FortisBC Energy Inc.

2016 Rate Design Application

Volume 5 – Consolidated Updated Application

February 6, 2018

Table of Contents

Order G-4-18 Updates, February 6, 2018

List of Appendices

Appendices are not numbered consecutively; rather they are numbered to correspond to the appropriate section in the Application where they are referenced.

Index of Tables

Index of Figures

FortisBC Energy Inc.
2016 Rate Design Application

Section 1:

EXECUTIVE SUMMARY

Table of Contents

1. EXECUTIVE SUMMARY

1.1 INTRODUCTION

In this 2016 Rate Design Application (Application or 2016 RDA), FortisBC Energy Inc. (FEI or the Company) reviews its existing rate design and proposes a number of changes to realign rates with accepted rate design principles.

The Application reflects an overall, full review of FEI's rate design. FEI conducted a cost of service allocation (COSA) study consistent with standard utility practice to confirm that each rate schedule (RS when referring to a specific rate schedule) adequately recovers its allocated cost of service. FEI conducted a review of its rate schedules considering rate design principles, government policy, stakeholder comments, jurisdictional comparisons, and the analysis of load characteristics and other data. FEI's rate design review includes the evaluation of customer segmentation, alternative rate structures (i.e., flat versus declining or inclining block), the appropriate level of fixed versus variable charges, intra-class rate economics, the calculation of demand charges, transportation service balancing requirements, and other terms and conditions of service.

Prior to filing this Application, FEI conducted a stakeholder engagement process consisting of information sessions, stakeholder workshops, and a residential customer online survey. FEI's stakeholder engagement process informed customers and other stakeholders about its current rate design and the potential rate design changes that FEI was considering. The workshops provided stakeholders with a forum to comment on and ask questions about FEI's rate design and potential rate design changes. Stakeholders were also provided the opportunity to bring rate design issues forward for FEI's consideration. In addition, FEI conducted a survey of residential customers regarding rate design preferences and understanding. FEI considered the comments and questions of stakeholders and the results of the residential survey in the rate design proposals set out in this Application.

As shown in this Application, FEI's review of its rate design considered each of its rate schedules, including COSA studies, for:

- Residential, commercial and industrial rates;
- The transportation customer business model; and
- FEI's General Terms and Conditions (GT&Cs).

There are four rate schedules that are not addressed in this Application. First, amendments to RS 30 are not proposed in the Application as RS 30 reflects current standard-form GasEDI contracts with third parties for off-system natural gas sales and purchases. Proposed amendments to RS 30 are typically dealt with as required, and usually consist of housekeeping changes. Second, consistent with past practice, FEI proposes all amendments to RS 36 through the FEI Customer Choice Program regulatory proceedings. Finally, RS 46 and RS 50 are not included in the scope of the Application, as they are approved by Orders in Council and not subject to change in this proceeding.[1]

A final area not being considered in this Application, save for one element, pertains to Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) stations owned by FEI that are used to provide service to natural gas for transportation customers. These stations have been established under the provisions of *Greenhouse Gas Reduction (Clean Energy) Regulation* (refer to Section 5.4.2) or Section 12B of FEI's GT&Cs. Unique rates are established and approved for each of these stations that are over and above the delivery charges required to deliver natural gas to a CNG station or LNG to an LNG station. These unique rates are designed to recover the costs of each station from the customers receiving CNG or LNG service at that station. CNG customers pay for delivery on FEI's system under RS 6, RS 23, or RS 25. For LNG customers, delivery on FEI's system occurs through RS 46. The one element of the rates for CNG and LNG station service being reviewed in this Application is the Overhead and Marketing Charge (refer to Section 11.3).

FEI has a number of tariff supplements, including bypass agreements. These tariff supplements are negotiated agreements and are approved separately by the Commission and, as such, FEI is not proposing any changes to existing tariff supplements in this Application. The exception to this is the proposed cancellation effective Q4 of 2018, of FEI Tariff Supplement G-21 between Creative Energy Vancouver Platforms Inc. (Creative Energy) and FEI. Please refer to Section 9 of the Application for more information.

FEI's review resulted in the identification of a number of rate design issues. In each case, FEI carefully analysed the issue, evaluated alternative solutions and identified proposals to improve the alignment of customer rates with rate design principles. FEI's proposed solutions to each issue represent what in FEI's view is the best balance of often conflicting principles and considerations.

FEI retained EES Consulting Inc. (EES Consulting), a third party expert in public utility rate design matters, to review and assist in developing the COSA study and rate design for FEI. As discussed in more detail in its report, EES Consulting concludes that the COSA study in this Application follows standard utility practice and is generally consistent with past practice for the utility and that the results are acceptable for purposes of setting just and reasonable rates for FEI. EES Consulting also concluded that FEI's rate design proposals reflect rate design principles and are appropriate.

A more detailed summary of each aspect of the proposed rate design is provided in the sections below.

[1] Order in Council (OIC) No. 557/2013 and OIC No. 749/2014.

Order G-4-18 Updates, February 6, 2018

1.2 RATE DESIGN BASED ON ACCEPTED PRINCIPLES

FEI's rate design review and proposals are guided by the widely accepted rate design principles identified by Dr. Bonbright in his seminal work, *Principles of Public Utility Rates*. The principles adopted by FEI, as previously articulated by the Commission are as follows:[2]

- 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.

1.3 COSA STUDY IN ACCORDANCE WITH STANDARD UTILITY PRACTICE

A COSA study is one of the major inputs that are used in developing proposed rates for FEI. The COSA study takes the revenue requirements established for the utility and allocates costs across the various customer classes, with the results used to ensure that proposed rates are fair, equitable, and not unduly discriminatory. EES Consulting worked with FEI staff in assessing the appropriateness of the COSA methodology and rate design, making recommendations for changes where warranted, and reviewing the COSA model created by FEI staff.

FEI conducted a COSA study in accordance with standard utility practice to allocate FEI's costs to each of FEI's rate schedules. The costs and revenues used in the COSA study reflect FEI's

[2] Appendix A of Order G-45-11 in the BC Hydro Residential Inclining Block Re-Pricing Application.

approved 2016 test year, plus known and measurable changes expected by or soon after January 1, 2018. The allocated costs by rate schedule are compared to the revenue collected by rate schedule to calculate the revenue to cost (R:C) ratio for each rate schedule. The R:C ratio shows whether the rates charged to each rate schedule adequately recover the allocated cost of service[3]. The resulting R:C ratios are, with limited exceptions, within a +/- 5% range of reasonableness.

FEI also conducted a COSA study after taking into account the impact of its rate design proposals in the Application, which have an impact on the allocation of costs amongst rate schedules and create shifts in revenues between rate schedules. After taking into account the proposals in the Application, the resulting R:C ratios remain within a +/- 5% range of reasonableness, except for RS 5/25, RS 22A and RS 6/RS 6P. FEI is not proposing to rebalance RS 22A as this is a closed rate schedule. Rebalancing is required to shift some revenue from RS 5/25 and RS 6/RS 6P to the residential rate schedule, as it is the only rate schedule below 100%.

A summary of the revenue shifts from rate design proposals and rebalancing is shown in Table 1-1 below.

[3] FEI also shows margin to cost (M:C) ratios in the following table. The M:C ratio shows whether delivery rates charged to each rate schedule adequately recover the allocated delivery cost of service. Delivery rates include Basic Charges, Demand Charges and Delivery Charges. Delivery cost of service excludes cost of gas and storage and transport costs.

Order G-4-18 Updates, February 6, 2018

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

Rate Schedule	Initial COSA		Revenue Shifts and Rebalance Amount ($000)	Approximate Annual Bill Change	COSA after Rate Design Proposals and Rebalancing	
	R:C	M:C			R:C	M:C
Rate Schedule 1 *Residential Service*	95.6%	93.1%	2,000.8	0.3%	96.6%	94.6%
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%	(1,093.3)	-1.2%	105.0%	112.6%
Rate Schedule 6/6P *Natural Gas Vehicle Service*	131.2%	159.1%	(75.9)	-20.3%	105.0%	109.5%
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)*	Initial COSA		Revenue Shifts and Rebalance Amount ($000)	Approximate Annual Bill Change	COSA after Rate Design 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

Order G-4-18 Updates, February 6, 2018

1.4 RESIDENTIAL RATE DESIGN: ADJUSTMENTS TO RATES

FEI reviewed the rate design for the residential rate class, which takes service under RS 1, RS 1U, RS 1X and RS 1B[4] (collectively referred to as RS 1). FEI considered the potential rate structure options for residential customers (i.e., flat, declining or inclining block) and the possible blends of fixed and volumetric charges.

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.

FEI is also proposing a 5% increase in the Basic Charge[5] and a corresponding decrease in the Delivery Charge[6], 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 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 no bill impact for an average use customer.

FEI is proposing a slight increase in the Delivery Charge per Gigajoule (GJ) as a result of rate design proposals in other rate schedules and the resulting rebalancing between customer classes. As shown in Table 1-1 above, as RS 1 has an R:C ratio of less than 100%, FEI proposes to shift $2,000.8 thousand to RS 1. The shift represents an annual bill impact of approximately 0.3% for RS 1 customers.

---

4 The differences in RS 1, RS 1U, RS 1X and RS 1B pertain to the commodity portion of small commercial rates. In all cases, the transportation and storage service (midstream service) and the delivery service are provided by FEI. Under RS 1, customers receive conventional natural gas from FEI as their commodity. Under R 1U, customers receive their commodity from a licensed natural gas marketer. In the event that there is a marketer failure, customers that had been served by a marketer under RS 1U may be served under RS 1X. Under RS 1B, customers receive commodity service from FEI, but have elected to receive a percentage of their natural gas as renewable natural gas (biomethane) with the balance being conventional natural gas.

5 As defined in the General Terms & Conditions: Means a fixed charge required to be paid by a Customer for Service as specified in the applicable rate schedule, or the prorated daily equivalent charge – calculated on the basis of a 365-day year (to incorporate the leap year), and rounded down to four decimal places.

6 Delivery Charge means the delivery charge defined in the Table of Charges of the applicable FEI Rate Schedules.

Order G-4-18 Updates, February 6, 2018

1.5 COMMERCIAL RATE DESIGN: ALIGNING INTRA-CLASS RATE ECONOMICS

FEI reviewed the rate design for its small commercial customers taking service under RS 2, RS 2U, RS 2X and RS 2B[7] (collectively referred to as RS 2), and large commercial customers that take service under RS 3, RS 3U, RS 3X, RS 3B[8] (collectively referred to as RS 3) and RS 23. FEI's review of the rate design considered the potential rate structure options for commercial customers (i.e., flat, declining or inclining block), customer segmentation, fixed and volumetric charges and intra-class rate economics.

Based on the analysis of the existing rate design and rate structure options for commercial customers, FEI is proposing the continuation of a flat rate structure and a 2,000 GJ per year customer segmentation threshold for its commercial customers in RS 2 and RS 3/RS 23. The existing flat rate structure and customer segmentation are consistent with other jurisdictions and in line with customer load characteristics. However, the rates for RS 2 and RS 3/RS 23 need minor adjustments to minimize the rate inequity for customers close to the 2,000 GJ threshold. FEI proposes to increase the Basic Charges for RS 2 and RS 3/RS 23, to reduce the Delivery Charge of RS 2 and increase the Delivery Charge of RS 3 and RS 23 to eliminate the customer bill differential for customers whose annual consumption is close to the 2,000 GJ threshold.

1.6 INDUSTRIAL RATE DESIGN: UPDATING RATES IN ACCORDANCE WITH COST CAUSATION

FEI reviewed the rate design for its industrial rate schedules (RS 4, RS 5/RS 25, RS 7/RS 27, and RS 22, and large industrial contract customers). FEI identified rate design issues, considered options to resolve those issues and has made proposals based on the best balance of competing principles in the context of each rate schedule.

FEI's General Firm Service (RS 5 and RS 25) is designed to serve process load customers with efficient utilization of the system. For this reason, RS 5 and RS 25 have a Demand Charge designed to provide lower average rates to higher load factor customers. Based on peak daily consumption information that was not available when the RS 5 and RS 25 Demand Charge was

[7] The differences in RS 2, RS 2U, RS 2X and RS 2B pertain to the commodity portion of residential rates. In all cases, the transportation and storage service (midstream service) and the delivery service are provided by FEI. Under RS 2, customers receive conventional natural gas from FEI as their commodity. Under RS 2U, customers receive their commodity from a licensed natural gas marketer. In the event that there is a marketer failure, customers that had been served by a marketer under RS 2U may be served under RS 2X. Under RS 2B, customers receive commodity service from FEI, but have elected to receive a percentage of their natural gas as renewable natural gas (biomethane) with the balance being conventional natural gas.

[8] The differences in RS 3, RS 3U, RS 3X and RS 3B pertain to the commodity portion of large commercial rates. In all cases the transportation and storage service and the delivery service are provided by FEI. Under RS 3, customers receive conventional natural gas from FEI as their commodity. Under RS 3U, customers receive their commodity from a licensed natural gas marketer. In the event that there is a marketer failure, customers that had been served by a marketer under RS 3U, may be served under RS 3X. Under RS 3B ,customers receive commodity service from FEI, but have elected to receive a percentage of their natural gas as renewable natural gas (biomethane) with the balance being conventional natural gas.

originally designed, FEI is proposing to update the multiplier in the peak day demand formula from 1.25 to 1.1 (the multiplier estimates the peak day demand from the average peak Monthly demand). As a result of the above change, FEI is also proposing to raise the Demand Charge for RS 5 and RS 25 by $3.00/GJ/Month to continue to provide a price signal for only high load factor customers to take General Firm Service. As the R:C ratio before rebalancing is 106%, FEI proposes to shift $1.093 million of revenue responsibility to RS 1 as explained in section 12.2.2. The R:C ratio after rebalancing is 105%, which is within the range of reasonableness directed by Order G-4-18. FEI is proposing to reduce the revenue responsibility of RS 5/25 by decreasing the Basic Charge by $118 per month.

RS 7 and RS 27 are for interruptible service. The RS 7 and RS 27 charges are set at a discount from firm service. The existing discount achieves a reasonable balance between maximizing the economic value of interruptible service, which helps to offset utility costs to firm customers, and providing a sufficient incentive for existing customers to stay on interruptible service and to attract new customers. FEI is therefore proposing to retain the current interruptible service rate structure and the method of calculating RS 7 and RS 27 Delivery Charges based on a discount from RS 5 and RS 25. FEI is proposing to update the RS 7 and RS 27 Delivery Charge calculation to reflect the change in the Daily Demand formula, including a 62.5% firm service load factor assumption and a 90.9% load factor discount.

For seasonal customers, FEI is proposing to maintain the existing rate structures and methodology to derive the RS 4 Delivery Charges. Since the RS 4 Delivery Charges are based on RS 5 and RS 7, FEI is proposing to update the RS 4 Delivery Charges to reflect the proposed changes to RS 5 and RS 7.

FEI's large industrial customers take service under RS 22, RS 22A, RS 22B, or individual contracts (the Vancouver Island Gas Joint Venture (VIGJV) and BC Hydro Island Generation (BCH IG)). FEI's existing rates are currently separated by geographical regions and there is no postage stamp, cost-based firm rate. FEI is proposing to continue to grandfather RS 22A and RS 22B as closed service offerings due to their unique characteristics. For all other large industrial customers, FEI is proposing to create a firm rate under RS 22 based on a cost allocation from the COSA model. This firm rate would be available for all large industrial customers, including VIGJV and BCH IG when their contracts expire. Under this option, Tariff Supplement G-21 for Creative Energy would be terminated and the contract for BCH IG would be included as a tariff supplement at their current rates. The RS 22 interruptible Delivery Charge is proposed to be set at the effective average cost per GJ of the firm rate.

1.7 TRANSPORTATION SERVICE RATE DESIGN: TIGHTENING BALANCING RULES CONSISTENT WITH INDUSTRY PRACTICE

FEI's transportation service is available to large commercial and industrial customers on FEI's system who source their own gas, either from a shipper agent or on their own, and have the gas delivered directly to FEI's system.

The transportation service model is generally working well. As such, FEI does not believe that significant changes are required. However, given industry improvements in monitoring, communicating, and implementing gas balancing, FEI is proposing changes to require transportation customers to balance their gas supply more tightly. In particular, FEI is proposing to eliminate monthly balancing and to require all transportation customers in all service areas to balance daily, which is consistent with FEI's own system balancing requirements at its interconnection points. FEI does not expect these requirements to be burdensome for shipper agents. Many shipper agents are already exclusively balancing daily.

FEI is also proposing to amend the balancing tolerance from 20% to 10%, coupled with a tiered charge approach under which charges increase as tolerance ranges are exceeded. The proposed charges and tiered approach will provide an incentive to balance within the 10% tolerance.

1.8 *FORT NELSON SERVICE AREA*

FEI conducted a full review of the rate design for the Fort Nelson Service Area (Fort Nelson or FEFN), including a separate COSA study for Fort Nelson. FEI received approval for Fort Nelson's revenue requirements and rates for 2018 in November 2016. At the time of filing the Application, FEI was in the process of adjusting its proposed Fort Nelson rate design to take into account the approved rates for 2018. FEI filed the proposed rate design for Fort Nelson on February 2, 2017 as part of a supplementary filing to this Application and an evidentiary update on April 7, 2017 with the proposed rate design for Fort Nelson set out in Section 13. Updates to Section 13 arising from Order G-4-18 will be filed on February 6, 2018.

1.9 *GENERAL TERMS AND CONDITIONS*

FEI's GT&Cs set out the Commission-approved terms and conditions of service provided by FEI. FEI is proposing amendments to all sections of the GT&Cs. Only minor housekeeping amendments are being proposed to Sections 10 (Service Lines) and 12 (Main Extensions), which were recently amended as part of the FEI 2015 System Extension Application and Decision (Order G-147-16, dated September 16, 2016).

A number of substantive amendments are being proposed to the GT&Cs, including:

- In the GT&C Definitions, a number of new definitions have been proposed or moved from the rate schedules into the GT&Cs to reduce repetition in multiple rate schedules These include definitions for Business Day,[9] CNG, CNG Service, Fort Nelson, LNG, LNG Service, and Service Line Cost Allowance.
- As a result of the phase in of amalgamation being completed by December 31, 2017, FEI is proposing to further combine service areas. The GT&Cs have combined all of the

9 To avoid repetition, the capitalized terms used in this section are the same terms defined in the GT&Cs.

service areas, with the exception of Fort Nelson, into one service area, which has been referred to as the Mainland and Vancouver Island Service Area.

- In Section 14 (Access to Premises and Equipment), FEI is proposing a new right to install and operate a remote meter, at the Customer's cost, in situations where FEI is unable to obtain regular access to a Customer's Premise.
- FEI is proposing the removal of Section 15A in its entirety, as the On-Bill Financing Pilot Program that was previously offered in some interior communities is no longer in effect.
- In Section 19.7 (Over-billing), a maximum refund period of six years has been proposed for over-billing errors.
- The name of FEI's "Equal Payment Plan" has been changed to "Monthly Payment Plan", as the reference to "equal" does not adequately convey that monthly payments amounts may be adjusted after an approved rate change, at reconciliation times or at other times, as may be appropriate.
- A new paragraph (e) is being proposed for Section 23.2 (Discontinuance or Refusal Without Notice), which would authorize FEI to discontinue or to refuse Service without notice in the event that a Customer tampers with or otherwise alters a Meter Set.

Numerous other proposed amendments to the GT&Cs are being proposed for stylistic consistency, as well as to simplify language where possible.

1.10 *CONCLUSION*

Table 1-2 below summarizes FEI's proposed rate changes, by showing the estimated COSA-based 2018 rates, the proposed rate changes and the estimated 2018 rates after the proposed changes. It is important to note that the proposed rate changes will be made to 2018 approved rates, not the estimated COSA-based rates. Therefore, the estimated 2018 rates below will not be the rates that are actually approved for 2018.

Table 1-2: FEI Rate Proposal Summary

Rate Schedule	Estimated COSA[10] Based 2018 Rate	Proposed Rate Changes	Estimated 2018 Rates After Proposed Changes
RS 1 – Residential			
Basic Charge (daily)	$0.3890	$0.0195	$0.4085
Delivery Charge ($/GJ)	$4.821	($0.059)	$4.762
RS 2 – Small Commercial			

[10] The COSA rates shown are 2016 approved rates plus known and measureable changes discussed in Section 6.

Rate Schedule	Estimated COSA[10] Based 2018 Rate	Proposed Rate Changes	Estimated 2018 Rates After Proposed Changes
Basic Charge (daily)	$0.8161	$0.1324	$0.9485
Delivery Charge ($/GJ)	3.850	($0.186)	3.664
RS 3/RS 23 – Large Commercial			
Basic Charge (daily)	$4.3538	$0.4357	$4.7895
Delivery Charge ($/GJ)	$3.189	$0.001	$3.190
RS 4			
Basic Charge (Monthly)	$439	Nil	$439
Delivery Charge ($/GJ) Off Peak	$1.278	$0.114	$1.392
Delivery Charge ($/GJ) Extended Period	$2.183	($0.018)	$2.165
RS 5/RS 25			
Basic Charge (Monthly)	$587.00	($118.00)	$469.00
Delivery Charge ($/GJ)	$0.887	Nil	$0.887
Demand Charge ($/Month/GJ)	$21.596	$3.00	$24.596
RS 6/RS 26			
Basic Charge (Monthly)	$61	Nil	$61
Delivery Charge ($/GJ)	$4.873	$1.622)	$3.251
RS 7/RS 27			
Basic Charge (Monthly)	$880.00	Nil	$880.00
Delivery Charge ($/GJ)	$1.455	($0.012)	$1.443
RS 22			
Basic Charge (Monthly)	$3,664.00	Nil	$3.664.00
Firm Demand Charge ($/Month/GJ)	n/a		$25.000
Firm MTQ ($/GJ)	n/a		$0.150
Interruptible MTQ ($/GJ)	$1.060	($0.088)	$0.972

Based on the analysis and considerations set out in the Application, FEI believes that its rate design proposals are just and reasonable and should be approved as proposed.

FORTIS BC

FortisBC Energy Inc.
2016 Rate Design Application

Section 2:

APPLICATION AND APPROVALS SOUGHT

Table of Contents

2. APPLICATION AND APPROVALS SOUGHT

2.1 APPLICATION

FEI files this 2016 Rate Design Application with the British Columbia Utilities Commission (the Commission or BCUC) pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA). The Application reviews FEI's existing rate design and proposes a number of rate design changes that will rebalance FEI's rates based on an updated COSA study and will realign FEI's rate design with accepted rate design principles.

Before filing the Application, FEI completed a robust stakeholder engagement process, consisting of information sessions, workshops and a residential customer survey. The stakeholder engagement process assisted in increasing the level of understanding of stakeholders and soliciting comments on FEI's existing rate design and potential changes. FEI compiled a key issues list through the stakeholder engagement process which informed FEI's rate design proposals in this Application.

The Application reflects an overall review of FEI's rate design. FEI conducted a COSA study consistent with standard utility practice to confirm that each rate schedule adequately recovers its allocated cost of service. A separate COSA study has been conducted for Fort Nelson. FEI has also conducted a review of its rate schedules considering rate design principles, government policy, stakeholder comments, jurisdictional comparisons, and the analysis of load characteristics and other data. FEI's rate design review includes the evaluation of customer segmentation, alternative rate structures (i.e., flat versus declining or inclining block), the appropriate level of fixed versus variable charges, intra-class and inter-class rate economics, the calculation of demand charges, transportation service balancing requirements and other terms and conditions of service.

There are four rate schedules that are not addressed in this Application. First, amendments to RS 30 are not proposed in the Application as RS 30 reflects current standard-form GasEDI contracts with third parties for off-system natural gas sales and purchases. Proposed amendments to RS 30 are typically dealt with as required, and usually consist of housekeeping changes. Second, consistent with past practice, FEI proposes all amendments to RS 36 through the FEI Customer Choice Program regulatory proceedings. Finally, RS 46 and RS 50 are not included in the scope of the Application, as they are approved by Orders in Council and not subject to change in this proceeding.[11]

A final area not being considered in this Application, save for one element, pertains to CNG and LNG stations owned by FEI that are used to provide service to natural gas for transportation customers. These stations have been established under the provisions of *Greenhouse Gas Reduction (Clean Energy) Regulation* (refer to Section 5.4.2) or Section 12B of FEI's General Terms and Conditions. Unique rates are established and approved for each of these stations that are over and above the delivery charges required to deliver natural gas to a CNG station or

[11] OIC No. 557/2013 and OIC No. 749/2014.

LNG to an LNG station. These unique rates are designed to recover the costs of each station from the customers receiving CNG or LNG service at that station. CNG customers pay for delivery on FEI's system under RS 23 or RS 25. For LNG customers, delivery on FEI's system occurs through RS 46. The one element of the rates for CNG and LNG station service being reviewed in this Application is the Overhead and Marketing Charge (refer to Section 11.3).

FEI has a number of tariff supplements, including bypass agreements. These tariff supplements are negotiated agreements and are approved separately by the Commission and, as such, FEI is not proposing any changes to existing tariff supplements in this Application. The exception to this is the proposed cancellation effective Q4 of 2018, of FEI Tariff Supplement G-21 between Creative Energy and FEI. Please refer to Section 9.8 of the Application for more information.

As demonstrated in this Application, FEI's current rate design is working well in most respects. FEI is proposing a number of changes to improve the alignment of customer rates with rate design principles. These changes include, for example, rate rebalancing, an increase to the residential Basic Charge to better align the recovery of fixed charges, adjustments to commercial customer charges to improve inter-class rate economics, adjustments to industrial charges to more accurately reflect cost causation and other principles, including the cost of a firm service rate for large industrial customers, and more stringent balancing requirements for transportation customers consistent with industry practice.

FEI notes that it filed a supplemental filing on February 2, 2017, and an evidentiary update on April 7, 2017 with the proposed rate design for Fort Nelson in Section 13. This later filing date was needed because FEI received approval for Fort Nelson's revenue requirements and rates for 2018 in November 2016, and FEI adjusted its proposed Fort Nelson rate design to take into account the approved rates for 2018. The supplemental filing on February 2, 2017 and evidentiary update filed on April 7, 2017 also included FEI's proposed amendments and housekeeping changes to the FEI rate schedules. The blacklined changes to each rate schedule reflecting the rate design proposals in the Application was included and filed as Appendix 11-3, and the supporting calculations for the proposed decrease to the Administration Charge per Month from $78.00 to $39.00 was included and filed as Appendix 11-4.

FEI retained EES Consulting, a third party expert in public utility rate design matters, to review and assist in developing the COSA study and rate design for FEI. EES Consulting concludes that the COSA study for this rate design follows standard utility practice and is generally consistent with past practice for the utility, and that the results of the COSA study are acceptable for purposes of setting just and reasonable rates for FEI. EES Consulting also concludes that FEI's rate design proposals reflect rate design principles and are appropriate. EES Consulting's report, including a review of FEI's COSA study and rate design, is attached as Appendix 6-1 to this Application.

FEI's proposals are set out below under Approvals Sought and discussed in additional detail in the following sections of the Application. Based on the analysis and considerations set out in the Application, FEI believes that its rate design proposals will result in a reasonable balance of rate design principles and other relevant considerations, are just and reasonable, and should be approved as proposed.

2.2 APPROVALS SOUGHT

Pursuant to section 58 to 61 of the UCA, FEI seeks the Commission's approval of the following, to be effective Q4 of 2018:

Midstream[12] Cost Allocation Methodology

1. Approval to use the three-year average load factor in RS 5 to allocate midstream costs when setting FEI's Storage and Transport Charges for RS 5, as discussed in Section 6.4.2.1 of the Application.

Residential Rate Schedules

2. Approval of the following for Rate Schedules 1, 1U, 1X, and 1B:
   - Approval to increase the Basic Charge per Day by $0.0195 from $0.3890 to $0.4085 to increase the proportion of fixed costs recovered by the Basic Charge, as discussed in Section 7.8 of the Application.
   - Approval to decrease the Delivery Charge per GJ by $0.086 to maintain revenue neutrality with the Basic Charge increase, as discussed in Section 7.8 of the Application.
   - Approval of proposed housekeeping and other amendments as set out in Appendix 11-3, and to be discussed in the supplemental filing to the Application to be filed February 2, 2017.
   - Approval to increase the Delivery Charge per GJ by $0.027 as a result of the revenue shifts and rebalancing of rates discussed in Section 12.2 of the Application.

Commercial Rate Schedules

3. Approval to adjust the basic charges and delivery charges of the commercial rate schedules to align with the 2,000 GJ threshold between small and large commercial customers, as discussed in Section 8.7 of the Application, as follows:
   - For Rate Schedules 2, 2B, 2U, and 2X:
     - Increase the Basic Charge per Day by $0.1324 from $0.8161 to $0.9485.
     - Decrease the Delivery Charge per GJ by $0.186.
   - For Rate Schedules 3, 3B, 3U, 3X, and 23:
     - Increase the Basic Charge per Day by $0.4357 from $4.3538 to $4.7895.
     - Increase the Delivery Charge per GJ by $0.001.

[12] The terms "storage and transport" and "midstream" are used interchangeably in this Application.

- For RS 23:
  - Decrease the Administration Charge per Month from $78.00 to $39.00, set out in Appendices 11-3 and 11-4, and to be discussed in the supplemental filing to the Application to be filed February 2, 2017.

4. Approval of proposed housekeeping and other amendments to Rate Schedules 2, 2U, 2X, 2B, 3, 3U, 3X, 3B, and 23, as set out in Appendix 11-3, and to be discussed in the supplemental filing to the Application to be filed February 2, 2017.

Industrial Rate Schedules

5. Approval to revise the multiplier in the Daily Demand formula in RS 5 and RS 25 from 1.25 to 1.10 and to increase the Demand Charge in RS 5 and RS 25 by $3.00/GJ/Month, as discussed in Section 9.5.
6. Approval to decrease the Basic Charge in RS 5 and RS 25 by $118.00 per month from $587.00 per month to $469.00 per month as discussed in Section 12.2.2.
7. Approval to decrease the Delivery Charge of RS 7 and RS 27 by $0.012/GJ as shown in Table 9-20 and discussed in Section 9.6.
8. Approval to increase RS 4 rates due to the proposed changes to RS 5 and RS 7 as shown in Table 9-21 and discussed in Section 9.7, by increasing the Off-Peak Delivery Rate by $0.114/GJ and by decreasing the Extension Period by $0.018/GJ.
9. Approval to set the charges for RS 22 on a cost of service basis for all large industrial customers, as discussed in Section 9.8.5, as follows:
   - Firm Demand Charge of $25.000/GJ/Month.
   - Firm MTQ Delivery Charge of $0.15/GJ.
   - Interruptible MTQ Delivery Charge of $0.972/GJ.
10. Approval to terminate Tariff Supplement G-21, FEI's contract with Creative Energy Vancouver Platforms Inc., effective Q4 of 2018, as discussed in Section 9.8.5 of the Application.
11. Approval of adjustments to the transportation model as follows:
    - Amendments to Rate Schedules 22, 22A, 22B, 23, 25, 26, and 27 to implement daily balancing for all transportation customers, as discussed in Section 10.6.
    - Amendments to Rate Schedules 22, 22A, 22B, 23, 25, 26, and 27 to reduce the daily balancing tolerance to a 10% threshold and to introduce a balancing charge of $0.25/GJ for transportation customers for gas supply shortfalls within a 10% to 20% tolerance level, as discussed in Section 10.7.
12. Approval of proposed housekeeping and other amendments to Rate Schedules 5, 7, 11B, 14A, 22, 22A, 22B, 25, 26, and 27 as set out in Appendices 11-3 and 11-4, and to be discussed in the supplemental filing to the Application to be filed February 2, 2017, including, but not limited to, the following:

- Approval to decrease the Administration Charge per Month from $78.00 to $39.00 in Rate Schedules 22, 22A, 22B, 25, 26, and 27, as set out in Appendix 11-3 and 11-4, and to be discussed in the supplemental filing to the Application to be filed February 2, 2017.
- Approval to cancel RS 6A General Service – Vehicle Refueling Service as set out in Appendix 11-3, and to be discussed in the supplemental filing to the Application to be filed February 2, 2017.
- Approval to cancel RS 40, as set out in Appendix 11-3, and to be discussed in the supplemental filing to the Application to be filed February 2, 2017.

13. Approval to decrease the Delivery Charge per GJ of RS 6 by $1.622/GJ to address rebalancing as discussed in Section 12.2.2 of the Application.
14. Approval to set the Delivery Charge per GJ for RS 6P to equal the Delivery Charge per GJ of RS 6 as discussed in Section 12.2.2 of the Application.

General Terms and Conditions

15. Approval of the housekeeping and other amendments to FEI's General Terms and Conditions as set out in Appendices 11-1 and 11-2 and discussed in Section 11 of the Application. The proposed amendments to the FEI General Terms and Conditions include the following:
    - Approval of the amendments to the Standard Fees and Charges Schedule, including renaming it the Standard Charges Schedule, as set out in Appendices 11-1 and 11-2, and discussed Section 12 of the Application.
    - Approval to rename the Application Fee to Application Charge and decrease the charge from $25.00 to $15.00.
    - Approval to rename the Dishonoured Cheque Charge to the Returned Payment Charge and decrease the charge from $20.00 to $8.00.
    - Approval to rename Disputed Meter Testing Fees to Meter Testing Charges.

A Draft Order setting out the approvals sought is attached as Appendix 1-2 to the Application.

2.3 *IMPLEMENTATION*

Based on the regulatory timetable as established by the Commission in Appendix A of Order G-5-18, FEI is seeking to implement its proposed rate design changes in the fourth quarter (Q4) of 2018. In order to provide adequate time to prepare for the implementation of approved changes, including billing system changes and notification to customers of the changes, FEI requests a Commission decision by August 2018.

FEI expects to implement the rate design changes in Q4 of 2018 for the following reasons:

- It is expected to provide sufficient time for the review of the Application, with flexibility for the process that the Commission considers appropriate as established in Appendix A to Order G-5-18.

- It is expected to provide sufficient time for FEI to implement the changes following a Commission decision. Implementation requires a number of activities, including programing and testing of rate design changes and notifying customers of the changes. FEI expects that it will require two to three months to implement all the proposed changes in the Application.
- Implementing the rate design mid-year avoids the need to coordinate the rate design changes with changes to rates implemented through the revenue requirements process. Implementing the rate design separately will be less complex than if combined with revenue requirement changes, and will enable clearer and simpler communications to customers.

While FEI is currently targeting implementation some time in Q4 of 2018, this is dependent on the Commission's ability to issue a decision by August, 2018. Alternatively, if the Commission is unable to render a decision early in 2018, FEI requests that the effective date of any rate design changes should, instead, be determined as part of the compliance filing following the Commission's determination of this Application. At the time of its compliance filing, FEI will be in a position to recommend an implementation date that considers the final determinations in the 2016 Rate Design Application decision, confirms implementation requirements and timing, allows adequate time for customer communication and notification, and, to the extent possible, considers the timing of other Commission decisions or pending decisions that may also impact rates.

2.4 *PROPOSED REGULATORY REVIEW PROCESS*

FEI proposes the following draft regulatory timetable as presented in Table 2-1 below. The timetable takes into consideration suggestions from Commission staff, and acknowledges the workload required by the Commission and all parties in this and other ongoing and anticipated proceedings. A draft procedural order has been provided in Appendix 1-1.

Table 2-1: Proposed Regulatory Timeline

ACTION	DATE (2017)
FEI Supplemental Filing – FEI Rate Schedules and Fort Nelson Rate Design and Rate Schedules	Thursday, February 2
FEI Publication of Notice	by Thursday, February 16
Registration of Interveners and Interested Parties and Confirmation of Participation at Workshop	Tuesday, February 20
Workshop #1 – Summary of Information Provided to Stakeholders at the May 19 Education & Background Information Session	Thursday, February 23
Workshop #2 – Review of COSA Model, Proposals in the Application, and Approvals Sought	Thursday, March 9
Commission Information Request (IR) No. 1 to FEI	Monday, March 27
Intervener IR No. 1 to FEI	Monday, April 3

Order G-4-18 Updates, February 6, 2018

ACTION	DATE (2017)
FEI Response to IRs No. 1	Monday, May 1
Procedural Conference (Timetable and Process)	Monday, May 15
Commission and Intervener IRs No. 2 to FEI	Tuesday, May 30
FEI Response to IRs No. 2	Thursday, June 29
Intervener Evidence (if required)	Thursday, July 13
IRs on Intervener Evidence (if required)	Thursday, July 27
Intervener Response to IRs on Evidence (if required)	Thursday, August 24
FEI Rebuttal Evidence (if required)	Thursday, September 7
FEI Final Argument	Thursday, September 21
Intervener Final Argument	Thursday, October 5
FEI Reply Argument	Thursday, October 19
Anticipated Commission Decision	Early 2018

The draft regulatory timetable provided above reflects a written process. FEI believes that this Application can be addressed efficiently and effectively by a written hearing process in light of the following three considerations. First, FEI has undertaken a robust stakeholder engagement process as described in Section 4 of the Application. Second, FEI believes that the relevant facts, such as load characteristics of customers, the current rate design and the impacts of implementing the rate design proposals, are clear and should not be contentious. Third, the proposed changes in the rate design involve technical issues and analysis that lend themselves to a written process.

While FEI is currently of the belief that a written process would be sufficient for this proceeding, FEI suggests that the appropriate hearing process should be the topic of a Procedural Conference after the first round of IRs and has included this in the proposed timetable above.

FEI looks forward to working with the Commission and Interveners towards an efficient review of this Application.

2.5 APPLICATION ORGANIZATION

The remainder of the Application is organized as follows:

- **Section 3:** Overview and History of FEI's Existing Rate Design – Provides an overview of FEI's service areas, service models, and existing rate schedules as background to the rate design. This section also provides a review of the regulatory history related to FEI's existing rate design, and the relevant Commission directions which FEI has addressed in the Application.

- **Section 4:** Stakeholder Engagement – Describes the Company's stakeholder engagement process undertaken prior to submission of the Application, including information sessions, workshop and residential customer survey.
- **Section 5:** Rate Design Principles - Discusses the legal context for the Application, the rate design principles adopted by FEI for the rate design, as well as relevant government policy.
- **Section 6:** FEI Cost of Service Allocation Methodology – Explains the history and methodologies employed in the development of the COSA study undertaken for the rate design.
- **Section 7:** Rate Design for Residential Customers – Provides a description of the customer characteristics of FEI's residential customers, reviews the existing residential customer rate design and describes FEI's proposed changes.
- **Section 8:** Rate Design for Commercial Customers – Provides a description of the customer characteristics of FEI's commercial customers, reviews the existing commercial customer rate design and describes FEI's proposed changes.
- **Section 9:** Rate Design for Industrial Customers – Provides a description of the customer characteristics of FEI's industrial customers, reviews the existing industrial customer rate design and describes FEI's proposed changes.
- **Section 10:** Transportation Service Review – Provides a description of FEI's sales customer business model and FEI's operations that balance the system on a daily basis. Reviews the details of FEI's transportation business model, including the various balancing related provisions, and identifies recommended changes to the transportation rate schedules.
- **Section 11:** General Terms and Conditions and Rate Schedules – Provides an overview and rationale for housekeeping and other proposed changes to FEI's General Terms and Conditions. FEI will make a supplemental filing on February 2, 2017, which will include blacklined proposed changes to FEI's rate schedules to reflect the proposals in the Application.
- **Section 12:** Summary and Conclusion – Provides a summary of the proposals in the Application.
- **Section 13:** Rate Design for the Fort Nelson Service Area – Provides the COSA Study, review of the existing rate design and FEI's rate design proposals for Fort Nelson. As discussed above, FEI filed this section of the Application with its supplemental filing on February 2, 2017 and an evidentiary update on April 7, 2017.

Order G-4-18 Updates, February 6, 2018

FortisBC Energy Inc.
2016 Rate Design Application

Section 3:

BACKGROUND AND REGULATORY HISTORY OF FEI'S RATE DESIGN

Table of Contents

3. BACKGROUND AND REGULATORY HISTORY OF FEI'S RATE DESIGN

3.1 *INTRODUCTION*

The proposed rate design in this Application is based on the principles and methodologies applied in FEI's previously approved rate design-related applications. The Commission's past approvals of FEI's rate design confirm that the rate design methodologies employed by FEI result in fair, just and reasonable customer rates. The Commission has accepted the appropriateness of FEI's rate design through its ongoing reviews and approvals, and the methodologies have generally received the support of interested parties in past years. As such, FEI's existing rate structures represent a principled and sound basis upon which to establish rates proposed for FEI.

The current FEI postage stamp rate design for delivery, midstream and commodity rates is the result of a series of proceedings and Commission approvals. The Commission's past approval of postage stamp rates applied to all FEI operating areas except Fort Nelson, which also has rates built on Commission approved rate design methodologies. Each past proceeding concerning rate design considered issues and progressively built on the previous proceedings and approvals. Prior rate design proceedings for customer delivery rates undertook COSA studies. In those proceedings, FEI proposed that a reasonable range for the R:C ratios that are an output of the COSA studies was between 90% and 110% and that this range could be used as a guide, among other principles, for rate setting.

A key component of FEI's rate design is the gas supply cost allocation methodology which has been in place since 1991. Pursuant to this methodology, FEI purchases natural gas and propane, as well as the necessary third party storage and pipeline resources, on behalf of sales customers and passes these costs through to sales customers without a mark-up. The 1991 Phase A Rate Design (Phase A) proceeding established this gas supply cost allocation methodology, which remains substantially the same today.[13] Gas costs are recovered from customers through gas cost recovery rates established based on the forecast costs of gas, third party storage arrangements and upstream pipeline resources for the prospective 12-month period. As gas cost recovery rates are based on forecast costs, the actual costs will differ from forecast costs. As such, gas cost deferral accounts are utilized to account for the differences between the purchased cost of gas and the revenues collected through the gas cost recovery rates. Deferral account balances are returned to customers in the case of over-recovery and recovered from customers in the case of under-recovery.

[13] Over the years, a number of minor changes have been made to the original Phase A gas cost allocation methodology approved in the decision in the 1991 Phase A Rate Design (Commission Order G-22-92, dated February 21, 1992). For example, FEI implemented a 3-year rolling average to calculate customer load factors instead of single year load factors. Also, RS 4 initially had a deemed 150% load factor for gas cost allocation purposes, but now RS 4 delivery rates are based upon RS 5, as will be discussed in Section 9.5.4. However, these and other minor changes have not changed the fundamental characteristics of the Phase A methodology.

This remainder of this section is organized as follows:

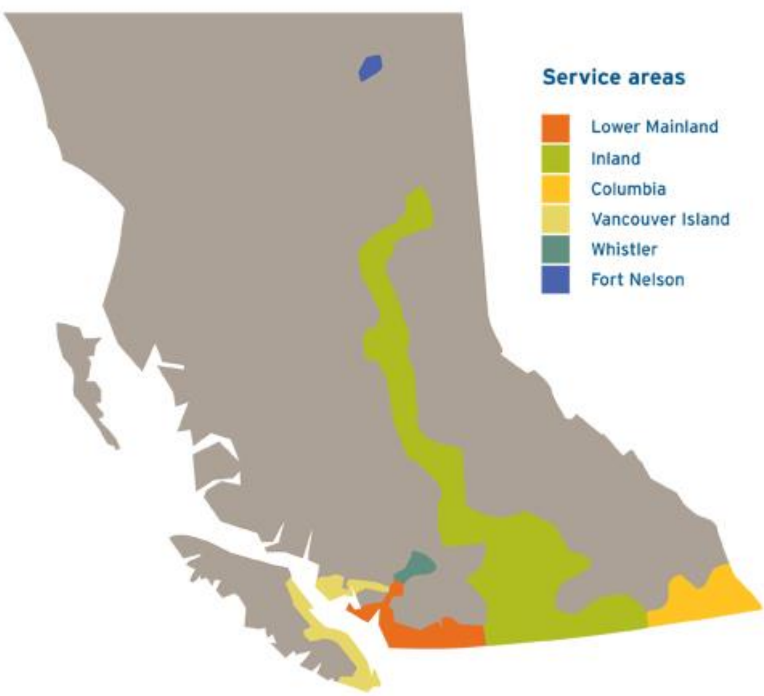
- Section 3.2 provides an overview of FEI's service areas, sales and transportation business models, customers and rate schedules;
- Section 3.3 summarizes FEI's rate design regulatory history since 1991; and
- Section 3.4 provides a list of past rate design directives that are addressed in the Application.

3.2 BACKGROUND

FEI provides service to approximately 990,000 residential, commercial, and industrial customers in approximately 140 communities throughout B.C.[14] FEI owns and operates natural gas pipelines and natural gas distribution facilities, including approximately 46,000 kilometres of transmission pipelines and distribution mains. FEI's distribution network serves approximately 95% of the natural gas customers in B.C. and delivers more than 20% of the total energy consumed in the province.

Figure 3-1 below shows FEI's service areas[15]:

Figure 3-1: FEI Service Areas



[14] As a significant number of these customers consist of multiple family members, the population served is much larger than 990,000.

[15] Upon amalgamation and effective January 1, 2015, the FEI Lower Mainland, Inland and Columbia service areas were combined into the main service area of Mainland in the FEI General Terms and Conditions and the FEI rate schedules.

3.2.1 Sales and Transportation Customer Business Models

FEI's customers are able to choose how they obtain their daily gas commodity supply and midstream (storage and transport) services as follows:

- Sales customers may choose to have their commodity provided by FEI (bundled service) or by a gas marketer[16] under the Customer Choice Program (unbundled service). Sales customers are also referred to as FEI's "core market" customers; and
- Transportation customers may choose to secure their commodity on their own or through a shipper agent.

Each of these customer groups has an associated business model: the sales customer business model (sales model), which operates under a framework called the Essential Services Model (ESM); and the transportation customer business model (transportation model).

Table 3-1 below identifies the total number of customers and aggregate demand from the sales customers and transportation customers in 2015. There are 13 shipper agents currently managing supply and demand requirements for transportation customers.

Table 3-1: FEI Sales and Transportation Customers (2015)

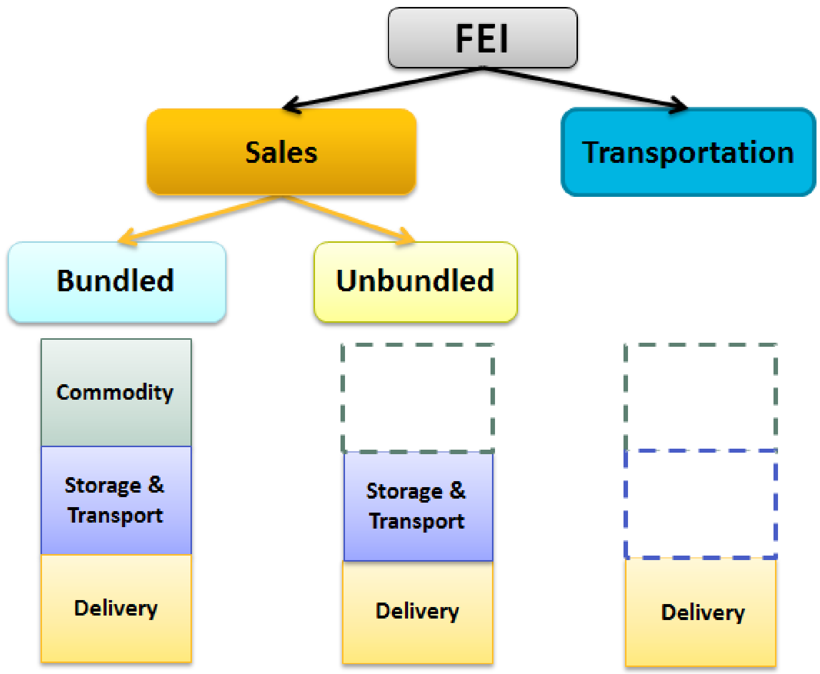
	Applicable Rate Schedules	Customers (#)	Customer Demand (PJ)
Sales Service Rates (Bundled)[17]	RS 1, RS 2, RS 3, RS 5, RS 5, RS 6, RS 7, RS 1B, RS 2B, RS 3B, RS 5B	947,250	107.5
Sales Service Rates (Unbundled)	RS 1U, RS 2U, RS 3U	32,015	4.5
Transportation Service Rates	RS 22, RS22A, RS22B RS 23, RS 25, RS 26, RS 27, RS 50	2,424	74.0
FEI Total		**981,689**	**186.0**

The sales model and transportation model are illustrated below in Figure 3-2.

[16] The term "gas marketer" in this Application refers to gas retailers selling gas to residential and commercial sales customers under the Customer Choice Program. While also commonly referred to as "marketers", agents of customer groups under the transportation business model are referred to in the Application as a "shipper agent".

[17] Excludes Fort Nelson and Revelstoke.

Figure 3-2: Overview of FEI Business Models



The sales model is shown in the left and middle columns in Figure 3-2 above. The column on the left represents the ESM for sales customers who choose bundled services from FEI for both commodity, and storage and transport services. The middle column represents the ESM for sales customers who choose unbundled services (i.e., taking storage and transport services from FEI but arranging to purchase the commodity through a gas marketer).

The transportation model is shown in the right column. The FEI transportation model is available to large commercial and industrial customers who source their own gas. Transportation customers arrange their own commodity, storage and transport resources to supply FEI's system with gas at interconnection points with adjoining upstream pipelines. Under this model, FEI provides delivery to the transportation customers' premises. As shown in Figure 3-2, customers in all three categories pay delivery costs.

Further information on commodity and storage and transport costs is provided below.

3.2.1.1 Commodity Costs

Commodity costs consist of market-priced annual "baseload"[18] gas purchased by FEI which is incorporated into customer rates without a mark-up. The commodity cost recovery charge for FEI's bundled sales customers is variable, reviewed quarterly by the Commission and adjusted

[18] Baseload is calculated as the total annual normalized volume of gas that FEI must purchase for its customers (the customers that purchase gas directly from FEI). Even though FEI's customers need more gas in the winter and less in the summer, FEI purchases the same amount each day of the year, this is referred to as the baseload in FEI's ESM.

if required. Sales customers under the Customer Choice Program are not charged the commodity cost recovery charge. These customers negotiate their own commodity supply requirements and pricing with a gas marketer directly.[19]

3.2.1.2 Storage and Transport Costs

Storage and transport costs are primarily incurred as a result of resources contracted by FEI to facilitate the flow of gas on FEI's system so that the load of sales customers can be served and the system stays in balance on a daily basis and are also incorporated into customer rates with no a mark-up. More particularly, storage and transport costs include the following:

- Storage and transport capacity on third-party pipelines that deliver gas to FEI's interconnecting points;
- Contracted gas storage facilities;
- Winter seasonal gas supply purchased by FEI that may be required to support higher than normal load requirements of core market customers; and
- Portions of the costs of certain FEI-owned assets (i.e., the Southern Crossing Pipeline (SCP) and the Mt. Hayes LNG storage facility).

The total cost of the storage and transport resources is partially offset by revenues collected from FEI's mitigation activities. These activities release a portion of FEI's storage and transport assets to third parties on a short term basis when they are not required to meet the requirements of sales customers or to manage the requirements of the system as a whole. Examples of FEI's mitigation activities include selling a portion of seasonal gas purchased for the winter months for those days it is not required to meet customer load and recovering fixed costs paid to a third party pipeline by releasing a portion of contracted pipeline capacity to other parties in the summer months. The storage and transport charges are reviewed quarterly by the Commission and are typically reset annually with a January 1st effective date.

3.2.2 FEI Customer Base

FEI's customer base includes sales customers and transportation customers which are categorized by their type of premises or business as being residential, commercial, industrial or other. These customer categories are further segregated into rate schedules which are based on the nature of the service (i.e., sales or transportation) and the load characteristics of annual consumption and load factor (i.e., how much the customer consumes on average as compared to its peak demand).

Table 3-2 below provides a list of FEI's existing rate schedules, including the nature of the service and the load characteristics.

[19] FEI is responsible for the billing and collection function from customers on behalf of gas marketers.

1 **Table 3-2: Existing Customer Segmentation and Load Characteristics**

Customer Group	Rate Schedule	Nature of the Service	Customers[20] (#)	Typical Load Characteristics	
				LF[21]	*UPC (GJ)*[22]
RESIDENTIAL	RS 1/ RS 1U/ RS 1X /RS 1B	• Residential firm service for use in residential applications, including central space heating, water heating, cooking, fireplaces and clothes dryers. • Applicable to residential customers only.	886,652	31.2%	82
COMMERCIAL	RS 2/ RS 2U/ RS 2X/ RS 2B	• Annual use < 2,000 GJ. • Small commercial firm service for use in approved appliances in small commercial, institutional, or small industrial operations. • Example customers: restaurants and apartment buildings.	84,737	31.1%	331
	RS 3/ RS 3U/ RS 3X /RS 3B	• Annual use > 2,000 GJ. • Large commercial firm service for use in approved appliances in large commercial, institutional, or small industrial operations. • Example customers: apartment buildings, recreation centers and care homes.	5,040	37.1%	3,595
	RS 23	• Annual use > 2,000 GJ. • Large commercial firm transportation service.	1,669	36.9%	5,374
INDUSTRIAL	RS 4	• Seasonal firm service for customers who typically consume gas during off-peak (April to October) periods. • Example customers: greenhouses and paving companies.	18	N/A	7,217
	RS 5/ RS 5B	• General firm service with an applicable Monthly demand charge per Month per GJ of Daily Demand. • Example customers: pulp, paper, and lumber operations, manufacturers, and apartment buildings.	230	45.2%	9,447
	RS 25	• General firm transportation service with an applicable Monthly demand charge per Month per GJ of Daily Demand.	566	55.5%	23,834

20 Number of Customers per rate schedule is as set out in the compliance filing for the Annual Review for 2016 Rates (Order G-193-15), Section 11, Schedule 19, column 1.

21 Load Factors are as in the Application COSA model.

22 Use per Customer in GJ is as set out in the compliance filing for the Annual Review for 2016 Rates (Order G-193-15), Section 11, Schedule 19, column 10 divided by column 9.

Customer Group	Rate Schedule	Nature of the Service	Customers[20] (#)	Typical Load Characteristics	
				LF[21]	*UPC (GJ)*[22]
INDUSTRIAL *(continued)*	RS 6	• Natural gas vehicle service (resale for natural gas vehicles). • Example customers: public fueling stations.	15	100.0%	3,120
	RS 7	• General interruptible service. • Example customers: manufacturers, greenhouses and service industry customers.	5	N/A	30,920
	RS 27	• General interruptible transportation service.	108	N/A	60,525
	RS 22	• Large volume transportation service with a minimum “take or pay” requirement of 12,000 GJ/Month. • Example customers: greenhouses, educational institutions and cement plants.	26	N/A	677,554
	RS 22A *(Closed)*	• Large volume firm and interruptible transportation service for select customers. • Example customers: pulp, paper and lumber operations.	9	N/A	1,005,394
	RS 22B *(Closed)*	• Large volume firm and interruptible transportation service for select customers. • Example customers: mining and pulp operations.	5	N/A	1,056,388
	RS 50	• Large volume firm and interruptible transportation service.	0	N/A	N/A
OTHER	RS 46	• LNG sales, dispensing, and transportation service. • Example customers: trucking companies and ferries.	13	N/A	51,438

3.3 REGULATORY HISTORY OF FEI’S RATE DESIGN

BC Gas Inc. (BC Gas) was created in 1989 for the purpose of amalgamating the Lower Mainland, Inland, Columbia and Fort Nelson gas utilities, all of which had previously been separate legal entities and which became divisions of BC Gas upon amalgamation. Order-in-Council No. 953-89 required these four divisions of BC Gas to continue to maintain separate rate bases, accounts and schedules until the end of September 1991.

The major approvals for FEI’s rate design methodologies that apply to the gas cost and delivery rates since FEI’s 1991 Phase A Rate Design are summarized in Table 3-3 below and each proceeding is discussed further in this section.

1 **Table 3-3: FEI Rate Design Approved Methodologies**

Application	Key Rate Design Methodologies Approved
1991 Phase A Rate Design	• Gas cost allocation methodology to address the deregulation of the gas supply environment. • Development of regional gas cost rates for sales customers in each of the Lower Mainland, Inland and Columbia service areas.
1992 Revenue Requirement Application and Negotiated Settlement Process	• The creation of a GCRA.
1993 Phase B Rate Design	• Development of postage stamp Basic Charge and delivery rate structures for firm sales and transportation customers (with the exception of RS 22A and the Columbia division) while maintaining regional large industrial rate structures.
1994/95 Revenue Requirement Application	• Revenue decoupling mechanism called the Revenue Stabilization Adjustment Mechanism (RSAM).[23]
1996 Rate Design	• Underlying postage stamp approach maintained. • Rebalancing of residential and large industrial rates as a result of a negotiated settlement process. • Basic charges were raised to more closely align with fixed costs.
1996/97 Revenue Requirement Application	• Modifications to the RSAM.[24]
2000 Southern Crossing Pipeline Cost Allocation	• On an interim basis Commission approved recovery of SCP costs in the Delivery Margin from all non-Bypass customers, but excluding RS 22B and Fort Nelson customers (Order G-74-00). • NSA parties agreed to the principle that customers that benefit from SCP should contribute to the cost recovery • The accounting treatment of SCP and allocation of SCP costs were deferred to the 2001 Rate Design Application.[25]
2001 Rate Design	• Underlying postage stamp approach maintained. • Rebalancing of residential and large industrial rates as a result of a negotiated settlement process. • Residential basic charges were increased to improve alignment with fixed costs. • To achieve an economic break point between RS 2 and RS 3/RS 23 that approaches the 2,000 GJ/year threshold, the commercial customer basic charges were increased. • Increases in basic charges were offset by corresponding decreases in delivery charges to maintain the revenue neutrality.

[23] Commission Order G-59-94, dated August 4, 1994.
[24] Commission Order G-99-95, dated November 27, 1995.
[25] Commission Order G-75-00, dated July 27, 2000.

Application	Key Rate Design Methodologies Approved
2004 and 2007 Commodity Unbundling Application and Customer Choice Program	• Implementation of the ESM. • Underlying postage stamp approach maintained. • Gas supply costs addressed. • Separation of the GCRA into two deferral accounts, the CCRA and the MCRA. • Gas supply portfolio components and costs assigned to the commodity portfolio or to the midstream portfolio. • Unbundling of the gas cost recovery charges to form separate commodity and midstream cost recovery charges. • Unbundling of the gas supply costs for sales customers: commercial in 2004 and residential in 2007.
2007 Certificate of Public Convenience and Necessity (CPCN) Application for Mt. Hayes LNG	• Decision to consider matters of cost and revenue allocation of Mt. Hayes LNG facility in a future rate design application.[26]
2010 and 2011 Revenue Requirements, Rates, Cost of Service, Rate Design and Revenue Deficiency Deferral Account Balance Application and Negotiated Settlement Agreement process	• The Negotiated Settlement Agreement did not agree on a rate design or specifically with the cost and revenue allocation matters for the Mt. Hayes LNG storage facility.
2012 Common Rates, Amalgamation and Rate Design Application and 2013 Reconsideration	• Application for amalgamation of FEI, FEVI and FEW entities[27] into a single entity and request to implement postage stamp rates across all of FEI. • The reconsideration application was approved, resulting in the amalgamation of the three utilities and postage stamp rates across all service areas, except for Fort Nelson.[28] • FEI's postage stamp rate design methodology was retained throughout the amalgamated service area. • Commodity costs to be allocated on an energy-related basis: maintained the CCRA deferral account across the amalgamated utility. • Midstream costs to be allocated on a demand-related basis: maintained MCRA deferral account across the amalgamated utility.

[26] Commission Order C-9-07, dated November 15, 2007.

[27] FEI's initial Amalgamation Application included FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc. (FEVI), FortisBC Energy (Whistler) Inc. (FEW) and Fort Nelson.

[28] Commission Order G-21-14, dated February 26, 2014.

3.3.1 1991 Phase A Rate Design Application

FEI's present rate design was developed in a two phase rate design process commencing with Phase A in 1991, followed by Phase B in 1993.[29] The first phase addressed gas costs, and the second phase addressed the remainder of the rate design, including delivery rates.

In October 1991, FEI (then BC Gas) filed its Phase A Rate Design Application, which dealt principally with the gas supply cost allocation methodology for the Lower Mainland and Inland service areas. By Commission Order G-22-92, the Commission approved the methodology to allocate commodity-related costs within the gas supply portfolio on an energy-related basis, while classifying fixed costs associated with storage and transport[30] as demand-related costs and allocating those costs to customer classes based on a coincident peak day demand methodology. This approach was approved on the basis that the need for fixed cost resources such as pipeline capacity, third party storage contracts and other peaking resources is driven by the gas supply requirements of the firm sales customers. As such, these customer classes should be allocated costs based on their respective share of the required peak resource capacity. The Commission also approved BC Gas' proposed regional gas cost allocation and gas cost rates for the Lower Mainland and Inland divisions as the gas commodity and midstream costs were managed as a single portfolio.

After the expiration of its long term gas supply contracts, the Columbia service area was subsequently brought into the common gas supply portfolio and gas cost allocation methodology with the Lower Mainland and Inland divisions.

3.3.2 1993 Phase B Rate Design Application

In April 1993, BC Gas filed the Phase B Rate Design Application, which considered the allocation of all other utility costs, other than gas supply costs. The application also sought approval for the consolidation of the Lower Mainland, Inland and Columbia divisions and related postage-stamping of delivery rates for residential, commercial and general firm service customer classes (regional gas cost allocation remained in place). To support this application, BC Gas filed a COSA study on both a regional and a consolidated basis. The COSA study included industry accepted studies for the minimum system costs and customer weightings used to: 1) classify distribution costs into demand and customer related components; and 2) allocate customer related costs. BC Gas determined the allocated cost of service of customer rate schedules with R:C to cost ratios and proposed a range of 90% to 110% on this ratio to be used as a guideline for setting rates.

In August 1993, the Commission approved consolidation of the divisions for regulatory purposes, including the adoption of common accounting practices.[31] Later that year, the Commission approved postage-stamp delivery rates for the Lower Mainland and Inland service

[29] Commission Order G-92-91, dated September 23, 1991, established the two-phase rate design review process.
[30] The fixed cost component of any commodity supply netback contracts then in place.
[31] Commission Order G-68-93, dated August 13, 1993.

areas.[32] The Commission did not approve the inclusion of the Columbia delivery rates in the postage stamping approved for the Lower Mainland and Inland divisions.[33] However, the Commission permitted BC Gas to set the same rates for Columbia and approved a tariff applicable to all three divisions effective January 1, 1994.[34] Since that time, the Columbia service area has had the same delivery rates and rate structures as the Lower Mainland and Inland service areas.

In its decision regarding the Phase B Rate Design Application, the Commission approved the adoption of a consolidated set of General Terms and Conditions to be applied across the BC Gas service areas (other than Fort Nelson).[35] The Commission also accepted BC Gas' proposal to price interruptible service at a discount to firm service based on the value of service. The revised industrial rates came into effect on November 1, 1993 and the revised residential and commercial rates came into effect on January 1, 1994.

The Commission directed BC Gas to bring forward a weather stabilization proposal and a general decoupling (RSAM) proposal that would serve to protect the utility from significant swings in revenue that could be caused by rate structures based on, for example, marginal cost pricing. This matter was addressed in the 1994/1995 and 1996/1997 Revenue Requirements Applications, as described below.

3.3.3 1994/95 and 1996/97 Revenue Requirements Applications

The 1994/95 Revenue Requirements application addressed the directive from the Commission in the Phase B Rate Design Application to bring forward a weather stabilization proposal and general decoupling proposal. The Commission approved the RSAM as a revenue stabilization account for the residential and commercial rate schedules covering the five month winter period. The RSAM was made effective on January 1, 1994. In the Commission approved negotiated settlement agreement for the 1996/97 Revenue Requirements Application, the RSAM was extended to all twelve months of the year.

3.3.4 1996 Rate Design Application

There have been two significant rate design proceedings since the 1991 Phase A and 1993 Phase B rate design proceedings. These two proceedings occurred in 1996 and 2001 and both built on the methodologies established in 1991 and 1993, with minor changes to the previously approved approach. The Commission's orders from these proceedings re-affirmed the fundamental methodologies outlined above.

[32] Page 10 of the Commission Order G-101-93 and Decision, dated October 25, 1993.

[33] Page 10 of the Commission Order G-101-93 and Decision, dated October 1993 stated: "The Commission concludes that the Columbia Division is sufficiently different from the Inland and Lower Mainland Divisions that, as a matter of rate design principle, Columbia Division gas delivery charges for residential, commercial and general firm service customers should not be linked to those of Inland and Lower Mainland customers through postage-stamping at this time."

[34] Commission Order G-101-93, dated October 25, 1993, BC Gas Tariff dated January 1, 1994, page R-1.1.

[35] Postage stamping for the Fort Nelson division was not proposed in the 1993 Rate Design Phase B Application.

In 1996, BC Gas filed a rate design application which included a COSA study including a minimum system study (MSS). BC Gas maintained that a reasonable guide for rate setting between customer classes was a range for R:C ratios between 90% and 110%. A Negotiated Settlement Process (NSP) was undertaken and the resulting Negotiated Settlement Agreement (NSA) was approved by Commission.[36] The key outcomes of the NSA were to:

- improve revenue alignment among customer classes to better reflect the customer class cost of service;
- establish a formula to estimate customer peak day demand for RS 5 and RS 25;
- deem a 50% load factor for the RS 5 allocation of gas supply fixed costs;
- increase the residential and commercial monthly basic charges in recognition of the higher level of fixed costs of serving these customers; and
- introduce RS 23 for large commercial transportation service.

3.3.5 2000 Southern Crossing Pipeline Cost Allocation Application

In 1997, BC Gas initiated an Integrated Resource Planning process to evaluate and select the most cost effective resource option to meet growing customer demand. Through the review process, the SCP project was selected and approved by the Commission in May 1999. Subsequently, and in order to determine the appropriate cost allocation treatment, BC Gas filed a SCP Cost Allocation Application in April 2000.

In the April 2000 Application, BC Gas proposed that customers who benefit from new SCP capacity be allocated the costs of the new capacity. These benefits included: (a) use of new capacity to access diverse peaking supplies; (b) lower future cost of pipeline reinforcement in the Interior; (c) an enhanced ability to provide balancing of planned and actual gas loads; (d) a better security of supply; and (e) opportunities for incremental revenues from third parties. Aside from RS 22B customers,[37] this approach proposed recovering SCP costs based on equal percentage increases in the contribution to delivery margin by customers. Since the SCP would provide customers with both capacity and supply benefits, BC Gas proposed allocating costs to both sales and transportation customers. The Commission approved this proposal on an interim basis as part of the Phase 1 NSA (Order No. G-74-00). The matter was referred to the 2001 Rate Design Application. On this basis the SCP costs were included in the delivery margin and allocated on the basis of the peak demand for each rate schedule to all non-bypass firm customers (except Columbia service area industrial customers served under RS 22B).

[36] Commission Order G-98-96 dated October 7, 1996.

[37] RS 22B customers were excluded because their supply arrangement was upstream of the Yahk pipeline interconnection point with SCP and separate from BC Gas' supply portfolio.

3.3.6 2001 Rate Design Application

In August 2000, the Commission directed[38] BC Gas to file another rate design application, which was filed on February 5, 2001. The focus of the 2001 Rate Design Application was the allocation of costs associated with newly completed capital projects[39] prior to 2001. The 2001 Rate Design Application addressed three main issues:

1. The level of rates between classes, or revenue realignment;
2. The structure of existing rate classes; and
3. Revisions required to the General Terms and Conditions, particularly for transportation customers.

At the request of participants of a workshop and prehearing conference, the Commission retained an independent rate design consultant, EES Consulting, to review the 2001 COSA study. EES Consulting was tasked with validating the COSA model and assessing the extent to which BC Gas' Cost of Service methodology corresponded to generally accepted rate setting practices. This EES Consulting review verified the validity and robustness of the COSA study.

The 2001 Rate Design Application was the subject of an NSP and the resulting settlement document was approved by Commission Order G-116-01. The approved settlement document included minor changes to the rate schedules.

3.3.7 Commodity Unbundling Applications (Customer Choice Program)

Natural gas commodity unbundling (i.e., the Customer Choice Program) was part of the 2002 Provincial Energy Policy which indicated that natural gas marketers would be permitted to sell directly to low-volume customers, and would be licensed in order to provide consumer protection. In response to this policy, the Commission directed BC Gas to update and reassess its unbundling program.[40] In 2003, the Commission subsequently directed that unbundling for small volume customers should be implemented in two phases:[41]

1. Commercial customers were to have an unbundled option effective November 2004 (Phase 1);
2. Residential customers in the second phase at some point in the future (Phase 2).

As the first step of the unbundling process, the business rules of the Customer Choice Program were defined by the ESM, which was approved by the Commission in 2003.[42] Under the ESM,

[38] Commission Order G-75-00, dated August 4, 2000.

[39] 2001 Rate Design Application filed with the Commission February 5, 2001, p.1: "With regard to the total cost of service, a significant change is the addition of a number of major capital projects to the infrastructure supporting the gas utility. The most notable among these is the Southern Crossing Pipeline (SCP) project; others include the IBIS financial management system, the Mercury billing system, and new buildings and facilities."

[40] Commission Letter L-49-02 dated December 13, 2002.

[41] Commission Letter L-14-03, dated April 16, 2003.

[42] Appendix A to Commission Letter L-25-03, dated June 6, 2003.

gas marketers contract with gas customers and deliver commodity to FEI based on the normalized forecast of the gas marketers' customers annual load requirements.

Subsequently, in October 2003, the commodity unbundling application for small commercial customers was filed. Upon the direction of the Commission, and to facilitate the implementation of the Customer Choice Program, the Gas Cost Reconciliation Account (GCRA) was separated into the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA). Although gas supply costs were split into two portfolios, the cost allocation methodology remained the same as was approved in 1991. In December 2013, the Commission approved, among other matters, formats for new commercial RS 2U and RS 3U.[43] Commencing in May 2004, gas marketers were able to start enrolling commercial customers in the commercial unbundling program.

In 2006, FEI (then Terasen Gas Inc.) filed a CPCN application for commodity unbundling for residential customers. The Commission approved the new RS 1U that outlined the residential unbundling service.[44]

The Customer Choice Program is offered by FEI and is available today to all customers except those in Revelstoke and Fort Nelson.

3.3.8 2007 CPCN Application to Enter into a Storage and Delivery Agreement for the Mt. Hayes LNG Storage Facility

On June 5, 2007, FEI (then Terasen Gas (Vancouver Island) Inc. or TGVI) submitted a CPCN application for approval to construct the Mt. Hayes LNG storage facility and to enter into a Storage and Delivery Services Agreement for the Mt. Hayes LNG storage facility. On December 14, 2007, the Commission issued its decision, which stated:

> The Commission Panel agrees with TGVI, BC Hydro and Power Authority (BC Hydro or BCH) and BCOAPO that matters of cost and revenue allocation should be considered in a future rate design application.[45]

3.3.9 2010 and 2011 TGVI Revenue Requirements, Rates, Cost of Service, Rate Design and Revenue Deficiency Deferral Account Balance Application

On June 29, 2009, FEI (then TGVI) filed an application for Approval of 2010 and 2011 Revenue Requirements, Rates, Cost of Service, Rate Design and Revenue Deficiency Deferral Account Balance as at December 31, 2008. Included in the application was a proposal for the cost

[43] Commission Order G-90-03, dated December 23, 2003.
[44] Commission Order C-6-06, dated August 14, 2006.
[45] Page 10 of the Commission Decision dated December 14, 2007 and Order C-9-07, dated November 15, 2007.

allocation of the Mt. Hayes LNG storage facility. The Commission approved an NSA regarding the application.[46] However, the NSA stated at page 17:

> The parties have differing views on the appropriate rate design. The Parties did not agree on an appropriate rate design, and did not agree on:
>
> a) Various cost allocation principles;
>
> b) R:C ratios; and
>
> c) The treatment of interruptible transportation revenues.

As such, FEI's proposals for the cost allocation of the Mt. Hayes LNG storage facility were not agreed to at that time

3.3.10 2012 Common Rates, Amalgamation and Rate Design Application (2012 RDA) and 2013 Reconsideration of 2012 RDA

On April 11, 2012, FEI and its affiliates filed an application with the Commission to amalgamate FEVI, FEW and FEI into a single entity and implement postage stamp rates across the amalgamated entity. In its application, FEI stated that it had been operating with a common management structure since the mid-2000s and that it viewed amalgamation as the next logical step towards integration.

FEI conducted a COSA study that combined each of FEI's utilities into an amalgamated entity and produced postage-stamp delivery, midstream, and commodity rates. FEI's rate structure was adopted for the amalgamated entity due to FEI's size in relation to other utilities and its more comprehensive service offerings. The customers of the other two utilities were allocated to FEI's existing rate schedules based on their annual consumption threshold and contractual requirements.

In February 2013, the Commission denied FEI's application for common rates and declined to consider the issue of amalgamation.[47] Following this decision, the Reconsideration and Variance of Order G-26-13 was requested in April 2013. In the Reconsideration and Variance application, FEI requested a determination that the proposed amalgamation was in the public interest and that the proposed postage stamp rates for the amalgamated utility (excluding the service area of Fort Nelson) be approved. The Commission established Phase I of the reconsideration process on May 8, 2013 which resulted in Order G-100-13, establishing Phase II of the reconsideration process and ordering, among other things, that new evidence would be accepted. On July 10, 2013, FEI provided new evidence regarding updated rate impacts for FEI, the level of integration of the FEI utilities, energy choices and efficiency programs as well as a report on FEVI's credit rating.

[46] Commission Order G-140-09, dated November 26, 2009.
[47] Commission Order G-26-13, dated February 25, 2013.

In February 2014, the Commission approved FEI's Reconsideration and Variance application with conditions.[48] In its decision, the Commission panel determined that the amalgamation was beneficial and in the public interest and that it would provide economic and other benefits that were in the public interest to FEI customers as a whole. The Commission also determined that in the context of FEI as an amalgamated entity, rate stability for the larger group of ratepayers would improve with the implementation of common rates. The Commission determined that FEI could adopt common rates for the amalgamated entity, subject to the Lieutenant Governor in Council's consent (which was approved by OIC No. 300 dated May 23, 2014) and subject to confirmation that the amalgamation had been effected. The Commission directed FEI to file a comprehensive rate design application for the amalgamated entity no later than two years after the effective date of amalgamation. This Application is made pursuant to that direction and presents a number of proposals related to the structure and rates within the FEI rate schedules.

3.3.11 Application to Amend the Balancing Charges for Rate Schedules 23, 25, 26 and 27

On May 13, 2014, FEI applied to the Commission to amend the balancing charges for monthly balancing gas applicable to transportation service under RS 23, RS 25, RS 26 and RS 27. FEI proposed an increase in the balancing charges under these rate schedules to provide an incentive to shipper agents to become responsible for balancing their groups and to be less reliant on the monthly balancing gas sales from FEI. At that time, FEI requested an increase to the existing charge per GJ for balancing gas to the Sumas daily price average for the month plus $0.10 per GJ.

In its decision, the Commission determined that FEI had the tools to ensure shipper agents comply with the intent of the rate schedules and that FEI should endeavour to better utilize these tools and amend business practices to ensure compliance. For these reasons, the application was denied. However, the Commission recognized that there was the possibility of harm being caused to the core market gas customers and directed FEI to file a rate design application on monthly balanced transportation service.

3.4 *PAST DIRECTIVES AND COMMITMENTS*

Table 3-4 below provides a brief summary of past Commission Directives and FEI Commitments relevant to this Application.

[48] Commission Order G-21-14, dated February 26, 2014.

1 **Table 3-4: Past Commission Directives and FEI Commitments**

FEI Application/Proceeding	Applicable Directive(s)/Reference & FEI Response
FEI Application for Approval of RS 22 Tariff Supplement No. G-21 Firm Transportation Service Agreement for Central Heat Distribution Ltd. (Creative Energy Vancouver Platforms Inc.) Commission Order G-128-05, dated December 1, 2005	1. The Commission approves for Terasen Gas, Tariff Supplement No. G-21 to provide firm transportation service to Central Heat, effective November 1, 2005, subject to the review of the Tariff Supplement No. G-21 rates in the next Terasen Gas rate design proceeding. <u>FEI Response</u>: FEI has reviewed tariff supplement No. G-21 and submits a proposal for RS 22 Firm Transportation in Section 9 of this Application.
FEVI Application for CPCN and Approval of a Storage and Delivery Agreement and FEI Application for Approval of a Storage and Delivery Agreement Commission Order C-9-07, dated November 15, 2007	In the Order, FEI was directed to comply with the directions of the Commission in the Reasons for Decision to follow. On page 78 of the Decision (from Section 8.0, Cost Recovery): In Reply, TGVI submits that it has not requested that the Commission approve any rate design proposal or any allocation of the costs or revenues associated with the Project as part of this Application. The Application includes illustrative cost allocations, but TGVI argues that the allocation of costs and the design of rates should be dealt with in a later proceeding, and that the regulatory review of this Application is not the appropriate venue for a rate design and cost allocation debate. TGVI also notes that both BC Hydro and BCOAPO agree in their Final Submission that allocation issues should not be determined in this proceeding (TGVI Reply Submission, p. 3). The Commission Panel considers the two cost allocation approaches were included to illustrate the potential range of rate impacts between the LNG and P&C alternatives. **The Commission Panel agrees with TGVI, BC Hydro and BCOAPO that matters of cost and revenue allocation should be considered in a future rate design application.** Therefore, the Commission Panel determines that, as per the Application, rate design is not part of this Decision and is not required for the other determinations the Commission Panel is required to make in this Decision. <u>FEI Response</u>: FEI has included a proposal for cost allocation of the Mt. Hayes LNG storage facility in Section 6.3.4.4 of this Application.
FortisBC Energy Utilities (FEU) Application for Reconsideration and Variance of Commission Order G-26-13 on the FEU's Common Rates, Amalgamation and Rate Design Application Commission Order G-21-14, dated February 26, 2014	5. The FEU is to file a rate design application for the Amalgamated Entity no later than two years after the effective date of the amalgamation of the FEU and Terasen Gas Holdings Inc. Page 19 of the Decision (from Fort Nelson section): The Commission Panel agrees there would appear to be a logical inconsistency in maintaining regional rates for Fort Nelson. However, the Panel also notes that the Fort Nelson and District Chamber of Commerce, which intervened in both the Original Application and the Reconsideration Application, took no position on the Reconsideration Application as no reconsideration of rates as applicable to Fort Nelson was sought. The FEU may want to address this apparent inconsistency in its next rate design application. <u>FEI Response</u>: FEI proposes a rate design for Fort Nelson in Section 13 of this Application.

FEI Application/Proceeding	Applicable Directive(s)/Reference & FEI Response
FEI Application for Approval to Amend the Balancing Charges for RS 23, RS 25, RS 26 and RS 27 Commission Order G-187-14, dated December 1, 2014	2. FEI is directed to file a rate design application on Monthly Balanced Transportation Service by no later than one year from the date of this order. <u>FEI Response</u>: The timing for the filing of a rate design application was extended by Order G-135-15 as described below. FEI provides a proposal for balancing provisions under Transportation Service in Section 10 of this Application.
FEI Application for Reconsideration of Order G-187-14 to Amend the Balancing Gas Charges for RS 23, RS 25, RS 26 and RS 27 Commission Order G-135-15, dated August 13, 2015	1. The deadline for FortisBC Energy Inc. to file a Monthly Balancing Rate Design Application is extended to December 31, 2016. 2. FortisBC Energy Inc. shall apply for a rate design on Monthly Balanced Transportation Service either as part of a broader rate design application as ordered by G-21-14, or as a separate filing along with the broader rate design application no later than December 31, 2016. FEI was directed to include a review or discussion of the following items for consideration in the rate design review regarding Monthly Balanced Transportation Service: • The ongoing need for continuing to offer Monthly Balanced Transportation Service and the value of providing such service. • The appropriate Balancing Charge to incent the appropriate behaviour across a range of market conditions. • The appropriate rate design mechanism to incent the appropriate behaviour not just at month-end but during the month as well. • The cost to the core customers of providing Monthly Balanced Transportation Service including both the instance where core resources are used to compensate for a positive imbalance as well as for a negative imbalance in a Monthly Balanced Transportation Service account. • The need for setting out imbalance tolerances in the tariff, whether these tolerances should apply to both positive and negative imbalances and including a review of the practices of other utilities in the region. • A review of the costs and benefits of the use of daily balanced transportation service in order to determine the applicability of this service for customers currently on Monthly Balanced Transportation Service and the impact of the two services on each other. 3. As ordered by G-135-15, FortisBC Energy Inc. is directed to add the following to the list of issues to be reviewed in the rate design on Monthly Balanced Transportation Service: • The appropriateness of the business practice of allowing transfers of imbalances between daily balanced and monthly balanced accounts. • The extent of FEI's use of core gas cost resources to balance the overall transportation service imbalances for each day and the cost to the core customers. <u>FEI Response</u>: FEI submits a proposal for balancing provisions under Transportation Service in Section 10 of this Application.

FEI Application/Proceeding	Applicable Directive(s)/Reference & FEI Response
FEI Response to British Columbia Utilities Commission Order G-105-15 – Directive to Recalculate the Overhead and Marketing Charge Commission Order G-105-15, dated August 21, 2015	On page 3 of the compliance filing, dated August 21, 2015, FEI stated the following: An updated Cost of Service Allocation (COSA) Study will be provided in the Comprehensive Rate Design Application (to be filed in 2016). FEI believes that the updated COSA will provide a more meaningful basis on which to conduct a further review of the OH&M charge for fueling station services. More specifically, **the direct allocation of overhead and marketing dollars will be considered as a part of the COSA and may result in changes that affect the OH&M charge applicable to the CNG and Liquefied Natural Gas fueling station services.** Thus, both FEI and the Commission will be in a more informed position to evaluate and review the OH&M charge following the update of the COSA study. FEI Response: FEI submits a proposal for the overhead and marketing (OH&M) charge applicable to CNG and LNG Stations in Section 11 of this Application.

1

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.

FortisBC Energy Inc.
2016 Rate Design Application

Section 4:

STAKEHOLDER ENGAGEMENT

Table of Contents

4. STAKEHOLDER ENGAGEMENT

4.1 INTRODUCTION

Prior to filing this Application, FEI conducted a stakeholder engagement process consisting of information sessions, stakeholder workshops and a residential customer online survey. FEI's stakeholder engagement process informed customers and other stakeholders about its current rate design and the potential rate design changes that FEI was considering. The workshops provided stakeholders with a forum to comment on and ask questions about FEI's rate design and potential rate design changes. Stakeholders were also provided the opportunity to bring rate design issues forward for FEI's consideration. In addition, FEI conducted a survey of residential customers regarding rate design preferences and understanding. FEI considered the comments and questions of stakeholders and the results of the residential survey in the rate design proposals set out in this Application.

The remainder of this section is organized as follows:

- Section 4.2 describes the participant funding made available to stakeholders to enable their participation in the engagement process;
- Section 4.3 provides an overview of the information sessions and stakeholder workshops and the process that FEI developed to capture stakeholder comments and questions;
- Section 4.4 sets out the key issues list developed as a result of the stakeholder workshops and where in the Application FEI has addressed these issues;
- Section 4.5 describes the residential customer survey that FEI used to reach out to its residential customers in all service areas, including a survey specific to Fort Nelson.

4.2 PARTICIPANT FUNDING

FEI sought to provide customers and other stakeholders with opportunities to participate in FEI's engagement process for this Application. In order to enable stakeholder participation, FEI made funding available to representatives of customer groups and other stakeholders to cover their costs for participating in the sessions and workshops that would occur in advance of filing the Application. As such, FEI developed Pre-Application Participant Funding Guidelines for funding that would be provided by FEI to qualifying stakeholders. These guidelines are attached as Appendix 4-1 to the Application.

FEI received requests for pre-application funding from five stakeholders, including:

1. the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, Together Against Poverty Society, and the Tenant Resource and Advisory Centre *et al*. (BCOAPO);

2. the B.C. Sustainable Energy Association and Sierra Club of British Columbia (BCSEA);
3. the Commercial Energy Consumers Association of British Columbia (CEC);
4. the Fort Nelson & District Chamber of Commerce (FNDCC); and
5. the Industrial Customer Group.

Upon completing the stakeholder engagement process, FEI requested that stakeholders submit their pre-application cost claims. FEI received cost claims from the five stakeholders for a total of $102,619.59. A breakdown of the claims by stakeholder is provided in Table 4-1 below.

Table 4-1: Pre-Application Participant Funding Cost Claims

Stakeholder	Consultant & Legal	Travel/ Other	TOTAL
BCOAPO	18,367.70	$33.97	18,401.67
BCSEA	14,738.85	720.57	15,459.42
CEC	36,461.78	-	36,461.78
FNDCC	480.00	1,614.96	2,094.96
Industrial Customer Group	28,399.90	$1,801.86	30,201.76
		TOTAL	**$102,619.59**

As indicated in the Pre-Application Participant Funding Guidelines, FEI has captured the funding provided to stakeholders in the approved Rate Design Application deferral account. As is the case with all additions to this deferral account, pre-application participant funding will be subject to Commission review and approval before being recovered from ratepayers.

4.3 *INFORMATION SESSIONS AND WORKSHOPS*

FEI's stakeholder engagement process included a series of information sessions and workshops. Table 4-2 below summarizes the date and intended purpose of each the information sessions and workshops.

Table 4-2: Application Pre-Filing Consultation and Workshop Schedule

Session	Date (2016)	Purpose of Session / Workshop
Introductory Application Information Session	February 26	Overview of application timing and purpose, introduction of stakeholders and project team members and brief issue identification discussion.
Education & Background Information Session	May 19	Overview of FEI sales and transportation service, including existing rate schedules and service offerings. Overview of rate design process, including COSA study, segmentation and rate structure fundamentals. Overview of FEI rate design history.
Workshop 1A FEI COSA	July 11	Discussion of preliminary COSA study results and allocations related to both the delivery and cost of gas.

Session	Date (2016)	Purpose of Session / Workshop
Workshop 1B FEFN Workshop	July 27	Discussion of preliminary COSA study results for Fort Nelson and discussion of other issues identified for Fort Nelson rate design.
Workshop 2 Transportation Review	August 12	Overview of transportation service business model. Discussion of identified transportation service issues and options and considerations for evaluation for changes.
Workshop 3 Rate Design & Segmentation	August 31	Discussion of rate design and segmentation options under consideration by FEI.

4.3.1 Information Sessions

FEI's information sessions were intended to provide stakeholders with information and an understanding of all aspects of FEI's rate design, including FEI's service models, rate design process, rate design concepts and rate design methodologies.

FEI's stakeholder engagement process started with an introductory information session in February 2016. The objective of this initial information session was to provide an overview of the Application timing and purpose, to introduce FEI's project team members, to introduce stakeholders to FEI and to one another and to facilitate a brief discussion of the rate design issues identified by FEI at that time.

FEI conducted a second information session in May 2016. This second session provided an overview of FEI's sales and transportation service business models and rate design concepts, studies, methodologies and process.

FEI received positive feedback from stakeholders regarding FEI's explanation of the context of the Application. Specific feedback, notes, action items and key issues from these sessions are included in the meeting notes attached in Appendix 4-2. A reference to where key issues from the information sessions are addressed in the Application is provided in Table 4-3. The feedback from the information sessions is also noted in the relevant sections of the Application.

4.4 WORKSHOPS

Subsequent to the two information sessions described above, FEI conducted four workshops on specific rate design topics. The objective of the workshops was to engage stakeholders and to collaborate in understanding, compiling and summarizing a key issues list which could then be used to focus the scope of the Application.

FEI prepared and circulated discussion guides one to two weeks in advance of each workshop to allow stakeholders to prepare and to participate effectively at the workshops. The discussion guides are included as Appendix 4-3 to the Application.

The topic-specific workshops were useful in garnering feedback from stakeholders on issues identified by FEI and potential options that FEI was considering for the rate design. These workshops also provided stakeholders with an opportunity to bring forward other discussion topics related to the Application. A number of suggestions were made to improve the understanding of issues and content of the Application. These requests were noted as action items in the workshop notes.

A workshop summary, including action items and key issues, was circulated to stakeholders approximately two weeks after each workshop and offered an opportunity for stakeholders to provide additional comments.[49] FEI offered to meet with stakeholders for further clarification on the topics discussed during the sessions and the workshops.

Action items arising from the workshops were addressed in the workshop notes or are being addressed in the Application. A consolidated workshop issues list is provided in Table 4-3 below.

4.5 WORKSHOP ISSUES LIST

Table 4-3 below provides a consolidated list of the issues raised in the four workshops together with a reference to where each issue is addressed in the Application, as applicable.

Table 4-3: Application Workshops – Consolidated Workshop Issues List

Workshop Issues List		Reference
Workshop 1A – FEI COSA: July 11, 2016		
1.	Demand Side Management (DSM) costs classification. Should DSM costs be energy related or customer related?	DSM costs are discussed in Section 6.3.5.5.
2.	Tilbury Expansion project costs and revenues. Request for 2018 cost of service and forecast revenues or 10 year levelized costs and revenues	The proposed treatment of the Tilbury Expansion Project is discussed in Section 6.3.2.3.
3.	Treatment of SCP in the COSA model. Why do the recommended changes make sense?	The treatment of SCP is discussed in Section 6.3.4.5.
4.	Treatment of Bypass customers. Is it possible to quantify and allocate bypass costs to these customers?	The treatment of Bypass customers is discussed in Section 6.3.1.5.
5.	Treatment of interruptible customers. Does it make sense to allocate any demand related costs to interruptible customers?	The treatment of interruptible customers is discussed in Section 9.6 for RS 7/RS 27 and Section 9.8 for RS 22.

[49] No comments were received from any stakeholder regarding the circulated meeting notes.

	Workshop Issues List	Reference
6.	R:C ratios – range of reasonableness. If outside the range of reasonableness, will FEI rebalance to unity or within the range of reasonableness given other rate design considerations?	The R:C for the customer rate schedules are provided in Section 6.5
Workshop 1B – Fort Nelson: July 27, 2016		
7.	Common Rates. Confirm that FEI will not be proposing the adoption of common rates for Fort Nelson in the Application.	FEI confirms that it is not proposing common rates for Fort Nelson at this time; a discussion on this topic will be provided in Section 13 to be filed in the supplemental filing on February 2, 2017.
8.	Rebalancing “Option 3”. Shift revenues to RS 25 to rebalance RS 2.1 and RS 2.2 and RS 25 (leave RS 1 at 92% R:C ratio).	The Fort Nelson R:C ratios and the rebalancing will be discussed in Section 13 to be filed in the supplemental filing on February 2, 2017.
9.	Investigate and report on Fort Nelson midstream costs and cost allocation. Should the midstream costs be zero for Fort Nelson due to the direct tap at the Spectra plant?	The cost allocation of midstream costs to Fort Nelson customers will be discussed in Section 13 to be filed in the supplemental filing on February 2 2017.
Workshop 2 – Transportation Service Review: August 12, 2016		
10.	Monthly versus Daily Balancing. Confirm that FEI will be proposing to have all customers daily balanced as discussed at the workshop. Confirm that FEI will not undertake financial evaluation for the value of daily versus monthly balancing.	The FEI daily balancing proposal is discussed in Section 10.6.3.
11.	Balancing tolerance and value. There is general agreement that some value exists for FEI’s balancing services. The Black & Veatch methodology as presented at the workshop is one option to value FEI balancing services for different tolerance levels. However, FEI needs to show an alternative method to value these balancing services. FEI to recommend tolerance levels based on further evaluation. FEI needs to develop an appropriate mechanism to capture the balancing service value for transportation customers.	FEI proposes a 10% balancing tolerance in Section 10.7.7.

