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May 11, 2017

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. 2016 Rate Design Application Project No. 3698899

We are counsel to the Commercial Energy Consumers Association of British Columbia (CEC). Attached please find the CEC's first set of Information Requests with respect to the above-noted matter.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jj
cc: CEC
cc: FortisBC Energy Inc.
cc: Registered Interveners

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA

INFORMATION REQUEST #1

FortisBC Energy Inc. 2016 Rate Design Application Project No. 3698899

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1. Reference: Exhibit B-1, page 1-3 and Appendix A2 page 6 and 6

- Principle 1: Recovering the Cost of Service; the aggregate of all customer rates and revenues must be sufficient to recover the utility's total cost of service
- Principle 2: Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates)
- Principle 3: Price signals that encourage efficient use and discourage inefficient use
- Principle 4: Customer understanding and acceptance
- Principle 5: Practical and cost-effective to implement (sustainable and meet long-term objectives).
- Principle 6: Rate stability (customer rate impact should be managed)
- Principle 7: Revenue stability
- Principle 8: Avoidance of undue discrimination (interclass equity must be enhanced and maintained)

FEI does not apply the eight principles above in any priority or with any particular weighting. Rate design is a complex balancing process as it frequently requires the application of multiple, and sometimes conflicting, principles and the consideration of viewpoints from various stakeholders. In addition, different rate design principles may have varying levels of importance in different contexts. FEI, therefore, applies its experience and judgment to consider and balance the most relevant principles in a given context when identifying rate design issues and proposing rate design solutions. Rate design should strive to strike a balance among competing rate design principles based on specific characteristics of customers in each rate schedule.

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.*

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.*

1.1. Please confirm that the Principles adopted by FEI are intended to reflect the same principles articulated by Bonbright as laid out in the Elenchus COSA Report.

1.2. Please confirm that Principle 1, Principle 2, Principle 3, Principle 4, Principle 5, Principle 7 and Principle 8 of FEI's Principles would all be supported by a rate design at unity in revenue to cost ratios for each rate class.

1.2.1. If not confirmed, please explain why not.

1.3. Please provide any thresholds or rates of change that FEI deems critical in managing Principle 6 - Rate Stability.

1.4. Please confirm that FEI's Principle 7, Customer Understanding and Acceptance, relates to Bonbright Principle 9.

2. Reference: Exhibit B-1, page 1-5

Table 1-1: R:C and M:C Results before and after Rate Design Proposals and Rebalancing

Rate Schedule	COSA		Revenue Shifts and Rebalance Amount ($000)	Approximate Annual Bill Change	COSA after all Proposals and Rebalancing	
	R:C	M:C			R:C	M:C
Rate Schedule 1 *Residential Service*	95.6%	93.1%	848.1	0.1%	96.4%	94.4%
Rate Schedule 2 *Small Commercial Service*	101.3%	102.5%	(1,174.1)	-0.5%	102.2%	104.1%
Rate Schedule 3/23 *Large Commercial Sales and Transportation Service*	101.6%	103.3%	1,174.1	0.6%	103.6%	107.6%
Rate Schedule 5/25 *General Firm Sales and Transportation Service*	104.9%	112.2%	45.2	0.0%	106.3%	116.0%
Rate Schedule 6/6P *Natural Gas Vehicle Service*	131.2%	159.1%	(61.7)	-16.5%	110.0%	119.0%
Rate Schedule 22A *Transportation Service (Closed) Inland Service Area*	109.5%	109.8%			113.0%	113.4%
Rate Schedule 22B *Transportation Service (Closed) Columbia Service Area*	99.7%	99.7%			103.1%	103.1%
Rate Schedule 22 *Large Volume Transportation Service*	1425.5%	1864.4%	(754.2)	-3.4%	100.0%	100.0%

Rate Schedule *(rates not set using allocated costs)*	COSA		Revenue Shifts and Rebalance Amount ($000)	Approximate Annual Bill Change	COSA after all Proposals and Rebalancing	
	R:C	M:C			R:C	M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	147.4%	550.9%	13.3	1.9%	150.2%	578.3%
Rate Schedule 7/27 *General Interruptible Sales and Transportation Service*	139.6%	712.3%	(90.7)	-0.3%	139.3%	713.6%

2.1. Please confirm that Revenue/Cost ratio is a key indicator of fair apportionment of costs.

2.2. Please confirm that FEI has used good load and costing data in its COSA evaluation.

2.3. Please confirm that a Revenue/Cost ratio of 100% or 1 is the fairer apportionment of costs among customers.

2.4. Please confirm that moving Revenue/Cost ratios towards 100% or 1 is directionally not unfair.

2.5. Please confirm that FEI's proposal results in Rate Schedule 2, Rate Schedule 3, Rate Schedule 5 Rate Schedule 22A, and Rate Schedule 22B and Rate Schedule 4 and Rate Schedule 7 all becoming increasing less fair based on the proposed Rate Design and Rebalancing.

2.5.1. If not confirmed, please explain why not.

3. Reference: BC Utilities Commission Act, Section 58.1

Rate rebalancing

58.1 (1) In this section, **"revenue-cost ratio"** means the amount determined by dividing the authority's revenues from a class of customers during a period of time by the authority's costs to serve that class of customers during the same period of time.

(2) This section applies despite:

(a) any other provision of

(i) this Act, or

(ii) the regulations, except a regulation under section 3, or

(b) any previous decision of the commission.

(3) The following decision and orders of the commission are of no force or effect to the extent that they require the authority to do anything for the purpose of changing revenue-cost ratios:

(a) 2007 RDA Phase 1 Decision, issued October 26, 2007;

(b) order G-111-07, issued September 7, 2007;

(c) order G-130-07, issued October 26, 2007;

(d) order G-10-08, issued January 21, 2008,

and the rates of the authority that applied immediately before this section comes into force continue to apply and are deemed to be just, reasonable and not unduly discriminatory.

(4) [Repealed RS1996-473-58.1 (5).]

(5) Subsection (4) is repealed on March 31, 2010.

(6) Nothing in subsection (3) prevents the commission from setting rates for the authority, but the commission, after March 31, 2010, may not set rates for the authority such that the revenue-cost ratio, expressed as a percentage, for any class of customers increases by more than 2 percentage points per year compared to the revenue-cost ratio for that class immediately before the increase.

3.1. Please confirm that Section 58.1 of the Utilities Commission Act applies expressly to the BC Hydro and Power Authority, and does not apply to FEI.

3.2. Are there any legal or other requirements preventing FEI from rebalancing toward achieving unity? Please explain.

4. Reference: Exhibit B-1, page 1-6

FEI is proposing the continuation of the flat rate structure for RS 1. The existing flat rate structure provides the best balance of rate design considerations for residential customers. Flat rates are simple to administer and easy to understand and provide more stable utility revenues and customer rates. The customer research survey results show that the flat rate structure is preferred by a majority of residential customers and the flat rate structure is used by the majority of Canadian natural gas utilities for their residential customers.

4.1. Please explain why a flat rate structure provides more stable utility revenues.

4.2. Please confirm that a flat rate schedule does not provide a price signal to discourage wasteful use of energy, particularly under low or declining commodity price conditions.

4.3. Please confirm that customer preference for a rate structure is not a Bonbright Principle, whereas Principle 4 of the Bonbright principles promotes the use of rate blocks in discouraging wasteful use both for total use and relative use to other energy sources.

4.4. Please confirm that a flat rate schedule does not provide a price signal promoting the use of clean alternative energy.

5. Reference: Exhibit B-1, pages 3-17 to 3-20 and page 6-32 and Exhibit A2-2, page 6

Table 3-4: Past Commission Directives and FEI Commitments

FEI Application/Proceeding	Applicable Directive(s)/Reference & FEI Response

3.5 *SUMMARY*

In this section, FEI has provided an overview of FEI, its sales and transportation business models, customer rate schedule segmentation and regulatory history. This information has been provided as historical background to provide context regarding FEI's existing rate design and proposed changes in the following sections of the Application.

- In Commission Order G-130-07 in response to BC Hydro's 2007 Rate Design Application, the Commission determined that a "range of reasonableness of 95 per cent to 105 per cent [was] the correct range for the purpose of future rebalancing in the circumstances of BC Hydro."[89] The rationale for the decision was based in part on the "the known system demand and demand metering of large commercial and industrial customers" and "the accuracy of the relatively sophisticated load research analysis."[90] As a result, the Commission panel determined for BC Hydro "that the appropriate target R:C ratio in each class is unity or one and that future rebalancing should only be required when a customer class falls outside of the range of reasonableness."[91]
- Similarly, in Order G-156-10, dated October 19, 2010, the Commission found that "the appropriate range of reasonableness of 95% to 105% is the correct range for the purpose of future rebalancing in the circumstances of FortisBC [electric]."[92] As in the BC Hydro decision, the Commission determined that the appropriate target R:C in each rate

5.1. Please provide any commentary, direction, orders, regulations or other legislative content that FEI is aware of from the Commission that indicates that 100% (or a ratio of 1) is the appropriate target for cost of service ratios.

5.2. Please provide any commentary, direction, orders, regulations or other legislative content that FEI is aware of that relates to range of reasonableness for FEI or for BC Hydro.

6. Reference: Exhibit A2-2, Elenchus Report, page 7 and page 29

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.

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.

6.1. Please provide the full dataset on the range of reasonableness for other gas utilities that FEI has available.

6.2. Please provide any other documentation that FEI has from consultants or other third parties that relate to the range of reasonableness for revenue to cost ratios for FEI or other gas providers.

7. Reference: Exhibit B-1, Appendix 4-5, page 4

Research Background and Objectives

- Sentis Research Inc. was retained by FortisBC Energy Inc. to conduct a customer research survey that covers the following general topics:
  - Residential customers' understanding of the current rate structure and bill determinants
  - Residential customers' preferences in terms of rate design considerations
  - Residential customers' evaluation of different rate structures
  - Residential customers knowledge of the BCUC role and perception of company among residential customers

7.1. Please confirm that the Residential Customer Research Final Report is most appropriately applied to Rate Design within the rate class, and should not create any implications for cost of service related issues.

7.2. Please confirm that customer 'preference' is not the same as customer 'acceptance'.

8. Reference: Exhibit B-1, Appendix 4-5, page 7

- The survey was conducted online using an online consumer panel. For Fort Nelson customers specifically, a telephone recruitment-to-online survey methodology (using a purchased list of Fort Nelson residential phone listings) was employed to obtain an oversample of Fort Nelson customers.
- To qualify for the survey, respondents must be individuals who are natural gas customers of FortisBC and who make payment decisions/review the natural gas bills.
- Sentis programmed and hosted the online survey at www.sentissurvey.com
- The survey was administered from July 25 to August 2, 2016. A total of 65 surveys were completed with Fort Nelson customers, and 753 surveys with customers from the rest of the province.
- The margin of error associated with each sample size is summarized below:

Region	Sample Size	Margins of Error (95% confidence level)
FEI	753	+/- 3.6%
Fort Nelson	65	+/- 12.2%

- Note: Throughout this report, "FEI" is used to refer to FortisBC Energy Inc. customers throughout the province excluding those from Fort Nelson. Fort Nelson customers will be referred to as such.

8.1. Were the participants in the group essentially self-selected or FEI selected, or was it a random sample?

8.1.1. If the group was self-selected or FEI selected, do the margins of error correct for any bias in the self-selection or FEI selection? Please explain and provide quantification of any bias to the extent it is available.

9. Reference: Exhibit B-1, page 6-4 and page 6-18 and Appendix 6-6

- **Minimum System Study:** The MSS approach assumes that a certain level (percent) of distribution plant investment is required to serve the minimum loading requirements of customers throughout the service territory (i.e., those minimum costs are more dependent on the number of customers, rather than being variable based on demand). The closer a plant item is located to a customer, the more that particular item is related to the specific requirements of that customer. As such, costs associated with such plant investment should be regarded as customer related costs. The remaining percentage of costs is then attributed to the demand-related component since any costs associated with a system larger than the minimal plant investment are due to customers using a delivery quantity greater than the minimum unit up to the level of their peak demand. The result of the MSS determines the proportion of distribution mains costs that are customer related versus costs that are demand related.

  The MSS is only applicable to mains, as meters and services are classified as 100% customer-related. Costs associated with meters and services are fully allocated based on customer weighting factors as each customer needs a meter and service regardless of the volume of service taken by the customer.

  While the minimum system, in theory, is designed to meet the minimal loading requirements for all customers, the actual mains are capable of carrying a load beyond the minimal load. The proportion of costs allocated to the customer-related component is therefore overstated and requires an adjustment to account for the PLCC of the minimum system.

