customer-related. As with bypass customers, rates are set at a discount to reflect some contribution to the fixed cost of the system while also recognizing the fact that all other customers benefit from interruptible sales. Similar to the bypass issue, the revenue to cost ratios in the COSA are misleading because there is no intention to change interruptible rates to match the COSA results. Therefore the revenues from the interruptible group that are above the allocated cost are not used to benefit other customers by offsetting the costs of all other groups, as is the case for bypass revenues. For that reason it would be more appropriate to treat all interruptible revenues in the same manner as bypass revenues. However, interveners have generally asked to see the revenue to cost ratios for the interruptible group in the past.

FEI continued to treat interruptible customers as having zero load in the baseline COSA, consistent with past practice. However, an adjustment was made in the final COSA to exclude interruptible sales and revenues when designing industrial rates to provide revenue to cost ratios that would be more appropriate for the circumstances.

Review of COSA Allocation Methods

The third step in performing a COSA is the allocation of the utility's total functionalized and classified revenue requirement to the customer groups. This is performed through the application of an appropriate allocation methodology.

For each of the primary classifiers discussed above, distinctions have been made within each category to better reflect cost-causation. The following are the specific allocation methods used in the FEI and Fort Nelson natural gas COSA. The specific method of cost classification and allocation for various rate base and expense items is discussed in further detail below.

Demand Allocation Factors

For purposes of this study, demand allocation factors were developed based on peak day demand to represent maximum use during an extreme weather condition. In some cases, the demand allocators were further differentiated to reflect the fact that not all customers use the facilities being allocated, and therefore some customers are excluded when developing specific allocation factors. Given the use of the PLCC adjustment as part of the minimum system treatment of distribution costs, the demand allocation factors are further adjusted by subtracting the PLCC amount times the number of customers in each rate group. This adjusted demand number represents the amount of demand that is not already included in the portion of distribution allocated on the basis of customers.

To be consistent with past COSA studies, the coincident peak day demand numbers were used for all allocation factors. While this is an acceptable methodology, there are cases where both a coincident peak (CP) and non-coincident peak (NCP) allocators are both used within a COSA. This is something that FEI may want to consider for future applications. The following describes both the CP and NCP demand calculations.

- *Coincident Peak Day Demand (CP).* The coincident peak day demand reflects the diversity among customers and reflects the peak day consumption used to develop the amount of gas supply purchased by the utility. Because this peak value better reflects the amount used for facilities closer to the upstream gas supply, it is generally used as the allocator for costs within the storage and transmission functions.

- *Non-Coincident Peak Day Demand Allocation Factor (NCP).* The NCP demand method allocates costs to each rate group based upon their highest non-coincident peak demand regardless of the time of occurrence. This peak reflects the system planning forecast of demand used for planning facilities close to the customer. The NCP is often used for facilities close to the customer, such as distribution.

Energy Allocation Factors

Energy costs vary directly with consumption. Accordingly, energy allocation factors were based upon annual gas sales for each customer group. As the energy allocator is used only for the gas supply function, it includes only the core customer groups that purchase natural gas from FEI. The only exception of energy-related costs being applied to transport customers is the assignment of the cost of gas associated with system losses.

Customer Allocation Factors

Two basic types of customer costs were identified—actual and weighted. This is generally consistent with past practice; however, we recommended a slight modification to reflect three rather than two different customer allocators. In addition to customers weighted for meters and services, we suggested that an allocator using customers weighted for customer accounting was more appropriate to use for some accounts and would better reflect cost causation. FEI therefore added this third allocator to the COSA. EES Consulting reviewed the calculations for both weighted customer allocators and found the results to be reasonable.

- *Actual Customers.* The allocation factor for actual customers was derived from the actual number of customers served in each customer group averaged across the 12 months of the 2016 test period.

- *Customers Weighted for Meters and Services.* The first weighted customer allocation factor considered the relative differences in meter costs among the various customer groups. The cost of actual meters and services installed for each rate group was used as the weighting factor for each group.

- *Customers Weighted for Customer Administration and Billing.* The second weighted customer allocation factor considered the cost of customer administration and billing as well as customer service for each rate group. The weighting factors were developed by FEI staff and were based on the estimated level of effort required per rate group. A standard weighting factor of 1.0 was used for the residential groups, with other groups receiving a weighting factor relative to the level of effort for a residential customer.

Allocation of Rate Base and Revenue Requirements

Gas supply rate base items and expenses were classified as energy-related and were appropriately allocated to customer groups on the basis of annual GJ for core customers.

Transmission and storage rate base and expense items were all classified as demand-related and were allocated on the basis of the CP demand.

Distribution rate base and expense items that were related to metering and services were classified as 100% customer and the customer numbers weighted for meters and services were used for allocation. For the other distribution items that were split between demand and customer, the actual numbers of customers was used as the customer allocator. The demand allocator was equal to the CP demand less the PLCC amount per customer times the actual customers in each rate group.

Customer Accounting and Marketing accounts used the customer allocator weighted for customer accounting. General plant and A&G costs were allocated to rate groups on the same basis as was used for each of the classified components.

Jurisdictional Review of Rates

As with the review of COSA methodologies used in other jurisdictions, EES Consulting reviewed the rates in place for other large gas utilities across Canada and the Pacific Northwest U.S. Rates were reviewed in terms of customer groups used, the structure of the rates, and the level of the customer charge. While the level of rates is interesting, all utilities face different costs and include different items in their delivery charges. For that reason, the level of the rates was not a focus of the review.

In general, there was greater consistency in COSA methods than there was in the actual customer segmentation of rate groups and rate design. More utilities were reviewed in terms of rate design than COSA methodology as utilities with different forms or unpublished COSA results did not need to be excluded. The following utilities were included in the jurisdictional gas rate design review:

- PNG (British Columbia)
- ATCO (Alberta)
- AltaGas (Alberta)
- SaskEnergy (Saskatchewan)
- Manitoba Hydro (Manitoba)
- Union Gas (Ontario)
- Enbridge (Ontario)
- Gaz Metro (Quebec)
- Gazifere (Quebec)
- Puget Sound Energy (Washington)
- Avista (Washington)
- Northwest Natural Gas (Oregon)

Tables showing the comparison of rates can be found in Appendices 7-3, 8-1 and 9-1.

Rate Group Segmentation

The first thing to note in the review is that there is a wide range of segmentation of customer groups between the various utilities. The rates for the utilities were looked at in terms of residential, commercial and industrial and NGV/Other categories, however, the rate groups did not all readily fall into those categories.

While all utilities had some form of service for residential customers, none of the utilities had more than one rate that would be applicable to residential customers. In some cases, there was no distinction between residential and other small users. Examples of this include ATCO, where service was for Low Use customers under 1,200 GJ per year and Union Gas, where the D1 rate applied to anyone with use below 50,000 m3 per year but with declining block rates to accommodate users of various sizes within that rate schedule.

For commercial customers, there were several cases where small and large commercial customers were broken out into two rate groups. This is true for PNG, AltaGas, SaskEnergy, Manitoba Hydro and Avista. For Union Gas and Gaz Metro commercial customers were accommodated with a declining block structure to allow for lower rates for larger commercial customers without the need for different customer groups.

Industrial rates varied quite a bit in terms of offerings. In some cases there was a distinction by size, such as Gazifere that has a moderate, large and very large volume service. Many of the utilities differentiated rates by load factor, such as for Enbridge, Union Gas, Gaz Metro, Puget Sound Energy and Avista. Firm vs. Interruptible rates were offered by Union Gas and Puget Sound Energy. Also the majority of industrial rates were for transport service only.

Only three other utilities had specific rates for NGV service, including PNG, Gazifere and Avista.

Rate Structure

The rate structure of a utility includes such things as whether there are flat or block rates and whether a demand charge is included.

In terms of flat or block rates, the utilities tend to have the same type of structure across the various rate groups. The majority of the Western utilities have flat rates for all or most of their rate schedules while the Eastern utilizes tend to have declining block rates. Note that the declining block rates in many of the cases are used to differentiate large and small users rather than having more rate groups.

Flat rates are used for most or all rate groups by PNG, ATCO, AltaGas, SaskPower, Manitoba Hydro, Puget Sound Energy and Northwest Natural.

Declining block rates are used for all customer groups by Union Gas, Enbridge, and Gaz Metro. Gazifere uses declining block rates for residential and commercial groups but not for industrial customers. SaskEnergy, Puget Sound Energy, Northwest Natural and Avista add declining block rates just for industrial customers.

Only one utility has an inclining block rate. Avista has inclining block rates for residential and small general service customers but has declining block rates for its larger commercial and industrial customers.

For NGV rates, PNG and Avista have flat rates while Gazifere has a declining block rate.

Most utilities use demand charges for industrial rates. Seven of the utilities have demand charges for industrial customers, while five utilities do not. For ATCO, only demand charges are applied and there is no energy rate for High Use customers. None of the utilities have demand charges for residential, commercial or NGV customers.

Customer Charge

The final comparison includes the level of the customer charge in place at the various utilities. While some charges were applied on a daily basis while others were applied on a monthly basis, all customer charges were converted to a monthly basis to allow a more applicable comparison.

For residential customers, the customer charge ranged from $7.00 per month for PNG and Avista to a high of over $36 for AltaGas. The majority of the customer charges were in the range of $10 to $20 per month.

For small commercial customers, the customer charge ranged from $7.00 per month for PNG to a high of $70 for Union Gas and Enbridge. The majority were in the range of $30 to $40 per month. Large commercial customer charges ranged from $77 to $412 per month.

Industrial customer charges per month had the largest range, from $149 for ATCO to $38,000 for one of Northwest Natural rate schedules. Because the eligibility and terms associated with the various types of industrial rates vary considerably, it is not surprising that the customer charge varies so much.

Rate Design

Rate design takes into account many different factors, of which the COSA is a starting point. As can be seen in the jurisdictional review, rate design varies considerable among utilities and must meet the specific needs of the utility in question. History, regulatory precedent, government policy, customer acceptance and understanding, competitiveness and desired price signals all play a role along with the cost circumstances of the utility when designing rates.

As discussed in the jurisdictional review, the segmentation of rate groups, the overall rate structure, and the level of various rate components are all part of the rate design for the utility. Interclass equity resulting from the COSA is also used to assist in determining whether any rebalancing between customer groups is required.

FEI is proposing to make some rebalancing adjustments as well as some rate design changes for certain customer groups. Many of the customer groups will see little change in the overall rate structure. EES Consulting has reviewed the rate design proposed by FEI and that review is discussed in the following sections.

Residential Rates

For the residential class, FEI is proposing to retain the current segmentation and increase the Basic charge per customer while lowering the Delivery charge to retain revenue neutrality. We agree that this proposal is appropriate.

In terms of segmentation, FEI looked at the correlation between load factor and average use and did not find a strong correlation. This makes sense as the convenience appliances used by customers with low consumption typically have a more sporadic usage pattern and may or may not be used on the peak day. In fact, FEI has shown that low users have a much wider range in their load factors than higher users. It is important to note that the load factors are estimated for each customer using regression analysis as the utility does not meter the daily loads of each customer. FEI has not found any evidence that would support further segmentation of the residential customer group.

FEI has proposed to increase the Basic charge by 5% to better reflect cost causation. The COSA results in customer-related costs of approximately $27.00 per month and includes such things as the cost of the meter, meter reading, billing, customer service and a share of the distribution system. A higher Basic charge is also consistent with the practice in other jurisdictions. Changing the Basic charge by 5% would increase it from an average of $11.84 per month to an average of $12.43. This proposal moves the Basic charge towards the cost resulting from the COSA. A much higher Basic charge could be supported by the COSA but has not been proposed based on the other rate design principles.

To retain revenue neutrality, the Delivery rate would decline by roughly 0.02%. While FEI considered alternatives to the flat Delivery charge, it is not proposing to make changes at this time. A declining block rate would be consistent with findings that the marginal cost for delivery is lower than the average delivery rate, and a declining block rate is found in several other jurisdictions in Canada. It does not, however, align with energy policy or customer acceptance. An inverted block rate is counter to marginal cost findings, is not found in other Canadian jurisdictions and is not easy to understand for most customers.

One issue brought up by stakeholders is the issue of Basic charges for low income customers. In our experience, low income customers are not necessarily low users of energy. This is due in part to the lack of capital to install more efficient appliances or weatherization measures. This is consistent with the findings of FEI using actual data for its service area. FEI's approach to deal with low income customers through measures outside of rate design is appropriate.

Finally, FEI is proposing to increase Residential rates to reflect inter-class inequities. The COSA shows that the Residential group is paying less than its cost of service, although the Revenue to Cost ratio is still within the target range of 90% to 110%. To offset the decreases necessary to bring other rate classes into the 90% to 110% range of reasonableness, the Residential class is the only class that is both below 100% and has revenues sufficient to make up for decreases in revenues from other rate groups. We agree that it is appropriate to increase the Residential rate to provide greater interclass equity.

The bill impacts associated with the changes to the Residential rate propose by FEI do not lead to any large impacts. Most customers will see less than a 1% change in their monthly bill as a result of the proposal.

Commercial Rates

For the Commercial class, FEI has separate rates for large and small users. FEI is proposing some minor adjustments to the rates to provide a better transition between the two rates. The overall rate structure is otherwise proposed to remain the same, and the current segmentation is proposed to remain at a 2,000 GJ breakpoint. The FEI proposal is appropriate for this customer group and reflects the rate design principles.

Commercial customers are split between small and large on the basis of annual consumption of 2,000 GJ. FEI looked at the load factors by usage level and the thresholds used for segmentation in other jurisdictions and found no compelling arguments to change the level of the threshold between the small and large Commercial rates. Based on stakeholder feedback, FEI did look at the impacts of changing the threshold to a lower level. The benefits of making such a change was not significant and would lead to disruption and large bill impacts for many customers. Based on all of the relevant factors, we believe it is appropriate to keep the threshold at 2,000 GJ.

Based on the results of the COSA, the revenue to cost ratio for the Commercial group is within the range of reasonableness and no interclass adjustment is required.

For the Commercial rate design, the misalignment of bills for customers close to the 2,000 GJ range was identified by FEI and rate changes were proposed to eliminate this misalignment. The proposal included an increase in the basic charge for both the small and large Commercial rates, a decrease in the Delivery rate for the small Commercial rate and an increase in the Delivery rate for the large Commercial rate. Increasing the Basic charge is appropriate given the higher customer-related costs resulting from the COSA, and is consistent with the change to the Residential group.

The bill impacts associated with the changes to the Commercial rates propose by FEI do not lead to any large impacts. The smallest users may see bill impacts up to 10 percent, but most bill impacts are much less than that.

Industrial Rates

The Industrial group contains several different rate schedules. Changes are being proposed for several of the Industrial rates to better reflect cost causation. No changes in the segmentation of the Industrial group are being proposed. In some cases the rate design is changing, and in some cases an adjustment for interclass equity is proposed.

Industrial rates are segmented into different rate groups on the basis of service type, including sales vs transport service and firm vs interruptible service. Gas volume also provides some segmentation of the group. Finally special circumstances, including NGV and seasonal sales are used for segmentation. These different factors are appropriate for the segmentation as they impact the costs of serving the various sub-groups. Because these rates include a demand charge, rates already take into account differing load factors by rate group and therefore, unlike other groups, load factor is not a factor required to segment the customers even further. The segmentation is consistent with that used in other jurisdictions, although for the Industrial group the factors included are much more specific to the circumstances of the utility and the types of Industrial customers on the system. FEI is not proposing any changes in the current segmentation.

While load factor is not an issue for the segmentation of Industrial customers, it is a significant factor to ensuring that rates are equitable between Industrial rate groups. For Rates 5 and 25 FEI is proposing to adjust the method for calculating the Daily Demand to better reflect actual peak demands and increasing the level of the Demand charge to better reflect the costs associated with peak loads and therefore create better equity among customers within the rate. As the current demand charge is lower than the demand-related costs resulting from the COSA, an increase in the demand charge is consistent with the COSA. FEI looked at several methods to better align the Daily Demand calculation with actual demand and found that applying the current approach but with a different multiplier to balance the ease of understanding and administration along with providing the least anomalous results. The proposed adjustments move the rate closer to cost causation and are appropriate.

FEI is proposing no change to the rate structure for Rates 7 and 27, which are interruptible rates. These rates are not based on the COSA but rather reflect an incentive to encourage interruptible service. We reviewed the approach used by FEI to develop a discount relative to the Rate 5/25 rates and found the approach to be reasonable. Because FEI believes the level of the rate is commensurate with the value provided, maintaining the current rate structure with the proposed discount is appropriate.

For seasonal service under Rate 4, FEI is not proposing any changes in the rate setting approach. Rate 4 has historically been set on the basis of Rate 5/25, and that approach is proposed to continue. The proposed changes to Rate 5/25 have a corresponding impact on the calculations used to develop Rate 4. Because the rate differential between seasonal and standard service is based on differences in value on a seasonal basis, the proposed rate structure is appropriate.

FEI's largest customers are on Rate 22 (including sub-rates 22A and 22B) or under special contract with FEI. Rates 22A and 22B have been closed for some time and FEI proposes to keep these rates closed with grandfathering of the current rate structures and accompanying terms and conditions. There are two special contract customers, including the Joint Venture (JV) and BC Hydro ICP. The JV contract expires at the end of 2017 and the BC Hydro ICP contract expires in 2022. At the time of the contract expiration, FEI proposes to place these customers on Rate 22 to provide consistent rates and service with its other Industrial customers. The Rate 22 rate structure is proposed to remain the same, with a Basic charge, Demand Charge and Delivery Charge for firm service. Rates for interruptible service would exclude the demand charge but results in a volumetric Delivery Charge per GJ that includes demand-related costs. The level of the rate is proposed to change to reflect the unit cost arising from the final COSA.

Summary and Conclusions

FEI prepared the COSA for this RDA to reflect the 2016 Rate Review as filed with the Commission, with several adjustments made to reflect large upcoming capital projects. It follows the three basic steps of functionalization, classification and allocation. We have reviewed both the COSA methodology and the COSA model itself to determine whether it is correct and appropriate. We find that the COSA follows standard utility practice, is generally consistent with past practice for the utility and the results are acceptable for purposes of setting just and reasonable rates for the amalgamated utility. There are a few items where it may be beneficial to consider a change in the methodology in future applications, which are addressed in previous sections of this report.

Use of COSA Results

Results of the COSA provide fully allocated costs for each customer class. Those costs are then compared to the revenues at present rates to determine the revenue to cost ratios.

The COSA is intended to provide findings on whether any rebalancing should occur between customer classes. It is not intended to set the actual rate levels as that is being done outside of this process. For the cost of gas, the actual rate levels are reviewed and set quarterly based on the actual costs of gas purchases. Midstream rates are generally updated on an annual basis outside of the annual revenue requirements process. For delivery rates, the actual rate levels are updated annually on the basis of the RRA. The method for assigning costs by customer class for the cost of gas, midstream costs and delivery costs, including the consolidation of those costs, is included with this COSA. The revenue requirements used for the COSA reflect the forecast of gas for 2016 with several adjustments and are not for the forecast period matching the implementation of the rates. Therefore the COSA is most appropriately used as a tool for looking at interclass equity and unit costs for rate design.

While the COSA reflects a 2016 test year, FEI does not intend to implement the proposed rate changes until June 1, 2018. At that time, the rates will reflect the approved revenue requirements at that time. It is typical to have a lag in implementation due to the time required for the regulatory process. The COSA is being used to examine the need for rebalancing between customer classes in light of the revenue to cost ratio results and adjustments to rate design are proposed that will be applied to the rates that are in place on June 1, 2018.

Revenue to cost ratios that are above 100% reflect a case where customers are paying more than their allocated share of costs, while numbers below 100% apply when customers are paying less than allocated costs. However, use of this 100% mark implies that the results of the COSA are completely accurate. While a COSA is the best method for determining a fair and equitable split of costs among customer classes, it relies on a forecast of both costs and sales that contain uncertainty, it contains methods that reflect the best estimate of cost causation but is subject to some interpretation, and it reflects load factors to determine peak day demands that are not metered in many cases. For all of these reasons, a revenue to cost range, sometimes referred to as a "range of reasonableness", rather than a firm 100% mark is used to determine reasonable revenue to cost ratios.

FEI has proposed using a 90% to 110% revenue to cost ratio "range of reasonableness" for setting proposed rates. We consider this to be a reasonable range for use when considering the adjusted revenue to cost ratios for FEI. While this is a broader range than what is currently accepted by the Commission for the electric utilities in B.C., it is consistent with the range previously accepted for gas utilities in the Province and the larger range is appropriate in this particular case. Anytime there is greater uncertainty in the COSA results, the resulting revenue to cost ratios are less accurate and reliable. This makes it advisable to use +/- 10% to reflect the uncertainty in the COSA. FEI COSA contains uncertainty due to several factors.

Gas utilities use peak days that reflect extreme weather planning conditions compared to the electric utilities that use actual or forecast loads under normal weather conditions. While the loads used in FEI COSA reflect the cost causation of the system, they contain less certainty than the loads used on the electric side. Because a large portion of costs are allocated on the basis of the peak day use per class, having uncertainty in the peak day loads used for allocation among the classes will lead to more uncertainty in the COSA results.

Rate Design Issues

For all of the rate classes, FEI looked at segmentation of the rate classes, the need to rebalance rates on the basis of the revenue to cost ratios in the COSA, and the rate design of each individual rate structure.

FEI did not find the need for further segmentation, or changes in the segmentation of the customer classes. We agree that this finding is appropriate.

In terms of rebalancing, FEI has proposed to increase revenues for the residential class by less than 1% in order to decrease the revenues for Rate 6 and Rate 22 based on the revenue to cost ratios resulting from the COSA. Note that the Rate 22 levels are set on the basis of costs for the group after the two special contract customers are added to the group for ratemaking purposes.

Some rate design changes have also been proposed to meet the various rate design principles of the utility. This includes an increase in the basic charge for the residential rate. For the commercial rate the basic charge would increase and energy charges would change to provide a smooth transition between the two commercial rates. For industrial customers the Rate 22 customers would be combined with two contract customers in the COSA to establish the rates going forward. However, rates for contract customers would not change until the end of the current contract.

After reviewing the various rate design changes, we agree that they are appropriate.

Attachment 3.1

1. Update the multiplier from 1.25 to 1.10 that is used in the current method to determine the Daily Demand as an estimate of a customer's peak demand. This change is proposed to more accurately estimate the peak Daily Demand for the purposes of the Demand Charge.
2. Increase the Demand Charge by $3.00. This change is proposed to continue the incentive for low load factor customers to take service under Large Commercial RS 3/RS 23 rather than General Firm Service RS 5/RS 25.

9.5.9 Bill Impact Analysis

The bill impact from the reduction in the multiplier in the Daily Demand formula is offset by the $3 increase in the Demand Charge. The net impact on RS 5/RS 25 revenues is an incremental $45 thousand of revenue, which is approximately a $0.003 per GJ increase or $5 per customer per month.

9.6 GENERAL INTERRUPTIBLE SERVICE – RS 7 AND RS 27

9.6.1 General Interruptible Service - Introduction

RS 7/RS 27 are companion rate schedules for General Interruptible Service. RS 7 is for sales customers and RS 27 is the corresponding transportation service. These rates schedules are available to small industrial and large commercial customers who have the ability to curtail their usage during system constraints. RS 7/RS 27 are intended for customers with gas consumption, generally, of less than 12,000 GJ per month.

The key factor for rate design for interruptible rates is the customer's ability to use and accommodate interruptible service. During periods of high system demand, interruptible customers must be able to curtail their gas usage (by either reducing production or utilizing backup fuel capability) upon short notice. FEI's ability to curtail these customers avoids the need for costly system expansions while also improving the overall system utilization in lower demand periods.

FEI's interruptible rates are designed to provide sufficient incentive to encourage existing customers to remain on interruptible service and attract new interruptible customers. For interruptible customers, contributors to their cost of taking interruptible service are factors such as:

- the customer's capital costs to install a backup energy system;
- the cost of the alternate backup fuel;
- the opportunity cost to the customer of potential lost production, should they need to curtail their operations; and
- the potential frequency and level of service curtailment to the customer.

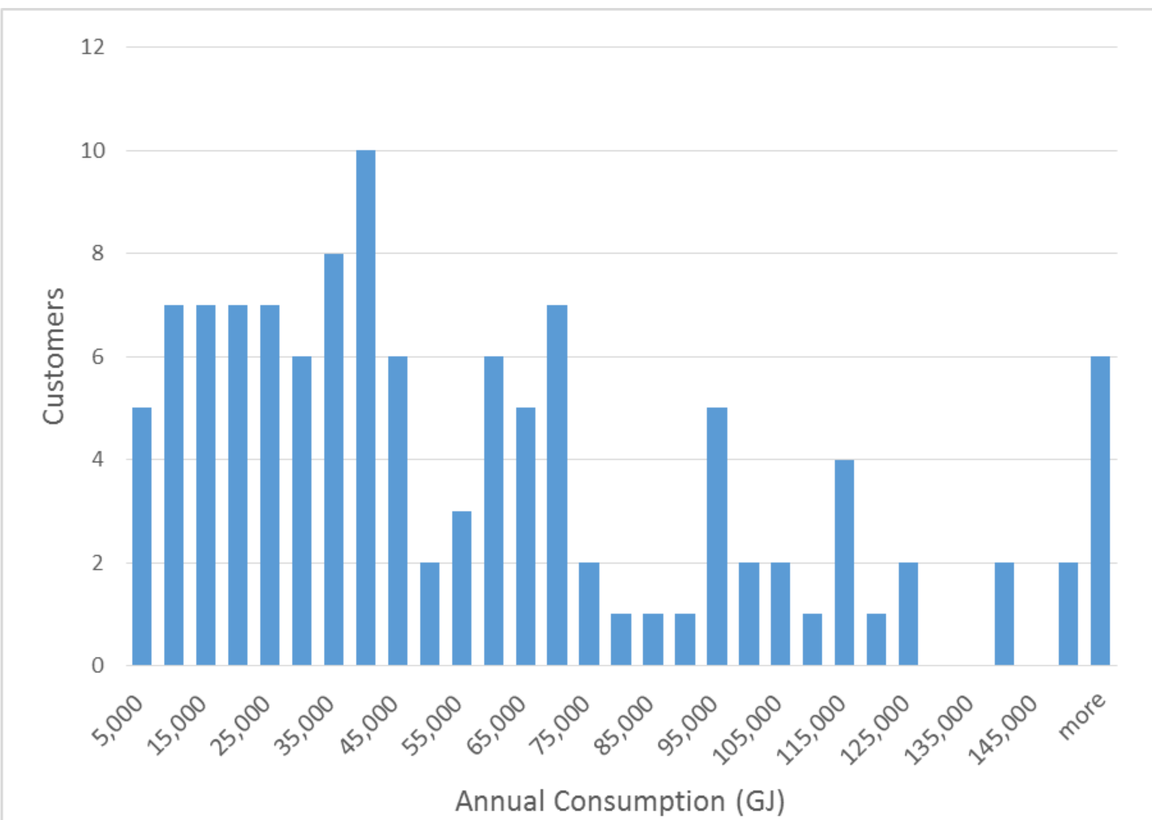
To compensate for these costs, FEI offers the service at a discount from the General Firm Service rate. Specifically, the existing delivery charges for RS 7/RS 27 are based on the General Firm Service RS 5/RS 25 Demand Charge based on an 80% load factor, plus the RS 5/RS 25 Delivery Charge.

Based on the review of interruptible rates discussed below, FEI concludes that the current rate structure is working well and as intended. The existing method has resulted in a consistent discount of approximately 18% from the firm rate, where the effective firm rate is based on an 80% load factor. FEI is proposing to maintain the existing discount and to update the RS 7/RS 27 charges for the proposed changes to RS 5/RS 25. In Section 9.6.5, FEI explains the changes that need to be made to the discount methodology to derive the interruptible delivery charge and the appropriate discount from the equivalent firm rate.

9.6.2 General Interruptible Service - Customer Characteristics

FEI currently has a total of 113 customers served under General Interruptible Service (sales and transport) that includes a wide range of industries such as asphalt plants, greenhouses, hospitals, sawmills and numerous other industries. These customers use an average of 59,200 GJ per year. Figure 9-5 below shows that the annual demand from these customers ranges from about 5,000 GJ to 150,000 GJ.

Figure 9-5: Annual Bill Frequency for RS 7 and 27 Combined



9.6.3 General Interruptible Service - Review of Existing Rate Design

9.6.3.1 Existing Rate Structure

The rate structure for Interruptible Sales and Transportation Service includes a monthly Basic Charge and a volumetric Delivery Charge per GJ. Transportation Service has an additional administration charge. These charges are shown in Table 9-15.

Table 9-15: 2016 COSA Rates for RS 7 and RS 27

	2016 COSA[150] Based Rates			
Rate Schedule	Basic Charge/ Month	Administration Charge/Month	Delivery Charge/GJ	Commodity + Storage & Transport Charge/GJ
RS 7 *General Interruptible Sales Service*	\$880.00	n/a	\$1.455	\$3.323
RS 27 *General Interruptible Transportation Service*	\$880.00	\$78.00	\$1.455	n/a

9.6.3.2 Existing Rate Setting Methodology

To encourage existing customers to remain on interruptible service and attract new interruptible customers, RS 7/RS 27 charges are set at a discount from the General Firm Service rate. Specifically, the existing delivery charges for RS 7/RS 27 are based on the General Firm Service RS 5/RS 25 Demand Charge based on an 80% load factor, plus the RS 5/RS 25 Delivery Charge. The regulatory history and methodology for calculating this discount are discussed below.

During the 1996 Rate Design, FEI established a discount for interruptible service from General Firm Service (RS 5/RS 25) based upon an 80% load factor. In the 2001 Rate Design proceeding, this relationship was reviewed again in relation to the value of the discount from firm service. This discount was applied in comparison to the firm service rate offered to RS 5/RS 25 customers, with the discounting calculation again based on an 80% load factor.

An example of how the discount was calculated in 2001 is provided below in Table 9-16. The table also shows the same calculation using 2016 current rates, and the 2016 COSA-rates which also includes known and measurable changes. The table uses the 80% load factor that was derived in the 1996 Rate Design to convert the RS 5/RS 25 demand charge into a volumetric equivalent for the purpose of the RS 7/RS 27 monthly basic charge and volumetric delivery charge. To convert the RS 5/RS 25 demand charge into an equivalent volumetric

[150] The COSA rates shown are estimated based on 2016 approved rates plus known and measureable changes discussed in Section 6.

charge, the demand charge for one GJ of Daily Demand is multiplied by 12 months and then divided by 365 GJ divided by the 80% load factor. The bottom row of Table 9-16 shows the amount of the discount from the firm rate and the relative percentage of the discount to the firm rate at an 80% load factor for each calculation.

Table 9-16: RS 5 at 80% Load Factor Compared to RS 7[151]

Rate Schedule	Line No.		2001	2016 - Current	2016 – COSA
Effective Rate/GJ for an RS 5 firm service customer at an assumed **80% Load Factor**	1	*Demand Charge*	$0.509	$0.825	$0.888
	2	*Delivery Charge*	$0.502	$0.825	$0.887
	3	*Total*	$1.011	$1.650	$1.775
RS 7 *General Interruptible Sales Service*	4	*Delivery Charge*	$0.836	$1.353	$1.455
Differential (per GJ) *RS 5 – RS 7*	5		$0.175	$0.297	$0.320
Discount as a Percentage of Total Firm	6		17.3%	18.0%	18.0%

Notes:

- Line 1 is the RS 5/RS 25 Demand Charge converted to a volumetric rate based on an 80% Load Factor (detailed in the footnote)
- Line 2 is the RS 5/RS 25 Delivery Charge
- Line 3 is the sum of lines 1 and 2
- Line 4 is the RS 7/RS 27 Delivery Charge
- Line 5 is the value of the discount (Line 3 – Line 4) between RS 5/RS 25 and RS 7/RS 27
- Line 6 is the value of the discount expressed as a percentage of the total Firm (Line 3).

As shown in Table 9-16 above, while the $/GJ value of the discount has increased from 2001 to 2016 COSA rates (due to general rate increases between 2001 and 2016), the relative percentage of the discount of the interruptible rate to the firm rate at an 80% load factor has remained relatively constant at about 18%.

The same analysis comparing the interruptible rate to a firm rate equivalent at a 55% load factor also shows that the discount has remained constant at approximately 33%. This analysis is shown below in Table 9-17.

[151] 2016 – Current Demand Charge is equal to $20.077 x 12 / 365 / 80% = $0.825; 2016 COSA plus known and measurable changes Demand Charge = $21.596 x 12 / 365 / 80% = $0.888.

Table 9-17: RS 5 at 55% Load Factor Compared to RS 7 at 80% Load Factor[152]

Rate Schedule	Line No.		2001	2016 - Current	2016 – COSA
Effective Rate/GJ for an RS 5 firm service customer at an assumed **55% Load Factor**	1	*Demand Charge*	$0.740	$1.200	$1.291
	2	*Delivery Charge*	$0.502	$0.825	$0.887
	3	*Total*	$1.242	$2.025	$2.178
RS 7 *General Interruptible Sales Service*	4	*Delivery Charge*	$0.836	$1.353	$1.455
Differential (per GJ) *RS 5 – RS 7*	5		$0.406	$0.672	$0.723
Discount as a Percentage of Total Firm	6		32.7%	33.2%	33.2%

The results illustrate that there has been no deterioration between the avoided cost of firm service and the interruptible delivery charge before consideration of any other rate changes proposed in this Application. Although the value of the discount between the cost of firm and interruptible service has increased, the relative percentage of the discount to the firm service has remained relatively static. The primary reason for this is that successive rate changes have been applied equally, percentage wise, to both firm (RS 5/RS 25) Demand and Delivery Charges as well as to interruptible (RS 7/RS 27) Delivery Charge.

9.6.3.3 Multi-Jurisdiction Review of Rates

As discussed above in Section 9.4, FEI conducted a review of the rate schedules offered by ten Canadian natural gas utilities. There are two utilities that also offer interruptible service - Manitoba Hydro and Union Gas. The interruptible service rates of these two utilities are summarized below in Table 9-18.

Table 9-18: Multi-Jurisdiction Review Summary for Interruptible Service

Company	FEI	Manitoba Hydro	Union Gas
Description	General Interruptible	High Volume Interruptible	Large Volume Interruptible
Eligibility	No restriction	>26,010 GJ/year	115 – 536 GJ/day (42,000 – 195,000 GJ/year)
Rate Type	Flat	Flat	Negotiated
Basic Charge (/month)	$880	$1,254	$352
Delivery Charge (/GJ)	$1.455[153]	$0.274	$1.233 (maximum)

[152] 2016 – Current Demand Charge is equal to $20.077 x 12 / 365 / 55% = $1.200; 2016 COSA plus known and measurable changes Demand Charge = $21.596 x 12 / 365 / 55% = $1.291.

It is difficult to draw any conclusions from the multi-jurisdictional review above as there are only two utilities that offer an interruptible service. Both of these other utilities have different eligibility criteria (from FEI's and from each other) and different rate levels. Consequently, FEI draws no conclusions from the multijurisdictional review.

9.6.4 Principle Based Review of Rate Design

Interruptible service should be offered at a suitable discount from firm service delivery rate in order to balance a number of the rate design principles, including:

- Principle 3: Price signals that encourage efficient use and discourage inefficient use
- Principle 4: Customer understanding and acceptance
- Principle 5: Practical and cost effective
- Principles 6 and 7: Rate and Revenue Stability

From the customer's perspective, the economic decision to take firm or interruptible service is dependent on whether the discount from firm is sufficient to compensate for the cost to have an alternate backup system and fuel that can be used or the cost from ceasing operations. Setting the discount either too high or too low would send the wrong price signals and could cause rate and revenue instability for customers and FEI, respectively. If the discount is too low, this may discourage new customers from considering interruptible service and may also cause existing interruptible customers to migrate to firm service. If the discount is too high and if the expected level of curtailment is very low, too many customers with firm service may elect to contract for interruptible service.

FEI believes that the discount is working well. FEI has experienced no unusual or unanticipated migration activity (from firm to interruptible or interruptible to firm) that would suggest the rates or rate structure are producing undesirable effects on customer's service option selections.

RS 7/RS 27 customers continue to receive value for service. FEI evaluated the interruptible discount against the level of service disruption that RS 7/RS 27 interruptible customers experience. Over the past twenty years, interruptible customers have experienced a total of approximately 19.5 days of capacity curtailment. On average, the annual curtailment is about one day per year.[154]

Based upon 2016 forecasts, FEI expects to receive approximately $11 million in revenues from these interruptible customers. This revenue goes to the credit of FEI's firm sales and transport customers by virtue of contributing to the total cost of service and avoiding system

[153] 2016 COSA plus known and measurable Rates: Current rates plus known and measurable changes.

[154] Based upon cold weather days where all interruptible customers are curtailed, but not including capacity constrained regions of the FEI system where partial curtailment happens every year, or for FEI system maintenance related curtailment

improvements that would be necessary if these customers were receiving firm service. As summarized above in Table 9-2, the RS 7/RS 27 customers are forecast to use 6.7 PJ, or an average use of approximately 18 TJ/day, representing a significant level of FEI's system peak demand that could be curtailed. The value to all customers of the avoided cost of service from RS 7/RS 27 interruptible customers is approximately $0.04 per GJ (Refer to Appendix 9-3).