Workshop Issues List		Reference
Workshop 3 – Rate Design & Segmentation: August 31, 2016		
12.	Application approach. FEI identified adjustments to residential, commercial and industrial rate design. Prior to making any final proposals, FEI will consider whether a change is required from the status quo. FEI will use rate design principles to identify the problem that exists (if any) and evaluate the options to resolve the problem and make proposals based on rate design principles.	The status quo and other options that were considered are identified in each of the sections where a rate design change has been proposed in this Application.
13.	Rebalancing. FEI will consider margin to cost ratios for rebalancing.	FEI considers the R:C and margin to cost ratios in Section 6.5.
14.	Residential Rate Design. Confirm whether FEI will be considering adjusting the ratio of the Basic Charge to the variable charge. Include a comparison of variable rate of the residential customer versus the marginal cost.	FEI's marginal cost study is provided in in Appendix 4-4 of the Application. A summary the study is included in Section 7.4.
15.	Commercial Rate Design. Confirm whether FEI will be evaluating changing the threshold to 1,600 GJ between RS 2 and RS 3/RS 23 as an alternative option.	The option to move the customer segmentation threshold to the revised economic crossover point at 1,400 GJ (revised from 1,600) is discussed in Section 8.6.2.
16.	Industrial Rate Design. For RS 5/RS 25, FEI will consider if any adjustments are required at this time considering that changes made to the rates for RS 5/RS 25 will have a ripple effect on rates for other rate schedules such as RS 7/RS 27, RS 22 and RS 1.	A review of RS 5/RS 25 is provided in Section 9.5 and a review of how changes to RS 5/RS 25 affect RS 7/RS 27 in Section 9.6.5 and RS 22 are provided in Section 9.8.5.

4.6 RESIDENTIAL CUSTOMER RESEARCH SURVEY

FEI worked with a BC-based independent research company, Sentis Research Inc (Sentis), to conduct an online survey of residential customers' rate design preferences and understanding. The survey covered all of FEI's service areas, including a survey specific to Fort Nelson. In the following sections, a brief summary of the survey methodology, scope and results is provided. The details of the survey methodology, questions and results are provided in a report by Sentis attached as Appendix 4-5 to the Application.

4.6.1 Survey Methodology and Scope

The Sentis survey was conducted using an online consumer panel. Some of the key features of the survey method are as follows:

- An 8 to 9 minute online survey with residential customers across the province was administered from July 25 to August 2, 2016;

- Qualified respondents were individuals who are FEI gas customers and who make payment decisions or review the FEI bills;
- The survey of FEI's customers outside of Fort Nelson used a total recommended sample size of 750 (250 for each of Metro Vancouver, Vancouver Island and the Interior). This resulted in 753 final surveys in these regions;
- The final data set was weighted geographically to accurately reflect FEI's residential customer base across the province; and
- For Fort Nelson, Sentis accessed approximately 600 publicly available landline telephone numbers, resulting in 65 final surveys.

The survey questionnaire was mainly focused on residential customers' understanding of current rates and bill determinants and an assessment of their preferences regarding various rate design considerations and different rate structures. The survey gathered information regarding residential customers':

- Understanding of the current rate structure and bill determinants;
- Preferences regarding various rate design considerations;
- Assessment of different rate structures (flat rate, inverted rates and declining block rates)
- Knowledge of the Commission's role and perception of FEI among residential customers.

The Fort Nelson residential customers' survey covered similar topics. However, due to the differences between FEI and Fort Nelson rate structures and bill components, the questions were slightly different. Fort Nelson customers were specifically asked if they would prefer to switch to an unbundled rate structure similar to FEI.

4.6.2 Summary of Results

A summary of the results from the online survey for residential customers is provided below. The residential customer survey results are discussed in more detail for FEI in Section 7.4 and for Fort Nelson in Section 13 which will be filed on February 2, 2017, as part of FEI's supplemental filing. FEI used the resulting survey information to inform its residential rate design proposals in the Application.

A summary of survey results is provided in Table 4-4 below.

Table 4-4: Summary of Survey Results

Survey Topic	Summary of Survey Results

Survey Topic	Summary of Survey Results
Understanding of current rates and bill determinants	FEI and Fort Nelson customers are fairly familiar with their respective current rates and bill determinants.
Preferences regarding rate design considerations	FEI and Fort Nelson customers consider that ease of understanding is a critical rate design principle. FEI and Fort Nelson customers' preferences differ on the issue of appropriate price signals: Fort Nelson customers placed less importance on rates that encourage users to use less natural gas and/or avoid gas usage during winter.
Assessment of rate structures	A flat rate is considered by FEI and Fort Nelson customers to be the easiest to understand and lead to more stable monthly bills. FEI and Fort Nelson customers' responses differed regarding which rate structure would most effectively ensure the efficient use of the system.
Knowledge of Commission role and perception of FEI	FEI and Fort Nelson customers are generally aware that the Commission reviews and approves FEI's natural gas rates and charges. The perception of FEI is relatively favourable. However, FEI customers outside of Fort Nelson have a more favourable view than Fort Nelson customers.
Unbundling of FEFN rates	Fort Nelson customers were relatively favourable to unbundling Fort Nelson rates similar to FEI's unbundled rates.

4.7 *SUMMARY OF STAKEHOLDER ENGAGEMENT*

The Rate Design Application stakeholder engagement process included communication and consultation with stakeholders through activities such as stakeholder information sessions, topic specific workshops, stakeholder meetings, a residential customer survey and web communication. To ensure that customers and stakeholders had the opportunity and ability to participate in the engagement process, FEI made funding available to eligible participants prior to filing the Application.

The pre-filing stakeholder engagement process was effective in discussing, compiling, and considering feedback on key issues related to this Application, which should lead to a more efficient regulatory review process. Stakeholders at the information sessions and workshops did not identify major concerns with FEI's existing rate design. Nevertheless, FEI has compiled a key issues list as shown in Table 4-3. These key issues have been used by FEI to focus the scope of this Application.

The residential customer survey conducted by FEI for all service areas was helpful in understanding residential customers' knowledge of FEI's existing rates and preferences regarding rate design considerations, such as rate design principles and rate structures. Based on the feedback from the survey, residential customers are generally aware of the existing rate structure, including applicable charges on their bills. Residential customers identified ease of understanding as a key rate design principle and were favourable to the flat rate structure that FEI has in place for all its service areas, except Fort Nelson. Fort Nelson residential customers are generally favourable to unbundling the rate structure (similar to FEI rates) for simplicity and transparency and supportive of the flat rate structure for delivery rates.

As discussed in this section, FEI has broadly engaged its stakeholders with respect to the Application. Feedback obtained through the stakeholder engagement process has been considered and incorporated into the Application where appropriate.

FortisBC Energy Inc.
2016 Rate Design Application

Section 5:

Legal Context, Rate Design Principles and Government Policy

Table of Contents

5. LEGAL CONTEXT, RATE DESIGN PRINCIPLES AND GOVERNMENT POLICY

5.1 *INTRODUCTION*

Three overarching considerations were taken into account in the proposed amendments to FEI's rate design. First, the legal context sets out the rules by and manner in which the Commission may fix customer rates. Second, rate design is guided by the widely accepted rate design principles identified by Dr. Bonbright in his seminal work, *Principles of Public Utility Rates.*[50] Third, government policy establishes energy policy objectives, including objectives related to energy efficiency, greenhouse gas (GHG) reduction and economic development.

Each of these three overarching considerations is described in the subsections below.

5.2 *LEGAL CONTEXT*

The Commission's rate-setting determinations are set out in sections 58 to 61 of the UCA. A brief synopsis of these sections is provided below.

- Section 58 of the UCA addresses the situations in which the Commission may order amendment of rate schedules. It states that the Commission may (on its own motion or through a complaint by a public utility or other interested person) after a hearing determine the just, reasonable and sufficient rates to be observed and in force.
- Section 59 of the UCA addresses the issue of rate discrimination. It states that a public utility must not make, demand or receive "an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it." Section 59 of the UCA also provides that a rate is "unjust" or "unreasonable" if the rate is: (a) more than a fair and reasonable charge for service of the nature and quality provided by the utility; (b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property; or (c) unjust and unreasonable for any other reason.
- Section 60 of the UCA provides broad rate-setting guidelines for the Commission to consider when determining rates. In setting a rate, the Commission must consider all matters that it considers to be proper and relevant affecting the rate. The Commission must have due regard to the setting of a rate that is not "unjust" and "unreasonable" within the meaning of section 59, provides the utility a fair and reasonable return on any expenditure made by it to reduce energy demands, and encourages public utilities to increase efficiency, reduce costs and enhance performance.

[50] James C. Bonbright, Albert L. Danielsen, David R. Kamershen, *Principles of Public Utility Rates,* second edition, 1988, pp. 383-384.

  - Section 60(b.1) of the UCA gives discretion to the Commission to "use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period".
  - Section 60(c) of the UCA provides general guidelines for utilities with more than one class of service and states that the Commission must: (i) segregate the various kinds of service into distinct classes of service; (ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as self-contained unit; and (iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates set for any other unit.
- Section 61 of the UCA requires a public utility to file rate schedules with the Commission, to receive the Commission's approval before rescinding or amending a schedule and to charge only those rates that are in accordance with the filed schedules.

5.3 *RATE DESIGN PRINCIPLES*

In conducting its rate design, FEI applies the rate design principles identified by Dr. Bonbright. FEI uses these principles to identify issues with the current design and to select rate design solutions.

The principles adopted by FEI for rate design, and as articulated by the Commission in a previous BC Hydro Decision[51], in no particular order, are:

- 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).

[51] Commission Decision and Order G-45-11, dated March 14, 2011, in the BC Hydro Residential Inclining Block Re-Pricing Application.

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.

5.4 GOVERNMENT POLICY

In addition to the eight rate design principles, FEI considers government policy as reflected in published government energy policy documents, and the legislation and regulations implementing those policies.

One of the major developments since FEI's rate design proceeding in 2001 is the implementation of the provincial government's climate action and energy policies. The overall thrust of these policies for FEI is twofold: (i) to promote energy efficiency and conservation through demand side and tax measures to curb GHG emissions; and (ii) to promote the role of natural gas in the transportation sector.

A summary of the most relevant government policies and regulations and their impact on FEI's rates is provided below.

5.4.1 2007 BC Energy Plan and the Resulting Regulations

The 2007 BC Energy Plan was released on February 27, 2007. Many of the policies outlined in the plan focused on the need for reduced energy use and energy conservation through policies that would encourage utilities, consumers, as well as builders and developers, to pursue cost effective and competitive demand-side measures. These policies were followed by an announcement on February 19, 2008 that introduced the B.C. carbon tax.

To implement the policies items outlined in the 2007 BC Energy Plan and the carbon tax, the provincial government passed legislation in the spring of 2008, including the following:

- *Greenhouse Gas Reduction Targets Act*;
- *Utilities Commission Amendment Act*, 2008;
- *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*;
- *Greenhouse Gas Reduction (Emission Standards) Statutes Amendment Act*, 2008; and
- *Carbon Tax Act*.

The carbon tax came into effect in July 2008, starting at $10/tonne of GHG emissions and increasing by $5 per tonne each year to $30/tonne in July 2012 where it has remained since then. Natural gas consumers in B.C. currently pay a volumetric charge of $1.49/GJ in carbon tax. As a volumetric charge, the carbon tax acts as a price signal to consumers to reduce natural gas consumption. Any future increases in carbon tax, such as those being contemplated by the recently-announced Pan-Canadian Framework on Clean Growth and Climate Change[52] will further increase the price signal for reduced natural gas usage.

There have been amendments to the legislation listed above. For instance, the *Utilities Commission Amendment Act, 2008* introduced amendments to the UCA that were designed to encourage public utilities to reduce GHG emissions and provided authority for the *Demand-Side Measures Regulation* (enacted in November 2008). The *Demand-Side Measures Regulation* sets out rules that the Commission must use when assessing the adequacy of a demand-side measure portfolio and the cost-effectiveness of demand-side measures proposed by a public utility. On July 10, 2014, the provincial government modified the *Demand-Side Measures Regulation* through B.C. Reg. 141/2014. This amendment raised the low income program eligibility threshold and added a deemed list of eligible low income customers.

The cumulative and individual impacts of these regulations on the cost of natural gas for FEI's customers have been significant. The *Carbon Tax Act,* for example, had a direct impact on FEI's customers' monthly bill amounts and bill components. Another significant impact of government policies on FEI's rate structure relates to the 2010-2011 Revenue Requirements NSA (2010-2011 NSA). Consistent with government energy policies, parties to the 2010-2011 NSA agreed to hold the Basic Charge constant at 2009 levels and to increase the volumetric Delivery Charge to recover the approved revenue requirements. Since the 2010-2011 NSA, all delivery margin increases have been allocated to the volumetric Delivery Charge. The impact of this allocation is discussed in more detail in Section 7 of the Application. Furthermore, the foundation of FEI's DSM programs and their corresponding costs (which are reflected in FEI's COSA model) are based on the *Utilities Commission Amendment Act, 2008* and the *Demand-Side Measures Regulation*.

5.4.2 2010 Clean Energy Act (CEA)

On April 28, 2010, the B.C. government announced the *Clean Energy Act* (CEA). The CEA set provincial energy objectives and mechanisms, including those for electricity self-sufficiency, clean or renewable energy, energy efficiency, GHG emission reductions and fuel switching to lower carbon intensity energy. The CEA's new definition for "demand side measure" excluded programs designed to encourage fuel switching that would have the impact of increasing GHGs in the province.

On May 14, 2012, through the *Greenhouse Gas Reduction (Clean Energy) Regulation* (GGRR), the provincial government established several "prescribed undertakings" to encourage the adoption of natural gas as a transportation fuel in the province. The government's press release

[52] https://www.canada.ca/en/services/environment/weather/climatechange/pan-canadian-framework/climate-change-plan.html

stated that the GGRR allows utilities to deliver natural gas transportation programs, including opportunities to:

- Offer incentives to transportation fleets that would use natural gas, such as buses, trucks or ferries;
- Build, own and operate CNG fueling stations or LNG fueling stations; and
- Provide training and upgrades to maintenance facilities to safely maintain natural gas-powered vehicles.

The GGRR was the first legislation which recognized the role of natural gas as a cost-effective means of reducing GHG emissions in the transportation sector.

On November 28, 2013, the provincial government amended the GGRR to include mine haul trucks and locomotives as vehicles eligible for incentives, while increasing expenditure caps on items such as grants for safety practices or maintenance facilities, expenditures on stations and a tanker truck load-out facility.

More recently, in August 2016, the GGRR was again amended (B.C. Reg. 214/2016) to expand the eligibility criteria for incentives and to introduce two new prescribed undertakings: one for incentives to support the adoption of natural gas for remote power generation; and a second for LNG storage and infrastructure to enhance the LNG distribution network to serve LNG customers.

The CEA and GGRR underpin FEI's current NGT programs. CEA sections 18(2) and (3) set limits on the Commission's jurisdiction over prescribed undertaking expenditures by a public utility.[53] These sections of the CEA, as well as subsequent amendments to the GGRR, informed the Commission's determinations regarding revenue and cost treatment for these programs, which has directly impacted FEI's cost allocation model and rates. For instance, the Commission's decision to allow the recovery of any revenue shortfalls from FEI's NGT programs in the rates of non-bypass customers was a direct result of the CEA and its subsequent amendments.[54]

5.4.3 LNG Service and Direction No. 5

A number of aspects of FEI's LNG service are the subject of Direction No. 5 to the Commission, which was issued in November 2013 (B.C. Reg. 245/2013) and amended on December 22, 2014 (B.C. Reg. 265/2014).

[53] Section 18(2) of the CEA requires the Commission to permit a public utility carrying out a prescribed undertaking to recover sufficient revenues to recover the costs of the prescribed undertaking. Section 18(3) of the CEA states that, "the commission must not exercise a power under the *UC* in a way that would directly or indirectly prevent a public utility referred to in subsection (2) from carrying out a prescribed undertaking".

[54] For instance, please refer to Commission letter L-42-14 dated 2014-08-08 regarding the rate treatment of expenditures under the GGRR.

Direction No. 5 has a number of direct impacts on the Application. First, RS 46 – LNG Sales, Dispensing and Transportation Service, and RS 50 – Large Industrial Transportation Service Rate Schedule, were established by Direction No. 5 and therefore not subject to change in this Application. Second, the costs and forecast revenues from projects exempt from review by Direction No. 5 and that are forecast to be completed by 2018 are included in FEI's COSA model and described in Section 6.3.2 as "known and measurable changes". Third, the impact of the FEI and BC Hydro letter agreement regarding the Burrard Thermal and the BC Hydro IG facilities' demand, as set out in Direction No. 5, is considered in FEI's COSA model.

The major components of Direction No. 5, as amended, are described below.

Rate Schedule 46 – LNG Sales, Dispensing and Transportation Service

Direction No. 5 established a new tariff for LNG service provided by FEI from LNG facilities such as Tilbury and Mt. Hayes, as well as for optional LNG transportation service if a customer elects such an optional service. This new tariff was called RS 46. Direction No. 5 provides that the Commission must not do anything to amend, cancel or suspend the LNG rate schedule, except on application by the utility. RS 46 became the replacement for RS 16, which was the rate schedule that had been approved by the Commission for LNG sales on a pilot program basis.

Additional Expansion at the Tilbury LNG Facility (Phase 1A and 1B)

At its inception, Direction No. 5 exempted expenditures of up to $400 million on the expansion of the Tilbury LNG facility from the Commission's CPCN requirements. The 2014 amendment to Direction No. 5 structured the Tilbury LNG facility expansion project into two separate phases (Phases 1A and 1B). Each phase is subject to a cap of $400 million plus construction carrying costs (the equivalent of Allowance for Funds Used during Construction (AFUDC)). Phase 1A of Tilbury expansion is identified as the initial CPCN exemption of $400 million plus AFUDC and feasibility and development costs defined in Direction No. 5. Phase 1B of Tilbury expansion includes an additional CPCN exemption for a second $400 million plus AFUDC and feasibility and development costs to provide additional liquefaction capacity, but not including storage. The liquefaction capacity of Phase 1B must be 70% contracted (on average) over the first 15 years of operation before proceeding with construction.

Rate Schedule 50 – Large Industrial Transportation Service Rate Schedule

The 2014 amendment to Direction No. 5 established a new tariff for firm transportation service for large volume industrial customers called RS 50. Among other things, the terms and conditions of RS 50 include a minimum firm demand of 45 TJ/Day and a contract term of at least 15 years. The structure of RS 50 is designed to generate incremental revenues to recover the costs of incremental capital investments required to serve RS 50 customers, and to provide additional contributions to benefit existing natural gas rate payers, beyond recovering the costs associated with the incremental capital investments.

Transmission Project CPCN Exemptions

The 2014 amendment to Direction No. 5 also exempts the following transmission projects from the Commission's CPCN review requirements:

1. the Coastal Transmission System (CTS) capacity expansion projects, including four transmission pressure (TP) projects: three projects on the Lower Mainland system (Cape Horn to Coquitlam, Nichol to Port Mann, Nichol to Roebuck), and one on Tilbury Island to increase pipeline capacity into the LNG plant; and
2. the Eagle Mountain Gas Pipeline Project.

FortisBC Energy - BC Hydro Letter Agreement:

The 2014 amendment to Direction No. 5 also directed the Commission to issue an order setting a letter agreement between FEI and BC Hydro as a rate. The letter agreement deals with BC Hydro's much-reduced need to transport gas across the FEI system after the closure of Burrard Thermal. After the closure occurs, BC Hydro will only require transportation capacity to deliver gas to the BC Hydro IG facility on Vancouver Island. In addition, the letter agreement permits BC Hydro, under certain conditions, to use its delivery capacity to deliver gas to the Woodfibre LNG facility, if (and when) that facility goes into service.

5.4.4 Postage Stamp Rate-Making

The government of B.C. continues to support a policy for postage stamp rate making. On July 9, 2013, the BC Ministry of Energy and Mines issued a letter to the Commission in support of FEI's application for common rates. The letter notes the following:

> From a public policy perspective, the Ministry is of the opinion that a common rate resulting from the proposed amalgamation of FortisBC Energy Utilities will have benefits for all Fortis BC Energy customers in British Columbia.
>
> Government policy has been to promote access to energy services on a postage stamp rate basis so that all British Columbians benefit from access to services at the lowest average cost.[55]

The B.C. Ministry of Energy and Mines has also issued a letter to the Commission, dated September 17, 2015, stating that postage stamp ratemaking continues to be provincial government policy. In this letter, the Ministry states that:

> Postage stamp rates provide access to services at the lowest average cost, promote investment equality across BC Hydro's service area, streamline

[55] FEU Common Rates, Amalgamation Rate Design Reconsideration Phase 2, Exhibit C3-1.

regulatory requirements and effective utility management, and minimize potential regional rate impacts as BC Hydro invests in its infrastructure.[56]

Consistent with the above policy, the Commission has approved a postage stamp rate across FEI's service areas, excluding Fort Nelson.

5.5 *SUMMARY*

The legal context, rate design principles and government policies, as noted above, have all been considered by FEI in the review of its rate design and in the development of the rate design proposals in the Application.

[56] BC Hydro 2015 Rate Design Application, Appendix C-1C.

FortisBC Energy Inc.
2016 Rate Design Application

Section 6:

FEI COST OF SERVICE ALLOCATION STUDY

Table of Contents

6. FEI COST OF SERVICE ALLOCATION STUDY

6.1 INTRODUCTION

A COSA study is a fundamental component in the preparation of a utility rate design application. A COSA study provides important contextual information in assessing how the proposed rates and rate structures perform against the relevant rate design principles and considerations. The results of the COSA study provide key metrics for assessing the proposed rate design against a number of the rate design principles identified in Section 5.3. Information for assessing the rate design's effectiveness in recovering the cost of service, providing a fair apportionment of costs among customers, avoiding undue discrimination or providing revenue stability can all be drawn from the COSA.

FEI conducted a COSA study in accordance with standard utility practice to allocate FEI's costs to each of FEI's rate schedules. The costs and revenues used in the COSA study reflect FEI's approved 2016 test year, plus known and measurable changes expected by or soon after January 1, 2018. The allocated costs by rate schedule are compared to the revenue collected by rate schedule to calculate the R:C ratio for each rate schedule. The R:C ratio shows whether the rates charged to each rate schedule adequately recover the allocated cost of service. The resulting R:C ratios are, with limited exceptions, within a +/- 5% range of reasonableness.

The COSA study results described in this section do not account for the rate design proposals set out in the Application. As some of FEI's rate design proposals affect the allocation of costs, revised R:C ratios taking into account the rate design proposals are presented in Section 12 of the Application. As discussed in Section 12, only limited rebalancing of rates is proposed to bring the R:C ratios within a +/- 5% range of reasonableness.

In this section, FEI describes the:

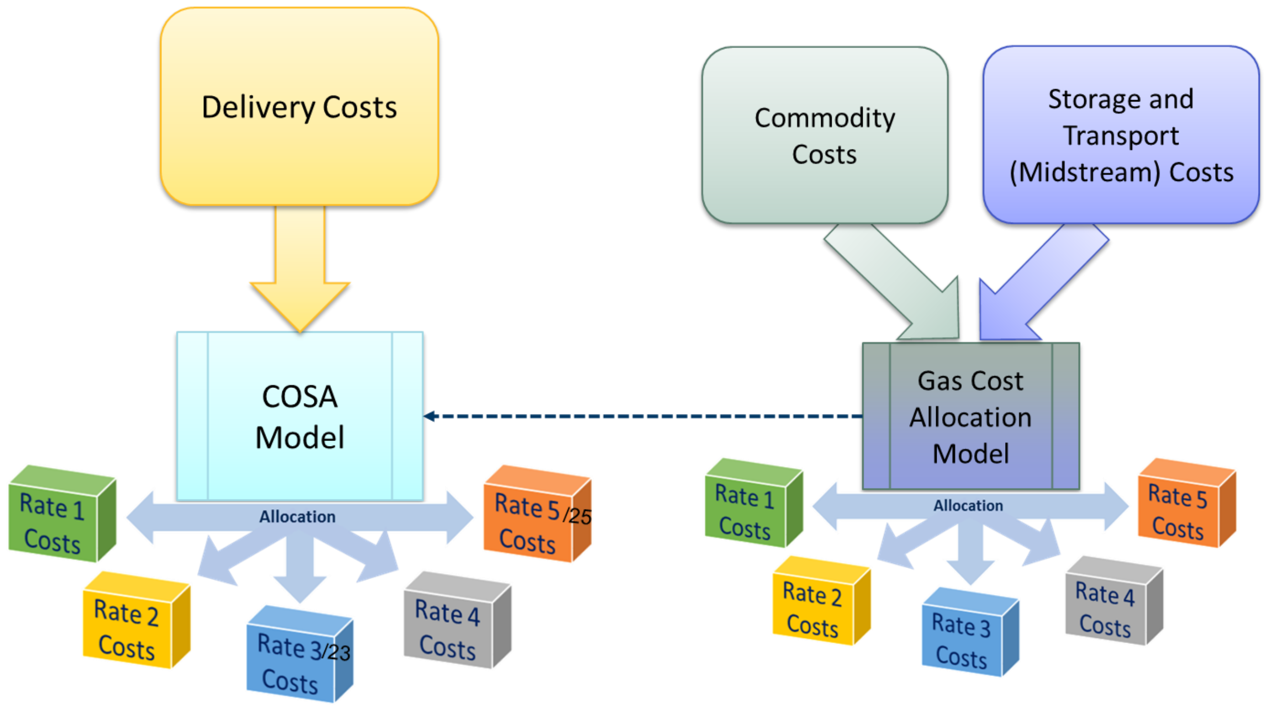
- COSA methodology;
- Delivery cost of service allocation;
- Gas cost allocation;
- Results of the COSA study; and
- Responses to stakeholder feedback.

6.2 COST OF SERVICE ALLOCATION METHODOLOGY

FEI conducted a COSA study to determine how to allocate and recover FEI's costs through customer rates. FEI's COSA methods have been reviewed by EES Consulting. EES Consulting found "*that the COSA follows standard utility practice, is generally consistent with past practice for the utility and the results are acceptable for purposes of setting just and* *reasonable rates for the utility*."[57] EES Consulting's report is included as Appendix 6-1 to the Application.

Figure 6-1 below provides an overview of how FEI's costs are accumulated and allocated to specific customer groups.

Figure 6-1: FEI Cost Allocation Overview



FEI's gas costs, including both commodity and storage and transport costs, are reviewed on a quarterly basis using a different model than FEI's delivery costs, which are reviewed on an annual basis. As such, FEI's revenue requirement in this Application is allocated into two categories: delivery costs and gas costs. FEI's delivery costs are defined as FEI's revenue requirement excluding gas costs[58] and are allocated in a delivery margin COSA model. Gas costs are then added to the allocated delivery margin to calculate the R:C ratios.[59]

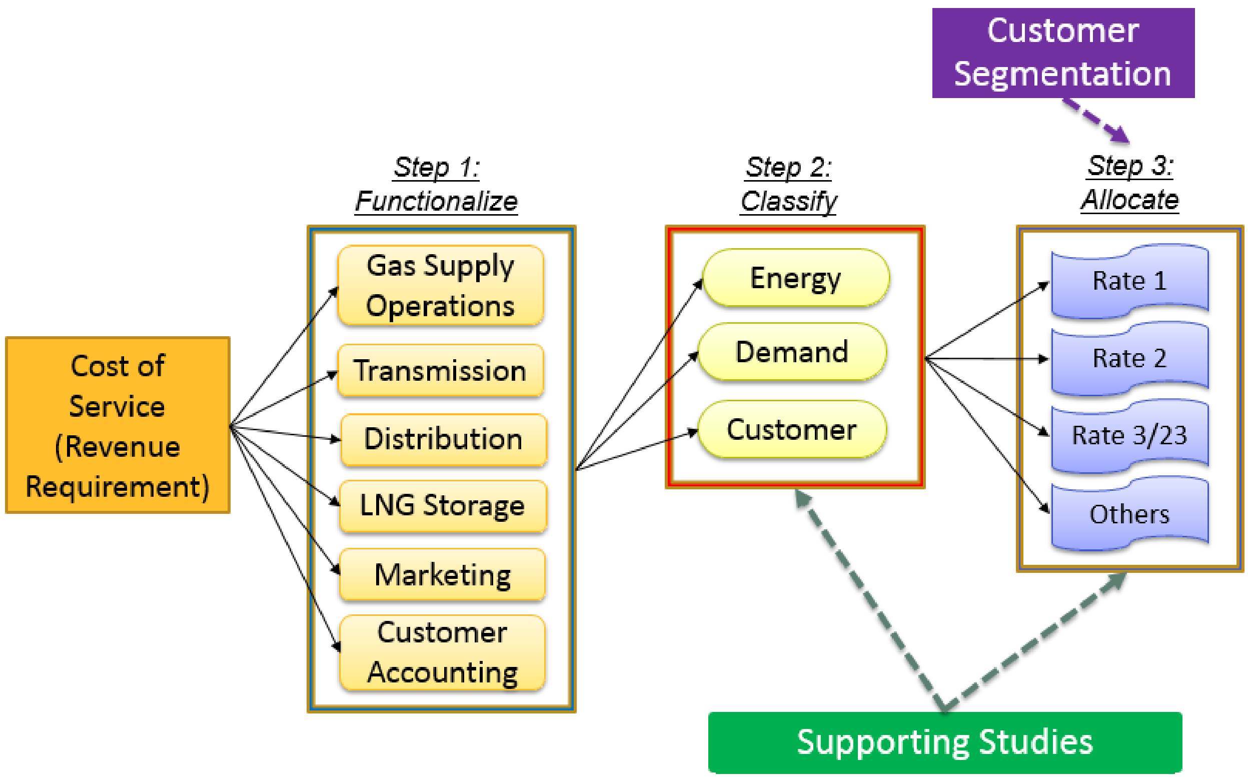
6.2.1 The Three Steps of Cost Allocation

The COSA study follows three standard steps to allocate the cost of service: functionalize, classify and allocate. The end result, as shown in Figure 6-2, is the allocation of FEI's cost of service to each customer rate schedule. Each of the three steps is discussed in the subsections below.

---

[57] Appendix 6-1: EES Natural Gas Cost of Service Review, page 1.
[58] The delivery margin equals the revenue minus the gas costs.
[59] Gas costs are not allocated in the delivery margin COSA model; they are included as cost inputs to FEI's COSA model based on pre-approved rates for the purpose of determining R:C ratios.

Figure 6-2: FEI COSA Steps



6.2.1.1 Functionalization

The first step in the COSA study is the functionalization of costs. The functionalization step involves separating the costs from the test year revenue requirement into the major categories that reflect the utility's plant investment code of accounts and different services provided to customers. After assigning plant costs functionally, related expenses are functionalized along the same basis. For FEI, the COSA contains the following functions: Gas Supply Operations, Transmission, Distribution, LNG Storage, Marketing and Customer Accounting. Costs that are directly related to the defined function are assigned to those functions. General costs and intangible plant costs are typically functionalized across all functions according to the relative functional portions of gross plant in service.

6.2.1.2 Classification

The second step in the COSA study is to classify the functionalized costs into cost-causation categories. These categories are related to the reason why FEI had to incur the cost (i.e., the drivers of the costs). The costs are generally incurred based on three drivers - peak day demand, energy delivered or the existence of a customer on the system. Each classification uses cost allocators that will distribute those costs among the appropriate customer rate schedules. The three classifiers are discussed further below.

- **Demand:** Demand-related costs are those associated with plant that is designed, installed and operated to meet maximum daily gas flow requirements, such as transmission and distribution mains. Essentially, these are all costs associated with having peak capacity on standby and available upon peak customer demand. Given this, transmission and distribution capacity, compressor costs, and LNG storage are classified as demand-related costs with respect to FEI's requirement for serving peak demand at the winter peak.
- **Energy:** Energy-related costs are those costs that vary with the volume of gas delivered to customers. In the case of FEI, other than the commodity supply purchased on behalf of FEI's customers, few of the costs to operate FEI's facilities are variable with respect to the volume of gas delivered to customers. Commodity supply expenses are classified as energy-related costs as a means to apportion the costs to sales customers.
- **Customer:** Customer-related costs are those that are incurred as a result of having a customer attached to the distribution system, metering the customer's gas usage and maintaining the customer's account. These costs may include capital costs associated with the investment in minimum size distribution mains, services, meters, house regulators, as well as marketing and customer accounting related activities. The costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas.

Not all functionalized groups classify neatly into one of the three cost causation factors. In such instances, additional supporting studies are required to determine appropriate classifications amongst the cost causation factors. The costs of distribution mains, for example, are caused by both customers connecting to the system and by the maximum daily gas flow requirements. A MSS and Peak Load Carrying Capacity (PLCC) adjustment, discussed below, were conducted and employed to aid the classification of distribution main costs into both customer and demand related costs.

- **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.

6.2.1.3 Allocation

The third step in the COSA process is to allocate the classified costs to FEI's rate schedules. This allocation of costs is based on a customer group's contribution to the specific classifier selected, as determined by a number of analyses that evaluate customer requirements, loads, usage characteristics, system design and operations, accounting and physical asset records. For example, costs that are classified as customer related are allocated across the rate schedules on the basis of the number of customers in each rate schedule.

6.2.1.4 R:C Ratios

The final step of cost allocation is to derive the R:C ratios by dividing the revenue from each rate schedule by the allocated costs. The resulting R:C ratios help inform the need for revenue rebalancing. Revenue rebalancing is the method by which the utility shifts revenue responsibility from one customer group to another.

6.3 *DELIVERY COST OF SERVICE ALLOCATION*

To allocate delivery costs to customers, FEI uses the same three-step cost functionalization, classification and allocation process as described above in Section 6.2. The allocation process is undertaken in a delivery margin COSA model, which will be referred to simply as the COSA model in this Section. To prepare the COSA model, assumptions and adjustments to the 2016 test year need to be made. These assumptions and adjustments are described in more detail below in Section 6.3.1 (Key Assumptions) and Section 6.3.2 (Known and Measurable Changes).

Following these two sections, the remainder of Section 6 provides details of each of the three COSA study steps:

- Section 6.3.4 Functionalization.
- Section 6.3.5 Classification.
- Section 6.3.6 Allocation.

6.3.1 Key Assumptions

6.3.1.1 Test Year

FEI utilized 2016 approved costs from its Annual Review for 2016 Delivery Rates proceeding[60] for allocation within the COSA model. FEI chose these approved costs as the base for allocation because they reflect current operating conditions, reflect the amalgamation of FEI, FEVI and FEW, and were the most recent available approved costs at the time the COSA study was prepared.

FEI has an approved revenue requirement of $1,237.5 million for 2016. FEI's 2016 test year cost structure, including first the rate base and then the cost of service, is summarized below in Table 6-1 and additional details are provided in Appendix 6-2.

Table 6-1: Summary of FEI's 2016 Test Year Cost Structure ($ millions)

Rate Base Components (mid-year)	
Gross Plant in Service	$ 5,593.6
Accumulated Depreciation	(1,751.3)
Contribution in Aid of Construction	(424.7)
Accumulated Amortization	143.2
Unamortized Deferred Charges	32.7
Capital Work In Process	35.2
Working Capital	61.0
Other	3.0
Total	**$ 3,692.7**

Revenue Requirement Components	
Cost of Gas	477.7
O&M Expense (net)	238.1
Depreciation and Amortization	199.5
Property Taxes	63.0
Othe Revenue	(41.9)
Income Taxes	46.2
Earned Return	254.9
Total	**$ 1,237.5**

60 Commission Order G-193-15, dated December 11, 2015.

Below, FEI summarizes the treatment of some of the items from the 2016 test year in the COSA model.

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.

6.3.1.3 Revenue Adjustment – RS 22A

The COSA model includes revenue from FEI's test year for calculation of R:C ratios. In preparing the COSA model, FEI found that a portion of the revenue and firm volume for RS 22A non-bypass customers in its approved 2016 revenues was misclassified as interruptible. FEI's COSA workshop presented the preliminary COSA results with this misclassification included because FEI had not discovered the error at that time. Since FEI uses firm demand to allocate costs, RS 22A attracted less costs than it would have if the volume was classified appropriately. In addition, FEI includes the interruptible revenue in the numerator for the R:C calculation. These two circumstances resulted in a preliminary R:C ratio for RS 22A of approximately 180% at the time of the COSA workshop. Subsequent to the workshop, FEI recalculated and corrected the classification of the revenue and volume for RS 22A non-bypass customers for COSA purposes. Table 6-2 below identifies the changes to RS 22A revenues and firm volume that have now been made within the COSA model.

Table 6-2: Correction to RS 22A Data in COSA Model

Particulars	2016 Annual Review	Corrected for COSA	Difference
Firm Revenue ($000s)	$4,446	$6,982	$2,536
Interruptible Revenue ($000s)	$3,980	$178	($3,802)
Firm Volume (TJ/Day)	20.483	29.721	9.238

This forecasting misclassification had a small impact on FEI's 2016 delivery rates in that delivery rates were set 0.2% too low. The revenue shortfall in 2016 that FEI will experience from this misclassification will be captured in FEI's Flow-through deferral account. Under FEI's PBR plan, the differences between the forecast and actual revenue accumulate in FEI's Flow-through

[61] Approved as part of FEI's PBR plan in Commission Order G-138-14, dated September 15, 2014.

deferral account[62] and are returned to or collected from non-bypass customers in the following year. FEI currently reviews its Industrial Survey results as part of its Annual Review or Revenue Requirements applications. As part of this review process, FEI is adding a revenue check for its RS 22, RS 22A, and RS 22B customers. The revenue check will ensure both firm and interruptible volumes are classified correctly in FEI's future applications so that revenues are calculated correctly.

6.3.1.4 Revenue Adjustment – BC Hydro

Commencing on November 1, 2016, the BC Hydro IG increased its firm demand from 40 TJ/Day to 45 TJ/Day and its rate increased by $0.10/GJ for firm demand. The adjustments to both revenue and firm demand from these changes are included in the COSA model for a full year.

FEI's contract with BC Hydro for Burrard Thermal expired on November 1, 2016. Consequently, FEI removed the revenue associated with the Burrard Thermal contract from the COSA model. Table 6-3 below details the changes related to BC Hydro IG and Burrard Thermal that have been included in the COSA model.

Table 6-3: Changed to BC Hydro IG and Burrard Thermal in COSA Model

Particulars	2016 Annual Review	Updated in COSA	Difference
BC Hydro IG Firm Revenue ($000s)	$13,097	$15,735	$2,638
BC Hydro IG Firm Volume (TJ/Day)	40	45	5
Burrard Thermal Firm Revenue ($000s)	$8,314	$0	($8,314)

6.3.1.5 Bypass and Large Industrial Contract Customers

Bypass contracts are service agreements included in FEI's tariff supplements related to its rate schedules. Bypass industrial customers are located in close proximity to upstream transmission pipelines and these customers have negotiated with FEI for delivery rates that are based on the customer's estimated cost of constructing and operating its own hypothetical pipeline to bypass FEI's system. With the exception of the specific rate (and rate-related terms and conditions), the terms and conditions of service in bypass contracts generally conform to the standard rate schedule under which the customer would otherwise receive service. All bypass rates are contractual obligations and the rates cannot be changed outside the terms of the contract, and the bypass agreements are approved by the Commission.[63] All of the bypass contracts have provision for O&M and property tax escalation or recovery of actual costs. The Application

62 Ibid.

63 Section 4.2 of the General Terms and Conditions refers to bypass contracts as "exceptional circumstances" where factors such as system by-pass opportunities exist. Factor inputs taken into consideration for negotiating the bypass agreements are: gas volume, capital cost, O&M costs, property taxes, income tax impacts, customers' capital structure and cost of capital, upstream pipeline connection charges. Also refer to BCUC Commissioner Vern Millard report to the LGIC, dated October 22, 1987.

contemplates no change to the rates, terms and conditions applicable to bypass customers which are set through their tariff supplements.

Table 6-4 below provides additional information on the bypass contracts.

Table 6-4: Information on Bypass Customers[64]

	RS 22	RS 22A	RS 25	Other	Total
Customers (#)	2	4	4	1	11
2016 Forecast Volume (TJ)	8,396		851	375	9,622
2016 Forecast Revenue ($000s)	846		435	44	1,325

Large industrial contract customers (referred to as contract customers) are those customers that have historically negotiated their rates with FEI. Contract customers' rates are fixed in their respective transportation service agreements. Contract customers served from the Vancouver Island transmission system include the VIGJV and the BC Hydro IG. All contract customer rates are approved by the Commission.

The COSA model (prior to any rate design proposals in the Application) treats bypass and contract customer revenues as credits to the cost of service and allocates that credit to each sales and non-contract transportation service rate schedule. This approach is consistent with past practice.

However, contract customers and large industrial rate schedules are evaluated in consideration of industrial customer segmentation and rate design in Section 9 of the Application, including specific consideration of the Joint Venture and BC Hydro IG.

6.3.1.6 Biomethane Customers

FEI's biomethane service offering allows customers to allocate a portion of their natural gas as renewable natural gas. Biomethane is a renewable and carbon neutral energy source that reduces GHG emissions when used in place of natural gas. Order G-194-10 approved the underlying biomethane service cost recovery mechanisms that are currently in place. Currently, all biomethane related costs (with the exception of some interconnections)[65] are included in the Biomethane Variance Account (BVA) to be recovered from biomethane customers through the Biomethane Energy Recovery Charge (BERC). Consequently, the only costs that remain in the COSA model for functionalization and allocation are the cost of six interconnections.[66] These interconnections are functionalized as distribution costs and allocated to all customers with access to the biomethane program.

[64] FEI has included Teck Coal (Byron Creek) with bypass customers in its Revenue Requirements. The contract is a Pipeline Agreement which specifies how the 'Actual Annual Service Charge' is determined. The annual service charge is not affected by Commission approved rate changes. As such, it is similar to FEI's bypass contracts.

[65] Commission Letter L-10-14, Response to Request for Clarification, dated February 18, 2014.

[66] Ibid.

6.3.1.7 Natural Gas for Transportation Customers

FEI's NGT program provides incentives to customers for the purchase of CNG or LNG vehicles or the conversion of ferries, locomotives or mine haul trucks. These vehicles in turn create demand for both CNG and LNG. To fuel the CNG/LNG powered vehicles, some customers require access to a fueling station. The rate treatment of the incentives and expenditures was approved for FEI in Order G-161-12 pursuant to Direction No. 5. The costs of FEI's NGT program are included in the delivery charges for all non-bypass customers. The fueling stations FEI has constructed attract CNG and LNG compression services revenue and overhead and marketing (OH&M) cost recovery that is included as Other Revenue and treated as an offset to the cost of service in the COSA model. NGT plant and related costs are included in the natural gas class of service[67] and included in the Distribution function. These costs are classified as part demand related and part customer related and allocated to all customers.

6.3.2 Known and Measurable Changes

In addition to costs from FEI's 2016 test year, the COSA model also includes known and measurable changes for projects expected to be in-service by or soon after January 1, 2018. The rate base cost of service of these known and measurable changes is included in the COSA model and functionalized, classified and allocated with existing costs as required.

With this rate design, FEI is endeavouring to establish rates that will be functional for the foreseeable future. Consequently, FEI has included in the COSA model large projects expected to be in-service or close to their in-service dates at the time that rates from this Application are put in place. Table 6-5 below is a list of these projects and their expected in-service dates.

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[68]

When the above project costs are added into the COSA model, they create an offsetting increase to the test year revenue margin to reflect the recovery of the costs, so that total costs equal total revenues. This treatment is consistent with the impact that these projects will have on customers' rates when they are placed into service and included in FEI's revenue requirement. Each of these projects is described below.

[67] OIC No. 557/2013, Direction No. 5 to the Commission, and Application Section 3.
[68] This represents the cost less the revenue.

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.

6.3.2.2 Coastal Transmission System Project

The three CTS Projects included in the COSA study are the Cape Horn to Coquitlam, Nichol to Port Mann, and Nichol to Roebuck projects. These projects involve the installation of 11 kilometres of transmission pressure pipeline in the City of Surrey and the City of Coquitlam and are intended to increase security of supply by reducing the number of single points of failure. Cost recovery in rates for these projects is authorized by Direction No. 5 to the Commission as amended (OIC No. 557/2013 and OIC No. 749/2014)[69]. The estimated capital cost of the three projects is $170 million including AFUDC, with an expected in-service date of November 2017 and an initial annual cost of service of approximately $14 million. The rate base and cost of service of the CTS Projects is included in the COSA model for allocation.

6.3.2.3 Tilbury Expansion Project

The Tilbury Expansion Project is an expansion to FEI's existing LNG facility located in Delta. The Project includes additional liquefaction of 35 TJ/Day and a 1 BCF LNG storage tank to serve growing LNG demand. The cost recovery of expenditures associated with the Tilbury Expansion Project was authorized by Direction No. 5 to the Commission as amended (OIC No. 557/2013 and OIC No. 749/2014). The Tilbury Expansion Project is expected to be in service in mid-2017. The Tilbury Expansion Project is estimated to cost $400 million plus development costs and AFUDC. The cost of service of the Tilbury Expansion Project is discussed further below.

FEI's general approach for known and measurable changes has been to include in its COSA model the annual cost of service for 2018 for the CTS projects and the annual cost of service for the first year of operations for LMIPSU. For the Tilbury Expansion Project, which is the only project that has associated revenues, FEI adopted a different approach. As described below, FEI used a ten-year levelized margin approach in the COSA model to more accurately reflect the ongoing impact of this project on customers.

[69] Refer to Appendix 2.

FEI expects that the volume of LNG sales from the Tilbury Expansion Project will grow over time to the full capacity of 35 TJ/day of liquefaction and will provide a net benefit to FEI customers over its useful life. To better reflect the medium term impact that the Tilbury Expansion Project will have on FEI's customers, FEI has included the ten-year levelized cost of service and revenues for the Tilbury Expansion Project in the COSA model.

The levelized costs are included in the COSA model and included in the LNG Storage function. The levelized RS 46 revenues are also included in the LNG Storage function. Both costs and revenues are directly allocated to RS 46 with the net difference between the two being allocated back to all other non-bypass customers.

The RS 46 demand forecast (TJ/year) that forms the basis for the ten year levelized revenue is included in Table 6-6 below.

Table 6-6: RS 46 Demand Forecast (TJ)

Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
2,956	5,545	6,021	7,998	8,496	12,242	12,242	12,242	12,242	12,242

6.3.3 Summary of COSA Methods

Table 6-7 below summarizes the methods utilized in the COSA model in this Application and compares those methods to those used in FEI's 2012 COSA model.

Table 6-7: Summary of Changes to COSA Methodologies from 2012

Application Section	Methodology Description	2012 COSA Method	2016 COSA Method	Comments
6.3.4	Functionalization	Eight Functional Categories: Gas Supply, Tilbury Storage, Mt. Hayes Storage, SCP, Distribution, Transmission, Customer Accounting and Marketing.	Seven Functional Categories. Eliminated SCP as a separate function and functionalized with Transmission.	Assets from the insourcing of the Customer Care function and costs embedded in General and Intangible plant are functionalized as Customer Accounting.
6.3.5	Classification	Three Cost Classifiers; Demand, Customer, Energy.	No change from 2012	
6.3.6	Allocations	Customer-related costs allocated based on average and weighted customers. Demand-related costs allocated to rate schedules based on coincident peak demand. Energy-related costs allocated based on sales volume.	No change from 2012 except that RSAM is classified as Energy-related and allocated it based on sales volume to rate schedules that it relates to (RS 1, RS 2, RS3)	The RSAM is in place for RS 1, RS 2 and RS 3 to mitigate revenue instability to both customers and the Utility from non-normal weather.
6.3.5.4	Distribution System Mains Classification	MSS was performed using 60 mm mains.	No change from 2012	

Application Section	Methodology Description	2012 COSA Method	2016 COSA Method	Comments
6.3.5.4	Peak Load Carrying Capacity	Based on capacity determination of a distribution system using 60 mm mains as the minimum.	No change from 2012	
6.3.1.5	Revenues Associated with Bypass and Contract Rates	Revenues treated as a credit to Cost of Service and allocated to all other rate schedules	No change from 2012 (**COSA**)	**Final COSA** results include rate design proposals which have BCH ICP and JV included with other industrials in an industrial rate schedule
6.3.1.3	Revenues Associated with Industrial Customers (RS 22A & RS 22B)	Revenues treated as a credit to Cost of Service and allocated to all other rate schedules	R:C ratios are calculated and included in COSA schedules	Workshop feedback suggested that these rate schedules should be shown within the COSA.

6.3.4 Functionalization

FEI has functionalized its test year revenue requirement into the major categories that reflect the utility's plant investment code of accounts and different services provided to customers. After assigning plant costs functionally, related expenses are also functionalized along the same basis. The results of the functionalization are included in Appendix 6-4, Schedule 2.

6.3.4.1 Functionalization Summary

Table 6-8 below summarizes the results of the delivery cost of service functionalization from the COSA model.

Table 6-8: Delivery Cost of Service Functionalization Summary

Function	($000s)	Percentage of total
Gas Supply Operations	2,004	0.3
Tilbury LNG Storage	36,274	4.6
Mt. Hayes LNG Storage	7,573	1.0
Transmission	171,890	22.0
Distribution	462,883	59.0
Marketing	50,084	6.4
Customer Accounting	52,140	6.7
Total	**782,847**	**100.0**

Each of the functions is described further below.

6.3.4.2 Gas Supply Operations

FEI's Gas Supply Operations function includes costs related to gas control, company use gas and an allocation of general costs and intangible plant costs and expenses.

6.3.4.3 Tilbury LNG Storage

FEI's Tilbury LNG Storage function includes costs related to the operation and maintenance of the facility and an allocation of general and intangible plant costs and expenses.

The existing Tilbury LNG Storage facility was constructed in 1971 and serves as a needle peaking resource to support the CTS's ability to meet customer requirements on extreme cold days. The Tilbury LNG Storage facility also supports transmission and distribution operations during maintenance and repair activities, emergency outages and supply constraints. Since the 1993 Phase B Rate Design, the costs for the Tilbury LNG Storage facility have been allocated to firm sales customers on a peak day demand basis.

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.

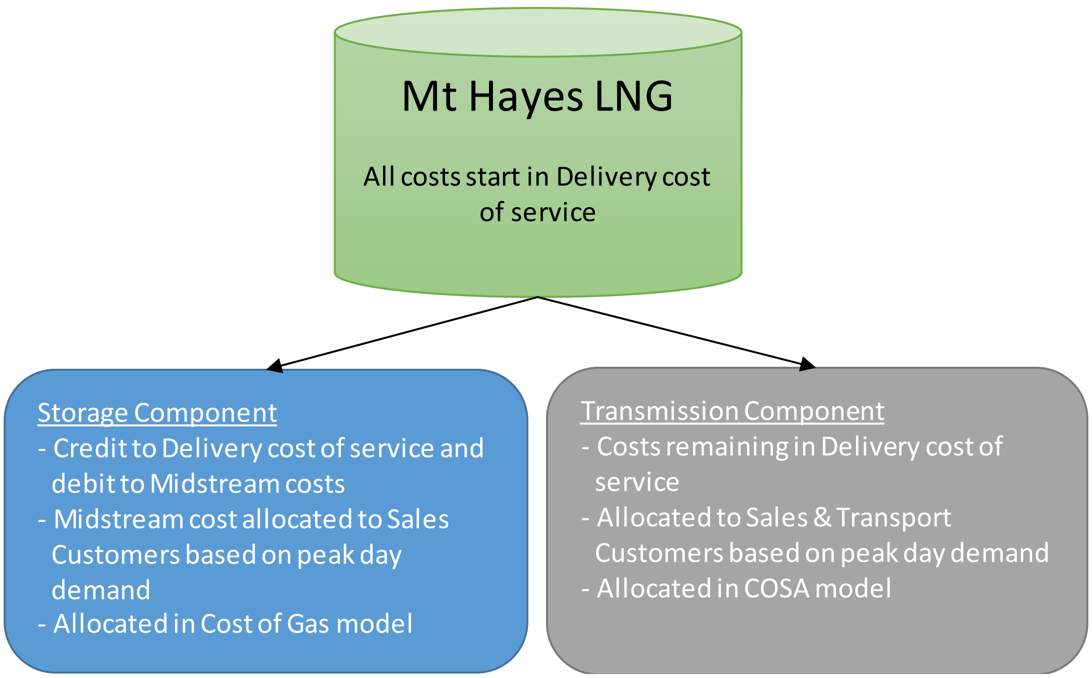
As discussed in Section 6.3.2.3 of the Application, the Tilbury Expansion project is included in the LNG Storage function. However, the allocation approach for Tilbury Expansion does not follow that of the existing storage plant. The Tilbury Expansion costs are directly allocated to RS 46 and offset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

6.3.4.4 Mt. Hayes LNG Storage

Mt. Hayes LNG Storage has a separate function from Tilbury LNG Storage. As this asset serves a different function, it is allocated differently than the Tilbury LNG Storage. Mt. Hayes LNG Storage includes costs related to the operation of the facility and an allocation of general costs and intangible plant costs and expenses. The Mt. Hayes LNG facility went into service in 2011. The Mt. Hayes LNG facility has a dual purpose of serving as (1) a gas supply storage facility and (2) a transmission facility which provides additional transmission system capacity to serve customers in the same fashion that pipeline looping and compression provide such capacity. The estimated avoided cost of third party storage and transportation that is credited to Other Revenue and reclassified to FEI's midstream costs is approximately $18 million per year. FEI has updated the calculation of this amount, and included this information in Appendix 6-11 Avoided Storage Cost Calculation. The cost of the Mt. Hayes LNG facility (net of the midstream value of approximately $18 million) is allocated to all sales and transport customers on a peak day demand basis.

In this manner, all sales customers receive an allocation of the Mt. Hayes facility through the midstream charge and the transmission delivery component of the cost of service through their delivery charge. Transportation customers receive an allocation through the transmission delivery component through their delivery charge as well. Figure 6-3 below depicts how Mt. Hayes LNG facility costs are split between delivery and midstream charges and the allocation method of each.

Figure 6-3: Mt. Hayes Storage and Transmission Costs



In Stakeholder Workshop 1, FEI discussed two options for the cost treatment for Mt. Hayes and its allocation within the COSA model. Option A is to continue to separate Mt. Hayes into its storage and transmission components as was discussed in the 2007 TGVI Mt. Hayes LNG Storage Application, FEVI's 2010-2011 Revenue Requirements and Rate Design Application, and FEI's 2012 Amalgamation Application. Option B is consistent with the Tilbury cost allocation, whereby all Mt. Hayes costs are allocated to delivery, consistent with the Tilbury cost allocation. Option B was also described in FEI's 2012 Common Rates, Amalgamation and Rate Design Application. Option B has the benefit of being more straightforward and would recognize the system capacity and reliability benefits all customers receive as a result of Mt. Hayes being part of the integrated transmission system.

The two cost allocation options are included in Table 6-9 below, including how costs are allocated to sales and transportation customers under both options through delivery margin and midstream costs.

Table 6-9: Comparison of Mt. Hayes Cost Allocation Approaches Allocated between Delivery Margin and Storage & Transport ($000s)

Allocation Methodology		SALES			TRANSPORT		Grand Total
		Del Margin	Midstream	Total	Del Margin	Total	
Allocate Mt Hayes storage costs to Midstream costs and Delivery margin	**Option A**	$ 6,583	$ 18,039	**$ 24,622 96.5%**	$ 886	**$ 886 3.5%**	**$ 25,508**
Allocate Mt Hayes storage costs to Delivery margin	**Option B**	$ 22,481		**$ 22,481 88.1%**	$ 3,027	**$ 3,027 11.9%**	**$ 25,508**

In the near term, Mt. Hayes is expected to provide a small amount of LNG for the NGT market. Over the next four years, FEI expects to serve two customers from the facility - Bridgeway and BC Ferries. As requested at the stakeholder workshop, Table 6-10 below presents the forecast LNG demand volume to serve these two customers that will be supplied from Mt. Hayes.

Table 6-10: RS 46 Demand Forecast Served by Mt. Hayes (TJ)

2016	2017	2018	2019
20	100	100	100

Option A continues to most closely represent how FEI utilizes Mt. Hayes as both a storage and transmission resource. As described above, in addition to being used as a gas supply storage facility, Mt. Hayes provides transmission system capacity to serve customers in the same fashion that pipeline looping and compression provide such capacity. Consequently, in the COSA model, FEI reclassified a portion of Mt. Hayes costs to FEI's Midstream portfolio.

6.3.4.5 Transmission

FEI's Transmission function includes costs related to the transmission pipe assets, compression, right of way and related maintenance, measurement control operations, and transmission supervision. It also includes an allocation of general and intangible plant costs and expenses. SCP costs are also included in the transmission function as discussed below.

The SCP was constructed and put into service in December 2000 and is owned and operated as an integral part of FEI's transmission system to meet the requirements of its customers. It is also used to provide third party transportation services. The SCP project was approved by the Commission in 1999 as the best option to meet future requirements of FEI's customers by providing reinforcement of the Interior Transmission System, a flexible peaking resource, greater diversity of supply by providing access to Alberta markets, and other operating benefits. The SCP assets are transmission pipeline assets and the cost of service of is included in FEI's overall cost of service. The value of the third party transportation agreements is credited against the delivery cost of service. In November 2005, one of the third party customers holding transportation capacity on SCP released its capacity. At that time, FEI considered the best option was to include this capacity in its midstream portfolio as part of its ACP. As a result, FEI Midstream effectively contracts for its capacity and the value of this is credited against the cost of service in the same manner as other third party contracts. The value of SCP costs included in the midstream portfolio is reviewed and approved by the Commission. The SCP cost of service is included in the Transmission function and the costs are allocated to all sales and transport customers based on the peak day demand.

6.3.4.6 Distribution

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

6.3.4.7 Marketing

FEI's Marketing function includes costs related to energy solutions, energy efficiency operating costs and amortization, resource planning and market development, and external relations. This function also includes an allocation of general costs and intangible plant costs and expenses.

6.3.4.8 Customer Accounting

FEI's Customer Accounting function includes costs related to administering FEI's customers including computer hardware and software, leasehold improvements, furniture, equipment and structures, customer billing, customer assistance, credit and collections, customer service supervision and an allocation of general costs and intangible plant costs and expenses. The related expenses follow the same functionalization.

6.3.5 Classification

Having functionalized the costs, the COSA study then classifies the functionalized costs into cost-causation categories as described above in Section 6.2.1.2. These cost causation categories are system demand, energy delivery and number of customers. A discussion on the classification of plant costs and related expenses for each of the functionalization categories follows.

6.3.5.1 Gas Supply Operations

As shown in the above Table 6-7, very few delivery costs are allocated to Gas Supply Operations. The delivery costs that are functionalized as Gas Supply are classified as Energy related as these costs vary by the volumes of gas delivered to our customers. The classification and allocation of gas costs are discussed in Section 6.4 below.

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 consistently classified as demand-related in each of those proceedings. FEI has maintained this classification approach in this Application. The Tilbury Expansion included in the Tilbury function is allocated entirely to RS 46. Consistent with historical treatment, the Mt. Hayes storage facility is being classified as Demand.

6.3.5.3 Transmission

Consistent with the 2001 and 2012 COSA study, the FEI Transmission functions are classified as 100% demand-related, since system capacity requirements are driven by the peak demand of each customer group.

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.

The MSS examines the various mains in place at the utility and separates the mains by pipe diameter and material (steel or polyethylene). Length of pipe installed and unit costs per length are then allocated to each pipe diameter to determine the actual total cost per pipe diameter for the entire distribution system. To determine how costs should be split between demand and customer related components, the costs of the minimum system must be compared to the costs of the overall distribution system. To do so, the MSS assumes that the actual pipe diameters could be replaced with only those pipe diameters that comprise the minimum distribution system (i.e., all pipe diameters equal to or less than 60 mm[73]). This approach multiplies, for each size of distribution main, the length of the main by the average replacement cost of polyethylene (PE) mains up to 60 mm. The sum of these results is divided by the sum of FEI's mains multiplied by the average replacement cost of mains at their existing diameters. The resulting percentage is considered the customer-related component of FEI's distribution mains and the remaining percentage is considered the demand-related component. The percentage results are then used

[70] Accepted by the Commission in Order G-156-10 (Section 2.7), dated October 19, 2010.
[71] Commission Order G-21-14, dated February 26, 2014.
[72] Refer to Appendix 6-1: EES Natural Gas Cost of Service Review, page 18.
[73] Sizing of Distribution Pipe – Mains and Services standard, Appendix 6-6.

to classify the distribution system costs into customer-related and demand-related components. This is an important cost allocation step due to the significant size of the distribution system costs.

The MSS results allocate 30% of the distribution system costs to the customer-related component and 70% to the demand-related component. The results are presented in Appendix 6-5.

Peak Load Carrying Capacity Adjustment

The MSS determines the minimum distribution system required to connect customers. In theory, a minimum system exists only to connect customers and not to deliver gas. However, since the MSS uses 60 mm PE as the minimum, it has a load carrying capacity. The PLCC adjustment is derived by dividing the capacity of the minimum sized distribution system by the number of customers served by the distribution system. This PLCC adjustment is then multiplied by the number of customers in each rate class, and the corresponding amount was subtracted from the peak demand for that rate class.

The PLCC adjustment for this Application was determined to be 0.205GJ/Day/customer.[74] When the adjustment is applied along with the Minimum System approach, the results more closely match the theoretical customer-related component of the distribution system. EES Consulting has reviewed the PLCC adjustment to the Minimum System and confirms that it is appropriate for FEI.

6.3.5.5 Marketing and Customer Accounting

The Marketing and Customer Accounting functions are generally classified as customer-related. This methodology is consistent with past practice and is appropriate as the underlying cost causation for these functions is directly related to the customers served under each rate schedule and not based on their volumetric usage or demand. One exception is DSM funding which is classified as energy-related since DSM programs reduce overall throughput via energy conservation. For the purposes of allocating costs to each customer class, FEI developed separate customer weighting factors for customer administration and billing, described further in Section 6.3.6.1, which are appropriate for this rate design.

6.3.5.6 Classification Summary

The following table summarizes the results of the delivery cost of service classification from the COSA model, details of which can be found on Schedule 4 of Appendix 6-4.

[74] Appendix 6-5.

Table 6-11: Delivery Cost of Service Classification Summary

Classification	$000s	Percentage of total
Energy	11,830	1.5
Demand	392,539	50.1
Customer	378,478	48.3
Total	**782,847**	**100.0**

6.3.6 Allocation

Once the functionalized costs have been classified into energy, demand and customer related components, these costs must then be allocated to each of the rate schedules based on an appropriate allocator. FEI has, for the most part, allocated these cost components to its rate schedules based on approaches consistent with past practices.

FEI allocates costs in the COSA model on the basis of:

- Demand (Peak Day)
- Customers (Weighted)
- Energy (Load)

Each of these allocators is discussed separately in the sections below.

Certain information is required to complete the allocations, specifically number of customers and demand. The following table shows the number of customers and annual demand in TJ for each rate schedule from FEI's 2016 test year.

Table 6-12: Customers and Annual Demand (TJ) by Rate Schedule

Rate Schedule	Customers (#)	Annual Demand (TJ)
1	886,652	72,466
2	84,737	28,012
3	5,040	18,121
23	1,669	8,969
4	18	130
5	230	2,173
25	566	13,490
6	15	47
7	5	155
27	108	6,536

Rate Schedule	Customers (#)	Annual Demand (TJ)
22	26	13,189
22A	9	9,030
22B	5	5,277
Total	**979,080**	**177,595**

As described in Section 6.3.1.5, revenue from bypass and contract customers has been treated as a credit to the cost of service and allocated to other rate schedules in the COSA model. Consequently, these rate schedules are not allocated any costs in the COSA model. However, for completeness, FEI has included the 2016 test year data from these customers in Table 6-12 below.

Table 6-13: Customers and Annual Demand (TJ) for Bypass and Contract Customers

Rate Schedule	Delivery Margin ($000s)	Customers (#)	Annual Demand (TJ)
22 Bypass	721	6	8,396
25 Bypass	422	4	851
Joint Venture[75]	4,572	1	4,758
BC Hydro IG	15,735	1	16,425
Total	**24,526**	**25**	**31,099**

In addition to the revenue from bypass and contract customers that has been treated as a credit to the cost of service in the COSA, FEI has also treated the revenue from RS 46 as a credit to the cost of service in the COSA. Rate Schedule 46 delivery margin, customers and annual demand equals $3,076 thousand, 13 and 669 TJ respectively. Demand (Peak Day)

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

The customer load from FEI's test year is adjusted by the load factor of each rate schedule to estimate the peak day demand. FEI allocates demand related costs based upon the rate schedule's contribution to the system peak. The peak demand is estimated using the method described below.

[75] The Joint Venture is comprised of five operations that act as one for billing and demand balancing.

The peak day (coldest day) temperature varies across FEI's service regions. To develop a peak day demand that is representative of the entire utility, FEI uses regional temperature data to calculate the peak day demand.

Independent calculations are completed for these regions:

- Lower Mainland
- Inland
- Columbia
- Vancouver Island
- Whistler

Independent calculations are completed for these rate schedules:

- RS 1 – Residential
- RS 2 – Small Commercial
- RS 3 – Large Commercial
- RS 23 – Large Commercial Transportation
- RS 5 – General Firm Large Volume
- RS 25 – General Firm Transportation Large Volume

The load factors for the heat sensitive rate schedules (RS 1, RS 2, RS 3/RS 23) and RS 5/RS 25 are calculated using a four step linear regression method for each region and rate schedule separately, as illustrated below.

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.

i. The Average Daily Consumption is the normalized[78] annual actual use per customer (UPC) divided by 365 days/year.

d. RS 5/RS 25:

i. The Actual Average Daily Consumption is used.

3. Calculate the **Load Factor** for each region and rate schedule:

Load Factor = Average Daily Consumption / Peak Day Demand

4. Calculate the **Three-Year Average Load Factor** for each region and rate schedule.

FEI calculates annual load factors by region, by rate schedule as described above. Subsequently, FEI then produces an annual weighted average load factor for each rate schedule by using the number of customers in each region to weight the load factors from those regions. Finally, FEI completes this process for three years and then averages them.

Lastly, the three-year average load factor from the four-step approach above is applied to the annual volume in the COSA model to create a coincident peak day demand, which is used to allocate demand-related costs among rate schedules.

The following calculation demonstrates how FEI uses the three-year average load factor by rate schedule to derive the Load Factor Adjusted Annual Volume (or coincident peak day demand) for the heat sensitive rate schedules in the COSA model.

Peak Day Demand = Annual Consumption / (LF x 365)

FEI notes that it would not be appropriate to calculate its peak day demand as the sum of all the peak-day demands by rate schedule and region from step 1 (b) above. This is because the data used in the multi-step process above uses normalized actuals from single years, and the data in the COSA model is based on a test (forecast) year. For this reason, unless the number of customers and consumption in the test year is equal to the normalized actuals, there will be a disconnect between the peak demand allocator and underlying costs being allocated. Also, as described above, there can be data in any individual year that could skew results[79]. For this reason, a three-year average is used. It would not be useful to average the sum of all the peak day demands by rate schedule and region from step 1 (b) when the underlying number of customers and demand changes from year to year.

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

[78] FEI normalizes demand using a 10 year average temperature.

[79] For example, new customers and disconnecting customers that do not have a full 365 days of consumption in any particular year could skew the Average over Peak ratio.

In addition to these firm heat sensitive rate schedules, FEI must also serve other customers to whom it provides firm service. RS 22, RS 22A[80] and RS 22B have contractual firm commitments under which FEI must deliver firm quantity. The sum of the heat sensitive rate schedules' peak day plus the firm contractual commitments is equal to FEI's total peak day demand. This is the load that the System must be able to deliver on the peak (coldest) day. The load factors including peak day and firm delivery volumes used in the COSA are shown below in Table 6-14.

Table 6-14: Load Factors Peak Day and Firm Demand by Rate Schedule[81]

Rate Schedule	Load Factor	Peak Day or Firm Demand (TJ/Day)
1	31.2%	635.5
2	31.1%	247.0
3	37.1%	134.0
4	n/a	0.0
23	36.9%	66.6
5	45.2%	13.2
25	55.5%	66.6
6	100.0%	0.1
22	n/a	2.0
22A	n/a	29.7
22B	n/a	11.5
7	n/a	0.0
27	n/a	0.0
Total		**1,213.1**

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

80 Rate Schedule 22A can be curtailed for 5 ½ days per year.

81 Table excludes BC Hydro Island Generation and Vancouver Island Joint Venture which have a combined 58 TJ/Day of firm demand.

administer. For the purposes of this analysis, weighting factors were calculated for each rate schedule relative to the residential rate schedule.[82]

Two types of weighting factors were developed to allocate customer costs:

- Weighting Factor for Administration and Billing; and
- Weighting Factor for Meters and Services.

Table 6-15 below shows the results for each rate schedule based on these two weighting factors.

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

6.3.6.1.1 WEIGHTING FACTOR FOR ADMINISTRATION AND BILLING

Large customers generally require a greater level of administrative effort or customer service than the average residential customer. As such, customer weighting factors are required to properly allocate customer administration, marketing and billing related costs to the various rate schedules.

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;

[82] FEI's residential rate schedule (RS 1) is used as the base upon which to weight other rate schedules because it is the least costly rate schedule to connect and administer. For this reason the Weighting Study shows the residential rate schedule with a factor of 1.0.

- 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.

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.

6.3.6.2 Energy

Within the delivery cost COSA model, there is $12 million of costs that have been classified as Energy-related. These costs include Own Use Gas, Gas Control Operations, amortization of DSM deferral and infrastructure costs. These costs have been allocated using the energy delivered by rate schedule which is provided in Table 6-11 above.

6.3.7 Summary of Cost Allocation

The following table summarizes the results of the delivery cost of service allocation to rate schedules from the COSA model.[84]

[83] Ibid.

[84] Further detail of the allocation results can be found in Appendix 6-4, Schedule 4.

Table 6-16: Delivery Cost of Service Allocation to Rate Schedules

Rate Schedule	($000s)	Percentage of total
1	510,654	65.2%
2	129,861	16.6%
3/23	95,247	12.2%
4	51	0.0%
5/25	35,111	4.5%
6	151	0.0%
7/27	1,540	0.2%
22	806	0.1%
22A	6,824	0.9%
22B	2,602	0.3%
Total	**782,847**	**100.0%**

6.4 *GAS COST ALLOCATION*

FEI has allocated its gas costs consistent with past practice, other than one adjustment to the load factor for RS 5 customers.

FEI's commodity costs and storage and transport costs are allocated to sales customers. Sales customers are also referred to as the "Core Market", being those customers that purchase their commodity from either FEI directly or from marketers under the Customer Choice Program. Transportation customers do not pay commodity or storage and transport charges.

Although there have been changes to the gas supply portfolio over the last 25 years, the gas cost allocation method remains largely consistent with what was approved in the 1991 Phase A Rate Design. FEI has maintained this cost allocation approach, but is proposing to change the load factor adjustment for RS 5 customers from 50% as previously approved by the Commission[85] to the three year average load factor for RS 5.

In the following sections, FEI describes the nature of its gas costs, including the distinction between commodity costs and storage and transport (midstream) costs. FEI then describes its allocation approach for gas costs and discusses the proposed change to the load factor adjustment for RS 5 customers.

6.4.1 Gas Costs

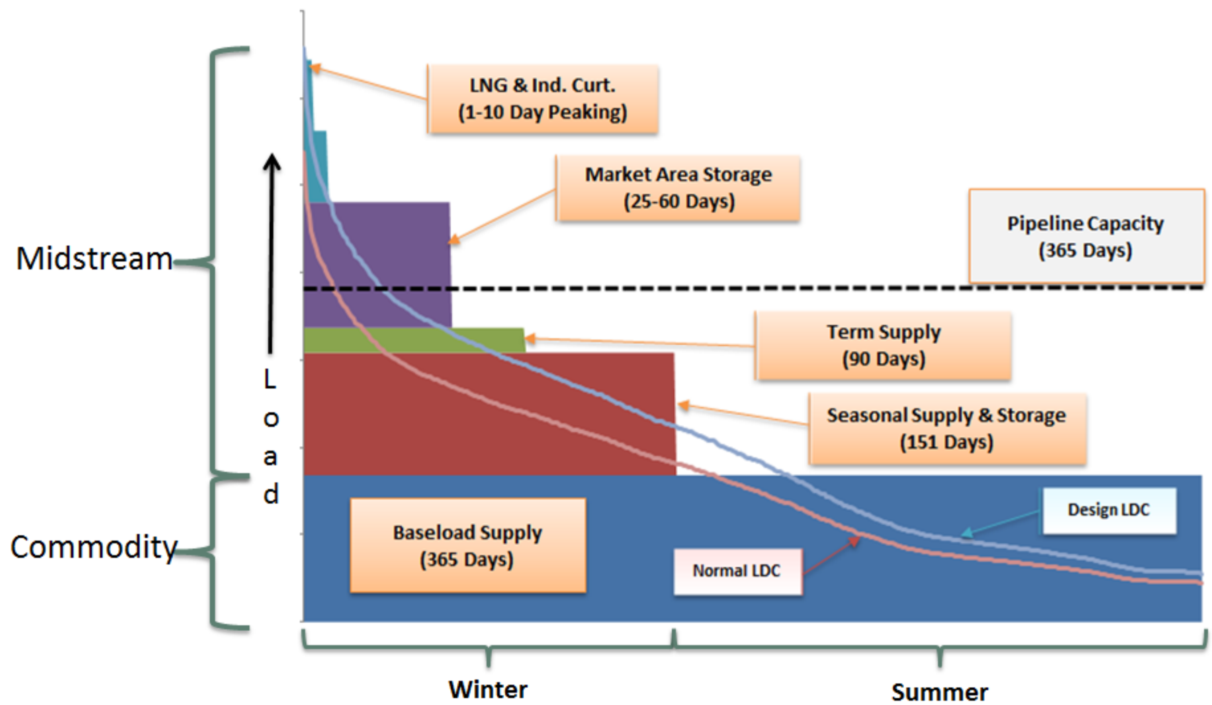
FEI incurs gas costs on behalf of all core market customers to meet peak customer demand. FEI's gas costs are separated into commodity and storage and transport costs, which

[85] 1996 Rate Design Application Negotiated Settlement Agreement, dated September 29, 1996, which the Commission approved as part of Commission Order G-98-96, dated October 7, 1996.

correspond to two of the components on a customer's bill. Commodity costs correspond to the Cost of Gas component of a customer's bill (also called the Commodity Cost Recovery Charge within the gas tariffs, or more simply referred to as the commodity charge). The storage and transport costs correspond to the Storage & Transport component of a customer's bill.

FEI's gas costs are illustrated below in Figure 6-4, which shows how FEI's gas resources are used according to FEI system demand throughout the year. For example, the commodity portion of gas costs comes from the base load supply of gas throughout the year. The storage and transport portion of gas costs comes from the purchase of seasonal gas, term gas, market area storage and LNG peaking resources.

Figure 6-4: Gas Supply Resources



The following sections describe in more detail what is included in the commodity and storage and transport costs.

6.4.1.1 Commodity

Commodity costs consist of market priced annual baseload gas purchased by FEI and flowed through in rates without mark-up. The Cost of Gas charge is variable and is reviewed quarterly by the Commission and adjusted, if required.

6.4.1.2 Storage and Transport

Storage and transport costs are mainly for resources contracted by FEI to facilitate the flow of gas into FEI's service territory so that the demand of the sales customers can be served and the pipeline system stays in balance on a daily basis. Storage and transport resources are used to balance FEI's entire gas distribution system by either supplementing it with gas supply when demand is greater than planned or removing excess gas supply out of the system when the demand is lower than planned. The resources that FEI has in place are to meet design day and design year conditions, and are secured in an open and competitive marketplace.

As illustrated above in Figure 6-4, the storage and transport costs include:

- Storage contracts and transportation capacity on external pipelines that deliver gas to FEI's various interconnecting points from the market hubs and contracted gas storage facilities.
- Winter seasonal gas supply purchased by FEI that may be required to support higher than normal load requirements of core customers.
- Allocation of costs for company-owned assets, such as the SCP described in Section 6.3.4.5 and the Mt. Hayes LNG facility described in Section 6.3.4.4.

Although storage and transport charges are only charged to sales customers, the resources are utilized each day to balance the system as a whole, which benefits both sales and transportation customers.

6.4.2 Allocation Approach

The current gas cost allocation methodology includes:

1. classifying the commodity costs as energy-related and allocating those costs to sales customers based on throughput; and
2. classifying the storage and transport costs as demand-related and allocated on a load factor adjusted volumetric basis.

The storage and transport costs are allocated to sales customers using a three-year rolling average load factor as discussed in Section 6.3.6, such that the basis of the allocation of the storage and transport costs is the load factor adjusted volumes (i.e., the peak day volume).

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

An exception to the rolling three-year average load factor is for General Firm Sales Service customers (RS 5), whose load factor was set at 50% in the 1996 Rate Design Application

Negotiated Settlement Agreement, dated September 29, 1996, which the Commission approved as part of Commission Order G-98-96.

FEI is proposing to adjust the load factor adjustment for RS 5 customers to use RS 5's three-year average load factor as discussed further below.

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]

---

[86] RS 5 load factor after rate design proposals as discussed in Section 9.
[87] Commission Order G-188-15, dated December 3, 2015.

Table 6-17: RS 5 Load Factor for Midstream Cost Allocation

Line	Particulars		Reference	Total	RATE 1	RATE 2	RATE 3	RATE 4	RATE 5	RATE 6	RATE 7
1	Midstream Purchased Volumes for Sales Customers	TJ	2015 Q4 Volume Projection for 2016	121,621	73,116	28,112	18,164		2,186	44	
2	Load Factor	%	2012 - 2014 Avg Load Factor		30.5%	30.1%	36.2%		50.0% [1]	100.0%	
3	Peak Demand [2]	TJ/day	Line 1 / (365 x Line 2)	1,062.9	657.2	256.2	137.4		12.0	0.1	
4	Percent	%	Line 3 / Total of Line3		61.8%	24.1%	12.9%		1.1%	0.0%	
5	Midstream Costs	($000's)	Line 4 x Total of Line 5	$ 131,348	$ 81,213	$ 31,665	$ 16,975		$ 1,480	$ 15	
6	Midstream Sales Volumes	TJ	2015 Q4 Volume Projection for 2016		72,679	27,944	18,056		2,172	44	
7	**Midstream Cost Recovery Charges [3]**	($/GJ)	Line 5 / Line 6		**$ 1.117**	**$ 1.133**	**$ 0.940**	**$ 0.681**	**$ 0.681**	**$ 0.341**	**$ 0.681**

[1] Deemed 50%

[2] RS 4 and RS 7 are both interruptible in winter therefore have a zero TJ/Day peak demand

[3] RS 4 and RS 7 assume RS 5's midstream costs

RS 5 @ calculated 44.8%

Line	Particulars		Reference	Total	RATE 1	RATE 2	RATE 3	RATE 4	RATE 5	RATE 6	RATE 7
1	Midstream Purchased Volumes for Sales Customers	TJ	2015 Q4 Volume Projection for 2016	121,621	73,116	28,112	18,164		2,186	44	
2	Load Factor	%	2012 - 2014 Avg Load Factor		30.5%	30.1%	36.2%		45.0% [1]	100.0%	
3	Peak Demand [2]	TJ/day	Line 1 / (365 x Line 2)	1,064.2	657.2	256.2	137.4		13.3	0.1	
4	Percent	%	Line 3 / Total of Line3		61.8%	24.1%	12.9%		1.3%	0.0%	
5	Midstream Costs	($000's)	Line 4 x Total of Line 5	$ 131,348	$ 81,111	$ 31,625	$ 16,954		$ 1,643	$ 15	
6	Midstream Sales Volumes	TJ	2015 Q4 Volume Projection for 2016		72,679	27,944	18,056		2,172	44	
7	**Midstream Cost Recovery Charges [3]**	($/GJ)	Line 5 / Line 6		**$ 1.116**	**$ 1.132**	**$ 0.939**	**$ 0.756**	**$ 0.756**	**$ 0.340**	**$ 0.756**

[1] Calculated 45%

[2] RS 4 and RS 7 are both interruptible in winter therefore have a zero TJ/Day peak demand

[3] RS 4 and RS 7 assume RS 5's midstream costs

The change in the allocation method for midstream costs will increase an average RS 5 customer's annual bill by 1.0%, RS 4 by 1.3%, and RS 7 by 1.5%. RS 1, RS 2, and RS 3 will also experience very small decreases to the Storage & Transport charge as RS 5 attracts some of the costs that would otherwise have been allocated to those rate schedules.

6.5 *R:C AND MARGIN TO COST RATIOS*

The COSA study is one of the primary tools used to establish cost guidelines for the evaluation of rate schedule revenue levels through the R:C ratios. The R:C ratios show whether the rates charged to each rate schedule adequately recover their allocated cost of service. For FEI's transportation rate schedules that have companion sales rate schedules (RS 23, RS 25 and RS 27) FEI imputes a cost of gas so that when the R:C ratios are calculated the final R:C ratio is on the same basis (delivery margin plus cost of gas) as for the sales rate schedules[88].

[88] Commission Order G-42-91, dated May 23, 1991, page 3. RS 23, RS 25 and RS 27 are transportation options for RS 3, RS 5 and RS 7 respectively. Since allocated cost for RS 3, RS 5 and RS 7 includes cost of gas, a cost of

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". Order G-4-18 directed FEI to use a range of reasonableness of 95 percent to 105 percent for purposes of informing rate design and rebalancing proposals. 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.

The result of the COSA study for each rate schedule is considered in light of this range of reasonableness and each rate schedule that falls within that range is deemed to be recovering its fair cost. If a rate schedule falls out of the range of reasonableness, this indicates that revenues are either insufficient in covering the cost of service or exceed the cost of service, which suggests that rate rebalancing may be in order. The "range of reasonableness" is therefore used as an indication of the rate schedules that require re-balancing. Even if all of the rate schedules fall within the range of reasonableness, some re-balancing may be necessary in light of rate schedule characteristics and rate design objectives.

The appropriate range of reasonableness will depend on the particular circumstances of a public utility. Recent Commission decisions regarding the range of reasonableness suggest that a range of reasonableness of 95 per cent to 105 per cent is appropriate for electric utilities in British Columbia. Specifically:

- 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

gas is imputed for RS 23, RS 25 and RS 27 to ensure consistency and to show R:C ratios on combined basis for RS 3/RS 23, RS 5/RS 25 and RS 7/RS 27.

89 Commission Decision and Order G-130-07, dated October 26, 2007, page 71.

90 Ibid.

91 Ibid.

92 Commission Decision and Order G-156-10, dated October 19, 2010, page 77.

schedule to be one, with future rebalancing necessary only when customer classes fell outside the range. The Commission also accepted FBC's position that the "range of reasonableness" is "based not only on the accuracy of its data, but also on policy considerations such as the Commission's prior decision regarding the range of reasonableness for BC Hydro."

Although there are precedents for a range of reasonableness of 95 per cent to 105 per cent in the case of BC electric utilities, FEI believes that this range is not appropriate for natural gas utilities. In the case of BC electric utilities, there is relative certainty in load research analysis that exists from known hourly system demand and demand metering data for large commercial and industrial customers with respect to the coincident peak demand calculation. The equivalent level of certainty does not exist for natural gas utilities because:

- The equivalent load research analysis for natural gas utilities does not draw from hourly system demand data but rather from daily system demand data.
- The load research analysis employed by natural gas utilities is based on peak days that reflect extreme weather planning conditions since natural gas demand is largely driven by temperature. This further diminishes the certainty of natural gas forecast loads compared to those produced by electric utilities that use actual or forecast loads under normal weather conditions. Since peak day loads are fundamental to cost allocations for natural gas utilities, greater data uncertainty with respect to peak day loads result in greater uncertainties in COSA results.

For these reasons, natural gas utilities have relatively less certain system demand data compared to those used for electric utilities.

Prior Commission decisions specific to natural gas also support a wider range of reasonableness. For natural gas utilities, the long standing precedent for the range of reasonableness for the R:C ratio has been 90 per cent to 110 per cent. In Commission Order G-42-91 that ruled on Ocelot Chemical's application seeking reconsideration of the Commission's ruling on Pacific Northern Gas' 1991 Rate Design Application (Order G-23-91), the Commission recognized the subjectivity inherent in cost allocation:

> The Commission is also cognizant of the considerable reliance upon judgement involved in the undertaking of a cost of service study. Although judgement is required in lesser amounts to determine the specific component of the total cost of service and functionalization of costs, significant judgement is required to classify costs between capacity, commodity and customer components. Even greater judgement is required in determining the appropriate method to allocate these costs amongst rate schedules. For example...different classes of customers impose different levels of risk on the utility, but quantifying the appropriate cost differential is not attempted in these studies. Finally, there are benefits attributable to serving certain classes of customers but these, too, have

not been included as an offset against costs within the study as they are not easily quantified.[93]

This reliance on judgment led the Commission to conclude:

> Given the imprecision inherent in cost of service studies in general, and in particular the studies in issue, the Commission believes that as long as revenues from a particular class of service and costs allocated to that class of service do not differ by more than 10%, there is no compelling evidence to determine that the cost of service results indicate rate restructuring is required.[94]

The Commission also accepted, as a guide to rate setting, a range of reasonableness of 90 per cent to 110 per cent in the FEI (formerly BC Gas) 1993 Phase B Rate Design.[95] The same range of reasonableness was used in the BC Gas 1996 Rate Design[96] and in the FEI (formerly Terasen Gas Inc.) 2001 Rate Design[97] and in FEI's 2012 Amalgamation Application

As directed by Order G-4-18, FEI is using a R:C ratio range of reasonableness of 95% to 105%.

6.5.2 R:C Ratios – The COSA Results

This section provides the R:C ratios and margin to cost ratios for each of the rate schedules based on the results of the COSA Study. The margin to cost ratio is calculated by dividing the total delivery margin collected from a rate schedule which includes Basic Charge, demand charge, volumetric Delivery Charge and administrative charge revenues, by the allocated embedded delivery costs. Gas and storage and transport costs are excluded from both the numerator and denominator when calculating the M:C ratios.

The results shown below in Table 6-18 represent FEI's COSA model prior to rate design and rebalancing proposals. These results help inform FEI's rate design proposals described in Sections 7 through 9 of this Application. The final COSA results including all rate design and rebalancing proposals are included in Section 12.

93 Commission Decision and Order G-42-91, dated May 23, 1991, page. 29.
94 Ibid.
95 Commission Decision and Order G-101-93, dated October 25, 1993, page12: "In previous decisions the Commission has accepted a 10% band as reasonable."
96 Commission Order G-98-96, dated October 7, 1996.
97 Commission Order G-116-01, dated October 3, 2001.

Order G-4-18 Updates, February 6, 2018

Table 6-18: R:C and M:C Ratio Results before Rate Design Proposals or Rebalancing[98]

Rate Schedule	R:C	M:C
Rate Schedule 1 *Residential Service*	95.6%	93.1%
Rate Schedule 2 *Small Commercial Service*	101.3%	102.5%
Rate Schedule 3/23 *Large Commercial Sales and Transportation Service*	101.6%	103.3%
Rate Schedule 5/25 *General Firm Sales and Transportation Service*	104.9%	112.2%
Rate Schedule 6 *Natural Gas Vehicle Service*	131.2%	159.1%
Rate Schedule 22A *Transportation Service (Closed) Inland Service Area*	109.5%	109.8%
Rate Schedule 22B *Transportation Service (Closed) Columbia Service Area*	99.7%	99.7%

Except for RS 6 and RS 22A, the R:C ratios are all within a range of 95% to 105%, and the margin to cost ratios are generally within the 90% to 110% range. This indicates that the revenue collected from each rate schedule is closely aligned with the costs caused by that rate schedule. This supports the principle of matching revenues and the related costs. In Section 5.3, this is the second rate design principle "Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates)". The general clustering of the R:C and margin to cost results within or close to the 95% to 105% range also suggests that the current rate design aligns well with the eighth rate design principle listed in Section 5.3 "Avoidance of undue discrimination (interclass equity must be enhanced and maintained)". FEI has been consistent in its cost allocation approach and as evidenced by the results in Table 6-17, the rates in place fairly collect each rate schedule's allocated costs.

FEI has excluded RS 4, RS 22, and RS 7/RS 27 from Table 6-17 above because Rate Schedule 4 is a seasonal service (firm in the summer and interruptible in the winter), RS 22 is predominantly interruptible[99] and RS 7/RS 27 is fully interruptible. These rates do not drive system capacity additions,[100] and consequently are not allocated any demand-related costs. The charges within these rate schedules are not set using their allocated costs from the COSA model. Nevertheless, FEI has calculated the ratios for these rate schedules, which are shown in Table 6-19 below.

[98] Refer to Appendix 6-4 which shows the COSA schedules using the 2016 test year. FEI has also included Appendix 6-9 which shows 2013 Test Year COSA Financial Schedules from the 2012 Amalgamation Application. These schedules assume that the former Mainland, Vancouver Island, Whistler and Fort Nelson service areas had all amalgamated.

[99] One RS 22 customer has 2 TJ per day of firm. All other RS 22 customers have no firm demand. Under RS 22, customers can negotiate a firm service level and rate that is subject to Commission approval.

[100] RS 4 is winter interruptible, which is when FEI's system peaks.

Order G-4-18 Updates, February 6, 2018

Table 6-19: R:C & M:C Ratio Results for Rate Schedules Not Set Using COSA allocations[101]

Rate Schedule	R:C	M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	147.4%	550.9%
Rate Schedule 7/27 *General Interruptible Sales and Transportation Service*	139.6%	712.3%
Rate Schedule 22 *Large Volume Transportation Service*	1425.5%	1864.4%

6.6 *STAKEHOLDER FEEDBACK RECEIVED*

As discussed in Section 4, FEI circulated a COSA Discussion Guide to all interested stakeholders and held a workshop on June 27, 2016. This Guide and Workshop described FEI's COSA analysis and presented a number of options that FEI was considering. The relevant stakeholder feedback is summarized below, with the detailed Meeting Summary and Notes attached in Appendix 4-2 to the Application.

Table 6-20: Summary of Outstanding Workshop Items

Item	Reference
Show R:C table when DSM costs are classified as Energy related	FEI has classified DSM costs as 100% energy and allocated to all customers using throughput
Tilbury Usage Forecast (assume Tilbury Expansion)	Section 6.3.2.3
Show R:C ratios with 3 decimals	Section 6.5.2
Provide allocation percentages for O&M split	Appendix 6-3
Provide NGT Forecast for Vancouver Island (assume Mt. Hayes)	Section 6.3.3.4
Provide detailed data and calculations for load factor calculations	Appendix 6-7
Explain how each rate schedule contributes to the system peak	Section 6.3.6
Provide history for gas costs and delivery rates	Appendix 6-10
Provide a comparison of previous and current COSA assumptions	Section 6.3.3
Provide a copy of Sizing of Distribution Pipe Standards	Appendix 6-6
Provide more details on the PLCC adjustment and how it is used in the COSA	Section 6.3.5.4
Provide calculations for the Customer Weighting and Customer Administration Factor Studies	Appendix 6-8

[101] R:C denotes Revenue to Cost Ratio and M:C denotes Margin to Cost Ratio

Item	Reference
Provide cost details for NGT customers	NGT Customers include customers taking delivery of gas under RS 25, RS 23, RS 6, RS 6P and RS 46. RS 23 and RS 25 NGT customer's costs are embedded in the rate schedule with all other customers that take delivery under these rate schedules. Further to section 2, RS 46 is not in scope for this application; consequently these customers are not separated out as an individual rate schedule within the COSA model.
Include Margin to Cost Ratios in tables	Section 6.5.2
Do RS 22 R:C ratios include Interruptible Revenue?	Yes, in Section 6 COSA Results
Why is the R:C ratio for RS 22A so high, is there some history behind this?	Section 6.3.1.3
What is the rate impact if BC Hydro IG terminates their contract in 2022	BC Hydro IG Revenue is approximately $16 million per year. Without this revenue, all other non-bypass customer's delivery rates would increase by approximately 2%.