- **Peak Load Carrying Capacity Adjustment:** The PLCC adjustment involves determining the theoretical capacity of each of the distribution systems in the utility's total service area. To accomplish this, an average minimum system capacity per customer is calculated, which is then multiplied by the number of customers in each rate class, and the corresponding amount is subtracted from the demand for that rate class. The result accounts for the PLCC of the minimum system and effectively adjusts the proportion of costs allocated to the customer-related component to a more representative level.

6.3.5.4 Distribution

Costs for Distribution Mains have been split between demand and customer related components based on the minimum system approach with a PLCC adjustment. The minimum system approach with PLCC adjustment was used in the 2009 FortisBC Inc. (Electric) Rate Design Application[70] and also in FEI's 2012 Amalgamation Application.[71] It has been used for this rate design analysis on the recommendation of EES Consulting.[72]

Minimum System Study

FEI splits distribution rate base between demand and customer classifiers according to a minimum system approach. This approach considers that the distribution system is in place in part because there are customers connected to the system and in part because those customers have a peak demand on the system. Therefore, it follows that any costs associated with a system larger than this minimum size are due to the customer's demand, and so are treated as demand related. To support this approach, FEI has conducted an MSS.

Appendix 6-6

SIZING OF DISTRIBUTION PIPE STANDARDS

9.1. Please provide all of FEI's standards for distribution lines, mains, pipe in relation to the number of customers that can be served from a given line or pipe size with the given appliance count estimate.

9.2. Please confirm that the COSA utilizes actual costs and revenues.

9.3. In that FEI is currently operating under PBR, in which capital spending is exceeding the formula, please comment on whether or not there is any impact on the results of the COSA analysis.

10. Reference: Exhibit B-1, page 6-7 and Appendix 6-3 page

6.3.1.2 Operating and Maintenance (O&M) Expenses

The COSA model requires an activity view of O&M expenses to assist with the cost allocation. In 2016, FEI is under performance based ratemaking (PBR) whereby total gross O&M is escalated using a formula.[61] The formulaic O&M in the approved revenue requirement is calculated based on total O&M and not at an activity level. To derive the necessary activity level of detail, FEI allocated the total approved O&M to each activity using the same percentages that existed in 2015 actual results. The ratio of each activity from 2015 to the total was applied to the 2016 approved formulaic O&M total so that the gross amount could be split into activities for allocation purposes within the COSA model. Appendix 6-3 shows the allocation percentages that were applied to FEI's 2016 formulaic O&M to derive an activity view for allocation in the COSA model.

FORTISBC ENERGY INC. Appendix 6-3

2016 Revenue Requirement O&M Split

		2016	Percentage
1	Operating & Maintenance Expense		
2	Distribution Supervision	$ 14,376.2	5.29%
3	Operation Centre - Distribution	11,848.4	4.36%
4	Preventative Maintenance - Distribution	2,664.7	0.98%
6	Operations - Distribution	7,104.0	2.62%
8	Emergency Management - Distribution	6,383.3	2.35%
10	Field Training - Distribution	2,825.5	1.04%
12	Meter Exchange - Distribution	3,032.3	1.12%
14	Corrective - Distribution	5,915.3	2.18%
16	Account Services - Distribution	1,432.1	0.53%
18	Bad Debt Management - Distribution	788.6	0.29%
20	Distribution Total	$ 56,370.5	
22			
24	Transmission Supervision	1,221.1	0.45%
26	Pipeline / Right of Way Operations	10,896.8	4.01%
28	Compression Operations	3,941.1	1.45%
30	Measurement Control Operations	861.8	0.32%
32	Pipeline / Right of Way - Maintenance	3,390.6	1.25%
34	Compression - Maintenance	2,719.0	1.00%
36	Measurement Control Operations	459.6	0.17%
38	Company Use Gas (Compression & Line Heating)	857.6	0.32%
40	Transmission Total	$ 24,347.5	

10.1. Please comment on why formulaic O&M is being used instead of Actuals.

10.2. When will 2016 Actuals be available?

10.3. Please confirm that there are no significant variances that are likely to occur from year to year.

10.3.1. If not confirmed, please provide an estimate of the range of variance that could occur in the allocation of O&M.

10.4. Please provide 'Actuals' with percentages for the last 5 years including 2016.

11. Reference: Exhibit B-1, page 6-10,

Table 6-5: Expected Project In-Service Dates and COSA Costs

Project	Expected In-Service Date	Mid-Year Rate Base Included in COSA ($millions)	Cost of Service Included in COSA ($millions)
Lower Mainland Intermediate Pressure System Upgrade Projects	October 2018	258	25
Coastal Transmission System Upgrade	November 2017	167	14
Tilbury Expansion Project	Mid 2017	399	7[88]

6.3.2.1 Lower Mainland Intermediate Pressure System Upgrade Project

The Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) CPCN application was filed with the Commission in December 2014 and approved through Order C-11-15. The LMIPSU includes the Coquitlam Gate IP Project which will address an increasing number of gas leaks on the Coquitlam Gate IP line. Operational flexibility and resiliency will be restored to the Metro Vancouver IP system and the Fraser Gate IP Project will provide required seismic upgrades to the Fraser Gate IP line. The Fraser Gate IP and the Coquitlam Gate IP Projects are expected to be in-service by October 2018. The estimated capital cost for the LMIPSU Projects, including AFUDC and abandonment/demolition costs, is approximately $256 million, with an initial annual cost of service of approximately $25 million. The LMIPSU Project's rate base and cost of service are included in the COSA model for allocation.

11.1. Please explain why the Mid Year Rate Base figures are slightly different than the figures cited in the write ups. For example, the LMIPSU Midyear Rate base is $258 million and the included cost is $256 million for the LMIPSU project description.

12. Reference: Exhibit B-1, page 6-14 and page 6-17

The customer classes that are allocated costs of the Tilbury LNG Storage facility are Residential, Small and Large Commercial (both Sales and Transport), NGV (RS 6) and General Firm Service (Sales and Transport). Large Commercial and General Firm customers are included in the allocation because on peak days the Tilbury plant supports the supply and delivery to these sales and transport customers. General Interruptible (RS 7 and RS 27) and Large Industrial (RS 22) customers are not allocated Tilbury costs because on the days of extreme cold weather their service would be curtailed to preserve the capacity of the system to serve the firm load.

6.3.5.2 LNG Storage

As discussed in Section 6.3.4.3, the existing Tilbury plant is a needle peaking facility designed predominantly to be used on extreme cold days. The Tilbury LNG Storage facility was included as a function in FEI's 1993, 1996 and 2001 Rate Design applications. The Tilbury function was

12.1. Does the Tilbury LNG storage never serve RS 7 or RS 27 or RS 22?

12.1.1. If the Tilbury LNG storage ever serves any of these Rate Schedules, please explain when and quantify the proportion of volume that is attributable to these rate schedules.

12.1.2. Please provide a record of Tilbury plant send out volumes by day, and a match of RS 7 or RS 27 or RS 22 consumption on those days, if there have been instances of Tilbury send out while RS 7, RS 27 or RS 22 customer have continued consumption.

13. Reference: Exhibit B-1, page 6-14

As discussed in Section 6.3.2.3 of the Application, the Tilbury Expansion project is included in the LNG Storage function. However, the allocation approach for Tilbury Expansion does not follow that of the existing storage plant. The Tilbury Expansion costs are directly allocated to RS 46 and offset with RS 46 revenues (within the function) and the net difference is allocated to all non-bypass customers.

13.1. Why is the net difference allocated to all non-bypass customers?

13.2. On what basis is the net difference allocated to the different rate classes of non-bypass customers?

14. Reference: Exhibit B-1, page 6-22

1. Calculate the **Peak Day Demand** for each region and rate schedule as follows:
   a. Develop a regression model for each region and rate schedule using 10 months[76] of actual demand data (converted to Daily Demand, based on the number of days in the month) against average monthly temperatures to establish the model parameters to a linear equation.
   b. Enter the regional design day temperature[77] into the above estimated linear models to establish the peak day demand for each region and rate schedule.
2. Calculate the **Average Daily Consumption** for each region and rate schedule:
   c. RS 1/RS 2/RS 3/RS 23:

[76] July and August are excluded,

[77] Design day temperature is derived through an Extreme Value Analysis, which estimates the coldest temperature expected to occur with a return period of one in twenty years.

14.1. Why are July and August excluded from the Peak Day Demand calculations?

14.2. Please provide the Extreme Value Analysis used to estimate coldest temperatures.

15. Reference: Exhibit B-1, page 6-24

6.3.6.1 Customer Costs

Customer-related costs are allocated across rate schedules on the basis of both average customers, and average customers with a weighting factor applied. Approximately 40% of FEI's customer-related costs are allocated using average customers with a weighting factor applied, 5% are allocated using only average customers and 55% are allocated based on the results of the two previous allocations. Customer-related costs that are allocated using average customers include land, structures, mains, measuring and regulating equipment. Customer-related costs that are allocated using average weighted customers include service lines and meters, customer billing and customer contact services including supporting infrastructure and energy solutions. Weighting average customers, and not simply using average customers, recognizes that not all customers cost the same to connect to FEI's system or cost the same to

15.1. Please provide the rationale for using 'average customers' for allocating land, structures, mains, measuring and regulating equipment costs.

15.2. Please provide the rationale for using' average weighted customers' for allocating service lines, meters, customer billing and customer contact services including supporting infrastructure and energy solution costs.

15.3. Please define 'energy solutions".

15.4.

15.5. Please explain how the remaining 55% of costs are 'allocated based on the results of the previous 2 allocations'.

15.6. What are the remaining 55% of costs that are allocated based on both the previous allocations?

15.7. Please provide the rationale for why the remaining costs are not able to be allocated based either on average customers, or average weighted customers.

15.8. Please confirm that FEI uses the best possible information it has available to determine the weightings.

16. Reference: Exhibit B-1, page 6-15

Table 6-15: Customer Weighting Factor Study and Customer Administration Factor Results

Rate Schedule	Customer Weighting Factor	Customer Admin & Billing Factor
1	1.0	1.0
2	1.7	1.0
3	7.0	1.2
4	13.6	0.9
5	11.1	43.0
6	13.3	43.0
7	132.5	43.0
22	49.9	75.0
22A	399.2	75.0
22B	562.6	75.0
23	10.3	75.0
25	17.6	75.0
27	46.2	75.0

Based on information from FEI's marketing, customer service and billing departments, weighting factors for each rate class were developed which take into consideration:

- the frequency of meter reading;
- the use of remote meter reading via cellular or other communications infrastructure and the method of collecting and retaining load data;
- the amount of time spent by customer service responding to inquiries;
- marketing programs and costs for different customer groups;
- the existence of dedicated account managers for commercial and industrial customers; and
- the number of resources dedicated to each customer class for customer billing, measurement and marketing.

The customer numbers in each rate schedule that are weighted for customer administration and billing are then used to allocate costs associated with customer administration to each rate schedule.

16.1. Did FEI rely on empirical evidence to support its weightings, or are the weightings more judgement based? Please explain.

16.1.1. If FEI has empirical evidence, please provide the empirical evidence behind these weighting factors.

16.1.2. If FEI does not have empirical evidence to support all of its weightings, please identify in what instances FEI has relied on judgement to assign weights.

16.2. Please provide FEI's historical weightings from previous cost of service studies.

16.2.1. Please confirm that FEI uses the best possible information it has to determine these weightings.

17. Reference: Exhibit B-1, page 6-26

6.3.6.1.2 WEIGHTING FACTOR FOR METERS AND SERVICES

The facility costs for the distribution system, such as meters, service lines and regulators, are not equal among all customers. Therefore, for these costs, FEI applies a weighting factor to the number of customers in each rate schedule so that the costs allocated to each rate schedule are proportionate to the costs to serve them.

The weighting factors are estimated values indicating the total relative value of meter and service assets associated with a specific rate schedule as compared to Rate Schedule 1.[83] Once the weighting factors have been calculated and assigned to each rate schedule, costs can be allocated appropriately across all rate schedules. This weighting factor helps ensure each rate schedule is assigned the appropriate proportion of customer-related costs based on cost causation.

17.1. Did FEI rely on judgement in providing weights or does it have empirical evidence to support its weightings?

17.1.1. If FEI has empirical evidence, please provide the empirical evidence behind these weighting factors.

17.1.2. If FEI does not have empirical evidence to support its weightings, please identify in what instances FEI has relied on judgement to assign weights.

17.2. Please provide FEI's historical weightings from previous cost of service studies.

18. Reference: Exhibit B-1, page 6-30

6.4.2.1 Load Factor Adjustment to RS 5 Customers

As noted above, FEI currently allocates midstream costs to RS 5 using a deemed 50% load factor. This value was established as part of the 1996 Rate Design Application Negotiated Settlement Agreement. FEI contracts for its midstream resources based on a peak day demand that is derived using a calculated load factor for RS 5, not a deemed load factor. This discrepancy means that the cost of the resources being contracted for is not being allocated to RS 5 in the same way in which they were caused.

Based upon the rate design principles to fairly apportion costs among customers and set price signals that encourage efficient use, FEI is proposing to utilize the same approach for allocating midstream costs to RS 5 as it does for RS 1, RS 2, and RS 3 by using a three-year rolling average load factor as discussed in Section 6.4.2. Under the new approach the load factor used to allocate midstream costs to RS 5 would be approximately 45%[86]. For clarity, 45% is the indicative load factor; however, the load factor that will be used to allocate midstream costs to RS 5 will be recalculated annually along with the load factors used to allocate midstream costs to RS 1, RS 2, and RS 3.

Table 6-17 below shows that changing the deemed RS 5 load factor from 50% to 45% changes the allocation of midstream costs and midstream charges for sales customers. The table is based on the data used to set January 1, 2016 midstream rates.[87]

18.1. What was the previous rationale for using a deemed load factor of 50% instead of the rolling average approach FEI is now proposing?

18.2. Please provide the 3 year rolling average load factor for all rate classes for the last 10 years.

18.3. Please confirm that FEI is using the best information it has available to determine load factors for allocation of midstream costs.

19. Reference: Exhibit B-1, page 6-32

6.5.1 R:C Ratios – The Range of Reasonableness

R:C ratios are assessed based on whether or not they fall within an established "range of reasonableness". FEI believes that the appropriate range of reasonableness for evaluating its R:C ratios is 90 per cent to 110 per cent. In theory, the R:C ratio should equal 100% for each rate schedule, indicating that the revenues recovered from each rate schedule would equal the indicated cost to serve them. However, achieving unity implies a level of precision that does not exist with any COSA. As a COSA study necessarily involves assumptions, estimates, simplifications, judgments and generalizations, a range of reasonableness is warranted and accepted when evaluating the appropriateness of the R:C ratios.

19.1. Please provide FEI's basis for the assumption that 10% is the appropriate range of reasonableness, as opposed to, for example, 5% or 7%.

19.2. Has FEI always relied on 10% as the appropriate range of reasonableness?

19.2.1. If not, what other figures has FEI relied on?

19.3. Please discuss the historical stability of FEI's revenue to cost ratios for each rate class over the last 20 years, and provide quantification of FEI's revenue to cost ratios over this period.

19.4. Please confirm that despite the existence of a 'range of reasonableness' and the use of assumptions it remains appropriate for the utility to achieve unity in its cost of service ratios based on the data available.

19.4.1. If not confirmed, please explain why not.

19.5. Please confirm that where the data is not illustrative of unity in cost of service, it remains appropriate for the utility to achieve unity.

19.6. Please confirm that the key issue with respect to rebalancing the revenue to cost ratios is the potential for rate impacts on customer classes with ratios below 1.

19.6.1. If not confirmed, please explain why not and outline the issues that would arise in rate rebalancing.

19.7. What 'range of reasonableness' has FEI applied to rate impacts, if any?

19.8. If revenue to cost ratios were rebalanced toward 1 or unity periodically, say very five or ten years, would FEI find such a Commission decision to be unfair, particularly if changes to rates were made within a range of reasonableness for rebalancing rate changes? Please explain why or why not.

20. Reference: Exhibit B-1, page 7-1

FEI is also proposing a 5% increase in the Basic Charge and a corresponding decrease in the volumetric Delivery Charge, such that the change is revenue neutral within RS 1. This proposal achieves a reasonable balance among competing rate design considerations. A one-time 5% increase in the Basic Charge and a corresponding decrease in the volumetric Delivery Charge will improve the cost recovery from low-consumption customers. The change will result in only a small annual bill impact for the majority of customers (less than 1%), and zero bill impact for an average use customer.

20.1. Please describe the competing objectives in this rebalancing and what makes a one time 5% change the appropriate end-point.

21. Reference: Exhibit B-1, page 7-7

To date, the decrease in demand due to declining residential use per customer has been nearly offset by the increase in demand from the newly attached residential customers. Nevertheless, the future rate levels and rate structure should consider options than can fairly mitigate the potential for a decrease in overall residential demand due to declining residential UPC.

21.1. What options does FEI suggest should be considered to counter or fairly mitigate the prospect of overall reduction in customer demand based on declining use per customer.

21.2. What are the beneficial consequences of declining use per customer what are the negative consequences? Please elaborate with quantification where possible.

22. Reference: Exhibit B-1, page 7-13

Table 7-2: Evaluation of Rate Structure Options Based on Major Rate Design Considerations

	Flat Rate	Declining Block Rate	Seasonal Rate	Inverted Block Rate
Ease of Understanding and Administration	It is easy to understand. The ease of understanding for the general public will lead to relatively higher customer satisfaction, less cost pressures and easier administration of the residential rate schedule.	The logic behind a declining block rate structure is not easily understandable to the general public and some may misinterpret it as a form of subsidization to high use customers or contrary to energy conservation and environmental objectives.	The concepts of peak demand and related costs attributed to seasonal rates may not be easily understandable to some customers. There is no simple methodology to come up with the ratio of winter to summer rates. This makes the administration of this rate more difficult. Administration related to customer bill inquiries will also be greater relative to simpler rate structures	Similar to declining rates, the inverted rates may not be easy to understand for some customers. Customers may not know at what level of consumption and at what time of a month their consumption goes over the first block, leading to higher customer dissatisfaction.
Economic Efficiency and Fairness	Compared to other rate structures, flat rate can be considered a neutral option for economic efficiency and fairness as it does not discourage or encourage consumption of natural gas in any particular pattern.	This rate structure could be efficient for those situations where higher load factor customers are also higher volume customers. From a cost perspective, declining rates can be justified when the long-run incremental cost of service is below the average cost, which is the case for FEI.	A seasonal rate is used as a proxy for a demand charge to ensure that the costs of serving peak winter demands are allocated to those most responsible for causing them. Seasonal rates will reduce the price competitiveness of natural gas during the winter when natural gas is most valued by customers. Seasonal rates can be said to introduce a form of regional price differential since the customers in colder environments might be impacted more than others.	Natural gas distribution is widely considered to have economies of scale, meaning that as the size of the utility increases (i.e., increased consumption), the total average cost of the utility decreases. Therefore, there is no cost basis to justify inverted block rates for natural gas utilities. Inverted rates may send inefficient price signals because low volume customers could be subsidized.
Customer bill impact	Flat rates help with customer bill impact since there will be no change in the volumetric rate based on consumption level.	Depending on the portion of costs recovered in the first block, the customer bill impact for low use customers can be significant.	The bill impact for those customers with natural gas space heating and for those in colder climates can be significant.	Depending on the portion of costs recovered in the first block, the customer bill impact for high volume customers can be significant.
Rate and/or revenue stability	Annual forecasting for flat rates is more accurate than other rate options. Forecast accuracy results in improved rate and revenue stability.	Compared to a flat rate, declining rate provides less utility revenue stability due to higher difficulty of forecasting the load in each block.	This rate structure provides less utility revenue stability and customer rate stability as the price differential between winter and summer months can be significant.	Compared to a flat rate, this rate structure provides less utility revenue stability due to higher difficulty of forecasting the load in each block.

22.1. Please confirm that most residential customers are likely to be familiar with inclining block rates from BC Hydro.

22.2. Please provide an estimate of the 'cost pressures' that would occur as a result of a change from the flat rate.

22.3. Please confirm that those cost pressures would be proportional to the slope of the incline variance from flat.

22.4. Please provide FEI's 'long run incremental cost of service'.

22.5. Please provide FEI's incremental cost of service for each of the elements in its supply stack used to meet winter peak use.

22.6. Please provide FEI's average cost of service.

22.7. Did FEI consider the use of a 'demand charge' instead of a 'seasonal rate' for Residential customers?

22.7.1. If no, please explain why not.

22.7.2. Could FEI implement optional Smart Meters and optional, alternative rate structures? Please explain and identify any options that FEI has considered.

22.7.2.1. If yes, please confirm that such optional rate structures would be consistent with the Clean Energy Act, Section 17, under which the Commission must consider the 'government's goal of having smart meters, other advanced meters and a smart grid…'

22.8. Please confirm that the Inverted Block Rate Structure would be consistent with conservation and efficiency principles.

22.9. Please provide FEI's views as to what constitutes a 'significant' rate impact.

22.10. Could seasonal rates more accurately reflect the cost of serving customers? Please explain why or why not.

22.11. Please confirm that there is no explicit regional 'price' differential using seasonal rates. Rather, there is likely to be a consumption differential which is controlled by the customers.

22.12. Please explain why annual forecasting for a flat rate is more accurate than other rate options. Please provide FEI's evidence for this statement.

22.13. Please elaborate on how forecast accuracy results in improved rate and revenue stability, and consider FEI's current status as operating under PBR.

22.13.1. Could such instability be addressed with deferral account? Please explain why or why not.

23. Reference: Exhibit B-1, page 7-16

7.4.5 Proposed Rate Structure Option

Based on the discussion above, FEI believes that its existing flat rate structure provides the best balance of rate design considerations for residential customers and that there is no basis to segment this rate schedule further as there is little statistical evidence to indicate that consumption data is sufficient to distinguish between low and high efficiency customers. FEI's residential customers are already familiar with this rate structure, flat rates are simple to administer and easy to understand and provide more stability in terms of both utility revenues and customers' rates. The customer research survey results also show that the flat rate structure is preferred by the majority of residential customers (Section 7.4.4). Furthermore, as indicated in Section 7.6, the flat rate structure has been adopted by the majority of Canadian natural gas utilities for their residential customers.

23.1. Please discuss whether or not FEI considers customer preference in other rate classes, and if so, how that is and has been factored in both now and in the past.

23.2. Does FEI have commercial customer survey results?

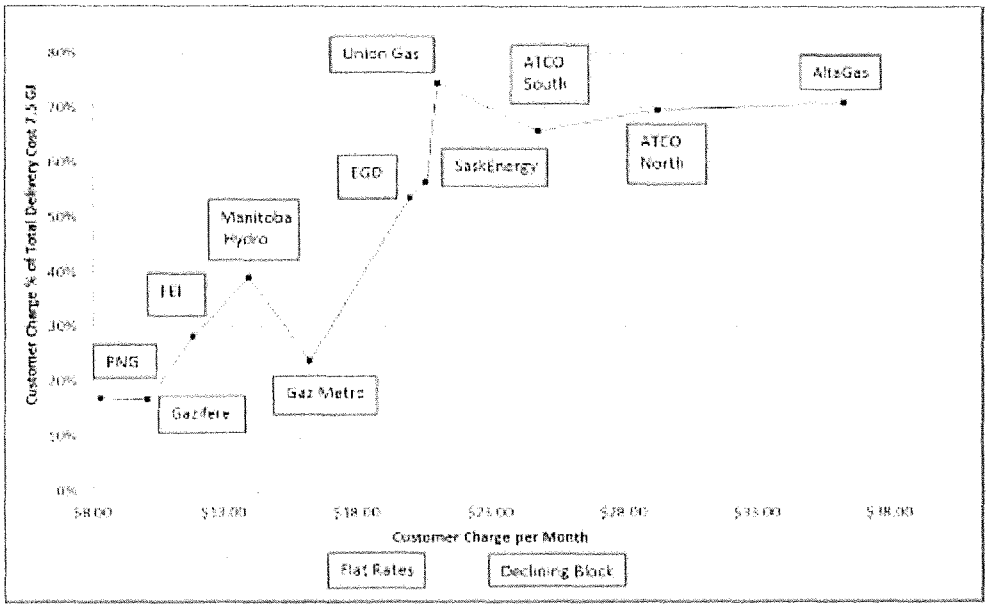
23.2.1. If not, please explain why not.

23.2.2. If yes, please provide these results.

23.3. What options does FEI have for distinguishing between high and low efficiency residential customers? Please explain.

24. Reference: Exhibit B-1, page Exhibit B-1, page 7-20

Figure 7-10: Residential Rate Structures for Various Canadian Natural Gas Distributors[113]



24.1. FEI's residential rates are some of the lowest in the country for flat rates. Please explain what circumstances create this situation.

24.1.1. Please provide a similar graphic for commercial rates.

24.2. Please break down this graphic by fixed charges and commodity rates to the extent the information is available.

24.2.1. Please provide similar graphics for commercial rates.

25. Reference: Exhibit B-1, page 7-19

The discussion above demonstrates that there are competing factors both for and against increasing the Basic Charge. Factors in favour of increasing the Basic Charge are:

- the fairness argument (Sections 7.3 and 7.5.1); and
- the evidence that other Canadian gas utilities have a higher percentage of cost recovery through a basic charge (Section 7.6).

The factors that militate against making significant changes to the Basic Charge are:

- the government energy efficiency and conservation policies (Section 7.5.2)
- bill impacts and rate stability for residential customers; and
- the feedback received from participants in FEI's Rate Design and Segmentation workshop (where there was no strong support for a change in the Basic Charge and the volumetric Delivery Charge).

In order to achieve a reasonable balance among competing rate design considerations, FEI is proposing a moderate one-time 5% increase in the Basic Charge and a corresponding decrease in the volumetric Delivery Charge.

25.1. Would an increase in the basic charge, combined with an inclining block rate structure for the volumetric delivery rate charge provide both a fairer cost recovery and support for energy efficiency and conservation principles?

25.1.1. If not, please explain why not.

26. Reference: Exhibit B-1, page 7-20

Four of the utilities presented in the above figure, ATCO Gas, Alta Gas, Union Gas and Gaz Metro, do not have a separate rate schedule for residential customers. Instead, their residential customers are part of a more heterogeneous group segmented based on consumption as low use[114]. This distinction offers a partial explanation for the significantly higher basic charges for these utilities, as commercial customers traditionally have higher basic charges than separately administered residential rate schedules. Similarly, it is important to note that residential natural gas customers in Quebec and Ontario have a declining block rate structure. A declining block rate structure is more favorable to customers with higher monthly consumption levels since the unit cost ($/GJ of consumption) will decline after a certain monthly consumption threshold is surpassed.

[113] PNG, Union Gas and ATCO gas have regional rates. For PNG, the average of all rates is used for presentation purposes. For Union Gas only M1 rate schedule (South Ontario region) is presented.

[114] Less than 1200, 419, 1912 and 5236 GJ/year for ATCO Gas, Gaz Metro, Union Gas and Alta Gas respectively.

26.1. Please provide a qualitative and quantitative comparison of residential and commercial customers identifying the characteristics that suggest the appropriateness of having separate rate schedules.

26.2. Please discuss whether it would or would not be feasible for FEI to eliminate the Residential rate schedule and utilize a rate structure based on consumption, as is done by ATCO gas, Alta Gas, Union Gas and Gaz Metro.

26.3. Please provide a list of the advantages and disadvantages of a rate structure that distinguishes customers based on volume rather than customer type.

26.4. Please provide an overview with FEI's best estimates as to how residential and commercial customer rates would be impacted by such a change.

27. Reference: Exhibit B-1, page 7-22

Any rate design proposal should consider the bill impact to customers and should be implemented in a way that avoids rate shock to customers.

The table below provides the Basic Charge and the volumetric Delivery Charge before rebalancing[115], after rebalancing (including changes caused by rate design proposals in other rate schedules)[116], and with rebalancing and also a 5% increase in the daily Basic Charge.

Table 7-7: Different Rate Scenarios for Residential Rate Schedule

Title	COSA before Rebalancing	COSA after Rebalancing	5% Increase in Basic Charge and offsetting Decrease in Delivery Charge
Daily Basic Charge ($/day)	0.3890	0.3890	0.4085
Delivery Charge ($/GJ)	4.821	4.832	4.746

27.1. Please provide FEI's definition of 'rate shock'.

27.1.1. Please provide evidentiary support for this definition if available.

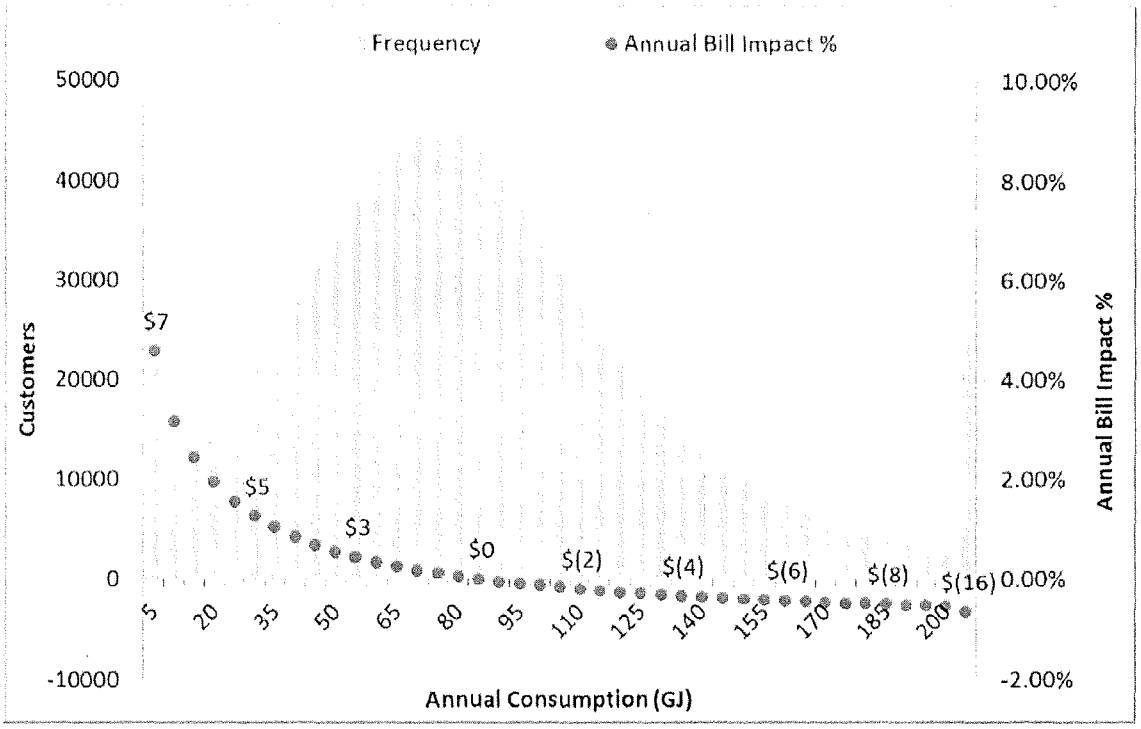
27.2. What are the kinds of costs that should be considered as fixed customer charges versus variable delivery charges.

27.2.1. Please provide a calculation of a basic charge using the full amount of the fixed customer costs to establish the basic charge.

27.2.2. Please provide the percentage of total fixed costs relevant for basic charges that the existing and proposed basic charge would collect.

28. Reference: Exhibit B-1, page 7-22

Figure 7-11: Customer Bill Impact[118]



28.1. How many customers will receive bill increases?

28.2. How many customers will receive bill decreases?

28.3. How many customers will receive fairer bills based on Bonbright fair cost allocation principles? Please provide an explanation.

29. Reference: Exhibit B-1, page 8-7

Table 8-2: Multi Jurisdiction Review of Commercial Rate Schedules

Company	Description	Eligibility	Type
Small Commercial			
FEI	Small Commercial	<2,000 GJ	Flat Rate
PNG	Small Commercial	<5,500 GJ	Flat Rate
AltaGas	Small General	<5,326 GJ	Flat Rate
Sask Energy[130]	Small Commercial	<3,825 GJ	Flat Rate
Manitoba Hydro	Small General	<535 GJ	Flat Rate
Gaz Metro	Distribution	<419 GJ	Declining
Large Commercial			
FEI	Large Commercial	>2,000 GJ	Flat Rate
PNG	Large Commercial	>5,500 GJ	Flat Rate
ATCO	Mid Use	1,200 – 8,000 GJ	Flat Rate
AltaGas	Large General	>5,326 GJ	Flat Rate
Sask Energy	Large Commercial	3,825 – 25,245 GJ	Flat Rate
Manitoba Hydro	Large General	536 – 26,010 GJ	Flat Rate
Union Gas	Large General	>1,712 GJ	Declining
Enbridge	General	No limit	Declining

29.1. Under what tariff does ATCO gas serve customers under 1200 GJ?
  29.1.1. Please provide the rate structure for these customers.

29.2. Under what tariff does Union Gas serve customers under 1,712 GJ?
  29.2.1. Please provide the rate structure for these customers.

30. Reference: Exhibit B-1, page 8-7

Table 8-2 shows that the threshold between small and large commercial customers ranges from 419 GJ/year for Gaz Metro to 5,500 GJ for Pacific Northern Gas (PNG). The 2,000 GJ threshold between RS 2 and RS 3/RS 23 used by FEI is roughly in the middle of this range. Consistent with FEI, most of these utilities use a flat rate structure for commercial customers.

The multi-jurisdiction review of the commercial customer rates shows that FEI's use of a flat rate structure is consistent with the commercial rate structure of most other utilities and also shows that FEI's current 2,000/year threshold is within the range of thresholds used by other utilities.

30.1. Has FEI conducted any commercial customer surveys to determine the preferred threshold?
  30.1.1. If not, why not.
  30.1.2. If so, please provide.

31. Reference: Exhibit B-1, page 8-8

8.3.2.1 Customer Bill Frequency

FEI has conducted a bill frequency analysis for RS 2 and RS 3/RS 23, which considers the annual consumption of the customers in each rate schedule. Figures 8-6 and 8-7 below show the 2015 annual consumption for RS 2 and RS 3/RS 23 customers, respectively.

Figure 8-6: Small Commercial Customer Bill Frequency

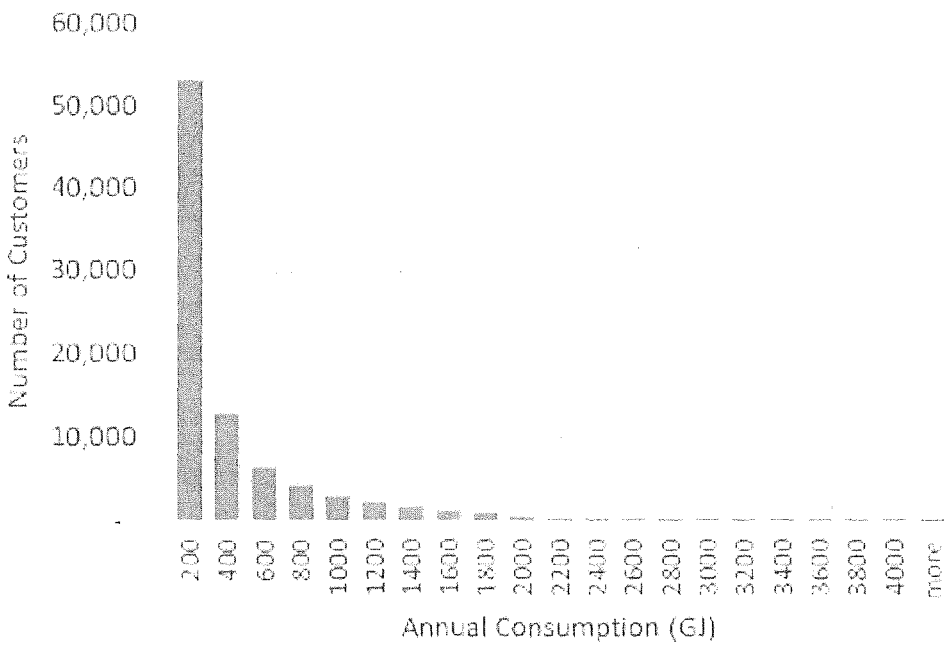


Figure 8-6 shows that approximately 72,000 (or approximately 85%) of the 85,000 small commercial customers use less than 600 GJ/year and approximately 84,000 (or 99%) customers use less than 2,000 GJ/year. There are approximately 600 customers whose annual consumption is greater than, the 2,000 GJ threshold. Many of the RS 2 customers consuming more than the 2,000 GJ threshold are either new customers whose annual consumption estimates were too low, or they are customers who have had a material change to their operations during the year. FEI reviews the customer consumption history annually to ensure that customer consumption meets the tariff requirements and will transfer customers to the appropriate rate schedule as necessary.

31.1. Please provide the above in tabular form, and break down those commercial customers consuming under 600 GJ into 50 GJ increments.

31.2. Please provide a comparison of a bill for customers consuming 100 GJ under both residential and small commercial tariffs.

31.3. Please provide a comparison of a bill for customers consuming 200 GJ under both residential and commercial tariffs.

32. Reference: Exhibit B-1, page 8-14

Table 8-4: Comparison of Fixed Costs and Fixed Charge Recoveries

Rate Schedule	Current Monthly Basic Charge[Tax]	Allocated Customer Cost from COSA ($/Month)	Basic Charge Percent of Customer Related Costs
RS 2 – Small Commercial	$24.84	$40.26	62%
RS 3/23 – Large Commercial	$132.52	$258.41	51%

As shown in the table above, the Basic Charge for both RS 2 and RS 3/RS 23 is at least half of FEI's customer allocated costs. The rate design principle to fairly apportion costs would suggest that FEI move the Basic Charge upwards to be in closer alignment with FEI's customer costs.

However, factors that militate against making significant changes to the Basic Charge are:

- At a level of 62% and 51% for RS 2 and RS 3/RS 23 respectively, FEI's commercial customer related costs are reasonably well recovered by the Basic Charge;
- Government energy efficiency and conservation policies discourages higher fixed charges;
- Increasing the Basic Charge would result in bill impacts and rate instability for commercial customers.

Based on these competing principles and considerations, FEI believes that the basic charges provide a reasonable recovery of FEI's commercial customer allocated fixed costs.

32.1. Does FEI consider 'at least half of FEI's allocated costs' to be a threshold of reasonableness? Please explain why or why not.

32.2. Please confirm that increasing the basic charge and lowering the delivery charge could be managed to reduce customer impacts and rate instability for customers.

32.2.1. If not confirmed, please explain why not.

33. Reference: Exhibit B-1, page 8-15

8.5 *Principle Based Review of Rate Design*

The principles adopted by FEI for its rate design are presented in Section 5 of the Application. As explained in that section, different rate design principles may have varying levels of importance for different rate schedules. Rate design should strive to strike a balance among competing rate design principles based on the specific characteristics of customers in each rate schedule.

Based on FEI's examination of each element of the commercial rate design as discussed above, the commercial rate structure works well in many respects. In particular, the customer segmentation and flat rate structure with a basic and delivery charge remains appropriate.

33.1. Please elaborate on how the importance of rate design principles differ between residential and commercial and provide specifics as to which rate design principle(s) are more and those which are less important for each rate class.

34. Reference: Exhibit B-1, page 8-18

As shown above, moving the segmentation threshold down to the 1,000 GJ/year level would result in considerable changes to the annual energy, average customer use and customer load factor of the commercial rate schedules. The annual energy would reduce by 33% for RS 2 and increase by 34% for RS 3/RS 23. The load factor for RS 2 would drop from 30.7% to 29.1%, similarly affecting FEI's cost allocation among all customer rate schedules. Lastly, the movement of RS 2 customers to RS 3 would cause approximately $2.3 million more revenue to be received under RS 3 than lost from RS 2, which would need to be considered in the overall revenue rebalancing analysis.

The significant customer disruption caused by moving customers representing approximately 1/3 of the entire demand within the rate schedule is not supported by the rate design principles of rate and revenue stability and is sufficient to exclude this option from further consideration.

34.1. Please provide the expected impacts for the COSA revenue to cost ratios for Rate Schedule 2 and 3 if the segmentation threshold were moved to the 1,000 GJ/year level.

34.2. Please provide the expected impacts for the COSA revenue to cost ratios for Rate Schedule 2 and 3 if the segmentation threshold were moved to the 1,400 GJ/year level.

35. Reference: Exhibit B-1, page 8-20 and page 8-11

The economic cross over point can be aligned with the 2,000 GJ threshold by simultaneously raising the Basic Charge for both RS 2 and RS 3/RS 23 and lowering the Delivery Charge for RS 2 and raising the Delivery Charge for RS 3/RS 23. These rate adjustments can be calculated to achieve revenue neutrality for the combined RS 2, RS 3 and RS 23 revenues.

The effects of these changes on RS 2 and RS 3 rates are represented by the dashed lines in Figure 8-12 below. The net effect of these adjustments is for the dashed lines to now cross at the 2,000 GJ threshold.

Figure 8-12: RS 2 and RS 3 Redesign at 2,000 GJ

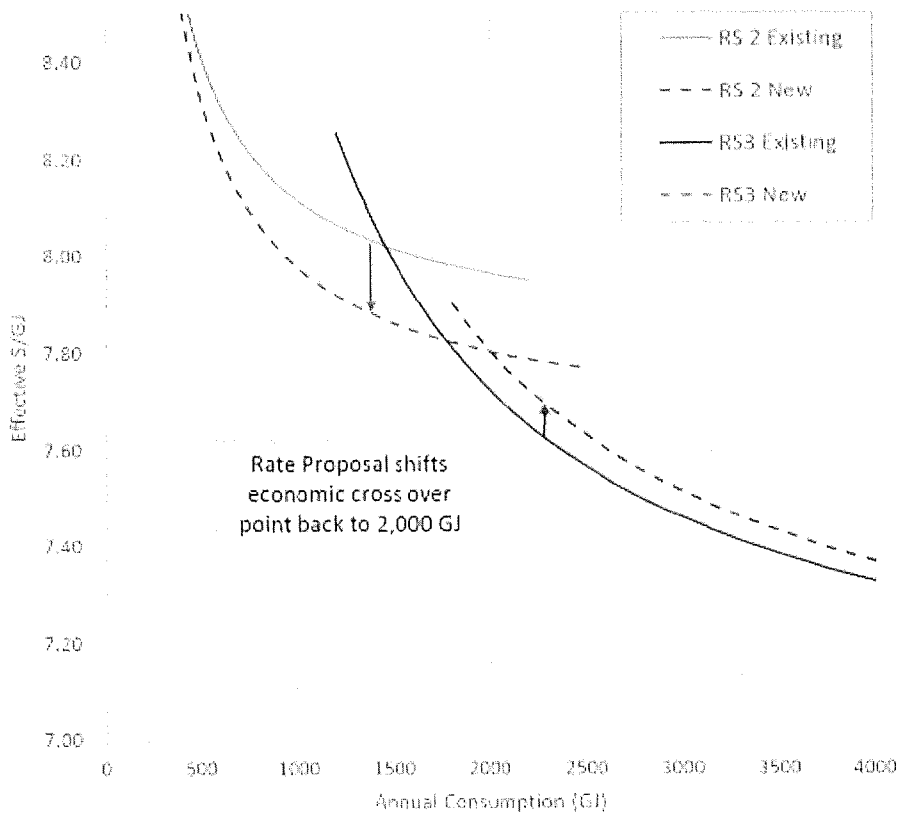


Figure 8-10: Average Commercial Customer Load Factor versus Annual Consumption Levels

35.1. FEI's three options include realigning the segmentation threshold to either 1,000 GJ, or 1,400 GJ, or to adjust the basic charge and delivery charge to support the existing crossover at 2,000 GJ, while achieving economic neutrality. Would it be possible to adjust the basic charge and the delivery charge to align with an economic crossover at about 1,000 GJ and still achieve economic neutrality? Please explain why or why not.

35.1.1. If yes, please provide details of the changes that would be required in order to do, and the impacts that might be expected from such changes.

35.1.2. If no, please explain briefly why not.

35.2. Has FEI considered the extent of the dispersion of load factors above 7000 GJ/year consumption, and would it make rate design sense to treat the customers in this group differently based on load factor? Please explain.

36. Reference: Exhibit B-1, page 9-9

The change in method to calculate the Daily Demand requires the Demand Charge to be reset to continue to send the appropriate price signals so that only customers with greater than 40% load factor have an incentive to take service under RS 5/RS 25. Customers with a load factor less than 40% should be taking service under FEI's Large Commercial rate schedules. FEI's proposed solution is to increase the Demand Charge by $3.00 which will send the appropriate price signals to customers.

36.1. On what basis has FEI established a 40% load factor as the appropriate threshold for customers to take service under RS 5/RS 25? Please provide the rationale and the evidence to support it.

37. Reference: Exhibit B-1, page 9-20

Table 9-4: 2016 COSA Rates for RS 5 and RS 25

	RS 5	RS 25
Basic Charge $ / Month	$587.00	$587.00
Demand Charge $ / Month / GJ of Daily Demand	$21.596	$21.596
Delivery Charge $ / GJ	$0.867	$0.867
Administrative Charge $ / Month	N / A	$78.00

37.1. What costs are recovered in the Administrative charge for RS 25?

38. Reference: Exhibit B-1, page 9-12

Table 9-5: Example of Demand Charge Calculation[147]

Line		Customer A	Customer B
1	Annual Consumption GJ	50,000	50,000
2	Load Factor	45%	55%
3	Peak Day Demand GJ = (Line 1 / 365) / Line 2	304	249
4	Demand Charge $ / GJ / Month	$21.596	$21.596
5	Annual Demand Charge = Line 3 x Line 4 x 12	$78,782	$64,529
6	Average Demand Charge Cost per GJ Delivered (Line 5 / Line 1)	$1.576	$1.291

As can be seen in the example above, the higher load factor customer will have a lower average cost because the Demand Charge is applied to a lower peak day demand (i.e., the Daily Demand as defined in the rate schedules). Using a Demand Charge is therefore a method of charging a lower average cost to efficient users of FEI's system with high load factors. This cannot be achieved by using a volumetric charge alone.

Since the utility's delivery costs are almost fully fixed, using a fixed Demand Charge and a fixed Basic Charge is more efficient for cost recovery of the allocated costs to serve industrial loads. FEI concludes that the existing rate structure for RS 5 and 25 is working well as intended. However, to use a demand charge it is necessary to have a means to determine what the peak day demand value is, which is discussed in Section 9.5.3.4.

38.1. Please confirm that the higher load factor customer contributes a smaller amount to peak demand, and therefore places lower costs on the system overall relative to consumption level.

39. Reference: Exhibit B-1, page 9-12

9.5.3.3 Multi-Jurisdiction Review of Rates

As discussed above in Section 9.4, FEI reviewed firm industrial rates offered by natural gas utilities in other jurisdictions. Based on this review, a demand charge with a volumetric delivery charge rate design is used by 6 out of 10 Canadian utilities as shown in Table 9-3. That is, six of the ten utilities surveyed used some form of demand charge. Also, three utilities required a minimum load factor to qualify for the rate.

The survey shows that FEI's rate structure for RS 5 and RS 25 is not unique in having a demand charge and a volumetric delivery charge to recover the costs to serve General Firm Service customers. This review supports FEI's continued use of a demand / volumetric delivery rate design for the firm general service rate schedule.

39.1. Did FEI consider a minimum load factor to qualify for this rate?

39.1.1. If not, please explain why not.

39.1.2. If yes, what options did FEI consider with regard to this possibility, and what were the outcomes? Please explain.

40. Reference: Exhibit B-1, page 9-13 and 9-14 and page 9-15

In short, a customer's peak day demand is derived based upon grossing up the customer's highest daily average usage from monthly billing data by a factor of 1.25 to estimate their peak day consumption within their peak month usage[148].

Today, all RS 5/RS 25 customers have metering in place that can provide daily consumption figures. With daily measurement information available for all RS 5/RS 25 customers, FEI reviewed the current demand formula multiplier of 1.25 to determine whether or not it is reflective of this customer group's peak day consumption and, if not, whether the multiplier should be adjusted or alternatively whether a new method should be developed and implemented.

The current method of determining the Daily Demand overestimates the peak day demand for the majority of RS 5/RS 25 customers. This can be seen by comparing the average Daily Demand using the current method to the results for the average consumption on the 3 or 5 coldest days. As shown in the table below, for approximately 450 of the 774 customers (those with a load factor >50%), the current method using a 1.25 multiplier yields an average Daily Demand that is 46% higher than the actual average consumption on the five coldest days (105 GJ / 72 GJ – 1). When considering all customers, the average Daily Demand is 30% higher than the average demand per day derived from actual consumption on the three or five coldest days (100 GJ / 77 GJ – 1).

Table 9-6: Average Daily Demand (GJ) per Customer by Load Factor Segment (Combined Totals for RS 5 and RS 25 Customers)

1		Current Formula for Daily Demand		Average Consumption on Coldest			
				3 Days		5 Days	
		Average Daily Demand	# of Customers	Average Daily Demand	# of Customers	Average Daily Demand	# of Customers
2	<40% Load Factor	174	55	150	44	159	33
3	40% to <45% Load Factor	93	75	97	54	109	43
4	45% to <50% Load Factor	73	196	77	93	72	87
5	>50% Load Factor	105	447	71	576	72	607
6	All Customers	100	774	77	774	77	774

FEI considered the following options for estimating peak day demand:

1. Status Quo/Current Formula – Continue to use the current Daily Demand formula with the 1.25 multiplier.
2. Current Formula with Updated Multiplier – Use the Current Formula method described above, but update the current 1.25 multiplier to align with the customer groups' coincident daily usage under peak weather conditions (5 coldest days for their region) for each customer.149
3. FEI System Maximum Day Send Out – Use the customer's actual consumption that occurred on the same day as FEI's maximum daily send out (i.e., during 2015 the maximum daily send out occurred on December 31, 2015).
4. Average Consumption on 3 or 5 Coldest Days in Region – Use the customer's actual average daily consumption over the 5 coldest days for their region.
5. Modified Formula – Use the greater of the customer's average consumption on the five coldest days for their region or one half of the average summer maximum day (as in the current formula method).

40.1. Would FEI agree that using customers' actual data represents a more accurate method of calculating load factor than grossing up highest daily averages? Please explain.

40.2. Please provide the anticipated outcomes for customers under each of the alternatives, including anticipated bill changes, and % bill changes and the number of customers affected in each of the load factor categories.

41. Reference: Exhibit B-1, page 9-18 and 9-19

Table 9-10: Summary of Methods to Determine Daily Demand

Methods	Pros	Cons
Status Quo / Current Formula • 1.25 x times the greater of highest monthly average day use from November 1 to March 31 or ½ of highest monthly average day use from April 1 to October 31	• Formula has been in use for many years and is well understood by customers • Rate calculation is understood and the information is readily available to customers	• 1.25 multiplier is not aligned with coincident peak usage • Multiplier is derived from the whole of all customers & may not reasonably calculate an individual customer's peak day
FEI System Maximum Day Send Out • Customers' consumption on FEI's maximum day send out	• Measures a customer's demand during FEI system max day	• Customer's Daily Demand on single day maximum send out is variable potentially producing erratic results from year to year • Unstable revenues from unstable Daily Demand • A formula will still be required for new customers for which there was no consumption record on system maximum day
Average Consumption on 5 Coldest Days in Region	• Average of multiple days reduces the impact of an anomalous day of low consumption which would not be representative of demand during regular business operations during cold weather days	• Requires additional detail related to weather station daily temperatures by region where customers are located • Anomalous result could still occur for customers who may have had consecutive days of reduced demand due to plant outages or reduced demand for holiday season • A formula will still be required for new customers where there is no consumption record during the 5 coldest days
Modified Formula • The greater of the average consumption on the 5 coldest days or ½ of highest monthly average day use from April 1 to October 31	• Removes factoring in of anomalous days of zero or very low demand in the winter period due to holiday season business operations • Provides Daily Demand measurement for customers whose peak occurs in the summer period (56 customers in 2015)	• Requires additional detailed information by weather station in regions where customers are located • Details might not be readily available to customers • Will need formula for new customers where there is no consumption record during the 5 coldest days
Current Formula with Adjusted Multiplier • (same as current method) except use lower multiplier that more closely aligns with peak demand as measured by average consumption on 5 coldest days)	• Formula has been in use for many years and is well understood by customers • Rate calculation is understood and information is readily available to customers • Updated multiplier aligns the Daily Demand to the peak demand of all General Firm customers during the 5 coldest days, i.e., the sum of all customers demand in their region	• Multiplier is based on all General Firm customers demand & not based on individual customer's peak consumption

41.1. Please confirm that using actual customer data, the load factor could be adjusted annually.

42. Reference: Exhibit B-1, page 9-17 and page 9-20

Table 9-8: Number of Customers by Load Factor Segment (Combined Totals for RS 5 and RS 25 Customers)

		Method 1	Method 2	Method 3	Method 4		Method 5
1		Current Formula for Daily Demand	Current Formula Updated Multiplier	FEI System Maximum Day Send Out	Average Consumption on Coldest 3 Days	5 Days	Modified Formula with 5 Day Average
2	Customers with Zero Demand	1	1	13	7	4	1
3	<40% Load Factor	55	26	55	44	33	35
4	40% to <45% Load Factor	75	22	64	54	43	43
5	45% to <50% Load Factor	196	65	104	93	87	87
6	>50% Load Factor	447	660	538	576	607	608
7	Total	774	774	774	774	774	774

This option strikes a balance between better alignment of an estimated coincident peak demand and a high level of customer understanding of how the rates would be applied. This option will also provide for more rate and revenue stability producing fewer anomalous results.

Other than the adjustment to the multiplier, this method uses the current formula, which has been used for many years and is understood by customers. The rate calculation is understandable and it is easy to implement. This method also reduces potential anomalous results that could understate or not be representative of a customer's peak demand. Anomalous results could be substantive from reduced demand on Sundays, statutory holidays or short term seasonal holidays, such as the Christmas / New Year period when some customers would have reduced operations. By maintaining the formula and not requiring daily consumption figures for every customer, new customers to this rate class that do not yet have daily metering can still determine if there is a benefit of moving into the rate class.

For all of these reasons, FEI proposes to update the multiplier in the Daily Demand formula to 1.10 as discussed above.

42.1. Please elaborate on the issue of potential anomalous results and how they might impact (a) the customer, (b) other customers within the rate class, and (c) customers in other rate classes.

42.2. Does FEI consider its industrial customers to be sophisticated consumers of energy? Please explain why or why not.

43. Reference: Exhibit B-1, page 9-21

FEI considered the following options to ensure there is an appropriate economic incentive for lower load factor customers to continue to take service under RS 3/RS 23 rather than RS 5/RS 25.

1. Change the Basic Charge – raising the Basic Charge will mostly incent low volume customers to take service under Large Commercial RS 3/RS 23, but would not target customers with a low load factor. This is because the Basic Charge is a fixed monthly charge independent of the monthly or annual demand or the load factor of the customer.
2. Change the Delivery Charge – raising the Delivery Charge will affect all customers based on their total demand without regard to the customer's load factor. This will encourage more customers with a high load factor to migrate to Large Commercial which is not the intent of the change that is required.
3. Remove the Demand Charge - removing the demand charge from RS 5/RS 25 (as suggested by a stakeholder during the stakeholder engagement workshop) would remove the mechanism that rewards more efficient system utilization by higher load factor customers. RS 5 and RS 25 were designed to serve high load factor customers.
4. Change the Demand Charge – raising the Demand Charge will more directly incent low load factor customers to take service under Large Commercial RS 3/RS 23.

Of the options listed above, the best mechanism to provide an incentive for customers whose load factor is less than 40% to take service under RS 3/RS 23, rather than RS 5/RS 25, is to increase the Demand Charge.

Specifically, FEI proposes to raise the Demand Charge by $3.00 per month per GJ of Daily Demand to increase the economic crossover point between RS 3/RS 23 and 5/25.

43.1. Could FEI simply introduce a restriction for a minimum load factor going forward and grandfather existing customers? Please explain why or why not.

43.1.1. If yes, would a 40% load factor be the appropriate cut-off? Please explain why or why not and provide FEI's view of the appropriate cut-off.

44. Reference: Exhibit B-1, page 9-22 and 9-23 and page 9-24

Specifically, FEI proposes to raise the Demand Charge by $3.00 per month per GJ of Daily Demand to increase the economic crossover point between RS 3/RS 23 and 5/25.

The economic cross over point after increasing the Demand charge by $3.00 is shown in Table 9-13 below. As shown in the table, the proposed increase to the Demand charge increases the economic cross over point such that there would be relatively few customers that would have sufficient annual volumes to make taking service under RS 5/RS 25 economic at a load factor less than 40%. Table 9-14 below shows the economic crossover from Table 9-13 and Table 9-7, with the proposed rates for RS 3/RS 23 and RS 5/RS 25 which shows the increased annual volume required for a commercial customer to be incented to take service under RS 5/RS 25.

Table 9-13: Large Commercial / General Firm Economic Crossover at Varying Load Factors at Proposed Rates

		RS 23		RS 25		
Monthly Charges (Basic + Admin. Fee) $/Month		$223.78		$665.00	From Table 9-7 at 2016 COSA RATES	
Demand Charge $/GJ/Month		N / A		$24.596		
Delivery Charge $/GJ		$3.175		$0.887		
		Economic Cross-over (GJ/Year)	Daily Demand	Peak Winter Month With 1.1 multiplier	Daily Demand	Peak Winter Month With 1.25 multiplier
	50%	7,894 GJ	43 GJ	1,180 GJ	35 GJ	840 GJ
	45%	10,783 GJ	66 GJ	1,790 GJ	48 GJ	1,145 GJ
Load Factor	40%	19,874 GJ	136 GJ	3,712 GJ	75 GJ	1,797 GJ
	39%	24,675 GJ	173 GJ	4,727 GJ	84 GJ	2,028 GJ
	38%	33,089 GJ	239 GJ	6,506 GJ	97 GJ	2,327 GJ
	37%	51,656 GJ	382 GJ	10,432 GJ	114 GJ	2,730 GJ
	36%	126,696 GJ	964 GJ	26,296 GJ	138 GJ	3,301 GJ

Table 9-14: Economic Crossover Volume at Proposed Rates (Table 9-13) Compared to at 2016 COSA Rates (Table 9-7)

Load Factor	Economic Crossover at Proposed Rates	Economic Crossover at 2016 COSA Rates
50%	7,894 GJ	6,386 GJ
45%	10,783 GJ	7,834 GJ
40%	19,874 GJ	10,930 GJ
39%	24,675 GJ	12,027 GJ
38%	33,089 GJ	13,447 GJ
37%	51,656 GJ	15,360 GJ
36%	126,696 GJ	18,073 GJ

The tables above demonstrate that the proposed rate changes improve the incentive for customers who are less than 40% load factor to appropriately take service under RS 3/RS 23 because of the increased volume it takes to reach the point of indifference when the annual bill would be the same under large commercial service or general firm service.

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.

44.1. The economic crossover is increased for all load factor and remains almost double for customers with load factors of 40%. Please comment on FEI's expectation of the impact of the higher crossover for customers with load factors of 40%, 45% and 50%.

44.2. Please provide Tables 9-13 and 9-14 demonstrating the economic crossovers of increasing the demand charge by $2 instead of $3.

44.2.1. Please provide a discussion of the bill impact of such a change.

44.3. Please provide Table 9-13 and 9-14 demonstrating the economic crossovers of increasing the demand charge by $1 instead of $3.

44.3.1. Please provide a discussion of the bill impact of such a change.

45. Reference: Exhibit B-1, page 9-24 and 9-6

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.

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.

45.1. Why did FEI establish 80% as the appropriate load factor for the RS5/RS 25 demand charge (plus delivery charge) on which to base the RS7/RS27 delivery charge.

45.2. Please provide the evidentiary base for using an 80% load factor.

46. Reference: Exhibit B-1, page 9-27

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).

[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.

46.1. Please extend the table to include FEI's proposed increase to the demand charge in RS 5/25

47. Reference: Exhibit B-1, page 9-27, and page 9-29

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%.

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%

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.

47.1. Please confirm that the appropriate discount rate should heavily consider the value to FEI, and to ratepayers of reducing peak demand.

47.1.1. If not confirmed, please explain why not.

47.2. Would it be theoretically appropriate for FEI to encourage as many customers as required to move off the peak, in order to minimize peak demand and achieve high and consistent throughput throughout the year? Please explain why or why not.

47.3. Please explain if FEI considers 18% to be the optimal discount at 80% load factor and 33% to be the optimal discount at 55% load factor, and please explain why.

47.3.1. If these are not the optimal discounts, please provide FEI's view as to the optimal discount

48. Reference: Exhibit B-1, page 9-30

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.

48.1. Please provide a graphic representation of, and the supporting data, the relationship between savings to non-bypass customers and increases in interruptible volumes.

48.2. Please provide an assessment of what might be required to incent additional interruptible volumes and whether or not discounts are sufficient.

49. Reference: Exhibit B-1, page 10-26

Most days of the year, the System operates under normal conditions. Under normal conditions, customers within daily balanced groups are required to adhere to a 20% balancing tolerance. A balancing charge applies when a transportation customer under-delivers (meaning demand is greater than supply) beyond the 20% tolerance. The tolerance is applied based on a "greater of" formula. When authorized supply plus the greater of 120% or 100 GJ is insufficient to meet demand for a day, balancing charges will apply. Charges are $1.10/GJ in the winter and $0.30/GJ in the summer.

49.1. What was FEI's original rationale for allowing monthly balanced groups as well as daily balanced groups?

49.2. What was FEI's original rationale for allowing a tolerance of 20%?

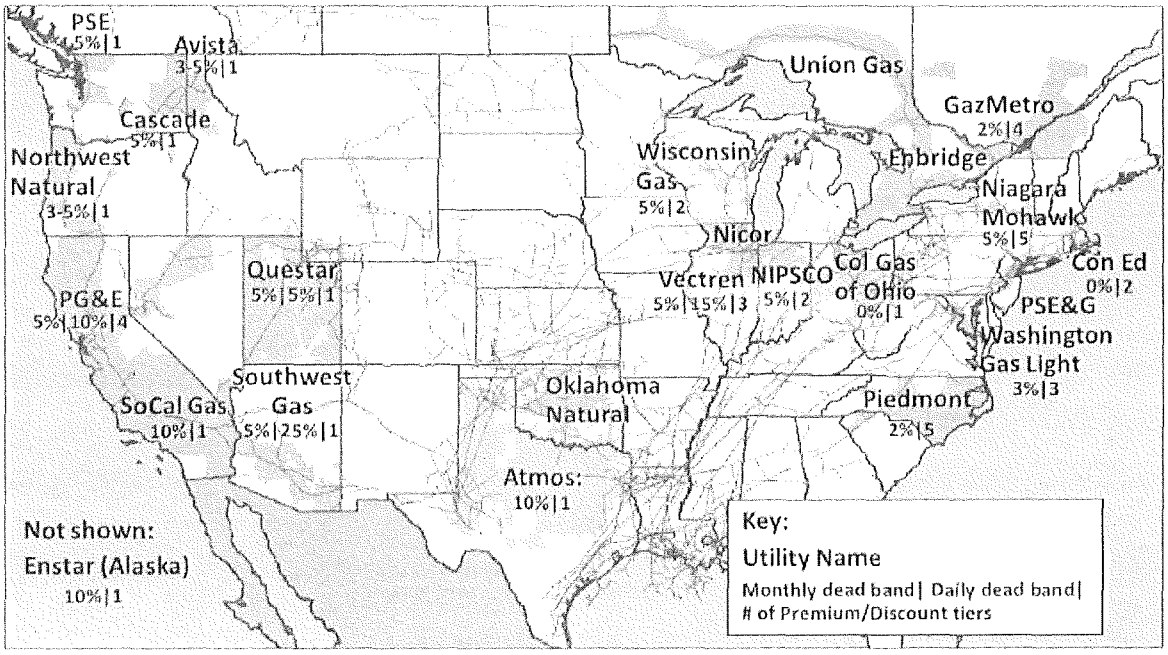
50. Reference: Exhibit B-1, page 10-27

Shipper agents managing daily balanced groups use the imbalance return service, which allows them access to their "banked" inventory on FEI's System. To build on the previous example, when imbalance return is authorized,[181] as shown in Figure 10-9 below, shipper agents can use their inventory as a source of gas supply in addition to the authorized supply at the interconnecting point. The authorized supply at the interconnecting point is 10,000 GJ combined with the amount of authorized imbalance return of 3,000 GJ for a total of 13,000 GJ. FEI then applies the tolerance calculation to determine if under-deliveries exceeded the tolerance. In this case, the shipper agent over-delivered by 600 GJ and no charges were incurred.

50.1. Please provide an approximation of the range of volumes of 'banked' inventory that shippers may have at their disposal at any given time.

51. Reference: Exhibit B-1, page 10-31

Figure 10-11: Comparison of Selected Balancing Provisions among North American LDCs



51.1. FEI's Figure 10-11 does not include the Prairie provinces. Please explain why, and provide the evidence if it is available.

51.2. Are there any LDCs that do not allow for balancing tolerances at all?

51.2.1. If yes, please identify those LDCs.

51.2.2. If yes, did FEI consider removing the balancing tolerances altogether? Please explain why or why not.

52. Reference: Exhibit B-1, page 10-32 to 10-33

Transportation customers who maintain large imbalances within the month are receiving value from FEI's midstream resources. Black & Veatch was tasked by FEI to estimate the value of this service. In the Application to Amend the Monthly Balancing Charges for Rate Schedules 23, 25, 26 and 27, the Commission directed FEI to evaluate the extent to which FEI uses core gas cost resources to balance the overall transportation service imbalances for each day and the cost to the sales customers.[184] The research and analysis to derive the replacement costs below addresses this directive. A summary of this study is provided below, and the entire report is provided in Appendix 10-1.

Black & Veatch developed a methodology to calculate the estimated replacement cost that transportation customers or shipper agents would have to incur to secure the balancing services currently provided by FEI (the Replacement Cost Analysis). As indicated in Table 10-7 below, the balancing service that FEI provides has market value.

Table 10-7: Replacement Cost of Balancing Services (Base Case)

	Total Replacement Costs	$/GJ
10%	$3,489,109	0.048
15%	$6,508,586	0.090
20%	$8,617,227	0.119

52.1. Please provide a brief overview of the Black and Veatch methodology for calculating the replacement value.

52.2. Please confirm that Black and Veatch's methodology does not provide the incremental cost to non-bypass customers of having Transportation customers utilize FEI's midstream resources.

53. Reference: Exhibit B-1, page 10-34

In determining an appropriate tolerance threshold for FEI's transportation model, FEI considered research by Black & Veatch which indicates that some utilities hold their customers to a 5% tolerance. FEI considered this tolerance, but determined that 5% is too stringent, especially in light of the current rate schedule terms and conditions where FEI reserves the right to impose a 5% tolerance under supply restriction circumstances.

FEI also considered the tolerances maintained by shipper agents operating under the transportation model today, under the current business rules with both daily and monthly provisions. Based on the analysis and balancing activity by transportation customers in 2014 and 2015, Table 10-8 below indicates that a number of shipper agents today (indicated below

53.1. Please elaborate on why 5% is too stringent a tolerance.

53.2. The CEC interprets FEI's concern of its right to impose a 5% tolerance under supply restriction circumstances as being a desire to retain a different tolerance between the situations relating to supply restriction. Please confirm or explain otherwise.

53.3. If confirmed, please explain why FEI wishes to retain a difference as opposed to eliminating the different tolerances altogether.

53.4. If confirmed, please e confirm that FEI could also lower and/or eliminate its tolerances under supply restriction conditions such that there is a difference between the two tolerances.

54. Reference: Exhibit B-1, page 10-34

Table 10-8: Imbalance data under a 10% tolerance

Shipper Agent	Service Area	# Imb Days / Year	Annual Volume in Excess	Volume in Excess / Day	Demand / Day	Volume in Excess / Demand
Shipper Agent N	INL	287	-2,010	-6	8	-67%
Shipper Agent N	LML	219	-30,843	-85	230	-37%
Shipper Agent M	LML	216	-74,312	-204	467	-44%
Shipper Agent I	INL	210	-28,100	-77	414	-19%
Shipper Agent E	INL	203	-209,596	-574	2,128	-27%
Shipper Agent C	LML	185	-848,871	-2,326	13,829	-17%
Shipper Agent O	LML	170	-4,442	-12	124	-10%
Shipper Agent D	INL	169	-210,408	-576	3,401	-17%
Shipper Agent D	LML	161	-652,440	-1,788	14,446	-12%
Shipper Agent E	LML	149	-691,630	-1,895	13,008	-15%
Shipper Agent A	LML	137	-256,193	-702	19,970	-4%
Shipper Agent C	INL	115	-143,545	-393	8,173	-5%
Shipper Agent I	LML	109	-56,657	-155	2,591	-6%
Shipper Agent H	INL	17	-21,248	-58	5,293	-1%
Shipper Agent B	INL	12	-13,784	-38	15,191	0%
Shipper Agent A	INL	11	-59,806	-164	10,978	-1%
Shipper Agent F	INL	7	-22,161	-61	14,602	0%
Shipper Agent B	LML	5	-7,141	-20	15,641	0%
Shipper Agent K	INL	4	-2,767	-8	1,199	-1%
Shipper Agent L	LML	3	-2,049	-6	1,155	0%
Shipper Agent H	LML	1	-405	-1	3,027	0%
Shipper Agent G	INL	1	-921	-3	9,830	0%
Shipper Agent J	LML	1	-69	0	1,435	0%

54.1. Please identify whether each of the shippers is Daily or Monthly Balanced.

55. Reference: Exhibit B-1, page 10-36

10.7.6 FEI System Balancing – Appropriate Charges

As shown in Figures 10-8 and 10-9, the current charges for exceeding the balancing tolerance of 20% are $1.30/GJ in the winter and $0.30/GJ in the summer. As FEI is proposing to reduce the System balancing tolerance from 20% to 10%, FEI evaluated the level of charges that would be appropriate for the tighter balancing tolerance. FEI is proposing a tiered approach in order to layer in charges that are incrementally higher as threshold percentages are exceeded. FEI considered three ranges, 0-10%, 10-20% and greater than 20%. For shipper agents operating within the 0-10% range, FEI proposes to impose no penalty. To determine a slightly higher charge for the 10-20% range, FEI evaluated the variable costs involved in balancing the System, both to and from its storage resources.

55.1. Why does FEI wish to 'layer in' charges?

55.2. Is it FEI's objective to reduce, or to eliminate excess imbalances altogether? Please explain.

56. Reference: Exhibit B-1, page 10-37

Based on the range in incremental variable costs, FEI is proposing to apply a mid-range charge of $0.25 CAD/GJ for the 10-20% range which would be applied in both the summer and winter months. Should the cost of gas exceed $5.00 US/MMBtu, which is the highest value FEI reviewed, FEI will apply to the Commission to update the charge.

In the third tolerance range, shipper agents that exceed the 20% tolerance level would be subject to the same charges applied today, $1.10/GJ in the winter months and $0.30/GJ in the summer months. Any of these charges paid by shipper agents for either the 10-20% range or above 20% will be credited back to the midstream portfolio to recover costs for resources held on behalf of sales customers.

Table 10-10 below summarizes the charges that would be imposed in the three tolerance ranges.

Table 10-10: Range of System Imbalance and Associated Charges

Range	Winter Charge/GJ	Summer Charge/GJ
Tier 1: 0-10%	No fee	No fee
Tier 2: 10-20%	$0.25	$0.25
Tier 3: 20+%	$1.10	$0.30

56.1. Please provide an estimate of the amounts that FEI expects to be credited back to the midstream portfolio?

56.2. Please provide FEI's best estimate of the costs that are incurred by non-bypass customers for holding resources on behalf of sales customers.

57. Reference: Exhibit B-2, Appendix 11-2

FEI 2016 Rate Design Application — Appendix 11-2

Basis for Calculation of
Standard Charges Schedule

FEI Proposed Returned Payment Charge

Based on FEI's weighted average costs for 2015 of handling returned cheques and returned electronic fund transfers (EFT):

Line	Particulars		Notes
1			
2	Returned Payments in 2015		
3			
4	Returned cheques	215	
5	Returned EFTs	3,647	EFTs are related to preauthorized payment plan returns
6	Total Returned Payments	3,862	Line 4 + Line 5
7			
8	TD Canada Trust charges and Symcor charges		
9	Weighted average per returned payment	$ 1.45	
10			
11	Finance Department Processing Cost		
12	Cost of return cheques	$ 2.00	
13			
14	Customer Service Billing Department Processing Cost		
15	Cost of return payments	$ 3.91	
16			
17	Total cost of handling a return payment	$ 7.36	Line 9 + Line 12+ Line 16
18			
19	FEI Proposed Return Payment Charge	$ 8.00	

57.1. Please explain why FEI is proposing a charge of $8.00 when the cost is closer to $7.00 or $7.50.

58. Reference: Exhibit B-1-3, page 11-28

Table 11-6: Update to OH&M Charge Calculation

	Forecast 2016	Forecast 2017	Total
Staff Resources ($000)	747	769	1,516
Customer Education ($000)	70	60	130
Total Overhead ($000)	817	829	1,646
Projected Volumes (TJ)	1,196	1,702	2,898
Annual Charge ($/GJ)	0.68	0.49	0.57

Using the 2016 and 2017 forecast volumes from the FEI Annual Review for 2017 Rates, Evidentiary Update filed October 5, 2016, the OH&M charge calculation in Table 11-6 results in $0.57/GJ. Given that the OH&M charge is dependent on forecast volumes which will vary from actual volumes, and because the term of the GGRR extends further than 2017 (to 2022), FEI expects this amount will decrease over time. FEI continues to update its forecasts for the remaining term of the GGRR and believes that the current levels of overhead and volumes continue to support the $0.52 OH&M charge.

11.3.3 Conclusion

Based on FEI's review and the updated calculation, FEI recommends the OH&M charge for CNG and LNG fueling station customers remain unchanged at $0.52/GJ.

58.1. Please explain why Customer Education is expected to be lower in F2017 than F2016.
58.2. Why did FEI average the two years instead of using the Forecast for 2017? Please explain.
58.3. If FEI has a forecast available for F2018 please provide.

59. Reference: Exhibit B-1-1-1 page 13-20 and Exhibit B-1-1 page 13-20 and Cover Letter pages 1-2

Table 13-12: Revenue to Cost and Margin to Cost Ratios

Rate	R:C	M:C
Rate 1 Domestic (Residential) Service	90.5%	88.0%
Rate 2.1 General (Small Commercial) Service	108.3%	110.7%
Rate 2.2 General (Large Commercial) Service	113.2%	118.2%
Rate Schedule 25 General Firm Transportation Service	112.1%	112.1%

During the Workshop, staff raised a question about whether there should be a different Peak Load Carrying Capacity (PLCC) value used for Fort Nelson as a separate entity.[1] The PLCC is intended to recognize that there is capacity embedded in the minimum system and make an adjustment in the Peak Day Demand allocator to account for this. Since the Workshop; FEI considered the notion of using a Fort Nelson-specific PLCC both internally and in consultation with EES Consulting and concluded that using a Fort Nelson specific PLCC would be more appropriate given Fort Nelson has its own Minimum System Study and because it is a separate region for rate making purposes. Consequently, FEI has conducted further analysis using a separate PLCC for Fort Nelson.

As a result, in this evidentiary update, the COSA results for Fort Nelson have been revised reflecting the use of a specific PLCC for Fort Nelson of 1.178 GJ per customer (as compared to the PLCC of 0.205 GJ per customer for FEI as a whole including Fort Nelson). FEI believes that the use of the Fort Nelson-specific PLCC is appropriate since it uses data and analysis specific to the service area in which it is being applied and is also better for Fort Nelson customers because it reduces the magnitude of rate rebalancing.

Table 13-12: Revenue to Cost and Margin to Cost Ratios

Rate	R:C	M:C
Rate 1 Domestic (Residential) Service	81.9%	77.5%
Rate 2.1 General (Small Commercial) Service	119.9%	126.4%
Rate 2.2 General (Large Commercial) Service	142.3%	164.5%
Rate Schedule 25 General Firm Transportation Service	112.1%	112.1%

59.1. The change in the PLCC has quite dramatically altered the COS Revenue to Cost ratios. Please elaborate on how the change in the PLCC resulted in this change.

60. Reference: Exhibit B-1-1-1 page 13-20

Table 13-12: Revenue to Cost and Margin to Cost Ratios

Rate	R:C	M:C
Rate 1 Domestic (Residential) Service	90.5%	88.0%
Rate 2.1 General (Small Commercial) Service	108.3%	110.7%
Rate 2.2 General (Large Commercial) Service	113.2%	118.2%
Rate Schedule 25 General Firm Transportation Service	112.1%	112.1%

Table 13-12 shows that R:C ratios for Rates 1 and 2.1 are within the range of reasonableness and Rate 2.2 and Rate Schedule 25 are above but near the upper bound of the range and that rebalancing may be necessary. FEI's proposal for rebalancing is discussed in Section 13.7.1.4.

60.1. Does FEI have a range of reasonableness it considers appropriate for the Margin to Cost ratio?

60.1.1. If yes, please provide FEI's views as to the range of reasonableness for the Margin to Cost ratio.

60.1.2. Please confirm that it is equally unfair for a customer group to be low on the Revenue to Cost Ratio as it is for customer groups to be high on the Revenue to Cost ratio.

60.1.2.1. If not confirmed, please explain why not.

60.1.2.2. If confirmed, please confirm that Rate 1 is virtually on the lower bound of the 10% range of reasonableness and rebalancing is necessary.

60.1.3. Please confirm that Rate 2.1 is approaching the upper bound of the 10% range of reasonableness.

60.2. Please calculate the rate impacts required for a rebalancing to unity implemented once every 10 years with a 1% adjustment to Rate Schedule 1 per year phased-in and proportionally equal reductions for those rate schedules higher than unity.

60.3. Please make the same calculation to show the rate impacts for a rate of implementation at 2% per year.

60.4. Please make the same calculation for a rate of implementation at 3% per year.

61. Reference: Exhibit B-1-1-1 page 13-20 and BC Clean Energy Act

Table 13-12: Revenue to Cost and Margin to Cost Ratios

Rate	R:C	M:C
Rate 1 Domestic (Residential) Service	90.5%	88.0%
Rate 2.1 General (Small Commercial) Service	108.3%	110.7%
Rate 2.2 General (Large Commercial) Service	113.2%	118.2%
Rate Schedule 25 General Firm Transportation Service	112.1%	112.1%

British Columbia's energy objectives

2 The following comprise British Columbia's energy objectives:

(a) to achieve electricity self-sufficiency;

(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

(d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

(e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers;

(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;

(g) to reduce BC greenhouse gas emissions

(i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

(ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

(iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

(iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

(v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;

(k) to encourage economic development and the creation and retention of jobs;

(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;

(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

(o) to achieve British Columbia's energy objectives without the use of nuclear power;

(p) to ensure the commission, under the *Utilities Commission Act*, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.

61.1. Please confirm that BC's Clean Energy Act, Section 2 Objectives, 2(g), 2(h) and 2(i) would support the provision of rates for natural gas that have revenue to cost ratios of one.

61.1.1. If not confirmed, please explain why not.

62. Exhibit B-1-1, page 13-23 and 13-24

There is a low percentage of residential and commercial customers that benefit from the declining rates. This is because the majority of Fort Nelson's customers do not consume more than the minimum usage block per month and therefore are never billed under the second lower rate block. The result is that for the majority of Fort Nelson customers the current declining block rate structure is effectively the same as a flat rate.

The graph below provides the percentage of residential customers with more than 30 GJ consumption in each month of the year.

As can be seen from the two graphs above, approximately 18% of residential customers and 5% or less (i.e.24 or less) of the commercial customers in the coldest months of the year consume more than the minimum threshold for the second rate block in any month. In other words, the majority of residential and commercial customers are effectively paying a flat rate from the first block.

62.1. Did FEI consider altering the minimum usage block threshold for either residential or commercial customers, so that more customers could participate? Please explain.

63. Reference: Exhibit B-1-1, page 13-31

13.5.4.4 Bill Impact Analysis

Any rate design proposal should consider the bill impact to customers and should be implemented in a way that minimizes the potential for rate shock. The analysis of residential customers' bill impact can be separated into two steps:

(1) the bill impact due to a transition from bundled declining block rates with a minimum - daily charge to an unbundled flat rate structure with a daily Basic Charge; and

(2) the impact from rebalancing and changes caused by rate design proposals in other rates/rate schedules as discussed in section 13.7.1.4.

63.1. Please confirm that the definition of 'rate shock' would not change from customer group to customer group.

63.1.1. If not confirmed, please elaborate on FEI's views as to how rate shock should be defined for each customer group.

64. Reference: Exhibit B-1-1, page 13-38 and page 13-40

Third, the Fort Nelson threshold of 6,000 GJ/year is not consistent with the 2,000 GJ/year threshold utilized for commercial customers for FEI's other service areas. It is also higher than the threshold selected by five other Canadian utilities that were reviewed. As noted in Section 8.3, FEI conducted a review of other Canadian utilities and found that the threshold for small commercial customers ranged from 419 GJ/year for Gaz Metro to 5,500 GJ for Pacific Northern Gas (PNG). The 6,000 GJ threshold used for Fort Nelson is outside the range selected by these utilities. The Multi-Jurisdictional Review of Rates study is provided in Appendix 8.

Finally, moving the threshold from 6,000 GJ/year to 2,000 GJ/year would not be overly disruptive to existing customers. It would only cause an estimated 9 small commercial customers to migrate to the large commercial rate. These migrating customers will receive a minor rate reduction due to the lower rates offered in Rate 2.2 as shown in Section 13.5.5.4 below.

For consistency with the customer segmentation employed in FEI's other service areas, FEI proposes to set the threshold for Fort Nelson's RS 2.1 and Rate 2.2 at a normalized 2,000 GJ per year. The impact of this change is discussed further below.

64.1. What is the value of achieving consistency with the threshold utilized for commercial customers in FEI's other service areas, and with other Canadian utilities? Please explain.

65. Reference: Exhibit B-1-1, page 13-39

The differentiation in the load factors, whether the threshold is 6,000 GJ/year or 2,000 GJ/year, provides evidentiary support for having a small and large commercial rate class, but the results do not lead to a preference for a threshold level. The results from Figure 13-14 above also do not provide a clear point at which to differentiate small and large commercial customers; however, visually, a differentiation would be appropriate that is somewhere within the range of 1,500 GJ to 2,000 GJ/year .

65.1. Please confirm that Load Factor is relevant in cost causation, and customers with higher load factors generally cause proportionally lower costs than those customers with lower load factors.

65.1.1. If not confirmed, please explain why not.

65.2. Would it be appropriate for FEI to distinguish customers based on load factor rather than consumption volume? Please explain why or why not.

65.2.1. If it would be appropriate, did FEI consider such an option? Please explain and elaborate on why FEI did not select this option.

65.3. If FEI were to distinguish large commercial from small commercial based on Load Factor, what would FEI consider as the appropriate threshold to distinguish small commercial from large commercial. Please explain why.

65.3.1. Please provide an overview of the magnitude of the impacts that an adjustment to FEI's identified Load Factor threshold could be expected to have on customer bills and on other customers, if any.

66. Reference: Exhibit B-1-1 page 13-41

Table 13-20: Comparison between Small & Large Commercial using 6000 GJ Threshold

	Rate 2.1	Rate 2.2
Customer Weighting Factor	1.6	5.7
Use per Customer	425 GJ	8,103 GJ
Load Factor	34.4%	40.5%
Average Customer-related Cost / Customer / Day	$1.403	$3.693
Average Demand-Related & Energy-related Cost / GJ	$2.722	$2.291

The customer weighting factor is the relative cost of metering/measurement devices and service lines to serve commercial customers compared to residential customers. The higher weighting factor for Rate 2.2 compared to Rate 2.1 coupled with the average customer-related cost of service per customer per month leads to the expectation that large commercial customers should have a higher Basic Charge than small commercial customers.

66.1. Please provide the calculations behind the customer weighting factors.

67. Reference: Exhibit B-1-1-1, page 13-50 and 13-51

Table 13-26: Revenue to Cost and Margin to Cost Ratios before rebalancing

Rate Schedule	Initial COSA		Revenue Shift ($000)	Approximate Annual Bill Change	COSA after Rate Design Proposals	
	R:C	M:C			R:C	M:C
Rate 1 *Domestic (Residential) Service*	90.5%	88.0%	0.6	0.1%	90.9%	88.4%
Rate 2.1 *General (Small Commercial) Service*	108.3%	110.7%	(126.0)	0.1%	107.2%	109.4%
Rate 2.2 *General (Large Commercial) Service*	113.2%	118.2%	127.0	0.1%	114.5%	118.4%
Rate Schedule 25 *General Firm Transportation Service*	112.1%	112.1%	(1.6)	-1.2%	111.0%	111.0%

The table above shows that Rate 2.2 and RS 25 are outside the range of reasonableness. FEI's rebalancing proposals include the following adjustments to revenue responsibility:

- Decrease Rate 2.2 revenue by $16 thousand which will reduce the R:C ratio of Rate 2.2 to within the range of reasonableness.

- Increase Rate 1 revenue by $16 thousand to offset the decrease in revenue from Rate 2.2.

The following table presents the rebalancing amounts and Revenue to Cost (and Margin to

The following table presents the rebalancing amounts and Revenue to Cost (and Margin to
Cost) ratios after rebalancing.

Table 13-27: Revenue to Cost and Margin to Cost Ratios after rebalancing

Rate Schedule	COSA after Rate Design Proposals		Rebalance Amount ($000)	Approximate Annual Bill Change	COSA after Rate Design Proposals and Rebalancing	
	R:C	M:C			R:C	M:C
Rate 1 *Domestic (Residential) Service*	90.9%	88.4%	16.0	1.9%	91.9%	89.7%
Rate 2.1 *General (Small Commercial) Service*	107.2%	109.4%			107.2%	109.4%
Rate 2.2 *General (Large Commercial) Service*	114.5%	118.4%	(16.0)	-3.2%	109.9%	112.6%
Rate Schedule 25 *General Firm Transportation Service*	111.0%	111.0%			111.0%	111.0%

Fort Nelson rates must be adjusted to account for the shift in revenue responsibility. For Rate 1, FEI will increase the Basic Charge to $0.3003 per day so that the $16 thousand in revenue shift is recovered from all residential customers equally. FEI chose to collect all of the revenue shift through the Rate 1 Basic Charge because the lowest consuming customers receive the greatest rate reductions to their annual bills through the unbundling of Fort Nelson residential rates. Before rebalancing, a customer with annual consumption of 34 GJ (one quarter of the average) will experience a 7% decrease to their annual bill. By applying the adjustment only to the Basic Charge, FEI moderates the decrease to lower consuming customers making the adjustments more equitable between low and high consumers in Rate 1. This also results in Fort Nelson collecting more of its customer-related charges through the Basic Charge. Fort Nelson will collect approximately 19% of its revenue from Rate 1 through the Basic Charge; the customer-related costs in the COSA equal 62%.

The following figure illustrates Rate 1 customer bill impacts from all changes including unbundling and rebalancing. Each point on the graph is an individual customer.

67.1. Please provide the costs that would need to be transferred to RS 1 in order to bring the revenue to cost ratios to within a range of reasonableness of +/-5%.

67.2. What opportunities are there for rate rebalancing in the future other than the current proceeding?