The discount of approximately $0.34 per GJ is sufficient to require interruptible customers to have alternative backup fuel / systems to use when interruption is required by FEI. This is evidenced by the stability of customers taking interruptible service, i.e., the lack of migration in or out of RS 7/RS 27. Also, all non-bypass customers avoid an incremental $0.04 per GJ cost of service from avoided system improvements. The net benefit to non-bypass customers is approximately $5 million dollars.

Table 9-19: Net Savings to the Cost of Service

RS 7/27 Volumes (Table 9-2) PJ's	**6.7**
x Discount (Table 9-19)	$0.344
Dollar Value of Discount ($000s)	$2,305
All Non-Bypass Volumes (Appendix 9-3) TJ's	182,942
Avoided Incremental Cost of Service $/GJ	$0.040
Avoided Cost of Service ($000s)	$7,318
Net Savings to all Non-Bypass Customers ($000s)	$5,013

FEI concludes that the existing rates for RS 7 and 27 achieve a reasonable balance between maximizing the economic value of interruptible service, which helps to offset utility costs to firm customers, and providing a sufficient incentive for existing customer to stay on interruptible service and to encourage new customers to sign up for interruptible service.

In alignment with the Bonbright principle to fairly allocate costs to customers, interruptible customers are not allocated any demand related costs.

The existing methodology for setting interruptible service at a discount to firm service has been in effect for many years. This methodology is therefore understood and accepted by customers. The method is also practical and cost effective to implement.

FEI is therefore proposing to maintain the existing discount. However, due to proposed changes to the RS 5/RS 25 Demand Charge, FEI is proposing an update to the RS 7/RS 27 charges as explained below.

9.6.5 Update to RS 7/RS 27 to Account for Proposed RS 5/RS 25 Charges

FEI is proposing to update the existing method of calculating delivery charges for RS 7/RS 27 to reflect the proposed changes to RS 5/RS 25.

As discussed in Section 9.5 above, for General Firm Service FEI is proposing to decrease the multiplier in the Daily Demand formula from 1.25 to 1.1 and to increase the Demand Charge by $3.00 per month per GJ of Daily Demand. As shown in Table 9-12 above, under the proposed Daily Demand formula, the load factor of RS 5/RS 25 customers increases compared to the load factor under the existing Daily Demand formula. A RS 5/RS 25 customer who has a 100% Load Factor, i.e., uses the same amount of gas each day, as a result of the 1.1 multiplier will have an effective load factor of 90.9% (100% / 1.1). Therefore, to preserve the discount between the firm and interruptible rate:

- the load factor of 55% used in the RS 7/RS 27 calculation (Table 9-17, Line 1) needs to be increased to 62.5% (55% / 80% = x% / 90.9%, where x equals 62.5%);
- the firm equivalent (Table 9-17, Line 3 and Table 9-20, Line 6) to which the RS 7/RS 27 charge is compared must also be increased by the 1.1/1.25 multiplier change in order to have an apples-to-apples comparison (i.e., a 55% load factor customer is now a 62.5% load factor customer; a 80% load factor customer is now an 90.9% load factor customer).

As shown below in Table 9-20, applying the same interruptible rate methodology originally approved in the 1996 Rate Design proceeding results in a RS 7/RS 27 Delivery Charge of $1.443 per GJ and a discount from the firm equivalent at an 80% load factor of 24%. However, if the adjustments listed above are made, then the discount remains consistent at about 18%. In short, the firm rate equivalent to which the interruptible rate is compared to must be adjusted for the change in the Daily Demand formula. After the change in the multiplier, an 80% load factor RS 5/RS 25 customer would now be a 90.9% load factor customer. Taking this into account, Table 9-20 below shows that the Interruptible rate of $1.443 per GJ remains the same, but the discount is only 18.8%. As the existing discount of approximately 18% is maintained, FEI believes that the Interruptible Delivery Charge of $1.443 per GJ is the appropriate rate.

Table 9-20: Resulting Discount from Adjustment to RS 7/RS 27

Rate Schedule	Line No.		2016 COSA with 80% Load Factor Adjustment	2018 RS 7/27 Charges using 2001 Methodology	2018 Proposed with 90.9% Load Factor Adjustment[155]
RS 5/25	1	*Demand Charge*	$21.596	$24.596	$24.596
Load Factor for Equivalent firm Demand Charge	2		80.0%	80.0%	90.9%
Load Factors for Interruptible Rate	3		N A	55.0%/80.0%	62.5%/90.9%
Effective Rate/GJ for an RS 5 firm service customer	4	*Demand Charge*	$0.888	$1.011	$0.889
	5	*Delivery Charge*	$0.887	$0.887	$0.887
	6	*Total*	$1.775	$1.898	$1.776
RS 7 *General Interruptible Sales Service*	7	*Delivery Charge*	$1.455	$1.443[156]	$1.443
Differential (per GJ) *RS 5 – RS 7*	8		$0.320	$0.455	$0.334
Discount as a Percentage of Total Firm	9		18.0%	24.0%	18.8%

FEI does not anticipate any migration of customers shifting from interruptible service to firm service or from firm service to interruptible service. FEI concludes the change to the load factor for equivalent firm is necessary to stabilize the effective rate per GJ (Line 6) from which the discount is measured. The change to the load factor for the interruptible rate coupled with the change in the load factor for equivalent firm results in the same interruptible rate whether the load factor is 55% and 80% or 62.5% and 90.9%.

9.6.6 Stakeholder Feedback Received

As discussed in Section 5, FEI has previously circulated a Rate Design and Segmentation Discussion Guide to all interested stakeholders and held a workshop on August 31, 2016. This Guide and Workshop covered FEI's current industrial rate structures and presented a number of

[155] For the 2018 Proposed with 90% Load Factor the RS 5/25 the Proposed Demand Charge of $24.596 is multiplied by x 12 / 365 / 0.909 = $0.889; and $24.596 x 12 / 365 x .62.5% / 90.9% + $0.887 = $1.443

[156] RS 7/RS 27 Delivery Charge is equal to $24.596 (RS 5/RS 25 Demand Charge) x 12 / 365 x 55% (RS 5/RS 25 Load Factor) / 80% + $0.887 = $1.443

options that FEI had under consideration. The relevant stakeholder feedback is summarized below, with the detailed Meeting Summary and Notes attached as Appendix 4-2.

During this workshop, FEI presented the interruptible discount based upon a load factor of 80%. The feedback FEI received consisted of two items:

1. ensure that these customers receive a fair discount so that they do not return to firm service; and
2. clarify how the 80% was determined and applied.

These two comments have been addressed above in Section 9.6.3.2 and 9.6.5.

9.6.7 General Interruptible Service – Summary of Rate Design Proposal

FEI believes that interruptible charges achieve a reasonable balance between maximizing the economic value of interruptible service, which helps to offset utility costs to firm customers, and providing a sufficient incentive for existing customers to stay on interruptible service and to attract new customers. FEI is therefore proposing to retain the current rate structure and to continue the method of calculating the RS 7 and RS 27 delivery charges based on a discount from RS 5/RS 25. FEI is proposing to update the calculation to reflect the change in the Daily Demand formula, including a 62.5% firm service load factor assumption and a 90.9% load factor discount.

9.6.8 Bill Impact Analysis

The proposed interruptible rate results in a $0.012 per GJ decrease in the Delivery Charge to $1.443 per GJ (Table 9-20) from $1.455 per GJ (Table 9-17). The decrease is a result of the increase in the RS 5/RS 25 Demand Charge and the proposed changes to the load factors in the discounting methodology to preserve the relationship between the firm and interruptible rates (55% to 62.5% and 80% to 90.9%). The total revenue reduction for RS 7/RS 27 is $91 thousand (7,548 TJ[157] x $0.012); this represents an average annual bill reduction of 0.7%. The smallest reduction is 0.2% and the maximum reduction is 0.8% for customers in RS 7/RS 27.

9.7 SEASONAL FIRM SERVICE – RS 4

9.7.1 Introduction

RS 4 serves the unique needs of seasonal customers who typically do not use natural gas during the winter and thus do not contribute to FEI's system peak demand. These seasonal customers use gas primarily during the off-peak period from April 1 to October 31 (referred to in RS 4 as the Off-Peak Period). However, some seasonal customers also use gas in the months

[157] 2015 Billed Consumption.

of November and March when there is still available capacity and gas. During the coldest months from December through February, seasonal customers do not take gas service.

During the Off-Peak Period seasonal customers receive firm sales service. The Off-Peak period Delivery Charge has been derived from the RS 5 Demand Charge converted to a volumetric rate at a 100% load factor, plus the RS 5 Delivery Charge.

From November 1 to March 31 (referred to in RS 4 as the Extension Period), seasonal customers receive only interruptible sales service. In order to provide service to RS 4 customers during the Extension Period, FEI must have sufficient supply of gas and capacity to deliver the gas. For the Extension Period, the RS 4 Delivery Charge is the RS 7 Delivery Charge times 1.5.

Based on continuing with the existing methodology, the RS 4 Delivery Charges will change due to the proposed changes to RS 5 and RS 7. The Delivery Charge in the Off-Peak Period will increase by $0.114 per GJ and in the Extension Period will decrease by $0.018 per GJ.

9.7.2 Customer Characteristics

Customers served under RS 4 - Seasonal Firm Gas Service include paving companies with asphalt plants and municipal swimming pools that consume natural gas mainly during the summer months. There are 18 seasonal customers forecast for 2016 with an annual demand of 130 TJ. These customers only receive firm gas delivery from April 1 to October 31 (the Off-Peak Period).

The unique needs of these customers distinguish them from firm service customers who require firm service all year and interruptible customers who can either switch to a back-up fuel or cease operations should FEI need to interrupt their service at any time, but otherwise take gas service year round.

9.7.3 Stakeholder Feedback Received

As discussed in Section 5, FEI circulated a Rate Design and Segmentation Discussion Guide to all interested stakeholders and held a workshop on August 31, 2016. This Guide and Workshop discussed FEI’s current rate structures and presented a number of options that FEI had under consideration. The detailed meeting summary and notes are attached as Appendix 4-2.

During the Workshop, FEI described the method to establish the Delivery Charge for RS 4. There were no questions from stakeholders and no discussion on this topic.

9.7.4 Principle-Based Review of Seasonal Service

The method of determining the seasonal delivery charges was established during the 1996 Rate Design. RS 4 for seasonal customers is working as intended in that the customers served under this rate schedule require and receive seasonal service and are not receiving service during the coldest peak periods of the winter.

In alignment with the Bonbright principle to fairly allocate costs to customers, seasonal customers are not allocated any demand related costs as they do not cause demand-related costs to be incurred in order to serve the firm load during the system peak requirements.

For the Off-Peak Period, the fairness principle is applicable. During these months, the seasonal customers require firm service and are therefore charged a firm rate based on the RS 5 Demand Charge plus Delivery Charge. Seasonal customers are served as a firm customer in the Off-Peak period only and as such their rate is based on the General Firm Service Rate. Since the Seasonal customers do not contribute to the System Peak which occurs in the Extension Period, the RS 4 Off-Peak rate is discounted from the RS 5 firm rate by using a 100% Load Factor equivalent rate.

During the Extension Period the seasonal Delivery Charge is set at 1.5 times the delivery charge for the RS 7 General Interruptible Service rate. The rationale for the 1.5 multiplier during the Extension Period is to set the Delivery Charge at a premium to discourage General Interruptible Service customers that are receiving year round service from migrating to the seasonal rate. That is, interruptible service customers that use gas throughout the winter period with rare curtailment during the Peak Demand Period are not the same as seasonal customers who do not use gas during the coldest winter months. This pricing methodology provides the price signals to incent customers to take service under the appropriate rate schedule service offering of General Firm or General Interruptible or Seasonal Service.

In the following section FEI proposes to continue with the existing method for determining RS 4 Delivery Charges in the Off Peak Period and considers this to be an appropriate balance of rate design principles.

9.7.5 Proposed RS 4 Delivery Charges

The Delivery Charge for RS 4 during the Off-Peak Period is set equal to the Demand Charge of RS 5/RS 25 at a 100% load factor, plus the Delivery Charge for RS 5/RS 25, and during the Extension Period is equal to 1.5 times the Delivery Charge for RS 7/RS 27. As discussed above, FEI is proposing a change to the RS 5/RS 25 Demand Charge, which also results in a change to the RS 7/RS 27 Delivery Charge.

The proposed changes to RS 5/RS 25 and RS 7/RS 27, and the impacts on RS 4 are shown below in Table 9-21.

Table 9-21: RS 4 Seasonal Service Delivery Charge for Off-Peak and Extension Periods

Row	RS 4	2016 COSA[158] Based Rates	Proposed Rates
1	RS 5/25 Demand Charge equivalent at 100% Load Factor[159]	$0.391	$0.505
2	RS 5/25 Delivery Charge ($/GJ)	$0.887	$0.887
3	**RS 4 Off-Peak Delivery Rate $/GJ (Row 1 + Row 2)**	**$1.278**	**$1.392**
4	RS 7/27 Delivery Charge ($/GJ)	$1.455	$1.443
5	**RS 4 Extension Period $/GJ (Row 4 x 1.5)**	**$2.183**	**$2.165**

The proposed Delivery Charge during the Off-Peak period is increased by $0.114 per GJ to $1.392 per GJ and the rate in the Extension Period decreases by $0.018 per GJ to $2.165 per GJ.

The bill impact of the proposed Delivery Charges is to increase the revenues received from the Seasonal customers by $13.3 thousand ((118.6 TJ x $0.114) – (11.3 TJ x $0.018 per GJ)).

The bill impact of the proposed Delivery Charges is to increase the revenues received from the Seasonal customers from $641 thousand to $654 thousand, or approximately 2%.

9.8 LARGE VOLUME TRANSPORTATION – RS 22 AND CONTRACT CUSTOMERS

FEI's large volume industrial transportation customers are currently segmented into four groups, RS 22, RS 22A, RS 22B and the Large Industrial Contract Customers (VIGJV and BC Hydro IG). These four groups are a legacy of the service areas of FEI's predecessor companies, with RS 22 customers located primarily in the Lower Mainland, RS 22A customers in the Inland Service Area, RS 22B customers in the Columbia Service Area and the two Large Industrial Contract Customers located on Vancouver Island and the Sunshine Coast. RS 22A and 22B have been closed to any new customers since 1993. Since that time, any new large industrial transportation customers have taken service through RS 22 throughout FEI's service area.

Based on a review of the existing large volume industrial transportation rates, FEI proposes the following:

[158] The COSA rates shown are estimated based on 2016 approved rates plus known and measureable changes discussed above in Section 7.

[159] For the Proposed RS 4 Off-Peak Period the volumetric rate would be the RS 5 Demand Charge of $21.596 for 2016 COSA Rates x 12 months / 365 x 55% and $24.596 for Proposed Rates x 12 months / 365 x 62.5% load factor.

Attachment 8.2

Market Area Storage Cost (Mist)

Source: Natural Gas Price Forecast from GLJA [Jan 2015], Storage and Transport Rates: Gas Supply, FEI

Calendar Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
RATE CHARGES											
Sumas Summer Price ($US/MMBtu)	$ 2.03	$ 2.12	$ 2.43	$ 2.56	$ 2.69	$ 2.81	$ 2.90	$ 3.04	$ 3.19	$ 3.32	$ 3.39
update NWP wi NWP 15 day storage charge ($US/MMBtu) *	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25
NWP Injection/Withdrawal Fuel Rate (%)	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%
NWP TF-1 Transport Demand Charge ($US/MMBtu)	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41
NWP Transport Fuel Rate (%)	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
Storage Deliverability Required Mcf/d	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
STORAGE CHARGE ($US 000)											
Demand: NWP Storage Charge for 150MMcf/d x 15 days	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162
Fuel: Injection Fuel Charge for 5-day (15-day first year)	$ 6	$ 6	$ 7	$ 8	$ 8	$ 9	$ 9	$ 9	$ 10	$ 10	$ 10
TRANSPORT CHARGE ($US 000)											
Demand: NWP TF-1@40% Transport Charge for 365 day	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156
Fuel 1: NWP Transport for 5-day Injection	$ 23	$ 24	$ 28	$ 29	$ 31	$ 32	$ 33	$ 35	$ 37	$ 38	$ 39
Fuel 2: NWP Transport for 5-day Withdrawal	$ 23	$ 24	$ 28	$ 29	$ 31	$ 32	$ 33	$ 35	$ 37	$ 38	$ 39
TOTAL STORAGE & TRANSPORT											
($US 000)	$ 14,372	$ 14,374	$ 14,382	$ 14,385	$ 14,389	$ 14,392	$ 14,394	$ 14,398	$ 14,402	$ 14,405	$ 14,407
($Cdn 000) applying Fx = 0.76 $Cdn/$US	$ 18,910	$ 18,913	$ 18,923	$ 18,928	$ 18,933	$ 18,936	$ 18,939	$ 18,944	$ 18,949	$ 18,954	$ 18,956

Calendar Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE CHARGES											
Sumas Summer Price ($US/MMBtu)	$ 3.46	$ 3.53	$ 3.60	$ 3.67	$ 3.74	$ 3.82	$ 3.89	$ 3.97	$ 3.02	$ 4.13	$ 3.15
update NWP wi NWP 15 day storage charge ($US/MMBtu) *	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25
NWP Injection/Withdrawal Fuel Rate (%)	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%
NWP TF-1 Transport Demand Charge ($US/MMBtu)	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41
NWP Transport Fuel Rate (%)	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
Storage Deliverability Required Mcf/d	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
STORAGE CHARGE ($US 000)											
Demand: NWP Storage Charge for 150MMcf/d x 15 days	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162
Fuel: Injection Fuel Charge for 5-day (15-day first year)	$ 11	$ 11	$ 11	$ 11	$ 11	$ 12	$ 12	$ 12	$ 9	$ 13	$ 10
TRANSPORT CHARGE ($US 000)											
Demand: NWP TF-1@40% Transport Charge for 365 day	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156
Fuel 1: NWP Transport for 5-day Injection	$ 40	$ 40	$ 41	$ 42	$ 43	$ 44	$ 45	$ 46	$ 35	$ 47	$ 36
Fuel 2: NWP Transport for 5-day Withdrawal	$ 40	$ 40	$ 41	$ 42	$ 43	$ 44	$ 45	$ 46	$ 35	$ 47	$ 36
TOTAL STORAGE & TRANSPORT											
($US 000)	$ 14,409	$ 14,410	$ 14,412	$ 14,414	$ 14,416	$ 14,418	$ 14,420	$ 14,422	$ 14,397	$ 14,426	$ 14,400
($Cdn 000) applying Fx = 0.76 $Cdn/$US	$ 18,959	$ 18,961	$ 18,963	$ 18,966	$ 18,968	$ 18,971	$ 18,974	$ 18,976	$ 18,944	$ 18,982	$ 18,948

Please note Conversion Factors: GJ/MMBtu 1.055056
GJ/Mcf 1.07588

STORAGE COST: PRESENT VALUE (Year 2015 $)	NWP TF-1@40%			
Period (Years)	*11*	*21*	*11*	*21*
Discount Rate	*6.0%*	*6.0%*	*10.0%*	*10.0%*
STORAGE CHARGE ($US 000)				
Demand: NWP Storage Charge for 150MMcf/d x 15 days	**$ 40,746**	**$ 60,807**	**$ 33,530**	**$ 44,648**
Fuel: Injection Fuel Charge for 5-day	**$ 65**	**$ 109**	**$ 52**	**$ 77**
TRANSPORT CHARGE ($US 000)				
Demand: NWP TF-1@40% Transport Charge for 365 day	**$ 72,269**	**$ 107,849**	**$ 59,470**	**$ 79,189**
Fuel 1: NWP Transport for 5-day Injection	**$ 244**	**$ 407**	**$ 197**	**$ 287**
Fuel 2: NWP Transport for 5-day Withdrawal	**$ 244**	**$ 407**	**$ 197**	**$ 287**
TOTAL STORAGE & TRANSPORT				
($US 000)	**$ 113,567**	**$ 169,579**	**$ 93,447**	**$ 124,489**
($Cdn 000) applying Fx = 0.76 $US/$Cdn	**$ 149,431**	**$ 223,130**	**$ 122,956**	**$ 163,801**
Levelized Storage Year Cost ($Cdn 000)	**$ 19,689**	**$ 19,450**	**$ 19,816**	**$ 19,604**

Unit Charge based on period & discount rate	*11yr @ 6%*	*21yr @ 6%*	*11yr @ 10%*	*21yr @ 10%*
Fixed unit charge ($Cdn/GJ)	$ 116.74	$ 116.74	$ 116.74	$ 116.74
Variable unit charge ($Cdn/GJ)	$ 0.57	$ 0.64	$ 0.56	$ 0.61
Unit charge ($Cdn/GJ)	$ 117.31	$ 117.38	$ 117.30	$ 117.36

** Storage Rate on NWP of $US 2.25/MMBtu = (($0.00347 x capacity x 365-days + $0.04045 x deliverability x 365-days)/capacity)*
where: deliverability = 150,000 MMscf/d; storage days = 15 days; capacity = deliverability x storage days.
capacity charge of $0.00347 and demand charge of $0.04045

Summary of T-South Cost with mitigation payments

Storage Contract Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
GLJA AECO One Year ($Cdn/MMBtu)	$ 2.70	$ 2.76	$ 3.27	$ 3.45	$ 3.63	$ 3.81	$ 3.90	$ 4.10	$ 4.30	$ 4.50	$ 4.60	$ 4.69	$ 4.79	$ 4.88	$ 4.98	$ 5.08	$ 5.18	$ 5.28	$ 5.39	$ 5.50	$ 5.61	$ 5.72
GLJA AECO One Year ($US/MMBtu) using GLGA Fx 0.85 US/Cdn	$ 2.11	$ 2.10	$ 2.49	$ 2.62	$ 2.76	$ 2.90	$ 2.96	$ 3.12	$ 3.27	$ 3.42	$ 3.50	$ 3.57	$ 3.64	$ 3.71	$ 3.78	$ 3.86	$ 3.94	$ 4.02	$ 4.10	$ 4.18	$ 4.26	$ 4.35
GLJA AECO One Year ($Cdn/GJ)	$ 2.63	$ 2.62	$ 3.10	$ 3.27	$ 3.44	$ 3.61	$ 3.70	$ 3.89	$ 4.08	$ 4.27	$ 4.36	$ 4.45	$ 4.54	$ 4.63	$ 4.72	$ 4.81	$ 4.91	$ 5.01	$ 5.11	$ 5.21	$ 5.31	$ 5.42
GLJA AECO Storage Year ($Cdn/GJ)	$ 2.63	$ 2.74	$ 3.14	$ 3.31	$ 3.48	$ 3.63	$ 3.74	$ 3.93	$ 4.12	$ 4.29	$ 4.38	$ 4.47	$ 4.56	$ 4.65	$ 4.74	$ 4.84	$ 4.93	$ 5.03	$ 5.13	$ 3.91	$ 5.34	$ 4.07
Station-2 Winter Price = 107.46035406174% Storage Year ($Cdn/GJ	$ 2.83	$ 2.94	$ 3.38	$ 3.56	$ 3.74	$ 3.90	$ 4.02	$ 4.23	$ 4.43	$ 4.61	$ 4.71	$ 4.80	$ 4.90	$ 5.00	$ 5.10	$ 5.20	$ 5.30	$ 5.41	$ 5.52	$ 4.20	$ 5.74	$ 4.37
Station-2 Summer Price = 94.6711756701855% Storage Year ($Cdn	$ 2.49	$ 2.59	$ 2.97	$ 3.14	$ 3.30	$ 3.44	$ 3.54	$ 3.72	$ 3.90	$ 4.06	$ 4.15	$ 4.23	$ 4.32	$ 4.40	$ 4.49	$ 4.58	$ 4.67	$ 4.77	$ 4.86	$ 3.70	$ 5.06	$ 3.85
Sumas Winter Price (US$/MMBtu)	$ 2.53	$ 2.63	$ 2.99	$ 3.14	$ 3.30	$ 3.43	$ 3.54	$ 3.71	$ 3.88	$ 4.03	$ 4.11	$ 4.20	$ 4.28	$ 4.36	$ 4.45	$ 4.54	$ 4.63	$ 4.72	$ 4.81	$ 3.73	$ 5.00	$ 3.81
Sumas Summer Price (US$/MMBtu)	$ 2.03	$ 2.12	$ 2.43	$ 2.56	$ 2.69	$ 2.81	$ 2.90	$ 3.04	$ 3.19	$ 3.32	$ 3.39	$ 3.46	$ 3.53	$ 3.60	$ 3.67	$ 3.74	$ 3.82	$ 3.89	$ 3.97	$ 3.02	$ 4.13	$ 3.15
Sumas Winter Price ($Cdn/GJ)	$ 3.16	$ 3.28	$ 3.73	$ 3.92	$ 4.11	$ 4.28	$ 4.41	$ 4.62	$ 4.84	$ 5.02	$ 5.13	$ 5.23	$ 5.34	$ 5.44	$ 5.55	$ 5.66	$ 5.77	$ 5.15	$ 5.25	$ 4.00	$ 5.46	$ 4.16
Sumas Summer Price ($Cdn/GJ)	$ 2.54	$ 2.64	$ 3.03	$ 3.20	$ 3.36	$ 3.50	$ 3.61	$ 3.79	$ 3.98	$ 4.14	$ 4.23	$ 4.31	$ 4.40	$ 4.49	$ 4.58	$ 4.67	$ 4.76	$ 4.48	$ 4.57	$ 3.48	$ 4.75	$ 3.62
T-South Demand Charges ($Cdn/Mcf)	$ 0.35	$ 0.36	$ 0.36	$ 0.37	$ 0.37	$ 0.38	$ 0.39	$ 0.39	$ 0.40	$ 0.40	$ 0.41	$ 0.42	$ 0.42	$ 0.43	$ 0.44	$ 0.45	$ 0.45	$ 0.46	$ 0.47	$ 0.48	$ 0.48	$ 0.49
T-South Demand Charges, Calendar Year ($Cdn/GJ)	$ 0.33	$ 0.33	$ 0.34	$ 0.34	$ 0.35	$ 0.35	$ 0.36	$ 0.36	$ 0.37	$ 0.38	$ 0.38	$ 0.39	$ 0.39	$ 0.40	$ 0.41	$ 0.41	$ 0.42	$ 0.43	$ 0.43	$ 0.44	$ 0.45	$ 0.46
T-South Demand Charges, Storage Year ($Cdn/GJ)	$ 0.33	$ 0.33	$ 0.34	$ 0.34	$ 0.35	$ 0.35	$ 0.36	$ 0.37	$ 0.37	$ 0.38	$ 0.38	$ 0.39	$ 0.40	$ 0.40	$ 0.41	$ 0.42	$ 0.42	$ 0.43	$ 0.44	$ 0.44	$ 0.45	$ 0.34
Station-2 Daily Gas Price = 1.5 times Winter Price ($Cdn/GJ)	$ 4.24	$ 4.41	$ 5.06	$ 5.34	$ 5.61	$ 5.86	$ 6.03	$ 6.34	$ 6.65	$ 6.91	$ 7.06	$ 7.20	$ 7.35	$ 7.50	$ 7.65	$ 7.80	$ 7.95	$ 8.11	$ 8.28	$ 6.30	$ 8.61	$ 6.55
Sumas Summer/Station-2 Winter daily Differential ($Cdn/GJ)	$ 1.70	$ 1.77	$ 2.03	$ 2.14	$ 2.25	$ 2.35	$ 2.42	$ 2.55	$ 2.67	$ 2.78	$ 2.84	$ 2.89	$ 2.95	$ 3.01	$ 3.07	$ 3.13	$ 3.19	$ 3.26	$ 3.32	$ 2.53	$ 3.46	$ 2.63
Station-2 Daily Winter T-South Fuel 3.3% ($Cdn/GJ)	$ 0.14	$ 0.15	$ 0.17	$ 0.18	$ 0.19	$ 0.19	$ 0.20	$ 0.21	$ 0.22	$ 0.23	$ 0.23	$ 0.24	$ 0.24	$ 0.25	$ 0.25	$ 0.26	$ 0.26	$ 0.27	$ 0.27	$ 0.21	$ 0.28	$ 0.22
Fixed cost (150MMcfd x 365days x T-South Demand Charge)(9 months first year)	$ 19,168	$ 19,478	$ 19,794	$ 20,115	$20,441	$20,772	$21,108	$21,450	$21,798	$22,151	$22,510	$22,874	$23,245	$23,621	$24,004	$24,393	$24,788	$25,190	$25,598	$26,012	$26,434	$26,862
Variable based on (150 MMcf/d x 5 days) (two days first year)	$ 1,486	$ 1,547	$ 1,776	$ 1,872	$ 1,969	$ 2,053	$ 2,116	$ 2,223	$ 2,330	$ 2,424	$ 2,476	$ 2,526	$ 2,576	$ 2,628	$ 2,681	$ 2,734	$ 2,789	$ 2,845	$ 2,901	$ 2,209	$ 3,019	$ 2,298
Total before mitigation	$ 20,654	$ 21,025	$ 21,570	$ 21,987	$22,409	$22,825	$23,224	$23,673	$24,128	$24,575	$24,986	$25,400	$25,821	$26,249	$26,685	$27,127	$27,577	$28,038	$28,503	$28,224	$29,456	$29,163
Mitigation (4 out of 5 winter months)	-$ 6,039	-$ 6,137	-$ 6,236	-$ 6,338	-$ 6,440	-$ 6,545	-$ 6,651	-$ 6,758	-$ 6,868	-$ 6,979	-$ 7,092	-$ 7,207	-$ 7,324	-$ 7,442	-$ 7,563	-$ 7,685	-$ 7,810	-$ 7,936	-$ 8,065	-$ 8,196	-$ 8,328	-$ 8,463
Total after mitigation	$ 14,615	$ 14,888	$ 15,333	$ 15,649	$15,969	$16,280	$16,574	$16,915	$17,260	$17,596	$17,894	$18,193	$18,498	$18,807	$19,122	$19,442	$19,767	$48,136	$48,937	$48,249	$50,580	$49,859

Variable cost: This is the 5 day usage charge for fuel and the added cost of summer/winter differential to secure supply.

Please note Conversion Factors: GJ/MMBtu 1.055056
GJ/Mcf 1.07588

WEI TRANSPORT COST: PRESENT VALUE (Year 2015 $)

Period (Years)	*11*	*21*	*11*	*21*
Discount Rate	*6.0%*	*6.0%*	*10.0%*	*10.0%*
Fixed cost (150MMcfd x 365days x T-South Demand Charge)	**$ 162,640**	**$ 257,563**	**$ 133,063**	**$ 185,419**
Variable based on (150 MMcf/d x 5 days) (two days first year)	**$ 15,523**	**$ 25,934**	**$ 12,537**	**$ 18,291**
Total before mitigation	**$ 178,163**	**$ 283,497**	**$ 145,600**	**$ 203,709**
Mitigation (4 out of 5 winter months)	**-$ 51,243**	**-$ 81,150**	**-$ 41,924**	**-$ 58,420**
Total after mitigation	**$ 126,920**	**$ 202,347**	**$ 103,676**	**$ 145,290**
Levelized Yearly Cost, before mitigatin ($Cdn 000)	**$ 22,573**	**$ 24,069**	**$ 22,417**	**$ 23,554**
Levelized Yearly Cost, after mitigation ($Cdn 000)	**$ 16,080**	**$ 17,179**	**$ 15,962**	**$ 16,799**

Unit Charge based on period & discount rate	*11yr @ 6%*	*21yr @ 6%*	*11yr @ 10%*	*21yr @ 10%*
Before mitigation unit charge ($Cdn/GJ)	$ 139.87	$ 149.14	$ 138.91	$ 145.95
After mitigation unit charge ($Cdn/GJ)	$ 99.64	$ 106.45	$ 98.91	$ 104.09

$NPV = \sum_{i=1}^{n} \frac{\text{unit charge}}{(1 + \text{discount rate})^{i}}$ where n is the period (12 year or 22 year) and discount rate is 6.2% or 10%

Attachment 15.2

Diane Roy
Vice President, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
www.fortisbc.com

June 15, 2022

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

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI) Transportation Service Report

FEI writes in compliance with the British Columbia Utilities Commission (BCUC) Decision and Order G-135-18 dated July 20, 2018, in the matter of FEI's 2016 Rate Design Application (2016 RDA Decision). In the 2016 RDA Decision, the BCUC directed FEI to file a written report with the BCUC on transportation service balancing by June 1, 2022 (Transportation Service Report).[1]

Subsequently, the BCUC issued its Decision and Order G-210-20 dated August 10, 2020 in the matter of a complaint filed by a marketer group directing that FEI address additional items the Transportation Service Report.[2]

On May 30, 2022, the BCUC issued a letter approving FEI's extension request to file the Transportation Service Report on June 15, 2022.

Attached is FEI's Transportation Service Report. If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

[1] 2016 RDA Decision, p. 81 and Directive 25 in the Summary of Directives.
[2] Decision and Order G-210-20, p. 12 and Directive 2 of Order G-210-20.

FortisBC Energy Inc.

Transportation Service Report

Compliance Filing in Accordance with BCUC Order G-135-18 and Order G-210-20

June 15, 2022

Table of Contents

List of Appendices

Index of Tables and Figures

1. INTRODUCTION

FortisBC Energy Inc. (FEI) files this Transportation Service Report (Report) in accordance with British Columbia Utilities Commission (BCUC) Decisions and Orders G-135-18[1] and G-210-20.[2] The purpose of the Report is to review and assess the performance of the Transportation Service Model under the new business rules which were approved in Order G-135-18. FEI conducted engagement with stakeholders including all shipper agents (also referred to as gas marketers or marketers)[3] as discussed in the Report. FEI's analysis and assessment of the Transportation Service Model shows that shipper agents are meeting the demand requirements of their customers under the daily balancing provisions and within the 10 percent tolerance. Further, shipper agents are managing inventory within reasonable levels and are not incurring significant charges under the new rules. Based on these results, FEI believes the Transportation Service Model is working well and as intended under the new business rules. As a result, FEI has no substantive changes to recommend at this time.

1.1 *BACKGROUND*

In the years leading up to 2016, FEI conducted a comprehensive rate design process culminating in the submission its 2016 Rate Design Application (2016 RDA). On July 20, 2018, the BCUC issued its Decision and Order G-135-18 (2016 RDA Decision), approving (among other things) various changes to the Transportation Service Model, including new and updated customer-balancing tariff terms, conditions and charges (New Rules). The New Rules included the elimination of monthly balancing provisions, implementation of daily balancing for all transportation service customers, a reduction of the daily balancing tolerance from 20 percent to 10 percent, and a new balancing charge of $0.25 per gigajoule (GJ) for balancing within the 10 to 20 percent range The New Rules were implemented in the Lower Mainland (including Vancouver Island) and Interior regions effective November 1, 2018, and in the Columbia region (including East Kootenay) effective November 1, 2019.

In the 2016 RDA Decision, the Panel directed FEI to file a written Report with the BCUC by June 1, 2022, later extended to June 15, 2022[4], assessing the impact of the changes to the New Rules. FEI was encouraged to engage in a stakeholder review in the preparation of the Report.

On August 10, 2020, the BCUC issued Decision and Order G-210-20 (BCGMC Complaint Decision) in the matter of a complaint filed by a marketer group including Cascadia Energy Ltd., Direct Energy Marketing Ltd. and Access Gas Services Inc. (collectively BCGMC) which directed

---

1 In the Matter of FEI's 2016 Rate Design Application.

2 In the Matter of a Complaint filed by Cascadia Energy Ltd., Direct Energy Marketing Ltd. and Access Gas Services Inc. (collectively BCGMC).

3 The term "gas marketer(s)" typically refers to gas retailers selling gas to residential and commercial sales customers under the FEI Customer Choice program. While also commonly referred to as "marketer(s)", agents of customer groups under the transportation service are generally referred to as a "shipper agent(s)".

4 On May 27, 2022, FEI applied for an extension request to file the report by June 15, 2022, which was approved by the BCUC by letter on May 30, 2022.

FEI to engage in a stakeholder review with all shipper agents addressing certain topics and to include the results of that review in the Report.

The following provides a summary of the reporting requirements directed in BCUC Orders G-135-18 and G-210-20 (BCUC Directives).

The 2016 RDA Decision (page 81 and Directive 25 in the Summary of Directives) set out the following requirements for the Report:

> The Panel directs FEI to file a written report with BCUC on transportation service balancing by June 1, 2022. The report is to include the following:
>
> - Impact of new balancing rules on the use of core resources including both changes to variable costs of balancing the system to accommodate transportation service and changes to fixed costs arising from a need to contract midstream resources differently;
> - Effectiveness of imbalance return as a tool for Shippers/Shipper Agents to manage excess inventory including discussion of any modifications made to the allocation methodology in response to changes in demand for imbalance return after the balancing rule changes are implemented;
> - Whether there should be further tightening of tolerances for under-supply;
> - Whether it is necessary to implement tolerances and associated charges for over-supply; and
> - Whether the balancing charges appropriately recover the costs of providing balancing to transportation service customers and provide sufficient incentive to transportation service customers to balance their supply and demand.