6.7 SUMMARY

FEI conducted a COSA study in accordance with standard utility practice. FEI's COSA methods have been reviewed by EES Consulting and were found to be consistent with standard utility practice, generally consistent with past practice for the utility and the results are acceptable for purposes of setting just and reasonable rates for the utility. FEI's COSA study follows three industry standard steps to allocate the cost of service: functionalization, classification and allocation.

With this rate design, FEI is endeavouring to establish rates that will be functional for the foreseeable future. As such, in addition to costs from FEI's 2016 test year, FEI also included known and measurable changes for projects expected to be in-service by or soon after January 1, 2018, including: the LMIPSU Project, the CTS Projects and the Tilbury Expansion Project.

Except as noted in Table 6-8, FEI has been consistent with past practice in the methods used within the COSA study. FEI's gas cost allocation method for commodity and midstream costs remains largely consistent with what was approved in the 1991 Phase A Rate Design.

The resulting margin to cost and R:C ratios are within a reasonable range indicating that the COSA study results are a suitable basis for setting utility rates to collect a fair level of revenue from each rate schedule.

FortisBC Energy Inc.
2016 Rate Design Application

Section 7:

RATE DESIGN FOR RESIDENTIAL CUSTOMERS

Table of Contents

7. RATE DESIGN FOR RESIDENTIAL CUSTOMERS

7.1 *INTRODUCTION*

FEI conducted a full review of the rate design for the residential rate class, which takes service under RS 1, RS 1U, RS 1X and RS 1B[102] (collectively referred to in this section as RS 1), guided by the legal context, rate design principles, government policy, and informed by FEI's data analysis, jurisdictional comparisons and feedback from the stakeholder engagement process. FEI's review of the RS 1 rate design considered the potential rate structure options for residential customers (i.e., flat, declining or inclining block) and the possible blends of fixed and volumetric charges.

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.

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.

The remainder of this section is organized as follows:

- Section 7.2 describes the characteristics of residential customers, including dwelling type, end use, consumption patterns and load factor, and demonstrates that the current single rate schedule for the residential class remains appropriate.
- Section 7.3 reviews the key rate design considerations for residential rates.
- Section 7.4 provides a principle-based review of the rate structure options for residential customers, including the advantages and disadvantages of the proposed flat rate structure, and demonstrates that the flat rate structure with a Basic Charge and volumetric Delivery Charge remains appropriate.

[102] The differences in RS 1, RS 1U, RS 1X and RS 1B pertain to the commodity portion of residential rates. In all cases the transportation and storage service (also called midstream service) and the delivery service are provided by FEI. Under RS 1 customers receive conventional natural gas from FEI as their commodity. Under RS 1U customers receive their commodity from a licensed natural gas marketer. In the event that there is a Marketer failure, customers that had been served by a Marketer under RS 1U, may be served under 1X. Under RS 1B customers receive commodity service from FEI, but have elected to receive a percentage of their natural gas as renewable natural gas (also called biomethane) with the balance being conventional natural gas.

- Section 7.5 provides a principle-based review of the Basic Charge and volumetric Delivery Charge ratio, and the basis for FEI's proposed 5% increase to the Basic Charge reflecting a balance of competing principles and considerations.
- Section 7.6 describes the result of the comparison of residential rates in other jurisdictions, confirming that FEI's proposals are consistent with residential rates in other jurisdictions.
- Section 7.7 summarizes the comments received in the stakeholder engagement process related to residential rates, and how FEI has addressed stakeholder comments.
- Section 7.8 analyzes the bill impacts of FEI's proposal, including a detailed discussion of the impact on low income customers, demonstrating that the impacts are reasonable given the balance of competing principles and considerations.
- Section 7.9 concludes this section and summarizes FEI's rate design proposals for residential customers.

7.2 CUSTOMER CHARACTERISTICS

RS 1 includes service to single family residences, and separately metered single family townhouses, row houses, and apartments. Table 7-1 below provides a summary profile of the residential customer class' average number of customers, annual consumption and revenue.

Table 7-1: FEI's Residential Customer Profile[103]

	Amount	Percentage of FEI Total
Average Number of Customers	886,652	91%
Annual Consumption (PJ)	72.5	35%
Revenue ($000s)	730,278	59%

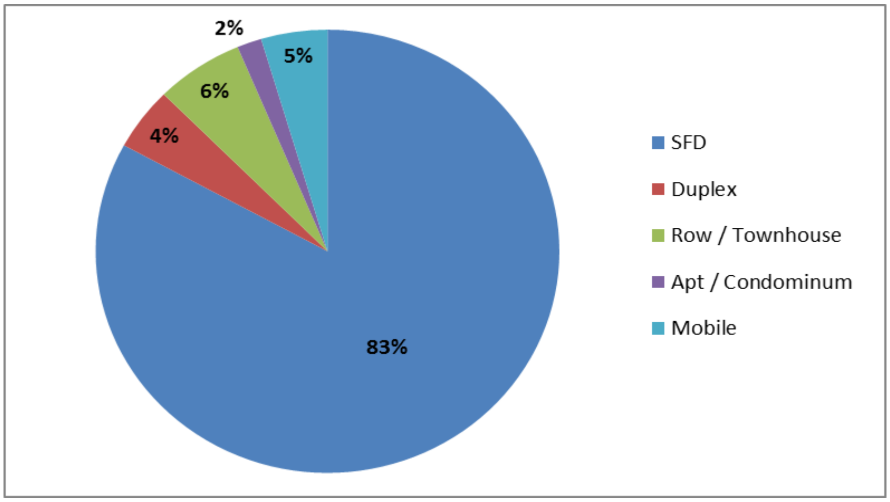
The following subsections discuss the main characteristics of RS 1 customers, including dwelling type, end use, consumption patterns, and load factor.

7.2.1 RS 1 Dwelling Types

The 2012 Residential End-Use Study (REUS), provided in Appendix 7-1, is the most recent detailed study of FEI's residential customers' characteristics. The 2012 REUS indicates that single family dwellings (SFD) dominate the residential customer base for FEI. SFDs account for approximately 83% of residential customers, although the recent trend shows that the percentage is declining. Figure 7-1 below provides a summary of FEI's residential customers by dwelling type.

[103] Based on 2016 Annual Review (Order G-193-15).

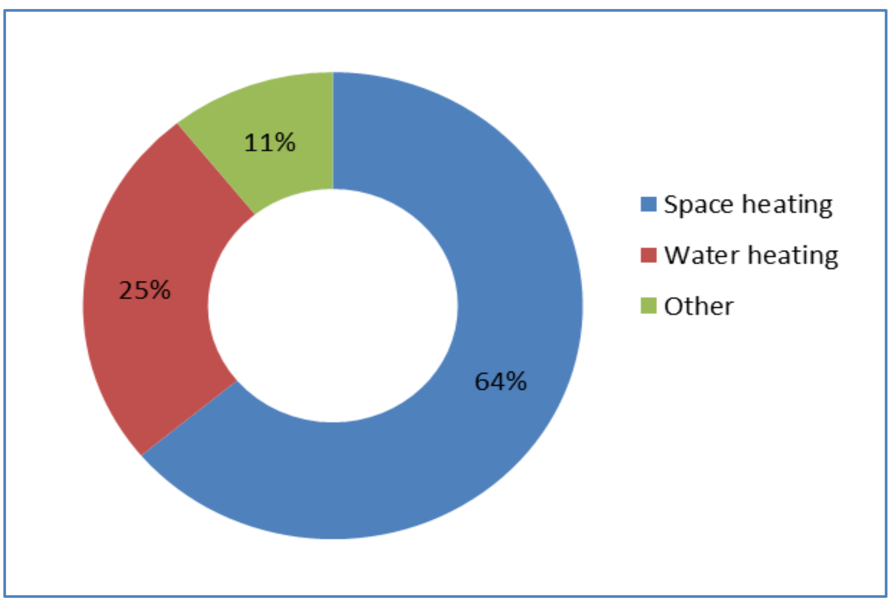
Figure 7-1: FEI's Residential Customers by Dwelling Type based on 2012 REUS



7.2.2 RS 1 End Uses

The majority of demand from residential customers is used for space heating and water heating purposes. Residential customers may also use natural gas for other purposes such as decorative fireplaces, cooking, pool heating and clothes drying. As shown in Figure 7-2 below, space and water heating are estimated to be approximately 64%[104] and 25% of residential consumption, respectively. The remaining 11% of demand includes the estimated consumption for decorative and free standing fireplaces, cooking appliances and dryers and pools.

Figure 7-2: Estimated Annual Consumption per Household by End-use based on 2012 REUS

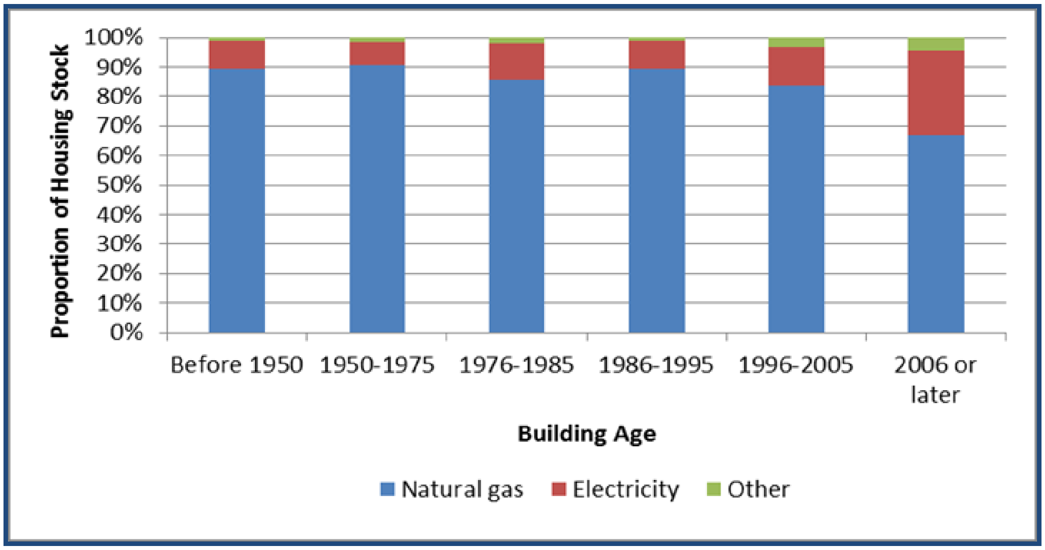


[104] Heater fireplace consumption is included in this percentage.

The data shows that the use of natural gas as a main space heating fuel for residential customers is diminishing, while the use of electricity as a main space heating fuel is on the increase. According to the 2012 REUS, new homes with gas service are less likely to use natural gas as the main space heating fuel and more likely to use electricity when compared to homes built prior to 2006.

Figure 7-3 below illustrates the main space heating fuel trend by dwelling age.

Figure 7-3: Natural Gas Use for Residential Space Heating



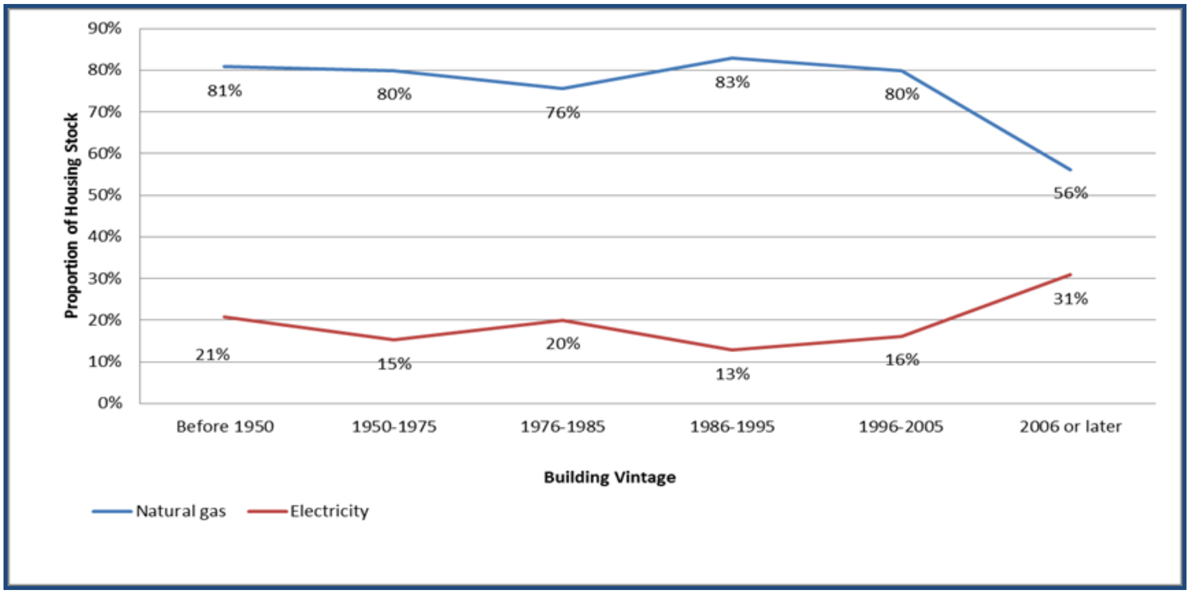
The increasing share of electricity use in space heating is also validated by BC Hydro's 2014 Residential End Use Survey[105].

A similar trend is occurring for domestic water heating. According to the 2012 REUS, new homes with gas service are less likely to use natural gas fired domestic water heating and more likely to use electricity compared to the homes built prior to 2006.

Figure 7-4 below illustrates the trend in domestic water heating fuel by dwelling age.

[105] BC Hydro's 2014 Residential End Use Survey, p.60 & p.106, included as Appendix C-3F of BC Hydro's Rate Design Application. Available online: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/2015-rda-appendices.pdf.

Figure 7-4: Trend in Residential Domestic Water Heating Fuel by Dwelling Vintage[106]



In the following sections, the impact of these trends on residential consumption patterns and load factors is reviewed in more detail.

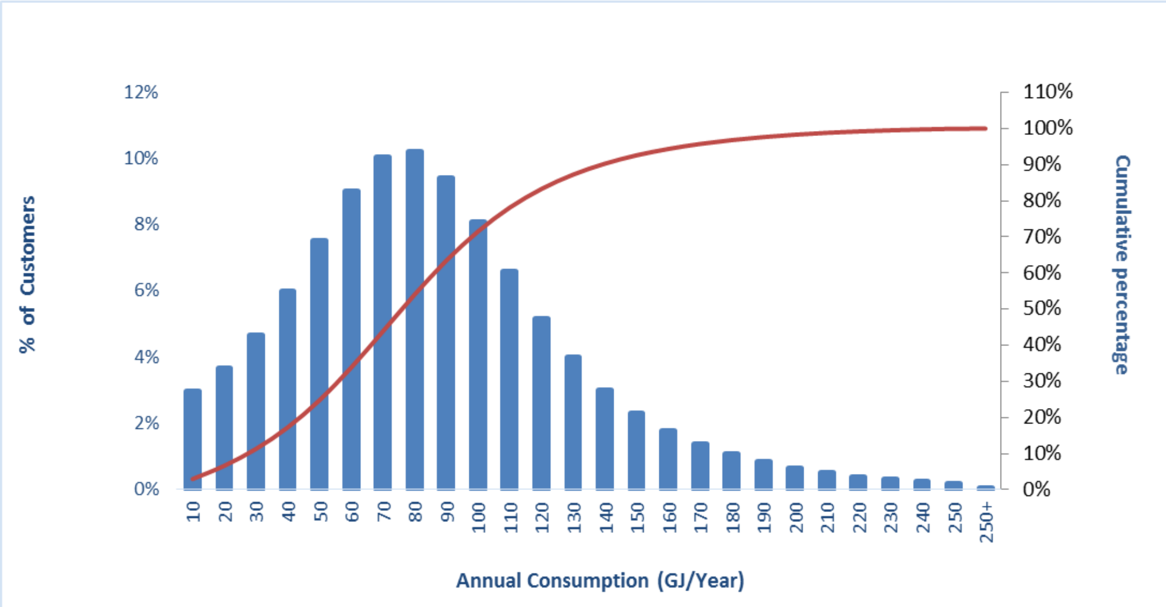
7.2.3 RS 1 Consumption Pattern

As shown in Figure 7-5 below, the 2015 residential annual consumption distribution forms a bell curve. There is a slight skew to the right relative to the mean annual consumption which is estimated at 81 GJ/year excluding outliers.[107]

[106] Numbers are not additive because some homes may have more than one domestic water heating appliance and energy source. “Don’t knows” and no responses have been excluded.

[107] Outliers are defined as the data points beyond the 99 percentile and include customers whose 2015 annual consumption was greater than 252 GJ.

Figure 7-5: 2015 Residential Normalized Consumption Distribution



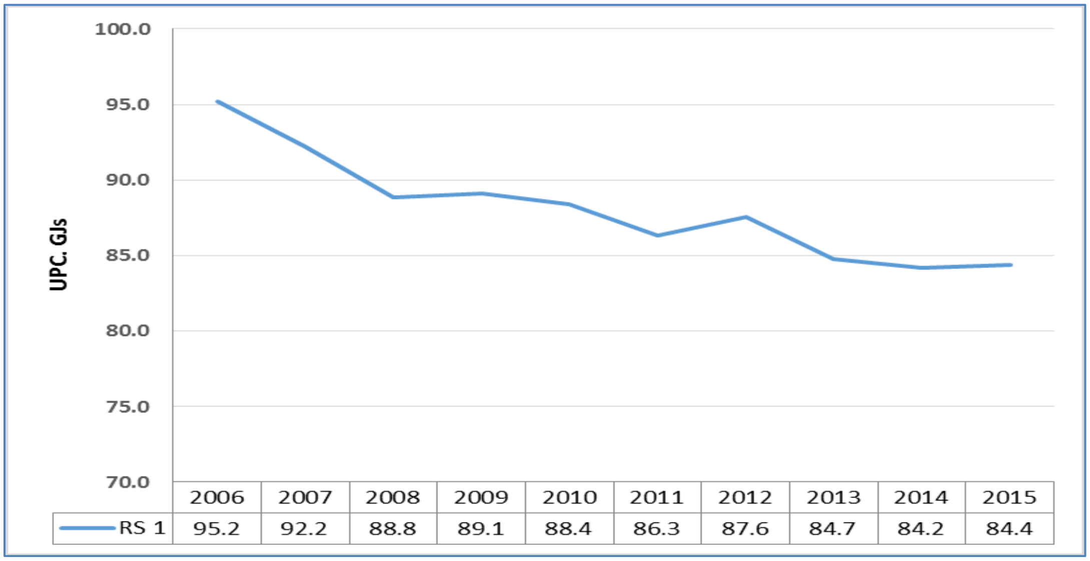
As can be seen from the figure above, the 70-80 GJ annual consumption range has the highest density of customers followed closely by the 60-70 GJ and 80-90 GJ consumption ranges.

Further data analysis undertaken by FEI shows that in the year 2015 approximately 10% of residential customers consumed equal to or less than 28 GJ/year. On the other side of the spectrum, approximately 10% of residential customers had annual natural gas consumption equal or greater than 140 GJ.

Consumption variations among RS 1 customers depend on many factors, such as type and number of appliances installed, regional temperature differences, size of household, size and type of homes and energy efficiency of the equipment and buildings.

As shown in Figure 7-6, FEI's residential annual use per customer, or UPC, has declined by more than 11% since 2006.

Figure 7-6: FEI's Historical Residential Normalized UPC



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.

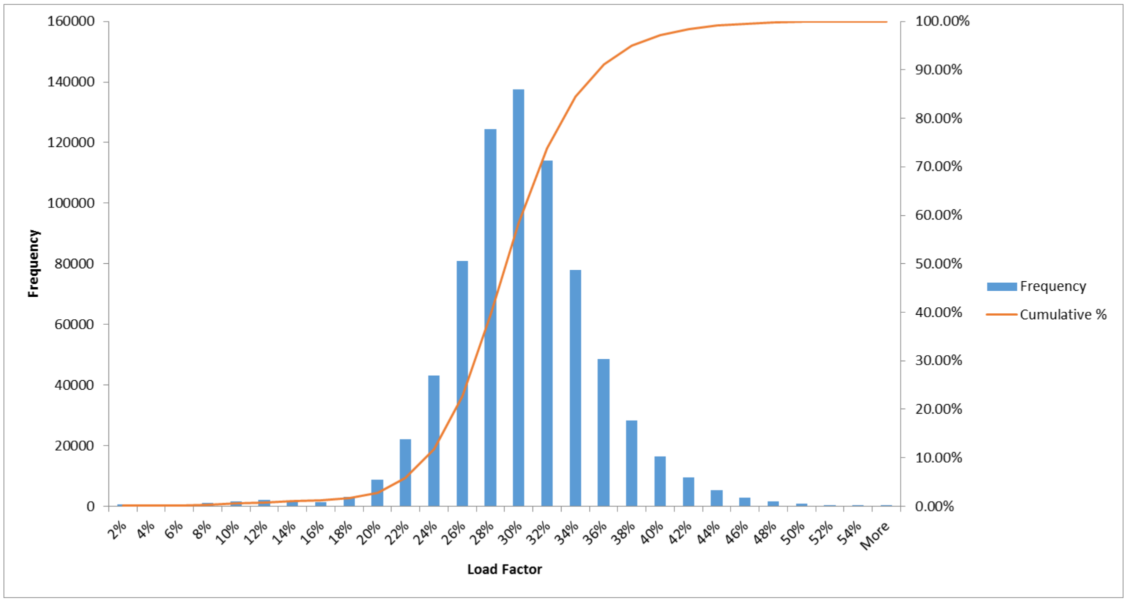
7.2.4 RS 1 Load Factor

The load factor is used to develop one of the main allocators in the COSA model to allocate demand-related costs between different rate schedules. However, the load factor for specific individual residential customers can be higher or lower than the average load factor for RS 1 used in the COSA Model.

To better understand the behaviour of residential customers, FEI conducted a load factor analysis for residential customers at individual premise levels. The load factor for each premise number is calculated based on the normalized daily consumption for each premise divided by the peak day consumption. The load factor analysis is based on a statistical analysis of loads relative to weather conditions as FEI does not meter the daily loads of residential customers.

The graph below provides a histogram of load factors for residential customers at the premise level. The histogram indicates that the residential customers' load factor at the premise level is in the form of a normal distribution function with a bell curve. The load factor for the majority of residential customers is around 30%.

Figure 7-7: Residential Customers' Load factor Distribution Calculated at Premise Level



The statistical estimation of load factors at the premise level enables FEI to analyze the relationship between load factor and consumption at the premise level and to investigate the hypothesis that the load factor for residential customers is dependent on the annual energy consumption of the customers. The following figure provides a scatter plot for the estimated load factor for RS 1 customers and their respective annual consumption.

Figure 7-8: RS 1 Load Factor and Annual Consumption Scatter Plot

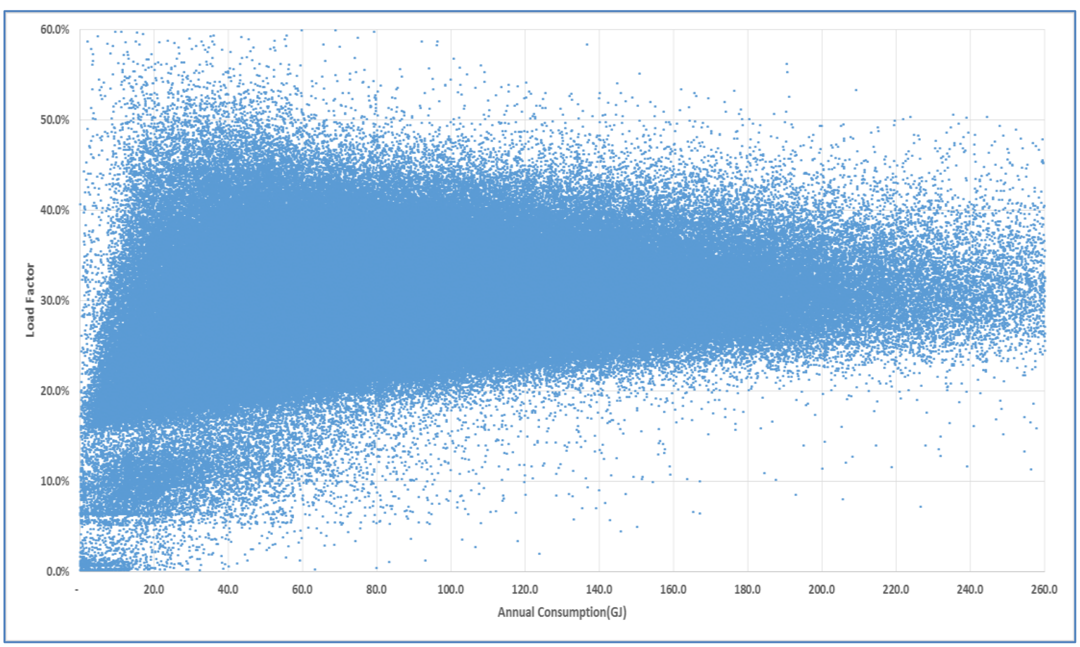


Figure 7-8 shows that the annual consumption of customers with a load factor of 15% or less is predominantly below 40 GJ. At the same time, the figure also demonstrates that many customers consuming less than 40 GJ/year have load factors that are well above the RS 1 average, and include some of the highest load factors observed amongst residential customers as a whole. A simple regression analysis was performed to check the correlation between annual use and load factor. The regression statistics provided a high level of significance (p-value equal to zero), but a low correlation value of 0.25. This means that the independent variable can only explain 25% of variations in the dependent variable. This indicates that there is a statistically significant relationship, but the margin of error and range of values within the sample is large. The results of the regression analysis are logical since, for instance, a low consumption customer, such as a single occupant in a studio apartment with natural gas domestic water heating, could have a higher than average load factor; conversely, a high consumption customer with natural gas space heating and a poorly insulated house can have low load factor. For these reasons, it is not possible to estimate a customer's load factor based on their annual or monthly consumption.

7.3 *PRINCIPLE-BASED REVIEW OF RESIDENTIAL RATES*

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 specific characteristics of customers in each rate schedule.

Considering that there are a large number of customers in RS 1, ease of understanding and administration of any proposed rates and rate structure is essential. As discussed in Section 7.4, some rate structures that may, in theory, provide a higher level of economic efficiency (such as seasonal rates), may, in fact, result in increased customer dissatisfaction and/or cost pressures in the long run.

Rate and revenue stability, as well as customer bill impact, are equally important considerations for RS 1.

FEI considered the fairness principle in relation to RS 1 in terms of inter-rate schedule and intra-rate schedule fairness, which are defined as follows:

- Inter-Rate Schedule Fairness: whether RS 1 customers are paying their fair share based on cost causation in terms of allocated costs as compared to the other rate schedules.
- Intra-Rate Schedule Fairness: whether some of the lower load factor or lower volume customers are paying their fair share as compared to higher load factor customers or higher volume customers within RS 1. This is important as FEI does not segment customers within RS 1. Intra-rate schedule fairness may also refer to finding the right balance between fixed and volumetric charges so that customers with varying load characteristics pay for their fair share of costs.

Government policies are also important factors that FEI has taken into consideration for the residential rate design. Some rate design options (such as declining block rates) may have economic justification, but are not in line with government policies and, as such, are not pursued by FEI. Similarly, excessively high fixed charges should be avoided since they will leave a smaller price signal in the volumetric charge and may discourage some customers from engaging in energy efficiency activities and programs. High fixed charges may also be a deterrent to low volume customers remaining as gas customers, meaning lost revenues if they leave the system, and increased rates for the remaining customers

FEI discusses below its review of the residential rate design in accordance with the principles discussed above.

7.4 RATE STRUCTURE OPTIONS FOR RESIDENTIAL CUSTOMERS

7.4.1 Introduction

This section provides a principle-based review of the relevant strengths and weakness of the rate structure options for RS 1. FEI believes that its existing flat rate structure provides the best balance of rate design considerations for residential customers. FEI's residential customers are already familiar with this rate structure, flat rates are simple to administer and easy to understand and they 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.

7.4.2 Rate Structure Options

Several types of rate structure options can be employed to price the delivery of natural gas to residential customers, all of which consist of two main components.

The first component is a fixed charge to recover a portion of the fixed costs (particularly customer-attributed costs). The alternative to a fixed charge is a monthly minimum charge, which combines a daily or monthly basic charge and a charge for a certain amount of gas.[108]

The second component is a volumetric charge which varies with the volume of gas taken. This charge may be expressed in different units (such as dollars per therm, per cubic meter, or per GJ) and in various forms. FEI uses a per GJ volumetric rate.

The rate design options are briefly discussed in the following sections:

[108] Currently, the Fort Nelson residential rate employs a monthly minimum charge that includes the first two GJs of natural gas each month.

Flat Rate Structure:

In a flat rate structure, also known as straight line meter rate structure, the volumetric charge is flat and does not vary with the customer's consumption. The flat rate structure is used by the majority of Canadian natural gas utilities for residential customers. Currently, FEI recovers the delivery cost of service allocated to the residential rate schedule through a daily Basic Charge (fixed charge) and a flat volumetric Delivery Charge calculated based on the monthly natural gas consumption.

Declining Block Rate Structure:

A declining block rate is designed with two or more successive blocks of use with decreasing prices per unit of volume. Rates of this type are usually designed to recover the substantial portion of costs in the initial block. As indicated in the jurisdictional comparison (Section 7.6), the natural gas utilities in Quebec and Ontario use a declining block rate for their residential customers. FEI's predecessor, BC Gas, used declining block rates for its residential customers prior to 1994.

Seasonal Rate Structure:

A seasonal rate structure refers to a rate structure in which rates may change based on the month of the year. The seasonal rate can be used as a proxy for a demand charge. In the 1993 Rate Design Decision, the Commission directed BC Gas to introduce a seasonal differential into its delivery margin. The Commission stated that the residential rates should be set on a seasonal basis such that the delivery rate during the 5 winter months was twice the summer rate. Despite the theoretical appeal, the seasonal rates did not perform well in respect to the rate design principle of customer understanding and acceptance. Some customer groups objected to this rate structure and claimed that seasonal rates unfairly impact the customers who are located in colder regions of the province such as northern areas of FEI's service territory. Following these complaints and a review process, the Commission decided to terminate the seasonal differential, effective January 1, 1998. FEI is not aware of any Canadian natural gas utilities with seasonal rates for their residential customer class.

Inverted Block Rate Structure:

The inverted rate is the reverse of the declining block rate. Under this rate structure, the rate for successive blocks increases as consumption increases. Inverted block rates can be used to reflect a situation in which increased consumption causes rising costs, that is, where the long-run incremental cost for the business is above the average cost. However, there is no evidence that increased consumption of natural gas leads to rising costs of the natural gas delivery system. Rather, the natural gas distribution industry is widely considered to be a natural monopoly with economies of scale characteristics, meaning that as the size of the firm increases (increased consumption), the average cost of the output of the firm decreases. Therefore, there is no cost basis to justify inverted block rates for natural gas distributors. This is supported by a historical incremental cost study conducted by EES Consulting as part of FEI's 2015 System Extension Application proceeding. The study showed that the incremental cost of attaching new customers is lower than the utility's average embedded cost. The methodology and results of this study were accepted by the Commission in the Decision and Order G-147-16 (the MX Decision) regarding FEI's 2015 System Extension application. EES Consulting has included a Review of Marginal Delivery Costs study, included in Appendix 4-4 to this Application, and a revised incremental cost resulting from the MX Decision is included. In its jurisdictional review FEI did not find residential inverted block rates in use in any gas utilities in Canada.

7.4.3 Evaluation of Rate Structure Options

In this section, the rate structure options are evaluated based on the major rate design principles, including ease of understanding, economic efficiency and fairness, customer bill impact and stability of rates and revenues. Table 7-2 below illustrates how each one of the above rate structures score against these principles:

1 **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.

7.4.4 Customer Research Regarding Bill Comprehension and Preference

As explained in Section 4.6, FEI retained the services of Sentis to conduct an online survey to measure residential customers' knowledge of FEI's current rate structure and bill components and to better understand customers' preference regarding various rate design considerations. The detailed version of this study can be found in Appendix 4-5 to this Application. In the following section, a brief summary of the survey results is presented.

Knowledge of current rate structure and bill components:

In general, the survey results indicate that the majority of FEI's residential customers have a relatively good understanding of their monthly bill components, with 84% of respondents indicating that they have a very clear or somewhat clear understanding of how their bill is calculated. This is corroborated by further evidence that approximately three-quarters of respondents were aware that their monthly bill is made up of both fixed and volumetric charges. The table below provides a snapshot of customers' understanding regarding various components of their monthly bills.

Table 7-3: Customer Understanding of Residential Monthly Bill Components

Level of understanding	Basic Charge	Delivery Charge	Storage & Transport Charge	Cost of Gas	Taxes and Levies
Very Well	33%	41%	24%	36%	36%
Somewhat	48%	44%	39%	42%	45%
Little	15%	12%	29%	18%	15%
Not at all	4%	3%	8%	4%	3%

Sentis' research concludes that after looking into customer ratings across all five components, 17% of customers indicated that they understand all components of their bill 'very well' and 56% of customers indicated that they understand all components of their bill either 'very' or 'somewhat' well. The relatively high level of customer understanding is indicative of customers' familiarity with the current rate structure which has been in place for many years.

Relative importance of rate setting considerations:

One of the objectives of conducting the survey was to analyse and understand residential customers' preferences for different rate options. As such, the customers were asked to rate the importance of various rate design considerations. As this was an online survey for a typical residential customer, the rate design principles were described in a simplified manner. The following is the simplified language used in the survey for major rate design considerations:

- Ease of understanding: Natural gas rates should be easy for average person to understand;

- Rate stability and bill impact: Natural gas bills should be stable and not fluctuate very much from month to month;
- Fairness (cost causation): Heavier natural gas users should not subsidize costs for those who use less; and
- Efficiency and government policy: The rate structure should be designed to encourage users to use less natural gas and/or to avoid high usage during winter months.

The respondents were clear that, from their perspective, ease of understanding is the most important rate setting consideration. Other rate design considerations were rated to be less important than ease of understanding, but all were rated approximately at the same level. Responses to this series of questions support FEI's position that due to the large number of residential customers taking service under RS 1, ease of understanding and administration is essential for any rate design for this rate schedule.

Perception of various rate structure options:

The survey also asked respondents to score various rate options against the rate design considerations. The results could be used both to test customers' understanding of various rate structure characteristics and to better understand customers' perception of various rate structure options.

The results were encouraging, as the majority of respondents were able to correctly understand and score various rate structure options. As shown in Table 7-4 below, customers correctly indicated that compared to other rate structures, the flat rate structure leads to better customer understanding, higher rate stability and a smaller bill impact. The respondents gave slightly higher scores to inclining block rates for promoting efficiency. This is probably due to the fact that, for a residential consumer, efficiency means less usage (rather than higher load factor), as in the concept of higher efficiency appliances, for instance. The flat rate also received the highest score for economic fairness.

Table 7-4: Percentage of Respondents Ranking Each Rate Structure Option

	Flat Rate	Declining Block Rate	Inclining Block Rate	Don't Know
Easiest to understand	68%	7%	17%	8%
Promote most efficient use of natural gas network	32%	14%	38%	16%
Results in most stable monthly natural gas bills	66%	13%	11%	10%
Most effectively allocate costs to align revenue recoveries with cost causation	34%	22%	30%	15%

Overall, the survey results indicate that residential customers have a good knowledge of their current bill components, give a higher level of importance to rate structures that are simple to understand for a layperson, and have a preference for flat rates compared to other rate structures.

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.

7.5 *FIXED VERSUS VARIABLE COSTS AND RATES*

RS 1 consists of a fixed daily Basic Charge and a volumetric Delivery Charge. The results of the COSA study discussed in Section 6 and included as Appendix 6-4, provide cost allocation results to help inform the appropriate level for the Basic Charge and the volumetric Delivery Charge. Increases or decreases to the Basic Charge combined with a corresponding adjustment to the volumetric Delivery Charge are revenue neutral, but generally change the relative amount of cost recovery from low and high consumption customers. A reasonable ratio of Basic Charge revenue to volumetric Delivery Charge revenue is one that balances competing rate design considerations.

FEI is proposing a one-time 5% increase in the Basic Charge and a corresponding decrease in the volumetric Delivery Charge to remain revenue neutral for RS 1. A 5% increase results in an annual bill impact for the majority of customers of less than +/-1% and a zero bill impact for an average use customer. FEI believes that the volumetric Delivery Charge decrease required to offset the one-time 5% increase in the Basic Charge will not discourage customers from engaging in energy efficiency activities and programs.

7.5.1 Fixed Costs, COSA Results and Fairness Principle

The COSA model indicates that the majority of the costs allocated to the residential rate schedule are fixed costs. These fixed costs are reflected in the customer and demand-related costs. Table 7-5 below provides the unit cost of recoverable customer and demand related costs allocated to the residential rate schedule based on the COSA model with all known and measurable changes included and applying the defined margin to cost ratio. The customer and demand related unit costs are calculated by dividing the recoverable customer and demand attributed costs by the average number of customers and twelve months.

Table 7-5: Comparison of Fixed Costs and Fixed Charges Recoveries[109]

Type of Cost	Unit Cost Based on COSA Results	Current Average Monthly Basic Charge	Difference
Customer-related cost	$27.10 per month		
Demand-related cost	$17.04 per month		
Total fixed costs	$44.14 per month	$11.84 per month	$32.30 per month

In the current residential rate structure, the current basic charge of $11.84 (when calculated as the average fixed monthly amount) recovers about 44%[110] of the customer costs and only about 27%[111] of the total of customer and demand costs allocated to the residential rate schedule. In other words, the Company's revenue is largely dependent on consumption even though the bulk of the costs associated with the system are fixed in nature.

The misalignment between fixed costs and the Basic Charge has been a re-occurring issue in FEI's rate design proceedings. The Commission has previously approved increases in the share of fixed costs recovered by fixed charges. As part of the 1996 NSA, the monthly Basic Charge was increased by approximately 11% from $6.32 to $7.00. In the 2001 NSA, the monthly Basic Charge was again increased by an additional 15% from $8.66 to $10.00. In both cases, the increase in the residential Basic Charge was offset by a decrease in the volumetric Delivery Charge, so that the increase in the residential Basic Charge would remain revenue neutral.

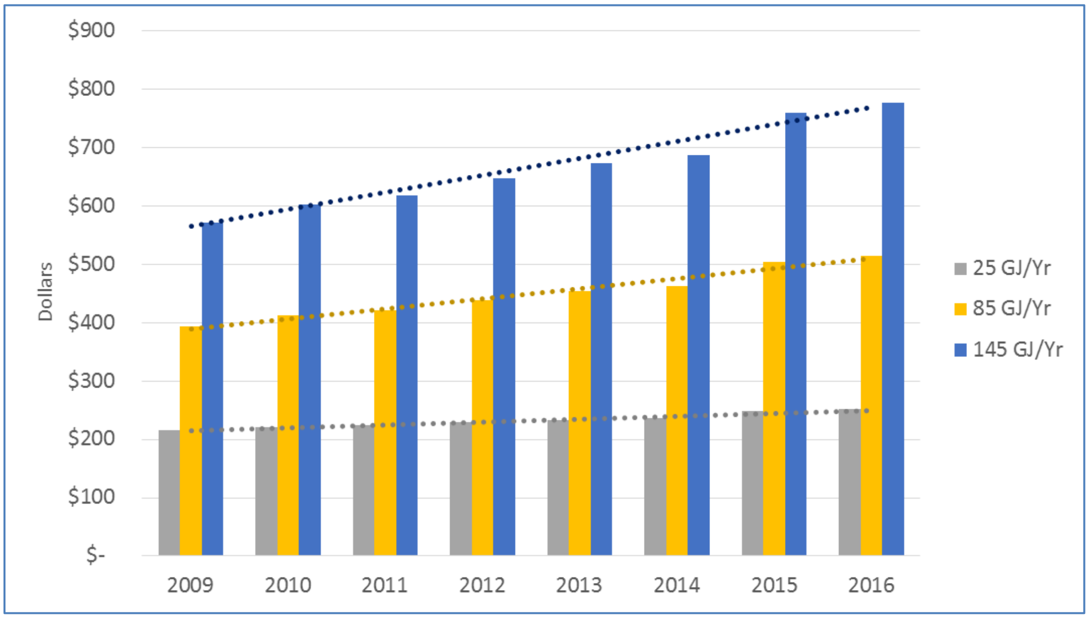
By Order G-141-09, the Commission approved FEI's 2010-2011 NSA. As part of the 2010-2011 NSA, and in alignment with government's energy conservation policies, the monthly Basic Charge was fixed at 2009 levels and all annual margin increases since 2009 have been allocated to variable volumetric charges. As shown in Figure 7-9 below, the effects of this decision over time can be seen by analyzing the impact of revenue margin increases on the delivery portion of customers' annual bills at varying use per customer levels.

[109] FEI's current RS 1 Basic Charge per day is $0.3890. For analysis purposes in this section, the daily Basic Charge has been converted to an equivalent monthly charge of $11.84/Month, based on 30.44 days in a Month ($0.3890 X 30.44 = $11.84). The 30.44 days per Month is derived by the calculation of 365.25 days in a year divided by 12 Months = 30.44 days per Month.

[110] $11.84 per Month / $27.10 per Month.

[111] $11.84 per Month / $44.14 per Month.

Figure 7-9: Impact of Delivery Rate Increases on Delivery Portion of Annual Bill at Varying UPCs



As can be seen in Figure 7-9, the slope of the trend line for a customer with an annual consumption of 145 GJ is much greater than the slope for a customer with a 25 GJ annual use. The analysis shows that within the 2009 to 2016 period, the delivery margin for customers with 25 GJ, 85 GJ, and 145 GJ annual consumption has increased by 16%, 30%, and 36%, respectively. In other words, by holding the Basic Charge constant, higher use customers are bearing a greater share of delivery revenue requirement increases.

Based on rate design Principle 2 (fair apportionment of costs among customers), an increase in cost recovery through the Basic Charge is desirable. However, as discussed below, other rate design considerations, including consideration of government policy and bill impacts, suggest that any increase in the Basic Charge should be moderated.

7.5.2 Government Energy Policy Considerations and Basic Charge

As mentioned above, alignment with government's energy conservation policy was the basis for the 2009 decision to hold the Basic Charge constant. The theory suggests that excessively high fixed charges (relative to volumetric charges) can lead to consumption behaviours that result in excessive usage. This behaviour, sometimes described by economists as a "buffet effect", refers to scenarios in which customers strive to consume more than desired levels in an effort to justify the break-even costs of a high fixed charge.[112] For the specific case of natural gas utilities, excessively high fixed charges, and correspondingly lower volumetric charges, may

[112] The term "buffet effect" was originally used to describe the customer behaviour in all you can eat restaurants but it is also referred to describe the effects of fixed rate plans (such as internet plans or phone and cable plans) on customer consumption behaviour. This is a much less of an issue for a distribution company since, even if all delivery charge is recovered by fixed costs, the mid-stream and storage as well as cost of gas will continue to be recovered in volumetric changes.

affect customers' behaviour through decreased customer participation in energy saving activities rather than a direct increase in consumption. That is, the customer may lose the incentive to achieve the desired level of energy savings.

In light of government's energy policy considerations, any increase in the Basic Charge should be done in a manner that does not discourage customers' engagement in energy saving initiatives. As such, a complete alignment between fixed costs and fixed charges is not desirable from an energy conservation and efficiency perspective.

7.5.3 Proposed Change in Basic Charge and Volumetric Delivery Charges

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 mitigate 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).

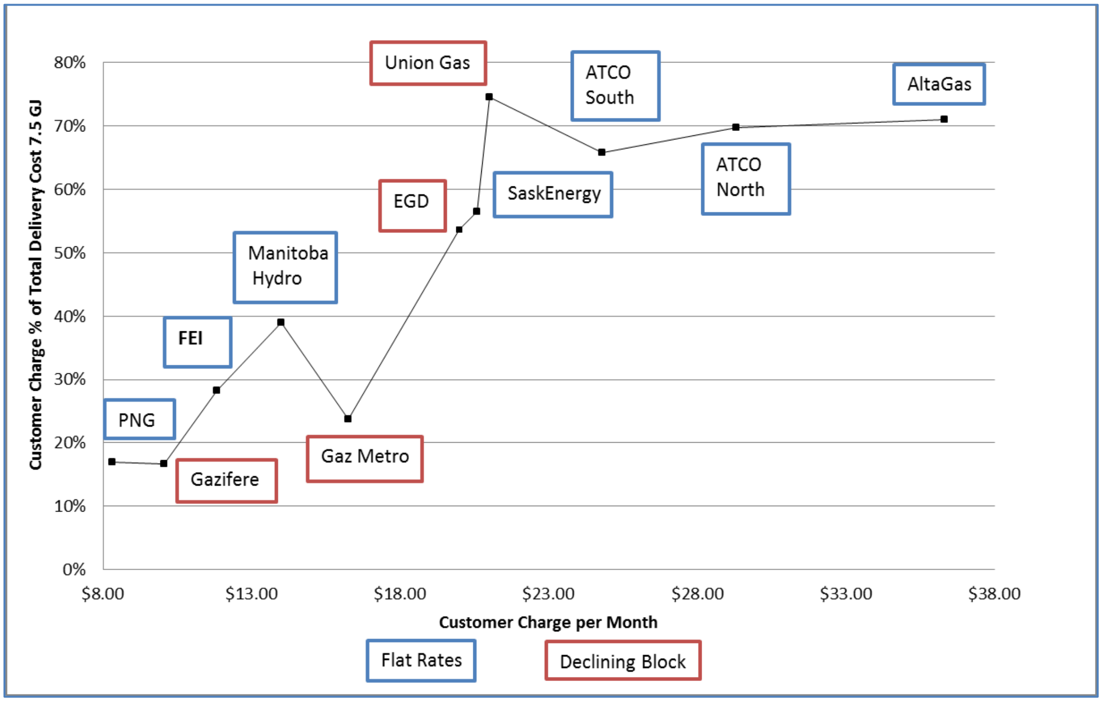
In order to achieve a reasonable balance among competing rate design considerations, FEI is proposing a moderate one-time 5% increase in the Basic Charge and a corresponding decrease in the volumetric Delivery Charge.

The bill impact and rate analysis for this proposal that is included in Section 7.8 of this Application demonstrates that a 5% increase leads to only a +/-1% annual bill impact for the majority of customers and a zero bill impact for an average use customer. In addition, a one-time 5% increase in the Basic Charge is not significant enough to discourage customers from engaging in energy savings activities. This is because a significant portion of FEI's costs continue to be recovered through volumetric charges and FEI proposes that future revenue requirement increases will continue to be allocated to the volumetric Delivery Charge.

7.6 *JURISDICTIONAL COMPARISON OF RATES*

FEI retained the services of EES Consulting to review the applicable rate structures for residential customers in other major Canadian provinces. The summary results of this study are provided in the Figure 7-10 below. The full results are provided in Appendix 7-2 of this Application.

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



The Y-axis in the chart presents the percentage of monthly fixed charge (customer or basic charge) to total delivery charges based on a consumption level of 7.5 GJ/month. The presentation of data with a specific monthly consumption amount makes the comparison of the basic charges amongst the utilities more meaningful.

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.

In summary, the jurisdictional comparison study demonstrates that most Canadian natural gas utilities have higher monthly fixed charges for their residential customers than FEI. In addition, the analysis indicates that FEI recovers a lower percentage of its delivery cost in fixed monthly charges than the majority of other Canadian natural gas utilities included in this study. This would suggest that an increase to the residential Basic Charge would not be inconsistent with fixed cost recovery in other jurisdictions.

7.7 STAKEHOLDER FEEDBACK

As discussed in Section 4, FEI circulated a Rate Design Discussion Guide to all interested stakeholders and held a workshop on August 31, 2016. This guide and the corresponding workshop covered various topics, including characteristics of residential customers, an evaluation of rate structure options, and a discussion of volumetric and fixed charges. The majority of stakeholders' questions were responded to at the workshop or as part of the discussion guide notes; however, some items required more time and were deferred to be addressed as part of the Application. The table below provides a summary of the relevant stakeholder feedback and FEI's action or response to address it. The detailed meeting summary and notes can be accessed in Appendix 4-2 to this Application.

Table 7-6: Outstanding Items from Rate Design Workshop and FEI's Actions

Topic	Undertaking	FEI's Action/Response
Residential customer characteristics	FEI was asked if it can provide a scatter plot of RS 1 customers' load factor and annual consumption	The requested scatter plot is provided in Figure 7-8 as part of residential customer characteristics section.
Low income customers' consumption pattern	FEI was asked to provide the annual uptake for the Low income energy conservation program and consider other resources if possible for its analysis	The additional information regarding FEI's Energy Conservation Assistance Program (ECAP) program and ECAP histogram was provided in the Discussion Guide Notes as well as Section 7.8.2 of this Application. Further, the result of a published 2015 study regarding energy consumption patterns of low income households in the U.S. is included in Section 7.8.2.
Rate structure option	FEI was asked if it had considered the merits of an inclining block rate structure. It was suggested that an incremental cost analysis can assist with the stakeholders' understanding of this issue.	As mentioned in the workshop, inverted rate structure was one of the options considered by FEI. Following the workshop, FEI asked EES Consulting to provide the incremental cost study it produced for FEI's 2015 System Extension Application. The results of this study (presented in Appendix 4-4) indicate that the incremental cost of new customers is less than the average embedded costs. This means that an inverted rate structure has little cost justification since increased consumption does not cause rising costs.

Topic	Undertaking	FEI's Action/Response
Basic versus volumetric Delivery Charges	Some participants in the workshop questioned the objective and reasoning for any change in basic and delivery charge ratio. FEI was asked to justify its proposal based on rate design considerations.	Section 7.5.1 studies the issue of fixed vs volumetric charges from the perspective of intra-rate schedule fairness, suggesting an increase in fixed charge is reasonable. Section 7.5.2 provides the opposing views regarding the government energy conservation policy. The impact on customers' rates and annual bill amounts is included in Section 7.8. The final proposal considers all of these issues in tandem.

7.8 *RATE DESIGN PROPOSAL*

FEI recommends a residential rate design which accomplishes the following:

1. Maintains the current flat rate structure with a fixed Basic Charge and a flat volumetric Delivery Charge; and
2. Improves the alignment between the fixed costs allocated to the residential rate schedule and the fixed charges recovered from residential customers by a one-time 5% increase to Basic Charge and corresponding decrease in the volumetric Delivery Charge.

The following provides a bill impact analysis of the proposed option and a discussion of the impact on low income customers in particular.

7.8.1 Bill Impact Analysis for Proposed Option

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	4.848	4.762

115 Including known and measurable changes.
116 As set out in Section 12.

As seen in the table above, the volumetric Delivery Charge after rebalancing (including the changes caused by rate design proposals in other rate schedules) is estimated to be approximately $4.848/GJ (based on a final 96.6% R:C ratio). The impact on customers' bills due to changes caused by rate design proposals in other rate schedules and rebalancing R:C ratios depends on the individual customers' consumption level (i.e., the higher the consumption, the higher the impact will be). For instance, the impact on the delivery portion of the annual bill amount of this change for an average use residential customer, who uses 82 GJ per year, is estimated to be around 0.4%.[117] The annual impact for all RS 1 customers for the rate design proposals and rebalancing is 0.3% (see Section 1, Table 1-1).

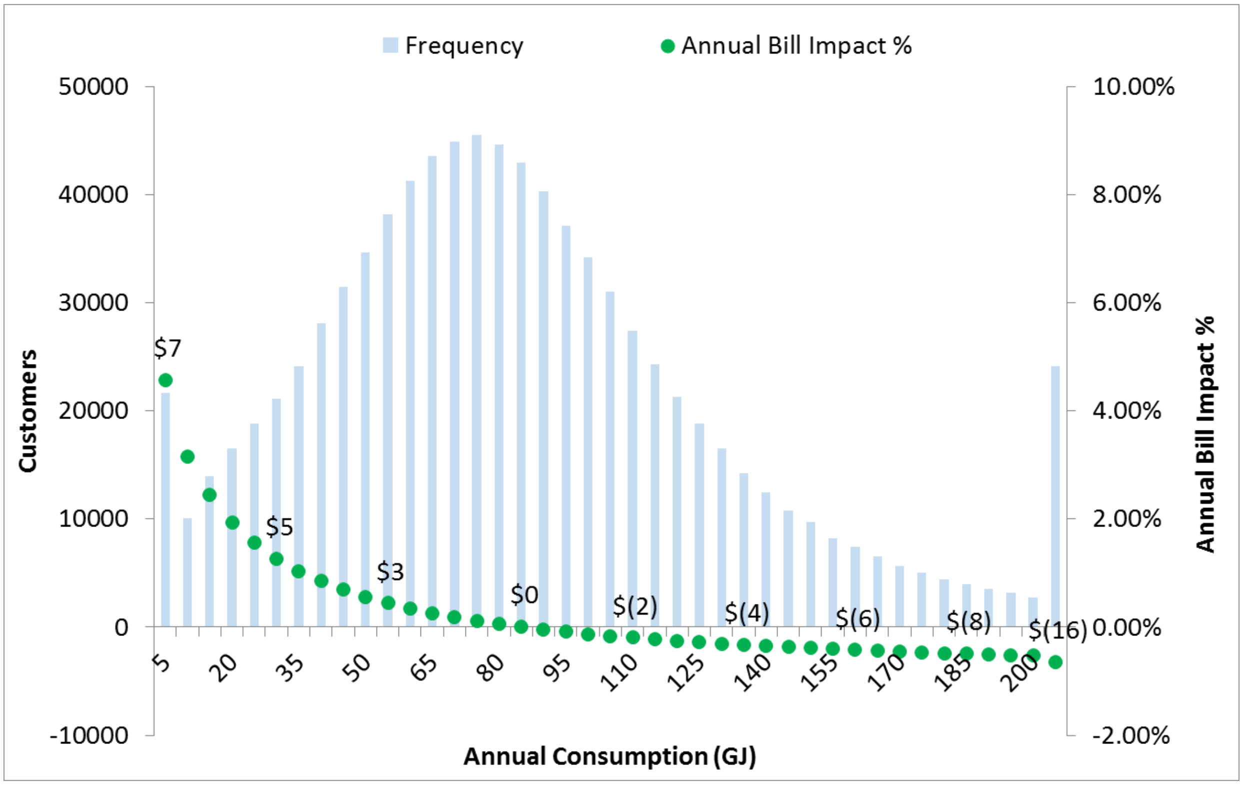
The impact from changes in the ratio of basic and variable charges is different because the changes are revenue neutral for RS 1. Implementing the proposed 5% increase in Basic Charge results in an increase in the daily Basic Charge from $0.3890 to $0.4085 per day and a corresponding decrease in the volumetric Delivery Charge from the $4.848 per GJ to $4.762 per GJ.

The annual consumption at which customers would experience no bill impact due to changes in the Basic Charge and the volumetric Delivery Charge is within the 80 to 85 GJ range (the average of the rate schedule). Customers with consumption above this range will experience a decrease of 0.04% to 0.64% in their annual bill amounts. Customers with consumption below this range will experience an increase of 0.06% to 5.0% in their annual bills depending on their consumption level. Lower use customers (customers with annual consumption less than 30 GJ per year) will experience a slightly higher bill impact (ranging from approximately $5 to $7 annually depending on the level of annual consumption). In all cases, customers will pay rates more closely matched to their allocated cost of service. The bill impact analysis for the recommended rate structure and fixed versus volumetric charges is demonstrated in Figure 7-11 and summarized in Table 7-8 below.

[117] (4.848-4.821)*82 GJ / (4.821*82+11.84*12).

Order G-4-18 Updates, February 6, 2018

Figure 7-11: Customer Bill Impact[118]



The following table describes the results that are shown in Figure 7-11 above.

Table 7-8: Bill Impact Explanations

Graph Item	Description
Frequency	These columns show the number of customers whose annual consumption falls within each 5 GJ increment. The number of customers is on the y-axis and the Annual Consumption (GJ) of each 5 GJ increment is on the x-axis.
Annual Bill Impact %	The dots on the graph show the approximate annual bill impact percent that customers will experience from the rate structure change, based on their annual consumption (at each 5 GJ increment into which they fit). The dots line up with the Annual Bill Impact % which is the y-axis. Some of the dots also include the annual dollar impact that customers will experience at the various consumption levels.

Table 7-9 below provides the dollar amount and percentage of annual bill impact of the recommended rates for various annual consumption levels:

[118] Customer Bill Impact from changes in ratio of basic to volumetric charges based on 2016 COSA model with known and measurable changes included and after rebalancing.

Table 7-9: Annual Bill Impact of 5% Increase in Basic Charge and Corresponding Decrease in Delivery Charge after Rebalancing

Annual Consumption	Annual Bill impact due to the 5% increase in Basic Charge	
	Dollar Amount	Percentage of Total Bill
0 GJ	$7.0	5.0%
40-45 GJ	$4.0	0.7%
60-65 GJ	$2.0	0.3%
80-85 GJ	$0.0	0.0%
100-105 GJ	$(2.0)	-0.2%
120-125 GJ	$(3.0)	-0.3%

7.8.2 Bill Impact on Low Income Customers

FEI also investigated the bill impact for low income customers and concluded that the recommended increase in the Basic Charge does not impact low income customers disproportionately. Even though low use customers are more negatively impacted by FEI's proposal (as shown in Table 7-9 above), low income customers are not necessarily low use customers.

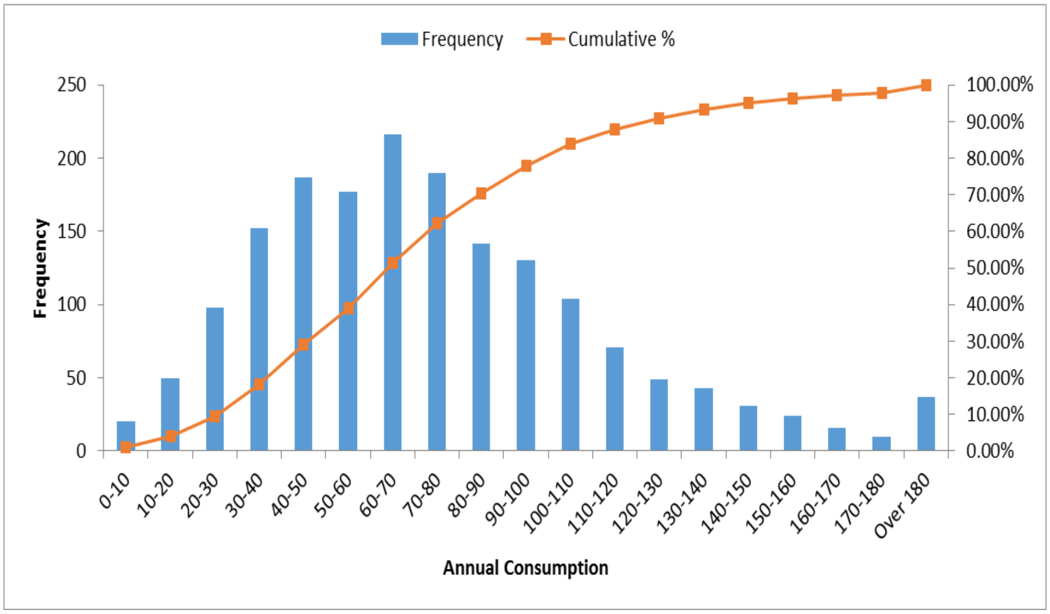
To reach this conclusion, FEI has collected data on income levels and natural gas consumption in its service territory from two different sources: (1) a database of low income customers who have applied to FEI's low income Energy Conservation Assistance Program (ECAP), and (2) the data collected as part of the 2012 REUS. Each is discussed below.

7.8.2.1 Low Income Energy Conservation Assistance Program Database

The low income ECAP was developed in 2011 in partnership with BC Hydro to provide energy savings for low income customers through direct installation measures such as faucet aerators, high efficiency showerheads or in some cases furnaces, draft-proofing, and insulation. To be eligible for this program, the applicant must meet the low income requirements stated in DSM Regulation. The ECAP database is, therefore, a reasonable source for analyzing the relationship between income and consumption for FEI's low income residential customers. The ECAP database contains the information on approximately 1,750 individual RS 1 customers who were part of this program since its initial launch in 2012. To study low income customers' consumption, FEI examined the 2015 normalized consumption for each residential premise number that was recorded in the database.

The figure below provides a histogram of the annual consumption of ECAP customers. The consumption pattern is similar to FEI's general consumption pattern (as provided in Figure 7-5 above) with a normal distribution skewed slightly to the right and an S-curve cumulative frequency diagram.

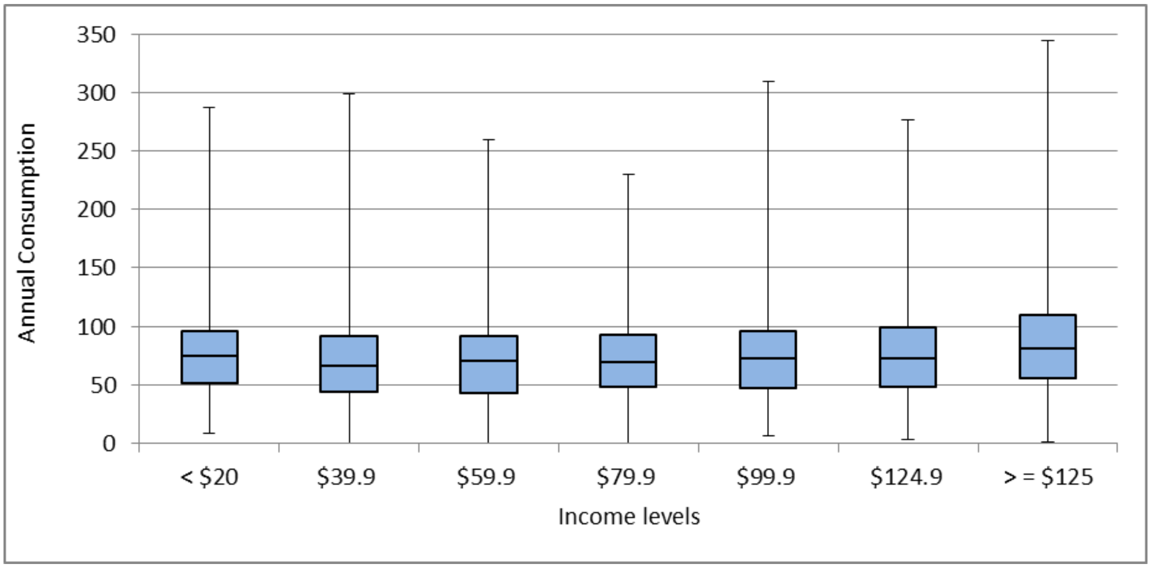
Figure 7-12: The 2015 Annual Consumption Histogram for Customers in ECAP



7.8.2.2 2012 REUS Database

The second source of information on residential customers' income levels and annual consumption in FEI's service territory is based on the 2012 REUS. In the 2012 REUS, approximately 31% of respondents chose not to answer questions regarding their income. The box plot below shows the consumption range by the upper household income limit for the respondents who provided their income and consumption range[119].

Figure 7-13: Income and Consumption Levels from 2012 REUS ($000s)



[119] There were over 2000 valid responses.

In the figure above, the bottom and top lines in each box represent the 1st and 3rd quartiles while the band inside the box is the 2nd quartile (median). The lines above and below of each box represent the minimum and maximum values of the data in that income group.

As demonstrated in the box plot above, there is no clear trend between income level and consumption, while there is a large amount of variability in terms of consumption within each income level group. The median annual consumption in the lowest income group is 75 GJ, which is close to the median annual consumption of 76 GJ for RS 1 as a whole (the average median of all income groups is approximately 73 GJ). In general, the data shows a lack of correlation between consumption and income level.

7.8.2.3 Conclusion on Low Income Customer Consumption

Both data sources discussed above lead to the conclusion that low income customers are not necessarily low use customers. This is logical considering that low income customers may be more likely to live in older and less efficient homes with less efficient appliances leading to higher natural gas usage for space heating and other purposes. Programs such as ECAP are designed to improve the efficiency of homes for low income customers.

The research into natural gas consumption and income levels in other jurisdictions supports FEI's conclusions. For instance, a 2015 study titled "*Public Policy and the Energy Needs of Low Income Families,*" published in the Journal of Sociology and Social Welfare, looked into the natural gas consumption pattern of a sample of low income households receiving help from the federally financed Low Income Households Energy Assistance Program (LIHEAP). The study concluded: "Natural gas consumption by LIHEAP households in the sample is comparable to consumption by all residential users."[120]

FEI believes there are effective and targeted means to assist low income households. Some of these targeted measures are explained in the next section.

7.8.2.4 Low Income Customer Assistance Measures

The government of B.C. has various programs that are specifically designed to assist with the affordability of energy for low income households. Some of these measures are directly designed for utility customers and some are broad and not specific to natural gas customers. For instance, the B.C. Low Income Climate Action Tax Credit[121] is a measure to offset the impact of the carbon taxes paid by low income individuals or families. This tax credit is not specific to natural gas customers but can be considered as an indirect partial subsidy to low income customers to offset the carbon tax amount on their monthly bills.

[120] Theisen, W.M. (2015) "Public Policy and the Energy Needs of Low Income Families, "*The Journal of Sociology & Social Welfare*: Vol. 20: Issue. 3, Article 7; p.97.

[121] The B.C. low income climate action tax credit helps offset the impact of the carbon taxes paid by low income individuals or families. One-quarter of the annual credit entitlement will be issued to eligible person four times a year. For example, if you are a single individual with no children and an income under $32,737, your quarterly low income climate action tax credit amount will be $28.88 ($115.50/4).

An example of programs specifically designed for low income residential customers includes those run by the Ministry of Social Development and Social Innovations (the Ministry), which consist of crisis assistance programs that specifically help utility customers. Under the Essential Utilities Supplement Program, a crisis supplement for essential utilities (fuel for heating and cooking, water and hydro are considered by this program as essential utilities) may be provided if recipients have reached their monthly or annual limit for crisis supplements, exhausted all resources, and do not have the ability to maintain essential utilities for their home when served with a disconnection notice or faced with the inability to re-establish essential utilities. The essential utilities supplement counts towards a recipient's cumulative annual limit for crisis supplements. Another program administered under the Ministry's supervision is the Utility Security Deposit program under which a supplement may be provided to assist recipients of income, hardship, and disability assistance with the cost of securing service for electricity or natural gas. This supplement is available under the Employment and Assistance Regulation and Employment and Assistance for Persons with Disabilities Regulation.

The DSM Regulation includes a policy initiative that is specific to low income natural gas customers. Under the Demand-Side Measures Regulation, a utilities' DSM portfolio is not adequate unless, among other things, it includes "*a demand-side measure intended specifically to assist residents of low income households to reduce their energy consumption*"[122]. To fulfil this requirement, FEI has developed and implemented a number of low income programs that are of no cost or low cost to low income participants. These programs are part of FEI's annual natural gas DSM program. In 2015, FEI's DSM program included three major low-income programs with a total expenditure of $1.55 million:

- <u>Energy Savings Kit (ESK) Program</u>: The ESK program enables low income customers to take simple steps towards saving energy by installing a bundle of easy to install items, such as high efficiency water fixtures, water heater pipe wrap, window film, etc.
- <u>Energy Conservation Assistance Program</u>: This program enables deep energy savings in low income customer homes and includes a bundle of customized measures such as professional draft proofing, insulation, improved ventilation and high efficiency furnaces. The majority of the low income DSM program budget is allocated to this program.
- <u>Residential Energy Efficiency Works (REnEW) Program</u>: This program targets individuals facing barriers to employment and provides training in energy efficiency retrofitting. The training is delivered by industry experts at no cost to participants.

B.C. government policy initiatives, therefore, provide support for low income natural gas customers, including through FEI's DSM funding.

7.8.3 Jurisdiction of the Commission Regarding Low Income Rates

At the time of filing this Application, the issue of the Commission's jurisdiction to implement low-income rates is currently being considered by the Commission in BC Hydro's rate design

[122] November, 2008, Ministerial Order No. M 271, Section 3[a].

proceeding. As reflected in FEI's joint submission with FortisBC Inc. in that proceeding, FEI's view is that the Commission does not have the jurisdiction to set rates based on the financial circumstances of FEI's customers. FEI has, therefore, not addressed this matter further in this Application.

7.9 CONCLUSION

In summary, FEI's review of RS 1, considering rate design principles, government policy, data analysis, jurisdictional comparisons and feedback from the stakeholder engagement process, demonstrates that the continuation of the flat rate structure with a 5% increase to the Basic Charge, and corresponding decrease to the volumetric Delivery Charge, reflects the appropriate balance of principles and other considerations.

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 customers' rates. The customer research survey results show that the flat rate structure is preferred by a majority of residential customers and is used by the majority of Canadian natural gas utilities for their residential customers.

A 5% increase in the Basic Charge and a corresponding decrease in the volumetric Delivery Charge achieve a reasonable balance among competing rate design considerations. A 5% increase to the Basic Charge will mitigate the subsidization of low-consumption customers, but will result in only an annual bill impact of less than +/-1% for the majority of customers, and a zero bill impact for an average use customer.

FortisBC Energy Inc.
2016 Rate Design Application

Section 8:

RATE DESIGN FOR COMMERCIAL CUSTOMERS

Table of Contents

8. RATE DESIGN FOR COMMERCIAL CUSTOMERS

8.1 *INTRODUCTION*

FEI conducted a full review of the rate design for its small commercial customers taking service under RS 2, RS 2U, RS 2X and RS 2B[123] (collectively referred to in this section as RS 2), and large commercial customers that take service under RS 3, RS 3U, RS 3X, RS 3B[124] (collectively referred to in this section as RS 3) and RS 23 (RS 23). FEI's review was guided by the legal context, rate design principles, and government policy as set out in Section 5 of the Application. FEI's review was also informed by FEI's data analysis, jurisdictional comparisons and feedback from the stakeholder engagement process. FEI considered the potential rate structure options for commercial customers (i.e., flat, declining or inclining block), customer segmentation, fixed and volumetric charges and intra-class rate economics.

Based on the analysis of the existing rate design and rate structure options for commercial customers, FEI is proposing to continue with the flat rate structure and a 2,000 GJ per year customer segmentation threshold for its commercial customers in RS 2 and RS 3/RS 23. The existing flat rate structure and customer segmentation are consistent with other jurisdictions. However, FEI believes that the rates for RS 2 and RS 3/RS 23 need minor adjustments to minimize the rate inequity for customers close to the 2,000 GJ threshold. FEI proposes to increase the Basic Charges and to reduce the Delivery Charges of RS 2, RS 3 and RS 23 to eliminate the customer bill differential for customers whose annual consumption is close to the 2,000 GJ threshold.

This section is organized as follows:

- Section 8.2 outlines the characteristics of the commercial customers taking service under the commercial RS 2, RS 3 and RS 23.
- Section 8.3 reviews the existing commercial rate design, including a review of the existing customer segmentation, economic crossover point between RS 2 and RS 3/RS 23, and rate structure, considering rate design principles, analysis of data and a jurisdictional comparison.

[123] The differences in RS 2, RS 2U, RS 2X and RS 2B pertain to the commodity portion of small commercial rates. In all cases the transportation and storage service (also called midstream service) and the delivery service are provided by FEI. Under RS 2 customers receive conventional natural gas from FEI as their commodity. Under RS 2U customers receive their commodity from a licensed natural gas marketer. In the event that there is a Marketer failure, customers that had been served by a Marketer under RS 2U, may be served under RS 2X. Under RS 2B customers receive commodity service from FEI, but have elected to receive a percentage of their natural gas as renewable natural gas (also called biomethane) with the balance being conventional natural gas.

[124] The differences in RS 3, RS 3U, RS 3X and RS 3B pertain to the commodity portion of large commercial rates. In all cases the transportation and storage service (also called midstream service) and the delivery service are provided by FEI. Under RS 3 customers receive conventional natural gas from FEI as their commodity. Under RS 3U customers receive their commodity from a licensed natural gas marketer. In the event that there is a Marketer failure, customers that had been served by a Marketer under RS 3U, may be served under RS 3X. Under RS 3B customers receive commodity service from FEI, but have elected to receive a percentage of their natural gas as renewable natural gas (also called biomethane) with the balance being conventional natural gas.

- Section 8.4 outlines how FEI has responded to the stakeholder feedback related to commercial rate design received from the stakeholder engagement process conducted prior to filing the Application.
- Section 8.5 discusses the rate design issues identified based on FEI's principle-based evaluation of the existing commercial rate design. FEI identifies two rate design issues: the relative rate economics of the commercial rate schedules and the existing customer segmentation threshold.
- Section 8.6 evaluates the potential options to resolve issues identified with the existing rate design, based on rate design principles and other relevant analysis and considerations.
- Section 8.7 provides proposed changes to the commercial rate design, balancing competing principles and other factors.
- Section 8.8 shows that the changes proposed by FEI do not cause a significant bill impact on the affected commercial customers.
- Section 8.9 concludes FEI's review of its commercial rate design with a summary of the results.

8.2 *COMMERCIAL CUSTOMER LOAD CHARACTERISTICS*

8.2.1 Introduction

FEI currently has a rate design for commercial customers comprised of a daily or monthly Basic Charge[125] that is fixed and a Delivery Charge per GJ for volumes delivered. Commercial customers are segmented into three rate schedules:[126]

- RS 2 - Small Commercial Service (normal annual consumption is less than 2,000 GJ)
- RS 3 - Large Commercial Service (normal annual consumption is 2,000 GJ or greater)
- RS 23 - Commercial Transportation Service (normal annual consumption is 2,000 GJ or greater)

Information on the commercial customers for each of these rate schedules is shown in Table 8-1 below.

[125] RS 2 and RS 3 have a daily Basic Charge and RS 23 has a monthly Basic Charge.
[126] Small commercial and large commercial customers can receive their base load commodity from a marketer under the Customer Choice Program under RS 2U and RS 3U, respectively. Alternatively, under RS 2B and 3B commercial customers can choose to purchase part or all of their commodity as biomethane (Renewable Natural Gas).

Table 8-1: Commercial Customer Data[127]

Rate Schedule	Avg # of Customers	% of Total Customers	Annual Demand Forecast (PJ)	% of Total Annual Demand	Average Load Factor	Basic Charge ($/day)	Delivery Charge ($/GJ)
RS 2 – Small Commercial	84,737	8.6%	28.0	13.5%	31.1%	$0.8161	$3.850
RS 3 – Large Commercial Sales	5,040	0.5%	18.1	8.7%	37.1%	$4.3538	$3.161
RS 23 – Large Commercial Transportation	1,669	0.2%	9.0	4.3%	36.9%	$4.3538	$3.161
Total Commercial	91,446	9.3%	55.1	26.5%			

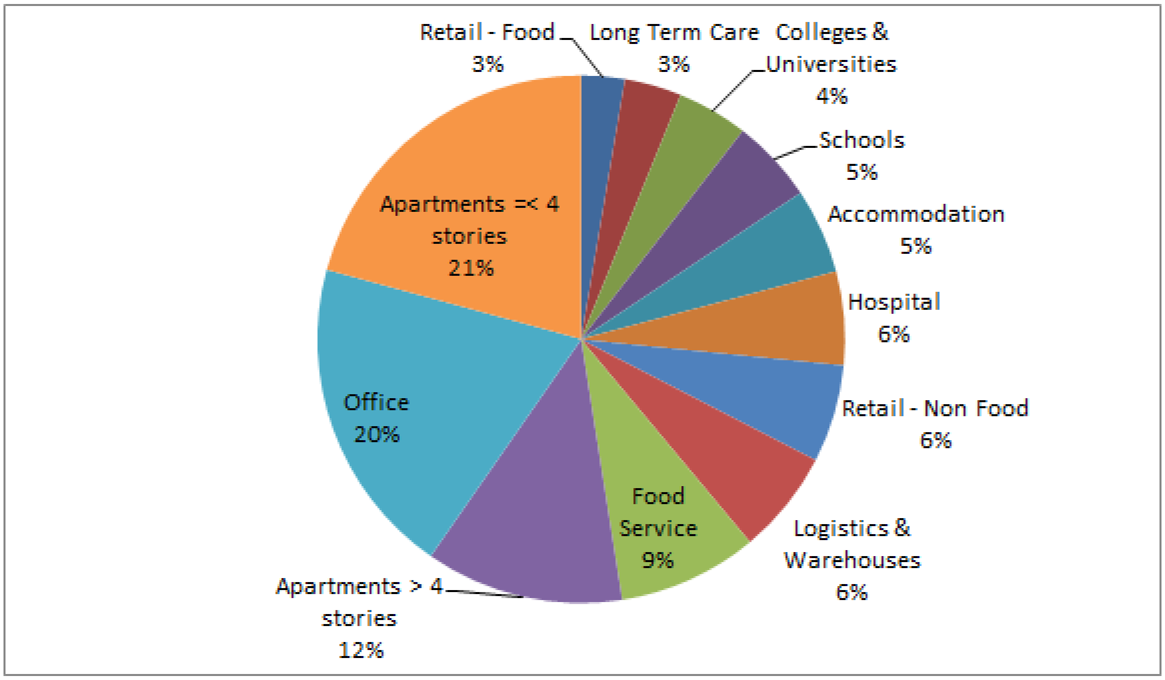
8.2.2 Commercial Customer Market Segments

Commercial customers cover a diverse range of natural gas end users which include restaurants, offices, health care facilities, retail outlets, apartments and numerous others, as shown below in Figure 8-1. FEI is currently serving more than 90,000 commercial customers accounts representing approximately 9% of FEI's total number of customers. Commercial customers also consume 55.1 petajoules (PJ) of natural gas representing 26.5% of FEI's total 2016 forecast throughput[128].

[127] Customer data are from Schedule 19 of the compliance filing for the Annual Review for 2016 Rates (Order G-193-15). The Basic and Delivery Charges in this table are estimated based upon the rates that were approved in the Annual Review for 2016 Rates, and including the known and measurable changes discussed in Section 6.

[128] FEI's compliance filing for the Annual Review for 2016 Rates (G-193-15), Schedules 18 and 19. Sum of forecast demand for RS 2, RS 3 and RS 23.

Figure 8-1: Commercial Customer Market Segments[129]

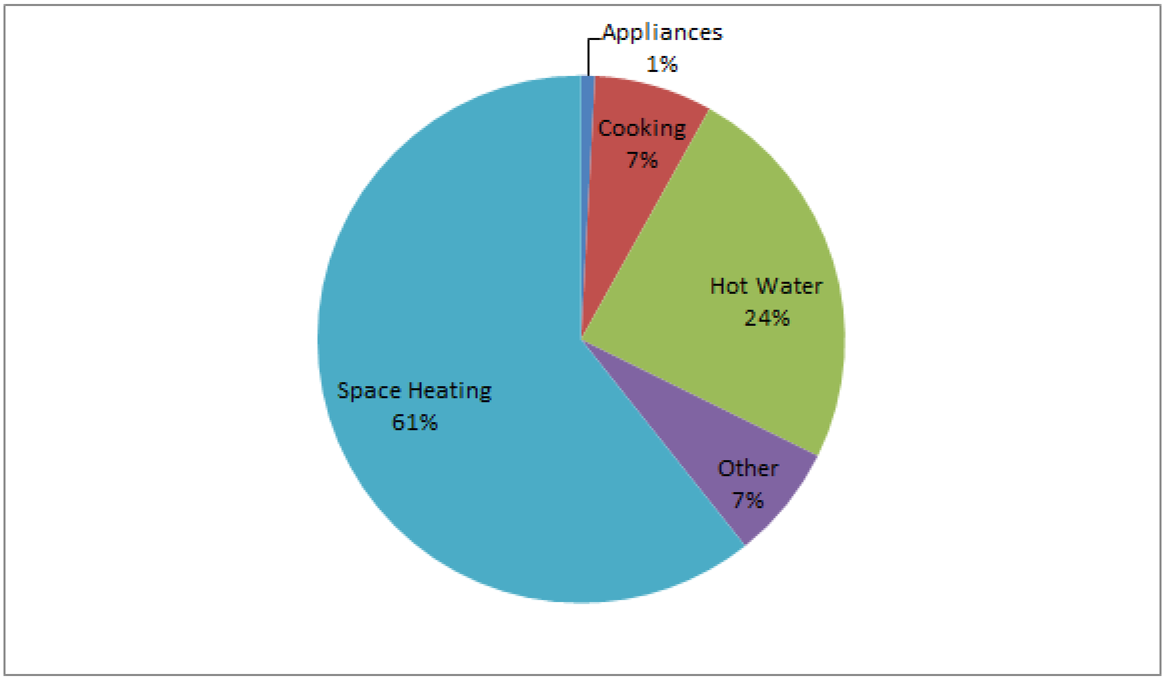


8.2.3 Commercial End Usage

FEI's Draft 2015 Conservation Potential Review (Draft CPR) study shows that for commercial customers, the highest end use is for space heating (61%) and the second highest end use is for domestic hot water (24%). This is illustrated in Figure 8-2 below.

[129] This figure is based on the draft results from the FEI 2015 Conservation Potential Review using a 2014 base year.

Figure 8-2: Commercial Customer End Usage Characteristics



8.2.4 Average Use per Customer

The average UPC for RS 2 and RS 3 has been relatively flat over time with a slight increase in average annual UPC for RS 23 customers, as shown in Figures 8-3 through 8-5 below.

Figure 8-3: RS 2 UPC

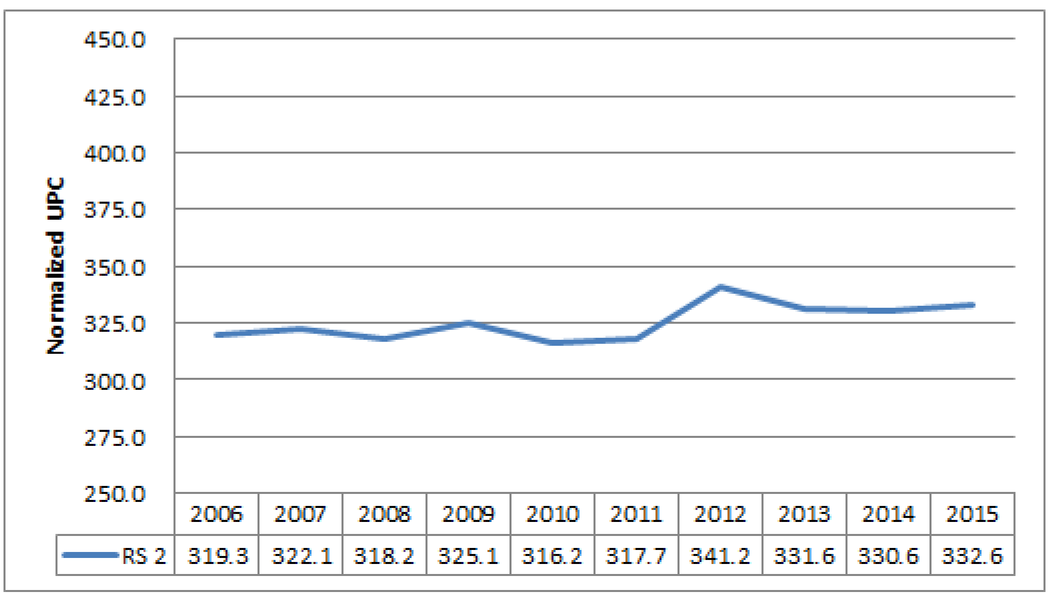


Figure 8-4: RS 3 UPC

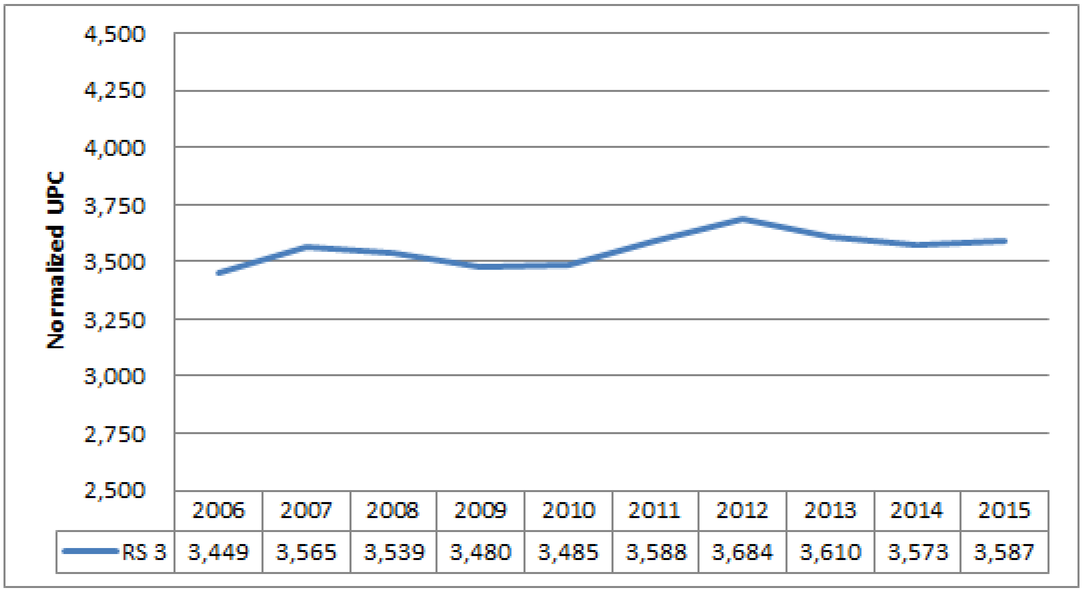
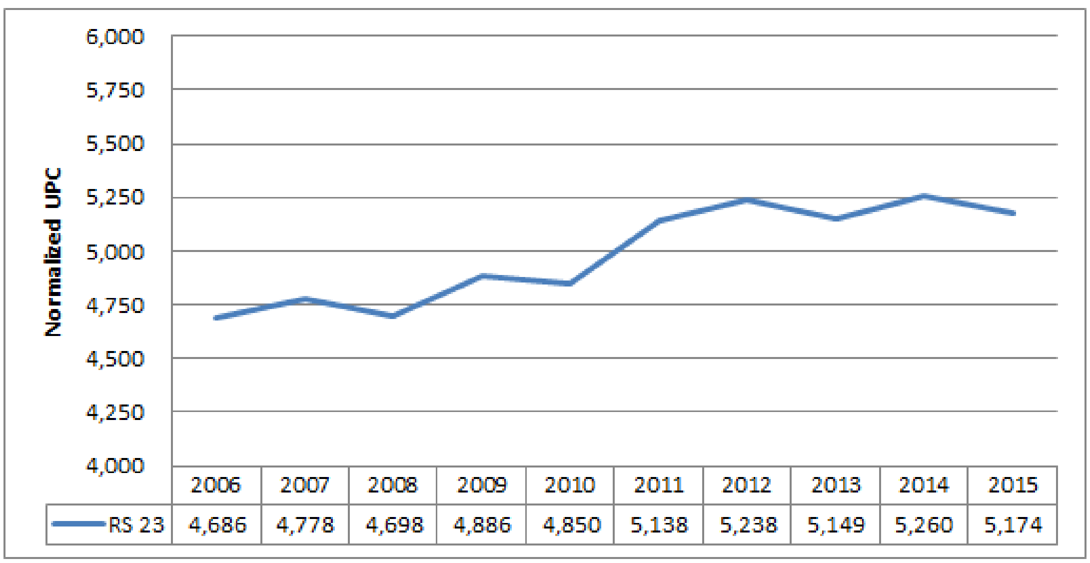


Figure 8-5: RS 23 UPC



8.3 *EXISTING RATE DESIGN*

8.3.1 Jurisdictional Comparison of Commercial Rates

FEI conducted a review of commercial customer rate schedules in other jurisdictions across Canada and the Pacific Northwest of the United States. The jurisdictional review is provided in Appendix 8. A summary is provided in Table 8-2 below.

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

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.

8.3.2 Review of Existing Customer Segmentation

FEI conducted a review of the segmentation threshold between the small commercial customer group (RS 2) and the large commercial customer groups (RS 3 and RS 23). For this review, FEI investigated the customer bill frequency data and customer load factor data. The analysis in the following two sections shows that the current segmentation threshold of 2,000 GJ/year remains reasonable.

[130] Sask Energy, Manitoba Hydro, Union Gas and Gaz Metro state their demand values in cubic metres These values have been restated into GJ equivalent using a conversion factor of 0.03825 GJ/m^3

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

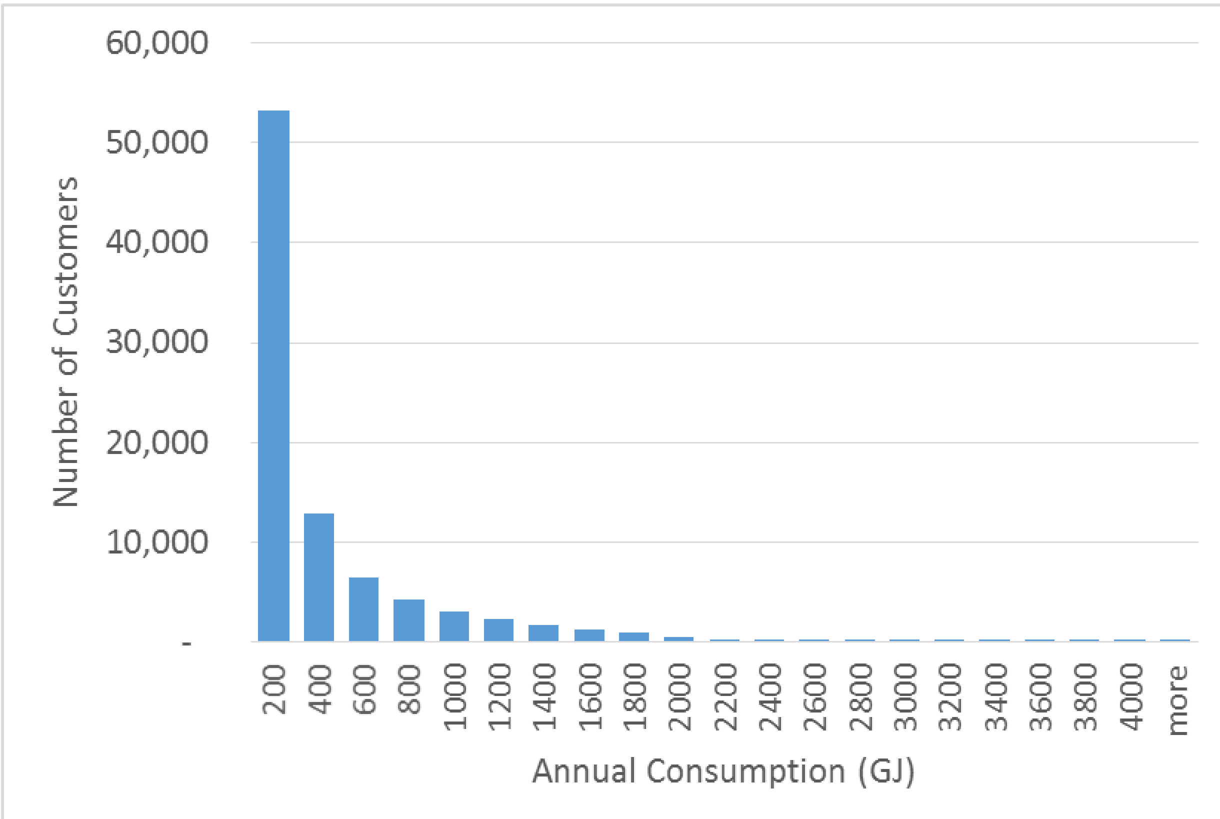
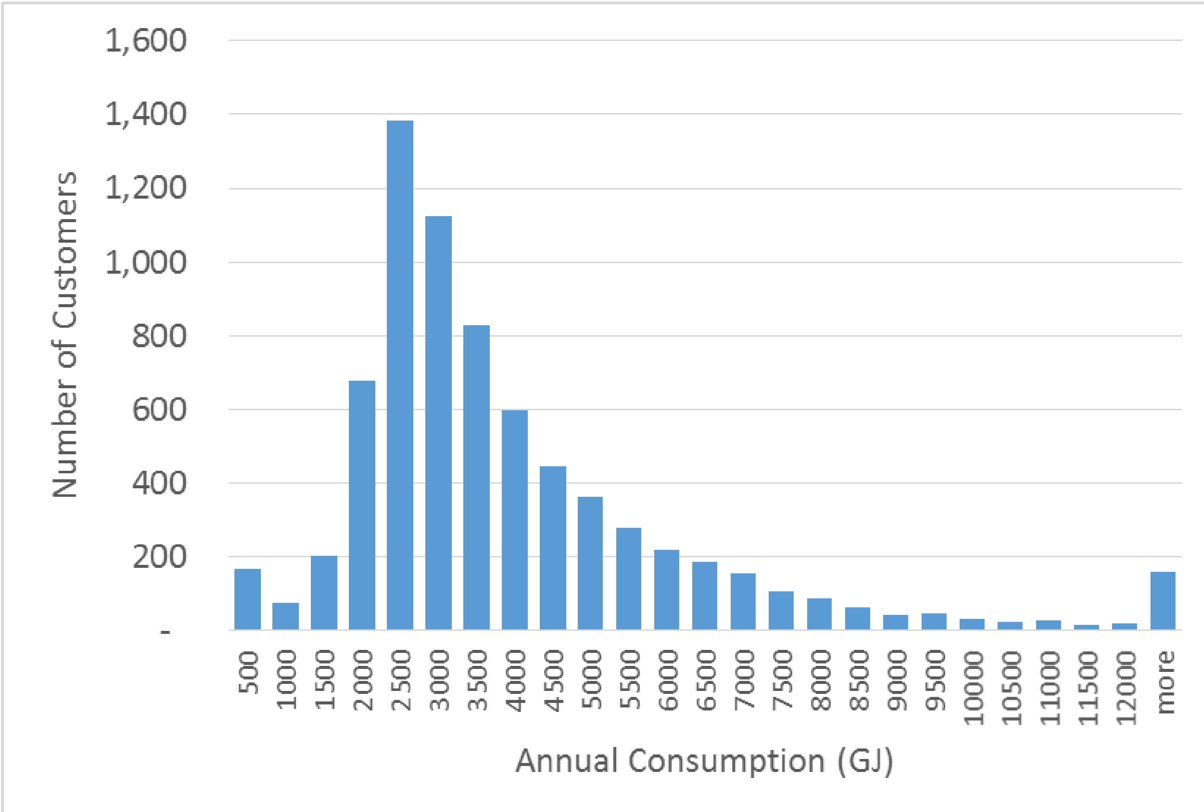


Figure 8-6 shows that approximately 72,000 (or approximately 85%) of the 85,000 small commercial customers use less than 600 GJ/year and approximately 84,000 (or 99%) customers use less than 2,000 GJ/year. There are approximately 600 customers whose annual consumption is greater than, the 2,000 GJ threshold. 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.