The BCGMC Complaint Decision (page 12) and Directive 2 of Order G-210-20 directed FEI to include the following additional items in the Report:

> Prior to filing its transportation service balancing written report with the BCUC by June 1, 2022, as directed by BCUC Order G-135-18, FEI is directed to engage in stakeholder review with all shipper agents and include results of that review in the report, to be filed. FEI is directed to include the following topics in its stakeholder review:
>
> a. Nature, timing and adequacy of information provided to shipper agents to manage gas supply resources;
>
> b. Administration of inter-customer group balancing and transparency of inter-customer group balancing rules; and
>
> c. FEI's criteria for curtailment of inventory returns to shipper agents.

FEI addresses the BCUC Directives in Section 5 of this Report.

In order to effectively address the BCUC Directives, FEI engaged an industry expert, Atrium Economics, LLC. (Atrium Economics), to prepare a report to evaluate how the Transportation Service Model has been performing under the New Rules (Atrium Economics Report). The Atrium Economics Report is attached in Appendix A to this Report. Atrium Economics are experts in the energy industry and assisted FEI during the 2016 RDA proceedings and provided evidence and support for the proposed changes.[5] FEI have engaged with Atrium Economics to help with the assessment of the New Rules in preparation for this Report.

1.2 ORGANIZATION OF THE REPORT

This Report is organized as follows:

- Section 2 – provides a summary of the conclusions in the Report and the stakeholder engagement process that was undertaken in the development of the Report;
- Section 3 – describes the background and history of the Transportation Service Model including the role of shipper agents;
- Section 4 – discusses the stakeholder engagement process FEI undertook in preparation of this Report;
- Section 5 – reviews each of the BCUC's Directives and provides a discussion and analysis supporting FEI's conclusions;
- Section 6 – includes discussion of additional requests made by shipper agents during the stakeholder sessions; and
- Section 7 – provides a summary of FEI's recommended changes.

[5] The primary consultants that worked with FEI during the 2016 RDA process were affiliated at the time with Black & Veatch and have since formed Atrium Economics LLC.

2. REPORT SUMMARY

The 2016 RDA Decision approved New Rules for the Transportation Service Model that were implemented November 1, 2018 and November 1, 2019.[6] The New Rules included exclusively daily balancing and a tighter tolerance of 10 percent, which represented the first material changes to the Transportation Service Model since 1993 and moved the Transportation Service Model closer to an industry standard approach.

Although the New Rules may require additional effort from some of the transportation shipper agents, the Transportation Service Model continues to work well and has improved. The evidence provided in this Report shows that the New Rules are operating as intended by incenting shipper agents to appropriately manage their supply and demand requirements daily on FEI's system on behalf of their customers. FEI's analysis shows that shipper agents are able to balance the gas supply and demands of their customers on a daily basis within the tighter tolerance of 10 percent. The relatively low levels of balancing charges being incurred by shipper agents and the reasonable inventory levels maintained on FEI's system since implementation of the New Rules demonstrate that shipper agents are able to manage their businesses under the New Rules. FEI also notes that shipper agents continue to actively participate in the Transportation Service Model[7] representing their customers under the New Rules. As shipper agents have demonstrated their ability to manage under the New Rules while also meeting the requirements of their customers, FEI concludes that the New Rules are working as intended.

FEI makes the following conclusions in this Report, which are discussed in more detail in the sections that follow:

- The New Rules are working as intended;
- The New Rules are providing the appropriate incentive for shipper agents to proactively plan and take necessary actions to better manage the supply and demand balance for their customers;
- Shipper agents have demonstrated they can manage under the New Rules;
- The Transportation Service Model has improved under the New Rules by bringing inventories to more reasonable levels;
- The New Rules bring balancing expectations more in line with industry standards.

In the preparation of this Report, FEI conducted multiple stakeholder engagement sessions which included participation by intervener representatives involved in FEI's rate design and rate setting processes, all shipper agents, and with BCUC staff present as observers. FEI conducted individual sessions with shipper agents and group sessions with shipper agents, intervener

[6] Implementation took place in the Lower Mainland (including Vancouver Island) and Interior regions effective November 1, 2018, and in the Columbia region (including East Kootenay) effective November 1, 2019.

[7] No shipper agents have chosen to discontinue operating under the Transportation Service Model given the New Rules.

representatives, and BCUC staff to gather feedback and facilitate discussion to better understand the issues they raised. FEI also provided opportunities for shipper agents to share their views on how the Transportation Service Model is working for them under the New Rules. These sessions included identification of and discussion on any issues or challenges they raised as well as reviewing the BCUC Directives. The individual sessions were held with each shipper agent in the spring of 2021. In addition, in the fall of 2021, FEI hosted a group stakeholder session with shipper agents, intervener representatives, and BCUC staff. Shipper agents were provided an opportunity to advance their issues, concerns and suggestions for changes or enhancements to the Transportation Service Model by providing supporting evidence and rationale. In May of 2022, FEI held a final group stakeholder session to provide a high-level summary of its findings and conclusions informing this Report based on the analysis undertaken to meet the BCUC's Directives. Further detail and discussion on the stakeholder engagement sessions is provided in Section 4.

3. TRANSPORTATION SERVICE MODEL

3.1 BACKGROUND

Since its inception in 1993, the intent of the Transportation Service Model has been to provide an option for the large commercial and industrial customers on FEI's system to source their gas from a shipper agent (marketer) or on their own, and have the gas delivered directly to FEI's system. Transportation service customers arrange their own commodity and storage and transport (midstream) resources to supply the FEI system with gas at the applicable interconnection points with upstream pipelines.

Large commercial and industrial customers may elect the following transportation rate schedules:

- Rate Schedule RS 22 – Large Volume Transportation Service
- Rate Schedule RS 22A – Transportation Service Inland Area (Closed)
- Rate Schedule RS 22B – Transportation Service Columbia Area (Closed)
- Rate Schedule RS 23 – Large Commercial Transportation Service
- Rate Schedule RS 25 – General Firm Transportation Service
- Rate Schedule RS 26 – Natural Gas Vehicle Transportation Service
- Rate Schedule RS 27 – General Interruptible Transportation Service
- Rate Schedule RS 46 – Liquefied Natural Gas Sales, Dispensing, Liquefied Natural Gas Transportation Service and Transportation Service

A customer's election will depend on their average annual demand and throughput, geographic location, and the provisions for firm and interruptible transportation service on the FEI system.

The transportation rate schedules establish the terms and conditions of the transportation service. They provide the operational and system-balancing rules, as well as the charges the customer may incur if balancing provisions are not met. Customers receiving service under a transportation rate schedule may act on their own behalf to purchase and manage their gas supply requirements, or they may appoint a shipper agent to act as an agent (marketer or shipper agent) on their behalf in all matters relating to their gas supply on the FEI system. Appended to each transportation rate schedule is a Transportation Agreement, which is an agreement between FEI and the shipper agent to receive transportation service under the applicable transportation rate schedule.

FEI's Transportation Service Model was developed in 1993 as part of the FEI Phase B Rate Design Application and Decision.[8] Until the 2016 RDA Decision changes were implemented, the rules and operating practices for the Transportation Service Model had remained essentially the

[8] BCUC Decision and Order G-101-93.

same. The below Figure 3-1 below shows the number of customers who have received transportation service from FEI in the past 10 years from 2011 to March 2022.

Figure 3-1: FEI Transportation Service Customer Count – 2011 to March 2022

In November 2019, nearly 950 transportation service customers returned to receive sales (bundled) service[9] directly from FEI. Sales (bundled) service customers receive their commodity as well as delivery service from FEI. The constrained regional market conditions in the years leading up to 2019, particularly at the Sumas market hub, were a contributing factor to the large number of customers returning to sales service. However, the October 9, 2018 pipeline rupture on the Enbridge Inc. (Enbridge) Westcoast Energy Inc. (WEI) T-South pipeline (Enbridge Incident), which exacerbated constrained market conditions, likely also factored into the decisions of many transportation service customers to return to sales service in November 2019. The Enbridge Incident restricted capacity at the already constrained Sumas market hub, which emphasized the commodity price risk to which some transportation service customers were exposed. As a consequence of the market conditions exacerbated by the Enbridge Incident, many transportation service customers faced market shock in their energy bills during Winter 2018-2019, which may have solidified their decisions to move to sales service in order to minimize their price-risk exposure or gas costs. As of March 2022, there were approximately 1,118 transportation service customers (down roughly 56 percent) from a peak of 2,541 customers in June 2017.

[9] For gas supply purposes, core customers are defined as RS 1 through 7 and 46 (sales customers), and also includes customers in the Renewable Natural Gas (RNG) and Customer Choice programs.

3.2 *ROLE OF SHIPPER AGENTS*

Each of the transportation service rate schedules contains a Notice of Appointment of Shipper Agent and a Shipper Agent Agreement.

The Shipper Agent Agreement is an agreement between FEI and the shipper agent that outlines the rights and obligations of FEI and the shipper agent, with the latter acting on behalf of transportation service customers. One of the main obligations of shipper agents relates to customer group nominations and gas balancing[10], as set out in Rate Schedule 25, Section 3.4, excerpt provided below:

> 3.4 Group Nominations and Balancing
>
> The Shipper Agent will provide Group nomination and balancing to FortisBC Energy in accordance with the sections of the applicable transportation rate schedules.

Shipper agents are responsible for nominating to FEI the physical gas supply required to meet the demand of their customers, as well as for meeting the balancing requirements of their customers as outlined in the transportation rate schedules. In order to meet these obligations, shipper agents are responsible for understanding the demand patterns and load requirements of their customers; developing forecasting tools to anticipate changes in demand; and monitoring weather, operational changes on FEI's system, and pipeline interruptions affecting supply deliveries, as well as other indicators that might impact the demand from their customers and their ability to balance their gas supply delivered to FEI's system appropriately.

The following is a list of shipper agents[11] that act on behalf of the 1,118 customers served under the Transportation Service Model, as of March 2022. FEI has included the date in which each shipper agent became active in FEI's current Web Information & Nomination System (WINS) nomination system:

- Absolute Energy Inc. (2003)
- Access Gas Services (2007)
- Canadian Forest Products Ltd. (2002)
- Campus Energy Partners[12] (2019)
- Cascadia Energy Ltd. (2009)
- Direct Energy (2003)

[10] Shipper Agents are responsible to make "group nominations", which entails supply deliveries onto FEI's system to meet their aggregate customer demand. Shipper Agents are also held to "gas balancing" for supply deliveries that exceed 10% balancing tolerance otherwise they are subject to penalty.

[11] Easy Energy Inc. was an active Shipper Agent effective January 2021, however as of October 31, 2021 they are no longer managing transportation service customers on FEI's System.

[12] Campus Energy Partners was previously known as Altagas Ltd, which started representing transportation service customers in 2002.

- IGI Resources Inc. (2002)
- Macquarie Energy Canada Ltd.[13] (2017)
- Powerex Corp. (2002)
- Sentinel Energy Management (2015)
- Shell Energy North America (Canada) Inc. (2002)
- Tidewater Midstream and Infrastructure (2019)

These transportation shipper agents have been operating under the Transportation Service Model for several years and are familiar with the terms, conditions and obligations in the transportation rate schedules. Since the New Rules came into affect on November 1, 2018, all shipper agents have continued to remain active under the Transportation Service Model and represent customers in BC.

[13] Previously Cargill Ltd. (2004).

4. STAKEHOLDER ENGAGEMENT

FEI conducted several stakeholder sessions individually and in groups in the preparation of this Report. Participants included all shipper agents, representatives from FEI's regular intervener groups and FEI's consultant, Atrium Economics. BCUC staff also participated in as observers in the group sessions.

The following table shows the stakeholder engagement FEI has conducted with various participants as part of this process.

Table 4-1: Stakeholder Engagement Meeting Summary

Meeting Type	Date	Participant(s)
Individual Conference Calls	April 14, 2021	Easy Energy
	April 16, 2021	Campus Energy
	April 20, 2021	Cascadia Energy
	April 23, 2021	Shell Energy
	April 26, 2021	Access Gas
	April 29, 2021	Direct Energy
	May 3, 2021	Absolute Energy
	May 6, 2021	Sentinel
	May 10, 2021	IGI
	May 14, 2021	Tidewater
	June 1, 2021	Macquarie
Pre-meeting Reviews of the Transportation Service Model	September 13, 2021	BCUC Staff
	September 15, 2021	Interveners: BCOAPO, BCSEA CEC, RCIA
Group Stakeholder Sessions	September 22, 2021	BCUC Staff, Interveners, Shipper Agent Community
	May 10, 2022	

In Appendix B, FEI provides the information and summary meeting notes from the various sessions.

FEI began holding individual conference calls with shipper agents in spring of 2021 to discuss their experience operating under the New Rules, review the BCUC Directives, and discuss any other issues. Generally, a wide range of views were expressed, with some shipper agents indicating that managing their business under the New Rules is manageable, while others expressed that they have experienced issues. Some of the suggestions from shipper agents included a specified delivery requirement and a return to the previous 20 percent balancing tolerance.

In Table 4-2 below, FEI has summarized the feedback and requests received from the shipper agents at the individual conference calls and has grouped ones related to specific BCUC Directives under those directives. As shown in the table, there were 29 requests for changes to the Transportation Service Model.

1 **Table 4-2: Summary of Shipper Agent Feedback from Meetings**

BCUC Directive	Feedback Summary	Requests
Impact of new balancing rules on the use of core resources including both changes to variable costs of balancing the system to accommodate transportation service and changes to fixed costs arising from a need to contract midstream resources differently	• FEI is analyzing the use of core resources including variable and fixed costs to determine the impact from the new balancing rules.	• FEI completed analysis and has no requests or recommendations for changes to the new balancing rules.
Effectiveness of imbalance return (IR) as a tool for Shippers/Shipper Agents to manage excess inventory including discussion of any modifications made to the allocation methodology in response to changes in demand for imbalance return after the balancing rule changes are implemented	• General feedback indicates the revised allocation is fair, reasonable and provides certainty for planning. • The allocation puts everyone on an equal playing field. • Helpful to manage load, and load swings. • When imbalance return is set to zero, it is difficult to balance within the 10% tolerance. • Questions asking for a better understanding of how FEI manages this service; the process and predictability when imbalance return is reduced or eliminated in order to prepare for these restrictions. • Portion allocated to shipper agent groups with smaller customer demand is small.	1. FEI to release a higher amount of IR as a whole. 2. Mechanism to allow greater IR to specific Marketer(s) by request. 3. Reallocation of unutilized service to other interested Marketers. 4. Minimum allocation of imbalance return to groups with smaller demand. 5. Modify the allocation to incorporate a volatility/load factor. 6. Make IR available during Hold to Authorize (HTA) [14]/Supply restriction periods.

[14] A Hold to Authorize ("HTA") and Supply Restriction refer to operational restrictions that come into affect when sustained cold weather occurs. Under these conditions shipper agents and their customers are held to a 5% tolerance and are subject to potential Unauthorized Over-run Charges.

BCUC Directive	Feedback Summary	Requests
Whether there should be <u>further tightening of tolerances</u> for under-supply	• No shipper agent is in favour of further tightening. • Many did not want the tolerance change to 10% in the first place. • Some shipper agents indicate they are managing under the 10% tolerance and others express difficulty especially during cold weather or customer load volatility. • If a further tightening is imposed, look for models that provide more timely information or certainty such as a delivery requirement.	7. Return to the 20% tolerance. 8. FEI to offer a different percentage of balancing tolerance by season or during specific times of year (i.e. shoulder months) when operational conditions allow.
Whether it is necessary to implement tolerances and associated charges for over-supply	• Nearly all shipper agents oppose an over-supply tolerance and associated charges, especially those with customers having volatile demand. • One shipper agent is open to limits during normal operational circumstances, but not during HTA periods. • If specific shipper agents are over-delivering, then apply the applicable Tariff terms, conditions and charges to withhold inventory.	9. FEI to withhold inventory/pack for specific marketers that are over-delivering as opposed to restricting the service for all.
Whether <u>the balancing charges appropriately recover the costs of providing balancing to transportation service customers</u> and provide sufficient incentive to transportation service customers to balance their supply and demand	• FEI is analyzing the volume of recovered charges. • Generally, shipper agents indicate the incremental charge ($0.25/GJ) provides incentive to balance and avoid the charge. • Some have indicated the charge does not factor into their business planning.	• FEI completed analysis and has no requests or recommendations for changes to the new balancing charges.

BCUC Directive	Feedback Summary	Requests
Nature, timing and adequacy of information provided to shipper agents to manage gas supply resources	• Some shipper agents indicate the data available to them via WINS[15] and SCADA[16] is adequate and sufficient to balance. • Some shipper agents indicate WINS data is insufficient especially when restrictions are in place. • The two-day lag in WINS is not helpful and challenging to use as a forecast. • More timely/real-time data would be useful.	10. FEI to investigate better measurement technology available in the industry. 11. FEI to provide an intra-day estimate in WINS. 12. FEI to improve data quality of the previous day estimate in WINS. 13. FEI to provide a daily delivery requirement during normal and/or Hold to Authorize[17] (HTA)/supply restriction periods.
Administration of inter-customer group balancing and transparency of inter-customer group balancing rules	• Grateful for the trades to reduce UOR charges • Continue process going forward. • Remain outside the Tariff. • Clarify policy/practice and communicate to shipper agents.	14. Automate the process and/or a bulletin board format. 15. Continue process as is (status quo). 16. Proposed a utility super group netting exercise, where if as a whole, all shippers combined deliver sufficient supply to meet demand there should be no penalty.
FEI's criteria for curtailment of inventory returns to shipper agents	• Mix of feedback with shipper agents that understand why FEI limits this service and others who question FEI' decisions to limit. • Shipper agents request a better understanding of FEI's considerations/parameters to enable better planning. • FEI encouraged to provide as much notice as possible when limiting this service.	17. Days when Imbalance return is reduced/ eliminated flag the line item in the nomination screen. 18. FEI to provide a "status update" for operational changes (weather/maintenance/ interconnecting pipeline status, etc.) when reducing IR.
Other: Daily Balancing Charges - Interior	• The Lower Mainland region has a single source of supply (Sumas), and source of supply for the Interior region is different, Station 2. However, penalty for daily balancing charges across all rate schedules is currently based on the Sumas price. Should have a different penalty rate for customers in the Interior.	19. Amend Rate Schedule 22A[18] Daily Balancing Gas charge to a Station 2 price.

15 Web Information & Nomination System. (WINS).

16 Supervisory Control and Data Acquisition (SCADA).

17 Hold to Authorize (HTA) and supply restriction are terms that are used inter-changeably. Under these conditions, the balancing tolerance is reduced from 10 percent to 5 percent and shipper agents are potentially subject to Unauthorize Over-Run (UOR) penalties.

18 Rate Schedule 22A sets out the terms and conditions for large commercial and industrial customers located in the Inland (Interior) region of BC.

BCUC Directive	Feedback Summary	Requests
Other: Timely Cycle Deadline[19]	• Cycle deadline (timely). WEI offers flexibility to extend the deadline.	20. FEI to allow Timely cycle deadline flexibility.
Other: Apply Penalties to Specific shipper agents	• Utility's approach is to treat everyone the same, which is a mistake. • FEI is encouraged to communicate with the BCUC, and report problems with specific shipper agents.	21. FEI to apply penalties to the entities that are causing core market problems.
Other: HTA and/or Supply Restrictions	• Shipper agents request a better understanding of FEI's considerations and/or parameters for issuing a HTA to enable better planning.	22. FEI to disclose the parameters and conditions for issuing HTA/Supply restrictions. 23. FEI to apply locational/regional HTA – not apply across all regions.
Other	• Requests received after the initial list was circulated	24. Include real time SCADA information prior to the intra-day cycles 25. Create marketer dashboards to provide collected data snapshots of marketer group information 26. Provide clear information, timelines, priorities and other information related to curtailment 27. Tariff be structured so FEI may curtail/HTA only when absolutely necessary 28. Clear and consistent criteria for the return of HTA gas inventory and a mechanism for returning any premium value of that inventory, and specifically that FEI publish its criteria so customer and marketers can understand how FEI will make its decisions/criteria so customer and marketers can understand how FEI will make its decisions 29. FEI to adhere to the Gas Marketers Code of Conduct

[19] There are five gas cycles within a gas day: Timely, Evening, Intra-day 1, Intra-day 2 and Intra-day 3. The Timely cycle is the first cycle of the gas day and each cycle has a defined time and is a measure of flow throughout the gas day as a whole.

The summarized list in Table 4-2 was distributed to shipper agents on July 16, 2021. In order to help prioritize the issues, FEI asked shipper agents to rank their top five requests. Once all entries were received, the list was re-distributed back to shipper agents on August 26, 2021. Six additional requests were received after the initial shipper agent summary was prepared for circulation and are included in Requests 24 to 29 in Table 4-2.

As indicated in Table 4-1, FEI held two pre-meeting reviews of the Transportation Service Model, one with BCUC staff on September 13, 2021, and a second with stakeholders (interveners only), on September 15, 2021. These meetings were to refresh the history of the 2016 RDA and the 2016 RDA Decision, review the stakeholder engagement to date, and discuss the objectives of the group stakeholder session.[20]

FEI also held a group stakeholder session, which took place on September 22, 2021 and included the majority of the shipper agents, interveners, BCUC staff, and Atrium Economics. The group stakeholder session was well attended, with most shipper agents present. There were three main objectives for the group stakeholder session. First, to hear feedback as to how the Transportation Service Model has been working under the New Rules. Second, to gather more detailed information from shipper agents to support the issues and requests for potential changes they identified in the individual conference calls held in the spring 2021. Third, to facilitate discussion of these matters with all stakeholders.

FEI did not present a view on any of the issues or requests raised by shipper agents at that time. Rather, FEI acted as a listener and facilitator to hear and better understand the shipper agents and their experience with the New Rules and the Transportation Service Model generally. FEI invited each shipper agent to present at the stakeholder session on the issues or requests that were most significant to them, asking that they provide support and justification for potential changes they were advocating for or advancing for consideration. One shipper agent, Direct Energy, prepared and presented material at the group stakeholder session emphasizing its challenges under the existing Transportation Service Model. Detailed discussion of the issues presented by shipper agents is covered in Section 5 of this Report. No other shipper agent came forward to present at this session.

FEI held the final stakeholder session on May 10, 2022, which included participation from the majority of the shipper agents, interveners, BCUC staff, and Atrium Economics. During this session, Atrium Economics provided a summary of their analysis on the performance of the Transportation Service Model since the New Rules were implemented. As well, FEI presented a high-level overview of its preliminary conclusions for the Report based on the results of its analysis in relation to the BCUC Directives and in consideration of the stakeholder feedback gathered from the earlier sessions.

[20] Held virtually due to COVID-19 restrictions.

5. REVIEW OF BCUC DIRECTIVES

In relation to the BCUC Directives, during the stakeholder sessions, as discussed in Section 4, FEI received feedback and requests for amendments or enhancements to the Transportation Service Model from shipper agents. In Table 4-2, FEI organized this feedback in summary form and grouped ones relevant to specific BCUC Directives. In this section, FEI reviews each of the BCUC Directives including the related requests from shipper agents by providing some background information as required and including discussion supporting FEI's conclusions.

5.1 *IMPACT OF THE NEW BALANCING RULES*

BCUC Directive 1: **Impact of new balancing rules on the use of core resources including both changes to variable costs of balancing the system to accommodate transportation service and changes to fixed costs arising from a need to contract midstream resources differently.**

Background:

FEI's midstream resources (core resources) are in place to serve FEI core customers (bundled sales customers)[21] in order to balance and meet their daily demand needs. FEI must balance its system daily as a whole at the end of each day. FEI does not procure additional midstream resources to meet the daily balancing needs of transportation service customers as this is the responsibility of each transportation service customer or their shipper agent. The fixed costs of FEI's midstream resources are recovered from FEI's core customers through the applicable storage and transport charge per gigajoule. The storage and transport charge is not applicable to FEI's transportation rate schedules and, as such, transportation service customers do not pay for those midstream resources and are not entitled to benefit from them at the expense of core customers. The implementation of the New Rules did not change how FEI's midstream costs are recovered from core customers, who continue to pay for the midstream resources through the applicable storage and transport charge per GJ.

The purpose of implementing daily balancing provisions and decreasing the balancing tolerance to 10 percent under the New Rules was to incent shipper agents to better match their daily supply requirements with the daily demand from their customers. Because FEI must balance the system as a whole each day, and core sales customers pay for the midstream resources (both contracted and variable), it would not be fair if FEI needed to incur incremental costs to acquire additional variable midstream resources (paid for by core sales customers) to balance the demand of transportation service customers if shipper agents fail to do so. By isolating the supply and demand imbalances of transportation service customers exclusively, as shown in Figures 5-1 and 5-2 below and the related discussion, FEI has observed that the New Rules have properly incented transportation service shipper agents to balance more tightly. The result of shipper

[21] FEI RS 1 to RS 7, and RS 46 (who have elected bundled service) including the applicable rate schedules under the RNG and Customer Choice programs.

agents balancing more tightly is less reliance on FEI's midstream resources (paid by core customers) to support the Transportation Service Model.

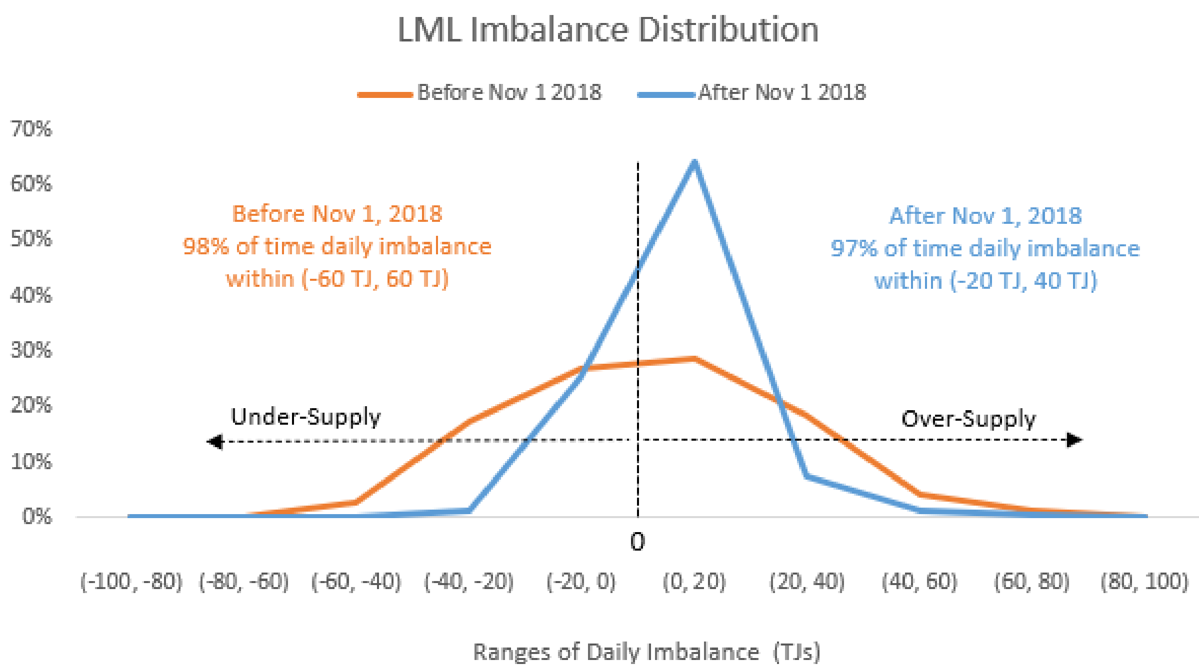
Discussion:

Since implementation of the New Rules, the data in Figure 5-1 and 5-2 shows that shipper agents representing customers in the Lower Mainland and Interior are balancing their supply and demand more closely.[22] When the supply and demand of transportation service customers is balanced more closely, it results in less dependency on FEI's midstream resources to adjust for imbalances caused by transportation customers. FEI believes the New Rules are having the desired impact to incent shipper agents to balance the supply and demand of their customers more closely.

The fluctuation of system supply volumes from shipper agents has changed since the implementation of the New Rules. Figure 5-1 shows the system imbalances borne by transportation customers exclusively in the Lower Mainland. The orange line represents the distribution or range of system imbalances for two years prior to the implementation of the New Rules. Prior to implementation of the New Rules, with daily and monthly balancing provisions in place, and a tolerance of 20 percent, 98 percent of the time system imbalances ranged from -60 TJ to +60 TJ. In contrast, for the three winters following the implementation of the New Rules, where exclusively daily balancing and a reduced tolerance of 10 percent was in effect, 97 percent of the time imbalances tightened to -20 TJ to +40 TJ. Further, the data shows that, nearly 65 percent of the time, imbalances fell within the 0 to 20 TJ range, which from a system perspective is an insignificant volume for FEI to manage. To put this volume into perspective, 20 TJ is less than 5 percent of the total system throughput from sales customers in the Lower Mainland on an average winter day, which ranges from 500 to 700 TJ. Based on this analysis, the improvement both in volume of imbalances as well as the range of imbalances suggests that, in order to balance the system as a whole on a daily basis, FEI is incurring lower variable midstream costs to balance the Transportation Model supply/demand imbalances as compared to before implementation of the New Rules.

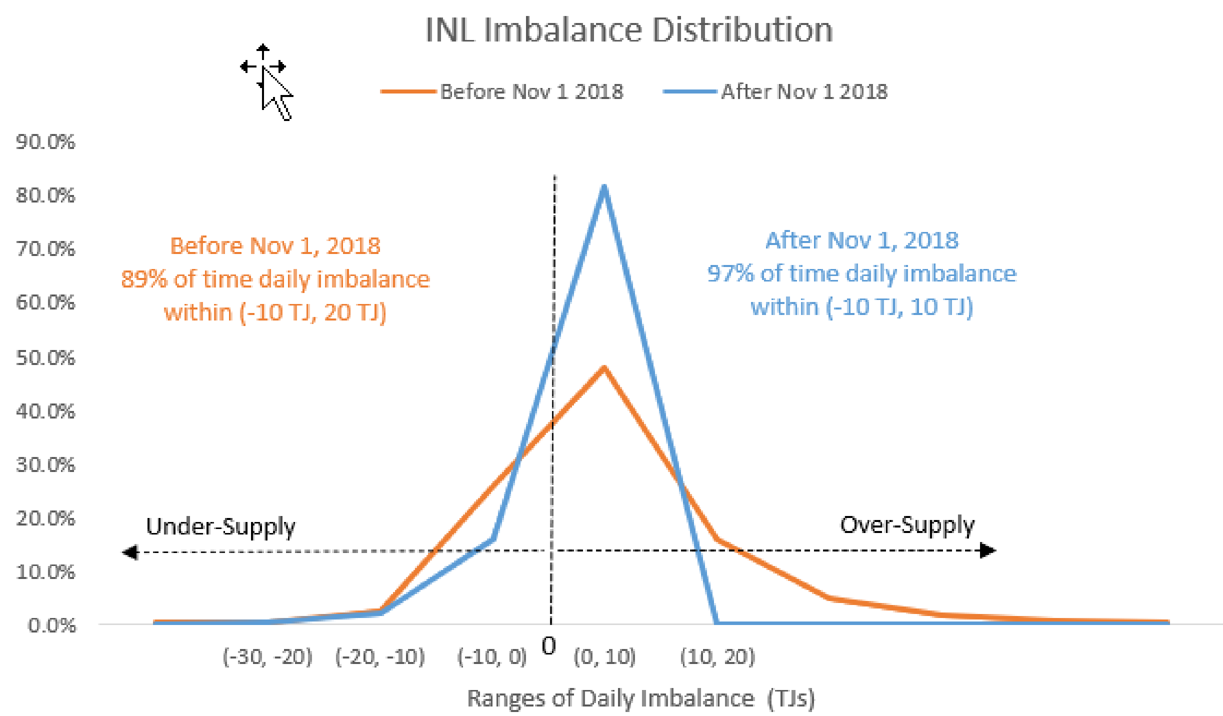
[22] Figures 5-1 and 5-2 shows the balancing performance before and after the New Rules were implemented for customers located in the Lower Mainland and Interior regions respectively. These two regions were isolated as they account for roughly 90% of total transportation demand on FEI's system and largely demonstrate the balancing performance across the system as a whole. For this reason, the Columbia and East Kootenay regions were excluded from this analysis, Analysis which shows total system imbalances including the Columbia and East Kootenay regions is in Section 2.4 of the Atrium Economics Report.

Figure 5-1: Transportation Imbalances in the Lower Mainland



FEI's analysis of system imbalances for customers in the Interior shows similar results. As shown in Figure 5-2, the orange line shows the range of system imbalances for two years prior to the implementation of the New Rules. Prior to implementation of the New Rules, with daily and monthly balancing provisions in place, and a tolerance of 20 percent, 98 percent of the time system imbalances ranged from -10 TJ to +20 TJ. For the three winters following the implementation of the New Rules, where exclusively daily balancing and a reduced tolerance of 10 percent was in effect, 97 percent of the time imbalances tightened slightly to -10 TJ to +10 TJ, which is an insignificant volume for FEI to manage. To put this volume into perspective, 10 TJ is roughly 5 percent of the total system throughput from sales customers in the Interior on an average winter day, which ranges from 150 to 250 TJ. While the change in system imbalances is less significant in the Interior as compared to the Lower Mainland, there has still been an improvement in response to the New Rules.

Figure 5-2: Transportation Imbalances in the Interior



The data in Figures 5-1 and 5-2 and the analysis of the data indicate that the implementation of the New Rules[23] has had a positive impact in decreasing under-supplied volumes since implementation. As such, FEI concludes that the New Rules are providing the appropriate level of incentive for shipper agents to more closely match the supply and demand requirements of their customers, ultimately resulting in less use of FEI's midstream resources to correct for imbalances caused by transportation service customers.

This conclusion is also supported by the independent review as discussed in Section 2 of the Atrium Economics Report. In evaluating the balancing performance both before and after the New Rules were implemented, Atrium Economics found that there was an improvement in the balancing performance of shipper agents.

Conclusion:

Since the implementation of the New Rules, midstream resources have not had to change for the purpose of providing balancing services to the Transportation model. Therefore, FEI has not had to incur any additional fixed (contracted) midstream resources for this purpose. As the data in Figures 5-1 and 5-2 demonstrates, supported by the analysis in Atrium Economics Report, the New Rules have achieved the desired outcome; namely to incent shipper agents to balance and manage their day-to-day business and their customers' daily supply and demand more tightly,

[23] Quantities of gas over the greater of 100 Gigajoules or equal to or in excess of 10 percent or less than 20 percent.

thus requiring less use of FEI's midstream resources to compensate for imbalances caused by transportation service customers. For the foregoing reasons, FEI believes that the New Rules are operating as intended and no further changes are required to the tariffs or business rules for the Transportation Service Model at this time.

5.2 *EFFECTIVENESS OF IMBALANCE RETURN*

BCUC Directive 2: **Effectiveness of Imbalance return to incent Shippers to manage system inventory, including discussion for modifications to the allocation in response to changes in demand for imbalance return after the balancing rules were implemented.**

Background:

Imbalance return is an interruptible service operating under FEI's business rules enabled in the transportation rate schedules.[24] The imbalance return service facilitates shipper agents' ability to have access to an allocated quantity of gas for the purposes of balancing their customers' demand with the supply they deliver to FEI's system daily within the balancing tolerances to avoid additional charges. Basically, the amount of imbalance return allocated to each shipper agent allows that shipper agent to use their banked supply as a buffer to draw on (or draft against) as a source of supply to match supply and demand for their customers daily in accordance with balancing rules. Shipper agents also have access to their own banked inventory of gas on the system which occurs if they oversupply (deliver more gas to FEI's system than their customers demanded) on a given day.

Imbalance return is an interruptible service on FEI's system and is a source of supply to assist shipper agents in balancing their customers' demand and supply requirements within the balancing tolerances under the New Rules. Imbalance return is an interruptible service because, if operational requirements necessitate, such as when colder weather occurs or during a supply restriction, FEI may need to reduce or eliminate access to imbalance return. In addition to balancing FEI's system overall on a daily basis, FEI's midstream group is also responsible for managing inventory levels for the imbalance return service, determining whether and when restrictions or interruption of the service is necessary, and identifying the amount of imbalance return available to each shipper agent. FEI notes that when restrictions or interruption of the imbalance return service are in place, shipper agents are required to deliver physical supply to FEI's system to meet their customer demand while adhering to the balancing tolerance in place at that time.

When it is necessary for FEI to restrict or interrupt access to imbalance return, shipper agents are incented to direct supply deliveries to interconnection points which discourages or prevents the use of drafting to match supply and demand for their customers on FEI's system. The imbalance

[24] RS 25, Section 8.4 (Adjustments to Inventory).

return service was analyzed in the Atrium Economics Report in Sections 2.2 and 2.3. In Section 2.2, Atrium Economics evaluates how volumes from imbalance return directly assist shipper agents in managing within the 10 percent to 20 percent tolerance. Section 2.3 of the Atrium Economics Report discusses the direct benefit of the imbalance return service in reducing the amount of balancing service charges incurred by shipper agents.

Typically, under normal operating conditions, the following volumes of imbalance return are available to shipper agents and transportation service customers on a daily basis:

a. Lower Mainland region: 20,000 GJ
b. Interior region: 40,000 GJ
c. Columbia region[25]: 10,000 GJ

The method FEI uses for allocating imbalance return volumes by region is handled through operational business rules which were reviewed with shipper agents in late 2018 and, based on their feedback, were revised and implemented effective November 1, 2018 (coincident with the implementation of the New Rules). The calculation which forms the basis of the allocation of available imbalance return volumes within each region for each shipper agent is based on each shipper agent's previous 30 day average demand. The allocation is revised and reset at the beginning of each month and applies for the duration of that month. FEI provides an example of how the allocation of available imbalance return gas volumes is calculated for shipper agents in the Interior region in Table 5-1 below. As noted above, the Interior region is allocated a total of 40,000 GJ of imbalance return gas monthly.

Table 5-1: Imbalance Return Calculation Example

Service Area: Interior	Average 30 Day Demand	Percentage Allocation	Allocated Amount
Shipper Agent A	15,000	29%	11,600
Shipper Abent B	7,500	14%	5,600
Shipper Agent C	2,000	4%	1,600
Shipper Abent D	1,500	3%	1,200
Shipper Agent E	6,000	12%	4,800
Shipper Abent F	8,000	15%	6,000
Shipper Abent G	12,000	23%	9,200
	52,000		**40,000**

In the example in Table 5-1 above, Shipper Agent A has a previous average 30-day demand volume of 15,000 GJ and, relative to the total average 30 day demand of 52,000 GJ, Shipper Agent A has an allocation of 29 percent. As a total of 40,000 GJ is available for the Interior region, Shipper Agent A is entitled to 29 percent of that 40,000 GJ, which equals 11,600 GJ. The same calculation applies to all other shipper agents in the Interior region.

[25] Includes East Kootenay region.

Table 5-2 shows the number of days by region that FEI has either reduced imbalance return, or eliminated the service for operational reasons from 2010 to May 2022. When imbalance return is reduced, it means only a portion of the amount authorized under normal operating conditions is available. While there is an increase in the number of days in 2018 and 2019 due to the Enbridge Incident, FEI's reductions of this service have remained consistent over time, and reductions in the 2020 and 2021 years are slightly less in comparison to the years prior to the implementation of the New Rules. As the data shows, this service is available to shipper agents largely throughout the year; the number of days that FEI reduced or eliminated this service in the 2020 and 2021 years is only 2 percent and 8 percent of the time respectively.

Table 5-2: Days of Elimination and Reduction of Imbalance Return From 2010 to May 2022

	Lower Mainland			Interior			Columbia & East Kootenay		
YEAR	Eliminated	Reduced	Total	Eliminated	Reduced	Total	Eliminated	Reduced	Total
2010	20	2	**22**	20	2	**22**			
2011	19	7	**26**	19	7	**26**			
2012	16		**16**	16		**16**			
2013	15	18	**33**	15	18	**33**			
2014	27	12	**39**	27	12	**39**			
2015	27		**27**	17		**17**			
2016	32	17	**49**	32	17	**49**			
2017	32	12	**44**	32	12	**44**			
2018	60	10	**70**	60	4	**64**			
2019	29	6	**35**	27	2	**29**			
2020	5	1	**6**	5	1	**6**	5	1	**6**
2021	28		**28**	22		**22**	22		**22**
2022		10	**10**		10	**10**		10	**10**
Grand Total	**310**	**95**	**405**	**292**	**85**	**377**	**27**	**11**	**38**

The general feedback from the individual conference calls with shipper agents in preparation for this Report indicates that the revised allocations implemented November 1, 2018 are working well for each region. Shipper agents indicated that the imbalance return allocations provide certainty, are done in a fair and equitable manner, and allow shipper agents to better plan their supply requirements for their customers with the assurance of allocated quantities throughout the month. Shipper agents have expressed to FEI that imbalance return is a valuable balancing resource and an essential part of managing the supply requirements of their customers. Additionally, shipper agents have expressed that when imbalance return service is reduced or eliminated, it is more difficult for them to balance within the 10 percent balancing threshold. Shipper agents asked for additional flexibility of this business practice, including allowing imbalance return during periods of restrictions (such as under Hold to Authorize (HTA) conditions), release of greater volumes, and a reallocation when more volumes are available.

In the individual conference calls with shipper agents, FEI received the following requests for amendments to the existing allocation:

1. Release a larger total volume of imbalance return as a whole (Request 1, Table 4-2);

2. Mechanism to allow greater imbalance return volumes to specific shipper agents by request (Request 2, Table 4-2);
3. Reallocation of available volumes to other interested shipper agents (Request 3, Table 4-2);
4. Minimum allocation of imbalance return to shipper agent groups with smaller demand (Request 4, Table 4-2);
5. Modify the allocation methodology to incorporate for volatility and/or load factor (Request 5, Table 4-2); and.
6. Make imbalance return available during HTA and/or supply restriction periods (Request 6, Table 4-2).

Discussion:

1. REQUEST 1: RELEASE A LARGER TOTAL VOLUME OF IMBALANCE RETURN AS A WHOLE

FEI considers that the current volume of imbalance return allocated by region is reasonable as it is based on the total volume under which FEI can efficiently manage, operate and balance the system daily. The total volume of imbalance return represents approximately 20 percent, 45 percent and 40 percent of the average daily winter transportation service load in the Lower Mainland, Interior and Columbia regions respectively.[26] Given that the total amounts of imbalance return allocated by region are rarely fully utilized or relied upon by shipper agents on a daily basis, the current volume of imbalance return allocated by region appears to be sufficient. FEI recognizes that having access to their allocated banked supply through the imbalance return service is a valuable tool for shipper agents to assist them in meeting their daily load and balancing requirements. FEI also recognizes that access to additional volumes of imbalance return would make daily balancing easier for shipper agents. However, because FEI manages the needs of the system as a whole, it requires the operational flexibility to restrict or interrupt the imbalance return service when conditions necessitate (typically during colder weather or supply restrictions/disruptions, i.e. the Enbridge Incident), FEI does not recommend increasing the volumes available under the interruptible imbalance return service. Additionally, FEI wants to avoid the potential for shipper agents to increasingly rely on this interruptible imbalance return service as a source of supply for balancing purposes. Therefore, FEI concludes that the volume of imbalance return by region available to shipper agents remains reasonable to assist in managing their customer demand and, to support FEI's operational flexibility requirements, should not be increased.

[26] Average daily demand over the 2020/21 winter was approximately 95 TJ in the Lower Mainland region (includes demand from the Island Cogen and JV). Available IR is 20 TJ, which represents 20% of daily demand. Average daily demand over the 2020/21 winter was approximately 90 TJ in the Interior. Available IR is 40 TJ which represents nearly 45% to daily demand. Average daily demand over the 2020/21 winter was approximately 25 TJ in the Columbia region (including East Kootenay). Available IR Is 10 TJ which represents 40% of the daily demand.

2. REQUEST 2: MECHANISM TO ALLOW GREATER IMBALANCE RETURN VOLUMES TO SPECIFIC SHIPPER AGENTS BY REQUEST

FEI believes allowing greater volumes of imbalance return to specific shipper agents by request would present challenges from a fairness and equitable perspective. The current allocation in which shipper agents receive a portion of the volume available based on their percentage of historical demand at a given location is fair and reasonable. The current allocation methodology for the imbalance return service was implemented in November of 2018 after FEI held a workshop with shipper agents (in September 2018) to discuss changes. At that time, shipper agents agreed that the revised allocation methodology based on historical demand was reasonable. Amending the allocation methodology to accommodate this request would require modifications to the WINS system with resulting time and costs for development of such a change. FEI believes no changes are required because the current allocation methodology remains fair and equitable to all shipper agents given it is based on the historical volume requirements of each shipper agent and was derived through a collaborative process with shipper agents.

3. REQUEST 3: REALLOCATION OF AVAILABLE VOLUMES TO OTHER INTERESTED SHIPPER AGENTS

Currently, if a shipper agent does not use their full imbalance return allocation, the unused volume is not reallocated to another shipper agent. Imbalance return is allocated fairly based on a shipper agent's percentage of demand, as discussed in Section 5.2, and each shipper agent has the option to choose whether, when and how much of their allocation to use. A reallocation of available volumes under the imbalance return service could cause shipper agents to increasingly rely on this interruptible imbalance return service as a source of supply for balancing purposes, which is not a desired outcome. In addition, developing the tools to manage such reallocations would require a substantial system change to the WINS system. Consequently, FEI believes the current allocation methodology is working well and the costs associated with system changes for WINS to enable the reallocation of volumes is not warranted or necessary at this time.

4. REQUEST 4: MINIMUM ALLOCATION OF IMBALANCE RETURN TO SHIPPER AGENT GROUPS WITH SMALLER DEMAND

This request is from shipper agents representing smaller customer groups with smaller demand, specifically in the Columbia region where in some cases the number of customers grouped at one location is less than ten and under 50 GJ per day. Based on the current allocation methodology, if the aggregate customer demand is small, then the amount of imbalance return allocated is also small. Conversely, if the shipper agent's customer group demand is large, the volume of imbalance return allocated is also large. Shipper agents with smaller customer groups have expressed that the smaller allocation of imbalance return causes them to be at an increased risk of incurring balancing charges. After reviewing this request and based on the minimal system changes required to implement this request, FEI believes it is fair, reasonable and feasible to implement this change by allocating a baseline volume of imbalance return to groups under a minimum volume of average daily demand. During the discussions with shipper agents, a minimum allocation of 100 GJ per day was suggested. FEI agrees this amount is reasonable and will amend the allocation to provide a minimum volume to shipper agents with smaller groups first, them the remaining volume would be allocated using the existing methodology to the remaining shipper agents. Over the next three months FEI will make the necessary system changes and update its operational business rules and practices to enable a minimum allocation and implement this change in the fall of 2022.

5. REQUEST 5: MODIFY THE ALLOCATION METHODOLOGY TO ACCOUNT FOR VOLATILITY AND/OR LOAD FACTOR

As discussed in Section 5.2, the current allocation methodology for calculating imbalance return is based on actual historical daily demand. If a shipper agent's historical daily customer demand is high or low, these characteristics are currently captured in the allocation of imbalance return[27].

With respect to amending the methodology to account for volatility (defined as load factor), FEI believes that shipper agents are in the best position to understand their customers' demand patterns and characteristics and should manage load swings through their own business practices, such as by securing additional supply or other resources. FEI believes that shipper agents operating within the Transportation Service Model should account for all aspects of their customers' load profile and demand characteristics, including demand swings and volatility. Amending the allocation methodology for imbalance return to account for volatility would require an investment of resources and costs and may result in a less equitable allocation of imbalance return among shipper agents. FEI believes the current allocation methodology is fair and reasonable and that the onus is on shipper agents to account for load volatility factors for their customers.

6. REQUEST 6: MAKE IMBALANCE RETURN AVAILABLE DURING HOLD TO AUTHORIZED (HTA) AND/OR SUPPLY RESTRICTION PERIODS

Historically, the interruptible imbalance return service is available for over 95 percent of the year. The times when imbalance return service is restricted or interrupted occurs due to major weather events or supply disruptions and constraints (e.g. the Enbridge Incident), FEI carefully considers limiting operational services such as imbalance return and or issuing HTA restrictions. Feedback from some shipper agents suggests they were concerned that the factors FEI takes into consideration when issuing a restriction or HTA have changed. FEI confirms that the factors FEI takes into consideration when determining whether a supply restriction is required have remained the same since the inception of the Transportation Service Model. As discussed throughout the individual shipper agent conference calls, HTA situations are variable and dependent upon a number of supply and capacity conditions including, but not limited to:

---

27 Customers with more volatile load profiles (which is also referred to as having a high load factor) are typically process driven and may consume multiple fuels which as a result can result in more unpredictable and larger volume swings in demand based on a customer's operational decisions or process upsets rather than customers with more steady heat sensitive loads.

- Upstream / downstream planned or unplanned pipeline supply curtailments and capacity constraints;
- Downstream planned or unplanned regional storage facility outages;
- Actual or forecasted extreme cold weather conditions by region;
- Duration of actual or forecasted extreme cold weather conditions by region;
- Health and inventory level of regional storage facilities; and
- The time of year (i.e., winter) can be a factor and extenuating circumstance for any of the above.

When FEI deems it necessary to issue a restriction such as HTA, shipper agents are held to a tighter balancing tolerance of 5 percent as opposed to the 10 percent under normal circumstances. By holding shipper agents and their transportation service customers to a 5 percent tolerance, shipper agents are required to bring on sufficient supply to meet their demand, and to balance independently or incur balancing charges. When HTA restrictions are in place, the imbalance return service is not available. This is the case because FEI requires operational flexibility to manage the daily balancing of the system given the circumstances that prompted the need for the restriction. During a restricted period, the transportation service charges become applicable to encourage shipper agents to match supply to meet their customers' demand. If FEI were to allow drafting at critical times, such as sustained cold weather or pipeline interruptions, FEI would need to acquire, and core customers would be paying for, additional incremental midstream resources to compensate for the imbalance. In the past, under supply and capacity constrained circumstances in which FEI issued a HTA for longer than normal periods (such as the Enbridge Incident and the reduced WEI capacity due the flooding in November 2021) FEI has, when operationally feasible,[28] provided some relief to shipper agents by allowing access to the imbalance return service. While historically it has not been common practice to release imbalance return during a restricted period, FEI will continue to closely monitor the system during restricted periods on a case-by-case basis to determine if, when, and to what degree it may be able release imbalance return in consideration of the circumstances at the time.

Conclusion:

FEI believes that the imbalance return service is working well as designed and remains fair and equitable because, since the implementation of the New Rules, inventory on FEI's system is being maintained at reasonable levels. In addition, as shown in Table 5-4 and 5-5, the charges incurred by shipper agents when they have been unable to balance under the New Rules have not been significant. Further, the findings in the Atrium Economics Report which demonstrate both an improvement in inventory levels and low charges incurred since the New Rules were implements support these conclusions. However, FEI believes that it is reasonable to proceed with Request

[28] Following the Enbridge incident where FEI imposed numerous days of HTA restrictions, as well as the flooding event in November 2021, FEI monitored daily capacity fluctuations and when there were periods of stabilization of the health of the pipe, FEI was able to provide some relief and allow access to imbalance return.

4, to enable a minimum allocation of imbalance return to groups with smaller demand, and plans to implement this change in the fall of 2022.

The methodology for the current allocation of imbalance return was discussed and agreed upon by shipper agents in the fall of 2018. Through stakeholder engagement in the development of this Report, FEI heard additional requests to further amend the allocation of imbalance return including: 1) for FEI to release greater volumes; 2) allow greater volumes to specific shipper agents; 3) a reallocation of unutilized volumes to other shipper agents; 4) minimum allocation to groups with smaller demand; 5) modify the allocation methodology to account for a volatility (load factor); and 6) allow the service be available during HTA periods, In summary, while the imbalance return service is available to shipper agents largely throughout the year as shown in Table 5-2, it is rarely fully utilized. The time, expense, and resources involved to modify this service based on the requests outweigh the potential benefits. However, as discussed above, FEI has committed to implementing the request (Request 4) to provide a minimum allocation of imbalance return to groups with smaller demand as FEI views this change as fair and reasonable, will incur minimal costs and is easy to implement from system perspective.

5.3 *FURTHER INCREASE TO UNDER-SUPPLY TOLERANCE*

BCUC Directive 3: Whether there should be further tightening of tolerances for under-supply.

Background:

In the 2016 RDA Decision, the BCUC approved the New Rules because they were found to be just, reasonable and not unduly discriminatory, consistent with rate design principles of a fair apportionment of costs among customers, and provide price signals that encourage efficient use of resources.[29] Further, the 2016 RDA Decision recognized that imbalances caused by transportation service customers were being managed by FEI using mid-stream resources that are paid for by sales customers and a greater incentive for transportation customers and their shipper agents to balance within the 10 percent range.[30] The BCUC also found that the 10 percent tolerance level was more in line with industry standards, albeit at the low end compared to other jurisdictions.[31] For the purposes of the preparation of this Report, Atrium Economics has updated its industry research (filed in Appendix 10-1 to the 2016 RDA Application), which is discussed in Section 3 of the Atrium Economics Report confirming that industry thresholds continue to range from zero percent to 15 percent, with 5 percent remaining the most common threshold

FEI's 10 percent tolerance, which applies to all transportation service customers equally, is based on both physical supply plus the quantity of imbalance return allocated to each shipper agent, as discussed in Section 5.2. Therefore, shipper agents who have higher volume requirements or

[29] 2016 RDA Decision, p. 67.
[30] Ibid.
[31] 2016 RDA Decision, pp. 67-68.

customer demand are allocated a greater volume of imbalance return within which to assist them to manage adherence to the 10 percent tolerance. The 10 percent tolerance applies all year, with the exception of HTA periods where the tolerance is reduced to 5 percent.[32] When the 10 percent tolerance is in effect, there are no charges for under-supply imbalances up to the 10 percent threshold; therefore, customers do not pay for balancing within a 10 percent tolerance. As approved under the New Rules, for imbalances within the 10 percent to 20 percent range, a balancing charge of $0.25/GJ is applied. The $0.25/GJ charge reflects (among other things), variable charges of moving gas out of storage facilities to cover the imbalance. For clarity, the New Rules did not change the charges applicable for imbalances beyond the 20 percent tolerance level, for which the balancing charge is $1.10/GJ in winter and $0.30/GJ in summer for gas supply shortfalls.

In the discussions with shipper agents regarding a further tightening of the tolerance for under-supply, no shipper agents were in favour of tightening tolerances further and many expressed they were also not in favour of the 10 percent tolerance approved by the New Rules. Shipper agents expressed a range of feedback with respect to their ability to manage their demand and supply balances under the 10 percent tolerance, especially under cold weather or customer volatility conditions. Consequently, shipper agents made the following two requests.

1. Return to the 20% tolerance (Request 7, Table 4-2); and
2. FEI to offer a different percentage of balancing tolerance by season or during specific times of the year, (i.e. shoulder months) when operational conditions allow (Request 8, Table 4-2).

Discussion:

1. REQUEST 7: RETURN TO THE 20% TOLERANCE.

During the stakeholder individual discussions, some shipper agents requested a return to the 20 percent tolerance which was in effect before the New Rules were implemented. As discussed above, the change to a 10 percent tolerance was approved along with the associated incremental charge for balancing within a 10 percent to 20 percent range as a fair allocation of costs. These New Rules provide an incentive for transportation customers and shipper agents to balance and, when failing to do so, the incremental charges compensate sales customers for the use of midstream resources to move gas in and out of storage facilities.

Based on the minimal level of balancing charges incurred for being outside the threshold as shown in Table 5-4 and 5-5, it is clear that shipper agents have demonstrated they are able to operate under the tighter balancing tolerance. Shipper agents have not presented any information or evidence to the contrary. Rather, the data presented in Figures 5-1 and 5-2 demonstrate that

[32] Pursuant to the Tariff, when supply restrictions are in place, shipper agents much manage within a 5% tolerance or else Unauthorized Over-Run charges apply.

shipper agents have performed with diligence in managing supply to meet demand under the New Rules while incurring minimal balancing charges. Additionally, in Section 3 of the Atrium Economics Report, an update Atrium's review of industry balancing rules and services continues to show that a tighter balancing threshold of 5 percent is most common in the industry.

As such, FEI is not recommending changes to the balancing tolerances implemented with the New Rules because they are working as intended by providing appropriate price signals which are incenting shipper agents to balance their supply and demand daily with minimal balancing charges.

2. <u>REQUEST 8: FEI TO OFFER A DIFFERENT PERCENTAGE OF BALANCING TOLERANCE BY SEASON OR DURING SPECIFIC TIMES OF THE YEAR, (I.E. SHOULDER MONTHS) WHEN OPERATIONAL CONDITIONS ALLOW.</u>

Shipper agents have requested a seasonal balancing tolerance or varied tolerances during specific times of the year when operational conditions allow. Neither FEI nor Atrium Economics is aware of other utilities or pipelines providing seasonal balancing tolerances. As discussed previously in this Report, the balancing provisions in place today incent shipper agents to balance more closely and match supply with customer demand, which is their responsibility as a shipper agent. FEI balances the system as a whole on a daily basis and adheres to tight tolerances with its upstream pipelines, such as 5 percent at Station 2 and plus/minus 2 percent at Nova/NGTL at all times of the year. Given that seasonal balancing is not industry standard and that extreme weather events or other supply and capacity situations can occur at any time of the year, FEI believes that implementing different balancing rules by season or specific times of the year would not be reasonable or practical, and would likely be cost prohibitive when considering the complexities to investigate, implement and operate the system under varying balancing rules.

<u>Conclusion:</u>

There was no evidence to suggest that a return to the 20 percent tolerance is reasonable or necessary. Nor is there evidence to support the design and implementation of variable or seasonal tolerances. Given shipper agents have demonstrated they are managing their supply and demand obligations consistently throughout the year to serve their customers under the 10 percent tolerance and have incurred a low level of balancing charges, FEI believes that the New Rules are reasonable, working as intended, and additional changes are not warranted.

5.4 *IMPLEMENTING AN OVER-SUPPLY TOLERANCE*

BCUC Directive 4: Whether it is necessary to implement tolerances and associated charges for over-supply.

Background:

FEI's balancing threshold of 10 percent applies when shipper agents do not deliver (supply) enough gas to the FEI's system at the interconnection point to meet demand from their customers (i.e., when supply is less than demand). This BCUC Directive asked FEI to consider whether implementation of a tolerance and associated charges for over-supply was necessary. Over-supply is when shipper agents deliver more gas than is required to FEI's system at the interconnection point to meet demand from their customers (i.e., when supply is greater than demand) resulting in excess supply left on FEI's system. During the 2016 Rate Design, FEI raised this issue and demonstrated that historically some shipper agents have over-supplied large volumes of gas to the interconnection point far in excess of the demand from their customers.

The feedback from shipper agents on the question of a threshold and associated charges for over-supplying FEI's system is that they do not wish to have such thresholds or charges implemented. Many shipper agents expressed concern that such tolerances would be too onerous to manage under, especially those with customers who have volatile load profiles. Some shipper agents indicated that the financial cost to buy the gas creates enough of a monetary incentive for shipper agents to not over-supply. Shipper agents encouraged FEI to use the currently approved terms in the tariff rate schedules to discourage or prevent over-supply. During the individual shipper agent calls, some shipper agents requested that:

1. FEI could withhold inventory/pack for specific shipper agents that are consistently over-delivering as opposed to restricting the service for all shipper agents (Request 3, Table 4-2); and

2. FEI to apply penalties and tariff to specific shipper agents (Request 21, Table 4-2).

Discussion:

FEI will discuss both of these requests together as they are similar in nature.

In cases where over-supply situations occur caused by shipper agents who consistently pack FEI's system, Section 7.2 (Adjustment of Requested Quantity) and Section 8.4 (Adjustments to Inventory) in the transportation rate schedules allows FEI to adjust the shippers nomination and inventory as follows:

> 7.2 Adjustment of Requested Quantity
>
> The Shipper or Shipper Agent will provide notice to FortisBC Energy on the WINS, or other method approved by FortisBC Energy, of adjustments to the Requested Quantity for the Day commencing in approximately 24 hours. Adjustments to the Requested Quantity must adhere to the elapsed pro-rata practices of the applicable Transporter(s). FortisBC Energy may adjust, in consultation with the Shipper, the Shipper's Requested Quantity, described in Section 7.1 (Requested

> Quantity), when in the reasonable opinion of FortisBC Energy such modification is required in order to limit the build-up of inventory account quantities.
>
> …
>
> 8.4 Adjustments to Inventory
>
> When on any Day the Shipper delivers more Gas to the Interconnection Point than its actual consumption, except for Gas purchased by FortisBC Energy under Section 21.8 (Shipper's Gas), FortisBC Energy will maintain an inventory account for the Shipper and will increase the balance in the account by the excess amount received. FortisBC Energy reserves the right to limit Gas quantities maintained in the Shipper's inventory account and will from time to time, at its discretion and in consultation with the Shipper, return excess inventory at no charge to the Shipper; this will not relieve the Shipper from its obligation to provide accurate nominations pursuant to Section 7.1 (Requested Quantity).

Section 7.2 allows FEI to adjust the shipper agent's Requested Quantity, which means that FEI has the ability to change their nomination in WINS. If a shipper agent is deliberately packing the system, FEI can amend the nomination to limit the supply delivered to FEI's system in order to limit the build-up of inventory.

Section 8.4 allows FEI the ability to remove the excess inventory from a shipper agent's account and return it to the shipper agent at a later date. This is a tool that FEI could use to manage shipper agents who are not cooperative in maintaining reasonable levels of inventory on FEI's system. This tool enables FEI to exercise action to remove a single shipper's inventory without affecting the entire shipper agent group as a whole. Generally, since implementation of the New Rules, FEI has not found shipper agent inventory levels to be excessive and shipper agents have been working cooperatively with FEI to manage their inventory levels within the 2-3 day range as requested by FEI. FEI's findings are supported in Figure 10 of Section 2.4 of the Atrium Economics Report which assesses system inventories both before and after the New Rules were implemented and finds that system imbalances had improved under the New Rules.

Conclusion:

Since implementation of the New Rules, shipper agent inventory levels are being maintained more consistently at reasonable levels. Consequently, inventory levels on FEI's system as a whole have improved since the New Rules were implemented[33]. FEI continues to actively monitor system imbalances for each shipper agent to ensure levels of inventory are within the 2-3 day acceptable range. Even in the 2018 and 2019 years that were impacted by the Enbridge incident, overall system inventory levels have been reasonable. While the tariff allows FEI to adjust a shipper's nomination and inventory (a paper rather than a physical transaction) and given that under-supply is not currently problematic, FEI does not believe that a tolerance for over-supply is

[33] Atrium Economics Report, Section 2.4.

necessary at this time. FEI will continue to monitor inventory levels should circumstances suggest that consideration of tolerances and associated charges for over-supply may be needed in future.

5.5 BALANCING CHARGES - COST RECOVERY AND INCENTIVE

BCUC Directive 5: Whether the balancing charges appropriately recover the costs of providing balancing to transportation service customers and provide sufficient incentive to transportation service customers to balance their supply and demand.

Background:

The balancing charge of $0.25 per GJ for balancing within the 10 to 20 percent range was implemented in the New Rules. When approving the balancing charge in the 2016 RDA Decision, the Panel found that the $0.25 per GJ charge applicable for daily under-deliveries in the 10 to 20 percent tolerance range was just, reasonable and not unduly discriminatory given the methodology for determining the charge is reflective of the potential variable cost to the core of supplying this gas.[34] The revenue from the balancing charges is a credit to the midstream portfolio and reasonably compensate sales customers who pay for the midstream resources used to balance the system.

Discussion:

This BCUC Directive has two aspects to consider. First, does the balancing charge at its current level of $0.25 per GJ continue to appropriately recover the costs of providing balancing to transportation service customers. Second, does the charge provide sufficient incentive for transportation service customers (or their shipper agents) to balance their supply and demand.

First, with respect to the level of the balancing charge, FEI has performed the same cost-based calculation as was performed for the 2016 RDA Application, but with updated inputs of the incremental variable costs based on the actual commodity price. Table 5-3 shows the analysis of the variable cost analysis for system balancing during the winter periods from 2018/19 to 2021/22. The variable costs including NWP commodity charges and fuel costs are based on Sumas prices multiplied by the actual fuel factors to move gas in and out of FEI's market area storage.
Based on the actual commodity price over this time, and the increased costs resulting from the Enbridge incident, the analysis shows that, on average, the incremental variable charge of $0.25 is within range and remains reasonable and appropriately recovers the costs of providing balancing within the 10 percent to 20 percent range.

[34] 2016 RDA Decision, p. 69.

Table 5-3: Incremental Variable Costs for System Balancing

	Sumas Price (CAD$/GJ)	NWP Commodity Charge	NWP Fuel	Storage Fuel	Incremental Variable Costs (CAD$/GJ)
2018/19	$15.05	$0.01	$0.42	$0.20	**$0.63**
2019/20	$3.25	$0.01	$0.07	$0.04	**$0.12**
2020/21	$4.11	$0.01	$0.07	$0.06	**$0.14**
2021/22	$5.76	$0.01	$0.10	$0.08	**$0.19**
Winter Average (CAD$/GJ)					**$0.27**

FEI will monitor midstream costs and periodically perform the cost-based calculation and, if necessary, bring forward a request for a revised charge in a future process.

Second, with respect to the incremental charge providing sufficient incentive to shipper agents to balance their supply and demand, FEI heard from shipper agents in the individual conference calls in spring 2021 that the charge factored into their daily operational decisions. In addition, FEI confirms that some shipper agents have been proactively contacting its Midstream Department to purchase incremental supply to balance their account to avoid incurring balancing charges. Further, with the low volume of incremental balancing charges within the 10 percent to 20 percent range, as discussed further below, it is evident that the charge and the level of the charge is having the intended effect of providing an appropriate incentive for shipper agents to better manage their supply and demand balance.

Table 5-4 below reflects the volume of all of the related transportation service charges (including the balancing service in the 10 percent to 20 percent range) in GJs and Table 5-5 below reflects the dollars collected for those charges incurred by shipper agents. Both Tables are summarized by calendar year from 2012 to March 2022. FEI notes that there are other transportation service charges which were either no longer applicable after implementation of the New Rules or were not impacted by the New Rules. For context in relation to Tables 5-4 and 5-5, the following describes each transportation service charge and its purpose.

- **Backstopping**: Gas made available by FEI as an interruptible backup supply if on any day the authorized quantity is less than the requested or nominated quantity. Backstopping is charged at the Sumas Gas Daily Midpoint price.
- **Monthly Balancing Gas:**[35] Any gas taken at the end of the month which is in excess of the total of the authorized quantity for the month. Monthly Balancing gas is charged at the average of the Sumas Gas Daily Midpoint price throughout the month.
- **Daily Balancing Gas:** Any gas taken during a Day in excess of the authorized quantity. Balancing gas daily is charged at the Sumas Gas Daily Midpoint price.

[35] As monthly balancing provisions were eliminated from the RDA Decision, Monthly Balancing gas charges no longer apply.

- **Balancing Service:** A charge per Gigajoule is provided for under-deliveries beyond the 20% balancing threshold. Charges are $1.10/GJ in winter months November to March and $0.30/GJ for summer months April to October.
- **Balancing Service 10%-20%:** As approved under the New Rules, this is a charge per Gigajoule for under-deliveries within the 10% to 20% balancing threshold. This is an annual charge at $0.25/GJ.
- **Replacement Gas:** Gas provided to a Shipper by FEI in the event the Shipper fails to return the Peaking Gas Quantity. Replacement gas is charged at the Sumas Daily Midpoint price plus 20%.
- **Unauthorized Overrun – under 5%:** Gas taken on any day in excess of the curtailed amount for under-deliveries between 0 and 5%. This charge applies during a Hold to Authorize or Supply restriction and is charged at the Sumas Gas Daily Midpoint price.
- **Unauthorized Overrun – over 5%:** Gas taken on any day in excess of the curtailed amount for under-deliveries over 5%. This charge applies during a Hold to Authorize or Supply restriction and is charged at the greater of Sumas Gas Daily Midpoint price times 1.5 or $20CAD.

Table 5-4: Transportation Service Balancing Charges Volume 2012 to March 31, 2022 (GJ)[36]

Charges	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Backstopping	104,213.0	260,112.0	134,613.0	288,418.0	78,842.0	64,770.0	19,971.0	3,227.0	3,340.0		
Monthly Balancing Gas	452,603.4	403,726.0	258,704.3	164,824.7	125,922.9	191,272.9	72,642.2	2,992.4			
Daily Balancing Gas	61,001.6	133,962.0	90,072.7	60,502.2	60,894.2	41,163.1	37,355.0	327,221.9	77,303.6	43,694.7	1,795.4
Balancing Service	87,457.5	110,989.4	85,304.5	31,274.9	76,409.8	23,450.7	47,465.6	469,373.4	207,256.9	253,544.2	55,883.1
Balancing Service 10% - 20%							10,098.4	256,547.7	119,306.4	94,953.6	33,796.2
Replacement Gas							12.1				
Unauthorized Overrun - Under 5%	2,802.8	800.4	19,591.5		5,790.9	6,738.7	17,145.2	9,756.6	5,334.7	871.2	
Unauthorized Overrun - Over 5%	3,063.8	968.4	20,629.0	12.6	499.9	4,407.0	2,916.4	555.2	409.2	986.2	
Grand Total	**711,142.10**	**910,558.20**	**608,915.00**	**545,032.40**	**348,359.70**	**331,802.40**	**207,605.90**	**1,069,674.16**	**412,950.83**	**394,049.90**	**91,474.70**

Table 5-5: Transportation Service Balancing Charges 2012 to March 31, 2022 (CAD$)

Charges	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Backstopping	$ 264,415.30	$ 1,329,350.73	$ 568,999.59	$ 827,168.84	$ 201,743.97	$ 200,050.35	$ 60,602.36	$ 16,709.95	$ 13,059.64		
Monthly Balancing Gas	$ 1,064,684.11	$ 1,531,926.09	$ 1,111,413.95	$ 473,199.56	$ 407,534.48	$ 609,658.99	$ 187,158.58	$ 8,323.21			
Daily Balancing Gas	$ 140,387.14	$ 465,469.74	$ 372,525.25	$ 165,960.23	$ 136,109.28	$ 133,474.86	$ 121,691.71	$ 1,648,243.19	$ 241,061.13	$ 256,874.00	$ 8,452.74
Balancing Service	$ 49,211.03	$ 73,772.02	$ 76,963.19	$ 18,428.39	$ 76,740.06	$ 23,665.29	$ 37,901.68	$ 370,049.77	$ 121,822.27	$ 121,372.98	$ 61,471.41
Balancing Service 10% - 20%							$ 2,524.64	$ 64,081.21	$ 29,826.44	$ 23,730.29	$ 8,449.12
Replacement Gas							$ 32.51				
Unauthorized Overrun - Under 5%	$ 8,464.58	$ 6,892.09	$ 166,639.45		$ 31,509.69	$ 25,973.17	$ 226,118.76	$ 260,365.46	$ 18,754.13	$ 5,993.34	
Unauthorized Overrun - Over 5%	$ 61,276.00	$ 19,368.00	$ 419,268.33	$ 252.00	$ 9,998.00	$ 88,140.00	$ 59,812.79	$ 17,572.88	$ 8,184.00	$ 19,762.02	
Grand Total	**$ 1,588,438.16**	**$ 3,426,778.67**	**$ 2,715,809.76**	**$ 1,485,009.02**	**$ 863,635.48**	**$ 1,080,962.66**	**$ 695,843.03**	**$ 2,385,345.67**	**$ 432,707.61**	**$ 427,732.63**	**$ 78,373.27**

36 FEI did not propose and there were no changes to the charges for Backstopping Gas, Unauthorized Overrun Gas, and Replacement Gas approved in the New Rules.

The incremental charge of $0.25 cents for balancing within the 10 percent to 20 percent range introduced by the New Rules in November 1, 2018 is highlighted in orange in Tables 5-4 and 5-5. The data shows that, with the exception of the number of months impacted from October 2018 to 2019 due to the Enbridge Incident,[37] the total volume of charges incurred including the incremental charge for balancing within the 10 percent to 20 percent range is not significantly higher than previous years, and is lower than the charges incurred in 2012 to 2014. During the months impacted by the Enbridge Incident, numerous system restrictions were put in place, which resulted in higher than normal charges. During this time, many shipper agents over delivered to the FEI system in order to avoid additional transportation service charges, in particular, the Unauthorized Overrun over 5 percent charge.[38] Consequently, shipper agents were drafting between the 10 percent to 20 percent tolerance, as well as the 20 percent+ tolerance and incurring additional charges within these ranges in order to access their banked supply. Still, even under the unprecedented circumstances in 2019 and in a more typical year such as 2020, Table 5-5 above shows the total revenues collected from the charge for "balancing service 10 percent to 20 percent" range implemented in the New Rules was relatively low.

In order to help put the volume of charges into perspective, FEI compared the volume of charges relative to total transportation customer demand or system throughput. In the year 2020, the total volume of charges was approximately 412,000 GJ, which is 0.6 percent of the system throughput of 67 PJ. In 2021, the total volume of charges was slightly less at approximately 395,000 GJ, which is 0.54 percent of the system throughput of 73 PJ. FEI submits that the low volume of charges as compared to total system demand reflects that shipper agents are well able to manage the supply and demand of their customers under the New Rules. Further, it is clear that shipper agents have taken steps to manage their business more proactively. For these reasons, shipper agents are largely avoiding significant balancing charges and other transportation service charges.

These relatively low levels of balancing charges in that range demonstrate that the New Rules are providing the appropriate incentive to shipper agents to balance their supply and demand more closely and that shipper agents are demonstrating they are able to do so while incurring minimal incremental balancing charges in that 10 percent to 20 percent category. This finding is supported in the Atrium Economics Report, Section 2.1.1, which concludes that the amount of charges in the 10 percent to 20 percent range after the New Rules were implemented is inconsequential.