Figure 8-7: Large Commercial Customer Bill Frequency



As shown in Figure 8-7 above, approximately 4,600 out of 6,700, or 69%, of large commercial customers use between 2,000 GJ/year and 4,000 GJ/year. There are also approximately 1,100 large commercial customers (or 16% of the 6,700 total) that had consumption less than 2,000 GJ. Many of these customers are customers who have reduced their operations, who installed energy efficiency equipment during the year or whose business changed ownership or had only partial year operations. As noted above, FEI reviews customer consumption data annually and will move customers to another rate schedule as necessary. However, when these customers move between rate schedules, there will be a bill impact which FEI discusses further below.

8.3.2.2 Load Factor

FEI investigated the load factors for the existing small and large commercial customers. This analysis is shown in Figure 8-8 and Figure 8-9 below.

Figure 8-8: Small Commercial Customer Load Factor Distribution

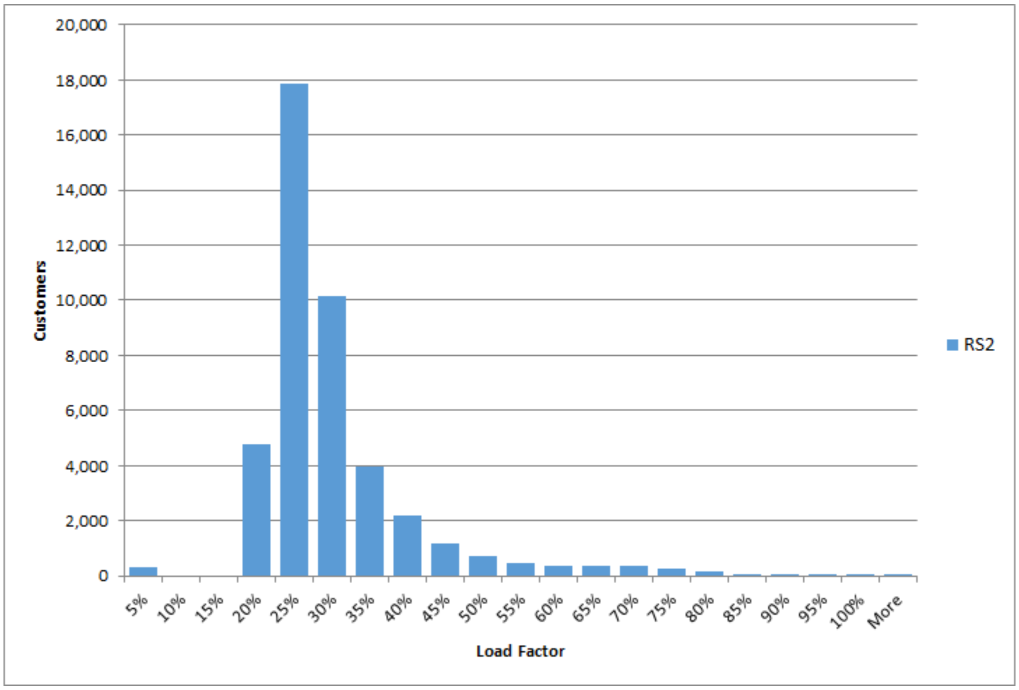
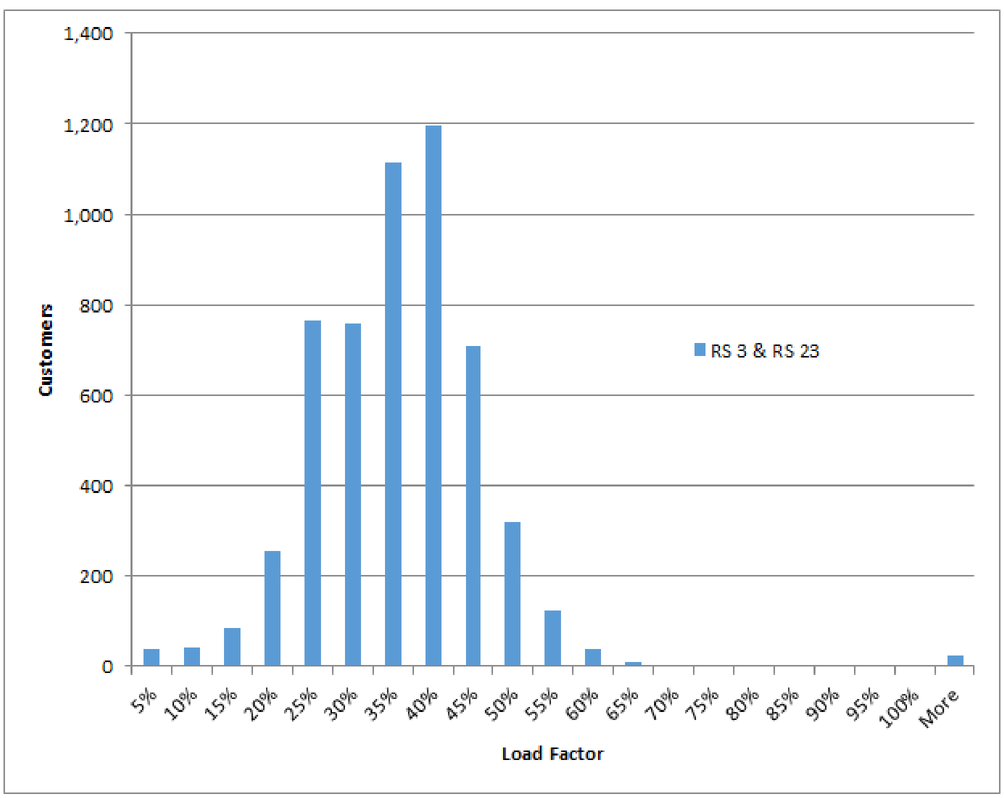


Figure 8-9: Large Commercial Customer Load Factor Distribution



Figures 8-8 and 8-9 support the customer segmentation into small and large customers based upon the difference in the average load factors for these two groups. Small commercial customers (RS 2) have an average load factor of 31.1%, compared to the large commercial customers (RS 3 and 23 combined) that have an average load factor of 37.0%.

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

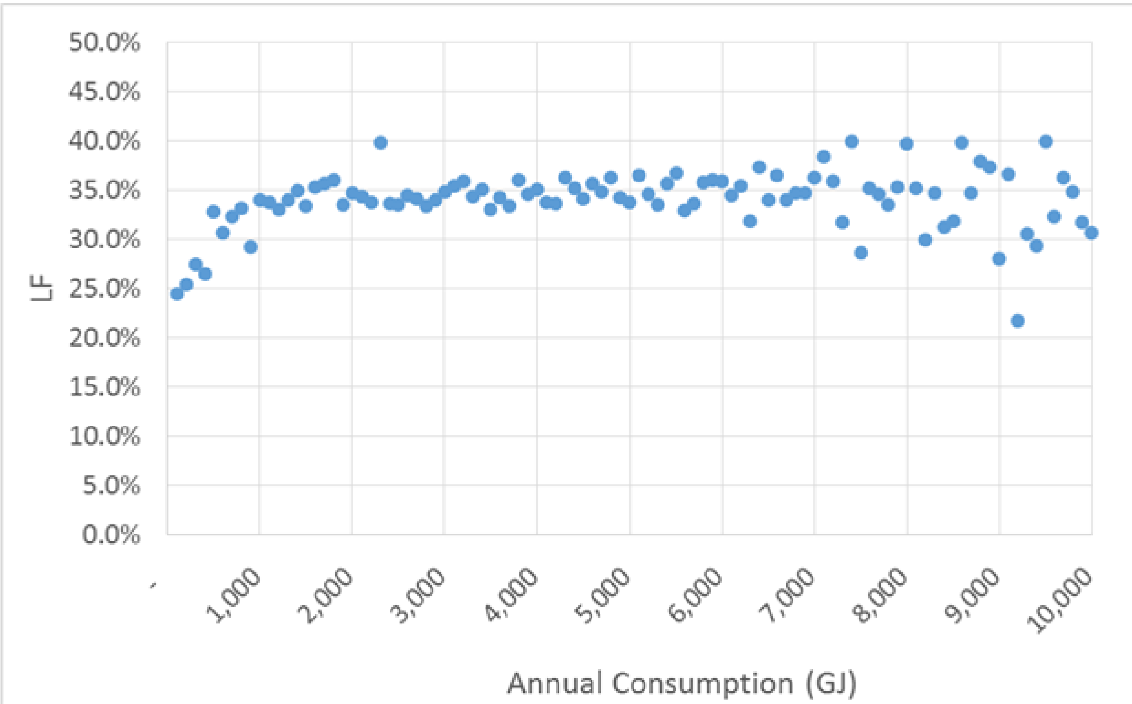


Figure 8-10 above is a chart showing commercial customer annual consumption in relation to load factor. The figure shows that the commercial customer load factor starts at a low of about 25% at around the 500 GJ/year level and increases to about 35% somewhere between 1,000 GJ/year and 2,000 GJ/year level, where it remains fairly constant through to higher levels of annual demand.

Given the load factor differentials, the current threshold of 2,000 GJ/year remains reasonable. While differences can be found at other threshold levels as well as at 2,000 GJ, the results would need to be significantly different to provide a compelling argument to move away from the existing threshold.

In the stakeholder engagement process, FEI received comments that other thresholds should be considered. FEI evaluates different thresholds in Section 8.6 below.

8.3.3 Economic Crossover Point between RS 2 and RS 3

The economic crossover point between RS 2 and RS 3 is the annual volume at which a customer would have the same annual total cost whether served under either RS 2 or RS 3.

The RS 2 and RS 3 should be aligned so that the economic crossover point occurs at the threshold between RS 2 and RS 3 of 2,000 GJ.

Table 8-3 below shows the calculation of the economic crossover between RS 2 and RS 3, which is at an annual consumption level of 1,457 GJ/year. This means that at current rates a customer who consumes more than 1,457 GJ and less than 2,000 GJ is better off financially as a RS 3 customer.

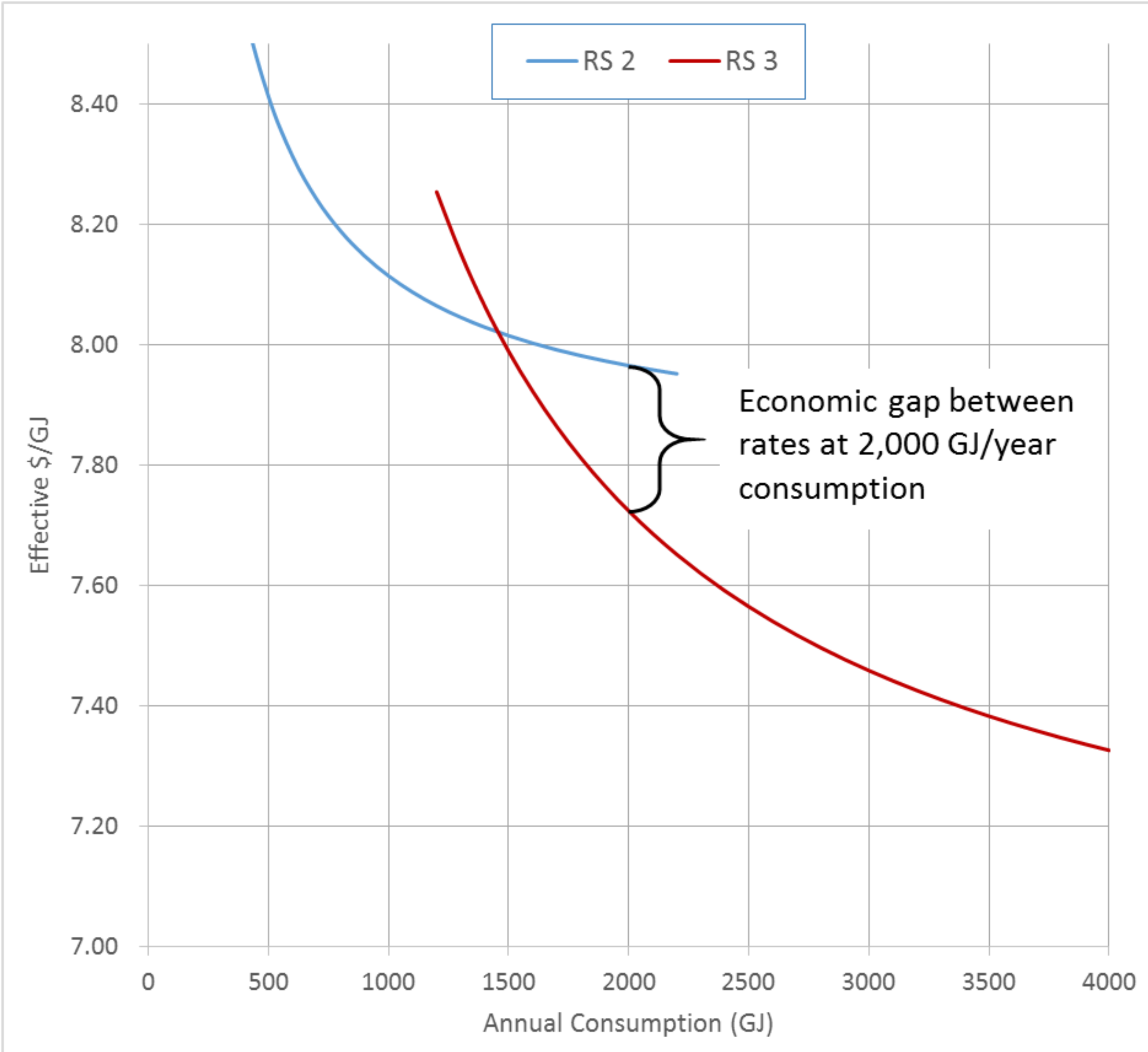
Table 8-3: Economic Crossover Volume for RS 2 and RS 3

Rate Components	RS 2	RS 3	Difference
1. Basic Charge (per day)	$0.8161	$4.3538	
2. Times number of days	365.25	365.25	
3. = Basic Charge Revenue	$298.08	$1,590.23	$1,292.14
4. Delivery Charge ($/GJ)	$3.850	$3.189	
5. Plus Cost of Gas ($/GJ)[131]	$3.967	$3.741	
6. = Total Variable Cost ($/GJ)	$7.817	$6.930	$0.887
7. Economic Crossover Point (Line 3/Line 6)			**1,457 GJ**

The economic crossover point is presented graphically in Figure 8-11 below. The figure shows that a customer who consumes 2,000 GJ/year would decrease their average rate by approximately $0.25/GJ by moving from RS 2 to RS 3.

[131] For the purpose of this calculation, FEI uses the gas costs from the compliance filing for the Annual Review for 2016 Rates (Order G-193-15).

Figure 8-11: Relative Economics between RS 2 and RS 3



In the sections below, FEI considers options for addressing this misalignment between RS 2 and RS 3.

8.3.4 Review of Commercial Rate Structure

The current commercial rate structure consists of a flat rate with a basic charge and delivery charge.

FEI reviewed the rate structure options for commercial customers. The options for commercial customers are a flat rate structure, declining block rate structure, seasonal rate structure and inverted block rate structure. These options are discussed in Section 7.4 Rate Structure Options for Residential Customers. The evaluation of each of the rate structure options in that section is applicable to the commercial rate schedules as well.

FEI concludes that its existing flat rate structure provides the best balance of rate design considerations for commercial customers. FEI's commercial 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. In addition, the review of commercial rate structures used by other Canadian utilities shows that a flat rate structure is used by the majority of Canadian utilities. FEI's therefore believe that the flat rate structure remains reasonable for the commercial rate schedules.

8.3.5 Fixed versus Variable Charge Alignment

When reviewing existing rate design and setting rates, and according to the fair apportionment of cost principle, FEI seeks to align cost recovery with cost causality. FEI therefore reviewed the alignment between the Basic Charge and the customer costs allocated to the commercial rate schedules from the COSA model.

Table 8-4 below compares the customer-related fixed costs with the fixed revenues received for commercial rate schedules.

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

Rate Schedule	Current Monthly Basic Charge[132]	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.

[132] The monthly charge is calculated by multiplying the daily charge by 365 days and dividing by 12 months.

Although the Basic Charge reasonably recovers customer-related costs, as discussed below in Section 8.6.3, FEI is proposing to increase the basic charges to align the intra-class rate economics between RS 2 and RS 3/RS 23.

8.4 *STAKEHOLDER FEEDBACK AND RESPONSE*

As discussed in Section 4, FEI circulated a Rate Design and Segmentation Discussion Guide to all interested stakeholders and held a workshop on August 31, 2016. This Guide and Workshop described FEI's current commercial rate structures and presented a number of rate structure options that FEI had under consideration. FEI undertook to respond to several requests from stakeholders at the workshop. The relevant stakeholder input is summarized in Table 8-5 below along with FEI's response. Detailed Meeting Summary and Notes are attached as Appendix 4-2.

Table 8-5: Outstanding Items from Rate Design Workshop and FEI's Actions

Topic	Item	FEI's Action/Response
Customer segmentation between small and large commercial customers	Revise the load factor scatter plot for the commercial customers.	The commercial customer load factor analysis is revised and provided as Figure 8-10 in Section 8.3.2.2.
Customer segmentation between small and large commercial customers	Confirmation that FEI will be looking into the RS 2 to RS 3 segmentation threshold at 1,600 GJ	FEI has investigated two options for moving the customer segmentation threshold between RS 2 and RS 3 below in Section 8.6. However, using 2016 rates with known and measurable changes, the economic threshold for RS 2 and RS 3 annual bill equivalence has moved to 1,400 GJ/year for this evaluation.
Commercial customer rate stability options	FEI should evaluate and discuss the segmentation options from a rate stability perspective.	FEI has evaluated three rate design options in Section 8.6 and provided a discussion comparing these options from a rate stability perspective.

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.

These facts, combined with R:C ratios for RS 2, RS 3 and RS 23 that are well within the 95% to 105% range of reasonableness, suggest that the existing commercial rate design strikes a reasonable balance on the rate design principles set out in Section 5.3. However, FEI identified two potential and related issues with the current commercial rate design: the economic cross-over point between RS 2 and RS 3/RS 23, and the customer segmentation threshold. Each of these issues is discussed below.

- **Economic Crossover Point:** As shown above in Section 8.3.3 and Figure 8-11, the economic cross-over point between RS 2 and RS 3/RS 23 is at approximately 1,400 GJ/ year. Therefore, the current rates in these rate schedules provide inappropriate price signals for small commercial customers consuming between 1,400 GJ and the 2,000 GJ threshold. This misalignment gives an incentive to customers on RS 2 to consume more energy so they can move above the 2,000 GJ threshold to achieve a lower rate and bill. The misalignment might also cause rate instability for customers whose year-to-year fluctuations in annual demand may occasionally cause them to move back and forth between these rate schedules. This can also cause revenue instability for the utility.
- **Customer Segmentation Threshold:** As shown above in Section 8.2.6 and Figure 8-10, the commercial customer load factor starts at a low of about 25% at around the 500 GJ/year level and increases to about 35% at the 2,000 GJ/year level where it remains fairly constant through to higher levels of annual demand. Based upon load factor, the customer segmentation threshold could conceivably range from 1,000 to 2,000 GJ/year. At 2,000 GJ/year the load factor in Figure 8-10 indicates that 2,000 GJ/year remains an appropriate threshold between small and large commercial customers because the load factor flattens out after this level of consumption. FEI currently uses a 2,000 GJ/year threshold to segment the commercial customers into small and large rate schedules – RS 2 and RS 3/RS 23, respectively.

The existing inter-class rate economics for commercial customers and the customer segmentation threshold are rate design issues since they suggest that there is room to improve the alignment with the following rate design principles:

- Principle 2 – Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates),
- Principle 3 – Price signals that encourage efficient use,
- Principle 6 – Rate stability,
- Principle 7 – Revenue stability, and
- Principle 8 – Avoidance of undue discrimination (specifically regarding interclass equity)

To revise the rate design to better align with rate design principles, FEI has evaluated three rate design options in Section 8.6 below.

8.6 *COMMERCIAL RATE DESIGN OPTIONS*

FEI has considered three options to improve the economics between RS 2 and RS 3, based on a range of potential thresholds that could potentially be implied from the customer load factor analysis.

- The first option is to move the threshold between small and large commercial customers from the existing level of 2,000 GJ downward to 1,000 GJ, which would be the lowest threshold that could potentially be implied by the customer load factor analysis discussed above in Section 8.3.2.2.
- The second option is to move the threshold between small and large commercial customers from the existing level of 2,000 GJ/year downward to 1,400 GJ, which would align the threshold with the current economic crossover point discussed above in Section 8.3.3.
- The third option is to retain the existing 2,000 GJ threshold, but adjust the fixed and variable components of the rates for RS 2 and RS 3/RS 23 so that the small commercial and large commercial rates are aligned at this threshold.

Each of these options is discussed in detail below.

8.6.1 Option A – Move the Threshold between Small and Large Commercial Customers to 1,000 GJ

Option A is to adjust the threshold between small and large commercial customers from 2,000 GJ/year down to 1,000 GJ/year.

FEI has investigated the option and the implications of moving to a 1,000 GJ/year threshold. By setting the segmentation threshold at this lower level, a significant number of customers would be required to move from RS 2 to RS 3. Using the customer billing data shown above in Figures 8-6 and 8-7, FEI has analysed the impact of moving customers and their related annual demand from RS 2 to RS 3. This migration effect is shown in Table 8-6 below.

Table 8-1: Potential Customer Migration Impact of a 1,000 GJ/year threshold[133]

Rate Schedule	Number of Customers	Annual Energy (PJ)	Change to Rate Schedule Energy (%)	Average Usage (GJ/year)	Load Factor (%)	Revenue Shift ($ millions)
RS 2 currently < 2,000 GJ/year threshold	84,737	28.0		330	30.7	
Remove RS 2 customers >	(6,682)[134]	(9.1)	(33%)	1,362	34.8	(37.0)

[133] Analysis based on customers and demand from the compliance filing for the Annual Review for 2016 Rates (Order G-193-15).

Rate Schedule	Number of Customers	Annual Energy (PJ)	Change to Rate Schedule Energy (%)	Average Usage (GJ/year)	Load Factor (%)	Revenue Shift ($ millions)
1,000 GJ/year						
RS 2 revised to < 1,000 GJ/year	78,055	18.9		242	29.1	
RS 3/23 currently > 2,000 GJ/year threshold	6,709	27.1		3,590	36.7	
Add RS 2 customers > 1,000 GJ/year	6,682	9.1	34%	1,360	34.8	39.6
RS 3/23 revised to > 1,000 GJ/year	13,391	36.2		2,703	36.2	
Net Revenue Shift						2.6

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.

8.6.2 Option B – Move the Threshold between Small and Large Commercial Customers to 1,400 GJ

Option B is to adjust the threshold between small and large commercial customers from 2,000 GJ to 1,400 GJ. A 1,400 GJ segmentation threshold would align with the current economic crossover point between RS 2 and RS 3/RS 23, as discussed above in Section 8.3.3 and shown in Table 8-3.

FEI has investigated the customer billing data from 2015 to determine how many customers would be affected by this option. This analysis is summarized in Table 8-7 below.

[134] This is an estimate of the RS 2 customers that would migrate due to the shift in the segmentation threshold to 1,000 GJ/year.

Table 8-2: Potential Customer Migration Impact of a 1,400 GJ Threshold

Rate Schedule	Number of Customers	Annual Energy (PJ)	Percentage Change to Rate Schedule Energy Total	Average Usage (GJ/year)	Load Factor (%)	Revenue Shift ($ millions)
RS 2 currently < 2,000 GJ/year threshold	84,737	28.0		330	30.7	
Remove customers > 1,400 GJ/year	(2,727)[135]	(4.5)	(16%)	1,650	36.6	($18.1)
RS 2 revised to < 1,400 GJ/year	82,010	23.5		287	29.8	
RS 3/23 currently > 2,000 GJ/year threshold	6,709	27.1		3,590	36.7	
Add RS 2 customers > 1,400 GJ/year	2,727	4.5	17%	1,650	36.6	18.7
Rate Schedule 3/23 revised to > 1,000 GJ/year	9,436	31.6		3,349	36.7	
Net Revenue Shift						0.6

By moving the annual energy threshold from the existing 2,000 GJ limit down to 1,400 GJ, this option would move approximately 2,700 small commercial customers from RS 2 to RS 3. The movement to RS 3 would represent an increase of approximately 41% in the number of customers and 17% of the energy in the large commercial group. Although this option has a smaller customer migration effect and causes proportionately less change to average customer use and load factors, it is still a material change. It would also lead to a $600 thousand net revenue shift to RS 3 that would need to be considered when reviewing the revenue rebalancing as discussed in Section 12.

This option is very similar to Option A, and although it causes less customer disruption, it is still significant and causes all of the other related customer impacts discussed above in Section 8.6.1. Therefore, FEI does not recommend re-setting the customer segmentation threshold on this basis.

8.6.3 Option C – Adjust the Basic and Delivery Charges for Commercial Customers

Instead of altering the threshold between the small and large commercial customers as considered in options A and B, Option C is to alter the Basic and Delivery Charges for both RS

[135] This is an estimate of those customers in RS 2 that would migrate due to the shift in the segmentation threshold to 1,400 GJ/year.

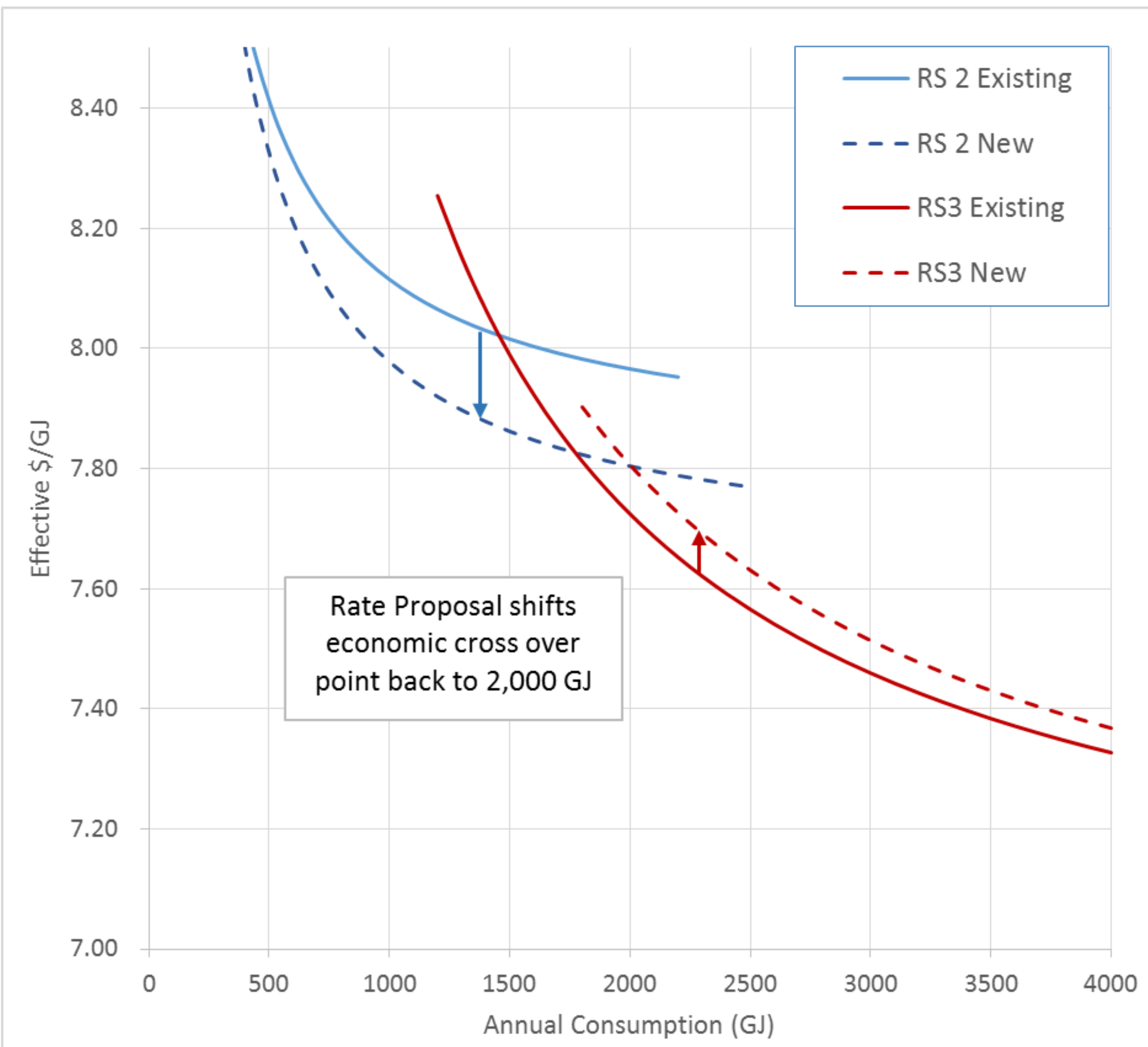
2 and RS 3/RS 23 so that the relative economics of RS 2 and RS 3/RS 23 are aligned with the existing 2,000 GJ/year threshold.

This option has the benefit of not causing the customer migration related disruptions by moving the segmentation threshold as considered in Options A and B. Instead, this option will require an adjustment to the customer rates and will cause customer rate impacts and a revenue shift.

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



This adjustment to the RS 2 and RS 3/RS 23 charges will align the RS 2 and RS 3/RS 23 charges with the economic crossover point between the rate schedules without the significant customer disruption caused by moving the current 2,000 GJ threshold as contemplated in Options 1 and 2. Option 3 is therefore the most reasonable rate design option for the commercial rate schedules.

8.7 *COMMERCIAL RATE DESIGN PROPOSAL*

The current rate design for the small and large commercial customers continues to work well. The multi-jurisdiction review and consideration of rate design principles support the continued use of a flat rate structure. The multi-jurisdiction review and the load factor analysis show that there is a range of acceptable customer segmentation thresholds. Based on the rate design issues identified and potential options available, FEI is proposing to increase the Basic Charge for RS 2, RS 3 and RS 23 and adjust the Delivery Charge to achieve revenue neutrality for the combined RS 2, RS 3 and RS 23 revenues, and eliminate the customer bill differential between RS 2 and RS 3/RS 23 for customers whose annual consumption is equal to 2,000 GJ. With this proposal, the R:C ratios continue to be within the range of reasonableness[136].

As discussed above, FEI evaluated three options to make the economic cross-over point between RS 2 and RS 3/RS 23 accord with the tariff threshold as noted in Section 8.3. Of these three options, the one that causes the least disruption or impact on customers is the third option which proposes minor changes to the customer Basic Charge and Delivery Charge for RS 2 and RS 3/RS 23. These proposed changes are shown below in Table 8-8. With these changes, FEI will eliminate the customer bill differential between RS 2 and RS 3/RS 23 for customers whose annual consumption is close to the 2,000 GJ threshold[137].

Table 8-3: Proposed Changes to Commercial Rates

Rate Schedule	COSA[138] Based Rate	Proposed Rate	Proposed Change
RS 2 – Small Commercial			
Basic Charge (daily)	$0.8161	$0.9485	$0.1324 or 16.2%
Delivery Charge ($/GJ)	$3.850	$3.664	$-0.186 or -4.8%
RS 3/23 – Large Commercial			
Basic Charge (daily)	$4.3538	$4.7895	$0.4357 or 10.0%
Delivery Charge ($/GJ)	$3.188	$3.189	$0.001 or 0.03%

[136] Refer to Section 12

[137] As noted in Table 8-3 the gas cost differential between RS 2 and RS 3 affects the economic crossover point. The gas cost differential has been accounted for in the proposed rates shown in Table 8-8.

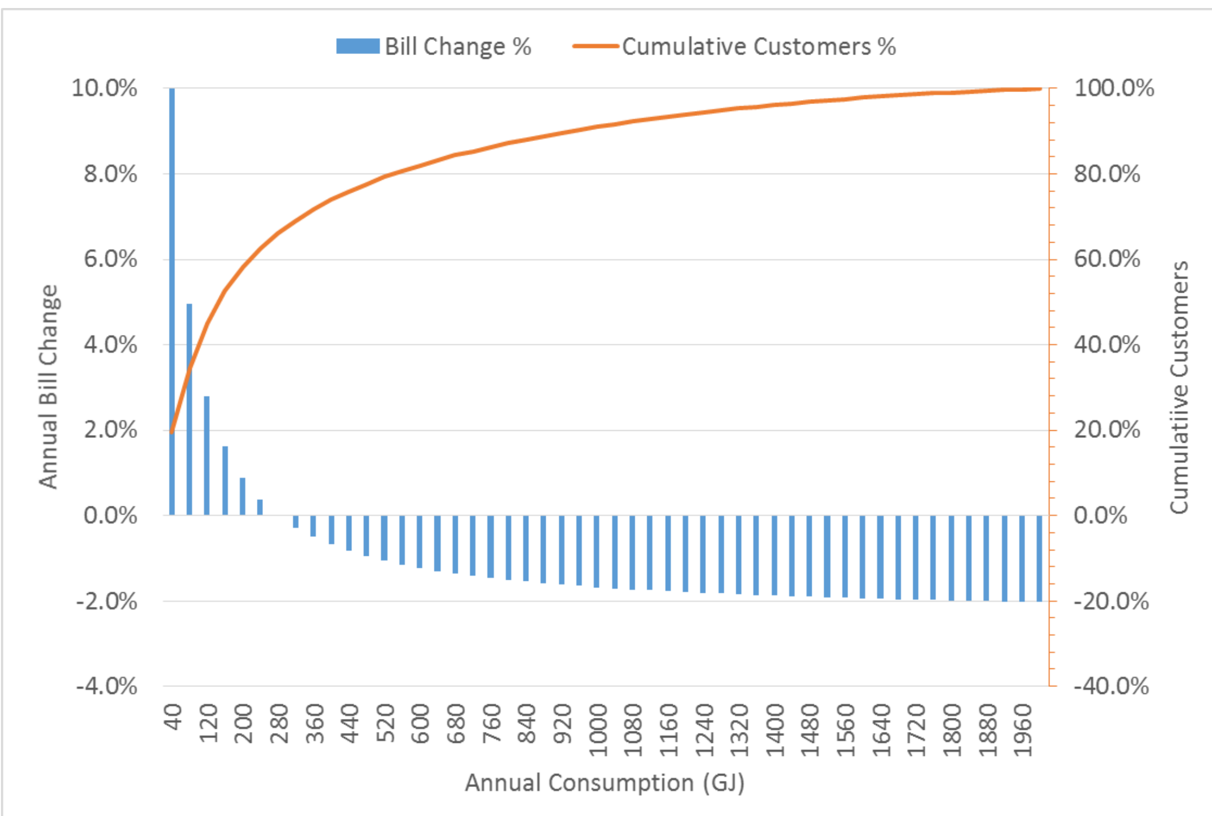
[138] The COSA rates shown are 2016 approved rates plus known and measurable changes discussed in Section 6.

The increase to the Basic Charge for RS 2 and RS 3/RS 23 is also supported by the rate design consideration of cost causation, as the allocated cost per customer from the COSA model is $1.323/day for RS 2 and $8.490/day for RS 3/RS 23. For example, raising the RS 2 Basic Charge from $0.8161/day to $0.9485/day, as shown above, will bring it closer to the allocated cost of $1.323/day.

8.8 *BILL IMPACT ANALYSIS*

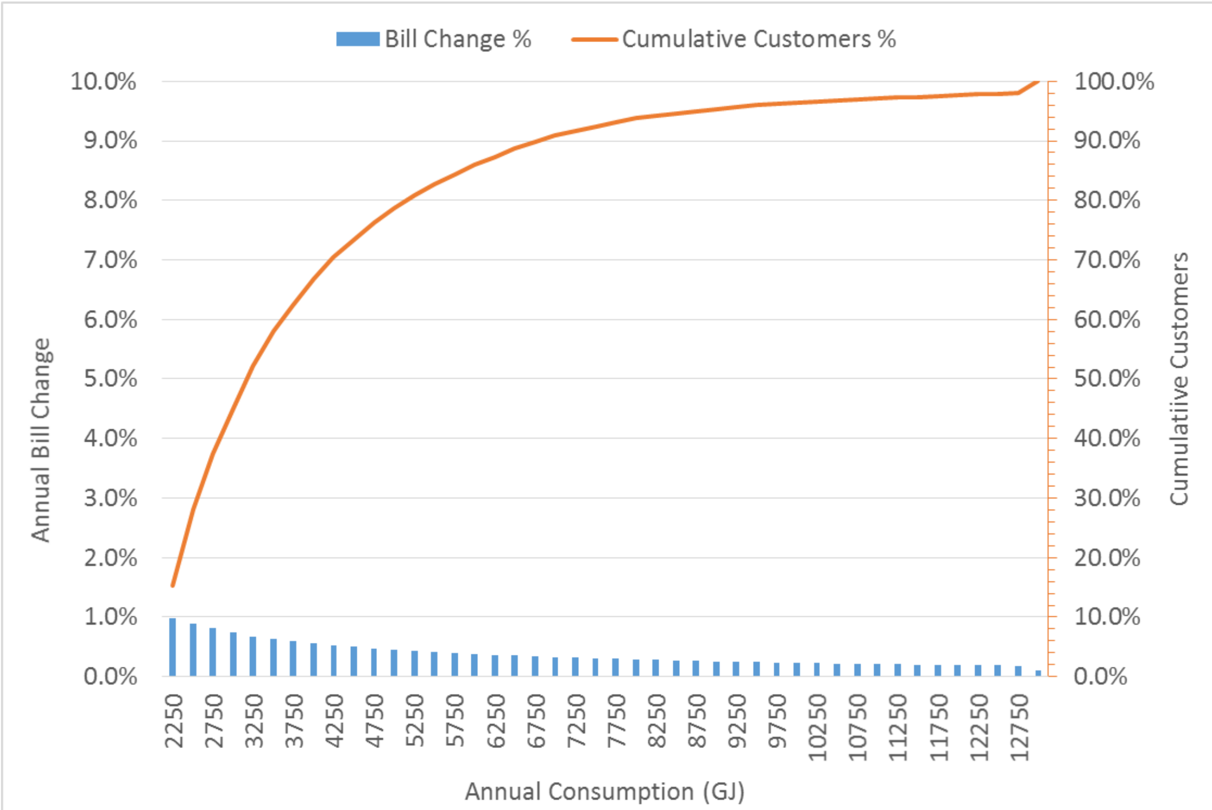
The customer bill impacts of FEI's proposed rate changes are shown below in Figures 8-13 and 8-14. As shown below, using customer data from 2015, FEI has estimated that with the proposed rates, RS 2 customers would receive an annual bill change of between -2.0% and +10%[139] and RS 3/RS 23 customers would receive a maximum bill change of between +0.1% and +1.0%.

Figure 8-13: RS 2 Bill Impact Analysis



[139] The +10% change pertains to small volume customers (<40 GJ/year) and is a small dollar amount (in the range of $45 annually)

Figure 8-14: RS 3/RS 23 Bill Impact Analysis



This figures show that the changes proposed by FEI do not cause a significant impact on the affected commercial customers.

8.9 *CONCLUSION*

In summary, FEI's review of the commercial rate schedules has considered the rate design principles, government policy, customer data analysis, multi-jurisdictional comparisons and feedback from the stakeholder engagement process.

FEI believes that the current rate design and customer segmentation threshold for the small and large commercial customers continue to work well.

The existing flat rate structure applied to these commercial rate schedules provides the best balance of the rate design considerations. Flat rates are simple to administer and easy to understand and provide more stable utility revenues and customer rates. The multi-jurisdiction review shows that the majority of Canadian natural gas utilities use flat rates for their commercial customers.

Also, the multi-jurisdiction review and the load factor analysis show that there is a range of customer segmentation thresholds, and therefore, there is no strong evidence to support a change in the threshold from the 2,000 GJ/year level.

However, FEI believes that the rate economics between RS 2 and RS 3/RS 23 need minor adjustments to minimize the rate inequity for customers close to the 2,000 GJ threshold.

Based on the rate design issues identified FEI has evaluated three potential solutions. Of these solutions, the one that causes the least disruption or impact on customer rates and revenues is Option C, which proposes minor changes to the customer Basic Charge and Delivery Charge for RS 2 and RS 3/RS 23.

FortisBC Energy Inc.
2016 Rate Design Application

Section 9:

RATE DESIGN FOR INDUSTRIAL CUSTOMERS

Table of Contents

9. RATE DESIGN FOR INDUSTRIAL CUSTOMERS

9.1 *INTRODUCTION*

FEI conducted a full review of the rate design for its industrial rate schedules (RS 4, RS 6, RS 5/RS 25, RS 7/RS 27, RS 22 and Large Industrial Contract Customers) guided by the legal context, rate design principles and government policy as set out in Section 5 of the Application. FEI's review was informed by data analysis, jurisdictional comparisons and feedback from the stakeholder engagement process. FEI's review of the rate design considered the potential rate structure options for industrial customers (i.e., flat, declining or inclining block) and the possible blends of fixed and volumetric charges. As discussed in this section, FEI identified a number of rate design issues, considered options to resolve those issues and has made proposals based on the best balance of competing principles in the context of each rate schedule. FEI's conclusions regarding each of the industrial rate schedules are summarized in the following paragraphs.

FEI's General Firm Service (RS 5 and RS 25) is designed to serve high load factor and process customers with efficient utilization of the system. RS 5/RS 25 has a Demand Charge designed to provide lower average rates to these higher load factor customers. The Demand Charge includes a peak day demand formula with a 1.25 multiplier to estimate the peak day demand from the average peak monthly demand. Based on peak daily consumption information that was not fully available when the RS 5/RS 25 demand charge was originally designed, FEI is proposing to update the multiplier in the peak day demand formula from 1.25 to 1.1. As a consequence of the above change, FEI is also proposing to raise the Demand Charge for RS 5 and 25 by $3.00 per month to continue to provide a price signal for only high load factor customers to take General Firm Service.

The discount from firm service under the existing RS 7 and RS 27 interruptible service charges achieves a reasonable balance between maximizing the economic value of interruptible service, which helps to offset utility costs to firm customers, and providing a sufficient incentive for existing customers to stay on interruptible service and to attract new customers. FEI is therefore proposing to retain the current interruptible service rate structure and the method of calculating RS 7 and RS 27 delivery charges based on a discount from RS 5/RS 25. FEI is proposing to update the RS 7 and RS 27 delivery charge calculation to reflect the change in the Daily Demand formula (discussed above under RS 5/RS 25), including a 62.5% firm service load factor assumption and a 90.9% load factor discount.

For seasonal customers, FEI is proposing to maintain the existing rate structures and methodology to derive the RS 4 Delivery Charges. Since the RS 4 Delivery Charges are based on RS 5 and RS 7, FEI is proposing to update the RS 4 Delivery Charges to reflect the changes discussed above to RS 5 and RS 7.

Fifteen public refueling stations take service under RS 6 Natural Gas Vehicle Service. As this rate structure is working well and is not impacted by any changes from the other rate schedules, aside from the Delivery rate change due to rebalancing (Refer to Section 12), FEI is not proposing any changes in this Application, and there is no further discussion of its structure in this section.

For FEI's large industrial customers which take service under RS 22, RS 22A, RS 22B or individual contracts (the VIGJV and BC Hydro IG), FEI's existing rates are currently separated by geographical regions and there is no postage stamp, cost-based firm rate. FEI is proposing to continue to grandfather RS 22A and RS 22B as closed service offerings due to their unique characteristics. For all other large industrial customers, FEI is proposing to create a firm rate under RS 22 based on the allocated cost from the COSA model. This firm rate would be available for all large industrial customers, including VIGJV and BC Hydro IG when their contracts expire. Under this option, Tariff Supplement G-21 for Creative Energy would be terminated and the contract for BC Hydro IG would be included as a Tariff Supplement at their current rates. The RS 22 interruptible Delivery Charge will be set equal to the effective average cost per GJ of the firm rate.

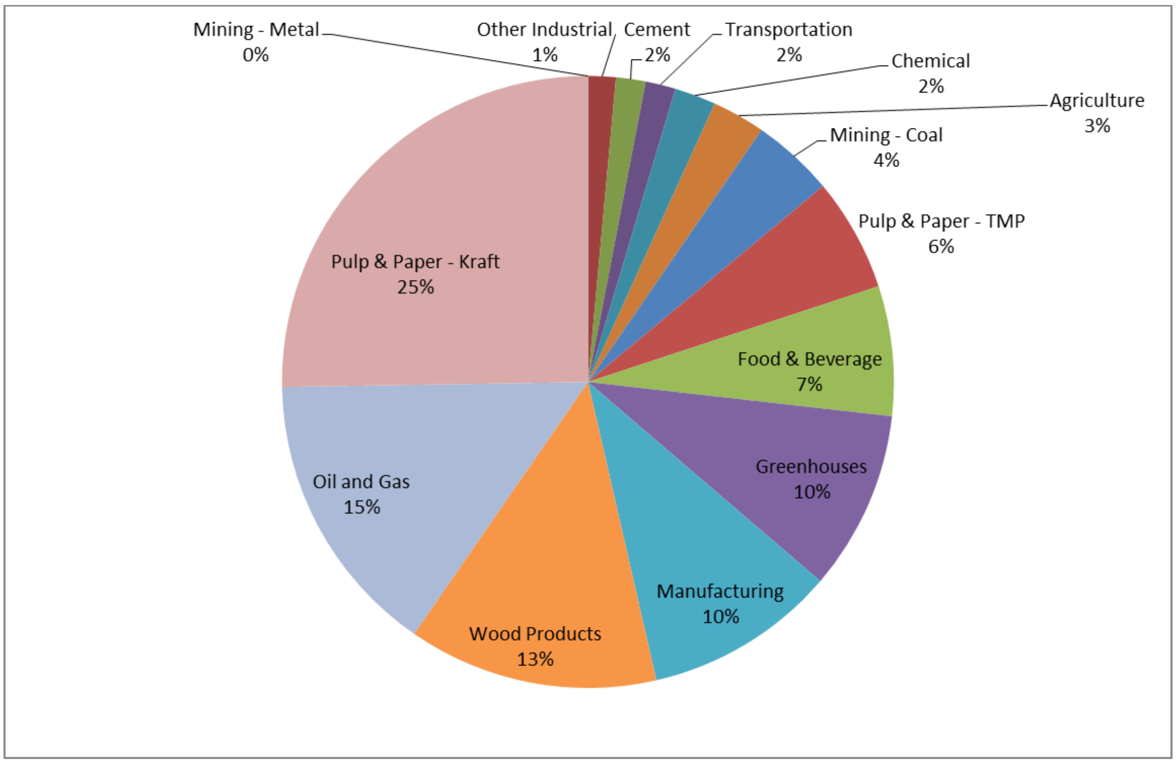
This section is organized as follows:

- Section 9.2 outlines the characteristics of the industrial customers, showing the range of industries and end uses served, as well as customers' annual demand.
- Section 9.3 describes the customer segmentation into various rate schedules, which has been established according to the different requirements of industrial customers.
- Section 9.4 reviews industrial rates which are offered in other jurisdictions.
- Section 9.5 provides a review of the existing rate design for General Firm Service RS 5/RS 25 and identifies a number of potential improvements to FEI's existing rate design. FEI evaluates a range of options to make these improvements and sets out its proposed solutions.
- Section 9.6 provides a review of the existing rate design for General Interruptible Service for RS 7/RS 27 and discusses the impact of changes to these rate schedules due to the proposed rate design changes for RS 5/RS 25 and sets out the rate design proposal for RS 7/RS 27.
- Section 9.7 provides a review of the existing rate design for Seasonal Firm Service RS 4 and proposed Delivery Charges.
- Section 9.8 provides a review of the existing rate design for large volume industrial transportation customers including RS 22 and contract customers (VIGJV and BC Hydro IG), discusses and evaluates potential rate design options and sets out rate design proposals for these large volume industrial transportation customers.
- Section 9.9 summarizes FEI's proposed rate design changes in the respective rate schedules for industrial customers.

9.2 *INDUSTRIAL CUSTOMER CHARACTERISTICS*

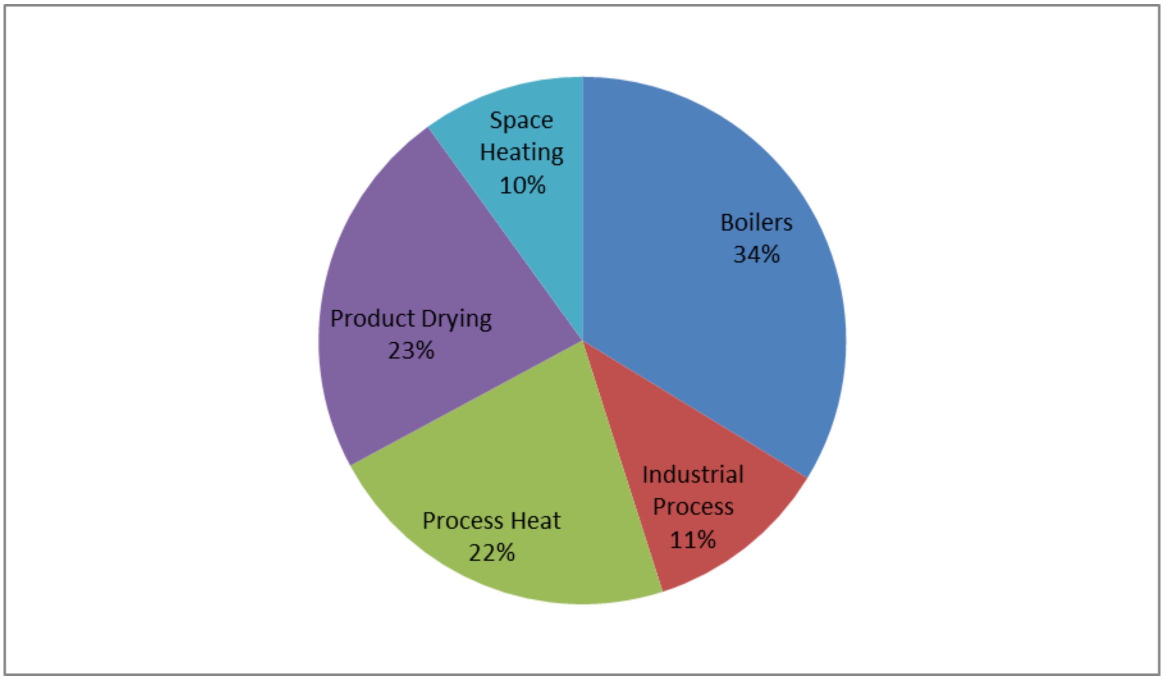
The industrial customer group represents a wide range of industries and end uses. The industrial sector makeup is shown in Figure 9-1 and the end usage is shown in Figure 9-2. Figure 9-1 shows that the major gas consuming industries are the pulp and paper, wood products, oil and gas, manufacturing and greenhouse industries. The proportion of gas use from these industrial sectors is 25%, 15%, 13%, 10% and 10%, respectively. Figure 9-2 shows that there are five primary end uses – boilers at 34%, product drying at 23%, process heating at 22%, industrial processes at 11% and space heating at 10%.

Figure 9-1: Industrial Sectors[140]



[140] This figure is based on the draft results from the FEI 2015 Conservation Potential Review (CPR) using a 2014 base year.

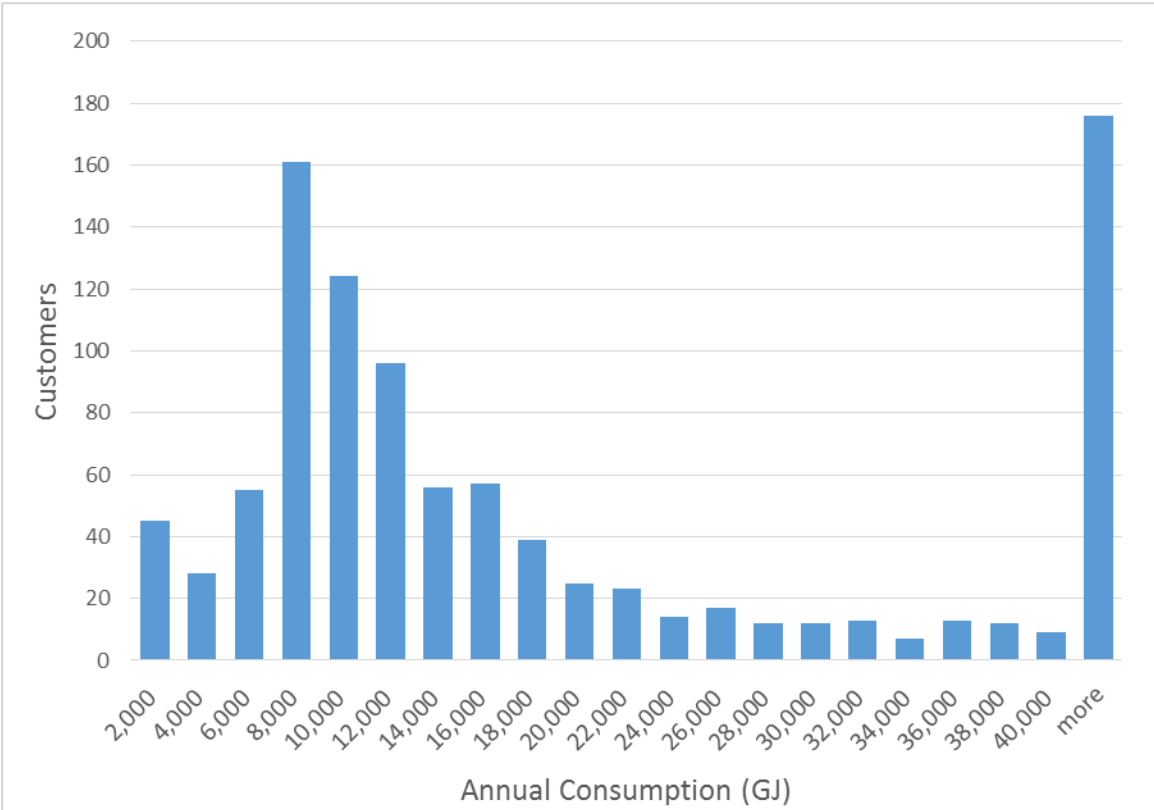
Figure 9-2: End Use by Industrial Customers[141]



Annual usage for industrial customers varies widely, as shown by Figure 9-3. This bill frequency graph also shows that there is a clustering of customers with annual consumption in the 8,000 GJ to 12,000 GJ range and another grouping of customers with annual consumption in excess of 40,000 GJ.

[141] This figure is based on the draft results from the FEI 2015 Conservation Potential Review (CPR) using a 2014 base year.

Figure 9-3: Industrial Customer Bill Frequency (GJ per Year)



The wide range of industries, end uses and annual consumption for the industrial customer group requires FEI to develop and maintain a variety of rate schedules that accommodate the varying characteristics of the market segments. These considerations and industrial customer segmentation are discussed in the next section.

9.3 *INDUSTRIAL CUSTOMER SEGMENTATION*

FEI segments industrial customers into rate schedules according to whether they buy gas from FEI (sales customers) or from third party shipper agents (transportation customers).

FEI further segments the sales and transportation customers into whether they require firm gas service or can accept occasional interruptions to their gas service. The interruptible service customers are required to either cease their operations during gas service interruptions or arrange for their own backup energy facilities and fuel source. These service interruptions to interruptible customers may occur on days when FEI experiences system peak demand levels or when FEI experiences other operational disruptions that may require the interruption (or curtailment) of interruptible natural gas service.

An additional segment is for sales customers that require gas on a firm, but seasonal basis primarily during the summer months.

Each of these types of sales customers requires separate rate schedules due to their operational requirements and the cost to provide service.

FEI has existing rate schedules and contracts to match the characteristics of its industrial customers, as listed in Table 9-1 below.

Table 9-1: Industrial Customer Groups and Corresponding Rate Schedules

Industrial Group	FEI Tariff Rate Schedule / Contract	Description
Seasonal Firm Gas Service	RS 4	• Seasonal firm service during the off-peak period (April 1 to October 31) and interruptible service during the extended period (November 1– March 31).
General Firm Service (Sales)	RS 5	• General firm sales service with a monthly demand charge per month per GJ of Daily Demand. • Firm sales service.
General Firm Transportation Service	RS 25	• General firm transportation service with a monthly demand charge per month per GJ of Daily Demand. • Firm transportation service on FEI's system.
General Interruptible Service (Sales)	RS 7	• General interruptible sales service. • Sales service is interruptible if there is insufficient capacity or if there are operational restrictions to deliver the gas.
General Interruptible Transportation Service	RS 27	• General interruptible transportation service. • Transportation service that can be interrupted if there is insufficient capacity or operational restrictions to deliver the customer's gas.
Large Volume Transportation Service	RS 22	• Large volume interruptible transportation service with a minimum "take or pay" of 12,000 GJ per month. • Option to negotiate firm service subject to BCUC approval.
Transportation Service (Closed) Inland Service Area	RS 22A *(Closed)*	• Large volume firm and interruptible transportation service for select customers in the Inland Service Area (closed rate schedule), available at the time of the 1993 Phase B Rate Design.
Transportation Service (Closed) Columbia Service Area	RS 22B *(Closed)*	• Large volume firm and interruptible transportation service for select customers in the Columbia Service Area (closed rate schedule), available at the time of the 1993 Phase B Rate Design.
Contract	Vancouver Island Gas Joint Venture	• Contract for firm and interruptible transportation service to five mills on Vancouver Island.
Contract	BC Hydro IG	• Contract for firm and interruptible transportation service to the Island Cogeneration Facility on Vancouver Island.

The customer data for each industrial rate schedule is shown below in Table 9-2.

Table 9-2: Industrial Customer Data[142]

Rate Schedule	2016 Average Number of Customers	2016 Demand Forecast (PJ)	Percentage of Industrial Total
RS 4 – Seasonal	18	0.1	0.1%
RS 5 – General Firm Sales	230	2.2	3.1%
RS 25 – General Firm Transportation	566	13.5	19.4%
RS 7 – General Interruptible Sales	5	0.2	0.3%
RS 27 – General Interruptible Transportation	108	6.5	9.3%
RS 22 / 22A / 22B – Large Volume Transportation	40	27.6	39.6%
Large Industrial Contract	2	19.7	28.3%
Industrial Total	**984**	**69.7**	**100.0%**

Each of these categories of industrial customers is discussed in greater detail in Sections 9.5 through 9.8.

9.4 *MULTI-JURISDICTIONAL COMPARISON OF INDUSTRIAL RATES*

FEI conducted a review of industrial rates offered by a number of Canadian natural gas utilities and the results are summarized below in Table 9-3. A detailed review of the results is provided in Appendix 9-1. A key finding of this review is that most of the utilities include a demand related charge in their rate structure with a flat or declining variable charge component. Also, each utility offers customer rates according to their daily or yearly demand levels. Lastly, four of the ten utilities listed below have an eligibility criteria based upon the customer load factor.

These findings support the existing FEI industrial customer segmentation into rate schedules according to the customer's need for firm and interruptible service and including demand related charges in rate structures designed for these types of customers.

[142] 2016 Forecast Customers and Energy from the compliance filing for the Annual Review for 2016 Rates (Order G-193-15).

Table 9-3: Multi-Jurisdiction Review of Industrial Rates

Company[143]	Description	Eligibility	Type
FEI	General Firm	N A	Flat w/Demand
	General Interruptible	N A	Flat
	Seasonal Firm Gas[144]	N A	Flat
	Large Volume - Interruptible with Firm Option[145]	N A	Flat w/ Minimum Volume Take or Pay of 12,000 GJ / Month
PNG	Industrial	Industrial Use	Flat
ATCO Gas	High Use	>8,000 GJ/year	Demand
AltaGas	Demand General Service	>10,125 GJ/year	Flat w/Demand
Sask Energy	Small Industrial	25,245 – 50,490 GJ/year	Declining Block
	Contract Industrial	>25,245 GJ/year	Negotiated
Manitoba Hydro	High Volume Firm	>26,010 GJ/year	Flat
	High Volume Interruptible	>26,010 GJ/year	Flat
Union Gas	Large Volume General	>1,913 GJ/year	Declining Block
	Firm Industrial	92 – 2,295 GJ/year	Declining w/Demand
	Medium Volume Firm	>536 GJ/day	Declining w/Demand
	Large Volume Interruptible	115 – 536 GJ/day	Negotiated
	Large Volume High Load Factor Firm	>3,825 GJ/day with > 70% load factor	Flat w/Demand
Enbridge Gas	General Service		Declining Block
	Large Volume Firm Contract	383 – 5,738 GJ/day	Flat w/Demand
	Large Volume Load Factor	>71 GJ/day with > 40% load factor	Declining w/Demand
	Large Volume High Load Factor	>45 GJ/day with > 80% load factor	Declining w/Demand
	Extra Large Volume Transport	>22,950 GJ/day	Demand Only
Gaz Metro	Distribution	<419 GJ/year	Declining Block
	Stable Load	>13 GJ/day and >60% load factor or >383 GJ/day	Declining Block

143 Sask Energy, Manitoba Hydro, Union Gas and Gaz Metro state their demand values in cubic metres. These values have been restated into GJ equivalent using a conversion factor of 0.03825 GJ/m^3

144 Firm April 1 to October 31; Interruptible November 1 to March 31.

145 Firm rate subject to separate BCUC approval.

Company[143]	Description	Eligibility	Type
Gazifere	Moderate Volume Firm	107 – 1,071 GJ/day and > 50% load factor	Flat w/Demand
	Large Volume Firm	1,071 – 10,710 GJ/day and > 50% load factor	Flat w/Demand
	Very Large Volume Firm	>10,710 GJ/day and > 50% load factor	Flat w/Demand

9.5 GENERAL FIRM SERVICE – RS 5 AND RS 25

9.5.1 General Firm Service – Introduction

RS 5 and RS 25 are FEI's General Firm Service rates for sales and transportation customers, respectively. Based on FEI's analysis and review, FEI concludes that both RS 5 and RS 25 are generally working as designed, taking into consideration the rate design principles, stakeholder feedback and comparison to rate schedules in other jurisdictions. FEI is, however, proposing to update the formula for determining a customer's peak day demand as set out in the rate schedules.

For purposes of calculating the Demand Charge, RS 5 and RS 25 estimate a customer's peak day demand (referred to in the rate schedules as the "Daily Demand") through a formulaic calculation that includes a 1.25 multiplier to estimate peak Daily Demand from peak monthly demand. The Daily Demand is the billing determinant to which the Demand Charge is applied. FEI's analysis shows that the current method of using a multiplier of 1.25 is over-estimating the peak day demand. This is an intra-class issue affecting how a customer's billing determinant, the Daily Demand, is calculated, and has no impact on customers in other rate schedules. As discussed below, FEI considered various options for calculating the Daily Demand. Having considered these options, FEI is proposing to maintain the formula to determine the Daily Demand, but to update the multiplier from 1.25 to 1.10 to more accurately estimate the RS 5/RS 25 average consumption during the 5 coldest days in the customers' respective region for the past 5 years compared to their peak monthly average consumption.

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.

In the sections below, FEI reviews the rate design of Firm General Service RS 5/RS 25 and discusses the basis for the proposed changes.

9.5.2 General Firm Service – Customer Characteristics

General Firm Service is intended for commercial and small industrial customers that generally use natural gas in a process - a load that is relatively non-temperature sensitive and therefore relatively constant throughout the year. The typical type of customers using firm service include condominium strata customers and hospitals that use a high proportion of their overall gas demand for water heating needs and commercial customers and small industrial customers who use gas for their processing load. These customers will generally have a relatively constant demand profile throughout the year. This relatively flat demand profile means that these customers utilize FEI's system in a manner that leads to a lower customer cost allocation.

FEI offers two related rate schedules to this type of customer: RS 5 for General Firm Service (for sales customers) and RS 25 for General Firm Transportation Service (for transportation customers who choose to purchase their natural gas from a shipper agent). RS 5 and 25 are "companion" rate schedules, in that each rate schedule has the same basic, demand and delivery charges. However, RS 25 has an additional administration charge to account for the separate administration and billing for customers who purchase their gas from a shipper agent.

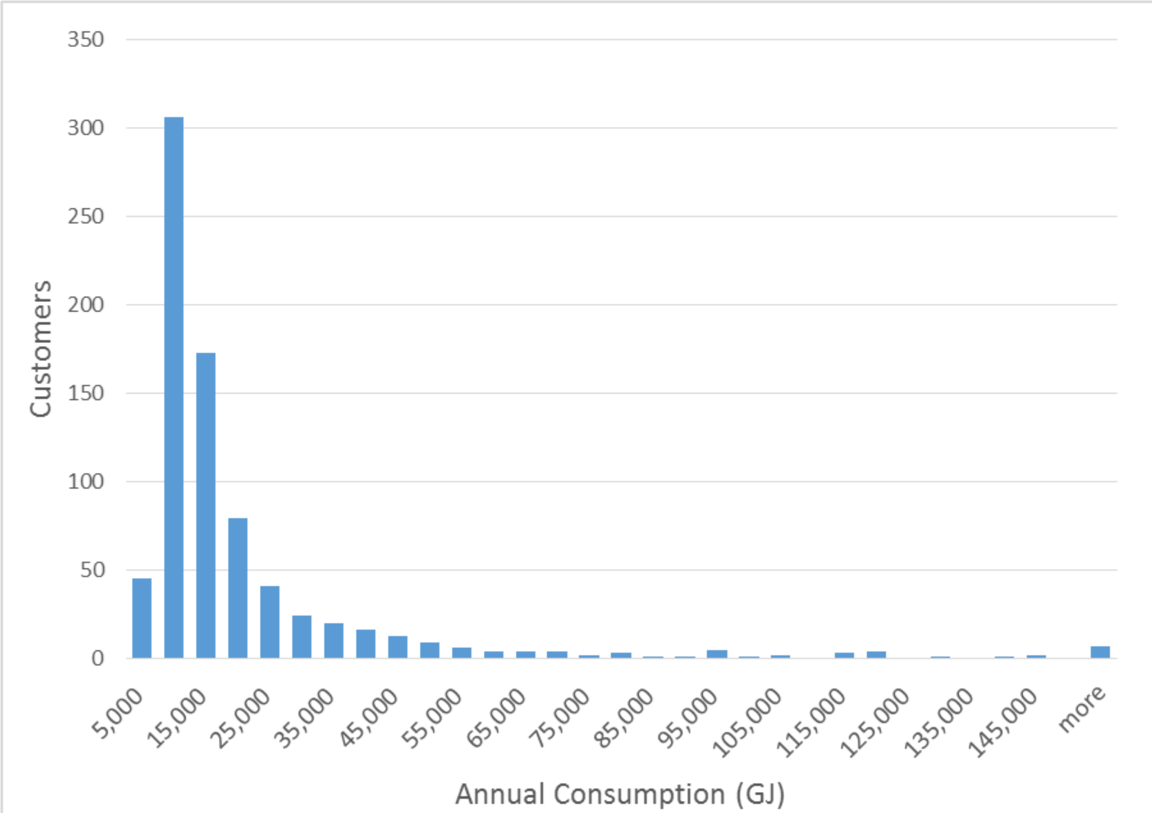
As shown in Table 9-2 above, for 2016, FEI forecasts 230 customers in RS 5 using a total of 2.2 PJ, and 566 customers in RS 25 using a total of 13.5 PJ.

9.5.3 General Firm Service – Review of Existing Rate Design

9.5.3.1 Customer Bill Frequency

The following Figure 9-4 shows the annual bill frequency for the combined RS 5 and 25 customers. It shows that the majority of these General Firm Service customers use between 5,000 GJ and 25,000 GJ per year, but some may use up to 150,000 GJ.

Figure 9-4: Annual Bill Frequency for RS 5 and RS 25 Customers Combined



9.5.3.2 Review of General Firm Service Rate Structure

FEI's cost allocation methodology allocates demand costs according to RS 5/RS 25 customers' load factor. As such, those customers with a higher load factor will be charged lower overall rates as a result of more efficient system utilization. Table 9-4 provides the 2016 COSA[146] rates for charges that are included in the delivery revenue.

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	$0.887	$0.887
Administrative Charge $ / Month	N / A	$78.00

[146] The COSA rates shown are estimated based on 2016 approved rates plus known and measureable changes discussed in Section 6.

The RS 5/RS 25 rate structure includes both a demand and a delivery charge which recover the allocated cost of service in a way that reflects each customer's load profile and demand. That is, a customer's average rate will depend upon their own individual load factor. For example, if two customers have the same annual demand, but have different load factors, the customer with the higher load factor will have a lower annual bill than the customer with the lower load factor. The following example illustrates this point.

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.

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

[147] Note the demand charge here is the demand charge for RS 5/RS 25 from Table 9-4.

Service customers. This review supports FEI's continued use of a demand / volumetric delivery rate design for the firm general service rate schedule.

9.5.3.4 Peak Day Demand Estimate

The current method of determining a RS 5/RS 25 customer's peak Daily Demand was established during the 1996 Rate Design. Given that daily consumption quantities were not available at the time for all customers, a Daily Demand formula was created to estimate a customer's peak consumption. Specifically, RS 5 and RS 25 include a Demand Charge per Month per GJ of Daily Demand, where "Daily Demand" is determined by the following formula:

> Daily demand is equal to 1.25 multiplied by the greater of a) the Customer's highest average daily consumption of any month during the winter period (November 1 to March 31), or one half of the Customer's highest average daily consumption of any month during the summer period (April 1 to October 31).

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).

[148] If the maximum average day occurs related to the months from April to end of October, the average day consumption is multiplied by 0.5.

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

9.5.3.5 Economic Incentive for Only High Load Factor Customers

RS 5 and RS 25 are designed for customers with higher load factors of 40% or above. The Demand Charge in RS 5 and RS 25 results in these higher load factor customers receiving a lower average cost. Customers with load factors lower than 40% should generally be taking service under Large Commercial Service RS 3/RS 23, where the average load factor is approximately 37%. To ensure that RS 5 and RS 25 are achieving their purpose, FEI reviewed whether the existing rates provide sufficient incentive for customers whose load factor is less than 40% to take service under Large Commercial Service RS 3/RS 23, rather than RS 5/RS 25.

Table 9-7 below provides the current economic crossover volume where a customer would have the same annual bill whether taking service under RS 23 or RS 25. If a customer volume for a given load factor is greater than the economic crossover volume shown in the table below, then the customer would receive a lower annual bill under RS 25 than under RS 23.

Table 9-7: Large Commercial / General Firm Economic Crossover at Varying Load Factors at 2016 Approved Rates + Known and Measurable Changes

		RS 23		RS 25
Monthly Charges (Basic + Admin. Fee)		$210.52		$665.00
Demand Charge		N / A		$21.596
Delivery Charge		$3.161		$0.887
		Economic Cross-over (GJ/Year)	**Daily Demand**	**Peak Winter Month With 1.25 multiplier**
Load Factor	50%	6,386 GJ	35 GJ	840 GJ
	45%	7,834 GJ	48 GJ	1,145 GJ
	40%	10,930 GJ	75 GJ	1,797 GJ
	39%	12,027 GJ	84 GJ	2,028 GJ
	38%	13,447 GJ	97 GJ	2,327 GJ
	37%	15,360 GJ	114 GJ	2,730 GJ
	36%	18,073 GJ	138 GJ	3,301 GJ

The economic crossover volumes at the 2016 COSA rates show that the existing rates provide sufficient incentive for customers whose load factor is less than 40% to receive service under RS 3/RS 23, rather than RS 5/RS 25. There are relatively few customers whose annual volumes would be high enough to make RS 5/RS 25 economic at a load factor lower than 40%.

9.5.4 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 in different rate contexts. Rate design should strive to strike a balance among competing rate design principles based on specific characteristics of customers in each rate schedule.

Based on FEI's examination of each element of the General Firm Service rate design as discussed above, FEI believes that the rate structure for RS 5/RS 25 works well in many respects. In particular, FEI believes that the customer segmentation and flat rate structure with a Monthly (Basic and Admin), Delivery and Demand charge remains appropriate.

However, as indicated in the analysis above, FEI identified a potential issue with the Daily Demand formula in the Demand charge. For the majority of customers, the current method of determining a customer's Daily Demand overestimates the customer's peak demand. Over estimating the Demand does not result in the fair apportionment of costs among customers in RS 5/RS 25 (Principle 2) and may distort the price signals for efficient use intended by the Demand charge (Principle 3).

As also discussed above, the existing rates provide an incentive for only high load factor customers to receive service under RS 5/RS 25. If there is a change to the calculation of the Daily Demand formula in RS 5/RS 25 or changes to the RS 3/RS 23 charges, the economic cross over points between the RS 3/RS 23 and RS 5/RS 25 may change. Therefore, the Demand charge in RS 5/RS 25 may need to be adjusted to continue to provide the appropriate price signals for only high load factor customers to take service under RS 5/RS 25 (Principle 3), as well as to generate the revenues needed to recover the cost of service (Principle 2).

To revise the rate design to better align with rate design principles, FEI has evaluated five Daily Demand calculation options as discussed below. Based on its evaluation of the options, FEI is proposing to continue to use the existing formula with an updated multiplier to calculate Daily Demand in the demand charge.

9.5.5 Peak Day Demand Estimate – Options and Evaluation

As discussed above, RS 5 and RS 25 include a Demand Charge per month per GJ of Daily Demand. Pursuant to RS 5 and RS 25, Daily Demand is determined by the following formula:

> Daily Demand is equal to 1.25 multiplied by the greater of a) the Customer's highest average daily consumption of any month during the winter period (November 1 to March 31), or one half of the Customer's highest average daily consumption of any month during the summer period (April 1 to October 31).

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).

[149] FEI notes that it did not present this option in the workshop. After considering comments made in the workshop and further investigation, FEI considered this option and included it in its options analysis.

The following two tables provide a summary based on the 2015 billing data of the number of customers and the average Daily Demand at different load factor ranges for each method. This provides a comparison of how the different methods impact average Daily Demand and consequently the number of customers whose load factor will change. The tables also indicate that the observed average consumption during the 3 or 5 coldest days is similar to the results of the current method for those customers who would have a load factor in the range of 45% to 50%. However, for approximately 450 of the 774 customers the current method yields an average Daily Demand that is 46% higher than the average consumption on the five coldest days (105 GJ / 72 GJ – 1).

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		Modified Formula with 5 Day Average
					3 Days	*5 Days*	
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**

Table 9-9: Average Daily Demand (GJ) per Customer 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	<40% Load Factor	174	149	160	150	159	152
3	40% to <45% Load Factor	93	169	89	97	109	109
4	45% to <50% Load Factor	73	87	82	77	72	72
5	>50% Load Factor	105	84	25	71	72	75
6	All Customers	100	88	82	77	77	80

The following table provides an evaluation of each of the 5 methods to estimate peak day demand:

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

Methods	Pros	Cons
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

9.5.5.1 Proposed Peak Day Demand Estimate Method

Based on the evaluation above, FEI proposes to implement Option 5. Under this option, the multiplier in the Daily Demand formula is adjusted from 1.25 to 1.10 to match the RS 5/RS 25 customers' corresponding demand for the average consumption during the 5 coldest days for their region for the past 5 years compared to their peak monthly average consumption. The 5 year average used to calculate the updated multiplier is shown in the table below:

Table 9-11: Updated Multiplier for Current Formula

Year	Average Consumption during the 5 Coldest Days/ Peak Month Average
2015	1.02
2014	1.12
2013	1.12
2012	1.18
2011	1.07
5 Yr Avg	**1.10**

Refer to Appendix 9-2 for a detailed description of the method for deriving the multiplier.

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.

9.5.6 Economic Incentive for High Load Factor Customers – Options and Evaluation

The proposed change to the calculation of the Daily Demand formula in RS 5/RS 25 and the proposed changes to the RS 3/RS 23 charges discussed in Section 8 of the Application will change the economic cross over points between the RS 3/RS 23 and RS 5/RS 25. Further, in this subsection, the proposed changes in rates for both RS 3/RS 23 and RS 5/RS 25 are relevant because of the impact on the increased annual volume that has to be consumed in order for a commercial customer with a load factor less than 40% to be better off under RS 5/RS 25 (Table 9-13).

The table below, which is the same as Table 9-7 but updated for FEI's proposals in RS 3/RS 23 and 5/25, shows the economic cross over point after the proposed rate changes to RS 3/RS 23 and the proposed change to the multiplier in the formula to calculate the Daily Demand in 5/25 (1.25 to 1.1). In Table 9-12 below, the peak winter month volume from Table 9-7 is reduced due to the change in the multiplier which then changes the Daily Demand. The economic crossover is then changed to take into account of the RS 3/RS 23 proposed rates and the lower Daily Demand. The load factor in Table 9-12 is then derived from the economic crossover volume and Daily Demand (volume / (365 x Daily Demand).

Table 9-12: Large Commercial / General Firm Economic Crossover at Varying Load Factors at Proposed Rates for RS 3/RS 23 but RS 5/RS 25 at 2016 COSA Rates With Proposed Multiplier

		RS 23		RS 25
Monthly Charges (Basic + Admin. Fee)		$223.78		$665.00
Demand Charge		N / A		$21.596
Delivery Charge		$3.175		$0.887
		Economic Cross-over (GJ/Year)	**Daily Demand**	**Peak Winter Month With 1.1 multiplier**
Load Factor	58.7%	5,810 GJ	27 GJ	739 GJ
	52.5%	7,079 GJ	37 GJ	1,007 GJ
	46.3%	9,793 GJ	58 GJ	1,581 GJ
	45.0%	10,754 GJ	65 GJ	1,784 GJ
	43.8%	12,000 GJ	75 GJ	2,048 GJ
	42.5%	13,676 GJ	88 GJ	2,402 GJ
	41.3%	16,054 GJ	107 GJ	2,905 GJ

Table 9-12 shows that the economic crossover volumes have been reduced from those shown in Table 9-7, which erodes the incentive for lower load factor customers to continue taking service under RS 3/RS 23.

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.

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.

9.5.7 Stakeholder Feedback Received

As discussed in Section 4 of the Application, FEI circulated a Rate Design and Segmentation Discussion Guide to stakeholders and held a workshop on August 31, 2016. This Guide and Workshop covered FEI's current industrial rate structures and presented a number of options that FEI had under consideration. The relevant stakeholder feedback is summarized below. A detailed Meeting Summary and Notes are attached as Appendix 4-2.

During the Workshop, FEI highlighted the two areas of interest identified above: the current method of estimating customer peak demand and the potential incentive for lower load factor customers to move to RS 5/RS 25 from RS 3/RS 23. FEI did not receive any comments of concern with these two topics, or the range of options FEI was considering. However, FEI was asked to provide a clearer explanation of the issues and whether the demand charge and current estimate of customer peak demand could be eliminated or removed in the interest of simplifying the overall rate structure. In the discussion above, FEI has clarified its explanation of the issues and considered the removal of the demand charge as a potential option.

9.5.8 General Firm Service – Summary of Rate Design Proposal

FEI reviewed the Firm General Service RS 5/RS 25 in consideration of the rate design principles, comparison with comparable rate schedules in other jurisdictions and other analysis as discussed above. FEI found that both RS 5 and RS 25 are generally performing as designed. However, FEI is proposing two adjustments, as follows:

1. Update the multiplier from 1.25 to 1.10 that is used in the current method to determine the Daily Demand as an estimate of a customer's peak demand. This change is proposed to more accurately estimate the peak Daily Demand for the purposes of the Demand Charge.
2. Increase the Demand Charge by $3.00. This change is proposed to continue the incentive for low load factor customers to take service under Large Commercial RS 3/RS 23 rather than General Firm Service RS 5/RS 25.

9.5.9 Bill Impact Analysis

The bill impact from the reduction in the multiplier in the Daily Demand formula is offset by the $3 increase in the Demand Charge. The net impact on RS 5/RS 25 revenues is an incremental $45 thousand of revenue, which is approximately a $0.003 per GJ increase or $5 per customer per month.

9.6 GENERAL INTERRUPTIBLE SERVICE – RS 7 AND RS 27

9.6.1 General Interruptible Service - Introduction

RS 7/RS 27 are companion rate schedules for General Interruptible Service. RS 7 is for sales customers and RS 27 is the corresponding transportation service. These rates schedules are available to small industrial and large commercial customers who have the ability to curtail their usage during system constraints. RS 7/RS 27 are intended for customers with gas consumption, generally, of less than 12,000 GJ per month.

The key factor for rate design for interruptible rates is the customer's ability to use and accommodate interruptible service. During periods of high system demand, interruptible customers must be able to curtail their gas usage (by either reducing production or utilizing backup fuel capability) upon short notice. FEI's ability to curtail these customers avoids the need for costly system expansions while also improving the overall system utilization in lower demand periods.

FEI's interruptible rates are designed to provide sufficient incentive to encourage existing customers to remain on interruptible service and attract new interruptible customers. For interruptible customers, contributors to their cost of taking interruptible service are factors such as:

- the customer's capital costs to install a backup energy system;
- the cost of the alternate backup fuel;
- the opportunity cost to the customer of potential lost production, should they need to curtail their operations; and
- the potential frequency and level of service curtailment to the customer.

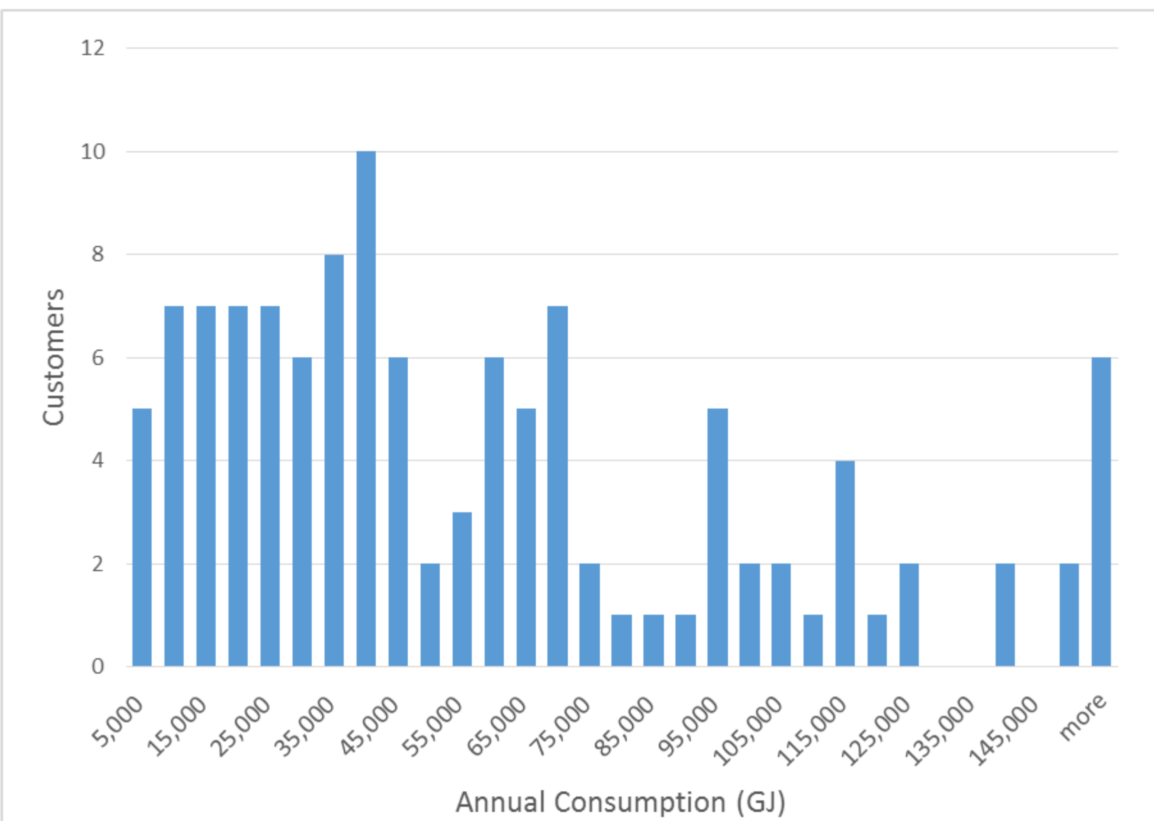
To compensate for these costs, FEI offers the service at a discount from the General Firm Service rate. Specifically, the existing delivery charges for RS 7/RS 27 are based on the General Firm Service RS 5/RS 25 Demand Charge based on an 80% load factor, plus the RS 5/RS 25 Delivery Charge.

Based on the review of interruptible rates discussed below, FEI concludes that the current rate structure is working well and as intended. The existing method has resulted in a consistent discount of approximately 18% from the firm rate, where the effective firm rate is based on an 80% load factor. FEI is proposing to maintain the existing discount and to update the RS 7/RS 27 charges for the proposed changes to RS 5/RS 25. In Section 9.6.5, FEI explains the changes that need to be made to the discount methodology to derive the interruptible delivery charge and the appropriate discount from the equivalent firm rate.

9.6.2 General Interruptible Service - Customer Characteristics

FEI currently has a total of 113 customers served under General Interruptible Service (sales and transport) that includes a wide range of industries such as asphalt plants, greenhouses, hospitals, sawmills and numerous other industries. These customers use an average of 59,200 GJ per year. Figure 9-5 below shows that the annual demand from these customers ranges from about 5,000 GJ to 150,000 GJ.

Figure 9-5: Annual Bill Frequency for RS 7 and 27 Combined



9.6.3 General Interruptible Service - Review of Existing Rate Design

9.6.3.1 Existing Rate Structure

The rate structure for Interruptible Sales and Transportation Service includes a monthly Basic Charge and a volumetric Delivery Charge per GJ. Transportation Service has an additional administration charge. These charges are shown in Table 9-15.

Table 9-15: 2016 COSA Rates for RS 7 and RS 27

	2016 COSA[150] Based Rates			
Rate Schedule	Basic Charge/ Month	Administration Charge/Month	Delivery Charge/GJ	Commodity + Storage & Transport Charge/GJ
RS 7 *General Interruptible Sales Service*	$880.00	n/a	$1.455	$3.323
RS 27 *General Interruptible Transportation Service*	$880.00	$78.00	$1.455	n/a

9.6.3.2 Existing Rate Setting Methodology

To encourage existing customers to remain on interruptible service and attract new interruptible customers, RS 7/RS 27 charges are set at a discount from the General Firm Service rate. Specifically, the existing delivery charges for RS 7/RS 27 are based on the General Firm Service RS 5/RS 25 Demand Charge based on an 80% load factor, plus the RS 5/RS 25 Delivery Charge. The regulatory history and methodology for calculating this discount are discussed below.

During the 1996 Rate Design, FEI established a discount for interruptible service from General Firm Service (RS 5/RS 25) based upon an 80% load factor. In the 2001 Rate Design proceeding, this relationship was reviewed again in relation to the value of the discount from firm service. This discount was applied in comparison to the firm service rate offered to RS 5/RS 25 customers, with the discounting calculation again based on an 80% load factor.

An example of how the discount was calculated in 2001 is provided below in Table 9-16. The table also shows the same calculation using 2016 current rates, and the 2016 COSA-rates which also includes known and measurable changes. The table uses the 80% load factor that was derived in the 1996 Rate Design to convert the RS 5/RS 25 demand charge into a volumetric equivalent for the purpose of the RS 7/RS 27 monthly basic charge and volumetric

[150] The COSA rates shown are estimated based on 2016 approved rates plus known and measureable changes discussed in Section 6.

delivery charge. To convert the RS 5/RS 25 demand charge into an equivalent volumetric charge, the demand charge for one GJ of Daily Demand is multiplied by 12 months and then divided by 365 GJ divided by the 80% load factor. The bottom row of Table 9-16 shows the amount of the discount from the firm rate and the relative percentage of the discount to the firm rate at an 80% load factor for each calculation.

Table 9-16: RS 5 at 80% Load Factor Compared to RS 7[151]

Rate Schedule	Line No.		2001	2016 - Current	2016 – COSA
Effective Rate/GJ for an RS 5 firm service customer at an assumed **80% Load Factor**	1	*Demand Charge*	$0.509	$0.825	$0.888
	2	*Delivery Charge*	$0.502	$0.825	$0.887
	3	*Total*	$1.011	$1.650	$1.775
RS 7 *General Interruptible Sales Service*	4	*Delivery Charge*	$0.836	$1.353	$1.455
Differential (per GJ) *RS 5 – RS 7*	5		$0.175	$0.297	$0.320
Discount as a Percentage of Total Firm	6		17.3%	18.0%	18.0%

Notes:

- Line 1 is the RS 5/RS 25 Demand Charge converted to a volumetric rate based on an 80% Load Factor (detailed in the footnote)
- Line 2 is the RS 5/RS 25 Delivery Charge
- Line 3 is the sum of lines 1 and 2
- Line 4 is the RS 7/RS 27 Delivery Charge
- Line 5 is the value of the discount (Line 3 – Line 4) between RS 5/RS 25 and RS 7/RS 27
- Line 6 is the value of the discount expressed as a percentage of the total Firm (Line 3).