Conclusion:

As discussed above, after having performed the cost-based calculation, the incremental charge of $0.25 per GJ remains reasonable and appropriately recovers the costs of balancing to transportation service customers within the 10 percent to 20 percent range. In addition, the low

[37] The Enbridge Incident occurred on October 9, 2018, causing severe supply constraint circumstances on the FEI System in the 2018/19 winter.

[38] Unauthorized Overrun over 5% charge is charged at the greater of 1.5 times the Sumas Daily price or $20 CAD per GJ.

level of incremental balancing charges indicates the charge provides sufficient incentive to transportation service customers to balance supply and demand more tightly as was the intent with the implementation of the New Rules. FEI will monitor midstream costs and periodically perform the cost-based calculation and, if necessary, bring forward a request for a revised charge in a future process.

5.6 ADEQUACY OF DATA

BCUC Directive 6: Nature, timing and adequacy of information provided to shipper agents to manage gas supply resources.

Background:

The issue of adequacy of data has been raised and extensively discussed in the 2016 RDA as well as in the BCGMC Complaint.

All shipper agents today have access to the WINS self-serve information platform to view individual customer and group demand by day, historical customer consumption, authorized supply from the interconnects, system inventory, and imbalances. Customer demand is updated daily, and shipper agents can access their customers' information 24 hours a day. To assist in managing large volume customers on FEI's system, shipper agents have also been provided with access to FEI's Supervisory Control and Data Acquisition (SCADA) system. Currently there are seven shipper agents accessing real time hourly flows for thirty-nine large volume customers.

In the 2016 RDA Decision, the Panel stated that the industry has evolved sufficiently and the necessary tools are now available to shipper agents to facilitate the estimation of the daily consumption requirements of their customers.[39] FEI's position remains that the data available to shipper agents is adequate. The fact that shipper agents are managing under the New Rules with minimal transportation service charges incurred supports the conclusion that the data available to shipper agents from WINS and SCADA is sufficient to manage the gas supply requirements of their customers. FEI continues to be of the view that the historical data available is only one input or tool that shipper agents should be considering as part of their overall forecasting process. In addition to historical data, other forecasting considerations need to include the weather forecast, degree-day calculation (which is also a forecast) and historical loads or trends.

Some shipper agents in the individual conference calls felt that the data available to them from WINS and SCADA was sufficient whereas others indicated the data caused challenges for their demand forecast. Those that expressed challenges made the following requests.

1. FEI to investigate better measurement technology available in the industry (Request 10, Table 4-2);

[39] 2016 RDA Decision, p. 64.

2. FEI to provide an intra-day estimate in WINS (Request 11, Table 4-2);
3. FEI to improve data quality of the previous day estimate in WINS (Request 12, Table 4-2);
4. FEI to provide a daily delivery requirement during normal and/or HTA/supply restriction periods (Request 13, Table 4-2);
5. Include read time SCADA information prior to the intra-day cycles (Request 24, Table 4-2); and
6. Create marketer dashboards to provide collected data snapshots of marketer group information (Request 25, Table 4-2).

Discussion:

As these requests are closely aligned, FEI will address the above requests together.

As noted above, FEI considers the data from WINS and SCADA is sufficient to manage gas supply requirements of customers. The independent review provided by Atrium Economics in Section 3 of the Atrium Economics Report of other local distribution companies (Appendix A) shows FEI's data systems are within industry standard practice. During the individual conference calls, some shipper agents stated the historical customer data in WINS, as well as real-time consumption through FEI's SCADA system, was sufficient to manage their customer demand. Currently there are seven shipper agents accessing real time hourly flows for thirty-nine large volume customers, which is roughly 60 percent of the entire transportation service customer demand. As discussed in the 2016 RDA and BCGMC Complaint proceedings, historical demand data is just one piece of information required to forecast customer supply requirements. FEI believes that all shipper agents need to develop their own forecasting methodology and systems to manage their customers' needs.

As discussed in Section 4 of the Atrium Economics Report, an industry survey was conducted with respect to balancing related policies. The survey considered what customer usage data was available to third-party shipper agents or marketers. The findings and conclusions in the Atrium Economics Report supports that FEI's provision of customer usage data through WINS and SCADA aligns with industry norms.

As shown in Section 5.1 of this Report, imbalances have trended in the right direction and overall supply by region has matched demand. Further, the low level of transportation service charges as shown in Tables 5-4 and 5-5 suggests that shipper agents are receiving access to sufficient data. Indeed, shipper agents' ability to perform well under the New Rules with minimal incremental balancing charges demonstrates that the existing tools available to shipper agents, including the current measurement platforms (WINS and SCADA), are providing sufficient data for shipper agents to manage well the supply and demand for their customers.

FEI heard requests from shipper agents for FEI to provide an intra-day estimate as well as improve the previous day estimate. At the May 10 stakeholder session, in order to address the intra-day request, FEI proposed to move the timing of the cellular devices calling into our system in order to provide the previous day metered customer consumption amount and a current day estimate. Shipper agents did not provide feedback on this proposal at the stakeholder session or anytime thereafter.

With respect to FEI providing a daily delivery requirement, this is not industry standard. Under the structure of the Transportation Service Model, it is the role and responsibility of shipper agents to forecast and manage their supply requirements on behalf of their customers. A model which incorporates a supply delivery requirement is consistent with FEI's Customer Choice model, which is separate from the Transportation Service Model. Shipper agents participate in the Transportation Service Model freely and, in doing so, have accepted the structure of the service offering including the tariffs and business rules that govern the model. Shipper agents are paid by their customers for this very purpose, to manage their supply portfolio in the most cost effective manner possible. In the transportation rate schedules, under Section 7.1 – Requested Quantity, shipper agents are required to provide their best estimate of the quantity of gas their customers will actually consume on the day.

With respect to SCADA information, customer data is refreshed on a real-time hourly basis and is available to shipper agents within all of the gas cycles. The SCADA information available to shipper agents today includes real time information prior to the intraday cycles. As for Request 25 – to create marketer dashboards, this request seems effectively the same as Request 14 – to automate group balancing through a bulletin board format, which is discussed further in Section 5.7. The nature of these requests would require time, information systems changes, and related costs to assess, develop and potentially build such dashboards or bulletin boards. FEI does not believe that an investment of time and resources in the potential creation of dashboards or bulletin boards is required because shipper agents are capable of exchanging information with each other if it is beneficial for them to do so.

Conclusion:

The various issues raised by some shipper agents regarding measurement are not new. During the individual conference calls, some shipper agents expressed that the data available to them from WINS and SCADA was sufficient. Based on FEI's analysis, shipper agents are meeting their supply obligations today under the New Rules (within the 10 percent balancing tolerance) without incurring substantive charges. FEI concludes that the existing data available to transportation customers and shipper agents is sufficient given shipper agents are managing well under the New Rules. This conclusion is also supported by the findings in the Atrium Economics Report.

5.7 ADMINISTRATION OF INTER-CUSTOMER GROUP BALANCING

BCUC Directive 7: Administration of inter-customer group balancing and transparency of inter-customer group balancing rules.

Background:

FEI has allowed retroactive inter-customer group balancing among shipper agents in the past to assist in mitigating Unauthorized Over-Run (UOR) charges in the over 5 percent category. FEI has permitted the practice of inter-customer group balancing, on a case-by-case basis, provided that shipper agents as a whole met the overall customer supply requirements at the interconnection location where the trade was being requested. If the overall supply obligations were met, and there was no detrimental impact to other customers, FEI has provided the flexibility of moving gas supply retroactively to help mitigate balancing charges which one or more shipper agents would have incurred.

In the discussions with shipper agents, generally everyone was appreciative of this informal retroactive inter-customer group balancing process and grateful for the reduction in charges that would otherwise have been incurred. Some shipper agents requested clarification of this process and suggestions for amendments to this process were the following.

1. Automate the process and/or a bulletin board format (Request 14, Table 4-2);
2. Continue process as is (status quo) (Request 15, Table 4-2); and
3. Proposed a utility super group netting exercise, where if as a whole, all shippers combined deliver sufficient supply to meet demand there should be no penalty (Request 16, Table 4-2).

Discussion and FEI General Assessment:

1. REQUEST 14: AUTOMATE THE PROCESS AND/OR A BULLETIN BOARD FORMAT.

Automating the practice of inter-customer group balancing through a new formal process or bulletin board format would involve costs and system changes. FEI's position is that while inter-customer group balancing may be of benefit in certain circumstances, the formalization of FEI's business practice through automation or some form of bulletin board may distort the Transportation Service Model in such a way that it may dis-incent shipper agents from delivering the appropriate supply requirements to their customers. Consistent with its reply submission in the BCGMC Complaint, FEI continues to believe that it:

a) would be of little benefit to the majority of Shipper Agents who do forecast accurately and do not incur significant balancing charges and potentially act as a disincentive for some Shipper Agents to nominate accurately; and

b) may be detrimental to the interests of FEI's sales customers.[40]

FEI notes that shipper agents did not present any proposals during the stakeholder sessions nor provide more clarity on this request. As indicated above, automation of this process may distort the Transportation Service Model. Further, there would be costs and resources required to

[40] BCGMC Complaint, Reply Submissions of FEI, dated May 22, 2020, p. 19.

implement system changes of this nature which may not provide benefit to all shipper agents. In addition, the frequency for which FEI fulfills requests to move gas after the fact is minimal throughout the year.[41] Therefore, in FEI's view, the resources and costs involved would be disproportionate to the potential benefits. Lastly, FEI believes the investment in an automated bulletin board for this purpose is not necessary given all shipper agents are known to each other and can continue to contact one another and disclose the related information as has been done in the past for this very purpose.

2. REQUEST 15: CONTINUE PROCESS AS IS (STATUS QUO).

While the process of the inter-group balancing has created more administrative work for FEI, the incidence of UOR in the over 5 percent category is infrequent, and not overly burdensome to FEI. The existing process is working and, as such FEI does not believe that incurring expenses to automate this process is beneficial. Further, it is important for FEI to maintain oversight to ensure shipper agents are meeting their obligations and making best efforts to meet overall supply requirements at each location prior to facilitating any assistance and concession. Therefore, FEI concludes it is appropriate to continue with the status quo.

3. REQUEST 16: PROPOSED A UTILITY SUPER GROUP NETTING EXERCISE, WHERE IF AS A WHOLE, ALL SHIPPERS COMBINED DELIVER SUFFICIENT SUPPLY TO MEET DEMAND THERE SHOULD BE NO PENALTY.

This request proposes the idea that if overall supply is sufficient to meet demand at a given location, then no charges should apply to any of the shipper agents at that location. The notion of "super-netting" is not standard industry practice and is not permitted by other local distribution companies or pipelines. The Shipper Agent Agreement (appended to the transportation service rate schedules) sets out the responsibilities and obligations between the shipper agent and the customer.[42] One of the primary obligations of shipper agents relates to nomination and in Section 7.1 of the transportation service rate schedules, the shipper agent is "required to provide their best estimate of the quantity" of gas the shipper or customer will actually consume on the day. Further, the transportation service charges included in the Table of Charges in each rate schedule provide incentive to ensure system balancing requirements are met under normal and more critical circumstances (such as cold or severe weather conditions, or upstream capacity or supply disruptions). If a super-netting provision was introduced, it may act as an incentive for some shipper agents to no longer nominate accurately. FEI would be concerned that super-netting could result in fairness and equity concerns among shipper agents and may result in additional risks and costs to sales customers. This type of request is a fundamental restructuring of the Transportation Service Model which would result in significant costs to redesign WINS the nomination system. FEI considers that this request would reduce or limit risk to the shipper agents at the expense of sales customers.

---

[41] For example, in the 2021/22 winter period, FEI facilitated seven requests to move gas after the fact to help mitigate UOR in the over 5% category.

[42] Transportation rate schedules, Appendix A – Shipper Agent Agreement, Section 3 – Shipper Agent Obligations.

In summary, with respect to the administration of inter-customer group balancing, FEI intends to continue to manage the process as is done today where FEI checks to ensure that the overall supply meets the demand. In doing so, FEI confirms that no additional midstream resources were required for balancing the system, thus ensuring there was no impact to sales customers before contemplating and enabling any supply exchanges in hindsight. FEI will continue to allow retroactive inter-customer group balancing among shipper agents to assist shipper agents in mitigating UOR charges in the over 5 percent category when appropriate to do so.

5.8 CURTAILMENT CRITERIA FOR IMBALANCE RETURN

BCUC Directive 8: FEI's criteria for curtailment of inventory returns to shipper agents.

Background:

This BCUC Directive elicited discussion about FEI's criteria for limiting the imbalance return practice. As indicated in Section 5.2, under the background discussion related to BCUC Directive 2, imbalance return is an interruptible service and can be restricted or reduced at FEI's discretion depending on operational needs of the system. As shown in Table 5-2, the number of days where FEI reduced or eliminated imbalance return have been consistent over time. Historically, FEI makes every effort to give as much advance notice as possible with respect to any reductions to or restrictions to the imbalance return service, but as a minimum, notice is provided by the timely cycle so that shipper agents can adjust their business requirements as necessary. There was a mix of feedback from shipper agents, some who indicated they understand why FEI needs to restrict imbalance return and others who questioned the basis for such decisions when issuing restrictions. FEI confirms that its practices related to determining when a restriction needs to be imposed, such as limiting access to imbalance return, have remained the same. While some shipper agents expressed concern that FEI uses an overly cautious approach when issuing restrictions, others felt the imbalance return service was more frequently restricted or interrupted in recent years. Generally, shipper agents expressed a desire for more clarification on how FEI makes these determinations, as well as how they receive notice when this service is limited.

In the discussions with shipper agents, suggestions for amendments to imbalance return were the following.

1. Days when imbalance return is reduced and/or eliminated flag the line item in the nomination screen (Request 17, Table 4-2); and

2. FEI to provide a "status update" for operational changes (weather/maintenance/ interconnecting pipeline status, etc.) when reducing imbalance return (Request 18, Table 4-2).

Discussion and Conclusion:

1. REQUEST 17: DAYS WHEN IMBALANCE RETURN IS REDUCED AND/OR ELIMINATED FLAG THE LINE ITEM IN THE NOMINATION SCREEN.

When the imbalance return service is reduced or interrupted, shipper agents currently receive a cut report issued from the WINS nomination system showing the reduction. Incorporating another layer of notification by flagging the imbalance return nomination field in WINS under these circumstances is a relatively straightforward system change with minimal cost. As such, FEI plans to proceed with enabling this change.

2. REQUEST 18: FEI TO PROVIDE A "STATUS UPDATE" FOR OPERATIONAL CHANGES (WEATHER/MAINTENANCE/ INTERCONNECTING PIPELINE STATUS, ETC.) WHEN REDUCING IMBALANCE RETURN.

As discussed in Section 5.2, the imbalance return service is an interruptible service on FEI's system because, when operational requirements necessitate (such as when colder weather occurs or during a supply or capacity restriction), FEI may need to reduce or eliminate access to imbalance return for operational purposes. When restriction or interruption of the imbalance return service is required, FEI provides notice and typically advises of the reason necessitating the restriction. FEI provides at least 24 hours notice prior to the start of the affected day by direct email as well as posting a notice on its website. If restrictions are required over a weekend, FEI provides as much advance notice as possible so shippers can make supply arrangements through the three-day weekend period[43]. FEI's notices include reasons for the restriction, typically due to cold weather and capacity or supply issues. When operational conditions change, for better or worse, FEI issues follow up notices advising of the change in conditions and restrictions as necessary. FEI carefully considers any decision to issue a restriction or limitation on FEI's system. When considering whether operational requirements on the system necessitate implementing a restriction, FEI takes into account several factors, as discussed in Section 5.2, under BCUC Directive 2, Request 6.

While every situation is different, FEI has remained consistent over time in the factors it considers when faced with reducing or interrupting the imbalance return service. Almost exclusively, FEI's decisions to limit imbalance return are consistent with the timing of restrictions imposed by inter-connecting pipelines[44] and typically are as a result of events or circumstances occurring in the Pacific Northwest.

FEI expects that shipper agents, similar to FEI, are actively monitoring market information that might result in pipeline restrictions, assessing the health of interconnecting pipes which may impact delivered supply or market price, weather, impact to market prices, and planned outages

---

[44] FEI interconnects with the following pipelines: Enbridge WEI T-South, Northwest Pipeline LLC (Williams) and Foothills PipeLine Ltd. (TCPL/Nova).

in order to plan ahead and be prepared for when restrictions occur. It is the ultimate responsibility of each shipper agent to understand their business and regional market environment to enable better business and contingency planning to ensure the supply needs of their customers are met under all circumstances. FEI currently provides the reasons in its notifications for changes in operational conditions affecting imbalance return, and will continue to do so going forward.

6. ADDITIONAL REQUESTS FOR DISCUSSION

In the Stakeholder engagement sessions, shipper agents raised additional requests for changes to the Transportation Service Model that were beyond what was requested in the BCUC Directives. This section reviews those remaining requests.

6.1 *DAILY BALANCING CHARGES – INTERIOR*

Background:

The RS 22A is the transportation service rate for customers in the Interior service area. The daily balancing gas charge as listed in the Table of Charges within RS 22A is a Sumas Gas Daily price. As gas delivered to the Interior region is generally sourced from Station 2, shipper agents requested a change in the price as follows.

1. Amend RS 22A Daily Balancing Gas Charge to a Station 2 Price (Request 19, Table 4-2).

Discussion and Conclusion:

1. REQUEST 19: AMEND RS 22A DAILY BALANCING GAS CHARGE TO A STATION 2 PRICE.

As indicated in the Table of Charges in all transportation rate schedules, balancing charges for Balancing and Backstopping Gas, Replacement Gas, as well as Unauthorized Overrun Gas charges are all based on a Sumas Gas Daily price.[45] The rationale behind this price point is that Sumas is a more liquid market hub and is a more appropriate benchmark for the market price for natural gas. The price of gas at Station 2 is not reflective of the market and additional costs such as pipeline tolls on Enbridge's WEI T-South system that are required to move the gas to the end user, whether to the Inland or Lower Mainland regions. The Sumas price point tied to all balancing charges is intended to provide the incentive for shipper agents to make arrangements to balance to avoid this charge. As indicated in Table 5-3, the amount of Daily Balancing Gas incurred in 2020 and 2021 is insignificant which demonstrates that the New Rules are achieving the intended outcome. For these reasons, a change to the RS 22A Daily Balancing Gas charge price is not required.

6.2 *TIMELY CYCLE DEADLINE FLEXIBILITY*

Background:

The Enbridge nomination system has the flexibility to extend the timely deadline to allow for late nominations. All of FEI's cycle deadlines, including the timely deadline, are fixed and are designed as timed events; once the cycle deadline is reached, the requests for nominations are

[45] With the exception of RS 25 for the Fort Nelson Service Area where the balancing charges are based on the Station 2 Daily price. Currently there are no customers under this rate schedule.

automatically sent to the interconnecting pipeline. FEI's WINS nomination system does not allow for flexibility to withhold or delay the outbound nominations to the interconnect system for any given cycle. In the discussions with shipper agents, the following request was made:

1. FEI to allow timely cycle deadline flexibility (Request 20, Table 4-2).

Discussion and Conclusion:

2. REQUEST 20: FEI TO ALLOW TIMELY CYCLE DEADLINE FLEXIBILITY.

In basic terms, FEI's existing nomination system incorporates ten timed events to handle both outbound and inbound files for each of the five gas cycles, namely: Timely, Evening, Intra-day 1, Intra-day 2 and Intra-day 3. Within each of the gas cycles, outbound and inbound files are exchanged at specific timed events or deadlines between interconnecting pipelines containing supply nominations and authorized supply for all shippers. These deadlines are in accordance with the North American Energy Standards Board (NAESB) standards, which are in place to establish clear and consistent traffic between pipelines for gas flows between pipelines. Changes to FEI's nomination system to enable flexibility would require time, money and resources. Further, cycle deadlines have been established for a purpose and FEI is not in favour of deviating from NAESB deadlines. Generally, the number of instances in which shipper agents have missed the nomination deadline are very few. FEI believes that the cost, time and resources to incorporate flexibility into the timely deadline far outweighs the benefit associated with a very rare occurrence which is within a shipper agent's control to manage meeting the deadlines.

6.3 HOLD TO AUTHORIZE AND SUPPLY RESTRICTIONS

Background:

Shipper agents have questioned FEI's practices of issuing restrictions such as the reduction or elimination of imbalance return and the issue of a HTA or supply restriction. Shipper agents have asked for more transparency and more clarity of communication so they can anticipate and forecast when limitations may come into play to enable better business and contingency planning to ensure supply needs of customers are met. For information purposes, Table 6-1 shows the number of days FEI has issued a HTA from 2010 to May 2022. FEI's practices and decision-making has remained consistent over time, and notwithstanding the increase in restricted days in the 2018 and 2019 years, the number of days are similar in comparison of before and after the New Rules were implemented.

Table 6-1: Days of Hold to Authorize From 2010 to May 2022

YEAR	Lower Mainland	Interior	Columbia and East Kootenay
2010		3	
2011		2	
2012		3	
2013		4	
2014		11	
2016		8	
2017		12	
2018	55	24	
2019	17	17	
2020	3	3	3
2021	23	15	15
Grand Total	**98**	**102**	**18**

In the discussions with shipper agents, suggestions for amendments regarding FEI's process when issuing operational restrictions, were as follows:

1. FEI to disclose the parameters and conditions for issuing HTA and/or supply restrictions (Request 22, Table 4-2);
2. FEI to apply locational/regional HTA – not apply across all regions (Request 23, Table 4-2);
3. Provide clear information, timelines, priorities and other information related to curtailment (Request 26, Table 4-2);
4. Tariff be structured so FEI may curtail/HTA only when absolutely necessary (Request 27, Table 4-2); and
5. Clear and consistent criteria for the return of HTA gas inventory and a mechanism for returning any premium value of that inventory, and specifically that FEI publish its criteria so customer and marketers can understand how FEI will make its decisions/criteria so customer and marketers can understand how FEI will make its decisions (Request 28, Table 4-2).

Discussions and Conclusions:

1. REQUEST 22: FEI TO DISCLOSE THE PARAMETERS AND CONDITIONS FOR ISSUING HTA AND/OR SUPPLY RESTRICTIONS.

Similar to the request regarding FEI's administration of imbalance return, this request asks for more clarity around issuing HTA or supply restrictions. Generally, as shipper agents are aware, FEI takes steps to reduce tolerance levels to 5 percent in response to cold weather or upstream pipeline restrictions to preserve FEI's midstream resources for the use of core customers (who pay for these resources). Since the inception of the Transportation Service Model, FEI has and continues to use a consistent approach when needing to apply such restrictions.

While every situation is different, FEI has remained consistent over time in the factors it considers when faced with reducing or interrupting the imbalance return service or issuing HTA restrictions. Almost exclusively, FEI's decisions to issue a HTA or supply restriction are consistent with the timing of restrictions imposed by its inter-connecting pipelines and typically are as a result of events or circumstances occurring in the Pacific Northwest.

FEI expects that shipper agents, similar to FEI, are actively monitoring market information that might result in pipeline restrictions, assessing the health of interconnecting pipes which may impact delivered supply or market price, weather, impact to market prices, and planned outages in order to plan ahead and be prepared for when restrictions occur. It is the ultimate responsibility of each shipper agent to understand their business and regional market environment to enable better business and contingency planning to ensure the supply needs of their customers are met under all circumstances.

2. REQUEST 23: FEI TO APPLY LOCATIONAL/REGIONAL HTA – NOT APPLY ACROSS ALL REGIONS.

FEI evaluates conditions both regionally and province wide when contemplating any operational restrictions such as reductions to imbalance return and HTA. Below are some recent examples where FEI imposed of lifted restrictions at a regional level.

- From December 27-29, 2021, FEI issued an interruptible curtailment exclusively for customers located in the Lower Mainland region, due to forecast Design Day temperatures at YVR. Customers in the Interior, Columbia and East Kootenay regions were not curtailed.
- Following the Enbridge Incident in October 2018, customers in the Lower Mainland, Vancouver Island and Interior regions were restricted to a hold to authorize and imbalance return was reduced to zero effective October 13. With these restrictions in place, from November 20 to 30, FEI released 30,000 GJ per day of available imbalance return to customers in the Lower Mainland region only to provide some relief and allow shipper agents to access banked gas without penalty given cumulative pack building since the Enbridge Incident.
- For 32 days from June 12 to August 13, 2019, FEI increased imbalance return levels in the Interior region from 40,000 to 60,000 GJ per day of available imbalance return (while the Lower Mainland region remained at 40,000) in order to help shipper agents bring down their Interior region pack following the Enbridge incident.

FEI will continue to assess conditions both regionally and province wide when contemplating operational restrictions.

3. REQUEST 26: PROVIDE CLEAR INFORMATION, TIMELINES, PRIORITIES AND OTHER INFORMATION RELATED TO CURTAILMENT.

FEI communicates directly with the affected customers regarding timing of interruptible customer curtailment, providing as much advance notice as possible as well as an estimate of duration. FEI also provides an advisory as a courtesy to the shipper agents in advance of curtailment.

4. REQUEST 27: TARIFF BE STRUCTURED SO FEI MAY CURTAIL/HTA ONLY WHEN ABSOLUTELY NECESSARY.

When cold weather or pipeline restrictions occur, it is FEI's responsibility to protect midstream assets to ensure they are available for use by core customers (who pay for them). In keeping with these obligations and acting reasonably, FEI takes steps only when necessary to impose restrictions to ensure that shipper agents utilize their own resources to meet the load of their customer base.

The relevant sections of FEI's transportation rate schedules regarding curtailment and the obligations of shipper agents under these conditions are set out below.

Section 4.2 of RS 22 states:

> If at any time FortisBC Energy, acting reasonably, determines that it does not have capacity on the FortisBC Energy System to accommodate the Shipper's request for interruptible transportation FortisBC Energy may, for any length of time, interrupt or curtail transportation Service under this rate schedule. Consistent with the provisions of Section 8.5 (Failure to Deliver to Interconnection Point), if at any time FortisBC Energy, acting reasonably, determines that it is not able to provide Balancing Gas or Backstopping Gas, FortisBC Energy may curtail the Shipper's take to the lesser of the Authorized Quantity or the Firm DTQ.

Similarly, Section 4.2 of RS 23 (and equivalent provisions in 25 and 27) provide:

> Consistent with the provisions of Section 7.5 (Failure to deliver to Interconnection Point), if at any time FortisBC Energy, acting reasonably, determines that it is not able to provide Balancing Gas or Backstopping Gas, FortisBC Energy may curtail the Shipper's take to the lesser of the Authorized Quantity or the Firm DTQ.

Section 9.3 of RS 22, and equivalent provisions in the other transportation service rate schedules, indicates the following regarding curtailment of gas balancing:

> FortisBC Energy may for any reason and for any length of time, interrupt or curtail Gas balancing under this rate schedule.

As indicated in Section 4.2 quoted above, FEI may restrict balancing and curtail or limit the shipper agent to their authorized quantity or firm DTQ. For any restrictions regarding imbalance return, interruptible customer curtailment and supply restrictions/HTA are implemented only when necessary. Historically, as a courtesy, FEI has provided notice of changes to imbalance return availability or HTA restrictions in advance of the timely cycle in order for shipper agents to arrange for the appropriate amount of gas with these restrictions in place.

5. REQUEST 28: CLEAR AND CONSISTENT CRITERIA FOR THE RETURN OF HTA GAS INVENTORY AND A MECHANISM FOR RETURNING ANY PREMIUM VALUE OF THAT INVENTORY, AND SPECIFICALLY THAT FEI PUBLISH ITS CRITERIA SO CUSTOMER AND MARKETERS CAN UNDERSTAND HOW FEI WILL MAKE ITS DECISIONS/CRITERIA SO CUSTOMER AND MARKETERS CAN UNDERSTAND HOW FEI WILL MAKE ITS DECISIONS.

The issue of the return of shipper agent HTA gas inventory and any premium value of that inventory was canvassed in the BCGMC Complaint. However, there was no evidence to support this assertion. FEI acknowledges that shipper agents tend to over deliver during HTA periods to avoid UOR penalties; however, historically it has been only a few shipper agents responsible for excessive over-supply. Excluding these few shipper agents that have excessively over-delivered during HTA periods, the volumes are not significant. As shown in Section 5.1, Figures 5-1 and 5-2, the volume of system imbalances as well as the range of imbalances have tightened since the implementation of the New Rules. Additionally, the analysis provided in the Atrium Economic Report shows that shipper agents are managing within the 10 percent to 20 percent tolerance and inventory levels have been reasonable since the New Rules were implemented. This supports the conclusion that the New Rules are incenting shipper agents to balance more tightly under all circumstances and, therefore, the issue of over-delivery during HTA periods is not occurring to the same degree as before the implementation of the New Rules.

It is the responsibility of the appointed shipper agent to forecast and deliver gas requirements for their customers under both normal and more restrictive periods. Any contingency resources required for a shipper agent to also perform during HTA periods is the cost of doing business for shipper agents who choose to operate under the Transportation Service Model. The issue of normal and peak supply arrangements and contingency assets or arrangements is a discussion that should be between the shipper agent and each of their customers including any potential risks their customers may be exposed to from those arrangements.

It is also the responsibility and obligation of shipper agents to monitor market conditions and changes in order to anticipate and forecast their customer supply requirements to ensure they have secured the resources needed under the various market conditions that could materialize.

Given that the over-supply volumes at this time are immaterial as shown in Figures 5-1 and 5-2, FEI believes that consideration of any mechanism and the associated costs for system changes to address managing over-supplied inventory during HTA is not necessary. Further, such a mechanism may, in fact, be a disincentive for shipper agents to properly manage their supply and demand.

6.4 ADDITIONAL FEEDBACK

Background:

As part of the BCGMC Complaint, the BCGMC suggested that FEI was in need of a code of conduct for its gas marketing activities to establish a competitive market and level playing field for all participants.

1. FEI TO ADHERE TO THE GAS MARKETERS CODE OF CONDUCT (REQUEST 29, TABLE 4-2).

Conclusion:

This issue of a code of conduct for FEI was reviewed in the BCGMC Complaint and rejected by the BCUC in it is Decision and Order G-210-20, which stated:

> The Panel further notes that the Transportation Service Model was designed to provide FEI with the same margin as its bundled service offerings, therefore providing FEI with no financial benefit from transportation service customers returning to bundled service. As such, the Panel does not consider FEI's regulated utility operations to be in competition with gas marketers or receiving a competitive advantage from control of FEI customer information. The Panel rejects BCGMC's argument that a separate code of conduct is required for FEI's regulated utility business in order to establish a competitive market for all gas marketers and their customers as FEI's regulated service offerings are governed by its tariffs.[46]

[46] BCUC Decision and Order G-210-20, pp. 11-12.

7. SUMMARY AND RECOMMENDED CHANGES

The purpose of the Report was to review and assess the performance of the Transportation Service Model under the New Rules. FEI conducted multiple sessions during the stakeholder engagement process to obtain feedback with respect to the BCUC Directives and consider specific requests made by shipper agents during those sessions in the Report.

For the reasons discussed in this Report, FEI concludes that the Transportation Service Model continues to perform well and has improved under the New Rules. The New Rules are working as intended, system inventories are reasonable, shipper agents are able to balance daily and within the 10 percent tolerance, and the amount of transportation service charges incurred has been minimal. As a result, FEI believes that the New Rules are appropriately incenting shipper agents to meet their obligations to balance, on a daily basis, the demand and supply requirements for their customers under the Transportation Service Model.

As a result of reviewing and evaluating the requests from shipper agents, FEI has committed to making two minor modifications to its operational business rules, which are reasonable, may provide some benefit, will not require material cost, and are relatively easy to implement. First, FEI will update its operational business rules and practices to provide a minimum allocation of imbalance return to groups with smaller demand (Request 4). Second, FEI will incorporate a flag to the imbalance return nomination field in WINS when the imbalance return service is restricted (Request 17).

Appendix A

ATRIUM ECONOMICS – TRANSPORTATION SERVICE BALANCING REVIEW REPORT

ATRIUM ECONOMICS
CENTERED ON ENERGY

FortisBC Energy, Inc.

Transportation Service Balancing Review

June 15, 2022

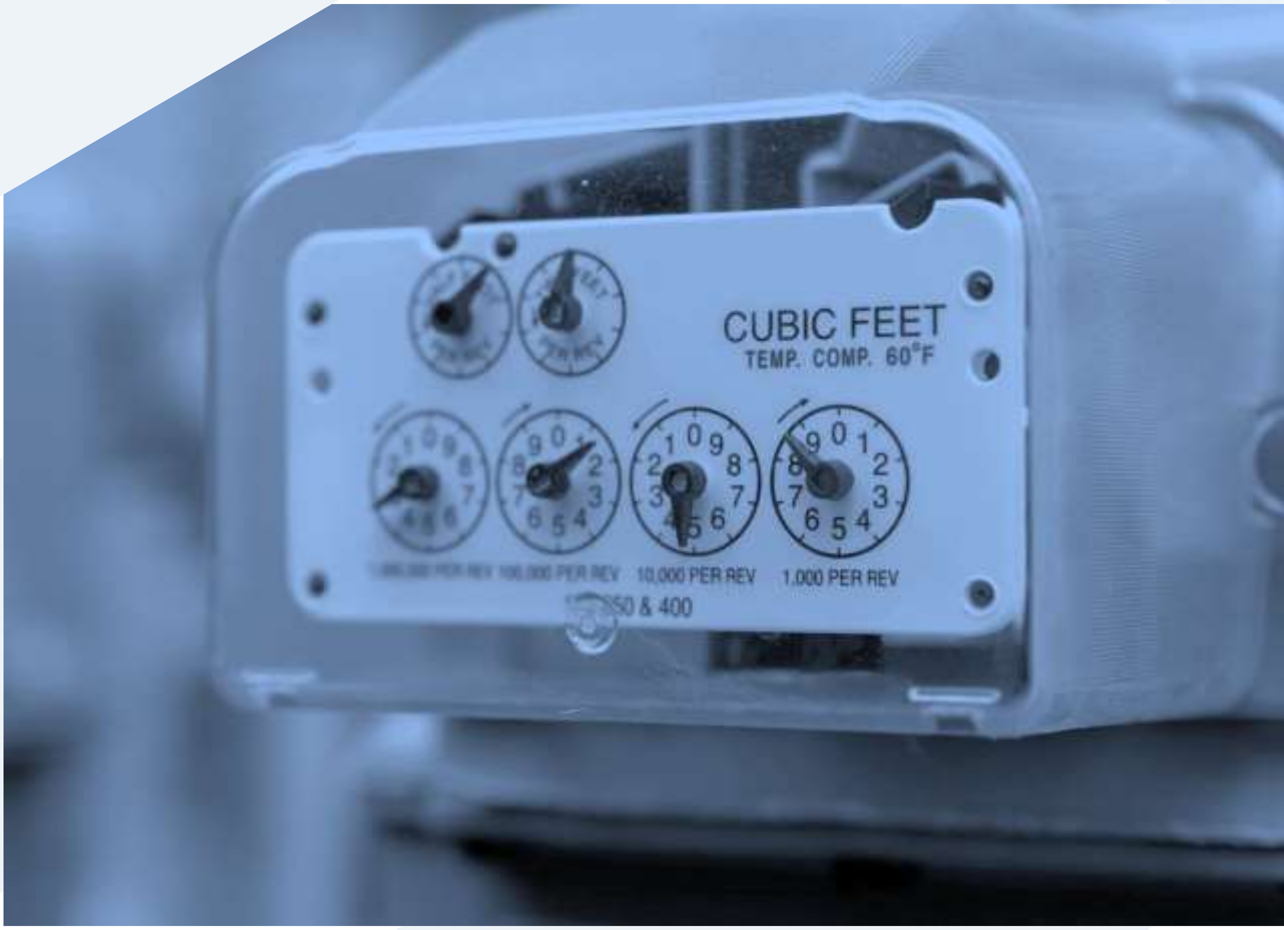


Table of Contents

List of Figures

List of Tables

1 Introduction and Overview of Atrium's Review

1.1 Atrium Economics' Assignment

FortisBC Energy Inc. ("FEI") retained Atrium Economics LLC ("Atrium") to provide consulting services related to a directive by the British Columbia Utilities Commission ("BCUC" or the "Commission"), in Order G-135-18 in FEI's 2016 Rate Design Application. FEI was directed to file a report on the impact of the amendments to the Transportation Service Model on transportation service balancing by June 1, 2022. In a subsequent BCUC Decision in a complaint filed by the BC Gas Marketers Coalition ("BC GMC"), the Commission included additional topics to be addressed in the FEI report.

An initial part of Atrium's assignment was to review all background material related to the BC GMC complaint, including the following:

- The Initial Letter of Complaint filed by the BC GMC, submitted September 4, 2019
- FEI's Response to the BC GMC complaint, submitted October 11, 2019
- Various Information Requests submitted by both BC GMC and FEI
- BC GMC Final Argument submitted May 15, 2020
- FEI Reply Argument submitted May 22, 2020
- BC GMC Reply Argument submitted May 28, 2020
- BCUC Order No. G-210-20, dated August 10, 2020, and Reasons for Decision

1.2 The BCUC's Directives to FEI

In FEI's 2016 Rate Design proceeding, the BCUC approved amendments to the Transportation Service Model by its Decision (Order G-135-18 dated July 20, 2018). The amendments related to customer balancing rules; implementation of daily balancing for all transportation service customers; a reduction of the daily balancing tolerance; and changes to daily balancing charges for gas supply shortfalls. For customers located in the Lower Mainland (including Vancouver Island) and the Interior, the approved changes became effective on November 1, 2018, and for customers in the Columbia and East Kootenay regions, on November 1, 2019.