As shown in Table 9-16 above, while the $/GJ value of the discount has increased from 2001 to 2016 COSA rates (due to general rate increases between 2001 and 2016), the relative percentage of the discount of the interruptible rate to the firm rate at an 80% load factor has remained relatively constant at about 18%.

The same analysis comparing the interruptible rate to a firm rate equivalent at a 55% load factor also shows that the discount has remained constant at approximately 33%. This analysis is shown below in Table 9-17.

[151] 2016 – Current Demand Charge is equal to $20.077 x 12 / 365 / 80% = $0.825; 2016 COSA plus known and measurable changes Demand Charge = $21.596 x 12 / 365 / 80% = $0.888.

Table 9-17: RS 5 at 55% Load Factor Compared to RS 7 at 80% Load Factor[152]

Rate Schedule	Line No.		2001	2016 - Current	2016 – COSA
Effective Rate/GJ for an RS 5 firm service customer at an assumed **55% Load Factor**	1	*Demand Charge*	\$0.740	\$1.200	\$1.291
	2	*Delivery Charge*	\$0.502	\$0.825	\$0.887
	3	*Total*	\$1.242	\$2.025	\$2.178
RS 7 *General Interruptible Sales Service*	4	*Delivery Charge*	\$0.836	\$1.353	\$1.455
Differential (per GJ) *RS 5 – RS 7*	5		\$0.406	\$0.672	\$0.723
Discount as a Percentage of Total Firm	6		32.7%	33.2%	33.2%

The results illustrate that there has been no deterioration between the avoided cost of firm service and the interruptible delivery charge before consideration of any other rate changes proposed in this Application. Although the value of the discount between the cost of firm and interruptible service has increased, the relative percentage of the discount to the firm service has remained relatively static. The primary reason for this is that successive rate changes have been applied equally, percentage wise, to both firm (RS 5/RS 25) Demand and Delivery Charges as well as to interruptible (RS 7/RS 27) Delivery Charge.

9.6.3.3 Multi-Jurisdiction Review of Rates

As discussed above in Section 9.4, FEI conducted a review of the rate schedules offered by ten Canadian natural gas utilities. There are two utilities that also offer interruptible service - Manitoba Hydro and Union Gas. The interruptible service rates of these two utilities are summarized below in Table 9-18.

[152] 2016 – Current Demand Charge is equal to \$20.077 x 12 / 365 / 55% = \$1.200; 2016 COSA plus known and measurable changes Demand Charge = \$21.596 x 12 / 365 / 55% = \$1.291.

Table 9-18: Multi-Jurisdiction Review Summary for Interruptible Service

Company	FEI	Manitoba Hydro	Union Gas
Description	General Interruptible	High Volume Interruptible	Large Volume Interruptible
Eligibility	No restriction	>26,010 GJ/year	115 – 536 GJ/day (42,000 – 195,000 GJ/year)
Rate Type	Flat	Flat	Negotiated
Basic Charge (/month)	$880	$1,254	$352
Delivery Charge (/GJ)	$1.455[153]	$0.274	$1.233 (maximum)

It is difficult to draw any conclusions from the multi-jurisdictional review above as there are only two utilities that offer an interruptible service. Both of these other utilities have different eligibility criteria (from FEI's and from each other) and different rate levels. Consequently, FEI draws no conclusions from the multijurisdictional review.

9.6.4 Principle Based Review of Rate Design

Interruptible service should be offered at a suitable discount from firm service delivery rate in order to balance a number of the rate design principles, including:

- Principle 3: Price signals that encourage efficient use and discourage inefficient use
- Principle 4: Customer understanding and acceptance
- Principle 5: Practical and cost effective
- Principles 6 and 7: Rate and Revenue Stability

From the customer's perspective, the economic decision to take firm or interruptible service is dependent on whether the discount from firm is sufficient to compensate for the cost to have an alternate backup system and fuel that can be used or the cost from ceasing operations. Setting the discount either too high or too low would send the wrong price signals and could cause rate and revenue instability for customers and FEI, respectively. If the discount is too low, this may discourage new customers from considering interruptible service and may also cause existing interruptible customers to migrate to firm service. If the discount is too high and if the expected level of curtailment is very low, too many customers with firm service may elect to contract for interruptible service.

FEI believes that the discount is working well. FEI has experienced no unusual or unanticipated migration activity (from firm to interruptible or interruptible to firm) that would suggest the rates or rate structure are producing undesirable effects on customer's service option selections.

RS 7/RS 27 customers continue to receive value for service. FEI evaluated the interruptible discount against the level of service disruption that RS 7/RS 27 interruptible customers

[153] 2016 COSA plus known and measurable Rates: Current rates plus known and measurable changes.

experience. Over the past twenty years, interruptible customers have experienced a total of approximately 19.5 days of capacity curtailment. On average, the annual curtailment is about one day per year.[154]

Based upon 2016 forecasts, FEI expects to receive approximately $11 million in revenues from these interruptible customers. This revenue goes to the credit of FEI's firm sales and transport customers by virtue of contributing to the total cost of service and avoiding system improvements that would be necessary if these customers were receiving firm service. As summarized above in Table 9-2, the RS 7/RS 27 customers are forecast to use 6.7 PJ, or an average use of approximately 18 TJ/day, representing a significant level of FEI's system peak demand that could be curtailed. The value to all customers of the avoided cost of service from RS 7/RS 27 interruptible customers is approximately $0.04 per GJ (Refer to Appendix 9-3).

The discount of approximately $0.34 per GJ is sufficient to require interruptible customers to have alternative backup fuel / systems to use when interruption is required by FEI. This is evidenced by the stability of customers taking interruptible service, i.e., the lack of migration in or out of RS 7/RS 27. Also, all non-bypass customers avoid an incremental $0.04 per GJ cost of service from avoided system improvements. The net benefit to non-bypass customers is approximately $5 million dollars.

Table 9-19: Net Savings to the Cost of Service

RS 7/27 Volumes (Table 9-2) PJ's	**6.7**
x Discount (Table 9-19)	$0.344
Dollar Value of Discount ($000s)	$2,305
All Non-Bypass Volumes (Appendix 9-3) TJ's	182,942
Avoided Incremental Cost of Service $/GJ	$0.040
Avoided Cost of Service ($000s)	$7,318
Net Savings to all Non-Bypass Customers ($000s)	$5,013

FEI concludes that the existing rates for RS 7 and 27 achieve a reasonable balance between maximizing the economic value of interruptible service, which helps to offset utility costs to firm customers, and providing a sufficient incentive for existing customer to stay on interruptible service and to encourage new customers to sign up for interruptible service.

In alignment with the Bonbright principle to fairly allocate costs to customers, interruptible customers are not allocated any demand related costs.

[154] Based upon cold weather days where all interruptible customers are curtailed, but not including capacity constrained regions of the FEI system where partial curtailment happens every year, or for FEI system maintenance related curtailment

The existing methodology for setting interruptible service at a discount to firm service has been in effect for many years. This methodology is therefore understood and accepted by customers. The method is also practical and cost effective to implement.

FEI is therefore proposing to maintain the existing discount. However, due to proposed changes to the RS 5/RS 25 Demand Charge, FEI is proposing an update to the RS 7/RS 27 charges as explained below.

9.6.5 Update to RS 7/RS 27 to Account for Proposed RS 5/RS 25 Charges

FEI is proposing to update the existing method of calculating delivery charges for RS 7/RS 27 to reflect the proposed changes to RS 5/RS 25.

As discussed in Section 9.5 above, for General Firm Service FEI is proposing to decrease the multiplier in the Daily Demand formula from 1.25 to 1.1 and to increase the Demand Charge by $3.00 per month per GJ of Daily Demand. As shown in Table 9-12 above, under the proposed Daily Demand formula, the load factor of RS 5/RS 25 customers increases compared to the load factor under the existing Daily Demand formula. A RS 5/RS 25 customer who has a 100% Load Factor, i.e., uses the same amount of gas each day, as a result of the 1.1 multiplier will have an effective load factor of 90.9% (100% / 1.1). Therefore, to preserve the discount between the firm and interruptible rate:

- the load factor of 55% used in the RS 7/RS 27 calculation (Table 9-17, Line 1) needs to be increased to 62.5% (55% / 80% = x% / 90.9%, where x equals 62.5%);
- the firm equivalent (Table 9-17, Line 3 and Table 9-20, Line 6) to which the RS 7/RS 27 charge is compared must also be increased by the 1.1/1.25 multiplier change in order to have an apples-to-apples comparison (i.e., a 55% load factor customer is now a 62.5% load factor customer; a 80% load factor customer is now an 90.9% load factor customer).

As shown below in Table 9-20, applying the same interruptible rate methodology originally approved in the 1996 Rate Design proceeding results in a RS 7/RS 27 Delivery Charge of $1.443 per GJ and a discount from the firm equivalent at an 80% load factor of 24%. However, if the adjustments listed above are made, then the discount remains consistent at about 18%. In short, the firm rate equivalent to which the interruptible rate is compared to must be adjusted for the change in the Daily Demand formula. After the change in the multiplier, an 80% load factor RS 5/RS 25 customer would now be a 90.9% load factor customer. Taking this into account, Table 9-20 below shows that the Interruptible rate of $1.443 per GJ remains the same, but the discount is only 18.8%. As the existing discount of approximately 18% is maintained, FEI believes that the Interruptible Delivery Charge of $1.443 per GJ is the appropriate rate.

Table 9-20: Resulting Discount from Adjustment to RS 7/RS 27

Rate Schedule	Line No.		2016 COSA with 80% Load Factor Adjustment	2018 RS 7/27 Charges using 2001 Methodology	2018 Proposed with 90.9% Load Factor Adjustment[155]
RS 5/25	1	*Demand Charge*	$21.596	$24.596	$24.596
Load Factor for Equivalent firm Demand Charge	2		80.0%	80.0%	90.9%
Load Factors for Interruptible Rate	3		N A	55.0%/80.0%	62.5%/90.9%
Effective Rate/GJ for an RS 5 firm service customer	4	*Demand Charge*	$0.888	$1.011	$0.889
	5	*Delivery Charge*	$0.887	$0.887	$0.887
	6	*Total*	$1.775	$1.898	$1.776
RS 7 *General Interruptible Sales Service*	7	*Delivery Charge*	$1.455	$1.443[156]	$1.443
Differential (per GJ) *RS 5 – RS 7*	8		$0.320	$0.455	$0.334
Discount as a Percentage of Total Firm	9		18.0%	24.0%	18.8%

FEI does not anticipate any migration of customers shifting from interruptible service to firm service or from firm service to interruptible service. FEI concludes the change to the load factor for equivalent firm is necessary to stabilize the effective rate per GJ (Line 6) from which the discount is measured. The change to the load factor for the interruptible rate coupled with the change in the load factor for equivalent firm results in the same interruptible rate whether the load factor is 55% and 80% or 62.5% and 90.9%.

9.6.6 Stakeholder Feedback Received

As discussed in Section 5, FEI has previously circulated a Rate Design and Segmentation Discussion Guide to all interested stakeholders and held a workshop on August 31, 2016. This

[155] For the 2018 Proposed with 90% Load Factor the RS 5/25 the Proposed Demand Charge of $24.596 is multiplied by x 12 / 365 / 0.909 = $0.889; and $24.596 x 12 / 365 x .62.5% / 90.9% + $0.887 = $1.443

[156] RS 7/RS 27 Delivery Charge is equal to $24.596 (RS 5/RS 25 Demand Charge) x 12 / 365 x 55% (RS 5/RS 25 Load Factor) / 80% + $0.887 = $1.443

Guide and Workshop covered FEI's current industrial rate structures and presented a number of options that FEI had under consideration. The relevant stakeholder feedback is summarized below, with the detailed Meeting Summary and Notes attached as Appendix 4-2.

During this workshop, FEI presented the interruptible discount based upon a load factor of 80%. The feedback FEI received consisted of two items:

1. ensure that these customers receive a fair discount so that they do not return to firm service; and
2. clarify how the 80% was determined and applied.

These two comments have been addressed above in Section 9.6.3.2 and 9.6.5.

9.6.7 General Interruptible Service – Summary of Rate Design Proposal

FEI believes that interruptible charges achieve a reasonable balance between maximizing the economic value of interruptible service, which helps to offset utility costs to firm customers, and providing a sufficient incentive for existing customers to stay on interruptible service and to attract new customers. FEI is therefore proposing to retain the current rate structure and to continue the method of calculating the RS 7 and RS 27 delivery charges based on a discount from RS 5/RS 25. FEI is proposing to update the calculation to reflect the change in the Daily Demand formula, including a 62.5% firm service load factor assumption and a 90.9% load factor discount.

9.6.8 Bill Impact Analysis

The proposed interruptible rate results in a $0.012 per GJ decrease in the Delivery Charge to $1.443 per GJ (Table 9-20) from $1.455 per GJ (Table 9-17). The decrease is a result of the increase in the RS 5/RS 25 Demand Charge and the proposed changes to the load factors in the discounting methodology to preserve the relationship between the firm and interruptible rates (55% to 62.5% and 80% to 90.9%). The total revenue reduction for RS 7/RS 27 is $91 thousand (7,548 TJ[157] x $0.012); this represents an average annual bill reduction of 0.7%. The smallest reduction is 0.2% and the maximum reduction is 0.8% for customers in RS 7/RS 27.

9.7 *SEASONAL FIRM SERVICE – RS 4*

9.7.1 Introduction

RS 4 serves the unique needs of seasonal customers who typically do not use natural gas during the winter and thus do not contribute to FEI's system peak demand. These seasonal customers use gas primarily during the off-peak period from April 1 to October 31 (referred to in

[157] 2015 Billed Consumption.

RS 4 as the Off-Peak Period). However, some seasonal customers also use gas in the months of November and March when there is still available capacity and gas. During the coldest months from December through February, seasonal customers do not take gas service.

During the Off-Peak Period seasonal customers receive firm sales service. The Off-Peak period Delivery Charge has been derived from the RS 5 Demand Charge converted to a volumetric rate at a 100% load factor, plus the RS 5 Delivery Charge.

From November 1 to March 31 (referred to in RS 4 as the Extension Period), seasonal customers receive only interruptible sales service. In order to provide service to RS 4 customers during the Extension Period, FEI must have sufficient supply of gas and capacity to deliver the gas. For the Extension Period, the RS 4 Delivery Charge is the RS 7 Delivery Charge times 1.5.

Based on continuing with the existing methodology, the RS 4 Delivery Charges will change due to the proposed changes to RS 5 and RS 7. The Delivery Charge in the Off-Peak Period will increase by $0.114 per GJ and in the Extension Period will decrease by $0.018 per GJ.

9.7.2 Customer Characteristics

Customers served under RS 4 - Seasonal Firm Gas Service include paving companies with asphalt plants and municipal swimming pools that consume natural gas mainly during the summer months. There are 18 seasonal customers forecast for 2016 with an annual demand of 130 TJ. These customers only receive firm gas delivery from April 1 to October 31 (the Off-Peak Period).

The unique needs of these customers distinguish them from firm service customers who require firm service all year and interruptible customers who can either switch to a back-up fuel or cease operations should FEI need to interrupt their service at any time, but otherwise take gas service year round.

9.7.3 Stakeholder Feedback Received

As discussed in Section 5, FEI circulated a Rate Design and Segmentation Discussion Guide to all interested stakeholders and held a workshop on August 31, 2016. This Guide and Workshop discussed FEI's current rate structures and presented a number of options that FEI had under consideration. The detailed meeting summary and notes are attached as Appendix 4-2.

During the Workshop, FEI described the method to establish the Delivery Charge for RS 4. There were no questions from stakeholders and no discussion on this topic.

9.7.4 Principle-Based Review of Seasonal Service

The method of determining the seasonal delivery charges was established during the 1996 Rate Design. RS 4 for seasonal customers is working as intended in that the customers served under this rate schedule require and receive seasonal service and are not receiving service during the coldest peak periods of the winter.

In alignment with the Bonbright principle to fairly allocate costs to customers, seasonal customers are not allocated any demand related costs as they do not cause demand-related costs to be incurred in order to serve the firm load during the system peak requirements.

For the Off-Peak Period, the fairness principle is applicable. During these months, the seasonal customers require firm service and are therefore charged a firm rate based on the RS 5 Demand Charge plus Delivery Charge. Seasonal customers are served as a firm customer in the Off-Peak period only and as such their rate is based on the General Firm Service Rate. Since the Seasonal customers do not contribute to the System Peak which occurs in the Extension Period, the RS 4 Off-Peak rate is discounted from the RS 5 firm rate by using a 100% Load Factor equivalent rate.

During the Extension Period the seasonal Delivery Charge is set at 1.5 times the delivery charge for the RS 7 General Interruptible Service rate. The rationale for the 1.5 multiplier during the Extension Period is to set the Delivery Charge at a premium to discourage General Interruptible Service customers that are receiving year round service from migrating to the seasonal rate. That is, interruptible service customers that use gas throughout the winter period with rare curtailment during the Peak Demand Period are not the same as seasonal customers who do not use gas during the coldest winter months. This pricing methodology provides the price signals to incent customers to take service under the appropriate rate schedule service offering of General Firm or General Interruptible or Seasonal Service.

In the following section FEI proposes to continue with the existing method for determining RS 4 Delivery Charges in the Off Peak Period and considers this to be an appropriate balance of rate design principles.

9.7.5 Proposed RS 4 Delivery Charges

The Delivery Charge for RS 4 during the Off-Peak Period is set equal to the Demand Charge of RS 5/RS 25 at a 100% load factor, plus the Delivery Charge for RS 5/RS 25, and during the Extension Period is equal to 1.5 times the Delivery Charge for RS 7/RS 27. As discussed above, FEI is proposing a change to the RS 5/RS 25 Demand Charge, which also results in a change to the RS 7/RS 27 Delivery Charge.

The proposed changes to RS 5/RS 25 and RS 7/RS 27, and the impacts on RS 4 are shown below in Table 9-21.

Table 9-21: RS 4 Seasonal Service Delivery Charge for Off-Peak and Extension Periods

Row	RS 4	2016 COSA[158] Based Rates	Proposed Rates
1	RS 5/25 Demand Charge equivalent at 100% Load Factor[159]	$0.391	$0.505
2	RS 5/25 Delivery Charge ($/GJ)	$0.887	$0.887
3	**RS 4 Off-Peak Delivery Rate $/GJ (Row 1 + Row 2)**	**$1.278**	**$1.392**
4	RS 7/27 Delivery Charge ($/GJ)	$1.455	$1.443
5	**RS 4 Extension Period $/GJ (Row 4 x 1.5)**	**$2.183**	**$2.165**

The proposed Delivery Charge during the Off-Peak period is increased by $0.114 per GJ to $1.392 per GJ and the rate in the Extension Period decreases by $0.018 per GJ to $2.165 per GJ.

The bill impact of the proposed Delivery Charges is to increase the revenues received from the Seasonal customers by $13.3 thousand ((118.6 TJ x $0.114) – (11.3 TJ x $0.018 per GJ)).

The bill impact of the proposed Delivery Charges is to increase the revenues received from the Seasonal customers from $641 thousand to $654 thousand, or approximately 2%.

9.8 LARGE VOLUME TRANSPORTATION – RS 22 AND CONTRACT CUSTOMERS

FEI's large volume industrial transportation customers are currently segmented into four groups, RS 22, RS 22A, RS 22B and the Large Industrial Contract Customers (VIGJV and BC Hydro IG). These four groups are a legacy of the service areas of FEI's predecessor companies, with RS 22 customers located primarily in the Lower Mainland, RS 22A customers in the Inland Service Area, RS 22B customers in the Columbia Service Area and the two Large Industrial Contract Customers located on Vancouver Island and the Sunshine Coast. RS 22A and 22B have been closed to any new customers since 1993. Since that time, any new large industrial transportation customers have taken service through RS 22 throughout FEI's service area.

Based on a review of the existing large volume industrial transportation rates, FEI proposes the following:

[158] The COSA rates shown are estimated based on 2016 approved rates plus known and measureable changes discussed above in Section 7.

[159] For the Proposed RS 4 Off-Peak Period the volumetric rate would be the RS 5 Demand Charge of $21.596 for 2016 COSA Rates x 12 months / 365 x 55% and $24.596 for Proposed Rates x 12 months / 365 x 62.5% load factor.

- To continue RS 22A and RS 22B as closed service offerings, with grandfathered terms due to their unique characteristics.
- To create a firm rate for RS 22, VIGJV and BC Hydro IG based on a cost of service allocation from the COSA[160] model. VIGJV will become a RS 22 customer taking service and paying for service at the tariff rates under this rate schedule. Under this proposal, the current contract for BC Hydro IG would be included as a Tariff Supplement at their current rates.

9.8.1 Large Volume Transportation - Customer Characteristics

As shown below in Table 9-22, there are 40 customers in RS 22, 22A and 22B with an annual demand forecast for 2016 of approximately 27.5 PJ, with approximately half of the forecast being for interruptible demand and the balance being for firm demand volumes. In addition, VIGJV and BC Hydro IG have a total 2016 annual demand forecast of approximately 21.2 PJ based upon their firm contract demand of 45 TJ/day for BC Hydro and 13 TJ/day for the VIGJV.

Table 9-22: Customers and Annual Demand (TJ) by Rate Schedule

Rate Schedule	Customers	Annual Demand (TJ)
RS 22	26	13,189
RS 22A	9	9,030
RS 22B	5	5,277
Subtotal	**40**	**27,496**
Joint Venture	1[161]	4,758
BC Hydro IG	1	16,425
Total	**42**	**48,679**

The following subsections describe each of these customer groups in more detail.

9.8.1.1 RS 22 – Customer Characteristics

In the 2016 forecast there are 26 RS 22 customers with an annual demand forecast of approximately 13,189 TJ. These customers represent industries varying from refineries, manufacturing, cement, forestry, healthcare, education, food/beverage and greenhouses. These customers generally use natural gas to fuel boilers, kilns and dryers. Due to the variety of industry sectors, consumption ranges from approximately 150 TJ to 2,000 TJ per year.

All RS 22 customers are receiving interruptible transportation service, with the exception of one that uses 2,000 GJ/day of firm transportation service with remaining volumes on an interruptible basis.

[160] The COSA rates shown are estimated based on 2016 approved rates plus known and measureable changes discussed above in Section 7.

[161] The Joint Venture is comprised of five operations that act as one for billing and demand balancing.

9.8.1.2 RS 22A (Closed) – Inland Service Area Customers Characteristics

RS 22A is only available to large industrial customers who were receiving transportation service prior to 1993 in the Inland Service Area. There are 9 non-bypass customers in RS 22A with an annual demand forecast of approximately 9,030 TJ. These customers include mining operations, manufacturing, refineries, pulp mills and forestry companies, which primarily use firm transportation service with a small amount of interruptible service.

Since the 1993 Phase B Rate Design Decision, the existing RS 22A customers have been "grandfathered" in recognition of the unique service offering combining firm and interruptible rates, although RS 22A customers are still subject to general rate changes. RS 22A is closed to any new customers.

Unlike RS 22 customers, RS 22A customers have a curtailment of firm service provision that provides peaking gas supply to sales customers. RS 22A customers can be curtailed to one half of their firm service for up to 5 days per year. The related supply from this curtailment is included as part of FEI's Annual Contracting Plan (ACP) as a gas supply portfolio resource that is available to meet needle peaking requirements for extreme weather conditions.

The Commission explained the reasons why RS 22A (and RS 22B) customers were segregated into separate closed rate schedules in the 1993 Phase B Rate Design Decision as follows:[162]

> BCGUL [now FEI] proposed that existing large volume transportation customers in the Inland and Columbia service areas ("interior customers") maintain their existing rates, but generally adopt terms and conditions similar to those in Schedule 22. These existing rates would not be available to new interior customers or for significant load increases by existing interior customers. BCGUL [FEI] proposed that the tariffs be named Schedules 22A (Inland) and 22B (Columbia) to indicate the similarity to Schedule 22. The rationale was that since virtually all of these interior customers moved their direct purchase gas on firm service, and used only small amounts of interruptible gas, they differed significantly from Lower Mainland large volume customers, who had historically been interruptible sales or service customers only and had no firm gas sales or transportation. Under these circumstances, considering that most of these interior customers had either individually negotiated rates (Inland bypass customers) or a uniquely linked rate design (Columbia customers) and few if any were likely to be requiring load increases, closed rates were argued to be appropriate.
>
> In considering the matter of closing Schedules 22A and 22B, the Commission is aware of the many special circumstances and negotiated agreements underlying the existing rates for these interior customers. … The Commission therefore approves the closing of Schedules 22A and 22B …"

[162] Commission Order G-101-93 and Decision dated October 25, 1993, pages 44, 45.

9.8.1.3 RS 22B (Closed) – Columbia Service Area Customers Characteristics

RS 22B is only available to large industrial customers who were receiving firm and interruptible transportation service prior to 1993 in the Columbia Service Area. There are 5 customers on RS 22B that consumed approximately 5,277 TJ. These customers include four coal mines and a pulp mill.

One customer taking service under RS 22B has lower rates than the other four customers. The lower rates were negotiated in the 1994 Columbia Industrial Rate Design, which recognized that the customer could be a 'bypass' candidate due to its proximity to the TransCanada system and size of load. The approved rates applicable to all five customers are shown in the RS 22B Table of Charges.

Unlike RS 22 and 22A, RS 22B allows monthly balancing. Gas delivered to the customers under RS 22B is predominantly firm service with a small component that is interruptible.

Since the Phase B Rate Design Decision and the Columbia Industrial Rate Design Decision in 1994, RS 22B customers have been grandfathered in recognition of the unique service offering for setting their firm and interruptible rates, although RS 22B customer rates are still subject to general rate changes. RS 22B is closed to new customers.

9.8.1.4 Large Industrial Contract Customers Characteristics

There are two Large Industrial Contract Customers located on Vancouver Island and the Sunshine coast. These customers are the VIGJV and BC Hydro IG. The VIGJV provides for the natural gas needs of five pulp mills and has a service contract for firm contract demand of 13,000 GJ per day which expires on December 31, 2017. FEI anticipates as an interim measure to extend the existing VIGJV contract until the Commission approved Rate Design becomes effective for RS 22. BC Hydro IG has a firm service contract for 40,000-50,000 GJ per day which expires in April 2022.

9.8.2 Large Volume Transportation - Review of Current Rate Design

The following table shows the rate structure and type of charges currently applicable to RS 22, RS 22A, RS 22B, the VIGJV and BC Hydro IG. This section discusses the review of each group of large volume transportation customers.

Table 9-23: Large Volume Transportation and Contract Customers' Charges

Rate Schedule	Basic Charge /Month	Admin Charge /Month	Delivery Demand Charge /Month /GJ of Firm Daily Trans. Quantity (DTQ)	Delivery Charge /GJ of Firm Monthly Trans. Quantity (MTQ)	Delivery Charge per GJ of Interruptible Monthly Trans. Quantity (MTQ)	Firm Delivery Charge of Contract Demand /GJ /Day	Interruptible Delivery Charge /GJ /Day
RS 22 *Large Volume Transportation Service*	$3,664.00	$78.00	n/a	n/a	$0.982[1]	n/a	n/a
RS 22A *Transportation Service (Closed) Inland Service Area*	$4,810.00	$78.00	$15.704	$0.110	$1.241	n/a	n/a
RS 22B *Transportation Service (Closed) Columbia Service Area*	$4,537.00	$78.00	$10.137	$0.108	$1.011 Apr 1 – Oct 31 $1.455 Nov 1 – Mar 31	n/a	n/a
Vancouver Island Joint Venture *Contract*	n/a	n/a	n/a	n/a	n/a	$0.9665[2]	***Tier 1*** 13-20 TJ $0.9665 ***Tier 2*** 20-30 TJ $0.7608 ***Tier 3*** ***30+ TJ*** ***$1.0632***
BC Hydro IG[3] *Contract*	n/a	n/a	n/a	n/a	n/a	$0.958	***Winter*** $1.458 ***Summer*** $0.958

[1] Delivery Charges for firm transportation service are subject to negotiation and prior approval by the BCUC.
[2] Firm Toll per GJ.
[3] All Tolls include a $0.10 per GJ wheeling charge.

9.8.2.1 Review of RS 22 Rate Design

Due to limited system capacity in FEI's Lower Mainland, RS 22 is almost entirely interruptible service. However, there is one customer in the Lower Mainland with 2,000 GJ/day of firm capacity.

As shown in Table 9-23, the RS 22 rate structure is comprised of fixed monthly charges which include a Basic Charge and an Administration Charge per Month in addition to the interruptible Delivery Charges per GJ. The large volume transportation service under RS 22 is intended for customers with a minimum delivery volume of 12,000 GJ per month. RS 22 has a minimum monthly bill provision of paying for 12,000 GJ of delivery charges whether or not 12,000 GJ is actually delivered.

The interruptible delivery charges in RS 22 are currently based on a discount to the firm service rate in RS 5/RS 25. During the 1996 Rate Design Application process, FEI established a method to calculate the RS 22 interruptible service rate based upon a 100% load factor in comparison to the firm service rate offered to RS 5/RS 25 customers.[163]

This method was reviewed and approved by the Commission during the negotiated settlement to the 1996 Rate Design Application.[164] As discussed earlier, FEI is proposing a change to the RS 5/RS 25 Demand Charge. This change will have an impact on the RS 22 interruptible rate if the current method of setting RS 22 rates is maintained.

If RS 22 customers wish to receive firm service, a tariff supplement is negotiated and submitted to the Commission for approval on a contract-by-contract basis.

The only current RS 22 customer that has firm service had their rate approved by Order G-128-05 dated December 1, 2005. For that customer, the Commission approved RS 22 Tariff Supplement No. G-21 to provide firm transportation to Central Heat (now Creative Energy), subject to the review of rates in the next FEI rate design proceeding. The firm delivery charges applicable to Creative Energy are comprised of a demand charge per month per GJ of Firm Daily Transportation Quantity (DTQ) and a firm variable delivery charge per GJ of Firm Monthly Transportation Quantity (MTQ). The Demand Charge applied to Creative Energy was calculated by multiplying the RS 5/RS 25 Demand Charge times the RS 5/RS 25 load factor of 55% to adjust the Demand Charge to assume a 100% load factor. Creative Energy is charged a Firm Demand Charge on a firm DTQ of 2,000 GJ per Day. In addition to the firm Demand Charge each month, the RS 5/RS 25 delivery charges are also charged on every GJ consumed each month up to the firm MTQ (Firm DTQ x # days in month). All volumes in any month exceeding the firm MTQ is charged at the RS 22 Interruptible Delivery Rate. In addition to the firm charges described above, there is also a $1,904 per month Facilities Charge.

The RS 22 Interruptible delivery charges and the RS 22 Firm Rates for Creative Energy are currently both determined by adjusting the RS 5/RS 25 firm rates to assume a 100% load factor. The difference between the two calculations is that the RS 22 Interruptible charge is converted into a complete volumetric charge per GJ and the RS 22 Firm Rates for Creative Energy maintain a demand charge and firm variable delivery charge.

[163] The formula to derive the RS 22 Interruptible Delivery Charge is: RS 5/25 Demand Charge x 12 / 365 x RS 5/25 Load Factor of 55% / 100% + RS 5/25 Delivery Charge.

[164] The same method was used in the 2001 Rate Design Application. However, in the Commission-approved Negotiated Settlement of the 2001 Rate Design Application a rate reduction adjustment of $0.046 / GJ was made to the RS 22 Delivery Charge.

FEI reviews the method for calculating RS 22 firm delivery rates in Section 9.8.5 below.

9.8.2.2 RS 22A/RS 22B (Closed)

The service under RS 22A and RS 22B is primarily firm service with a small component on an interruptible basis. As shown in Table 9-23 above, the RS 22A and RS 22B rate structure is comprised of fixed monthly charges which include a Basic Charge and an Administration Charge per month in addition the firm and interruptible delivery charges. The firm delivery charges are comprised of a firm demand charge per month per GJ of Firm DTQ and firm volumetric delivery charge per GJ of Firm MTQ delivered per month. The pricing for interruptible service is volumetric per GJ on any volumes over the firm MTQ and set at a premium of firm service prices to encourage customers to maintain their Firm DTQ.

There is no minimum delivery volume for RS 22A or RS22B, but these rate schedules have a firm daily Demand Charge and the minimum firm contracted capacity of these customers is currently above 12,000 GJ per month.

RS 22A and RS 22B are both working as intended and FEI proposes to continue to grandfather both of these rate schedules that have been closed service offerings since 1993 given their unique characteristics.

9.8.2.3 Large Industrial Contract Customers

As shown in Table 9-23, the rate structures for the VIGJV and BC Hydro agreements are similar. The rate structure for these two customers currently does not have a Basic Charge or Administration Charge per month like RS 22, RS 22A and RS 22B. The rate structure is comprised of a firm demand toll expressed in dollars per GJ of contract demand per day and the interruptible rates are expressed in dollars per GJ on any volumes consumed on a daily basis over their firm daily contracted capacity or contract demand per day. In addition to their delivery charges, the VIGJV and BC Hydro IG are responsible for a portion of system gas, which includes line heater fuel, compressor fuel and unaccounted for gas, associated with transporting gas to Vancouver Island and the Sunshine Coast. The VIGJV and BC Hydro IG are also charged a commodity toll for odorant and motor fuel tax.

The rates that are in effect for both BC Hydro IG and VIGJV are based on existing contracts, and therefore the rate structure has not been adjusted as a result of the amalgamation of the Vancouver Island gas utility. FEI considered potential options to derive rates for contract customers such as the VIGJV and BC Hydro IG, including using the COSA to derive firm and interruptible rates for this group of customers. These options are discussed in Section 9.8.5.

9.8.3 Principle-Based Review of Rate Design

FEI reviewed the rate design for RS 22, the VIGJV and BC Hydro IG considering the rate design principles discussed above in Section 6.1, government policy and in light of the amalgamation of utilities. Based upon this review, FEI concluded that it should consider the potential for new cost-based firm and interruptible rates under RS 22 that would be applicable to all large industrial customers. Similar rates and rate structures for RS 22 and each of the VIGJV and BC Hydro IG may be more aligned with the fair apportionment of costs (Principle 2) and avoidance of undue discrimination among similar type customers (Principle 8). Large Industrial customers receiving similar service and having similar rates and rate structures would also be likely to improve customer understanding and acceptance (Principle 4). FEI considers this option in comparison to the status quo below.

9.8.4 Stakeholder Feedback Received

The questions FEI received from stakeholders primarily involved clarifying the history for RS 22A and RS 22B and why these rate schedules have been closed and grandfathered. This explanation and clarification has been provided above in Sections 9.8.1.2, 9.8.1.3 and 9.8.2.2. FEI received some questions regarding the history of the R:C ratio for RS 22A and was asked what would happen to rates in 2022 if the BC Hydro IG contract was terminated. Please refer to Section 6.6 Table 6-20 for FEI's responses to these requests.

9.8.5 Rate Design Options for RS 22 and Large Industrial Contract Customers

Based on the review of the existing rate design of large volume transportation customers, FEI has considered two options:

1. Status Quo with RS 22 Firm Rate: Maintain separate contract based rates for the VIGJV and BC Hydro IG; continue to determine the RS 22 firm and interruptible rates on a 'value of service' rather than cost basis with the firm rate included in RS 22. Having a stated frim rate for the Demand Charge and firm Delivery Charge would be a change from the current negotiated rates for each customer. Refer to Section 9.8.5.1 for the discussion of Option 1.
2. Postage Stamp Cost of Service Rates: Establish firm and interruptible rates for RS 22 that are cost based and applicable to all large industrial customers, including Creative Energy, the VIGJV and BC Hydro IG. Refer to Section 9.8.5.2 for the discussion of Option 2.

9.8.5.1 Option 1: Status Quo with RS 22 Firm Rate

Under this option, FEI would determine both firm and interruptible rates that would apply to all RS 22 customers[165], but rates for the VIGJV and BC Hydro IG would continue to be contract based rates. FEI would use the existing method to calculate the RS 22 interruptible rate and the method used in the Creative Energy contract to calculate the firm rate. Both of these methods are linked to the RS 5/RS 25 rates and are value of service based, as discussed below.

FEI's established method to calculate the RS 22 interruptible service rate is based upon the firm service rate offered to RS 5/RS 25 customers, adjusted to a 100% load factor. This established

[165] All RS 22 **does not** include RS 22A, RS 22B and RS 22 bypass customers.

method converts the RS 5/RS 25 Demand Charge and variable Delivery Charge into a variable Delivery Charge adjusted to a 100% Load Factor. The pricing for interruptible service would remain volumetric per GJ on any volumes over the firm MTQ. FEI would maintain the same formula to derive the RS 22 Interruptible Delivery Charge as follows:

(RS 5/25 Demand Charge) X (12 / 365) X (RS 5/25 Load Factor of 55% / 100%)
+ RS 5/25 Delivery Charge

For the RS 22 Firm Rate, FEI would use the method for setting the RS 22 firm rates for Creative Energy by converting the RS 5/RS 25 Demand Charge to a 100% Load Factor equivalent charge per GJ per month plus RS 5/RS 25 firm Delivery Charges on all firm delivered volumes per month, as discussed in Section 9.8.2.1. The firm Delivery Charges would be comprised of a firm Demand Charge per Month per GJ of Firm Daily Transportation Quantity (DTQ) and firm volumetric Delivery Charge per GJ of Firm Monthly Transportation Quantity (MTQ) delivered per month. FEI would maintain the same formula to derive the RS 22 Firm Delivery Charges as follows:

RS 22 Firm Demand Charge = RS 5/25 Demand Charge X RS 5/25 Load Factor of 55%

Under these methodologies, the firm and interruptible delivery charges would, in effect, be set equal to each other. RS 22 customers could select to secure some firm service for a portion of their load subject to capacity being available. If capacity were available, electing firm service would require a fixed demand charge commitment which would increase the customer's overall fixed monthly charges. This type of rate structure for RS 22 would be similar to what is in place for Creative Energy today and what is also in place for closed RS 22A and RS 22B.

As the firm and interruptible rates under Option 1 are tied to RS 5/RS 25, these rates can be seen as "value of service based" and not cost of service based. The following table shows the firm and interruptible rates for RS 22 under this option, based on the RS 5/RS 25 rates as described above.

Table 9-24: Option 1 - RS 22 Firm Demand Charge, Firm MTQ Delivery Charge & Interruptible MTQ Charge[166]

	RS 25		RS 22		
	2016 COSA	**Proposed**	**2016 Current / 2016 COSA**	**Formula Applied to 2016 COSA**	**Formula Applied to RS 5/25 Proposed**
Demand Charge $/GJ/Month	$21.596	$24.596		$11.878	$13.528
Delivery Charges $/GJ	$0.887	$0.887			
Firm MTQ Charge $/GJ				$0.887	$0.887
Demand Charge $/GJ				$0.391	$0.445
Delivery Charge $/GJ				$0.887	$0.887
Interruptible Rate $/GJ			$0.982 / $1.060	$1.278	$1.332

Under this option, FEI would continue to have contract based rates with the VIGJV and BC Hydro IG. These rates may not be based upon COSA results and may not be cost based. The revenues from BC Hydro IG and the VIGJV would continue to be treated as a credit in the COSA Model.

A summary of the proposed rates under Option 1 can be seen in the table below.

Table 9-25: Option 1 RS 22, VIGJV and BC Hydro IG Rates

Rate Schedule	Basic Charge /Month	Administration Charge /Month	Delivery Demand Charge /Month /GJ of Firm Daily Transportation Quantity (DTQ)	Delivery Charge per GJ of Firm Monthly Transportation Quantity (MTQ)	Delivery Charge per GJ of Interruptible Monthly Transportation Quantity (MTQ)
RS 22 *Large Volume Transportation Service*	$3,664.00	$78.00	$13.528	$0.887	$1.332
Vancouver Island Joint Venture *Contract*	Contract Rates (current rate is $0.9665/GJ)				
BC Hydro IG[3] *Contract*	Contract Rates but cannot exceed price cap of $0.958/GJ until April 2022				

[166] The RS 22 Demand Charge at 100% Load Factor is equal to RS 25 Demand Charge times 55% (the load factor for RS 5/RS 25). The RS 5/RS 25 Demand Charge expressed as a volumetric rate is equal to the Demand Charge x 12 / 365 x RS 5/25 Load Factor (55%)

9.8.5.2 Option 2: Postage Stamp Cost-Based Rates

Under this option, RS 22, VIGJV and BC Hydro IG would be grouped together to derive firm rates based on the allocated cost of service results. The firm rate(s) would be applicable to RS 22 customers, the VIGJV and BC Hydro IG[167] and would be set equal to the allocated costs in the COSA Model. The interruptible rates would be based on the firm rate.

FEI would establish a postage stamp, cost of service firm rate for all large industrial customers. To derive the firm rates for RS 22, the costs from the COSA model allocated to large industrial customers would be converted into the following charges:

- Basic and Administration Charge per month;
- Firm Demand charge per month per GJ of Firm Daily Transportation Quantity (DTQ); and
- Firm volumetric Delivery Charge per GJ of Firm Monthly Transportation Quantity (MTQ) delivered each month.

The volumetric Delivery Charge under this option would be approximately consistent with the Delivery charge under RS 22A and RS 22B and would have a high proportion of fixed Demand charges. The Demand charge would encourage customers to shift to firm service for only base load consumption that has a high load factor (subject to capacity being available).

Under this option, the rates for interruptible service would be set equal to the firm rates. The allocated cost of firm delivery from the COSA model is \$0.972/GJ; the interruptible rate would also be set at \$0.972/GJ. This ensures that there is no incentive for customers to shift from firm contracted capacity to interruptible service. Currently, all of the RS 22 customers, except for Creative Energy, are fully interruptible. If any interruptible customer wished to firm up a portion of their capacity, subject to firm service availability, the customer would need to make a demand charge commitment for firm capacity, increasing their fixed monthly charges. The pricing for interruptible service would remain volumetric per GJ on any volumes over the firm MTQ.

Under this option, the existing contract rates would be addressed as follows:

- Tariff Supplement G-21 for Creative Energy would be terminated and Creative Energy would take firm service under the new charges for firm service under RS 22.
- The VIGJV could choose to become a RS 22 customer after the expiration of their agreement on December 31, 2017. FEI anticipates as an interim measure to extend the existing VIGJV contract until the Commission approved Rate Design becomes effective for RS 22.
- BC Hydro IG would continue to take service under its existing agreement, which continues until April, 2022. For the duration of BC Hydro's contract, the Firm demand

[167] The BC Hydro IG contract has a cap ceiling for its firm rate at \$0.958/GJ until the end of the Initial Term of the Agreement.

toll for BC Hydro would be expressed as a Firm Demand Toll consistent with their agreement in dollars per GJ of Contract Demand per Day and the Interruptible rates would be expressed in dollars per GJ. The BC Hydro IG Contract has a cap ceiling for its firm rate at the current rate of $0.958/GJ until the end of the Initial Term of the Agreement of April 2022. After the contract expires, BC Hydro IG could choose to become a RS 22 customer.

A summary of the rates under Option 2 is provided in the table below.

Table 9-26: Option 2 FEI's Proposed Charges for RS 22

Rate Schedule	Basic Charge /Month	Administration Charge /Month	Delivery Demand Charge /Month /GJ of Firm Daily Transportation Quantity (DTQ)	Delivery Charge /GJ of Firm Monthly Transportation Quantity (MTQ)	Delivery Charge /GJ of Interruptible Monthly Transportation Quantity (MTQ)	Firm Delivery Charge of Contract Demand /GJ /Day	Interruptible Delivery Charge/ GJ /Day
RS 22 *Large Volume Transportation Service (including VIGJV)*	$3,664.00	$78.00	$25.00	$0.15	$0.972	n/a	n/a
BC Hydro IG[3] *Contract*	n/a	n/a	n/a	n/a	n/a	$0.958	$0.958

9.8.5.3 Option Evaluation

FEI is proposing Option 2 as it reflects a more reasonable balance of rate design principles.

Option 2 will establish a firm cost of service based rate applicable to all large industrial customers. This option is consistent with the rate design principles of fair apportionment of costs and avoidance of undue discrimination among similar types of customers. Moving towards a postage stamp firm rate for all large industrial customers is also consistent with government policy in favour of postage stamp rates.

FEI also believes that cost-based, firm rates as proposed under Option 2 are more transparent and consistent with the principle of customer understanding and acceptance. In the stakeholder workshop the issue of how contract rates under Option 1 for BC Hydro IG and VIGJV would work within this process was raised as a possible issue. While negotiated contract rates would still be subject to BCUC approval under Option 1, FEI believes that Option 2 is preferable in this case.

In addition, under Option 1, the resulting proposed rates for firm and interruptible service for RS 22 customers result in a 36% rate increase compared to the current 2016 rates. These rate increases are due to (1) setting the Demand Charge for RS 22 at 55% of the proposed RS 5/RS 25 Demand Charge, (2) setting the Firm MTQ Charge equal to the RS 5/RS 25 Delivery Charge, and (3) setting the Interruptible MTQ Charge equal to the result of the formula described in Option 1. This level of rate increase would lead to rate shock. In comparison, Option 2 would have a relatively minor rate impact on RS 22 customers as well as the VIGJV.

The following table summarizes the revenue, change in revenue and change in rates for RS 22 and the VIGJV. BC Hydro is not shown since its charges are capped under its existing contract, which does not expire until 2022.

Table 9-27: Summary of Change in Revenue and Change in Rates for RS 22 and VIGJV

	Current Rate	Option 1	Option 2	Difference	
				Option 1 vs Current Rate	Option 2 vs Current Rate
RS Demand Charge $ / Month / DTQ	N / A	$13.528	$25.000		
Firm MTQ $ / GJ	N / A	$0.887	$0.150		
Interruptible MTQ $ / GJ	$0.982	$1.332	$0.972	35.6%	(1.0%)
VIGJV Firm $ / Day / DTQ	$0.967	N / A	N / A		
RS 22 Revenue ($000s)	$14,235	$18,640	$14,109	30.9%	(0.9%)
VIGJV Revenue (including System Gas)	$4,588	$4,588	$4,420	0.0%	(3.7%)
Total	**$18,823**	**$23,228**	**$18,529**	**23.4%**	**(1.6%)**

FEI therefore considers that Option 2 is the preferred option, representing a more reasonable balance of rate design principles.

9.8.5.4 Large Volume Industrial Transportation - Rate Design Conclusion and Proposal

FEI has reviewed the existing large volume industrial transportation rates and, for the reasons discussed above, is proposing the following:

- FEI will continue to grandfather RS 22A and RS 22B as closed service offerings due to their unique characteristics.
- FEI will create a firm rate for RS 22, VIGJV and BC Hydro IG based on a cost allocation from the COSA model. Under this option, Tariff Supplement G-21 for Creative Energy would be terminated and the VIGJV could choose to become a RS 22 customer after its contract expires. The contract for BC Hydro IG would be included as a Tariff Supplement and, after the contract expires, BC Hydro could choose to become a RS 22 customer.

9.9 SUMMARY

FEI proposes the following for the industrial customer rate design:

- Implement the updated multiplier of 1.1 in the calculation of daily peak demand for the General Firm Service RS 5 and RS 25 Demand Charge.
- Raise the Demand Charge for RS 5 and RS 25 by $3.00 (per Month per GJ of Daily Demand).
- Maintain the existing rate structures for RS 7 and RS 27, but adjust the resulting rates and update the load factors used in the calculation of the Delivery Charge to reflect the proposed changes to RS 5 and RS 25.
- Maintain the existing rate setting methodologies for RS 4, but adjust the resulting rates due to the change to the RS 5 Demand Charge and RS 7 Delivery Charge.
- Maintain RS 22A and RS 22B as closed and grandfathered for existing customers.

Calculate a single RS 22 firm rate based on the allocated costs in the COSA Model for RS 22, VIGJV and BC Hydro IG together as a group.

FortisBC Energy Inc.
2016 Rate Design Application

Section 10:

TRANSPORTATION SERVICE REVIEW

Table of Contents

10. TRANSPORTATION SERVICE REVIEW

10.1 *INTRODUCTION*

FEI's transportation service is available to large commercial and industrial customers on FEI's system who source their own gas, either from a shipper agent or on their own, and have the gas delivered directly to FEI's System. FEI conducted a full review of it transportation service business model, guided by legal requirements, the rate design principles and government policy, and informed by the stakeholder engagement process, data analysis and jurisdictional comparisons. Based on these considerations, the transportation service model is generally working well. As such, FEI does not believe that significant changes are required.

However, given industry improvements in monitoring, communicating and implementing gas balancing, FEI is proposing changes to require transportation customers to balance their gas supply more tightly. In particular, FEI is proposing to eliminate monthly balancing and to require all transportation customers in all service areas to balance daily, which is consistent with FEI's own system balancing requirements at its interconnection points. FEI does not expect these requirements to be burdensome for shipper agents. Many shipper agents are already exclusively balancing daily.

FEI is also proposing to amend the balancing tolerance from 20% to 10%, coupled with a tiered charge approach under which charges increase as tolerance ranges are exceeded. The proposed charges and tiered approach will provide an incentive to balance within the 10% tolerance.

The remainder of this section is organized as follows:

- In Section 10.2, FEI describes its sales customer business model and how FEI uses contracted resources on behalf of sales customers to balance the System to benefit all customers, including transportation customers, throughout the year.
- In Section 10.3, FEI reviews its transportation customer business model, including FEI's gas balancing operations, the transportation rate schedules and their key features, customer pooling, imbalance return, balancing tolerance and customer charges.
- In Section 10.4, transportation rate design issues FEI has identified are discussed with consideration given to the rate design principles, FEI's research and analysis and a jurisdictional comparison.
- In Section 10.5, transportation service comments FEI received through the stakeholder engagement process are summarized, including how FEI has addressed those comments.
- In Section 10.6, daily and monthly balancing provisions for transportation service are discussed, including concerns and options considered by FEI, as well as FEI's proposal to move to daily balancing.

- In Section 10.7, the existing balancing tolerance provisions are described, including the options FEI considered and its proposal to tighten the percentage tolerance to 10% and to tier balancing charges to incent greater balancing efficiencies.
- In Section 10.8, Firm Transportation Service south to the Huntingdon Delivery area (T-South Long-Haul)[168] is discussed, including FEI's proposal to continue to allocate this capacity to transportation customers through its ACP process.
- In Section 10.9, the proposals identified in Section 10 are summarized.

10.2 *FEI'S SALES CUSTOMER BUSINESS MODEL AND SYSTEM OPERATIONS*

As explained in Section 3, FEI has two business models in place that allow customers flexibility in how they choose to source their daily gas commodity supply and midstream (storage and transportation) services. The two primary customer groups are sales customers and transportation customers. Each of these customer groups has an associated business model: the sales customer business model and the transportation customer business model.

In the sections below, FEI provides an overview of its sales customer business model, the resources it has acquired to meet sales customer load and its operations to balance its System on a daily basis for all customers.

10.2.1 Sales Customer Business Model Overview

FEI contracts on behalf of sales customers for firm resources to meet the daily load requirements of sales customers over the course of each year. The contracting of all resources needed to provide service to sales customers includes the filing of the ACP with the Commission in the spring of each year. After Commission review and acceptance of the ACP, the required commodity, storage, and pipeline resources are contracted for, as necessary, with third-party suppliers of these resources.

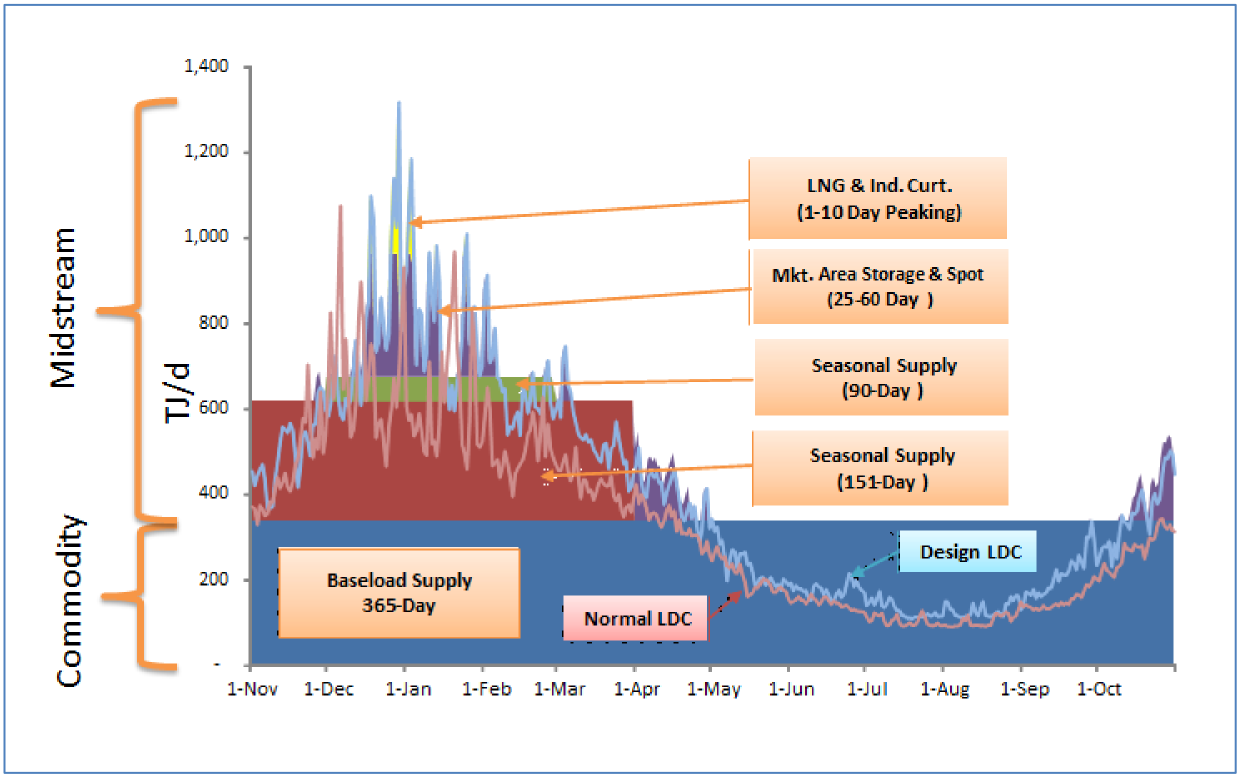
The ACP details the proposed contracting of resources that are needed to meet the forecast requirements of RS 1 to RS 7 sales customers for the upcoming gas contract year under all weather conditions, ranging from normal loads to design loads. The ACP objectives, which have been accepted by the Commission and remained consistent, are as follows:

1. To contract for resources that ensure a balance of security, diversity, and reliability of gas supply in order to meet the design day (peak) demand for the core market (firm supply customers) and the annual requirements, while minimizing the overall cost of the portfolio.
2. To develop a mix of resources in the portfolio that provides contract flexibility for resources based on consideration of short term and long term planning needs, and evolving market dynamics.

[168] Spectra Energy's Firm Transportation Service allows for the movement of gas south from a receipt point at Compressor Station No. 2 (Station 2) to a delivery point within the Huntingdon Delivery area.

Figure 10-1 below shows the forecast design (peak) load and the normal load and how they are served by the various resources contracted by FEI. Figure 10-1 demonstrates the need to have a diverse set of firm resources that are capable of delivering gas when and where the load is required on any given day.

Figure 10-1: ACP Resources Available to Meet Design and Normal Loads



The supply of gas above the baseload commodity (as denoted by the Baseload Supply 365-Day blue-colored band in Figure 10-1) is provided by resources contracted as part of the midstream portfolio. The midstream portfolio includes resources such as seasonal and peaking gas supply, storage capacity, and transportation capacity on third-party pipelines. All regional third-party pipeline and storage resources contracted by FEI must be available on a firm basis to provide security of supply under all weather conditions and to deal with operational emergencies and planned or unplanned system outages.

The design day or peak day forecast is determined through extreme value analysis modelling of the expected coldest day temperature (i.e., the coldest day expected to occur once every twenty years). The design day load forecast is determined by applying the expected coldest day consumption (based on the relationship between consumption and temperature) and multiplying it by FEI's current customer accounts within its various operating regions.

The annual normal load forecast is determined by applying the consumption based on the average daily temperature for the past ten years to the forecast number of FEI customer accounts within its various operating regions. This calculation is made to produce a forecast for each day of the year.

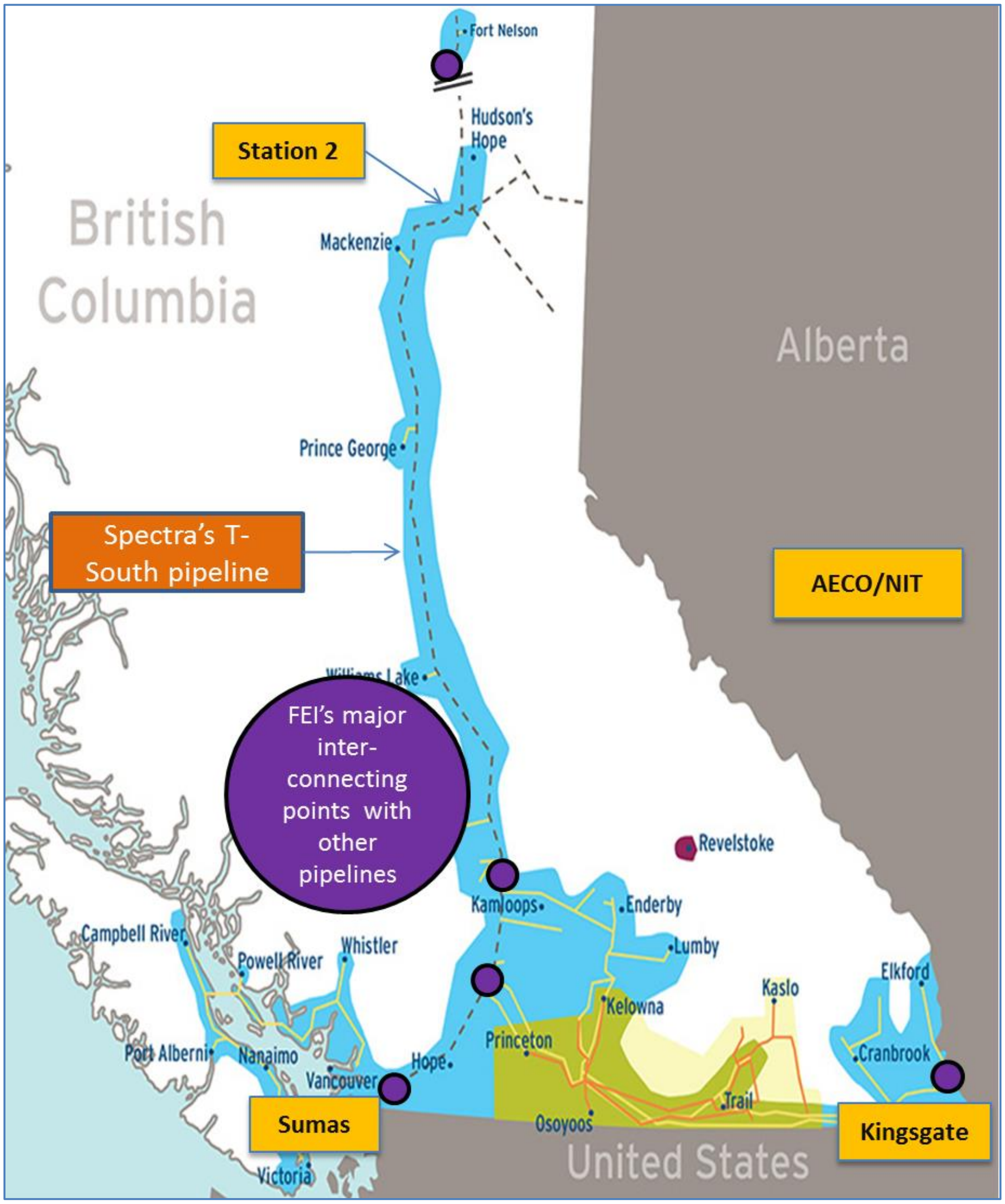
FEI continually assesses the regional supply and demand situation for available resources while also evaluating the requirement to develop new resources or infrastructure in order to meet its dynamic needs. This review is included in each filing of the ACP and it helps to plan the resource requirements beyond the immediate gas year to a three to five year time frame. Longer-term planning is important because certain resources considered in the ACP may be limited or controlled by third parties who may restrict or even eliminate their renewability after existing contracts expire. The development of comparable new regional resources may require several years to assess, garner necessary regulatory approvals, and construct before being implemented into the portfolio. An overview of the marketplace in which FEI must procure these resources is provided below.

10.2.2 Regional Marketplace Overview

The regional marketplace for gas supply, pipeline transportation and storage services that are employed by FEI and neighbouring utilities in the Pacific Northwest is limited and utilized to serve large load centers in the winter months. During periods of extreme weather, the resources can be constrained and operate at capacity to service the needs of the region. The marketplace in B.C. and the Pacific Northwest does not have the liquidity and flexibility of the Alberta marketplace with respect to access to intraday spot gas purchases and sales, and the availability of a large number of storage services.

The regional marketplace where gas supply is received by FEI to bring into its distribution system and an overview of gas trading hubs is shown in Figure 10-2 below.

Figure 10-2: FEI's major interconnecting points and location of gas trading hubs



The majority of gas in the regional marketplace is bought and sold by FEI and other Pacific Northwest utilities at the Sumas and Station 2 hubs, located along Spectra Energy's T-South pipeline system. These two hubs have a very limited intraday marketplace and no published intraday prices that are posted on electronic bulletin boards. Almost all gas sales and purchase transactions at these two hubs are conducted on a "day out" basis by utilities and shipper agents based on the next day's forecast demand of their respective customer groups. Some volumes of gas are also purchased from the AECO/NIT market in Alberta and delivered each day to the eastern region of FEI's system.

In the unlikely event that FEI purchases gas intraday at Station 2 or AECO/NIT, there may not be adequate pipeline capacity available to transport that supply to the required market center.

Consequently, FEI and its neighbouring regional utilities rely primarily on storage services available within the region, accompanied by firm pipeline capacity, as a source of gas supply to meet demand and balance their pipeline systems for intraday load swings.

The same regional pipelines and storage services that are contracted in FEI's portfolio are also accessed and relied upon by other large neighbouring utilities, resulting in a constrained marketplace for limited resources. As such, FEI must assess the marketplace continually and secure firm contracts for midstream resources, with the ability to extend or renew the contracts, to ensure that these resources remain available to meet the requirements of FEI's sales customers year after year.

10.2.3 FEI Daily System Operations

Gas supply is received by FEI each day on behalf of both sales customers and transportation customers. Transportation customers deliver gas daily at designated interconnecting points of FEI's system with third-party pipelines, since transportation customers are responsible for procuring their own upstream contracts directly. Sales customers' daily business is conducted by FEI under the ESM. The ESM is a framework under which sales customers have a choice of commodity supplier (shipper agents or FEI) while all other key functions are performed by FEI. Shipper agents managing the gas supply requirements for transportation customers must provide gas to FEI at prescribed supply hubs, which are trading points on external pipeline systems where natural gas is transacted: namely, at Station 2 and at AECO/NIT (shown in Figure 10-2 above). Regardless of sales customers' commodity provider, FEI is responsible for receiving the gas at the supply hubs and transporting it on FEI's system for final delivery to customers.

10.2.3.1 FEI Available Resources for Sales Customers

FEI has a diverse set of gas supply resources in order to meet the demand of sales customers daily, within the day and over the course of the year. Throughout the year, FEI prioritizes the use and optimization of available resources in order to meet daily load in the following way:

- Gas from year-round (i.e., baseload) or seasonal supply contracts are usually drawn first to meet load.
- Resources such as storage are deployed as required depending upon the type of storage contract and weather conditions. Storage contracts with a longer duration of deliverability (i.e., Aitken Creek) are used sooner to provide supply into the System, while storage contracts with fewer days of deliverability (i.e., Jackson Prairie, Mist) are used more sparingly to meet colder weather of shorter duration.
- On-system LNG is used only under extreme or peak weather and emergency situations due to its limited availability and refilling characteristics.

The purpose of this plan is to ensure that these resources will be available for use when required, or mitigated to the extent possible when they are not needed, as part of an overall plan to manage the portfolio cost effectively for customers.

10.2.3.2 FEI Daily Load Balancing Functions

Gas supply is managed on a “day out” basis whereby supply is nominated/ordered a day ahead to meet the next day’s expected demand. The day’s supply arrangements are coordinated by FEI and shipper agents to meet their respective customers’ forecast demand at the various locations. However, during the actual gas day, as the supply gets delivered, the actual difference between supply and demand varies, for a number of reasons, from the quantity estimated the previous day.

The factors that influence System load swings each day include:

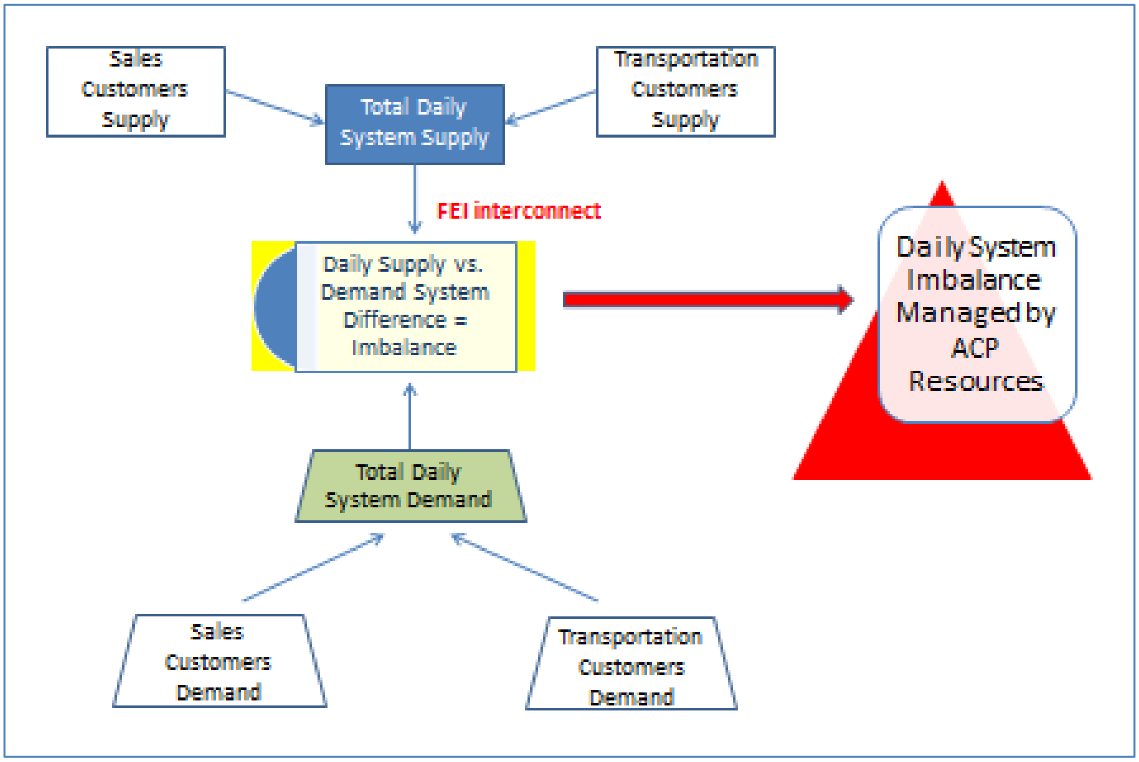
1. Hourly changes in temperature and weather conditions, which impacts load swings caused by heat sensitive customers.
2. Dynamic consumption levels for customers with industrial process loads. These load swings can be much more severe during cold weather, resulting in a large shortfall or surplus of gas within the distribution system.
3. Supply cuts experienced due to upstream system or plant upsets resulting in a shortfall of gas supply entering FEI’s system to meet demand.

FEI’s diversified portfolio of resources plays a significant role in how these daily swings are managed on FEI’s System.

FEI balances the System by each day’s end, which involves using the resources approved in the ACP regardless of the customers or customer groups causing the imbalance. Gas supply must be made available in an expeditious manner when there is a gas shortage due to demand changes and, conversely, excess gas supply must be dissipated out of the System so that the pipeline operates within prescribed tolerance levels and pipeline pressures are maintained. In these circumstances, FEI and shipper agents must manage and adjust the supply requirements to accommodate gas variations intraday. ACP resources are used almost every day of the year, except under rare extreme weather conditions or emergency situations when tighter restrictions are placed on transportation customers, as discussed in the next section.

Figure 10-3 below illustrates daily system load balancing when the total supply does not match the total demand on FEI’s System, causing a daily System imbalance.

Figure 10-3: Daily System Load Balancing Overview



10.2.3.3 Restricted Period System Operations

During periods of cold or extreme weather or operational issues that cause a disruption on the System, FEI imposes restrictions on transportation customers to better match supply with demand and maintain balancing tolerances each day. FEI imposed supply restrictions often result in transportation customers over-delivering gas supply to avoid charges imposed when their demand exceeds supply.

While over deliveries by transportation customers may reduce the level of resource deployment for sales customers on certain days, FEI would need to deploy its resources on subsequent days to return the excess supply back to the transportation customers.

The daily requirements of sales customers must be met under all weather conditions including emergency situations through the procurement of midstream resources by FEI and the provision of daily baseload commodity supply by both FEI and Customer Choice marketers. As such, in managing supply for its sales customers, FEI cannot rely on the possibility that transportation customers will over-deliver gas into the system. There is no certainty as to which days and how much over-delivery will occur, if any, during restricted periods. The usefulness of transportation customers' over-delivery depends on where it occurs on FEI's pipeline System relative to where a shortfall of gas occurs. For example, an over-delivery of gas in the Interior region of the System may not be able to satisfy the need for gas on the Lower Mainland.

10.2.3.4 Pipeline Balancing Agreements

The total gas supply received at FEI's interconnecting points with other external pipelines must be balanced. Balancing agreements are in place to account for differences encountered between the nominated gas flow for a gas day and the actual physical gas flow. These agreements allow interconnecting pipelines to assist each other for a variety of operational reasons as the flow of gas from one system to another is typically significant.

Gas "drafted" from or "packed" [169] by FEI on third-party pipelines must fall within the contractual operating daily balancing provisions. Imbalances must trend towards zero as soon as possible in the ensuing days. Gas that is drafted or packed excessively on pipelines such as Spectra Energy's T-South pipeline could have commercial ramifications pertaining to price movements at the trading hubs on ensuing days, should the pipeline immediately remedy the imbalance situation. These marketplace price movements could be more amplified during cold weather events.

FEI's balancing agreements with its interconnecting pipelines are in place to facilitate operational support and assistance between the pipeline systems. The balancing agreements are not intended to act as a resource for provision of gas supply to manage system load swings.

10.3 TRANSPORTATION CUSTOMER BUSINESS MODEL

10.3.1 Introduction

Transportation service is available to large commercial and industrial customers on FEI's System to source their own gas, either from a shipper agent or on their own, and have the gas delivered directly to FEI's System at an interconnecting point[170]. Once FEI receives the gas at the specified interconnecting point, FEI will move the gas through the System for delivery to customers' premises.

Although FEI's approximate 2,500 transportation customers represent only 0.2% of the total number of FEI customers, transportation customer volumes constitute approximately 40% of the total annual throughput on FEI's System. Thirteen transportation shipper agents currently manage supply and demand requirements for transportation customers.

Since its inception in 1993, the transportation model has operated well, as it has allowed customers with different load profiles to manage their gas supply requirements to fit their business needs. However, FEI believes amendments to the transportation model are required at this time. FEI is of the opinion that the transportation balancing rules need to be revisited and

[169] On a day when customer demand is greater than the delivered gas supply, this imbalance results in a "draft" on FEI's System. Conversely, when customer demand is less than the delivered gas supply, this imbalance results in a "pack" or gas left on FEI's System.

[170] As defined in the transportation rate schedules, an interconnect point "means a point where the FortisBC Energy System interconnects with the facilities of one of the Transporters of FortisBC Energy, as specified in a Transportation Agreement".

updated in order to reflect updated industry practices and operating procedures with third-party pipelines and improved efficiencies and sophistication in today's gas supply market. Current technology permits customers and shipper agents to access daily consumption data. This allows FEI and transportation customers to better manage and match gas supply and demand on a daily basis.

In the following sections, the key aspects of the transportation model are provided, including daily and monthly balancing provisions, the balancing tolerance, and associated balancing charges. For each of these key aspects, FEI is proposing changes that will adjust the business rules to incent tighter balancing on FEI's System.

10.3.2 Transportation Services Operating Model

FEI's ESM, used for its sales customers and the transportation business model, operates independently to serve distinct sets of customers. While the ESM and transportation models are separate, FEI is required to balance the System as a whole, which includes imbalances caused by transportation customers. This method of balancing the System as a whole is necessary and valuable, as it allows FEI to proactively manage the total System operations safely and efficiently each day of the year while also reducing the risks and overall costs to customers.

Under the ESM, FEI contracts for resources to meet core market demand throughout the year. Transportation customers share the same responsibility to contract for resources to meet their demand throughout the year. Transportation customers are required to provide their best estimate of the quantity of gas that will actually be consumed each day. For example, Section 8.2 of Rate Schedule 22 includes the following requirement:

> The Shipper's Requested Quantity each Day will equal the Shipper's best estimate of the quantity of Gas the Shipper will actually consume on such Day.

In addition, Section 3.1 of the Shipper Agent Agreement states:

> The Shipper Agent is responsible for the management of all Balancing Gas for the Group and its members.

As such, customers and shipper agents under the transportation model are expected to make best efforts to bring on sufficient supply to meet customer demand.

10.3.3 Transportation Rate Schedules Overview

The intent of the transportation model is to give customers a greater service choice, and in doing so, provide a business structure for shipper agents and transportation customers to manage their gas supply needs on FEI's System. Subject to eligibility, customers can choose to take service under transportation rate schedules that allow for firm or interruptible transportation capacity on FEI's System. If taking transportation service, the shipper agent or customer is required to manage supply into the System. However, FEI manages the System as a whole on a daily basis.

The transportation model rate schedules with the terms and conditions of the transportation service include RS 22, RS 22A, RS 22B, RS 23, RS 25 and RS 27. Some the key aspects of these rate schedules are as follows:

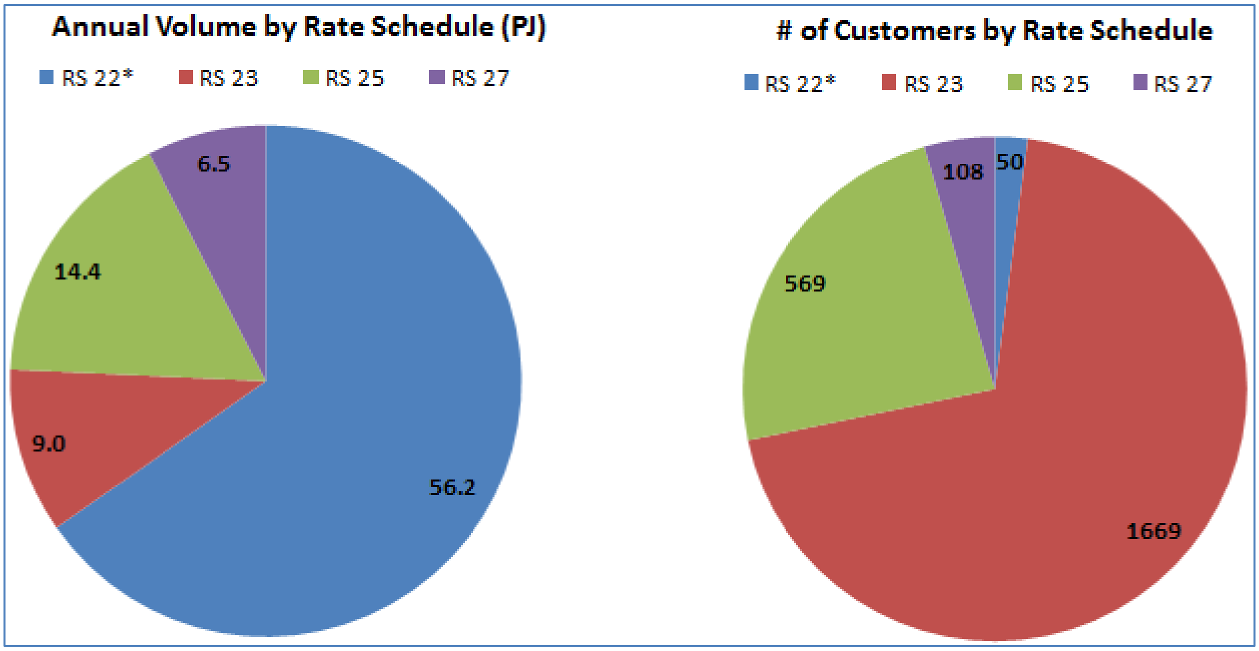
- RS 22 customers may elect for firm or interruptible transportation service on FEI's System[171].
- RS 22 and RS 22A customers are required to be daily balanced, meaning that gas supply and demand must be balanced on a daily basis. Customers that elect these rate schedules receive a daily balancing service from FEI for under-deliveries up to 20%. As well, these customers may also incur charges for daily balancing gas if inventory levels go below zero.
- RS 22A and RS 22B were created in the Inland and Columbia regions, respectively, and apply to large industrial customers specifically listed. These tariffs are closed and unavailable for enrolment by new customers.
- RS 23 and RS 25 provide customers with firm transportation service on FEI`s System and customers under these schedules can currently be balanced monthly. This means that by month end, the aggregate supply of gas over the month must balance with the aggregate demand.
- RS 27 provides for fully interruptible transportation service for large volume customers which can currently be balanced monthly.

Aside from RS 22 and RS 22A, customers under the other transportation rate schedules do not receive a balancing service throughout the month; however, FEI will balance these customers by month end if the total demand is greater than the total supply delivered.

Figure 10-4 below is a breakdown of the approximate throughput by rate schedule in the year 2015, and the associated number of customers under rate schedule.

[171] There is only one RS 22 customer on FEI's system that has a small amount of firm service.

Figure 10-4: 2016 Forecast Transportation Throughput Volume by Rate Schedule and Customer Count



*Includes RS 22/RS 22A/RS 22B, Joint Venture and BC Hydro Island Generation

10.3.4 Customer Pooling

FEI's transportation model allows customers to be either daily or monthly balanced, with the exception of customers served under RS 22, which must be daily balanced. Shipper agents are also permitted to pool their customers in daily or monthly balanced groups. Each shipper agent is permitted to have one daily and one monthly balanced group for each receipt or interconnecting point on the System. FEI permits grouping or pooling of customers, which allows shipper agents to operate within the tolerance limits to manage the overall load of its customer group. The percentage of customers that balance in daily and monthly groups and their respective annual demand is shown below in Table 10-1.

Table 10-1: Daily and Monthly Balancing Pools

Customer Pooling Type	% of Customers	% of 2015 Annual Demand
Daily	24%	55%
Monthly	76%	45%

While there are a higher percentage of customers pooled in monthly balanced groups, daily balanced group customers represent a higher load percentage on the system.

10.3.5 Imbalance Return

Imbalance return is a balancing tool in which shipper agents with daily balanced groups use their stored inventory on FEI's System as a source of supply. Historically, FEI limits the amount of imbalance return to 40,000 GJ/Day in the Interior and 40,000 GJ/Day in the Lower Mainland (including Vancouver Island).[172] Shipper agents submit requests to FEI to use a portion of the available amount, and quantities are allocated by FEI.

FEI has observed that on a typical day when imbalance return is authorized for a shipper agent, that shipper agent will combine the allocated portion of its inventory with physical supply made available at the interconnecting point to meet the demand of its customer group.

When colder weather or operational restrictions occur, FEI reduces or eliminates the availability of imbalance return. FEI provides as much notice as possible when the availability of this service changes. When imbalance return is eliminated due to colder weather or for operational purposes, daily balanced groups must supply enough physical gas supply to meet demand (and not rely on their inventory), or balancing charges apply. Conversely, monthly balancing groups do not have the same requirements to balance daily and, therefore, have the ability to under-deliver to the System under these circumstances.

10.3.6 Balancing Tolerance and System Inventory

Daily and monthly balanced customers can incur charges when imbalance tolerances are exceeded. As set out in the transportation service rate schedules, FEI may, for any reason and for any length of time, interrupt or curtail gas balancing tolerances as needed. When imbalance tolerances are reduced, FEI provides customers or shipper agents with as much notice as possible; however, FEI has the right to impose limitations, either through reduced or eliminated imbalance return or supply and capacity restrictions, within the same day with not less than four hours' notice, unless prevented by Force Majeure. The following sections describe the balancing tolerances FEI can impose as required:

- For daily balanced customers, under normal day conditions, the balancing tolerance is 20%. This means that if a transportation customer's under-deliveries exceed the 20% tolerance, balancing charges will apply. These charges are currently $0.30/GJ in the summer (April to October) and $1.10/GJ in the winter (November to March).
- Monthly balanced customers have no daily balancing tolerances, but must end the month with a zero or positive inventory imbalance. Given this, monthly balanced groups typically do not match supply with demand on a daily basis.
- When colder weather or operational issues occur, FEI may reduce or eliminate imbalance return. This means that daily balanced customers must bring on sufficient physical gas supply to meet or exceed demand and not rely on their stored inventory as

[172] The limit of 40,000 GJ/Day per region is the maximum FEI has found to be operationally manageable during the year under normal weather conditions.

an additional source of supply. When this service is withdrawn, monthly balanced customers remain unaffected when imbalance return is reduced or eliminated and have the ability to draft the system under these circumstances.

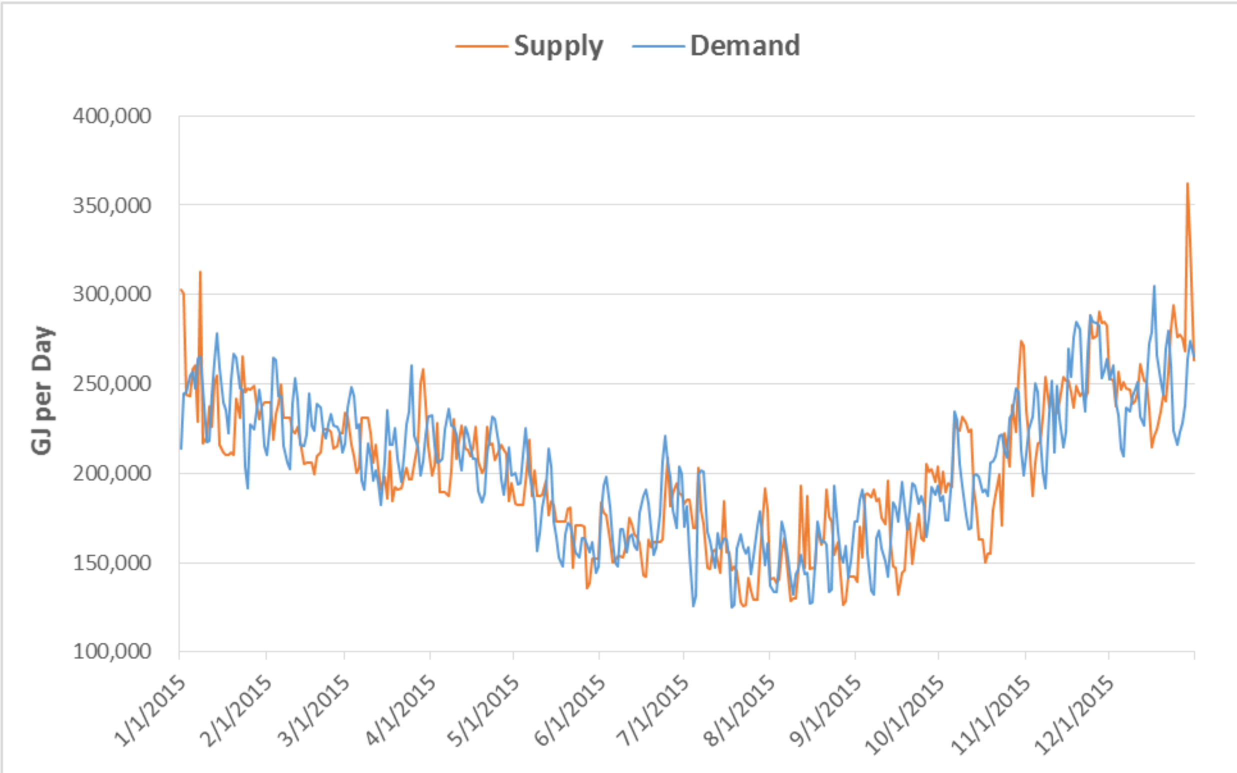
- Under a supply restriction, FEI can reduce the balancing tolerance to 5%. If this occurs, the tolerance is then applied to both daily and monthly balanced customers. If the 5% tolerance is exceeded, unauthorized over-run charges will apply. For under-deliveries for the first 5%, gas is sold to the transportation customer at the Sumas Gas Daily Midpoint price. For under-deliveries greater than 5%, gas is sold at the greater of 1.5 times the Sumas Gas Daily Midpoint price or $20.00/GJ.
- If there is a problem at a specific location on the system, FEI may curtail specific interruptible customers at that location. FEI may request the customer(s) reduce their consumption to their specified daily transportation quantity (DTQ), or to disconnect from the System completely.

In part due to the above described balancing provisions, the amount of inventory held on FEI's System can vary. Figure 10-5 below shows the actual gas deliveries (or supply) provided by transportation customers in comparison to the actual customer demand in 2015. When over-deliveries occur (i.e., daily supply is greater than daily demand), the excess supply is identified in the transportation customer or shipper agent's account as banked inventory. When under-deliveries occur (i.e., daily supply is less than daily demand), customers or shipper agents draft from FEI's System inventory and may incur charges for doing so.

When contracting for gas supply to meet the load requirements of transportation service customers, a shipper agent secures physical supply through contracts with third parties and then nominates gas supplied from interconnecting third-party pipelines onto the FEI System. FEI's experience is that shipper agents generally make their nominations to FEI up to 24 hours before the gas day starts, consistent with how the Station 2 and Sumas markets operate. Given supply and demand are rarely perfectly balanced, when over-deliveries or under-deliveries occur, FEI balances the entire System as a whole using midstream resources.

As seen in Figure 10-5 below, gas supply frequently deviates from demand by as much as 50,000 GJ/day once the day comes to a close. These imbalances may constitute a significant volume relative to the total daily demand on the System. These imbalances require FEI to use midstream resources to withdraw or inject quantities of gas, often on an intraday basis, to balance the entire System. While it is the shipper agent and/or customer's responsibility to make best efforts to match supply and demand, under the current daily and monthly balancing provisions offered by FEI, shipper agents have not matched supply and demand on a consistent basis.

Figure 10-5: 2015 Actual Supply and Demand for Transportation Customers



FEI is aware of a number of factors that contribute to this variance or mismatch between transportation customer gas supply and demand. Shipper agents' business practices can incent two different behaviours. Shipper agents with daily balanced groups tend to oversupply gas to avoid penalties, while those with monthly balanced groups tend to draft the System. Shipper agents with large monthly balanced groups at the major load centres in the Lower Mainland and Interior have the ability to draft the System and are able to do so under existing rate schedules without penalty.

The penalty-free daily balancing tolerance of 20% also contributes to the mismatch of transportation customer gas supply and demand.

As noted by the Commission in the determination from the Application to Amend the Balancing Charges for Rate Schedules 23, 25, 26 and 27 (Monthly Balancing Gas Application),[173] FEI has the tools to ensure compliance with the rate schedules and to amend business practices to more closely align supply and demand. The changes proposed in this Application are intended to reduce the daily imbalances currently permitted under the transportation model.

FEI monitors the inventories on the System and takes into account both the daily and monthly combined supply/demand balancing inventory levels at a given location. Under normal circumstances, FEI requests that shipper agents holding both daily and monthly balanced

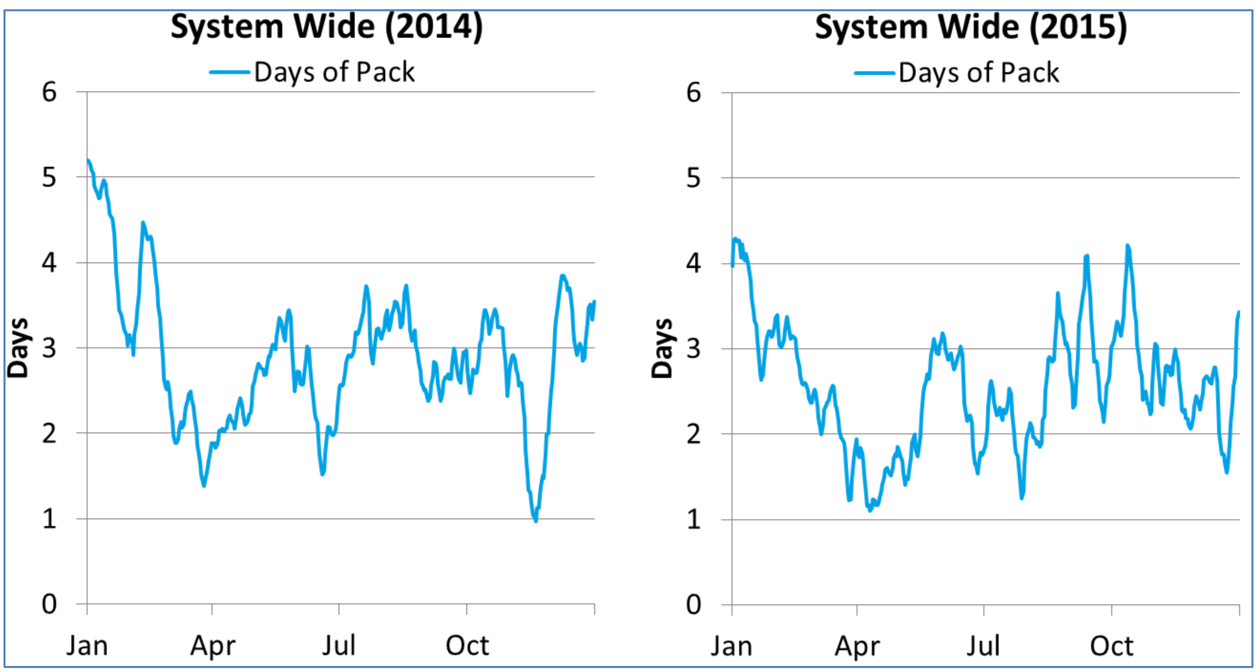
[173] Commission Order G-187-14, dated December 1, 2014.

groups keep to a 2 to 3 day pack/draft balancing inventory level, which FEI has deemed to be reasonable to manage the System as a whole. The 2 to 3 days of inventory is based on the average consumption of the daily and monthly balanced customer groups divided by the total inventory held. As indicated by the Commission in the Monthly Balancing Gas Application decision:

> The Panel observes that the tolerance equivalent to two to three days of daily load requirements is not set out in the terms of the FEI tariffs and, as a business practice, FEI can change it as required. The Panel encourages FEI to review its business practices and consider changing its allowable tolerance on imbalances from that of two to three days (which is equivalent to 6.5% to 10% of total monthly load) to a smaller tolerance such as a day or a day and a half.[174]

Based on this directive, FEI evaluated system tolerances, which are discussed further below. As shown in Figure 10-6 below, the amount of inventory held on FEI's System fluctuates on a month-to-month basis. Furthermore, the inventory size is largely unpredictable, as it does not exhibit a clear seasonal pattern. As a result, the amount of pack held on FEI's System can frequently dip below 2 days of supply. Figure 10-6 below illustrates the variation in the amount of inventory held for the transportation shipper agents across FEI's entire System during 2014 and 2015.