The Final Decision in the rate design proceeding directed FEI to file a report on transportation service balancing and assess the impact of the tariff changes by June 1, 2022. The decision directed that the report include an assessment and discussion of the following:

- Impact of new balancing rules on the use of core resources, including both changes to variable costs of balancing the system to accommodate transportation service and changes to fixed costs arising from a need to contract midstream resources differently

- Effectiveness of imbalance return as a tool for shippers/shipper agents[1] to manage excess inventory, including discussion of any modifications made to the allocation methodology in response to changes in demand for imbalance return after the balancing rule changes are implemented,
- Whether there should be further tightening of tolerances for under-supply,
- Whether it is necessary to implement tolerances and associated charges for over-supply, and
- Whether the balancing charges appropriately recover the costs of providing balancing to transportation service customers and provide sufficient incentive to transportation service customers to balance their supply and demand.

In the BCUC Order No. G-210-20, dated August 10,2020 and Reasons for Decision, FEI was directed to include these additional topics in the report:

- Nature, timing, and adequacy of information provided to shipper agents to manage gas supply resources,
- Administration of inter-customer group balancing and transparency of inter-customer group balancing rules, and
- FEI's criteria for curtailment of inventory returns to shipper agents

1.3 Atrium's Review of FEI's Transportation Service Model

Atrium was asked to perform the following analyses using the spreadsheet models that had been developed during our prior engagement with FEI related to the development of the balancing rules, associated tolerance thresholds, and charges:

- Perform analysis of shipper-agents balancing performance before and after the implementation of the new balancing rules, which includes both charges and inventory levels. Compare the performance during the Enbridge pipeline rupture event (2018/2019) versus a normal winter (2019/2020 and 2020/2021).
- Evaluate the use of Imbalance Return (IR) for negative imbalances (i.e., IR draw to meet demand when there is a negative imbalance)
- Provide an assessment of the incidents of Marketers' incurrence of imbalance charges for drafting above the 10% imbalance threshold
- Analyze the imbalance inventory levels (i.e., higher/lower) before and after implementation of the new balancing rules.

[1] Throughout this report, the terms Shippers, Shipper-agents, and Marketers are common natural gas industry terminology used inter-changeably to refer to the commercial entities delivering gas supplies on behalf of transportation customers. Shippers on FEI's system are referred to as Marketers.

1.4 Benchmarking of FEI's Transportation Balancing Rules

Along with the preceding analyses in Section 1.3, Atrium performed a benchmarking study of Local Distribution Companies' ("LDC's") balancing rules & services, including a survey of specific areas of interest to FEI. The benchmarking study and survey are intended to assist FEI in responding to the BCUC's requirement in its Order G-135-18 for an assessment and discussion of the aforementioned list of topics related to the new transportation service balancing rules implemented in 2018-2019. The benchmarking and survey included the following specific areas of interest:

- Review and assessment of the impact of usage measurement on forecasting demand,
- Review and assessment of the rules governing operational restrictions,
- Assessment of the reasonableness of providing concession allowances for smaller shipper groups, and
- Evaluation of appropriateness of eliminating monthly balanced customer groups within FEI's transportation service model.

1.5 Summary of Atrium's Findings and Conclusions

Atrium's research of gas LDCs practices with respect to the provision of customer usage data found no support for the notion that FEI's current measurement and usage information system is an impediment to Marketer's ability to provide reasonable nominations for their customers under similar transportation models. The insignificant levels of imbalance charges incurred by Marketers suggest that the current measurement data provided by FEI are sufficient.

Atrium's benchmarking information showed that defining specific operational conditions and circumstances in a tariff, under which restrictions are to be imposed on shippers, is not a common industry practice. Atrium finds that FEI's process for identifying the conditions under which an operational or supply restriction is warranted conforms with industry practices.

Atrium found no examples of other gas LDCs that provide accommodations within their fee-based gas storage related services, which are on par with FEI's Imbalance Return service, for shippers with small daily demands. However, it is not unreasonable for FEI to provide the described concession in its IR service for shipper/agents serving customer groups with small daily demands if it can be accommodated within the IR structure, is not detrimental to other Marketers, and is not administratively burdensome.

The elimination of monthly balancing and moving exclusively to daily balancing aligns with industry standards. Elimination of monthly balancing appears to have removed the potential for gaming activity, as evidenced by imbalance inventory levels since the new daily balancing provisions were implemented. Daily balancing provides the expected remedy.

2 Atrium's Analysis of FEI's Transportation Balancing Under the Revised Rules

FEI provided Atrium daily source data from January 2015 through May 2021 on each shipper, including daily demand, supply, imbalance return, and ending inventory, from which to conduct an analysis of FEI's transportation balancing under the revised rules. To complement this analysis, FEI also supplied Atrium with a record of Balancing Service charges made from December 2011 through May 2022. Balancing Service charges include those where shipper quantities of gas supplied were:

1. Over the greater of 100 gigajoules (GJs) or equal to or in excess of 20% of the applicable tariffs' Authorized Quantity, and
2. Over the greater of 100 GJs or equal to or in excess of 10% or less than 20% of the applicable tariffs' Authorized Quantity (this charge only applies to shippers in the Lower Mainland and Interior service areas after November 1, 2018, and shippers in all other service areas after November 1, 2019)

2.1 Shipper Balancing Performance Before/After New Rules

Atrium was tasked with evaluating shipper/shipper-agents balancing performance before and after the implementation of the new balancing rules. This includes evaluating both Balancing Service charges and inventory levels for each shipper across FEI's service territory.

Additionally, Atrium completed a comparison of shipper performance in the winter (November through March) during the Enbridge pipeline rupture event (2018/2019) and several typical winters (all other winters from 2014/2015 through 2021/2022).

To evaluate balancing performance, Atrium looked at one winter-time period before implementation of the new rules (November 2016 through March 2017) and one after (November 2019 through March 2020). We compared the percentage of total days in the time period each shipper landed within supply imbalance ranges (i.e., 0 – 10%, between 10 – 20%, or over 20% of the Authorized Quantity[2]), which encompass the imbalance thresholds in FEI's transportation tariffs of 10% and 20%, whereby imbalance charges are incurred. In Figure 1 and Figure 2 below, this comparison is laid out for the Lower Mainland ("LML") service area.

[2] Authorized Quantity = Total physical delivered supply + authorized supply from imbalance return.

Figure 1 - Percentage of days within supply thresholds for the LML service area Nov 2016 – Mar 2017

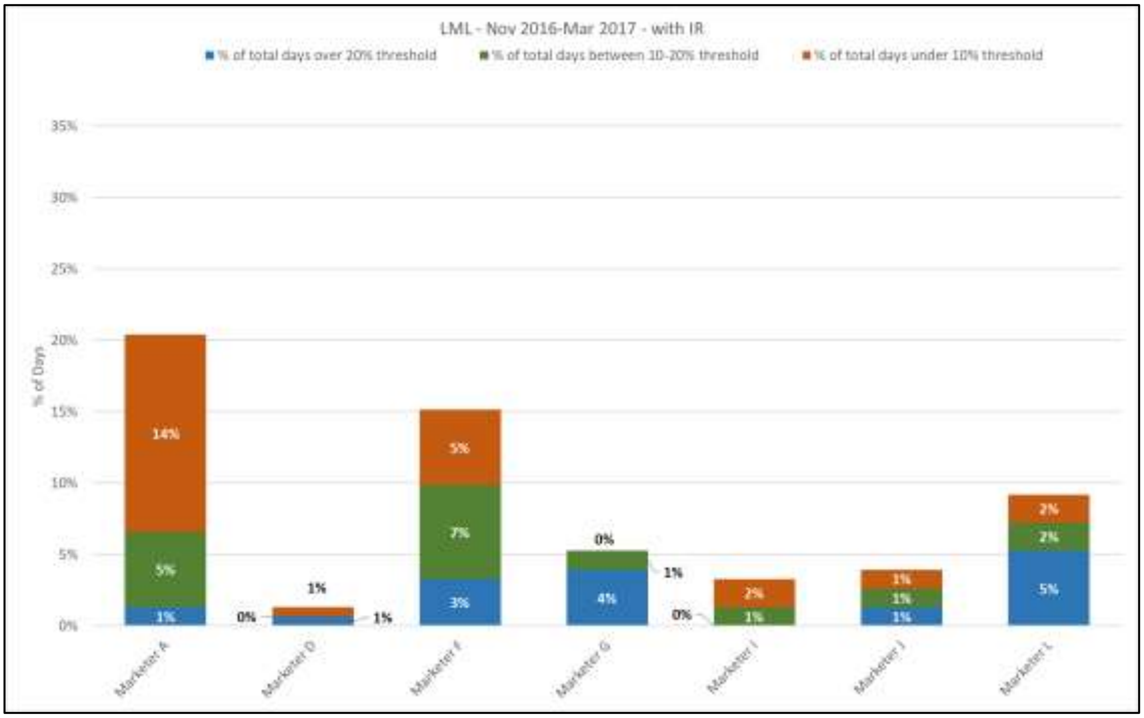
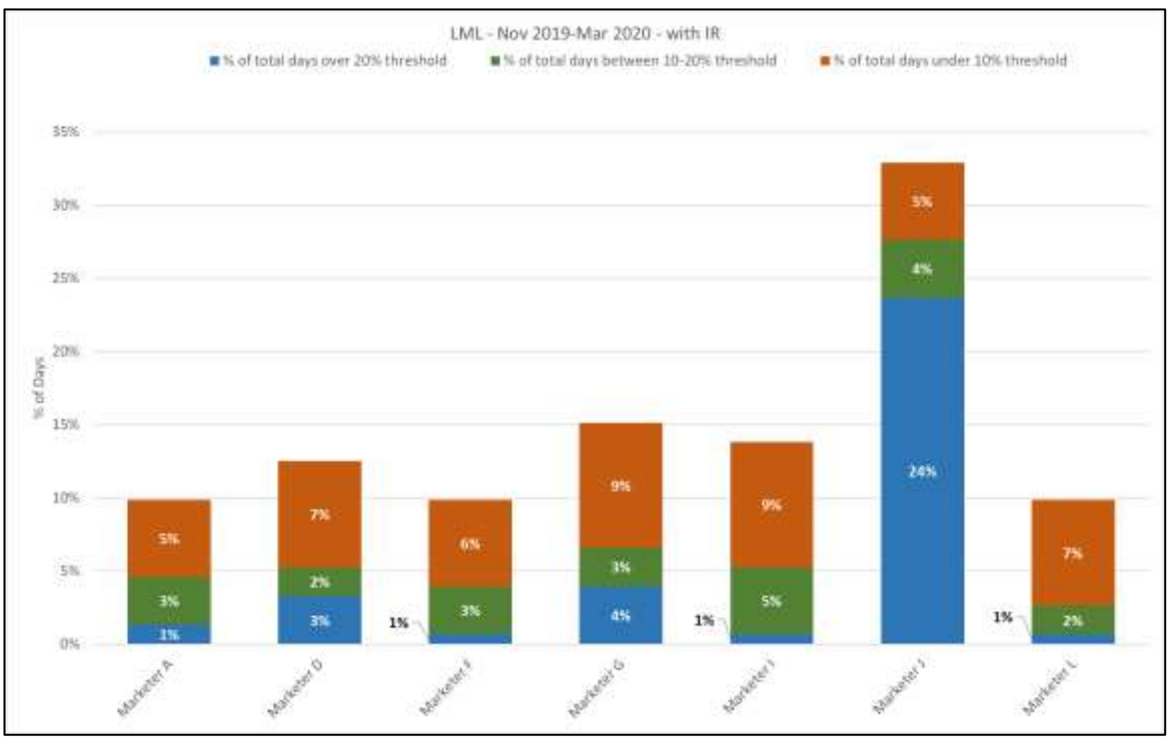


Figure 2 - Percentage of days within supply thresholds for the LML service area Nov 2019 - Mar 2020



This comparison is a good indication of overall Marketer performance and ability to match daily supply to daily demand. It also indicates relative performance for each Marketer between the before and after time periods, and between imbalance thresholds. For example, Marketers F and L have reduced their days above the 20% threshold, while Marketers A, F, and L also reduced their days within the new incremental threshold of 10 – 20%, as shown in Figure 2. The increased size of the bars in the 0 – 10% range relative to the other threshold ranges in Figure 2 are also indicative of the incentive to further manage imbalances provided by the new balancing fee for exceeding the 10% threshold.

For the LML service area as a whole, the average percentage of days where Authorized Quantity was less than daily demand increased from 8.4% to 14%, indicating a greater number of days of under-supplying. However, almost all Marketers remained constant or decreased their percentage of days above the 20% threshold. Comparatively, the average percentage of days under 10% greatly *increased* from 3.6% to 6.9%, with most Marketers able to manage their Authorized Quantities under 10% vis-a vis the higher thresholds, thereby avoiding Balancing Service charges.[3] LML Marketer J's performance, with a significant increase in the percentage of days above the 20% threshold in Figure 2, appears to indicate that this shipper was intentionally drafting more heavily based on its own operational strategy. Collectively, the overall trend shown in Figures 1 and 2 is moving in the right direction and it is apparent that Marketers are complying with the new balancing rules.

This overall trend is also the case when analyzing the Inland/Interior ("INL") service area (**Error! Reference source not found.** and Figure 4 below). There are different combinations of Marketers shown in the following Figures for the INL service area based on the number of active Marketers in this service area. This will also apply to Section 2.2.

[3] The 0 – 10% range is not explicitly addressed in the FEI tariff and Marketers are not required to balance within this range under normal operating conditions.

Figure 3 - Percentage of days within supply thresholds for the INL service area Nov 2016 - Mar 2017

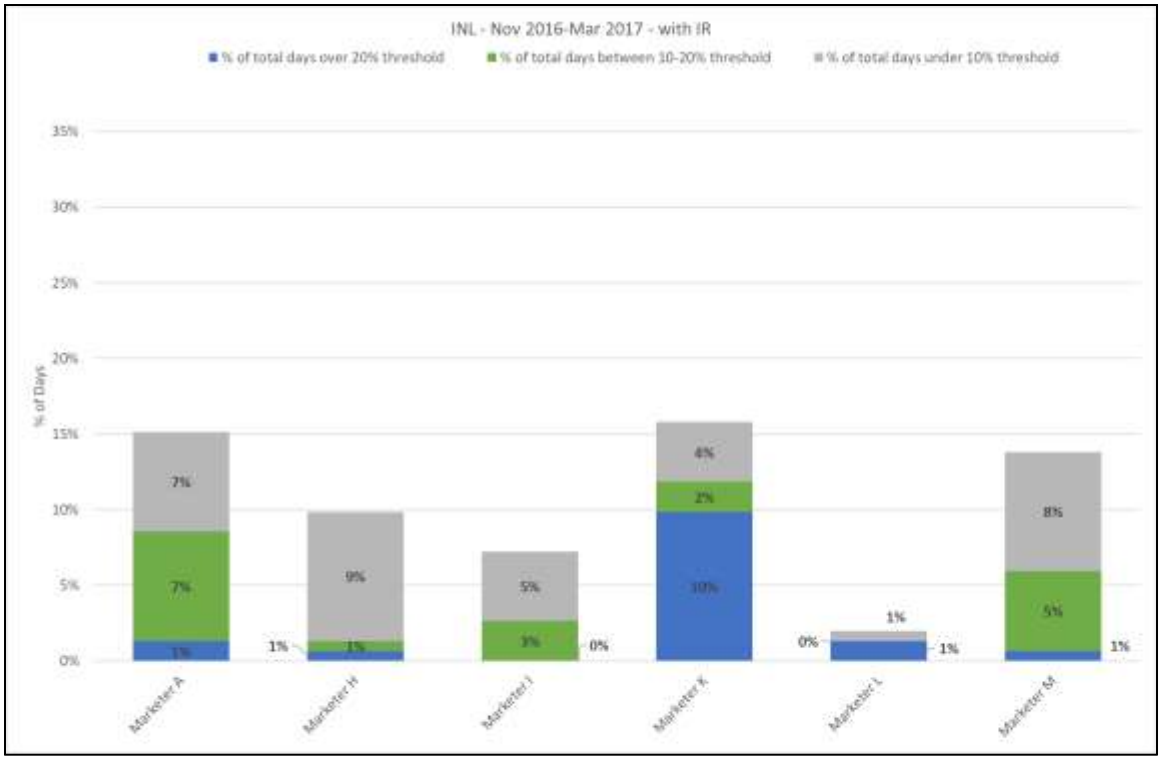
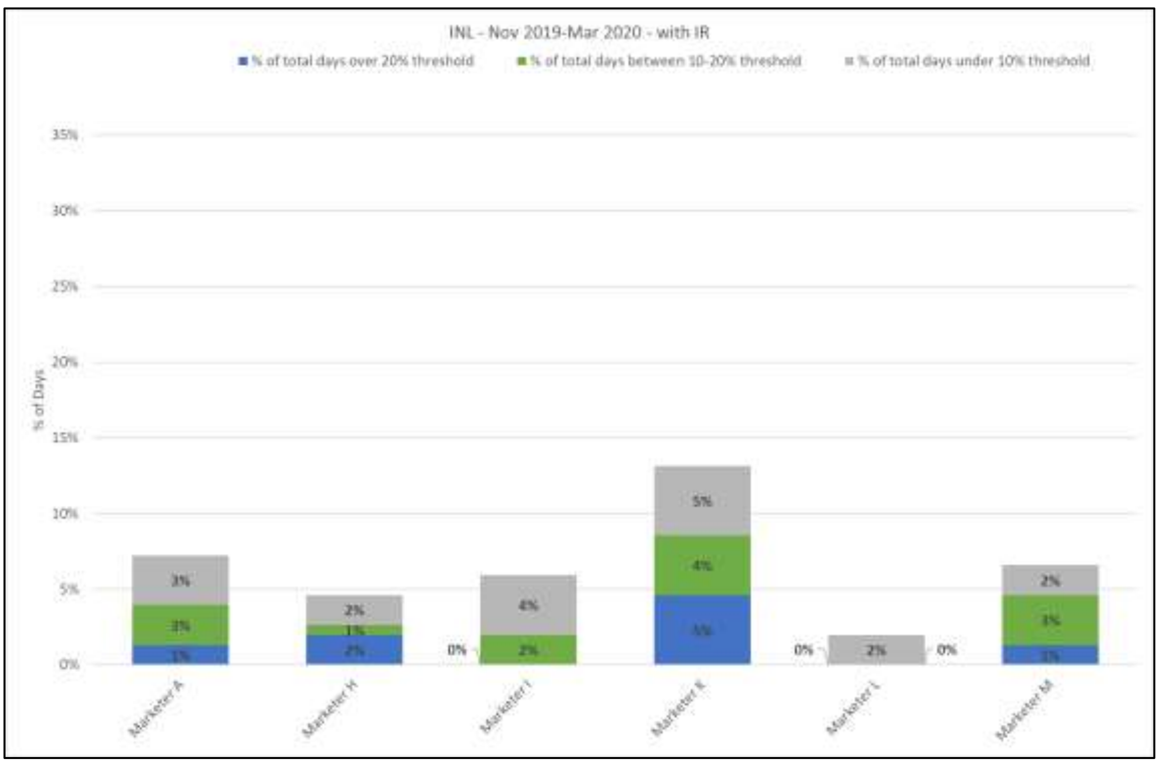


Figure 4 - Percentage of days within supply thresholds for the INL service area Nov 2019 - Mar 2020



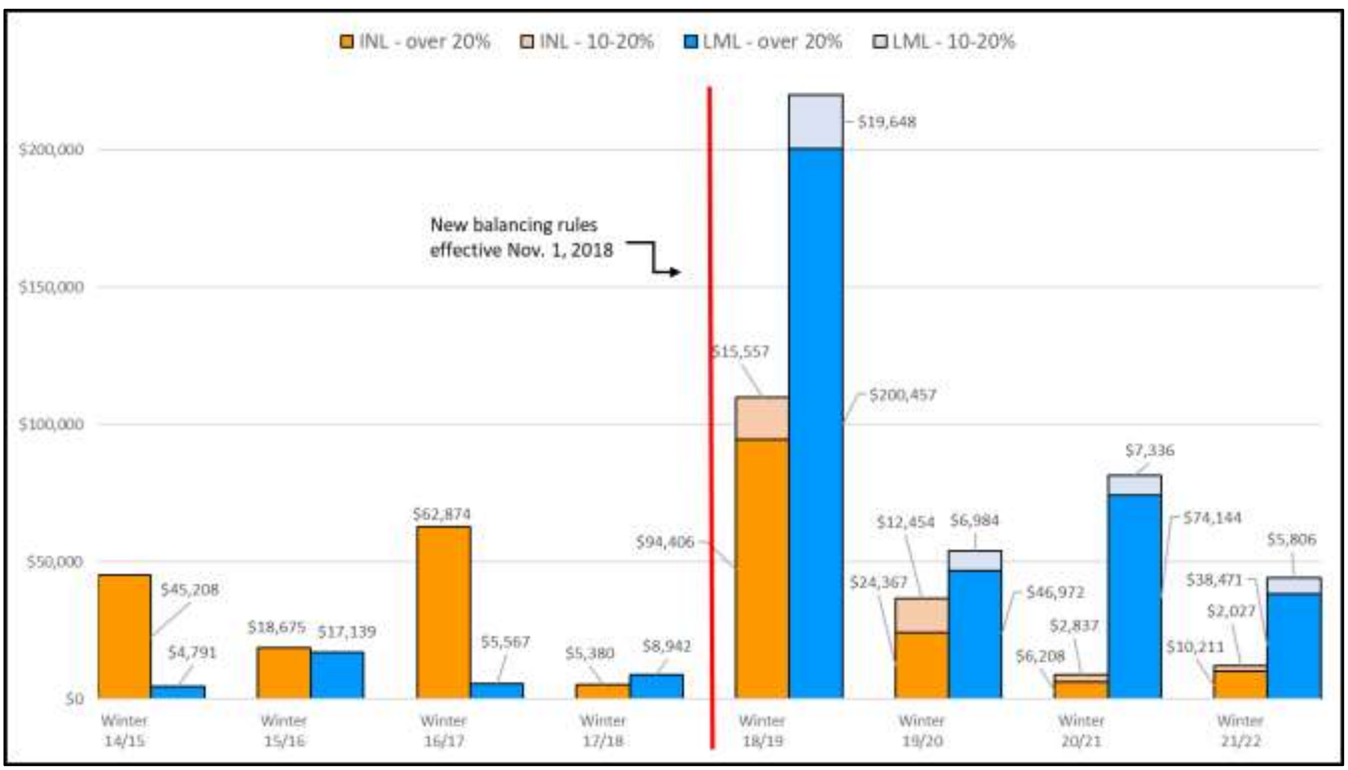
Conversely in the INL service area as a whole, the average percentage of days where Authorized Quantity was less than daily demand *decreased* from 11% to 7%, indicating a lesser number of days of under-supplying, and an overall reduction of Balancing Service charges. Almost all Marketers remained constant or decreased their percentage of days above the 20% threshold, and Marketers A and I also reduced their days within the new incremental threshold of 10 – 20%, as shown in Figure 4. Collectively, the overall imbalance trend shown in Figure 3 and Figure 4 is moving in the right direction and it is apparent that Marketers are complying with the new balancing rules.

Balancing Service charges for negative imbalances in the two service areas under the two thresholds above 10%, while not zero, indicate that Marketers were generally balancing within the rules, reducing instances above the charge thresholds. In addition, due to the relatively few number of days in the time period where undersupply takes place, the corresponding charges appear inconsequential.

2.1.1 Enbridge event vs. normal winters

In Figure 5 below, the Balancing Service charges for the LML and INL service areas are graphed for each winter from 2014/2015 to current, with the different thresholds of charges (10-20% and over 20%) noted separately. The Columbia, East Kootenay, and Fort Nelson service areas are not included here due to low or no Balancing Service charges during these winter-time periods.

Figure 5 – Summary of balancing charges during winter periods from 2014/15 to 2021/22



The rate per GJ charged to shippers for Balancing Service for negative imbalances above the 20% threshold was unchanged over the entire period shown. Both before and after the new balancing rules became effective, the Balancing Service rate remained at $1.10/GJ for winter months. Also, before implementation of the new balancing rules, Marketers managed within daily and monthly balancing provisions. While there were no over-delivery ceilings imposed by FEI either before or after the implementation of the new balancing rules, FEI has consistently requested that Marketers adhere to a two- to three-day level of over-delivery imbalance inventory.

The level of Balancing Service charges shown in Figure 5 for the winter 2018/2019 spiked significantly due to an Enbridge pipeline rupture. Therefore, the level of charges for that period are not representative of a normal winter and are not an appropriate example to demonstrate Marketer performance under the revised balancing rules. During such a critical event, Marketers are held to a 5% under-delivery imbalance level. However, during this period, when operational conditions on the FEI system allowed, flexibility was provided to Marketers via access to their IR inventories. Cooperatively, FEI and the Marketers managed through the extremely disruptive winter 2018/2019 event through the flexibility inherent in the new balancing rules and FEI's administration of them.

Aside from the anomaly of the Enbridge rupture event in winter 2018/2019, under normal operating conditions the INL service area showed significant reductions in Balancing Service charges for negative imbalances above the 20% threshold after implementation of the new rules. The factors influencing the higher level of Balancing Service charges in the LML service area during the years following the 2018/2019 winter event are unknown but appear to indicate that those LML shippers were intentionally drafting more heavily based on their own operational strategies. However, Atrium has no insight into those Marketers' commercial arrangement or business practices. Charges for negative imbalances within the 10-20% threshold, while not zero, indicate that Marketers in both service areas were generally balancing within the new rules and the corresponding charges appear inconsequential.

2.2 Evaluation of the Use of Imbalance Return (IR)

Atrium used a similar approach to evaluate the use of IR for negative imbalances by Marketer. However, with this comparison, Atrium looked at one winter-time period (November 2019 through March 2020) both with and without the use of IR and compared the percentage of days each shipper landed within a certain supply threshold. This comparison is laid out in Figure 6, Figure 7, Figure 8, and Figure 9 below for the LML and INL service areas.

Figure 6 - Percentage of negative imbalance days for the LML service area without IR

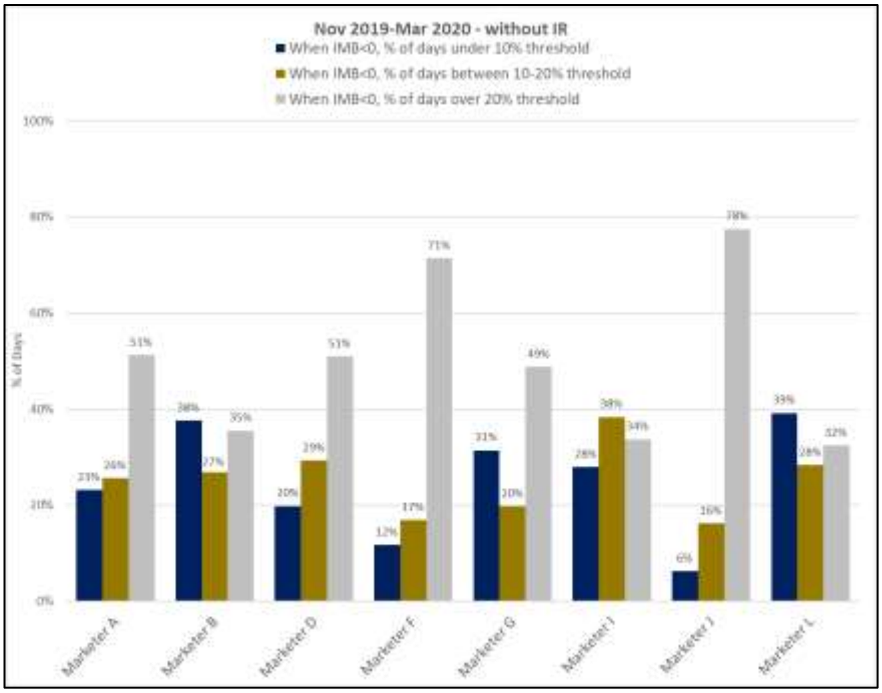


Figure 7 - Percentage of negative imbalance days for the LML service area with IR

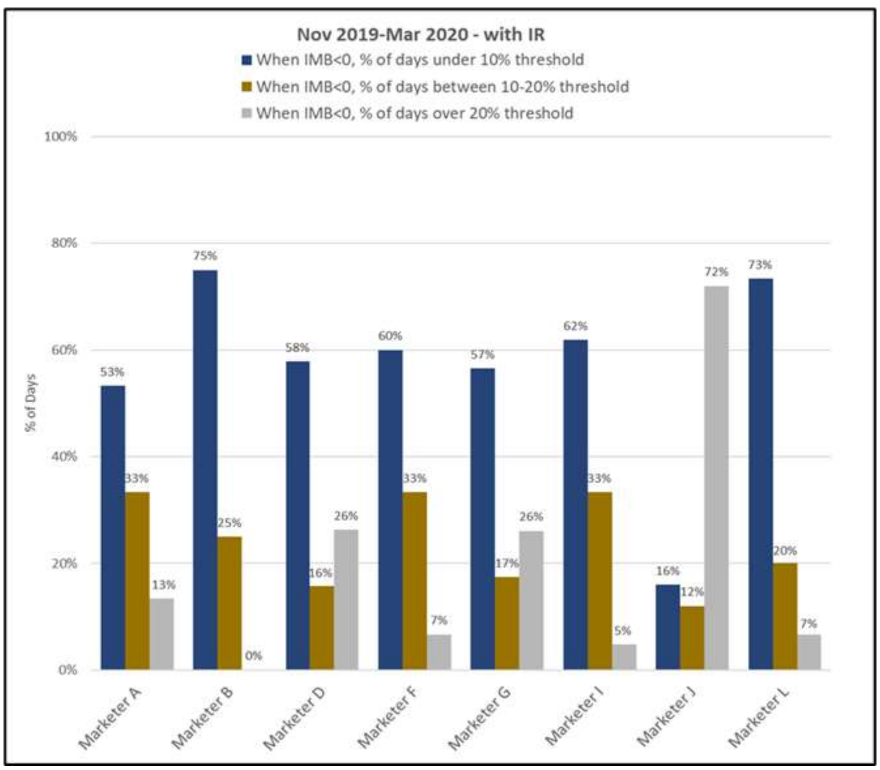


Figure 8 - Percentage of negative imbalance days for the INL service area without IR

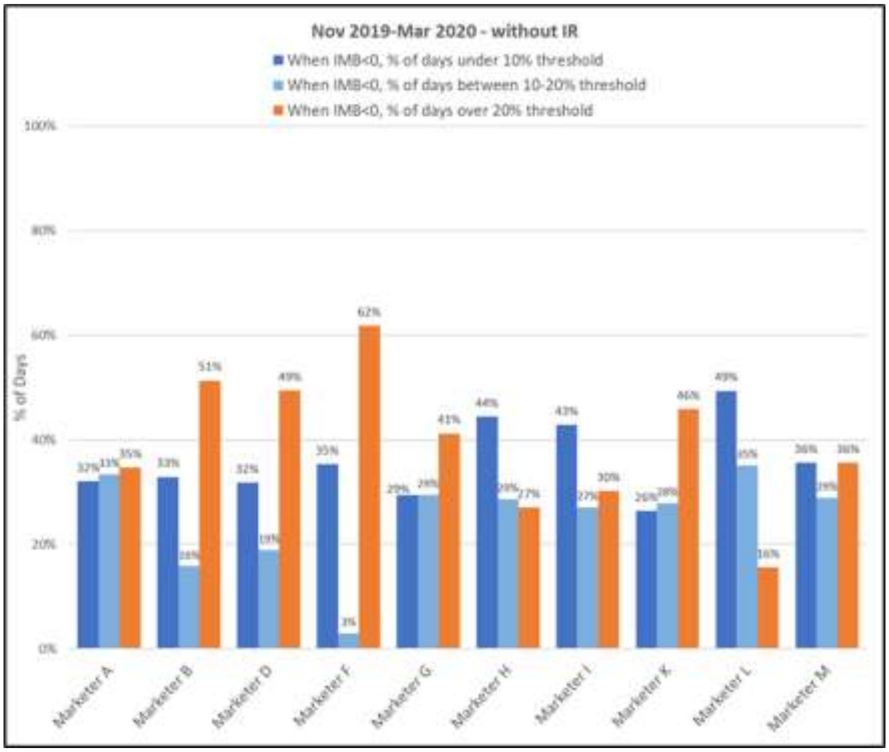
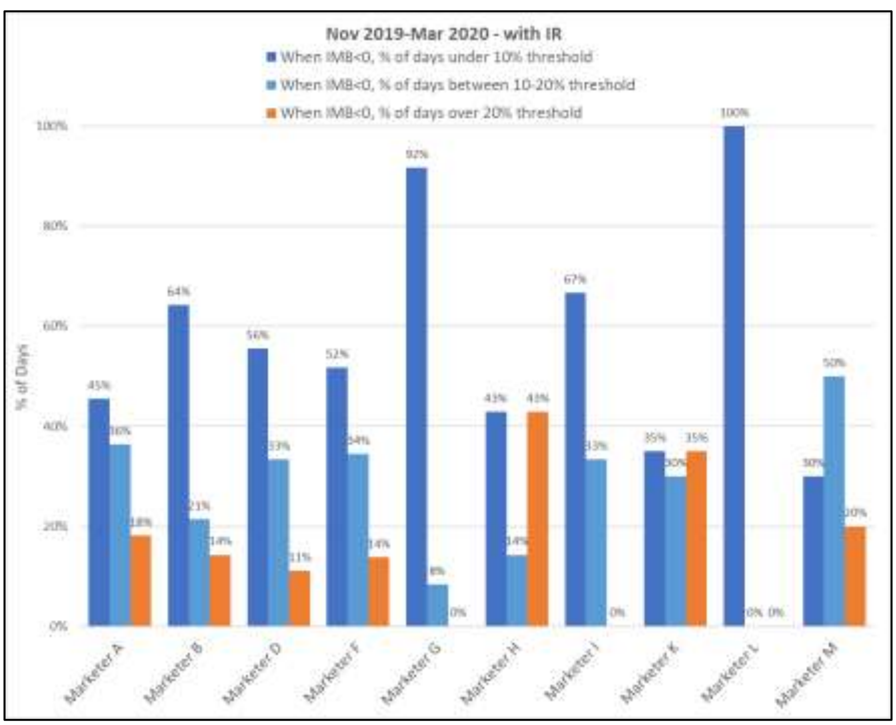


Figure 9 - Percentage of negative imbalance days for the INL service area with IR



The benefit of the IR service to Marketers is evident from these tables. For the LML service area, in this one winter shown, IR helped seven out of eight Marketers lower their percentage of days above the 20% threshold by an average of 34%. Also, IR helped all eight Marketers increase their percentage of days below the 10% threshold by an average of 32%. Likewise, for the INL service area, in this one winter shown, IR has helped nine out of the ten Marketers lower their share of days above the 20% threshold, by an average of 28%. Also, IR helped nine out of the ten Marketers raise their share of days below the 10% threshold, by an average of 26%.

2.3 Assessment of Imbalance Charges for Drafting Above the 10% Imbalance Threshold

For the same winter analyzed previously (November 2019 – March 2020), Atrium assessed amounts (in GJs) Marketers supplied above the 10% imbalance threshold and subsequent Balancing Service charges incurred. This same assessment was analyzed without using IR to calculate the value of the IR service. Significant reductions in Balancing Service charges were realized when utilizing IR. Table 1 below summarizes these findings for the total FEI system.

Table 1 - Amounts and charges when drafting above the 10% threshold with & without IR for Nov 2019 – Mar 2020[4]

Marketer	GJs over 10% threshold (w/o IR)	*Without IR, Balancing Service charges ($)*	GJs over 10% threshold (with IR)	*With IR, Balancing Service charges ($)*	Reduction in Charges when using IR (%)
Marketer L	411,150	*$176,831*	32,352	*$8,181*	-95%
Marketer F	106,179	*$76,730*	15,565	*$4,251*	-94%
Marketer B	193,972	*$104,793*	23,410	*$6,965*	-93%
Marketer I	88,243	*$45,101*	13,726	*$3,540*	-92%
Marketer E	3,536	*$1,106*	418	*$105*	-91%
Marketer A	803,153	*$442,653*	118,122	*$55,934*	-87%
Marketer G	261,843	*$172,568*	55,080	*$22,190*	-87%
Marketer K	193,699	*$133,922*	44,013	*$20,061*	-85%
Marketer D	14,995	*$9,461*	2,926	*$1,867*	-80%
Marketer H	13,758	*$9,576*	4,792	*$4,909*	-49%
Marketer J	64,859	*$62,521*	39,780	*$36,460*	-42%
Marketer M	146,210	*$124,390*	83,800	*$87,637*	-30%

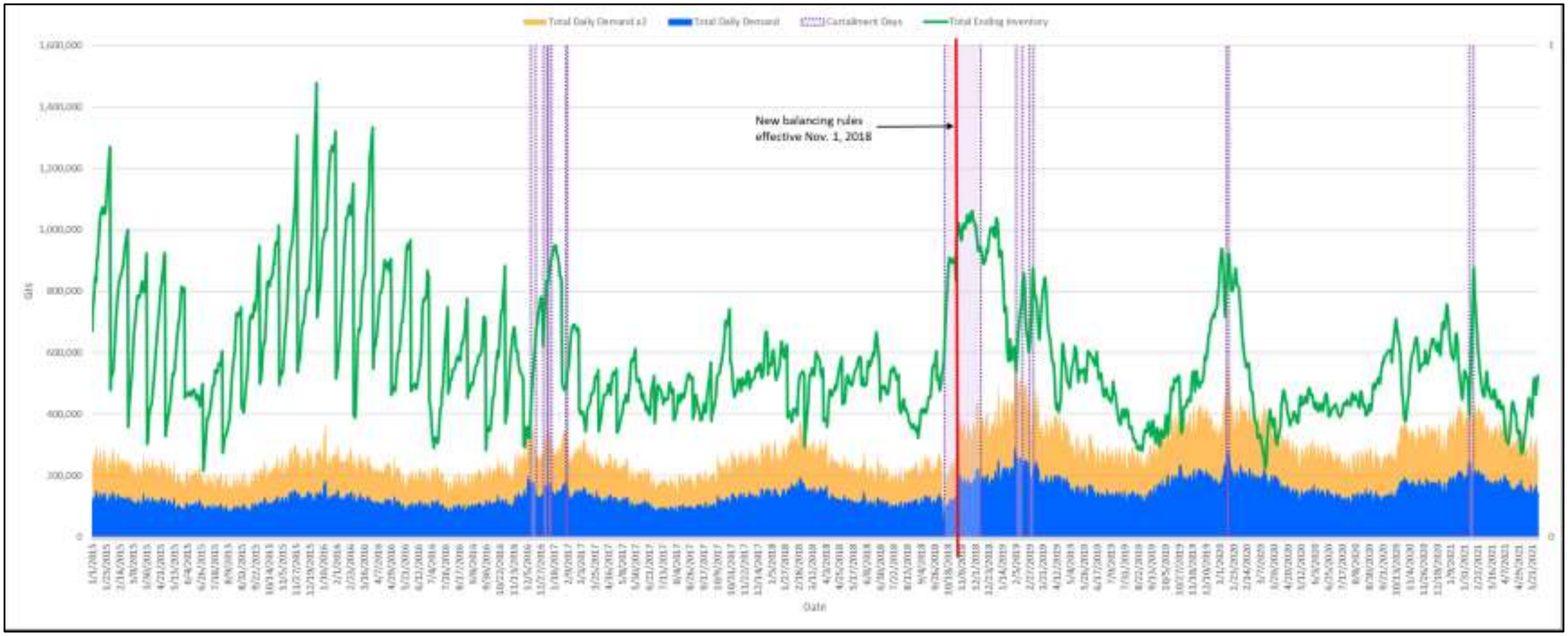
[4] Marketer C is absent from this table because it was not active during this period. Marketer H combines two Marketers that merged during this period.

Significant reductions in Balancing Service charges were evident when using IR to lower the level of imbalances over the total FEI system. Most LDCs with access to storage resources require shippers to subscribe to fee-based balancing, short duration parking/lending, or storage services. Imbalance Return ranks above industry standards as a no-fee, short-duration, storage service that provides Marketers with day-to-day flexibility to address customer differences between expected and actual daily demand, thereby reducing imbalances and the associated imbalance charges.

2.4 Inventory Levels

A final analysis was completed to compare imbalance inventory levels before and after implementation of the new balancing rules, as shown in Figure 10, below. The green line shows the level of daily imbalance inventory from January 1, 2015, to May 21, 2021. The narrow vertical columns identify days when FEI implemented system curtailments days. The vertical red line separates the before-and-after rule implementation periods

Figure 10 - Total System Ending Inventory, Daily Demand, and noted Curtailment Days 2015-2021



Since the implementation of the new balancing rules, inventory levels have trended downward from historical levels and are exhibiting less seasonal volatility. The historically high inventory levels during periods of curtailment are expected. The yellow shaded area combined with the blue, indicates two days of demand, which approximates the level requested by FEI; specifically, that Marketers maintain two to three days of demand in their imbalance inventory.

The metric of "daily ending inventory as a multiple of daily demand" was used to compare the performance of service areas and FEI's total system for three winters before and three winters after implementation of the new rules. Table 2, Table 3, and Table 4 below show the total FEI system, INL, and LML service area imbalance inventory levels over different winter-time periods. Notably, the Winter 18/19 table entry includes the Enbridge rupture event and is not indicative of normal performance. It is only included in the table below for continuity.

Table 2 - Total System Inventory Levels Before and After New Rules

	Total System		
	(a)	(b)	(c) = (b) / (a)
	Avg Daily Demand (GJ)	Avg Daily Ending Inventory (GJ)	Daily End Inv as a multiple of Daily Demand
Winter 15/16	7,814	54,083	6.92
Winter 16/17	9,070	38,604	4.26
Winter 17/18	8,383	30,490	3.64
Winter 18/19	9,522	40,016	4.20
Winter 19/20	5,142	14,916	2.90
Winter 20/21	4,056	12,851	3.17

Table 3 - INL Inventory Levels Before and After New Rules

	INL		
	(d)	(e)	(f) = (e) / (d)
	Avg Daily Demand (GJ)	Avg Daily Ending Inventory (GJ)	Daily End Inv as a multiple of Daily Demand
Winter 15/16	9,541	49,863	5.23
Winter 16/17	11,272	42,388	3.76
Winter 17/18	10,192	29,406	2.89
Winter 18/19	8,767	37,882	4.32
Winter 19/20	8,175	19,622	2.40
Winter 20/21	6,963	20,211	2.90

Table 4 - LML Inventory Levels Before and After New Rules

	LML		
	(g)	(h)	(i) = (h) / (g)
	Avg Daily Demand (GJ)	Avg Daily Ending Inventory (GJ)	Daily End Inv as a multiple of Daily Demand
Winter 15/16	6,374	57,599	9.04
Winter 16/17	7,151	35,306	4.94
Winter 17/18	6,775	31,453	4.64
Winter 18/19	10,352	42,363	4.09
Winter 19/20	6,389	24,826	3.89
Winter 20/21	5,703	23,236	4.07

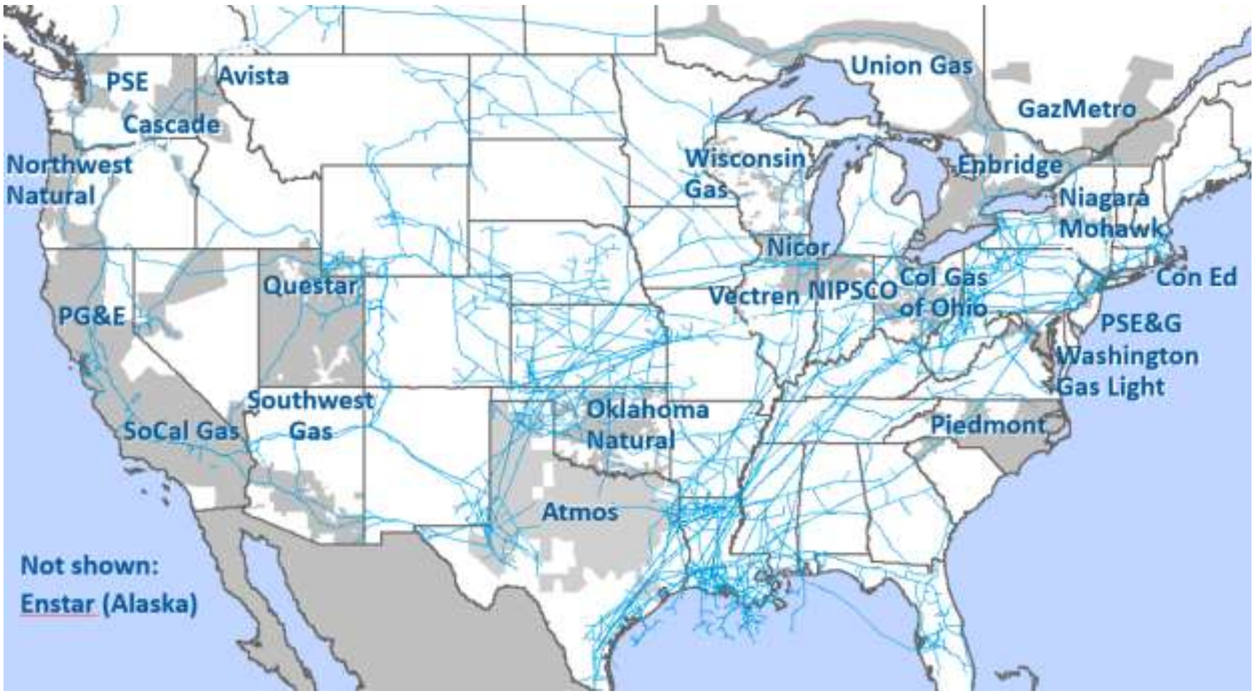
As stated above, FEI requests that Marketers maintain two to three days of demand in their imbalance inventory. Table 2, Table 3, and Table 4 highlight Marketers' improved performance in adhering to this request, as daily ending inventory as a multiple of daily demand have trended downward winter after winter.

The elimination of monthly balancing and moving exclusively to daily balancing aligns with industry standards, as discussed later in Section 3.1.1. Elimination of monthly balancing appears to have removed the potential for gaming activity, as evidenced by imbalance inventory levels under normal operating conditions since the new daily balancing provisions were implemented. Daily balancing provides the expected remedy as evidenced by the downward trend of daily ending inventory as a multiple of daily demand.

3 Industry Insights – Benchmarking LDC Balancing Rules and Services

Atrium examined the balancing provisions contained within the tariffs of twenty-two representative LDCs across North America to determine commonalities between them and highlight unique cases that could be instructive for FEI. The LDCs included in the benchmarking study, their service territories, and upstream interstate or interprovincial pipeline systems are depicted in Figure 11 below.

Figure 11 - LDC's Included in Atrium's Transportation Service Benchmarking & Survey



3.1 Key Provisions of LDC Transportation Balancing Service Tariffs

Balancing provisions vary widely across LDCs due to a lack of mandated standardization, allowing LDCs to develop balancing rules that reflect their unique load profiles and geographic location on an interstate or interprovincial pipeline system. A balancing charge can be a set multiple of the transportation fee, the cost of storage, or incremental gas, depending on whether the imbalance is an over- or under-delivery.

Irrespective of these differences, there are some commonalities among balancing rules, such as the reliance on a penalty structure that allows imbalances within a certain tolerance level, or "dead band," but charges escalating fees beyond the dead band depending on the volume of an imbalance. Many LDCs also offer various storage-related services to their customers to mitigate or net positive and negative imbalances.

3.1.1 Transportation balancing time period

Balancing of Marketer transportation delivered volumes can be required on a daily basis, a monthly basis, or a cumulative basis. Atrium's research showed that the majority of LDCs imposed daily balancing, along with end-of-month cash-outs. Some instances of monthly balancing involved large managed pools of Residential and small Commercial customers in state jurisdictions and LDC service territories where gas commodity unbundling under "customer choice" programs applied to all customer classes of service.

3.1.2 Balancing tolerance thresholds

A balancing tolerance threshold, typically expressed as +/- a percentage of Maximum Daily Quantity ("MDQ" – but also in some cases as a fixed volume – beyond which imbalance quantities are subject to penalties. The percentage is typically applied to a customer's MDQ that they have under contract with a Marketer. Among LDCs examined by Atrium, 5% was the most common dead band; however, the threshold variance ranged from 0% (under certain restrictive conditions) to 15%. Atrium found one instance of a dead band that could be set to various levels for a fee; and reverted to 0% if the transportation customer or Marketer opted out.

3.1.3 Operational flow orders or other restrictions of transportation deliveries

Transportation customers are generally allowed to accrue imbalances on an interruptible basis. An LDC can unilaterally restrict overtake or undertakes on a given day if system conditions require them to do so. To facilitate this, LDCs often have provisions that set different balancing rules and cash-out mechanisms when an operational flow order ("OFO") is declared. Typically, during an OFO, an LDC will be less likely to allow customers to create new imbalances and will restrict access to some services such as imbalance trading or netting. Cash-out terms and penalties will increase, or imbalances will be subject to more stringent dead bands.

3.1.4 Use of premium or discounted gas price-based balancing tiers

Levels of imbalance charges typically increase based on the size of the imbalance incurred. Among LDCs that structured their imbalance fees in this manner, three of them had two tiers of imbalance fees, and four had two to five tiers of fees.

3.1.5 LDC provided transportation balancing services

Many LDCs offer customers various balancing-related services, such as imbalance trading or imbalance aggregation. Imbalance trading allows customers to arrange trades among themselves where a customer with an overtake position, for example, finds another customer with an undertake position on the same system and "trades" the imbalance so that the imbalances net themselves to zero. Similarly, other services allow a customer to net overtake and undertake positions among a customer's different delivery points or pooling points listed in its transportation contract. Other LDCs offer more elaborate services for a fee, such as a balancing account that allows them to use system storage to inject and withdraw quantities to maintain a zero imbalance when imbalance trading services are insufficient to alleviate a customer's imbalance. This last temporary storage service is analogous to FEI's Imbalance Return service.

4 Industry Survey of Specific Aspects of Transportation Balancing

4.1 Comparison of LDC Balancing Provisions

Atrium asked North American LDCs the following five survey questions regarding their transportation balancing tariffed rules and other non-tariffed balancing related policies:

1. What is your company's gas delivery nomination process and schedule for third-party gas supply Marketers or transportation customers (Monthly, Daily, Intra-day)?
2. What customer usage data does your company provide to third-party Marketers to support their ability to understand their customers' daily load profile for the purpose of accurately nominating gas deliveries? What frequency is this data provided (e.g., real time via electronic portal, estimated one/two days before the gas day, actuals day after, once/twice a day, none as it is directly provided by the Marketer's customer)?
3. What rules govern the issuance of operational restrictions or flow orders? How much flexibility does your company have when determining the need for and frequency of operational restrictions (e.g., reduction or elimination of imbalances) or upstream supply restrictions (e.g., hold to pre-authorized level)?
4. Are there any special balancing accommodations or short-term (i.e., within the month) storage related services (parking/lending) offered to shippers? If so, are there limitations as to the number of days or maximum/minimum levels of daily quantities to qualify for the storage related services?
5. Has your company received any requests recently from Marketers or transportation customers for modifications related to your balancing rules, nomination procedures, access to usage data or other transportation related services? If so, please describe the nature of these requests.

4.1.1 Question 1 – LDC's Gas Delivery Nomination Process and Schedule

Contextual Information Related to the Question

This topic was of general interest to FEI in comparing the administrative activities and communication channels of other gas LDCs related to the process of receiving, validating, and processing nominations of supply deliveries from shippers and/or shipper agents.

Representative information from Respondents

Individual customer shippers or shipper agents on LDC distribution systems generally nominate daily. Nominating parties can make changes each cycle when necessary. Marketers provide nominations prior to the LDC's timely deadline and LDCs are flexible to nomination changes up to the timely deadline. For short notice or intra-day nomination changes, some LDCs require that Marketers check via Instant Message ("IM") or phone to verify the changes were received and executed.

The following is a representative example from Manitoba Hydro – Centra Gas Manitoba:

> Transportation Service customers or their nominating agents provide a notification to Centra Gas in the form of an email and spreadsheet attachment that details the customer's forecast consumption, the amount of supply being nominated to Centra's delivery area, as well as any balancing adjustment being made to their account. These notifications may be provided to the LDC at any of the timely, evening, ID1, ID2, or ID3 nomination windows, and must match the supply nominated to Centra's delivery area on the pipeline's scheduling system.

Atrium's Findings and Conclusions

Daily nominations on LDC distribution systems are the industry standard, within the guidelines required by the upstream pipeline(s) to meet the scheduled confirmation deadlines of each of the upstream pipelines connected to the LDC distribution system. The availability of intra-day nominations or changes generally follow the corresponding upstream pipeline requirements. The LDC then confirms changes on every nominating cycle.

FEI's nomination process via the Web Information and Nomination System ("WINS"), or other method approved by FEI, prior to the Timely Nomination Cycle on each Day, is consistent with the industry standard. Marketers provide notice to FortisBC Energy on the WINS of adjustments to the requested quantity for the Day commencing in approximately 24 hours. FEI will notify the Marketer on WINS (or other approved method) if the authorized quantity is less than the requested quantity.

4.1.2 Question 2 – Impact of Usage Measurement on Forecasting Demand

Contextual Information Related to the Question

Feedback was provided by shipper/agents as part of stakeholder engagement interviews conducted by FEI. One of the issues raised and pursued was that usage data provided by FEI (WINS and SCADA) is insufficient to forecast demand. FEI provides customer usage data in the WINS nomination system, whereby the previous day is an estimate, and the second previous day is actual metered consumption. The assertion is that this delay in measurement is a hardship for the shipper/agents to properly forecast demand.

Representative information from Respondents

The majority of respondents indicated they provided actual daily usage at various intervals, which would be within a set number of hours (typically 24 – 48 hours) after the close of the gas day. Some LDCs provide usage estimates within hours of the end of the gas day via Electronic Bulletin Board. To gain access to hourly usage data in real-time, some transportation customers install their own equipment on-site. In some instances, estimates or load profiles are provided for forecasting purposes by subscription for a fee. An example of a fee-based service, estimated daily use for the next five days was provided on the day before each gas day, based on the most recent forecast of heating degree days.[5] The advent of automated metering infrastructure in some jurisdictions and LDCs has made faster turn-around of daily usage data possible for transportation customers and their supplier agents.

Atrium's Findings and Conclusions

Actual daily usage data provided within 24 – 48 hours of the close of the gas day, by various electronic methods, is the natural gas utility industry standard. FEI's provision of transportation customer usage data via its WINS and SCADA systems aligns with industry norms.

Based on Atrium's research of gas LDCs practices with respect to the provision of customer usage data, and the results of Atrium's quantitative analysis, we found no evidence to support the notion that FEI's current measurement and usage information system is an impediment to Marketer's ability to provide reasonable nominations for their customers under similar transportation models. The relatively insignificant levels of imbalance charges incurred by Marketers suggest that the current measurement data provided by FEI are sufficient.

4.1.3 Question 3 – Rules Governing the Issuance of Operational Restrictions or Flow Orders

Contextual Information Related to the Question

Currently, FEI has no specific tariff rules defining specific pipeline system operating conditions and circumstances that govern the imposition of operational restrictions (e.g., reduction or elimination of Imbalance Return) or supply restrictions (e.g., hold to authorize). Issues raised during the stakeholder engagement interviews allege FEI has become increasingly strict in imposing operational restrictions for a variety of reasons.

Representative information from Respondents

The common LDC practice, with respect to Operational Flow Orders, is to follow the upstream pipe's OFO restrictions on their system. Most LDCs have tariff language reserving the right to issue flow orders, restrictions, and entitlements "at their sole discretion."

Some LDCs do provide varying levels of guidance in the "Terms and Conditions" section of the Transportation Service tariffs regarding the restriction process and defining the conditions under which an operational restriction will likely occur. Example of tariff language: "Critical Day"

[5] This service was for Suppliers serving Residential and Small Commercial customer groups under an Aggregation Service. As of May 1, 2022, estimated daily use will no longer be provided. Illinois Commerce Commission Order in Northern Illinois Gas Company Docket 20-0606, May 13, 2021.

> *"Declared by the Company whenever any of the following five anticipated conditions occurs: (a) when the Company experiences failure of Transmission, Storage or Distribution facilities; (b) when Transmission system pressures or other unusual conditions jeopardize the operation of the system; (c) Company's pipeline and supply resources are being used at or near maximum deliverability; (d) when any of the Company's [upstream] transporting pipelines or suppliers call the equivalent of a Critical Day; or (e) when the Company is unable to fulfill its firm contractual obligations or otherwise when necessary to maintain the overall operational integrity of all or a portion of the Company's system."* [Northern Illinois Gas Company]

Atrium's Findings and Conclusions

Formalizing and documenting tariff rules within the tariff governing the imposition of operational or supply restrictions should not be viewed as overly restrictive or "tying the hands" of the LDC.

Tariff rules should provide the LDC with the flexibility to respond as needed to various situations that will occur that require decisive action to preserve reliable operation of its distribution system. Notice by the LDC of operational or supply restrictions provides guidance to transportation customers' shipper/agents. It is the responsibility of the shipper/agents to anticipate, recognize, and respond to the most common weather-related, upstream pipeline, and regional gas market conditions that could warrant an operational or supply restriction.

Defining specific operational conditions and circumstances in a tariff, under which restrictions are to be imposed on shippers, are few and not a common industry practice. The purpose behind non-prescriptive tariff rules that provide LDCs the right to issue flow orders, restrictions, and entitlements "at their discretion" is to ensure the integrity of the distribution system is preserved and customers are protected from service interruption. Atrium finds that FEI's process for identifying the conditions on its pipeline system under which an operational or supply restriction is warranted conforms with common industry practices.

4.1.4 Question 4 – Special Balancing Accommodations or Short-term Storage Services

Contextual Information Related to the Question

As part of the reporting requirements from the BCUC's Final Decision in the rate design proceeding, FEI was directed to report on the effectiveness of imbalance return as a tool for Shippers/Shipper Agents to manage excess inventory including discussion of any modifications made to the allocation methodology in response to changes in demand for imbalance return after the balancing rule changes are implemented.

Representative information from Respondents

Most LDCs with access to storage resources require shippers to subscribe to fee-based balancing, short-duration parking/lending, or storage services. Some examples are listed below:

- Mandatory Storage Capacity Assignment Program: Under this program, the LDC releases a "piece of the pie." The Company then allows "trading," which customers/Marketers use to trade across days to get them into their balance limitations.
- No Notice Transportation Service: This is a form of balancing service provided from the customer's Storage Service Agreement (SSA). The shipper's SSA service is utilized to balance supply and demand, and to adjust shipper's nominations.
- System Balancing Charge: Under this balancing program, a volumetric rate per unit [Dth / Mcf] is charged on all delivered volumes.

Where LDCs do not have storage service, some Park and Loan services are provided by upstream interstate or intrastate pipelines.

Atrium's Findings and Conclusions

Most LDCs with access to storage resources require shippers to subscribe to fee-based balancing, short-duration parking/lending, or storage services.

FEI's Imbalance Return meets or exceeds comparable industry practices as a no-fee, short-duration, storage service that provides Marketers with day-to-day balancing flexibility to address supply/demand variability of their customers.

4.1.5 Question 5 - Requests for Modifications Related to Balancing Rules

Contextual Information Related to the Question

Feedback from some shipper/agents suggests that FEI's current transportation Imbalance Return service provisions benefit larger shipper/agent customer groups with corresponding large daily demands over the shipper/agents with smaller customer groups with typically small daily demands. A request has been received that FEI amend the allocation of Imbalance Return whereby if the percentage of demand for the service is under a specified threshold, a minimum level or base amount of IR should be allowed.

Atrium's Findings and Conclusions

Atrium found no examples of other gas LDCs that provide accommodations within their fee-based gas storage related (e.g., Parking/Lending) services, which are on par with FEI's Imbalance Return service, for shippers with small daily demands. Such services tend to require a minimum level of daily demand to qualify.

However, it is not unreasonable for FEI to provide the described concession in its IR service for shipper/agents serving customer groups with small daily demands if it can be accommodated within the IR structure, is not detrimental to other Marketers, and is not administratively burdensome.

5 Concluding Remarks

Historically, FEI had some of the more generous transportation balancing tariff rules in the natural gas LDC industry, while providing appropriate performance incentives for Marketers. Members of Atrium's review team assisted FEI with revisions to its Transportation Service Model ("the Model"), as part of the 2016 Rate Design Application. These revisions were not a wholesale overhaul of the Model, but rather intended to progress toward industry standards while protecting the integrity of the long-standing Model. As stated earlier, Transportation balancing provisions vary widely across LDCs and are not standardized in a "one size fits all" form, allowing LDCs to develop balancing rules that reflect their unique load profiles and geographic location on interstate or interprovincial pipeline systems. FEI's balancing rules reflect the regional attributes of its interconnected upstream pipelines and gas market environment. Atrium finds the revised balancing rules of FEI to be reasonable and working as originally intended, as the metrics in our analyses have shown.

Appendix B

CONSULTATION SUMMARY

From: [redacted]
To: [redacted]
Cc: FortisBC Regulatory Affairs-Gas; [redacted]
Subject: Invitation to Participate in the Review of the Transportation Service Model
Date: Thursday, March 25, 2021 11:21:42 AM
Attachments: Notice to Marketers for Stakeholder Sessions.pdf

---

Good day,

Please see the attached notice and invitation to participate in a review of FortisBC's Transportation Service Model.

Feel free to pass this notice to others in your organization as you see fit.

Should you have any questions, please let me know.

Regards,

Stephanie Salbach
Transportation Services Manager
FortisBC Energy Inc.
[redacted]
Hotline: 604-592-7799

FortisBC Energy Inc.
16705 Fraser Highway
Surrey, B.C. V4N 0E8
www.fortisbc.com

Attention: Gas Marketers/Shipper Agents

Re: Invitation to Participate in the Review of the Transportation Service Model

FortisBC Energy Inc. (FEI) is inviting Marketers/Shipper Agents representing customers taking service under FEI's Transportation Service Model through Rate Schedules, 22, 22A, 22B, 23, 25, 27 and 46 to participate in upcoming workshop sessions intended to gather feedback on the Transportation Service Model. All Marketers are encouraged to participate.

As most of you are aware, in the 2016 Rate Design proceeding, the British Columbia Utilities Commission (BCUC) approved amendments to the Transportation Service Model by its Decision and Order G-135-18 dated July 20, 2018. The amendments related to customer balancing rules, implementation of daily balancing for all transportation service customers, a reduction of the daily balancing tolerance and changes to daily balancing charges for gas supply shortfalls. For customers located in the Lower Mainland (including Vancouver Island) and the Interior, the approved changes came into affect on November 1, 2018 and for customers in the Columbia and East Kootenay regions, on November 1, 2019.

The decision also directed FEI to file a written report with the BCUC on by June 1, 2020 on transportation service balancing (Report) assessing the impact of the changes by June 1, 2022. FEI was encouraged to engage in a stakeholder review in the preparation of the report. The decision directed that the Report include an assessment and discussion of the following:

- Impact of new balancing rules on the use of core resources including both changes to variable costs of balancing the system to accommodate transportation service and changes to fixed costs arising from a need to contract midstream resources differently;
- Effectiveness of imbalance return as a tool for Shippers/Shipper Agents to manage excess inventory including discussion of any modifications made to the allocation methodology in response to changes in demand for imbalance return after the balancing rule changes are implemented;
- Whether there should be further tightening of tolerances for under-supply;
- Whether it is necessary to implement tolerances and associated charges for over-supply; and
- Whether the balancing charges appropriately recover the costs of providing balancing to transportation service customers and provide sufficient incentive to transportation service customers to balance their supply and demand.

In addition, on August 10, 2020 in Order G-210-20[1], FEI was directed to include the following topics in its Report:

[1] https://www.bcuc.com/Documents/Proceedings/2020/DOC_58897_G-210-20-FEI-BCGMC-Complaint-Reasons.pdf.

- Nature, timing and adequacy of information provided to shipper agents to manage gas supply resources;
- Administration of inter-customer group balancing and transparency of inter-customer group balancing rules; and
- FEI's criteria for curtailment of inventory returns to shipper agents.

The stakeholder review will take place in three web-based virtual workshops planned to be held in September 2021, January 2022 and April 2022. BCUC staff will be invited to attend. Prior to the first workshop, FEI will host conference calls with each Marketer individually to discuss and document feedback on the issues to be addressed in the Report as well as any other issues Marketers may raise. FEI will begin arranging these conference calls in spring 2021. Prior to the summer, FEI will circulate a discussion document summarizing feedback from the conference calls with Marketers, which will form the basis of discussions during the first workshop in September. Following the September session, FEI will prepare a draft report for circulation to all Marketers by November, which will be reviewed at the second workshop in January 2022. Based on additional discussion and feedback from second workshop, FEI will update the report by March end and will recirculate a final draft for review at third workshop in April 2022.

We look forward to working with all stakeholders in the preparation and filing of the Report.

If you have any questions or wish to schedule your initial conference call and confirm your participation in the stakeholder engagement process, please contact Stephanie Salbach at [redacted] or by email to [redacted] Feel free to invite other members within your organization as you see fit to participate in this process.

Sincerely,

FORTISBC ENERGY INC.

Shawn Hill
Director, Energy Supply

cc (email only): BCUC

From: [redacted]
To: [redacted]
Cc: FortisBC Regulatory Affairs-Gas; [redacted]
Subject: Transportation Service Model Review Update
Date: Friday, July 16, 2021 1:34:17 PM
Attachments: FEI Transport Model Review Update.pdf
Summary Marketer Feedback.pdf

Good afternoon,

Please see the attached update on the Transportation Model Review and, the summary of feedback provided by Shipper Agents/Marketers from individual conference calls over the last few months. Thank you for your time and participation.

Regards,

Stephanie Salbach
Transportation Services Manager
FortisBC Energy Inc.
[redacted]
Hotline: 604-592-7799

FortisBC Energy Inc.
16705 Fraser Highway
Surrey, B.C. V4N 0E8
www.fortisbc.com

Attention: Gas Marketers/Shipper Agents

Re: Update on Stakeholder Engagement for the Transportation Service Model Review

Over the last few months, FortisBC Energy Inc. (FEI) has conducted 11 individual meetings with Marketers/Shipper Agents (Shipper Agents) representing customers taking service under FEI's Transportation Service Model through Rate Schedules 22, 22A, 22B, 23, 25, 27 and 46 to gather feedback on the Transportation Service Model. The meetings mark the first step in gaining insight as to how the model is working under the approved amendments to the Transportation Service Model through the British Columbia Utilities Commission (BCUC) Decision and Order G-135-18 in FEI's 2016 Rate Design Application (RDA Decision), which largely came into affect November 1, 2018. The approved amendments related primarily to customer balancing rules, specifically the implementation of daily balancing for all transportation service customers, a reduction to the daily balancing tolerance, and changes to the daily balancing charges for gas supply shortfalls.

FEI has attached a summary of feedback and requests received from Shipper Agents to date under each of the directives in the RDA Decision. The documented feedback will be used as a basis to generate discussion and consideration for possible future changes to the Transportation Service Model.

As shown in the summary, there are multiple requests for changes to the model within each of the discussion sections. While all items will be given fair and reasonable consideration, in order to prioritize potential changes that each Shipper Agent feels would be most important for FEI to investigate and evaluate, FEI requests that each Shipper Agent provide FEI with a ranked short-list of their top five requests from all of those identified in the summary. This prioritized list from each Shipper Agent will help guide FEI in its evaluation of potential system and process changes that may be considered as well as investigating both the lead-time required for such changes and the associated costs. FEI will include all of these factors into the feasibility of proposing potential changes, if any, to the Transportation Service Model. Please provide your top-five requests to FEI by email to Stephanie Salbach by email to: [redacted] Friday, August 6, 2021.

Regarding next steps, FEI will host the first workshop in September at which time we will review all requests as a group including the aggregation of each Marketer's top-five requests. FEI will present an assessment of the feasibility of the requests in terms of development time and costs involved for further consideration. For that workshop, we will ask that Shipper Agents come prepared to participate in a general discussion regarding the group's experience operating under the amended balancing rules, as well as their prioritized requests under each of the BCUC's directives.

FEI would like to thank all of the Shipper Agent participants for taking the time to meet with FEI and for the candid feedback provided. If there are any questions or a need for clarification, please email or call Stephanie directly at [redacted].

Sincerely,

FORTISBC ENERGY INC.

Shawn Hill
Director, Energy Supply

cc (email only): BCUC Commission Secretary

BCUC Directive	Feedback Summary	Requests
Impact of new balancing rules on the use of core resources including both changes to variable costs of balancing the system to accommodate transportation service and changes to fixed costs arising from a need to contract midstream resources differently;	• FEI is analyzing the use of core resources including variable and fixed costs to determine the impact from the new balancing rules.	TBD
Effectiveness of imbalance return (IR) as a tool for Shippers/Shipper Agents to manage excess inventory including discussion of any modifications made to the allocation methodology in response to changes in demand for imbalance return after the balancing rule changes are implemented;	• General feedback indicates the revised allocation is fair, reasonable and provides certainty for planning. • The allocation puts everyone on an equal playing field. • Helpful to manage load, and load swings. • When IR is set to zero, it is difficult to balance within the 10% tolerance. • Questions asking for a better understanding of how FEI manages this service; the process and predictability when IR is reduced or eliminated in order to prepare for these restrictions. • Portion allocated to Marketer groups with smaller customer demand is small.	1. FEI to release a higher amount of IR as a whole. 2. Mechanism to allow greater IR to specific Marketer(s) by request. 3. Reallocation of unutilized service to other interested Marketers. 4. Minimum allocation of IR to groups with smaller demand. 5. Modify the allocation to incorporate a volatility/load factor. 6. Make IR available during Hold to Authorize (HTA)/Supply restriction periods.
Whether there should be further tightening of tolerances for under-supply;	• No marketer in favour of further tightening. • Many did not want the tolerance change to 10% in the first place. • Some Marketers indicate they are managing under the 10% tolerance and others express difficulty especially during cold weather or customer load volatility. • If a further tightening is imposed, look for models that provide more timely information or certainty such as a delivery requirement.	7. Return to the 20% tolerance. 8. FEI to offer a different percentage of balancing tolerance by season or during specific times of year (i.e. shoulder months) when operational conditions allow.

BCUC Directive	Feedback Summary	Requests
Whether it is necessary to implement tolerances and associated charges for over-supply;	• Nearly all Marketers oppose an over-supply tolerance and associated charges, especially those with customers having volatile demand. • One Marketer is open to limits during normal operational circumstances, but not during HTA periods. • If specific Marketers are over-delivering, exercise the tariff to withhold inventory.	9. FEI to withhold inventory/pack for specific marketers that are over-delivering as opposed to restricting the service for all.
Whether <u>the balancing charges appropriately recover the costs of providing balancing to transportation service customers</u> and provide sufficient incentive to transportation service customers to balance their supply and demand.	• FEI is analyzing the volume of recovered charges.	TBD
Whether <u>the balancing charges</u> appropriately recover the costs of providing balancing to transportation service customers and <u>provide sufficient incentive to transportation service customers to balance their supply and demand.</u>	• Generally, Marketers indicate the incremental charge ($0.25/GJ) provides incentive to balance and avoid the charge. • Some have indicated the charge does not factor into their business planning.	
<u>Nature, timing and adequacy of information</u> provided to shipper agents to manage gas supply resources;	• Some Marketers indicate the data available to them via WINS and SCADA is adequate and sufficient to balance. • Some Marketers indicate WINS data is insufficient especially when restrictions are in place. • The two-day lag in WINS is not helpful, and challenging to use as a forecast. • More timely/real-time data would be useful.	10. FEI to investigate better measurement technology available in the industry. 11. FEI to provide an intra-day estimate in WINS. 12. FEI to improve data quality of the previous day estimate in WINS. 13. FEI to provide a daily delivery requirement during normal and/or HTA/supply restriction periods.

BCUC Directive	Feedback Summary	Requests
Administration of <u>inter-customer group balancing</u> and transparency of inter-customer group balancing rules;	• Grateful for the trades to reduce UOR charges • Continue process going forward. • Remain outside the tariff. • Clarify policy/practice and communicate to marketer community.	14. Automate the process and/or a bulletin board format. 15. Continue process as is (status quo). 16. Proposed a utility super group netting exercise, where if as a whole, all shippers combined deliver sufficient supply to meet demand there should be no penalty.
FEI's criteria for <u>curtailment of inventory returns</u> to shipper agents	• Mix of feedback with Marketers that understand why FEI limits this service and others who question FEI' decisions to limit. • Marketers request a better understanding of FEI's considerations/parameters to enable better planning. • FEI encouraged to provide as much notice as possible when limiting this service.	17. Days when Imbalance return is reduced/eliminated flag the line item in the nomination screen. 18. FEI to provide a "status update" for operational changes (weather/maintenance/ interconnecting pipeline status, etc.) when reducing IR.
Other: Daily Balancing Charges - Interior	• The Lower Mainland has a single source of supply from Westcoast (Sumas). • Source of supply for the Interior is different, Station 2. • Penalty for daily balancing charges across all rate schedules is currently based on the Sumas price. • Should have a different penalty rate for customers in the Interior.	19. Amend Rate 22A Daily Balancing Gas charge to a Station 2 price.
Other: Timely Cycle Deadline	• Cycle deadline (Timely). Westcoast offers flexibility to extend the deadline.	20. FEI to allow Timely cycle deadline flexibility.
Other: Apply Penalties to Specific Marketers	• Utility's approach is to treat everyone the same, which is a mistake. • FEI is encouraged to communicate with the BCUC, and report problems with specific marketers.	21. FEI to apply penalties to the entities that are causing core market problems.

BCUC Directive	Feedback Summary	Requests
Other: Hold to Authorize (HTA) /Supply Restrictions	• Marketers request a better understanding of FEI's considerations/parameters for issuing a HTA to enable better planning.	22. FEI to disclose the parameters and conditions for issuing HTA/Supply restrictions. 23. FEI to apply locational/regional HTA – not apply across all regions.

Request No.	Request Description	Marketer Ranking	Notes
7.	Return to the 20% tolerance.	1	
6.	Make IR available during Hold to Authorize (HTA)/Supply restriction periods.	2	
2.	Mechanism to allow greater IR to specific Marketer(s) by request.	3	Received same number of votes
3.	Reallocation of unutilized service to other interested Marketers.		
14.	Automate the process and/or a bulletin board format.	4	
1.	FEI to release a higher amount of IR as a whole.	5	Received same number of votes
11.	FEI to provide an intra-day estimate in WINS.		
12.	FEI to improve data quality of the previous day estimate in WINS.		
19.	Amend Rate 22A Daily Balancing Gas charge to a Station 2 price.		
4.	Minimum allocation of IR to groups with smaller demand.	6	Received same number of votes
13.	FEI to provide a daily delivery requirement during normal and/or HTA/supply restriction periods.		
16.	Proposed a utility super group netting exercise, where if as a whole, all shippers combined deliver sufficient supply to meet demand there should be no penalty.		
20.	FEI to allow Timely cycle deadline flexibility.		
21.	FEI to apply penalties to the entities that are causing core market problems.		
23.	FEI to apply locational/regional HTA – not apply across all regions.		
8.	FEI to offer a different percentage of balancing tolerance by season or during specific times of year (i.e. shoulder months) when operational conditions allow.	7	Received same number of votes
10.	FEI to investigate better measurement technology available in the industry.		
17.	Days when Imbalance return is reduced/eliminated flag the line item in the nomination screen.		
24.	Include real time SCADA information prior to the intra-day cycles	8	Requests identified after initial Marketer Summary prepared
25.	Create marketer dashboards to provide collected data snapshots of marketer group information		
26.	Provide clear information, timelines, priorities and other information related to curtailment		
27.	Tariff be structured so FEI may curtail/HTA only when absolutely necessary		
28.	Clear and consistent criteria for the return of HTA gas inventory and a mechanism for returning any premium value of that inventory, and specifically that FEI publish its criteria so customer and marketers can understand how FEI will make its decisions it's criteria so customer and marketers can understand how FEI will make its decisions		
29.	FEI to adhere to the Gas Marketers Code of Conduct		

Request No.	Request Description	Marketer Ranking	Notes
5.	Modify the allocation to incorporate a volatility/load factor.	0	not selected by Marketers when ranking
9.	FEI to withhold inventory/pack for specific marketers that are over-delivering as opposed to restricting the service for all.		
15.	Continue process as is (status quo).		
18.	FEI to provide a “status update” for operational changes (weather/maintenance/ interconnecting pipeline status, etc.) when reducing IR.		
22.	FEI to disclose the parameters and conditions for issuing HTA/Supply restrictions.		

Stakeholder Session to Review FEI's Transportation Service Model

September 2021

Stephanie Salbach, Transportation Services Manager

September 22, 2021

Today's Agenda

- Primary objective – Hear from Stakeholders
- Brief overview of the approved changes from FEI's 2016 Rate Design Application
- Review the RDA Decision Directives
- Review of the Stakeholder engagement to date
- Next steps – report circulation and workshop
- Direct Energy Presentation – James Fredricksen and Nicole Black
- Roundtable discussion

Rate Design Approved Changes– effective Nov 2018

Main asks to apply to all transportation customers' Rate Schedules/Tariffs proposed in the Application:

- Eliminate monthly balancing - daily balancing for all transportation customers.
- Reduce the daily balancing tolerance from 20 percent to 10 percent and introduce a balancing charge of $0.25/ gigajoule (GJ) for gas supply shortfalls within a 10 to 20 percent tolerance level.

July 20, 2018 - Decision Issued on the 2016 Rate Design Application (Order G-135-18)

https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/item/316310/index.do

Imbalance Return – consultative process

Directives and Report Filing by June 2022

RDA Transportation Service Directives

Report to include:

- Impact of new balancing rules on the use of core resources
- Effectiveness of Imbalance return
- Evaluate further tightening balancing tolerance (>10%)
- Evaluate an over-supply tolerance
- Evaluate if the balancing charges have provided sufficient incentive to balance and if charges are sufficient for cost recoveries
- Nature, timing and adequacy of data/information
- Administration of inter-customer group balancing
- FEI's criteria for curtailment of inventory returns

Engage in Stakeholder feedback

Additional Subjects raised

- Daily Balancing Charges – different Interior rate
- Timely cycle deadline
- Report *bad apples* to the BCUC and Apply penalties to specific Marketers
- Hold to Authorize/Supply Restriction and Imbalance Return

Requests for Changes to the Model

23 Requests – streamlined to top five

Request No.	Request Description	Marketer Ranking	Notes
7.	Return to the 20% tolerance.	1	
6.	Make IR available during Hold to Authorize (HTA)/Supply restriction periods.	2	
2.	Mechanism to allow greater IR to specific Marketer(s) by request.	3	Received same number of votes
3.	Reallocation of unutilized service to other interested Marketers.		
14.	Automate the process and/or a bulletin board format.	4	
1.	FEI to release a higher amount of IR as a whole.	5	Received same number of votes
11.	FEI to provide an intra-day estimate in WINS.		
12.	FEI to improve data quality of the previous day estimate in WINS.		
19.	Amend Rate 22A Daily Balancing Gas charge to a Station 2 price.		

September 2021 forward

September meeting expectations

- Listen and discuss the model as a group

Next Steps

- Evaluate feasibility of changes
- Draft of the Report early in 2022

Energy at work FORTIS BC™

FortisBC Transportation Service

Stakeholder Session
September 22, 2021

Direct Energy

Challenges

- The nature of this market makes restrictions on daily balancing thresholds hard to manage.
- The market trades on a next day basis but the majority of the consumption window occurs outside of the trading cycle.
- Hold to Authorize events have zero tolerance and extreme penalties that without better visibility hold Marketers to a challenging standard by the utility.
- Offering some flexibility with greater Imbalance Return, Marketer inventory transactions, and increased tolerances can help mitigate these challenges.

Proposed Improvements

- One idea is to allow Marketers to balance their daily accounts retrospectively by dealing those volumes with other Marketers once the meters show actual consumption.
- This would mitigate some of the price risk associated with buying supply before knowing burns.
- Currently, over-supplying a Marketer account during restricted Imbalance Return (typically initiating a higher price environment) means Marketers are not able to liquidate excess inventory until prices come down, exposing Marketers to unnecessary price risk.
- Retrospective balancing between Marketers should not impact the system or the utility.

Proposed Improvements

- In Alberta, through co-operation between the Marketers and the utility, ATCO Gas has moved from "in kind" to financial gas load settlement in accordance with AUC Decision 26013-D01-2021 issued March 1, 2021:

  12. The Commission finds that the current "in kind" settlement process is vulnerable to price differentials due to the time lag between the initial gas allocation from ATCO Gas to retailers and the settlement adjustment. DEML and ENMAX both raised concerns about the unintended consequences of the current "in kind" settlement process; DERS demonstrated that the estimated harm of the current gas volume settlement amounted to nearly $1 million in losses over the course of two months and raised concerns about how these fluctuations may affect its customers.

Proposed Improvements

- Excerpts from AUC Decision 26013-D01-2021:

  13. The costs of the current settlement, due to recently increased market price volatility, have been significant to retailers. Moreover, there is no expected adverse impact from the proposed change on end-use customers. Rather, end-use customers may benefit from improved operation stability of the retailers. Based on DERS' analysis, the method should significantly reduce the cost variations by aligning monthly cash settlement pricing to match the daily imbalance with the daily market price.

  14. The Commission agrees that the new settlement process will eliminate the price fluctuations between the day-of-use price and the prices used for each of the settlement intervals and supports its implementation. Therefore, the Commission approves the new settlement process, the associated changes to ATCO Gas's Retailer Terms and Conditions for Gas Distribution Service and the removal of the requirement for its imbalance window to match the transmission balance zone of NGTL to effect this change.

- ATCO Gas is indifferent to the change as the cost of load balancing is carried in a deferral account.

Thank you

For further information, please contact:

Stephanie Salbach, Transportation Service Manager

[redacted]

Cell: [redacted]

Find FortisBC at:
fortisbc.com
talkingenergy.ca
604-576-7000

Follow us **@fortisbc**

Attendees for the September 22/21 Stakeholder Session - Transportation Services Workshop

Company	Name	In-Meeting Duration	First Join time	Last Leave time	Role
?	7787730785	1h 24m 6s	8:55 AM	10:19 AM	Attendee
Absolute Energy	Susan Juilfs	1h 21m 13s	8:57 AM	10:19 AM	Attendee
Absolute Energy	Kirby Morrow	1h 18m 31s	9:00 AM	10:19 AM	Attendee
Absolute Energy	Cory Fung	1h 5m 33s	9:13 AM	10:19 AM	Attendee
Access Gas	Patti Andersen	1h 24m 26s	8:54 AM	10:19 AM	Attendee
Access Gas	Sheri Clemons	1h 22m 32s	8:56 AM	10:19 AM	Attendee
Access Gas	James Bartlett	1h 3m 27s	8:59 AM	10:03 AM	Attendee
Atrium Economics	Ron Amen	1h 23m 38s	8:55 AM	10:19 AM	Attendee
Atrium Economics	John Taylor	1h 19m 42s	8:59 AM	10:19 AM	Attendee
Atrium Economics	Chris Hutchinson	1h 18m 36s	9:00 AM	10:19 AM	Attendee
BCSEA	Bill Andrews	1h 21m 16s	8:57 AM	10:19 AM	Attendee
BCUC	O'Neal, Joshua	1h 18m 38s	9:00 AM	10:19 AM	Attendee
BCUC	Lavoie, Ted	1h 18m 28s	9:00 AM	10:19 AM	Attendee
BCUC	Vancise, Billy	1h 16m 48s	9:02 AM	10:19 AM	Attendee
BCUC	Janet Rhodes	1h 14m 35s	9:04 AM	10:19 AM	Attendee
BCUC	Kehoe, Aidan	49m 25s	9:08 AM	9:58 AM	Attendee
CEC	David Craig	1h 24m 21s	8:54 AM	10:19 AM	Attendee
Direct Energy	Nicole Black	1h 19m 47s	8:59 AM	10:19 AM	Attendee
Direct Energy	James Fredricksen	1h 16m 26s	9:02 AM	10:19 AM	Attendee
Easy Energy	Tom Dixon	1h 14m 8s	9:05 AM	10:19 AM	Attendee
FortisBC	Bevacqua, Ilva	1h 24m 37s	8:54 AM	10:19 AM	Presenter
FortisBC	Salbach, Stephanie	1h 22m 22s	8:56 AM	10:19 AM	Organizer
FortisBC	Hodgins, Kevin	1h 21m 45s	8:57 AM	10:19 AM	Presenter
FortisBC	Hill, Shawn	1h 21m 10s	8:58 AM	10:19 AM	Presenter
FortisBC	Gill, Manpreet	1h 20m 24s	8:58 AM	10:19 AM	Presenter
FortisBC	Yasinchuk, Matt	1h 18m 56s	9:00 AM	10:19 AM	Presenter
IGI Resources	Johnston, Kim	1h 20m 51s	8:58 AM	10:19 AM	Attendee
IGI Resources	Renfro, Wendy L	1h 18m 43s	9:00 AM	10:19 AM	Attendee
Macquarie	Gerilynne Pickett	1h 17m 42s	9:01 AM	10:19 AM	Attendee
RCIA	Peter Helland	56m 48s	9:22 AM	10:19 AM	Attendee
Sentinel	Jim Langley	1h 8m 50s	9:10 AM	10:19 AM	Attendee
Shell Energy	Gill, Blake	1h 18m 17s	9:00 AM	10:19 AM	Attendee

Shell Energy	Mccordic, Mary	1h 16m 3s	9:03 AM	10:19 AM	Attendee
Shell Energy	Foster, Danielle	1h 36s	9:18 AM	10:19 AM	Attendee
Tidewater Midstream	Mahdis Sadeghi	1h 19m 10s	8:59 AM	10:19 AM	Attendee

FEI's May 2022 Stakeholder Session

Review of Directives and Transportation Marketer Requests

Stephanie Salbach, Transportation Services Manager, FortisBC Energy Inc.

Ron Amen, Managing Partner, Atrium Economics

May 10, 2022

Today's Session

2016 Rate Design Application

Order G-135-18 – BCUC Directives; Additional topics Order G-210-20

Stakeholder Engagement

Atrium Economics Assessment

Review the Directives, Marketer Feedback and FEI Assessment

Background – Transportation Service Changes

- 2016 Rate Design Application – Approved Changes to the Transportation Model
- Directives from the Decision – Report filing
- Stakeholder engagement sessions
- Presentation from Atrium Economics

FEI General Comments

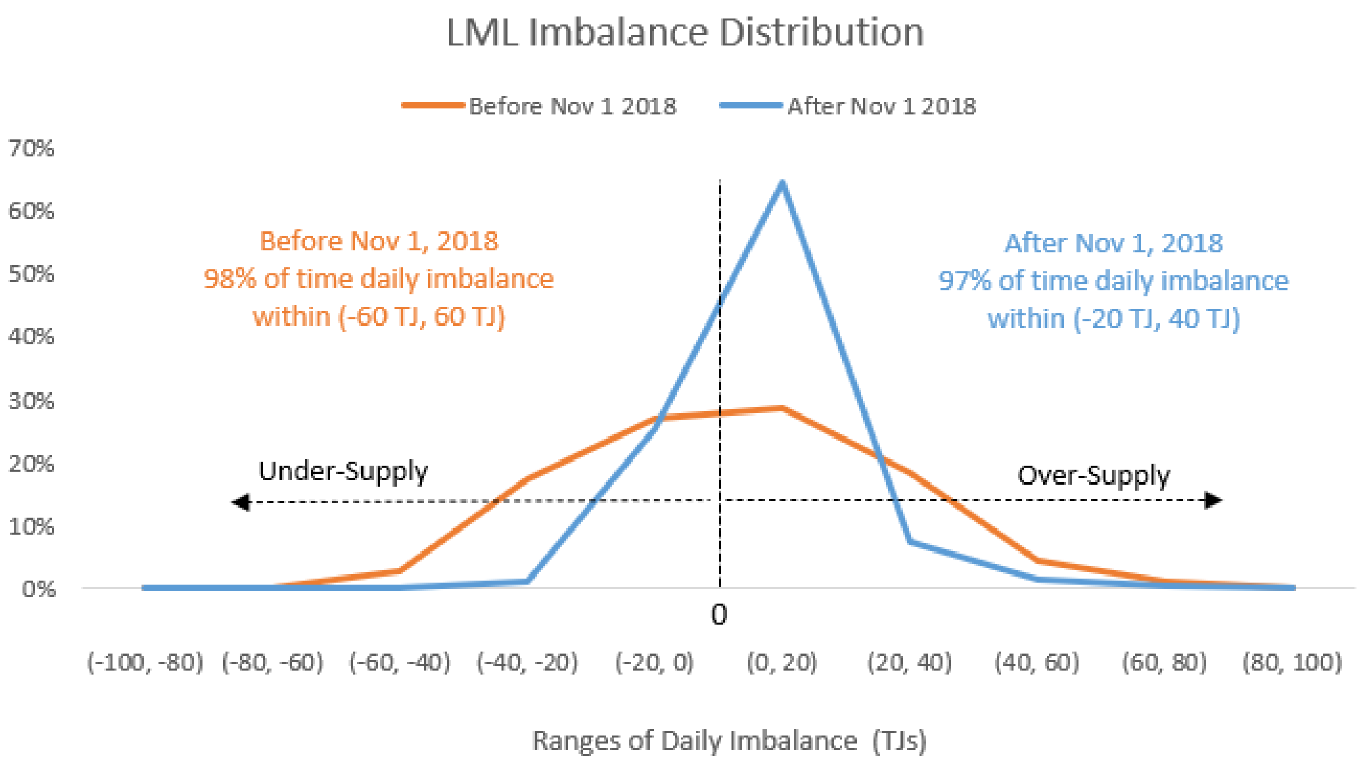
- The purpose of the report - performance under the new rules
- The model has continued to work well and as intended under the revised rules
- FEI expected this outcome given the very thorough rate design process
- Marketers are demonstrating their ability to balancing daily and within the 10% tolerance
- Shipper agents provided suggestions and feedback – FEI considered each of the requests in the report
- FEI is not recommending any substantive changes to the model or the rules at this time
- FEI has recommended smaller changes that are easy to implement

Directive 1: FEI Response

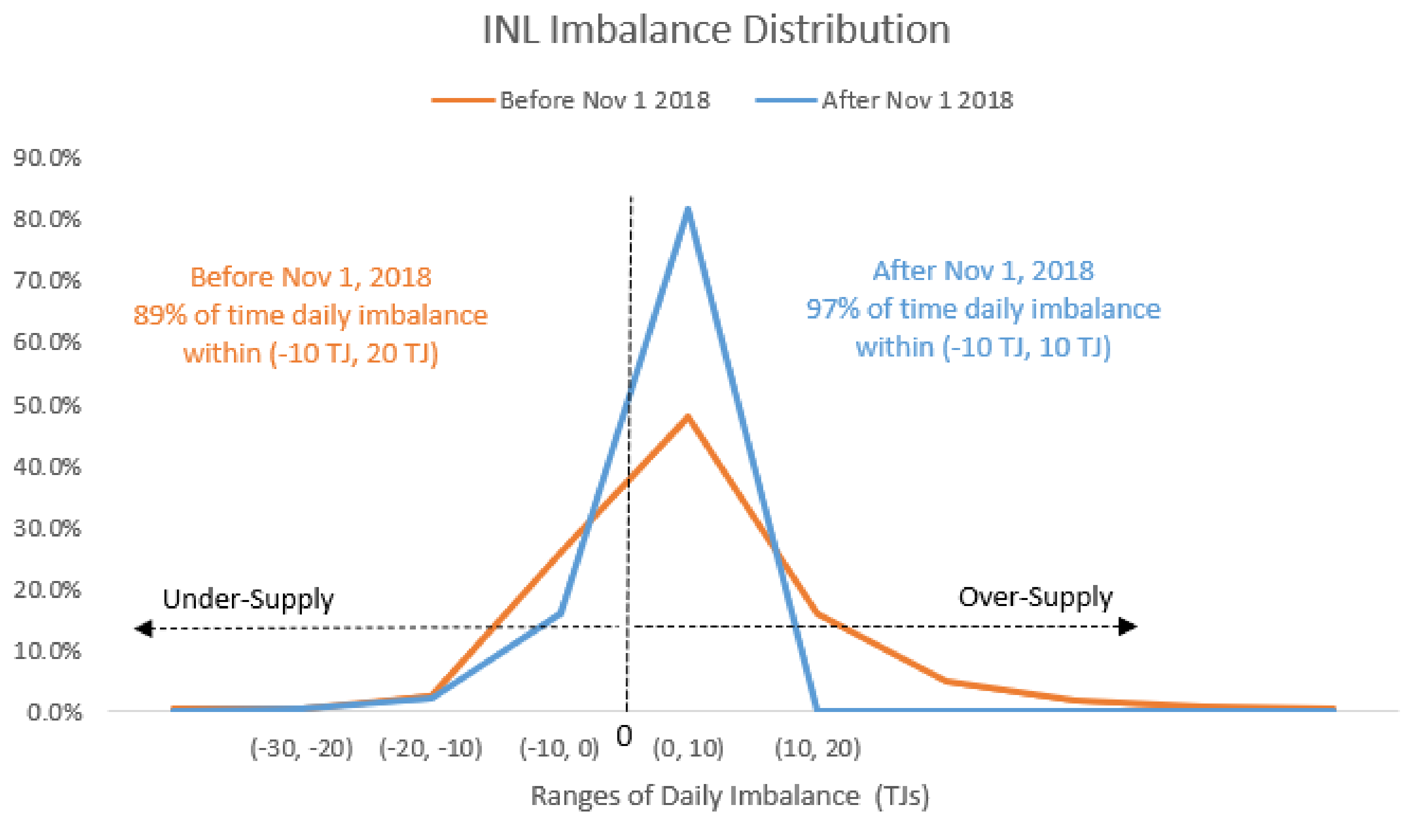
Impact of new balancing rules on the use of core resources including both changes to variable costs of balancing the system to accommodate transportation service and changes to fixed costs arising from a need to contract midstream resources differently;

- FEI manages the OBA as a whole, difficult to determine if daily imbalances are born by core or transportation customers
- FEI observes that in aggregate shipper agents are matching supply and demand
- Charges are not significant
- FEI's view, revised rules are achieving closer balancing, therefore less action from midstream to adjust the gas day for imbalances borne by transportation customers.
- Regarding fixed costs - FEI has not incurred additional fixed costs for resources held for sales customers to balance Transportation customers

Transportation Imbalances – Lower Mainland



Transportation Imbalances – Interior



Directive 2

Effectiveness of Imbalance return to incent Shippers to manage system inventory, including discussion for modifications to the allocation in response to changes in demand for IR after the balancing rules were implemented.

Marketer Feedback and Requests

Marketer Feedback:

- Revised allocation is working well, provides certainty
- Distributed fairly and equitably
- Valuable resource to manage customer load and to balance within the 10% tolerance

Requests:

1. FEI to release a higher amount of IR as a whole.
2. Mechanism to allow greater IR to specific Marketer(s) by request.
3. Reallocation of unutilized service to other interested Marketers.
4. Minimum allocation of IR to groups with smaller demand.
5. Modify the allocation to incorporate a volatility/load factor.
6. Make IR available during Hold to Authorize (HTA)/Supply restriction periods.

FEI Feedback

Recommends: Minimum allocation to groups with smaller demand

- Revised allocation is fair and reasonable
- FEI observes IR is not fully utilized
- There is not perfect model
- Revised allocation is working well based on inventory levels and minimal charges

Directive 3

Whether there should be further tightening of tolerances for under-supply

Marketer Feedback and Requests

Marketer Feedback:

- No shipper agents were in favour of an increased balancing tolerance
- Mixed feedback regarding the 10% tolerance

Requests:

7. Return to the 20% tolerance, and
8. FEI to offer a different percentage of balancing tolerance by season or during specific times of the year (i.e. shoulder months) when operational conditions allow.

FEI Feedback

Recommendation: FEI does not feel a further tightening is necessary at this time.

- The approved changes from the RDA effectively moved the Transportation Model rules closer to industry standard.
- FEI – Station 2 (5%), NGTL (+/- 2%)
- Avista (3-5%), Cascade and Puget Sound Energy (5%)
- Provide the incentive to manage demand more independently and closely
- Supply tracks closely to demand
- Minimal charges

Directive 4

Whether it is necessary to implement tolerances and associated charges for over-supply

Marketer Feedback and Request

Marketer Feedback:

- No interest in a tolerance for over-supply
- FEI encouraged to use the tools in the tariff to manage over-supply incompliance

Requests:

9. FEI to withhold inventory/pack for specific marketers that are over-delivering as opposed to restricting the service for all.

21. Apply tariff charges to specific shipper agents

FEI Feedback

Recommendation: FEI does not feel a tolerance and charges for over-supply are necessary at this time

- FEI monitors inventories on a regular basis and requests a 2-3 day range
- With the move unified daily balancing and the increased 10% tolerance, imbalances have not been excessive
- Rules within the existing tariff allow FEI to take action if needed

Directive 5 – FEI Feedback

Whether the balancing charges appropriately recover the costs of providing balancing to transportation service customers and provide sufficient incentive to transportation service customers to balance their supply and demand.

Recommendation: the balancing charges remain appropriate and provide the sufficient incentive

- FEI reviewed and updated the inputs into the incremental $0.25 and determined it remains reasonable and appropriately recovered balancing costs within the 10-20% range
- With respect to sufficient incentive, many of the Marketers indicated the charge factored into their daily decisions
- This is further supported by the low levels of charges incurred

Summary of Charges 2012 to 2022

Row Labels	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Backstopping - Daily	104,213.0	260,112.0	134,613.0	288,418.0	78,842.0	64,770.0	19,971.0	3,227.0	3,340.0		
Balancing gas	452,603.4	403,726.0	258,704.3	164,824.7	125,922.9	191,272.9	72,642.2	2,992.4			
Balancing Gas Daily	61,001.6	133,962.0	90,072.7	60,502.2	60,894.2	41,163.1	37,355.0	327,221.9	77,303.6	43,694.7	1,795.4
Balancing service	87,457.5	110,989.4	85,304.5	31,274.9	76,409.8	23,450.7	47,465.6	469,373.4	207,256.9	253,544.2	55,883.1
Balancing service 10% - 20%							10,098.4	256,547.7	119,306.4	94,953.6	33,796.2
Replacement gas							12.1				
Unauthorized Overrun - Daily B1	2,802.8	800.4	19,591.5		5,790.9	6,738.7	17,145.2	9,756.6	5,334.7	871.2	
Unauthorized Overrun - Daily B2	3,063.8	968.4	20,629.0	12.6	499.9	4,407.0	2,916.4	555.2	409.2	986.2	
Grand Total	**711,142.10**	**910,558.20**	**608,915.00**	**545,032.40**	**348,359.70**	**331,802.40**	**207,605.90**	**1,069,674.16**	**412,950.83**	**394,049.90**	**91,474.70**

Row Labels	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Backstopping - Daily	$ 264,415.30	$ 1,329,350.73	$ 568,999.59	$ 827,168.84	$ 201,743.97	$ 200,050.35	$ 60,602.36	$ 16,709.95	$ 13,059.64		
Balancing gas	$ 1,064,684.11	$ 1,531,926.09	$ 1,111,413.95	$ 473,199.56	$ 407,534.48	$ 609,658.99	$ 187,158.58	$ 8,323.21			
Balancing Gas Daily	$ 140,387.14	$ 465,469.74	$ 372,525.25	$ 165,960.23	$ 136,109.28	$ 133,474.86	$ 121,691.71	$ 1,648,243.19	$ 241,061.13	$ 256,874.00	$ 8,452.74
Balancing service	$ 49,211.03	$ 73,772.02	$ 76,963.19	$ 18,428.39	$ 76,740.06	$ 23,665.29	$ 37,901.68	$ 370,049.77	$ 121,822.27	$ 121,372.98	$ 61,471.41
Balancing service 10% - 20%							$ 2,524.64	$ 64,081.21	$ 29,826.44	$ 23,730.29	$ 8,449.12
Replacement gas							$ 32.51				
Unauthorized Overrun - Daily B1	$ 8,464.58	$ 6,892.09	$ 166,639.45		$ 31,509.69	$ 25,973.17	$ 226,118.76	$ 260,365.46	$ 18,754.13	$ 5,993.34	
Unauthorized Overrun - Daily B2	$ 61,276.00	$ 19,368.00	$ 419,268.33	$ 252.00	$ 9,998.00	$ 88,140.00	$ 59,812.79	$ 17,572.88	$ 8,184.00	$ 19,762.02	
Grand Total	**$ 1,588,438.16**	**$ 3,426,778.67**	**$ 2,715,809.76**	**$ 1,485,009.02**	**$ 863,635.48**	**$ 1,080,962.66**	**$ 695,843.03**	**$ 2,385,345.67**	**$ 432,707.61**	**$ 427,732.63**	**$ 78,373.27**

GJs	2020	2021
Annual Throughput	67,000,000	73,000,000
10-20%	120,000	95,000
Total Charges	413,000	395,000
%		
10-20%	0.18%	0.13%
Total Charges	0.62%	0.54%

Directive 6

Nature, timing and adequacy of information provided to shipper agents to manage gas supply resources.

Marketer Feedback and Requests

Marketer Feedback:

- Mixed feedback regarding data sufficiency

Marketer Requests:

10. FEI to investigate better measurement technology available in the industry.
11. FEI to provide an intra-day estimate in WINS.
12. FEI to improve data quality of the previous day estimate in WINS.
13. FEI to provide a daily delivery requirement during normal and/or HTA/supply restriction periods.
24. Include real time SCADA information prior to the intra-day cycles
25. Create marketer dashboards to provide collected data snapshots of marketer group information

FEI Feedback

Recommendation: (1) Evaluating a change in the timing of meters calling into FEI and (2) Advanced Metering Infrastructure (AMI) Application

- BCUC determined the data provided by FEI was sufficient
- Atrium Economics peer review – FEI data consistent with industry standard
- Historical data is one component in forecasting process
- The volume of charges supports data sufficiency

Directive 7

Administration of inter-customer group balancing and transparency of inter-customer group balancing rules.

Marketer Feedback and Requests

Marketer Feedback:

- Generally appreciative of this process

Marketer Requests:

14. Automate the process and/or a bulletin board format.
15. Continue process as is (status quo).
16. Proposed a utility super group netting exercise, where if as a whole, all shippers combined deliver sufficient supply to meet demand there should be no penalty.

FEI Feedback

Recommendation: FEI is in favour of the status quo

- Process of amending nominations is not overly burdensome
- Occurs infrequently for days in the year
- FEI involvement and oversight ensures Shipper Agents are meeting their obligations
- There is a cost to automation
- Super-netting would be a disincentive to manage supply

Directive 8

FEI’s criteria for curtailment of inventory returns to shipper agents.

Marketer Feedback and Requests

Marketer Feedback

- Mixed feedback around FEI's decisions to limit this service

Marketer Requests

17. Days when Imbalance return is reduced/eliminated flag the line item in the nomination screen.
18. FEI to provide a "status update" for operational changes (weather/maintenance/ interconnecting pipeline status, etc.) when reducing IR.

FEI Feedback

Recommendation: FEI can accommodate flagging the nomination screen

- Imbalance return is an interruptible service at the utility's discretion
- Historically FEI has made every effort to provide advance notice
- FEI has not changed its approach to when limiting this service (cold weather/capacity disruption)
- Consistent with regional pipeline restrictions

Additional Requests – FEI Feedback

Marketer Request

19. Daily Balancing Charges Interior (Sumas to Station 2 price)

Recommendation: FEI is not in favour of amending this charge

- Table of Charges – all based on a Sumas Gas Daily price
- Sumas is a more appropriate market price benchmark
- Price of gas at Station 2 is not reflective of the market and do not incorporate pipeline tolls
- Volume of Daily Balancing Gas incurred is insignificant
- Charge achieves intended outcome

Additional Requests – FEI Feedback

Marketer Request:

20. Timely cycle deadline flexibility

Recommendation: FEI is not in favour of implementing this change

- Enbridge has the flexibility to extend/keep open timely deadline to allow for late nominations
- WINS has deadlines that are Timed events – no flexibility
- Once the cycle deadline is reached, the requests are sent off automatically to the interconnecting pipeline
- Changes to the WINS system would require money, time and resources
- Not a frequent occurrence

Additional Requests

Marketer Requests:

22. FEI to disclose the parameters and conditions for issuing HTA/Supply restrictions.

23. FEI to apply locational/regional HTA – not apply across all regions.

26. Provide clear information, timelines, priorities and other information related to curtailment

27. Tariff be structured so FEI may curtail/HTA only when absolutely necessary

28. Clear and consistent criteria for the return of HTA gas inventory and a mechanism for returning any premium value of that inventory, and specifically that FEI publish its criteria so customer and marketers can understand how FEI will make its decisions it's criteria

FEI Feedback

Recommendation: FEI's practice for issuing HTA/supply restrictions status quo

- Never FEI's intent to limit services
- Decisions remained consistent over time – as much as advance notice as possible
- Issues HTA in response to cold weather or pipeline restrictions
- FEI assess regional and provincial wide conditions when limiting services
- Consistent with the timing of Northwest Pipeline's restriction practices

Additional Requests – FEI Feedback

29. FEI to adhere to the Gas Marketers Code of Conduct

- Rejected G-210-20

Summary

- The model has continued to work well and as intended under the revised rules
- In aggregate, marketers are balancing daily and within the 10% tolerance
- FEI is not recommending any substantive changes to the model or the rules at this time
    - *Minimum allocation of Imbalance Return to smaller groups*
    - *Flag nomination screen with Imbalance Return is reduced/eliminated*
    - *Evaluating timing of meter call-in to provide a previous day actual and current day estimate*
    - *Status quo for inter-customer group balancing*
- Report filing June 2022

Thank you

For further information, please contact:

Stephanie Salbach, Transportation Service Manager [redacted]

Find FortisBC at:
fortisbc.com
talkingenergy.ca
604-576-7000

Follow us @**fortisbc**

Attendees for the May 10/22 Stakeholder Session - Transportation Services Workshop

Company	Name	In-Meeting Dura	First Join	Last Leave	Role
Absolute Energy	Kirby Morrow	1h 29m 10s	5/10/22, 11:01:12 AM	5/10/22, 12:30:22 PM	Attendee
Access Gas	Sheri Clemons	1h 36m 17s	5/10/22, 10:53:55 AM	5/10/22, 12:30:12 PM	Attendee
Access Gas	Patti Andersen	1h 34m 33s	5/10/22, 10:55:48 AM	5/10/22, 12:30:22 PM	Attendee
Access Gas	Charlie Barrotta	1h 33m 47s	5/10/22, 10:56:32 AM	5/10/22, 12:30:19 PM	Attendee
Atrium Economics	Ron Amen	1h 36m 31s	5/10/22, 10:53:55 AM	5/10/22, 12:30:26 PM	Presenter
Atrium Economics	Chris Hutchinson	1h 36m 23s	5/10/22, 10:53:55 AM	5/10/22, 12:30:18 PM	Presenter
Atrium Economics	John Taylor	1h 29m 48s	5/10/22, 11:00:31 AM	5/10/22, 12:30:19 PM	Attendee
BC PIAC	Executive Director	1h 21s	5/10/22, 11:01:54 AM	5/10/22, 12:02:15 PM	Attendee
BCUC	Engels, Greg	1h 30m 21s	5/10/22, 10:59:59 AM	5/10/22, 12:30:21 PM	Attendee
BCUC	Lavoie, Ted	1h 30m 9s	5/10/22, 11:00:15 AM	5/10/22, 12:30:24 PM	Attendee
BCUC	O'Neal, Joshua	1h 28m 20s	5/10/22, 11:02:09 AM	5/10/22, 12:30:30 PM	Attendee
Direct Energy	Fredricksen, James	1h 29m 33s	5/10/22, 11:00:08 AM	5/10/22, 12:29:42 PM	Attendee
Direct Energy	Black, Nicole	59m 37s	5/10/22, 11:00:20 AM	5/10/22, 11:59:57 AM	Attendee
Direct Energy	DSilva, Kenneth	1h 12m 53s	5/10/22, 11:00:41 AM	5/10/22, 12:13:35 PM	Attendee
Direct Energy	Brand, James	55m 7s	5/10/22, 11:01:30 AM	5/10/22, 12:13:09 PM	Attendee
FortisBC	Salbach, Stephanie	1h 36m 42s	5/10/22, 10:53:42 AM	5/10/22, 12:30:25 PM	Organizer
FortisBC	Gill, Manpreet	1h 32m 15s	5/10/22, 10:58:05 AM	5/10/22, 12:30:21 PM	Presenter
FortisBC	Hodgins, Kevin	1h 29m 21s	5/10/22, 11:00:57 AM	5/10/22, 12:30:18 PM	Presenter
FortisBC	Yasinchuk, Matt	1h 28m 34s	5/10/22, 11:01:56 AM	5/10/22, 12:30:30 PM	Presenter
FortisBC	Bevacqua, Ilva	1h 24m 36s	5/10/22, 11:05:47 AM	5/10/22, 12:30:24 PM	Presenter
FortisBC	Hill, Shawn	1h 20m 34s	5/10/22, 11:09:48 AM	5/10/22, 12:30:22 PM	Presenter
IGI Resources	Johnston, Kim	1h 2m 22s	5/10/22, 10:59:21 AM	5/10/22, 12:01:44 PM	Attendee
RCIA	Peter Helland	1h 31m 34s	5/10/22, 10:59:01 AM	5/10/22, 12:30:35 PM	Attendee
Sentinel	Jim (Guest)	40m 29s	5/10/22, 11:45:28 AM	5/10/22, 12:25:58 PM	Attendee
Shell Energy	Kalinowsky, Jade	1h 34m	5/10/22, 10:56:20 AM	5/10/22, 12:30:21 PM	Attendee
Shell Energy	Foster, Danielle	1h 31m 13s	5/10/22, 10:59:01 AM	5/10/22, 12:30:15 PM	Attendee
Shell Energy	Mccordic, Mary	1h 29m 37s	5/10/22, 11:00:37 AM	5/10/22, 12:30:15 PM	Attendee
Shell Energy	Gill, Blake	1h 28m	5/10/22, 11:02:18 AM	5/10/22, 12:30:19 PM	Attendee
Shell Energy	Ragheb, Hend	1h 24m 33s	5/10/22, 11:05:55 AM	5/10/22, 12:30:28 PM	Attendee
Tidewater Midstream	Mahdis Sadeghi	1h 29m 49s	5/10/22, 11:00:30 AM	5/10/22, 12:30:19 PM	Attendee