Figure 10-6: Days of Supply Held on Behalf of all Shipper Agents on FEI's System



[174] Commission Decision and Order G-187-14, dated December 1, 2014, page 13.

There are provisions within the terms and conditions of the transportation rate schedules which allow FEI to manage inventory levels if necessary. These provisions include the ability for FEI to limit or reduce inventory, to modify the shipper agent's requested quantities to limit or adjust its inventory accumulation, and to limit or remove a shipper agent's excess inventory and return it at a later date. Although FEI has developed a working relationship with the transportation shipper agents in managing the inventory levels on the System, FEI reviewed the current business practices as part of this Application and is proposing changes related to balancing as discussed below.

10.3.7 List of Customer Charges

As set out in the transportation rate schedules, it is the responsibility of transportation customers and/or their shipper agents to make efforts to match gas supply and customer demand for both daily and monthly balanced customers. The transportation rate schedules include charges which may apply when certain tolerances are exceeded. These charges are laid out in the Table of Charges in each of the transportation rate schedules and are summarized in Table 10-2 below.

Table 10-2: Transportation Charges by Rate Schedule

Charge Type	Rate Schedules				
	22/22A	22B	23	25	27
Backstopping	√	√	√	√	√
Replacement Gas	√		√	√	
Daily Balancing Gas*	√				
Balancing Service Charge (20%)*	√				
Monthly Balancing Gas			√	√	√
Unauthorized Overrun	√	√	√	√	√
Demand Surcharge*	√	√			

*If customers under RS 23, 25 and 27 are included with a customer under RS 22, 22A or 22B then the group and it's members will be subject to Daily Balancing Gas, Balancing Service Charge and Demand Surcharges.

Backstopping charges are applied when a customer's authorized quantity of gas from the interconnecting point is less than the customer's nominated quantity. Replacement gas charges are applied when SCP peaking gas is not returned.

The following charges are applied when balancing tolerances are exceeded:

- Daily or monthly balancing gas charges can be incurred when the customer demand on the day/month exceeds the supply. Daily or monthly balancing gas is sold by FEI to make up for the short fall.

- If the gas supply is insufficient beyond the tolerance threshold, balancing premium charges also apply. Currently, the balancing premium charge is applicable to quantities of gas needed to balance actual consumption that exceeds the greater of 100 GJ or 20% of the authorized quantity of supply.
- When colder weather or operational restrictions occur, FEI can reduce the balancing tolerance from 20% to 5%. If under-deliveries exceed this threshold, unauthorized over-run charges apply.
- In the case where a customer's gas supply is curtailed, demand surcharges will apply if the customer takes gas on the System.

When any of the above charges are incurred, shipper agents have the ability to pass them directly to their own customer(s) or to pay them themselves.

10.4 *PRINCIPLE-BASED REVIEW OF TRANSPORTATION BUSINESS MODEL*

FEI examined the rules set out in the rate schedules applicable to managing transportation service customers, giving consideration to the rate design principles, research and analysis, and a jurisdictional comparison. Based on the analysis, FEI believes that the transportation model is working well in most respects. However, FEI identified three potential and related issues under the current business rules with regard to matching of transportation service customer supply and demand. These are daily and/or monthly balancing provisions, the daily balancing tolerance, and the economic incentive to stay within the balancing tolerance. Each of these issues is discussed below.

- <u>Balancing Provisions</u>: FEI currently has two balancing options for transportation service: monthly balancing and daily balancing. Under the current rate schedules, transportation customers are required to balance by month end or on a daily basis.
- <u>Balancing Tolerance</u>: There are no daily balancing requirements applicable to monthly balanced customers whereas daily balanced transportation customers are held to a 20% tolerance level. As discussed in the following sections, FEI understands that customers are capable of balancing to a tighter tolerance level and that numerous other jurisdictions require tighter tolerance levels.
- <u>Balancing Charges</u>: Currently, there is no charge when imbalances occur within the 20% tolerance level; balancing charges only apply when imbalances exceed this level.

FEI considers that the existing balancing provisions, tolerance, and charges do not adequately achieve a balance of the following rate design principles:

- 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
- Principle 8 – Avoidance of undue discrimination (interclass equity must be enhanced and maintained)

In the following sections, FEI discusses the three issues noted above in more detail. Following a discussion of stakeholder feedback, FEI considers options to resolve each issue and discusses the rationale for its proposed option.

10.4.1 Balancing Provisions

Monthly balanced customers do not incur the same charges that daily balanced customers are subject to, which does not accord with Principle 3 or Principle 8. Monthly balanced customers can incur significant daily imbalances, with no charges or tolerance limits. Research indicates that this is not consistent with industry practice.

FEI believes that the current monthly balancing practices may lead to inefficient use of FEI's System resources. As discussed below, FEI proposes to require that all transportation customers daily balance, which will reduce the inequitable treatment that currently exists between monthly and daily balanced transportation customers, with the same price signals for efficient use for all transportation customers.

10.4.2 Balancing Tolerance

When transportation customers incur large imbalances and rely upon FEI midstream resources that have been acquired for sales customers, there may not be a fair apportionment of costs among customers, which is not consistent with Principle 2. Under normal conditions throughout the year, price signals (Principle 3) such as balancing gas charges and balancing tolerance levels are in place for RS 22 customers giving them an incentive to balance daily without using or relying on FEI for balancing. Customers in RS 23, RS 25 and RS 27 that adhere to monthly balancing provisions are not subject to daily balancing gas charges or tolerances and, therefore, there is no price signal to encourage efficient use of System resources. As discussed below, FEI proposes to tighten the current 20% tolerance to 10% to incent tighter balancing on the System.

10.4.3 Balancing Charges

There is currently no direct charge for transportation customers who incur imbalances up to the 20% tolerance. In addition to tightening the tolerance to 10%, FEI is proposing to amend the balancing charges to provide an incentive to encourage more efficient use and discourage inefficient use of the FEI System resources, in accordance with Principle 3. As discussed below, FEI is proposing a tiered charge whereby charges increase as tolerance ranges are exceeded, which achieves Principle 5.

10.5 *STAKEHOLDER FEEDBACK FROM THE WORKSHOPS*

As part of FEI's stakeholder engagement process discussed in Section 4, FEI circulated a Transportation Service Review Discussion Guide to interested stakeholders and held a workshop on August 12, 2016. In this guide and workshop, FEI provided an overview of the current transportation business model and identified a number of issues with the current business rules, which facilitated discussions on a number of these topics. These topics included daily versus monthly balancing, the balancing tolerance and associated charges, and T-South capacity.

As indicated at the transportation service workshop, FEI provides value to transportation customers by balancing the System as a whole. At the workshop, Black & Veatch presented an analysis and calculation of a balancing fee that could be applied to all transportation customers based on System throughput. There was lack of support for a balancing fee expressed at the workshop and disagreement that Black & Veatch's analysis accurately represented the costs shipper agents would incur in the absence of FEI's System balancing. Given the comments received, FEI evaluated the alternative option of tightening the daily balancing tolerance instead of charging a balancing fee. Under this option, the responsibility or onus would remain on transportation customers to balance daily within a tighter tolerance.

A summary of the workshops is provided in Section 4, detailed notes and comments from the workshops are provided in Appendix 4-2, and copies of the discussion guides are provided in Appendix 4-3 to the Application. A summary of stakeholder feedback is provided in Table 10-3 below. The proposals included within the following sections take this feedback into account.

Table 10-3: Summary of Stakeholder Feedback for Transportation Services

Topic	Undertaking	FEI's Action/Response
Monthly vs Daily Balancing	FEI received a suggestion to look into a number of options for the balancing rules: status quo, monthly balancing with adjustments and daily balancing.	FEI's evaluation of the three balancing options is provided in Section 10.6 and 10.7 below.
Balancing Tolerance	FEI was asked about the existing 5% tolerance level, when does it happen and how often it occurred?	In Section 10.7.1, FEI provides a detailed discussion of how and when FEI implements a supply restriction. Table 10-6 shows the number of days of supply restrictions since 2008.

Topic	Undertaking	FEI's Action/Response
Balancing Valuation	FEI was asked to look at a range of methods to price balancing services.	FEI considered another method to price the balancing services to transportation customers. In Sections 10.7.3 and 10.7.4, FEI discusses the Black & Veatch valuation methodology based on FEI balancing the System as a whole – including the daily and monthly balanced groups. In lieu of charging a balancing fee, FEI is proposing a tighter tolerance to incent improved business practices and less reliance on FEI and midstream resources to balance the System.
Daily Balancing	FEI was asked to re-run the Replacement Cost analysis presented by Black & Veatch assuming that daily balancing occurred.	This analysis was not undertaken as FEI is not proposing to amend the daily balancing charge.
Balancing Bandwidth	FEI was asked to evaluate amending the bandwidth to 10%.	Through analysis conducted by Black & Veatch, FEI evaluated the cost to balance the System under 0, 5, 15 and 20% bandwidths in Section 10.7.4. FEI has assessed potential charges for a 10% balancing bandwidth in Section 10.7.6.
Benefits from Transport customers	FEI was asked to consider a potential offsetting effect that transportation customers may provide to sales customers.	FEI has addressed this consideration in Section 10.2.3.3 of this Application.
Unauthorized Over-run and Demand charges	FEI was asked to evaluate whether these charges are excessive.	FEI determined these charges should remain in place. They are intended to incent transportation customers to avoid these charges.

10.6 *BALANCING PROVISIONS: REVIEW OF OPTIONS AND PROPOSAL*

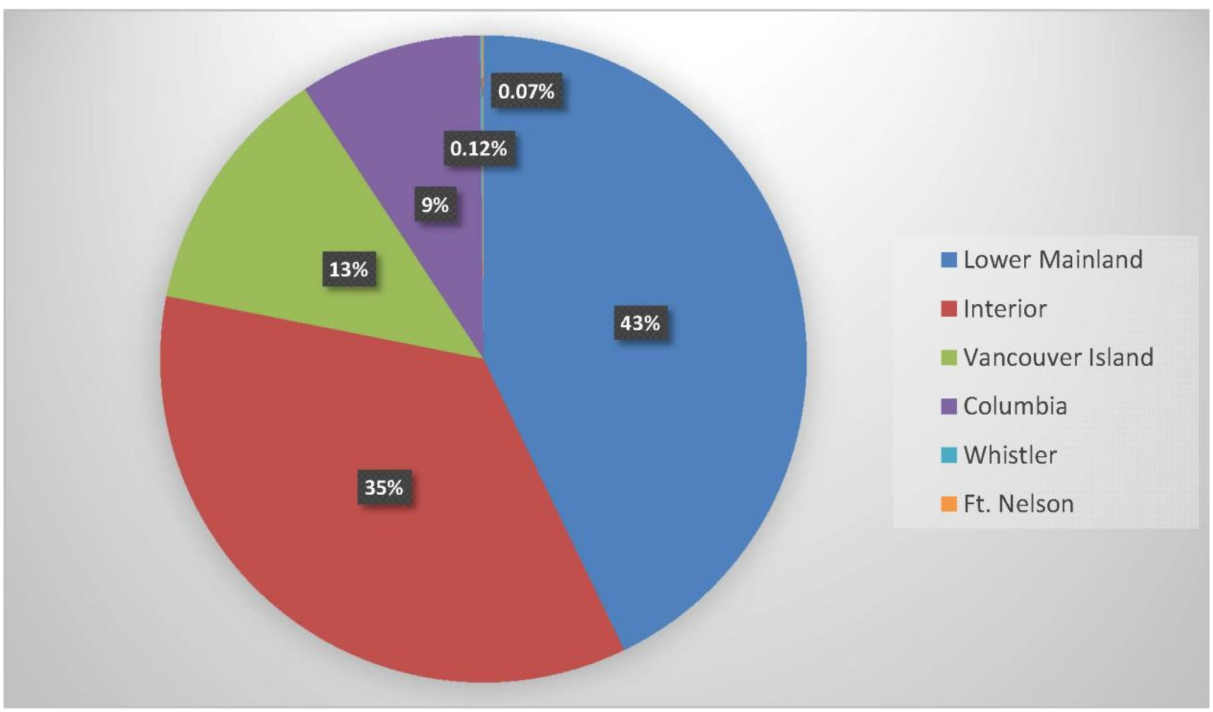
10.6.1 Review of Issue

As discussed above, the current transportation rate schedules include both daily and monthly balancing provisions. RS 22 customers are required to balance daily and RS 23, RS 25 and RS 27 customers can balance on a monthly basis. In order to manage a group of customers in aggregate, shipper agents may pool their customers in daily or monthly balanced groups. Each shipper agent is permitted to have one daily and one monthly balanced group at an interconnecting point on the System (i.e., the Lower Mainland or Interior). When RS 23, RS 25 or RS 27 customers are pooled with a RS 22 customer or customers, the group as a whole must adhere to daily balancing provisions and are subject to the charges included in RS 22.

FEI observes that shipper agents with a daily and monthly balanced group at the same location (i.e., the Lower Mainland) typically over-supply their daily group, and grow a positive inventory through the month to avoid daily balancing charges. These same shipper agents also typically under-supply their monthly group as there are no balancing tolerances on the day for monthly balanced customers, and in doing so grow a negative inventory through the month. The shipper agents are then incented to net out or transfer imbalances from their daily to their monthly group to avoid imbalance charges at month end. Under the transportation rate schedules, FEI administers and enables this transfer.

Shipper agents today hold a total of 16 daily balanced groups and 36 monthly balanced groups at the major interconnections on FEI's system.[175] Within the 36 monthly balanced groups, there are approximately 1,865 customers whose annual load on the system is approximately 33 PJ. For the 16 daily balanced groups, there are 600 customers whose annual load on the system represents approximately 40 PJ with a total throughput of 73 PJ. Figure 10-7 below identifies the demand by region for the 2015 year. The Lower Mainland and Interior regions are the primary load centres in B.C.

Figure 10-7: Transportation Consumption by Region (2015)



Transportation customers managed in daily balanced groups are held to a 20% tolerance, whereas those in monthly balanced groups have no daily balancing tolerance and may draft the System under normal conditions through the month. As indicated above, regardless of the balancing option, the transportation rate schedules require customers to balance their supply

[175] The group and customer counts were measured as at September 2016.

and demand. Customers and shipper agents are required to provide a best estimate of the quantity of gas they will actually consume on a day. When imbalances from transportation customers occur, FEI must manage the System as a whole.

Monthly and daily balancing provisions result in unequal treatment between shipper agents and customers, and creates the potential for arbitrage opportunities. Under the applicable rate schedules, FEI charges the Sumas daily price average for the month per GJ for balancing gas supplied, and the Sumas daily price is defined as the daily midpoint price. This presents a potential price arbitrage opportunity, as there is no marketplace instrument that allows transportation customers and shipper agents to buy gas at the average Sumas daily price at the end of a month. The monthly average of the Sumas daily prices may be different from the Sumas daily price on a given day. Thus, shipper agents managing monthly balanced groups can take advantage of differences in the price for balancing gas supplied by FEI and the price for gas supply available in the marketplace on any day to meet their requirements, and may use balancing gas as a low-cost gas supply alternative for the benefit of either themselves and/or their customers.

Research conducted by Black & Veatch for comparable utilities within Canada and the U.S. found that daily balancing is general industry practice today.[176] As a large shipper on pipelines both upstream and downstream of FEI's System[177], FEI itself is required to balance daily. Larger RS 22 customers on the System are also currently required to balance daily, which matches the upstream requirement.

A number of FEI shipper agents have moved their customers into an exclusively daily balanced group and are adhering already to daily balancing provisions. Table 10-4 below provides an example of two shipper agents today, one with a large daily load profile and one with a smaller daily load profile, which manage exclusively daily balanced groups at the Lower Mainland and Interior. Table 10-4 details the approximate number of customers at each location, the approximately average daily winter load (based on the 2015/16 winter year), and the customer breakdown by rate schedule. Even with diversity in customer types and volumes, these shipper agents are able to manage the supply requirements of the group in aggregate on a daily basis.

Table 10-4: Shipper Agent Examples that hold Daily Balanced Groups Only

Marketer	Region	# of Customers[1]	Avg Winter Load[2]	Customer Rate Schedule Breakdown			
				Rate 22	Rate 23	Rate 25	Rate 27
Shipper Agent A	Lower Mainland	450	18,000-25,000	2%	77%	18%	3%
Shipper Agent A	Interior	120	15,000-24,000	5%	66%	23%	6%
Shipper Agent B	Lower Mainland	10	1,500-3,400	20%	10%	50%	20%
Shipper Agent B	Interior	5	4,200-6,700	33%	0%	33%	33%

1 Approximate number of customers as of Oct 2016
2 Approximate average daily winter load based on 2015/16 data

176 Appendix 10-1, Comparison of Balancing Provisions for Selected Companies, pages 16 to 35.
177 FEI's OBA to balance daily is discussed further in Sections 10.2.3.1 to 10.2.3.4.

The combination of improved technology and increased nomination cycles has resulted in greater ability for market participants to match supply and demand more closely on a daily basis. The examples provided here show that shipper agents with both large and small customer groups are able to manage and balance within a tighter tolerance. FEI's upstream and downstream pipelines have operational requirements to balance daily and, as such, balancing transportation service daily would align better operationally.

Transportation customers have access to tools to amend gas requirements on the day to reflect changes in load. For example, over the past several years, there have been technology improvements such as wireless metering,[178] which allow shipper agents to access and track supply and daily consumption by customer more closely. Through FEI's Web Information and Nomination System (WINS), shipper agents have access to historical daily consumption which helps to forecast customer load under varied weather conditions.

In April 2016, the North American Energy Standards Board (NAESB) introduced an additional gas nomination cycle, ID3, which provides greater flexibility to adjust supply requirements as a result of load changes. The additional gas cycle has been beneficial for utilities like FEI that hold firm resources to adjust nominations within the day in response to load swings.

In summary, the combination of improved technology and increased nomination cycles has resulted in greater ability for market participants to match supply and demand more closely on a daily basis.

10.6.2 Options Analysis

FEI has evaluated the following three options to address the possible changes to the daily and monthly balancing practices:

1. Status quo;
2. Modify terms to monthly balancing; and
3. Move exclusively to daily balancing for all Rate Schedules.

Each of these options is discussed and evaluated in further detail below.

10.6.2.1 Balancing Option 1 – Status Quo

The status quo option would maintain the existing provisions for daily and monthly balancing for transportation customers and FEI would continue to require daily balancing for RS 22 customers.

FEI believes that maintaining the status quo is not the best option as it does not address the equality and arbitrage issues identified above. If no changes are made to the current balancing

[178] FEI has made significant advancement in meter reading accuracy and reliability. Measurement devices have evolved from wired devices that required a telephone line to wireless technology.

rules, then an uneven playing field for shipper agents would continue to exist. Two types of balancing provisions exist within the model today, and with that, two different balancing practices are observed. Under this option, the business practices of the shipper agents would continue as they do today, where they over-supply the daily groups and under-supply the monthly groups, creating an opportunity for price arbitrage at the expense of other customers. As indicated in the Commission determinations from the Monthly Balancing Gas Application, FEI was asked to determine "the appropriate rate design mechanism to incent the appropriate behaviour not just at month-end but during the month as well."[179] If the status quo was retained, the Commission's objective would not be achieved.

10.6.2.2 Balancing Option 2 – Modified Monthly Balancing

Another option would be to retain monthly balancing practices and to impose increased balancing charges for customers. In the Monthly Balancing Gas Application filed in 2014, FEI proposed to increase the cost of the monthly balancing gas charge to more appropriately incent shipper agents to become accountable to balance their groups.

In light of the review and evaluation of the Commission directives from the Monthly Balancing Gas Application contained in Section 3.4, the option to continue with Monthly balancing going forward is not being proposed. The industry tools now exist to balance the System on a daily basis in the interest of fairness across all customer types.

10.6.2.3 Balancing Option 3 – Daily Balancing

The third option would be to remove the monthly balancing provisions entirely and move all transportation customers to daily balancing. Based on the principle of fairness, this option would treat all customers and shipper equally. Daily balancing also addresses concerns regarding arbitrage opportunities within the current monthly balancing provisions in the transportation rate schedules. Daily balancing is consistent with industry practice and available technology.

Exclusive daily balancing satisfies the Commission's directive from the Monthly Balancing Gas Application decision that FEI determine the "appropriate rate design mechanism to incent the appropriate behaviour not just at month-end but during the month as well."[180]

10.6.3 Balancing Proposal

FEI recommends eliminating the existing monthly balancing provisions entirely for the transportation model and requiring all transportation customers in all service areas to balance daily. FEI is held to daily balancing at the major interconnecting points at the Lower Mainland and Interior, and in the interest of fairness, FEI proposes that daily balancing provisions apply equally across all regions.

[179] Commission Decision and Order G-187-14, dated December 1, 2014, page 22.
[180] Ibid.

Consistent with the rate design principles, eliminating the monthly balancing provisions will lead to more efficient use of FEI system resources (Principle 3), more fairly apportion FEI System resource costs (Principle 2), and will reduce or eliminate concerns over arbitrage opportunities which exist under the current rules against customers required to balance daily (Principle 8). The rules for daily balancing are easy to understand (Principle 4), and practical for FEI to implement (Principle 5).

Implementing daily balancing requirements will not affect shipper agents that are already adhering to daily balancing with customers on RS 22. Daily balancing will also satisfy the Commission directives cited in Section 3.4.

10.7 *BALANCING TOLERANCE AND CHARGES: REVIEW OF OPTIONS AND PROPOSAL*

While the sales and transportation business models exist independently, FEI balances the System on behalf of both sales and transportation customers using midstream resources contracted by FEI, and paid for by sales customers. Transportation customers receive a benefit from these resources when FEI balances the System as a whole each day. When transportation customers over-deliver, there is no benefit provided to sales customers, as FEI already holds sufficient midstream resources under its ACP to meet sales customers' gas demands. In the event that transportation customers store gas on the System, FEI is required to return it on a subsequent day, which also has impacts on the System. The following section discusses the benefit transportation customers receive and potential options to amend the balancing tolerance to incent greater balancing efficiencies.

10.7.1 Transportation Balancing Tolerances and Overview

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.

In the example below in Figure 10-8, a shipper agent made supply arrangements of 10,000 GJ and the total demand was 15,000 GJ. Based on the tolerance calculation, FEI provides a 2,000 GJ tolerance before charges would be applied on the remaining under-delivery of 3,000 GJ. If this scenario occurred in the winter months, November to March, the total charge would equal $3,300. In the summer, from April to October, the total charge would equal $900.

Figure 10-8: Example of 20% Balancing Tolerance and Charges Applied

Nominated Supply:	10,000
Authorized Supply:	10,000
Authorized Supply x 1.20	12,000
Authorized Supply + 100GJ	10,100
Revised Authorized Supply:	12,000
Demand:	**15,000**
(Under)/Over Deliveries	(3,000)
Winter Charge ($1.10/GJ)	$3,300
Summer Charge ($0.30/GJ)	$900

Balancing Tolerance
Midstream Resources are used to manage this tolerance/shortfall.

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.

Figure 10-9: Example of 20% Balancing Tolerance and Charges Applied with Imbalance Return

Nominated Supply:	10,000
Authorized Supply:	10,000
Imbalance Return Authorized:	3,000
Total Authorized Supply	13,000
Authorized Supply x 1.20	15,600
Authorized Supply + 100GJ	13,100
Revised Authorized Supply:	15,600
Demand:	**15,000**
(Under)/Over Deliveries	600
Winter Charge ($1.10/GJ)	$0
Summer Charge ($0.30/GJ)	$0

Balancing Tolerance
Midstream Resources are still used to manage this tolerance/ shortfall.

When colder weather or operational restrictions occur, FEI reduces or eliminates the availability of imbalance return as required. This level of imbalance return is managed within WINS. FEI

[181] While FEI may authorize imbalance return, the amount of supply to be used from inventory depends on the amount of inventory banked in the account. If there is no inventory, no additional supply will be added to the physical day supply.

provides notice to the extent practicable when this service is amended by email and notices on its website. When imbalance return is eliminated due to colder weather or for operational purposes, shipper agents managing daily balanced groups must then bring on enough physical supply to meet demand (and not rely on their inventory) or balancing charges will apply. Conversely, shipper agents managing monthly balancing groups do not have the same requirements to balance daily and therefore have the ability to draft the System under these circumstances. Table 10-5 below identifies the number of days FEI reduced or eliminated imbalance return by year and location between 2008 and 2015.

Table 10-5: Days of Reduction or Elimination of Imbalance Return by Location

YEAR	Interior		Lower Mainland	
	Reduced	Eliminated	Reduced	Eliminated
2008	76	50	76	50
2009	16	12	17	12
2010	2	20	2	20
2011	7	20	7	20
2012	0	17	0	16
2013	18	15	18	15
2014	12	27	12	27
2015	0	17	0	27
Total	**131**	**178**	**132**	**187**
Total Reduced & Eliminated	**309**		**319**	

Weather is a primary driver that influences the availability of imbalance return. For instance, imbalance return availability was significantly impacted in 2008 due to prolonged cold periods during the winter months, and overall, the average load was 11% above normal. In the event of sustained colder weather or near design temperatures, FEI can issue a supply restriction which applies to all customers and groups, both daily and monthly. Similar to the management of imbalance return, FEI uses WINS to impose supply restrictions with the requirement to "hold" shipper agents to their authorized supply. Under these circumstances, shipper agents must bring on physical supply as they are unable to use their inventory and all customers or groups must balance daily and adhere to a 5% balancing tolerance. Historically, FEI imposes supply restrictions at FEI's major load centres in the Lower Mainland and Interior service areas.[182] If under-deliveries occur, customers may be subject to unauthorized over-run charges.

Figure 10-10 below demonstrates how unauthorized over-run charges are calculated. As shown below, the scenario shows an under-delivery of 5,000 GJ. Charges are calculated based both on the first 5% balancing tolerance and for demand over the 5%. The first 5% is calculated based on the authorized supply of 10,000 GJ, which equals 500 GJ. The charge for the first 500 GJ is the Sumas Gas daily price. The charge for demand over 5% or 4,500 GJ is the greater of one and a half times the Sumas Gas daily price or $20.

Figure 10-10: Example of 5% Tolerance under a Supply Restriction and Associated Charges

Nominated Supply:	10,000
Authorized Supply:	10,000
Demand:	**15,000**
(Under)/Over Deliveries	(5,000)
Unauthorized Over-Run 1st 5%	500
Unauthorized Over-Run over 5%	4,500

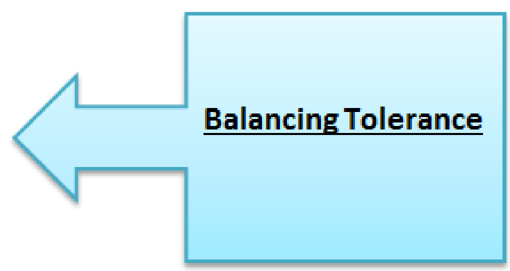


Table 10-6 below lists the number of days FEI imposed a supply restriction in the Lower Mainland and Interior regions from 2008 to 2016.

[182] Typically, FEI issues a supply restriction in the major load centers of the Lower Mainland and Interior regions. Due to the small load in the Columbia region, it has not been necessary from an operational standpoint to restrict this region historically.

Table 10-6: Days of Supply Curtailment by Region[183]

YEAR	Interior	Lower Mainland
2008	9	9
2009	0	0
2010	3	3
2011	2	2
2012	3	3
2013	4	4
2014	11	11
2015	0	0
2016	0	0
Total Curtailment	**32**	**32**

Historically, FEI has imposed few supply restrictions, with the exception of 2008 and 2014 where colder, sustained weather was responsible for the restrictions.

10.7.2 System Balancing – Industry Practices (Black & Veatch)

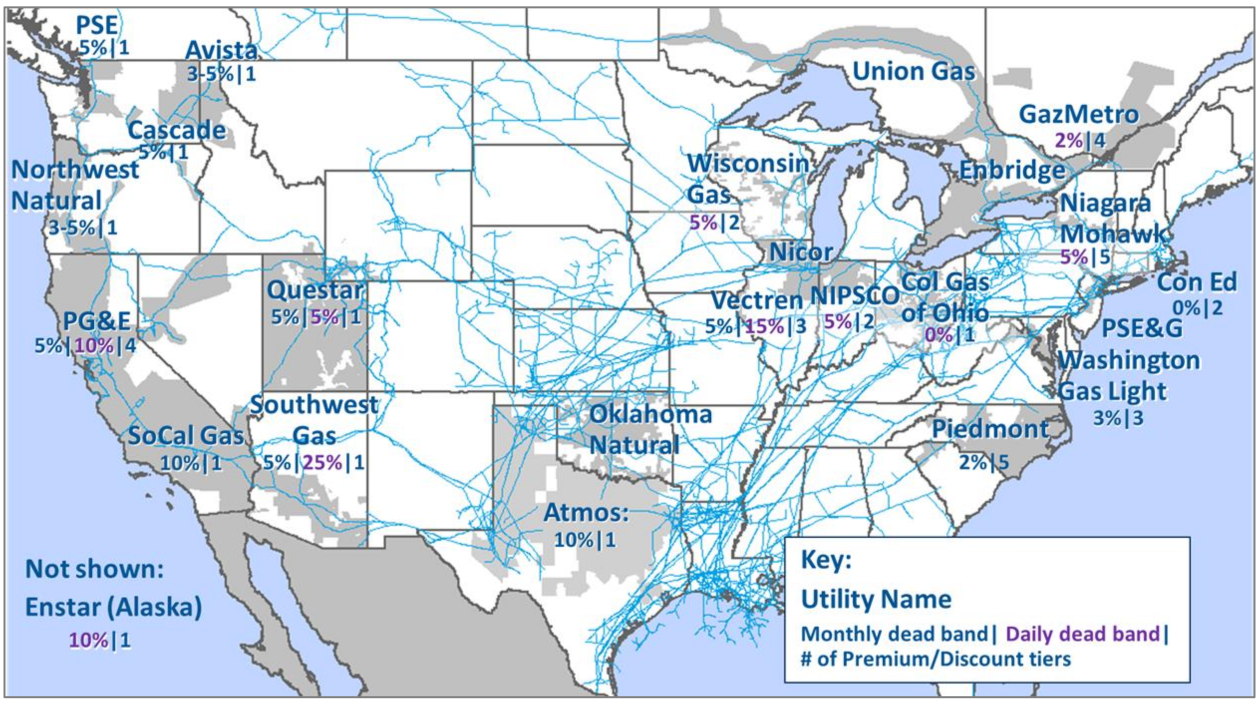
Industry-wide, balancing provisions can differ substantially between local distribution companies (LDCs) based on regional infrastructure differences. For example, balancing provisions can be relatively stringent for LDCs (such as FEI) with service territories adjacent to major natural gas market hubs in order to reduce the opportunity for shipper agents to profit from price swings by running imbalances to transport gas in excess of their contracted transportation quantity. Further, many LDCs offer distinctive "balancing services" that work to maintain favourable system conditions by allowing shipper agents the flexibility to incur imbalances when operationally feasible.

However, there are common practices in setting balancing provisions that are typical of LDCs across North America. LDCs typically require customers to balance on a daily and/or monthly basis. Imbalances are measured at the end of each day or each month and checked against a set balancing tolerance (also known as a threshold, or a dead-band). The imbalance is quantified according to a schedule of imbalance charges for quantities that exceed the threshold. Since most LDCs' balancing provisions have a similar structure, it is possible to compare how stringent or lenient balancing thresholds and charges are based on how these provisions compare to that of an LDC's peers.

[183] The 2016 data is to September 30, 2016.

Black & Veatch was tasked by FEI to research the balancing provisions of a sampling of LDCs in the U.S. and Canada in order to compare FEI's balancing provisions. The LDCs that were examined were typically large LDCs with a mix of transmission and distribution assets on their system. As shown in the map in Figure 10-11 below, many LDCs across the U.S. and Canada set balancing thresholds at approximately 5%, a level applicable to both monthly and daily balanced transportation service customers. Thresholds rarely exceed 10%, and sometimes are as low as 0%. This research found that FEI's current balancing provisions are substantially more accommodating than its North American LDC peers.

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

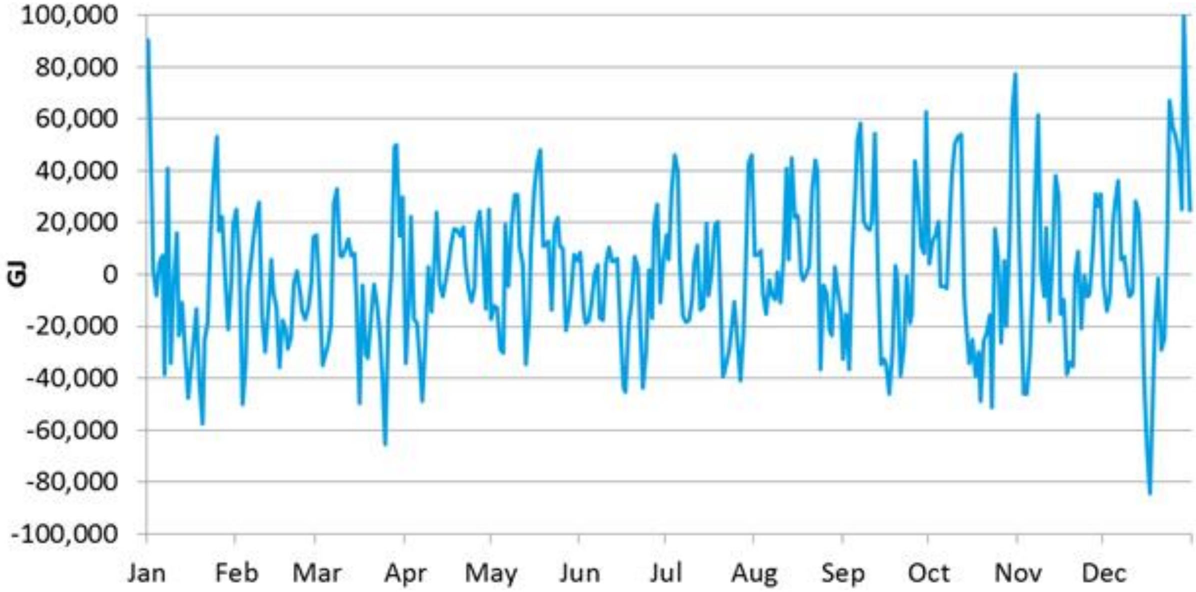


10.7.3 FEI System Balancing Issues

Under current balancing provisions between monthly and daily groups and the 20% tolerance limits, FEI's System is subject to large fluctuations in gas demand from transportation customers that is often not offset by matching gas supply deliveries. Even after adjusting for monthly true-up transactions (i.e., when a shipper agent with a monthly balanced set of accounts offsets its cumulative imbalance position, or inventory, with its daily balanced accounts at the end of each month to avoid monthly imbalance charges), FEI manages the System as a whole when supply and demand is not equally matched. Imbalances that exceed the threshold at each interconnecting point require the use of resources on FEI's System, typically by injecting excess gas into storage or withdrawing gas from storage in order to meet the transportation customers' delivery imbalance swings.

Figure 10-12 below shows the extent to which the aggregate imbalances varied or fluctuated daily on FEI's System (including transportation customers) in 2015.

Figure 10-12: Aggregate Adjusted Imbalance (2015)



These fluctuations occur in part due to monthly balanced shipper agents' ability to under-supply the FEI's System daily, and also due to the relatively liberal 20% balancing threshold that is currently permitted.

To address frequent balancing fluctuations, FEI uses storage and associated pipeline resources that are currently paid for entirely by FEI's sales customers, which includes contracted capacity at the Mist storage facility, the Jackson Prairie storage facility, and Northwest Pipeline (NWP). As such, under the current transportation rate schedules, sales customers are paying for services that are also used by transportation customers, which means that the two major customer groups are not equally paying for services received.

10.7.4 FEI Value of Balancing Service – Summary of the Black & Veatch Study

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

[184] Commission Decision and Order G-187-14, dated December 1, 2014, page 22.

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

The 20% base case analysis shows that the current threshold provided by FEI provides $0.119/GJ of value to shipper agents, as measured by the replacement cost of each shipper agent securing the service elsewhere. Furthermore, the value of balancing services provided by FEI decreases with more stringent balancing tolerances at 15% and 10%. Table 10-7 above provides a starting point for discussions on how to set balancing service levels and associated charges based on the preferences of FEI's transportation customers; a more flexible threshold is associated with higher costs.[185]

Taken as a whole, the replacement cost analysis shows that the balancing service FEI provides has market value. While there are several assumptions that could be adjusted to change the base case value, all results point toward a relatively constant range of values. For the 20% threshold case, which corresponds to the service FEI currently provides, the calculated value of the service is $0.119/GJ. With a 10% balancing tolerance, the calculated value is $0.048/GJ.

10.7.5 Balancing Tolerance and Charges

Given the analysis of balancing tolerances upheld by other utilities and the value determined by Black & Veatch for this service, FEI considered two possible options to incent a narrower balancing range: (1) apply a "balancing fee"; or (2) tighten the balancing tolerance.

Imposing a balancing fee charge or cost across all customers under Option 1 would represent a significant change to the existing transportation model. As discussed below, FEI is not proposing a balancing charge, as its intent is not to penalize shipper agents that hold and manage tighter balancing tolerances today, nor to interfere with individual shipper agent business models. As such, FEI has determined that Option 2 is the preferred option.

Option 1 – Balancing Fee (service offering)

The midstream resources that balance the System as a whole are paid by sales customers. As supported by the analysis conducted by Black & Veatch, FEI believes there is value in the

[185] At the transportation service workshop, FEI was asked to re-run the replacement cost analysis assuming that daily balancing occurred. At this time, FEI is not able to conduct the analysis to quantify this value. The balancing behaviour exhibited under the current rate schedules are a function of the effects of the daily and monthly balancing provisions combined. However, FEI expects that the midstream costs used to balance a unified daily balanced platform will be reduced.

balancing services currently being providing. As was presented at the transportation service workshop, FEI evaluated the option of charging a balancing fee to account for the use of sales resources by transportation customers. Under this option, a balancing fee would effectively be applied to each GJ of throughput for transportation customers, which in 2015 was 74 PJ. This "balancing fee" would apply to all customers regardless of how they balance on the System today, which would contribute a revenue stream back to FEI's midstream portfolio to recover the balancing costs. Based on the replacement cost analysis provided above in Table 10-7, the cost recovery for the total transportation volume of 74 PJ at the 20% tolerance threshold would be approximately $8.8 million, compared to a 10% tolerance threshold where the recovery would be $3.6 million.

There were concerns raised at the transportation service workshop about the methodology and inputs used to value the balancing fee. There are several ways to derive a value for this service. Unlike Alberta, the B.C. marketplace does not have liquidity and flexibility for spot gas purchases and sales. As a result, there is a very limited intraday market with no published intraday prices on electronic bulletin boards. In the absence of published prices to act as a benchmark or indicator, it is not possible to arrive at a definitive value or price.

FEI determined that applying a balancing fee to all shipper agents based on throughput would not be appropriate. Some shipper agents manage within a tighter tolerance and bear the costs to do so. FEI does not intend to interfere with the individual business models that shipper agents hold with their customers today. Charging a balancing fee to all shipper agents would penalize transportation customers that are proactively and more closely managing imbalances today. A fee-based approach does not provide an incentive to balance more closely on the System and effectively removes the shipper agents' responsibility to manage and match supply and demand which is a fundamental obligation in the rate schedules. A balancing fee would fundamentally change the model and might cause shipper agents to vary imbalances on the System. For these reasons, FEI does not propose imposing a balancing fee.

Option 2 – Tighten the Threshold

As supported by the research of Black & Veatch canvassing other LDCs and their balancing thresholds, FEI's current threshold of 20% is lenient compared to other LDCs. FEI believes that tightening the balancing tolerance will provide an a better incentive to reduce the large fluctuation swings experienced today, which in turn should reduce FEI's involvement in balancing the load of transportation customers. By tightening the balancing tolerance, shipper agents will be incented to manage their customer load more closely. Instead of imposing a balancing fee as considered in Option 1, a tighter tolerance would put the responsibility and onus on the shipper agent, which is consistent with the shipper agent's obligations under the transportation rate schedules.

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 the red line) are managing their business substantially within a 10% tolerance. Those shipper agents above the red line are currently exceeding the 10% tolerance on a regular basis. The distinction between those that are working within the 10% tolerance and those that are not can be seen in the third column, which states the number of days per year that the 10% threshold has been exceeded. The shipper agents below the red line all have less than 20 occurrences in a year of exceeding the 10% tolerance threshold, while the shipper agents above the red line all have more than 100 occurrences in a year of exceeding the 10% tolerance threshold.

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%

The fields of data in Table 10-8 above are defined below:

- Shipper Agent: Each letter (i.e., "Shipper Agent A") corresponds to a shipper agent that has a pool in the Lower Mainland and/or the Inland service area on FEI's system. The shipper agents are sorted from those with the most aggregate demand on the System to the least aggregate demand (i.e., Shipper Agent A has more load than Shipper Agent B).
- Service Area: Specifies whether the customer pool is for the Lower Mainland (LML) or Inland (INL) service area. The daily and monthly pools were aggregated into one pool for each of the major service areas.
- # Imbalance Days / Year: Number of days in which a negative imbalance exceeded the given threshold in 2014 and 2015, divided by 2 (to annualize the result). The red line divides the shipper agents who are routinely operating within the given balancing threshold and those who are not.
- Annual Volume in Excess: The negative imbalance quantity in excess of the threshold during 2014 and 2015, divided by 2.
- Volume in Excess / Day: The annual volume in excess divided by 365.
- Demand / Day: The volume of gas delivered to a pool's customers per day.
- Volume in Excess / Demand: Volume in excess / day divided by demand / day

Shipper agents operating within the 10% threshold today have both large and small portfolios and varied customer profiles. Furthermore, the shipper agents achieving this tolerance are primarily those with exclusively daily balanced groups. With a change to a tighter bandwidth and daily balancing provisions, FEI expects a reduction in overall variable costs to balance the System. As such, FEI is proposing to amend the balancing tolerance to apply to under-deliveries from 20% to 10%.

FEI considered imposing an upper threshold which would apply when over-deliveries on the System occur. When over deliveries have occurred in the past, the excess gas has been manageable from an operations and systems perspective. The tool of imbalance return provides flexibility to manage inventory on FEI's System. For these reasons, FEI is not proposing a balancing tolerance for over-deliveries at this time.

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.

The following Table 10-9 shows the incremental variable costs involved in System balancing. As shown below, the variable costs were calculated based on the commodity charge, pipeline fuel and storage fuel. The NWP and storage fuel costs were calculated as a percentage of the commodity price. Given this, FEI considered the potential charge for a range of commodity prices from $2.50 US/MMBtu to $5.00 US/MMBtu and the resulting incremental variable costs ranged from $0.20 CAD/GJ to $0.33 CAD /GJ.

Table 10-9: Transportation Balancing Incremental Variable Costs[186]

Sumas Price (US$/MMBtu)	NWP Com. Charge	NWP Fuel	Storage Fuel	Incremental Variable Costs (US$/MMBtu)	Incremental Variable Costs (CAD$/GJ)
$2.50	$0.06	$0.07	$0.04	**$0.16**	**$0.20**
$3.00	$0.06	$0.08	$0.04	**$0.19**	**$0.23**
$3.50	$0.06	$0.10	$0.05	**$0.21**	**$0.25**
$4.00	$0.06	$0.11	$0.06	**$0.23**	**$0.28**
$4.50	$0.06	$0.12	$0.07	**$0.25**	**$0.31**
$5.00	$0.06	$0.14	$0.07	**$0.27**	**$0.33**

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

[186] Key assumptions in this table: Exchange rate is $1.30 CDN/US; Energy conversion 1 MMBtu = 1 Dth = 1.055056 GJ; Northwest Pipe Commodity Charge = $0.03 USD/Dth * 2; Northwest Pipeline transmission fuel (both directions) = 1.36% * 2; Average storage injection fuel of JPS & MIST = 1.48%.

FEI believes the proposed charges and tiered approach will provide an appropriate incentive to balance within the 10% tolerance.

10.7.7 Balancing Tolerance and Associated Charges Proposals

Based on the two options of a balancing fee or tightening the balancing tolerance, FEI believes that tightening the balancing tolerance from 20% to 10% is an appropriate incentive mechanism and maintains the shipper agents' responsibility to more tightly manage their daily business. Imposing a fee, as indicated, to account for the balancing services would not provide an incentive to manage imbalances more tightly and would effectively penalize shipper agents who are today balancing within a threshold of under 10%. Some shipper agents today are operating within the 10% threshold and are able to do so while managing both large and small portfolios and varied customer profiles. As identified above, shipper agents that are achieving this tighter tolerance are primarily those that manage their customers exclusively in daily balanced groups.

FEI proposes to amend the balancing tolerance from 20% to 10%, and in the relevant rate schedules to amend the table of charges for balancing service as shown above in Table 10-10. If the cost of gas were to exceed $5.00 US/MMBtu, FEI would reassess the charges and apply to the Commission for any adjustments that may be required to ensure the charges reflect FEI's costs of balancing the System.

By reducing the balancing tolerance from the current 20% down to 10% and imposing a fee (i.e., a price signal) on customers who exceed the lower 10% limit, FEI will improve the efficient use of the FEI System (Principle 3). FEI also believes that the fees collected for exceeding this lower threshold level be credited against the midstream portfolio costs, which may also improve the apportionment of costs among customers (Principle 2) by reducing the amount that transportation customers rely upon FEI System midstream resources contracted for, and paid for by sales customers.

10.8 *TRANSPORTATION SERVICE SOUTH TO HUNTINGDON DELIVERY (T-SOUTH LONG-HAUL) CAPACITY OFFERING*

This section of the Application discusses the firm transportation service from Spectra Energy south to the Huntingdon Delivery area (T-South Long-Haul) which FEI secured in late 2015 and allocated to transportation customers, as approved by the Commission through FEI's ACP process. This service allows for the movement of gas south from a receipt point at Compressor Station No. 2 (Station 2) to a delivery point within the Huntingdon Delivery area. Appendix 10-2 to this Application is FEI's Report on T-South Allocation, dated November 28, 2016, filed with the Commission on the T-South Long-Haul capacity in compliance with Letter L-20-16. This report describes FEI's acquisition of the T-South Long-Haul capacity and how it has been allocated to transportation customers.

As described below, the issue of whether the allocation of the Spectra Energy T-South Long-Haul capacity should be formalized in the transportation rate schedules was discussed in FEI's stakeholder engagement process.

10.8.1 Background

Due to market conditions affecting the future level of firm transportation contracting on Spectra Energy's T-South Long-Haul pipeline, FEI contracted for additional T-South Long-Haul capacity for transportation service customers potentially seeking to return to bundled service. FEI was successful in contracting for an additional 75 TJ/day of T-South Long-Haul capacity effective November 1, 2015. Out of the 75 TJ/day in additional capacity, FEI planned to allocate 40 TJ/day to transportation service customers.[187]

On May 2, 2016, FEI filed its 2016/17 ACP with the Commission (on a confidential basis). In the ACP, FEI proposed allocating the 40 TJ/day portion of the additional T-South Long-Haul capacity on a short term basis to transportation service customers for the 2016/17 gas year. FEI acquired this capacity for transportation customers as transportation service customers and shipper agents may not have the credit requirements to secure long-term firm T-South Long-Haul capacity. Transportation service customers and shipper agents have, therefore, been relying on purchasing gas at the Huntingdon market. The T-South Long-Haul capacity protects these customers from poor supply availability at Sumas and potentially higher prices.

On May 30, 2016, FEI issued a letter to the shipper agents requesting a list of their customers that were interested in the T-South Long-Haul capacity offering along with the requested amount of capacity. In the interim, FEI received Commission approval for the ACP, which included the T-South Long-Haul service offering. The total request for capacity from the shipper agents exceeded the available capacity. FEI validated the customer requests against their historical consumption data and allocated quantities to the customers. Shipper agents were then notified of the allocations. Contracts have now been signed with these shipper agents for the T-South Long-Haul capacity for a one-year period, effective November 1, 2016.

Following the execution of the capacity releases, FEI was directed by the Commission to file a report summarizing the process and outcome of its plans to release a portion of the T-South Long-Haul capacity to transportation service customers for the 2016/17 gas year. This report is provided in Appendix 10-2. The report provides details of the events to date, and suggestions on how the T-South Long-Haul allocation could be carried out in the future. FEI will continue to update the Commission on any process changes to the T-South Long-Haul capacity allocation through ACP filings each May.

During the transportation service workshop on August 12, 2016, FEI identified two options to manage the T-South Long-Haul capacity. The first option was to continue to manage the T-South Long-Haul capacity as a temporary capacity release, using the same allocation process that FEI used for the 2016/17 ACP as described above. The second option was to include the

[187] The remaining 35 TJ/d of additional T-South Long-Haul capacity was reserved for the liquefaction capacity for Tilbury 1 A to serve RS 46 customers.

capacity in the transportation rate schedules so that customers could elect into the service. A brief summary of these options is included below.

10.8.2 Option A - Energy Supply

Under Option A, FEI would manage and administer the T-South Long-Haul capacity under the ACP. This option is consistent with how FEI currently manages T-South capacity assignments. Continuing to manage the T-South Long-Haul capacity in this manner provides FEI with administrative flexibility to manage the capacity on a year-to-year basis. If there were changes in the market (i.e., a capacity expansion) causing a reduction in its value, then the capacity would be mitigated in the market to recover costs.

10.8.3 Option B - Transportation Rates

Under Option B, FEI would include the T-South Long-Haul capacity specifically within the transportation rate schedules. FEI would amend the rate schedules to permit customers to elect this service and specify the amount requested. Fees for this option would be added to the table of charges. FEI would then allocate the available capacity across all requesting customers using the same methodology as used in the 2016/17 gas year.

10.8.4 Stakeholder Feedback

During the transportation service workshop on August 12, 2016, stakeholders generally preferred Option A due to the administrative challenges of having the T-South Long-Haul included in the transportation rate schedules. For example, under Option A, all of the arrangements are between FEI and the shipper agents on behalf of the transportation service customers. Option B would involve having signed transportation agreements in place between FEI, shipper agents, and all of the transportation service customers who wish to participate in the T-South Long-Haul capacity offering. Generally, many of the shipper agents were in favor of Option A, including some shipper agents that sent FEI letters of interest.

10.8.5 T-South Proposal

Given the stakeholder feedback, FEI proposes to continue managing the additional T-South Long-Haul capacity on an annual basis through the ACP. This will allow FEI to continue to manage all of the gas supply resources under its comprehensive contracting plan (i.e., the ACP). The request for Commission approval to allocate the capacity assignments under the ACP will be included in the 2017/18 ACP filing in the spring of 2017.

10.9 *SUMMARY*

In summary, FEI is not proposing significant changes to the transportation model. FEI is proposing some changes to incent tighter balancing for transportation customers. The areas where FEI has proposed changes are as follows:

- Eliminate the existing monthly balancing provisions entirely for the transportation model and require all transportation customers in all service areas to balance daily.
- Amend the balancing tolerance from 20% to 10%, and implement a tiered charge approach whereby charges increase as tolerance ranges are exceeded.

In addition to the proposed changes to the existing transportation model stated above, FEI proposes to continue to manage the additional T-South Long-Haul capacity on an annual basis through the ACP.

FortisBC Energy Inc.
2016 Rate Design Application

Section 11:

FEI General Terms and Conditions and Rate Schedules for Service

Table of Contents

11. FEI GENERAL TERMS AND CONDITIONS AND RATE SCHEDULES FOR SERVICE

11.1 *FEI GENERAL TERMS AND CONDITIONS*

11.1.1 Introduction

The FEI GT&Cs set out the Commission approved terms and conditions of service provided by FEI, which includes Fort Nelson. The Table of Contents of the GT&Cs is provided below.

Table 11-1: Current GT&Cs Table of Contents

Section No.	Section Heading	Page No.
N/A	Definitions	D-1
N/A	Service Areas	D-8
1	Application Requirements	1-1
2	Agreement to Provide Service	2-1
3	Conditions on Use of Service	3-1
4	Rate Classification	4-1
5	Application Fee and Charges	5-1
6	Security for Payment of Bills	6-1
7	Term of Service Agreement	7-1
8	Termination of Service Agreement	8-1
9	Delayed Consumption	9-1
10	Service Lines	10-1
11	Meter Sets & Metering	11-1
12	Main Extensions	12-1
12B	Vehicle Fueling Stations	12B-1
13	Interruption of Service	13-1
14	Access to Premises and Equipment	14-1
15	Promotions and Incentives	15-1
15A	On-Bill Financing Pilot Program	15A-1
16	Billing	16-1
17	Thermal Energy	17-1

***Note**: Sections 12A and 18 are Reserved for Future Use.*

FEI is proposing amendments to all sections of the GT&Cs. FEI notes that only minor housekeeping amendments are being proposed to Sections 10 (Service Lines) and 12 (Main Extensions), which were recently amended as part of the FEI 2015 System Extension Application and Decision (Order G-147-16, dated September 16, 2016). Pursuant to Order G-147-16, the amendments were made effective September 16, 2016.

11.1.2 Summary of Proposed Amendments

In this Application, a number of substantive amendments are being proposed to the GT&Cs, effective Q4 of 2018:

- In the GT&C Definitions, a number of new definitions have been proposed or moved from the rate schedules into the GT&Cs to reduce repetition in multiple rate schedules. These include definitions for Business Day[188] CNG, CNG Service, Delivery Charge, Fort Nelson, LNG, LNG Service, and Service Line Cost Allowance.
- FEI is proposing to further combine service areas. The proposed GT&Cs have combined all of the service areas, with the exception of Fort Nelson, into one service area, which has been referred to as the Mainland and Vancouver Island Service Area.

[188] To avoid repetition, the capitalized terms used in this Section are the same terms defined in the GT&Cs.

- In Section 14 (Access to Premises and Equipment), FEI is proposing a new right to install and operate a remote meter, at the Customer's cost, in situations where FEI is unable to obtain regular access to a Customer's Premises.
- FEI is proposing the removal of Section 15A in its entirety, as the On-Bill Financing Pilot Program that was previously offered in some interior communities is no longer in effect.
- In Section 19.7 (Over-billing), a maximum refund period of six years has been proposed for over-billing errors.
- The name of FEI's "Equal Payment Plan" has been changed to "Monthly Payment Plan", as the reference to "equal" does not adequately convey that monthly payment amounts may be adjusted after an approved rate change, at reconciliation times or at other times, as may be appropriate.
- A new paragraph (e) is being proposed for Section 23.2 (Discontinuance or Refusal Without Notice), which would authorize FEI to discontinue or to refuse Service without notice in the event that a Customer tampers with or otherwise alters a Meter Set.

Numerous other proposed amendments to the GT&Cs are being proposed for stylistic consistency, as well as to simplify language where possible.

Additional details regarding proposed amendments to the individual sections of the GT&Cs are provided below.

11.1.2.1 Proposed Amendments to the FEI General Terms and Conditions – Sections 1 to 28

The proposed amendments to Sections 1 to 28 of the GT&Cs are briefly summarized below in numerical order.

Section 1 (Application Requirements)

Amendments to Section 1.2 (Required Documents) are proposed to clarify that the reference to "other" rate schedules was intended to refer to rate schedules other than Residential Service or Commercial Service.

Amendments to Section 1.5 (Rental Premises) are also proposed to make it clearer that FEI may require a Landlord to assume responsibility for a Tenant's non-payment for Service.

Section 2 (Agreement to Provide Service)

Section 2.3 (No Assignment / Transfer) is being amended to specify that FEI's prior written approval is required to transfer or assign an agreement for Service.

Section 3 (Conditions on Use of Service)

Section 3.2 (Unauthorized Sale / Supply / Use) has been revised to state that a Customer cannot sell or supply Gas supplied to it by FEI, without first obtaining the prior written approval of FEI, which consent may be exercised by FEI in its sole discretion.

Section 4 (Rate Classification)

Minor amendments to Section 4 (Rate Classification) have been proposed to use the defined term “Service”, and to clarify the wording with respect to FEI’s authority to assign a customer to the appropriate rate schedule and to calculate the customer’s charges according to the appropriate rate schedule.

Section 5 (Application Charge and Other Charges)

The references to “fees” in Section 5 have been replaced by references to “charges” in order to be consistent with the Table of Charges in the applicable rate schedules.

In Section 5.3 (Waiver of Application Charge), a 31 Day maximum is being proposed in situations where FEI waives an Application Charge to a Landlord that has a new Tenant replacing a previous Tenant.

Section 6 (Security for Payment of Bills)

FEI is proposing an amendment to Section 6.3 (Refund of Deposit) to permit FEI to refund a security deposit to a Customer that has paid its account in full for the previous Year.

Amendments are also proposed to Section 6.6 (Replenish Security Deposit) to make it clearer that FEI has discretion as to whether to require a security deposit or equivalent form of security to be provided to reconnect or continue service to a Customer.

Section 7 (Term of Service Agreement)

As “Residential Service” is a defined term, additional references have been made to “Service” through the Section.

Section 8 (Termination of Service Agreement)

No changes have been proposed.

Section 9 (Delayed Consumption)

In Section 9.1 (Additional Charges), references to the appropriate rate schedule have been inserted.

Section 10 (Service Lines)

As mentioned above, no substantive amendments to Section 10 have been proposed as amendments were recently approved by the Commission in Order G-147-16.

Section 11 (Meter Sets and Metering)

Amendments to Section 11.1 (Installation) have been proposed to clarify that Meter Sets will generally be installed outside of buildings on Customers' Premises.

Section 11.2 (Measurement) has been updated to refer to the renamed federal agency, Measurement Canada.

Other minor changes were proposed throughout the section for consistency with the definitions and style used in other GT&C sections.

Section 12 (Main Extensions)

Similar to Section 10, no substantive amendments to Section 12 have been proposed as amendments were recently approved by the Commission in Order G-147-16.

Section 12A (Section Reserved for Future Use)

No new provisions are being proposed in the Section 12A placeholder.

Section 12B (Vehicle Fueling Stations)

Minor changes have been proposed throughout Section 12B to use the defined terms for CNG Service and LNG Service.

Section 13 (Interruption of Service)

No substantive changes have been proposed.

Section 14 (Access to Premises and Equipment)

A new Section 14.3 (Installation of Remote Meter) has been proposed, which would provide FEI with the ability to install a remote meter to measure a Customer's consumption data when regular access to a Customer's Premises cannot be reasonably arranged. In such circumstances, the Customer would be responsible for the costs associated with installing and maintaining the remote meter.

Section 15 (Promotions and Incentives)

No changes have been proposed.

Section 15A (On-Bill Financing Pilot Program)

This Section has been deleted, as the On-Bill Financing Pilot Program that was previously offered in some interior communities is no longer in effect.

Section 16 (Billing)

No changes have been proposed.

Section 17 (Thermal Energy)

No changes have been proposed.

Section 18 (Section Reserved for Future Use)

No new provisions are being proposed in the Section 18 placeholder.

Section 19 (Back-Billing)

The reference to the limitation period in Section 19.5 (Tampering / Fraud) was removed, as reference to it was not necessary.

Changes are proposed to Section 19.7 (Over-billing) to provide for a maximum refund period of six years from the date that an error is discovered. This amended language is proposed instead of referencing the applicable limitation period.

Section 20 (Monthly Payment Plan)

FEI is proposing changing the name of the "Equal Payment Plan" to "Monthly Payment Plan" to make it clearer that FEI has the discretion to increase or decrease the Monthly instalments under Section 20.4 (Changes in Instalments). As such, all Monthly instalments may not all be equal.

Section 21 (Late Payment Charge)

No substantive changes have been proposed.

Section 22 (Returned Cheque Charge)

No substantive changes have been proposed.

Section 23 (Discontinuance of Service and Refusal of Service)

A new paragraph (e) is being proposed to Section 23.2 (Discontinuance or Refusal Without Notice), which would authorize FEI to discontinue or refuse Service without notice in the event that a Customer has tampered with or otherwise altered a Meter Set.

Section 24 (Limitations on Liability)

No substantive changes have been proposed.

Section 25 (Miscellaneous Provisions)

No changes have been proposed.

Section 26 (Direct Purchase Agreements)

No substantive changes have been proposed.

Section 27 (Commodity Unbundling Service)

Paragraph (a) of Section 27.1 (Unbundling Service Terms and Conditions) has been revised to make it clear that a notice of appointment of marketer must be made in a form acceptable to FEI.

No other substantive changes have been proposed to this Section.

Section 28 (Biomethane Service)

No substantive changes have been proposed.

Table 11-2 below provides a summary of the proposed amendments to the GT&Cs, effective Q4 of 2018.

Table 11-2: Summary of Proposed Amendments to the FEI General Terms and Conditions

Section	Page No.	Proposed Amendments	Rationale
Table of Contents	i	Replaced “Fee” with “Charge” and added “Other”.	The proposed new title of Section 5 is Application Charge and Other Charges.
Table of Contents	i	Replaced “&” with “and”.	For stylistic consistency with other section titles. This same change has been made elsewhere in the document.
Table of Contents	ii	Changed “Equal” with “Monthly”.	The proposed new title of Section 20 is Monthly Payment Plan.
Table of Contents	ii	Replaced “Cheque” with “Payment”.	The proposed new title of Section 22 is Returned Payment Charge.
Table of Contents	ii	Removed phrase “Fees And”.	Amendment made to mirror the proposed new title of the Standard Charges Schedule.
Definition: “Application Fee”	D-1	Changed “Application Fee” to “Application Charge”.	Amendment made to mirror changes in the Standard Charges Schedule.

Section	Page No.	Proposed Amendments	Rationale
Definition: "Basic Charge"	D-1	Deleted the term "down" from definition.	The Basic Charge will be calculated to four decimals in all cases, not only where it is rounded "down".
Definition: "British Columbia Utilities Commission"	D-1	Formatting.	Formatting.
Definition: "Business Day"	D-2	Moved definition.	As this definition was common to a number of rate schedules, it has been moved to the GT&C.
Definition: "Carbon Offsets"	D-2	Amended definition.	The definition has been amended to clarify that it is referring to a gas volume, which may include Biomethane or other forms of gas.
Definition: "CNG"	D-2	New definition.	As this term is used independently in the GT&Cs, a separate definition has also been added.
Definition: "CNG Service"	D-2	New definition.	Added term for use in Section 12B.
Definition: "Commodity Cost Recovery Charge"	D-2	Amended definition.	Definition has been slightly amended to follow the style of the other definitions.
Definition: "Commodity Unbundling Service"	D-2	Word "Commodity" added after "Residential".	Proposed new title of RS 1U is "Residential Commodity Unbundling Service".
Definition: "Day"	D-2	Amended definition.	The definition has been slightly amended to make it more specific to the applicable Service Agreement.
Definition: "Delivery Charge"	D-2	New definition.	Added term for use with applicable rate schedules.
Definition: "Delivery Point"	D-3	Amended definition.	The definition has been slightly amended to make it more specific to the applicable Service Agreement.
Definition: "Financing Agreement"	D-3	Moved definition.	Placed definition in alphabetical order.
Definition: "First Nations	D-3	Moved and amended definition.	The definition has been slightly amended. "Legally recognized" is already captured by the reference to validly enacted legislation and agreements in the definition.
Definition: "Franchise Fees"	D-3	Moved definition.	Placed definition in alphabetical order.

Section	Page No.	Proposed Amendments	Rationale
Definition: "Gas"	D-3	Amended definition.	The definition has been slightly amended to reflect circumstance where it may not have been FEI that has added odorant to the natural gas.
Definition: "General Terms and Conditions of FortisBC Energy"	D-3	Amended definition.	The definition has been slightly amended. "Of FortisBC Energy" is already captured in the definition.
Definition: "Gigajoule"	D-3	Amended definition.	The definition has been slightly amended to reflect all circumstances where it may be applicable.
Definition: "Hydronic Heating System"	D-4	Amended definition.	The definition has been slightly amended for grammar. "Means" was also added for stylistic consistency.
Definition: "Landlord"	D-4	Amended definition.	The definition has been amended to reduce redundancy with definition of Tenant, which incorporates concept of the Persons not being the same. "Means" was also added for stylistic consistency.
Definition: "LNG"	D-4	New definition.	Added term for use in Section 12B.
Definition: "LNG Service"	D-4	New definition.	Added term for use in Section 12B.
Definition: "Main"	D-4	Amended definition.	The definition has been amended slightly to reflect references to pipe in the singular and plural.
Definition: "Main Extension"	D-4	Amended definition.	The definition has been amended slightly for consistency in verb use.
Definition: "Meter Set"	D-4	Amended definition.	Definition broadened to make it clear that ancillary equipment to the Meter Set, on its own, satisfies the definition.
Definition: "Municipal Operating Fees"	D-5	Amended definition.	As this appears to be a single aggregate, replaced "or" with "and".
Definition: "Other Service Charges"	D-5	Amended definition.	Changed "Social Services" with "Provincial Sales".

Section	Page No.	Proposed Amendments	Rationale
Definition: "Profitability Index"	D-5	Amended definition.	"Means" was also added for consistency. The definition was expanded to include customers of RS 3 or higher and Service Header connections, as provided for under Section 10.1(d). Added the applicable term of 40 years.
Definition: "Rate Schedule"	D-5	Amended definition.	The definition was amended slightly for consistency with the definition of "General Terms and Conditions".
Definition: "Service Area"	D-6	Formatting.	Changed ampersand to "and".
Definition: "Service Line Cost Allowance"	D-6	New definition.	This definition is referred to as a capitalized term in Section 10.1.
Definition: "Service Related Charges"	D-6	Amended definition.	Changed "fees" to "charges". Changed "Social Services" with "Provincial Sales".
Definition: "Service Fees & Charges Schedule"	D-7	Amended definition and name.	Amendment made to mirror changes in the Standard Charges Schedule.
Definition: "Storage and Transport Charge"	D-7	Amended definition.	The definition has been slightly amended for stylistic consistency.
Definition: "Tenant"	D-7	Amended definition	The definition has been slightly amended for stylistic consistency.
Definition: "Thermal Energy"	D-7	Amended definition.	"Premises" has been capitalized.
Definition: "Thermal Metering"	D-7	Amended definition.	The definition has been slightly amended for stylistic consistency.
Definition: "Unauthorized Transportation Service"	D-7	Moved definition.	As this definition was common to a number of transportation service rate schedules, it has been moved to the GT&Cs.
Definition: "Year"	D-8	Amended definition.	The definition has been slightly amended to reflect billing practices.

Section	Page No.	Proposed Amendments	Rationale
Service Areas	D-9 to D-12	Removed "of FortisBC Energy". Renamed and combined all service areas except Fort Nelson into "Mainland and Vancouver Island" and amended other sections as necessary.	Wording amended for consistency with the definition of "General Terms and Conditions". Mainland, Vancouver Island, and Whistler Service Areas combined as "Mainland and Vancouver Island".
1.2 (Required Documents)	1-1	Amended part (c).	As Residential Service and Commercial Service each have several rate schedules, the provision has been slightly amended for clarity that part (c) applies to all other types of applications.
1.5 (Rental Premises)	1-2	Amended part (a).	Wording amended so that a Landlord must assume responsibility for a Tenant's non-payment. Agency is contemplated in the definition of Landlord.
2.2 (Customer Status)	2-1	Replaced "shall" with "will".	For stylistic consistency with previous sections.
2.3 (No Assignment/Transfer)	2-1	Inserted "prior" into consent provision. Replaced "consent" with "approval".	Wording amended to ensure FEI receives prior written approval.
3.1 (Authorized Consumption)	3-1	Inserted "prior" before "written approval".	Wording amended to ensure FEI receives prior written approval.
3.2 (Unauthorized Sale/Supply/Use)	3-1	Removed wording "Unless authorized in writing by FortisBC Energy…" Inserted wording "without the prior written approval of FortisBC Energy at its sole discretion."	Wording amended to ensure FEI has the discretion to approve the resale of gas.
4.1 (Rate Classification)	4-1	Amended "served" with "provided Service".	Amendment uses the defined term "Service".
4.2 (Special Contracts and Tariff Supplements)	4-1	Amended "served" with "Service" and "keep the Customer on-system" with "continue to provide the Customer with Service."	Amendment uses the defined term "Service".
4.3 (Periodic Review)	4-1	Amended wording to paragraphs (b) and (c).	Amendments provide additional clarity with respect to rate schedule reviews.

Section	Page No.	Proposed Amendments	Rationale
5 **(Application Fee and Charges)**	5-1 to 5-2	Changed Section title to “Application Charge and Other Charges”. All other references to “Application Fee” throughout this section have been changed to “Application Charge”.	Amendment made to mirror changes in the Standard Charges Schedule.
5.3 **(Waiver of Application Fee)**	5-1	Sub-section title changed to “Waiver of Application Charge”. Amended wording in paragraph (b) by removing “for a short period of time” and adding “up to a maximum of 31 Days”.	Amendments clarify time-period for waiver of the Application Charge.
5.4 **(Reactivation Charges)**	5-1 to 5-2	List formatting.	Formatting to make clear that the result only follows if the conditions set out in parts (a) and (b) are met.
6.1 **(Security for Payment of Bills)**	6-1	Removed wording “Customer or applicant” and replaced with “applicable Premises”.	Amendments made to match current business practices.
6.2 **(Interest)**	6-1	Amended section to include wording regarding the return of security deposits.	Amendments made to match current business practices.
6.3 **(Refund of Deposit)**	6-1	Amended section to include wording regarding the return of security deposits.	Amendments made to match current business practices.
6.4 **(Unclaimed Refund)**	6-2	Replaced “trace” with “locate” and “becomes” with “will become”.	Amended for stylistic consistency and to correct tense.
6.6 **(Replenish Security Deposit)**	6-2	Removed word “must” and replaced with phrase “may be required to”.	Amendments made to match current business practices.
7.1 **(Initial Term for Residential and Commercial Service)**	7-1	Added “Service” after “Residential”.	Use of the full defined term.
7.2 **(Initial Term for Gas Service other than Residential or Commercial Service)**	7-1	Added “Service” after “Residential”.	Use of the full defined term.

Section	Page No.	Proposed Amendments	Rationale
7.3 (Transfer to Residential or Commercial Service)	7-1	Added “Service” after “Residential”.	Use of the full defined term.
7.4 (Renewal of Agreement)	7-1	Added “Service” after “Residential”.	Use of the full defined term.
9.1 (Additional Charges)	9-1	Added reference to “appropriate Rate Schedule” pertaining to the referenced charge	Amended wording to clarify that the charges referred to (not defined), are set out in the appropriate rate schedule.
10.1 (Provided Installation)	10-1	Changed reference from “Standard Fees and Charges Schedule” to “Standard Charges Schedule”. Amended paragraph (d) by adding the additional wording of: “Customers of” before RS 3, “of Rate Schedules numbered higher than Rate Schedule 3” after Customers, and “Main Extensions” after Section 12. Removed word “larger” before Customers.	Amendment made to mirror changes in the Standard Charges Schedule. Amended wording to clarify applicability and section name.
10.6 (Additional Connections)	10-2	Changed “Fee” to “Charge”. Removed “set out in the Standard Fees and Charges Schedule”.	Amendment made to match changes in the Standard Charges Schedule. The definition of Application Fee contains reference to the Standard Fees and Charges.
10.13 (No Unauthorized Changes)	10-3	Replaced “shall” with “will”.	For consistency with previous sections.
10.13 (Site Preparation)	10-4	Capitalized “Service Line”.	New defined term.
11.1 (Installation)	11-1	Added phrases “on surrounding land” and “of any buildings on”.	To clarify location of Meter Sets.
11.2 (Measurement)	11-1	Replaced “Consumer and Corporate Affairs Canada” with “Measurement Canada”. Abbreviated EGI Act.	Updated the name. Abbreviated EGI Act, as it is later used in its abbreviated form in Section 19.
11.3 (Testing Meters)	11-1	Amended paragraphs (a) and (b) to mirror language more closely.	Amended wording to clarify that the same testing would be used to investigate whether a Meter Set is recording correctly.

Section	Page No.	Proposed Amendments	Rationale
11.5 (Protection of Equipment)	11-1	Deleted "and related equipment".	Language included in the definition of Meter Set, which includes ancillary equipment.
11.6 (No Unauthorized Changes)	11-1	Amended "Meter Set" to singular and amended written approval. Deleted "and related equipment".	Amended for stylistic consistency with prior sections.
11.8 (Customer Requested Meter Relocation or Modifications)	11-2	Deleted "and related equipment".	Language included in the definition of Meter Set, which includes ancillary equipment.
11.9 (Meter Set Consolidations)	11-2	Changed "Fee" to "Charge".	Amendment made to match changes in the Standard Charges Schedule.
11.10 (Delivery Pressure)	11-2	Replaced "The" with "FortisBC Energy's".	Provides clarity that 1.75 kPa is FEI's normal Delivery Pressure.
11.11 (Customer Requested Mobile Service)	11-2	Replaced "brought on" with "necessitated".	Amended for consistency with language used in Section 11.8(b).
12.2 (Ownership)	12-1	Replaced "remain" with "be".	Amendment uses forward looking language.
12.4 (Revenue)	12-1	Replaced "Fees" with "Charges".	Amendment made to mirror changes in the Standard Charges Schedule.
12.9 (Extensions to Contributory Extensions)	12-4	Amended word "test" to lowercase after Main Extension.	Amendment made to match definition.
12.11 (System Extension Fund Pilot)	12-4 to 12-5	Amended paragraph (a) by adding the word "located" and changing the phrase from "Mainland, Vancouver Island, and Whistler" to "Mainland and Vancouver Island". Amended paragraph (b) by adding an "s" to "Premise". Amended last paragraph by adding an "s" after "Contribution".	Amendment made to mirror new Service Area definition and provide clarity. Amended for stylistic consistency with prior sections. Amendment made to match Section 12.8 title (Refund of Contributions).
12B.1 (Compression and Dispensing Service for Compressed Natural Gas (CNG)	12B-1	Replaced long form terms with definitions. Replaced words "compression, gas" with "compressor".	Amendment uses new definitions for CNG Service and LNG Service. Amendment made to provide clarity regarding equipment.

Section	Page No.	Proposed Amendments	Rationale
12B.2 (Ownership)	12B-1	Replaced “customer’s” with “Customer’s”.	Use of defined term.
12B.3 (Cost of Service Recovery)	12B-2	Amendments to use defined terms.	Amendments allow for consistency with previous sections.
12B.4 Calculation of Cost of Service)	12B-2	Amended paragraph (b) by adding an “s” to “expense”. Amended paragraph (d) by replacing “NGV” with natural gas vehicle and “CPI” with consumer price index. Amended last paragraph by capitalizing “Service”.	For stylistic consistency with paragraph. Terms are not defined. Use of defined term.
13.3 (Notice)	13-1	Replaced “a” with “the”.	Amendment provides consistency in Section with other references to Customer.
14.1 (Access to Premises)	14-1	Replaced “must” with “will”.	For stylistic consistency with previous sections.
14.3 (Installation of Remote Meter)	14-1	New Section.	Amendment allows FEI to recover the costs of installing and maintaining a remote meter if FEI is unable to access a Customer’s Premises or access necessary Equipment.
15.1 (Promotion of Gas Appliances)	15-1	Removed the capital “G” from natural gas.	Natural gas is not a defined term.
15A (On-Bill Financing Pilot Program)	15A-1	Section removed.	The On-Bill Financing Pilot Program ended effective January 1, 2015.
17.1 (All references to Gas)	17-1	Replaced “shall” with “will”. “Service” added after “Residential”.	For stylistic consistency with previous sections.
19.1 (When Required)	19-1	Replaced “herein” and “hereunder” with plain language. Removed word “subsisting”. Replaced “an equal payment plan billing” with “Monthly Payment Plan bill”.	For stylistic consistency with previous sections. Amendment made to be consistent with the new title of Section 20.

Section	Page No.	Proposed Amendments	Rationale
19.2 Definition	19-1	Deleted EGI Act reference and replaced "thereof" with "of them".	EGI Act is defined in Section 12 and other amendments made for stylistic consistency with previous sections.
19.4 (Billing Basis)	19-2	Replaced "contract" with "agreement for Service".	For stylistic consistency with the language used in Section 2.
19.5 (Tampering/Fraud)	19-2	Removed "subject to the applicable limitation period provided by law". Changed "(Under-Billing)" to "(Under-billing)".	Amendment made to be consistent with amendments to Section 19.7. Amendment made to be consistent with the title of Section 19.8.
19.7 (Over-billing)	19-2 to 19-3	Replaced "subject to the applicable limitation period provided by law" with "except that, if the date of when the error first occurred cannot be determined with reasonable certainty, the maximum refund period will be 6 years back from the date the error was discovered".	Amendment made to provide clarity with respect to refund time periods.
19.8 (Under-billing)	19-3	Replaced "contract" with "agreement for Service".	For stylistic consistency with the language used in Section 2.
19.10 (Disputed Back-bills)	19-3	Replaced "shall" with "will".	For stylistic consistency with previous sections.
19.11 (Changes in Occupancy)	19-3	Moved "back-billing" in sentence.	Amendment made for clarity.
20 (Equal Payment Plan)	20-1	Name of plan changed from "Equal Payment Plan" to "Monthly Payment Plan".	Name change will make it clearer to customers that monthly installments may not always be equal throughout the period, (as set out in Section 20.4 (Changes in Instalments).
20.1 (Definitions)	20-1 to 20-2	Capitalized new definition of Monthly Payment Plan Period and replaced 12 consecutive months with "one Year".	Capitalization for consistency with the earlier sections. This change was also made throughout Section 20. As the definition of "Month" can be interpreted as being as few as 27 days, the use of "Year" was used to capture an entire year.
21.2 (Equal Payment Plan)	21-1	Title of Section changed from "Equal Payment Plan" to "Monthly Payment Plan".	Amendment made to be consistent with amendments to Section 20.

Section	Page No.	Proposed Amendments	Rationale
22 **(Returned Cheque Charge)**	22-1	Title of Section changed from “Returned Cheque Charge” to Returned Payment Charge”.	Amendment made to mirror changes in the Standard Charges Schedule.
22.1 **(Dishonoured Cheque Charge)**	22-1	Title of Section changed from “Dishonoured Cheque Charge” to “Returned Payment Charge”.	Amendment made to mirror changes in the Standard Charges Schedule.
23.2 **(Discontinuance or Refusal Without Notice)**	23-2	Added to section (e) a specification about tampering with the Meter Set.	Amendment provides FEI the ability to discontinue or refuse service if a Meter Set is tampered with.
26.2 **(Direct Purchase Customers Returning to FortisBC Energy System Supply)**	26-1	Replaced “can” with “may”.	For stylistic consistency with previous sections.
27.1 **(Unbundling Service Terms and Conditions)**	27-1	Replaced “Notice of Appointment of Marketer” as it is not a defined term. Amended “shall” with “must”. Capitalized “Service” throughout, as it is a defined term. Replaced periods with semicolons in the list.	For stylistic consistency with previous sections.
28 **(Biomethane Service)**	28-1 to 28-3	Replaced “agree” with “must” throughout.	For stylistic consistency with previous sections.
28.3 **(Reduced Supply)**	28-1	Removed “in an amount equal to the greenhouse gas reduction that would have been achieved through Biomethane supply, and”.	Terms are already outlined in the definition of Carbon Offsets.
28.6(g) **(Switching to a Gas Marketer Contract)**	28-3	Added “(Commodity Unbundling Service)” after Section 27.	Amendment made to be consistent with the title of Section 27.
Standard Fees and Charges Schedule	S-1	Changed Title to “Standard Charges Schedule”.	Amendment provides clarity by having all components listed in the schedule outlined as charges.
Standard Fees and Charges Schedule	S-1	Changed “Application Fee” to “Application Charge”.	New title of the schedule is “Standard Charges Schedule”.
Standard Fees and Charges Schedule	S-1	Changed “Dishonoured Cheque Charge” to “Returned Payment Charge”.	Name of title broadened to encompass returned electronic fund transfers in addition to returned cheques.

Section	Page No.	Proposed Amendments	Rationale
Standard Fees and Charges Schedule	S-1	Added an "s" to "FortisBC Energy".	Amendment provides clarity.
Standard Fees and Charges Schedule	S-1	Changed "Disputed Meter Testing Fees" to "Meter Testing Charges".	New title of the schedule is "Standard Charges Schedule".

FEI has provided in Appendix 11-1 a blacklined version of the proposed changes to FEI's GT&Cs effective Q4 of 2018.

11.1.2.2 Proposed Amendments to the FEI GT&Cs – Standard Fees and Charges Schedule

FEI has reviewed its rates for the Standard Fees and Charges Schedule both in a jurisdictional review of other Canadian utilities, as well as an internal cost review. In its jurisdictional review, FEI considered the fees and charges of the following other Canadian utilities:

- BC Hydro;
- PNG;
- ATCO Gas and Pipelines Ltd. – Alberta-North and South (ATCO);
- Direct Energy Regulated Services – Alberta-North and South (Direct Energy);
- AltaGas Utilities Inc. (AltaGas);
- SaskEnergy Incorporated (SaskEnergy);
- Manitoba Hydro;
- Union Gas Ltd. (Union); and
- Enbridge Gas Distribution Inc. (Enbridge).

FEI conducted this jurisdictional research in order to determine whether FEI's rates for its Standard Fees and Charges were reasonable when compared with other Canadian utilities. FEI's internal cost review research was conducted in order to determine whether the current rates charged continue to reflect the costs to perform the services the fee is intended to recover.

Standard Fees and Charges Schedule – Proposed Name Changes:

During FEI's jurisdictional review, FEI also considered whether to propose a new name for its standard fee or charge in order to better reflect the nature of the fee or to be more consistent with other utilities' naming conventions for similar fees.

FEI is proposing to simplify the name of the Standard Fees and Charges Schedule by renaming it the "Standard Charges Schedule". FEI is also proposing the following changes:

- "Application Fee" to "Application Charge";
- "Dishonoured Cheque Charge" to "Returned Payment Charge"; and
- "Disputed Meter Testing Fees" to "Meter Testing Charges".

Fee or Charge Proposed Rate Change:

FEI is proposing the following rate changes to the current Standard Charges in order to better reflect the actual costs of providing these services:

- Application Charge proposed reduction from $25.00 to $15.00; and
- Returned Payment Charge proposed reduction from $20.00 to $8.00.

The proposed reductions to the Application Charge and the Returned Payment Charge primarily reflect efficiencies in the business processes resulting from increased access to online and electronic information necessary to perform these two services. The online web-based self-serve nature of most application processes now requires less manual intervention from customer service representatives, and thus, a reduction in the costs to perform this service. The Returned Payment Charge reduction also reflects the decreased customer service representative work involved resulting from improved automation in banking processes. A contributing factor to the analysis supporting FEI's proposal to reduce the Application Charge and Returned Payment Charge is that the costs reviewed are based on the in-house Customer Service model, whereas, previous cost reviews were based on the out-sourced model, which included a bundled suite of services in place at the time. Appendix 11-2 contains the supporting information that was utilized for the proposed rate changes.

Table 11-3 below provides a summary of the proposed changes to the current Standard Charges Schedule.

Table 11-3: Summary of Proposed Changes to the Standard Charges Schedule

Standard Charge/Fee Name		Fee/Charge	
Current	Proposed	Current	Proposed
Application Fee[1]	Application Charge[1]	**$25.00**	**$15.00**
Late Payment Charge	No change	1.5% per month[2]	No change
Dishonoured Cheque Charge	Returned Payment Charge	**$20.00**	**$8.00**
Interest on Cash Security Deposits	No change	FEI's prime interest rate minus 2%[3]	No change
Disputed Meter Testing Fees[4]	Meter Testing Charges[4]	**$60.00**	No change

Standard Charge/Fee Name		Fee/Charge	
Current	Proposed	Current	Proposed
Disputed Meter Testing Fees[5]	Meter Testing Charges[5]	Actual Costs of Removal and Replacement	No change
Reactivation Charges Performed During Regular Working Hours	No change	**$90.00**	No change
Reactivation Charges Performed After Regular Working Hours	No change	**$115.00**	No change

Notes:

[1] Includes: Existing Installation
New Installation – Manifold Meters
New Installation – Vertical Subdivision

[2] 19.56% per annum on outstanding balance.

[3] FortisBC Energy prime interest rate is defined as the floating annual rate of interest which is equal to the rate of interest declared from time to time by FortisBC Energy's lead bank as its "prime rate" for loans in Canadian dollars.

[4] Meters rated at less than or equal to 14.2 m3/Hour.

[5] Meters rated greater than 14.2 m3/Hour.

Table 11-4 below provides a summary of the jurisdictional review of the amounts of the fees and charges which other Canadian utilities are currently charging for the services similar to those included in the FEI Standard Charges Schedule.

Table 11-4: Summary of Jurisdictional Review of Canadian Utilities

Utility	Application Charge	Late Payment Charge	Returned Payment Charge	Interest on Cash Security Deposits	Meter Testing Charges	Reactivation Charges
BC Hydro	$12.40	1.5% (19.6% per annum)[1]	$6[1]	BC Hydro's Weighted Average Cost of Debt for the most recent fiscal year[1]	$181[1]	$30 Remote[1] $280 Manual[1]
PNG	$30.00	1.5% (19.56% per annum)	$20	PNG's Prime Rate minus 2%	$60 (meters <=14.2 m^3/hr) Actual Cost (meters >=m^3/hour)	$60 Reg. Hours
ATCO	By retailer	1%	$31	Rate specified in the Alberta *Residential Tenancies Act*	$117 (Residential) $117 Minimum (Non-Residential)	$122 Reg. Hours $286 After Hours
Direct Energy	$10.00 (plus credit check if required)	1.5%	$25	N/A	ATCO Applicable Charge	$25[3]
AltaGas	$37.00	1.5% (18% per annum)	$26	Alberta Government established tenant security deposit interest rates	$79 (Residential) Actual Cost (Non-Residential)	$53 (Residential) Actual Cost (Other)
SaskEnergy	Reg. Hours $30 After Hours $65	1.17% (15% per annum)	$25	The average TD Canada Trust Prime interest rate for the prior year (rounded)	$25 (Residential & Commercial Small) $50 (Commercial Large & Industrial)	Residential & Commercial Small • $68 Regular Hours • $95 After Hours Commercial Large & Industrial • $100 Regular Hours) • $135 (After Hours)
Manitoba Hydro	Not specified	1.25%	$20	Manitoba Hydro's average short-term borrowing cost	$35 (Residential) $130 (Commercial)	$50 Regular Hours $65 After Hours
Union	$35.00	1.5% (18%[2] per annum)	$20	Simple interest based on current bank savings rate (calculated monthly)	Actual Cost	$35

Utility	Application Charge	Late Payment Charge	Returned Payment Charge	Interest on Cash Security Deposits	Meter Testing Charges	Reactivation Charges
Enbridge	$25.00	1.5% (18%[2] per annum)	$20	Rate is set by the Ontario Energy Board (for deposits that have been on file for a minimum of 6 months)	$105 (Residential) Actual Cost (Commercial)	$75

Notes:
[1] Proposed as part of BC Hydro's 2015 Rate Design Application.
[2] Effective per annum rate = 19.56%.
[3] Charge applicable in addition to ATCO's applicable charges.

11.1.3 Conclusion

FEI proposes that the changes to the Standard Charges Schedule be approved, effective Q4 of 2018.

11.2 FEI RATE SCHEDULES FOR SERVICE

11.2.1 Introduction

The FEI rate schedules set out Commission approved specific terms, conditions, and applicable charges for each of FEI's different service offerings.

Table 11-5 below outlines the current FEI rate schedules and provides a description of the applicable service offering under each rate schedule.

Table 11-5: The Current FEI Rate Schedules for Service

Rate Schedule	Rate Schedule Title	General Description of Service Offering
1	Residential Service	• Residential firm service
1B	Residential Biomethane Service	• Residential firm biomethane service
1U	Residential Service	• Residential firm unbundled service
1X	Residential Service	• Residential firm unbundled service ○ *In the event of marketer failure, customers served under RS 1U may be served under RS 1X*
2	Small Commercial Service	• Small commercial firm service • Normalized annual consumption is less than 2,000 GJ per year
2B	Small Commercial Biomethane Service	• Small commercial firm biomethane service • Normalized annual consumption is less than 2,000 GJ per year
2U	Small Commercial Service	• Small commercial firm unbundled service • Normalized annual consumption is less than 2,000 GJ per year
2X	Small Commercial Service	• Small commercial firm unbundled service • Normalized annual consumption is less than 2,000 GJ per year ○ *In the event of marketer failure, customers served under RS 2U may be served under RS 2X*

Order G-4-18 Updates, February 6, 2018

Rate Schedule	Rate Schedule Title	General Description of Service Offering
3	Large Commercial Service	• Large commercial firm service • Normalized annual consumption is greater than 2,000 GJ per year
3B	Large Commercial Biomethane Service	• Large commercial firm biomethane service • Normalized annual consumption is greater than 2,000 GJ per year
3U	Large Commercial Service	• Large commercial firm unbundled service • Normalized annual consumption is greater than 2,000 GJ per year
3X	Large Commercial Service	• Large commercial firm unbundled service • Normalized annual consumption is greater than 2,000 GJ per year ○ *In the event of marketer failure, customers served under RS 3U may be served under RS 3X*
4	Seasonal Firm Service	• Seasonal firm service for customers that typically consume gas during off-peak periods (April to October)
5	General Firm Service	• General firm service with an applicable monthly demand charge per month per GJ of Daily Demand
5B	General Firm Biomethane Service	• General firm biomethane service with an applicable monthly demand charge per month per GJ of Daily Demand
6	Natural Gas Vehicle Service	• Natural gas vehicle service • Includes the provision for the resale of natural gas to natural gas vehicles
6A	General Service – Vehicle Refueling Service	• On-site natural gas vehicle refueling and compression service
6P	Public Service – Natural Gas Vehicle Refueling Service	• Natural gas vehicle refueling service at FEI Surrey Operations
7	General Interruptible Service	• General interruptible service
11B	Biomethane Large Volume Interruptible Sales	• Biomethane large volume interruptible sales • Customer must enter into an FEI transportation agreement pursuant to RS 22, RS 22A, RS 22B, RS 23, RS 25, RS 26 or RS 27

Rate Schedule	Rate Schedule Title	General Description of Service Offering
14A	Term and Spot Gas Sales	• Natural gas term and spot sales • Customer must not have/or has not appointed a shipper agent • Customer must enter into an FEI transportation agreement pursuant to RS 22, RS 22A, RS 22B, RS 23, RS 25, RS 26 or RS 27
22	Large Volume Transportation	• Large volume interruptible transportation service (with the option to negotiate firm rate) • Minimum monthly consumption of 12,000 GJ (take or pay)
22A	Transportation Service (Closed) Inland Service Area	• Large volume firm and interruptible transportation service for select customers (closed rate schedule)
22B	Transportation Service (Closed) Columbia Service Area	• Large volume firm and interruptible transportation service for select customers (closed rate schedule)
23	Commercial Transportation Service	• Large commercial firm transportation service • Normalized annual consumption is greater than 2,000 GJ per year
25	General Firm Transportation Service	• General firm transportation service with an applicable monthly demand charge per month per GJ of Daily Demand
26	NGV Transportation Service	• Natural gas vehicle transportation service • Includes the provision for the resale of natural gas to natural gas vehicles
27	General Interruptible Transportation	• General interruptible transportation service
30	Off-System Sales and Purchases Rate Schedule and Agreement (Canada and U.S.A.)	• GasEDI base contract with terms and conditions for off-system natural gas sales or purchases with third parties
36	Commodity Unbundling Service	• Terms and conditions for commodity unbundling service between FEI and natural gas marketers
40	West to East SCP Transportation Service Rate Schedule	• Transportation service in a West to East direction via the SCP
46	Liquefied Natural Gas Sales, Dispensing and Transportation Service	• LNG sales, dispensing and transportation service

Rate Schedule	Rate Schedule Title	General Description of Service Offering
50	Large Volume Industrial Transportation	• Large volume firm and interruptible transportation service • Customers must enter into a transportation agreement for a minimum period of 15 years and require firm transportation service of at least 45 TJ per day

11.2.1.1 Scope of Review

The scope of the rate schedule review in this Application includes all of FEI's rate schedules outlined in Table 11-5, except for the following:

- RS 30;
- RS 36;
- RS 46; and
- RS 50.

Amendments to RS 30 are not proposed in the Application because this rate schedule reflects the current standard provisions used for GasEDI contracts with third parties for off-system natural gas sales and purchases. As such, there are no proposed amendments required at this time. Typically, changes to RS 30 are generally of a housekeeping nature, and addressed as required. With respect to RS 36, consistent with past practice, any amendments to this rate schedule are handled through the Customer Choice Program Annual General Meeting regulatory proceeding. Finally, as outlined in Section 1 of the Application, RS 46 and RS 50 are not included in the scope of this Application; therefore, no amendments have been proposed, as these rate schedules are approved by Orders in Council and not subject to change in this proceeding.[189]

In addition to the rate schedules outlined in Table 11-5 above, FEI has a number of tariff supplements and Bypass agreements (filed with and approved by the Commission in the form of tariff supplements) currently in place. These tariff supplements have been negotiated and approved by the Commission and, as such, FEI is not proposing any changes to existing tariff supplements in this Application.[190]

FEI will be making a supplemental filing on February 2, 2017, which will include Appendices 11-3 and 11-4. Appendix 11-3 will provide the blacklined changes to each rate schedule reflecting the rate design proposals in the Application, and will also include any housekeeping changes FEI is proposing. Appendix 11-4 will provide supporting calculations for the proposed decrease

[189] OIC No. 557/2013 and OIC No. 749/2014 (refer to Appendix 2).

[190] With the exception of the proposed cancellation effective Q4 of 2018, of FEI Tariff Supplement G-21 between Creative Energy Vancouver Platforms Inc. and FEI. Please refer to Section 9 of the Application for more information.

to the Administration Charge per Month for RS 22, RS 22A, RS 22B, RS 23, RS 25, RS 26 and RS 27.

11.2.2 Conclusion

FEI proposes that the changes to the rate schedules, being filed in the supplemental filing on February 2, 2017, be approved, effective Q4 of 2018.

11.3 *OVERHEAD AND MARKETING CHARGE FOR CNG AND LNG STATION CUSTOMERS*

11.3.1 Introduction

The OH&M charge is intended to recover an appropriate portion of overhead and marketing expenses directly from CNG and LNG station customers. The methodology and amount of the OH&M charge was set by the Commission in Order G-78-13, dated May 14, 2013. Order G-78-13 set the OH&M charge at $0.52/GJ. On June 18, 2015, the Commission issued Order G-105-15, which, among other things, directed FEI to:

> Recalculate the Overhead and Marketing (OH&M) Charge, using the most recent cost and volume forecast, and the same methodology as Order G-78-13, to determine if the $0.52/GJ OH&M Charge continues to be appropriate.

On August 21, 2015, FEI submitted its Order G-105-15 compliance filing, recalculating the OH&M charge based on the methodology of Order G-78-13, using total NGT forecast volumes. At that time, the results of the recalculation supported maintaining the OH&M charge at $0.52/GJ. FEI also indicated in its compliance filing that a further review of the OH&M charge would be appropriate as part of the Rate Design Application, since the direct allocation of overhead and marketing dollars would be considered at that time and may affect the OH&M charge applicable to CNG and LNG fueling station services.

11.3.2 OH&M Charge Updated Calculation

FEI is not proposing any changes to how overhead and marketing dollars are currently directly allocated. As a result, there is no change to the methodology for the inputs to the OH&M charge calculation. Table 11-6 below provides an updated calculation of the OH&M charge using the forecast of 2016 and 2017 costs and NGT volumes based on the methodology of Order G-7-13.

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.

FortisBC Energy Inc.
2016 Rate Design Application

Section 12:

SUMMARY AND CONCLUSIONS

Table of Contents

Order G-4-18 Updates, February 6, 2018

12. SUMMARY AND CONCLUSIONS

FEI's rate design proposals described in Sections 7 to 11 of the Application have an impact on the COSA results presented in Section 6 and result in a $786.4 thousand revenue deficit. FEI proposes to shift this revenue deficit to RS 1, which is the only rate schedule with an R:C ratio of less than 100%. After taking into account this revenue change, FEI's Final COSA results for each rate schedule are within the range of reasonableness except for RS 22A and RS 6/RS 6P. FEI is not proposing to rebalance RS 22A as this is a closed rate schedule. FEI is proposing to rebalance RS 6/RS 6P (for natural gas refuelling stations) to be within the range of reasonableness. With this rebalancing, FEI believes that its rate design proposals will result in a reasonable balance of rate design principles, are just and reasonable and should be approved as proposed.

This section is organized as follows:

- Section 12.1 summarizes the impact of FEI's proposed rate design changes on the COSA and FEI's proposal to shift the resulting revenue deficit to RS 1.
- Section 12.2 presents FEI's Final COSA results after taking into account revenue changes due it rate design proposals, and sets out FEI's proposal to rebalance RS 6 and RS 6P to be within the range of reasonableness.
- Section 12.3 shows FEI's Final COSA results after rebalancing.
- Section 12.4 provides a summary of FEI's proposed changes to rates, comparing the estimated 2018 rates resulting from the COSA before and after the proposed changes.
- Section 12.5 concludes the Application.

12.1 *COSA ADJUSTMENTS FROM RATE DESIGN PROPOSALS*

FEI presented its COSA results prior to any rate design changes in Section 6 of the Application. As noted in Section 6, the COSA results will be impacted by any proposed rate design changes and therefore need to be recalculated to take those impacts into account. In the sections below, FEI summarizes the rate design proposals discussed in Sections 7, 8, 9, 10 and 11 and the resulting adjustments to the COSA.

12.1.1 Residential Rate Design Proposal Summary and COSA Adjustment

FEI proposes to make following changes to RS 1:

1. Increase the Basic Charge per Day by $0.0195 from $0.3890 to $0.4085 to increase the proportion of fixed costs recovered by the Basic Charge, as discussed in Section 7.8 of the Application.
2. Decrease the Delivery Charge per GJ by $0.086 to maintain revenue neutrality, as discussed in Section 7.8 of the Application.

FEI's proposal for adjusting the basic and delivery charges as described in the above points for these rate schedules is revenue neutral and does not result in any adjustments required for the COSA.

12.1.2 Commercial Rate Design Proposals Summary and COSA Adjustment

FEI proposes to adjust the Basic Charges and Delivery Charges of the commercial rate schedules to align with the 2,000 GJ threshold between small and large commercial customers, as discussed in Section 8.7 of the Application, as follows:

1. For RS 2:
   - Increase the Basic Charge per Day by $0.1324 from $0.8161 to $0.9485.
   - Decrease the Delivery Charge per GJ by $0.186.
2. For RS 3 and RS 23:
   - Increase the Basic Charge per Day by $0.4357 from $4.3538 to $4.7895
   - Increase the Delivery Charge per GJ by $0.001

FEI's proposal for adjusting the Basic Charges and Delivery Charges for RS 2 and RS 3/RS 23 to re-establish the economic cross-over point between RS 2 and RS 3 to 2,000 GJ/year is revenue neutral within the commercial rate schedules, but results in a revenue shift from RS 2 to RS 3/RS 23. The revenue shift is approximately $1.2 million. When included in the COSA, this decreases the R:C ratio for RS 2 by 0.5 % and increases the R:C ratio for RS 3/RS 23 by 0.6 %. This impact is reflected in the Final COSA results in Section 12.2 below.

12.1.3 Industrial Rate Design Proposals Summary and COSA Adjustment

The proposed changes to the industrial rate schedules are summarized as follows:

1. For RS 5 and RS 25:
   - Revise the multiplier from 1.25 to 1.10 in the Daily Demand formula and increase the Demand Charge by $3.00/Month/GJ, as discussed in Section 9.5 of the Application.
2. For Rate Schedules 22, 22A, 22B, 23, 25, 26, and 27:
   - Adjustment the transportation model, as discussed in Section 10 of the Application, as follows:
     i. Implement daily balancing for all transportation customers.
     ii. Reduce the daily balancing tolerance to a 10% threshold and introduce a balancing charge of $0.25/GJ for transportation customers for gas supply shortfalls within a 10% to 20% tolerance level.
3. For RS 7 and RS 27:

- Decrease the Delivery Charge by $0.012/GJ as discussed in Section 9.6 and shown in Table 9-20 of the Application.

4. For RS 4:

- Change rates due to the proposed changes to RS 5 and RS 7 as shown in Table 9-21 of the Application by increasing the off-peak delivery rate by $0.114/GJ and by decreasing the extension period by $0.018/GJ.

5. For RS 6:

- Decrease the Delivery Charge per GJ by $1.318/GJ as a result of the rebalancing of rates discussed in Section 12.2.2 below.

6. For RS 6P:

- Set the Delivery Charge per GJ to equal the Delivery Charge per GJ of RS 6 as discussed below in Section 12.2.2.

7. For RS 22:

- Set the RS 22 charges on a cost of service basis as discussed in Section 9.8.5 of the Application, as follows:
    i. Firm Demand Charge of $25.000/Month/GJ.
    ii. Firm MTQ Delivery Charge of $0.150/GJ.
    iii. Interruptible MTQ Delivery Charge of $0.972/GJ.

FEI's proposal for RS 5 and RS 25 is to decrease the multiplier in the peak Daily Demand formula to 110% from 125% and to increase the Demand Charge by $3.00/Month/GJ. These two changes are offsetting, resulting in only a small increase in revenue from RS 5/25 collectively. The net increase in revenue is $45.2 thousand, which does not change the R:C ratio for RS 5/25.

FEI's proposal for an increase in the Demand Charge for RS 5 and RS 25 has an effect on the calculation of the RS 7/RS 27 charges, as discussed in Section 9.6. The adjusted rate for RS 7/RS 27 results in approximately $90.7 thousand less from this customer group. The $90.7 thousand is shifted to RS 1. The net decrease in revenue of $90.7 thousand decreases the R:C ratio for RS 7/RS 27 by 0.3%. This impact is reflected in the final COSA results in Section 12.2 below.

FEI's proposal for RS 22 results in a $754 thousand decrease in revenue from RS 22 customers. As a group, the R:C ratio for RS 22 customers is 103.5% before any adjustments. As the RS 22 firm offering is a new service offering, FEI is proposing to set the new offering at a 100% R:C ratio, in the middle of the 95% to 105% range of reasonableness. When comparing the firm revenues for the current RS 22 customers and VIGJV using the rates derived in Section 9.8 to the revenues embedded in the test year, FEI will collect $473 thousand less revenue. In addition, BC Hydro IG has contract rates in place until 2022 that are marginally lower than they

Order G-4-18 Updates, February 6, 2018

would pay under the new RS 22 service. This results in an additional $281 thousand reduction in revenue. In total, after setting rates for this new service offering at allocated costs, FEI will collect $754 thousand less revenue from these customers. As indicated in Section 12.2 below, FEI proposes to collect this revenue from RS 1 customers, which represents an approximate annual bill impact of 0.1% for RS 1 customers. This impact is reflected in the final COSA results in Section 12.2 below.

12.1.4 Summary of Revenue Changes due to Rate Design Proposals

The adjustments discussed above result in a total revenue reduction of $786.4 thousand as outlined in Table 12-1 below.

Table 12-1: Revenue Changes from Rate Design Proposals

Rate Schedule	Revenue Change ($000s)
2	-$1,174.1
3 / 23	+$1,174.1
4	+$13.3
5 / 25	+$45.2
7 / 27	-$90.7
22	-$754.2
Total	**-$786.4**

As RS 1 is the only rate schedule with an R:C ratio of less than 100%, FEI proposes to shift the $786.4 thousand deficit to RS 1. The shift represents an approximate annual bill impact of 0.1% for RS 1 customers and results in an increase to the Delivery Charge per GJ by $0.011.

FEI's final COSA results reflecting the above revenue shifts are shown below.

12.2 *FINAL COSA RESULTS AND REBALANCING*

12.2.1 Final COSA Results

FEI recalculated the COSA to reflect the revenue shifts from the proposed rate design changes discussed above to arrive at the COSA model results after rate design proposals. The initial COSA results, revenue shifts from rate design proposals, approximate bill impacts and COSA results after revenue shifts are shown in Table 12-2 below.

Table 12-2: COSA R:C and M:C Results after Rate Design Proposals

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 Schedule 1 *Residential Service*	95.6%	93.1%	786.4	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%			131.7%	160.4%
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)*	Initial COSA		Revenue Shift ($000)	Approximate Annual Bill Change	COSA after Rate Design Proposals	
	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%

FEI notes that FEI's proposed firm rate for RS 22 changes the R:C ratios of the other rate schedules. As described in Section 6.3.1.5, the initial COSA results treat BC Hydro IG and VIGJV as credits to the cost of service. By treating these two customers as credits to the cost of service, no costs are allocated to them in the initial COSA. Conversely, the COSA results after Rate Design proposals included in Table 12-2 above do not treat BCH IG and VIGJV as credits to the cost of service. Instead, these customers are grouped together with RS 22 customers as discussed in Section 9.8.5.2 and are allocated costs based on their firm demand. The difference in the allocation of costs between the Initial COSA results and the above COSA results after rate design proposals changes the R:C ratio of rate schedules because the same revenue is divided by different allocated costs.

As shown in Table 12-2, all rate schedules are within the range of reasonableness of 95% to 105%, except for RS 5/RS25, RS 22A, and RS 6/RS 6P.

FEI is not proposing to rebalance RS 22A this is a closed rate schedule. RS 22A and RS 22B are not allocated costs in a postage stamp manner in the COSA as they are not allocated a portion of FEI's distribution system costs. FEI has continued to allocate costs in this manner to be consistent with past practice and the rate schedules' grandfathered status. Rebalancing the charges under RS 22A would be inconsistent with continuing to grandfather the terms and conditions of service under this rate schedule. Since RS 22 is available for all large industrial customers, grandfathered RS 22A (and RS 22B) customers may elect this rate schedule as an alternative. FEI's proposed rebalancing for RS 5/25 and RS 6/RS 6P is discussed below.

12.2.2 Rebalancing of RS 5/25 to be within the Range of Reasonableness

After Rate Design proposals, the R:C ratio for RS 5/25 is 106.3%, which is outside the range of reasonableness established by Order G-4-18. To rebalance within the range of reasonableness, FEI proposes for the following reasons to decrease RS 5/25 revenues by reducing the basic charge:

- By decreasing the basic charge for RS 5/25, FEI's proposals for RS 7, RS 27 and RS 4 remain unchanged and there will be no additional revenue shift from RS 7, RS 27 and RS 4 to RS 1.
- Changing only the basic charge, and not the demand or delivery charge, supports rates that continue to attract customers with at least a 40% Load Factor. With the proposed rates, including rebalancing, a customer in RS 5/25 consuming 15,000 GJ would need to have a load factor of approximately 40% to be better off (when compared to RS 3 and RS 23), which is the intent of the General Firm Service offering.

FEI is therefore proposing to decrease the RS 5/25 Basic Charge by $118 per month to $469 per month.

Decreasing the basic charge by $118 per month creates a revenue responsibility decrease of $1.093 million for RS 5/25. Recognizing that RS 1 is within the approved range of reasonableness, but at the lower bound, FEI proposes to shift this revenue responsibility to RS 1, which results in an annual average bill impact for all RS 1 of approximately 0.15%.

12.2.3 Rebalancing of RS 6/RS 6P to be within the Range of Reasonableness

Based on FEI's Final COSA model results above, RS 6/RS 6P has an R:C ratio of 131.7%. There are 15 customers who take service under RS 6. These customers operate public CNG refueling stations. RS 6P is for public natural gas vehicle refueling at FEI's Surrey Operation Centre.

To set the R:C ratio for RS 6/RS 6P within the range of reasonableness, FEI is proposing a reduction of $75.9 thousand in the revenue required from RS 6/RS 6P by decreasing the Delivery Charge by $1.622/GJ. FEI is proposing to reduce the revenue to bring the R:C ratio in alignment with the upper end of the range of reasonableness and decrease the Delivery Charge to match the reduction in revenue.

The decrease to the Delivery Charge supports the government's policy goal of reducing GHG emissions by making natural gas more affordable as a vehicle fuel substituting for gasoline or diesel for those members of the public and fleets that are using the RS 6/RS 6P stations. After the proposed adjustment, RS 6/RS 6P will have an R:C ratio of 105% and RS 6 customers will experience approximately a 20% decrease in their annual bills from this adjustment. As RS 6P is for public natural gas vehicle fueling stations, it is not possible for FEI to calculate an annual bill impact for customers using RS 6P because the volume by customer using the public fueling station is not tracked. As RS 1 is the only rate schedule with an R:C ratio of less than 100%, FEI proposes to shift the $75.9 thousand deficit to RS 1. The shift represents an approximate annual bill impact of 0.01% (rounding to 0.0%) for RS 1 customers.

RS 6P for CNG fueling services to customers at FEI's Surrey Operations Centre was approved by Order G-165-11A. The Delivery Charge for RS 6P was set equal to the Delivery Charge of RS 6 and was intended to remain equal to the RS 6 Delivery Charge over time. Since the approval of RS 6P, however, the Delivery Charge for RS 6P and RS 6 are no longer equal with the RS 6P Delivery Charge being $0.022/GJ less than that of RS 6. As a housekeeping amendment, FEI proposes to set the Delivery Charge for RS 6P equal to the Delivery Charge of RS 6 after all other rate design proposals and rebalancing are effected. This proposal is included in the rebalancing results for RS 6 below.

12.3 *FINAL COSA RESULTS AFTER REBALANCING*

Table 12-4 below shows FEI's final COSA results before and after rebalancing, along with the proposed rebalancing amounts. As seen in Table 12-3, with the exception of RS 22A, the R:C ratios for all rate schedules are within the range of reasonableness after rebalancing.

Table 12-3: R:C and M:C Results after Rate Design Proposals and 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 Schedule 1 *Residential Service*	96.4%	94.6%	1,214.4	0.2%	96.6%	94.6%
Rate Schedule 2 *Small Commercial Service*	102.2%	104.1%			102.2%	104.1%
Rate Schedule 3/23 *Large Commercial Sales and Transportation Service*	103.6%	107.6%			103.6%	107.6%
Rate Schedule 5/25 *General Firm Sales and Transportation Service*	106.3%	112.6%	(1,138.5)	-1.2%	105.0%	112.6%
Rate Schedule 6/6P *Natural Gas Vehicle Service*	131.7%	160.4%	(75.9)	-20.3%	105.0%	109.5%
Rate Schedule 22A *Transportation Service (Closed) Inland Service Area*	113.0%	113.4%			113.0%	113.4%
Rate Schedule 22B *Transportation Service (Closed) Columbia Service Area*	103.1%	103.1%			103.1%	103.1%
Rate Schedule 22 *Large Volume Transportation Service*	100.0%	100.0%			100.0%	100.0%

Rate Schedule *(rates not set using allocated costs)*	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 Schedule 4 *Seasonal Firm Gas Service*	150.2%	578.3%			150.2%	578.3%
Rate Schedule 7/27 *General Interruptible Sales and Transportation Service*	139.3%	713.6%			139.3%	713.6%

FEI notes that RS 22 was excluded from the COSA results in Table 6-11 because customers in RS 22 were predominantly interruptible. However, as discussed in Section 9.8, FEI is proposing a new firm service rate under RS 22. As such, FEI includes the R:C and M:C ratios for RS 22 in Table 12-3 above. FEI further notes that the COSA results from Section 6 include interruptible revenues for RS 22, while the Final COSA results are based only on allocated costs and firm revenue. In the Final COSA, RS 22 Interruptible revenue is treated as a credit to the cost of service and allocated to all non-bypass rate schedules (except RS 22) based on margin.

Detailed Final COSA schedules are included as Appendix 12.

12.4 *COMPARISON OF FEI'S CURRENT RATES AND PROPOSED RATES*

Table 12-4 below summarizes FEI's proposed rate changes, by showing the estimated COSA-based 2018 rates, the proposed rate changes and the estimated 2018 rates after the proposed changes. It is important to note that the proposed rate changes will be made to 2018 approved rates, not the estimated COSA-based rates. Therefore, the estimated 2018 rates below will not be the rates that are actually approved for 2018.

Table 12-4: FEI Rate Proposal Summary

Rate Schedule	Estimated COSA-Based 2018 Rates[191]	Proposed Rate Changes	Estimated 2018 Rates After Proposed Changes
RS 1 – Residential			
Basic Charge (daily)	$0.3890	$0.0195	$0.4085
Delivery Charge ($/GJ)	$4.821	($0.059)	$4.762
RS 2 – Small Commercial			
Basic Charge (daily)	$0.8161	$0.1324	$0.9485
Delivery Charge ($/GJ)	3.850	($0.186)	3.664
RS 3/RS 23 – Large Commercial			
Basic Charge (daily)	$4.3538	$0.4357	$4.7895
Delivery Charge ($/GJ)	$3.189	$0.001	$3.190
RS 4			
Basic Charge (Monthly)	$439	Nil	$439
Delivery Charge ($/GJ) Off Peak	$1.278	$0.114	$1.392
Delivery Charge ($/GJ) Extended Period	$2.183	($0.018)	$2.165
RS 5/RS 25			
Basic Charge (Monthly)	$587.00	($118.00)	$469.00
Delivery Charge ($/GJ)	$0.887	Nil	$0.887
Demand Charge ($/Month/GJ)	$21.596	$3.00	$24.596
RS 6/RS 26			
Basic Charge (Monthly)	$61	Nil	$61
Delivery Charge ($/GJ)	$4.873	($1.622)	$3.251
RS 7/RS 27			
Basic Charge (Monthly)	$880.00	Nil	$880.00

[191] The COSA rates shown are 2016 approved rates plus known and measureable changes discussed above in Section 6.

Rate Schedule	Estimated COSA-Based 2018 Rates[191]	Proposed Rate Changes	Estimated 2018 Rates After Proposed Changes
Delivery Charge ($/GJ)	$1.455	($0.012)	$1.443
RS 22			
Basic Charge (Monthly)	$3,664.00	Nil	$3.664.00
Firm Demand Charge ($/Month/GJ)	n/a		$25.000
Firm MTQ ($/GJ)	n/a		$0.150
Interruptible MTQ ($/GJ)	$1.060	($0.088)	$0.972

12.5 *CONCLUSION*

Based on the analysis and considerations set out in the Application, FEI believes that its rate design proposals will result in a reasonable balance of rate design principles, are just and reasonable and should be approved as proposed.

FortisBC Energy Inc.
2016 Rate Design Application

Section 13:

RATE DESIGN FOR FORT NELSON

Table of Contents

Order G-4-18 Updates, February 6, 2018

Index of Tables and Figures

Order G-4-18 Updates, February 6, 2018

Order G-4-18 Updates, February 6, 2018

13. RATE DESIGN FOR THE FORT NELSON SERVICE AREA

In this section, FEI discusses the rate design for the Fort Nelson Service Area (Fort Nelson). The rates for Fort Nelson are established separately from the rates for FEI's other service areas.

Fort Nelson's rate design proposals are set out below under approvals sought and discussed in additional detail in the following subsections. Based on the analysis and rate design considerations set out in the Application, FEI believes that its rate design proposals for Fort Nelson are just and reasonable, and should be approved as proposed.

This section is organized as follows:

- Section 13.1 sets out the approvals sought by FEI for Fort Nelson;
- Section 13.2 provides a brief overview of Fort Nelson customers, gas supply background and the regulatory history of Fort Nelson rates and rate setting methodologies since 1992;
- Section 13.3 summarizes the stakeholder engagement process for Fort Nelson, including the residential customer survey, undertaken to gather stakeholder and customer feedback, comments and questions, that assisted in compiling a key issues list and were taken into account in the Fort Nelson rate design proposals;
- Section 13.4 describes the cost of service allocation methodology and study for Fort Nelson;
- Section 13.5 presents the proposed changes to the existing rate design for residential, commercial and industrial customers rates;
- Section 13.6 summarizes the changes to the Fort Nelson Gas Tariff; and
- Section 13.7 summarizes the rate design proposals, including rebalancing of rates and associated bill impacts, postage stamp rate analysis and concludes the section.

13.1 *APPROVALS SOUGHT*

Pursuant to section 58 to 61 of the UCA, FEI seeks the Commission's approval of the following for Fort Nelson, to be effective in the fourth quarter (Q4) of 2018:

Cancellation of Rates

1. Approval to cancel the following Fort Nelson Rates, each of which has no customers:
    - Rate 1 Option A - Domestic Service for Primary space heating equipment purchased from FEI Fort Nelson
    - Rate 2.4 - Compression/Dispensing Service

- Rate 3.2 – Industrial Service
- Rate 3.3 – Industrial Service

Renaming of Rates

2. Approval to rename Fort Nelson's existing Rates to the following to align with FEI's Rate Schedule naming convention:
    - Rate 1 Option B Domestic Service to Rate Schedule 1 Residential Service
    - Rate 2.1 General Service to Rate Schedule 2 Small Commercial Service
    - Rate 2.2 General Service to Rate Schedule 3 Large Commercial Service
    - Rate 2.3 Natural Gas Vehicle Fuel Service to Rate Schedule 6 Natural Gas Vehicle Service
    - Rate 3.1 Industrial Service to Rate Schedule 5 General Firm Service
    - Rate Schedule 25 General Firm Transportation to Rate Schedule 25 General Firm Transportation Service

Unbundling of Rates

3. Approval to unbundle Fort Nelson's residential and commercial rates to provide transparency into the different components of customer bills and provide Fort Nelson customers the option to access services that require unbundled rates as discussed in section 13.5.2 below.

Billing System Changes Cost

4. Approval for a deferral account to record the cost of changes to the billing system for Fort Nelson that will be required to unbundle Fort Nelson's rates. The costs will be recorded in the account on a net-of-tax basis (in keeping with normal practice) and amortized over 5 years beginning in 2019. The one-time pre-tax cost is expected to be approximately $70 thousand.

Commodity Cost Recovery Charge and Storage and Transport Charge

5. Approval of the following for Rate Schedules 1, 2, 3, 5, 6 (until these changes are approved these have been Rates 1, 2.1, 2.2, 3.1, and 2.3):
    - To set a Commodity Cost Recovery Charge based on classifying commodity costs as energy-related and allocating those costs to all sales customers based on throughput, as discussed in section 13.4.2.

- To set a Storage and Transport Charge based on classifying midstream costs as demand-related and allocating those costs to all sales customers based on their load factor adjusted volume, as discussed in section 13.4.2.

Residential Rates

6. Approval of the following for Rate Schedule 1 (formerly Rate 1):

- To set the Basic Charge per Day at $0.3701 and the Delivery Charge at $3.512 per GJ as a result of (i) unbundling the rate structure in a way that minimizes the bill increase for any individual customer as discussed in sections 13.5.4 and 13.7, and (ii) rebalancing as discussed in section 13.7.1.4.

Commercial Rates

7. Approval to change the annual volume threshold between small and large commercial customers from 6,000 GJ to 2,000 GJ and to set the Basic, Delivery, Commodity, and Storage and Transport Charges for commercial customers to align with the 2,000 GJ threshold for FEI customers as discussed in sections 13.5.5 and 13.7, as follows:

- For Rate Schedule 2 (formerly Rate 2.1 – customers whose normal annual consumption is less than 2,000 GJ):
  - To set the Basic Charge per Day at $1.2151 and Delivery Charge at $3.781 per GJ as a result of (i) unbundling the rate structure as discussed in sections 13.5.5 and 13.7, and (ii) rebalancing as discussed in section 13.7.1.4.
- For Rate Schedule 3 (formerly Rate 2.2, and Rate 2.1 customers whose normal annual consumption is greater than 2,000 GJ):
  - To set the Basic Charge per Day at $3.6845 and Delivery Charge at $3.330 per GJ as a result of (i) unbundling the rate structure as discussed in sections 13.5.5 and 13.7, and (ii) rebalancing as discussed in section 13.7.1.4.
- For Rate Schedule 6 (formerly Rate 2.3):
  - To set the Basic Charge per Day and Delivery Charge equal to FEI's approved January 1, 2018 RS 6 rates, as a result of unbundling the rate structure.

Industrial Rates

8. Approval of the following for Rate Schedule 5 (formerly Rate 3.1):

- To set the Daily Demand equal to 1.10 multiplied by the greater of:
  1. The customer's highest average daily consumption of any month during the winter period (November 1 to March 31); or

ii. One half of the Customer's highest average daily consumption of any month during the summer period (April 1 to October 31).

The calculation of Daily Demand will be based on the Customer's actual gas use during the preceding Contract Year.

- To set the Basic Charge at $600.00 per Month, the Demand Charge per Month per GJ of Daily Demand at $30.350, the Delivery Charge per GJ at $1.000.
- To phase-out the Rate Revenue Stabilization Adjustment Mechanism Charge (Rate Rider 5) over two years as discussed in Section 13.5.6.

9. Approval of the following for Rate Schedule 25:

- To set the Daily Demand equal to 1.10 multiplied by the greater of:
  i. The customer's highest average daily consumption of any month during the winter period (November 1 to March 31); or
  ii. One half of the Customer's highest average daily consumption of any month during the summer period (April 1 to October 31).

  The calculation of Daily Demand will be based on the Customer's actual gas use during the preceding Contract Year.
- Amendments to implement daily balancing, as discussed in Section 10.6 of the Application.
- Amendments to reduce the daily balancing tolerance to a 10% threshold and to introduce a balancing charge of $0.25/GJ for gas supply shortfalls within a 10% to 20% tolerance level, as discussed in Section 10.7 of the Application.
- To set the Basic Charge at $600.00 per Month, the Demand Charge per Month per GJ of Daily Demand at $30.350, the Delivery Charge per GJ at $1.000, and the Administrative Charge per Month at $39.00.
- To phase-out the Rate Revenue Stabilization Adjustment Mechanism Charge (Rate Rider 5) over two years as discussed in Section 13.5.6.

The Fort Nelson Gas Tariff

10. Approval of the housekeeping and other amendments to the Fort Nelson Gas Tariff as set out in Appendix 13-6. The proposed amendments to the Fort Nelson Gas Tariff include the following:

- Approval of the amendments to the terms and conditions for Rate Schedules 1, 2, 3, 5, 6 (until these changes are approved these have been Rates 1, 2.1, 2.2, 3.1, and 2.3) and Rate Schedule 25.

Order G-4-18 Updates, February 6, 2018

An updated draft order setting out the approvals sought in the Application is attached as Appendix 1-2.

13.2 OVERVIEW OF FORT NELSON AND REGULATORY HISTORY

13.2.1 Overview

FEI currently serves approximately 2,500 customers in Fort Nelson who consume approximately 0.6 PJ of natural gas annually. This represents a small portion of FEI's overall customer base; approximately 0.2% of the total number of customers and approximately 0.3% of the total demand.

Fort Nelson has two types of customer groups – sales customers and transportation customers. For Fort Nelson sales customers FEI purchases all the gas and upstream resources required for delivery of the gas to the customer. Transportation customers procure their own gas to be delivered to FEI's interconnecting point in Fort Nelson and therefore do not pay a Gas Cost Recovery Charge to FEI.

13.2.1.1 Fort Nelson Rates

The table below outlines the current and proposed Fort Nelson classification of rates, as outlined in the Fort Nelson Gas Tariff, (the Fort Nelson Tariff).

Table 13-1: Description of the Current and Proposed Fort Nelson Classification of Rates

Current Classification of Rates		Proposed Classification of Rates	
Rate	**Rate Title and Description**	**Rate Schedule**	**Rate Schedule Title and Description**

1 Option A	• Domestic Service
	  ○ Primary space heating equipment purchased from FEI Fort Nelson
	  ○ Closed in 1990
		Not Applicable	• Not Applicable
			  ○ Propose to cancel

1 Option B	• Domestic Service ○ Primary space heating equipment not purchased from FEI Fort Nelson	**1**	• Residential Service
2.1	• General Service	**2**	• Small Commercial Service
2.2	• General Service	**3**	• Large Commercial Service
2.3	• Natural Gas Vehicle Service	**6**	• Natural Gas Vehicle Service
2.4	• Compression/Dispensing Service	**Not Applicable**	• Not Applicable ○ Propose to cancel
3.1	• Industrial Service	**5**	• General Firm Service

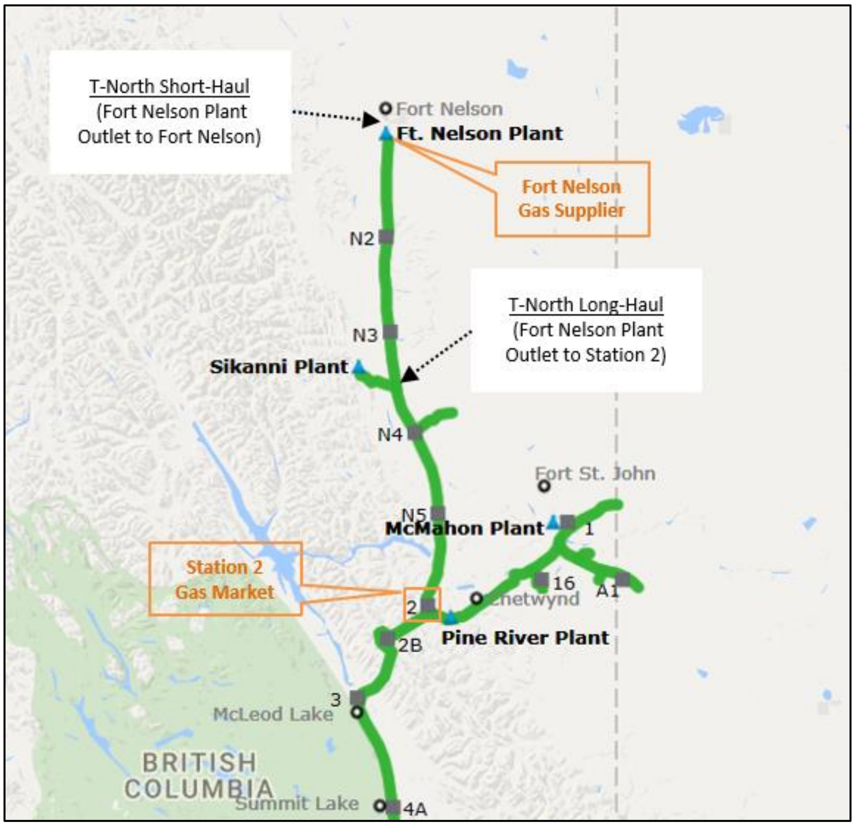
Current Classification of Rates		Proposed Classification of Rates	
Rate	**Rate Title and Description**	**Rate Schedule**	**Rate Schedule Title and Description**
3.2	• Industrial Service	**Not Applicable**	• Not Applicable ○ Propose to cancel
3.3	• Industrial Service	**Not Applicable**	• Not Applicable ○ Propose to cancel
RS 25	• General Firm Transportation	**25**	• General Firm Transportation Service

13.2.1.2 Fort Nelson Gas Supply

To serve Fort Nelson, FEI sources gas from the Fort Nelson gas plant. FEI's supply agreement allows FEI to transact or nominate a volume, depending on customer demand, of up to the equivalent of 5 TJ per day at the outlet of the Fort Nelson gas plant. At this particular transfer point, there is no industry standard or published index to establish the price for this gas. Thus, FEI agreed with the supplier to price the transaction based on the closest market hub with a published index, which is Station 2. The map below shows the locations of the demand, supply and Spectra Energy's T-North Short-Haul Firm Transportation Service (T-North Short-Haul[192]) that is required to flow gas from the Fort Nelson gas plant outlet to Fort Nelson.

[192] Spectra Energy's T-North Short-Haul Firm Transportation Service allows for the movement of gas north from a receipt point at the Fort Nelson gas plant outlet to the interconnect with FEI's gas distribution system in Fort Nelson.

Figure 13-1: Fort Nelson Gas Supply



A unique feature of FEI's current supply agreement for Fort Nelson is that the supplier allows FEI to change the nomination on a daily basis to better match the demand profile of Fort Nelson customers. Consequently, for Fort Nelson, the gas is not purchased at a 100% load factor. This ability to change the gas nomination daily has value to Fort Nelson customers because FEI would otherwise need to hold firm capacity on Spectra Energy's T-North Long-Haul pipeline as a Firm Transportation Service (T-North Long-Haul[193]) to move the gas to Station 2, even when the gas was not needed for Fort Nelson. Any T-North Long-Haul capacity would have a fixed demand charge associated with it for 365 days of the year.

Fort Nelson's gas supply portfolio also includes a pricing arrangement whereby the commodity price for a portion of Fort Nelson's winter gas supply is determined based on the cost of gas FEI injects into the Aitken Creek storage facility during the preceding summer. The Aitken Creek storage arrangement captures the summer winter price differential at the Station 2 market which helps to stabilize gas costs for Fort Nelson customers.

The Fort Nelson midstream cost consists of the costs of T-North Short-Haul on Spectra Energy's system. FEI contracts firm Transportation T-North Short-Haul pipeline capacity with Spectra Energy from the Fort Nelson gas plant outlet to Fort Nelson. As summarized above, T-

[193] Spectra Energy's T-North Long-Haul Firm Transportation Service allows for the movement of gas south from a receipt point at the Fort Nelson gas plant outlet to a delivery point at Station 2.

North Long-Haul pipeline capacity is not required for Fort Nelson customers since the current supply agreement allows FEI to change the nomination on a daily basis.

13.2.2 Regulatory History of Fort Nelson

Although not a separate legal entity, Fort Nelson has its own rate base and revenue requirements for the purposes of determining rates.

Fort Nelson was purchased by FEI's predecessor company in 1985. Since that time, FEI has not undertaken a full rate design for Fort Nelson[194], although there have been two proceedings related to the potential for postage stamp rates for the service area.

In its 1992 Revenue Requirements Application, FEI (formerly BC Gas Utility Ltd.) sought consolidation of its Lower Mainland, Inland, Columbia and Fort Nelson divisions. There were no customer objections to the matter of consolidation for the Inland and Columbia Service Areas; however, objections were received from Fort Nelson. The objections were based on Fort Nelson's concern about the lack of consultation regarding the consolidation proposal, as well as the Fort Nelson residents' belief that the local utility was able to operate as an independent entity with rates being established on a separate basis from the rest of FEI's service areas.

Although the Commission recognized the benefits of the consolidation proposal at that time, Order G-63-92 denied the consolidation proposal. In its decision, the Commission stated that "*while the saving is material, the canvassing of the full impact on all customers is more important.*"[195] The Commission deferred a decision on consolidation to the 1993 Phase B Rate Design hearing to allow time to determine the full rate impact of consolidation on all service areas. FEI (formerly BC Gas Utility Ltd.) did not pursue including Fort Nelson in the consolidation and postage stamping of rates in its 1993 Phase B Rate Design Application. Approval was received to consolidate the Lower Mainland, Columbia, and Inland divisions.

As discussed in section 3.3.10, in 2012, FEI and its affiliates filed an application with the BCUC to amalgamate FEVI, FEW and FEI into a single entity and implement postage stamp rates across the amalgamated entity including Fort Nelson. In its application, FEI stated that it had been operating with a common management structure since the mid-2000s and that it viewed amalgamation as the next logical step towards integration. In February 2013, the Commission denied FEI's application for common rates and declined to consider the issue of amalgamation.[196] Following this decision, the Reconsideration and Variance of Order G-26-13 was requested in April 2013. In the Reconsideration and Variance application, FEI requested a determination that the proposed amalgamation was in the public interest and that the proposed postage stamp rates for the amalgamated utility (excluding the service area of Fort Nelson) be approved. In February 2014, the Commission approved FEI's Reconsideration and Variance application with conditions. In its Decision, the Commission stated:

[194] FEI does not know when the last Rate Design proceeding was done for Fort Nelson prior to 2012.
[195] At the time, the savings were estimated at between $500 thousand and $600 thousand.
[196] Commission Order G-26-13, dated February 25, 2013.

> The Commission Panel agrees there would appear to be a logical inconsistency in maintaining regional rates for Fort Nelson. However, the Panel also notes that the Fort Nelson and District Chamber of Commerce, which intervened in both the Original Application and the Reconsideration Application, took no position on the Reconsideration Application as no reconsideration of rates as applicable to Fort Nelson was sought. The FEU may want to address this apparent inconsistency in its next rate design application.

In summary, although past proceedings explored the issue of common rates for Fort Nelson, Fort Nelson has remained separate from FEI's general revenue requirement applications and has its own revenue requirements filings and a separate tariff[197].

13.3 *STAKEHOLDER ENGAGEMENT*

As discussed in section 4 of the Application, FEI's stakeholder engagement process consisted of information sessions, stakeholder workshops and a separate residential customer survey for Fort Nelson. FEI's engagement process informed Fort Nelson customers and other stakeholders about its current rate design and the potential changes FEI was considering at that time for Fort Nelson.

On July 27, 2016, FEI held a workshop in Fort Nelson to provide stakeholders with an overview of the rate design for Fort Nelson and to seek feedback on a number of key discussion topics. The workshop was open to all natural gas customers of Fort Nelson to attend. As discussed in Section 4, on July 14, 2016 FEI circulated a Discussion Guide to all interested Fort Nelson stakeholders in advance of the workshop. A summary of the meeting notes including the action items and key issues was circulated to stakeholders for review and comment, about two weeks after the workshop. Stakeholders were invited to add additional comments or seek further clarification on the topics discussed during the workshop. The detailed meeting notes are attached under Appendix 4-2 and the Fort Nelson discussion guide is in Appendix 4-3.

13.3.1 Fort Nelson Workshop

During the Fort Nelson workshop, FEI sought stakeholder input on the key discussion topics for the Fort Nelson rate design. Table 13-2 below provides a list of action items and key discussion topics including FEI's response and a reference to where each item is addressed in the Application.

[197] As per the Fort Nelson Tariff, the applicable definitions and General Terms and Conditions are the FEI General Terms and Conditions and definitions contained therein.

Table 13-2: Action Items, Key Discussion Topics and FEI Response

Action Items	Action / Response	Reference
Physical flow and commercial transactions contributing to gas costs	FEI has provided a background on gas supply arrangement to understand the physical flow and commercial transactions contributing to the gas costs.	Section 13.2.1.2
Estimated costs to unbundle Fort Nelson bills	Costs are estimated at approximately $70 thousand to unbundle and restructure the rates for Fort Nelson	Section 13.5.2
Efficiencies gained from unbundling	Fort Nelson customers sum to approximately 0.2% of FEI's total customers. Unbundling Gas and Delivery Charges for Fort Nelson bills will simplify the discussion for FEI's Customer Service Representatives but will not result in a reduction of employees.	
Key Discussion Topics	**Action / Response**	**Reference**
Bundled or Unbundled Rates	FEI is proposing to unbundle the rates which will make rate changes more transparent.	Section 13.5.2
Gas Cost Allocation Methodology	FEI is proposing to allocate midstream costs based on a load factor volume adjusted basis and allocate commodity costs based on sales volumes.	Section 13.4.2
Customer Segmentation – Commercial Customers	FEI is proposing to change the customer segmentation threshold between small and large commercial customers from 6,000 GJ/year to 2,000 GJ/year.	Section 13.5.5
Revenue to Cost Ratio and Rebalancing	FEI is proposing to rebalance Rate 2.1, Rate 2.2 and RS 25 to bring their R:C ratios within the range of reasonableness. The revenue responsibility would be shifted to Rate 1 with an average bill impact of approximately +5.5% for Rate 1 customers, -2.2% for Rate 2.1 customers, -8.5% for Rate 2.2 customers and +4.9% for the RS 25 customer.	Section 13.7.1.4
Common Rates	FEI is not proposing the adoption of postage stamp rates for Fort Nelson at this time.	Section 13.7.3

FEI received feedback from stakeholders and customers regarding FEI's explanation of the context of Fort Nelson's rate design provided in the workshop. Specific feedback on the key discussion topics and issues mentioned above is included in the relevant sections below as set out in the table above.

13.3.2 Residential Customer Survey

As explained in Section 4.6, FEI retained the services of Sentis to conduct an online survey to measure residential customers' knowledge of Fort Nelson's existing rate structure and bill components and to better understand customers' preference regarding various rate design considerations. The detailed version of this study can be found in Appendix 4-5 to this Application. A brief summary of the survey results is presented below.

Knowledge of Current Rate Structure and Bill Components:

In general, the survey results indicate that the majority of Fort Nelson's residential customers have a relatively good understanding of their monthly bill components, with 74 percent of respondents indicating that they have a very clear or somewhat clear understanding of how their bill is calculated. However, Fort Nelson customers' understanding of monthly bill components is slightly lower than the level of bill comprehension in the rest of the province under FEI's rate structure. The table below provides a snapshot of customers' understanding regarding various components of their monthly bills.

Table 13-3: Fort Nelson Customer Understanding of Residential Bill Components

Level of Understanding	Basic Charge	Charge for Gas Used	Taxes and Levies
Very Well	30%	29%	31%
Somewhat	51%	52%	45%
Little	15%	17%	22%
Not at all	4%	2%	2%

Relative Importance of Rate Setting Considerations:

One of the objectives of conducting the survey was to analyse and understand residential customers' preferences for different rate options. As such, the customers were asked to rate the importance of various rate design considerations. As this was an online survey for a typical residential customer, the rate design principles were described in a simplified manner. The following is the simplified language used in the survey for major rate design considerations:

1. Ease of understanding: Natural gas rates should be easy for the average person to understand;
2. Rate stability and bill impact: Natural gas bills should be stable and not fluctuate very much from month to month;
3. Fairness (cost causation): Heavier natural gas users should not subsidize costs for those who use less; and
4. Efficiency and government policy: The rate structure should be designed to encourage users to use less natural gas and/or to avoid high usage during winter months.

Similar to FEI's survey results, Fort Nelson respondents were clear that, from their perspective, ease of understanding is the most important rate setting consideration. Other rate design considerations were rated to be less important than ease of understanding. Compared to FEI customers, Fort Nelson respondents gave similar weight to rate stability and fairness principles but less weight to economic efficiency and government policy principles. This may be due to the fact that Fort Nelson experiences longer and colder winters and has a higher average use per customer than FEI's other service areas.

Bundled vs. Unbundled Rates

A mentioned earlier, one of the rate design options considered in this Application is to unbundle Fort Nelson residential rates in a fashion similar to FEI's unbundled rate structure in order to provide more transparency to Fort Nelson customers of what comprises their natural gas bills. Fort Nelson respondents were asked if they prefer to maintain their existing bundled rates or to unbundle their rates similar to the residential rates in the rest of the province. The results indicate that respondents were twice as likely to prefer unbundled rates compared to their existing rates while a little more than a third of respondents had no specific preference.

Perception of Various Rate Structure Options:

The survey also asked respondents to score various rate options against the rate design considerations. As shown in Table 13-4 below, Fort Nelson customers correctly indicated that compared to other rate structures, the flat rate structure leads to better customer understanding, higher rate stability and a smaller bill impact. However, compared to FEI survey results, Fort Nelson respondents are more likely to express uncertainty (more "Don't know" responses) regarding which rate structure will result in the best outcomes. Furthermore, Fort Nelson respondents give a less favourable rating to inclining block rates, which may again be due to their higher use per customer.

Table 13-4: Percentage of Fort Nelson Respondents Ranking Each Rate Structure Option

	Flat Rate	Declining Block Rate	Inclining Block Rate	Don't Know
Easiest to understand	57%	18%	13%	13%
Promote most efficient use of natural gas network	32%	27%	18%	23%
Results in most stable monthly natural gas bills	42%	23%	17%	18%
Most effectively allocate costs to align revenue recoveries with cost causation	30%	24%	19%	27%

Overall, the survey results indicate that residential customers have a good knowledge of their current bill components, give a higher level of importance to rate structures that are simple to understand for a layperson, are more likely to prefer unbundled rates than bundled rates and have a preference for flat rates compared to other rate structures.

13.4 COST OF SERVICE ALLOCATION (COSA) METHODOLOGY

FEI follows the same cost allocation methods for Fort Nelson that it uses for the rest of its service areas. This methodology is described in detail in Section 6.2, but is restated briefly here.

8. **Functionalization** – In this step costs are functionalized into the business function that incurs these costs. For a greater explanation of this step, please refer to Section 6.2.1.1.

9. **Classification** – In this step costs are classified according to whether the costs are energy-related, demand-related or customer-related. For a greater explanation of this step please refer to Section 6.2.1.2.

iv. Not all functionalized groups classify neatly into one of the three cost classification factors. For Fort Nelson, FEI also uses a Minimum System Study (MSS)[198] and Peak Load Carrying Capability (PLCC)[199] adjustment to aid in the classification of distribution costs into both customer-related and demand-related components. For an explanation of the MSS and PLCC, please refer to Section 6.2.1.2.

10. **Allocation** – In this step all the classified costs are allocated to specific customer rate groups. For a greater explanation of this step, please refer to Section 6.2.1.3.

In addition to the foregoing COSA methodology steps for Fort Nelson, FEI also makes an adjustment for direct allocations. Direct allocations are used when a cost is known to be caused by certain customer group(s) or rate (classes). For Fort Nelson, the cost for the industrial customer meter stations has been directly assigned to RS 25 – General Firm Transportation.

13.4.1 Delivery Cost of Service Allocation

To allocate delivery costs to customers, FEI uses the three-step functionalization, classification and allocation process as described above. The allocation process is undertaken in a delivery margin COSA model. To prepare the COSA model, one adjustment to the 2018 Test Year costs was necessary. The adjustment is described in detail in Section 13.4.1.3. FEI first completed a COSA model which produces cost of service allocations before any rate design proposals, the results of which are presented in Section 13.7. Section 13.7 provides the result of Fort Nelson's final COSA after rebalancing and rate design proposals.

13.4.1.1 Test Year

FEI is using approved costs for 2018 from the Application for 2017 and 2018 Revenue Requirements and Rates for the Fort Nelson Service Area Application (the Fort Nelson 2017-2018 RRA)[200] for allocation within the Fort Nelson COSA Model.

The COSA Model uses Fort Nelson's 2018 approved costs, with the adjustment that is discussed in Section 13.4.1.3. Fort Nelson has an approved revenue requirement of $3.162 million for 2018. Fort Nelson's 2018 test year cost structure, including both rate base and cost of service, is summarized below in Table 13-5. Full details are provided in Appendix 13-2.

[198] Appendix 13-1.
[199] Ibid.
[200] Approved by Orders G-162-16 and G-173-16 dated November 9, 2016 and November 29, 2016 respectively.

Table 13-5: Summary of Fort Nelson's 2018 Test Year Cost Structure ($ thousands)

Rate Base Components (mid-year)	
Gross Plant in Service	$16,149.5
Accumulated Depreciation	(4,549.0)
Contribution in Aid of Construction	(1,326.0)
Accumulated Amortization	744.0
Unamortized Deferred Charges	126.0
Capital Work In Process	35.0
Working Capital	48.0
Total	**$11,227.5**

Revenue Requirement Components	
Cost of Gas	673.0
O&M Expense (net)	913.0
Depreciation and Amortization	514.0
Property Taxes	139.0
Deferred 2017 Revenue Deficiency	146.0
Other Revenue	(26.0)
Income Taxes	75.0
Earned Return	728.0
Total	**$ 3,162.0**

13.4.1.2 Operating and Maintenance Expenses and Rate Base

The Fort Nelson COSA Model uses the activity view of O&M and mid-year rate base from the Fort Nelson 2018 test year for cost allocation purposes. Rate base is predominantly comprised of the mid-year balance of net plant assets, net contribution in aid of construction, and unamortized deferrals.

The activity view of O&M from Fort Nelson's 2017 and 2018 Revenue Requirements and Rates Application includes detailed O&M for Distribution Operations and a single line item labelled Shared Services Agreement. The Shared Services Agreement line item is an allocation from those FEI departments that provide functional support to Fort Nelson. These shared services departments include Information Systems, Energy Supply and Resource Development, Transmission, Customer Service, Energy Solutions and External Relations, Engineering Services, Finance and Regulatory, Operations Support, Governance, Human Resources, Environment, Health and Safety and Corporate. To functionalize the Shared Services costs within the COSA Model, FEI has to split the Shared Services line item into its component parts. To split Fort Nelson's Shared Services costs, FEI used the same proration method that was used to break FEI's formulaic O&M into an activity view as described in Section 6.3.1.2, but did not include FEI's Distribution or LNG O&M components as Fort Nelson has direct distribution costs and does not have any LNG activity. The detailed split of the Shared Services cost can be found in Appendix 13-3.

13.4.1.3 Adjustment to Test Year Inputs

FEI has made one adjustment to the 2018 approved forecast for the number of customers and revenue as one of the RS 25 customers has moved from RS 25 to Rate 2.1. There was no volume forecast for this customer in the 2018 Teat Year so that the revenue shown below is only related to the fixed charges. The impact of this move is presented in the following table:

Table 13-6: Adjustment to 2018 Test Year from Movement of RS 25 Customer

	RS 25	Rate 2.1	Total
Revenue ($000)	-$24.3	+$0.5	-$23.8
Customers	-1	+1	0

Moving this RS 25 customer to Rate 2.1 in the COSA creates a revenue deficiency of $23.8 thousand for which an adjustment to the Test Year margin is required. To make up for the lost revenue, the margin for each rate in the COSA model is increased by approximately 1%. On average Fort Nelson customers will experience a 0.8% increase in their annual bills from this customer migration.

13.4.1.4 Customers, Annual Volume, Load Factor and Peak Day

The number of customers and annual volume by rate schedule from Fort Nelson's 2018 test year, as adjusted, are used to develop many of the allocators within the Fort Nelson COSA Model. Generally, the Fort Nelson delivery system has been designed and constructed to meet peak day (coldest day) demand of all its firm service customers. The customer load from the Fort Nelson test year is adjusted by the load factor of each rate category to estimate the peak day demand for each rate schedule. The peak day demand is used to allocate much of Fort Nelson's system costs that are classified as demand. Currently, there is one customer that is taking service in Fort Nelson under RS 25 and that customer has a load factor of 27%. This low load factor is a result of the customer scaling back on its operations and only using gas for space heating purposes. As in FEI, Fort Nelson's Rate Schedule 25 is intended to serve process load customers. Generally, process load customers have higher annual throughput and are less heat sensitive than large commercial customers. As described in Section 9.5.1, customers with load factors less than 40% are more heat sensitive than a typical process load and should be taking service under the large commercial rate. As per the Reasons for Decision, page 21, for Commission Order G-4-18, FEI updated the COSA model using the actual load factor of 27% for RS 25.

In addition to system costs in place to meet peak day demand, Fort Nelson has costs caused by connecting customers to the delivery system. The number of customers in each rate category is used to allocate the customer costs that are caused from a customer joining Fort Nelson's delivery system. The following table summarizes the values used in the Fort Nelson COSA Model for allocation purposes.

Table 13-7: Customers, Annual Volume, Load Factor and Peak Day by Rate

Rate	Customers	Annual Volume (TJ)	Load Factor	Peak Day Demand (TJ)
1	1,961	259.9	35.7%	2.0
2.1	480	203.7	33.4%	1.7
2.2	7	56.7	40.5%	0.4
RS 25	1	39.5	27.0%	0.4
Total	**2,449**	**559.8**		**4.5**

13.4.1.5 Delivery Cost Allocation Results

The following section summarizes the above COSA analysis into the three key steps of cost allocation: functionalization, classification and allocation. A full set of COSA schedules can be found in Appendix 13-4.

13.4.1.5.1 FUNCTIONALIZATION SUMMARY

The functional categories used for Fort Nelson for the Application are consistent with those used for FEI with the exception of the Storage function. As described in Sections 6.3.4.3 and 6.3.4.4, FEI has two LNG storage facilities; however, Fort Nelson does not have LNG or other storage facilities. Table 13-8 provides a summary of the delivery cost of service functionalization from the Fort Nelson COSA Model.

Table 13-8: Delivery Cost of Service Functionalization Summary

Function	($000s)	% of total
Gas Supply Operations	$8	0.3%
Transmission	$831	33.4%
Distribution	$1,491	59.9%
Marketing	$94	3.8%
Customer Accounting	$65	2.6%
Total	**$2,489**	**100.0%**

13.4.1.5.2 CLASSIFICATION SUMMARY

Table 13-9 summarizes the results of the delivery cost of service classification from the Fort Nelson COSA Model.

Order G-4-18 Updates, February 6, 2018

Table 13-9: Delivery Cost of Service Classification Summary

Classification	($000s)	%of total
Energy	$19	0.8%
Demand	$1,363	54.8%
Customer	$1,107	44.4%
Total	**$2,489**	**100.0%**

13.4.1.5.3 COST ALLOCATION SUMMARY

Table 13-10 summarizes the results of the delivery cost of service allocation to rates from the Fort Nelson COSA Model.

Table 13-10: Delivery Cost of Service Allocation to Rates Summary

Rate	($000s)	% of total
1	$1,233	49.5%
2.1	$902	36.3%
2.2	$191	7.7%
RS 25	$162	6.5%
Total	**$2,489**	**100.0%**

13.4.2 Gas Cost Allocation

For Fort Nelson sales customers, the gas cost is currently bundled with the delivery cost. This means that the Gas Cost Recovery Charge is not shown separately on Fort Nelson customers' bills. However, each sales customer (Rate 1, Rate 2.1 and Rate 2.2) has an allocation of FEI's cost of gas included in the charges shown on their bill, including the commodity cost and the midstream cost, which is named the Gas Cost Recovery Charge in the Fort Nelson Tariff. FEI does not allocate any storage or LNG costs to Fort Nelson in its midstream costs, but does include T-North Short-Haul capacity cost on the Spectra pipeline system as a midstream cost.

Customers on RS 25 are required to arrange their own gas supply to be delivered to Fort Nelson's interconnecting point through a shipper agent and so are not charged for either of the commodity or upstream pipeline transportation (midstream) costs.

Details regarding what gas supply resources are included in the commodity and midstream (storage and transport) costs for Fort Nelson are provided in section 13.2.1.2. Below, FEI describes the current and proposed gas cost allocation approach.

13.4.2.1 Current Gas Cost Allocation Methodology

Fort Nelson's current gas cost allocation methodology allocates gas costs (both commodity and midstream) to sales customers using forecast annual consumption. For Rates 3.1, 3.2 and 3.3 which have no customers, the cost of gas in these rates is the Fort Nelson average cost of gas embedded in the bundled rate of Rate 1, 2.1 and 2.2. For Rate 2.3, which also has no customers, the bundled rate also has embedded in it the Fort Nelson average cost of gas.

13.4.2.2 Proposed Gas Cost Allocation Methodology

The proposed gas cost allocation methodology classifies the commodity costs as energy-related and allocates those costs to sales customers based on their forecast consumption which is the same as the current method. The midstream costs are proposed to be classified as demand-related and allocated to all sales customers based on their load factor adjusted volume. This proposal follows cost causation as these costs are incurred to meet peak-day demand. This approach is the same as FEI's method of midstream cost allocation.

For Rates 2.3 (NGV) and 3.1 (Industrial Service) that do not have any customers, FEI proposes to set the commodity equal to that of the average for Fort Nelson, and to set the midstream rate based on Spectra's T-North Short Haul toll adjusted for a deemed load factor of 100% for Rate 2.3 and 40% for Rate 3.1. 100% is the Load Factor of FEI's RS 6 NGV service and 40% is the approximate minimum load factor of FEI's RS 5 General Firm Service customers. The load factors will be updated in the future to reflect any future changes for FEI's RS 6 and RS 5 or when there are customers being served in Fort Nelson under Rate 2.3 and 3.1 (or RS 6 and RS 5 after approval of the proposed renaming).

13.4.2.3 Gas Cost Allocation Results

A comparison of the current method of allocating gas costs and the proposed method is provided in Table 13-11 below. As shown on lines 4 and 15 of the table, the proposed gas cost allocation will have minimal impact on residential and commercial customers' rates.

Table 13-11: Comparison of the Current and Proposed Gas Cost Allocation[201]

Line No.	Particulars	Total	Residential	Commercial Small	Commercial Large
1	**Current Method**				
2	Forecast Volume (GJ)	602,200	268,100	209,700	124,400
3	Total Cost of Gas [1]	$ 779,247	$ 346,922	$ 271,352	$ 160,974
4	$ / GJ (Line 3 / Line 2)	$ 1.294	$ 1.294	$ 1.294	$ 1.294
5					
6	**Proposed Method**				
7	Forecast Volume (GJ)	602,200	268,100	209,700	124,400
8	Total Commodity Cost [2] (Line 23)	$ 767,900	$ 341,870	$ 267,401	$ 158,630
9	Commodity Cost / GJ (Line 8 / Line 7)	$ 1.275	$ 1.275	$ 1.275	$ 1.275
10					
11	Load Factor Adjusted Volume (Line 20)	1,650,768	736,538	607,826	306,404
12	Midstream Cost (Storage & Transport Cost) [3]	$ 11,347	$ 5,063	$ 4,178	$ 2,106
13	Storage & Transport Cost / GJ (Line 12 / Line 7)	$ 0.019	$ 0.019	$ 0.020	$ 0.017
14					
15	Total Cost of Gas per GJ	$ 1.294	$ 1.294	$ 1.295	$ 1.292
16	**Net Change per GJ (Line 4 - Line 15)**	$ -	$ (0.000)	$ (0.001)	$ 0.002
17					
18	Forecast Volume (GJ)	602,200	268,100	209,700	124,400
19	Load Factor %		36.4%	34.5%	40.6%
20	Load Factor Adjusted Volume (Line 17 / Line 18)	1,650,768	736,538	607,826	306,404
21					
22	Total Cost of Gas	$ 779,247			
23	Less: Midstream - Pipeline Costs	(11,347)			
24	Total Commodity	$ 767,900			

Notes to Table 13-11:

1. The current method allocates the average cost equally to residential and commercial customers.
2. Under the proposed method the total commodity cost is allocated to customers based on their combined total forecast volume resulting in the same Commodity Cost Recovery Charge to residential and commercial customers. This is the same as the current method except the total commodity cost is lower as it does not include midstream.
3. Under the proposed method the midstream cost is allocated to customers based on the peak day demand or load factor adjusted volumes. Peak day demand is equal to Load Factor Adjusted Volume (Line 20) divided by 365 days.

[201] FEI Fort Nelson Service Area, GCRA 2016 2nd Quarter Gas Cost Report filed June 1, 2016. Load factors are rolling 3 year average for the years 2013, 2014 and 2015.

13.4.3 Revenue to Cost and Margin to Cost Ratios

As directed by Commission Order G-4-18, FEI is using a range of reasonableness of 95% to 105%. For further discussion of Revenue to Cost ratios and the range of reasonableness, please see Section 6.5.1 of the Application.

The table below provides the R:C and M:C ratios for each of Fort Nelson's rates based on the Fort Nelson 2018 RRA, plus the adjustment discussed in section 13.4.1.3 and utilizing a 27% load factor for the RS 25 customer. The results are from Fort Nelson's COSA Model before rebalancing and rate design proposals.

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

Rate	R:C	M:C
Rate 1 Domestic (Residential) Service	91.4%	89.0%
Rate 2.1 General (Small Commercial) Service	109.4%	112.2%
Rate 2.2 General (Large Commercial) Service	114.4%	119.8%
Rate Schedule 25 General Firm Transportation Service	92.4%	92.4%

Table 13-12 shows that R:C ratios for all rates are outside the 95% - 105% range of reasonableness. FEI's proposal for rebalancing is discussed in Section 13.7.1.4.

13.5 *FORT NELSON RATE DESIGN*

13.5.1 Introduction

FEI reviewed the rate design for Fort Nelson residential, commercial and industrial customers that take service under Rate 1, Rate 2.1, Rate 2.2 and Rate Schedule 25. FEI discusses unbundling the rates for Fort Nelson customers and also the potential delivery rate structure options for Fort Nelson customers (i.e. flat, declining or inclining block).

As shown in Table 13-1, FEI is proposing to change the classification of Fort Nelson rates as outlined in the Fort Nelson Tariff to be consistent with FEI's rate schedules. FEI is also proposing to change Fort Nelson's current bundled declining block rates to unbundled flat rates for residential, commercial and industrial customers. This means that Fort Nelson residential and commercial customers will see a separate volumetric Commodity Cost Recovery Charge per GJ, Storage and Transport Charge per GJ, Basic Charge per Day and Delivery Charge per GJ in the Fort Nelson Tariff and on their bill. Fort Nelson transportation customers taking service under Rate Schedule 25 will see a separate Basic Charge per Month, Administration Charge per Month, Demand Charge per GJ per Month and Delivery Charge per GJ. The proposed Rate

Schedule 5 General Firm Industrial Service will have the same charges as Rate Schedule 25 except there will not be an Administration Charge and there will be a Commodity Cost Recovery Charge per GJ and Storage and Transport Charge per GJ.

The remainder of this section is organized as follows:

- Section 13.5.2 summarizes FEI's proposal to unbundle rates for Fort Nelson customers.
- Section 13.5.3 summarizes FEI's proposal to adopt a flat rate structure for Fort Nelson customers as opposed to the existing declining block rate structure.
- Section 13.5.4 provides the characteristics of Fort Nelson residential customers, includes the rate design proposal and analyzes the bill impacts.
- Section 13.5.5 provides the characteristics of Fort Nelson commercial customers, includes the rate design proposal and analyzes the bill impacts.
- Section 13.5.6 provides the characteristics of Fort Nelson's industrial customer, includes the rate design proposal and analyzes the bill impacts.

13.5.2 Bundled Versus Unbundled Rates

In the 1980s, the unbundling of competitive and non-competitive aspects of the natural gas business[202] was conducted to promote competition in the industry as part of restructuring efforts. Since then, the competitive aspects of the natural gas industry developed and FEI applied for an unbundled rate structure for its Lower Mainland, Inland and Columbia Service Areas in the early 1990s. As described in Section 13.2.2 a full rate design and similar rate unbundling process have never been undertaken for Fort Nelson.

The unbundling of rates allows customers to see on their bill the different components that are set out in the rate schedules (i.e. commodity, midstream and delivery), including changes in a particular component from one period to the next. Unbundling the rates in this manner provides transparency into the different components of customers' bills and provides Fort Nelson customers with the ability to participate in other services that require unbundled rates in the future, such as the Renewable Natural Gas program (subject to Commission approval on a potential separate future application).

The results from the residential customer research survey support a move towards unbundled rates. When provided with an example of how their rate structure differs from the rest of the

[202] Upstream activities are considered to be competitive and distribution is considered to possess natural monopoly characteristics. The unbundling of upstream resources in the late 1980s caused utilities to have to contract separately for various upstream resources (i.e. to buy gas from producers or marketers and pipeline capacity or storage from upstream providers of those resources). Prior to that, local utilities typically bought a bundled product from the upstream pipeline company at a regulated price.

province, only 21% of Fort Nelson customers prefer the current rate structure and 42% preferred a structure that matches the rest of the province.

FEI believes that unbundling of Fort Nelson's rates, similar to FEI's rates, is reasonable and should be adopted.

The unbundling of Fort Nelson rates will require changes to the billing system. FEI has estimated that the one-time pre-tax cost to make these changes is approximately $70 thousand. This one-time cost is for billing system changes, bill reconfiguration and testing. As Fort Nelson's rates have already been approved for 2017 and 2018, FEI is requesting approval for a deferral account to record the cost of changes to the billing system for Fort Nelson that will be required to unbundle Fort Nelson's rates. The actual costs will be recorded in the account on net-of-tax basis consistent with normal practice and amortized over five years beginning in 2019. The five-year amortization period is appropriate given the long-term benefit of unbundling rates, and will spread out the rate impact of these costs on Fort Nelson customers.

13.5.3 Declining Block Rates Versus Flat Rates

Another significant difference between existing FEI and Fort Nelson rates relates to their rate structures. FEI's rates are flat and will not vary depending on the level of consumption, while Fort Nelson has a declining block rate. For Fort Nelson residential customers, rates decline for any consumption in excess of a minimum volume of 30 GJ per month. For Fort Nelson commercial customers, rates decline to a lower block rate for any consumption in excess of 300 GJ per month.

FEI formerly had a declining block rate structure, but it was terminated in the 1993 Rate Design proceeding. Fort Nelson was excluded from that application and therefore their declining block rate structure was not reviewed.

Section 7.4.2 of the Application provides a description of various rate structures and Section 7.4.3 includes a summary discussion of the strengths and weaknesses of flat, declining and inclining block and seasonal rate structures for customers. Despite the advantages of declining block rates in terms of the economic efficiency principle, FEI believes that the flat rate structure is preferable for the following reasons:

1. <u>The Most Common Rate Structure</u>

FEI conducted a review of residential rate structures across Canada and, as noted in Section 7-6, a flat rate structure is used by 7 out of 11 Canadian natural gas utilities.

2. <u>Changes in Government Policy</u>

Government policy has changed significantly during the last 20 years. Today, energy efficiency and conservation is a major focus of B.C. provincial government policies. Declining block rates may send price signals that can discourage customer engagement in energy efficiency and conservation programs and activities.

3. Customer Survey Results

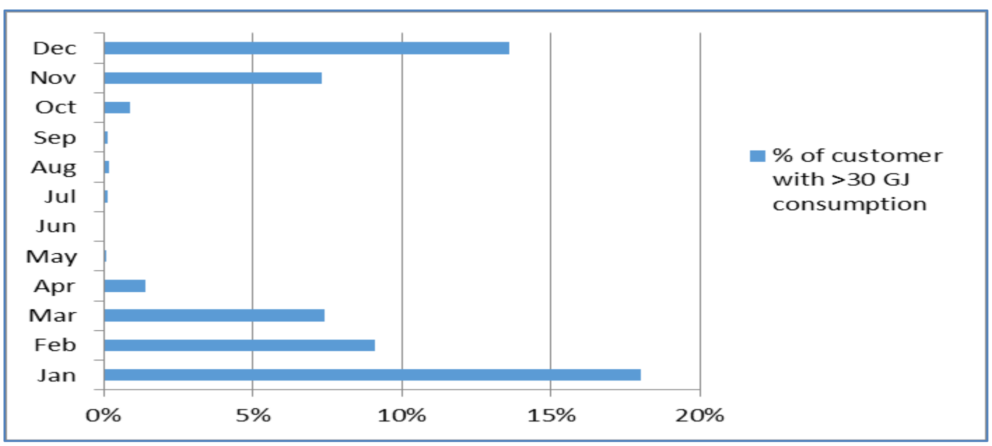
The customer research survey results indicate that the flat rate structure is preferred by the majority of Fort Nelson's residential customers as it received the highest marks on all rate design considerations compared to other rate structure options. The high level of preference for a flat rate structure may be explained by the fact that the majority of Fort Nelson's residential customers would like to see a rate structure that is simple, transparent and easy to understand.

4. Lack of Evidence of Benefits from Declining Block Rates

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.

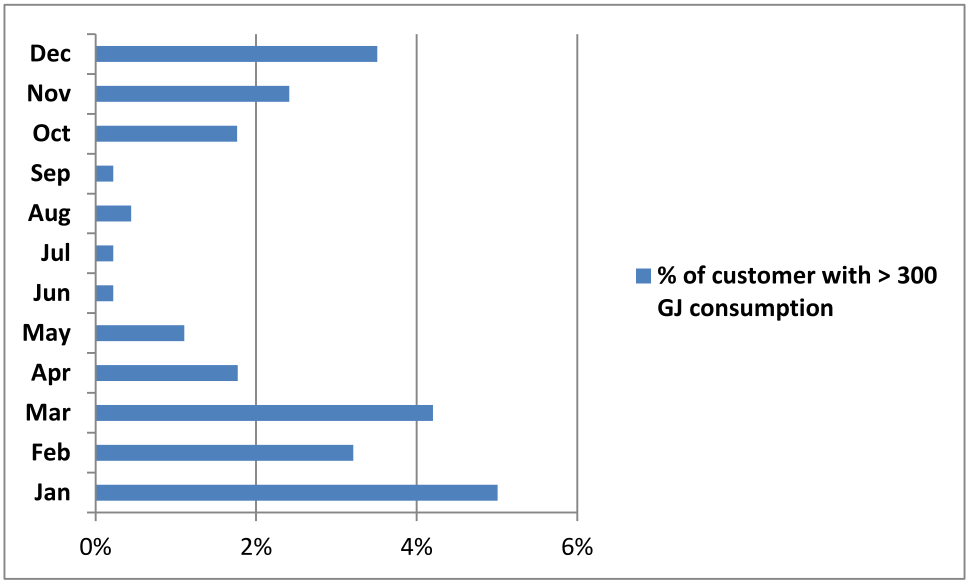
The graph below provides the percentage of residential customers with more than 30 GJ consumption in each month of the year.

Figure 13-2: Percentage of Fort Nelson Rate 1 Customers with >30 GJ Monthly Consumption



The graph below provides the percentage of commercial customers with more than 300 GJ consumption in each month of the year.

Figure 13-3: Percentage of Fort Nelson Rates 2.1 & 2.2 with > 300 GJ Monthly Consumption

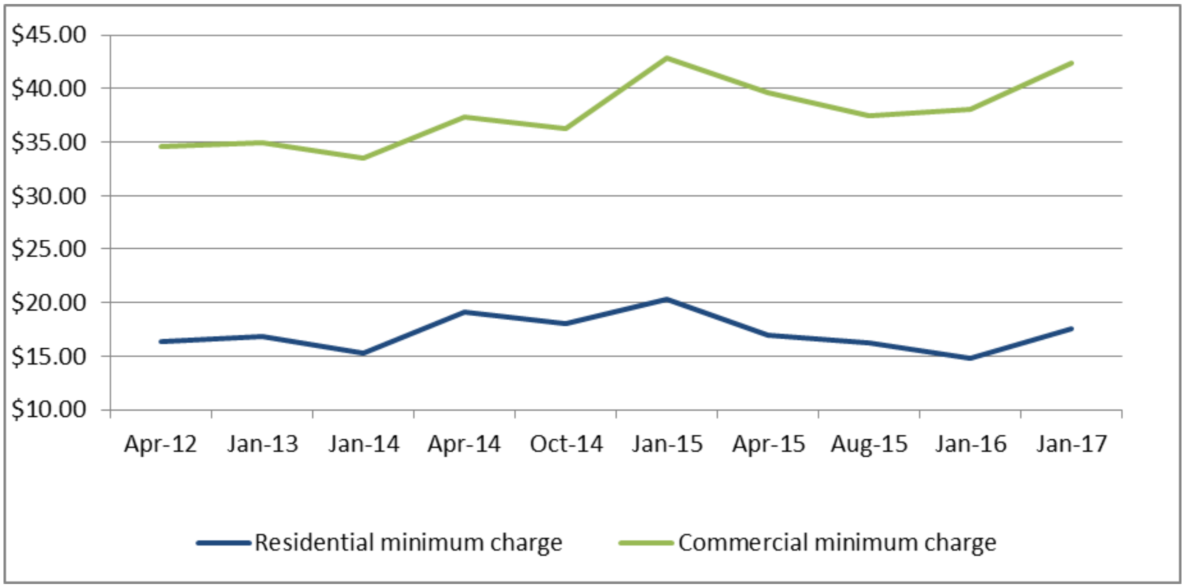


As can be seen from the two graphs above, approximately 18% of residential customers and 5% or less (i.e.24 or less) of the commercial customers in the coldest months of the year consume more than the minimum threshold for the second rate block in any month. In other words, the majority of residential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

5. <u>Fluctuating Minimum Charges</u>

Fort Nelson's existing rate design consists of a minimum daily charge calculated based on a minimum 2 GJ per month consumption pro-rated on a daily basis. Fort Nelson's existing minimum charge approach results in volatility, fluctuating with natural gas commodity prices. The Figure 13-4 below demonstrates the minimum charges (calculated based on a 30 day month) from January 2012 till October 2015 for residential and commercial customers.

Figure 13-4: Volatility in Fort Nelson's Monthly Minimum Charge[203]



As indicated in the above figure, the monthly minimum charge for residential customers has increased from $15.30 in January of 2014 to $20.30 in January of 2015 and then decreased to $14.85 in January of 2016. Similarly, the commercial minimum charge calculated on monthly basis has increased from $33.48 in January of 2014 to $42.90 in January of 2015 and then decreased back to $38.05 in January of 2016. These kinds of fluctuations in residential and commercial minimum charges can cause customer dissatisfaction and are not in accordance with the rate stability principle. When customers consume less than two GJ in a month they are paying through the minimum charge for gas they have not consumed.

13.5.4 Fort Nelson Residential Customer Rate Design

13.5.4.1 Introduction

Rate 1 includes services to single family residences, separately metered single family townhouses, row houses, apartments and common areas serving strata lot owners of residential condominium complexes supplied through one meter.

Fort Nelson's existing rate design consists of a minimum daily charge (calculated based on a minimum 2 GJ per month consumption pro-rated on a daily basis) and a declining block rate consisting of two consumption blocks. Fort Nelson's 2018 bundled rates based on the approved 2018 delivery charges and assuming a gas cost of $1.294 per GJ are provided in Table 13-13 below.

[203] Based on 30 day month.

Table 13-13: Fort Nelson Rate 1 Existing Rate Structure

Line	Item Description	Minimum daily charge	Next 28 GJ in any month ($/GJ)	Excess of 30 GJ in any month ($/GJ)
1	Approved 2018 Delivery Charge	$0.4588	$3.557	$3.455
2	Gas Cost Recovery Charge	$0.0850[204]	$1.294	$1.294
3	Bundled 2018 Rates	$0.5438	$4.851	$4.749

Based on the above table, in January 2018 Fort Nelson customers may pay a minimum of $16.31[205] per month for their natural gas service irrespective of their consumption, which is higher than FEI's current residential Basic charge. A customer with an average monthly use of 12 GJ will pay $64.82[206] per month (assuming no change in the gas recovery charge and excluding riders)[207].

The delivery charges calculated from the COSA model are slightly higher than the 2018 approved delivery charges shown above due to the revenue deficiency caused by one customer moving from RS 25 to Rate 2.1 as discussed in section 13.4.1.3. This deficiency causes an increase to the 2018 delivery charges of approximately 1%.

13.5.4.2 Residential Customer Characteristics

Table 13-14 below provides a summary profile of the residential customer class' number of customers, annual consumption and revenue.

Table 13-14: Fort Nelson Residential Customer Profile for Forecast 2018

	Amount	% of Total
Number of Customers	1,961	80%
Annual Consumption (TJ)	260	46%
Revenue ($000's)	$1,423	45%

The following subsections discuss the main characteristics of Rate 1 customers, including dwelling type, end use, consumption patterns and load factor.

[204] Pro-rated to daily basis based on the following formula: $0.085 per day = 2 GJ per month * $1.294/GJ * 12 / 365.25.

[205] Based on 30 day month.

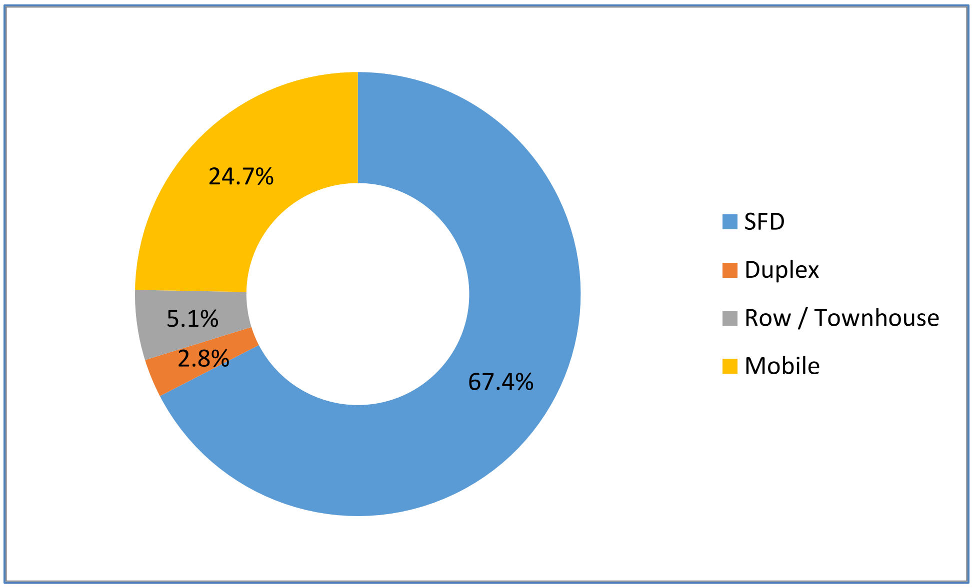
[206] 0.5438*30 + 4.851*10 (the first 2 GJ is covered by the minimum charge).

[207] Due to potential changes in natural gas commodity prices, the bundled rates in 2018 may differ from the rates shown.

13.5.4.2.1 RESIDENTIAL DWELLING TYPES

The 2012 Residential End-Use Study (REUS), provided in Appendix 7-1, is the most recent detailed study of Fort Nelson residential customers' characteristics. The 2012 REUS indicates that single family dwellings (SFD) dominate the residential customer base for Fort Nelson. SFDs account for approximately 67% of residential customers, and are followed by mobile homes at 25%. Figure 13-5 below provides a summary of Fort Nelson's residential customers by dwelling type.

Figure 13-5: Fort Nelson Residential Customers by Dwelling Type based on 2012 REUS

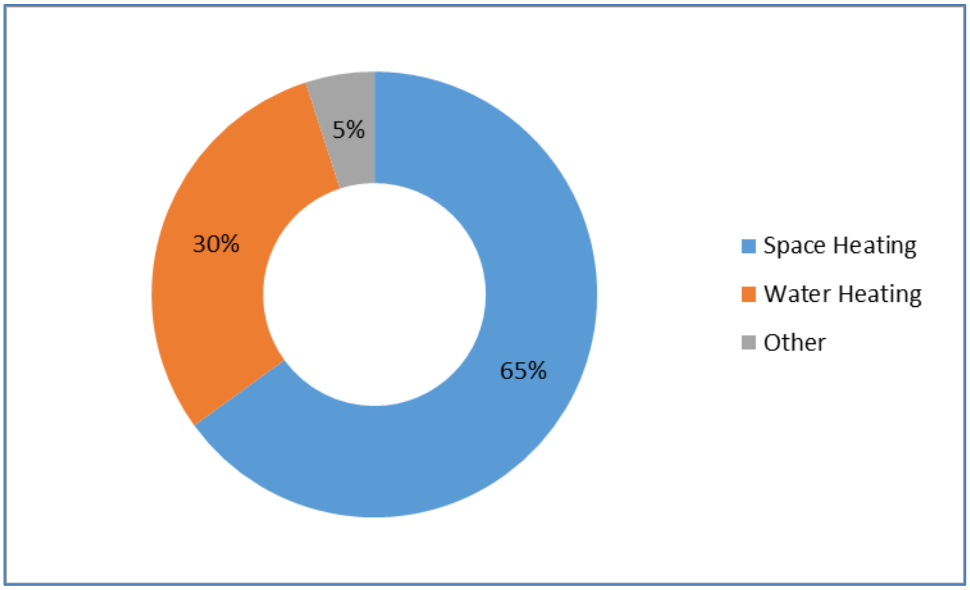


13.5.4.2.2 RESIDENTIAL END USES

The majority of demand from residential customers is for space heating and water heating purposes. Residential customers may also use natural gas for other purposes such as decorative fireplaces, cooking and barbecues. As shown in Figure 13-5 below, space and water heating are estimated to be approximately 65 percent[208] and 30 percent of residential consumption, respectively. The remaining 5% of demand includes the estimated consumption for decorative fireplaces, cooking appliances and BBQs.

[208] Heater fireplace consumption is included in this percentage.

Figure 13-6: Fort Nelson Estimated Annual Consumption per Household by End-use based on 2012 REUS



13.5.4.2.3 RESIDENTIAL CONSUMPTION PATTERN

Figure 13-7 below provides the 2016[209] bill frequency for Fort Nelson residential customers. Similar to FEI's residential consumption histogram, Fort Nelson's annual consumption per customer is in the form of a normal distribution function. However, Fort Nelson residential customers' annual consumption is higher than FEI's other service areas. As can be seen from the figure below, the 100-110 GJ annual consumption range has the highest density of customers (compared to 70-80 GJ for other FEI customers), followed closely by the 110-120 GJ and 120-130 GJ consumption ranges. This is to be expected since Fort Nelson is located in the northern part of the province with colder and longer winters.

[209] 2016 normal volumes are based on December 2015 through November 2016 data; December 2016 data is not yet available in time for the Supplemental Filing.

Figure 13-7: Fort Nelson Residential 2016 Bill Frequency

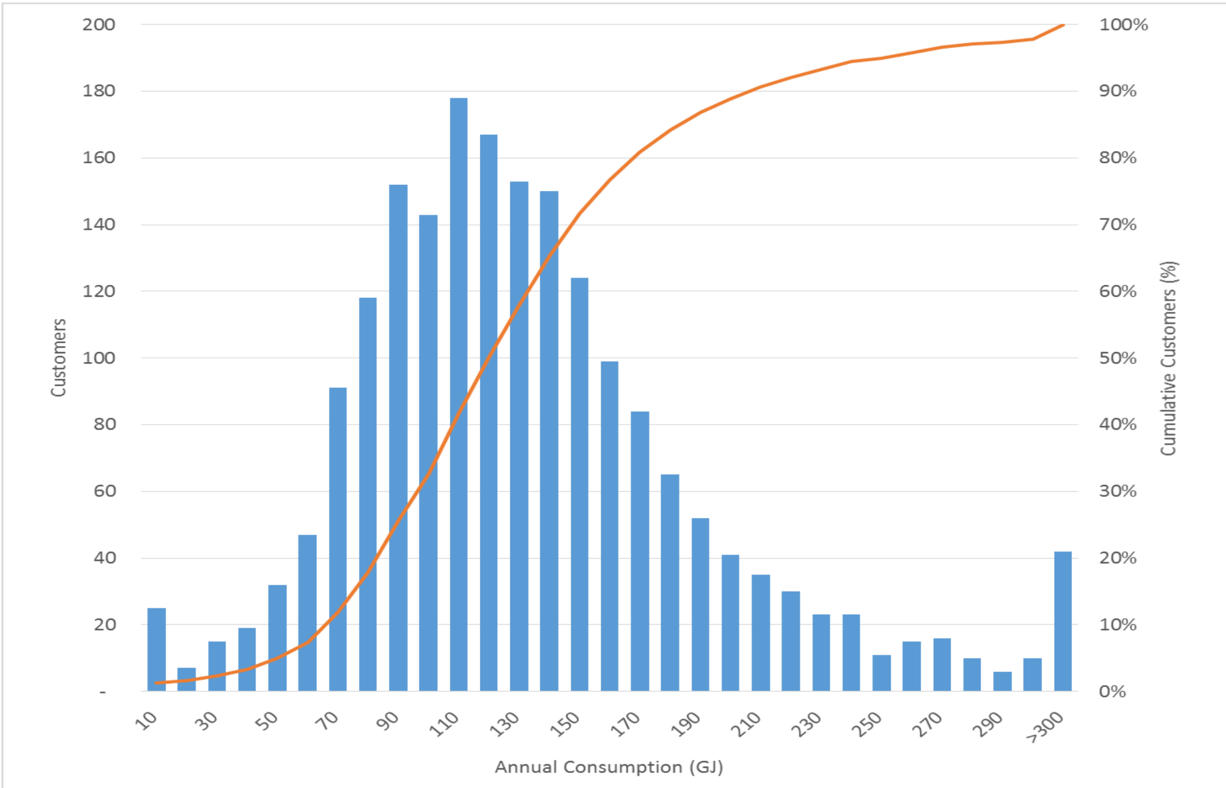
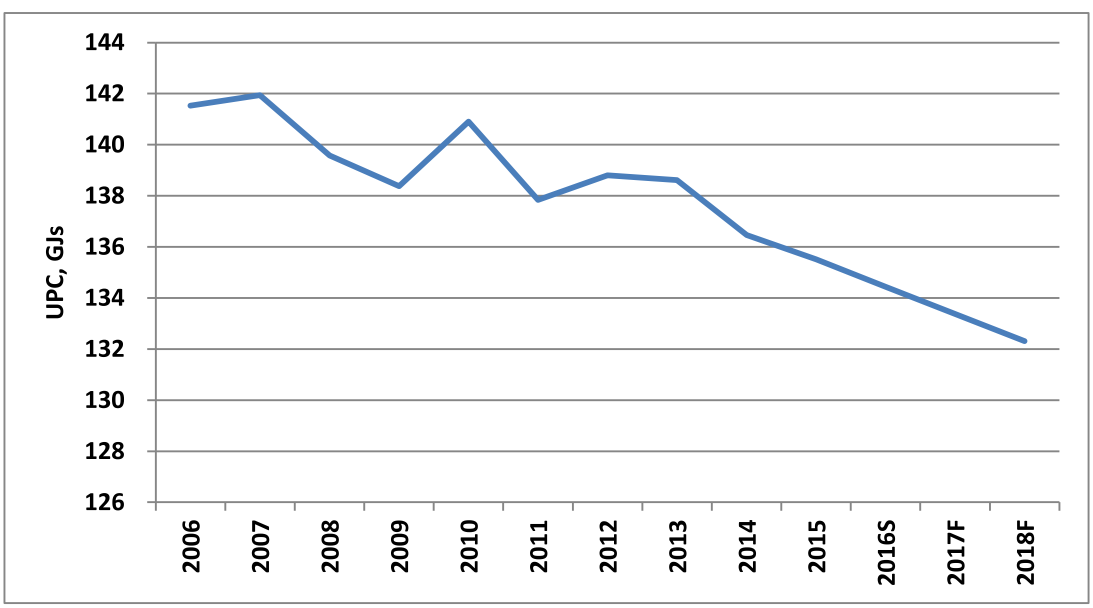


Figure 13-8 below provides the actual residential UPC for the years 2006 through 2015 and forecast 2017 and 2018. It shows a declining pattern similar to FEI's residential customers' UPC, except that Fort Nelson's residential UPC is higher.

Figure 13-8: Fort Nelson Residential Historical Normalized UPC 2006 – 2018



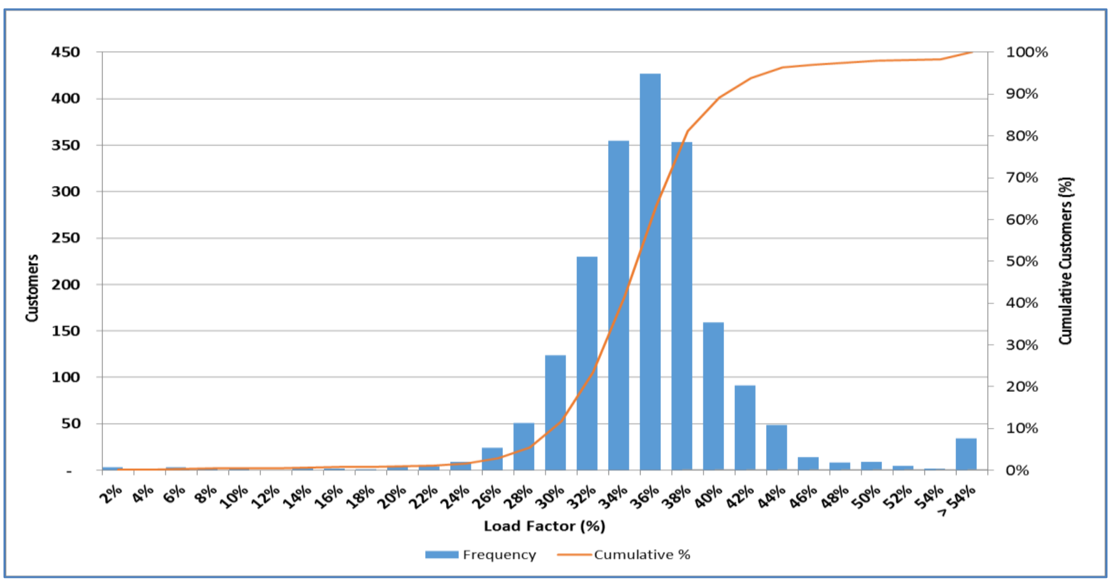
13.5.4.2.4 RESIDENTIAL LOAD FACTOR

The load factor is used to develop one of the main allocators in the cost of service allocation model to allocate demand-related costs between different rates/rate schedules. However, the load factor for specific individual residential customers can be higher or lower than the average load factor for Rate 1 used in the COSA Model.

To better understand the behaviour of Fort Nelson residential customers, FEI conducted a load factor analysis for residential customers at the individual premise level. The load factor for each premise is calculated based on the normalized daily consumption for each premise divided by the peak day consumption. The load factor analysis is based on a statistical analysis of loads relative to weather conditions as FEI does not meter the daily loads of residential customers.

The graph below provides a histogram of load factors for residential customers at the premise level. The histogram indicates that the residential customers' load factor at the premise level is in the form of a normal distribution function. The load factor for the majority of residential customers is around 34 to 36 percent.

Figure 13-9: Fort Nelson Residential Customers' Load Factor Distribution Calculated at Premise Level



13.5.4.3 Residential Rate Design

As stated above, FEI is proposing to unbundle the rates and adopt a flat rate structure for Fort Nelson customers. For residential customers, under this proposal FEI will unbundle Fort Nelson's rates to implement a separate Commodity Cost Recovery Charge, Storage and Transport Charge and a flat volumetric Delivery Charge with a fixed daily Basic Charge similar to FEI's residential rate structure.

Based on Fort Nelson's COSA Model and assuming no change in the Gas Cost recovery charge, the proposed Rate 1 unbundled rates are as follows (the table below excludes the RSAM rider):

Table 13-15: Fort Nelson Unbundled Residential Rates Based on COSA Model

Item Description	Rate
Daily Basic Charge	$0.2783
Delivery Charge per GJ	$3.512 per GJ
Commodity Cost Recovery Charge	$1.275 per GJ
Storage and Transport Charge	$0.019 per GJ

When unbundling, there are various ways to apportion the costs for recovery from fixed and volumetric charges. For instance, the daily Basic charge can be set to be equal to FEI's Basic charge with the rest of the costs recovered through the volumetric Delivery Charge. Another option would be to set the ratio of fixed Basic charge and volumetric Delivery Charge in a way to achieve zero bill impact for a pre-defined average monthly consumption amount. However, both these options may result in significant bill impacts for certain customers.

The proposed daily Basic Charge and volumetric Delivery Charge set out in the table above are calculated in a way that achieves the lowest maximum dollar amount bill increase for any individual customer. This was done using a linear programming technique in which minimization of the upward increase in annual bills is set as one of the constraints for the calculations.[210]

In the above table, the sum of the Commodity Cost Recovery Charge and the Storage and Transport Charge is equal to the Gas Cost Recovery Charge included in Fort Nelson's bundled rates.

The following section provides a bill impact analysis of the proposed option.

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:

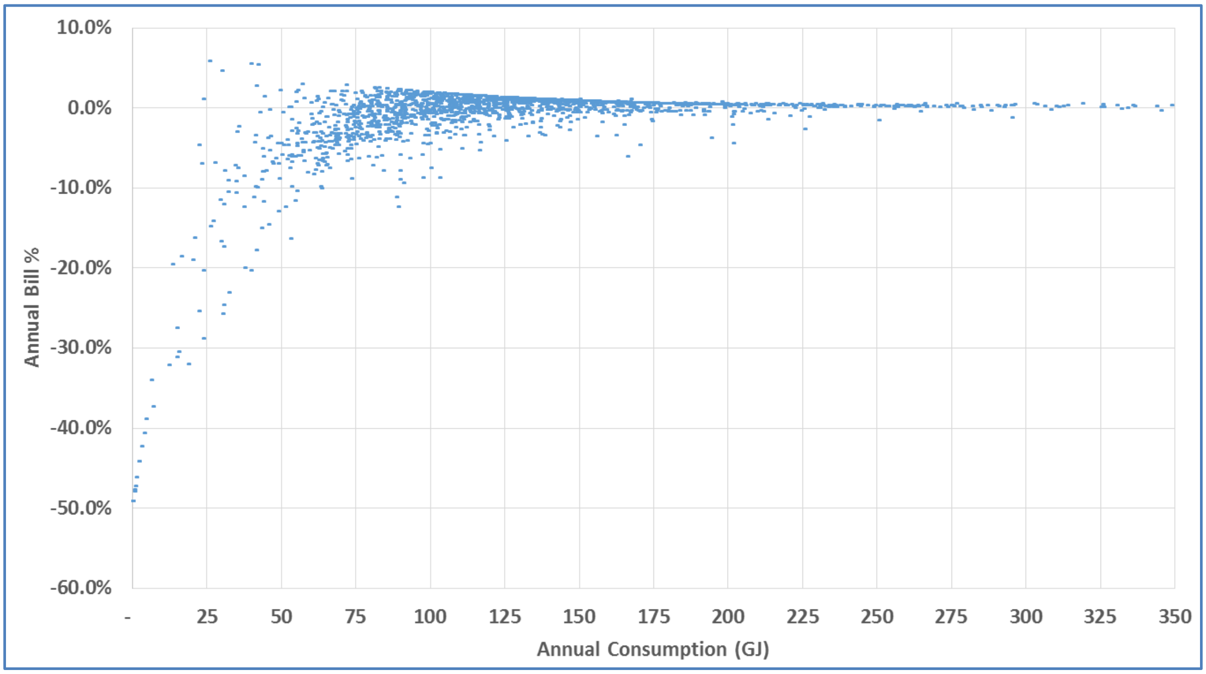
(1) the bill impact due to a transition from bundled declining block rates with a minimum - daily charge to an unbundled flat rate structure with a daily Basic Charge; and

(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.

[210] FEI used Microsoft Excel Solver to calculate these rates.

The following figure presents the results of step 1 above. It shows the percentage bill impact relative to the various levels of annual consumption from all the changes that FEI is proposing for Fort Nelson residential customers before rebalancing. The second step is discussed in section 13.7.1.4.

Figure 13-10: Annual Bill % Change at Various Annual Consumption Levels for Fort Nelson Residential



Due to the 2 GJ monthly threshold for the minimum daily charge calculations and the declining block rate structure of Fort Nelson's existing rates, the bill impact on individual customers due to the transition to unbundled flat rates will depend on if a customer's monthly consumption is equal or less than the first 2 GJ included in minimum daily charge or exceeds the declining block rate at 30 GJ. For instance, two customers with identical annual consumption can have different bill impacts if one has a monthly consumption between 2 and 30 GJ every month of the year, and the other has monthly consumption less than 2 GJ or more than 30 GJ in at least one month of the year.

The bill impact analysis provided in Figure 13-10 above is performed on the premise level based on actual monthly consumption of individual customers. The impact of the transition from a bundled declining block rate with a minimum charge to an unbundled flat rate with a daily Basic Charge is most favourable to customers with the most number of months of consumption less than 2 GJ (closer to zero consumption the more favourable) and no monthly consumption in excess of 30 GJ. On the other hand, the bill impact will be least favourable to customers with no monthly consumption below 2 GJ and the highest number of months of consumption above 30 GJ.

13.5.4.5 Conclusion

In summary, FEI's review of Fort Nelson's residential rates supports a transition from the existing bundled declining block rates with a minimum daily charge to unbundled flat rates with a fixed daily Basic Charge. The existing bundled rates are unnecessarily complex and do not provide the customer with the appropriate level of transparency. In addition, existing declining rates may discourage some customers from engaging in energy efficiency and conservation initiatives and are not aligned with government policy. The proposed flat rate on the other hand is easy to understand and administer, provides better rate and revenue stability and is used by the majority of Canadian natural gas utilities. Further, the customer research survey results show that the flat rate structure is preferred by a majority of Fort Nelson residential customers. Finally, the transition from the existing daily minimum charge to a fixed daily Basic Charge will improve rate stability for Fort Nelson residential customers.

13.5.5 Fort Nelson Commercial Customer Rate Design

13.5.5.1 Introduction

Fort Nelson commercial customers are served under the following two Rates:

- Rate 2.1 - General Service (normal annual consumption is less than 6,000 GJ)
- Rate 2.2 - General Service (normal annual consumption is 6,000 GJ or greater)

The delivery charges calculated from the COSA model are slightly higher than the 2018 approved delivery charges shown above due to the revenue deficiency caused by one customer moving from RS 25 to Rate 2.1 as discussed in section 13.4.1.3. This deficiency causes an increase to the 2018 delivery charges of approximately 1%.

Fort Nelson's existing rate design consists of a minimum daily charge (calculated based on a minimum 2 GJ per month consumption pro-rated on a daily basis) and a declining block rate consisting of two consumption blocks. Fort Nelson's 2018 bundled rates based on approved 2018 delivery charges and assuming a Gas Cost Recovery Charge of $1.294 per GJ are provided in Table 13-16 below.

Table 13-16: Fort Nelson Rate 2.1 / 2.2 Existing Rate Structure

Line	Item Description	Minimum daily charge	Next 298 GJ in any month ($/GJ)	Excess of 300 GJ in any month ($/GJ)
1	Approved 2018 Delivery	$1.3487	$4.042	$3.916
2	Gas Cost Recovery	$0.0850[211]	$1.294	$1.294
3	Bundled 2018 Rates	$1.4337	$5.336	$5.210

[211] Pro-rated to daily basis based on the following formula: $0.0850 per day = 2 GJ per month * $1.294/GJ * 12 / 365.25.

The applicable blocks and charges are the same for both Rates 2.1 and 2.2[212].

13.5.5.2 Customer Characteristics

The number of customers and demand from Fort Nelson's Test Year[213] for each of these rates is shown in Table 13-17 below.

Table 13-17: Fort Nelson Commercial Customer Segment Data[214]

Rates	2018 Avg # of Customers	2018 Annual Demand Forecast (TJ)	% of Total Commercial Annual Demand	Average Load Factor
Rate 2.1 – General (Small Commercial)	479	203.7	78 %	33.4%
Rate 2.2 – General (Large Commercial)	7	56.7	22 %	40.5%
Total Commercial	486	260.4	100 %	

FEI is currently serving 486 commercial customers accounts representing approximately 20% of the total number of customers in Fort Nelson. Commercial customers consume 260 terajoules (TJ) of natural gas representing 46% of the total 2018 forecast throughput for Fort Nelson.

Please see sections 8.2.2 and 8.2.3 for overall FEI Commercial Customer Market Segments and Commercial End Usage.

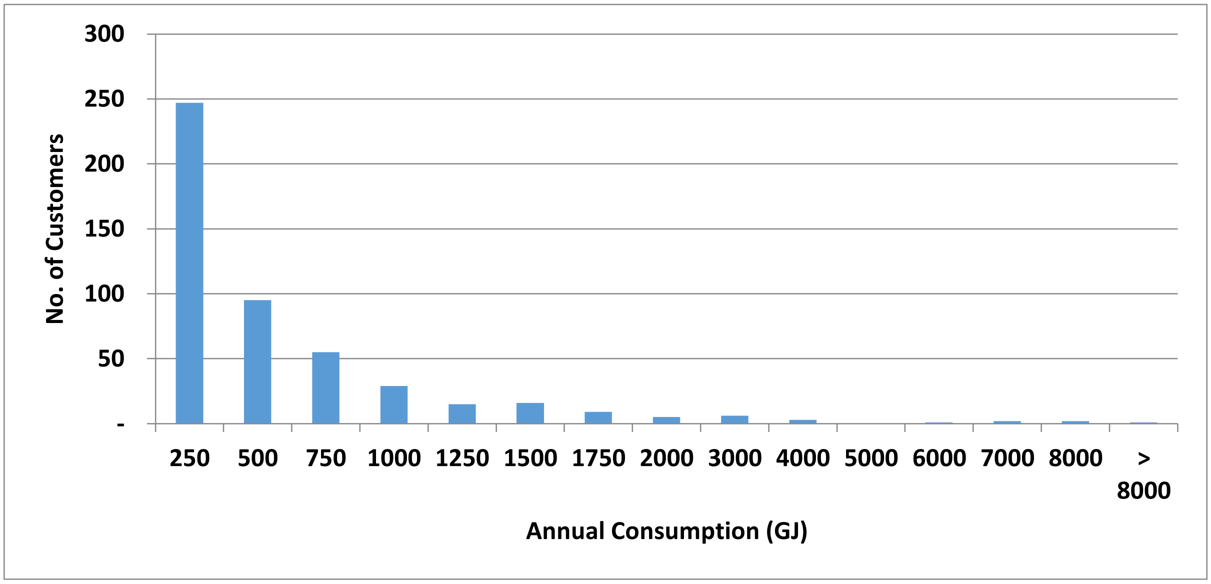
13.5.5.2.1 COMMERCIAL CUSTOMER CONSUMPTION

In this section, FEI presents the bill frequency and use per customer for Fort Nelson Commercial customers.

The following figure shows the bill frequency for commercial customers.

[212] Order E-1-97 in the Application by BC Gas Utility Ltd. for Approval of a 1996/97 Gas Supply Contract and the 1997 Rates for the Fort Nelson Service Area.
[213] Before the Test Year adjustment described in Section 13.4.1.3.
[214] Rates exclude RSAM rate rider and include adjustments to test year.

Figure 13-11: Fort Nelson Commercial Customers 2016 Bill Frequency[215]



The above table shows that there are a few customers at annual consumption levels of 1,500 GJ and greater, providing no clear separation point between small and large commercial customers.

The following Figure 13-12 and Figure 13-13 show Fort Nelson commercial customers' historical normalized use per customer from 2006 through 2018. For the years 2006 through 2014 the normalized use is the result before the migration of commercial customers in 2015 whose individual annual consumption was less than 6,000 GJ as described below.

In 2015, 24 customers whose individual annual consumption was less than 6,000 GJ were switched from Rate 2.2 to Rate 2.1 part way through the year to match the annual consumption requirements for these rates. This switch contributed to the 2015 increase in the average normalized use per customer as shown in the two figures below. For Rate 2.1 the normalized UPC increased from 456 GJ in 2014 to 482 GJ in 2015 but is then projected to decline sharply in 2017 and 2018[216]. For Rate 2.2 the normalized UPC increased from 3,425 GJ in 2014 to 6,616 GJ in 2015. For 2016 to 2018, the forecast Rate 2.2 UPC is approximately 8,100 GJ per year.

---

[215] 2016 normal volumes are based on December 2015 through November 2016 data; December 2016 data is not yet available in time for the Supplemental Filing.

[216] UPC for Rates 2.1 and 2.2 are explained in the Fort Nelson 2017 and 2018 Revenue Requirements and Rates Application in Section 3. See also FEI's response to BCUC IR 1 2.3, page 6, dated September 1, 2016.

Figure 13-12: Fort Nelson Small Commercial Historical Normalized UPC 2006 - 2018

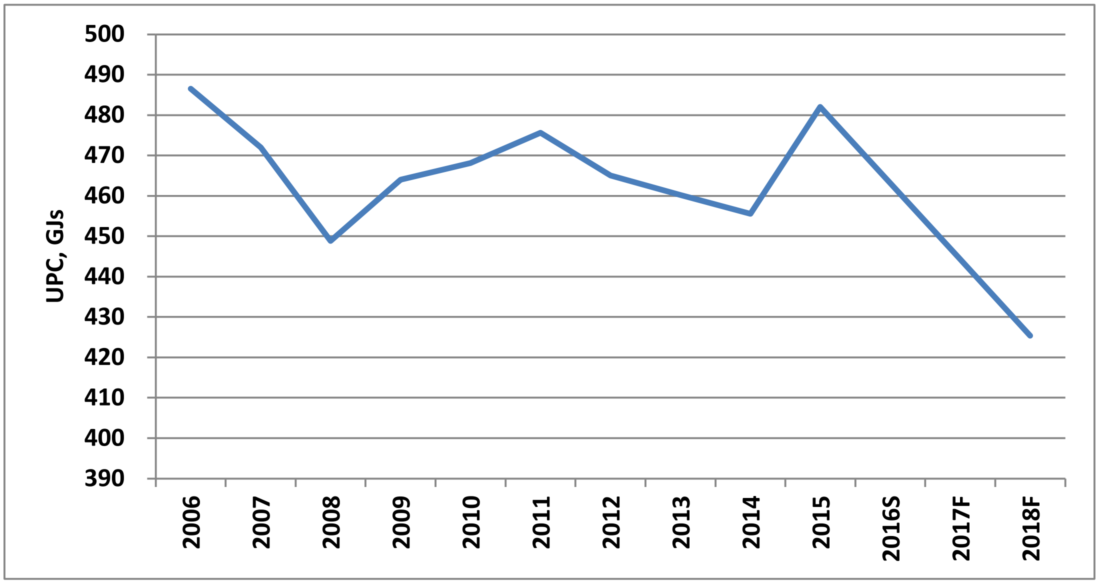
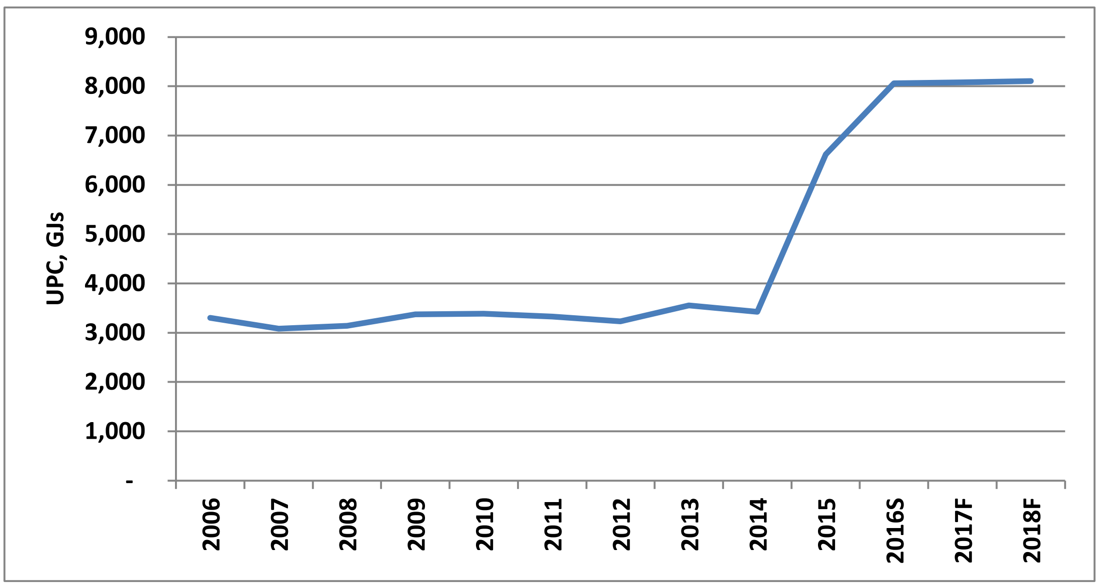


Figure 13-13: Fort Nelson Large Commercial Historical Normalized UPC 2006 - 2018



13.5.5.2.2 COMMERCIAL CUSTOMER LOAD FACTOR

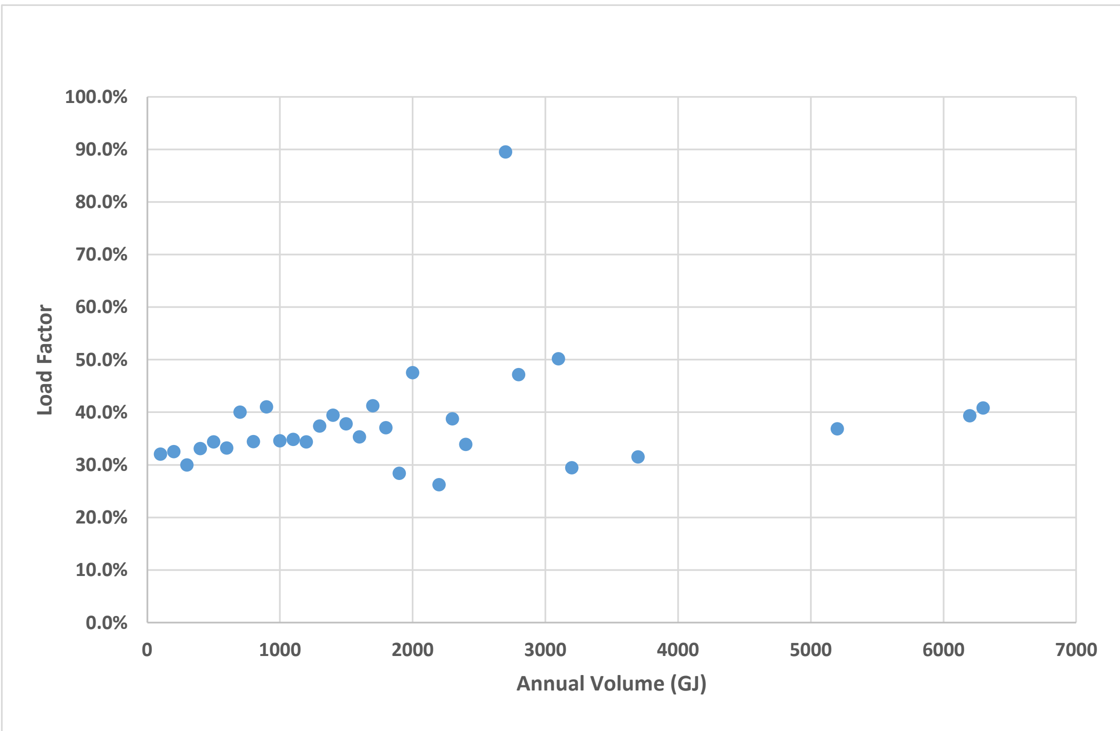
The load factor for Rate 2.1 is 33.4% and for Rate 2.2 is 40.5% based on the customers in each rate. The load factors are a 2014 to 2016 three-year average, calculated for each year based on a regression of consumption and temperature and estimating the peak day demand applied to a design day temperature (coldest day temperature in the past 20 years).

Table 13-18: Load Factor & Peak Day for Commercial Customers from Normalized 2016 Consumption

	Annual Volume (GJ)	Peak Day (GJ/Day)	Load Factor
Rate 2.1	203,700	1,668	33.4%
Rate 2.2	56,700	383	40.5%
Total	260,400	2,052	34.7%

The following graph shows the load factor and consumption of all commercial customers.

Figure 13-14: Fort Nelson Commercial Load Factor and Annual Volume



The graph visually shows there is a general gradual increase in the load factor from 30% to 40% for volumes above zero to approximately 1,500 GJ. Thereafter, there is a small, somewhat random looking dispersion of load factors between 30% and 50% for volumes 2,000 GJ and greater. The graph does not show a definite point in which the load factor changes to clearly segregate small commercial versus large commercial. When looking at all customers within a segmented group, as in Table 13-17, there is a difference between small and large commercial customers. Where the segmentation should occur, however, is unclear from Figure 13-14.

13.5.5.3 Commercial Rate Design

For the reasons discussed above, FEI is proposing to unbundle the rates and adopt a flat rate structure for Fort Nelson customers. For commercial customers, under this proposal, FEI will unbundle Fort Nelson's rates to implement a separate Commodity Cost Recovery Charge, Storage and Transport Charge and a flat volumetric Delivery Charge with a fixed daily Basic Charge similar to FEI's commercial rate structure.

FEI is also proposing to set the annual consumption threshold between small and large commercial customers at 2,000 GJ/year (from the current 6,000 GJ/year) to be consistent with FEI's RS 2 to RS 3 threshold. This change and the proposed levels for the Basic and Delivery Charges for small and large commercial customers are discussed below.

13.5.5.3.1 CHANGING THE THRESHOLD TO 2,000 GJ/YEAR

Fort Nelson general service (or commercial) customers are currently segmented into Rate 2.1 and 2.2 based on a 6,000 GJ/year separation point. For a number of reasons, FEI concluded that the 6,000 GJ/year separation point cannot be justified and that a 2,000 GJ/year separation point should be considered.

First, based on the 2016 billing data of the 486 commercial customers, only 5 customers had sufficient volumes (i.e. at or above 6000 GJ) to qualify for Rate 2.2 at the current threshold. (Current charges for Rates 2.1 and 2.2 can be found in Section 13.5.5.1).

Second, FEI reviewed the existing customer segmentation and did not find statistical evidence supporting a small and large commercial separation point of 6,000 GJ per year. Figure 13-14 above shows that a separation point of 1,500 to 2,000 GJ per year would be more reasonable.

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.

13.5.5.3.2 ANALYSIS OF SMALL AND LARGE COMMERCIAL CUSTOMER THRESHOLD OF 2,000 GJ

FEI analysed the customer bill frequency, load factor and economics of the small and large commercial rates. Based on this analysis, FEI concluded that the 2,000 GJ/year threshold segments the lower demand and lower load factor customers into the small commercial segment and the higher demand and higher load factor customers into the large commercial segment. This threshold is consistent with FEI's commercial rate schedules, provincial government policy supporting same service for same or similar price, and other Canadian utilities.

When examining the normalized customer data, whether the threshold is at 6,000 GJ/year or at 2,000 GJ/year, there is a distinct separation between Rate 2.1 and Rate 2.2, with the load factor for the two rates differing by approximately 6% in both cases. The following table summarizes the derived load factors when setting the threshold at 6,000 GJ or at 2,000 GJ based on 2016 normalized volume and 2016 load factor (not the rolling three year average). In 2016 there was one customer in Rate 2.2 whose normalized volume was 961 GJ and in the following table this customer has been treated as a Rate 2.1 customer (the values here are different from Table 13-17 above).

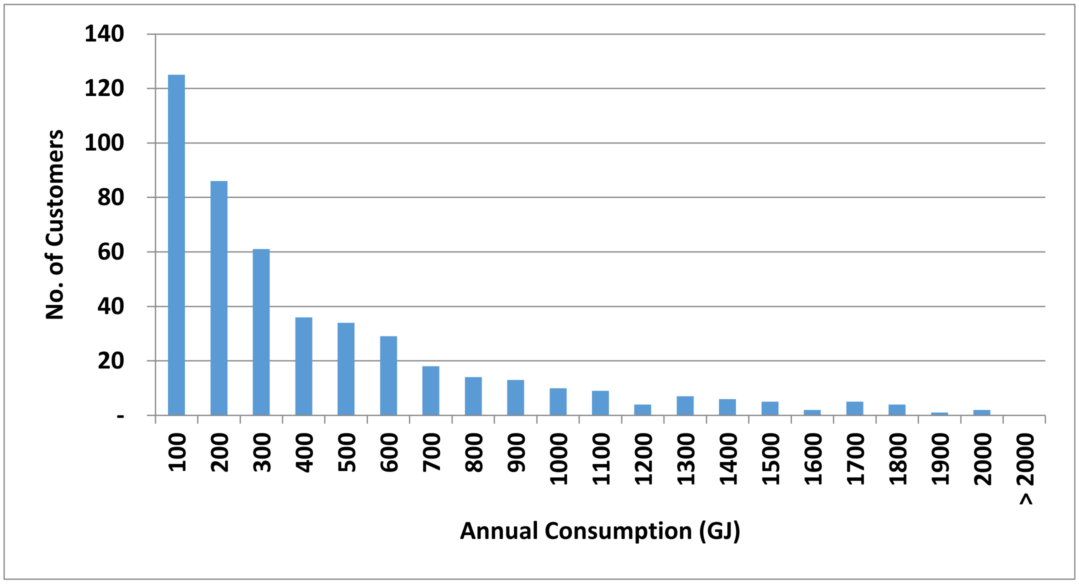
Table 13-19: Load Factor for Small & Large Commercial Customers from Normalized 2016 Consumption

	Annual Volume (GJ)	Peak Day (GJ/Day)	Load Factor
Threshold at 6,000 GJ			
Rate 2.1	204,661	1,684	33.3%
Rate 2.2	55,739	390	39.2%
Total:	**260,400**	**2,074**	**34.4%**
Threshold at 2,000 GJ			
Rate 2.1	180,418	1,509	32.8%
Rate 2.2	79,982	565	38.8%
Total:	**260,400**	**2,074**	**34.4%**

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 .

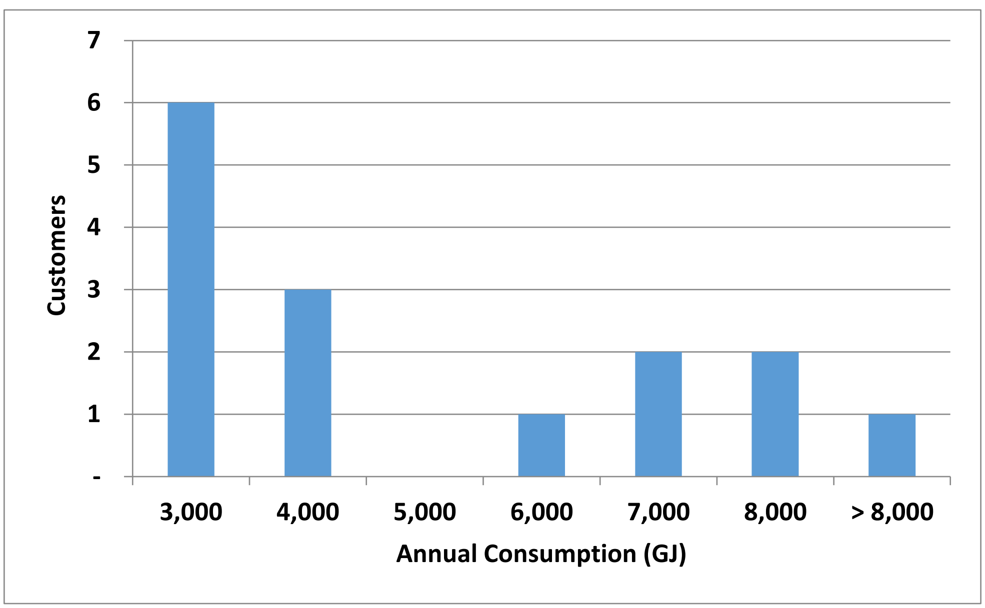
The following two figures below show the bill frequency for commercial customers using a threshold of 2,000 GJ to separate small and large commercial customers. The bill frequency shown in Figure 13-15 is for Rate 2.1 customers who use less than 2,000 GJ per year. It is evident that at about 1,500 GJ to 2,000 GJ per year and higher there are very few customers in each bin. This is consistent with the bins in the following Figure 13-16 for Commercial customers whose annual consumption is greater than 2,000 GJ.

Figure 13-15: Small Commercial 2016 Bill Frequency (2,000 GJ Threshold)



The bill frequency shown in Figure 13-16 is for commercial customers who use more than 2,000 GJ per year.

Figure 13-16: Large Commercial 2016 Bill Frequency (2,000 GJ Threshold)



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.

13.5.5.3.3 LEVEL OF CHARGES FOR SMALL AND LARGE COMMERCIAL CUSTOMERS

There are differences in the cost to serve Fort Nelson small and large commercial customers, and there are differences in the load characteristics that justify having a differentiated daily Basic Charge and Delivery Charge.

The following table compares the small and large commercial customers of Fort Nelson based on the existing volume threshold of 6,000.GJ/year and based on the rate under which they are currently served.

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	$3.222	$3.207

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.

The higher load factor of Rate 2.2 compared to the Rate 2.1 load factor means that large commercial customers will have a lower average demand-related cost per GJ, which is the result in the table above, this in turn leads to the expectation that the proposed Delivery Charge for large commercial customers will be lower than the Delivery Charge for small commercial customers.

In determining the proposed rates before rebalancing and taking into consideration the 2,000 GJ economic crossover, FEI has sought, as one of its objectives, to align the basic charge of both Rate 2.1 and Rate 2.2 proportionally to the customer classified costs from the COSA model and to limit the bill impact that individual customers in the two rate classes will experience. These observations must be coupled with the objective that at 2,000 GJ/year small and large commercial customers would have the same annual bill.

Changing the proposed threshold between Rate 2.1 and 2.2 to 2,000 GJ per year will result in 9 customers that would be moved to large commercial from small commercial, as these 9 customers' normalized annual consumption exceeds 2,000 GJ, but is less than the current 6,000 GJ threshold. The number of customers in Rate 2.1 will decrease from 479 customers to 471, with a net reduction of 23 TJ, and the average use per customer will decrease from 426 GJ per year to 384 GJ per year. Rate 2.2 average use per customer of 8,000 GJ per year will decrease to 5,267 GJ per year.

The table below summarizes the impacts of the proposed threshold change.

Table 13-21: Commercial Customer Migration Impact

Rate	Number of Customers	Annual Energy (TJ)	Percentage Of Total	Average Usage
Rate 2.1	**479**	**204**	**78%**	**426**
Adj. to RRA for customers < 6,000 GJ	1	1	0%	961
Rate 2.1 COSA # of customers / volume < 6,000 GJ per year	480	205	79%	427
Remove Rate 2.2 with > 2,000 GJ	(9)	(24)	(9)%	2,667
New Rate 2.1 after Migration	**471**	**181**	**70%**	**384**
Rate 2.2	**7**	**56**	**22%**	**8,000**
Adj. to RRA for customers < 6,000 GJ	(1)	(1)	(0)%	961
Rate 2.2 COSA # of customers / volume > 6,000 GJ per year	6	55	21%	9,167
Add Rate 2.2 > 2,000 GJ	9	24	9%	2,667
Net Rate 2.2 after Migration	**15**	**79**	**30%**	**5,267**
Total of Rate 2.1 & 2.2:	**486**	**260**	**100%**	**535**

13.5.5.3.4 SUMMARY OF COMMERCIAL RATE DESIGN PROPOSAL

FEI proposes the following Fort Nelson commercial rate design:

1. Unbundle the Commodity Cost Recovery Charge, Storage and Transport Charge, the fixed Basic Charge, and volumetric Delivery Charge in the customer rates;
2. Move to a flat rate structure;
3. Move the small to large commercial customer threshold to an annual demand of 2,000 GJ; and
4. Establish the daily and volumetric delivery charges to have an equal annual bill for Rate 2.1 and 2.2 at the economic crossover point at 2,000 GJ.

13.5.5.4 Bill Impact Analysis

Moving the threshold from 6,000 GJ/year to 2,000 GJ/year and setting the rates to result in an economic crossover at 2,000 GJ results in the following range of bill impacts when compared to existing bills. The largest decrease for a Rate 2.1 customer would be 21.2% (for customers with zero load paying minimum charges) and the largest increase would be 2%, with the average Rate 2.1 customer having a decrease of 2.6%. The largest increase for a Rate 2.2 customer would be 0.7% and the largest decrease would be 0.2%, with the average Rate 2.2 customer having an increase of 0.1%.

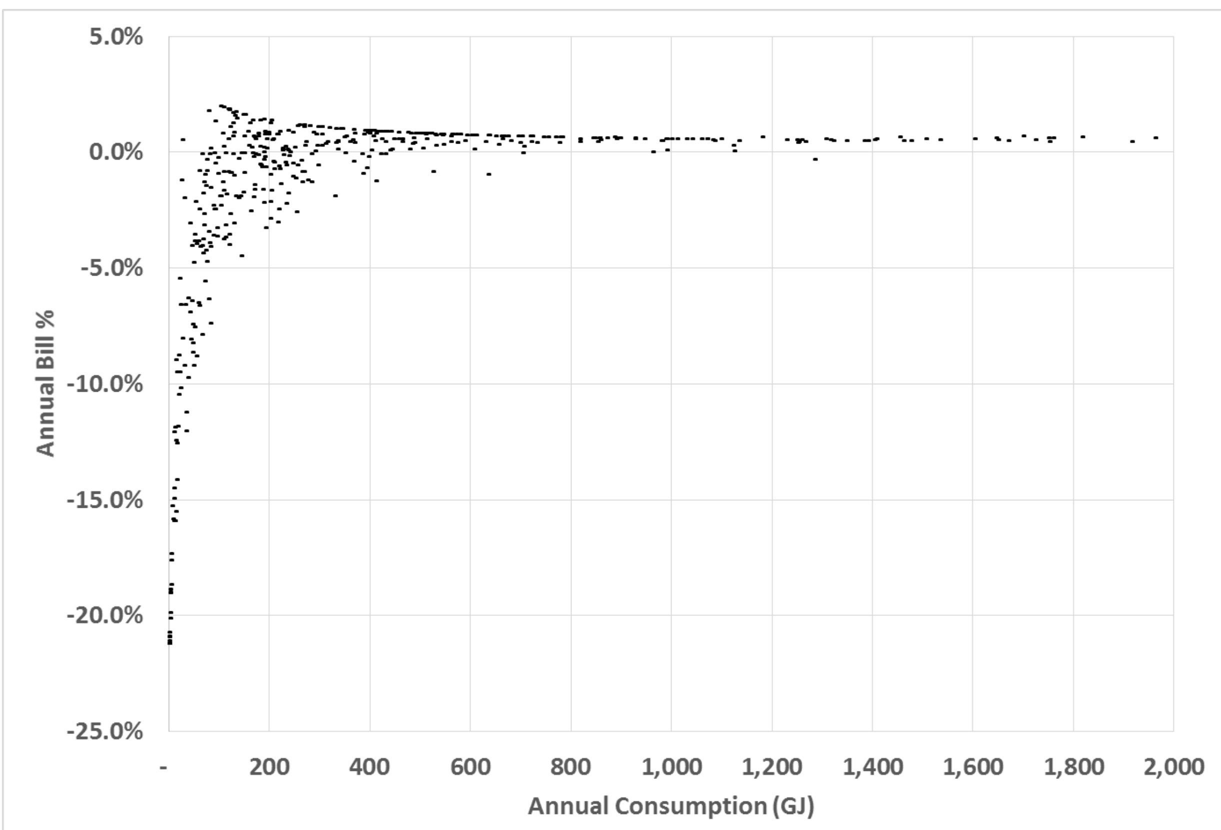
Table 13-22: Proposed Charges for Rate 2.1 & 2.2 Before Rebalancing

	Rate 2.1	Rate 2.2
Basic Charge $/Day	$1.1296	$1.8862
Delivery Charge $/GJ	$4.057	$3.919

The proposed rates in Table 13-22 do result in Rate 2.1 having a lower Basic Charge than Rate 2.2 and Rate 2.1 having a higher Delivery Charge than Rate 2.2 which is relationally the expected outcome as mentioned in section 13.5.5.3.

The following Figure 13-17 shows the percentage bill impact relative to the various levels of annual consumption from all the changes that FEI is proposing for Fort Nelson Rate 2.1 small commercial customers before rebalancing.

Figure 13-17: Annual Bill % Change at Various Annual Consumption Levels for Fort Nelson Small Commercial (< 2,000 GJ)



Fort Nelson small commercial customers that have an annual consumption of 2 GJ or less will have a large **decrease** in their annual bill (21% decrease or $111 annual decrease). The primary reason for this is that the current rate structure minimum bill effectively has a take or pay of 2 GJ per month including delivery cost of service plus cost of gas. After unbundling the cost of gas, there is a significant decrease for these customers as they will now only have a daily Basic Charge. The average decrease for the approximately 471 small commercial customers would be 2.6% or an average annual decrease of $7.

For the 15 Fort Nelson large commercial customers, the largest percentage decrease is 0.2% (annual bill decrease of $108) and the largest percentage increase is 0.7% (annual bill increase of $80). The average percentage increase for all 15 customers is 0.1% or $0. A similar graph to Figure 13-17 was not produced for Rate 2.2 because of the small number of customers (15).

13.5.6 Fort Nelson Industrial Customer Rate Design

13.5.6.1 Introduction

Fort Nelson's has the following rates in place to serve industrial customers:

- Rate 3.1 / 3.2 / 3.3 - Industrial Service
- Rate Schedule 25 - General Firm Transportation Service

The delivery charges calculated from the COSA model are slightly higher than the 2018 approved delivery charges shown above due to the revenue deficiency caused by one customer moving from RS 25 to Rate 2.1 as discussed in section 13.4.1.3. This deficiency causes an increase to the 2018 delivery charges of approximately 1%.

Fort Nelson's existing industrial rates consist of a minimum monthly charge and a declining block rate consisting of three consumption blocks. Rates 3.1, 3.2 and 3.3 have a Gas Cost Recovery Charge per GJ and Rate Schedule 25 has a monthly Administration Charge.

Fort Nelson's 2018 bundled rates based on the approved 2018 Revenue Requirement[217] and gas cost of $1.294 per GJ are provided in Table 13-23 below. The rates and blocks are the same for Rate 3.1, 3.2 and 3.3. The annual volume threshold for Rate 3.1 is 96,000 GJ, for Rate 3.2 it is greater than 96,000 GJ and less than 360,000 GJ, and for Rate 3.2 it is a minimum of 360,000 GJ. FEI is proposing to cancel Rate 3.2 and 3.3. There have been no customers served in Rate 3.1, 3.2, or 3.3 since 2001.

[217] Orders G-162-16 and G-173-16.

Table 13-23: Fort Nelson Industrial Rate Structure

Charge	Rate 3.1	RS 25
Administration Charge (per Month)	n/a	$202
Delivery Charge First 20 GJ/Month ($/GJ)	$4.552	$4.552
Delivery Charge Next 260 GJ/Month ($/GJ)	$4.201	$4.201
Delivery Charge Excess over 280 GJ/Month ($/GJ)	$3.450	$3.450
Minimum Monthly Charge ($/Month)	$1,826	$1,826
Gas Cost Recovery Charge ($/GJ)	$1.294	n/a

13.5.6.2 Customer Characteristics

Fort Nelson has only one industrial customer taking service under RS 25 as of November 1, 2016 and, as stated above, no customers in Rates 3.1, 3.2 or 3.3. The customer is no longer operating its production facility, but is still using natural gas for space heating to protect facilities and equipment from extreme cold weather damage. The customer's 2018 forecast demand is 40 TJ and its three year average load factor is 27%.

13.5.6.3 Fort Nelson Industrial Rate Design

For consistency, FEI is proposing to adopt the same rate structure for Fort Nelson as exists in FEI's other service areas. The charges included for the two industrial rate schedules would be: a Basic Charge, Demand Charge, and a Delivery Charge. Rate 3.1 would have a Commodity Cost Recovery Charge and a Storage and Transport Charge and RS 25 would have an Administration Charge.

The proposed 2018 rates will be designed to collect the same revenue as was forecast in Fort Nelson's 2017-2018 Revenue Requirement so that no other Rate Schedules are affected by this change.

FEI's proposed rates before rebalancing are set out in the table below.

Table 13-24: Fort Nelson Proposed Rate Structure Before Rebalancing

	Rate 3.1	RS 25
Basic Charge (per Month)	$600.00	$600.00
Demand Charge (per GJ per Month)	$28.727	$28.727
Delivery Charge (per GJ)	$1.000	$1.000
Administration Charge (per Month)	n/a	$39.00
Commodity Cost Recovery Charge (per GJ)	$1.275	n/a
Storage and Transport Charge (per GJ)	$0.019	n/a

FEI is also proposing to phase-out the application of the Revenue Stabilization Adjustment Mechanism (RSAM) for Rate 3.1 and RS 25. The RSAM stabilizes delivery margin received from customers on a Use Per Customer (UPC) basis. If customers' actual UPC varies from the forecast UPC used to set rates, whether due to weather variances or other causes, FEI records the delivery charge differences in the RSAM deferral account for refunding or charging through a rate rider to the RSAM rate schedules over the ensuing two years.

It would no longer be reasonable for the RSAM to apply to Fort Nelson's Rate 3.1 and RS 25 since a very large portion of the revenues will now be recovered through fixed charges – the Basic Charge, Administrative Charge and Demand Charge. This treatment of exclusion from the RSAM is consistent with FEI's exclusion of RS 5 and 25 from the RSAM mechanism.

However, since RS 25 customer(s) will be contributing to the build-up of the RSAM deferral balance up to the end of 2017 under the existing rate design, it is reasonable that RS 25 would attract the RSAM rider for the years 2018 and 2019, but only for its part of the 2017 ending RSAM deferral balance. FEI is proposing that the Industrial share of the December 31, 2017 RSAM balance be calculated on the 2016 and 2017 additions from the variance in actual consumption versus forecast consumption less one-half of the Industrial Rider 5 recoveries in 2017. (Due to the lag in recovering RSAM calculations and two year amortization, one half of the 2017 recoveries is related to 2016 additions).

When FEI calculates the RSAM charge for 2018 the amount to be recovered will be fixed from the 2017 RSAM balance assigned to Industrial classes, however the charge per GJ for RS 25 and Rate 3.1, will be the amount to be amortized divided by the years' forecast volumes 2018 and 2019. The RSAM Rider for the industrial rates will be eliminated starting January 1, 2020. If there are no Industrial customers at 2017 year end, i.e. the remaining RS 25 customer migrates to a commercial sales class, FEI proposes that the RSAM be eliminated effective January 1, 2018 for Industrial customers.

13.6 *THE FEI FORT NELSON GAS TARIFF*

The Fort Nelson Tariff sets out the Commission approved terms, conditions rates and rate schedule for each of Fort Nelson's different service offerings. Appendix 13-6 contains the existing Fort Nelson Tariff blacklined with the proposed revisions to reflect the proposals in the Application and to align the tariff language with that of FEI's rate schedules. FEI has also taken the opportunity to make minor revisions to wording and housekeeping changes for consistency purposes.

The following provides a high-level summary of the primary changes being proposed to each of the proposed Fort Nelson's rate schedules. Please refer to Appendix 13-6 to review the detailed revisions proposed.

Rate Schedule 1: Residential Service

Fort Nelson RS 1, consistent with FEI RS 1, is applicable for all Residential Customers and now includes a common table of charges. FEI has removed details regarding an optional rate previously available for customers whose primary heating was from equipment installed with the assistance of a promotional incentive which is no longer applicable.

Rate Schedule 2: Small Commercial Service

Fort Nelson RS 2, consistent with FEI RS 2, is applicable for small Commercial Customers with normalized annual consumption of less than 2,000 GJs. Fort Nelson RS 2 now includes a common table of charges for applicable small Commercial Customers. Previously, two rates existed for Commercial Customers, (formerly named General Service Customers), depending on their annual consumption: those who consumed less than 6,000 GJs or those who consumed 6,000 GJs or higher during the previous gas year (which runs from their first bill in November to their final bill the following October each year).

Rate Schedule 3: Large Commercial Service

Fort Nelson RS 3 is a new rate schedule for large Commercial Customers, which is consistent with FEI RS 3. Fort Nelson RS 3 is applicable for large Commercial Customers with normalized annual consumption of more than 2,000 GJs. Fort Nelson RS 3 also has a common table of charges for applicable large Commercial Customers.

Rate Schedule 5: General Firm Service

Fort Nelson RS 5 is a new rate schedule for Fort Nelson General Firm Service customers, which is substantially consistent with FEI RS 5.

Rate Schedule 6: Natural Gas Vehicle Service

Fort Nelson RS 6 is a new rate schedule for Fort Nelson Natural Gas Vehicle Service customers, which is substantially consistent with FEI RS 6.

Rate Schedule 25: General Firm Transportation Service

Fort Nelson RS 25 has been revised to mirror the terms and conditions of FEI RS 25. Similarly, the form of Transportation Agreement and Schedule A in Fort Nelson RS 25 (Shipper Agent Agreement) has been revised to mirror the proposed amendments made to FEI RS 25. In addition, an Appendix A (Notice of Appointment of Shipper Agent) has been added to the Transportation Agreement.

For additional information regarding the amendments made to the existing terms and conditions for FEI RS 25, please refer to Section 9.5 of the Application and Appendix 11-3 for a blacklined version.

FEI proposes that the changes to the Fort Nelson Tariff be approved effective Q4 of 2018.

13.7 SUMMARY AND CONCLUSIONS

Fort Nelson's rate design proposals described in section 13.5.5.4 above have an impact on the COSA results presented in section 13.4.3. In addition, the COSA results as presented in section 13.4.3 show that all of the Fort Nelson rates are outside the range of reasonableness. As directed by Order G-4-18, FEI is using a range of reasonableness of 95% to 105%. Therefore, FEI is proposing to rebalance rates to bring Fort Nelson's Rate 1, Rate 2.1, Rate 2.2 and RS 25 to the boundaries of the range of reasonableness. With this rebalancing, FEI believes that its rate design proposals will result in a reasonable balance of rate design principles, are just and reasonable and should be approved as proposed.

This section is organized as follows:

- Section 13.7.1 summarizes the impact of Fort Nelson's rate design proposals on the COSA, presents Fort Nelson's final COSA results after taking into account revenue changes due to rate design proposals, shows Fort Nelson's final COSA results after rebalancing to bring rates within the range of reasonableness and presents the associated bill impacts to Fort Nelson customers.
- Section 13.7.2 provides a summary of Fort Nelson's proposed changes to rates, comparing the 2018 rates resulting from the COSA before and after the proposed changes.
- Section 13.7.3 reviews whether or not postage stamping FEI rates to Fort Nelson is suitable.
- Section 13.7.4 concludes this section.

13.7.1 COSA Adjustments from Rate Design Proposals

FEI has included in Fort Nelson's COSA the changes based on the rate design proposals set out above. A summary of the rate design proposals and resulting changes included in the COSA Model are outlined below.

13.7.1.1 Rate 1 – Residential

FEI's proposal for residential rates is to unbundle the delivery cost from gas costs by removing the declining block rate structure and adopting the following charges: Basic Charge per day, Delivery Charge per GJ, Cost of Gas Charge per GJ and Storage and Transport Charge per GJ (plus applicable riders).

The charges that FEI derived are expected to collect the same amount of revenue from Rate 1 as are currently collected, resulting in no changes to the COSA.

13.7.1.2 Rate 2.1 and Rate 2.2 – Commercial

FEI's proposal for Rate 2.1 and Rate 2.2 is as follows:

1. Unbundle the delivery cost from the cost of gas by removing the declining block rate structure and adopting the following charges: Basic Charge per day, Delivery Charge per GJ, Commodity Cost Recovery Charge per GJ and Storage and Transport Charge per GJ (plus applicable riders).
2. Move the small to large commercial customer threshold to an annual demand of 2,000 GJ.
3. Establish the Daily Basic and volumetric Delivery Charges to have an equal annual bill for Rate 2.1 and Rate 2.2 at the economic crossover point of 2,000 GJ.

By changing the threshold from 6,000 GJ/year to 2,000 GJ/year, nine Rate 2.1 customers consuming more than 2,000 GJ/year would be moved to Rate 2.2 and one Rate 2.2 customer consuming less than 2,000 GJ/year would be moved to Rate 2.1. The movement of these customers is reflected in the COSA by shifting their annual volume, revenue and cost of gas in the COSA Model. The following table illustrates the resulting changes.

Table 13-25: Commercial Customer Shifting in the COSA

	Rate 2.1	Rate 2.2
Customers	-8	+8
Volume (TJ)	-23.3	+23.3
Revenue ($000)	-126.7	+126.7
Cost of Gas ($000)	-30.1	+30.1

The shifting of customers between Rate 2.1 and Rate 2.2 is revenue neutral between the two commercial rates. When included in the COSA the R:C ratio for Rate 2.1 decreases by 1.2 % and the R:C for Rate 2.2 increases by 1.4 %.

13.7.1.3 Rate Schedule 25 and Rate 3.1 – Industrial

FEI's proposal for RS 25 and Rate 3.1 is to eliminate the block rate structure and adopt FEI's rate structure as follows:

Rate 25

1. Remove the declining block rate structure.
2. Adopt the following charges: Basic Charge per Month, Administrative Charge per Month, Demand Charge per Month per GJ of Daily Demand, and Delivery Charger per GJ (plus applicable riders).

Rate 3.1

1. Remove the declining block rate structure.
2. Adopt the following charges: Basic Charge per Month, Demand Charge per Month per GJ of Daily Demand, Delivery Charger per GJ, Commodity Cost Recovery Charge per GJ, Storage and Transport Charge per GJ (plus applicable riders).

Neither RS 25 nor Rate 3.1 would contribute to the RSAM due to variances in the forecast use rate versus actual use rate. The industrial customers would continue to contribute to the recovery / refund of the December 31, 2017 RSAM balance in 2018 and 2019, On January 1, 2020 the RSAM Rate Rider would be eliminated for industrial customers.

By adopting FEI's Rate Schedule 5 and 25 rate structure and setting the charges to collect the existing RS 25 revenue there is no impact to the COSA.

In addition, FEI proposes to decrease the Administration Charge per Month for RS 25 from $202.00 to $39.00 as set out in Appendix 11-3, Section 1.4 and Appendix 11-4. The reduction in the Administration Charge decreases the revenue collected from RS 25 by $1,956 annually. When reflected in the COSA, this change causes an annual bill increase for Rate 1, Rate 2.1 and Rate 2.2 of 0.08%, while RS 25 receives an annual bill decrease of 1.2%.

13.7.1.4 Final COSA Results and Rebalancing

The table below presents the R:C and M:C ratios before rebalancing and after the rate design proposal changes discussed above.

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*	91.4%	89.0%	0.8	0.1%	91.7%	89.4%
Rate 2.1 *General (Small Commercial) Service*	109.4%	112.2%	(126.0)	0.1%	108.2%	110.8%
Rate 2.2 *General (Large Commercial) Service*	114.4%	119.8%	127.0	0.1%	115.8%	120.0%
Rate Schedule 25 *General Firm Transportation Service*	92.4%	92.4%	(1.8)	-1.2%	91.5%	91.5%

As directed by Order G-4-18, FEI is using the range of reasonableness of 95% to 105% to inform rate design and rebalancing proposals.

The table above shows that Rate 1, Rate 2.1, Rate 2.2 and RS 25 are outside the 95% to 105% range of reasonableness. FEI is therefore proposing to adjust revenue responsibility as follows:

- Decrease Rate 2.1 revenue by $35.0 thousand, which will reduce the R:C ratio of Rate 2.1 to within the range of reasonableness;
- Decrease Rate 2.2 revenue by $37.2 thousand, which will reduce the R:C ratio of Rate 2.2 to within the range of reasonableness;
- Increase RS 25 revenue by $5.7 thousand, which will increase the R:C ratio of RS 25 to within the range of reasonableness; and
- Increase Rate 1 revenue by $66.5 thousand to offset the decrease in revenue from Rate 2.1 and Rate 2.2 and the increase in revenue from RS 25.

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*	91.7%	89.4%	66.5	5.4%	95.9%	94.8%
Rate 2.1 *General (Small Commercial) Service*	108.2%	110.8%	(35.0)	-2.2%	105.0%	106.6%
Rate 2.2 *General (Large Commercial) Service*	115.8%	120.0%	(37.2)	-8.6%	105.0%	106.4%
Rate Schedule 25 *General Firm Transportation Service*	91.5%	91.5%	5.7	6.2%	95.0%	95.0%

13.7.1.5 Rate Design and Rebalancing Proposal Implementation

Fort Nelson rates must be adjusted to account for the shift in revenue responsibility as shown in Table 13-27 above. For Rate 1, FEI will increase the Basic Charge to $0.3701 per day so that the $66.5 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 22% of its revenue from Rate 1 through the Basic Charge; the customer-related costs in the COSA equal 63%.

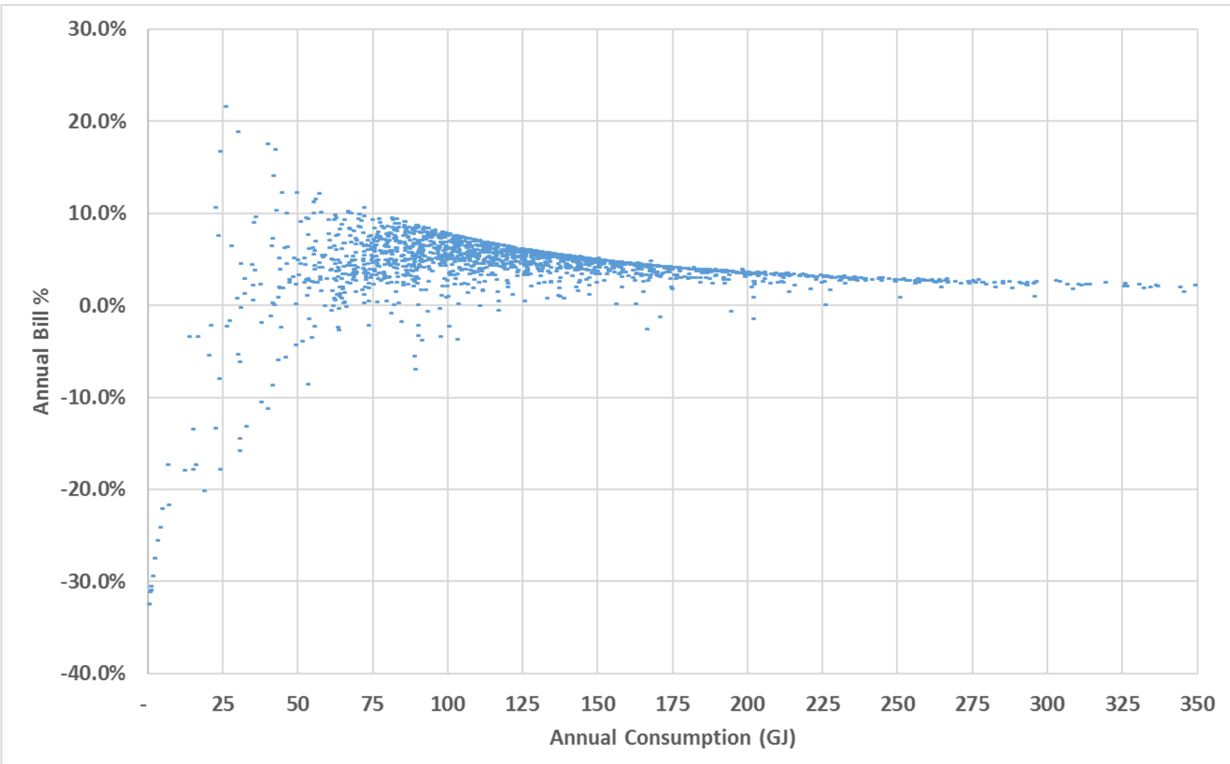
For Rate 2.1 and Rate 2.2, FEI adjusted rates to account for the decrease in revenue responsibility of $35.0 thousand and $37.2 thousand, respectively. This adjustment was made to maintain an economic breakeven threshold of 2,000 GJ /year as discussed in section

13.5.5.4, to align the basic charge of both Rate 2.1 and Rate 2.2 proportionally to the customer classified costs from the COSA model, and to limit any individual customer's annual bill impact.

For Rate Schedule 25, FEI adjusted the Demand Charge to account for the increase in revenue responsibility of $5.7 thousand.

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.

Figure 13-18: Rate 1 Bill Impacts from all Rate Design Proposals



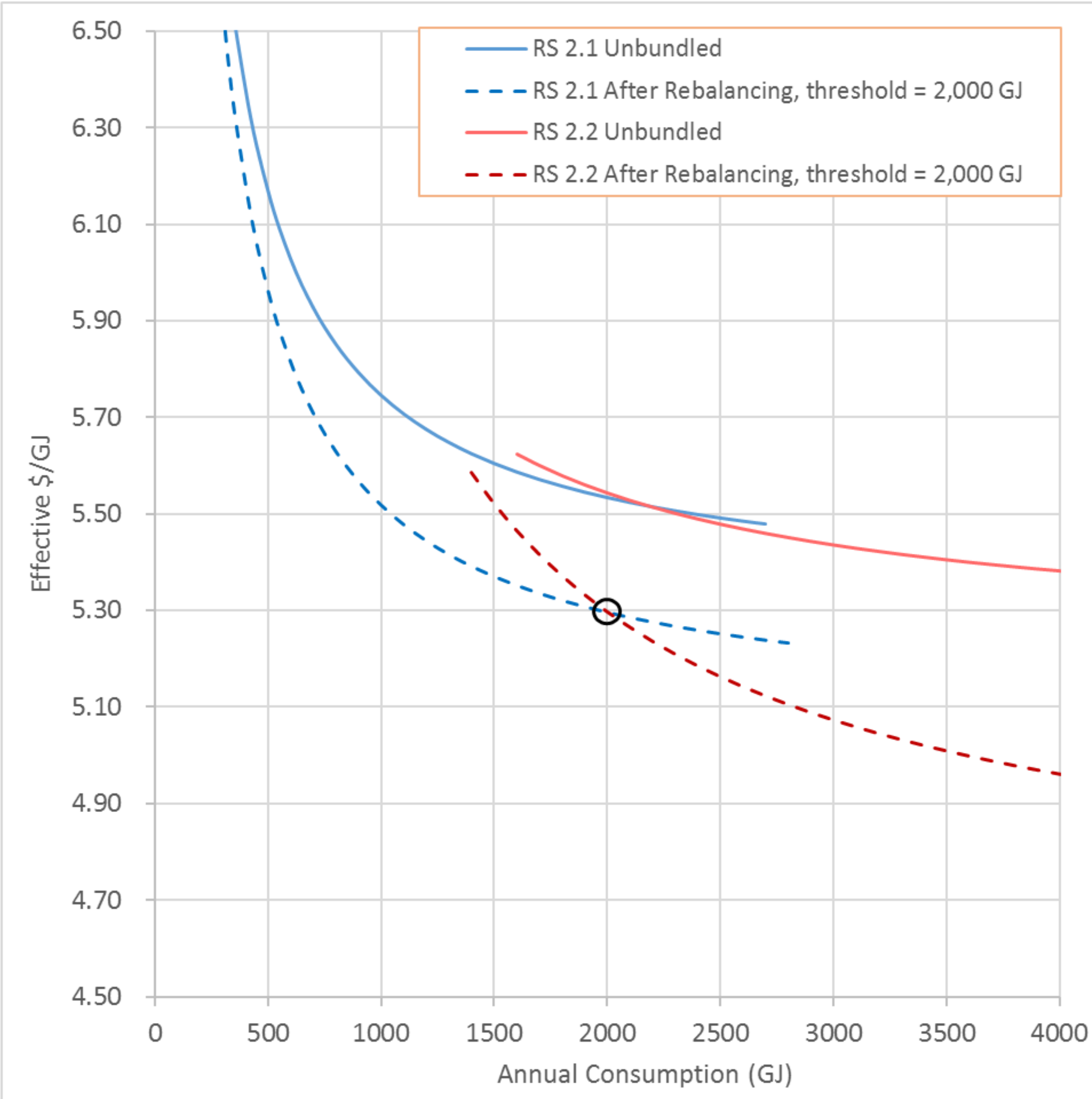
The following table shows the rates for the daily Basic Charge and the volumetric Delivery Charge for Rate 2.1 and 2.2.

Table 13-28: Rate 2.1 and 2.2 Charges after all Rate Design Proposals

	Rate 2.1	Rate 2.2
Daily Basic Charge ($/Day)	1.2151	3.6845
Delivery Charge ($/GJ)	3.781	3.330

The following figure compares the effective rates per GJ for Rate 2.1 and 2.2 after unbundling and removing declining block, set (including rebalancing) to attain a 2,000 GJ/year breakeven point and minimizing individual customer bill impacts.

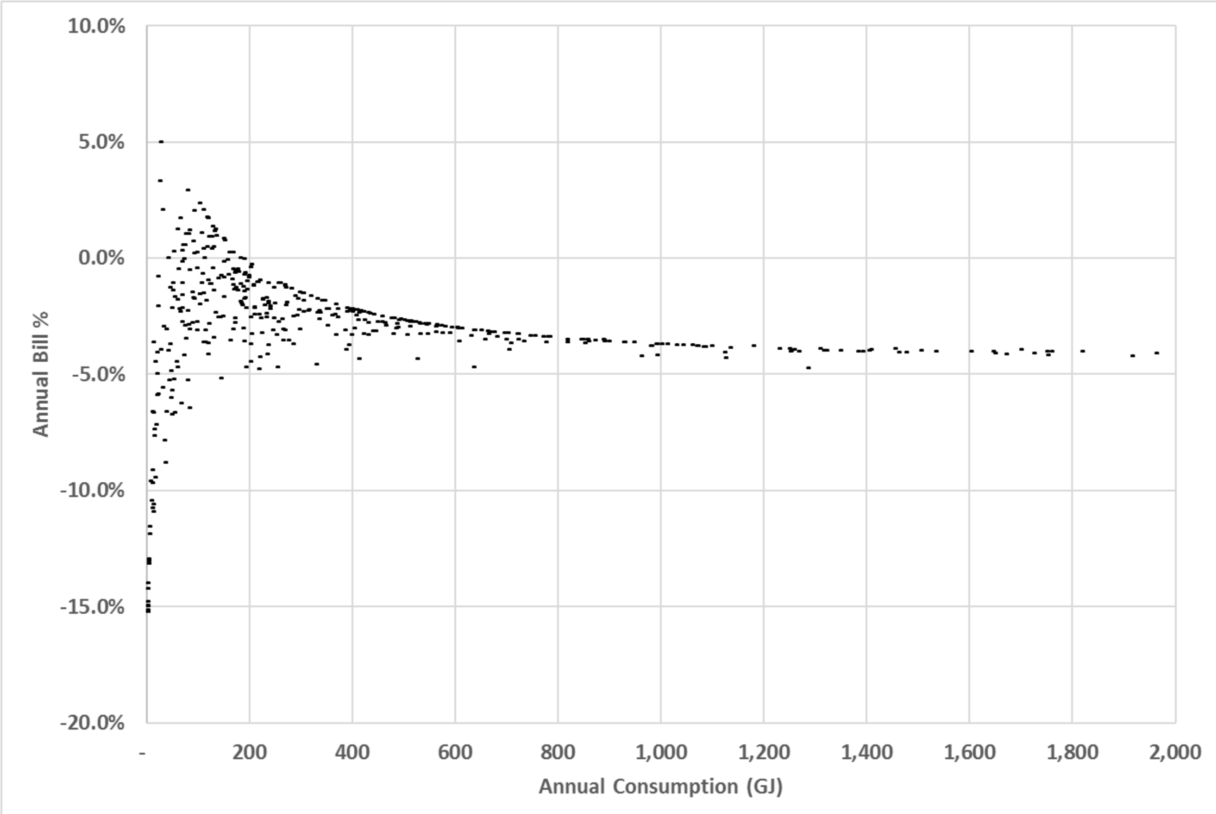
Figure 13-19: Rate 2.1 and 2.2 Effective $/GJ



The two solid lines are the effective delivery rates ($/GJ) after Rate 2.1 and Rate 2.2 are unbundled, where the charges are set to collect the existing revenue responsibility of each Rate and so that the bill impact to any one customer is minimized. The two dotted lines are the effective delivery rates ($/GJ) after Rate 2.1 and Rate 2.2 are unbundled, Rate 2.1 and Rate 2.2 are rebalanced, the breakeven threshold is set to 2,000 GJ per year, the bill impact to any one customer is limited and charges are set so that the basic charges of Rate 2.1 and Rate 2.2 are proportionately aligned to the customer classified costs from the COSA.

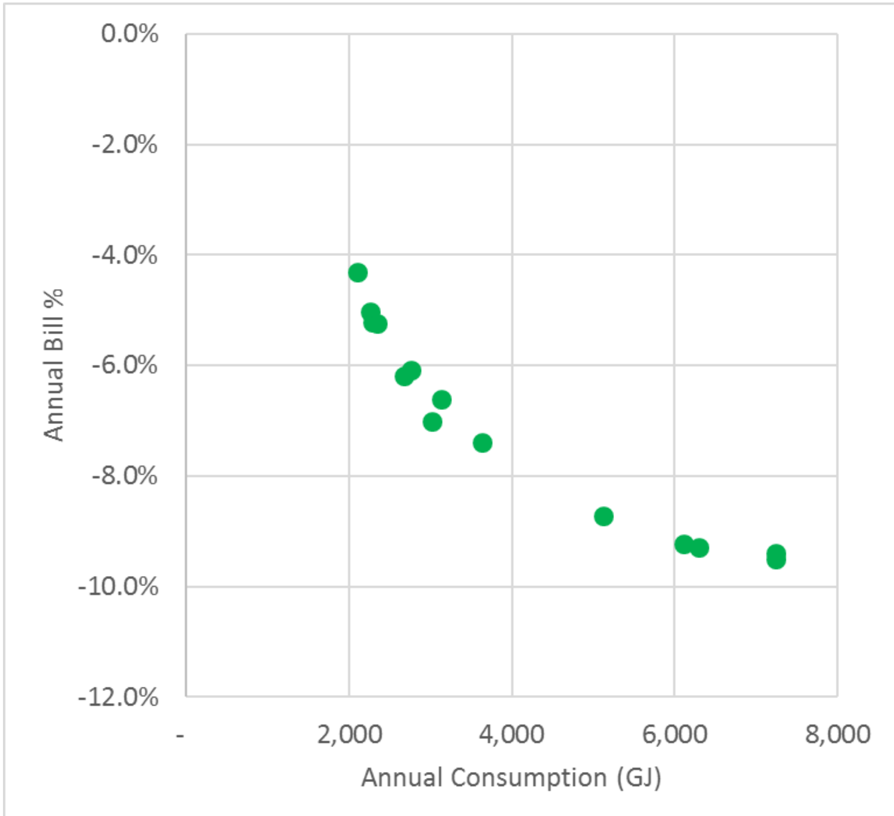
The following two figures show Rate 2.1 and Rate 2.2 customer bill impacts from all changes including unbundling, setting the breakeven to 2,000 GJ per year and rebalancing.

Figure 13-20: Rate 2.1 Bill Impacts from all Rate Design Proposals



The figure above shows Rate 2.1 customers' bill impacts after unbundling and rebalancing, setting the breakeven threshold between Rate 2.1 and Rate 2.2 to 2,000 GJ/year and limiting any one customer's bill impact. Each point is an individual customer. Rate 2.1 customers experience between a 5% increase and 15% decrease in their annual bills.

Figure 13-21: Rate 2.2 Bill Impacts from all Rate Design Proposals



The figure above shows Rate 2.2 customers' bill impacts after unbundling and rebalancing, setting the breakeven threshold between Rate 2.1 and Rate 2.2 to 2,000 GJ/year and limiting any one customer's bill impact. Each point is an individual customer. Rate 2.2 customers experience about a 4.0% or greater decrease in their annual bills.

For Rate Schedule 25, FEI adjusted the Demand Charge to account for the increase in revenue responsibility of $5.7 thousand. FEI increased the demand charge per month per GJ of daily demand from $28.727 to $30.350 resulting in an annual bill increase of approximately 4%.

Detailed Final COSA schedules are included as Appendix 13-5.

13.7.2 Summary of Rate Proposals

Table 13-29 below presents a summary of FEI's rate design proposals for Fort Nelson.

Table 13-29: Fort Nelson Rate Proposal Summary

Rate Component	Rate 1	Rate 2.1	Rate 2.2	Rate 3.1	RS 25
Existing COSA Rates[218]					
Minimum daily Charge incl. 1st 2 GJ/month	$0.5483	$1.4337	$1.4337		
Administration Charge (/month)					$202
Next 28 GJ/month	$4.885				
Excess over 30 GJ/month	$4.782				
Next 298 GJ/ month		$5.336	$5.336		
Excess over 300 GJ/month		$5.210	$5.210		
Delivery Charge First 20 GJ/month				$4.522	$4.522
Delivery Charge Next 260 GJ/month				$4.201	$4.201
Excess over 280 GJ/month				$3.450	$3.450
Minimum Delivery Charge/month				$1,826	$1,826
Total Annual Bill:[219]	**$742**	**$2,433**	**$28,546**	**n/a**[220]	**$148,664**
Proposed Rates					
Basic Charge/Day	$0.3701	$1.2151	$3.6845		
Basic Charge (/Month)				$600.00	$600.00
Administration Charge (/Month)					$39.00
Demand Charge (/GJ/Month)				$30.350	$30.350
Delivery Charge ($/GJ)	$3.512	$3.781	$3.330	$1.000	$1.000
Commodity Cost Recovery Charge ($/GJ)	$1.275	$1.275	$1.275	$1.275	
Storage and Transport Charge ($/GJ)	$0.019	$0.020	$0.017	$0.019	
Total Annual Bill:	**$784**	**$2,383**	**$25,989**	**n/a**[221]	**$153,943**

13.7.3 Annual Bill Impact and Phase-in Period Discussion for Rate 1 Customers

As explained in FEI's response to BCUC-FEI IR 2.84.1.1, when considering the 2018 revenue requirement increases and using a 95 percent to 105 percent range of reasonableness, the total percentage increase in 2018 from 2017 exceeds the 10 percent rate impact threshold. The table below provides the percentage of bill increases for residential customers when considering for 2018 revenue requirement increases:

[218] The COSA rates shown are 2018 approved rates, $1.294 Gas Cost Recovery Charge, and test year adjustments discussed above in Section 13.4.1.3.
[219] Based on an average annual demand per customer of 135 GJ for Rate 1, 382 GJ for Rate 2.1 and 5,332 GJ for Rate 2.2 and 39,500 GJ for RS 25.
[220] There are no customers taking service under Rate 3.1, therefore Total Annual Bill shows as n/a.
[221] Ibid.

Table 13-30: Percentage Annual Bill Increase for Residential Customers

Bill Impact Items	Percentage annual bill impact for Rate 1
2018 Revenue requirement increases	5.10 %
2018 Rate design proposal	0.10 %
2018 Rate design rebalancing to 95% to 105% range of reasonableness (based on Order G-4-18)	5.40 %
Total year 2018 percentage increase	10.60%

In response to BCUC-FEI IR 2.84.2, FEI discussed the potential option of phasing-in the rate changes for Rate 1 customers over two years with rate changes for this period to apply in the form of revenue shifts in dollar amounts.

FEI has re-examined the two year phase-in period option, and does not recommend a phase-in for the following reasons:

- The timing and overall bill impact of 2018 revenue requirement increases: The 2018 delivery margin increases were applied to the rates effective January 1, 2018. The delivery margin increases were more than offset by commodity cost decreases, mitigating the overall bill impact on Rate 1 customers.
- The timing of rate design and rebalancing implementation: FEI believes that the initial target date of June 1, 2018 to implement rate design changes is no longer achievable. The rate design implementation target date is now in the fourth quarter of 2018 (the actual implementation date depends on the timing of the Commission's rate design decision for entire Application). As such, the rate design and rebalancing related revenue responsibility changes will only apply to the last months of 2018 and their overall impact on customers' 2018 annual bills would be minimal.

It is not known at this time what, if any, the 2019 revenue requirement changes may be on the overall bill impact experience for Rate 1 customers. FEI will review the 2019 revenue requirement changes and may propose a phase in of the potential revenue requirement increases for 2019 in its revenue requirement filing.

13.7.4 Postage Stamp Rates

In this section FEI shows the rate impacts to Fort Nelson customers if delivery rates and gas costs were to be postage stamped with the rest of FEI's service areas. Due to the potential rate impacts from postage stamp rates, and in consideration of the impacts from the proposed rebalancing and already approved rate changes for 2017 and 2018, FEI is not proposing to postage stamp Fort Nelson rates at this time.

Table 13-31 below shows a comparison between FEI and Fort Nelson effective delivery rates for residential, commercial and industrial customers.

Table 13-31: Comparison between FEI and Fort Nelson Delivery Rates

Fort Nelson Rate Design
Postage Stamp Comparison - *Effective Delivery Rate*

				Fort Nelson			
	FEI Proposed Rates		Proposed Rates		Difference		FN/FEI
Rate Schedule 1 (1b)							
Basic Charge/Day	$	0.4085	$	0.3701	$	(0.0384)	
Delivery Charge/GJ	$	4.762	$	3.512	$	(1.250)	
Annual Usage (GJ)		132.53		132.53			
Effective Rate/GJ	**$**	**5.89**	**$**	**4.53**	**$**	**(1.36)**	-23%
Rate Schedule 2 (2.1)							
Basic Charge/Day	$	0.9485	$	1.2151	$	0.2666	
Delivery Charge/GJ	$	3.664	$	3.781	$	0.117	
Annual Usage (GJ)		382.2		382.2			
Effective Rate/GJ	**$**	**4.57**	**$**	**4.94**	**$**	**0.37**	8%
Rate Schedule 3 (2.2)							
Basic Charge/Day	$	4.7895	$	3.6845	$	(1.1050)	
Delivery Charge/GJ	$	3.190	$	3.330	$	0.140	
Annual Usage (GJ)		5,332.1		5,332.1			
Effective Rate/GJ	**$**	**3.52**	**$**	**3.58**	**$**	**0.06**	2%
Rate Schedule 25							
Admin Charge/Mth	$	39	$	39	$	-	
Basic Charge/Mth	$	469	$	600	$	131	
Demand Charge/GJ/Mth	$	24.596	$	28.727	$	4.131	
Delivery Charge/GJ	$	0.887	$	1.000	$	0.113	
Contract Demand		292.7		292.7			
Annual Usage (GJ)		39,500.0		39,500.0			
Effective Rate/GJ	**$**	**3.23**	**$**	**3.75**	**$**	**0.52**	16%

As shown above, the proposed Fort Nelson residential customers' effective delivery rate is 23% lower than the delivery rates proposed for FEI residential customers. The effective delivery rate of commercial customers served under Rate Schedule 2 (formerly Rate 2.1) is 8% higher under Fort Nelson proposed changes compared to FEI RS 2 customers. With the proposed changes discussed above, Rate Schedule 3 (formerly Rate 2.2) customers' effective delivery rate is 2% higher than FEI proposed rates for RS 3 customers, while Rate Schedule 25 Fort Nelson customers' effective delivery rate will be 16% higher than FEI's RS 25 rates.

The following table compares the gas cost recovery for Fort Nelson and FEI for residential, small commercial and large commercial as of July 1, 2016 and January 1, 2017.

Table 13-32: Comparison of Gas Cost Recovery FEI and Fort Nelson Residential and Commercial Customers

Line				
As of July 1, 2016				
	Fort Nelson	**Rate 1**	**Rate 2.1**	**Rate 2.2**
1	**Total:**	**$1.294**	**$1.294**	**$1.294**
	FEI	**RS 1**	**RS 2**	**RS 3**
2	Commodity Cost Recovery rates	$1.719	$1.719	$1.719
3	Storage & Transport rates	$1.117	$1.133	$0.940
4	**Total:**	**$2.836**	**$2.852**	**$2.659**
5	Variance (Line 4 – Line 1)	$1.542	$1.558	$1.365
As of January 1, 2017				
	Fort Nelson	**Rate 1**	**Rate 2.1**	**Rate 2.2**
6	**Total:**	**$2.086**	**$2.086**	**$2.086**
	FEI	**RS 1**	**RS 2**	**RS 3**
7	Commodity Cost Recovery rates	$2.050	$2.050	$2.050
8	Storage & Transport rates	$1.009	$1.020	$0.851
9	**Total:**	**$3.059**	**$3.070**	**$2.901**
10	Variance (Line 9 – Line 6)	$0.973	$0.984	$0.815

Whether looking at the variance of the gas cost as of July 1, 2016 or January 1, 2017, there is a substantive difference in the gas costs for Fort Nelson customers compared to the postage stamp rates for FEI's other customers. The primary reason for this difference is that the transport costs for delivery to Fort Nelson on Spectra's T-North Short Haul is only approximately two cents (see Table 13-11, Line 13).

Table 13-33 below shows the result if the effective delivery rate difference for residential and commercial classes in Table 13-31 is added to the gas cost variance in Table 13-32 (based on January 1, 2017 gas costs embedded in customers' bundled rates). The table shows that residential and commercial customers have lower rates in Fort Nelson than in FEI's other service areas.

Table 13-33: Summation of Effective Delivery Variance and Cost of Gas Variance $ / GJ

	Residential	Small Commercial	Large Commercial
Effective Delivery Rate Difference	$1.36	$(0.37)	$(0.06)
Total Cost of Gas Variance	$0.97	$0.98	$0.82
Total Variance	$2.33	$0.61	$0.76
Total Variance %	-26%	-7%	-12%

In addition to the rate differences summarized in Table 13-33 above, and in consideration of the proposed rebalancing discussed in section 13.7.1.4 of the Application and the delivery rate changes approved for 2017 and 2018 by Order G-162-16 related to Fort Nelson's revenue requirements and rates application, FEI is not proposing to postage stamp rates for Fort Nelson customers at this time.

13.7.5 Conclusion

Based on the analysis and considerations set out above in this section, FEI believes that its rate design proposals for Fort Nelson customers will result in a reasonable balance of rate design principles, are just and reasonable and should be approved as proposed.

Appendix 1-2

DRAFT FINAL ORDER
ORDER G-4-18 UPDATE, FEBRUARY 6, 2018
CLEAN

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
2016 Rate Design Application

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On December 19, 2016, FortisBC Energy Inc. (FEI or the Company) filed an Application with the British Columbia Utilities Commission (Commission) seeking the necessary approvals, pursuant to sections 58 to 61 of the *Utilities Commission Act* (Act), to adjust its rate design and terms and conditions of service for all service areas to improve the alignment with accepted rate design principles (Application);

B. On January 20, 2017, the Commission commenced its review of the Application and issued Order G-6-17 establishing a Regulatory Timetable;

C. On February 2, 2017, in accordance with the Regulatory Timetable, FEI submitted its supplemental filing which included FEI's revisions to its rate schedules reflecting the proposals in the Application and the proposed rate design for the Fort Nelson Service Area;

D. On March 2, 2017, a Workshop was held to review the information provided to stakeholders at the May 19, 2016, Education & Background Information Session;

E. On March 9, 2017, a second Workshop was held to review the COSA Model, Proposals in the Application, and Approvals Sought;

F. On [DATE, 2017], the Commission held a procedural conference to address, among other things, the process and timetable for the remainder of the review of the Application;

G. On [DATE, 2017], the Commission issued Order G-XX-2017 establishing a written/oral hearing process; and

Order G-4-18 Updates, February 6, 2018

H. The Commission has reviewed and considered the Application, the evidence filed, and the submissions provided by all participants, and has determined that the requested changes, as outlined in the Application, should be approved.

NOW THEREFORE the Commission orders as follows:

Midstream Cost Allocation Methodology

1. The use of a three-year average load factor in RS 5 to allocate midstream costs when setting FEI's Storage and Transport Charges for RS 5, as discussed in Section 6.4.2.1 of the Application, is approved.

FEI Residential Rate Schedules

2. The following rate design proposals for Rate Schedules 1, 1U, 1X, and 1B are approved:
   - An increase to the Basic Charge per Day by $0.0195 from $0.3890/Day to $0.4085/Day to increase the proportion of fixed costs recovered by the Basic Charge, as discussed in Section 7.8 of the Application.
   - A decrease to the Delivery Charge per GJ by $0.086/GJ to maintain revenue neutrality with the Basic Charge increase, as discussed in Section 7.8 of the Application.
   - The housekeeping and other amendments as set out in Appendix 11-3, and discussed in the supplemental filing to the Application.
   - An increase the Delivery Charge per GJ by $0.027/GJ as a result of the revenue shifts and rebalancing of rates discussed in Section 12.2 of the Application.

FEI Commercial Rate Schedules

3. The adjustments to the basic charges and delivery charges of the commercial rate schedules to align with the 2,000 GJ threshold between small and large commercial customers, as discussed in Section 8.7 of the Application, are approved, as follows:
   - For Rate Schedules 2, 2B, 2U, and 2X:
     - Increase the Basic Charge per Day by $0.1324 from $0.8161/Day to $0.9485/Day.
     - Decrease the Delivery Charge per GJ by $0.186/GJ.
   - For Rate Schedules 3, 3B, 3U, 3X, and 23:
     - Increase the Basic Charge per Day by $0.4357 from $4.3538/Day to $4.7895/Day.
     - Increase the Delivery Charge per GJ by $0.001/GJ.
   - For RS 23:
     - Decrease the Administration Charge per Month from $78.00 to $39.00, set out in Appendices 11-3 and 11-4, and discussed in the supplemental filing to the Application.
4. The proposed housekeeping and other amendments to Rate Schedules 2, 2U, 2X, 2B, 3, 3U, 3X, 3B, and 23, as set out in Appendix 11-3, and discussed in the supplemental filing to the Application, are approved.

FEI Industrial Rate Schedules

5. The revision to the multiplier in the Daily Demand formula in RS 5 and RS 25 from 1.25 to 1.10 and the increase in the Demand Charge in RS 5 and RS 25 by $3.00/GJ/Month, as discussed in Section 9.5, are approved.

6. The decrease to the Basic Charge in RS 5 and RS 25 by $118.00 per month from $587.00 per month to $469.00 per month, as discussed in Section 12.2.2, is approved.

7. The decrease in the Delivery Charge of RS 7 and RS 27 by $0.012/GJ as shown in Table 9-20 and discussed in Section 9.6, is approved.

8. The increase to RS 4 rates due to the proposed changes to RS 5 and RS 7 as shown in Table 9-21 and discussed in Section 9.7, by increasing the Off-Peak Delivery Rate by $0.114/GJ and by decreasing the Extension Period by $0.018/GJ, is approved.

9. Setting the charges for RS 22 on a cost of service basis for all large industrial customers, as discussed in Section 9.8.5 and set out below, is approved:

   - Firm Demand Charge of $25.000/GJ/Month.
   - Firm MTQ Delivery Charge of $0.015/GJ.
   - Interruptible MTQ Delivery Charge of $0.972/GJ.

10. Termination of Tariff Supplement G-21, FEI's contract with Creative Energy Vancouver Platforms Inc., effective in the fourth quarter of 2018, as discussed in Section 9.8.5 of the Application, is approved.

11. The following adjustments to the transportation model are approved:

    - Amendments to Rate Schedules 22, 22A, 22B, 23, 25, 26, and 27 to implement daily balancing for all transportation customers, as discussed in Section 10.6.
    - Amendments to Rate Schedules 22, 22A, 22B, 23, 25, 26, and 27 to reduce the daily balancing tolerance to a 10% threshold and to introduce a balancing charge of $0.25/GJ for transportation customers for gas supply shortfalls within a 10% to 20% tolerance level, as discussed in Section 10.7.

12. The proposed housekeeping and other amendments to Rate Schedules 5, 7, 11B, 14A, 22, 22A, 22B, 25, 26, and 27 as set out in Appendices 11-3 and 11-4, and discussed in the supplemental filing to the Application, are approved.

13. The decrease to the Delivery Charge per GJ of RS 6 by $1.622/GJ to address rebalancing, as discussed in Section 12.2.2 of the Application, is approved.

14. Setting the Delivery Charge per GJ for RS 6P to equal the Delivery Charge per GJ of RS 6, as discussed in Section 12.2.2 of the Application, is approved.

General Terms and Conditions

15. The housekeeping and other amendments to FEI's General Terms and Conditions, as set out in Appendices 11-1 and 11-2 and discussed in Section 11 of the Application, are approved.

16. The proposed amendments to the FEI Rate Schedules as set out and discussed in Appendix 11-3 of the Application are approved.

Fort Nelson Service Area

17. The cancellation of the following Fort Nelson Rates, each of which has no customers, is approved:
    - Rate 1 Option A - Domestic Service for Primary space heating equipment purchased from FEI Fort Nelson
    - Rate 2.4 - Compression/Dispensing Service
    - Rate 3.2 – Industrial Service
    - Rate 3.3 – Industrial Service
18. The proposal to rename Fort Nelson's existing Rates to align with FEI's Rate Schedule naming convention, as set out in Table 13-1 of Section 13.2.1.1 of the Application, is approved.
19. The proposal to unbundle Fort Nelson's residential and commercial rates, as discussed in Section 13.5.2 of the Application, is approved.
20. The proposal to record the cost of changes to the billing system in a deferral account on a net-of tax basis and amortized over 5 years beginning in 2019, as discussed in Section 13.5.2 of the Application, is approved.
21. The following rate design proposals for Rate Schedules 1, 2, 3, 5, and 6 are approved
    - To set a Commodity Cost Recovery Charge based on classifying commodity costs as energy-related and allocating those costs to all sales customers based on throughput, as discussed in section 13.4.2 of the Application.
    - To set a Storage and Transport Charge based on classifying midstream costs as demand-related and allocating those costs to all sales customers based on their load factor adjusted volume, as discussed in section 13.4.2 of the Application.
22. The following rate design proposal for Rate Schedule 1 is approved
    - To set the Basic Charge per Day at $0.3701 and the Delivery Charge at $3.512 per GJ as a result of (i) unbundling the rate structure in a way that minimizes the bill increase for any individual customer as discussed in sections 13.5.4 and 13.7 of the Application, and (ii) rebalancing as discussed in section 13.7.1.4.
23. The following rate design proposals for Rate Schedules 2 and 3 are approved
    - To change the annual volume threshold between small and large commercial customers from 6,000 GJ to 2,000 GJ.
    - To set the Basic, Delivery, Commodity, and Storage and Transport Charges for commercial customers to align with the 2,000 GJ threshold as discussed in Sections 13.5.5 and 13.7 of the Application, as follows:
        - For Rate Schedule 2 (formerly Rate 2.1 – customers whose normal annual consumption is less than 2,000 GJ): set the Basic Charge per Day at $1.2151 and Delivery Charge at $3.781 per GJ as a result of (i) unbundling the rate structure as discussed in Sections 13.5.5 and 13.7 of the Application, and (ii) rebalancing as discussed in section 13.7.1.4.
        - For Rate Schedule 3 (formerly Rate 2.2, and Rate 2.1 customers whose normal annual consumption is greater than 2,000 GJ): set the Basic Charge per Day at $3.6845 and Delivery Charge at $3.330 per GJ as a result of (i) unbundling the rate structure as discussed in sections 13.5.5 and 13.7 of the Application, and (ii) rebalancing as discussed in section 13.7.1.4.

- For Rate Schedule 6 (formerly Rate 2.3): set the Basic Charge per Day and Delivery Charge equal to FEI's approved January 1, 2018 RS 6 rates, as a result of unbundling the rate structure.

24. The following rate design proposals for Rate Schedule 5 and 25 as discussed in Section 13.5.5.3 of the Application are approved
    - To set the Daily Demand equal to 1.10 multiplied by the greater of:
        i. The customer's highest average daily consumption of any month during the winter period (November 1 to March 31); or
        ii. One half of the Customer's highest average daily consumption of any month during the summer period (April 1 to October 31).

    The calculation of Daily Demand will be based on the Customer's actual gas use during the preceding Contract Year.

25. The following rate design proposals for Rate Schedule 5 as discussed in Section 13.5.5.3 of the Application are approved:
    - To set the Basic Charge at $600.00 per Month, the Demand Charge per Month per GJ of Daily Demand at $30.350, the Delivery Charge per GJ at $1.000.
    - To phase-out the Rate Revenue Stabilization Adjustment Mechanism Charge (Rate Rider 5) over two years as discussed in Section 13.5.6 of the Application.

26. The following rate design proposals for Rate Schedule 25 as discussed in Section 13.5.5.3 of the Application are approved:
    - Amendments to implement daily balancing, as discussed in Section 10.6 of the Application.
    - Amendments to reduce the daily balancing tolerance to a 10% threshold and to introduce a balancing charge of $0.25/GJ for gas supply shortfalls within a 10% to 20% tolerance level, as discussed in Section 10.7 of the Application.
    - To set the Basic Charge at $600.00 per Month, the Demand Charge per Month per GJ of Daily Demand at $30.350, the Delivery Charge per GJ at $1.000, and the Administrative Charge per Month at $39.00.
    - To phase-out the Rate Revenue Stabilization Adjustment Mechanism Charge (Rate Rider 5) over two years as discussed in Section 13.5.6 of the Application.

27. The housekeeping and other amendments to the Fort Nelson Gas Tariff, as set out in Appendix 13-6 and the amendments to the terms and conditions for Rate Schedules 1, 2, 3, 5, 6 and 25, are approved

Implementation

1. FEI is directed to file with the Commission amended tariff pages in accordance with the terms of this order to be effective in the fourth quarter of 2018.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner