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December 19, 2016

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Laurel Ross, Acting Commission Secretary and Director

Dear Ms. Ross:

Re: FortisBC Energy Inc. (FEI)

2016 Rate Design Application

Pursuant to sections 58 to 61 of the *Utilities Commission Act*, FEI files the attached 2016 Rate Design Application.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties to FEI's PBR Annual Reviews
Pre-Application Rate Design Information Sessions and Workshop Participants and Stakeholders

FORTISBC ENERGY INC.

2016 Rate Design Application

Volume 1 - Application

December 19, 2016

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FortisBC Energy Inc.
2016 Rate Design Application

Section 1:

EXECUTIVE SUMMARY

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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 June 1, 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.

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 +/- 10% 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 +/- 10% 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. Rebalancing is required to shift some revenue from 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.

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

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

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

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 $848.1 thousand to RS 1. The shift represents an annual bill impact of approximately 0.1% 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.

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's review of the 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 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 small commercial 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/Month to continue to provide a price signal for only high load factor customers to take General Firm Service.

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 is in the process of adjusting its proposed Fort Nelson rate design to take into account the approved rates for 2018. FEI will be filing the proposed rate design for Fort Nelson on February 2, 2017 as part of a supplementary filing to this Application.

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 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.

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

- 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	($0.075)	$4.746
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

[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
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	Nil	$587.00
Delivery Charge ($/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	($1.318)	$3.555
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.

FortisBC Energy Inc.
2016 Rate Design Application

Section 2:

APPLICATION AND APPROVALS SOUGHT

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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 June 1, 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 will be submitting a supplemental filing on February 2, 2017, with the proposed rate design for Fort Nelson in Section 13. This later filing date is needed because FEI received approval for Fort Nelson's revenue requirements and rates for 2018 in November 2016, and FEI is adjusting its proposed Fort Nelson rate design to take into account the approved rates for 2018. The supplemental filing on February 2, 2017 will also include 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 will be 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 will be 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 June 1, 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 $0.011 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 Delivery Charge of RS 7 and RS 27 by $0.012/GJ as shown in Table 9-20 and discussed in Section 9.6.
7. 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.
8. 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 $0.015/GJ.
   - Interruptible MTQ Delivery Charge of $0.972/GJ.
9. Approval to terminate Tariff Supplement G-21, FEI's contract with Creative Energy Vancouver Platforms Inc., effective June 1, 2018, as discussed in Section 9.8.5 of the Application.
10. 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.
11. 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.

12. Approval to decrease the Delivery Charge per GJ of RS 6 by $1.318/GJ to address rebalancing as discussed in Section 12.2.2 of the Application.
13. 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

14. 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*

FEI is seeking to implement its proposed rate design changes effective June 1, 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 early in 2018.

FEI is targeting a June 1, 2018 effective date for implementation for the following reasons:

- This date is expected to provide sufficient time for the review of the Application, with flexibility for the process that the Commission considers appropriate.

- This date 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 a June 1, 2018 implementation date, this is dependent on the Commission's ability to issue a decision early in 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

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 will file this section of the Application with its supplemental filing on February 2, 2017.

FortisBC Energy Inc.
2016 Rate Design Application

Section 3:

BACKGROUND AND REGULATORY HISTORY OF FEI'S RATE DESIGN

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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:

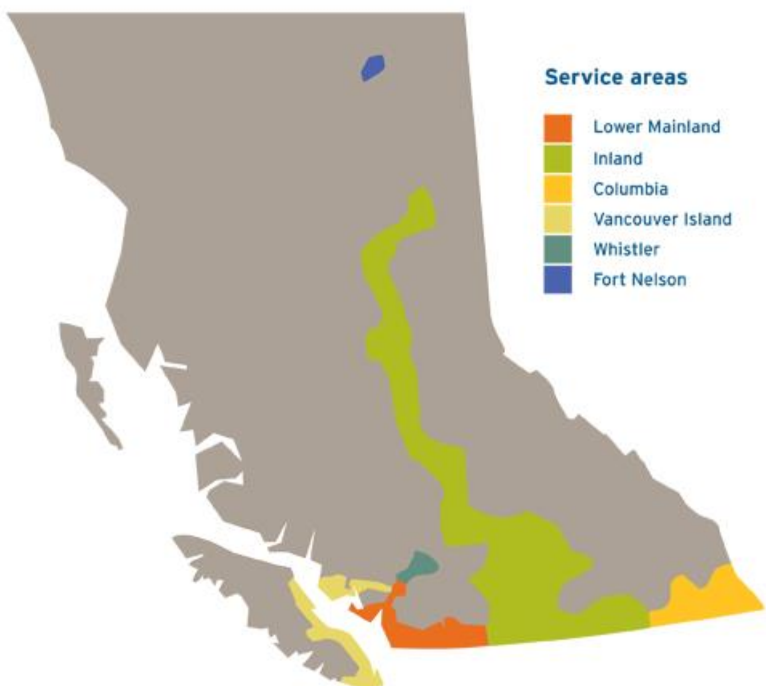
- Section 3.2 provides an overview of FEI's service areas, sales and transportation business models, customers and rate schedules;
- Section 3.3 summarizes FEI's rate design regulatory history since 1991; and
- Section 3.4 provides a list of past rate design directives that are addressed in the Application.

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)

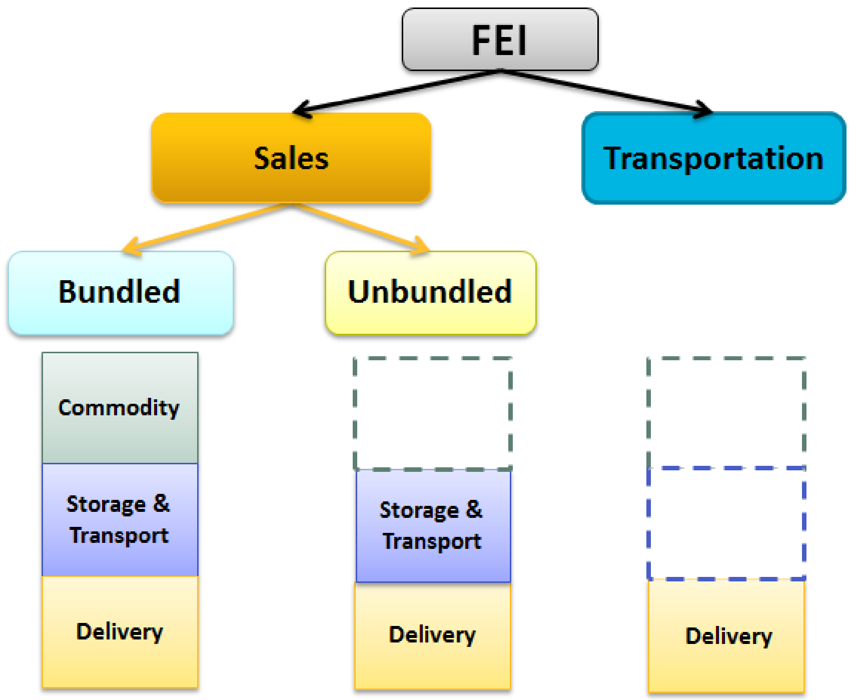
	Applicable Rate Schedules	Customers (#)	Customer Demand (PJ)
Sales Service Rates (Bundled)[17]	RS 1, RS 2, RS 3, RS 5, RS 5, RS 6, RS 7, RS 1B, RS 2B, RS 3B, RS 5B	947,250	107.5
Sales Service Rates (Unbundled)	RS 1U, RS 2U, RS 3U	32,015	4.5
Transportation Service Rates	RS 22, RS22A, RS22B RS 23, RS 25, 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.

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

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[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]
	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
INDUSTRIAL *(continued)*	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.
1993 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.

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[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 2013, 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.

Table 3-4: Past Commission Directives and FEI Commitments

<table>
<tr><th>FEI Application/Proceeding</th><th>Applicable Directive(s)/Reference
& FEI Response</th></tr>
<tr><td>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</td><td>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.</td></tr>
<tr><td>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</td><td>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.</td></tr>
<tr><td>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</td><td>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.</td></tr>
</table>

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. <u>FEI Response</u>: FEI submits a proposal for the overhead and marketing (OH&M) charge applicable to CNG and LNG Stations in Section 11 of this Application.

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

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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.
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

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

	Workshop Issues List	Reference
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 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.

	Workshop Issues List	Reference
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
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.

Survey Topic	Summary of Survey Results
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.

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Section 5:

LEGAL CONTEXT, RATE DESIGN PRINCIPLES AND GOVERNMENT POLICY

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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.
    - 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,

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

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).

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

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

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 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;

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

- 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).

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

[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.

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 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.

[55] FEU Common Rates, Amalgamation Rate Design Reconsideration Phase 2, Exhibit C3-1.
[56] BC Hydro 2015 Rate Design Application, Appendix C-1C.

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.

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Section 6:

FEI Cost of Service Allocation Study

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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 +/- 10% 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 +/- 10% range of reasonableness.

In this section, FEI describes the:

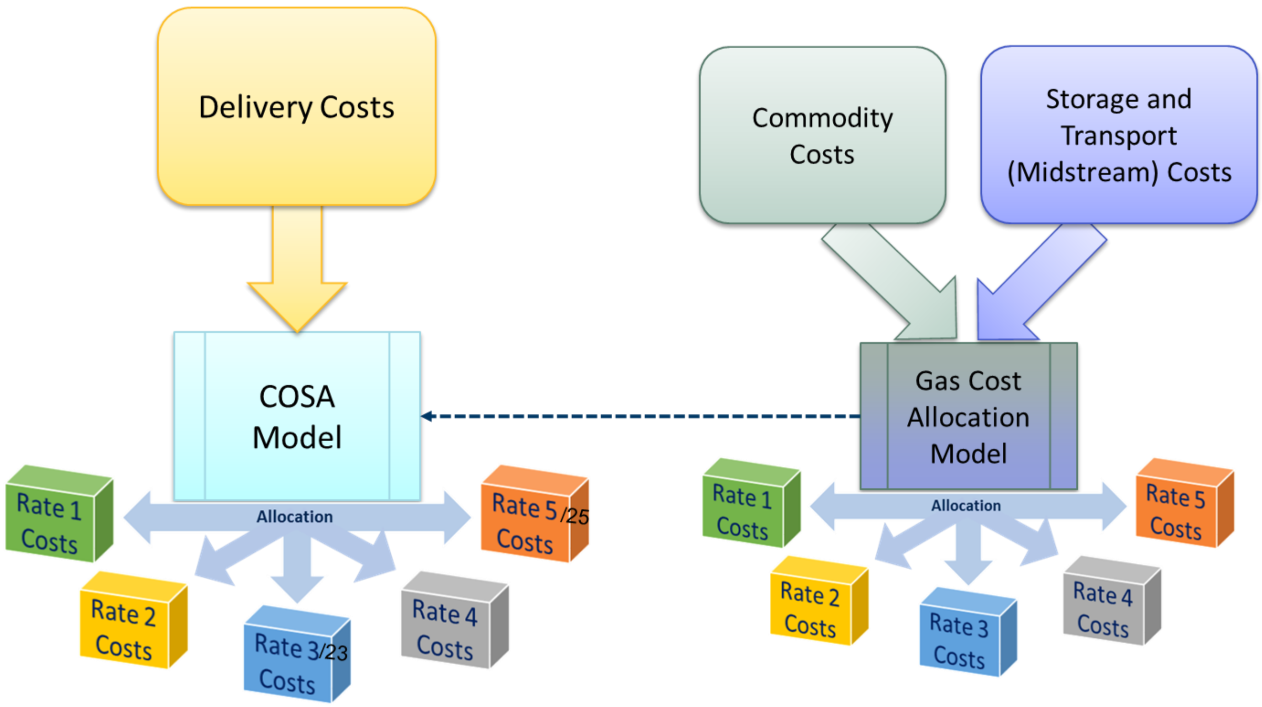
- COSA methodology;
- Delivery cost of service allocation;
- Gas cost allocation;
- Results of the COSA study; and
- Responses to stakeholder feedback.

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



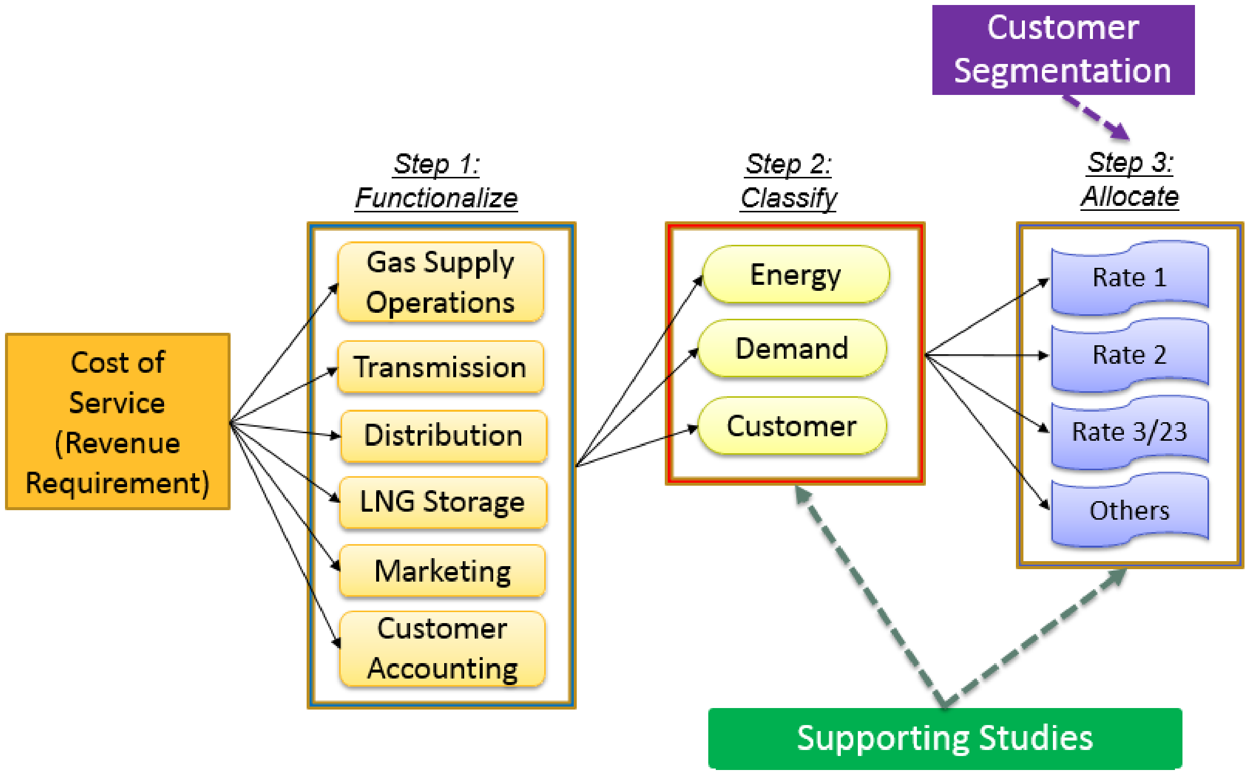
FEI's gas costs, including both commodity and storage and transport costs, are reviewed on a quarterly basis using a different model than FEI's delivery costs, which are reviewed on an annual basis. As such, FEI's revenue requirement in this Application is allocated into two categories: delivery costs 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.

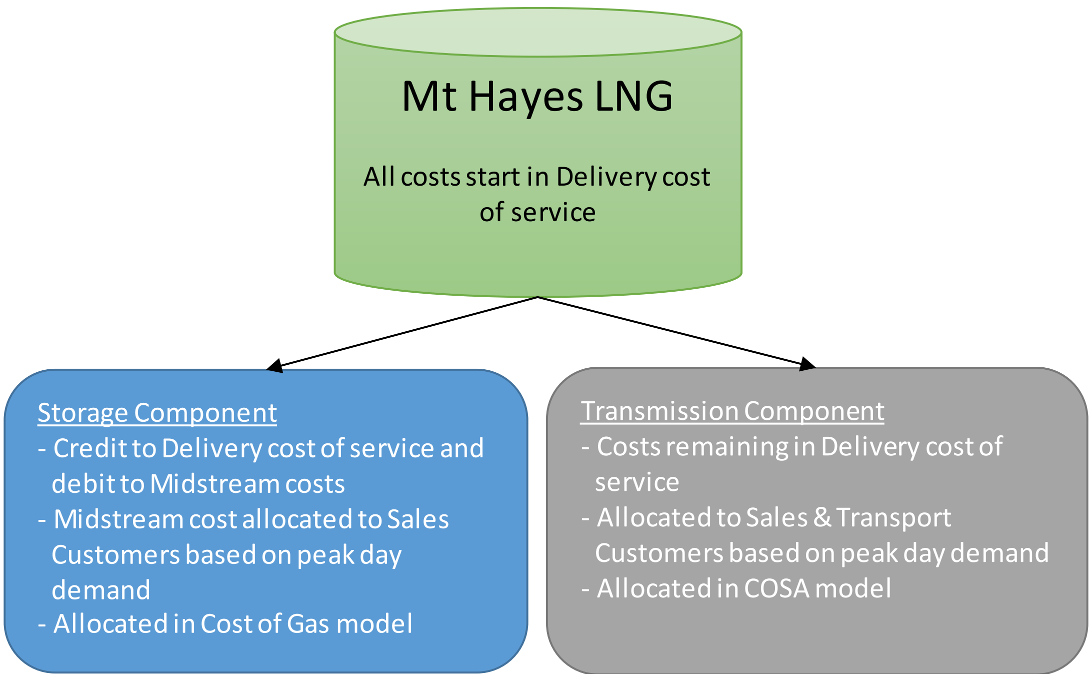
As discussed in Section 6.3.2.3 of the Application, the Tilbury Expansion project is included in the LNG Storage function. However, the allocation approach for Tilbury Expansion does not follow that of the existing storage plant. The Tilbury Expansion costs are directly allocated to RS 46 and offset 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

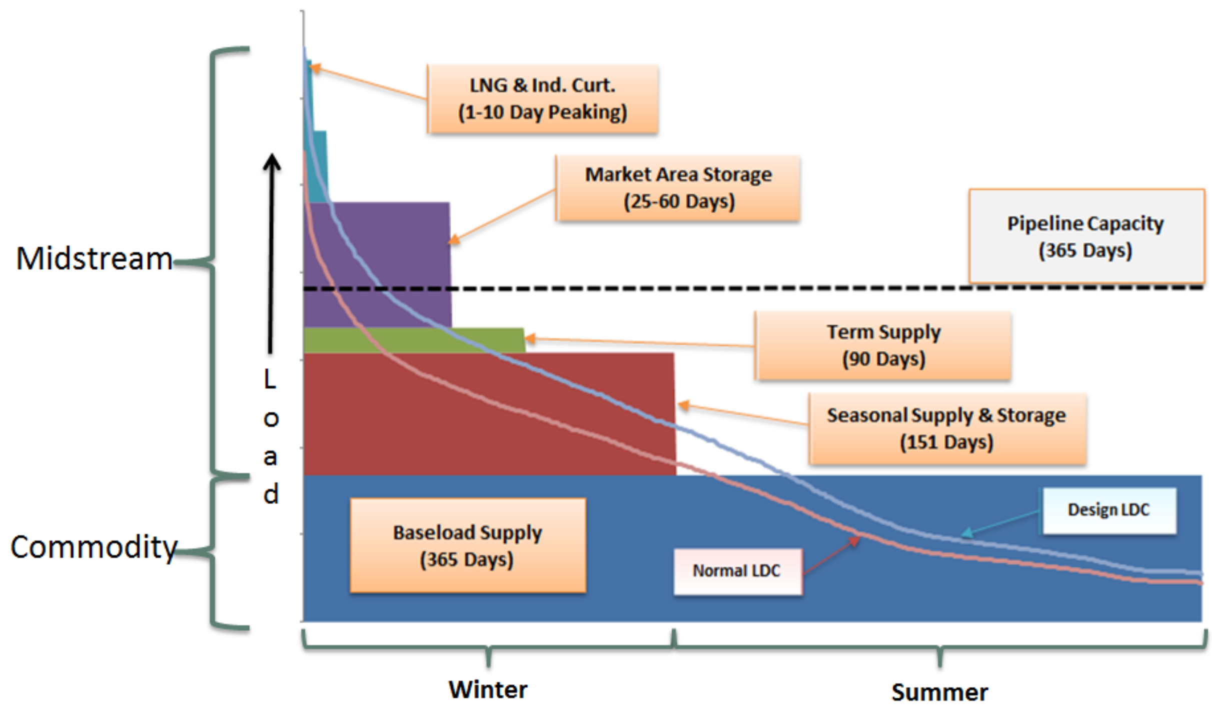
FEI incurs gas costs on behalf of all core market customers to meet peak customer demand. FEI's gas costs are separated into commodity and storage and transport costs, which

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

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

Consistent with past precedent and practice, FEI has applied a range of reasonableness of 90% to 110% in this Application.

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.

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 90% to 110% 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.

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

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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%

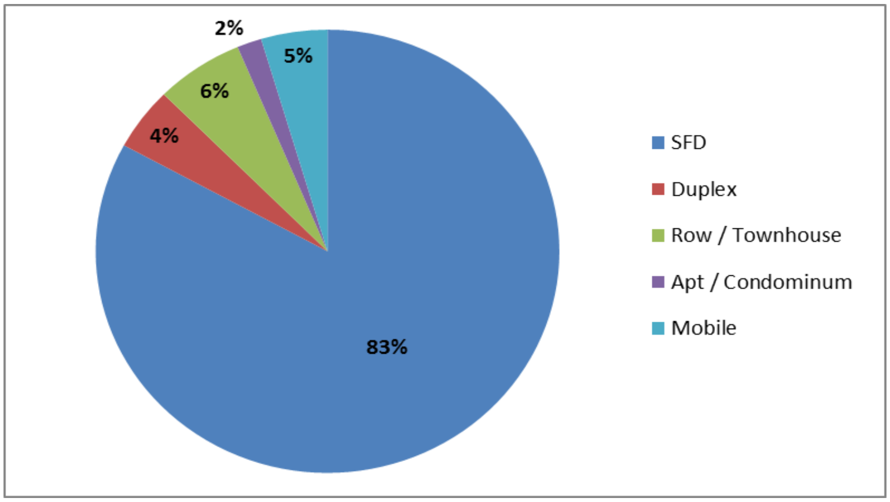
The following subsections discuss the main characteristics of RS 1 customers, including dwelling type, end use, consumption patterns, and load factor.

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).

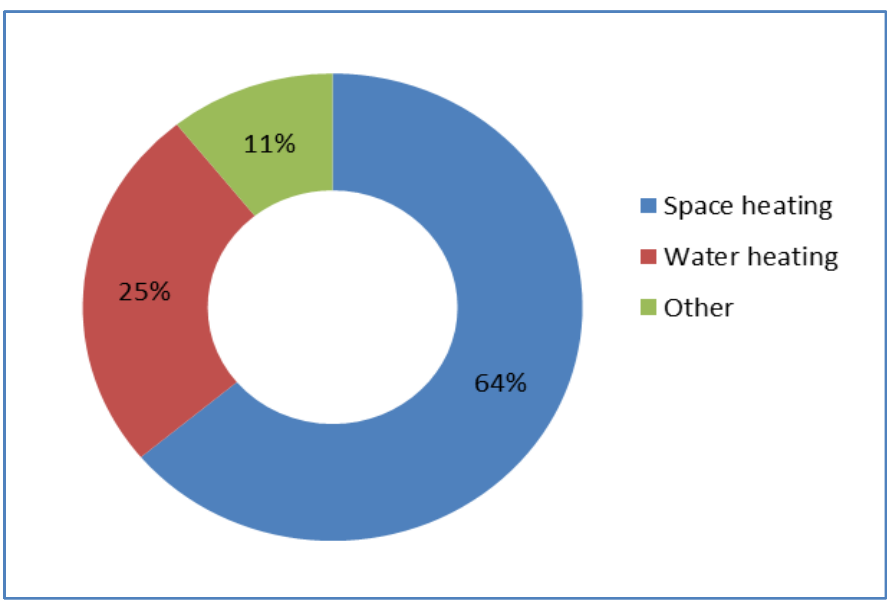
Figure 7-1: FEI's Residential Customers by Dwelling Type based on 2012 REUS



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

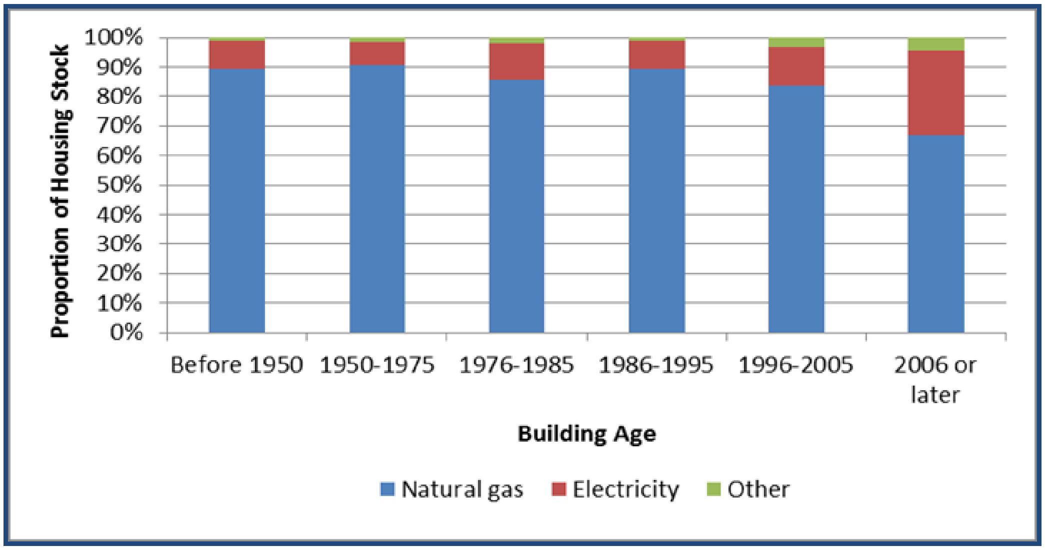


[104] Heater fireplace consumption is included in this percentage.

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



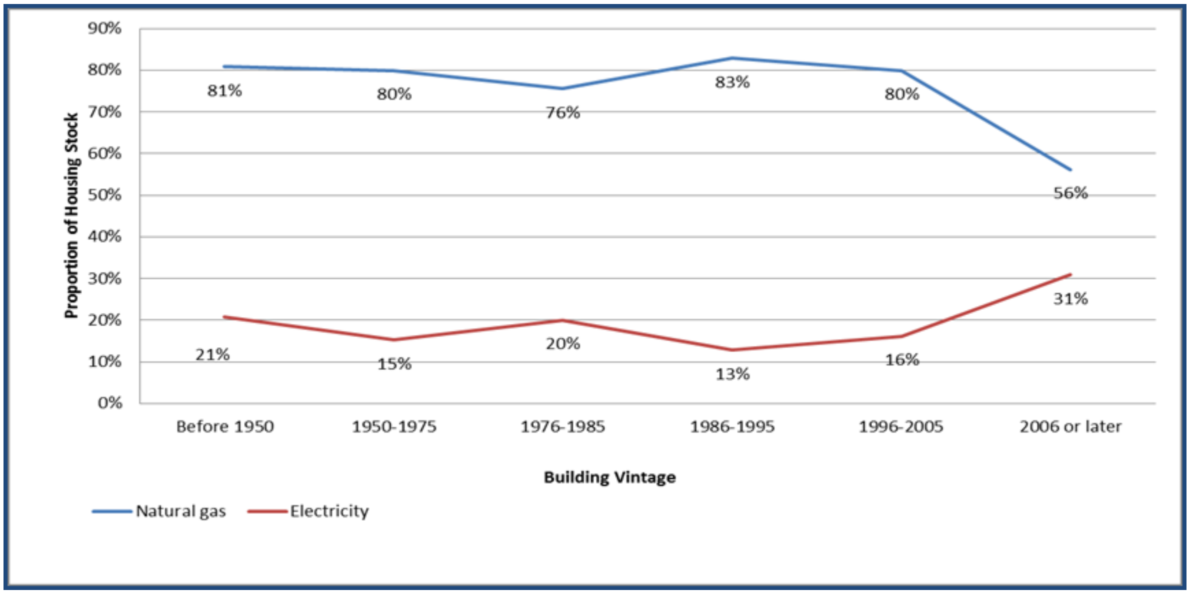
The increasing share of electricity use in space heating is also validated by BC Hydro's 2014 Residential End Use Survey[105].

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.

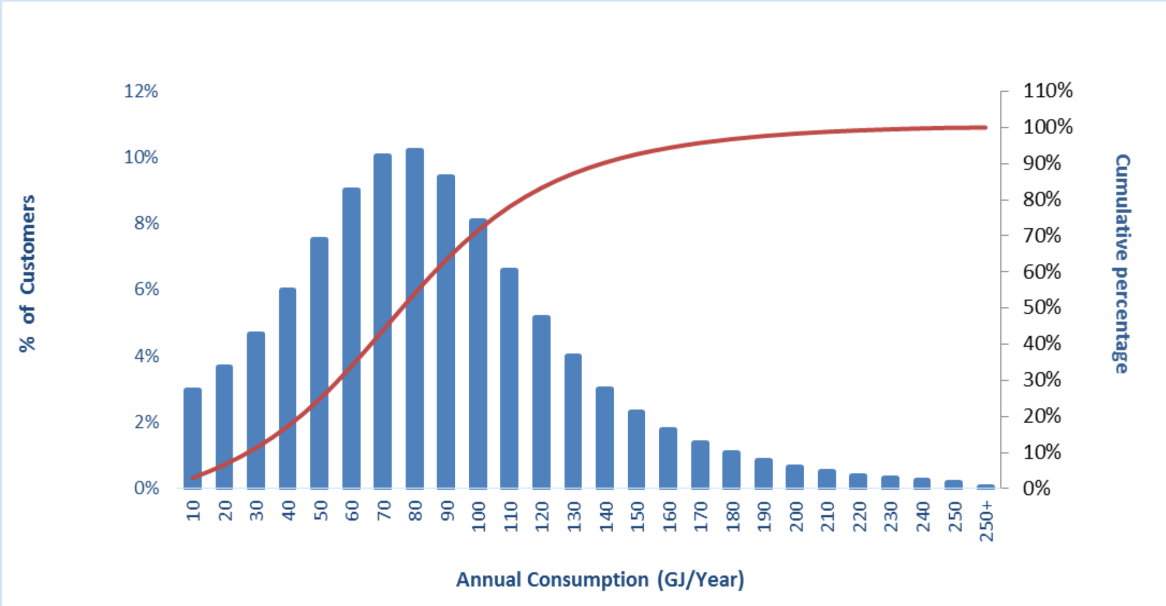
7.2.3 RS 1 Consumption Pattern

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



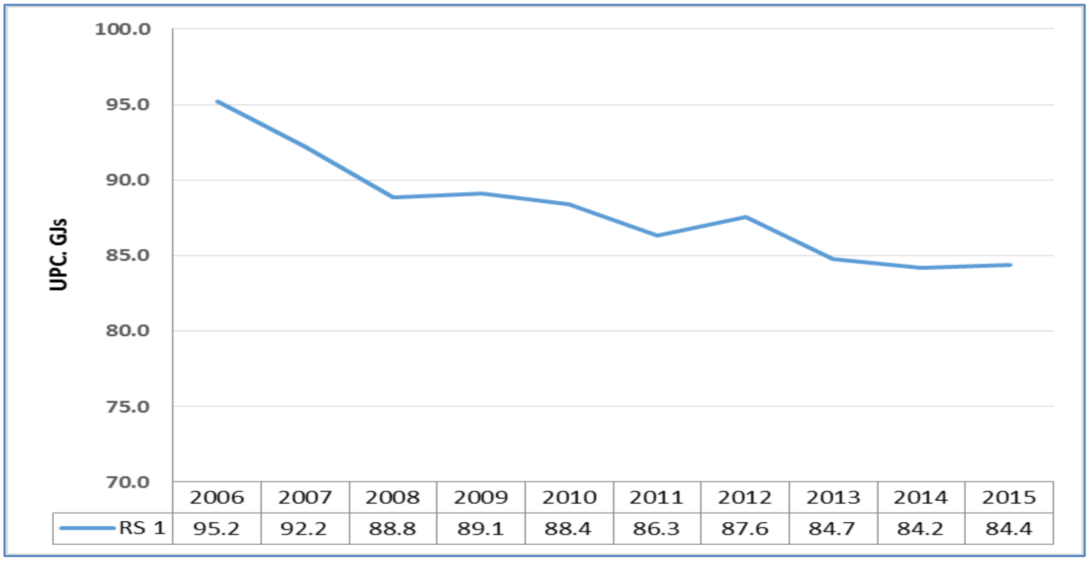
As can be seen from the figure above, the 70-80 GJ annual consumption range has the highest density of customers followed closely by the 60-70 GJ and 80-90 GJ consumption ranges.

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



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
RS 1	95.2	92.2	88.8	89.1	88.4	86.3	87.6	84.7	84.2	84.4

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.

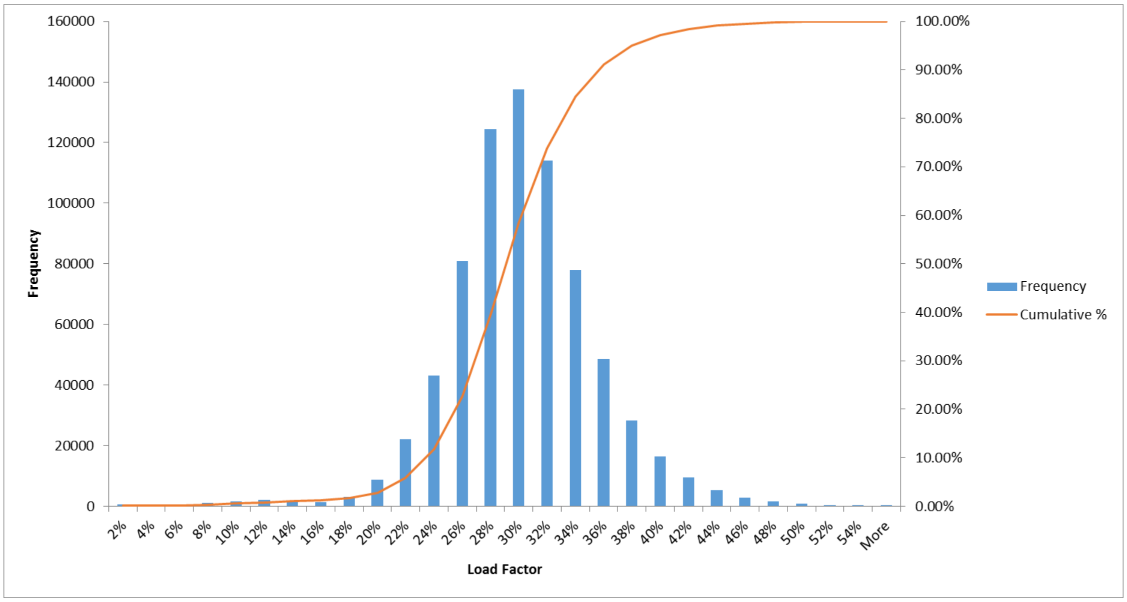
7.2.4 RS 1 Load Factor

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

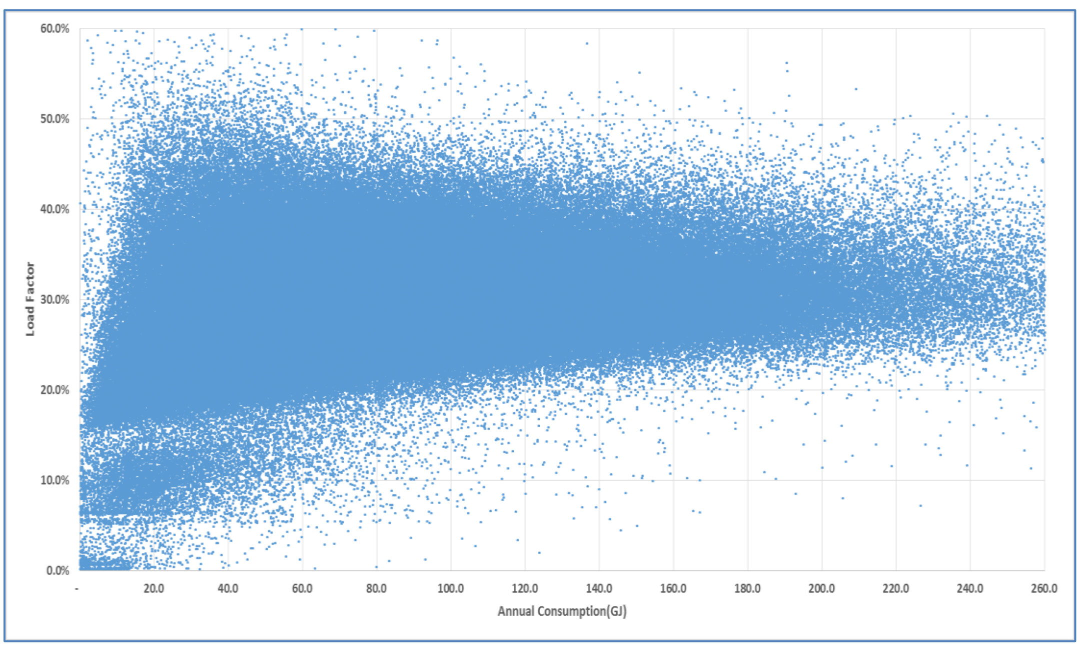


Figure 7-8 shows that the annual consumption of customers with a load factor of 15% or less is predominantly below 40 GJ. At the same time, the figure also demonstrates that many customers consuming less than 40 GJ/year have load factors that are well above the RS 1 average, and include some of the highest 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:

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[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.

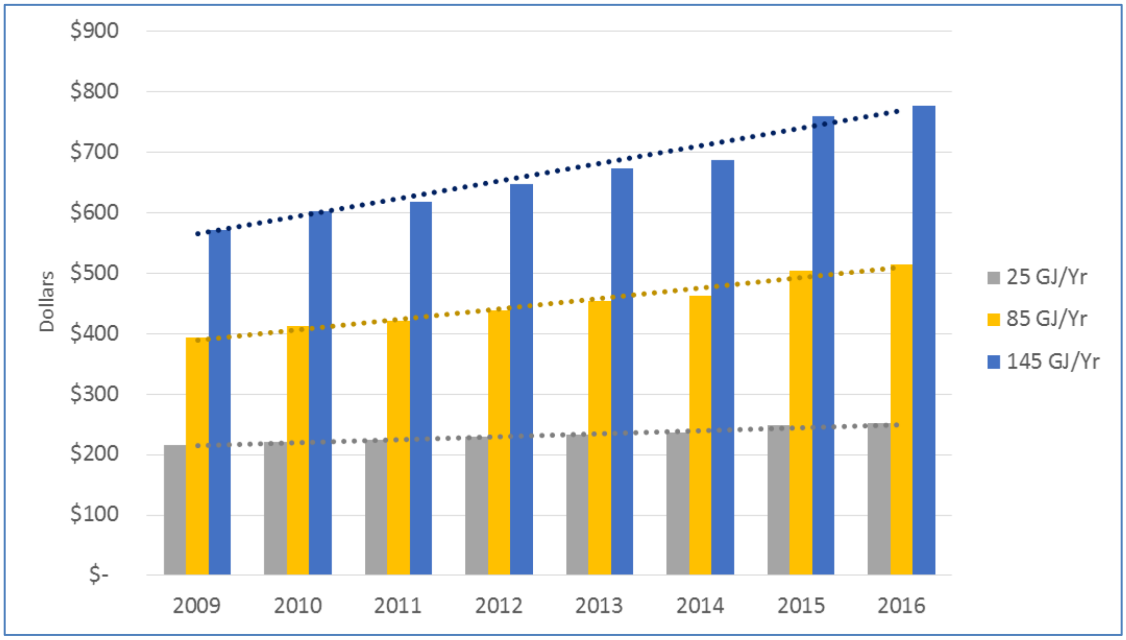
By Order G-141-09, the Commission approved FEI's 2010-2011 NSA. As part of the 2010-2011 NSA, and in alignment with government's energy conservation policies, the monthly Basic Charge was fixed at 2009 levels and all annual margin increases since 2009 have been allocated to variable volumetric charges. 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 charges.

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 militate against making significant changes to the Basic Charge are:

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

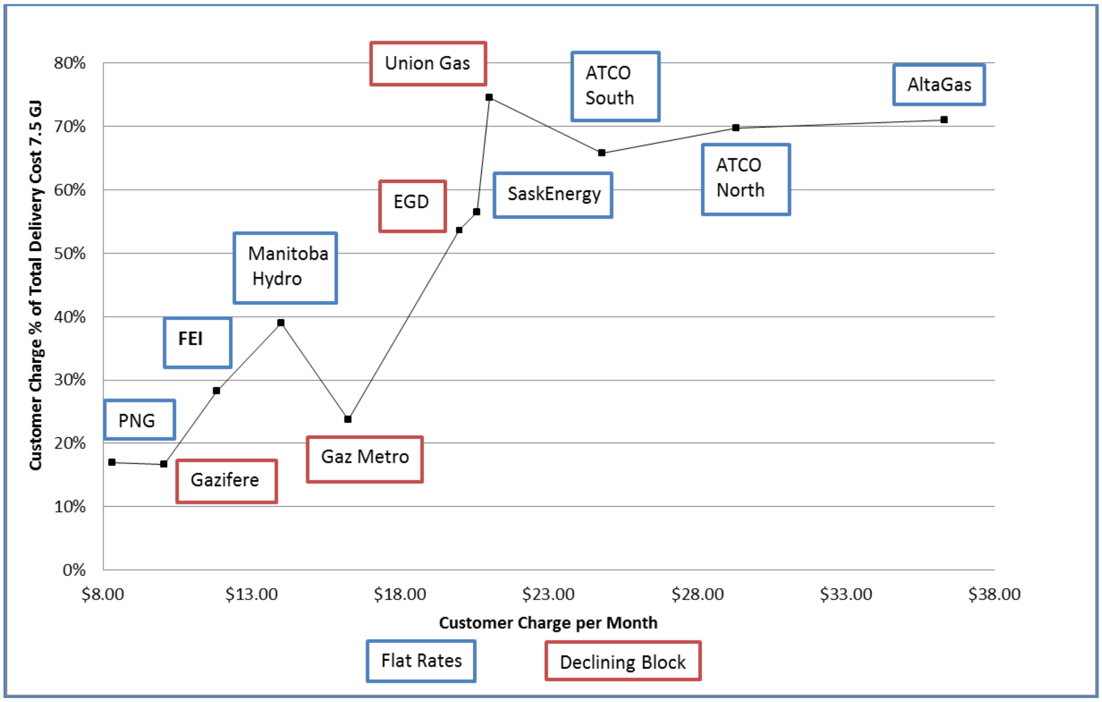
In order to achieve a reasonable balance among competing rate design considerations, FEI is proposing a moderate one-time 5% increase in the Basic Charge and a corresponding decrease in the volumetric Delivery Charge.

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	4.832	4.746

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

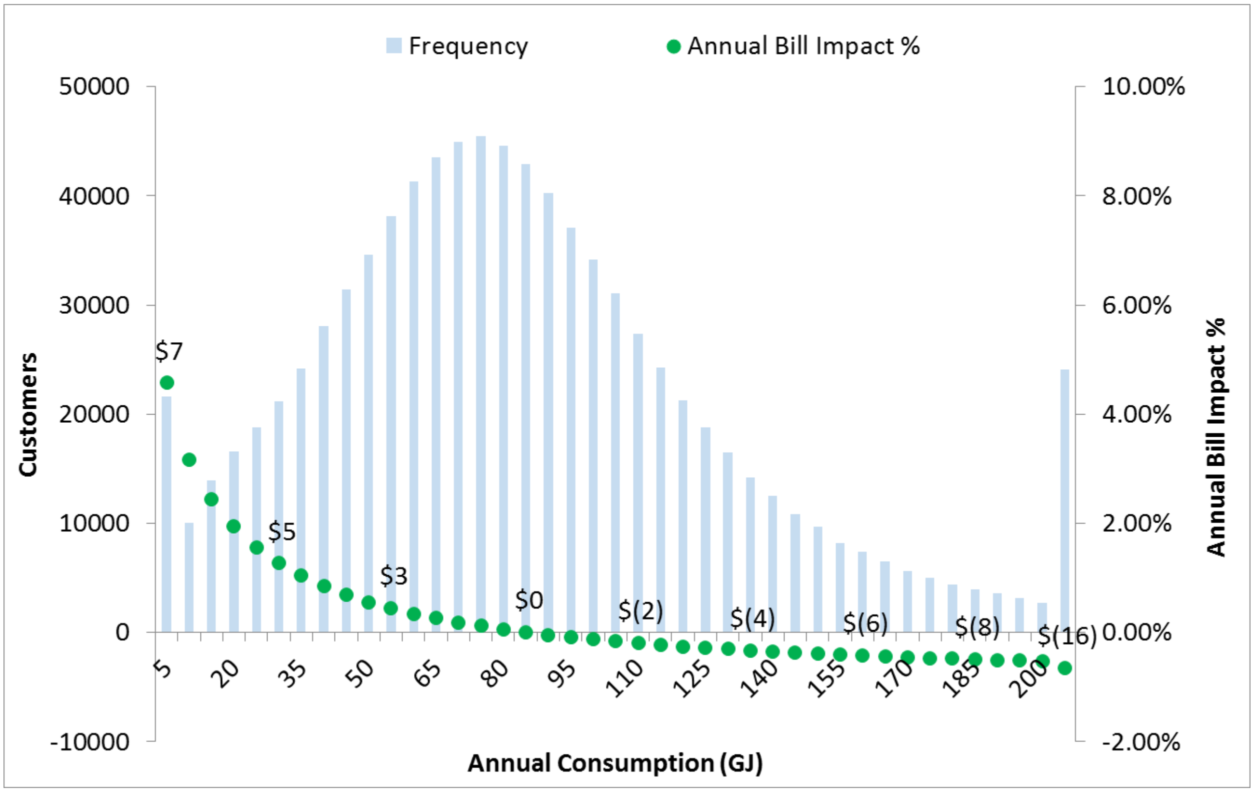
As seen in the table above, the volumetric Delivery Charge after rebalancing (including the changes caused by rate design proposals in other rate schedules) is estimated to be approximately $4.832/GJ (based on a final 96.4% R:C ratio). The impact on customers' bills due to changes caused by rate design 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 is estimated to be around 0.2%.[117]

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 $4.832 per GJ to $4.746 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] (4.832-4.821)*82 GJ / (4.821*82+11.84*12).

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.

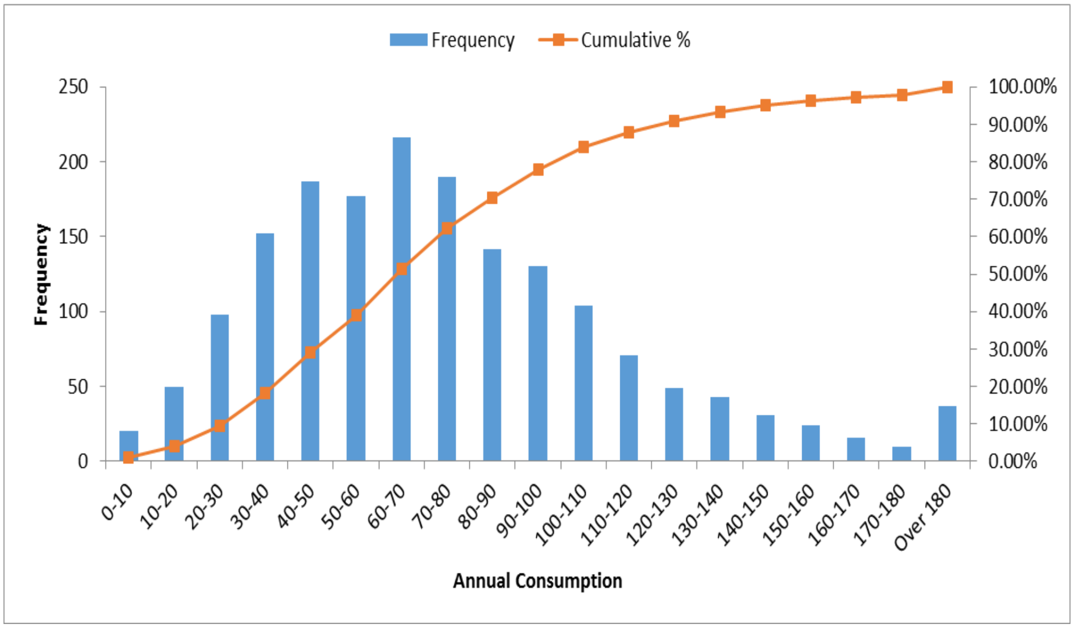
To reach this conclusion, FEI has collected data on income levels and natural gas consumption in its service territory from two different sources: (1) a database of low income customers who have applied to FEI's low income Energy Conservation Assistance Program (ECAP), and (2) the data collected as part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

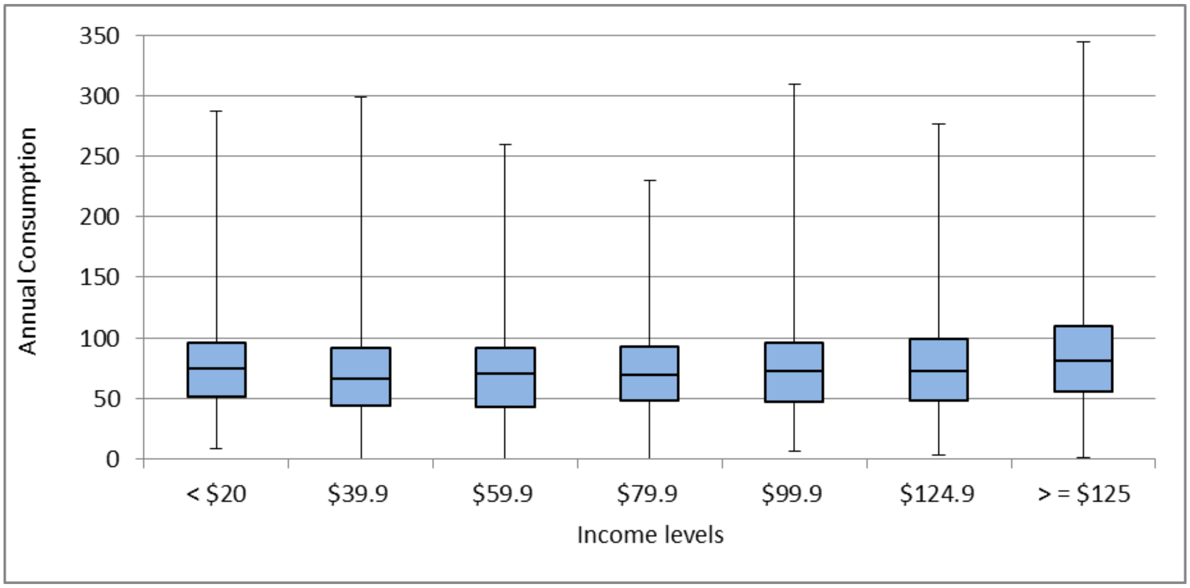
Figure 7-12: The 2015 Annual Consumption Histogram for Customers in ECAP



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:

- Energy Savings Kit (ESK) Program: 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.
- Energy Conservation Assistance Program: 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.
- Residential Energy Efficiency Works (REnEW) Program: 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

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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%			

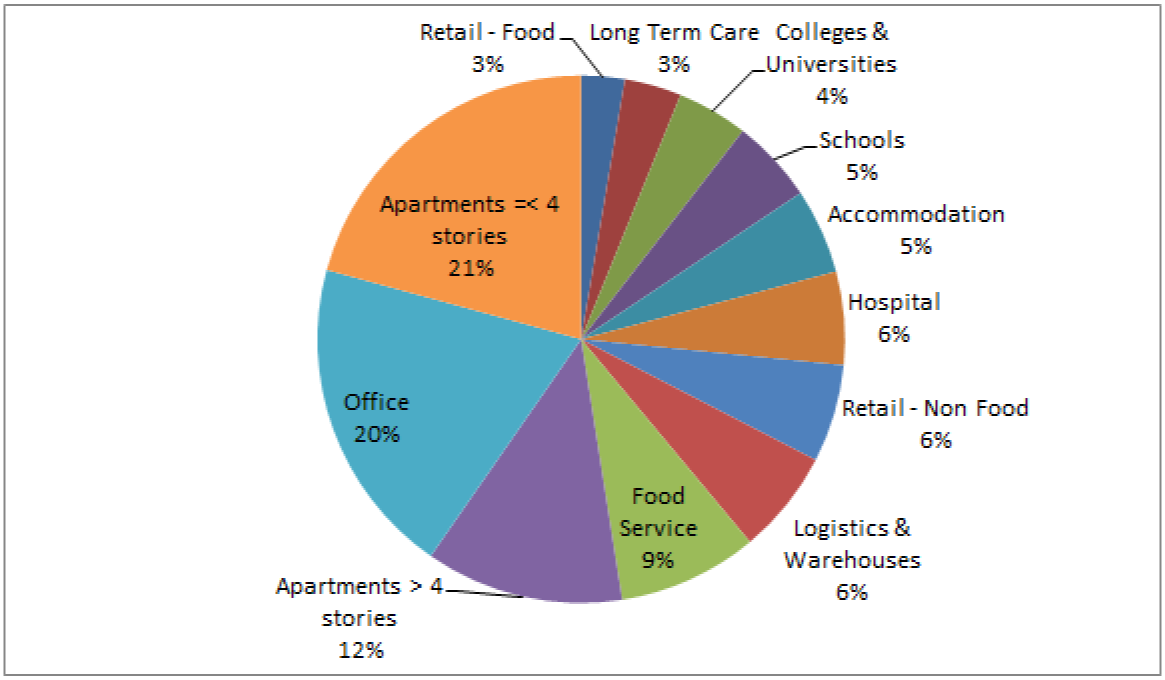
8.2.2 Commercial Customer Market Segments

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]

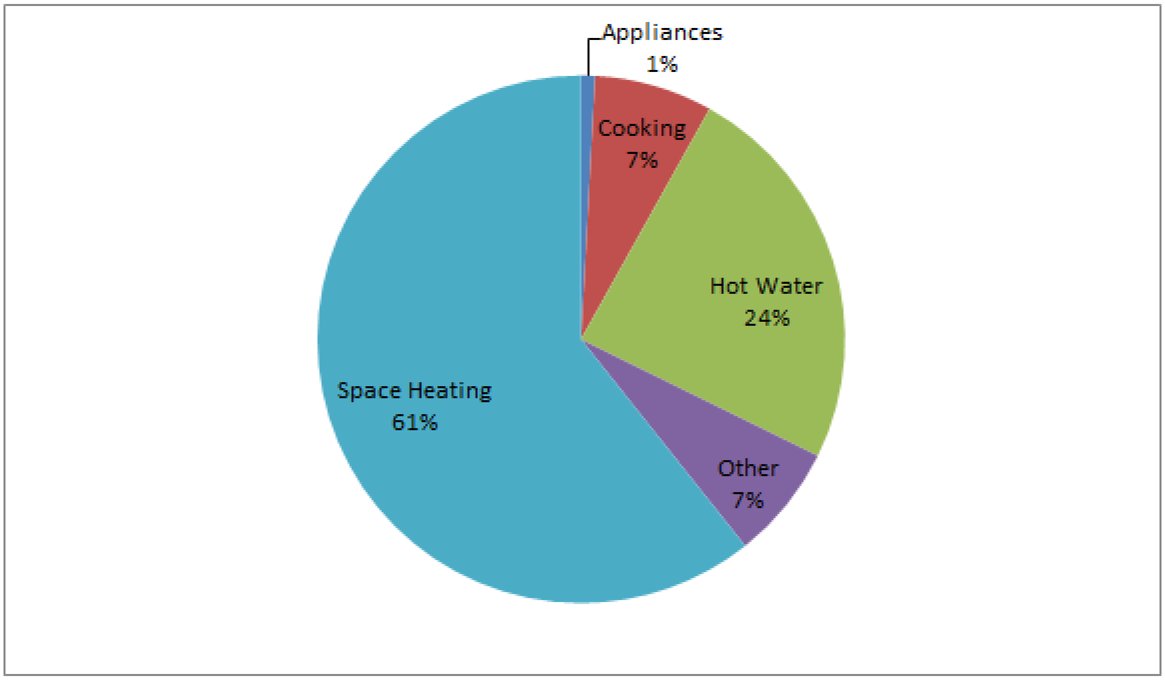


8.2.3 Commercial End Usage

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

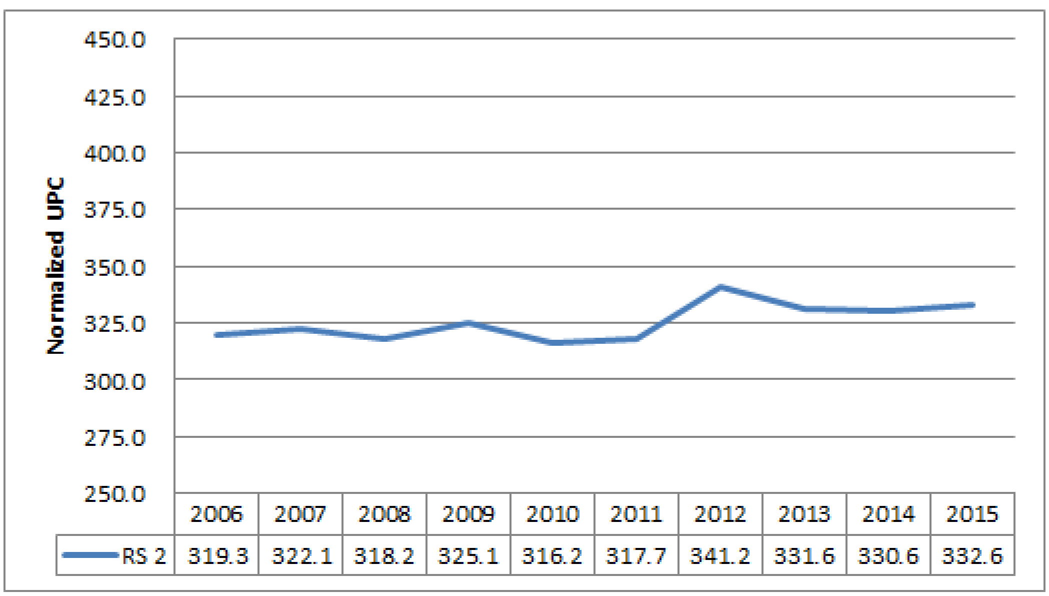


Figure 8-4: RS 3 UPC

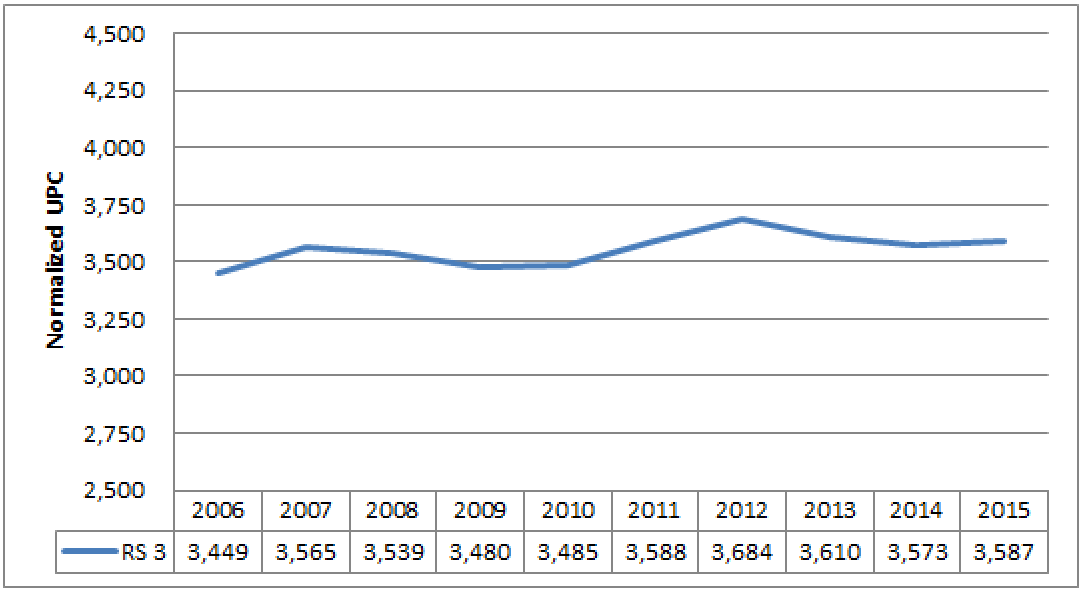
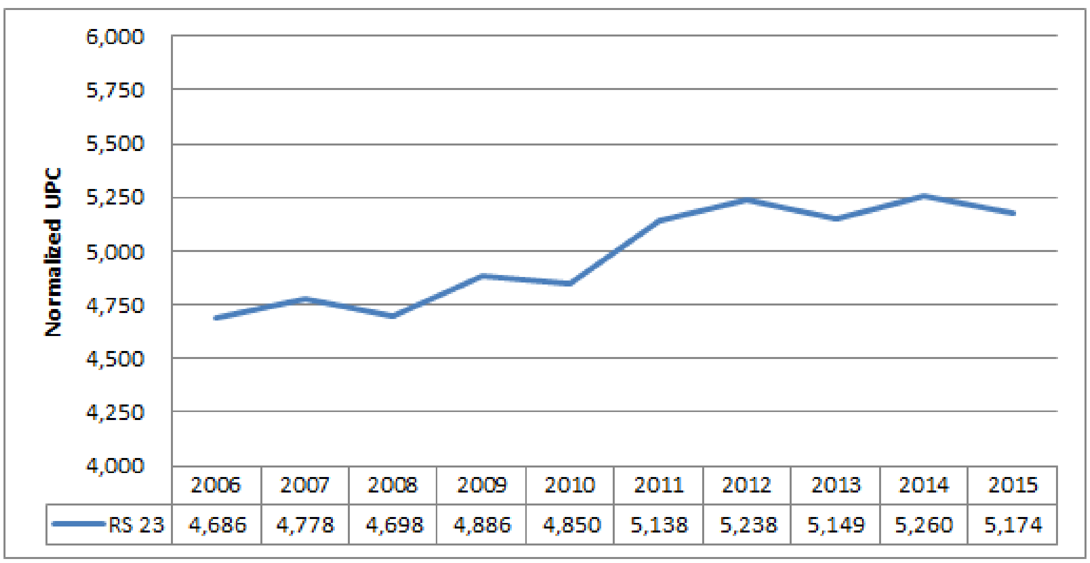


Figure 8-5: RS 23 UPC



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

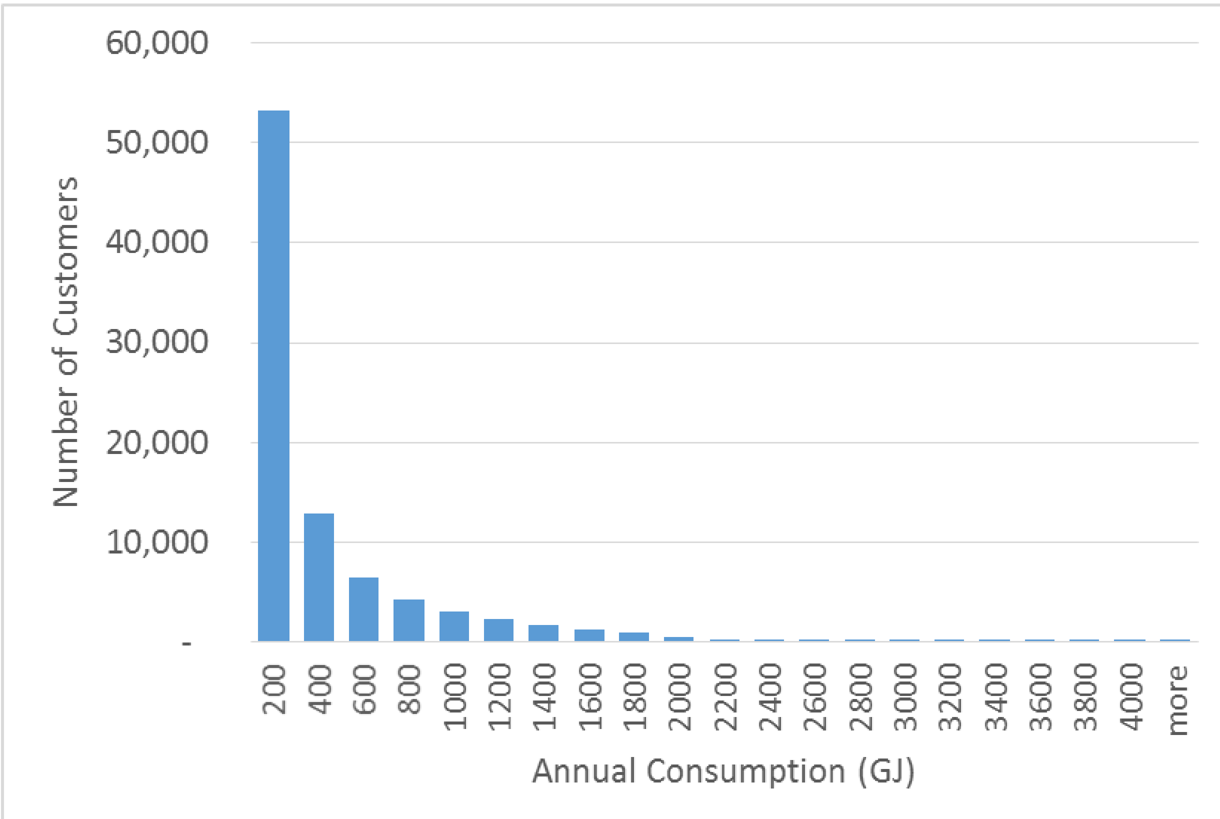
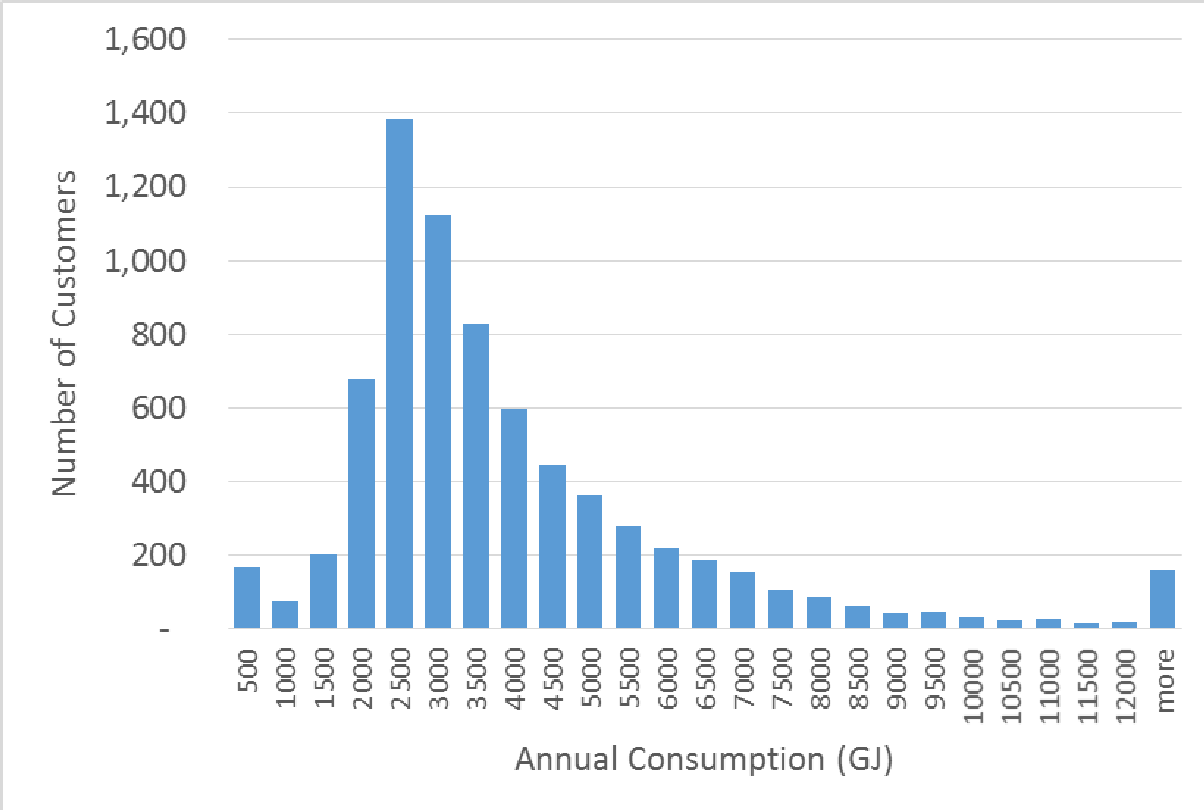


Figure 8-6 shows that approximately 72,000 (or approximately 85%) of the 85,000 small commercial customers use less than 600 GJ/year and approximately 84,000 (or 99%) customers use less than 2,000 GJ/year. There are approximately 600 customers whose annual consumption is greater than, the 2,000 GJ threshold.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

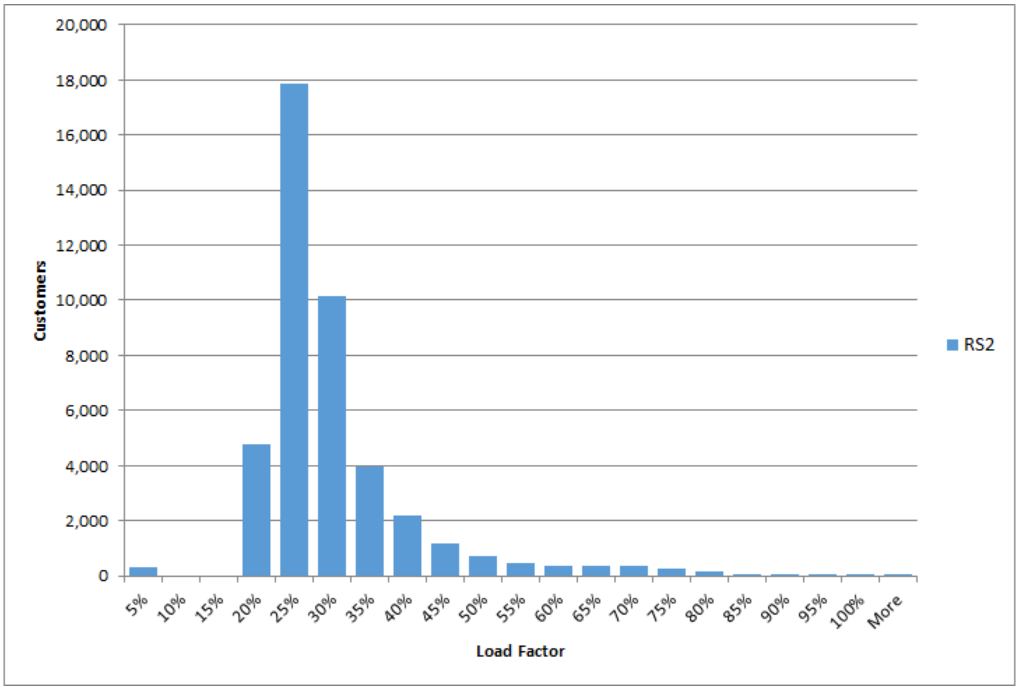
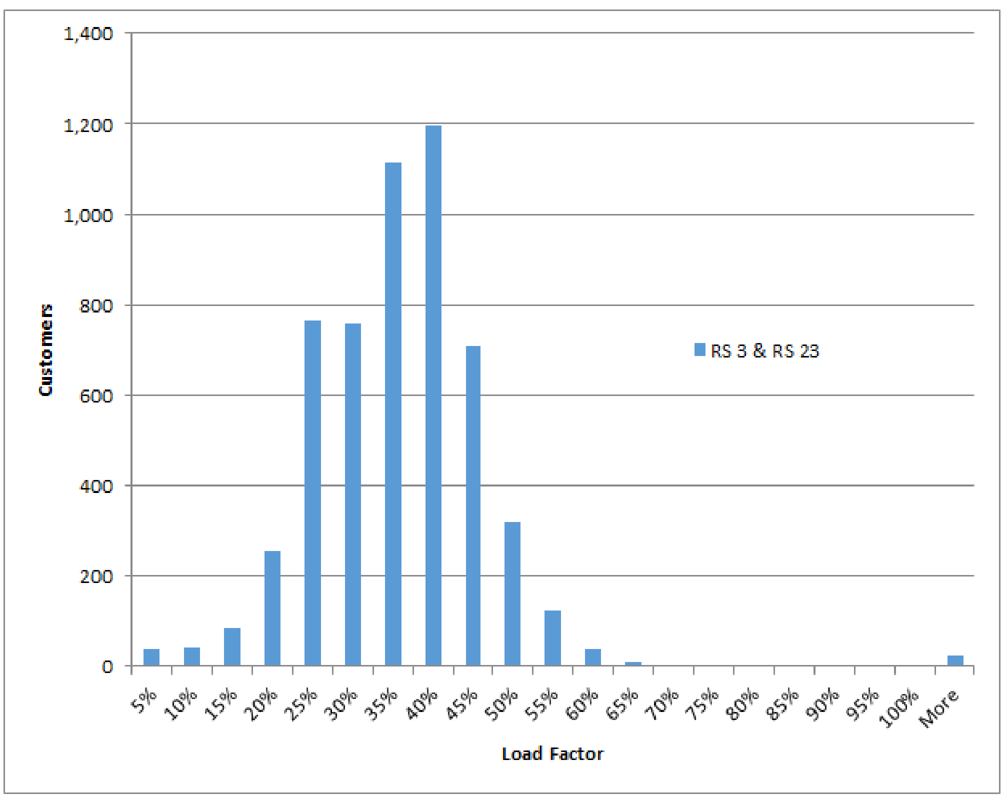


Figure 8-9: Large Commercial Customer Load Factor Distribution



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

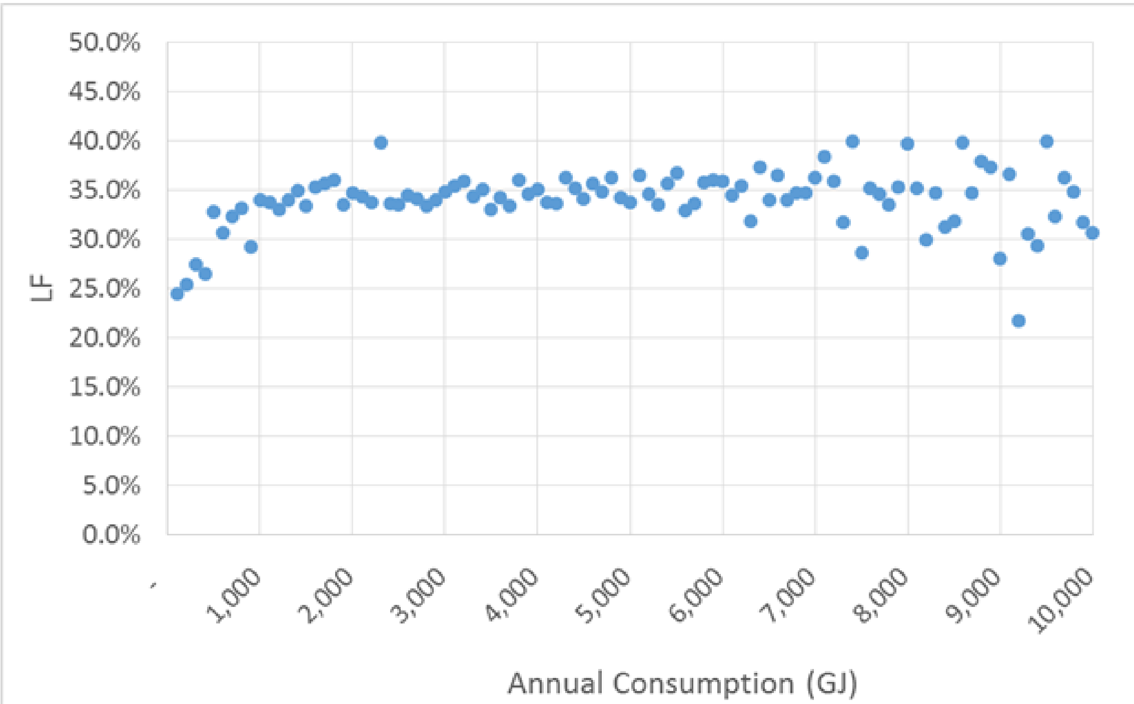


Figure 8-10 above is a chart showing commercial customer annual consumption in relation to load factor. The figure shows that the commercial customer load factor starts at a low of about 25% at around the 500 GJ/year level and increases to about 35% somewhere between 1,000 GJ/year and 2,000 GJ/year level,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

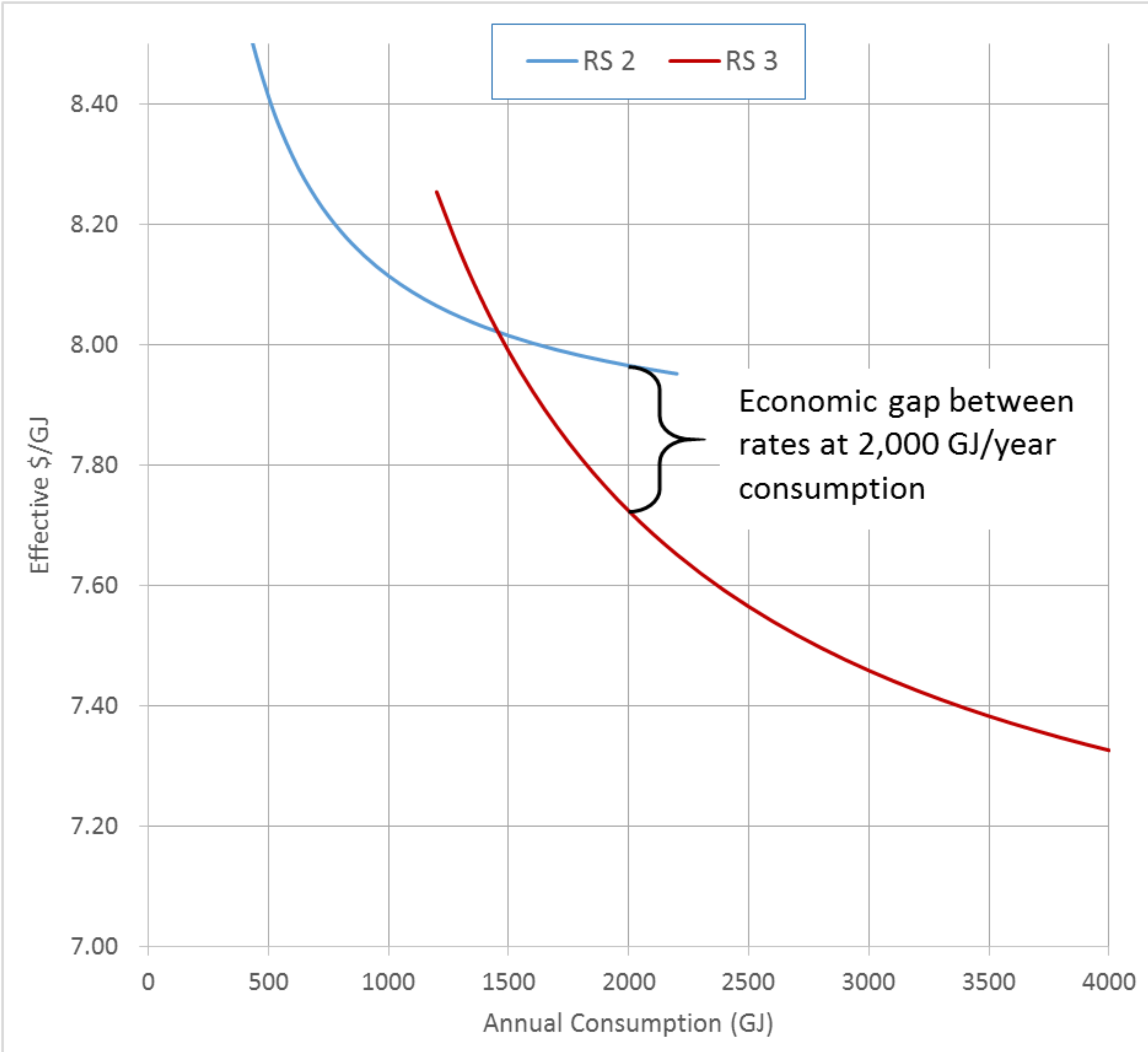
Table 8-3: Economic Crossover Volume for RS 2 and RS 3

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 90% to 110% 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.

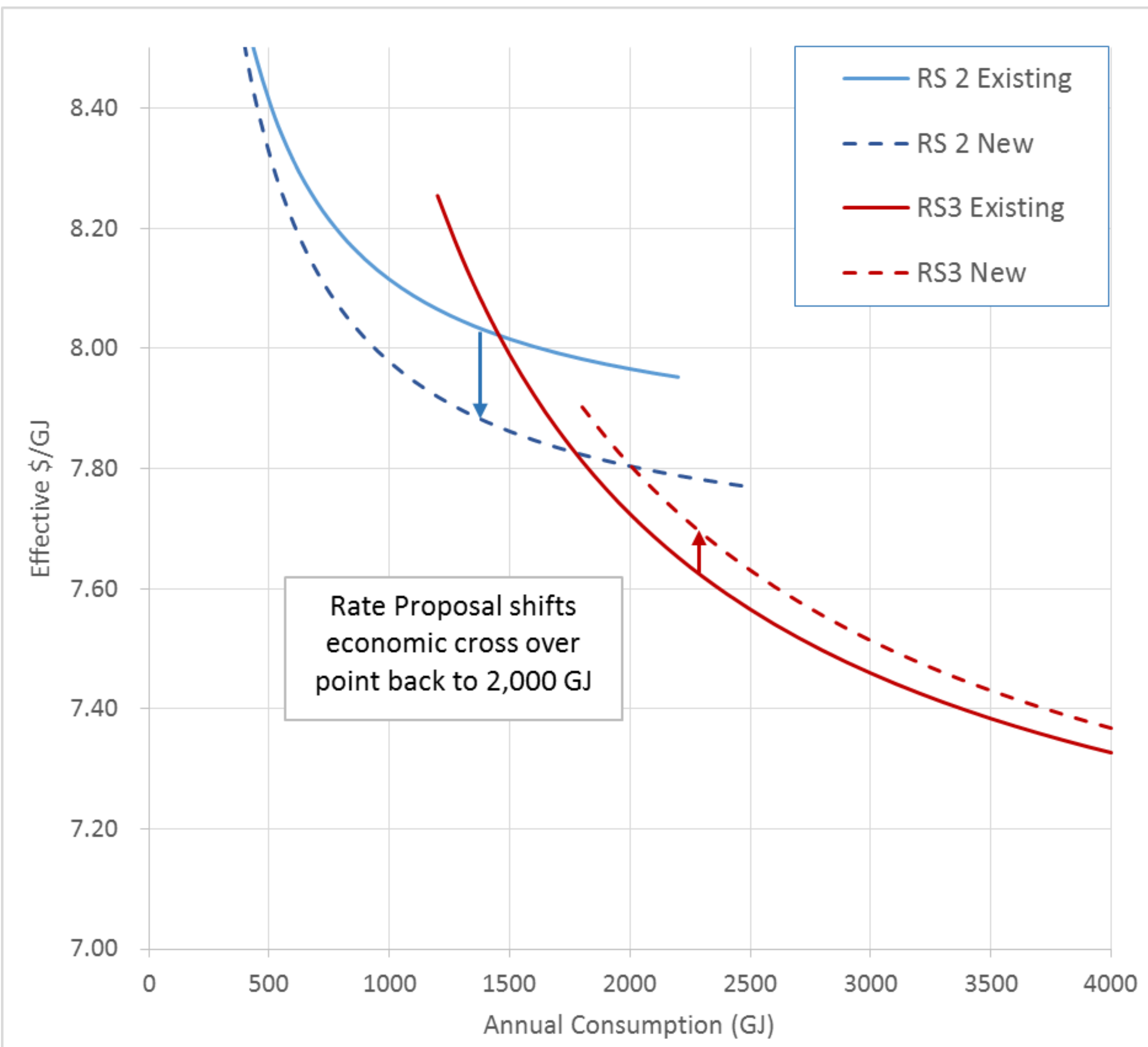
2 and RS 3/RS 23 so that the relative economics of RS 2 and RS 3/RS 23 are aligned with the existing 2,000 GJ/year threshold.

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%

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

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.

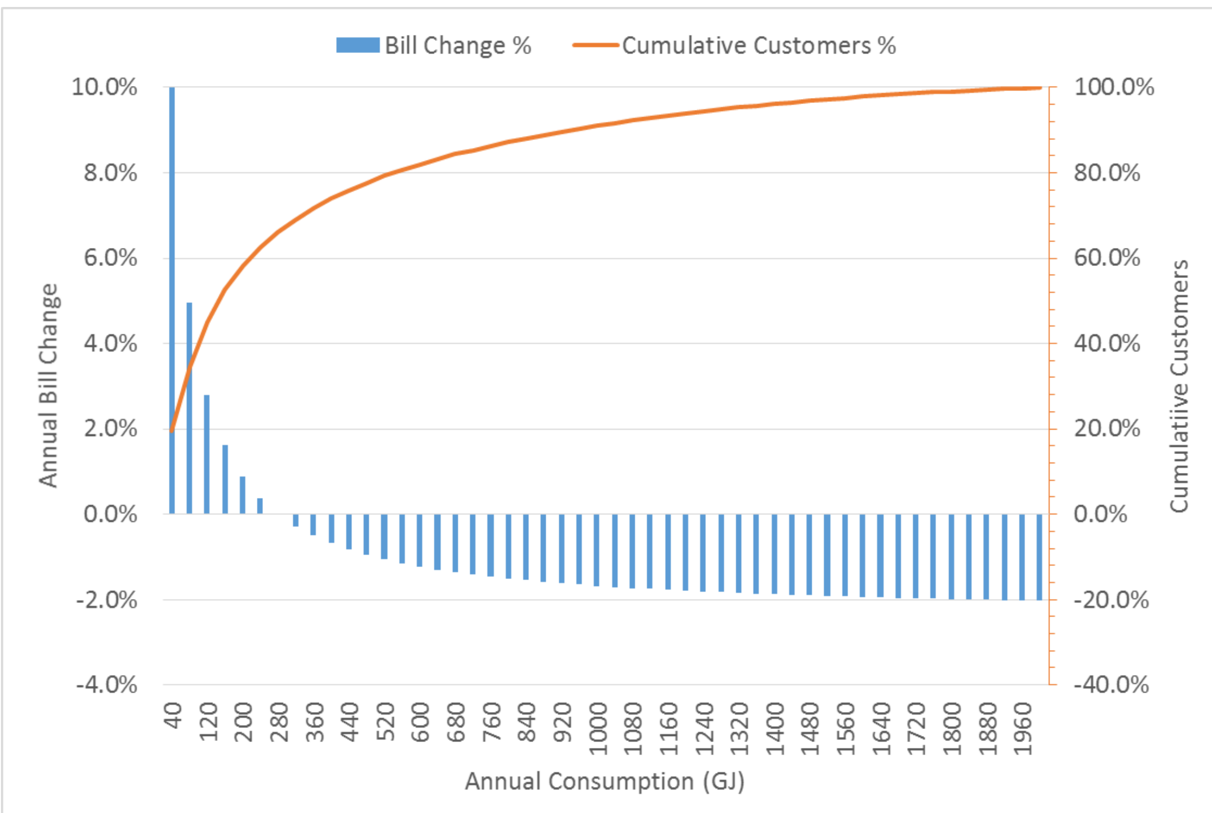
138 The COSA rates shown are 2016 approved rates plus known and measurable changes discussed in Section 6.

$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*

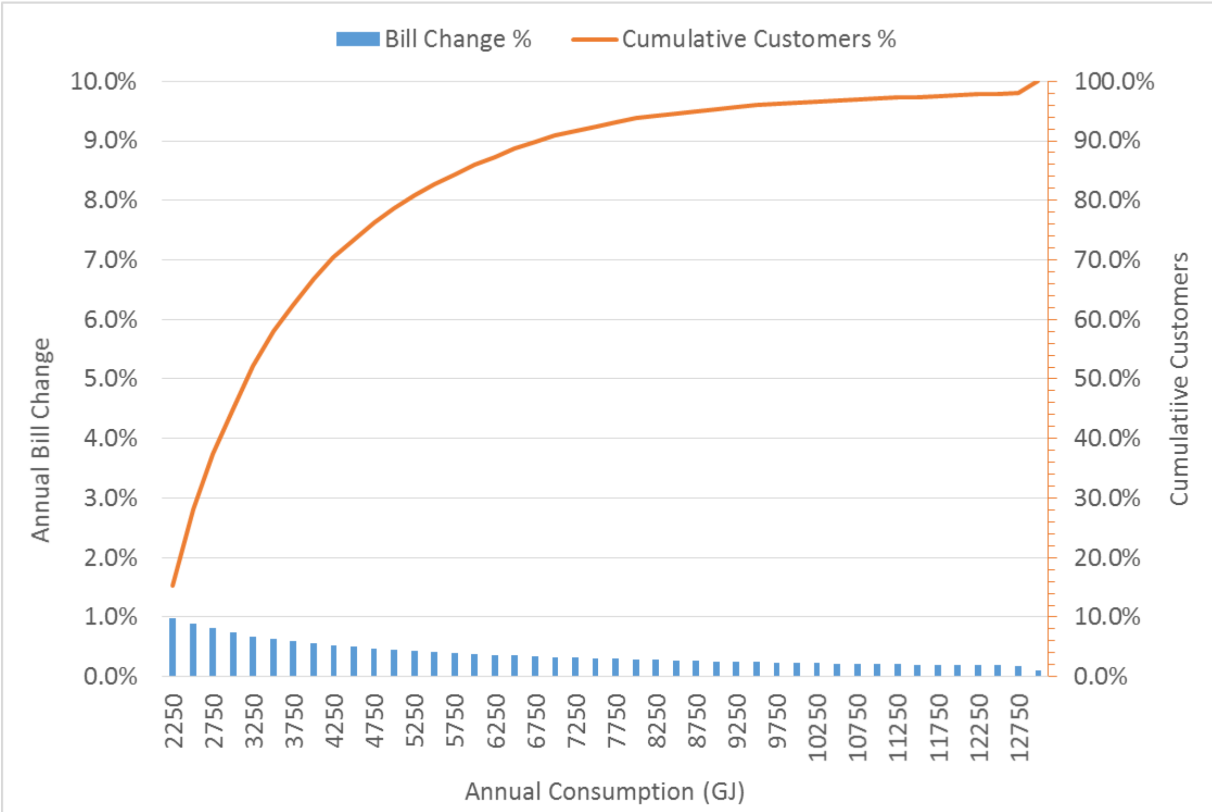
The customer bill impacts of FEI's proposed rate changes are shown below in Figures 8-13 and 8-14. As shown below, using customer data from 2015, FEI has estimated that with the proposed rates, RS 2 customers would receive an annual bill change of between -2.0% and +10%[139] and RS 3/RS 23 customers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

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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.

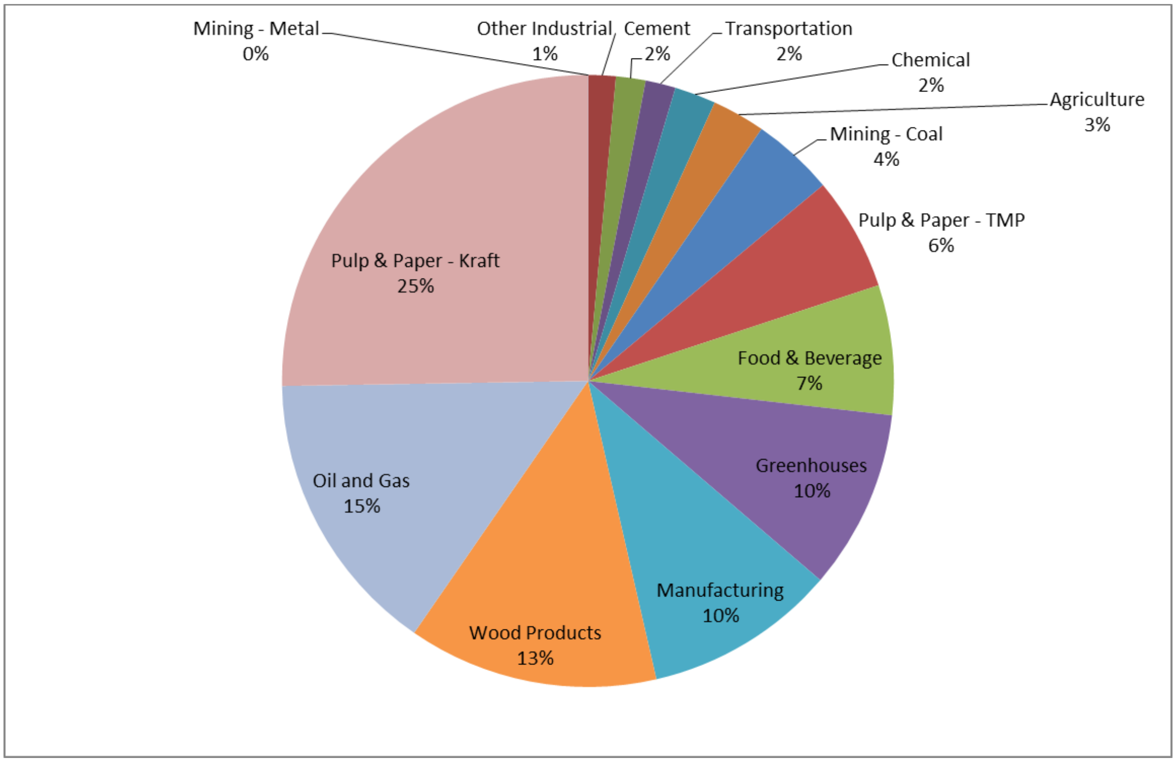
This section is organized as follows:

- 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*

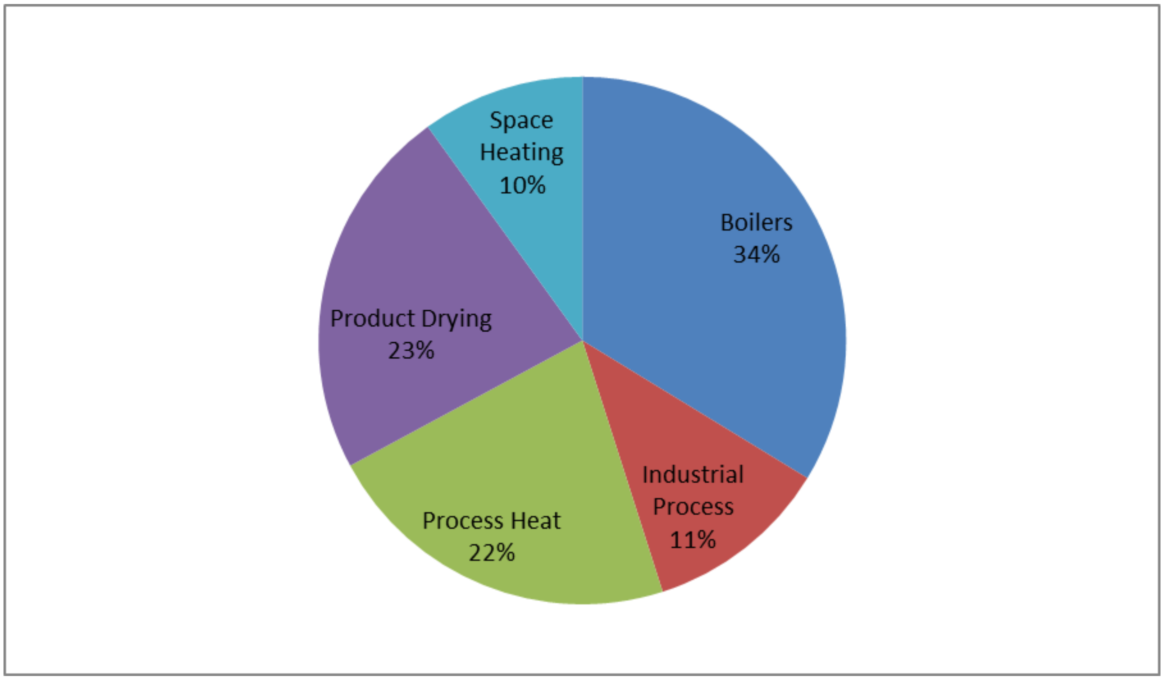
The industrial customer group represents a wide range of industries and end uses. The industrial sector makeup is shown in Figure 9-1 and the end usage is shown in Figure 9-2. Figure 9-1 shows that the major gas consuming industries are the pulp and paper, wood products, oil and gas, manufacturing and 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.

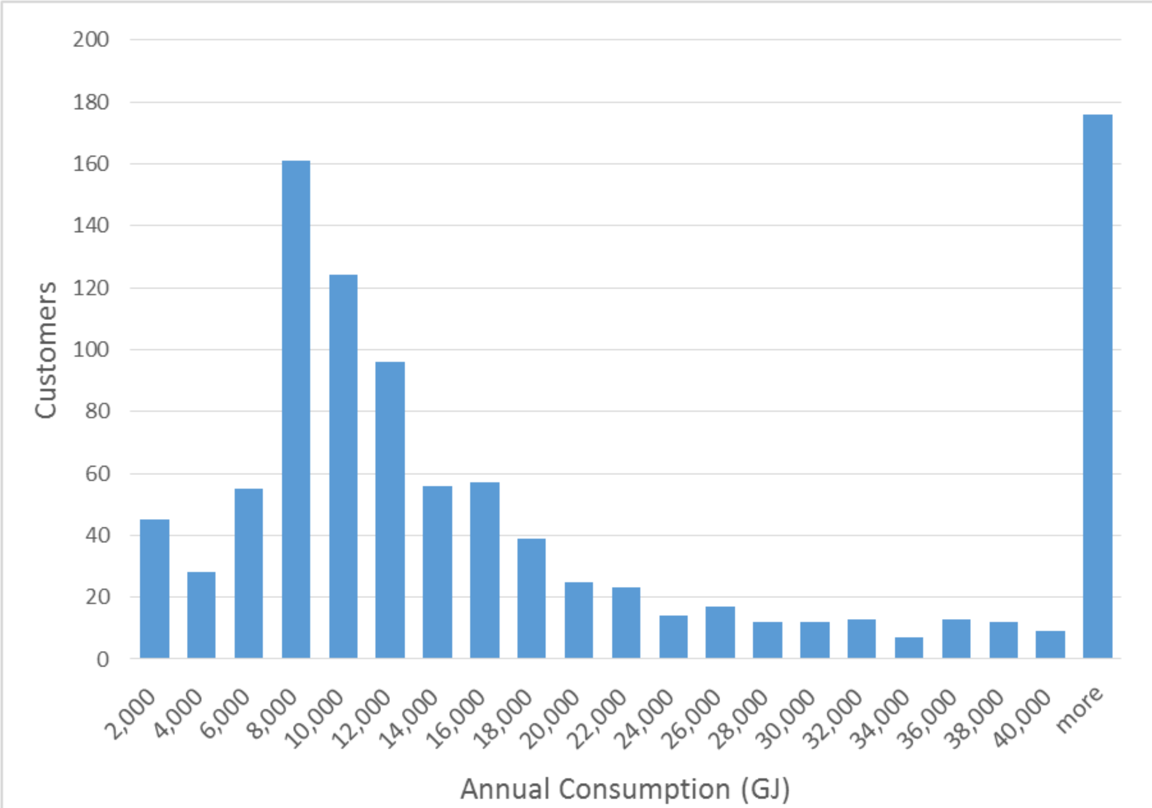
Figure 9-2: End Use by Industrial Customers[141]



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).

1 **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.

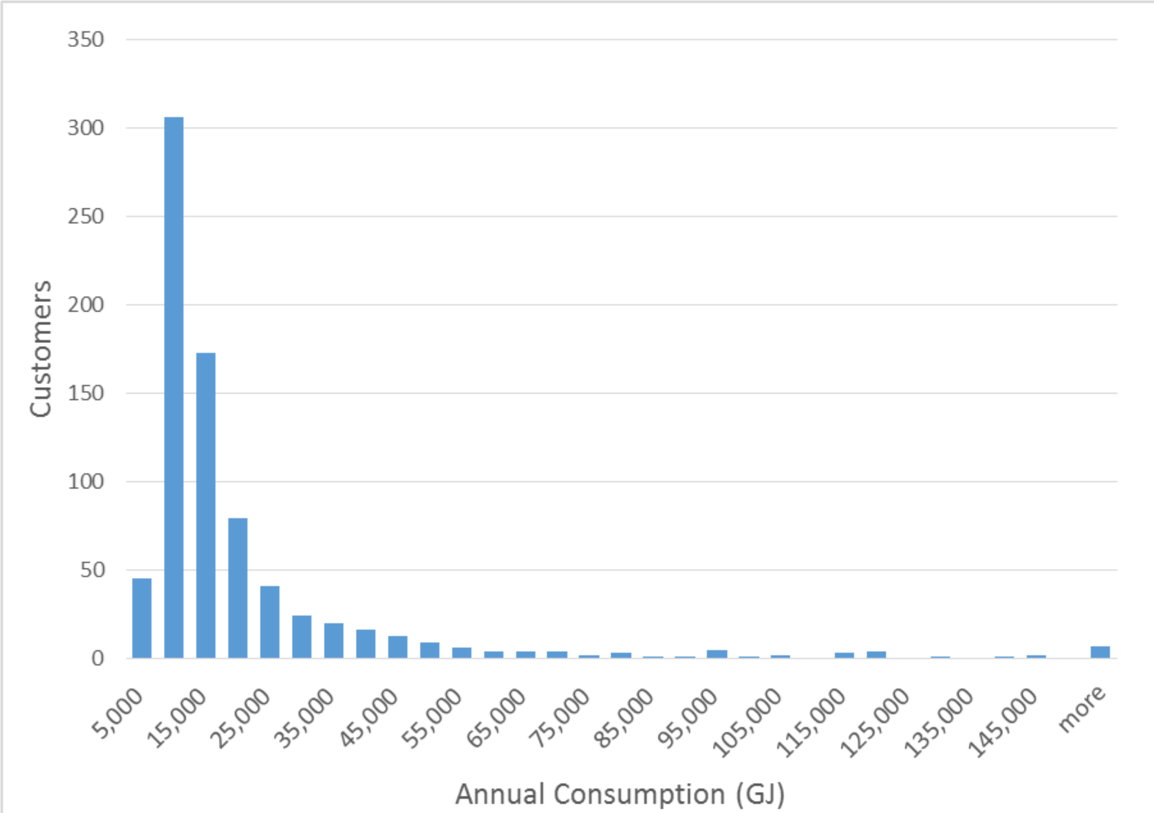
As shown in Table 9-2 above, for 2016, FEI forecasts 230 customers in RS 5 using a total of 2.2 PJ, and 566 customers in RS 25 using a total of 13.5 PJ.

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

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

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

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

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

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

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		Modified Formula with 5 Day Average
					3 Days	*5 Days*	
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.

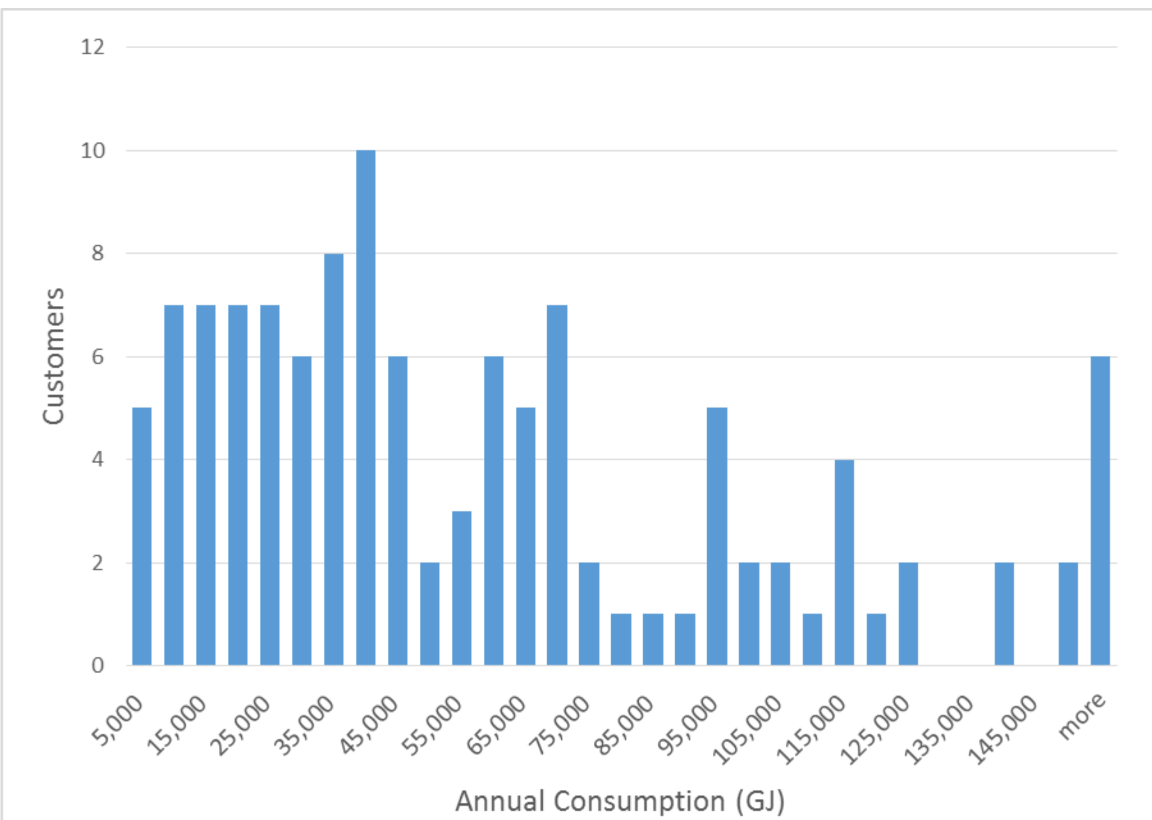
To compensate for these costs, FEI offers the service at a discount from the General Firm Service rate. Specifically, the existing delivery charges for RS 7/RS 27 are based on the General Firm Service RS 5/RS 25 Demand Charge based on an 80% load factor, plus the RS 5/RS 25 Delivery Charge.

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 delivery charge. To convert the RS 5/RS 25 demand charge into an equivalent volumetric

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

charge, the demand charge for one GJ of Daily Demand is multiplied by 12 months and then divided by 365 GJ divided by the 80% load factor. The bottom row of Table 9-16 shows the amount of the discount from the firm rate and the relative percentage of the discount to the firm rate at an 80% load factor for each calculation.

Table 9-16: RS 5 at 80% Load Factor Compared to RS 7[151]

Rate Schedule	Line No.		2001	2016 - Current	2016 – COSA
Effective Rate/GJ for an RS 5 firm service customer at an assumed **80% Load Factor**	1	*Demand Charge*	\$0.509	\$0.825	\$0.888
	2	*Delivery Charge*	\$0.502	\$0.825	\$0.887
	3	*Total*	\$1.011	\$1.650	\$1.775
RS 7 *General Interruptible Sales Service*	4	*Delivery Charge*	\$0.836	\$1.353	\$1.455
Differential (per GJ) *RS 5 – RS 7*	5		\$0.175	\$0.297	\$0.320
Discount as a Percentage of Total Firm	6		17.3%	18.0%	18.0%

Notes:

- Line 1 is the RS 5/RS 25 Demand Charge converted to a volumetric rate based on an 80% Load Factor (detailed in the footnote)
- Line 2 is the RS 5/RS 25 Delivery Charge
- Line 3 is the sum of lines 1 and 2
- Line 4 is the RS 7/RS 27 Delivery Charge
- Line 5 is the value of the discount (Line 3 – Line 4) between RS 5/RS 25 and RS 7/RS 27
- Line 6 is the value of the discount expressed as a percentage of the total Firm (Line 3).

As shown in Table 9-16 above, while the \$/GJ value of the discount has increased from 2001 to 2016 COSA rates (due to general rate increases between 2001 and 2016), the relative percentage of the discount of the interruptible rate to the firm rate at an 80% load factor has remained relatively constant at about 18%.

The same analysis comparing the interruptible rate to a firm rate equivalent at a 55% load factor also shows that the discount has remained constant at approximately 33%. This analysis is shown below in Table 9-17.

[151] 2016 – Current Demand Charge is equal to \$20.077 x 12 / 365 / 80% = \$0.825; 2016 COSA plus known and measurable changes Demand Charge = \$21.596 x 12 / 365 / 80% = \$0.888.

Table 9-17: RS 5 at 55% Load Factor Compared to RS 7 at 80% Load Factor[152]

Rate Schedule	Line No.		2001	2016 - Current	2016 – COSA
Effective Rate/GJ for an RS 5 firm service customer at an assumed **55% Load Factor**	1	*Demand Charge*	$0.740	$1.200	$1.291
	2	*Delivery Charge*	$0.502	$0.825	$0.887
	3	*Total*	$1.242	$2.025	$2.178
RS 7 *General Interruptible Sales Service*	4	*Delivery Charge*	$0.836	$1.353	$1.455
Differential (per GJ) *RS 5 – RS 7*	5		$0.406	$0.672	$0.723
Discount as a Percentage of Total Firm	6		32.7%	33.2%	33.2%

The results illustrate that there has been no deterioration between the avoided cost of firm service and the interruptible delivery charge before consideration of any other rate changes proposed in this Application. Although the value of the discount between the cost of firm and interruptible service has increased, the relative percentage of the discount to the firm service has remained relatively static. The primary reason for this is that successive rate changes have been applied equally, percentage wise, to both firm (RS 5/RS 25) Demand and Delivery Charges as well as to interruptible (RS 7/RS 27) Delivery Charge.

9.6.3.3 Multi-Jurisdiction Review of Rates

As discussed above in Section 9.4, FEI conducted a review of the rate schedules offered by ten Canadian natural gas utilities. There are two utilities that also offer interruptible service - Manitoba Hydro and Union Gas. The interruptible service rates of these two utilities are summarized below in Table 9-18.

Table 9-18: Multi-Jurisdiction Review Summary for Interruptible Service

Company	FEI	Manitoba Hydro	Union Gas
Description	General Interruptible	High Volume Interruptible	Large Volume Interruptible
Eligibility	No restriction	>26,010 GJ/year	115 – 536 GJ/day (42,000 – 195,000 GJ/year)
Rate Type	Flat	Flat	Negotiated
Basic Charge (/month)	$880	$1,254	$352
Delivery Charge (/GJ)	$1.455[153]	$0.274	$1.233 (maximum)

[152] 2016 – Current Demand Charge is equal to $20.077 x 12 / 365 / 55% = $1.200; 2016 COSA plus known and measurable changes Demand Charge = $21.596 x 12 / 365 / 55% = $1.291.

It is difficult to draw any conclusions from the multi-jurisdictional review above as there are only two utilities that offer an interruptible service. Both of these other utilities have different eligibility criteria (from FEI's and from each other) and different rate levels. Consequently, FEI draws no conclusions from the multijurisdictional review.

9.6.4 Principle Based Review of Rate Design

Interruptible service should be offered at a suitable discount from firm service delivery rate in order to balance a number of the rate design principles, including:

- Principle 3: Price signals that encourage efficient use and discourage inefficient use
- Principle 4: Customer understanding and acceptance
- Principle 5: Practical and cost effective
- Principles 6 and 7: Rate and Revenue Stability

From the customer's perspective, the economic decision to take firm or interruptible service is dependent on whether the discount from firm is sufficient to compensate for the cost to have an alternate backup system and fuel that can be used or the cost from ceasing operations. Setting the discount either too high or too low would send the wrong price signals and could cause rate and revenue instability for customers and FEI, respectively. If the discount is too low, this may discourage new customers from considering interruptible service and may also cause existing interruptible customers to migrate to firm service. If the discount is too high and if the expected level of curtailment is very low, too many customers with firm service may elect to contract for interruptible service.

FEI believes that the discount is working well. FEI has experienced no unusual or unanticipated migration activity (from firm to interruptible or interruptible to firm) that would suggest the rates or rate structure are producing undesirable effects on customer's service option selections.

RS 7/RS 27 customers continue to receive value for service. FEI evaluated the interruptible discount against the level of service disruption that RS 7/RS 27 interruptible customers experience. Over the past twenty years, interruptible customers have experienced a total of approximately 19.5 days of capacity curtailment. On average, the annual curtailment is about one day per year.[154]

Based upon 2016 forecasts, FEI expects to receive approximately $11 million in revenues from these interruptible customers. This revenue goes to the credit of FEI's firm sales and transport customers by virtue of contributing to the total cost of service and avoiding system

[153] 2016 COSA plus known and measurable Rates: Current rates plus known and measurable changes.
[154] Based upon cold weather days where all interruptible customers are curtailed, but not including capacity constrained regions of the FEI system where partial curtailment happens every year, or for FEI system maintenance related curtailment

improvements that would be necessary if these customers were receiving firm service. As summarized above in Table 9-2, the RS 7/RS 27 customers are forecast to use 6.7 PJ, or an average use of approximately 18 TJ/day, representing a significant level of FEI's system peak demand that could be curtailed. The value to all customers of the avoided cost of service from RS 7/RS 27 interruptible customers is approximately $0.04 per GJ (Refer to Appendix 9-3).

The discount of approximately $0.34 per GJ is sufficient to require interruptible customers to have alternative backup fuel / systems to use when interruption is required by FEI. This is evidenced by the stability of customers taking interruptible service, i.e., the lack of migration in or out of RS 7/RS 27. Also, all non-bypass customers avoid an incremental $0.04 per GJ cost of service from avoided system improvements. The net benefit to non-bypass customers is approximately $5 million dollars.

Table 9-19: Net Savings to the Cost of Service

RS 7/27 Volumes (Table 9-2) PJ's	**6.7**
x Discount (Table 9-19)	$0.344
Dollar Value of Discount ($000s)	$2,305
All Non-Bypass Volumes (Appendix 9-3) TJ's	182,942
Avoided Incremental Cost of Service $/GJ	$0.040
Avoided Cost of Service ($000s)	$7,318
Net Savings to all Non-Bypass Customers ($000s)	$5,013

FEI concludes that the existing rates for RS 7 and 27 achieve a reasonable balance between maximizing the economic value of interruptible service, which helps to offset utility costs to firm customers, and providing a sufficient incentive for existing customer to stay on interruptible service and to encourage new customers to sign up for interruptible service.

In alignment with the Bonbright principle to fairly allocate costs to customers, interruptible customers are not allocated any demand related costs.

The existing methodology for setting interruptible service at a discount to firm service has been in effect for many years. This methodology is therefore understood and accepted by customers. The method is also practical and cost effective to implement.

FEI is therefore proposing to maintain the existing discount. However, due to proposed changes to the RS 5/RS 25 Demand Charge, FEI is proposing an update to the RS 7/RS 27 charges as explained below.

9.6.5 Update to RS 7/RS 27 to Account for Proposed RS 5/RS 25 Charges

FEI is proposing to update the existing method of calculating delivery charges for RS 7/RS 27 to reflect the proposed changes to RS 5/RS 25.

As discussed in Section 9.5 above, for General Firm Service FEI is proposing to decrease the multiplier in the Daily Demand formula from 1.25 to 1.1 and to increase the Demand Charge by $3.00 per month per GJ of Daily Demand. As shown in Table 9-12 above, under the proposed Daily Demand formula, the load factor of RS 5/RS 25 customers increases compared to the load factor under the existing Daily Demand formula. A RS 5/RS 25 customer who has a 100% Load Factor, i.e., uses the same amount of gas each day, as a result of the 1.1 multiplier will have an effective load factor of 90.9% (100% / 1.1). Therefore, to preserve the discount between the firm and interruptible rate:

- the load factor of 55% used in the RS 7/RS 27 calculation (Table 9-17, Line 1) needs to be increased to 62.5% (55% / 80% = x% / 90.9%, where x equals 62.5%);
- the firm equivalent (Table 9-17, Line 3 and Table 9-20, Line 6) to which the RS 7/RS 27 charge is compared must also be increased by the 1.1/1.25 multiplier change in order to have an apples-to-apples comparison (i.e., a 55% load factor customer is now a 62.5% load factor customer; a 80% load factor customer is now an 90.9% load factor customer).

As shown below in Table 9-20, applying the same interruptible rate methodology originally approved in the 1996 Rate Design proceeding results in a RS 7/RS 27 Delivery Charge of $1.443 per GJ and a discount from the firm equivalent at an 80% load factor of 24%. However, if the adjustments listed above are made, then the discount remains consistent at about 18%. In short, the firm rate equivalent to which the interruptible rate is compared to must be adjusted for the change in the Daily Demand formula. After the change in the multiplier, an 80% load factor RS 5/RS 25 customer would now be a 90.9% load factor customer. Taking this into account, Table 9-20 below shows that the Interruptible rate of $1.443 per GJ remains the same, but the discount is only 18.8%. As the existing discount of approximately 18% is maintained, FEI believes that the Interruptible Delivery Charge of $1.443 per GJ is the appropriate rate.

Table 9-20: Resulting Discount from Adjustment to RS 7/RS 27

Rate Schedule	Line No.		2016 COSA with 80% Load Factor Adjustment	2018 RS 7/27 Charges using 2001 Methodology	2018 Proposed with 90.9% Load Factor Adjustment[155]
RS 5/25	1	*Demand Charge*	$21.596	$24.596	$24.596
Load Factor for Equivalent firm Demand Charge	2		80.0%	80.0%	90.9%
Load Factors for Interruptible Rate	3		N A	55.0%/80.0%	62.5%/90.9%
Effective Rate/GJ for an RS 5 firm service customer	4	*Demand Charge*	$0.888	$1.011	$0.889
	5	*Delivery Charge*	$0.887	$0.887	$0.887
	6	*Total*	$1.775	$1.898	$1.776
RS 7 *General Interruptible Sales Service*	7	*Delivery Charge*	$1.455	$1.443[156]	$1.443
Differential (per GJ) *RS 5 – RS 7*	8		$0.320	$0.455	$0.334
Discount as a Percentage of Total Firm	9		18.0%	24.0%	18.8%

FEI does not anticipate any migration of customers shifting from interruptible service to firm service or from firm service to interruptible service. FEI concludes the change to the load factor for equivalent firm is necessary to stabilize the effective rate per GJ (Line 6) from which the discount is measured. The change to the load factor for the interruptible rate coupled with the change in the load factor for equivalent firm results in the same interruptible rate whether the load factor is 55% and 80% or 62.5% and 90.9%.

9.6.6 Stakeholder Feedback Received

As discussed in Section 5, FEI has previously circulated a Rate Design and Segmentation Discussion Guide to all interested stakeholders and held a workshop on August 31, 2016. This Guide and Workshop covered FEI's current industrial rate structures and presented a number of

[155] For the 2018 Proposed with 90% Load Factor the RS 5/25 the Proposed Demand Charge of $24.596 is multiplied by x 12 / 365 / 0.909 = $0.889; and $24.596 x 12 / 365 x .62.5% / 90.9% + $0.887 = $1.443

[156] RS 7/RS 27 Delivery Charge is equal to $24.596 (RS 5/RS 25 Demand Charge) x 12 / 365 x 55% (RS 5/RS 25 Load Factor) / 80% + $0.887 = $1.443

options that FEI had under consideration. The relevant stakeholder feedback is summarized below, with the detailed Meeting Summary and Notes attached as Appendix 4-2.

During this workshop, FEI presented the interruptible discount based upon a load factor of 80%. The feedback FEI received consisted of two items:

1. ensure that these customers receive a fair discount so that they do not return to firm service; and
2. clarify how the 80% was determined and applied.

These two comments have been addressed above in Section 9.6.3.2 and 9.6.5.

9.6.7 General Interruptible Service – Summary of Rate Design Proposal

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

9.6.8 Bill Impact Analysis

The proposed interruptible rate results in a $0.012 per GJ decrease in the Delivery Charge to $1.443 per GJ (Table 9-20) from $1.455 per GJ (Table 9-17). The decrease is a result of the increase in the RS 5/RS 25 Demand Charge and the proposed changes to the load factors in the discounting methodology to preserve the relationship between the firm and interruptible rates (55% to 62.5% and 80% to 90.9%). The total revenue reduction for RS 7/RS 27 is $91 thousand (7,548 TJ[157] x $0.012); this represents an average annual bill reduction of 0.7%. The smallest reduction is 0.2% and the maximum reduction is 0.8% for customers in RS 7/RS 27.

9.7 *SEASONAL FIRM SERVICE – RS 4*

9.7.1 Introduction

RS 4 serves the unique needs of seasonal customers who typically do not use natural gas during the winter and thus do not contribute to FEI's system peak demand. These seasonal customers use gas primarily during the off-peak period from April 1 to October 31 (referred to in RS 4 as the Off-Peak Period). However, some seasonal customers also use gas in the months

[157] 2015 Billed Consumption.

of November and March when there is still available capacity and gas. During the coldest months from December through February, seasonal customers do not take gas service.

During the Off-Peak Period seasonal customers receive firm sales service. The Off-Peak period Delivery Charge has been derived from the RS 5 Demand Charge converted to a volumetric rate at a 100% load factor, plus the RS 5 Delivery Charge.

From November 1 to March 31 (referred to in RS 4 as the Extension Period), seasonal customers receive only interruptible sales service. In order to provide service to RS 4 customers during the Extension Period, FEI must have sufficient supply of gas and capacity to deliver the gas. For the Extension Period, the RS 4 Delivery Charge is the RS 7 Delivery Charge times 1.5.

Based on continuing with the existing methodology, the RS 4 Delivery Charges will change due to the proposed changes to RS 5 and RS 7. The Delivery Charge in the Off-Peak Period will increase by $0.114 per GJ and in the Extension Period will decrease by $0.018 per GJ.

9.7.2 Customer Characteristics

Customers served under RS 4 - Seasonal Firm Gas Service include paving companies with asphalt plants and municipal swimming pools that consume natural gas mainly during the summer months. There are 18 seasonal customers forecast for 2016 with an annual demand of 130 TJ. These customers only receive firm gas delivery from April 1 to October 31 (the Off-Peak Period).

The unique needs of these customers distinguish them from firm service customers who require firm service all year and interruptible customers who can either switch to a back-up fuel or cease operations should FEI need to interrupt their service at any time, but otherwise take gas service year round.

9.7.3 Stakeholder Feedback Received

As discussed in Section 5, FEI circulated a Rate Design and Segmentation Discussion Guide to all interested stakeholders and held a workshop on August 31, 2016. This Guide and Workshop discussed FEI's current rate structures and presented a number of options that FEI had under consideration. The detailed meeting summary and notes are attached as Appendix 4-2.

During the Workshop, FEI described the method to establish the Delivery Charge for RS 4. There were no questions from stakeholders and no discussion on this topic.

9.7.4 Principle-Based Review of Seasonal Service

The method of determining the seasonal delivery charges was established during the 1996 Rate Design. RS 4 for seasonal customers is working as intended in that the customers served under this rate schedule require and receive seasonal service and are not receiving service during the coldest peak periods of the winter.

In alignment with the Bonbright principle to fairly allocate costs to customers, seasonal customers are not allocated any demand related costs as they do not cause demand-related costs to be incurred in order to serve the firm load during the system peak requirements.

For the Off-Peak Period, the fairness principle is applicable. During these months, the seasonal customers require firm service and are therefore charged a firm rate based on the RS 5 Demand Charge plus Delivery Charge. Seasonal customers are served as a firm customer in the Off-Peak period only and as such their rate is based on the General Firm Service Rate. Since the Seasonal customers do not contribute to the System Peak which occurs in the Extension Period, the RS 4 Off-Peak rate is discounted from the RS 5 firm rate by using a 100% Load Factor equivalent rate.

During the Extension Period the seasonal Delivery Charge is set at 1.5 times the delivery charge for the RS 7 General Interruptible Service rate. The rationale for the 1.5 multiplier during the Extension Period is to set the Delivery Charge at a premium to discourage General Interruptible Service customers that are receiving year round service from migrating to the seasonal rate. That is, interruptible service customers that use gas throughout the winter period with rare curtailment during the Peak Demand Period are not the same as seasonal customers who do not use gas during the coldest winter months. This pricing methodology provides the price signals to incent customers to take service under the appropriate rate schedule service offering of General Firm or General Interruptible or Seasonal Service.

In the following section FEI proposes to continue with the existing method for determining RS 4 Delivery Charges in the Off Peak Period and considers this to be an appropriate balance of rate design principles.

9.7.5 Proposed RS 4 Delivery Charges

The Delivery Charge for RS 4 during the Off-Peak Period is set equal to the Demand Charge of RS 5/RS 25 at a 100% load factor, plus the Delivery Charge for RS 5/RS 25, and during the Extension Period is equal to 1.5 times the Delivery Charge for RS 7/RS 27. As discussed above, FEI is proposing a change to the RS 5/RS 25 Demand Charge, which also results in a change to the RS 7/RS 27 Delivery Charge.

The proposed changes to RS 5/RS 25 and RS 7/RS 27, and the impacts on RS 4 are shown below in Table 9-21.

Table 9-21: RS 4 Seasonal Service Delivery Charge for Off-Peak and Extension Periods

Row	RS 4	2016 COSA[158] Based Rates	Proposed Rates
1	RS 5/25 Demand Charge equivalent at 100% Load Factor[159]	$0.391	$0.505
2	RS 5/25 Delivery Charge ($/GJ)	$0.887	$0.887
3	**RS 4 Off-Peak Delivery Rate $/GJ (Row 1 + Row 2)**	**$1.278**	**$1.392**
4	RS 7/27 Delivery Charge ($/GJ)	$1.455	$1.443
5	**RS 4 Extension Period $/GJ (Row 4 x 1.5)**	**$2.183**	**$2.165**

The proposed Delivery Charge during the Off-Peak period is increased by $0.114 per GJ to $1.392 per GJ and the rate in the Extension Period decreases by $0.018 per GJ to $2.165 per GJ.

The bill impact of the proposed Delivery Charges is to increase the revenues received from the Seasonal customers by $13.3 thousand ((118.6 TJ x $0.114) – (11.3 TJ x $0.018 per GJ)).

The bill impact of the proposed Delivery Charges is to increase the revenues received from the Seasonal customers from $641 thousand to $654 thousand, or approximately 2%.

9.8 LARGE VOLUME TRANSPORTATION – RS 22 AND CONTRACT CUSTOMERS

FEI's large volume industrial transportation customers are currently segmented into four groups, RS 22, RS 22A, RS 22B and the Large Industrial Contract Customers (VIGJV and BC Hydro IG). These four groups are a legacy of the service areas of FEI's predecessor companies, with RS 22 customers located primarily in the Lower Mainland, RS 22A customers in the Inland Service Area, RS 22B customers in the Columbia Service Area and the two Large Industrial Contract Customers located on Vancouver Island and the Sunshine Coast. RS 22A and 22B have been closed to any new customers since 1993. Since that time, any new large industrial transportation customers have taken service through RS 22 throughout FEI's service area.

Based on a review of the existing large volume industrial transportation rates, FEI proposes the following:

[158] The COSA rates shown are estimated based on 2016 approved rates plus known and measureable changes discussed above in Section 7.

[159] For the Proposed RS 4 Off-Peak Period the volumetric rate would be the RS 5 Demand Charge of $21.596 for 2016 COSA Rates x 12 months / 365 x 55% and $24.596 for Proposed Rates x 12 months / 365 x 62.5% load factor.

- 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 method converts the RS 5/RS 25 Demand Charge and variable Delivery Charge into a variable

[165] All RS 22 **does not** include RS 22A, RS 22B and RS 22 bypass customers.

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 toll for BC Hydro would be expressed as a Firm Demand Toll consistent with their

[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.

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

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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.

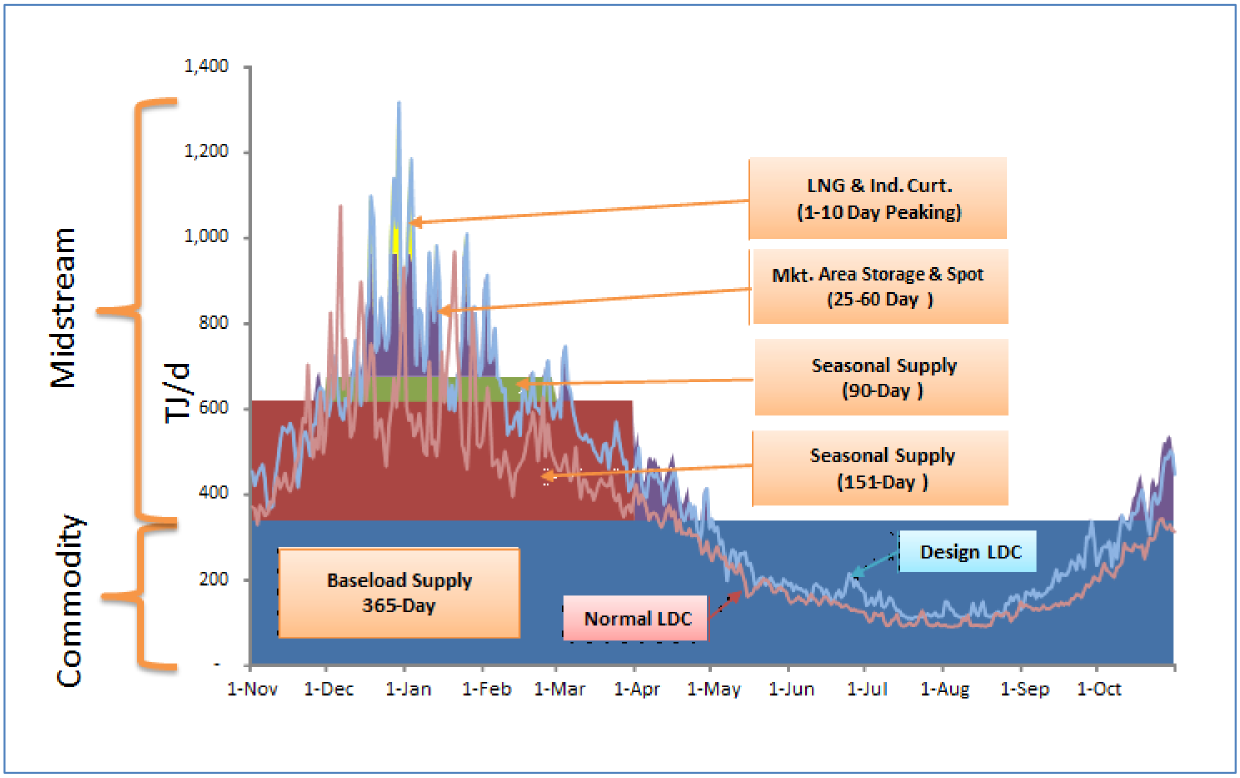
The ACP details the proposed contracting of resources that are needed to meet the forecast requirements of RS 1 to RS 7 sales customers for the upcoming gas contract year under all weather conditions, ranging from normal loads to design loads. The ACP objectives, which have been accepted by the Commission 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.

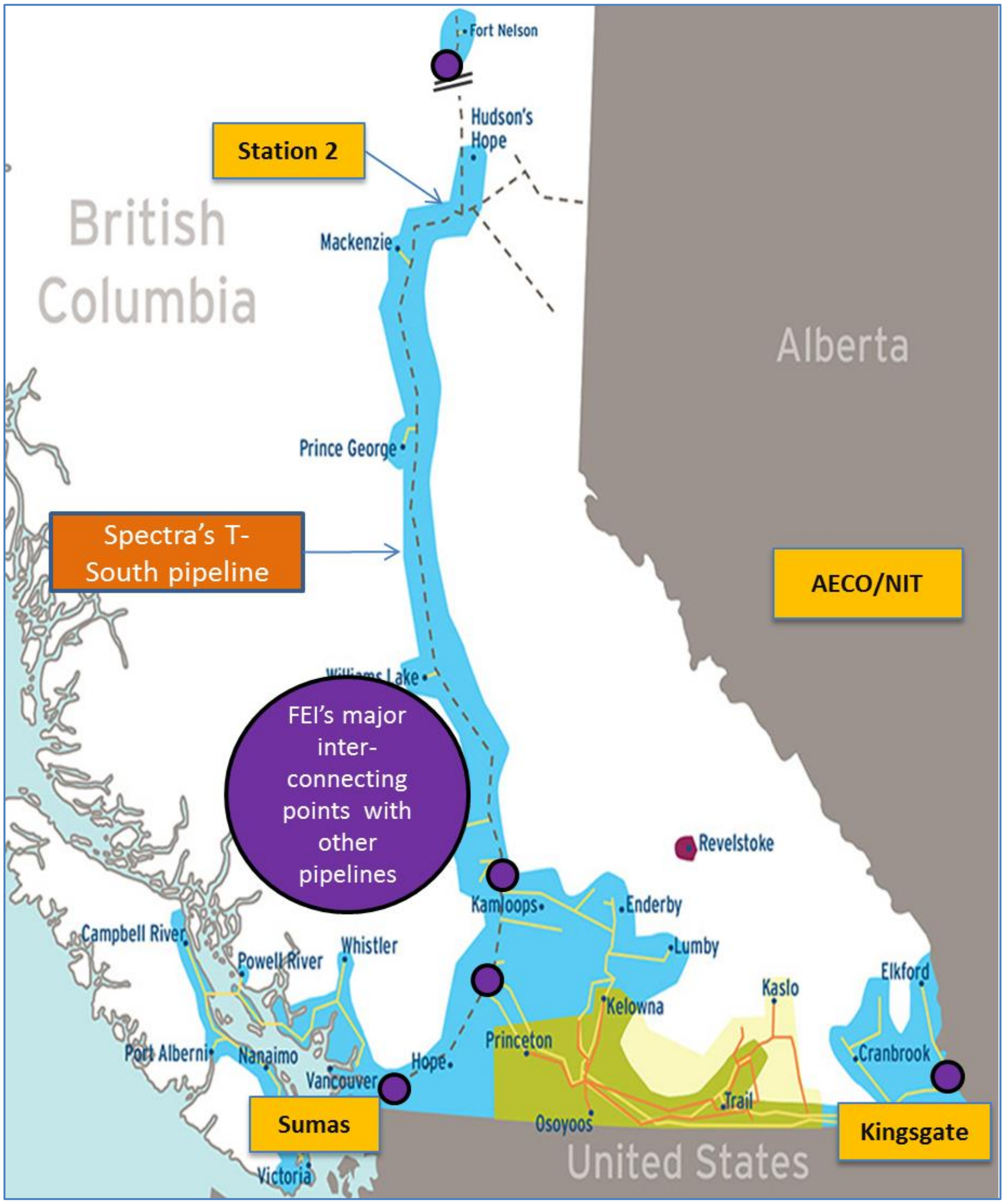
FEI continually assesses the regional supply and demand situation for available resources while also evaluating the requirement to develop new resources or infrastructure in order to meet its dynamic needs. This review is included in each filing of the ACP and it helps to plan the resource requirements 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:

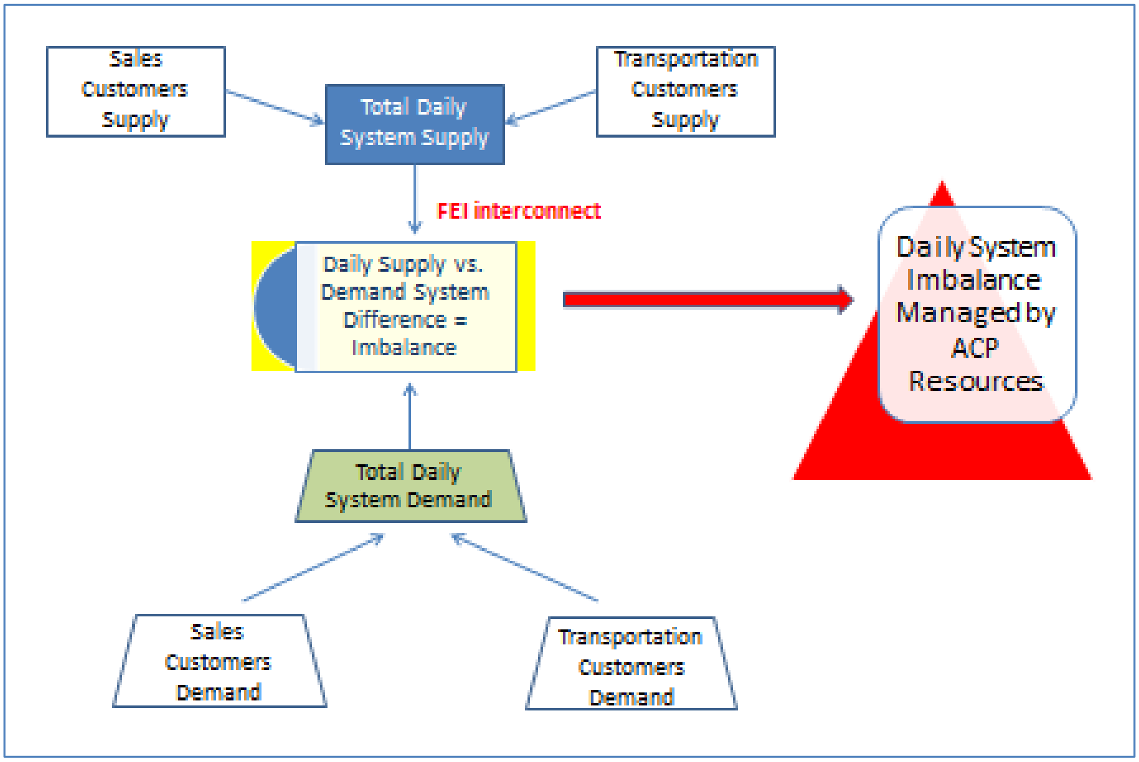
1. Hourly changes in temperature and weather conditions, which impacts load swings caused by heat sensitive customers.
2. Dynamic consumption levels for customers with industrial process loads. These load swings can be much more severe during cold weather, resulting in a large shortfall or surplus of 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 updated in order to reflect updated industry practices and operating procedures with third-party

[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".

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:

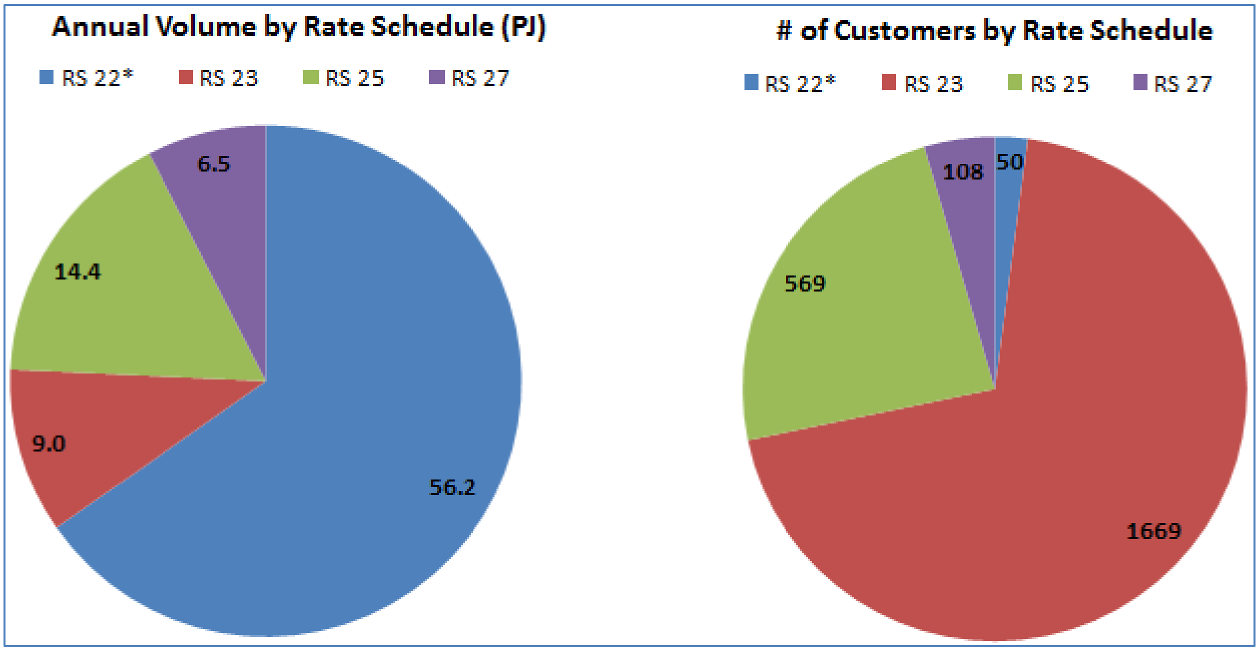
- RS 22 customers may elect for firm or interruptible transportation service on FEI's System[171].
- RS 22 and RS 22A customers are required to be daily balanced, meaning that gas supply and demand must be balanced on a daily basis. Customers that elect these rate schedules receive a daily balancing 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 an additional source of supply. When this service is withdrawn, monthly balanced

[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.

customers remain unaffected when imbalance return is reduced or eliminated and have the ability to draft the system under these circumstances.

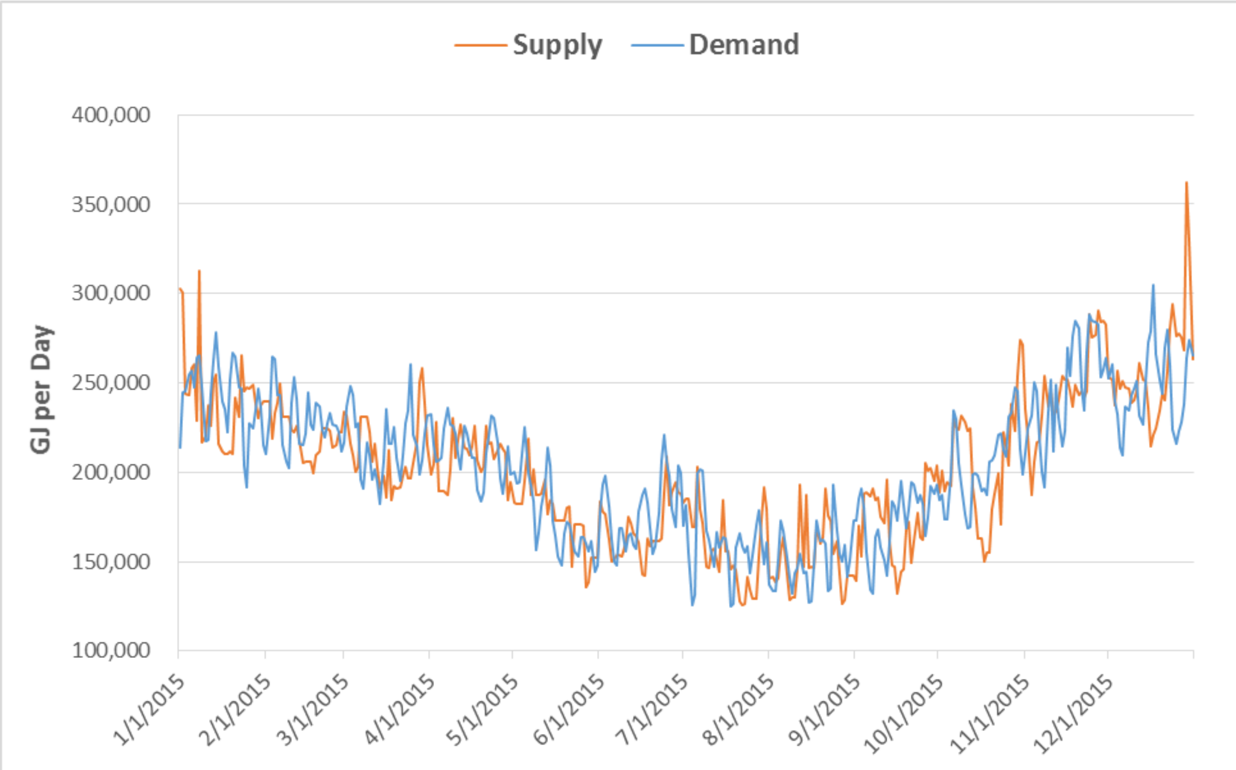
- Under a supply restriction, FEI can reduce the balancing tolerance to 5%. If this occurs, the tolerance is then applied to both daily and monthly balanced customers. If the 5% tolerance is exceeded, unauthorized over-run charges will apply. For under-deliveries for the first 5%, gas is sold to the 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 groups keep to a 2 to 3 day pack/draft balancing inventory level, which FEI has deemed to be

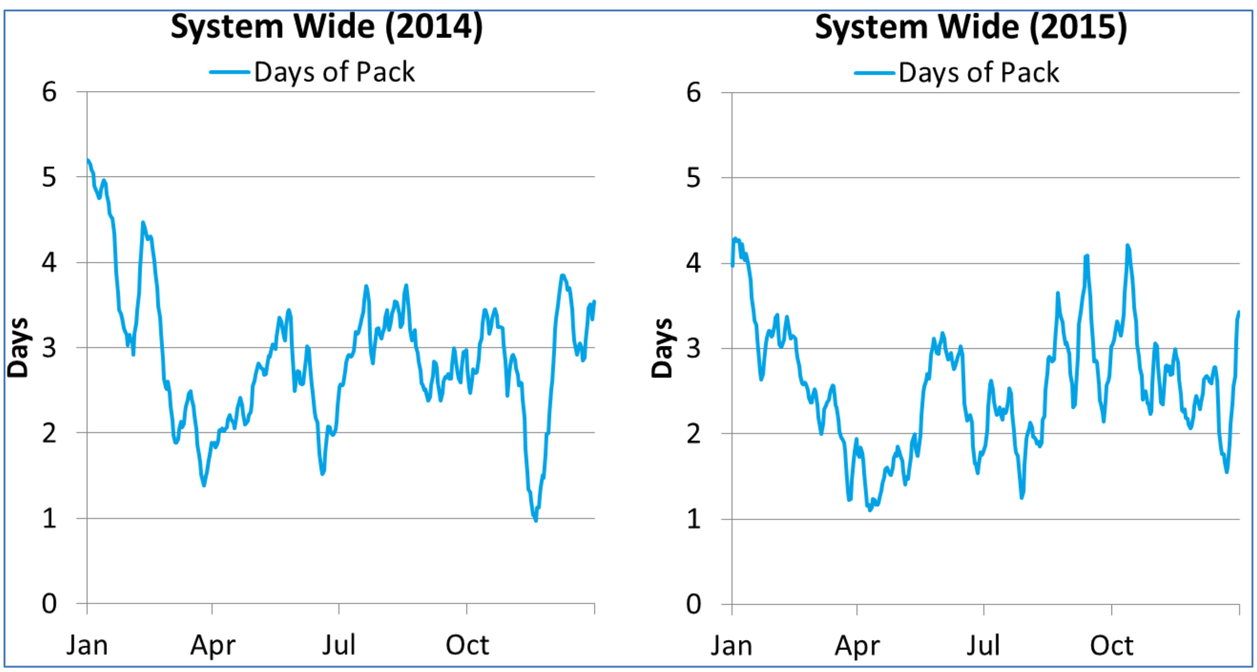
[173] Commission Order G-187-14, dated December 1, 2014.

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



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

[174] Commission Decision and Order G-187-14, dated December 1, 2014, page 13.

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.

- Balancing Provisions: 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.
- Balancing Tolerance: 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.
- Balancing Charges: 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*

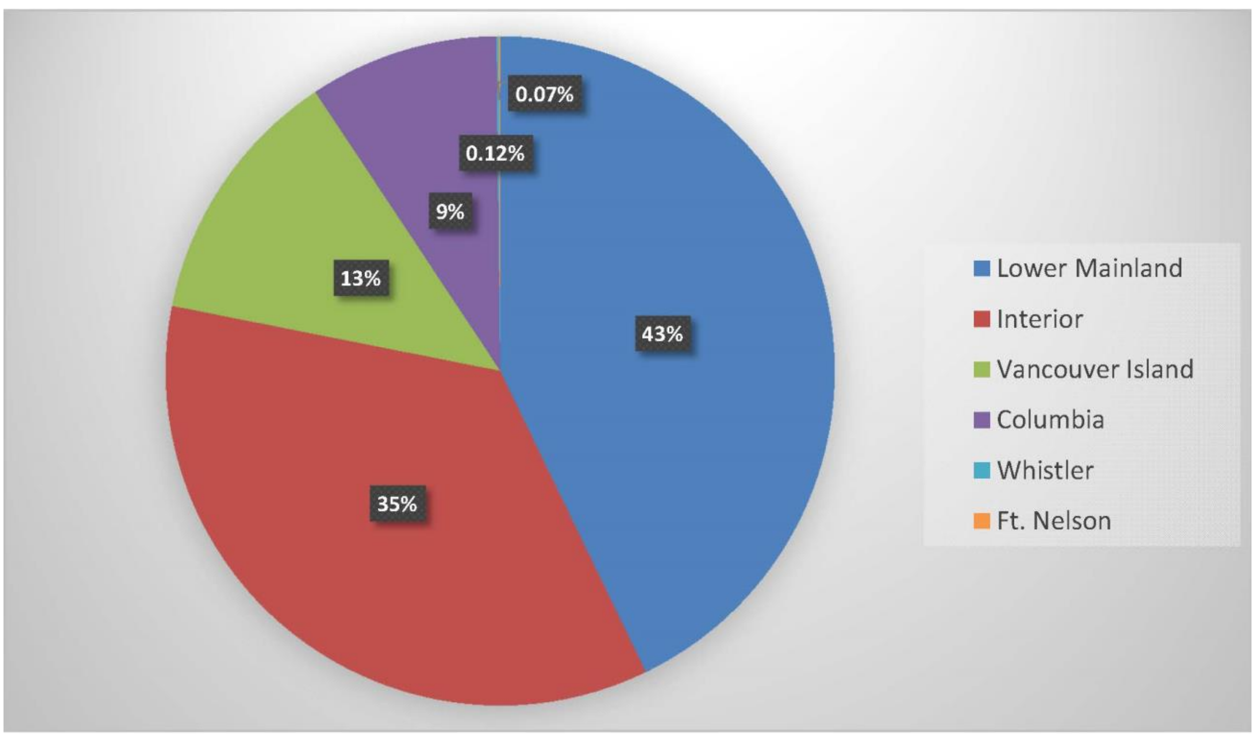
10.6.1 Review of Issue

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

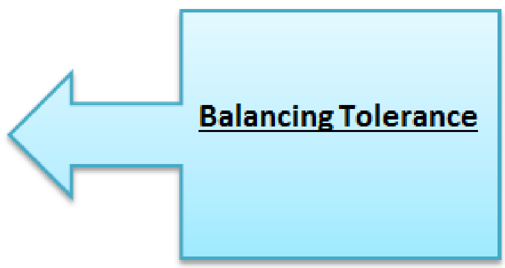


Table 10-6 below lists the number of days FEI imposed a supply restriction in the Lower Mainland and Interior regions from 2008 to 2016.

[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)

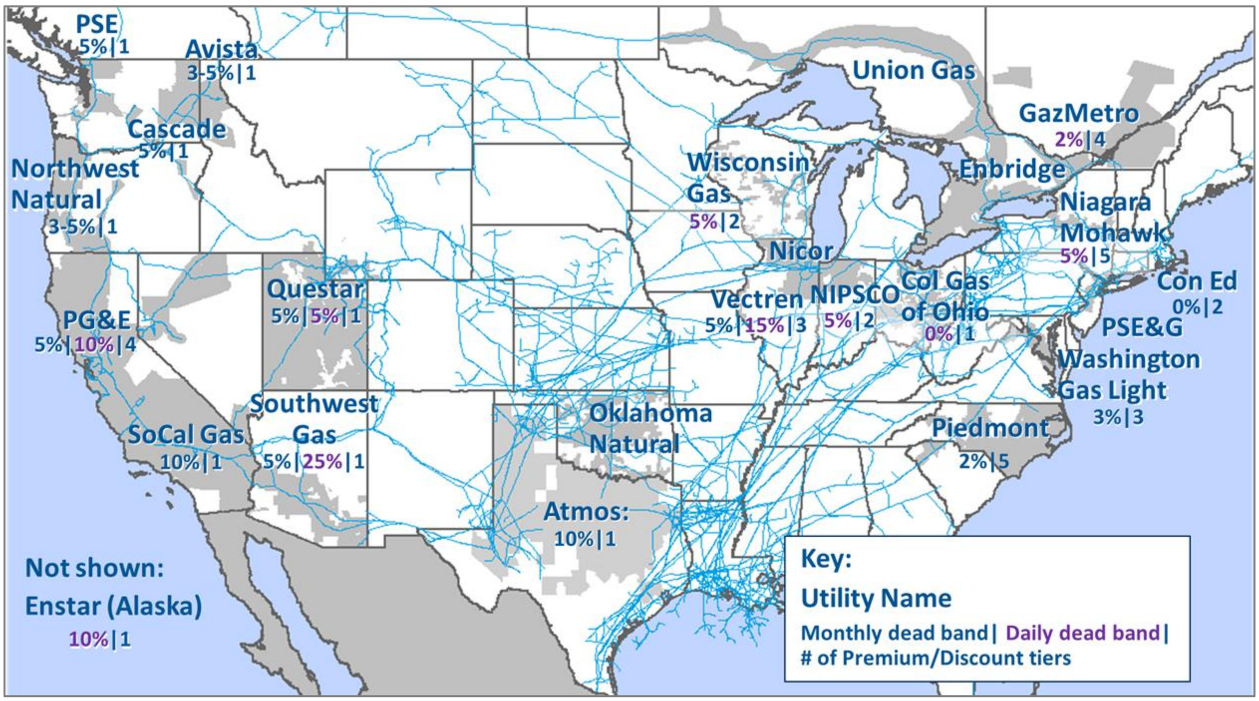
Industry-wide, balancing provisions can differ substantially between local distribution companies (LDCs) based on regional infrastructure differences. For example, balancing provisions can be relatively stringent for LDCs (such as FEI) with service territories adjacent to major natural gas market hubs 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

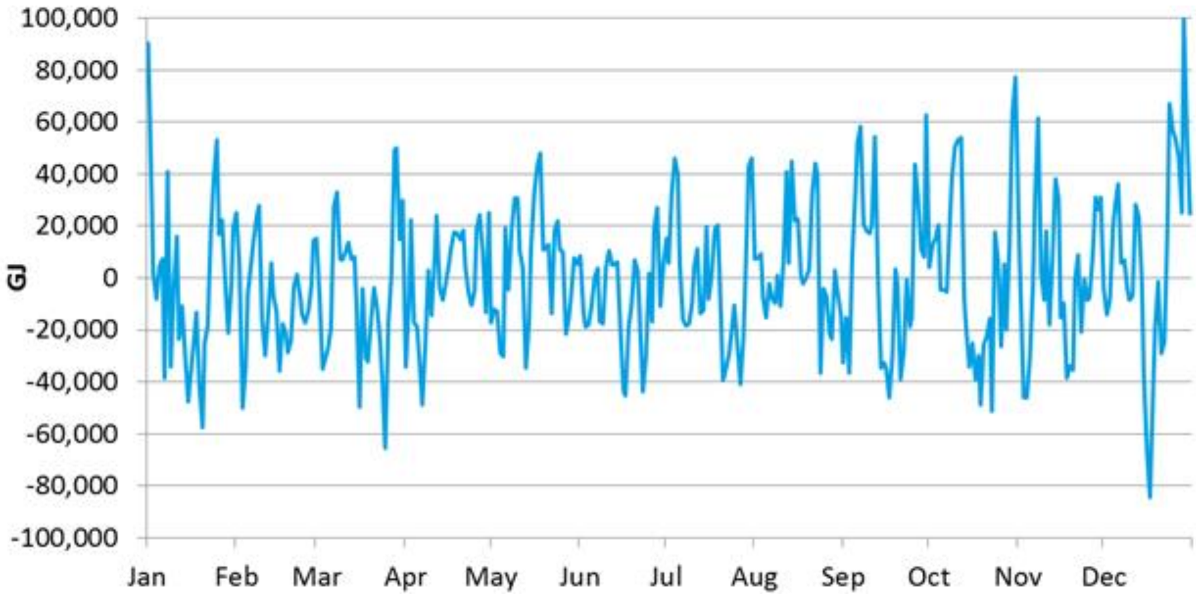


10.7.3 FEI System Balancing Issues

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

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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.
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28	Biomethane Service	28-1
N/A	*Standard Fees and Charges Schedule*	*S-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 June 1, 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 June 1, 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 June 1, 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.

1 **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 June 1, 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*

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 June 1, 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 June 1, 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 2020), 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

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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 90% to 110% 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 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 R:C	Initial COSA M:C	Revenue Shift ($000)	Approximate Annual Bill Change	COSA after Rate Design Proposals R:C	COSA after Rate Design Proposals 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 R:C	Initial COSA M:C	Revenue Shift ($000)	Approximate Annual Bill Change	COSA after Rate Design Proposals R:C	COSA after Rate Design Proposals 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 90% to 110%, except for 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 6/RS 6P is discussed below.

12.2.2 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 $61.7 thousand in the revenue required from RS 6/RS 6P by decreasing the Delivery Charge by $1.318/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 110% and RS 6 customers will experience approximately a 17% 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 $61.7 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%	94.4%	61.7	0.0%	96.4%	94.4%
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%	116.0%			106.3%	116.0%
Rate Schedule 6/6P *Natural Gas Vehicle Service*	131.7%	160.4%	(61.7)	-16.5%	110.0%	119.0%
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	($0.075)	$4.746
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

[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
RS 5/RS 25			
Basic Charge (Monthly)	$587.00	Nil	$587.00
Delivery Charge ($/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	($1.318)	$3.555
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

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

13. RATE DESIGN FOR FORT NELSON

TO BE FILED ON FEBRUARY 2, 2017 AS PART OF THE SUPPLEMENTAL FILING

Appendix 1
DRAFT ORDERS

Appendix 1-1

DRAFT PROCEDURAL ORDER

British Columbia Utilities Commission

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

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
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;

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

C. FEI proposes a regulatory timeline for the proceeding which includes workshops to review the information provided to stakeholders and to review the Cost of Service Allocation (COSA) model, proposals in the Application, and approvals sought;

D. FEI believes the Application can be addressed efficiently and effectively by a written hearing process, but proposes that the issue of whether an oral hearing is required be addressed at a Procedural Conference;

E. The Commission considers that establishing a preliminary Regulatory Timetable for the review of the Application is warranted.

NOW THEREFORE the British Columbia Utilities Commission orders as follows:

1. A public hearing process shall proceed according to the preliminary Regulatory Timetable attached as Appendix A to this Order.

2. Workshop #1 to review the information provided to stakeholders will be held on Thursday, February 23, 2017, commencing at 9:00 a.m. in the Commission Hearing Room on the 12th Floor, 1125 Howe Street, Vancouver, BC.

…/2

3. Workshop #2 to review the COSA model, proposals in the Application, and approvals sought will be held on Thursday, March 9, 2017, commencing at 9:00 a.m. in the Commission Hearing Room on the 12th Floor, 1125 Howe Street, Vancouver, BC.

4. A Procedural Conference will be held on Monday, May 15, 2017, commencing at 9:00 a.m. in the Commission Hearing Room on the 12th Floor, 1125 Howe Street, Vancouver, BC.

5. The Procedural Conference will address matters such as:

   a. identification of principle issues for the Application;
   b. process options for review of the Application, including;
      - a written hearing
      - an oral public hearing
      - or, as appropriate, some combination of the above
   c. timetable (information requests, responses, intervener evidence, rebuttal evidence etc.), and in particular the remainder of the regulatory timetable;
   d. location(s) of the proceedings;
   e. other matters that will assist the Commission to efficiently review all aspects of the Application.

   After the Procedural Conference, the Commission will issue a further procedural order and regulatory timetable for the remaining review of the Application.

6. FortisBC Energy Inc. is to publish, as soon as possible, the Public Notice, attached as Appendix B to this Order, in such local and community newspapers as to provide adequate notice to those parties who may have an interest in or be affected by the Application.

7. The Application, together with any supporting materials, will be available for inspection at FEI Office, 16705 Fraser Highway, Surrey, BC, V4N 0E8. The Application and supporting materials will also be available on the FortisBC website at www.fortisbc.com.

8. Interveners who wish to participate in the regulatory proceeding are to register with the Commission by completing a Request to Intervene Form, available on the Commission's website at http://www.bcuc.com/Registration-Intervener-1.aspx, by the date established in the Regulatory Timetable attached as Appendix A to this order and in accordance with the Commission's Rules of Practice and Procedure.

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

Attachments

FortisBC Energy Inc.
2016 Rate Design Application

PRELIMINARY REGULATORY TIMETABLE

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
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

British Columbia Utilities Commission

Public Notice of FortisBC Energy Inc. 2016 Rate Design Application

On December 16, 2016, FortisBC Energy Inc. (FEI) filed an Application with the British Columbia Utilities Commission (the Commission) seeking approvals, pursuant to sections 58 to 61 of the *Utilities Commission Act*, to adjust its rate design and terms and conditions of service to improve the alignment with accepted rate design principles. The Application considers the rate design for residential, commercial and industrial customers in all service areas, including the Fort Nelson Service Area, changes to the transportation customer business model, and FEI's General Terms and Conditions.

How to get involved

Persons who are directly or sufficiently affected by the Commission's decision or have relevant information, or expertise and who wish to actively participate in the proceeding can request intervener status by submitting a completed Request to Intervene Form by February 20, 2017. Forms are available on the Commission's website at www.bcuc.com. Interveners will receive notification of all non-confidential correspondence and filed documentation, and should provide an email address if available.

Persons not expecting to participate, but who have an interest in the proceeding, should register as interested parties through the Commission's website. Interested parties receive electronic notice of submissions and the decision when it is released.

Letters of comment may also be submitted using the Letter of Comment Form found online at www.bcuc.com. By participating and/or providing comment on the application, you agree to your comments being placed on the public record and posted on the Commission's website. All submissions and/or correspondence received, including letters of comment are placed on the public record, posted on the Commission's website, and provided to the Panel and all participants in the proceeding.

For more information about participating in a Commission proceeding please see the Rules of Practice and Procedure available at www.bcuc.com. Alternatively, persons can request a copy of the Rules of Practice and Procedure in writing. All forms are available on the Commission's website or can be requested in writing.

If you wish to attend the Workshops and/or Procedural Conference, please register with the Commission Secretary using the contact information provided at the end of this notice.

	Workshop #1 FEI will review materials provided at the Stakeholder Sessions
Date:	Thursday, February 23, 2017
Time:	9:00 a.m.
	Workshop #2 FEI will review the Application, Proposals, and Approvals Sought, and will answer questions
Date:	Thursday, March 9, 2017
Time:	9:00 a.m.
	Procedural Conference The Commission will consider the process to complete the review of the Application.
Date:	Monday, May 15, 2017
Time:	9:00 a.m.

Location:	Commission Hearing Room 12th Floor, 1125 Howe Street Vancouver, BC

View the application
The application and all supporting documentation are available on the Commission's website on the "Current Applications" page. If you would like to review the material in hard copy, it is available to be viewed at the locations below:

British Columbia Utilities Commission Sixth Floor, 900 Howe Street Vancouver, BC V6Z 2N3 Commission.Secretary@bcuc.com Telephone: 604-660-4700 Toll Free: 1-800-663-1385	**FortisBC Energy Inc.** 16705 Fraser Highway Surrey, BC V4N 0E8

For more information please contact Laurel Ross, Acting Commission Secretary using the contact information above.

Appendix 1-2

DRAFT FINAL ORDER

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

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
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 [DATE, 2017], the Commission issued Order G-XX-2017 establishing a Preliminary Regulatory Timetable for the review of the Application;

C. On [DATE, 2017], a Workshop was held to review the information provided to stakeholders at the May 19, 2016, Education & Background Information Session;

D. On [DATE, 2017], a second Workshop was held to review the COSA Model, Proposals in the Application, and Approvals Sought;

E. 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;

F. On [DATE, 2017], the Commission issued Order G-XX-2017 establishing a written/oral hearing process; and

G. 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 pursuant to sections 59 to 61 of the *Utilities Commission Act*, the British Columbia Utilities Commission orders as follows:

.../2

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.

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 $0.011/GJ as a result of the revenue shifts and rebalancing of rates discussed in Section 12.2 of the Application.

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.

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 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 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.

7. 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.

8. 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.

9. Termination of Tariff Supplement G-21, FEI's contract with Creative Energy Vancouver Platforms Inc., effective June 1, 2018, as discussed in Section 9.8.5 of the Application, is approved.

10. 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.

11. 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.

12. The decrease to the Delivery Charge per GJ of RS 6 by $1.318/GJ to address rebalancing, as discussed in Section 12.2.2 of the Application, is approved.

13. 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

14. 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.

Implementation

15. FEI is directed to file with the Commission amended tariff pages in accordance with the terms of this order to be effective June 1, 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

Appendix 2

ORDER IN COUNCIL NO. 557/2013 AND 749/2014 AND DIRECTION NO. 5

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 557 , *Approved and Ordered* November 27, 2013

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the attached Direction No. 5 to the British Columbia Utilities Commission is made.

DEPOSITED

November 28, 2013

B.C. REG. 245/2013

Minister of Energy and Mines and Minister Responsible for Core Review

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 3

Other:

November 4, 2013 R/589/2013/27

SCHEDULE

DIRECTION NO. 5 TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Contents

1 Definitions
2 Application
3 CNG services and LNG services
4 Expansion facilities
5 LNG rate schedule and LNG purchase agreement

APPENDIX 1

APPENDIX 2

Definitions

1 In this direction:

"Act" means the *Utilities Commission Act*;

"applicable customers" means customers of a utility other than customers receiving service

(a) under a fixed rate, or

(b) in the Fort Nelson service area of the utility, unless the Fort Nelson service area no longer has a distinct rate base;

"CNG" means compressed natural gas;

"CNG service" means a service that includes one or both of the following:

(a) compressing and dispensing of natural gas through specialized fuelling facilities or equipment;

(b) transporting CNG using specialized trailers or equipment;

"expansion facilities" means LNG facilities to be constructed, owned and operated, after this direction comes into force, by a utility at Tilbury Island, Delta, British Columbia;

"fixed rate" means a charge for natural gas service not subject to adjustment based on changes in the revenue requirements of a utility;

"LNG" means liquefied natural gas;

"LNG dispensing service" means the dispensing service referred to in sections 3 to 5 of the LNG rate schedule;

"LNG facility" means a facility that produces, stores and dispenses LNG and, in some cases, vaporizes LNG;

"LNG rate schedule" means the utility's Liquefied Natural Gas Sales, Dispensing and Transportation Service Rate Schedule 46 as set out in Appendix 1 attached to this direction;

"LNG service" means one or more of the following services:

(a) procurement of natural gas and electrical power for the purposes of LNG production;

(b) procurement of LNG;

(c) transmission and distribution of natural gas to an LNG facility;

(d) production of LNG from natural gas at an LNG facility;

(e) storage of LNG;

(f) provision or sale of LNG, including LNG dispensing service;

(g) use of LNG fuelling stations and fuelling equipment;

(h) transportation of LNG, including LNG transportation service;

(i) use of cryogenic receptacles, including, but not limited to, tankers, containers and vessels;

"LNG transportation service" means the transportation service referred to in section 6 of the LNG rate schedule;

"utility" means

(a) FortisBC Energy Inc.

(b) FortisBC Energy (Vancouver Island) Inc., or

(c) FortisBC Energy (Whistler) Inc.,

or any of those entities' successor entities on amalgamation, merger or consolidation.

Application

2 This direction is issued to the commission under section 3 of the Act.

CNG services and LNG services

3 In setting rates under the Act for a utility, the commission must do all of the following:

(a) treat CNG service and LNG service, and all costs and revenues related to those services, as part of the utility's natural gas class of service;

(b) allocate all costs and revenues related to CNG service and LNG service to all applicable customers;

(c) allow recovery of costs of purchasing LNG under the agreement referred to in section 5 (1) (b) of this direction.

Expansion facilities

4 (1) The commission must not exercise its power under section 45 (5) of the Act in respect of the expansion facilities.

(2) In setting rates under the Act for FortisBC Energy Inc., the commission must do both of the following:

(a) include in the utility's natural gas class of service rate base the lesser of

(i) the capital costs of constructing the expansion facilities, and

(ii) $400 million;

(b) include the utility's feasibility and development costs on or after January 1, 2013, related to the expansion facilities, plus a return on those costs equal to the utility's weighted average cost of capital, in the utility's natural gas class of service rate base.

LNG rate schedule and LNG purchase agreement

5 (1) Within 20 days of the date this direction comes into force, the commission must do all of the following:

(a) issue an order setting the LNG rate schedule as a rate for FortisBC Energy Inc. effective on the date the order is issued;

(b) accept for filing under section 71 of the Act the Gas Liquefaction, Storage and Dispensing Service Agreement between FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy Inc. as set out in Appendix 2 attached to this direction;

(c) issue an order setting the agreement referred to in paragraph (b) as a rate for FortisBC Energy (Vancouver Island) Inc.

(2) The commission must not do anything to amend, cancel or suspend the LNG rate schedule, except on application by the utility.

(3) If FortisBC Energy Inc. applies to the commission to amend a charge in the LNG rate schedule, the commission must not set the charge by reference to charges imposed by other providers providing similar services.

(4) The commission must not exercise a power under the Act in a way that would directly or indirectly prevent FortisBC Energy Inc. from providing LNG dispensing service under the LNG rate schedule.

APPENDIX 1

FORTISBC

FORTISBC ENERGY INC.

RATE SCHEDULE 46
LIQUEFIED NATURAL GAS SALES,
DISPENSING AND TRANSPORTATION SERVICE

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LNG TRANSPORTATION SERVICE AGREEMENT TA-46.1

1 Definitions

1.1 Definitions – Except where the context requires otherwise, all words and phrases defined below or in the General Terms and Conditions of FortisBC Energy Inc. (FortisBC Energy) and used in this Rate Schedule have the meanings set out below or in the General Terms and Conditions of FortisBC Energy. Where any of the definitions set out below conflicts with the definitions in the General Terms and Conditions of FortisBC Energy, the definitions set out below govern.

(a) Available LNG Capacity – means the total quantity of LNG available for sale to all Customers from LNG Facilities under this Rate Schedule as determined by FortisBC Energy in its sole discretion. FortisBC Energy's determination of the Available LNG Capacity may consider FortisBC Energy's assessment of its overall LNG liquefaction and storage requirements, which include providing peaking and emergency resources.

(b) Biomethane Energy Recovery Charge (BERC) – means the charge approved by the British Columbia Utilities Commission that is applicable for Customers selecting a percentage of Biomethane as a portion of their Gas.

(c) Contract Demand – means the minimum quantity of LNG, measured in Gigajoules, that FortisBC Energy agrees to supply and the Customer agrees to purchase and pay per year under the LNG Agreement, whether or not such quantity is actually consumed by the Customer.

(d) Contract Term – means the term specified in the LNG Agreement, and will expire at 12:00 a.m. Pacific Standard Time on the Expiry Date.

(e) Customer – means a Person entering into the LNG Agreement or LNG Transportation Service Agreement with FortisBC Energy.

(f) Day – means any period of twenty-four consecutive hours beginning and ending at 12:00 a.m. Pacific Standard Time.

(g) Delivery Charge – means the sum of:

(i) a LNG Facility Charge, which is the unit cost per Gigajoule to deliver natural gas from the Interconnection Point to the LNG Facilities, and to produce, store, and Dispense all LNG at the LNG Facilities, excluding the Electricity Surcharge; and

(ii) an Electricity Surcharge, which is the unit cost per Gigajoule for electricity consumed by the LNG Facilities to produce, store and Dispense all LNG at the LNG Facilities.

(h) Dispensing or any form of the verb Dispense – means the act of filling a Tanker with LNG from the LNG Facilities.

(i) Expiry Date – means the date specified in the LNG Agreement when service under the LNG Agreement ceases.

(j) Force Majeure – means any acts of God, strikes, lockouts, or other industrial disturbances, civil disturbances, arrests and restraints of rulers or people, interruptions by government or court orders, present or future valid orders of any regulatory body having proper jurisdiction, acts of the public enemy, wars, riots, blackouts, insurrections, failure or inability to secure materials or labour by reason or regulations or orders of government, serious epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, explosions, breakage or accident to machinery, liquefaction, storage, and dispensing equipment, or lines of pipes, or freezing of wells or pipelines, or the failure of Gas supply, temporary or otherwise, from a Supplier of Gas, or a declaration of Force Majeure by a gas Transporter that results in Gas being unavailable for delivery at the Interconnection Point, or any major disabling event or circumstance in relation to the normal operations of the party concerned as a whole which is beyond the reasonable control of the party directly affected and results in a material delay, interruption or failure by such party in carrying out its obligations under the Rate Schedule. Force Majeure events cannot be due to negligence of the party claiming Force Majeure.

(k) Gas – means natural gas (including odorant added by FortisBC Energy), or Biomethane, or a mixture of any or all of the above.

(l) Interconnection Point – means the point where the FortisBC Energy System interconnects with the facilities of Westcoast Energy Inc. at Sumas.

(m) LNG – means liquefied natural gas.

(n) LNG Facilities – means the current or future LNG production and storage plants and equipment that are owned or operated by FortisBC Energy or are under contract with FortisBC Energy to provide LNG to FortisBC Energy, but excludes any marine loading facilities.

(o) LNG Agreement – means the Liquefied Natural Gas Sales and Dispensing Service Agreement between FortisBC Energy and the Customer for the provision of LNG Service, a form of which is attached to this Rate Schedule.

(p) LNG Service – means the service of the liquefaction, storage and Dispensing of LNG from the LNG Facilities, and includes Long-Term LNG Service, Short-Term LNG Service and Spot LNG Service. LNG Service does not include LNG Transportation Service or marine loading service.

(q) LNG Spot Charge – means the LNG spot charge per Gigajoule of LNG as set out in the Table of Charges.

(r) LNG Transportation Service – means the optional service provided by FortisBC Energy as further specified in section 6 of this Rate Schedule that consists of:

(i) use of a Tanker owned or provided by FortisBC Energy;

(ii) hauling via land of the Tanker loaded with LNG from the LNG Facilities to a Customer designated location;

(iii) unloading of LNG from the Tanker; and,

(iv) hauling of the empty Tanker from the Customer designated location to the LNG Facilities.

(s) LNG Transportation Service Agreement – means the LNG Transportation Service Agreement for LNG Transportation Service between FortisBC Energy and the Customer, a form of which is attached to this Rate Schedule.

(t) Long-Term LNG Service – means LNG Service under this Rate Schedule with a minimum Contract Term of five (5) years or more and a specified Contract Demand for the duration of the Contract Term.

(u) Minimum Monthly Charge – means a minimum Monthly charge, applicable to Long-Term LNG Service and Short-Term LNG Service only, calculated by multiplying one-twelfth of the annual Contract Demand by the Delivery Charge.

(v) Month – means, subject to any changes from time to time required by FortisBC Energy, the period beginning at 12:00 a.m. Pacific Standard Time on the first day of the calendar month and ending at 12:00 a.m. Pacific Standard Time on the first day of the next succeeding calendar month.

(w) Process Fuel Gas – means Gas consumed in the production of LNG at the LNG Facilities, which for 2013 and 2014 is deemed to be a quantity equal to 1% (one percent) of the LNG Dispensed to the Customer, but thereafter the percentage is to be updated annually based on the prior year's actual fuel gas consumption at the LNG Facilities.

(x) Rate Schedule 46 or this Rate Schedule – means this Rate Schedule, inclusive of the appended Table of Charges, LNG Agreement, and, if applicable, the LNG Transportation Service Agreement.

(y) Short-Term LNG Service – means the LNG Service under this Rate Schedule with a minimum Contract Term of one (1) year and a maximum Contract Term of less than five (5) years and a specified Contract Demand for the duration of the Contract Term.

(z) Spot LNG Service – means the Dispensing and sales of LNG on a spot load basis to a Customer at the LNG Spot Charge per Gigajoule, as further specified in section 3.4 of this Rate Schedule.

(aa) Supplier of Gas – means a party who sells natural gas to the Customer or FortisBC Energy.

(bb) Table of Charges – means the appended table or tables of prices, fees and charges.

(cc) Tanker – means a cryogenic receptacle used for receiving, storing and transporting LNG, including without limitation, portable tankers, ISO containers, or other similar equipment.

(dd) Transporter – means, in the case of the Inland and Lower Mainland service areas, Westcoast Energy Inc., FortisBC Huntingdon Inc., and any other gas pipeline transportation company connected to the facilities of FortisBC Energy from which FortisBC Energy receives natural gas for the purposes of natural gas transportation or resale.

2 Applicability

2.1 Applicability – This Rate Schedule applies to the LNG Service provided by FortisBC Energy from the LNG Facilities. This Rate Schedule also applies to the optional LNG Transportation Service if a Customer elects such optional service.

2.2 Amendment of Rate Schedule – Amendments to this Rate Schedule must be in accordance with the Direction to the British Columbia Utilities Commission respecting FortisBC Energy's Liquefied Natural Gas Service and Compressed Natural Gas Service.

3 Conditions of LNG Service

3.1 Availability of LNG Service – FortisBC Energy will only provide LNG Service to a Customer if

(a) adequate capacity exists on the FortisBC Energy System;

(b) there is Available LNG Capacity that is not already subject to the Contract Demand under LNG Agreements for Long-Term LNG Service or Short-Term LNG Service; and

(c) the Customer has entered into a LNG Agreement.

FortisBC Energy will endeavor to provide LNG Service from one of the LNG Facilities selected by the Customer in its LNG Agreement, but reserves the right, in its sole discretion, to designate at the time of entering the LNG Agreement and/or during the Contract Term another facility for Dispensing some or all of the Contract Demand.

3.2 Limitation on Short-Term LNG Service – If, in the determination of FortisBC Energy, the sum of the Contract Demand of all LNG Agreements for Short-Term LNG Service exceeds 20% of the Available LNG Capacity, FortisBC Energy may in its sole discretion:

(a) decline to enter into new LNG Agreements for Short-Term LNG Service; or

(b) limit the Contract Demand under new LNG Agreements for Short-Term LNG Service.

3.3 LNG Service Priority Where There Are Competing Requests for LNG Service – In allocating Available LNG Capacity that is not already committed as Contract Demand under a LNG Agreement among competing requests for new Long-Term LNG Service or Short-Term LNG Service, FortisBC Energy will give priority based on

(a) first, length of Contract Term, with longer terms having priority over shorter terms;

(b) and if the desired Contract Term is the same for more than one potential Customers, then by volume, with larger volumes having priority over smaller volumes.

3.4 Spot LNG Service Availability – Spot LNG Service is the lowest priority LNG Service and will be conditional based on the availability of sufficient capacity remaining after deducting the Contract Demand from all LNG Agreements for Long-Term LNG Service and Short-Term LNG Service from the Available LNG Capacity. FortisBC Energy is under no obligation to reserve or set aside Available LNG Capacity for either new or existing Spot LNG Service. The Customer may request Spot LNG Service without contracting for Long-Term LNG Service or Short-Term LNG Service.

3.5 LNG Service Subject to Curtailment – LNG Service is subject to curtailment under section 5.2 (Curtailment of Dispensing Service) of this Rate Schedule.

4 Purchase of LNG

4.1 **Determination of Contract Demand** – FortisBC Energy will determine the Contract Demand for each Customer, taking into consideration the Customer's forecast Daily or Monthly LNG requirements, the Available LNG Capacity, the Contract Demand under other LNG Agreements, and other service and operational requirements. FortisBC Energy may, in its sole discretion, specify a per Customer or per project limit on the Customer's Contract Demand.

4.2 **Allocation of Contract Demand** – At the time the Customer enters into a LNG Agreement, FortisBC Energy will allocate the Contract Demand equally over either the Days or Months of the year, with the choice of Days or Months being at the sole discretion of FortisBC Energy.

4.3 **Alternative Supplier of LNG** – In the event that FortisBC Energy is not able to supply LNG by reason of a curtailment under section 5.2 (Curtailment of Dispensing Service) of this Rate Schedule, the Customer may utilize a temporary LNG supplier until FortisBC Energy is able to resume supply and the Contract Demand shall be adjusted by the amount of LNG obtained from such temporary supplier.

4.4 **Purchase Over Contract Demand** – A Customer may purchase in excess of the Contract Demand as Spot LNG Service, subject to section 3.4 (Spot LNG Service Availability). The rate payable for any excess quantity purchased shall be the Spot Load Charge as specified in section 8.1 (LNG Service Charges).

5 Dispensing of LNG

5.1 **Dispensing of LNG** – Subject to section 13.2 (Right to Restrict) of the General Terms and Conditions of FortisBC Energy and all of the terms and conditions of this Rate Schedule, the Customer or its agent(s) is responsible for directly connecting Tanker or other similar equipment to the LNG Facilities for Dispensing unless the Customer has entered into a LNG Transportation Service Agreement.

5.2 **Curtailment of Dispensing Service** – FortisBC Energy may, for any length of time, curtail under this Rate Schedule by reason of Force Majeure under section 16, for Periodic Repair by FortisBC Energy under section 16.7 of this Rate Schedule, and for purposes and reasons under section 13.2 (Right to Restrict) of the General Terms and Conditions of FortisBC Energy.

If FortisBC Energy determines that curtailment under this Section is required, FortisBC Energy will curtail in the following manner:

(a) Spot LNG Service will be curtailed first.

(b) If further curtailment is required, then Short-Term LNG Service will be curtailed before Long-Term LNG Service. Short-Term LNG Service will be curtailed pro-rata based on Contract Demand.

(c) If further curtailment is required, then Long-Term LNG Service with a Contract Term of between five (5) and ten (10) years in duration will be curtailed pro-rata based on Contract Demand.

(d) If further curtailment is required, then Long-Term LNG Service with a Contract Term longer than ten (10) years will be curtailed pro-rata based on Contract Demand.

In the event of any curtailment in excess of 72 hours in any given Month, then the Minimum Monthly Charge will be prorated in that Month to reflect the full duration of the curtailment. The Customer remains responsible for the total Minimum Monthly Charge if the curtailment is less than 72 hours in that Month.

5.3 Notice of Curtailment – Notwithstanding section 13.3 (Notice) of the General Terms and Conditions, unless prevented by Force Majeure, each notice from FortisBC Energy to the Customer with respect to curtailment of LNG Service by FortisBC Energy will be by telephone, email or fax and will specify the portion of the Customer's Contract Demand that is to be curtailed and the time at which such curtailment is to commence.

5.4 Title Transfer – Possession of, title to and risk of loss of, damage to, or damage caused by the LNG sold and Dispensed hereunder shall pass from FortisBC Energy to the Customer at the LNG Facilities; specifically, title transfer shall occur at the point of Dispensing to the Tanker or at outlet flange of the FortisBC Energy mass flow meter as applicable. This is the case irrespective of whether FortisBC Energy has provided the Tanker for the LNG Transportation Service.

6 Transportation of LNG

6.1 Transportation of LNG – The Customer is responsible for providing a Tanker and for hauling the Tanker from the LNG Facilities unless it has entered into a LNG Transportation Service Agreement.

6.2 Availability of LNG Transportation Service – Services provided by FortisBC Energy under this Rate Schedule can also include, at the option of a Customer, LNG Transportation Service. FortisBC Energy will only provide LNG Transportation Service to the Customer if

(a) FortisBC Energy has Tankers;

(b) FortisBC Energy has available Tanker capacity taking into account other LNG Transportation Service Agreements and any safety and regulatory requirements;

(c) FortisBC Energy has determined in its sole discretion that it has the operational ability to provide the service;

(d) FortisBC Energy is able to contract with third parties to provide hauling of the Tanker at the desired times;

(e) the Customer has entered into a LNG Agreement for a Contract Term at least as long as the term for which LNG Transportation Service is sought; and

(f) the Customer has entered into a LNG Transportation Service Agreement.

FortisBC Energy is under no obligation to procure additional Tanker capacity or hauling services to provide new LNG Transportation Service.

6.3 Charges for LNG Transportation Service – a Customer who selects the LNG Transportation Service and enters into a LNG Transportation Service Agreement will be responsible for both the LNG Tanker Charge and the Tanker Hauling Charge as specified in section 8.2 of this Rate Schedule.

7 Rights and Responsibilities

7.1 **Responsibility for Compliance** – The Customer, in its acceptance, transport, use or storage of the LNG, shall at all times be in compliance with the requirements of all applicable laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter, including, but not limited to, the federal *Transportation of Dangerous Goods Act* and associated regulations and British Columbia's *Environmental Management Act* and associated regulations. It is the sole responsibility of the Customer to ensure that any personnel, vehicle or Tanker provided by the Customer or its agent for Dispensing and transportation meets those requirements.

7.2 **Right to Refuse** – Notwithstanding subsection 7.1 above, FortisBC Energy at its sole discretion may refuse to Dispense LNG to the Customer, if in FortisBC Energy's good faith determination, the Dispensing or transportation of LNG to the Customer may be contrary to any laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction, including, but not limited to, the federal *Transportation of Dangerous Goods Act* and its associated regulations and British Columbia's *Environmental Management Act* and associated regulations.

7.3 **Responsibility for LNG Transportation Emergency Response** – The Customer acknowledges that FortisBC Energy will incur costs to comply with applicable laws relating to emergency response during the transportation of the LNG Dispensed to the Customer under this Rate Schedule whether or not the Customer has not selected the LNG Transportation Service. FortisBC Energy reserves the right to charge the Customer for costs FortisBC Energy incurs to comply with such laws.

In the event FortisBC Energy responds to a transportation emergency involving LNG Dispensed to the Customer under this Rate Schedule, the Customer shall at its expense provide assistance to FortisBC Energy upon request. The Customer shall reimburse FortisBC Energy for all costs incurred by FortisBC Energy responding to such an emergency.

7.4 **Required Insurance** – The Customer must maintain General Commercial Liability Insurance for bodily injury, death and property damage in the minimum amount of $5,000,000 per occurrence naming FortisBC Energy as an additional insured with respect to LNG Service or LNG Transportation Service provided to the Customer.

8 Terms of Payment

8.1 LNG Service Charges – The Customer will pay to FortisBC Energy the following charges for LNG Service as provided in the Table of Charges:

(i) For Long-Term LNG Service and Short-Term LNG Service, the Customer will pay to FortisBC Energy all of the following charges:

(A) A charge calculated as the greater of

i. the Delivery Charge, multiplied by the quantity of LNG, measured in Gigajoules, Dispensed to the Customer,

or

ii. the Minimum Monthly Charge; plus

(B) A Commodity Charge calculated by multiplying

i. the quantity of LNG, measured in Gigajoules, Dispensed to the Customer plus Process Fuel Gas

by

ii. the sum of Sumas Monthly Index Price plus Market Factor

and by

iii. the percentage of LNG supplied from conventional natural gas as selected by the Customer; plus

(C) where a Customer has selected a percentage of Biomethane as part of the Gas to be used in providing LNG Service, a Biomethane Energy Recovery Charge calculated by multiplying

i. the quantity of LNG, measured in Gigajoules, Dispensed to the Customer

by

ii. the selected percentage of Biomethane

and by

iii. the BERC.

(ii) A Long-Term LNG Service or Short-Term LNG Service Customer whose Contract Demand is greater than 1,825,000 Gigajoules may choose to provide its own natural gas commodity and Process Fuel Gas to the Interconnection Point. In such cases, the Customer will not be subject to a Commodity Charge.

(iii) Spot Load LNG Charge - For Spot LNG Service, the Customer will pay to FortisBC Energy all of the charges in section 8.1(i), except that, in lieu of the charge under section 8.1(i)(A), the Customer will pay a Spot Charge calculated by multiplying:

i. the quantity of LNG, measured in Gigajoules, Dispensed to the Customer plus Process Fuel Gas

by

ii. the LNG Spot Charge.

8.2 LNG Transportation Service Charges – The Customer will pay to FortisBC Energy both of the following charges for LNG Transportation Service as provided in the Table of Charges:

(i) LNG Tanker Charge – a charge per Day or partial Day for the use of a Tanker owned or provided by FortisBC Energy; and

(ii) LNG Tanker Hauling Charge – a hauling fee based on the cost to FortisBC Energy to contract with a third-party contractor to haul the Tanker, plus 15%.

8.3 Currency – Unless otherwise indicated, all dollar amounts or the use of the symbol '$' in this Rate Schedule, including the Table of Charges and the LNG Agreement and LNG Transportation Service Agreement shall be deemed to refer to Canadian dollars.

8.4 Payment of Amounts – The Customer will pay to FortisBC Energy all of the applicable charges set out in the Table of Charges for LNG Service and, if applicable, Table of Charges for LNG Transportation Service.

9 Daily Loading and Scheduling

9.1 Requested Quantity and Loading Schedule – At least 24 hours in advance of the Day of the Customer's desired loading time, the Customer or its agent will provide FortisBC Energy by fax or email such information as may be requested by FortisBC Energy, which will include, but is not limited to, the Customer's requested quantity of LNG for the given Day.

9.2 Adjustment of Loading Schedule – FortisBC Energy may adjust, in consultation with the Customer or its agents, the Customer's loading schedule when in the reasonable determination of FortisBC Energy such modification is necessary in order to:

(a) minimize the costs to FortisBC Energy of Dispensing LNG;

(b) accommodate multiple Customers; or

(c) if the Customer is taking LNG Transportation Service, address the non-availability of the Tanker or non-availability of third parties for hauling the Tanker.

10 Term of LNG Agreement

10.1 Renewal – There is no right of renewal of a LNG Agreement. A Customer seeking LNG Service beyond the Contract Term must enter into a new LNG Agreement.

10.2 Early Termination by FortisBC Energy – The term of the LNG Agreement is subject to early termination by FortisBC Energy in accordance with section 13 (Default or Bankruptcy).

10.3 Survival of Covenants – Upon termination of the LNG Agreement, whether pursuant to section 13 (Default or Bankruptcy) of this LNG Rate Schedule or otherwise,

(a) all claims, causes of action or other outstanding obligations remaining or being unfulfilled as at the date of termination, and

(b) all of the provisions in the LNG Agreement and this Rate Schedule relating to the obligations of any of the parties to account to or indemnify the other and to pay to the other any monies owing as at the date of termination in connection with this Rate Schedule,

will survive such termination.

11 Statements and Payments

11.1 Statements to be Provided – FortisBC Energy will, on or about the 15th Day of each Month, deliver to the Customer, a statement for the preceding Month showing all services provided to the Customer or its agents and the amount due. Any errors in any statement will be promptly reported to the other party as provided hereunder, and statements will be final and binding unless questioned within one year after the date of the statement.

11.2 Payment and Late Payment Charge – Payment for the full amount of the statement, including all taxes imposed by any federal, provincial, municipal, territorial, local or any agency or political subdivision thereon, will be made to FortisBC Energy at its office in Surrey, British Columbia, or at such other place in Canada as FortisBC Energy will designate, on or before the 1st business Day after the 30th calendar Day following the billing date. If the Customer fails or neglects to make any payment required under this Rate Schedule, or any portion thereof, to FortisBC Energy when due, FortisBC Energy will include in the next bill to the Customer a late payment charge specified in the Standard Fees and Charges Schedule of the General Terms and Conditions.

11.3 Form of Payments – All payments required to be made under statements and invoices rendered pursuant to this Rate Schedule will be made by wire transfer to, or cheque or bank cashier's cheque drawn on a Canadian chartered bank or trust company, payable in lawful money of Canada at par in immediately available funds in Vancouver, British Columbia.

11.4 Examination of Records – Each of FortisBC Energy and the Customer will have the right to examine at reasonable times the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, charge, computation or demand made pursuant to any provisions of this Rate Schedule.

11.5 Security – In order to secure the prompt and orderly payment of the charges to be paid by the Customer or its assignees as specified in section 19.3 (Remedies Cumulative) of this Rate Schedule to FortisBC Energy under this Rate Schedule, FortisBC Energy may require the Customer or its assignees to provide, and at all times maintain, an irrevocable letter of credit in favour of FortisBC Energy issued by a financial institution acceptable to FortisBC Energy in an amount equal to the estimated maximum amount payable by the Customer under this Rate Schedule for a period of 90 Days and in a form satisfactory to FortisBC Energy. If the Customer or its assignees is able to provide alternative security acceptable to FortisBC Energy, FortisBC Energy may in its sole discretion accept such security in lieu of a letter of credit.

12 Measurement

12.1 Unit of Measurement – The unit of measurement of LNG for all purposes hereunder will be kilograms or pounds.

12.2 Determination of Quantity – The quantity of LNG Dispensed pursuant to this Rate Schedule shall be measured at the scale at the LNG Facilities or an alternate scale that is approved and certified by Measurement Canada. The Tanker or other cryogenic receptacle into which the LNG is Dispensed will be weighed at the scale before and after Dispensing. The measurement of the amount of LNG Dispensed shall be based on the difference, expressed in kilograms or pounds, of these two weights. In the event that the cryogenic receptacle cannot be weighed by the scale, then the quantity of LNG Dispensed shall be measured through the use of mass flow meters.

12.3 Conversion to Energy Units – In accordance with the *Electricity and Gas Inspection Act* of Canada, volumes of LNG Dispensed each Day will be converted to energy units by multiplying the standard volume by the Heat Content of each unit of LNG. Volumes will be specified in kilograms or pounds rounded to the nearest unit and energy will be specified in Gigajoules rounded to one decimal place. FortisBC Energy will use the following formula to convert kilograms or pounds of LNG to GJ of LNG:

Converting Weight of LNG to Gigajoules

	Gross Weight after LNG Dispensing (kilograms or pounds)
minus	Gross Weight prior to Dispensing (kilograms or pounds)
equals	Net Weight of the Delivered LNG (kilograms or pounds)
	Net Weight of the Delivered LNG (kilograms or pounds)
multiplied by	The energy density as determined by FortisBC Energy through analysis of vaporized LNG on a periodic basis. For greater certainty, unless otherwise determined by FortisBC Energy, the energy density shall be 0.055058 gigajoule/kilogram or 0.024974 gigajoule/pound equals Delivered LNG (Gigajoule)

13 Default or Bankruptcy

13.1 Default by the Customer – If the Customer at any time fails or neglects

(a) to make any payment due to FortisBC Energy or as designated under this Rate Schedule within 30 calendar Days after payment is due, or

(b) to correct any default of any of the other terms, covenants, conditions or obligations imposed upon it under this Rate Schedule, within 30 calendar Days after FortisBC Energy gives to the Customer notice of such default, or

(c) in the case of a default that cannot with due diligence be corrected within a period of 30 Days, the Customer fails to proceed promptly after the giving of such notice to correct the same and thereafter to prosecute the correcting of such default with all due diligence,

then FortisBC Energy may in addition to any other remedy that it has, at its option and without liability therefor:

(d) suspend further LNG Service to the Customer until the default has been fully remedied, and no such suspension or refusal will relieve the Customer from any obligation under this Rate Schedule, or

(e) suspend further LNG Service to the Customer and terminate the Customer's LNG Agreement.

13.2 Bankruptcy or Insolvency of the Customer – If the Customer becomes bankrupt or insolvent or commits or suffers an act of bankruptcy or insolvency or a receiver is appointed pursuant to a statute or under a debt instrument or the Customer seeks protection from the demands of its creditors pursuant to any legislation enacted for that purpose or commences proceedings under the *Companies' Creditors Arrangement Act* of Canada, FortisBC Energy will have the right, at its sole discretion, to terminate the supply of LNG, the LNG Agreement by giving notice in writing to the Customer and thereupon FortisBC Energy may cease further supply of LNG to the Customer.

13.3 **Obligations of Customer Upon Suspension or Termination** – In the event of a suspension of LNG Service, or termination of a LNG Agreement, any amount then outstanding for service provided under this Rate Schedule will immediately be due and payable by the Customer. The Contract Demand shall not be reduced during the period of any suspension. In the event of early termination of a LNG Agreement, an amount equal to the Minimum Monthly Charge that would have otherwise been payable for the remainder of the Contract Term will become immediately due and payable by the Customer.

14 Notice

14.1 **Notice** – Any notice, request, statement or bill that is required to be given or that may be given under this Rate Schedule will be in writing and will be considered as fully delivered when mailed, personally delivered or sent by fax to the other in accordance with the following:

If to FortisBC Energy	FORTISBC ENERGY INC.
MAILING ADDRESS:	16705 Fraser Highway Surrey, B.C. V4N 0E8
BILLING AND PAYMENT:	Attention: Industrial Billing Telephone: 1-855-873-8773 Fax: 1-888-224-2720 Email industrial.billing@fortisbc.com
CUSTOMER RELATIONS:	Attention: Business Development Telephone: (778) 571-3296 (604) 592-7949 Email: LNG@fortisbc.com
LEGAL AND OTHER:	Attention: Director, Legal and Governance Services Telephone: (604) 443-6512 Fax: (604) 443-6540

If to the Customer, then as set out in the Customer's LNG Service Agreement and, if applicable, LNG Transportation Service Agreement.

14.2 **Specific Notices** – Notwithstanding section 14.1 (Notice) and section 5.3 (Notice of Curtailment), notices with respect to suspension of LNG Service by FortisBC Energy for reasons of Force Majeure will be sufficient if given by FortisBC Energy in accordance with section 13.3 (Notice) of the General Terms and Conditions.

15 Indemnity and Limitation on Liability

15.1 Limitation on Liability -- FortisBC Energy, its employees, contractors or agents are not responsible or liable for any loss, damage, costs or injury (including death) incurred by the Customer or any person claiming by or through the Customer caused by or resulting from, directly or indirectly, any discontinuance, suspension or curtailment of, or failure or defect in, or refusal to provide LNG Service, unless the loss, damage, costs or injury (including death) is directly attributable to the gross negligence or willful misconduct of FortisBC Energy, its employees, contractors or agents provided, however that FortisBC Energy, its employees, contractors and agents are not responsible or liable for any loss of profit, loss of revenues, or other economic loss even if the loss is directly attributable to the gross negligence or willful misconduct of FortisBC Energy, its employees, contractors or agents.

15.2 Customer Indemnity -- The Customer will indemnify and hold harmless FortisBC Energy, its employees, contractors and agents from all claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) arising from or out of

(a) the negligence or willful misconduct of the Customer, employees, contractors or agents; or

(b) the breach by the Customer of any of the provisions contained in this Rate Schedule, including the LNG Agreement and if applicable the LNG Transportation Service Agreement, including those related to the payment by the Customer of all federal, provincial, and municipal taxes (or payments made in lieu thereof).

16 Force Majeure

16.1 Force Majeure -- Subject to the other provisions of this section 16, if either party is unable or fails by reason of Force Majeure to perform in whole or in part any obligation or covenant set out in this Rate Schedule, the obligations of both FortisBC Energy and the Customer will be suspended to the extent necessary for the period of the Force Majeure condition.

16.2 Curtailment Notice -- If FortisBC Energy claims suspension pursuant to this section 16, FortisBC Energy will be deemed to have issued to the Customer a notice of curtailment.

16.3 Exceptions - Neither party will be entitled to the benefit of the provisions of section 16.1 under any of the following circumstances:

(a) to the extent that the failure was caused by the negligence or contributory negligence of the party claiming suspension,

(b) subject to section 16.5 (No Exception for Payments) to the extent that the failure was caused by the party claiming suspension having failed to diligently attempt to remedy the condition and to resume the performance of the covenants or obligations with reasonable dispatch, or

(c) unless as soon as possible after the happening of the occurrence relied on or as soon as possible after determining that the occurrence was in the nature of Force Majeure and would affect the claiming party's ability to observe or perform any of its covenants or obligations under this Rate Schedule, the party claiming suspension will have given to the other party notice to the effect that the party is unable by reason of Force Majeure (the nature of which will be specified) to perform the particular covenants or obligations.

16.4 Notice to Resume – The party claiming suspension will likewise give notice, as soon as possible after the Force Majeure condition has ceased, to the effect that it has ceased and that the party has resumed, or is then in a position to resume, the performance of the covenants or obligations.

16.5 Settlement of Labour Disputes – Notwithstanding any of the provisions of this section 16, the timing and terms and conditions of the settlement of strikes, labour disputes or industrial disturbances will be entirely within the discretion of the particular party involved and the party may make settlement of it at the time and on terms and conditions as it may deem to be advisable and no delay in making settlement will deprive the party of the benefit of section 16.1.

16.6 No Exemption for Payments – Notwithstanding any of the provisions of this section 16, Force Majeure will not relieve or release either party from its obligations to make payments to the other party under a LNG Agreement or LNG Transportation Service Agreement. In the event of any Force Majeure event affecting FortisBC Energy that results in a curtailment in excess of 72 hours per Month, then the Minimum Monthly Charge as specified in section 8.1 (LNG Service Charges) of this Rate Schedule will be prorated accordingly. Should an event of Force Majeure affecting the Customer prevent the Customer from taking LNG Service, the Minimum Monthly Charge will not be reduced.

16.7 Periodic Repair by FortisBC Energy – FortisBC Energy may temporarily suspend Dispensing of LNG from the LNG Facilities for the purpose of repairing or replacing a portion of the FortisBC Energy System or its equipment and FortisBC Energy will make reasonable efforts to give the Customer as much notice as possible with respect to such suspension, not to be less than 24 hours prior notice except when prevented by Force Majeure. FortisBC Energy will make reasonable efforts to schedule repairs or replacement to minimize suspension or curtailment of LNG Service to the Customer, and to restore Service as quickly as possible.

17 Disputes

17.1 Mediation – Where any dispute arises out of or in connection with the LNG Service, FortisBC Energy and the Customer agree to try to resolve the dispute by participating in a structured mediation conference with a mediator under the National Arbitration Rules of the ADR Institute of Canada, Inc. The mediation will take place in Vancouver, BC.

17.2 Arbitration – If FortisBC Energy and the Customer fail to resolve the dispute through mediation within 30 days of a party giving written notice of a dispute, then either party may refer the dispute to binding arbitration for final resolution. The place of arbitration will be Vancouver, BC, and the substantive law governing the dispute will be the law of British Columbia. Unless otherwise agreed by the parties in writing, the arbitration will be conducted by a single arbitrator in accordance with the National Arbitration Rules of the ADR Institute of Canada, Inc..

17.3 Award – The arbitrator shall have the authority to award:

(a) money damages, to the extent provided in the Rate Schedule;

(b) interest on unpaid amounts from the date due;

(c) specific performance; and

(d) permanent relief.

17.4 Obligations Continue – The parties will continue to fulfill their respective obligations pursuant to this Rate Schedule, the LNG Agreement, and, if applicable, the LNG Transportation Service Agreement during the resolution of any dispute in accordance with this section 17.

18 Interpretation

18.1 Interpretation – Except where the context requires otherwise or except as otherwise expressly provided, in this Rate Schedule, including the LNG Agreement and LNG Transportation Service Agreement,

(a) all references to a designated section are to the designated section of this Rate Schedule unless otherwise specifically stated;

(b) the singular of any term includes the plural, and vice versa, and the use of any term is equally applicable to any gender and, where applicable, body corporate;

(c) any reference to a corporate entity includes and is also a reference to any corporate entity that is a successor by merger, amalgamation, consolidation or otherwise to such entity;

(d) all words, phrases and expressions used in this Rate Schedule that have a common usage in the gas industry and that are not defined in this Rate Schedule or in the General Terms and Conditions have the meanings commonly ascribed thereto in the gas industry; and

(e) the headings of the sections set out in this Rate Schedule are for convenience of reference only and will not be considered in any interpretation of this Rate Schedule.

19 Miscellaneous

19.1 No joint venture or partnership – Nothing contained in this Rate Schedule, including the LNG Agreement and the LNG Transportation Service Agreement shall be construed to place the parties in the role of partners or joint venturers or agents and no party shall have the power to obligate or bind any other party in any manner whatsoever.

19.2 Waiver – No waiver by either FortisBC Energy or the Customer of any default by the other in the performance of any of the provisions of this Rate Schedule will operate or be construed as a waiver of any other or future default or defaults, whether of a like or different character.

19.3 Remedies Cumulative – All rights and remedies of each party under this Rate Schedule are cumulative and may be exercised at any time and from time to time, independently and in combination.

19.4 Enurement – This Rate Schedule, including the LNG Agreement and, if applicable, the LNG Transportation Service Agreement, will enure to the benefit of and be binding upon the parties and their respective successors and permitted assigns, including without limitation, successors by merger, amalgamation or consolidation.

19.5 Assignment – The Customer may not assign its rights under this Rate Schedule, including the LNG Agreement and, if applicable, the LNG Transportation Service Agreement, in whole or in part without the prior written consent of FortisBC Energy, provided, however, that Customer may assign without the consent of FortisBC Energy if:

(a) such assignment is made pursuant to the assignment of all of the Customer's rights and obligations hereunder to a partnership, limited liability company, corporation, trust or other organization in whatever form succeeds to all or substantially all of the Customer's assets and business;

(b) the assignee assumes such obligations by contract, operation of law, or otherwise; and

(c) at least five (5) days prior to the assignee taking service under this Rate Schedule, the Customer provides notice in writing to FortisBC Energy of the assignment of its rights and obligations as Customer under this Rate Schedule, and the assignee provides confirmation in writing to FortisBC Energy of its assumption of rights and obligations as Customer under this Rate Schedule.

Upon such assumption of obligations, and if required, the receipt of the prior written consent of FortisBC Energy, which consent shall not be unreasonably delayed or withheld, the Customer shall be relieved of and fully discharged from all obligations hereunder. This provision applies to every proposed assignment by the Customer.

19.6 Law – This Rate Schedule will be construed and interpreted in accordance with the applicable laws of the Province of British Columbia and the laws of Canada.

19.7 Time is of Essence – Time is of the essence of this Rate Schedule and of the terms and conditions thereof.

19.8 Subject to Legislation – Notwithstanding any other provision hereof, this Rate Schedule and the rights and obligations of FortisBC Energy and the Customer under this Rate Schedule are subject to all present and future laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction over FortisBC Energy or the Customer.

19.9 Further Assurances – Each of FortisBC Energy and the Customer will, on demand by the other, execute and deliver or cause to be executed and delivered all such further documents and instruments and do all such further acts and things as the other may reasonably require to evidence, carry out and give full effect to the terms, conditions, intent and meaning of this Rate Schedule, including the LNG Agreement and, if applicable, the LNG Transportation Service Agreement, and to assure the completion of the transactions contemplated hereby.

Table of Charges
for LNG Transportation Service

All sales and service taxes, carbon tax and any future new taxes, are extra and shall be applied as applicable.

2013 LNG Tanker Charge per Day or Partial Day	$249.00
LNG Tanker Charge per Day or Partial Day for 2014 and subsequent years	2013 LNG Tanker Charge, escalated annually at the greater of 2% or the British Columbia Consumer Price Index.
LNG Tanker Hauling Charge	FortisBC Energy cost plus 15% Administration Charge

Table of Charges
for LNG Service

All sales and service taxes, carbon tax and any future new taxes, are extra and shall be applied as applicable.

2013 LNG Facility Charge	$ 3.47/GJ
2013 Electricity Surcharge	$ 0.88/GJ
Commodity Charge per Gigajoule	Sumas Monthly Index Price[1] plus the Market Factor[2]
Charge per Gigajoule of Biomethane supplied (if applicable)	Current approved BERC rate
2013 LNG Spot Charge	$ 4.60/GJ
LNG Facility Charges, Electricity Surcharges, premiums, and LNG Spot Charges for 2014 and thereafter	Per Note 3

Notes:

1. Sumas Monthly Index Price – means the Sumas Monthly Index Price as set out in Inside F.E.R.C.'s Gas Market Report for gas delivered to Northwest Pipeline Corporation at Sumas, converted to Canadian dollars using the noon exchange rate as quoted by the Bank of Canada for the first Day of each Month in which the Sumas Monthly Index Price shall apply. Energy units are converted from MMBtu to Gigajoule by application of a conversion factor equal to 1.055056 Gigajoule per MMBtu.

2. Market Factor – means the charge that is the premium above the Sumas Monthly Index that is calculated by FortisBC Energy for that Month to cover costs related to securing incremental natural gas supply for that Month, including market premiums levied by suppliers for ensuring physical delivery of natural gas and any demand charges related to incremental physical purchases and contribution to the reservation fees and variable costs of core assets which may be used during that Month. For greater clarity, this premium will be based on actual market quotations at Sumas received by FortisBC Energy.

3. LNG Facility Charges, Electricity Surcharges, premiums and LNG Spot Charges for 2014 and beyond – The LNG Facility Charges, Electricity Surcharges, premiums and LNG Spot Charges for 2014 and thereafter will be determined by taking the base charges shown in (1) below, which are expressed in 2013 dollars, and resetting and adjusting those base charges annually on January 1 in accordance with (2) below.

(1) The following base charges, expressed in 2013 dollars, shall apply in accordance with the specified aggregate daily Contract Demand for all Customers and the specified Available LNG Capacity:

(a) Where on January 1 of a given year each of the aggregate prorated daily Contract Demand for all Customers and the Available LNG Capacity is between 0 Gigajoules per day and 35,000 Gigajoules per day, the following base charges apply for that year:

LNG Facility Charge	$ 3.47/GJ
Electricity Surcharge	$ 0.88/GJ
LNG Spot Charge	$ 4.60/GJ

(b) Where on January 1 of a given year each of the aggregate prorated daily Contract Demand for all Customers and the Available LNG Capacity is at least 35,000 Gigajoules per day and less than 100,000 Gigajoules per day, the following base charges apply for that year:

LNG Facility Charge	$ 2.68/GJ
Electricity Surcharge	$ 0.87/GJ
LNG Spot Charge	$ 4.20/GJ

(c) Where on January 1 of a given year each of the aggregate prorated daily Contract Demand for all Customers and the Available LNG Capacity is at least 100,000 Gigajoules per day, the following base charges apply for that year:

LNG Facility Charge	$ 1.84/GJ
Electricity Surcharge	$ 0.86/GJ
LNG Spot Charge	$ 3.35/GJ

(2) The base charges shown in (1) above, which are presented in 2013 dollars, will be reset and adjusted annually as follows:

(a) The LNG Facility Charge and all premium charges in (d) below shall be escalated annually at the greater of 2% or the British Columbia Consumer Price Index.

(b) The Electricity Surcharge shall be adjusted based upon the actual prior year electricity use per Gigajoule of LNG output of the LNG Facilities and actual BC Hydro rate increases incurred at the LNG Facilities.

(c) The LNG Spot Charge is $0.25/GJ greater than the sum of the LNG Facility Charge and adjusted Electricity Surcharge, as adjusted under (a) and (b) above.

(d) Where each of the aggregate prorated daily Contract Demand for all Customers and the Available LNG Capacity is at least 35,000 Gigajoules per day:

i. Customers with a daily prorated Contract Demand of less than 5,000 GJ/day shall pay a premium of $0.15/GJ;

ii. Customers with a Contract Term of less than 10 years shall pay a premium of $0.25/GJ; and

iii. Customers with a daily prorated Contract Demand of less than 5,000 GJ/day and a Contract Term of less than 10 years shall pay a premium of $0.40/GJ.

LIQUEFIED NATURAL GAS SALES AND DISPENSING SERVICE AGREEMENT

This Agreement (LNG Natural Gas Sales and Dispensing Agreement or LNG Agreement) is dated ____________, 20___ (Effective Date) between FortisBC Energy Inc. (FortisBC Energy) and ________________________________ (Customer).

WHEREAS:

A. FortisBC Energy owns and operates the FortisBC Energy System in British Columbia.

B. The Customer has requested that FortisBC Energy provide services for liquefaction of natural Gas and Dispensing of LNG from the LNG Facilities.

NOW THEREFORE THIS LNG AGREEMENT WITNESSES THAT in consideration of the terms, conditions and limitations contained herein, the parties agree as follows:

1. Specific Information

Applicable Rate Schedule:	46
Type of Service:	☐ Long Term ☐ Short Term ☐ Spot
Dispensing Point Preferred by Customer:	☐ Tilbury ☐ Mt. Hayes ☐ Other
Contract Demand:	________ Gigajoules per Year
Contract Demand Allocation	☐ Daily ☐ Monthly
Biomethane Percentage Selection:	____________________
Commencement Date:	____________________
Expiry Date:	____________________
Service Address:	____________________
Account Number:	____________________

2. Incorporation of Rate Schedule

2.1 Additional Terms – All rates, terms and conditions and definitions set out in the LNG Sales, Dispensing and Transportation Service Rate Schedule as any of them may be amended in accordance with section 2.2 (Amendment of Rate Schedule) of this Rate Schedule and in the General Terms and Conditions of FortisBC Energy as any of them may be amended by FortisBC Energy and approved by the British Columbia Utilities Commission, are in addition to the terms and conditions contained in this LNG Agreement and form part of this LNG Agreement and bind FortisBC Energy and the Customer as if set out in this LNG Agreement.

2.2 Conflict – Where anything in this LNG Agreement conflicts with either the other terms in Rate Schedule or the General Terms and Conditions of FortisBC Energy, the provisions of this LNG Agreement govern. Where anything in the Rate Schedule conflicts with any of the rates, terms and conditions set out in the General Terms and Conditions of FortisBC Energy, the provisions of the Rate Schedule govern.

3 General

3.1 Amendments to be in Writing -- Except as otherwise set out in the Rate Schedule, no amendment or variation of this LNG Agreement will be effective or binding upon the parties unless such amendment or variation is set out in writing and duly executed by the parties.

3.2 Notice -- Any notices or other communication which may be or is required to be given or made pursuant to the Agreement shall, unless otherwise expressly provided herein, shall be in writing and shall be personally delivered to or sent by facsimile to either party at its address set forth below:

If to FortisBC Energy	FORTISBC ENERGY INC.
MAILING ADDRESS:	16705 Fraser Highway Surrey, B.C. V4N 0E8
If to the Customer	____________________
MAILING ADDRESS:	____________________ ____________________ ____________________
	Attention: ____________

3.3 Severability – If any provision of this LNG Agreement is determined by a court of competent jurisdiction to be invalid, illegal or unenforceable in any respect, such determination does not impair or affect the validity, legality or enforceability of any other provision of this LNG Agreement.

3.4 **Execution** – This LNG Agreement may be executed in counterparts, each of which shall be deemed as an original, but all of which shall constitute one and the same instrument. Delivery of an executed counterpart of this letter by facsimile or electronic transmission hereof shall be as effective as delivery of an originally executed counterpart hereof.

IN WITNESS WHEREOF the parties hereto have executed this LNG Agreement.

FORTISBC ENERGY INC.	______________________ (Insert legal name of Customer)
BY: ______________________ (Signature)	BY: ______________________ (Signature)
______________________ (Title)	______________________ (Title)
______________________ (Name – Please Print)	______________________ (Name – Please Print)
DATE: ______________________	DATE: ______________________
	BY: ______________________ (Signature)
	______________________ (Title)
	______________________ (Name – Please Print)
	DATE: ______________________

LNG TRANSPORTATION SERVICE AGREEMENT

THIS AGREEMENT (LNG Transportation Service Agreement or Agreement) is made effective as of the _____ of ____________, 20__ (the Effective Date) between FortisBC Energy Inc. (FortisBC Energy) and ____________________________________ (the Customer).

NOW THEREFORE, in consideration of the mutual promises set out herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged) the parties agree as follows:

1. Incorporation by Rate Schedule

1.1 Additional Terms – All rates, terms and conditions and definitions set out in the LNG Sales, Dispensing and Transportation Service Rate Schedule (Rate Schedule 46) as any of them may be amended in accordance with section 2.2 (Amendment of Rate Schedule) of this Rate Schedule and in the General Terms and Conditions of FortisBC Energy as any of them may be amended by FortisBC Energy and approved by the British Columbia Utilities Commission, are in addition to the terms and conditions contained in this Agreement and form part of this Agreement and bind FortisBC Energy and the Customer as if set out in this Agreement.

1.2 Conflict – Where anything in this Agreement conflicts with either the other terms in Rate Schedule 46 or the General Terms and Conditions of FortisBC Energy, the provisions of this Agreement govern. Where anything in Rate Schedule 46 conflicts with any of the rates, terms and conditions set out in the General Terms and Conditions of FortisBC Energy, the provisions of Rate Schedule 46 govern.

2. Additional Definitions

2.1 Approvals – means those consents, permits, filings, orders or other approvals of any municipal, provincial, or federal governmental authority having jurisdiction over any aspect of the LNG Transportation Service.

3. Term

3.1 Term – The term of this Agreement (the Term) shall commence on the Effective Date and shall expire no later than the date the Customer's LNG Agreement expires or terminates.

4. LNG Transportation Service

4.1 Subject to the terms and conditions of Rate Schedule 46 and section 9 of this Agreement, FortisBC Energy shall perform the LNG Transportation Service:

(a) in accordance with good industry practices and in a good and workmanlike manner;

(b) in accordance with the requirements of applicable Approvals, laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter, including, but not limited to, the federal *Transportation of Dangerous Goods Act*; and

(c) in accordance with all reasonable safety procedures required by the Customer with respect to the Customer's property or designated location.

5. Request for LNG Transportation Service

5.1 Subject to section 6.2 (Availability of LNG Transportation Service) of Rate Schedule 46, if the Customer wishes to use LNG Transportation Service, the Customer or its agents shall notify FortisBC Energy by fax or email prior to 12:00 am Pacific Standard Time (or other such time as may be specified from time to by FortisBC Energy) and provide FortisBC Energy with such information as may be requested by FortisBC Energy, which shall include, but is not limited to, the Customer's desired quantity of LNG and the desired date and time of arrival of LNG at the Customer designated location, provided FortisBC Energy receives such notice no later than 48 hours prior to the requested date and time of arrival of the Tanker at the Customer designated location.

6. Subcontracting

6.1 FortisBC Energy may, without prior consent of the Customer, retain the services of a qualified third party to perform some or all of its obligations under this Agreement.

7. Ownership of the Tanker and Rental of Tanker

7.1 Ownership of the Tanker – FortisBC Energy shall retain all right, title and interest in and to the Tanker whether or not the Tanker (or any part thereof) is affixed to the Customer's property and the Customer acknowledges and agrees that notwithstanding any rule of law or equity to the contrary, the Tanker shall not be considered a fixture. The Customer shall have no right, title or interest in the Tanker other than the right to rent and utilize the Tanker in accordance with the terms and conditions of this Agreement.

7.2 With respect to storage of LNG in the Tanker at the Customer designated location, to the extent that FortisBC Energy has consented to such storage, the Customer shall:

(a) comply with the requirements of any applicable Approvals, laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter;

(b) be responsible for ensuring that the Tanker is provided with security satisfactory to FortisBC Energy in the form of locked fencing, video surveillance and periodic patrol outside of business hours;

(c) be responsible for all costs and expenses incurred by FortisBC Energy to repair:

(i) any and all damage to the Tanker arising directly or indirectly from the acts or omissions of the Customer or its agents or other persons for whom at law the Customer is responsible; and

(ii) any and all damage to the Tanker arising directly or indirectly from the acts or omissions of a third party.

7.3 The Customer acknowledges and agrees that FortisBC Energy is not responsible for storage of LNG in the Tanker at the Customer designated location and is not obligated to consent to the Customer using the Tanker as storage at the Customer designated location.

8. LNG Tanker and Tanker Hauling Charges

8.1 LNG Tanker Hauling Charge – In addition to any fees or charges related to the supply of LNG pursuant to Rate Schedule 46, in exchange for performance by FortisBC Energy of the LNG Transportation Service, the Customer agrees to pay FortisBC Energy the LNG Hauling Charge as set out in the Table of Charges under Rate Schedule 46, as which may be amended in accordance with section 2.2 (Amendment of Rate Schedule) of the Rate Schedule.

8.2 LNG Tanker Charge – In addition to any fees or charges related to the sale and Dispensing of LNG pursuant to Rate Schedule 46 or the LNG Transportation Service, the Customer agrees to pay FortisBC Energy the LNG Tanker Charge as set out in the Table of Charges under Rate Schedule 46, as which may be amended in accordance with section 2.2 (Amendment of Rate Schedule) of the Rate Schedule, for each Day or partial Day that the Tanker is in use for providing the LNG Transportation Service to the Customer, including Days or partial Days that the Tanker is used to provide storage of LNG at the Customer designated location.

9. Access to the Customer Location

9.1 Access – The Customer shall provide cleared and graded lands at the Customer designated location satisfactory to FortisBC Energy to allow FortisBC Energy to perform the LNG Transportation Service. The Customer shall ensure that there is no traffic at the Customer designated location within a 15 metre perimeter of the Tanker during any unloading of LNG.

10. Permits and Approvals

10.1 FortisBC Energy Approvals – Except as otherwise specified herein, FortisBC Energy shall be responsible, at its sole cost, for obtaining and maintaining the necessary Approvals with respect to the LNG Transportation Service and maintenance of the Tanker, including the necessary approvals of the British Columbia Utilities Commission, and shall ensure such Approvals are duly transferred or provided to the Customer where appropriate. The Customer shall use its commercially reasonable efforts to assist FortisBC Energy in obtaining such Approvals where necessary.

10.2 The Customer Approvals – The Customer shall be responsible, at its sole cost, for obtaining and maintaining the necessary Approvals required for the storage of LNG in the Tanker at the Customer designated location and shall ensure such Approvals are duly transferred or provided to FortisBC Energy where appropriate. FortisBC Energy shall use its commercially reasonable efforts to assist the Customer in obtaining such Approvals where necessary.

11. Termination

11.1 A party to this Agreement shall be in default under this Agreement if such party becomes insolvent, files any proceeding in bankruptcy or acquires the status of a bankrupt, has a receiver or receiver manager appointed with respect to any of its assets or seeks the benefit of any statute providing protection from creditors. Subject to section 15 of this Agreement, a party to this Agreement shall also be in default under this Agreement if such party is in breach of a material term, covenant, agreement, condition or obligation imposed on it under this Agreement, including without limitation, failure to comply with applicable Approvals, laws and regulations as provided in this Agreement, provided:

(a) the other party provides the defaulting party with a written notice of such default and a 30-day period within which to cure such a default (the Cure Period); and

(b) the defaulting party fails to cure such default by the expiry of the Cure Period, or if such default is not capable of being cured within the Cure Period, fails to commence in good faith the curing of such default upon receipt of written notice from the other party and to continue to diligently pursue the curing of such default thereafter until cured.

11.2 If a party to this Agreement is in default of this Agreement, the other party may at its option and without liability therefore or prejudice to any other right or remedy it may have, terminate this Agreement, provided that the defaulting party pay any monies due and owing to the other party within 15 calendar Days of the other's party's written notice to terminate this Agreement.

11.3 Either party may terminate this Agreement at any time upon giving 120 calendar days prior written notice to the other party.

12. Additional Insurance Requirements

12.1 Insurance Requirements of the Customer – Without limiting section 7.4 (Required Insurance) of Rate Schedule 46, the Customer shall obtain at its own expense, maintain during the Term of the Agreement and provide proof to FortisBC Energy, the following insurance coverage:

(a) Workers' Compensation Insurance in accordance with the statutory requirements in British Columbia for all its employees engaged in any of the work or services under this Agreement; and

(b) a minimum of $5 million of automobile liability insurance and any other insurance coverage required by law.

All insurance policies required herein shall provide that the insurance with respect to this Agreement shall not be cancelled or changed without the insurer giving at least 10 calendar days written notice to FortisBC Energy and shall be purchased from insurers registered in and licensed to underwrite insurance in British Columbia. Where the Customer fails to comply with the requirements of this section 12, FortisBC Energy may take all necessary steps to affect and maintain the required insurance coverage at the Customer's expense.

12.2 Insurance Requirements of FortisBC Energy – FortisBC Energy shall obtain at its own expense, maintain during the Term of the LNG Transportation Service Agreement and provide proof to the Customer upon request, the following insurance coverage:

(a) Workers' Compensation Insurance in accordance with the statutory requirements in British Columbia for all its employees engaged in any of the work or services under this Agreement; and

(b) General Commercial Liability Insurance for bodily injury, death and property damage in the amount of $5 million per occurrence naming the Customer as an additional insured with respect to this Agreement.

All insurance policies required herein shall provide that the insurance with respect to this Agreement shall not be cancelled or changed without the insurer giving at least 10 calendar days written notice to the Customer and shall be purchased from insurers registered in and licensed to underwrite insurance in British Columbia. Where FortisBC Energy fails to comply with the requirements of this section of this Agreement, the Customer may take all necessary steps to affect and maintain the required insurance coverage at FortisBC Energy's expense.

13. Environmental Covenant

13.1 "Contaminants" means collectively, any contaminant, toxic substances, dangerous goods, or pollutant or any other substance which when released to the natural environment is likely to cause, at some immediate or future time, material harm or degradation to the natural environment or material risk to human health, and includes any radioactive materials, asbestos materials, urea formaldehyde, underground or aboveground tanks, pollutants, contaminants, deleterious substances, dangerous substances or goods, hazardous, corrosive or toxic substances, hazardous waste or waste of any kind, pesticides, defoliants, or any other solid, liquid, gas, vapour, odour or any other substance the storage, manufacture, disposal, handling, treatment, generation, use, transport, remediation or release into the environment of which is now or hereafter prohibited, controlled or regulated by law.

13.2 The Customer acknowledges and agrees that FortisBC Energy and its employees, directors and officers are not responsible and shall not be responsible for any Contaminants now present, or present in the future, in, on or under the Customer designated location, or that may or may have migrated on or off the Customer designated location except to the extent that the presence of such Contaminants is a direct result of the negligent acts or omissions of FortisBC Energy or person for whom it is in law responsible in carrying out the LNG Transportation Service.

14. Limitation of Liability and Indemnity

14.1 The Customer acknowledges and agrees that FortisBC Energy and its employees, directors and officers are not responsible for and shall not be responsible for any claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) incurred by the Customer or any third party except to the extent such claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) are a direct result of FortisBC Energy's breach of this Agreement, or the negligence or willful misconduct of FortisBC Energy, its employees or contractors in performing the LNG Transportation Service.

14.2 The Customer shall indemnify and hold harmless FortisBC Energy and its employees, directors and officers from and against any and all claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) except to the extent such claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) are a direct result of FortisBC

Energy's breach of this Agreement, or the negligence or willful misconduct of FortisBC Energy, its employees or contractors in performing the LNG Transportation Service.

14.3 FortisBC Energy shall indemnify and hold harmless the Customer and its employees, directors and officers from and against any and all claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) arising from or out of:

(a) the negligence or willful misconduct of FortisBC Energy, its employees, or contractors; or

(b) the breach by FortisBC Energy of this Agreement.

14.4 FortisBC Energy's liability to the Customer and the Customer's liability to FortisBC Energy under section 15 of this Agreement for damages from any cause whatsoever including but not limited to a cause in the nature of a breach of a material term, covenant, agreement, condition or obligation imposed under this Agreement regardless of the form(s) of action, whether in contract or tort, including negligence or strict liability or otherwise, shall be limited to the payment of direct damages and such damages shall in no event in the aggregate exceed $100,000 over the Term of this Agreement. Each party has a duty to mitigate the damages that would otherwise be recoverable from the other party pursuant to this Agreement by taking appropriate and commercially reasonable actions to reduce or limit the amount of such damages or amounts.

14.5 Notwithstanding the foregoing, in no event shall either party be responsible or liable under this Agreement for any indirect, consequential, punitive, exemplary or incidental damages of the other or any third party arising out of or related to the Agreement, including but not limited to loss of profit, loss of revenues, or other special damages, even if the loss is directly attributable to the negligence or willful misconduct of such party, its employees, or contractors.

15. Force Majeure

15.1 Except with regard to a party's obligation to make payment due under the Agreement, if either party is unable or fails by reason of Force Majeure to perform in whole or in part any obligation or covenant set forth in this Agreement, such inability or failure shall be deemed not to be a breach of such obligation or covenant and the obligations of both parties under this Agreement shall be suspended to the extent necessary during the continuation of any inability or failure so caused by such Force Majeure.

15.2 The parties intend that the term "Force Majeure" shall have the same meaning as in the Rate Schedule, and without limiting that provision, Force Majeure under this Agreement also includes :

(a) unavailability of LNG from the LNG Facilities by reason of curtailment or otherwise; and

(b) unavailability of the Tanker due to FortisBC Energy's use of the Tanker in providing emergency services as may be required in the event of FortisBC Energy's pipeline failure or other disruption to the FortisBC Energy System;

(c) disruption in third party hauling services.

16. Survival

16.1 Upon the termination of this Agreement:

(a) All claims, causes of action or other outstanding obligations remaining or being unfulfilled as at the date of termination, and,

(b) All of the provisions in this agreement relating to the obligation of either of the parties to provide information to the other in connection with this Agreement

will survive such termination.

17. General

17.1 Amendments to be in Writing – Except as otherwise set out in the Rate Schedule, no amendment or variation of this LNG Transportation Service Agreement will be effective or binding upon the parties unless such amendment or variation is set out in writing and duly executed by the parties.

17.2 Notice – Any notices or other communication which may be or is required to be given or made pursuant to the Agreement shall, unless otherwise expressly provided herein, shall be in writing and shall be personally delivered to or sent by facsimile to either party at its address set forth below:

If to FortisBC Energy	FORTISBC ENERGY INC.
MAILING ADDRESS:	16705 Fraser Highway Surrey, B.C. V4N 0E8

If to the Customer	______________________
MAILING ADDRESS:	______________________ ______________________ ______________________
	Attention: ______________

17.3 Severability – If any provision of this Agreement is determined by a court of competent jurisdiction to be invalid, illegal or unenforceable in any respect, such determination does not impair or affect the validity, legality or enforceability of any other provision of this Agreement.

17.4 Execution – This Agreement may be executed in counterparts, each of which shall be deemed as an original, but all of which shall constitute one and the same instrument. Delivery of an executed counterpart of this letter by facsimile or electronic transmission hereof shall be as effective as delivery of an originally executed counterpart hereof.

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the day and year first above written.

FORTISBC ENERGY INC.
by its authorized signatory:

____

____

THE CUSTOMER: ________________
by its authorized signatory:

____

____

APPENDIX 2

GAS LIQUEFACTION, STORAGE AND DISPENSING SERVICE AGREEMENT

Between

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

and

FORTISBC ENERGY INC.

GAS LIQUEFACTION, STORAGE AND DISPENSING SERVICE AGREEMENT

This GAS LIQUEFACTION, STORAGE AND DISPENSING SERVICE AGREEMENT made as of this ______ day of ____________, 2013.

BETWEEN:

FORTISBC ENERGY (VANCOUVER ISLAND) INC. a company incorporated under the laws of British Columbia having an office at 16705 Fraser Highway, Surrey, British Columbia ("FEVI")

AND:

FORTISBC ENERGY INC. a company incorporated under the laws of British Columbia having an office at 16705 Fraser Highway, Surrey, British Columbia ("FEI")

as sometimes referred to herein jointly as the "Parties" and individually as a "Party".

WHEREAS:

A. FEVI operates a Liquefied Natural Gas ("LNG") Storage Facility on Vancouver Island at Mount Hayes near Ladysmith.

B. FEVI operates an integrated natural gas transmission and distribution system that serves customers on the Sunshine Coast and Vancouver Island.

C. FEI wishes to contract with FEVI for gas liquefaction, storage and dispensing services for the benefit of FEI's customers under its Rate Schedule 46 - Liquefied Natural Gas Sales, Dispensing and Transportation Service.

NOW THEREFORE, in consideration of the promises set forth herein, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

1. **DEFINITIONS**

In this Agreement:

"Agreement" means this Gas Liquefaction, Storage and Dispensing Service Agreement;

"BCUC" means the British Columbia Utilities Commission and any successor regulatory authority;

"Day" means any period of 24 consecutive hours beginning and ending at 12:00 midnight;

"FEVI System" means the FEVI transmission system;

"Force Majeure" means any acts of God, strikes, lockouts, or other industrial disturbances, civil disturbances, arrests and restraints of rulers or people, interruptions by government or court orders, present or future valid orders of any regulatory body having proper jurisdiction, acts of the public enemy, wars, riots, blackouts, insurrections, failure or inability to secure materials or labour by reason or regulations or orders of government, serious epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, explosions, breakage or accident to machinery, liquefaction, storage, and dispensing equipment, or lines of pipes, or freezing of wells or pipelines, or the failure of gas supply, temporary or otherwise, from a Supplier of Gas, or a declaration of Force Majeure by a gas Transporter that results in gas being unavailable for delivery at the Interconnection Point, or any major disabling event or circumstance in relation to the normal operations of the party concerned as a whole which is beyond the reasonable control of the party directly affected and results in a material delay, interruption or failure by such party in carrying out its obligations under the Agreement. Force Majeure events cannot be due to negligence of the party claiming Force Majeure;

"Interconnection Point" means the point where the FortisBC Energy System interconnects with the facilities of Westcoast Energy Inc. at Sumas;

"LNG" means liquefied natural gas;

"LNG Facility" is the LNG Production and Storage facility at Mount Hayes near Ladysmith on Vancouver Island;

"LNG Service" has the meaning set out in section 3;

"Service Charge" means the charge for LNG Service set out in section 7;

"Supplier of Gas" means a party who sells natural gas to FEVI or FEI;

"Tanker" means a cryogenic receptacle used for receiving, storing and transporting LNG, including without limitation, portable tankers, ISO containers, vessels or other similar equipment;

"Term" has the meaning set out in section 2; and

"Transporter" means Westcoast Energy Inc., FortisBC Huntingdon Inc., and any other gas pipeline transportation company connected to the facilities of FEI from which FEI receives natural gas for the purposes of natural gas transportation or resale.

2. TERM

2.1 The commencement date for the provision of LNG Service under this Agreement is the later of June 1, 2014 or such date notified by FEVI to FEI pursuant to section 2.4 ("Commencement Date").

2.2 The term of this Agreement shall continue until termination or expiry of the Storage and Delivery Agreement made between the parties as of January 10, 2008 (the "Term") and as amended from time to time.

2.3 Notwithstanding Section 2.2, FEI may provide FEVI with two months' written notice of termination at any time during the term of the Agreement.

2.4 FEVI will provide 60 days written prior notice to FEI of the Commencement Date. FEVI will notify FEI in writing of any expected change in the Commencement Date due to delay in commencement of construction of the facility necessary to provide LNG Dispensing Service.

3. LNG SERVICE

3.1 During the Term of this Agreement, FEVI will liquefy gas supplied by FEI or FEI's customers for the purpose, and then store and dispense such LNG into Tankers (the "LNG Service") provided by FEI or FEI's customers. Title transfer shall occur at the inlet flange of the Tanker or at the outlet flange of the FEVI meter as applicable. FEI shall at all times be in compliance with the requirements of all applicable laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter, including, but not limited to, the federal *Transportation of Dangerous Goods Act* and associated regulations and British Columbia's *Environmental Management Act* and associated regulations. FEI shall require of its customers that any personnel, vehicle or Tanker provided by its customers or their agents for LNG Service meets those requirements.

3.2 Notwithstanding section 3 above, FEVI may at its sole discretion refuse to provide LNG Service to any of FEI's customers, if in FEVI's opinion, the supply of LNG to such customer may be contrary to any laws, rules, regulations and orders of any legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction including, but not limited to, the federal *Transportation of Dangerous Goods Act* and its associated regulations and British Columbia's *Environmental Management Act* and associated regulations.

3.3 At least 24 hours in advance of the Day of FEI's or FEI's customer's desired loading time, FEI or FEI's customer or its agent, as the case may be, will provide FEVI by fax or email, prior to 12:00 a.m. Pacific Standard Time on each Day (or such other time as may be agreed to from time to time by the parties) such information as may be requested by FEVI, which will include, but is not limited to, FEI's and its customers' requested quantity of LNG for the given Day. Loading of Tankers with LNG shall take place between 8:00 a.m. - 4:00 p.m. (Pacific Standard Time) Monday through Friday (excluding British Columbia statutory holidays) or such other times as agreed upon by the parties from time to time.

4. CONTRACT LEVELS

FEVI will make available to FEI a minimum of 17,600 Gigajoules per week of LNG Service at the LNG Facility or such other minimum or maximum weekly volumes as may be determined from time to time by FEVI with reference to the LNG requirements of each of the parties.

5. PERFORMANCE OBLIGATIONS

5.1 Subject to section 6, Force Majeure, FEVI shall provide LNG Service on each day except when planned maintenance of the LNG Facility prevents FEVI from providing the LNG Service.

5.2 FEVI will use reasonable commercial efforts to schedule planned maintenance such that planned maintenance does not interfere with providing the LNG Service. Prior to April 1 of each year in the Term, FEVI will provide FEI with a forecast schedule of planned maintenance to take place over the next 12 months.

6. FORCE MAJEURE

6.1 Except for FEI's obligation to make payments under this Agreement, if either Party is rendered unable, in whole or in part, by Force Majeure to carry out its obligations under this Agreement, then upon such Party's giving notice of the particulars of such Force Majeure to the other Party as soon as reasonably possible (with such notice to be confirmed in writing), the obligations of the Party giving such notice, from the inception of the Force Majeure, will be suspended and excused during the continuance of any inability so caused. The obligations of the affected Party will be suspended and excused for such time only to the extent they are affected by such Force Majeure. The cause of the Force Majeure will be remedied by the affected Party with all reasonable diligence and dispatch.

7. SERVICE CHARGE

Each month, FEI will pay to FEVI an amount (the "Service Charge") per gigajoule of LNG liquefied, stored and dispensed under this Agreement equal to the total of the Delivery Charge per Gigajoule (not including any premiums that may be charged by FEI to FEI's customers) set out in FEI's Rate Schedule 46 for FEI's Long-Term and Short-Term LNG Service, as adjusted or amended from time to time by FEI.

8. BILLING

8.1 FEVI will provide FEI by the 15th day of each month beginning in the month following the commencement of the term of this Agreement with an invoice for the Service Charges for LNG Service provided in the preceding month plus applicable taxes. In the event that FEI is late in paying the invoice then FEVI will assess FEI and FEI will pay to FEVI a late payment fee equal to the current prime interest rate charged by the Main Branch of the Toronto-Dominion Bank in Vancouver, British Columbia, to its most creditworthy commercial customers, plus 4%, per annum calculated on a daily basis.

9. NOTICES

9.1 Except as may be expressly provided otherwise in this Agreement, any notice, request, authorization, direction, or other communication under this Agreement will be made given in writing and will be delivered in person, or by facsimile transmission, properly addressed to the intended recipient as follows:

a) If to FEI: FortisBC Energy Inc.
16705 Fraser Highway
Surrey, B.C. V4N OEB
Attention: VP, Energy Supply & Resource Development
Facsimile: 604-592-7420

b) If to FEVI: FortisBC Energy (Vancouver Island) Inc.
16705 Fraser Highway
Surrey, B.C. V4N OEB
Attention: VP, Strategic Planning, Corporate Development & Regulatory Affairs
Facsimile: 604-576-7074

Either Party may change its address specified above by giving the other Party notice of such change in accordance with this section 9.

10. GOVERNING LAW

10.1 This Agreement and the respective rights and duties of the Parties arising out of this Agreement will be governed by and construed, enforced and performed in accordance with the laws of the Province of British Columbia.

11. EFFECT OF WAIVER OR CONSENT

11.1 No waiver or consent by either Party, expressed or implied, or any breach or default by the other Party in the performance of any of such other Party's obligations under this Agreement will operate or be construed as a waiver or consent to any other breach or default hereunder. Failure of a Party to complain of any act of the other Party or to declare the other Party in breach or default with respect to this Agreement, irrespective of how long that failure continues, does not constitute a waiver by the Party of any of its rights with respect to that breach or default.

12. HEADINGS

12.1 The headings for the sections of this Agreement are for convenience of reference only and in no way affect the meaning or interpretation of any of the provisions of this Agreement.

13. SEVERABILITY

13.1 Except as otherwise stated in this Agreement, any provision or section declared or rendered unlawful by a court of law or regulatory agency with jurisdiction over this Agreement, the Parties or either of them, or deemed unlawful because of statutory change, will thereupon be deemed to have been severed from this Agreement and will not otherwise affect the lawful obligations that arise under other provisions of this Agreement.

14. ASSIGNMENT

14.1 Subject to the provisions of this section 14, this Agreement will enure to and be binding upon the respective successors and permitted assigns of the Parties. Neither Party may assign this Agreement without the prior written consent of the other Party, which consent will not be unreasonably withheld, provided, that either Party may assign its interest under this Agreement (a) to any entity that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with such Party, (b) to any entity into which it consolidates or merges or (c) as security to the holder of any indebtedness, present or future, of such Party, without the prior written approval of the other Party, but no such assignment will operate to relieve the assigning Party of any of its obligations under this Agreement. Any Party's transfer or assignment in violation of this section 14 will be void.

15. RESPONSIBILITY FOR DAMAGE

15.1 As between the Parties, FEVI will be deemed to be in exclusive control and possession of gas which is the subject of this Agreement and will be responsible for any damage or injury caused thereby prior to the point of transfer of title set out in section 3. As between the Parties, FEI will be deemed to be responsible for any damage or injury or damage caused thereby after the point at which FEI or FEI's customers receives gas pursuant to this Agreement.

16. INDEMNITY

16.1 FEI hereby indemnifies and saves FEVI harmless from and against all claims by FEI's customers and any other third parties in respect to loss of life, personal injury, loss or damage to property relating to the provision of LNG Service to FEI's customers.

17. TERMINATION

17.1 If either Party is at any time in material breach of or default under this Agreement (the "Defaulting Party"), the other Party (the "terminating Party") will have the right to terminate this Agreement by giving the Defaulting Party written notice of such termination. Such termination will be effective upon the Defaulting Party's receipt of such notice of termination pursuant to this section 17. For the purposes of this section 17, a Party will be deemed to be in material breach if or default under this Agreement if such Party:

a) fails to cure any material breach under this Agreement by such Party prior to the later of (i) the expiration of thirty days after the Terminating Party gives the Defaulting Party written notice of the breach or default; and (ii) the date upon which the Terminating Party gives the Defaulting Party written notice of termination;

b) is unable to meet its obligations as they become due or such Party's liabilities exceed its assets in the aggregate; or

c) makes a general assignment of substantially all of its assets for the benefits of its creditors, files a petition of bankruptcy, commences, authorizes or acquiesces in the commencement of a proceeding or cause under any bankruptcy, insolvency or similar law for the protection of creditors or have such petition filed or proceeding commenced against it, or seeks other relief under any applicable insolvency laws.

In no event will either Party incur any liability (whether for lost revenues or lost profits or otherwise) as a result of any termination of this Agreement pursuant to this section 17.

17.2 All rights and remedies of either Party under this Agreement and at law and in equity will be cumulative and not mutually exclusive and the exercise by one Party of one right or remedy will not be deemed a waiver of any other right or remedy available to that Party. Nothing contained in any provision of this Agreement will be construed to limit or exclude any right or remedy of either Party (arising on account of the breach or default by the other Party or otherwise) now or hereafter existing under any other provision of this Agreement.

18. WAIVER OF CERTAIN DAMAGES

18.1 Subject to the indemnity provided to FEVI in section 16, in no other event will either Party be liable to the other Party for consequential, incidental, punitive, special, exemplary or indirect damages, in tort, strict liability, warranty, contract, equity or otherwise.

19. DISPUTE RESOLUTION

19.1 All disputes arising under or relating to this Agreement, except only disputes with respect to which the BCUC has jurisdiction, which the BCUC is prepared to exercise, shall, after the parties have attempted in good faith to settle the dispute between themselves, be submitted to and finally settled by arbitration under the Commercial Arbitration Act. The arbitration will take place in Vancouver, British Columbia before a single arbitrator and will be administered by the British Columbia Commercial Arbitration Centre ("BCICAC") in accordance with its "Procedures for Cases under the BCICAC Rules.

20. ENTIRE AGREEMENT

20.1 This Agreement constitutes the entire agreement and supersedes all others between the Parties relating to the subject matter contemplated by this Agreement. There are no prior or contemporaneous agreements or representations (whether written or oral) affecting such subject matter. No amendment, modification or change to this Agreement will be enforceable, except as specifically provided for in this Agreement, unless reduced to writing and hereafter signed (which may be done by facsimile) by both Parties.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their authorized representatives as of the date first written above.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

BY:______________________________
(Signature)

____
(Name – Please Print)

____
(Title)

FORTISBC ENERGY INC.

BY:______________________________
(Signature)

____
(Name – Please Print)

____
(Title)

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 749 , *Approved and Ordered* December 19, 2014

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that Direction No. 5 to the British Columbia Utilities Commission, B.C. Reg. 245/2013, is amended as set out in the attached Schedule.

DEPOSITED
December 22, 2014
B.C. REG. 265/2014

Minister of Energy and Mines and
Minister Responsible for Core Review

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, s. 3

Other: OIC 557/2013

December 4, 2014 RESUB-1 R/632/2014/27

SCHEDULE

1 *Section 1 of Direction No. 5 to the British Columbia Utilities Commission, B.C. Reg. 245/2013, is amended*

(a) by renumbering the section as section 1 (1),

(b) in subsection (1) in paragraph (a) of the definition of "**applicable customers**" *by striking out* "or", *in paragraph (b) by striking out* "rate base;" *and substituting* "rate base, or" *and by adding the following paragraph:*

(c) under the transportation rate schedule. *;*

(c) by adding the following definitions:

"**construction carrying costs**" means a return on the feasibility, development and capital costs of a facility, equal to the utility's weighted average cost of capital, that will be incurred during the period ending when the facility enters a utility's natural gas class of service rate base;

"**contract demand**" has the same meaning as in the LNG rate schedule;

"**CTS expansion project**" means any of the following projects:

(a) the project to expand the transmission facilities of FortisBC Energy Inc. at and between the Cape Horn Valve Assembly and Coquitlam Gate Station;

(b) the project to expand the transmission facilities of FortisBC Energy Inc. at and between the Nichol Valve Assembly and Port Mann Crossover Station;

(c) the project to expand the transmission facilities of FortisBC Energy Inc.at and between the Nichol Valve Assembly and Roebuck Valve Assembly;

(d) the project to expand the transmission facilities of FortisBC Energy Inc.at and between the Tilbury Gate Station and Tilbury LNG Facility;

"**EGP project**" means the project to expand the transmission facilities of FortisBC Energy (Vancouver Island) Inc at and between the Eagle Mountain Compressor Station in Coquitlam and an LNG Facility in Woodfibre, and at the Port Mellon Compressor Station;

"**extraordinary retirement costs**" means asset retirement costs from causes not reasonably anticipated when calculating the depreciation of the asset;

"**letter agreement**" means the letter agreement as set out in Appendix 3 attached to this direction;

"**liquefaction capacity**" means the capacity of an LNG facility, measured in terajoules per day, to liquefy natural gas to produce LNG;

"**LNG agreement**" has the same meaning as in the LNG rate schedule;

"**LNG revenue variance regulatory account**" means an account to capture the first 3 annual revenue variances between

(a) the forecast revenues from the LNG rate schedule that are used by the commission in setting rates for applicable customers, and

(b) the actual annual revenues received under the LNG rate schedule;

"**long-term LNG service**" has the same meaning as in the LNG rate schedule;

"operating costs", in relation to a facility, means

(a) operating and maintenance expenses,

(b) electricity expenses,

(c) interest expenses,

(d) taxes, including property taxes,

(e) return on equity,

(f) extraordinary retirement costs, and

(g) amount with respect to the depreciation of the

(i) capital costs,

(ii) construction carrying costs,

(iii) feasibility and development costs,

(iv) sustaining capital costs, and

(v) decommissioning and salvaging costs

determined with reference to the remaining service life of the facility, as estimated by the commission in setting rates for applicable customers;

"operation period", with respect to phase 1B facilities, means the period beginning on the date those facilities begin operations and ending 15 years later;

"phase 1A facilities" means expansion facilities to provide

(a) liquefaction capacity of up to 40 terajoules per day of LNG, and

(b) storage capacity of between 1.0 petajoules and 1.1 petajoules of LNG;

"phase 1B facilities" means expansion facilities other than phase 1A facilities, but does not include LNG storage facilities;

"specified agreement" means an LNG agreement for long-term LNG service having

(a) a contract term of 10 years or more, and

(b) a contract demand specified for 10 years or more of the contract term;

"sustaining capital costs" means capital costs expended for the purpose of maintaining or extending the life of an asset;

"transportation rate schedule" means the Large Volume Industrial Transportation Rate Schedule 50 of FortisBC Energy Inc. as set out in Appendix 4 attached to this direction;, *and*

(d) by adding the following subsection:

(2) In this direction, a reference to a utility referred to in the definition of "utility" in subsection (1) includes any successor entities of that utility on amalgamation, merger or consolidation.

2 *Section 4 is repealed and the following substituted:*

Expansion facilities

4 (1) The commission must not exercise its power under section 45 (5) of the Act in respect of

(a) phase 1A facilities, and

(b) phase 1B facilities, if, on the date construction of phase 1B facilities begins, specified agreements are in place representing an average of at least 70% of the intended liquefaction capacity of the phase 1B facilities for the operation period, calculated as follows:

$$AV = Y/15$$

where:

AV = the average of the intended liquefaction capacity of phase 1B facilities for the operation period;

Y = the sum of the amounts of intended liquefaction capacity of phase 1B facilities represented by specified agreements for each year of the operation period.

(2) In setting rates under the Act for FortisBC Energy Inc., the commission must do all of the following:

(a) on January 1 of the year immediately following the year in which phase 1A facilities are completed, include in the utility's natural gas class of service rate base the sum of the following:

(i) the lesser of

(A) the capital costs of the phase 1A facilities, and

(B) $400 million;

(ii) the construction carrying costs for the phase 1A facilities;

(iii) the feasibility and development costs incurred on or after January 1, 2013;

(b) on January 1 of the year immediately following the year in which phase 1B facilities are completed, include in the utility's natural gas class of service rate base the sum of the following:

(i) the lesser of

(A) the capital costs of phase 1B facilities, and

(B) $400 million;

(ii) the construction carrying costs for phase 1B facilities;

(iii) the feasibility and development costs incurred on or after January 1, 2013;

(c) include in the calculation of rates for applicable customers

(i) the annual revenues from the sale of LNG from phase 1A facilities and phase 1B facilities,

(ii) the annual operating costs of phase 1A facilities and phase 1B facilities, and

(iii) the capital costs, construction carrying costs, sustaining capital costs, decommissioning and salvaging costs and feasibility and development costs respecting phase 1A facilities and phase 1B facilities;

(d) allow a utility to establish an LNG revenue variance regulatory account for the following 2 purposes, if applicable:

(i) for the operation of the phase 1A facilities;

(ii) for operation of the phase 1B facilities;

(e) set rates for applicable customers in such a way as to allow the LNG revenue variance regulatory account to be cleared from time to time, and within a reasonable period by allowing the balance to be returned to or recovered from applicable customers.

3 *Section 5 is amended by adding the following subsection:*

(1.1) Before January 1, 2015, the commission must issue an order, amending the LNG rate schedule as set out in Appendix 5 attached to this direction, effective on January 1, 2015.

4 *The following sections are added:*

Transportation rate schedule

6 (1) Within 60 days of the date this section comes into force, the commission must issue an order setting the transportation rate schedule as a rate for FortisBC Energy Inc., effective on the date the order is issued.

(2) In calculating rates for applicable customers, the commission must include the annual revenues and operating costs arising from services provided under the transportation rate schedule.

(3) Section 5 (2) applies to the transportation rate schedule.

(4) The commission must not exercise a power under the Act in a way that would directly or indirectly prevent FortisBC Energy Inc. from providing service under the transportation rate schedule.

(5) If the shipper is not creditworthy and has not provided the guarantee referred to in section 13.2 (b) of the transportation rate schedule, the commission must set the required security amount on the basis of the following:

(a) the shipper's creditworthiness;

(b) the contract demand and the contract term of the transportation agreement;

(c) the book value of the incremental system upgrades constructed, acquired, contracted for or secured by a utility to serve the shipper;

(d) any other matter the commission considers relevant.

(6) Terms used in subsection (4) and not defined in this direction have the same meaning as in the transportation rate schedule.

EGP project

7 (1) Within 60 days of the date this section comes into force, the commission must, by regulation under section 45 (4) of the Act, exclude the EGP project from the operation of section 45 (1) of the Act.

(2) In setting rates under the Act for FortisBC Energy (Vancouver Island) Inc., the commission must

(a) on January 1 of the year immediately following the year in which the EGP project is completed, include in the utility's natural gas class of service rate base the capital costs, construction carrying costs and feasibility and development costs for the EGP project,

(b) allow the utility to earn a return on the costs referred to in paragraph (a), and

(c) include in the calculation of rates for applicable customers

(i) the annual operating costs of the EGP project, and

(ii) the capital costs, construction carrying costs, sustaining capital costs, decommissioning and salvaging costs and feasibility and development costs respecting the EGP project.

CTS expansion projects

8 (1) The commission must refrain from exercising its power under section 45 (5) of the Act with respect to a CTS expansion project.

(2) In setting rates under the Act for FortisBC Energy Inc., the commission must

(a) on January 1 of the year immediately following the year in which a CTS expansion project is completed, include in the utility's natural gas class of service rate base the capital costs, construction carrying costs and feasibility and development costs for the CTS expansion project,

(b) allow the utility to earn a return on the costs referred to in paragraph (a), and

(c) include in the calculation of rates for applicable customers

(i) the annual operating costs of the CTS expansion project, and

(ii) the capital costs, construction carrying costs, sustaining capital costs, decommissioning and salvaging costs and feasibility and development costs respecting the CTS expansion project.

Letter agreement

9 (1) Within 60 days of the date this section comes into force, the commission must issue an order setting the letter agreement as a rate for FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc., effective, subject to section 2.1 of the letter agreement, on the date the order is issued.

(2) Section 5 (2) applies to the letter agreement.

5 *The following Appendices are added:*

APPENDIX 3

FORTISBC

LETTER AGREEMENT

November 20, 2014

British Columbia Hydro and Power Authority
333 Dunsmuir Street, 17th Floor
Vancouver, BC V6B 5R3

Attention: Rohan Soulsby

Dear Sirs:

Re: **British Columbia Hydro and Power Authority ("BC Hydro")**
FortisBC Energy Inc. ("FEI")
FortisBC Energy (Vancouver Island) Inc. ("FEVI")

BC Hydro, FEVI and FEI (together, the "**Parties**" and each a "**Party**") wish to agree in this letter agreement (the "**Letter Agreement**") on certain terms related to the following:

a) the Transportation Service Agreement between BC Hydro and Terasen Gas (Vancouver Island) Inc. ("**TGVI**") dated September 19, 2007 ("**IGTSA**"), pursuant to which FEVI provides BC Hydro with long term firm transportation service ("**FTS**") and interruptible transportation service ("**ITS**") to the Island Cogeneration Project located in Campbell River on Vancouver Island, British Columbia, which is now known as Island Generation ("**IG**");

b) the Bypass Transportation Agreement for Rate Schedule 22 dated November 27, 1998 between BC Hydro and BC Gas Utility Ltd. (the "**BTA**"), pursuant to which FEI provides BC Hydro with FTS to the thermal generating facility in Port Moody, British Columbia ("**Burrard Thermal**");

c) the capacity assignment agreement among BC Hydro, Terasen Gas Inc. ("**TGI**") and TGVI dated September 19, 2007 (the "**CAA**"), pursuant to which BC Hydro may assign to FEVI firm gas transportation capacity available to BC Hydro under the BTA, to be used by FEVI to provide BC Hydro with FTS to IG under the IGTSA;

d) the peaking agreement between BC Hydro and TGVI dated September 19, 2007 (the "**PA**", and together with the BTA, the IGTSA and the CAA, the "**Applicable Agreements**"), pursuant to which BC Hydro agrees to provide capacity rights to FEVI for the purposes of serving FEVI's Core Market (as defined in the PA);

e) the long term firm transportation service that FEI expects to provide to the proposed liquefied natural gas ("**LNG**") facility at the former Woodfibre pulp mill site near Squamish, British Columbia ("**Woodfibre**"), which will be set out in a transportation service agreement between the owner of Woodfibre (or its nominee) (the "**Woodfibre Customer**") and FEI (or its successor) (the "**Woodfibre TSA**"); and

f) the capacity sharing agreement that BC Hydro and the Woodfibre Customer may enter into pursuant to which BC Hydro would provide the Woodfibre Customer with access to firm gas transportation capacity available to BC Hydro under the IGTSA, for the purposes of serving Woodfibre (the "**Woodfibre Capacity Agreement**").

The Parties acknowledge that, under the Applicable Agreements, FEI is a successor to BC Gas Utility Ltd. and TGI, and FEVI is a successor to TGVI.

The Parties intend that certain terms of this Letter Agreement be organized into two phases:

(a) **Phase 1:** the terms described in section 1 of this Letter Agreement, which set forth certain amendments to the BTA and IGTSA to reflect certain commercial arrangements among the Parties in relation to the delivery of gas to Burrard Thermal and IG; and

(b) **Phase 2:** the terms described in section 2 of this Letter Agreement, which set forth certain amendments to the IGTSA and PA to reflect certain commercial arrangements among the Parties relating to BC Hydro's proposed use of its capacity under the IGTSA to facilitate the delivery of gas to Woodfibre.

Now therefore, in consideration of the mutual premises and agreements and other good and valuable consideration (the receipt and sufficiency of which is acknowledged by each Party), the Parties agree as follows:

1. PHASE 1 TERMS

1.1 <u>**BTA Amendments (Phase 1)**</u>: The BTA is amended as set forth in this section 1.1.

1.1.1 Notwithstanding section 3.01 of the BTA, the BTA will automatically terminate on the earlier of:

a) October 31, 2017; and

b) the date as of which the BTA may be terminated pursuant to article 8 of the BTA.

1.1.2 The second and third paragraphs of section 8.03 of the BTA are deleted.

1.1.3 The Parties acknowledge that in order to maintain the transmission pressure on the lateral pipeline serving Burrard Thermal (the "**Lateral Pipeline**"), FEI must be able to perform in-line inspections on the Lateral Pipeline. To perform in-line inspections on the Lateral Pipeline, FEI requires a minimum natural gas flow rate of approximately 30 TJ per Day at Burrard Thermal. The Parties will cooperate to allow FEI to pig the Lateral Pipeline at the latest date practical before the BTA is terminated for the purposes of performing in-line inspections on the Lateral Pipeline, and to permit Burrard Thermal to have the ability to consume a minimum natural gas flow rate of approximately 30 TJ per Day during the period of such in-line inspections. FEI will work with BC Hydro to prepare an implementation plan for all in-line inspections of the Lateral Pipeline, with the objective of minimizing all costs related to, or arising from, such in-line inspections.

1.2 **IGTSA Amendments (Phase 1).** The IGTSA is amended as set forth in this section 1.2. Capitalized terms in this section 1.2 that are used but not otherwise defined in this Letter Agreement have the meaning given in the IGTSA.

1.2.1 BC Hydro shall not exercise its right to terminate the IGTSA under section 5.1 of the IGTSA.

1.2.2 Upon termination of the CAA, the Demand Toll will be adjusted to include an allocation of costs payable by FEVI to FEI under the Wheeling Agreement at the same unit cost as other Shippers on the current FEVI System. This will initially result in an increase in the Demand Toll from $0.858 to $0.958 per GJ per Day. The Parties acknowledge that the Demand Toll will be reviewed from time to time and is subject to British Columbia Utilities Commission ("**BCUC**") approval. FEI and FEVI will not, and will cause their affiliates to not, apply to the BCUC for a Demand Toll that exceeds $0.958 per GJ per Day at any time during the Initial Term.

1.2.3 At section 2.1(10) of the IGTSA, the definition of "Delivery Point" is deleted, and replaced with the following:

> *"Delivery Point" means the points where the Connecting Facilities connect to the facilities of ICP and BC Hydro's Burrard Thermal generation station in Port Moody, British Columbia;*

1.2.4 At section 2.1(8) of the IGTSA, the definition of "Connecting Facilities" is deleted, and replaced with the following:

> *"Connecting Facilities" means the pipeline, metering and related facilities (i) installed by TGVI or FEVI to connect ICP to the FEVI System or the TGVI System, and (ii) installed by Terasen Gas Inc. or FEI to connect BC Hydro's Burrard Thermal generation station in Port Moody, British Columbia to the Terasen System or the FEI System;*

1.2.5 At section 2.1(13) of the IGTSA, the definition of "Expansion Facility" is deleted, and replaced with the following:

> *"Expansion Facility" or "Expansion Facilities" means a material facility or facilities that TGVI or FEVI proposes to construct on the FEVI System or the TGVI System after the Commencement Date in respect of which TGVI or FEVI has provided BC Hydro an Expansion Notice pursuant to section 4.2, but excluding:*
>
> *(a) the Mt. Hayes Storage Facility;*
>
> *(b) any replacement of, or upgrade to, a facility in existence at the Commencement Date except to the extent that replacement facility or upgrade causes a material increase in the capacity of the TGVI System or the FEVI System; and*
>
> *(c) the proposed expansion facilities to provide Firm Transportation Service to Woodfibre.*

1.2.6 At section 2.1(12) of the IGTSA, the definition of "Dispatch Event" is deleted, and replaced with the following:

> *"Dispatch Event" means an event in which ICP is not operating as a result of a direction from BC Hydro, in its capacity as the purchaser of electricity from ICP, to the owner and/or operator of ICP to dispatch off ICP for market reasons;*

1.2.7 A new section 2.1(32) of the IGTSA is added, as follows:

> *"Woodfibre" means the proposed liquefied natural gas facilities to be located at the former Woodfibre pulp mill site near Squamish, British Columbia.*

1.2.8 Upon termination of the BTA, BC Hydro shall have the right to use its Firm Transportation Service under the IGTSA to nominate up to 2 TJ per Day of Gas for delivery for use at its own facilities at Burrard Thermal, and BC Hydro shall pay for any commercially reasonable modifications to the FEI facilities at Burrard Thermal that FEVI may reasonably require to allow continued Firm Transportation Service to BC Hydro at Burrard Thermal, provided however that:

(a) FEVI shall notify BC Hydro in advance of making any such modifications for which FEVI claims payment from BC Hydro; and

(b) BC Hydro shall have the right to cease deliveries to Burrard Thermal rather than be subject to any payment obligation in respect of such modifications.

1.2.9 Gas delivered by FEVI or FEI to BC Hydro at Burrard Thermal will be at a pressure of not less than 60 psig and Gas delivered by FEVI to IG will be at a pressure of not less than 500 psig.

1.2.10 Upon the termination of the BTA, and for the remainder of the Initial Term, under section 6.3 of the IGTSA, the minimum Contract Demand will be automatically increased from 40 TJ per Day to 45 TJ per Day, provided that the minimum Contract Demand will automatically return to 40 TJ per Day upon occurrence of either of the following conditions:

a) the BCUC approves the Large Volume Industrial Transportation Rate Schedule 50 (**"Rate Schedule 50"**) as a rate for FEI and such Rate Schedule 50 comes into effect, a customer of FEI or any of its affiliates signs a transportation service agreement under Rate Schedule 50 for service to a facility, and a customer commences delivery of Gas under Rate Schedule 50 for firm transportation service; or

b) FEI or its affiliate commences delivery of LNG to a customer from the Tilbury Phase 1B Facilities, where **"Tilbury Phase 1B Facilities"** means the expansion of operations at the Tilbury LNG facility in Delta, British Columbia (the **"Tilbury Facility"**) from Phase 1A Facilities (meaning expansion facilities to be constructed, owned and operated by a utility at Tilbury Island, Delta, British Columbia to provide liquefaction capacity of up to 40 TJ per Day of LNG) to add additional liquefaction capacity of at least 100 TJ per Day of LNG.

1.2.11 For greater certainty, from and following termination of the BTA, FEVI will, or will cause FEI to, provide Burrard Thermal with service in accordance with the terms of the IGTSA, and if FEI and FEVI have not amalgamated to form an amalgamated entity ("**Amalco**") at such time as the BTA is terminated such that the contractual rights of FEI and FEVI under the Applicable Agreements continue to be the rights and interests of Amalco and Amalco continues to be liable for the obligations of FEI and FEVI under the Applicable Agreements, the Parties will use their best efforts to promptly negotiate and agree upon such additional amendments to the IGTSA and all other required relevant agreements that all Parties, acting reasonably, determine are necessary or appropriate to accommodate the provision of service to Burrard Thermal.

2. PHASE 2 TERMS

2.1 **Phase 2 Terms**: Subject to sections 3.1 and 3.2 of this Letter Agreement, the terms set forth in sections 2.2 and 2.3 of this Letter Agreement shall be effective from earlier of:

a) the date as of which each of the Woodfibre TSA and the Woodfibre Capacity Agreement has come into effect; and

b) November 1, 2016.

For greater certainty, the Parties agree and acknowledge that this Letter Agreement will not be taken to impose any commitment on the part of any person (including any Party) to negotiate or enter into either the Woodfibre TSA or the Woodfibre Capacity Agreement, and that the terms and conditions of the Woodfibre TSA and the Woodfibre Capacity Agreement, if concluded, shall be determined in the sole discretion of the parties to such agreements.

2.2 **IGTSA Amendments (Phase 2)**: Subject to section 2.1 of this Letter Agreement, the IGTSA is amended as set forth in this section 2.2. Capitalized terms in this section 2.2 that are used but not otherwise defined in this Letter Agreement have the meaning given in the IGTSA.

2.2.1 After the Initial Term, BC Hydro's right to nominate and deliver Gas for delivery to Woodfibre pursuant to section 9.4 of the IGTSA shall be subject to the following conditions:

(a) BC Hydro having renewed the Service Period for a Renewal Term of 10 years or greater following the Initial Term; and

(b) at the time that BC Hydro nominates and delivers Gas pursuant to section 9.4 of the IGTSA, BC Hydro having a contractual obligation to deliver gas to IG (subject to any contractual rights that BC Hydro may have to interrupt, suspend or reduce gas supply in any circumstance where IG is not operating, or otherwise).

2.2.2 Section 9.4 of the IGTSA is deleted and replaced with the following:

Dispatch Event. If BC Hydro initiates a Dispatch Event, BC Hydro may use its Firm Transportation Service under this Agreement to nominate and deliver Gas for delivery to Woodfibre during such period, provided that:

(1) ICP is not operating;

(2) BC Hydro continues to be responsible for all obligations under this Agreement; and

(3) volumes delivered to Woodfibre pursuant to this section do not exceed 40 TJ per Day.

Notwithstanding section 6.4, if BC Hydro initiates a Dispatch Event, the hourly rate of delivery to Woodfibre will be based on 1/24 of the Authorised Quantity (less the quantity of gas delivered as System Gas and inventory imbalance).

2.2.3 If BC Hydro wishes to use its Firm Transportation Service to nominate and deliver Gas for delivery to Woodfibre under section 9.4 of the IGTSA, BC Hydro must provide FEVI with notice of such nomination and delivery by no later than 6:00 am of the Day that precedes the Day on which BC Hydro requires that nomination and delivery of Gas for delivery to Woodfibre commence, provided that BC Hydro will use reasonable efforts to provide FEVI with notice of such nomination and delivery 48 hours prior to the time that BC Hydro requires nomination and delivery of Gas for delivery to Woodfibre to commence.

2.2.4 If BC Hydro is using its Firm Transportation Service during a Dispatch Event to nominate and deliver Gas for delivery to Woodfibre under section 9.4 of the IGTSA, and BC Hydro wishes to use its Firm Transportation Service to nominate and deliver Gas for delivery to IG, BC Hydro must provide FEVI with notice of such nomination and delivery by no later than 6:00 am of the Day that precedes the Day on which BC Hydro requires that nomination and delivery of Gas for delivery to Woodfibre commence, provided that BC Hydro will use reasonable efforts to provide FEVI with notice of such nomination and delivery 48 hours prior to the time that BC Hydro requires nomination and delivery of Gas for delivery to IG to commence.

If BC Hydro provides 48 hours' or less notice to FEVI, FEVI will allow deliveries to be returned to IG, provided that:

(a) upon receipt of notification from BC Hydro, Gas deliveries to Woodfibre for the then current Day that BC Hydro has nominated for delivery to Woodfibre will stop immediately and the capacity created by the cessation of such deliveries will be made available to FEVI at no cost to prepare the FEVI System for change in deliveries to IG for the succeeding Day;

(b) BC Hydro and the FEVI customer associated with Woodfibre make the required intraday nominations to stop delivery onto the FEVI System of the volumes of Gas that BC Hydro has nominated for delivery to Woodfibre; and

(c) FEVI may delay the time at which deliveries are returned to IG until such time as FEVI, acting reasonably, considers the change in deliveries from Woodfibre to IG will not adversely impact the operational stability and integrity of the FEVI System, provided that FEVI shall ensure that any such delay is not more than 48 hours following the delivery of BC Hydro's notice to FEVI.

2.2.5 FEVI will continue to provide BC Hydro with Interruptible Transportation Service for deliveries from the Receipt Point to any Delivery Point (either IG or Burrard Thermal) subject to BC Hydro not using its Firm Transportation Service to nominate deliveries to Woodfibre as would otherwise be permitted during a Dispatch Event.

2.2.6 If BC Hydro elects to use its Firm Transportation Service to nominate and deliver Gas for delivery to Woodfibre under section 9.4 of the IGTSA:

(a) FEVI will meet BC Hydro's requests for Interruptible Transportation Service only after FEVI meets its requirements for its Core Market (as defined in the PA) customers, and any requests for Interruptible capacity on the FEVI System made by transportation customers other than BC Hydro and the Woodfibre Customer; and

(b) FEI must receive confirmation from BC Hydro (which may take the form of a copy of an agreement between BC Hydro and the Woodfibre Customer), to FEVI's satisfaction (acting reasonably), that the Woodfibre Customer has agreed that requests by the Woodfibre Customer for Interruptible Transportation Service under the Woodfibre TSA, along with requests by BC Hydro for Interruptible Transportation Service under the IGTSA, will be secondary to other Shippers.

2.2.7 Any payment that BC Hydro may receive from the Woodfibre Customer as a recovery of fixed or demand charges paid by BC Hydro to FEVI for Firm Transportation Service used under section 9.4 of the IGTSA (the "**Assigned FTS**") shall be shared equally between BC Hydro and FEVI. For clarity, BC Hydro may retain the entirety of, and shall have no obligation to share with FEVI, any payment that BC Hydro may receive from the Woodfibre Customer in respect of any of the following:

(a) variable charges associated with any delivery of Gas to Woodfibre; and

(b) reimbursement of financial benefits that BC Hydro would have realized (as determined by BC Hydro, acting reasonably) if BC Hydro had retained the Assigned FTS to deliver Gas to IG rather than initiating a Dispatch Event at the Woodfibre Customer's request.

2.3 <u>PA Amendments (Phase 2)</u>: Subject to section 2.1 of this Letter Agreement, the PA is amended as set forth in this section 2.3.

2.3.1 For greater certainty, FEVI's Capacity Right pursuant to section 3.1 of the PA will continue to apply if BC Hydro has nominated some or all of the Firm Capacity for delivery to Woodfibre.

2.3.2 The Maximum Curtailment Volume that FEVI may nominate for use under its Capacity Right will increase from 100,000 to 200,000 GJ per Winter Period provided that FEVI shall not exceed a curtailment volume related to IG deliveries of 100,000 GJ in aggregate over any Winter Period.

2.3.3 FEVI's Intra-Day Additional Right pursuant to section 4.1 of the PA shall continue to apply whether or not the Firm Capacity is being used to deliver gas to IG or to Woodfibre.

2.3.4 Section 4.1(4) of the PA is amended by deleting the phrase "*provided that BC Hydro shall use reasonable efforts to maintain a full inventory of distillate to the extent commercially reasonable*".

2.3.5 Section 5.1(2) of the PA is amended by deleting the clause in its entirety and replacing it with the following:

> *Distillate Carrying Charge – an amount equal to one-twelfth of the product obtained by multiplying the Distillate Index Price by the lesser of the Maximum Curtailment Volume and 100,000 GJs and further multiplying by 0.08.*

3. **GENERAL TERMS**

3.1. **Effective Date**: This Letter Agreement shall be effective from the date immediately following the date the conditions precedent in section 3.2 of this Letter Agreement are satisfied.

3.2 **Conditions Precedent**: This Letter Agreement is subject to BCUC's approval of Rate Schedule 50 as a rate for FEI, and such Rate Schedule 50 coming into effect.

3.3 **Authority**: Each Party represents that it has all requisite corporate and other authority to enter into, execute and be bound by the terms of this Letter Agreement.

3.4 **Confidentiality**: The Mutual Confidentiality and Non-Disclosure Agreement between BC Hydro and FEVI dated October 24, 2013 continues in full force and effect in accordance with its terms.

3.5 **Arbitration**: All disputes arising under or relating to this Letter Agreement, except only disputes in respect to which the BCUC has jurisdiction, which the BCUC is prepared to exercise, will, after the Parties have attempted for a period not exceeding 15 days in good faith to settle the dispute between themselves, be submitted to and finally settled by arbitration under the Commercial Arbitration Act. The arbitration will take place in Vancouver, British Columbia before a single arbitrator and will be administered by the British Columbia International Commercial Arbitration Centre ("BCICAC") in accordance with this "Procedures for Cases under the BCICAC Rules".

3.6 **Choice of Law**: This Letter Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and, subject to section 3.4 of this Letter Agreement, the Parties attorn to the jurisdiction of the courts of British Columbia.

3.7 **Enurement**: This Letter Agreement enures to the benefit of, and is binding upon, each of the Parties and their respective successors and permitted assigns. Without limiting the effect of the foregoing sentence:

(a) the Parties acknowledge that FEI and FEVI, on or about December 31, 2014, intend to amalgamate with each other pursuant to the provisions of the *Business Corporations Act* (British Columbia) under the name "FortisBC Energy Inc."; and

(b) the Parties agree that, upon and following any amalgamation of FEI and FEVI, the contractual rights of FEI and FEVI under each of the Applicable Agreements, and under this Letter Agreement, will continue to be the rights and interests of the entity that is formed by such amalgamation, and such amalgamated entity will continue to be liable for the obligations of FEI and FEVI under the Applicable Agreements and this Letter Agreement.

3.8 <u>Amendment</u>: This Letter Agreement may be amended only by an instrument in writing signed by the Parties.

3.9 <u>Entire Agreement</u>: This Letter Agreement, and the Applicable Agreements (as amended by this Letter Agreement), contains the whole agreement between the Parties in respect of the subject matter hereof, and there are no terms, conditions or collateral agreements express, implied or statutory other than as expressly set forth in the aforesaid agreements and the aforesaid agreements supersede all of the terms of any written or oral agreement or understanding between the Parties in respect of the subject matter hereof.

3.10 <u>Without Prejudice</u>: Except with respect to those matters that have been expressly agreed to by the Parties pursuant to this Letter Agreement and in the Applicable Agreements, nothing in this Letter Agreement, or in any of the Applicable Agreements, shall prejudice any positions that any of the Parties may take in the future on any and all matters brought before the BCUC in regard to FEI or FEVI's services, tolls and the GT&Cs (as defined in the IGTSA), whether those matters are initiated by BC Hydro, FEI, FEVI or any other person.

3.11 <u>Facsimile or Electronic Transmission</u>: This Letter Agreement may be executed by the Parties and transmitted by facsimile or electronic transmission and, if so executed and transmitted, this Letter Agreement will be for all purposes as effective as if the Parties had delivered an executed original agreement.

3.11 <u>Counterparts</u>: This Letter Agreement may be executed in counterparts with the same effect as if all Parties had signed the same document. All counterparts will be construed together and will constitute one and the same instrument.

If you are in agreement with the foregoing, please indicate this by signing the enclosed duplicate and returning it to us on or before 5:00 p.m. PST on November 21, 2014.

Yours truly,

FORTISBC ENERGY INC.

(Authorized Signature)
Print Name:
Michael Mulcahy

APPENDIX 4

FORTIS BC™

FORTISBC ENERGY INC.

RATE SCHEDULE 50
LARGE VOLUME INDUSTRIAL TRANSPORTATION

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1. Definitions

1.1 **Definitions**. Except where the context otherwise requires, the following terms when used in this Rate Schedule or in the Transportation Agreement shall have the following meanings:

(a) **Affiliate** – means, in relation to FortisBC Energy or the Shipper, any Person that, directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, that Party where "control" means, with respect to the relationship between two or more Persons, the possession, directly or indirectly or as trustee, personal representative or executor, of the power to direct or cause the direction of the affairs or management of a Person, including through the direct or indirect ownership of voting securities, as trustee, personal representative or executor, by statute, contract, credit arrangement or otherwise.

(b) **Authorized Quantity** – means the quantity of Gas for each Day approved by the Transporter for transportation service on the Transporter's pipeline system, based on the quantity requested and adjusted pursuant to Section 4 (Requested Quantity and Authorized Quantity).

(c) **BCUC** – means the British Columbia Utilities Commission continued pursuant to the *Utilities Commission Act, R.S.B.C. 1996 c.473*, or such successor or other entity as may be designated according to the laws of the Province of the British Columbia to carry out the functions of the BCUC in respect of the regulation of public utilities.

(d) **Business Day** – means any day, excluding Saturdays, Sundays and statutory holidays in British Columbia.

(e) **Carbon Tax** – means, in connection with any System Gas delivered by the Shipper to FortisBC Energy at the Receipt Point under this Rate Schedule and the Transportation Agreement, any amounts payable: (i) under the Carbon Tax Act (British Columbia) or any successor or replacement legislation; (ii) for any offsets, credits, allowances, rights to discharge greenhouse gases, renewable electricity certificates or other commodities which must be obtained and/or retired under applicable law to offset all or part of the greenhouse gas emissions or other environmental attributes of the System Gas; or (iii) to satisfy any payments required to be made under applicable law, of whatever kind, the value of which is determined in whole or in part by the greenhouse gas emissions or other environmental attributes of the System Gas.

(f) **Commencement Date** – means the date, on or after the Effective Date on which Firm Transportation Service commences, as set out in the Transportation Agreement provided that the Commencement Date shall not occur before the amalgamation of FortisBC Energy and FortisBC Energy (Vancouver Island) Inc. pursuant to the Business Corporations Act (British Columbia).

(g) **Commodity Toll** – means the commodity toll, expressed in dollars per gigajoule, charged under this Rate Schedule for costs incurred by FortisBC Energy, in respect of Firm Transportation Service and Interruptible Transportation Service, as allocated to the Shipper by FortisBC Energy, acting reasonably, which may include:

(i) any excise or other taxes payable by FortisBC Energy in respect of System Gas, including taxes payable under the *Motor Fuel Tax Act* (British Columbia) and any Carbon Tax payable by FortisBC Energy in respect of System Gas;

(ii) any excise or other taxes payable by FortisBC Energy in respect of Shipper's Gas transported and delivered through the System;

(iii) odorant costs incurred by FortisBC Energy in respect of Shipper's Gas transported and delivered through the System; and

(iv) any costs incurred by FortisBC Energy for electricity used for the compression of Gas in connection with the transportation and delivery of Shippers' Gas through the System.

(h) **Contract Demand** – means the quantity of Gas set out in a Transportation Agreement in respect of which FortisBC Energy is obligated to provide Firm Transportation Service, provided that if FortisBC Energy reasonably determines in respect of any Day or future period that the volume-weighted average heat content for all Gas received on the System during that Day or future period is or is reasonably likely to be less than 38 GJ / 10^3m^3, then FortisBC Energy may by written notice to the Shipper adjust the Contract Demand for that Day or future period to an amount measured in GJ that FortisBC Energy reasonably estimates at the time of such adjustment will allow FortisBC Energy to deliver to the Shipper the volumetric equivalent in 10^3m^3 per Day of the Contract Demand, as set out in the Transportation Agreement.

(l) **Creditworthy** – means, in respect of any Shipper, that:

(i) has been issued a credit rating by one or more of DBRS, Moody's or S&P on its senior unsecured long-term debt ("long-term debt rating") that is equivalent to or better than the minimum credit rating acceptable to FortisBC Energy as shown in Table 1 - Equivalent Credit Ratings for Long-Term Debt (which table may be amended by FortisBC Energy from time to time with approval of the BCUC);

(ii) meets the Minimum Tangible Net Worth requirements; and

(iii) its head office or its principal place of business is located in Canada or the United States or in a country that meets the Minimum Sovereign Risk Rating and such country is otherwise acceptable to FortisBC Energy.

If the Shipper has been issued a long-term debt rating by more than one of DBRS, Moody's or S&P that are not of the equivalent level, then:

1. if the lowest long-term debt rating issued to that Person is ranked no more than one level below the highest long-term debt rating issued to that Person as shown in Table 1 - Equivalent Credit Ratings for Long-Term Debt (as amended from time to time), then that Person's long-term debt rating will be deemed to be the highest of such long-term debt ratings issued to that Person; and

2. if the lowest long-term debt rating issued to that Person is ranked more than one level below the highest long-term debt rating issued to that Person as shown in Table 1 - Equivalent Credit Ratings for Long-Term Debt (as amended from time to time), then that Person's long-term debt rating will be deemed to be equivalent to the long-term debt rating shown in Table 1 - Equivalent Credit Ratings for Long-Term Debt (as amended from time to time) on the row immediately below the highest of such long-term debt ratings issued to that Person.

Table 1

Equivalent Ratings for Long-Term Debt

DBRS	Moody's	S&P
AAA	Aaa	AAA
AA (high)	Aa1	AA+
AA	Aa2	AA
AA (low)	Aa3	AA-
A (high)	A1	A+
A	A2	A
A (low)	A3	A-
BBB (high)	Baa1	BBB+
BBB*	Baa2*	BBB*
BBB (low)	Baa3	BBB-
BB (high)	Ba1	BB+
BB	Ba2	BB
BB (low)	Ba3	BB-

** Minimum credit rating acceptable to FortisBC Energy*

(j) **cubic metre or m^3** – means the volume of gas which occupies 1 cubic metre when such gas is at temperature of 15°C and at an absolute pressure of 101.325 kilopascals.

(k) **Curtailment Notice** – means a notice delivered by FortisBC Energy to the Shipper pursuant to Section 3.2 (Reduction in Contract Demand), Section 6.2 (Curtailment for Planned Maintenance), or Section 6.3 (Curtailment of Interruptible Transportation Service) advising the Shipper that FortisBC Energy intends to limit the quantities of Gas to be delivered to the Shipper at the Delivery Point on any Day by an amount set out in such notice or is deemed to be a Curtailment Notice pursuant to Section 6.5 (Curtailment for Force Majeure).

(l) **Day** – means, subject to Section 1.2 (Change in Definition of "Day"), any period of twenty-four consecutive hours beginning and ending at 0700 PST or DST, as the case may be.

(m) **Daily Imbalance** – means the difference between the Receipt Quantity (less the quantity of Gas delivered to the Receipt Point by the Shipper as System Gas or to correct inventory imbalances) and the Delivered Quantity as set out in a daily system operations report provided to the Shipper by FortisBC Energy pursuant to Section 8 (Daily Imbalances).

(n) **DST** – means Pacific Daylight Savings Time.

(o) **Delivered Quantity** – means, in respect of any Day, the total quantity of Gas delivered to the Shipper at the Delivery Point.

(p) **Delivery Point** – means one or more points where the System interconnects with the facilities of the Shipper, as set out in the Transportation Agreement, which for greater certainty shall be located immediately downstream of the outlet flange of FortisBC Energy's meter installed at each such point (or as otherwise stated in the Transportation Agreement).

(q) **Effective Date** – means the date the Transportation Agreement becomes effective as set out in Section 9.1 (Effective Date).

(r) **Expiry Date** – means the expiry date set out in the Transportation Agreement, which shall be no earlier than November 1st in the year that is 15 full years after the Commencement Date or such later date determined by the operation of Section 19.6 (Extension of Term).

(s) **Final Gas Balance** – has the meaning ascribed to it in Section 8.6 (Final Gas Balance).

(t) **Final Gas Balance Payment** – has the meaning ascribed to it in Section 8.6 (Final Gas Balance).

(u) **Firm Demand Toll** – means, in respect of Firm Transportation Service, the common demand toll, expressed in dollars per gigajoule, set out in the Table of Charges.

(v) **Firm Transportation Service** – means the obligation of FortisBC Energy pursuant to Section 5.1 (Firm Transportation Service) to transport and deliver Gas to the Delivery Point up to the Contract Demand on a take or pay basis.

(w) **Force Majeure** – means, any acts of God, strikes, lockouts, or other industrial disturbances, civil disturbances, riots, acts of the public enemy, wars, insurrections, any order, regulation or restriction imposed by any government, regulatory authority or court having jurisdiction, blackouts, serious epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, explosions, breakage or accident to machinery or lines of pipes, or freezing of wells or pipelines, or the failure of gas supply, temporary or otherwise, from a Supplier, and any other event or circumstance which is beyond the control of the Party, but specifically excluding:

  (i) an act of negligence or wilful misconduct by the Party claiming Force Majeure;

  (ii) any lack of money, credit, markets or economic hardship on the part of the Party claiming Force Majeure; and

(iii) any act or omission of any vendor, supplier, contractor or customer of the Party claiming Force Majeure, unless such acts or omissions would themselves be excused by reason of Force Majeure as defined in this Agreement.

(x) **Force Majeure Notice** – means a written notice delivered by one Party to the other in the event of Force Majeure in accordance with Section 19.2 (Force Majeure Notice).

(y) **FortisBC Energy** – means FortisBC Energy Inc.

(z) **Gas** – means natural gas (including odorant added by FortisBC Energy), which shall be measured in gigajoules or terajoules for purposes of this Rate Schedule.

(aa) **Gas Inspection Act** – means the *Electricity and Gas Inspection Act, R.S.C. 1985, c. E4* as amended, and includes the regulations enacted thereunder and in effect from time to time.

(bb) **gigajoule or GJ** – means 1,000,000,000 joules.

(cc) **Interruptible Demand** – means for any Day during the Service Period the amount by which the Delivered Quantity exceeds the Contract Demand and, if provided for in the Transportation Agreement, means for any Day during the Pre-Commissioning Period, the whole of the Delivered Quantity.

(dd) **Interruptible Demand Toll** – means, in respect of Interruptible Transportation Service, the common interruptible toll, expressed in dollars per gigajoule, set out in the Table of Charges.

(ee) **Interruptible Transportation Service** – means the obligation of FortisBC Energy pursuant to Section 5.2 (Interruptible Transportation Service) to transport and deliver Gas to the Delivery Point in any amount exceeding the Contract Demand.

(ff) **joule** – means the amount of work done when the point of application of a force of 1 Newton is displaced a distance of 1 meter in the direction of the force.

(gg) **Maintenance** – means any maintenance, repairs, improvements, expansion or other work performed on the System which FortisBC Energy anticipates will impair FortisBC Energy's ability to deliver Gas to the Delivery Point at the times, hourly rates, pressure and heat content and in the quantities contemplated in this Rate Schedule and/or a Transportation Agreement in respect of the Firm Transportation Service or Interruptible Transportation Service or both.

(hh) **Minimum Sovereign Risk Rating** – means the foreign currency credit rating for a country that is equivalent to or better than the minimum credit rating acceptable to FortisBC Energy as shown in Table 2- Equivalent Sovereign Ratings for Sovereign Risk. Where a country has two or more ratings that differ, if the lowest long-term debt rating issued to a country is ranked no more than one level below the highest long-term debt rating issued to that country as shown in Table 2 - Equivalent Sovereign Ratings for Sovereign Risk, then that country's long-term debt rating will be deemed to be the highest of such long-term debt ratings issued to that country. If the lowest long-term debt rating issued to that country is ranked more than one level below the highest long-term debt rating issued to that country as shown in Table 2, then that country's long-term debt rating will be deemed to be equivalent to the long-term debt rating shown in Table 2 - on the row immediately below the highest of such long-term debt ratings issued to that country.

Table 2

Equivalent Ratings for Sovereign Risk

DBRS	Moody's	S&P
AAA	Aaa	AAA
AA (high)	Aa1	AA+
AA*	Aa2*	AA*
AA (low)	Aa3	AA-
A (high)	A1	A+
A	A2	A
A (low)	A3	A-
BBB (high)	Baa1	BBB+
BBB	Baa2	BBB
BBB (low)	Baa3	BBB-
BB (high)	Ba1	BB+
BB	Ba2	BB
BB (low)	Ba3	BB-

** Minimum credit rating acceptable to FortisBC Energy*

(ii) **Minimum Tangible Net Worth** – means, in respect of any Shipper, that Shipper's Tangible Net Worth is equal to or greater than the greater of:

(i) 5 years of Firm Demand Tolls; and

(ii) the book value of the incremental System Upgrades constructed, acquired, contracted or secured by FortisBC Energy to serve the Shipper.

(jj) **Month** – means the period of time commencing at 0700 PST or DST, as the case may be, on the first Day of any calendar month and ending at 0700 PST or DST, as the case may be, on the first Day of the next succeeding calendar month.

(kk) **Net Present Value** – means in respect of any future payment or revenue stream, the net present value of such payment or revenue stream calculated using a discount rate equal to FortisBC Energy's weighted average cost of capital rate calculated on an after-tax basis. The weighted average cost of capital shall be, determined with reference to (i) FortisBC Energy's actual weighted average cost of debt and (ii) the BCUC-approved return on equity and capital structure, all being determined as at the time the calculation is made.

(ll) **petajoule or PJ** – means 1,000,000,000,000,000 joules.

(mm) **PST** – means Pacific Standard Time.

(nn) **Party or Parties** – means, with respect to a Transportation Agreement, FortisBC Energy and/or the Shipper.

(oo) **Person** – includes an individual, a partnership, a body corporate, a joint venture, a trust, an unincorporated syndicate, association, organization, a government, any governmental agency, or other entity.

(pp) **Pre-Commissioning Period** – means the period, if any, as set out in the Transportation Agreement during which FortisBC Energy agrees to provide Interruptible Transportation Service only to the Shipper, solely for the purpose of commissioning the facility to which Gas is to be transported and delivered by FortisBC Energy.

(qq) **Prime Rate** – means the rate of interest per annum posted by the main Vancouver branch of FortisBC Energy's primary bank from time to time as a reference rate of interest for the determination of interest rates that it charges to its most creditworthy customers for Canadian dollar loans made by it in Canada.

(rr) **Rate Schedule 50 or this Rate Schedule** – means this Rate Schedule, including all rates, terms and conditions, and the Table of Charges.

(ss) **Receipt Point** – means one or more points where the System interconnects with the facilities of one of the Transporters, as set out in the Transportation Agreement.

(tt) **Receipt Quantity** – means, in respect of any Day, the total quantity of Gas delivered by the Shipper to FortisBC Energy at the Receipt Point.

(uu) **Requested Quantity** – means, in respect of any Day, the total quantity of Gas requested by the Shipper for Firm Transportation Service and Interruptible Transportation Service.

(vv) **Required Security Amount** – means, at any time, the amount of the required Security set out in the most recent notice delivered by FortisBC Energy to the Shipper in accordance with Section 13.1 (Determination of Creditworthy and Security).

(ww) **Security** – means the security provided by the Shipper in accordance with Section 13 (Security and Credit) to secure the prompt and orderly payment of the amounts to be paid by the Shipper to FortisBC Energy under this Rate Schedule and the Transportation Agreement, the nature, type and form of which shall be acceptable to FortisBC Energy, which may include:

(i) one or more letters of credit or other cash form of security in favour of FortisBC Energy, issued by a financial institution acceptable to FortisBC Energy, in an aggregate amount not less than the Required Security Amount;

(ii) a guarantee from a Person acceptable to FortisBC Energy guaranteeing payment of the Termination Payment and all other payment obligations of the Shipper under this Rate Schedule and the Transportation Agreement; or

(iii) any combination of one or more letters of credit or other cash security as set out in (i) together with one or more guarantees from a Person acceptable to FortisBC Energy as set out in (ii).

(xx) **Service Period** – means the period from 0700 PST or DST, as the case may be, on the Commencement Date until 0700 PST or DST, as the case may be, on the Expiry Date, or such other period as may be set out in the Transportation Agreement.

(yy) **Shipper** – means any Person who enters into a Transportation Agreement with FortisBC Energy.

(zz) **Shipper Planned Maintenance** – means any maintenance, repairs, improvements or other work performed at the facilities of the Shipper which the Shipper anticipates will impair the Shippers' ability to receive Gas at the Delivery Point.

(aaa) **Shipper Specific Charges** – means any Shipper specific charges as determined by FortisBC Energy under Section 6.3 of the Table of Charges.

(bbb) **System** – means the gas transmission and distribution pipeline system and related facilities owned or operated by FortisBC Energy, as such system is expanded, reduced or modified from time to time, extending from points of interconnection with the facilities of Transporters of FortisBC Energy to various delivery points in British Columbia, including those on the Sunshine Coast and Vancouver Island.

(ccc) **System Contribution** – means the amount per GJ that is embedded in the Firm Demand Toll and Interruptible Demand Toll for use of FortisBC Energy's existing System.

(ddd) **System Gas** – means that quantity of Gas which FortisBC Energy requires for fuel and other operating uses and for lost and unaccounted for Gas incurred in the operation and maintenance of the System, other than cost of Gas that is capitalized as part of the cost of a pipeline construction or repair project.

(eee) **System Upgrades** – means the classes of assets that FortisBC Energy constructs, acquires, contracts or secures to serve Shippers under this Rate Schedule. For greater certainty, the System Upgrades include all capital projects, upgrades, replacements, expansions, compression, pipeline looping or other modifications to any element of the System and more specifically including the EGP project to expand the transmission facilities of FortisBC Energy (Vancouver Island) Inc.:

(i) at and between the Eagle Mountain Compressor Station in Coquitlam and the Woodfibre LNG Export Facility; and

(ii) at the Port Mellon Compressor Station,

and the CTS expansion projects to expand transmission facilities:

(i) at and between the Cape Horn Valve Assembly and Coquitlam Gate Station;

(ii) at and between the Nichol Valve Assembly and Port Mann Crossover Station;

(iii) at and between the Nichol Valve Assembly and Roebuck Valve Assembly; and

(iv) at and between Tilbury Gate Station and Tilbury LNG Facility.

(fff) **Supplier** – means the Shipper, if the Shipper has access to its own supplies of Gas, or a Person who sells Gas to the Shipper or FortisBC Energy.

(ggg) **Table of Charges** – means the table of tolls, prices, fees and charges appended to this Rate Schedule.

(hhh) **Tangible Net Worth** – means, in respect of a Shipper, means a Shipper's total assets, excluding intangible assets (including goodwill, copyright, patents, trademarks, intellectual property and other intangible assets), minus total liabilities, as shown on the Shipper's most recent audited annual financial statements prepared in accordance with generally accepted accounting principles.

(iii) **terajoule or TJ** – means 1,000 gigajoules.

(jjj) **Termination Payment** – means the amount payable by the Shipper on termination of the Transportation Agreement by FortisBC Energy in accordance with Section 22.1 (Default) or Section 22.2 (Bankruptcy or Insolvency), calculated in accordance with Section 22.3 (Termination Payment).

(kkk) **Transportation Agreement** – means a transportation service agreement under which FortisBC Energy agrees to provide Firm Transportation Service and, if applicable, Interruptible Transportation Service, to the Shipper under this Rate Schedule in substantially the form appended hereto.

(lll) **Transporter** – means, in the case of the Columbia service area, TransCanada PipeLines Limited, B.C. System, and Nova Gas Transmission Ltd., and in the case of the Inland, Lower Mainland, and Vancouver Island service areas, Westcoast Energy Inc., FortisBC Huntingdon Inc., and any other gas pipeline transportation company connected to the facilities of FortisBC Energy from which FortisBC Energy receives gas for the purposes of gas transportation or resale.

(mmm) **Unauthorized Overrun Gas** – means any Gas taken on any Day in excess of the curtailed quantity set out in any Curtailment Notice, and for greater certainty Unauthorized Overrun Gas includes all Gas taken by the Shipper to the extent that the obligation of FortisBC Energy to deliver such Gas is suspended by reason of Force Majeure.

(nnn) **10^3m^3** – means 1,000 cubic metres of gas.

1.2 **Change in Definition of "Day".** FortisBC Energy may amend the definition of "Day" from time to time to suitably align its operations with those of its Transporters. If FortisBC Energy amends the definition of "Day", a pro-rata adjustment of quantities of Gas and charges to account for any Day of more or less than 24 hours will be made and the term of the Transportation Agreement will be similarly adjusted.

2. Applicability

2.1 **Description of Applicability.** This Rate Schedule applies to the provision of Firm Transportation Service and Interruptible Transportation Service through the System and through one meter station to one Shipper, except as previously agreed upon by Shipper and FortisBC Energy.

2.2 **Status of FortisBC Energy.** FortisBC Energy does not provide transportation service as a common carrier. FortisBC Energy will only transport Gas under this Rate Schedule to the Shipper in the territory served by FortisBC Energy under this Rate Schedule if the Shipper has entered into a Transportation Agreement for a minimum Service Period of 15 years (or such longer minimum Service Period required by FortisBC Energy as a condition of service), and for a minimum of 45 terajoules per Day of Firm Transportation Service.

3. Contract Demand

3.1 **Contract Demand.** For each Day during the Service Period, the quantity of Gas which FortisBC Energy is obligated to transport and deliver in respect of Firm Transportation Service will be the Contract Demand, as set out in the Transportation Agreement.

3.2 **Reduction in Contract Demand.** FortisBC Energy may set out conditions in the Transportation Agreement that allow FortisBC Energy to curtail the Shipper until the System Upgrades required to provide the Shipper with Firm Transportation Service are completed.

4. Requested Quantity and Authorized Quantity

4.1 **Requested Quantity.** The Shipper shall, on each Day prior to 0730 PST or DST, as the case may be, or prior to such other time as may be agreed to in writing by the Shipper and FortisBC Energy, provide FortisBC Energy by fax or other method approved by FortisBC Energy with an accurate and complete nomination schedule, in a form acceptable to FortisBC Energy, setting out for the next succeeding Day:

(a) the quantities of Gas that the Shipper desires to take at each Delivery Point;

(b) the allowance for System Gas;

(c) the quantity of Gas required to correct any imbalance between the Receipt Quantity and the Delivered Quantity for any preceding Day or Days; and

(d) such additional information as may be reasonably requested by FortisBC Energy.

If, in respect of any Day, the Shipper fails to provide FortisBC Energy with a nomination schedule in accordance with this Section 4.1 (Requested Quantity), the nomination shall be considered zero for that Day.

4.2 **Adjustment to Requested Quantity.** In the course of any Day, in respect of that Day or for the next succeeding Day, and at such times permitted by FortisBC Energy in accordance with FortisBC Energy's nomination schedule, if the Shipper wishes to change the Requested Quantity at a Delivery Point provided under Section 4.1 (Requested Quantity), then the Shipper shall provide FortisBC Energy by fax or other method approved by FortisBC Energy with a revised nomination schedule, in a form acceptable to FortisBC Energy, setting out:

(a) the revised quantities of Gas that the Shipper desires to take at each Delivery Point;

(b) the allowance for System Gas;

(c) the revised quantity of Gas required to correct any imbalance between the Receipt Quantity and the Delivered Quantity for the current Day or any preceding Day or Days (as applicable); and

(d) such additional information as may be reasonably requested by FortisBC Energy.

4.3 **Adjustment by FortisBC Energy.** If at any time FortisBC Energy, acting reasonably, determines that the capacity on the System is not sufficient to accommodate any portion of the Requested Quantity that is in excess of the Contract Demand, either as initially nominated pursuant to Section 4.1 (Requested Quantity) or as adjusted by the Shipper in accordance with Section 4.2 (Adjustment to Requested Quantity), then FortisBC Energy may by notice to the Shipper reduce the Requested Quantity to an amount not less than the Contract Demand which, FortisBC Energy determines, acting reasonably, may be accommodated by the capacity on the System at that time.

4.4 **Authorized Quantity.** If FortisBC Energy expects to have sufficient capacity available on the System to accommodate the Requested Quantity as adjusted by the Shipper pursuant to Section 4.2 (Adjustment to Requested Quantity), then FortisBC Energy will notify the Transporter of the Requested Quantity nominated by the Shipper pursuant to Section 4.1 (Requested Quantity), as adjusted. If FortisBC Energy has adjusted the Requested Quantity pursuant to Section 4.3 (Adjustment by FortisBC Energy) then FortisBC Energy will notify the Transporter of the Requested Quantity, as adjusted. In either case FortisBC Energy will request that the Transporter provide to FortisBC Energy the Authorized Quantity for the next succeeding Day or the current Day, as applicable.

4.5 **Notice of Authorized Quantity.** FortisBC Energy shall, as soon as reasonably practicable after receiving confirmation from the Transporter as to the Authorized Quantity for the current or succeeding Day (or, if an adjustment has been requested by the Shipper pursuant to Section 4.2 (Adjustment to Requested Quantity) as soon as reasonably practicable), FortisBC Energy will provide the Shipper by fax or other method approved by FortisBC Energy with a schedule setting out the following (as applicable):

(a) the total quantity of Gas authorized by the Transporter to be delivered to FortisBC Energy at the Receipt Point on behalf of the Shipper;

(b) as applicable, an indication that the Authorized Quantity is less than the Requested Quantity; and

(c) as applicable, the quantity of Gas required to correct any imbalance between the Receipt Quantity and the Delivered Quantity for the current Day or any preceding Day or Days.

4.6 **Delivery to Receipt Point.** The Shipper will cause to be delivered to the Receipt Point on each Day a quantity of Gas at least equal to the Authorized Quantity.

4.7 **Failure to Deliver to Receipt Point.** If on any Day the Receipt Quantity is less than the Authorized Quantity, or if any portion of the gas delivered by the Shipper to FortisBC Energy at the Receipt Point does not meet the quality standards set out in Section 14.1 (Quality at Receipt Point), then FortisBC Energy may interrupt or curtail the Interruptible Transportation Service first by the amount of the shortfall or by the amount of the gas failing to conform with the quality specifications set out in Section 14.1 (Quality at Receipt Point), and then Firm Transportation Service to the extent of any remaining shortfall or amount of the gas failing to conform with the quality specifications set out in Section 14.1 (Quality at the Receipt Point).

5. Delivery of Gas

5.1 **Firm Transportation Service.** Subject to the other provisions of this Rate Schedule and the provisions of the Transportation Agreement, FortisBC Energy shall, on each Day in the Service Period, transport and deliver to the Shipper at the Delivery Point that quantity of Gas equal to the lesser of:

(a) the Contract Demand; or

(b) the Authorized Quantity,

provided that the Shipper delivers such quantity of Gas to FortisBC Energy at the Receipt Point in conformity with the quality specifications set out in Section 14.1 (Quality at Receipt Point) on each such Day.

5.2 **Interruptible Transportation Service.** Subject to the other provisions of this Rate Schedule and the provisions of the Transportation Agreement, FortisBC Energy shall, on each Day in the Service Period and, if provided for in the Transportation Agreement, during the Pre-Commissioning Period, transport and deliver to the Shipper at the Delivery Point a quantity of Gas equal to the Interruptible Demand, provided that the Shipper delivers such Gas to FortisBC Energy at the Receipt Point in conformity with the quality specifications set out in Section 14.1 (Quality at Receipt Point) on each such Day.

5.3 **Adjustment to Rate of Delivery.** The Shipper shall take delivery of Gas at the Delivery Point as nearly as practicable at a uniform hourly rate of flow. If the Shipper anticipates that the hourly delivery rate on any Day to the Delivery Point will be greater or less than 1/24 of the Authorized Quantity (less the quantity of Gas delivered by the Shipper to the Receipt Point as System Gas or for inventory imbalances) for such Day, then the Shipper will notify FortisBC Energy of the anticipated hourly deliveries. FortisBC Energy may authorize such deliveries provided that such rates of delivery may not:

(a) adversely impact the operating stability, security and safety of the System; or

(b) result in a breach of any regulatory rules or contractual obligations applicable to FortisBC Energy, including in respect of Transporter's balancing rules.

If FortisBC Energy does not authorize the delivery rates requested by the Shipper, then the Shipper shall adjust the hourly rate of flow at which it takes delivery of Gas at the Delivery Point to an amount equal to 1/24 of the Authorized Quantity (less the quantity of Gas delivered by the Shipper to the Receipt Point as System Gas or for inventory imbalances) for such Day for the Delivery Point or shall adjust the Authorized Quantity for such Day in accordance with this Section 5.3 (Adjustment to Rate of Delivery) to match the hourly delivery rate at the Delivery Point. Notwithstanding any prior delivery authorizations made by FortisBC Energy, FortisBC Energy will not be required to deliver Gas at the Delivery Point in any hour of a Day in an amount greater or less than 1/24 of the Authorized Quantity (less the quantity of Gas delivered by the Shipper to the Receipt Point as System Gas or for inventory imbalances) if FortisBC Energy considers that the rate of delivery should be limited to:

(a) maintain the operating stability, security and safety of the System; or

(b) comply with any regulatory rules or contractual obligations applicable to FortisBC Energy, including in respect of Transporter's balancing rules.

6. Adjustments and Curtailment

6.1 Planned Maintenance:

(a) On or before November 1 of each year during the Service Period, FortisBC Energy shall provide Shipper written notice specifying the anticipated dates of planned Maintenance, together with a summary of such planned Maintenance, to occur during the following year. FortisBC Energy shall, provide the Shipper with periodic updates to the schedule of planned Maintenance.

(b) FortisBC Energy shall provide the Shipper with a minimum 3 Days prior notice of any planned Maintenance, which notice shall specify the duration and timing of any anticipated reduction in FortisBC Energy's ability to deliver Gas to the Delivery Point at the times, hourly rates, pressure and heat content and in the quantities contemplated under the Transportation Agreement.

6.2 **Curtailment for Maintenance.** During any Maintenance, if FortisBC Energy determines, acting reasonably, that the capacity available on the System during a Day is not sufficient to permit FortisBC Energy to fulfill the Firm Transportation Service as contemplated under the Transportation Agreement, FortisBC Energy may curtail its deliveries of Gas at the Delivery Point to an amount that is less than the lesser of Contract Demand and the Authorized Quantity by providing the Shipper with a Curtailment Notice specifying the quantity of Gas to which the Shipper is curtailed and the time at which such curtailment is to be made. FortisBC Energy shall provide the Curtailment Notice to the Shipper by telephone and/or fax and use its reasonable efforts to provide the Curtailment Notice as soon as possible, but in any event not less than 2 hours prior to such curtailment, unless prevented or delayed by Force Majeure. FortisBC Energy shall, to the extent reasonably practicable, seek to reduce, to the extent feasible, any curtailment of Firm Transportation Service as a result of the Maintenance.

6.3 **Curtailment of Interruptible Transportation Service.** If at any time FortisBC Energy, determines that it does not have capacity on the System to accommodate a Requested Quantity in respect of Interruptible Transportation Service, FortisBC Energy may, for any length of time, interrupt or curtail transportation service under this Rate Schedule to an amount that is not less than the lesser of Contract Demand and Authorized Quantity by providing the Shipper with a Curtailment Notice specifying the quantity of Gas to which the Shipper is curtailed and the time at which such curtailment is to be made. FortisBC Energy shall provide the Curtailment Notice to the Shipper by telephone and/or fax and use its reasonable efforts to provide the Curtailment Notice as soon as possible, unless prevented or delayed by Force Majeure.

6.4 **Default Regarding Curtailment.** The Shipper will comply with a Curtailment Notice to interrupt or curtail the Shipper's take. If the Shipper at any time fails or neglects to comply with a Curtailment Notice, then FortisBC Energy may, in addition to any other remedy that it may then or thereafter have, at its option, without liability therefor and without any prior notice to the Shipper:

(a) restrict the flow of Gas or turn off the valve at the applicable Delivery Point, or

(b) deliver such Gas and charge the Shipper the unauthorized overrun charges set out in the Table of Charges for any Unauthorized Overrun Gas.

6.5 **Curtailment for Force Majeure.** If a condition of Force Majeure has occurred and is continuing in respect of which FortisBC Energy has delivered a Force Majeure Notice, FortisBC Energy may elect to suspend the performance of Firm Transportation Service and Interruptible Transportation Service or to continue to perform such Gas transportation services but curtail its deliveries of Gas at the Delivery Point by any amount, including to an amount below Contract Demand or the Authorized Quantity. Any Force Majeure Notice delivered pursuant to Section 19.2 (Force Majeure Notice) which includes information in respect of a curtailment required by a Force Majeure event will be deemed to be a Curtailment Notice and the Shipper shall comply with such Curtailment Notice in accordance with Section 6.4 (Default Regarding Curtailment).

7. Receipt and Delivery Temperature and Pressure

7.1 **Temperature and Pressure at Receipt Point.** The Shipper shall deliver Gas to FortisBC Energy at the Receipt Point that meets or exceeds the minimum, and shall not exceed the maximum, delivery pressure and temperature standards set out in the applicable Transporter's general terms and conditions.

7.2 **Pressure at Delivery Point.** FortisBC Energy shall deliver Gas to the Shipper at the Delivery Point that meets the delivery pressure set out in the Transportation Agreement.

8. Daily Imbalances

8.1 **Daily Operations Report.** FortisBC Energy shall provide the Shipper by fax or other method approved by FortisBC Energy with a daily service operations report for the previous Day, which report shall set out:

(a) the Receipt Quantity;

(b) the Delivered Quantity for each Delivery Point;

(c) the required allowance for System Gas as determined in accordance with Section 10.2 (System Gas);

(d) the resulting Daily Imbalance; and

(e) the balance maintained in the Shipper's inventory account (if any).

8.2 **Daily Imbalance.** The Shipper shall use best efforts to avoid and limit imbalances at all times, including hourly imbalances. The Shipper shall correct the Daily Imbalance set out in the daily service operations report provided to Shipper in accordance with Section 8.1 (Daily Operations Report) in a manner acceptable to FortisBC Energy as soon as reasonably practicable.

8.3 **Inventory Account.** FortisBC Energy will maintain an inventory account for the Shipper. The balance in the inventory account will be deemed to be zero as of the Commencement Date or, if a Pre-Commissioning Period is provided for in the Transportation Agreement, as of the commencement date of the Pre-Commissioning Period. For each Day during the Service Period and the Pre-Commissioning Period, if any, FortisBC Energy will adjust the balance in the inventory account as follows:

(a) if the Receipt Quantity (less the quantity of Gas delivered to the Receipt Point by the Shipper as System Gas or for inventory imbalances) is greater than the Delivered Quantity, then FortisBC Energy will increase the inventory account by the amount of the Daily Imbalance; and

(b) if the Receipt Quantity (less the quantity of Gas delivered to the Receipt Point by the Shipper as System Gas or for inventory imbalances) is less than the Delivered Quantity, then FortisBC Energy will decrease the balance in the inventory account by the amount of the Daily Imbalance.

8.4 **No Relief.** Nothing in this Section 8 shall relieve the Shipper from its obligation to provide accurate nominations pursuant to Section 4.1 (Requested Quantity).

8.5 **FortisBC Energy May Correct Imbalances.** If the Shipper fails to correct a shortfall in the Daily Imbalance as required pursuant to Section 8.2 (Daily Imbalance), or fails to maintain an appropriate balance in the Shipper's inventory account in accordance with Section 8.3 (Inventory Account), then FortisBC Energy may correct that Daily Imbalance or take such actions as may be needed to restore the balance in the Shipper's inventory account balance to an appropriate amount. In addition, at any time, FortisBC Energy may charge the Shipper for any negative shortfalls in the Shipper's inventory account at the rates set out in the Table of Charges for Unauthorized Overrun Gas.

8.6 **Final Gas Balance.** As soon as reasonably practicable after the expiration or termination of the Transportation Agreement, FortisBC Energy will determine, acting reasonably, the sum of any positive or negative balance maintained in the Shipper's inventory account as of the Expiry Date or date of termination (the "Final Gas Balance"). If the Final Gas Balance is positive, FortisBC Energy may at its option, either return an amount of Gas equal to the Final Gas Balance to the Shipper at the Receipt Point or may purchase such Gas from the Shipper at an amount determined by FortisBC Energy, acting reasonably, to be reflective of current market conditions, as of the Expiry Date or the date of termination (the "Final Gas Balance Payment") and FortisBC Energy will set-off the amount of the Final Gas Balance Payment against the aggregate amounts payable by the Shipper to FortisBC Energy on the Expiry Date or date of termination of the Transportation Agreement. If the Final Gas Balance is negative then the Shipper will pay an amount equal to the Final Gas Balance Payment to FortisBC Energy as soon as reasonably practicable after the Expiry Date or date of termination.

9. Effective Date and Term of Transportation Agreement

9.1 **Effective Date.** The Transportation Agreement shall become effective upon the date ("Effective Date") that:

(a) FortisBC Energy obtains all certificates, licenses, permits and authorizations necessary for the receipt, transportation and delivery of Gas pursuant to this Rate Schedule and the Transportation Agreement; and

(b) the Shipper obtains all necessary authorizations, permits, licenses, certificates and agreements required by it to obtain and deliver Gas to FortisBC Energy at the Receipt Point and to take delivery of Gas at the Delivery Point in accordance with this Rate Schedule and the Transportation Agreement.

9.2 **Term.** The initial term of the Transportation Agreement will begin at 0700 PST or DST, as the case may be, on the Effective Date and will expire on the Expiry Date.

9.3 **Early Termination.** The Transportation Agreement is subject to early termination by FortisBC Energy in accordance with Section 22 (Default or Bankruptcy).

10. Charges

10.1 **Charges.** In respect of all Gas transportation services provided by FortisBC Energy pursuant to this Rate Schedule and the Transportation Agreement in each Month of the Service Period, and in respect of Interruptible Transportation Service, during the Pre-Commissioning Period (if any), the Shipper will pay to FortisBC Energy all of the charges set out in the Table of Charges, including:

(a) in respect of the Firm Transportation Service, an amount equal to the Firm Demand Toll multiplied by the Contract Demand multiplied by the number of Days in that Month, irrespective of the actual amount of Gas delivered by FortisBC Energy to the Delivery Point in aggregate, or on any given Day, during that Month;

(b) in respect of the Interruptible Transportation Service, an amount equal to the Interruptible Demand Toll multiplied by the sum of amounts by which the quantity of Gas delivered by FortisBC Energy to the Delivery Point exceeded the Contract Demand on each Day during the Month that Interruptible Transportation Service was provided;

(c) any Unauthorized Overrun Charges payable pursuant to Section 8.5 (FortisBC Energy May Correct Imbalances); and

(d) if applicable, Shipper Specific Charges.

10.2 **System Gas.** In addition to the charges payable pursuant to Section 10.1 (Charges), the Shipper shall in respect of each Day deliver to FortisBC Energy at the Receipt Point an allowance for System Gas equal to that quantity of Gas, which is the sum of:

(a) the allocated quantity of System Gas, other than fuel for line heaters at meter stations, required to transport and deliver to the Delivery Point the Receipt Quantity of Gas (less the quantity of Gas delivered to the Receipt Point by the Shipper as System Gas or for inventory imbalances), which allocation will be determined by FortisBC Energy acting reasonably; plus

(b) if applicable, the quantity of Gas incurred in the operation of line heaters at the meter stations at the Delivery Point where Gas is delivered to the Shipper in accordance with the Transportation Agreement.

10.3 **Other Charges.** In addition to the charges payable pursuant to Section 10.1 (Charges), the Shipper is responsible for Commodity Tolls.

11. Demand Toll Credits

11.1 **Demand Toll Credits.** Subject to Section 11.3 (Limitations on Demand Toll Credits), if on any Day the Delivered Quantity is less than the lesser of the Contract Demand and the Authorized Quantity and the shortfall results from:

(a) any Maintenance on the System that is undertaken by FortisBC Energy on less than 3 Days' notice to the Shipper; or

(b) an event of Force Majeure which prevents FortisBC Energy from delivering to the Shipper at the Delivery Point all or any portion of the gas delivered by the Shipper to the Receipt Point on that Day,

then the Shipper will be entitled to a Demand Toll Credit for that Day which FortisBC Energy will apply to a following monthly bill rendered pursuant to Section 12 (Statements and Payments).

11.2 **Amount of Demand Toll Credit.** The Demand Toll Credit applied by FortisBC Energy in respect of any Day pursuant to Section 11.1 (Demand Toll Credits) will be in an amount equal to the product of the Firm Demand Toll multiplied by the difference between the Delivered Quantity and the lesser of the Contract Demand, an average of the Authorized Quantity for the three Days immediately preceding any Day for which FortisBC Energy issues Demand Toll Credits, and the Authorized Quantity.

11.3 **Limitations on Demand Toll Credits.** For greater certainty, the Shipper will not be entitled to a Demand Toll Credit if the shortfall in the Delivered Quantity results directly or indirectly from:

(a) any act or omission of the Shipper; or

(b) the occurrence of one or more of the following, for any reason, including Force Majeure:

(i) the Shipper fails to deliver any portion of the Receipt Quantity to FortisBC Energy at the Receipt Point;

(ii) all or any portion of the gas delivered by the Shipper to FortisBC Energy at the Receipt Point fails to conform to the quality specifications set out in Section 14.1 (Quality at the Receipt Point); or

(iii) the Shipper fails to take delivery of Gas at any Delivery Point.

12. Statements and Payments

12.1 **Statements to be Provided.** FortisBC Energy shall, within 15 Days following the end of each Month, deliver to Shipper a statement setting out the quantities of Gas delivered to the Shipper at the Delivery Point during such Month and the amount payable by the Shipper for all services provided by FortisBC Energy to the Shipper during the Month. Where actual quantities of Gas are not available, FortisBC Energy may base the statement on a reasonable estimate of the amount of Gas, to be adjusted in a subsequent Month when actual quantities become available. Any statement delivered pursuant to this Section 12.1 (Statements to be Provided) shall be deemed to have been delivered on the Day on which it is received by the Shipper.

12.2 **Payment and Interest.** The Shipper shall, within 10 Days of the receipt of the statement for any Month pursuant to Section 12.1 (Statements to be Provided) or within 25 Days following the end of such Month, whichever is the later, pay the full amount of the statement, including federal, provincial and municipal taxes or fees applicable, in Canadian funds to FortisBC Energy at its Vancouver, British Columbia head office, or such other place in Canada as it may designate by written notice to the Shipper. If the Shipper fails or neglects to make any payment required under this Rate Schedule, or any portion thereof, to FortisBC Energy when due, interest on the outstanding amount will accrue, at the Prime Rate plus:

(a) 2% from the date when such payment was due for the first 30 Days that such payment remains unpaid, and 5% thereafter until the same is paid where the Shipper has not, during the immediately preceding six Month period, failed to make any payment when due hereunder; or

(b) 5% from the date when such payment was due until the same is paid where the Shipper has, during the immediately preceding six Month period, failed to make any payment when due hereunder.

13. Security and Credit

13.1 **Determination of Creditworthy and Security.** At least 30 Business Days prior to the Commencement Date and from time to time thereafter FortisBC Energy will deliver a written notice to the Shipper advising the Shipper whether or not FortisBC Energy has determined the Shipper to be Creditworthy, the nature, type and form of the Security required by FortisBC and the Required Security Amount FortisBC has determined is required in accordance with Section 13.2 (Required Security Amount).

13.2 **Required Security Amount.** FortisBC Energy shall determine, and from time to time may adjust, the Required Security Amount, as follows:

(a) If the Shipper is Creditworthy, then the Required Security Amount shall be:

(i) an amount equal to the product of Contract Demand x Firm Demand Toll x 90 Days; or

(ii) if FortisBC Energy applies to the BCUC for approval of an amount other than that specified in (i), the amount set by the BCUC.

(b) If the Shipper is not Creditworthy but has provided Security by way of a guarantee acceptable to FortisBC Energy guaranteeing payment of the Termination Payment and all other payment obligations of the Shipper under this Rate Schedule and the Transportation Agreement, then the Required Security Amount shall be the amount specified in Section 13.2(a) above.

(c) If the Shipper is not Creditworthy and has not provided the guarantee referred to in Section 13.2(b) above, then the Required Security Amount shall be set by the BCUC.

13.3 **Obligation to Deliver Security.** No less than one Business Day before the Commencement Date, the Shipper will deliver the Security to FortisBC Energy in an amount not less than the Required Security Amount.

13.4 **Obligation to Deliver Supplemental Security.** Shipper will maintain, amend or supplement the Security as required from time to time to ensure that the aggregate amount of the Security is not less than the Required Security Amount. If for any reason the Security, if by way of a guarantee, is no longer acceptable to FortisBC Energy, or if the aggregate amount of the Security falls below the Required Security Amount, including as a result of:

(a) a draw-down on the Security in accordance with Section 13.5 (Enforcing the Security);

(b) a change in the creditworthiness of the Shipper, such that the Shipper is no longer Creditworthy;

(c) a change in long-term debt rating or other change in the creditworthiness of a Person providing a guarantee in accordance with Section 13.3 (Obligation to Deliver Security) such that the Person providing a guarantee is no longer acceptable to FortisBC Energy;

(d) a financial institution which issued or confirmed one or more letters of credit comprising all or part of the Security:

  (i) has disclaimed, disaffirmed, repudiated, terminated, rejected, has challenged the validity of, or otherwise invalidated, in whole or in part, such letters of credit; or

  (ii) is no longer acceptable to FortisBC Energy; or

(e) FortisBC Energy has adjusted the Required Security Amount in accordance with Section 13.2 (Required Security Amount) and delivered a notice in writing to the Shipper specifying the adjusted amount,

then the Shipper will, within 15 Business Days of the requirement to do so arising under this Section 13.4 (Obligation to Deliver Supplemental Security), provide additional Security sufficient to supplement, replenish or replace the existing Security such that the aggregate amount of the Security is not less than the Required Security Amount.

13.5 **Enforcing the Security.** Without limiting any other remedy available to it under this Rate Schedule or the Transportation Agreement, at law or in equity, FortisBC Energy may enforce and immediately draw down or realize upon the Security as follows:

(a) all or any portion of the Security, if and to the extent of any amount that is owed by the Shipper to FortisBC Energy under this Rate Schedule or the Transportation Agreement remains unpaid for a period of 5 Days following the date that such amounts are due and apply the proceeds of the Security to such unpaid amounts; or

(b) all or any portion of the Security, immediately upon FortisBC Energy terminating the Transportation Agreement in accordance with Section 22.1 (Default) or Section 22.2 (Bankruptcy or Insolvency), and apply the proceeds of the Security as partial payment of the Termination Payment.

13.6 **Non-Interference.** The Shipper agrees that if FortisBC Energy elects to draw down or realize upon the Security, the Shipper will not pursue any legal, commercial or other steps, including by way of an injunction or otherwise, to prevent FortisBC Energy from drawing down or realizing upon the Security. Any and all disputes as to whether FortisBC Energy is entitled to draw down or realize upon the Security will be resolved pursuant to Section 20 (Arbitration) after FortisBC Energy has drawn down or realized upon the Security and applied the proceeds in accordance with Section 13.5 (Enforcing the Security).

13.7 **Return of Security.** If at any time the actual amount of the letters of credit or other cash security delivered by the Shipper exceeds the Required Security Amount, then FortisBC Energy will return and release to the Shipper the excess amount of such letters of credit or other cash security. Following the Expiry Date, FortisBC Energy will return and release to the Shipper the remaining Security to the Shipper within 30 days of the date upon which all amounts owing to FortisBC Energy under this Rate Schedule and the Transportation Agreement have been paid and settled by the Shipper.

14. Gas Quality

14.1 **Quality at Receipt Point.** The gas delivered by the Shipper to FortisBC Energy at the Receipt Point shall meet or exceed the minimum, and not exceed the maximum quality specifications specified by the applicable Transporter. Whenever the gas offered for delivery to FortisBC Energy at the Receipt Point fails to conform with the quality specifications set out in the applicable Transporter's general terms and conditions, FortisBC Energy may, without prejudice to any other rights it may have, refuse to take delivery of such gas in which case:

(a) FortisBC Energy shall give notice of such refusal to the Shipper setting forth the reasons therefor; and

(b) FortisBC Energy shall, as soon as practicable, accept deliveries of gas at the Receipt Point after the failure to conform has been remedied and the Shipper has given FortisBC Energy notice thereof.

14.2 **Quality at Delivery Point.** Gas delivered by FortisBC Energy to the Shipper at the Delivery Point shall conform to the quality standards specified by the applicable Transporter. Whenever the Gas delivered by FortisBC Energy to the Shipper at the Delivery Point fails to conform with any of the specifications referred to in this Section 14.2 (Quality at Delivery Point), the Shipper may, without prejudice to any other rights it may have, refuse to take delivery of such Gas, in which case:

(a) The Shipper shall give notice of such refusal to FortisBC Energy setting forth the reasons therefor; and

(b) The Shipper shall, as soon as practicable, accept deliveries of Gas at the Delivery Point after the failure to conform has been remedied and FortisBC Energy has given the Shipper notice thereof.

15. Measurement

15.1 **Volume.** The unit of volume of Gas for all purposes hereunder shall be one cubic metre at an absolute pressure of 101.325 kilopascals and at a temperature of 15 degrees centigrade.

15.2 **Measurement at the Delivery Point.** The following provisions shall apply to the measurement of all Gas delivered by FortisBC Energy to the Shipper at the Delivery Point.

(a) the volume of Gas delivered by FortisBC Energy to the Shipper at the Delivery Point shall be measured and computed on a daily basis by FortisBC Energy in accordance with the requirements established under the *Gas Inspection Act* with respect to orifice, positive displacement, turbine rotary and ultrasonic meters;

(b) corrections shall be made on each Day of the Service Period for the deviation from Boyle's Law at the pressure and temperature at which the Gas is metered. To determine the factors for such corrections, a quantitative analysis of the Gas will be made by FortisBC Energy at reasonable intervals and such factors will be obtained from data contained in the American Gas Association Manual for Determination of Supercompressibility Factors for Natural Gas – Par Research Project NX19 of December 1962, as published by the American Gas Association and the American Gas Association Report No. 8, or any subsequent revisions thereto acceptable to both the Shipper and FortisBC Energy or directed for use pursuant to the *Gas Inspection Act*. If positive displacement or turbine meters are used, the supercompressibility factor shall be squared;

(c) the relative density of the Gas shall be determined by FortisBC Energy from time to time utilizing the method prescribed in the American Gas Association Publication 2529 and samples of Gas taken from points on the System where the sample or samples of Gas taken are representative of the Gas delivered through the System;

(d) the flowing temperature of Gas in the meters installed and operated by FortisBC Energy shall be determined by means of temperature devices installed and operated in accordance with the requirements established under the *Gas Inspection Act*; and

(e) the atmospheric pressure at the actual altitude of each of the Delivery Point shall be calculated in accordance with the requirements established under the *Gas Inspection Act*.

15.3 **Conversion of Units**. The volumes of Gas delivered by the Shipper to FortisBC Energy at the Receipt Point on each Day of the Service Period and the Pre-Commissioning Period (if any), and the volumes of Gas delivered by FortisBC Energy to the Shipper at the Delivery Point on each Day of the Service Period and the Pre-Commissioning Period (if any), shall be converted to energy units by multiplying the volume of Gas so delivered by the heat content of each cubic metre of Gas in accordance with then procedures established under the *Gas Inspection Act*. The heat content of the Gas delivered at the Delivery Point shall be measured by FortisBC Energy.

16. Measuring Equipment

16.1 **FortisBC Energy Measuring Equipment.** FortisBC Energy shall install, maintain and operate suitable metering and other equipment complying with the requirements established under the *Gas Inspection Act* and necessary to measure the volume, temperature and pressure of all Gas delivered at the Delivery Point, and shall calibrate and adjust such meters and other equipment and change the charts as required.

16.2 **Access to Measuring Equipment.** The Shipper shall have access to such meters and other equipment during reasonable hours, and shall be entitled to be present at the time of any installing, testing, cleaning, changing, repairing, inspecting, calibrating or adjusting done to or in connection with the meters and other measuring equipment installed and maintained by FortisBC Energy at the Delivery Point, and FortisBC Energy shall give the Shipper reasonable advance notice of such activities in order that the Shipper or its representatives can be present.

16.3 **Shipper-Installed Measuring Equipment.** The Shipper may install, maintain and operate at its own expense check measuring equipment at the Delivery Point, for the purpose of verifying the measurements obtained by FortisBC Energy from FortisBC Energy's meters and other measuring equipment.

16.4 **Verification of Measurements.** Each of the Shipper and FortisBC Energy shall conduct regular testing to verify the accuracy of its respective meters and other measuring equipment at the Delivery Point at least once every two Months or at such other intervals as may be agreed to by the Shipper and FortisBC Energy. At any time during the intervening period between regular testing, the Shipper and FortisBC Energy shall conduct exceptional testing to verify the accuracy of their respective meters and other measuring equipment at the Delivery Point if requested to do so by the other Party. If, upon undertaking exceptional testing for a requested verification, a meter or other measuring equipment is found to be registering correctly, subject to an inaccuracy not exceeding two percent, the cost of such exceptional testing shall be charged to and be borne by the Party requesting the verification, otherwise, the cost of all such requested verifications shall be borne by the Party whose meters and other measuring equipment at the Delivery Point is being tested. If, upon any test, a meter or other measuring equipment is found to be inaccurate by not more than two percent, previous readings of such equipment shall be considered correct in computing deliveries of Gas at the Delivery Point, but such equipment shall be adjusted at once to record accurately. If, upon any test, any meter or other measuring equipment is found to be inaccurate by more than two percent, then any previous readings of such equipment shall be corrected to zero error for any period which is known or can be agreed upon, but if the period is not known or cannot be agreed upon, such correction shall be for a period covering the last half of the time elapsed since the date of the previous test of that meter or measuring equipment.

16.5 **Procedures if Measuring Equipment Out of Service.** If for any period FortisBC Energy's meter or other measuring equipment is out of service or out of repair so that the quantity of Gas delivered cannot be correctly determined by the reading thereof, then FortisBC Energy, acting reasonably, shall estimate the quantity of Gas delivered during such period on the basis of the best available data, using the first of the following methods which is feasible:

(a) by using the registration of any check measuring equipment installed and operated by the Shipper, provided such equipment is registering accurately;

(b) by correcting the error if the percentage of error can be ascertained by calibration, test or mathematical calculations; or

(c) by estimating the quantities of Gas delivered to the Shipper utilizing deliveries during prior periods of similar conditions when the meter or other measuring equipment was registering accurately.

17. Possession and Control of Gas

17.1 **Possession and Control.** FortisBC Energy shall be deemed to be in possession and control of, and responsible for all Gas received by it at the Receipt Point until such Gas is delivered by it to the Shipper at the Delivery Point as if it were the owner thereof, and shall have the right at all times to commingle such Gas with other Gas in the System. Nothing in this Rate Schedule shall be interpreted as:

(a) effecting the transfer of any right, title or interest; or

(b) a contract of bailment between FortisBC Energy and the Shipper,

in respect of any Gas delivered by the Shipper to FortisBC Energy at the Receipt Point while such Gas is in FortisBC Energy's possession and control.

18. Representations and Acknowledgments

18.1 **Representations of FortisBC Energy.** FortisBC Energy represents and warrants to the Shipper that it has full right, power and authority to enter into a Transportation Agreement with the Shipper.

18.2 **Representations of Shipper.** The Shipper represents and warrants to FortisBC Energy that:

(a) it has full right, power and authority to enter into a Transportation Agreement with FortisBC Energy, and that all Gas delivered to FortisBC Energy thereunder at the Receipt Point shall be free from all liens and encumbrances of any nature;

(b) the Shipper is or will be the sole legal and beneficial owner and user of the facility to which Gas is to be delivered under this Rate Schedule and the Transportation Agreement or, with the knowledge and consent of FortisBC Energy, the Shipper has entered into a long-term agreement with a third party with respect to the sale of Gas from the Shipper to such third party in an amount not less than the Contract Demand for a period of not less than the Service Period (as outlined in the Transportation Agreement), and the Shipper will fully comply with all the terms and conditions of such agreement and not undertake any actions that could cause Shipper to breach, become in default of or terminate such agreement; and

(c) the Shipper acknowledges that, as between the Shipper and FortisBC Energy, the Shipper is solely responsible for acquiring under contract sufficient Gas supplies or reserves, and sufficient gathering, processing and transportation capacity required to deliver to the Receipt Point the quantities of Gas to be transported and delivered by FortisBC Energy pursuant to the Transportation Agreement, and for obtaining all governmental authorizations and approvals required in connection therewith.

19. Force Majeure

19.1 **Force Majeure.** Subject to Section 19.5 (No Relief for Payment Obligations), neither FortisBC Energy nor the Shipper shall be considered in default of any of its obligations under this Rate Schedule or the Transportation Agreement to the extent that it is prevented or delayed in performing such obligations by Force Majeure, provided that it has delivered a Force Majeure Notice in accordance with Section 19.2 (Force Majeure Notice). The Party claiming Force Majeure shall use all commercially reasonable efforts to diligently attempt to resume the performance of its obligations and to mitigate the effect of the Force Majeure on the other Party. Where a time or period of time is stipulated for the performance of any obligation and Force Majeure has been relied upon as delaying such performance, the time or period of time for such performance shall be extended by the length of time the condition of Force Majeure operates to delay or prevent such performance.

19.2 **Force Majeure Notice.** The Party relying upon Force Majeure shall provide the other Party with notice of such Force Majeure which shall describe in reasonable detail the following:

(a) the Force Majeure event that has occurred;

(b) the extent to which the affected Party is or will be affected by the Force Majeure, the steps that the affected Party has taken, using commercially reasonable efforts to remedy the cause of the Force Majeure event and an estimate, if practicable, of the anticipated duration of the Force Majeure event; and

(c) if the Party claiming Force Majeure is FortisBC Energy and FortisBC Energy has elected to curtail Gas transportation service in lieu of suspending it in its entirety, the Force Majeure Notice shall specify the quantity of Gas to which the Shipper is curtailed and when such curtailment commenced or will commence.

19.3 **Notice to Resume.** As soon as reasonably practicable after the Force Majeure event has been remedied the Party claiming Force Majeure will notify the other Party that the Force Majeure event has been remedied and the date and time the Party has resumed, or will be in a position to resume, the performance of its obligations under this Rate Schedule and the Transportation Agreement.

19.4 **Settlement of Labour Disputes.** Notwithstanding any of the provisions of this Section 19 (Force Majeure), the settlement of labour disputes or industrial disturbances will be entirely within the discretion of the particular Party involved and the Party may make such settlement of it at the time and on terms and conditions as it may deem to be advisable and no delay in making settlement will deprive the Party claiming Force Majeure of the benefit of Section 19.1 (Force Majeure).

19.5 **No Relief for Payment Obligations.** Notwithstanding any of the provisions of this Section 19 (Force Majeure), Force Majeure will not operate to relieve any Party from any of its payment obligations under this Rate Schedule or the Transportation Agreement.

19.6 **Extension of Term.** Where FortisBC Energy has claimed Force Majeure, the Expiry Date shall be automatically extended by the number of Days, to a maximum of 60 Days, during which FortisBC Energy failed to deliver any Gas to the Shipper at the Delivery Point. FortisBC Energy shall provide a notice to the Shipper of such new Expiry Date. Notwithstanding the foregoing, the Transportation Agreement may further limit the number of Days by which the Expiry Date may be extended in the event that such new Expiry Date (s) could occur after the expiry of permits required for commercial operation of the Shipper's facility.

20. Arbitration

20.1 **Arbitration.** All disputes arising out of, in relation to or as a consequence of this Rate Schedule or the Transportation Agreement (including the validity or interpretation of this Rate Schedule, the Transportation Agreement or any provision therein), except for disputes concerning matters falling within the exclusive jurisdiction of the BCUC, which cannot be settled amicably through negotiations between the Parties shall be referred to and finally resolved by binding arbitration under the International Commercial Arbitration Rules of Procedure of the British Columbia International Commercial Arbitration Centre ("BCICAC") then in effect. The place of arbitration shall be Vancouver, British Columbia and the language of arbitration shall be English. The arbitration shall be conducted before a sole arbitrator (the "Arbiter"). The Appointing Authority shall be the BCICAC. FortisBC Energy and the Shipper agree to execute, if requested by the Arbiter, a reasonable engagement letter with the Arbiter.

20.2 **Arbitration Binding.** Subject to applicable statutory remedies of judicial review or appeal, the arbitration award shall be final and binding on FortisBC Energy and the Shipper, and judgment on the award may be entered by any court of competent jurisdiction. If the Parties settle the dispute in the course of the arbitration, the settlement shall be approved by the Arbiter on request of either Party and shall become the award.

20.3 **Concurrent Proceedings.** If a dispute arises under another agreement between the Parties and is pending concurrently with a dispute pending under this Rate Schedule or the Transportation Agreement, based on the same or similar facts and circumstances, then, upon mutual consent, the Parties may consolidate those disputes in a single arbitration proceeding with the intent of avoiding any unnecessary multiplicity of proceedings.

20.4 **Obligations Continue.** The Parties will continue to fulfill their respective obligations pursuant to this Rate Schedule and the Transportation Agreement during the resolution of any dispute in accordance with this Section 20 (Arbitration).

21. Notices

21.1 **Notice.** Subject to Section 0 (Designated Persons), Section 21.3 (Electronic Communications) and Section 21.5 (Notice of Force Majeure), any notice, request, statement or bill that is required to be given or that may be given under this Rate Schedule or under the Transportation Agreement will, unless otherwise specified, be in writing and will be considered as fully delivered when mailed, personally delivered, sent by fax, or other method approved by FortisBC Energy to the other Party in accordance with the following:

<u>If to FortisBC Energy</u>	FORTISBC ENERGY INC.	
MAILING ADDRESS:	16705 Fraser Highway Surrey, B.C. V4N 0E8	
BILLING AND PAYMENT:	Attention: Telephone: Fax:	Industrial Billing 1-855-873-8773 (604) 293-2920
CUSTOMER RELATIONS:	Attention: Telephone: Fax:	Commercial & Industrial Energy Solutions (604) 592-7843 (604) 592-7894
LEGAL AND OTHER:	Attention: Telephone: Fax:	General Counsel (604) 443-6538 (604) 443-6540

<u>If to the Shipper</u>, then as set out in the Transportation Agreement.

21.2 **Designated Persons.** The Shipper shall give written notice to FortisBC Energy from time to time setting out the name, title, telephone and fax numbers of the Person designated by the Shipper to receive: any notices in respect of adjustments to Contract Demand, notices of adjustment pursuant to Section 4.3 (Adjustment by FortisBC Energy), notices of Authorized Quantity pursuant to Section 4.5 (Notice of Authorized Quantity), notices of Planned Maintenance pursuant to Section 6.1 (Planned Maintenance), Curtailment Notices pursuant to Section 6.2 (Curtailment for Planned Maintenance) and Section 6.3 (Curtailment of Interruptible Transportation Service), daily service operations reports pursuant to Section 8.1 (Daily Operations Report), notices pursuant to Section 14.1 (Quality at Receipt Point), notices of installation and other activities pursuant to Section 16.2 (Access to Measuring Equipment), notices of Force Majeure pursuant to Section 19.2 (Force Majeure Notice), notices of remedy of Force Majeure condition pursuant to Section 19.3 (Notice to Resume) and notices of default or of suspension or termination pursuant to Section 22.1 (Default). FortisBC Energy shall give written notice to the Shipper from time to time setting out the name, title, telephone and fax numbers of the Person designated by FortisBC Energy to receive: Requested Quantity notices pursuant to Section 4.1 (Requested Quantity), notices of adjustments to Requested Quantity notices pursuant to Section 4.2 (Adjustment to Requested Quantity), Shipper Planned Maintenance notices pursuant to Section 6.1 (Planned Maintenance), notices pursuant to Section 14.2 (Quality at Delivery Point), notices of Force Majeure pursuant to Section 19.2 (Force Majeure Notice), notices of remedy of Force Majeure condition pursuant to Section 19.3 (Notice to Resume).

21.3 **Electronic Communication.** Where the Shipper and FortisBC Energy agree to do so, the notices and other schedules to be provided by the Shipper and FortisBC Energy in respect of adjustments to Contract Demand and pursuant to Section 4.1 (Requested Quantity), Section 4.2 (Adjustment to Requested Quantity), Section 4.3 (Adjustment by FortisBC Energy), Section 4.5 (Notice of Authorized Quantity), Section 6.1 (Planned Maintenance), Section 6.2 (Curtailment for Planned Maintenance), Section 6.3 (Curtailment of Interruptible Transportation Service) and the daily service operations reports to be provided by FortisBC Energy in accordance with Section 8.1 (Daily Operations Reports) may be delivered by one Party to the other by means of a computerized system of communication rather than by fax, as approved by FortisBC Energy.

21.4 **Changes in Nomination Procedures.** If the Transporter or any other Person operating a pipeline which transports Gas for delivery through the System changes its Gas nomination and authorization procedures, FortisBC Energy may make any changes to its Gas nomination and authorization procedures, including changes that conflict with these processes set out in this Rate Schedule as FortisBC Energy reasonably requires to reflect such changed procedures.

21.5 **Notice of Force Majeure.** Notwithstanding Section 21.1 (Notice), notices pursuant to Section 19 (Force Majeure) will be sufficient if:

(a) given by FortisBC Energy in writing by fax, orally in person, by telephone, or other method approved by FortisBC Energy (to be confirmed in writing) to the Person designated from time to time by the Shipper pursuant to Section 0 (Designated Persons); or

(b) given by the Shipper by telephone (to be confirmed by fax) to the Person designated from time to time by FortisBC Energy pursuant to Section 0 (Designated Persons) in the following manner:

To claim Force Majeure..."Please be advised that (name of company and location of plant) has (reason for claiming Force Majeure as provided in Section 19 of Rate Schedule 50) and hereby claims suspension by reason of Force Majeure in accordance with the terms of Rate Schedule 50 effective 0700 PST or DST, as the case may be (date Force Majeure suspension to become effective)."

To resume after Force Majeure..."Please be advised that (name of company and location of plant) requests a return to normal natural gas service in accordance with Rate Schedule 50 and the Transportation Agreement effective 0700 PST or DST, as the case may be, (date Force Majeure suspension to end, but not to be retroactive) whereby the suspension by reason of Force Majeure currently in force will be terminated."

22. Default or Bankruptcy

22.1 **Default.** If the Shipper at any time:

(a) fails or neglects to make any payment due to FortisBC Energy under this Rate Schedule or the Transportation Agreement within 5 Days after payment is due;

(b) fails or neglects to deliver, maintain, amend, replace or supplement the Security as required under Section 13 (Security and Credit); or

(c) fails or neglects to correct any default of any of the other terms, covenants, agreements, conditions or obligations imposed upon it under this Rate Schedule or the Transportation Agreement, within 5 Days after FortisBC Energy gives to the Shipper notice of such default or, in the case of a default that cannot with due diligence be corrected within a period of 5 Days, fails to correct the default with all due diligence; or

(d) purports to terminate its obligations under the Transportation Agreement,

then, FortisBC Energy may, in addition to any other remedy that it has at law or in equity, at its option and without liability:

(e) suspend Firm Transportation Service and Interruptible Transportation Service by giving notice in writing to the Shipper, which suspension notice shall be effective as of 07:00 PST or DST, as the case may be, on the Day immediately after the suspension notice is delivered, until the default has been fully remedied, and no such suspension or refusal will relieve the Shipper from any obligation under this Rate Schedule or the Transportation Agreement; and

(f) if:

(i) the Shipper has defaulted under Section 22.1(a), (c) or (d) and failed to remedy the default within 15 Days of FortisBC Energy delivering a suspension notice pursuant to Section 22.1(e) (Default), or if one or more of the other defaults set out in Sections 22.1(a), (b), (c) or (d) has occurred within such suspension period;

(ii) the Shipper fails or neglects to deliver, maintain, amend, replace or supplement the Security as required under Section 13 (Security and Credit); or

(iii) the Shipper (or any receiver or third party on behalf of the Shipper) has failed to affirm the Transportation Agreement within the time required under Section 22.2 (Bankruptcy or Insolvency) or the Shipper (or any receiver or third party on behalf of the Shipper) fails at any time to continue to fully comply with all of the terms, covenants, agreement, conditions or obligations imposed upon the Shipper under this Rate Schedule and the Transportation Agreement following an event of bankruptcy or insolvency set out in Section 22.2 (Bankruptcy or Insolvency),

then FortisBC Energy may immediately terminate the Transportation Agreement, by giving notice in writing to the Shipper, which termination notice shall be effective as of 07:00 PST or DST, as the case may be, on the Day immediately after the termination notice is delivered to the Shipper.

22.2 **Bankruptcy or Insolvency.** If the Shipper becomes bankrupt or insolvent or commits or suffers an act of bankruptcy or insolvency or a receiver is appointed pursuant to a statute or under a debt instrument over all or substantially all the assets of the Shipper or the Shipper seeks protection from the demands of its creditors pursuant to any legislation enacted for that purpose, then FortisBC Energy will have the right, at its sole discretion, to immediately terminate the Transportation Agreement by giving notice in writing to the Shipper and thereupon FortisBC Energy may cease further delivery of Gas to the Shipper. However, if the Shipper (or any receiver or other third party acting on behalf of the Shipper) affirms the Transportation Agreement within 2 Business Days of the occurrence of any such events of bankruptcy or insolvency, FortisBC Energy shall not have the right to immediately terminate the Transportation Agreement for so long as the Shipper (or any receiver or other third party on behalf of the Shipper) continues to fully comply with all of the terms, covenants, agreements, conditions or obligations imposed upon the Shipper under this Rate Schedule and the Transportation Agreement.

22.3 **Termination Payment.** If FortisBC Energy terminates this Agreement in accordance with Section 22.1 (Default) or Section 22.2 (Bankruptcy or Insolvency), then the Shipper shall pay to FortisBC Energy a payment ("Termination Payment") equal to the Net Present Value of the product of 90% x Contract Demand x Firm Demand Toll x 365 days per year x the number of months from the termination date until the Expiry Date divided by 12.

22.4 **Liquidated Damages.** FortisBC Energy and the Shipper acknowledge that the Termination Payment is a genuine pre-estimate of the damages to be incurred by FortisBC Energy from early termination of the Transportation Agreement and is not a penalty. The Shipper irrevocably waives any right it may have to raise as a defense that the Termination Payment is excessive, punitive, or not a genuine pre-estimate of damages. The Shipper acknowledges that the Termination Payment is reasonable in light of the following costs and risks to FortisBC Energy from such early termination:

(a) the construction costs assumed by FortisBC Energy prior to the commencement of the Service Period;

(b) FortisBC Energy may be unable to materially reduce the expenses associated with the operation and maintenance of the System Upgrades;

(c) this Rate Schedule is a common rate, with the full cost of constructing the System Upgrades not allocated to the Shipper but embedded in FortisBC Energy's overall rate base;

(d) the cost of the System Upgrades may remain in FortisBC Energy's overall rate base to be borne by the other customers of FortisBC Energy through increased rates, resulting in the risk of other customers discontinuing service, stranded assets elsewhere in the System, and additional direct and indirect costs and lost profits;

(e) if the whole or any part of the System Upgrades are removed from FortisBC Energy's overall rate base, FortisBC Energy may bear the costs of that portion of the System Upgrades; and

(f) the costs of abandonment and/or removal of the System Upgrades may not be fully recovered through rates paid by the Shipper.

22.5 **Other Remedies.** For greater certainty, FortisBC Energy and the Shipper agree that, upon any termination of the Transportation Agreement under circumstances where FortisBC Energy is entitled to the Termination Payment and such Termination Payment is paid in full, FortisBC Energy shall be precluded from any other remedy against the Shipper at law or in equity or otherwise (including an order for specific performance) and shall not seek to obtain any recovery, judgment, or damages of any kind, including consequential, indirect, or punitive damages, against the Shipper or any of its Affiliates, or against any of their respective directors, officers, employees, partners, managers, members, shareholders or Affiliates in respect of the early termination of the Transportation Agreement.

23. Indemnity and Limitation on Liability

23.1 **Liability of FortisBC Energy.** In no event shall FortisBC Energy be liable to the Shipper under this Rate Schedule or the Transportation Agreement, in any circumstances, for any amount other than any Demand Toll Credits credited to the Shipper pursuant to Section 11 (Demand Toll Credits). For greater certainty, FortisBC Energy shall in no circumstances be liable to the Shipper for the Shipper's direct, indirect, special or consequential loss, damage, cost or expense whatsoever, whether based on breach of contract, negligence, strict liability or otherwise, including capital costs, business interruption losses, lost profits or revenues, cost of lost, purchased or replacement Gas, or lost permits, certificate or contracts.

23.2 **Indemnity.** The Shipper will indemnify and hold harmless each of FortisBC Energy, its Affiliates and their respective employees, contractors and agents from and against any and all adverse claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) arising from or out of each of the following:

(a) any defect in title to any Gas delivered to FortisBC Energy at the Receipt Point on behalf of the Shipper from Suppliers other than FortisBC Energy, or arising from any Person's security interest in the Gas delivered to FortisBC Energy;

(b) any Gas delivered by the Transporter or the Shipper to FortisBC Energy at the Receipt Point failing to meet the quality specifications set out in Section 14.1 (Quality at Receipt Point);

(c) any act, accident, event or omission in connection with the construction, installation, presence, maintenance and operation of the property, facilities and equipment of the Shipper;

(d) any breach of this Rate Schedule or the Transportation Agreement by the Shipper; and

(e) all federal, provincial, and municipal taxes (or payments made in lieu thereof), whether payable on the delivery of Gas to FortisBC Energy at the Receipt Point by the Shipper or on the delivery of Gas to the Shipper by FortisBC Energy at the Delivery Point, or on any other service provided by FortisBC Energy to the Shipper.

24. Interpretation

24.1 **Interpretation.** Except where the context requires otherwise or except as otherwise expressly provided, in this Rate Schedule or in the Transportation Agreement

(a) all references to a designated section are to the designated section of this Rate Schedule unless otherwise specifically stated;

(b) the singular of any term includes the plural, and vice versa, and the use of any term is equally applicable to any gender and, where applicable, body corporate;

(c) the words "include", "includes" and "including" shall be read as if followed by the words "without limitation";

(d) any reference to a corporate entity includes and is also a reference to any corporate entity that is a successor by merger, amalgamation, consolidation or otherwise to such entity;

(e) any reference to an act or regulation includes a reference to that act or regulation as amended or replaced from time to time;

(f) all words, phrases and expressions used in this Rate Schedule or in the Transportation Agreement that have a common usage in the gas industry and that are not defined the Definitions or in the Transportation Agreement have the meanings commonly ascribed to such words, phrases and expressions in the gas industry;

(g) the headings of the sections set out in this Rate Schedule or in the Transportation Agreement are for convenience of reference only and will not be considered in any interpretation of this Rate Schedule or the Transportation Agreement; and

(h) any decision, election, authorization, determination, acceptance, waiver, consent or other discretion to be granted, made or exercised by FortisBC Energy or the Shipper hereunder shall be at that Party's sole discretion unless otherwise expressly stated.

25. Miscellaneous

25.1 **Waiver.** No waiver by either Party of any default by the other in the performance of any of the provisions of the Transportation Agreement shall operate or be construed as a waiver of any other or future default or defaults, whether of a like or a different character.

25.2 **Amendment of Rate Schedule.** From time to time FortisBC Energy may amend the terms and conditions of this Rate Schedule and the Table of Charges by filing an amendment to the Rate Schedule and obtaining the approval of the BCUC.

25.3 **Enurement.** The Transportation Agreement shall enure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns.

25.4 **Assignment.** The Transportation Agreement may not be assigned in whole or in part by the Shipper unless the Shipper has first obtained the prior written consent of FortisBC Energy. Nothing herein contained shall prevent either of the Parties from pledging, charging or mortgaging its rights under this Rate Schedule or the Transportation Agreement as security for its indebtedness or obligations without the consent of the other Party. Any Person who has acquired a security interest under this Rate Schedule or in the Transportation Agreement as security for the indebtedness or obligations of either Party may, without the consent of the other Party, assign the Transportation Agreement to another Person in connection with the enforcement of the security interest.

25.5 **Entire Agreement.** This Rate Schedule and the Transportation Agreement constitute the entire agreement between the Parties and supersede all previous agreements, understandings, negotiations and representations between the Parties in respect of the subject matter of this Rate Schedule and the Transportation Agreement.

25.6 **Amendment.** No amendments or variation of the Transportation Agreement shall be effective and binding upon the Parties unless such amendment or variation is set forth in writing and duly executed by the Parties. Amendments requiring approval of the BCUC shall become effective and binding upon the Parties only upon the effective date of the BCUC approval.

25.7 **Time of the Essence.** Time is of the essence of this Rate Schedule and the Transportation Agreement and of the terms and conditions thereof.

25.8 **Relationship.** Nothing in this Rate Schedule or the Transportation Agreement shall be construed as creating any partnership, joint venture, agency or other fiduciary relationship between FortisBC Energy and the Shipper.

25.9 **Survival.** Notwithstanding the termination of the Transportation Agreement, the provisions of Section 8.6 (Final Gas Balance), Section 12 (Statements and Payments), Section 13.5 (Enforcing the Security), Section 13.6 (Non-Interference), Section 13.7 (Return of Security), Section 17 (Possession and Control of Gas), Section 20 (Arbitration), Section 22.3 (Termination Payment), Section 22.4 (Liquidated Damages), Section 22.5 (Other Remedies), Section 23 (Indemnity and Limitation of Liability), Section 24 (Interpretation), Section 25.8 (Relationship), Section 25.9 (Survival), Section 25.11 (Choice of Law) and Section 25.12 (Payments) shall survive the termination of the Transportation Agreement. The Parties shall use reasonable efforts to make all adjustments and to settle all accounts which are outstanding between the Parties as of the Expiry Date within the payment periods specified in this Rate Schedule or, if no payment period is specified, as soon as reasonably practicable.

25.10 **Further Assurances.** Each of FortisBC Energy and the Shipper will execute and deliver or cause to be executed and delivered all such further documents and instruments and do all such further acts and things as the other may reasonably require to evidence, carry out and give full effect to the terms, conditions, intent and meaning of this Rate Schedule and the Transportation Agreement and to assure the completion of the transactions contemplated hereby.

25.11 **Choice of Law.** The Transportation Agreement and this Rate Schedule shall be construed in accordance with the laws of the Province of British Columbia and the laws of Canada applicable therein and the Transportation Agreement shall be treated in all respects as contracts made, entered into and to be wholly performed in British Columbia by parties domiciled and resident therein.

25.12 **Payments.** All payments required to be made under statements and invoices rendered pursuant to this Rate Schedule or the Transportation Agreement will be made by wire transfer to, or certified cheque or bank draft drawn on a Canadian chartered bank or trust company, payable in lawful money of Canada in immediately available funds in Vancouver, British Columbia.

TABLE OF CHARGES (ToC)

1. ToC - DEFINITIONS

(a) **AFUDC** - means a return earned on FortisBC Energy's capital and development costs of constructing utility assets until such assets are included in FortisBC Energy's rate base equal to FortisBC Energy's after tax weighted average cost of capital, determined annually based on the return on equity and capital structure approved by the BCUC for FortisBC Energy from time to time and FortisBC Energy's embedded cost of debt.

(b) **Cost Model** - means the cost model used by FortisBC Energy to determine the Initial Firm Demand Toll, variables of which include the Forecast Rate Schedule 50 Annual Demand, Cost of Service of System Upgrades, capital investment in System Upgrades and a System Contribution.

(c) **Cost of Service** - means the total costs to be used in determining any rate or any rate adjustment pursuant to the ToC, which costs shall be determined by FortisBC Energy acting reasonably, including:

(i) the actual capital investment in the System Upgrades including, without limitation, any associated labour, equipment, material, and any other costs necessary to serve Shippers under this Rate Schedule including a reasonable allocation of FortisBC Energy's overhead associated with the construction of the System Upgrades, net of any grants, or tax credits offsetting the full costs of the System Upgrades;

(ii) depreciation and net negative salvage rates and expenses related to the net amount described in (i);

(iii) incremental operating and maintenance expenses needed to serve Shippers under this Rate Schedule;

(iv) applicable property and income taxes;

(v) the Return on Rate Base; and

(vi) if any Shipper was an existing customer of FortisBC Energy at any time prior to its Commencement Date for service under this Rate Schedule, an amount equal to the allocated cost of service attributable to that Shipper taking service under another rate schedule as set out in the cost of service allocation study most recently approved by the BCUC at the time of entering into the Transportation Agreement;

less, as set out in Section 6.3 (Shipper Specific Charges), the cost of service of any contributions in aid of construction and additional tolls or rate riders multiplied by applicable Shipper Contract Demand.

For clarity, Cost of Service does not include any costs, expenses, taxes or other applicable amounts that are included in the Commodity Toll.

(d) **Existing Rate Schedule 50 Annual Demand** - means the sum of the Contract Demand of all existing Rate Schedule 50 Shippers that FortisBC Energy is obligated to transport and deliver to on December 31 of the year prior to any year for which an annual rate is being calculated as contemplated in the Table of Charges, multiplied by 365. Existing Rate Schedule 50 Annual Demand does not include the Contract Demand of a Shipper whose Transportation Agreement will be terminated during the year for which an annual rate is being calculated.

(e) **Forecast Rate Schedule 50 Annual Demand** - means the sum of the Contract Demand of all Rate Schedule 50 Shippers with a Transportation Agreement the Service Period of which is included in any year for which the annual rate is being calculated as contemplated in the Table of Charges, multiplied by 365. Forecast Rate Schedule 50 Annual Demand does not include the Contract Demand of a Shipper whose Transportation Agreement will be terminated during the year for which an annual rate is being calculated.

(f) **General Rate Change** - means, in any year, a rate change approved by the BCUC, (including an interim rate change), applicable in a uniform manner to all non-bypass customers, and for greater certainty excludes rate changes related to rate design. In any year where there is no rate change applicable in a uniform manner to all non-bypass customers, the General Rate Change is deemed to be zero.

(g) **Initial Demand Toll** - means the Firm Demand Toll and Interruptible Toll(s) effective during the Initial Service Period.

(h) **Initial Service Period** - means the period commencing on 0700 PST or DST, as the case may be, on the earlier of the Commencement Date or the first Day of any Pre-Commissioning Period, as set out in the first Transportation Agreement entered into under this Rate Schedule 50 and ending immediately prior to 0700 DST on January 1st following the anniversary of the Commencement Date in that Transportation Agreement.

(i) **Notional Calculated Toll** – means:

(i) in the year following the Initial Service Period, the Firm Demand Toll determined for the Initial Service Period under Sections 2.2 and 2.3, but without accounting for the Rate Floor; and

(ii) in all other years, the toll amount determined under Section 4.1(a) for the prior year (and for greater certainty, without accounting for the Rate Floor).

(j) **Presumptive Initial Firm Demand Toll** - means the Initial Demand Toll for Firm Transportation Service as set out in ToC Section 2.2 (Presumptive Initial Firm Demand Toll) of this Table of Charges unless adjustments are required under ToC Section 2.3 (Adjustments) of this Table of Charges.

(k) **Rate Floor** – means the minimum Demand Toll for Firm Transportation Service despite any other provision in this Table of Charges, and is deemed to be:

(i) $0.55 per GJ if the Forecast Rate Schedule 50 Annual Demand is equal to or less than 200 PJ per year;

(ii) $0.50 per GJ if the Forecast Rate Schedule 50 Annual Demand is greater than 200 PJ per year and equal to or less than 400 PJ per year; and

(iii) $0.45 per GJ if the Forecast Rate Schedule 50 Annual Demand is greater than 400 PJ per year.

(l) **Return on Rate Base** - means the regulated rate of return earned by FortisBC Energy on rate base assets equal to FortisBC Energy's weighted average cost of capital, determined based on the return on equity and capital structure approved by the BCUC for FortisBC Energy from time to time and FortisBC Energy's embedded cost of debt.

(m) **Sumas Daily Price** – means the "NW Sumas" Daily Midpoint Price as set out in Gas Daily's Daily Price Survey for Gas delivered to Northwest Pipeline Corporation at Sumas, converted to Canadian dollars using the noon exchange rate as quoted by the Bank of Canada, one business day prior to Gas flow date, for each Day. Energy units are converted from MMBtu to gigajoule by application of a conversion factor equal to 1.055056 gigajoule per MMBtu.

2. ToC - Determination of Initial Demand Toll For Firm Transportation Service

2.1 **Initial Demand Toll for Firm Transportation Service.** The Initial Demand Toll for Firm Transportation Service during the Initial Service Period shall be the Presumptive Initial Firm Demand Toll specified in Section 2.2 unless adjustments are required under Section 2.3, in which case the adjusted amount determined under Section 2.3(a) and (b), shall be the Initial Demand Toll for Firm Transportation Service.

2.2 **Presumptive Initial Firm Demand Toll.** The Presumptive Initial Firm Demand Toll is \$0.770 per GJ and includes a \$0.100 per GJ System Contribution. FortisBC Energy determined the Presumptive Initial Firm Demand Toll using the Cost Model calculated on the basis of information available as of November 1, 2014.

2.3 **Adjustments.** In determining the Initial Demand Toll for Firm Transportation Service, the Presumptive Initial Firm Demand Toll is subject to adjustment as follows:

(a) If the updated inputs in the Cost Model as determined in Section 2.3(b) yield a toll that differs from the Presumptive Initial Firm Demand Toll by more than 3%, then the Initial Demand Toll for Firm Transportation Service shall be the toll calculated in accordance with Section 2.3(b). If the updated inputs in the Cost Model yield a number that differs from the Presumptive Initial Firm Demand Toll by 3% or less, then the Initial Demand Toll for Firm Transportation Service shall be the Presumptive Initial Firm Demand Toll, subject to the Rate Floor.

(b) For the purposes of the calculation under Section 2.3(a):

i. the inputs in the Cost Model will be updated as of the date that is 45 Days prior to the first Commencement Date set out in any Transportation Agreement entered into under this Rate Schedule 50, using the applicable rates and quantities as of that date, actual capital costs incurred, and otherwise FortisBC Energy's best estimates of such capital costs.

ii. The inputs in the Cost Model that will be updated are:

Forecast Rate Schedule 50 Annual Demand
The capital costs (and associated AFUDC) of the System Upgrades expected to be in service at the first Commencement Date set out in any Transportation Agreement entered into under this Rate Schedule 50.
FortisBC Energy's Return on Rate Base
Depreciation rates for asset classes associated with the System Upgrades
Tax changes (including income taxes and property taxes), plus or minus

3. ToC - Tolls for Interruptible Transportation Service

3.1 **Initial Interruptible Demand Toll April to October** - The Interruptible Demand Toll applicable on the Days April 1 through October 31 during the Initial Service Period is equal to 90% of the Initial Demand Toll for Firm Transportation Service.

3.2 **Initial Interruptible Demand Toll November to March** - The Interruptible Demand Toll applicable on the Days November 1 through March 31 inclusive during the Initial Service Period is equal to 115% of the Initial Demand Toll for Firm Transportation Service.

3.3 **Initial Pre-Commissioning Period Interruptible Demand Toll** - The Interruptible Demand Toll applicable during the Pre-Commissioning Period (if any) during the Initial Service Period is equal to the 115% of the Initial Demand Toll for Firm Transportation Service.

4. ToC - Determination of Demand Toll For Firm Transportation Service After Initial Service Period

4.1 The Firm Demand Toll is subject to adjustment annually, on each January 1st following the Initial Service Period as follows:

The Firm Demand Toll in effect in any year shall be the greater of the amount determined under (a) and (b):

(a) The sum of (i) and (ii):

(i) $$B \times \left(100\% + MAXIMUM\left((MINIMUM(C\ AND\ 3\%)\ AND\ 0\%)\right)\right)$$

where:

1. B equals the existing System Contribution
2. C equals the General Rate Change

(ii) $$\frac{\left(\left((A-B) \times \left(100\% + MAXIMUM\left((MINIMUM(C\ AND\ 3\%)\ AND\ 0\%)\right)\right) \times D\right) + E\right)}{F}$$

where:

1. A equals the Notional Calculated Toll
2. B equals the existing System Contribution
3. C equals the General Rate Change
4. D equals the Existing Rate Schedule 50 Annual Demand
5. E equals the forecast incremental Cost of Service associated with the Forecast Rate Schedule 50 Annual Demand
6. F equals the Forecast Rate Schedule 50 Annual Demand

(b) The Rate Floor.

5. TOC - DETERMINATION OF DEMAND TOLL FOR INTERRUPTIBLE TRANSPORTATION SERVICE AFTER INITIAL SERVICE PERIOD

5.1 **Interruptible Demand Toll April to October** - The Interruptible Demand Toll applicable on the Days April 1 through October 31 inclusive of each is equal to 90% of the Firm Demand Toll on that Day.

5.2 **Interruptible Demand Toll November to March** - The Interruptible Demand Toll applicable on the Days November 1 through March 31 inclusive of each is 115% of the Firm Demand Toll on that Day.

5.3 **Pre-Commissioning Period Interruptible Demand Toll** - The Interruptible Demand Toll applicable to Interruptible Transportation Service in the Pre-Commissioning Period is the Firm Demand Toll. If the Firm Demand Toll is not in place at time of the Pre-Commissioning Period of the first Shipper, the applicable toll shall be the Presumptive Initial Firm Demand Toll. .

6. ToC - OTHER APPLICABLE CHARGES

6.1 **Commodity Toll** – the applicable Commodity Toll for the Month, as set out in Section 1.1(g) (Definitions), and Section 10.3 (Other Charges).

6.2 **Unauthorized Overrun Gas Charges** - Unauthorized Overrun Gas Charges, for each Day on which there is Unauthorized Overrun Gas, are:

(a) Per GJ charge on the first 1,000 GJs in excess of the amount set out in the Curtailment Notice or in the case of imbalances, in the inventory imbalance account.	Sumas Daily Price X 1.5
(b) Per GJ charge on all Gas over 1,000 GJs in excess of the amount set out in the Curtailment Notice or in the case of imbalances, in the inventory imbalance account.	The greater of \$20.00/GJ or the Sumas Daily Price x 1.5

6.3 **Shipper Specific Charges** – If, at the time a Shipper enters into a Transportation Agreement, the forecast incremental Cost of Service associated with providing Transportation Service to such Shipper causes the Firm Demand Toll to increase by more than 5% above the Firm Demand Toll that would have applied if the Shipper had not entered into a Transportation Agreement under this Rate Schedule, then FortisBC Energy shall require such Shipper to:

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

(b) pay an additional toll or rate rider,

that has the effect of limiting the increase in the Firm Demand Toll to 5% above the Firm Demand Toll that would have applied if the Shipper had not entered into a Transportation Agreement under this Rate Schedule. FortisBC Energy may elect (a) or (b) in its sole discretion.

7. TOC - CHANGES TO TOLLS AND CHARGES APPROVED BY THE BCUC

7.1 FortisBC Energy may, in its sole discretion, bring forward applications to the BCUC to change any tolls or charges, or the formulae by which the tolls and charges and adjustments to them are determined, and Rate Schedule 50 will be amended consistent with any BCUC orders.

ILLUSTRATIVE EXAMPLE: ANNUAL RATE CHANGE MECHANISM CALCULATION

1. Rate Change Variables

(a) Toll Components

(i) Existing Notional Calculated Toll less System Contribution	$	0.670	*per GJ*
(ii) System Contribution	$	0.100	*per GJ*
Existing Notional Calculated Toll	**$**	**0.770**	*per GJ*

(b) Annual Demand

(i) Existing Rate Schedule 50 Annual Demand	110,000	*TJ*
(ii) Forecast year incremental demand	30,000	*TJ*
Forecast Rate Schedule 50 Annual Demand	**140,000**	*TJ*

(c) FortisBC Energy's Forecast incremental Cost of Service

(i) Forecast incremental Cost of Service	$	2,000	*Thousand*[1]

(d) Applicable General Rate Change percent

(i) Percent increase to all FortisBC Energy non-bypass delivery rates is equal to 2.30%,

(ii) 2.30% is less than maximum increase of 3%; and greater than the minimum of 0%; therefore the applicable increase is 2.30%

2. Rate Change Calculation

(a) System Contribution

(i) Existing System Contribution	$	0.100	*per GJ*
(ii) Multiplied by (1 + General Rate Change percent)		1.023	
(iii) Revised System Contribution	$	0.102	*per GJ*

(b) Existing Notional Calculated Toll Less System Contribution

(i) Existing Notional Calculated Toll less System Contribution	$	0.670	*per GJ*
(ii) Multiplied by (1 + General Rate Change percent)		1.023	
(iii)	$	0.685	*per GJ*
(iv) Multiplied by Existing Rate Schedule 50 Annual Demand		110,000	*TJ*
(v)	$	75,350	*Thousand*
(vi) Plus Forecast Incremental Cost of Service	$	2,000	*Thousand*
(vii)	$	77,350	*Thousand*
(viii) Divided by Forecast Rate Schedule 50 Annual Demand		140,000	*TJ*
(ix) Revised Notional Calculated Toll less System Contribution	$	0.553	*per GJ*

(c) Firm Demand Toll

(i) System Contribution (a, (iii))	$	0.102	*per GJ*
(ii) Revised Notional Calculated Toll less System Contribution (b, (ix))	$	0.553	*per GJ*
(iii) New Notional Calculated Toll (sum of (i) and (ii))	$	0.655	*per GJ*
(iv) Rate Floor	$	0.550	*per GJ*

Effective Date:

(v) Firm Demand Toll applied (greater of (iii) and (iv))	$	0.655	*per GJ*

All applicable taxes will apply to the total bill as calculated above.

[1]**Notes:**
Example Determination of the forecast Incremental Cost of Service

Line	Inputs & Rates	$ thousands	
1	Incremental Capital Investment	20,000	(including AFUDC)
2	Incremental Shipper Specific CIAC	-	
3	Incremental O&M	200	
4	Incremental Property Tax	78	
5	Incremental Shipper Specific Recoveries	-	
6			
7	Depreciation Rate	1.55%	
8	Amortization Rate for CIAC	n/a	
9	CCA Rate	6.00%	
10	Annual Salvage Rate	0.14%	
11	Tax Rate	26.00%	
12	Return on Equity	8.75%	
13	Equity Ratio	38.50%	
14	Weighted Average Cost of Debt	6.43%	
15	Debt Ratio	61.50%	
16			
17	**Cost of Service Calculations ($ thousands)**		
18			
19	Rate Base		
20	Opening Plant in Service	-	
21	Additions (Opening Adjustment)	20,000	Line 1
22	Closing Plant in Service	20,000	
23			
24	Opening Accumulated Depreciation	-	
25	Depreciation Expense	(310)	-(Line 20 + Line 21) x Line 7
26	Closing Accumulated Depreciation	(310)	
27			
28	Opening CIAC	-	
29	Additions (Opening Adjustment)	-	Line 2
30	Closing CIAC	-	
31			
32	Opening Accumulated Amortization	-	
33	Amortization Expense	-	-(Line 28 + Line 29) x Line 8
34	Closing Accumulated Amortization	-	
35			
36	Mid Year Net Plant in Service	19,845	
37			
38	Deferred Charges		
39	Opening Neg. Salvage	-	
40	Amortization Expense (Removal Provision)	(28)	Line 21 x Line 10
41	Closing Neg. Salvage	(28)	
42			
43	Mid Year Deferred Charges	(14)	
44			
45	Rate Base	19,831	Line 36 + Line 43

Effective Date:

46			
47	Income Tax Expense		
48	CCA Deduction		
49	Opening UCC	-	
50	Additions	20,000	Line 21 + Line 29
51	CCA	(1,200)	(Line 49 + Line 50) x Line 9
52	Closing UCC	18,800	
53			
54	Equity Return	668	Line 45 x Line 12 x Line 13
55	Add: Depreciation Expense	310	Line 25
56	Add: Amortization Expense	28	Line 33 + Line 40
57	Deduct: CCA	(1,200)	Line 51
58	Taxable Income After Tax	(194)	
59			
60	Tax Expense	(68)	(Line 58 / (1 - Line 11) x Line 11
61			
62	**Forecast Incremental Cost of Service ($ thousands)**		
63			
64	O&M	200	Line 3
65	Property Taxes	78	Line 4
66	Depreciation Expense	310	Line 25
67	Amortization Expense	28	Line 33 + Line 40
68	Shipper Specific Recoveries	-	Line 5
69	Income Tax Expense	(68)	Line 60
70	Equity Return	668	Line 45 x Line 12 x Line 13
71	Debt Expense	785	Line 45 x Line 14 x Line 15
72	Total	2,000	

Effective Date:

TRANSPORTATION AGREEMENT FOR RATE SCHEDULE 50

This Agreement is dated ____________________, 20___between FortisBC Energy Inc. ("FortisBC Energy") and ____ (the "Shipper").

WHEREAS:

A. FortisBC Energy owns and operates the System; and

B. The Shipper has requested that FortisBC Energy arrange for the transportation of Gas on a firm and interruptible basis through the System from the specified Receipt Point(s) to the specified Delivery Point(s) in accordance with Rate Schedule 50 as set out below and the terms set out herein.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the terms, conditions and limitations contained herein, the Parties agree as follows:

1. Specific Information

The Parties agree to the following terms and that the following information shall be applicable to each reference in either this Transportation Agreement or Rate Schedule 50.

Firm Contract Demand:	___________ Gigajoules per day
Conditions upon Firm Contract Demand (Section 3.2):	
Volumetric Equivalent:	___________ 10^3m^3 per day
Pre-Commissioning Period:	______________________________
Commencement Date:	______________________________
Expiry Date:	November 1, 20_____ (Insert Date not less than 15 years following the Commencement Date)
Form of Security:	______________________________

Receipt Point(s):	The point at (________ km-post ________) where the Transporter's pipeline system in British Columbia interconnects with the System
Delivery Point(s):	________________________
Pressure at the Delivery Point(s):	________________________ (only specify where applicable as set out in Section 7.2 of Rate Schedule 50)
Shipper's service address:	________________________
Account Number:	________________________

Address of Shipper for receiving notices:

________________________ (name of Shipper)	Attention: ________________________
________________________ (address of Shipper)	Telephone: ________________________
________________________	Fax: ________________________
________________________	Email: ________________________
________________________	

The information set out above is hereby approved by the Parties and each reference in either this Transportation Agreement or Rate Schedule 50 to any such information is to the information set out above.

2. Rate Schedule 50

2.1 **Defined Terms** – Capitalized terms not otherwise defined herein shall have the meanings as set out in the FortisBC Energy Inc. Rate Schedule 50 Large Volume Industrial Transportation effective January 1, 2015, as approved from time to time by the BCUC ("Rate Schedule 50").

2.2 **Additional Terms** - All rates, terms and conditions set out in Rate Schedule 50, as may be amended by FortisBC Energy and approved from time to time by the BCUC, are hereby incorporated by reference in this Transportation Agreement and are in addition to the terms and conditions contained in this Transportation Agreement and bind FortisBC Energy and the Shipper as if set out in this Transportation Agreement.

2.3 **Payment of Amounts** - Without limiting the generality of the foregoing, the Shipper will pay to FortisBC Energy all of the amounts set out in Rate Schedule 50 for the services provided by FortisBC Energy to Shipper under Rate Schedule 50 and this Transportation Agreement.

2.4 **Conflict** - Where anything in Rate Schedule 50 conflicts with any of the terms and conditions set out in this Transportation Agreement, this Transportation Agreement governs. The General Terms and Conditions of FortisBC Energy do not apply to the services provided by FortisBC Energy to Shipper under Rate Schedule 50 and this Transportation Agreement

2.5 **Acknowledgement** - The Shipper acknowledges receiving and reading a copy of Rate Schedule 50 and agrees to comply with and be bound by all terms and conditions set out therein. Without limiting the generality of the foregoing, where the transportation service provided by FortisBC Energy to Shipper hereunder is Interruptible Transportation Service or is otherwise subject to curtailment as set out in Rate Schedule 50, the Shipper acknowledges that it is able to accommodate such interruption or curtailment and releases FortisBC Energy from any liability for the Shipper's inability to accommodate such interruption or curtailment of transportation service.

2.6 **Independent Legal Advice** - Shipper represents and warrants to FortisBC Energy that it has received independent legal advice regarding the terms of this Transportation Agreement and Rate Schedule 50.

2.7 **Counterparts** - This Transportation Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original and all of which taken together shall be deemed to constitute one and the same instrument. Counterparts may be executed in original, faxed or e-mail form and the Parties adopt any signatures received by fax or e-mail as original signatures of the Parties.

IN WITNESS WHEREOF the Parties hereto have executed this Transportation Agreement.

FORTISBC ENERGY INC.	______________________ (here insert name of Shipper)
BY: ______________________ (Signature)	BY: ______________________ (Signature)
______________________ (Title)	______________________ (Title)
______________________ (Name – Please Print)	______________________ (Name – Please Print)
DATE: ______________________	DATE: ______________________

APPENDIX 5

Amendments to FortisBC Energy Inc. Rate Schedule 46
Liquefied Natural Gas Sales, Dispensing and Transportation Service Tariff

Rate Schedule 46 Reference Information and Amendments			
Section Number	**Section Name**	**Existing Tariff Language**	**Amended Tariff Language**
1.1 (p)	**Definitions** **LNG Output**	**[new definition added]**	**(p) LNG Ouput** - means the total quantities of Gas delivered from the LNG Facilities either by vaporization of LNG or Dispensing of LNG.
1.1 (w)	**Definitions** **Process Fuel Gas**	**(w) Process Fuel Gas** - means Gas consumed in the production of LNG at the LNG Facilities, which for 2013 and 2014 is deemed to be a quantity equal to 1% (one percent) of the LNG Dispensed to the Customer, but thereafter the percentage is to be updated annually based on the prior year's actual fuel gas consumption at the LNG Facilities.	**(x) Process Fuel Gas** – means: (i) Gas consumed in the production of LNG at the LNG Facilities; and (ii) losses of Gas. Process Fuel Gas is deemed to be a quantity equal to 1% (one percent) of the LNG Dispensed to the Customer until and including the next annual rate update for this Rate Schedule after the Available LNG Capacity exceeds 20,000 Gigajoules per Day, but thereafter the Process Fuel Gas percentage will be updated annually based on the prior year's actual percentages of Gas consumed and losses of Gas at the LNG Facilities.

Rate Schedule 46 Reference Information and Amendments			
Section Number	**Section Name**	**Existing Tariff Language**	**Amended Tariff Language**
8.4	**Payment of Amounts**	**8.4 Payment of Amounts -** The Customer will pay to FortisBC Energy all of the applicable charges set out in the Table of Charges for LNG Service and, if applicable, Table of Charges for LNG Transportation Service.	**8.4 Payment of Amounts -** The Customer will pay to FortisBC Energy all of the applicable charges set out in the Table of Charges for LNG Service and, if applicable, Table of Charges for LNG Transportation Service. If the LNG Dispensed from the LNG Facilities is hauled to a Customer designated location and will be distributed at that location to more than one Customer, the applicable charges will be proportionately allocated among Customers based on the quantity of LNG distributed to each Customer.
9.1	**Requested Quantity and Loading Schedule**	**9.1 Requested Quantity and Loading Schedule -** At least 24 hours in advance of the Day of the Customer's desired loading time, the Customer or its agent will provide FortisBC Energy by fax or email such information as may be requested by FortisBC Energy, which will include, but is not limited to, the Customer's requested quantity of LNG for the given Day.	**9.1 Requested Quantity and Loading Schedule -** At least ~~24~~ 48 hours in advance of the Day of the Customer's desired loading time, the Customer or its agent will provide FortisBC Energy by fax or email such information as may be requested by FortisBC Energy, which will include, but is not limited to, the Customer's requested quantity of LNG for the given Day. (a) FortisBC Energy may charge a fee for loading LNG of $150 per hour when loading takes in excess of two hours; and (b)If the Customer cancels a scheduled loading time with less than 12 hours notice, FortisBC Energy may charge a fee of $500.

Rate Schedule 46 Reference Information and Amendments			
Section Number	**Section Name**	**Existing Tariff Language**	**Amended Tariff Language**
12.2	**Determination of Quantity**	**12.2 Determination of Quantity -** The quantity of LNG Dispensed pursuant to this Rate Schedule shall be measured at the scale at the LNG Facilities or an alternate scale that is approved and certified by Measurement Canada. The Tanker or other cryogenic receptacle into which the LNG is Dispensed will be weighed at the scale before and after Dispensing. The measurement of the amount of LNG Dispensed shall be based on the difference, expressed in kilograms or pounds, of these two weights. In the event that the cryogenic receptacle cannot be weighed by the scale, then the quantity of LNG Dispensed shall be measured through the use of mass flow meters.	**12.2 Determination of Quantity -** The quantity of LNG Dispensed pursuant to this Rate Schedule shall be measured at the scale at the LNG Facilities or an alternate scale that is approved and certified by Measurement Canada. The Tanker or other cryogenic receptacle into which the LNG is Dispensed will be weighed at the scale before and after Dispensing. The measurement of the amount of LNG Dispensed shall be based on the difference, expressed in kilograms or pounds, of these two weights. In the event that the cryogenic receptacle cannot be weighed by the scale, then the quantity of LNG Dispensed shall be measured through the use of ~~mass flow meters~~ <u>other industry standard measuring methods and measuring equipment</u>.
15.3	**Customer Indemnity**	**[new section 15.3 added]**	<u>**15.3 Customer Indemnity for LNG Transportation -** Notwithstanding section 15.2, the Customer will indemnify and hold harmless FortisBC Energy, its employees, contractors and agents from all claims, losses, suits, actions, judgments, demands, debts, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) arising from or out of the conduct of the Customer, its employees, contractors and agents where the Customer is responsible for providing a Tanker and movement of the Tanker from the LNG Facilities.</u>

Rate Schedule 46 Reference Information and Amendments			
Section Number	**Section Name**	**Existing Tariff Language**	**Amended Tariff Language**
Table of Charges	**Table of Charges for LNG Transportation Service**	**[new Note 1 added]**	**Notes:** 1. The charges set out in this Table of Charges are not applicable if the Tanker is used as both Dispensing equipment for LNG Service and as equipment for LNG Transportation Service.
Table of Charges	**Table of Charges for LNG Service**	**Note 3 (2) (b):** The Electricity Surcharge shall be adjusted based upon the actual prior year electricity use per Gigajoule of LNG output of the LNG Facilities and actual BC Hydro rate increases incurred at the LNG Facilities.	**Note 3 (2) (b):** The Electricity Surcharge shall be adjusted by a 2% increase in 2015 and each subsequent year until and including the next annual rate update for this Rate Schedule after the Available LNG capacity exceeds 20,000 Gigajoules per Day, but thereafter shall be adjusted based upon the estimated prior year electricity use per Gigajoule of LNG output of the LNG Facilities and approved interim or permanent BC Hydro rate increases incurred at the LNG Facilities.
Table of Charges	**Table of Charges for LNG Service**	**[new Note 4 added]**	**Notes:** 4. The charges for transporting natural gas from the Interconnection Point to the LNG Facilities, defined as "firm demand toll" and as set out in Table of Charges in FortisBC Energy Rate Schedule 50, are embedded in the LNG Facility Charge in this Rate Schedule.
Table of Charges	**Table of Charges for LNG Service**	**[new Note 5 added]**	**Notes:** 5. Process Fuel Gas is applied as set out in section 8.1 (i) (B).

LNG Transportation Service Agreement, Section 5	**5. Request for Transportation Sevice**	5.1 Subject to section 6.2 (availability of LNG Tranporation Service) of Rate Schedule 46, if the Customer wishes to use LNG Transportation Service, the Customer or its agents shall notify FortisBC Energy by fax or email prior to 12:00 Pacific Standard Time (or other such time as may be specified from time to by FortisBc Energy) and provide FortisBC Energy with such information as may be requested by FortisBC Energy, which shall include, but is not limited to, the Customer's desied quantity of LNG and the desired date and time of arrival of LNG at the Customer designated location, provided FortisBC Energy receives such notice no later than 48 hours prior to the requested date and time of arrival of the Tanker at the Customer designated location.	5.1 Subject to section 6.2 (availability of LNG Tranporation Service) of Rate Schedule 46, if the Customer wishes to use LNG Transportation Service, the Customer or its agents shall notify FortisBC Energy by fax or email prior to 12:00 Pacific Standard Time (or other such time as may be specified from time to by FortisBc Energy) and provide FortisBC Energy with such information as may be requested by FortisBC Energy, which shall include, but is not limited to, the Customer's ~~desied~~ desired quantity of LNG and the desired date and time of arrival of LNG at the Customer designated location~~, provided FortisBC Energy receives such notice no later than 48 hours prior to the requested date and time of arrival of the Tanker at the Customer designated location~~.
LNG Transportation Service Agreement, Section 11	**11. Termination**	11.3 Either party may terminate the Agreement at any time upon giving 120 calendar days prior written notice to the other party.	~~11.3 Either party may terminate the Agreement at any time upon giving 120 calendar days prior written notice to the other party.~~

B.C. Reg. 245/2013
O.C. 557/2013

Deposited November 28, 2013

Utilities Commission Act

DIRECTION NO. 5 TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Note: Check the Cumulative Regulation Bulletin 2015 and 2016
for any non-consolidated amendments to this regulation that may be in effect.

[includes amendments up to B.C. Reg. 265/2014, December 22, 2014]

Link to Point in Time

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1 Definitions
2 Application
3 CNG services and LNG services
4 Expansion facilities
5 LNG rate schedule and LNG purchase agreement
6 Transportation rate schedule
7 EGP project
8 CTS expansion projects
9 Letter agreement

Appendix 1 and Appendix 2

Appendix 3 to Appendix 5

Definitions

1 (1) In this direction:

"Act" means the *Utilities Commission Act*;

"applicable customers" means customers of a utility other than customers receiving service

(a) under a fixed rate,

(b) in the Fort Nelson service area of the utility, unless the Fort Nelson service area no longer has a distinct rate base, or

(c) under the transportation rate schedule;

"CNG" means compressed natural gas;

"CNG service" means a service that includes one or both of the following:

(a) compressing and dispensing of natural gas through specialized fuelling facilities or equipment;

(b) transporting CNG using specialized trailers or equipment;

"construction carrying costs" means a return on the feasibility, development and capital costs of a facility, equal to the utility's weighted average cost of capital, that will be incurred during the period ending when the facility enters a utility's natural gas class of service rate base;

"contract demand" has the same meaning as in the LNG rate schedule;

"CTS expansion project" means any of the following projects:

(a) the project to expand the transmission facilities of FortisBC Energy Inc. at and between the Cape Horn Valve Assembly and Coquitlam Gate Station;

(b) the project to expand the transmission facilities of FortisBC Energy Inc. at and between the Nichol Valve Assembly and Port Mann Crossover Station;

(c) the project to expand the transmission facilities of FortisBC Energy Inc. at and between the Nichol Valve Assembly and Roebuck Valve Assembly;

(d) the project to expand the transmission facilities of FortisBC Energy Inc. at and between the Tilbury Gate Station and Tilbury LNG Facility;

"EGP project" means the project to expand the transmission facilities of FortisBC Energy (Vancouver Island) Inc at and between the Eagle Mountain Compressor Station in Coquitlam and an LNG Facility in Woodfibre, and at the Port Mellon Compressor Station;

"expansion facilities" means LNG facilities to be constructed, owned and operated, after this direction comes into force, by a utility at Tilbury Island, Delta, British Columbia;

"extraordinary retirement costs" means asset retirement costs from causes not reasonably anticipated when calculating the depreciation of the asset;

"fixed rate" means a charge for natural gas service not subject to adjustment based on changes in the revenue requirements of a utility;

"letter agreement" means the letter agreement as set out in Appendix 3 attached to this direction;

"liquefaction capacity" means the capacity of an LNG facility, measured in terajoules per day, to liquefy natural gas to produce LNG;

"LNG" means liquefied natural gas;

"LNG agreement" has the same meaning as in the LNG rate schedule;

"LNG dispensing service" means the dispensing service referred to in sections 3 to 5 of the LNG rate schedule;

"LNG facility" means a facility that produces, stores and dispenses LNG and, in some cases, vaporizes LNG;

"LNG rate schedule" means the utility's Liquefied Natural Gas Sales, Dispensing and Transportation Service Rate Schedule 46 as set out in Appendix 1 attached to this direction;

"LNG revenue variance regulatory account" means an account to capture the first 3 annual revenue variances between

(a) the forecast revenues from the LNG rate schedule that are used by the commission in setting rates for applicable customers, and

(b) the actual annual revenues received under the LNG rate schedule;

"LNG service" means one or more of the following services:

(a) procurement of natural gas and electrical power for the purposes of LNG production;

(b) procurement of LNG;

(c) transmission and distribution of natural gas to an LNG facility;

(d) production of LNG from natural gas at an LNG facility;

(e) storage of LNG;

(f) provision or sale of LNG, including LNG dispensing service;

(g) use of LNG fuelling stations and fuelling equipment;

(h) transportation of LNG, including LNG transportation service;

(i) use of cryogenic receptacles, including, but not limited to, tankers, containers and vessels;

"LNG transportation service" means the transportation service referred to in section 6 of the LNG rate schedule;

"long-term LNG service" has the same meaning as in the LNG rate schedule;

"operating costs", in relation to a facility, means

(a) operating and maintenance expenses,

(b) electricity expenses,

(c) interest expenses,

(d) taxes, including property taxes,

(e) return on equity,

(f) extraordinary retirement costs, and

(g) amounts with respect to the depreciation of the

(i) capital costs,

(ii) construction carrying costs,

(iii) feasibility and development costs,

(iv) sustaining capital costs, and

(v) decommissioning and salvaging costs

determined with reference to the remaining service life of the facility, as estimated by the commission in setting rates for applicable customers;

"operation period", with respect to phase 1B facilities, means the period beginning on the date those facilities begin operations and ending 15 years later;

"phase 1A facilities" means expansion facilities to provide

(a) liquefaction capacity of up to 40 terajoules per day of LNG, and

(b) storage capacity of between 1.0 petajoules and 1.1 petajoules of LNG;

"phase 1B facilities" means expansion facilities other than phase 1A facilities, but does not include LNG storage facilities;

"specified agreement" means an LNG agreement for long-term LNG service having

(a) a contract term of 10 years or more, and

(b) a contract demand specified for 10 years or more of the contract term;

"sustaining capital costs" means capital costs expended for the purpose of maintaining or extending the life of an asset;

"transportation rate schedule" means the Large Volume Industrial Transportation Rate Schedule 50 of FortisBC Energy Inc. as set out in Appendix 4 attached to this direction;

"utility" means

(a) FortisBC Energy Inc.,

(b) FortisBC Energy (Vancouver Island) Inc., or

(c) FortisBC Energy (Whistler) Inc.,

or any of those entities' successor entities on amalgamation, merger or consolidation.

(2) In this direction, a reference to a utility referred to in the definition of "utility" in subsection (1) includes any successor entities of that utility on amalgamation, merger or consolidation.

[am. B.C. Reg. 265/2014, s. 1.]

Application

2 This direction is issued to the commission under section 3 of the Act.

CNG services and LNG services

3 In setting rates under the Act for a utility, the commission must do all of the following:

(a) treat CNG service and LNG service, and all costs and revenues related to those services, as part of the utility's natural gas class of service;

(b) allocate all costs and revenues related to CNG service and LNG service to all applicable customers;

(c) allow recovery of costs of purchasing LNG under the agreement referred to in section 5 (1) (b) of this direction.

Expansion facilities

4 (1) The commission must not exercise its power under section 45 (5) of the Act in respect of

(a) phase 1A facilities, and

(b) phase 1B facilities, if, on the date construction of phase 1B facilities begins, specified agreements are in place representing an average of at least 70% of the intended liquefaction capacity of the phase 1B facilities for the operation period, calculated as follows:

$$AV = Y/15$$

where

AV	=	the average of the intended liquefaction capacity of phase 1B facilities for the operation period;
Y	=	the sum of the amounts of intended liquefaction capacity of phase 1B facilities represented by specified agreements for each year of the operation period.

(2) In setting rates under the Act for FortisBC Energy Inc., the commission must do all of the following:

(a) on January 1 of the year immediately following the year in which phase 1A facilities are completed, include in the utility's natural gas class of service rate base the sum of the following:

(i) the lesser of

(A) the capital costs of the phase 1A facilities, and

(B) $400 million;

(ii) the construction carrying costs for the phase 1A facilities;

(iii) the feasibility and development costs incurred on or after January 1, 2013;

(b) on January 1 of the year immediately following the year in which phase 1B facilities are completed, include in the utility's natural gas class of service rate base the sum of the following:

(i) the lesser of

(A) the capital costs of phase 1B facilities, and

(B) $400 million;

(ii) the construction carrying costs for phase 1B facilities;

(iii) the feasibility and development costs incurred on or after January 1, 2013;

(c) include in the calculation of rates for applicable customers

(i) the annual revenues from the sale of LNG from phase 1A facilities and phase 1B facilities,

(ii) the annual operating costs of phase 1A facilities and phase 1B facilities, and

(iii) the capital costs, construction carrying costs, sustaining capital costs, decommissioning and salvaging costs and feasibility and development costs respecting phase 1A facilities and phase 1B facilities;

(d) allow a utility to establish an LNG revenue variance regulatory account for the following 2 purposes, if applicable:

(i) for the operation of the phase 1A facilities;

(ii) for the operation of the phase 1B facilities;

(e) set rates for applicable customers in such a way as to allow the LNG revenue variance regulatory account to be cleared from time to time, and within a reasonable period by allowing the balance to be returned to or recovered from applicable customers.

[en. B.C. Reg. 265/2014, s. 2.]

LNG rate schedule and LNG purchase agreement

5 (1) Within 20 days of the date this direction comes into force, the commission must do all of the following:

(a) issue an order setting the LNG rate schedule as a rate for FortisBC Energy Inc., effective on the date the order is issued;

(b) accept for filing under section 71 of the Act the Gas Liquefaction, Storage and Dispensing Service Agreement between FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy Inc. as set out in Appendix 2 attached to this direction;

(c) issue an order setting the agreement referred to in paragraph (b) as a rate for FortisBC Energy (Vancouver Island) Inc.

(1.1) Before January 1, 2015, the commission must issue an order amending the LNG rate schedule as set out in Appendix 5 attached to this direction, effective on January 1, 2015.

(2) The commission must not do anything to amend, cancel or suspend the LNG rate schedule, except on application by the utility.

(3) If FortisBC Energy Inc. applies to the commission to amend a charge in the LNG rate schedule, the commission must not set the charge by reference to charges imposed by other providers providing similar services.

(4) The commission must not exercise a power under the Act in a way that would directly or indirectly prevent FortisBC Energy Inc. from providing LNG dispensing service under the LNG rate schedule.

[am. B.C. Reg. 265/2014, s. 3.]

Transportation rate schedule

6 (1) Within 60 days of the date this section comes into force, the commission must issue an order setting the transportation rate schedule as a rate for FortisBC Energy Inc., effective on the date the order is issued.

(2) In calculating rates for applicable customers, the commission must include the annual revenues and operating costs arising from services provided under the transportation rate schedule.

(3) Section 5 (2) applies to the transportation rate schedule.

(4) The commission must not exercise a power under the Act in a way that would directly or indirectly prevent FortisBC Energy Inc. from providing service under the transportation rate schedule.

(5) If the shipper is not creditworthy and has not provided the guarantee referred to in section 13.2 (b) of the transportation rate schedule, the commission must set the required security amount on the basis of the following:

(a) the shipper's creditworthiness;

(b) the contract demand and the contract term of the transportation agreement;

(c) the book value of the incremental system upgrades constructed, acquired, contracted for or secured by a utility to serve the shipper;

(d) any other matter the commission considers relevant.

(6) Terms used in subsection (4) and not defined in this direction have the same meaning as in the transportation rate schedule.

[en. B.C. Reg. 265/2014, s. 4.]

EGP project

7 (1) Within 60 days of the date this section comes into force, the commission must, by regulation under section 45 (4) of the Act, exclude the EGP project from the operation of section 45 (1) of the Act.

(2) In setting rates under the Act for FortisBC Energy (Vancouver Island) Inc., the commission must

(a) on January 1 of the year immediately following the year in which the EGP project is completed, include in the utility's natural gas class of service rate base the capital costs, construction carrying costs and feasibility and development costs for the EGP project,

(b) allow the utility to earn a return on the costs referred to in paragraph (a), and

(c) include in the calculation of rates for applicable customers

(i) the annual operating costs of the EGP project, and

(ii) the capital costs, construction carrying costs, sustaining capital costs, decommissioning and salvaging costs and feasibility and development costs respecting the EGP project.

[en. B.C. Reg. 265/2014, s. 4.]

CTS expansion projects

8 (1) The commission must refrain from exercising its power under section 45 (5) of the Act with respect to a CTS expansion project.

(2) In setting rates under the Act for FortisBC Energy Inc., the commission must

(a) on January 1 of the year immediately following the year in which a CTS expansion project is completed, include in the utility's natural gas class of service rate base the capital costs, construction carrying costs and feasibility and development costs for the CTS expansion project,

(b) allow the utility to earn a return on the costs referred to in paragraph (a), and

(c) include in the calculation of rates for applicable customers

(i) the annual operating costs of the CTS expansion project, and

(ii) the capital costs, construction carrying costs, sustaining capital costs, decommissioning and salvaging costs and feasibility and development costs respecting the CTS expansion project.

[en. B.C. Reg. 265/2014, s. 4.]

Letter agreement

9 (1) Within 60 days of the date this section comes into force, the commission must issue an order setting the letter agreement as a rate for FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc., effective, subject to section 2.1 of the letter agreement, on the date the order is issued.

(2) Section 5 (2) applies to the letter agreement.

[en. B.C. Reg. 265/2014, s. 4.]

Appendix 1 and Appendix 2

The appendices are not included in this consolidation. The text of the appendices is available to read in Volume 56, No. 23 of the British Columbia Gazette, Part II and online at http://www.qplegaleze.ca and http://www.bclaws.ca.

Appendix 3 to Appendix 5

[en. B.C. Reg. 265/2014, s. 5.]

The appendices are not included in this consolidation. The text of the appendices is available to read in Volume 57, No. 23 of the British Columbia Gazette, Part II and online at http://www.qplegaleze.ca and http://www.bclaws.ca.

[Provisions relevant to the enactment of this regulation: *Utilities Commission Act*, R.S.B.C. 1996, c. 473, section 3]

Appendix 4

STAKEHOLDER ENGAGEMENT

Appendix 4-1

PRE-APPLICATION PARTICIPANT FUNDING GUIDELINES

Pre-Application Participant Funding Guidelines

Overview

FEI anticipates filing the 2016 Rate Design Application (2016 RDA) with the British Columbia Utilities Commission (BCUC) in October of 2016.[1] In advance of the filing, to facilitate the understanding of FEI's upcoming application and to achieve regulatory efficiency, FEI expects to follow a pre-filing consultation and workshop schedule consisting of several sessions as shown in Table 1 below.[2]

FEI recognizes that some stakeholders may require funding to cover their costs for participating in the sessions that will occur in advance of FEI filing the 2016 RDA with the BCUC. As such, this document outlines the guidelines for pre-application funding that may be provided by FEI to eligible stakeholders.

FEI will capture any funding provided to stakeholders in the Commission approved 2017 Rate Design Deferral Account and, similar to all additions to this deferral account, pre-application stakeholder funding will be subject to Commission review and approval.[3]

Table 1: 2016 RDA Anticipated Pre-Filing Consultation and Workshop Schedule

Session	Date (2016)	Duration	Purpose of Session
Introductory Application Information Session	February 26	2.5 hours	Overview of application timing and purpose, introduction of stakeholders and project team members and brief issue identification discussion
Education and Background Session	May 19	1 Day	Overview of FEI sales and transportation service, including existing rate schedules and service offerings. Overview of rate design process, including cost of service study, segmentation and rate structure fundamentals. Overview of FEI rate design history.
Session 1 and 1B	June TBD	1.5 Days	Discussion of updated Cost of Service Study results and allocations related to both delivery and cost of gas. One half day session to be focused on Fort Nelson results.
Session 2	July TBD	0.5 to 1 Day	Discussion of results from segmentation analysis and any proposed changes to rate schedules and rate design
Session 2B	July TBD	0.5 to 1 Day	Discussion of options and proposed changes to Transportation related services
Session 3 and 3B	August TBD	1.5 Days	Discussion of proposed changes to Terms and Conditions of Service and updated results and analysis from previous sessions. One half day session to be focused on Fort Nelson results.

1 In accordance with Order G-21-14 the 2016 RDA must be filed by December 31, 2016.
2 Please note that Table 1 was amended based on the information received at the February 26, 2016 workshop.
3 Decision accompanying Order G-86-15, Section 3.3 page 24 and Directive 21 as identified in Section 5.

Eligibility

The following stakeholders are eligible to request for funding if they:

- represent a ratepayer group(s); or
- clearly demonstrate that they do not have the means to fund their own participation.

Further, consistent with current BCUC Participant Assistance/Cost Award Guidelines (Order G-72-07), FEI will also consider whether the stakeholder's participation in the pre-application process is likely to meet the "substantial interest in a substantial issue" criterion as it may relate to the 2016 RDA.[4]

Eligible Costs and Rates

Eligible costs will be limited to time associated with preparation for and attendance of the sessions listed in Table 1 above and may include meal and travel costs for out of town participants.

FEI will use the Legal Fee, Consultant and Travel Rates as set out in Appendix A to Order G-72-07 as a guideline when evaluating budget and cost award requests from stakeholders. These include daily legal fees in the range of $1,200 to $1,800 per day, daily consultant fees in the range of $640 to $1,450 per day, case manager fees to a maximum of $500 per day, daily meal allowances of $49 per day, mileage rates of $0.54/km and economy airfare.[5]

FEI will treat pre-application session participation based on one-half or one proceeding day, depending on the actual length of each session. Where reports or other material are circulated in advance to participants for review in preparation for the session, the ratio of two to one will apply (i.e., one preparation day per 0.5 day session, or 2 preparation days per one session day). Where materials are not circulated, the workshop attendance will be treated based on the actual length (one-half day or one day).

Budget Submissions

Stakeholders eligible for funding must submit a budget of their funding request to FEI by April 29, 2016. This funding budget must provide an estimate of hours broken down by category (legal counsel, consultant, applicable daily rate(s), and applicable travel or disbursement costs). This funding budget must be in written form and provided by way of a letter addressed to FortisBC Energy Inc. Regulatory Services and submitted to Gas.Regulatory.Affairs@fortisbc.com.

FEI will confirm receipt of the funding request and will contact the stakeholder by May 16, 2016 if there are any concerns with the budget as submitted.

[4] Appendix A to Order G-72-07, page 1

[5] Please note that FEI does not expect stakeholders to seek reimbursement for foregone earnings for the pre-application process. Further, the mileage rate has been updated based on the reasonable per-kilometre allowance rate for 2016 as provided by the Canada Revenue Agency (http://www.cra-arc.gc.ca/tx/bsnss/tpcs/pyrll/bnfts/tmbl/llwnc/nntx-eng.html).

Cost Award Submissions

Stakeholders must submit to FEI (Gas.Regulatory.Affairs@fortisbc.com) an itemized invoice for funding within 60 days of the final pre-application session. The invoice must provide a breakdown of costs by category, including applicable GST/PST, the hours claimed, applicable daily rates, and disbursements as well, itemized travel costs and receipts if applicable. The invoice must also provide a breakdown of costs directly attributable to the Fort Nelson Service Area, if applicable. Where the actual cost award requests are more than $500 of the submitted funding budget, the stakeholder must also provide a comparison to the funding budget and a discussion of reasons for the variance. The invoice must state clearly who the amount is payable to, including the mailing address.

FEI will confirm receipt of the invoice and will contact the stakeholder if there are any concerns with the request for payment as submitted.

FEI will determine the entitlement to a full or partial payment taking into account these guidelines, the variance from the budgeted cost and any supporting information provided by the stakeholder.

Appendix 4-2

STAKEHOLDER FEEDBACK, NOTES AND ACTION ITEMS

2016 Rate Design Application
FortisBC Energy Inc. (FEI)

Stakeholder Introductory Information Session

February 26, 2016

FORTIS BC™

Agenda

Rate Design Application Overview

- Anticipated process & schedule
- Scope of application
- Topics to be addressed as currently planned

Roundtable

- General areas of interest
- Topics and issues that you would like to see FEI address with this Application
- Feedback on process & schedule as currently planned

Stakeholder Funding

- Guidelines for funding stakeholder participation prior to Application filing
- Process for receiving funding

Next Steps

FEI Rate Design History

This will be the first Rate Design Application covering the amalgamated entity

Application required to be filed by December 31, 2016 in accordance with the Amalgamation Reconsideration Decision

- 2012 FortisBC Energy Utilities (FEU) Common Rates, Amalgamation and Rate Design Application
  - Approval by Commission Order G-21-14, (and in accordance with Order in Council No. 300), to amalgamate FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc., and to adopt common rates effective January 1, 2015 (with three year phase-in period)
  - Main purpose of rate design information in this proceeding was to demonstrate that FEVI and FEW could be added to existing FEI rate schedules
- 2010 and 2011 Revenue Requirements Application
  - Revenue deficiencies or surpluses flowed through to volumetric and demand charges only; with basic and admin charges to remain at existing levels
- 2004 Customer Choice Unbundling Program
  - Unbundling of the gas supply costs for Core Market customers, small and large commercial in 2004 and residential in 2007
  - Separation of the Gas Cost Reconciliation Account (GCRA) into two deferral accounts, the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA)
  - Otherwise largely retained the same rate design for gas costs

FEI Rate Design History

- 2001 Rate Design
  - Rebalancing of residential and large industrial rates as a result of a negotiated settlement process
  - Higher basic charges to be more in line with fixed costs
- 1996 Rate Design
  - Rebalancing of residential and large industrial rates as a result of negotiated settlement process
  - Higher basic charges more in line with fixed costs
- 1993 Rate Design (“Phase B”)
  - Development of postage stamp Core Market rate class basic and delivery rate structures while maintaining regional large industrial rate structures
  - Development of the GCRA deferral account
- 1991 Rate Design (“Phase A”)
  - Gas cost allocation methodology responding to the deregulation of the gas supply environment
  - Development of regional Core Market gas cost rates for each of the FEI service areas

FEI Gas Tariff Rate Schedules

Residential Service	**Rate Schedule 1** – *Residential Service*
	Rate Schedule 1B – *Residential Biomethane Service*
	Rate Schedule 1U – *Residential Unbundling Service*
Small Commercial Service	**Rate Schedule 2** – *Small Commercial Service (<2,000 GJs)*
	Rate Schedule 2B – *Small Commercial Biomethane Service*
	Rate Schedule 2U – *Small Commercial Unbundling Service*
Large Commercial Service	**Rate Schedule 3** – *Large Commercial Service (>2,000 GJs)*
	Rate Schedule 3B – *Large Commercial Biomethane Service*
	Rate Schedule 3U – *Large Commercial Unbundling Service*
General Firm Service	**Rate Schedule 5** – *General Firm Service (Demand Charge)*
	Rate Schedule 5B – *General Firm Biomethane Service*

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FEI Gas Tariff Rate Schedules

Distribution Rate Schedules	**Rate Schedule 4** – *Seasonal Firm Service*
	Rate Schedule 6 – *Natural Gas Vehicle Service (Gas Stations)*
	Rate Schedule 6P – *Public Service (Surrey Ops Pump)*
	Rate Schedule 7 – *General Interruptible Service*
Transportation Rate Schedules	**Rate Schedule 22** – *Large Volume Transportation (Min Quantity of 12,000 GJs per Month)*
	Rate Schedule 23 – *Commercial Transportation Service (>2,000 GJs)*
	Rate Schedule 25 – *General Firm Transportation Service (Demand Charge)*
	Rate Schedule 27 – *General Interruptible Transportation Service*
	Rate Schedule 50 – *Large Volume Industrial Transportation*
Other Rate Schedules	**Rate Schedule 11B** – *Biomethane Large Volume Interruptible Sales*
	Rate Schedule 14A – *Term and Spot Gas Sales*
	Rate Schedule 36 – *Commodity Unbundling Service (Terms and Conditions)*
	Rate Schedule 46 – *LNG Sales, Dispensing and Transportation Service*

Process & Schedule as Currently Planned

Milestone	Anticipated Date	Notes
Session 1: Preliminary Allocation Recommendations for Discussion	June 2016	Review of delivery & cost of gas COSA and potential rebalancing impacts
Session 1B: Fort Nelson Preliminary Recommendations for Discussion	June 2016	To be held in Fort Nelson
Session 2: Segmentation & Rate Design Recommendations	July 2016	Discussion of options and proposed changes to rate schedules and rate design
Session 2B: Transportation Model Recommendations for Discussion	July 2016	Discussion of options and proposed changes to Transportation related services
Session 3: Proposed Changes to Terms & Conditions and Updated Results & Recommendations from Sessions 1 & 2	August 2016	Proposals are expected to form the basis of the Application
Session 3B: Fort Nelson Proposed Changes to Terms & Conditions and Updated Results & Recommendations from Sessions 1 & 2	August 2016	To be held in Fort Nelson
Application Filed	**October 2016**	**Early October filing planned**
Effective Date for Rates that reflect Decision	January 1, 2018	Date aligned with completion of phase-in to common rates

FEI's Public Consultation Session Expectations

Material for Review	Target of minimum 2 weeks in advance of each planned session
	Ex. COSA study results, allocation options, segmentation analysis, proposed changes to terms and conditions, balancing charge recommendations and options, etc.
Interactive and Efficient	Active stakeholder participation and focused feedback
	Anticipated brief presentation with majority of time allocated for discussion
	Each session expected to be a minimum of ½ day but may extend the entire day

Application Scope

General	Cost Allocation Methodologies- *how costs are broken down*
	Customer Segmentation- *how customers are grouped*
	Rate Structure Design- *how costs are recovered*
Gas Costs	Cost Allocation Methodologies
	Review of Transportation Model, including balancing service
	Potential new capacity service for Transportation customers
Terms and Conditions	Tariff changes (housekeeping as well changes to reflect segmentation and rate structure changes, if any)
Fort Nelson	Common rate evaluation
	Stand alone cost allocation, rebalancing and rate design
Out of Scope	Bypass and special contract rates
	Rate Schedule 46 (LNG) and Rate Schedule 50 (Large Volume Contract Transportation)

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Key Topics to be Addressed

Cost Allocation	Segmentation	Rate Design	Other?
• LNG infrastructure related costs (Tilbury & Mt. Hayes) • Impact of major projects such as the Lower Mainland Intermediate Pressure System Upgrade Project • Southern Crossing Pipeline allocation • Rebalancing	• Appropriateness of existing segmentation • Lower volume residential customers • Multi-family dwellings • District Energy Systems that use Natural Gas for system peaking and back-up	• Fixed and variable components • Demand charges • NGT Fueling Station OH&M Charge • Balancing charges	• Roundtable discussion • Topics that develop through consultation process

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Roundtable Discussion

- General areas of interest pertinent to this Application
- Topics and issues that you would like to see FEI address with this Application
- Feedback on process & schedule

Stakeholder Funding for Pre-application Consultation Sessions

- FEI will provide document by March 30th regarding the guidelines for pre-application funding
- Subject to changes to PACA guidelines, FEI expects to follow a process and funding model similar to the currently established PACA guidelines
  - Any participant who intends to participate in the consultation process must submit a budget estimate to FEI by Friday, April 29th
  - FEI expects that costs will be limited to time associated with session preparation and attendance
  - Funding will be limited to stakeholders representing ratepayer groups and other stakeholders that have demonstrated not to have the means to fund their own participation without assistance

Next Steps

Documentation

- FEI will distribute notes from this Information Session by Friday, March 4th

Funding

- Subject to changes to PACA guidelines and the pre-application funding document provided by FEI, Stakeholders should plan to submit funding estimates by April 29th
- If there are any concerns, you will be contacted by FEI by May 16th

Communication

- FEI Gas Rate Design website will be established in the coming months

Session 1

- Preparation for Session 1 and 1B that is expected to occur in June to discuss and evaluate preliminary recommendations

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For further information, please contact:

Gas.Regulatory.Affairs@fortisbc.com

Find FortisBC at:

Fortisbc.com

604-576-7000

2016 FEI Rate Design Application

Draft List of Past BCUC Directives

FEI Application/Proceeding	BCUC Order No.	Date	Applicable Directive(s)/Reference
FortisBC Energy Utilities (FEU) Application for Reconsideration and Variance of Commission Order G-26-13 on the FEUs' Common Rates, Amalgamation and Rate Design Application	G-21-14	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 Section Fort Nelson):** 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.**

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FEI Application/Proceeding	BCUC Order No.	Date	Applicable Directive(s)/Reference
FEI Application for Approval to Amend the Balancing Charges for Rate Schedules 23, 25, 26 and 27	G-187-14	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.
FEI Application for Reconsideration of Order G-187-14 to Amend the Balancing Gas Charges for Rate Schedules 23, 25, 26 and 27	G-135-15	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. **3.** 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.

FEI Application/Proceeding	BCUC Order No.	Date	Applicable Directive(s)/Reference
FEI Response to British Columbia Utilities Commission Order G-105-15 – Directive to Recalculate the Overhead and Marketing Charge	G-105-15	Filed August 21, 2015	**On page 3 of the compliance filing, 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 Application/Proceeding	BCUC Order No.	Date	Applicable Directive(s)/Reference
FEVI Application for Approval of 2014 Revenue Requirements and Rates	G-15-14	May 23, 2014	**Page 15 of the Decision:** <u>5.1.3 Industrial Demand</u> For the 2014 test year, FEVI forecasts no customer growth for the Industrial customers (Exhibit B-1, p. 24). Demand from the Industrial rate classes is forecast to remain at approximately 23.2 PJs based on current contracts (Exhibit B-10, BCUC IR 2.5.1). FEVI states in response to CEC IR 1.5.4 that in the Industrial rate group, a very small number of customers account for the majority of the load, which is why the Industrial customer group did not experience a corresponding increase in demand relative to customer additions (Exhibit B-3, p. 9). FEVI further states in response to CEC IR 1.4.3 that it is heavily reliant on throughput and revenue from two major Industrial customers: (i) the Vancouver Island Gas Joint Venture and (ii) BC Hydro for Island Generation in Campbell River (Exhibit B-3, p. 6). **FEVI submits in its response to BCUC IR 2.5.2 that it will review the methodology for its Industrial demand forecast in its next rate design (Exhibit B-10, p. 20).**

FEI Application/Proceeding	BCUC Order No.	Date	Applicable Directive(s)/Reference
FEVI Application CPCN Application to Enter into a Storage and Delivery Agreement and FEI Application to Enter into a Storage and Delivery Agreement	C-9-07	November 15, 2007	**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.

FEI Application/Proceeding	BCUC Order No.	Date	Applicable Directive(s)/Reference
FEI Application for Approval of Rate Schedule 22 Tariff Supplement No. G-21 Firm Transportation Service Agreement for Central Heat Distribution Ltd. (Creative Energy Vancouver Platforms Inc.)	G-128-05	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.
FEI Application for a CPCN for the Southern Crossing Pipeline Project	G-51-99	May 21, 1999	**Page 51 of the Decision (from Section 7.4 Customer Views):** The Lower Mainland Large Volume Gas Users Association ("LMLGUA") opposed the SCP in its February submission but did not provide further evidence or make final argument in the hearing (Exhibit LMLGUA-1). The Commission notes that the LMLGUA opposes the SCP because of a concern that some costs of the pipeline will be allocated to LMLGUA members. ***This rate design matter will be dealt with in a future proceeding but the Commission anticipates that all ratepayers who benefit from the SCP, directly or indirectly, will contribute to its costs in proportion to the benefit it provides to each rate category.***

Information Session Summary

Meeting:	Stakeholder Information Session
Date:	February 26, 2016
Time:	9am to 11am
Location:	BCUC Hearing Room, 12th Floor, 1125 Howe Street, Vancouver
Facilitator:	Michelle Carman, FEI
Participants:	Andrews, Bill (BCSEA); Braithwaite, Tannis (BCPIAC); Caumanns, Nick (Cascadia Energy); Connelly, Steve (Cascadia Energy); Craig, David (CEC); Dixon, Tom (Access Gas); Doyle, Gordon (BC Hydro); Fuhr, Ken (Independent Energy Consultants) via teleconference; Hackney, Tom (BCSEA) via teleconference; Langley, James (Sentinel Energy Mgmt); Marr, Cathy (BCUC); McCordic, Mary (Shell Energy); Morrow , Kirby (Absolute Energy); Running, Melissa (Absolute Energy); Vandersteen, Bev (Fort Nelson & District Chamber of Commerce [FNDCC]) via Teleconference; Walsh, Sarah (BCUC); Weafer, Chris (CEC);
FEI Attendees:	Bevacqua, Ilva; Carman, Michelle; Gosselin, Rick; Gravel, Colleen; Hill, Shawn; Hill, Song; Hodgins, Kevin; Hopping, Uschi; Moore, Ed; Salbach, Stephanie; Sinclair, Corey;
Material Provided	Presentation and Draft List of Directives attached following notes.
Agenda:	1. Welcome and Introductions 2. Overview of Application • Anticipated Process & Schedule • Scope • Topics to be Addressed 3. Roundtable • General areas of interest • Topics and issues that you would like to see FEI address with this Application • Feedback on anticipated process & schedule 4. Stakeholder Funding • Guidelines for funding stakeholder participation prior to Application filing • Process for receiving funding

Meeting Summary and Notes

	Feedback	FEI Response
Summary of Questions/Comments during Presentation:		
1.	**Clarity of Scope** ***CEC (David Craig), CEC (Chris Weafer), BCSEA (Bill Andrews)*** • The importance of clarity regarding the scope of the application was discussed. It was noted that FEI must be clear regarding what is in and out of scope and it would be helpful to elaborate on the justification for why something is considered out of scope. • It is important for everyone involved to understand how items out of scope affect the various components of the Application (i.e. cost of service study, terms and conditions, rate proposals).	• FEI will clearly identify out of scope items through the workshop process and will discuss why certain items are out of scope and how they may affect the other components of the Application as a result. • Further, based on the feedback received at the information session, FEI will be providing a rate design education session before the first workshop in June that will be open to all stakeholders interested in attending. As a part of this session, FEI will cover topics like Bypass rates, the Main Extension Test, the Biomethane Program and other topics/service offerings that are expected to be out of scope for this proceeding.
2.	**Impact of Future Major Capital Projects** ***CEC (David Craig), BCUC (Cathy Marr)*** Will the Application consider the impacts of approved CPCNs such as the Lower Mainland Intermediate Pressure System Upgrade project, LNG investments, the Woodfibre project and other major capital projects such as potential future interior transmission system projects?	• Yes, FEI will be considering various scenarios, including the impact of expected future significant capital projects. • A desired outcome of this Application is to set in place rates that will continue to make sense when such projects are complete and embedded in rates.

Information Session Summary

<table>
<tr><th colspan="2">Feedback</th><th>FEI Response</th></tr>
<tr><td>3.</td><td>Alignment with other FEI Filings
CEC (David Craig)
The importance of alignment with other FEI Applications and reports was discussed. To the extent that FEI can be consistent amongst all applications, and where deviations are necessary point them out and explain them, will greatly aid in review and understandability.
For example, consistency with the Long Term Resource Plan in terms of major capital projects will be one area of importance.</td><td>FEI agrees that this type of consistency is important. While timing differences in filings may lead to more recent information and variations in forecasts, FEI will endeavor to be as clear as possible and explain differences where relevant and necessary.</td></tr>
<tr><td colspan="3">COMMENTS DURING ROUNDTABLE DISCUSSIONS:</td></tr>
<tr><td>4.</td><td>Cascadia Energy (Nick Caumanns)
Industrial customers transportation service – rules, balancing rules, day-to-day activities and costs. Looking out for our transportation customers and how costs are allocated to them, what they will be paying in the future vs. other rate classes. Hope end of day end up with much more streamlined process, lots of complicated rules, supportive of anything that streamlines it. Currently there are various kinds of groups, those were relevant years ago, but perhaps not any more, gas business has changed, people more responsive to change, those things to be simplified. Rates for our customers, rules. Process after application filed – is it a hearing?</td><td>What we are doing leading up to the application is to ensure it is as comprehensive as possible, once we have filed there may be other workshops or technical workshops, filing in the fall gives us a year for process and decision, whether we end up going to an NSP, written hearing, etc. that will be determined when we go through the process.
More to come, this is the lead up.</td></tr>
<tr><td>5.</td><td>BCOAPO (Tannis Braithwaite)
Cost of service allocations, whether it needs to be updated, how being done, breakdown between fixed and variable charges, low volume residential customers, terms and conditions around reconnections and disconnections, disproportionally impact certain groups of customers. No concern with process.</td><td></td></tr>
</table>

	Feedback	FEI Response
6.	**CEC (Chris Weafer)** Act for commercial customers, broad interest. Will be active on the key topics, approach Bonbright principles, will review from that perspective. Other topics of interest more definition around bypass, what is out of scope, impact of those, interaction with other processes, no surprises down the road. Good benefit of BCH process was much more elaborate, tie into participants in the North. Seeing the whole picture on the Application. Key topic is COSA, balancing, value to consider making available funding for ensuring utility is doing best practices, ratepayers get assurance or comfort of resources in the workshop process. Testing by an expert. How do you see if there is another proposal and how you see it happening? If something is not in your analysis or in other jurisdictions, are you open to feedback? Timing, no comments other than a few other material processes with BCH etc.	• It is challenging for participants and we expect we will go through the FN results here and then up there. • Expert review, worth considering how we might implement. • Feedback can be provided at sessions or in advance of sessions, as soon as we can respond, we will. My expectation is the 3rd session in August we can discuss results on. • We are open to feedback within reason, if there are certain things that will not work in this jurisdiction, then it may be discounted at the start, but reasonable, valid alternatives we are open to. • The filing date is fairly firm, but if we go into this and see there is a completely different process we can step back and re-evaluate. • As soon as you identify something, contact us, let us know, we will start evaluating immediately. • We are planning to get a website up and running as an effective way to share with stakeholders. • We sincerely want results that help us create an application that we all feel we have done good work, we may not agree and will work through issues, but we want to reflect the feedback from our customers. Balancing competing interests, fair rates, reflect how customers use the system, feedback and ideas are very important.

	Feedback	FEI Response
7.	**CEC (David Craig)** Fortis has been looking at remote community connection, whether that might be a CNG service, interested in whether we will be looking at that and some scenarios and different rate perspectives as to how those might be treated as part of the system, extension may not be physical pipe, but an equivalent type of connection. GHG concerns as a backdrop to the extent that there is policy issues or scenarios that may be relevant to be looked at and whether or not they impact cost allocations or rate designs. An area worth canvasing. Municipalities intending to have an interest in DES, finding challenging, to the extent that there is a scenario or future for how those may evolve and impacts to the RDA processes, potentially broader range of Municipal concerns. Greenhouse growers, unique use of natural gas, use CO_2 as well as heat, produce energy for lighting, long-term concerns with how those things will develop in the future, would be relevant for CEC to be involved with the discussion. Whole Gas system, in part designed from the point of view of the peak requirements, we don't have rate design that addresses the peak, would like some discussion about – rates that we charge that addresses peak.	• Certainly, we will be considering those systems and their potential impacts; although, we may not be able to rely on data because of the small customer base, but some of the scenarios will be considered. • GHGs will be addressed and underlying principles, including potential changes to legislation. • Yes, we will discuss rates that address the peak requirements of the system
8.	**BC Hydro (Gord Doyle)** General interest, interest around multi-family Rate Schedule 5/25.	

Information Session Summary

	Feedback	FEI Response
9.	**BCUC (Sarah Walsh)** • Commission staff will participate in your utility led workshop group and any related discussions regarding the FortisBC Energy Inc. 2016 Rate Design Application workshop process in a Clarification/Information Provider role in an effort to promote the efficiency and effectiveness of the Commission through greater communication with FortisBC Energy Inc. and/or to gain an understanding of the issues and context around certain matters. • In the Clarification/Information Provider role staff may ask clarifying questions and inform the group of applicable regulatory information such as on legislation, orders, decisions, regulatory process information, Commission-stated issues, and government-stated policy issues. In the event that the discussions evolve into consensus building staff would excuse themselves from participation in the group. Commission staff may be involved in the review of any application to the Commission related to the work of this group. • As a quasi-judicial tribunal, the Commission must maintain an independent, arms-length relationship with the companies it regulates. Commission staff do not have voting privileges and will not be taking minutes/notes or a leadership role for the group. Commission staff cannot advocate for specific interests or interest groups, recommend ideas or solutions, take positions on issues, or provide written support for the work of the group. • Commission staff involvement in a group cannot be claimed as endorsement for any projects or initiatives presented at the group. Under the Utilities Commission Act only Commissioners have decision-making power and any information provided by Commission staff is non-binding on the Commission.	

Information Session Summary

	Feedback	FEI Response
10.	**BCUC (Cathy Marr)** List of past directives, will be asking the Compliance Group to review and confirm. Industrial T- service.	
11.	**Absolute Energy (Melissa Running)** Anything related to bypass rates, gas supply backstopping, balancing rules, changes, have input into changes. No issues with the schedule.	
12.	**Access Gas (Tom Dixon)** Interest in changes to rate structure across all customer groups, transportation service managed going forward, interested in hearing new service offering for T-south. No issues with process or schedule.	
13.	**Shell Energy (Mary McCordic)** Transportation rates and operational issues with respect to T Service. No issues with schedule.	

Information Session Summary

	Feedback	FEI Response
14.	**BCSEA (Bill Andrews)** Interest in GHG and EEC and how those play out in terms of rate design, whether subtle or not engaged at all. Involved in BCH RDA which is different where supply is part of the price. Process is valuable to us to have materials in advance to process what may affect our interests and what not. BCH process found useful the minutes recorded comments that were made, whether or not BCH agreed with them, and had a consideration memo, about this comment was made, and stated their position – agree, disagree, will look at further, better to know the stage of the dialogue. One of the things BCH would say ask for input on an issue, 5 options, we don't think certain options warrant further exploration, what do you think, and based on feedback may or may not impact what they pursued. Particular issues rates for regional communities (Fort Nelson, Revelstoke, and new community concepts and MX discussion). Terms and conditions for Low Income customers, if there are mechanisms for RDA in the gas sector affecting conservation would be interested in pursuing, has not been done in the past, and we're not necessarily saying there should be.	• FEI has heard a lot of positive feedback regarding the BCH Rate Design consultation process. • FEI is interested in suggestions and experience learned through that process to help facilitate effective and efficient workshops for FEI Rate Design.
15.	**Sentinel Energy (Jim Langley)** Non-core, industrial transportation customers, COS allocation if still appropriate, balancing rules, gas supply, transport. No problem with schedule.	
16.	**BCSEA (Tom Hackney)** Nothing further to add.	
17.	**Independent Energy Consultants (Ken Fuhr)** Concur with Jim Langley.	

Information Session Summary

	Feedback	FEI Response
18.	**FNDCC (Bev Vandersteen)** When notes are done, will a list of participants be included? No issues with the schedule other than it is summer, may pose participation issues. Bring good concise information about how ratemaking takes place and what all goes into the end rate that the consumer pays.	• Yes, list of participants will be in the note. • FEI sees tremendous value in providing an education session to members of the Fort Nelson community as well as other stakeholders

Action Items and Next Steps

Item		Responsibility
1.	Notes from session today will be out by March 4	FEI
2.	Funding information, stakeholders to provide pre-application funding estimates by April 29, and FEI will advise of concerns by May 16	FEI to send out guidelines by March 30th Stakeholders to submit estimates by April 29th
3.	Review of Past Directives- Participants asked to review draft list of past directives provided at the session and advise FEI if they are aware of any omissions	Participants
4.	Rate Design Website will be up and running in the coming months	FEI
5.	FEI to hold education session(s) before sessions currently planned for June	FEI
6.	Preparations for sessions 1 and 1B in June and material to be sent out 2 weeks in advance	FEI
7.	Reach out to FEI with thoughts, concerns, if you want to meet.	All participants

2016 Rate Design Application
FortisBC Energy Inc. (FEI)

Information Session #2

May 19, 2016

FORTIS BC™

Purpose

To provide context and information in support of the forthcoming Application workshops

- Physical system and assets used to move natural gas in BC
- Services provided by FEI and the rate schedules that apply to these services
- General rate design topics and concepts

Focused and effective workshops where we can review results, evaluate proposals and collaborate on potential alternatives

Agenda

Part I: Gas Supply Fundamentals, Essential Services Model and Transportation Model Overview

- Introduction
  - *Michelle Carman, Manager, Rate Design and Tariffs*
- Gas Supply Basics and Essential Services Model
  - *Rohit Pala, Resource Development Manager*
- Transportation Model Overview
  - *Stephanie Salbach, Transportation Services Manager*

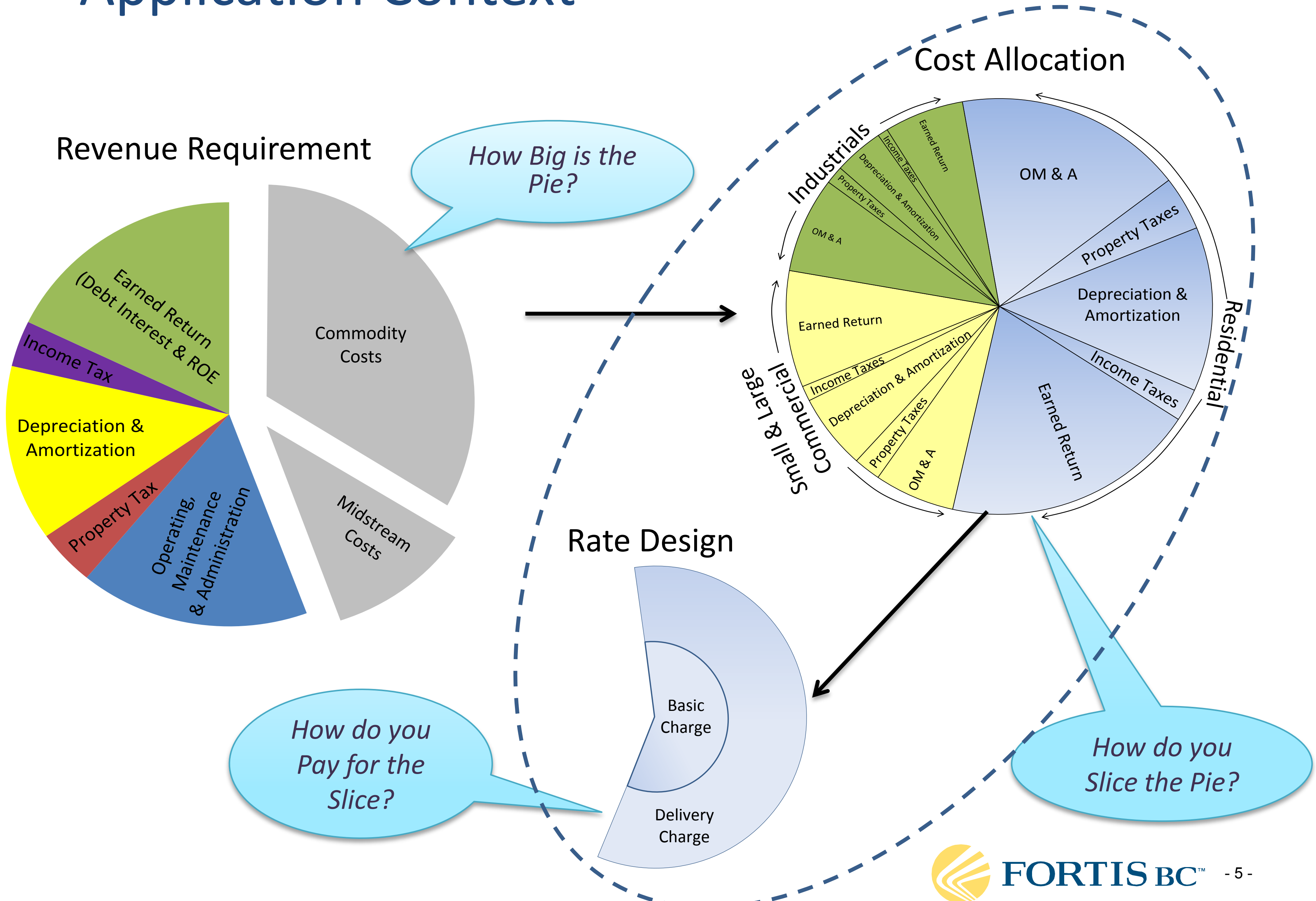
Part II: Rate Design Fundamentals & Tariff Overview

- Introduction
  - *Michelle Carman*
- Cost of Service, Segmentation and Rate Design Concepts
  - *Richard Gosselin, Manager, Cost of Service*
- Tariff Rate Schedules and Services Overview
  - *Colleen Gravel, Tariff, Rate Design and Projects Manager*

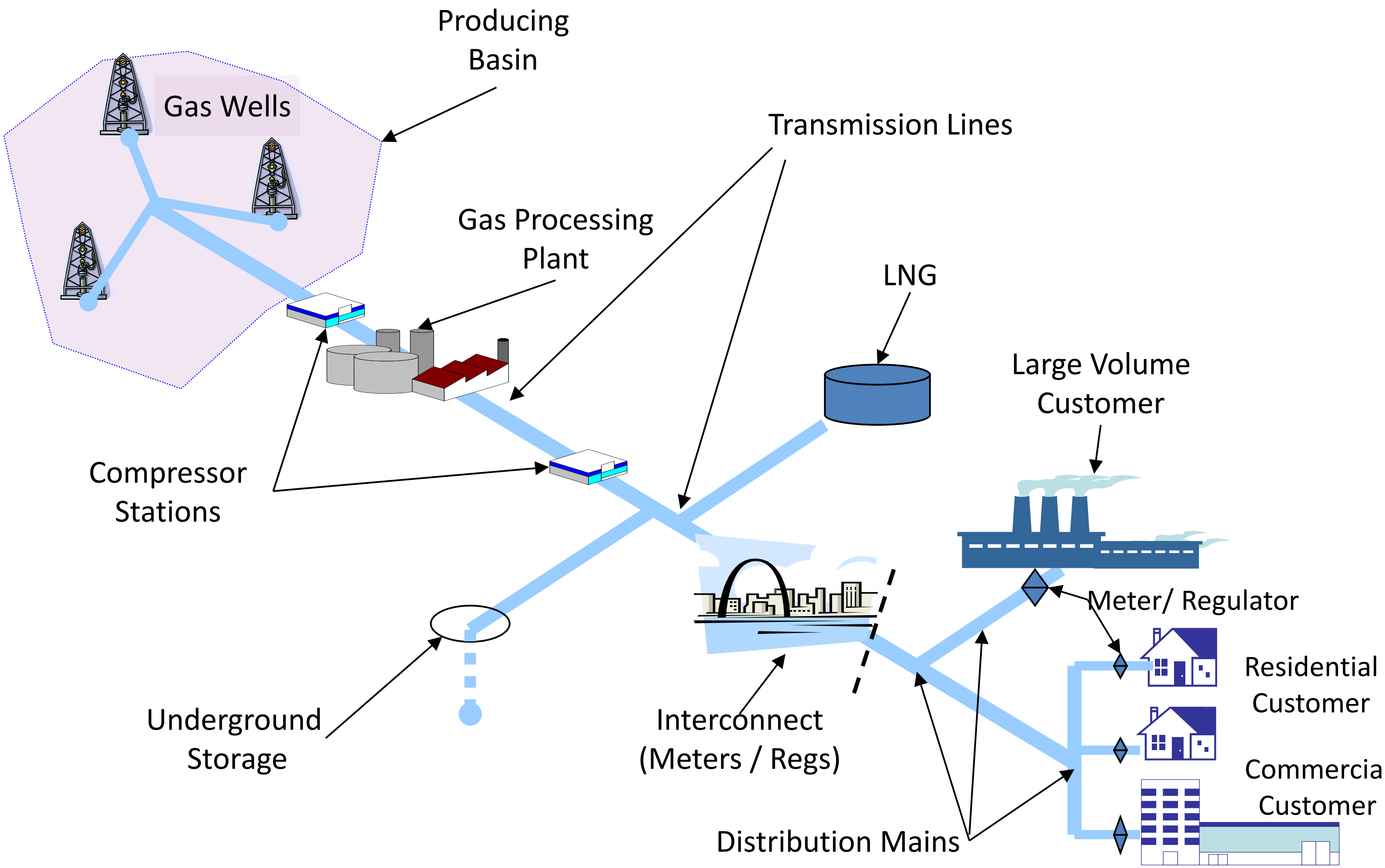
Part I

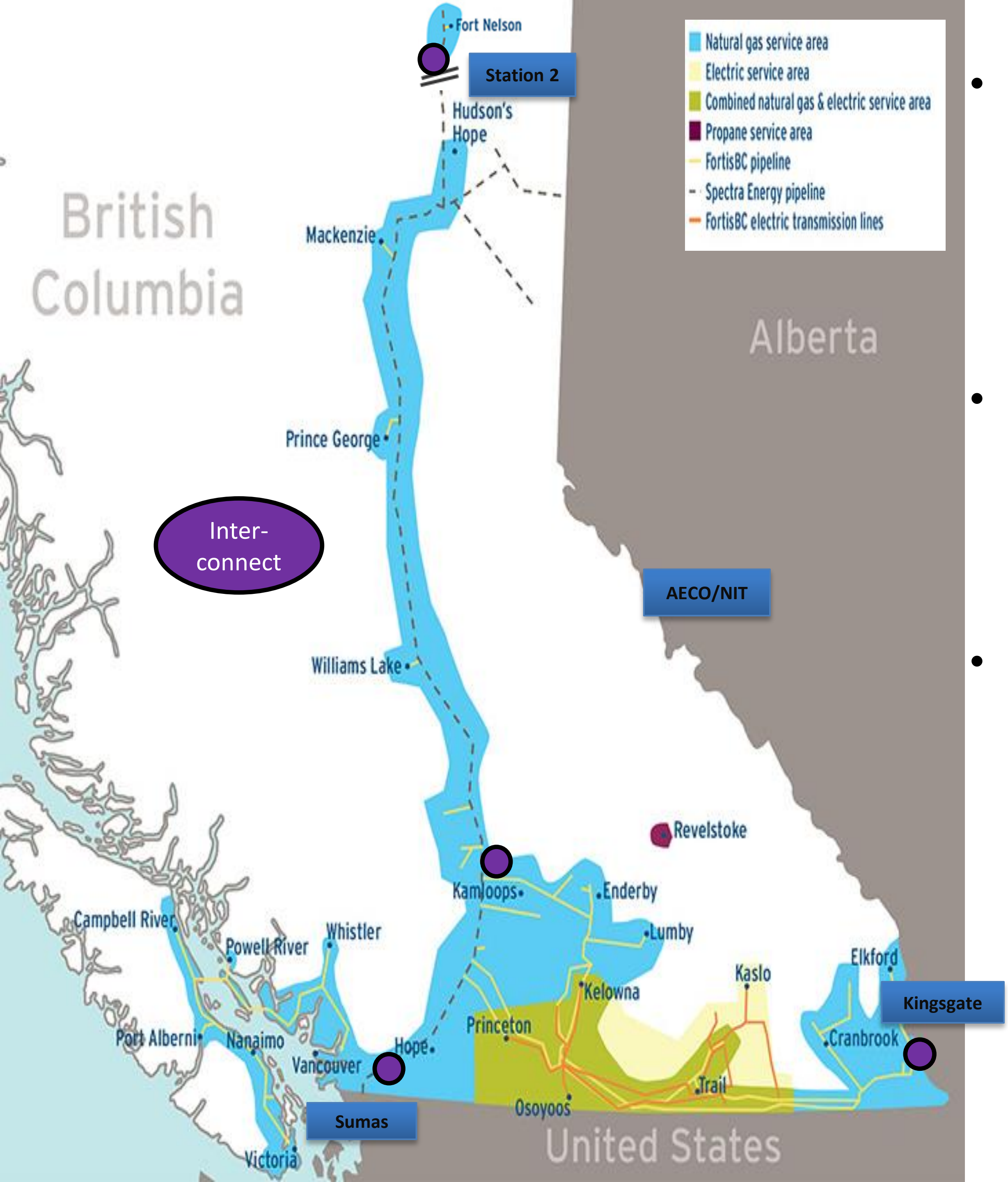
INTRODUCTION

Application Context



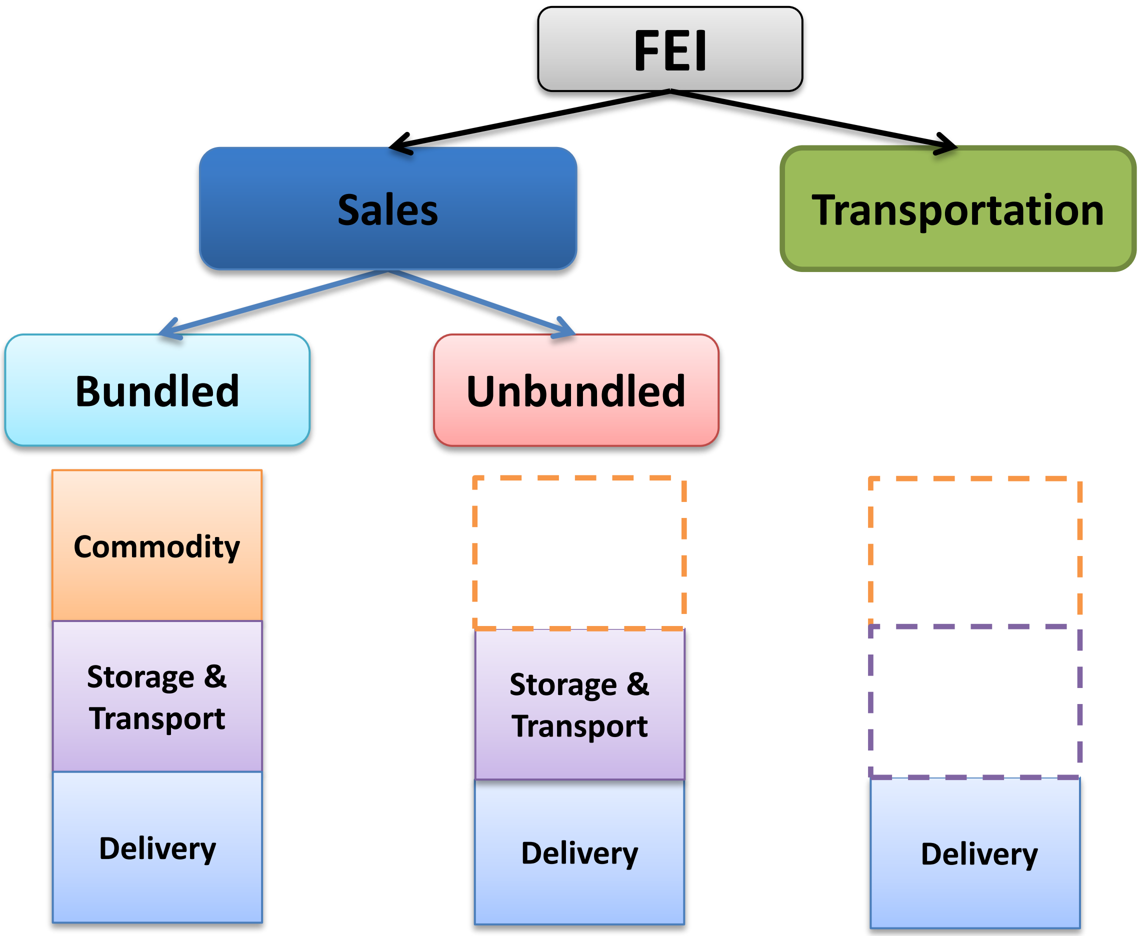
All Components Affect Rate Design

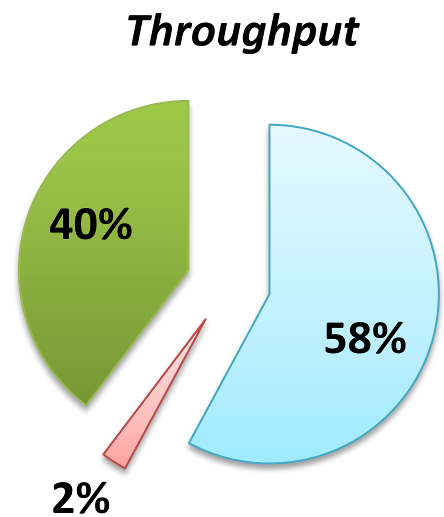




- The **Essential Services Model (ESM)** is in place to ensure Gas gets from supply hubs to our service territory
- **Sales service** picks ups the gas that the ESM delivers and moves it through the system to customers
- **Transportation service** allows customers to bring gas to our system at specific points whereby we take possession and deliver

Overview of FEI Services & Rates





"Storage and Transport" also referred to as "Midstream"

1 PJ = 1,000 TJ = 1,000,000 GJ

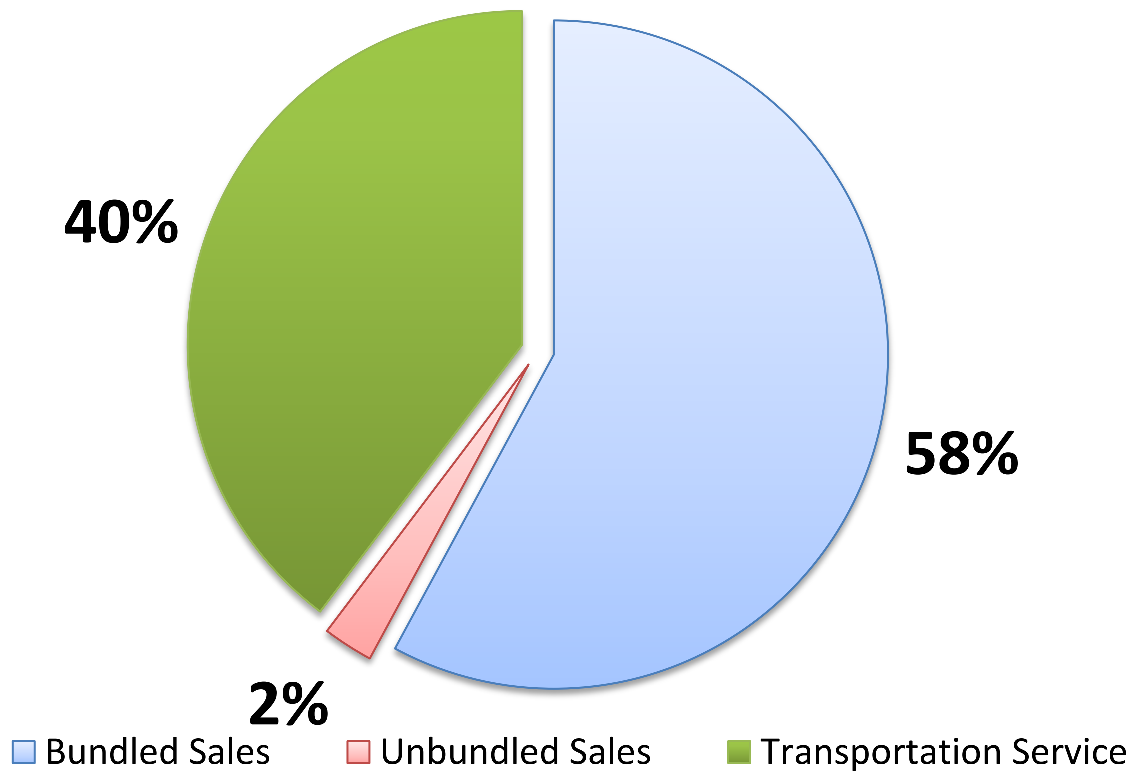
GAS SUPPLY BASICS AND ESSENTIAL SERVICES MODEL

Overview

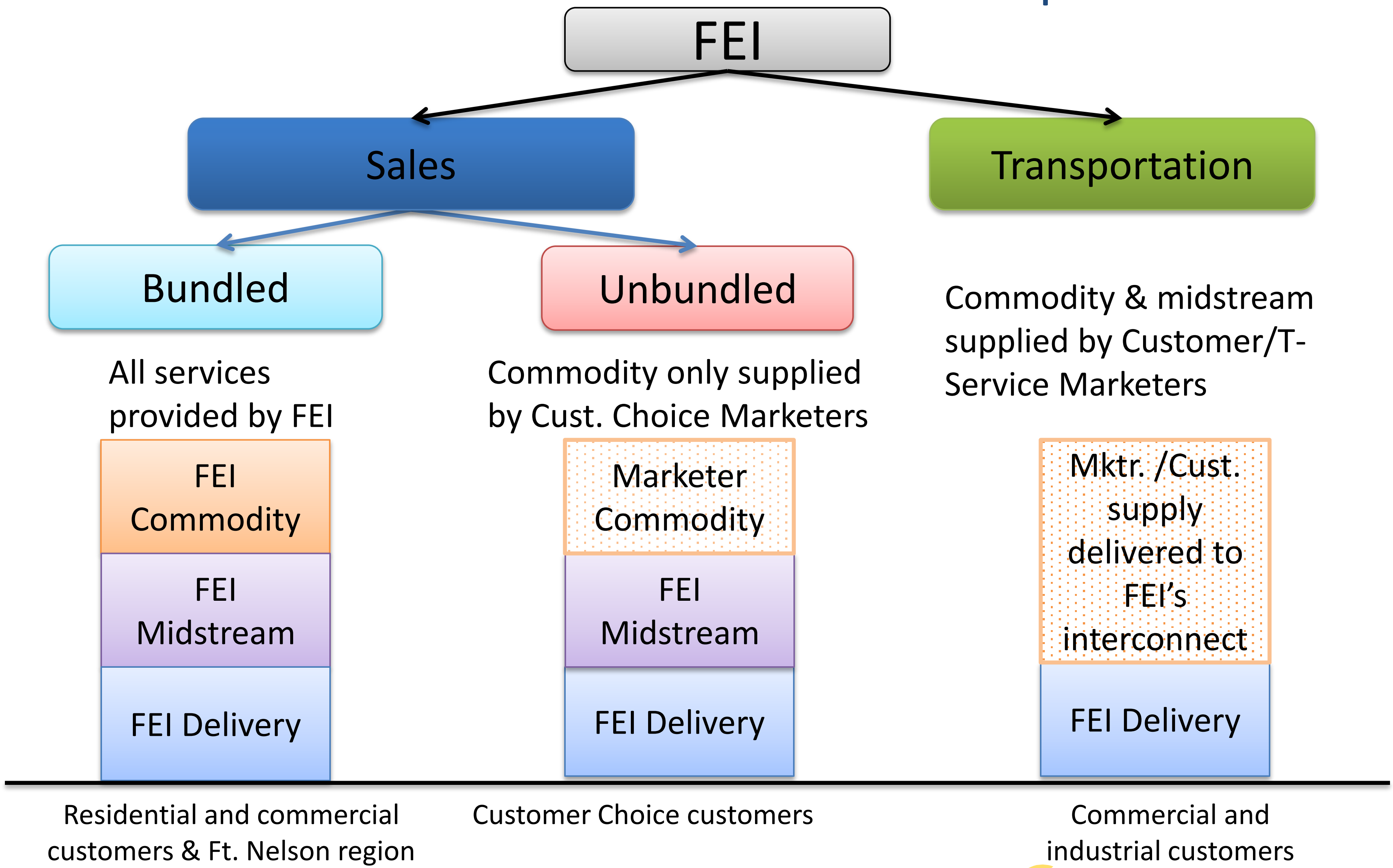
- FEI Services & Bill Components
- Commodity Unbundling & Essential Services Model
- Overview of Region & FEI's Resources

FEI SERVICES AND BILL COMPONENTS

Approximate System Throughput



Current FEI Business Model & Bill Components



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Bill Components – Commodity Rate

FEI Commodity

FEI Storage & Transport (Midstream)

FEI Delivery

Consists of:

- Market based rate – flowthrough with no markup
- Annual baseload commodity purchases by FEI
- Station 2 and AECO/NIT supply
- Variable (market) rate offering to customer by FEI
- Reviewed quarterly & subject to quarterly resetting

Bill Components – Storage & Transport (Midstream) Rate

FEI Commodity

FEI Storage & Transport (Midstream)

FEI Delivery

Consists of:

- Market & Cost based rate – flowthrough with no markup
- Shaped winter gas supply & seasonal storage
- Upstream pipeline capacity on external pipeline systems
- Shorter duration market area and on-system LNG storage
- Load balancing functions for entire system
- Backstopping functions
- Reviewed quarterly but normally reset annually

Bill Components – Delivery Rate

FEI
Commodity

FEI
Storage &
Transport
(Midstream)

FEI
Delivery

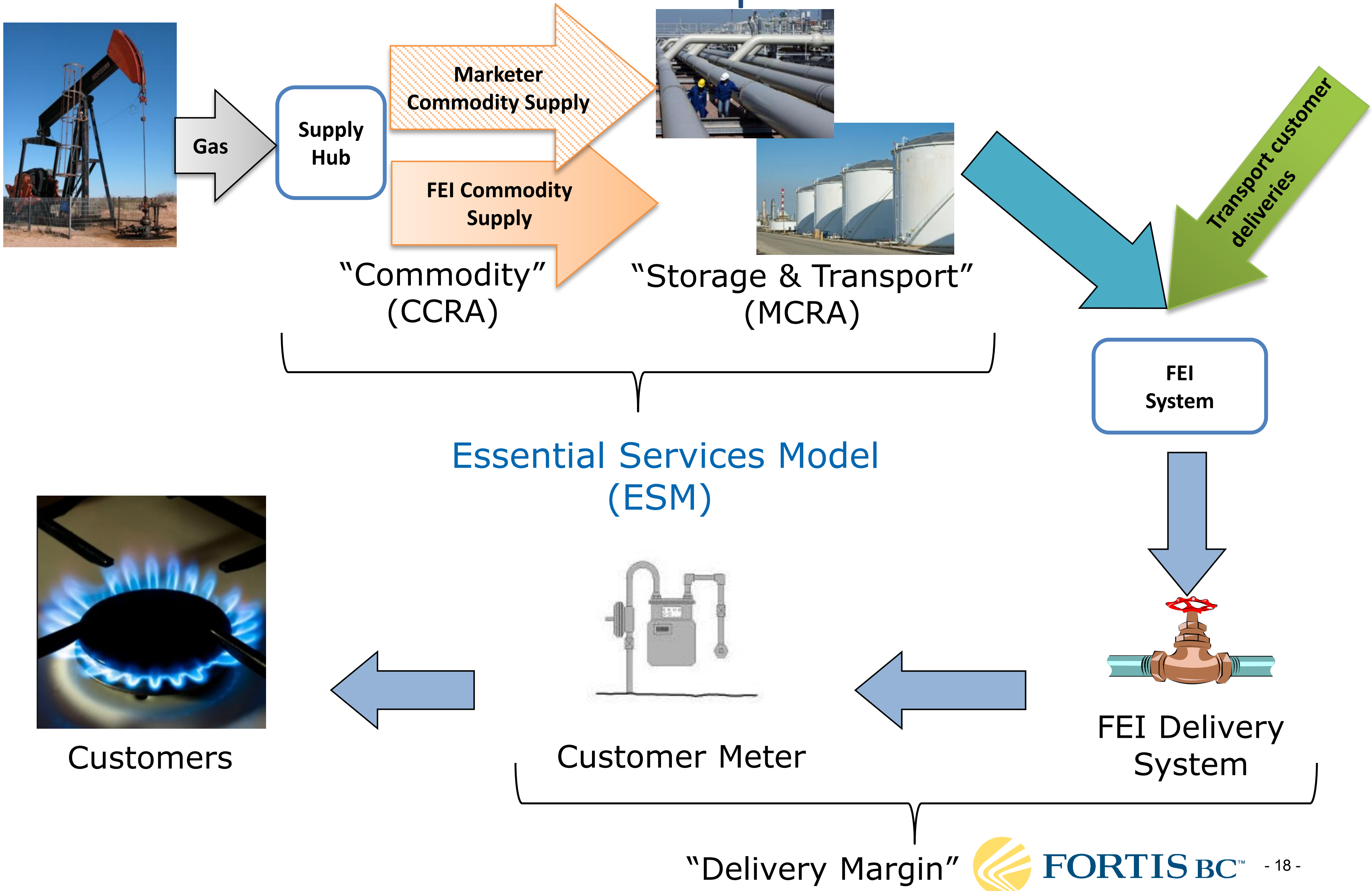
Consists of:

- Charges for FEI operations and delivering gas through FEI's system
- Includes variable and fixed charges
- Generally determined by RRA and PBR
- Typically adjusted annually

Sales Service

COMMODITY UNBUNDLING AND ESSENTIAL SERVICES MODEL

From Wellhead to Burnertip



ESM - Cost of Gas Accounting

Separate accounts facilitate cost tracking & allocation

CCRA

Commodity Cost Reconciliation Account

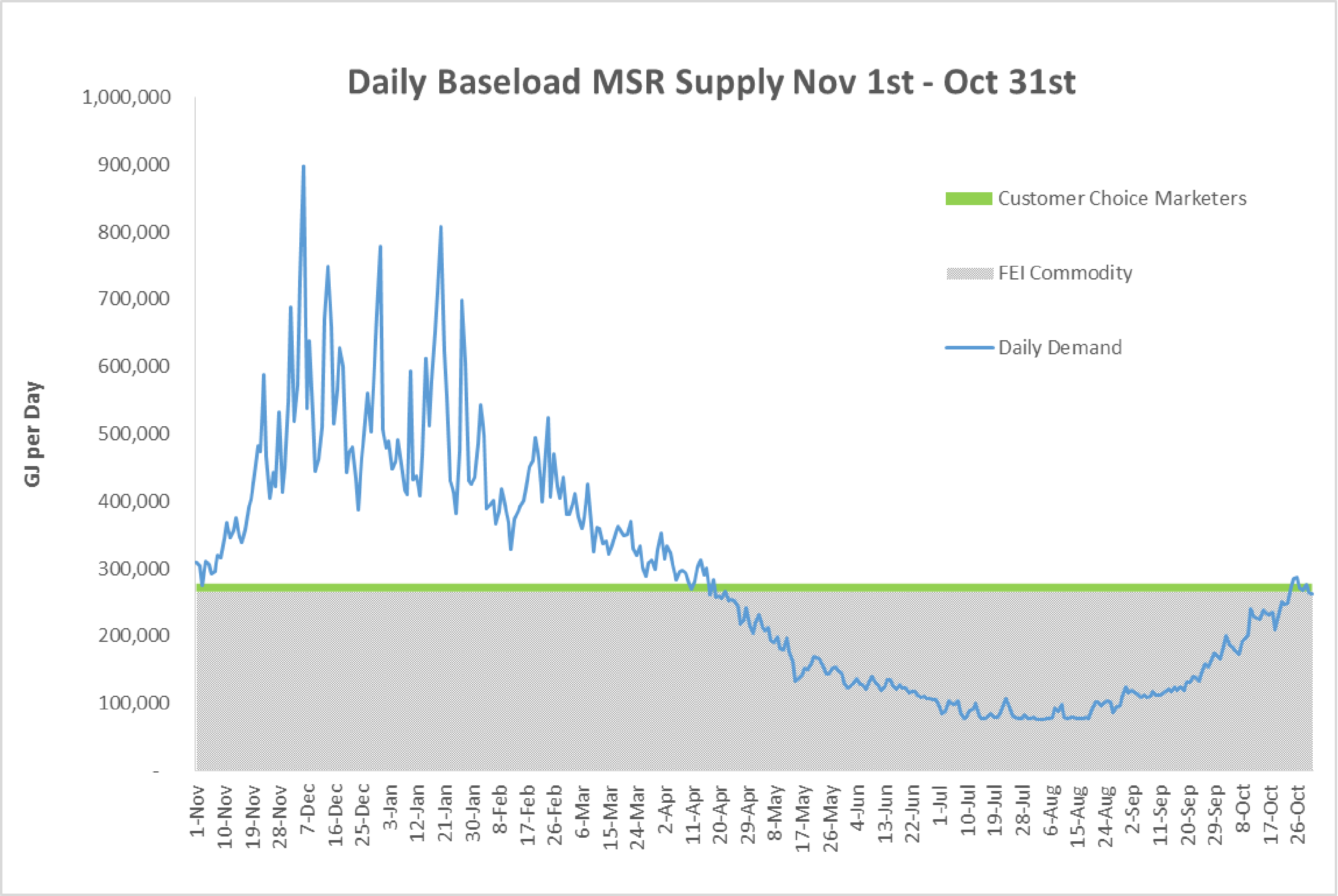
- Baseload commodity supply costs & revenues collected from Commodity Rates
- Paid for by FEI's fully bundled customers

MCRA

Midstream Cost Reconciliation Account

- Costs incurred in performing midstream functions and revenues collected from midstream rates
- Paid for by both FEI's bundled & Customer Choice Marketers' customers

ESM – Marketer Supply Requirement (MSR)



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ESM-FEI Responsibility

Contracts and manages midstream resources including seasonal supply, pipeline and storage capacity

Provides load balancing each day and peaking gas services

Infrastructure planning & supply framework and emergency response

Supplier of Last Resort – FEI backstops any shortfall for marketer supply failure

Provides commodity to customers staying with the utility under same framework as Customer Choice marketers

Billing and collection services

ESM- Marketer Responsibility

- Deliver gas to FEI at two supply/market hubs (Stn. 2 & AECO)
- Delivers same volume every day all year per MSR calculation
- Backstopping charges for short-term supply shortfall
- Share annual operating costs of the Customer Choice Program

Background & Overview of Regional Infrastructure

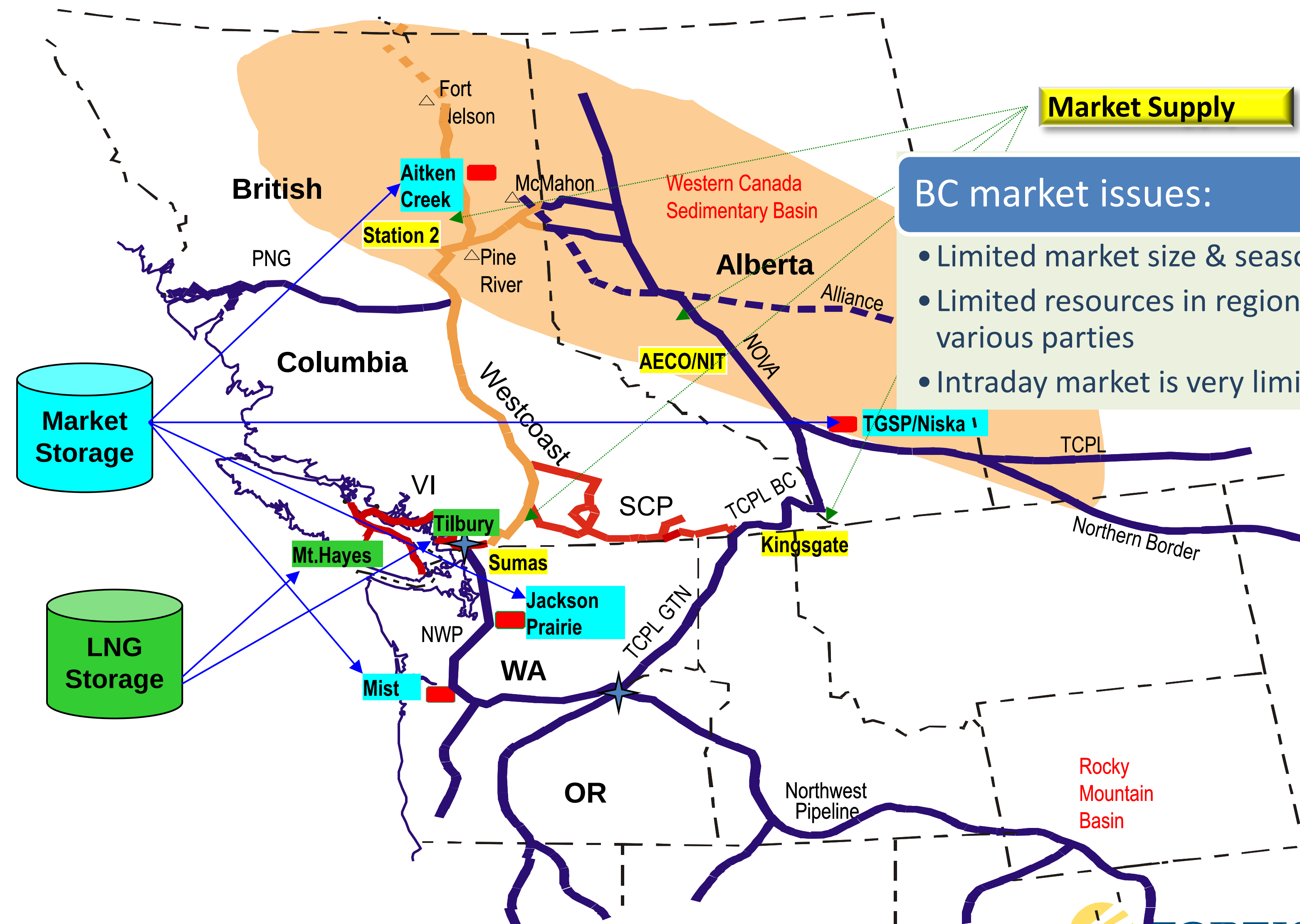
FEI'S SYSTEM AND RESOURCES

ESM Planning Objectives

Key component is Annual Contracting Plan (ACP):

- *Security and reliability of daily gas supply*
- *Diversity of resources, pricing & counterparties*
- *Flexibility*
- *Cost minimization*

Regional Gas Market Resources

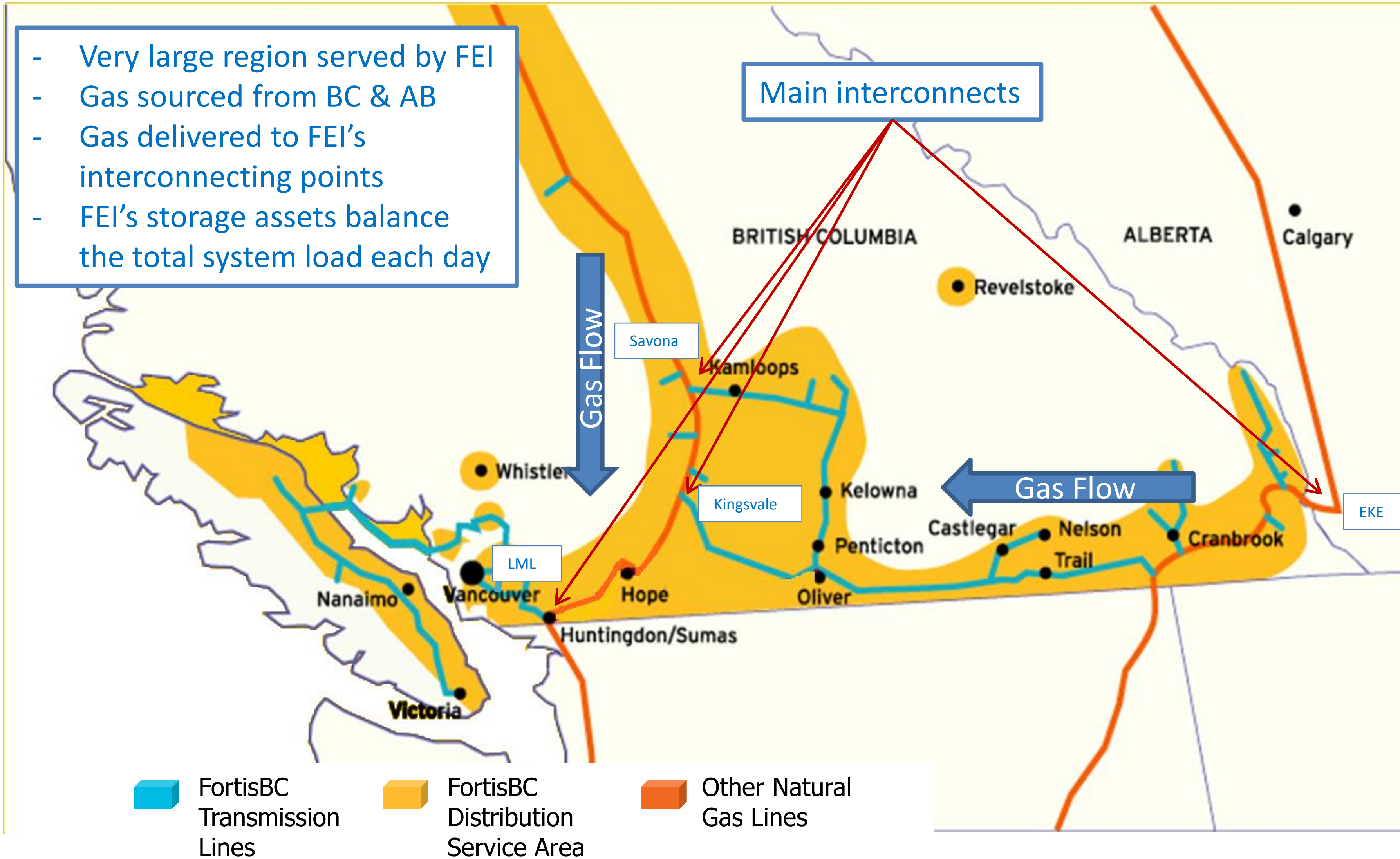


BC market issues:

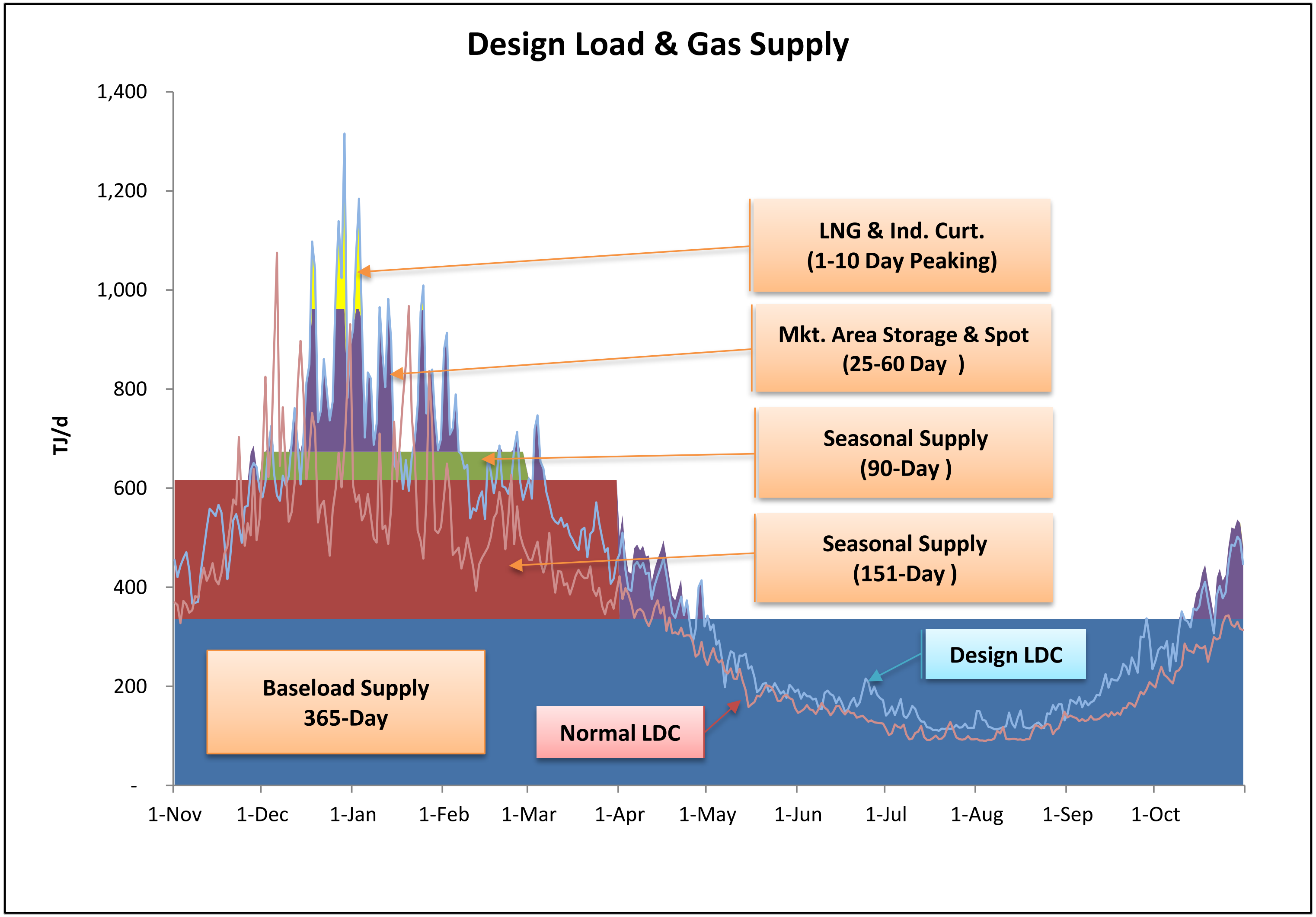
- Limited market size & seasonal demand
- Limited resources in region accessed by various parties
- Intraday market is very limited

FortisBC Gas System Regional Overview

- Very large region served by FEI
- Gas sourced from BC & AB
- Gas delivered to FEI's interconnecting points
- FEI's storage assets balance the total system load each day

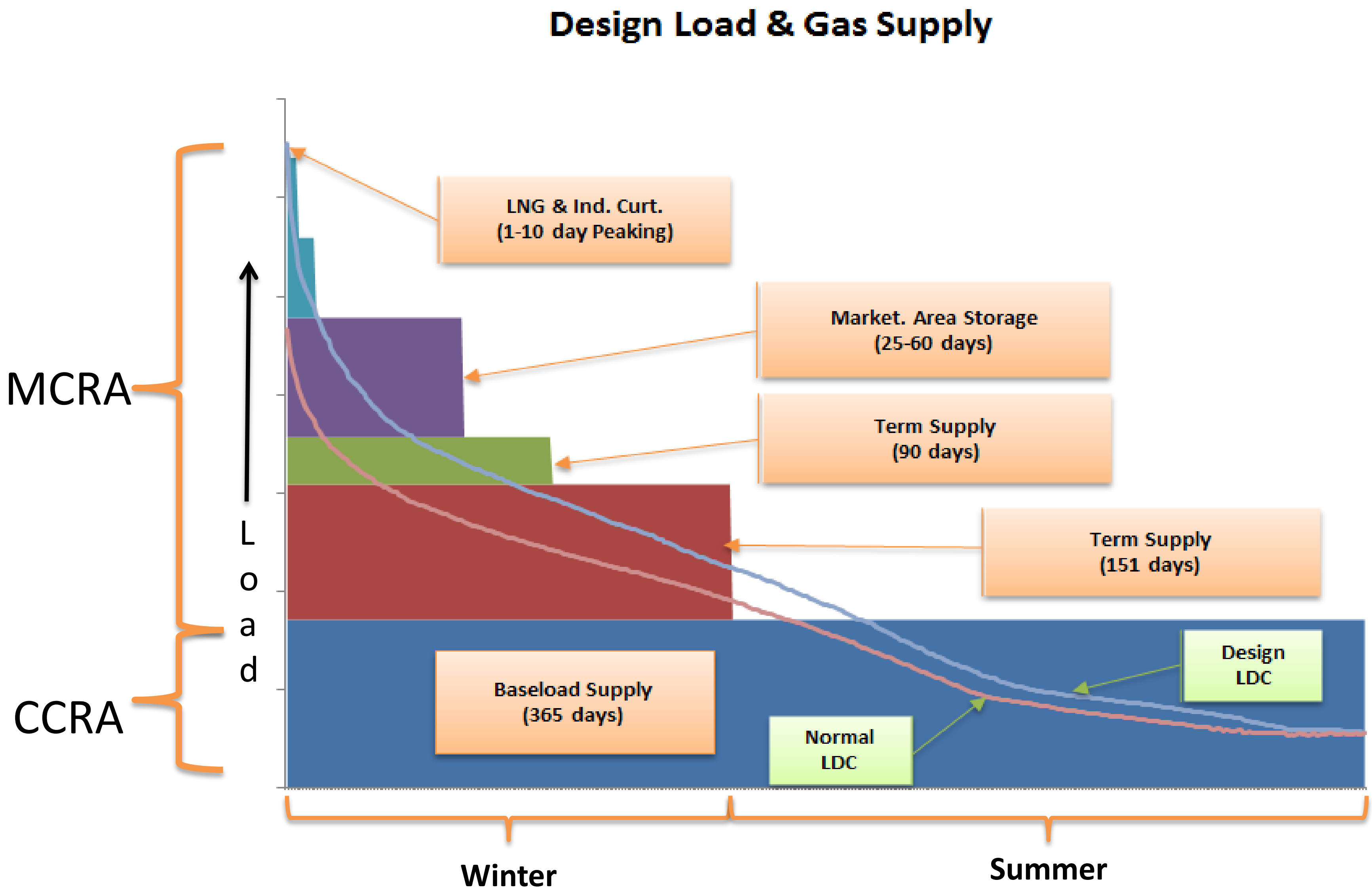


Load Duration Curve Based on Gas Year



Load Duration Curve ("LDC")

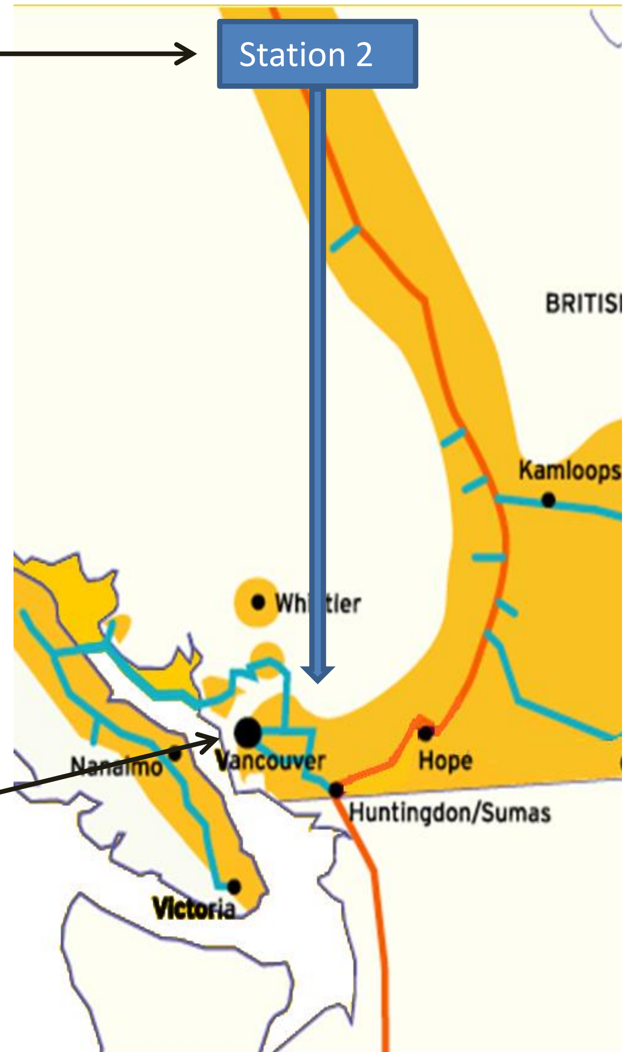
Diversity and Flexibility of Resources



Example – Daily Supply vs. Demand

Supply:
- FEI CCRA
- ESM Marketers
- Storage - seasonal & intraday supply

Station 2



Demand =	700 TJ
Supply =	650 TJ
Short =	50 TJ

Supply: Transport customers delivery at LML

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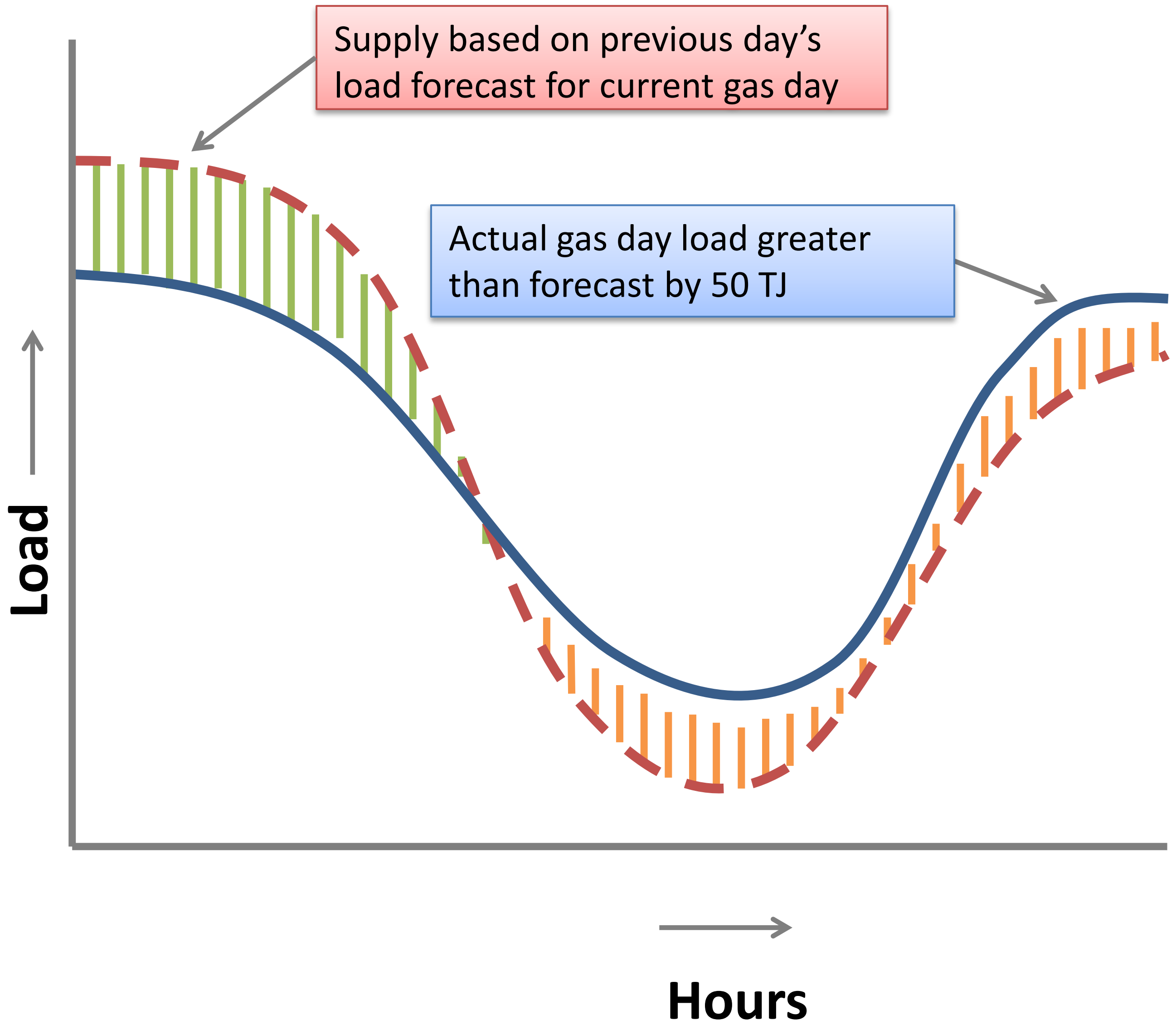
Example- Daily Supply vs. Demand (cont'd)



Demand dynamics:

- Changes hourly / peaks
- Temperature fluctuations throughout the day
- Industrial customer consumption variances

Supply flow:

- Gas nominated day prior
- Intra-day supply scarce
- Upstream disruptions

Daily load balancing:

- Tight deadlines between final load forecast & placing nominations
- Midstream assets balance entire system on behalf of all customers

Summary

- Limited resources in the region accessed by many parties
- FEI has a separate model for each business segment
- FEI's pool of resources provides gas supply for all core market customers
- Each day total system load is balanced on the intraday by FEI's midstream resources
- FEI has a regional presence so that a diverse pool of resources is required in the portfolio

TRANSPORTATION MODEL OVERVIEW

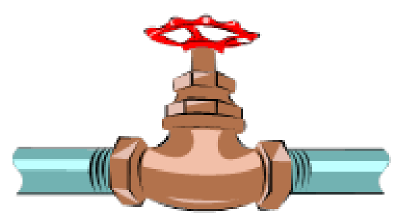
Overview

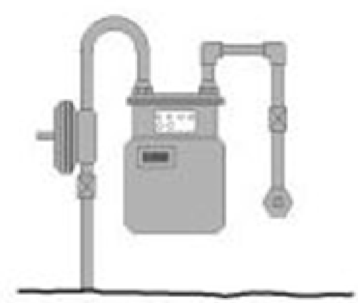
- General Background
- Key Components of the Transport Model
- Administering the Tariff and Applicable Charges
- Summary

GENERAL BACKGROUND

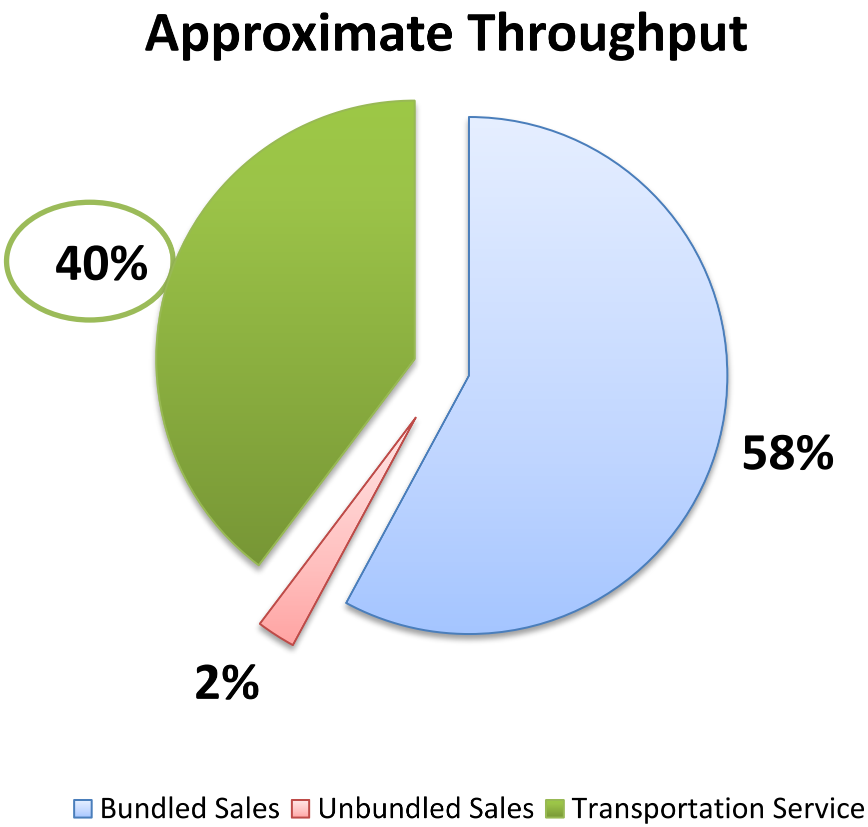
Highlights

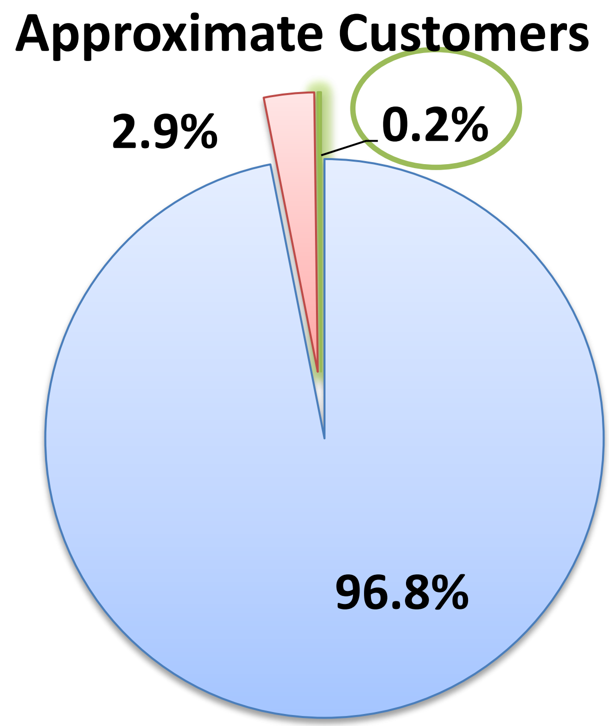
- Designed to give larger customers “choice” in who they to procure their gas supply from
- Transportation service customers can make supply arrangements on their own behalf, or through Marketers participating in the transport model
- Natural gas supply is delivered to FEI at the interconnect and FEI transports and delivers it to the customer’s premise
- Transportation Rate Schedules set terms and conditions of service offering



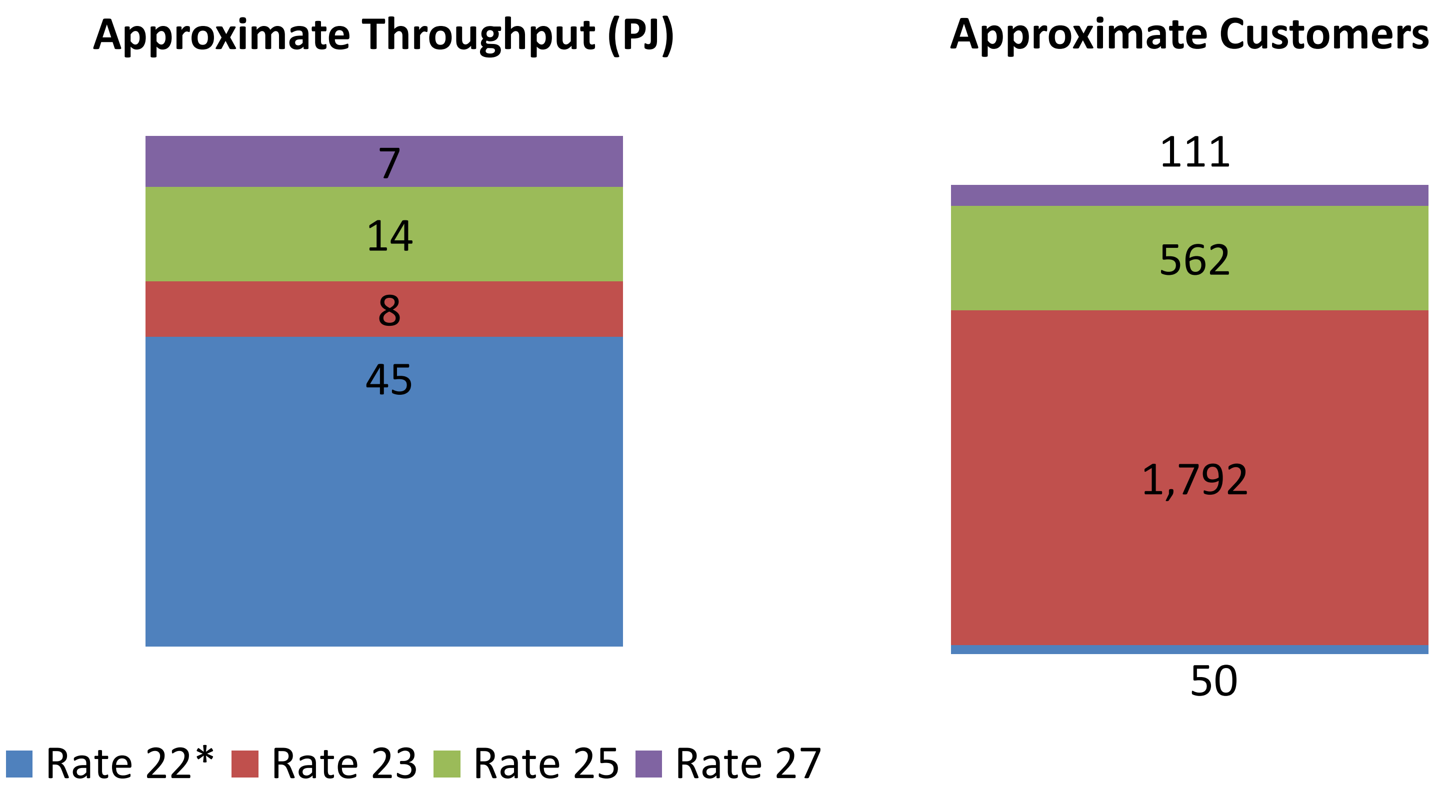


System Throughput & Customers



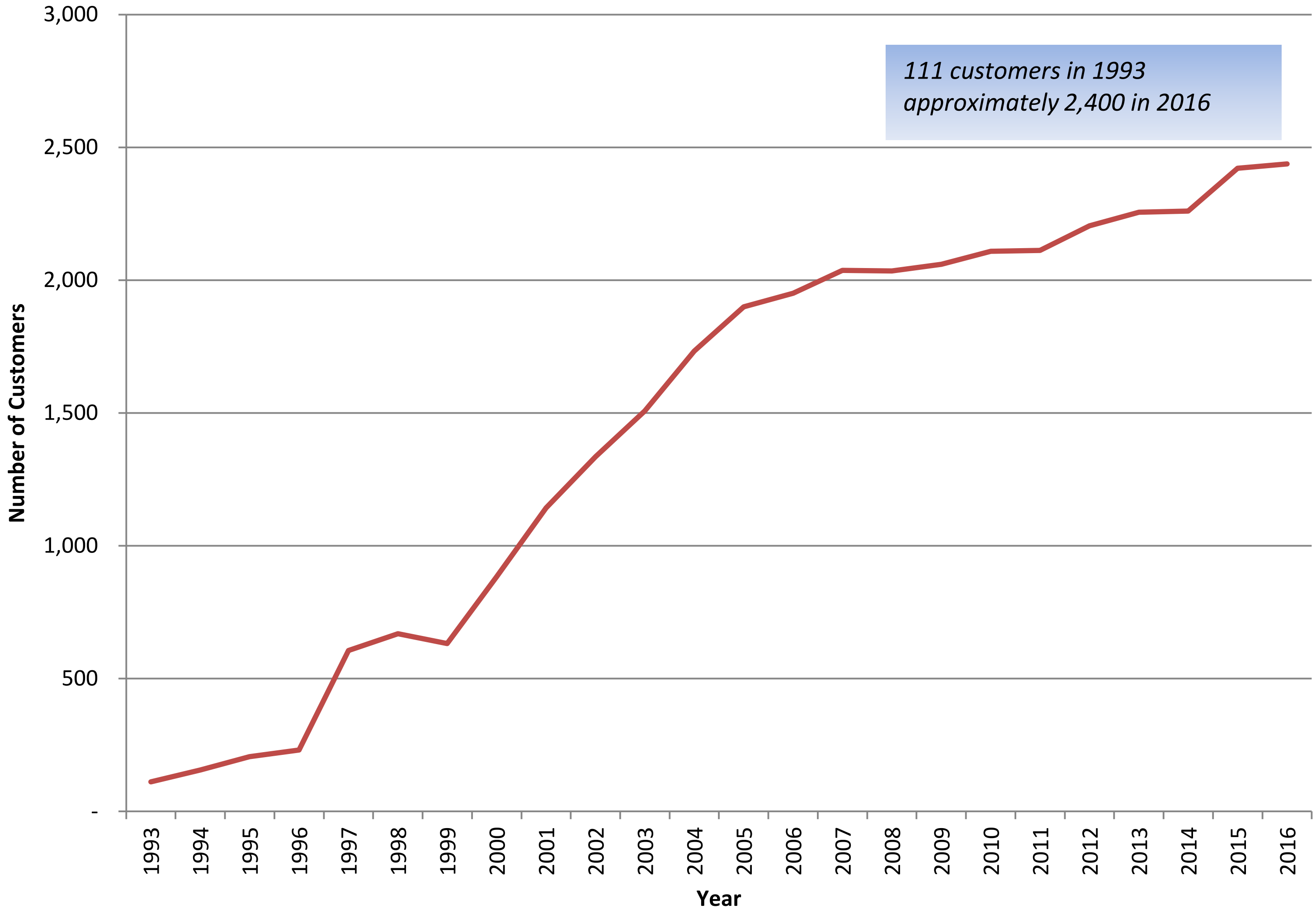


Transportation Throughput & Customers



* Includes R22/22A/22B , VIGJV and BC Hydro ICP

Historical Transportation Customer Growth



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Gas Requirements

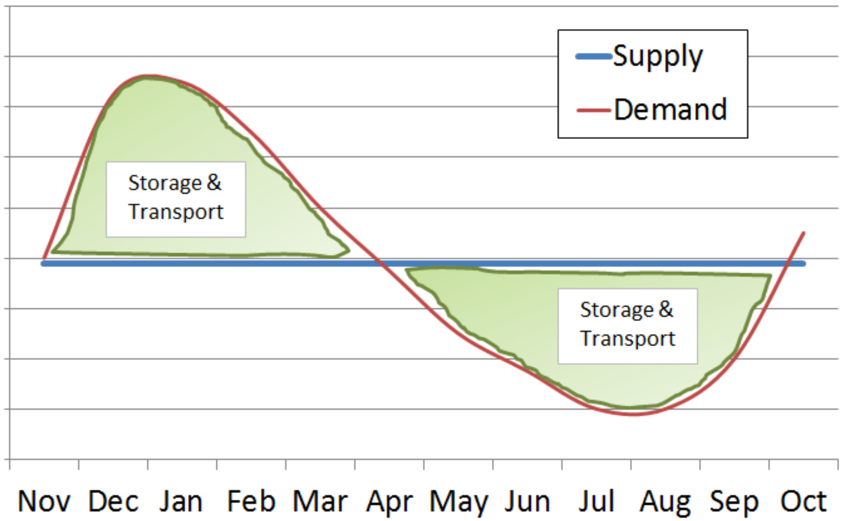
The role or responsibility of the marketer is purchase and manage the gas supply needs on behalf of their customers

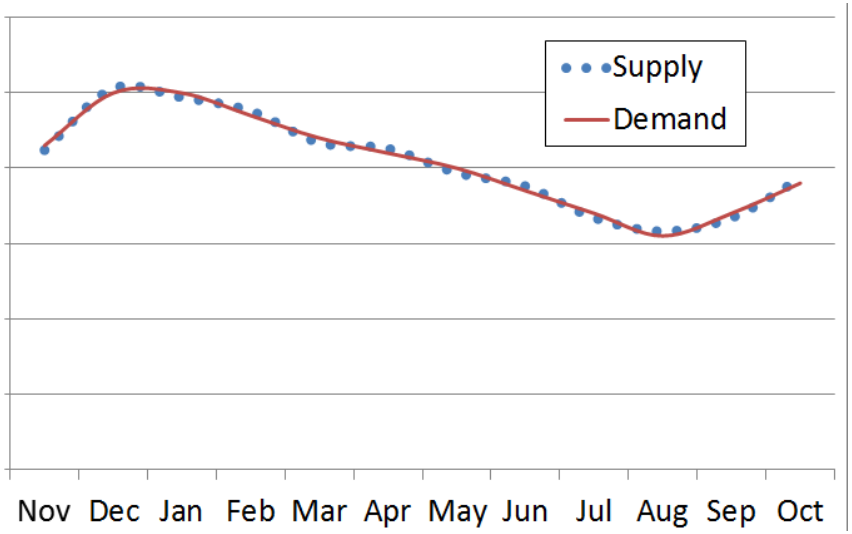
Expected to bring on sufficient supply to meet customer demand

Terms and conditions and potential charges when certain limits or tolerances are exceeded

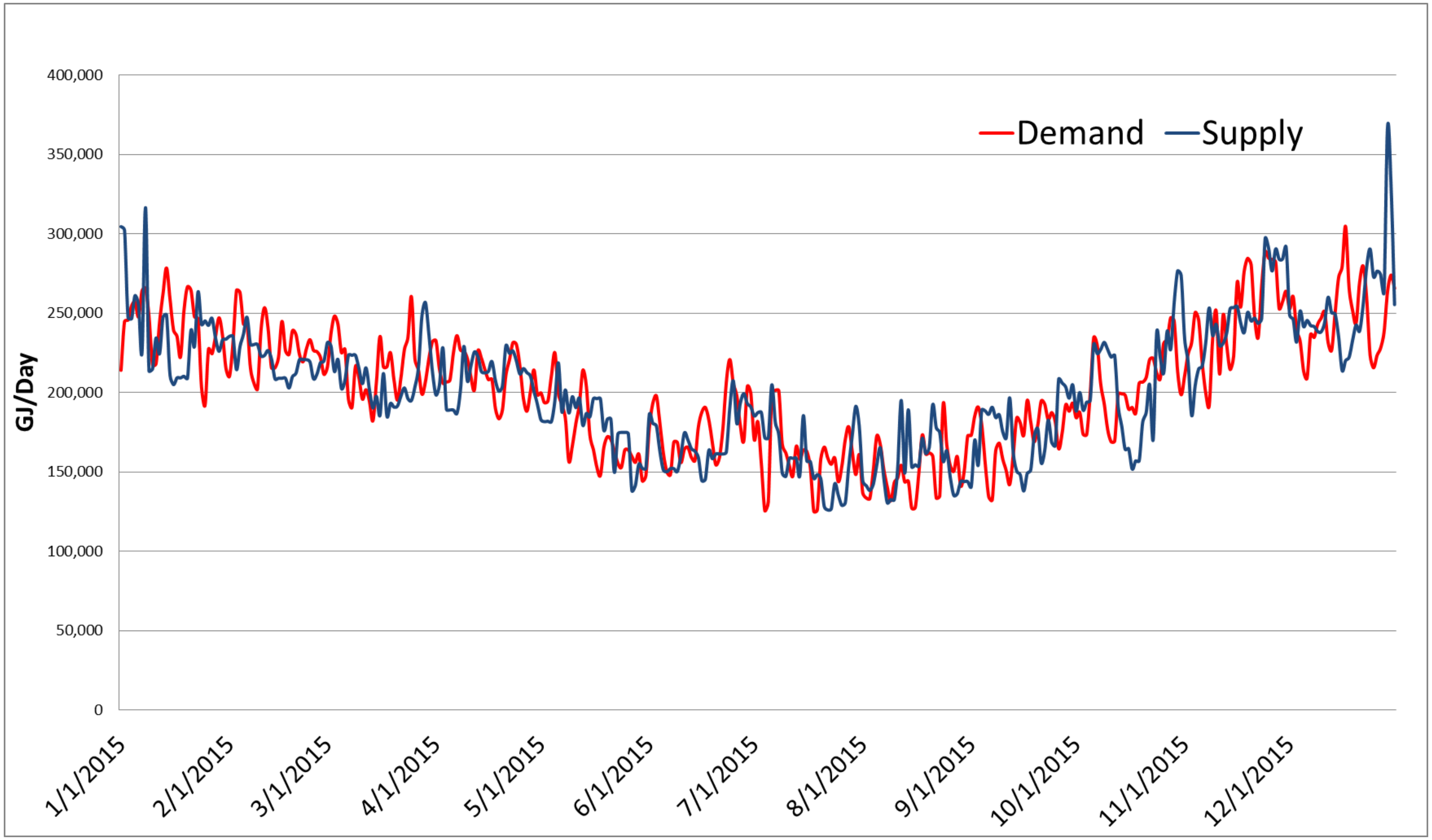
Model Comparison

ESM Essential Services Model		TSM Transportation Service Model
Bundled Service	Unbundled Service	Transportation Service





2015 Actual Transportation Supply and Demand



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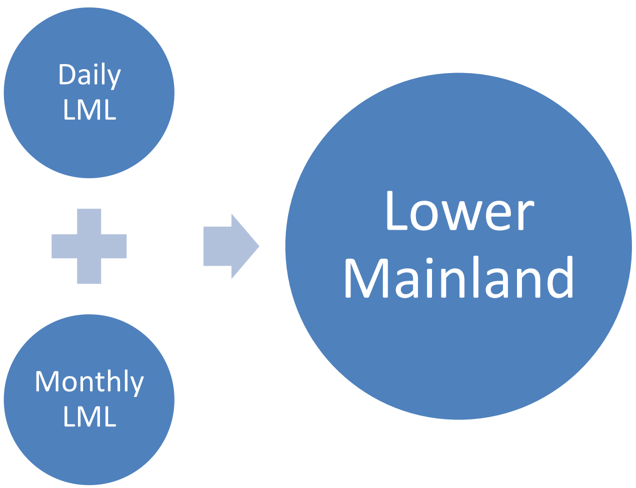
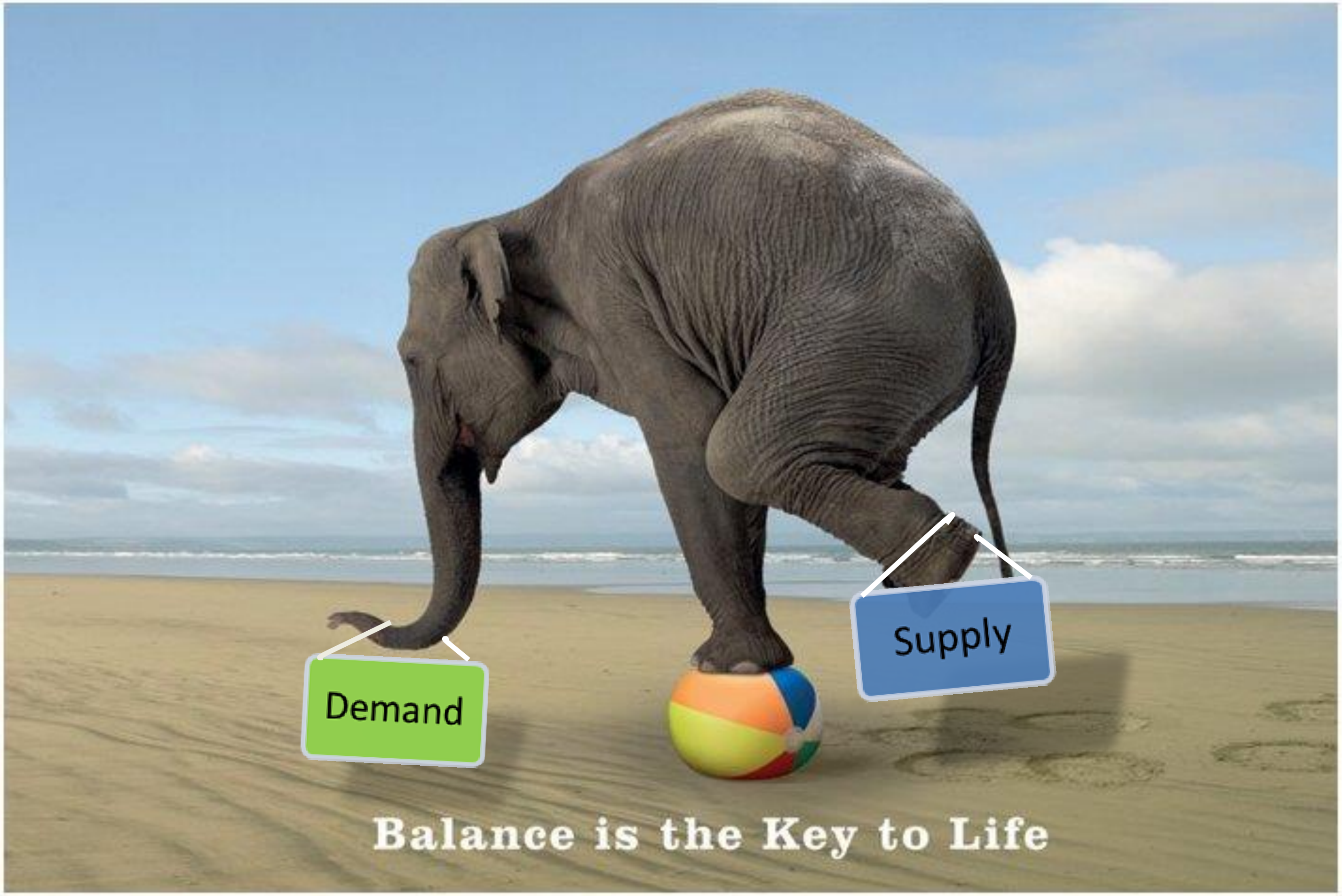
KEY COMPONENTS

Pooled Groups

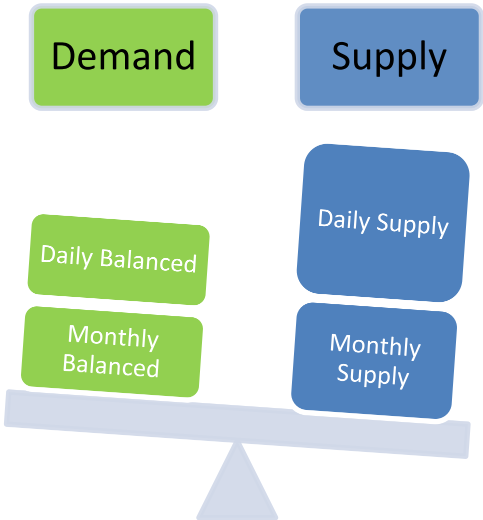


- Marketers may pool their customers in daily and monthly balanced groups
- 2,400+ customers
  - 16 Daily groups and 34 Monthly groups
  - 600 customers in Daily Balanced groups
  - 1,865 customers in Monthly Balanced groups

Transportation Service Balancing Requirements



Daily Balancing on FEI's system



Marketers can pool their customers in either a daily or monthly balanced group

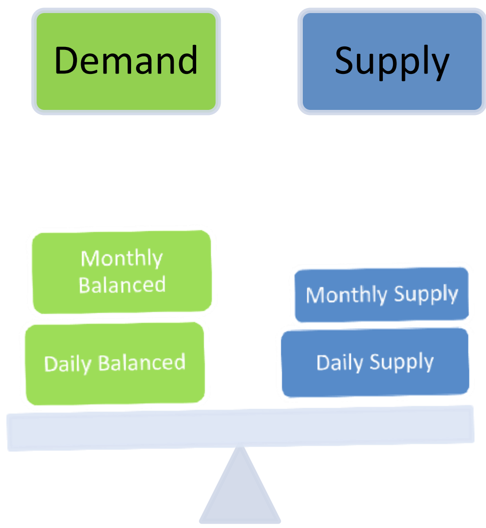
For daily groups, daily supply =/> demand

If under-deliveries on a given day, Fortis will "balance them" and sell daily balancing gas

If under-deliveries extend beyond a 20% tolerance, a balancing premium surcharge may apply

When over-deliveries occur, the marketers gas is banked as inventory on FEI's system

Monthly Balancing on FEI's system



Monthly balanced groups are not required to balance on a daily basis but by month end

If at month end total supply is <u>less</u> than total demand, FEI will balance the group and sell monthly balancing gas

Marketers with a daily and monthly balanced group at the same location typically over deliver to their daily group and under-deliver to their monthly – and net out at month end

Imbalance Return

Tool for daily balanced groups only

Imbalance return allows daily balanced groups to use their inventory as a source of supply

FEI sets the amount available

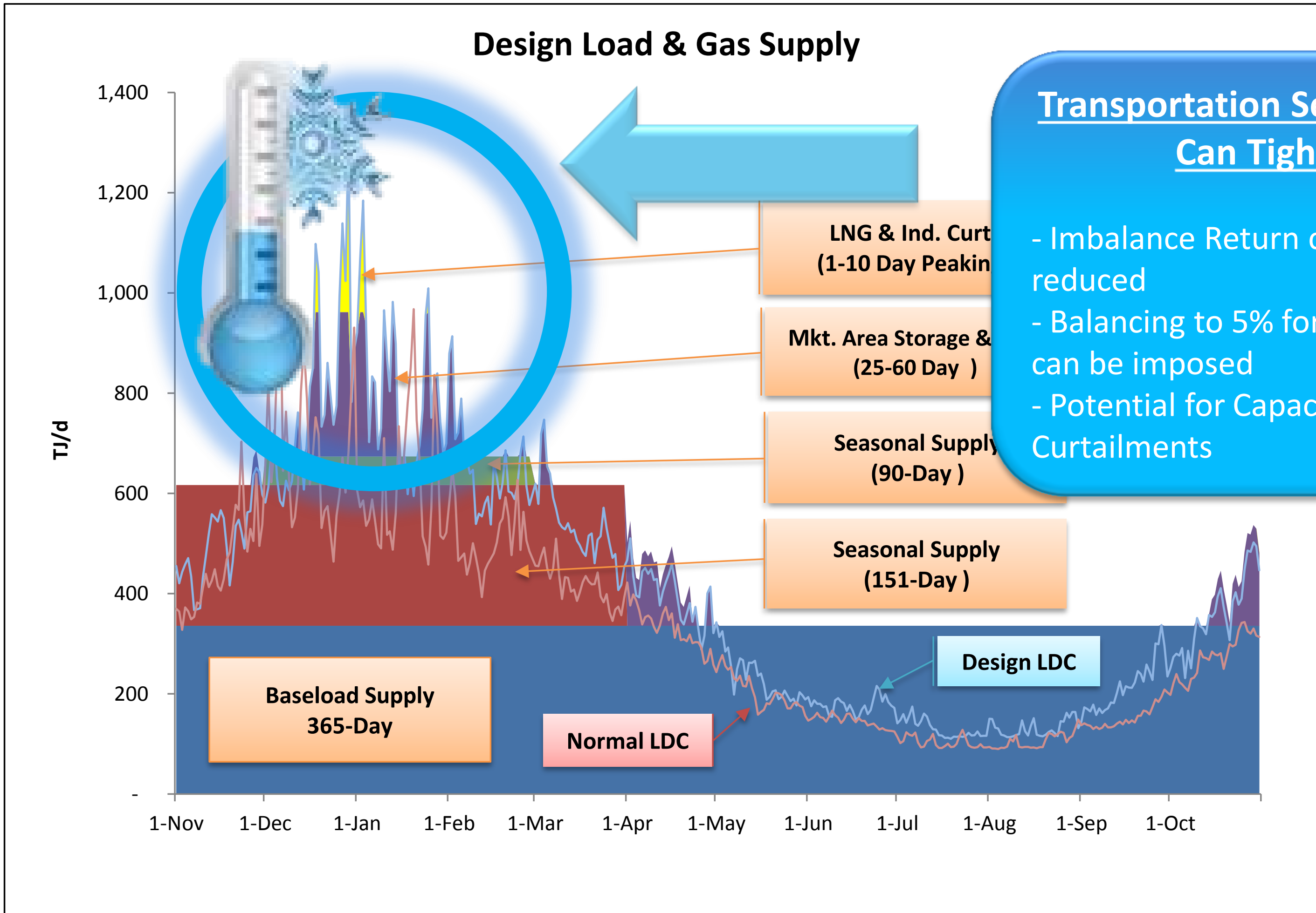
Deemed as *interruptible supply*

Inventory Levels

- Responsibility of the marketer to manage inventory on FEI's system
- FEI business practice is to monitor and limit inventory to +/- 2-3 days
  Example:
    Avg burn = 5,000Gjs/day
    Inventory= 15,000Gjs
    Pack = 3 days
- Good working relationship
- FEI has tools to limit or reduce inventory as necessary

ADMINISTERING THE TARIFF

Imbalance Restrictions Tightened at Peak Times



Transportation Service Rules Can Tighten

- Imbalance Return can be reduced
- Balancing to 5% for all groups can be imposed
- Potential for Capacity Curtailments

Applicable Charges

- **Backstopping** (Sumas Gas Daily)
- **Daily and Monthly Balancing Gas sold** (Sumas Gas Daily)
- **Daily Balancing Premium Surcharge** ($1.10 in winter, $0.30 in summer per GJ)
- **Unauthorized over run (UOR)** – under and over 5% (Sumas Gas Daily and greater of 1.5 times Sumas Gas Daily or $20/GJ)
- **Replacement gas** (Sumas Daily plus 20%)
- **Demand Surcharge** ($17 x 12 x quantity)

Backstopping

Backstopping Example:

Nominated Quantity:	10,000	GJ
Delivered Quantity:	8,000	GJ
Backstopping sold	(2,000)	GJ

2,000 GJ of Backstopping incurred

Charged at the Sumas Gas Daily price

Daily Balancing Gas and Balancing Premium Surcharge

Daily Balancing Gas Example:

Nominated Quantity:	10,000	GJ
Delivered Quantity:	10,000	GJ
Customer Demand:	15,000	GJ
DIFFERENCE	(5,000)	GJ

5,000GJ of Daily Balancing gas incurred
Charged at the Sumas Gas Daily price

Balancing Premium Surcharge Example:

Nominated Quantity:	10,000	GJ
Delivered Quantity:	10,000	GJ
Greater of:		
10,000 x 1.2 =	12,000	GJ
10,000 + 100 =	10,100	GJ
REVISED Delivered Quantity:	12,000	GJ
Customer Demand:	15,000	GJ
DIFFERENCE	(3,000)	GJ

Surcharge Calculation:

Summer	3,000 x $0.30 =	$	900
Winter	3,000 x $1.10 =	$	3,300

Monthly Balancing Gas

Monthly Balancing Gas Example:

Sum of Delivered Quantities:	50,000	GJ
Sum of Customer Demand:	55,000	GJ
DIFFERENCE	(5,000)	GJ

5,000GJ of Monthly Balancing gas incurred

Charged at the Sumas Gas Daily price average for the month

Hold to Authorize/Supply Restriction

- Issued when sustained cold weather occurs or reach design day temperatures
- FEI can issue intra-day or day ahead
- Applies to all groups – daily and monthly at a specific location
- Shippers must bring on sufficient supply to meet or exceed group demand
- Balancing buffer changes from 20% to 5%
- Unauthorized over-run charges will apply if under-deliveries occur

Unauthorized Over-Run (Supply Restriction)

Unauthorized Over-run Example:

Nominated Quantity:	10,000	GJ
Delivered Quantity:	10,000	GJ
Customer Demand:	15,000	GJ
DIFFERENCE - UOR applied	(5,000)	GJ

First 5% of 10,000 = 500 > > > sold at Sumas Gas Daily

Over 5% = 4,500 > > > > > sold at the greater of

Sumas gas daily x 1.5

or $20 per GJ

Capacity Curtailment – Interruptible Customers

- Applies to specific Interruptible customers, typically either a Rate 22/22A/22B or 7/27 at a specific location on our system
- Does not apply to the marketer
- Decision to curtail or limit a specific customer(s) is determined by FEI's Gas Control Department
- Customer may be required to reduce consumption or curtailed completely
- If customer takes in excess of the curtailed quantity, Unauthorized Over-Run (UOR) and potentially Demand Surcharges may apply

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Unauthorized Over-Run **(Capacity Curtailment)**

EXAMPLE:

Curtailment Quantity:	10,000	GJ
Customer Demand:	15,000	GJ
DIFFERENCE - UOR applied	(5,000)	GJ

First 5% of 10,000 = 500 > > > charged at Sumas Gas Daily

Over 5% = 4,500 > > > > > charged at the <u>greater of</u>

Sumas gas daily x 1.5

or $20 per GJ

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Demand Surcharge **(Capacity Curtailment)**

If on three or more Days during a Contract Year, a Shipper does not comply with a "Notice of Curtailment"

Demand Surcharge Example:

Curtailment Quantity:		10,000	GJ
Customer Demand:		15,000	GJ
Greater of:			
10,000 x 110% =		**11,000**	**GJ**
10,000 + 100 =		10,100	GJ
Demand Surcharge applied		(4,000)	GJ
Demand Surcharge	$	17	GJ
times 12			
Demand Surcharge quantity		4,000	GJ
	$	816,000	

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Summary

- Transportation service customers can make supply arrangements on their own behalf, or through Marketers participating in the transport model
- Natural gas supply is delivered to FEI at the interconnect and FEI transports and delivers it to the customer's premise
- FEI balances the system on an hourly and daily basis as a whole
- Transportation Model has been working well

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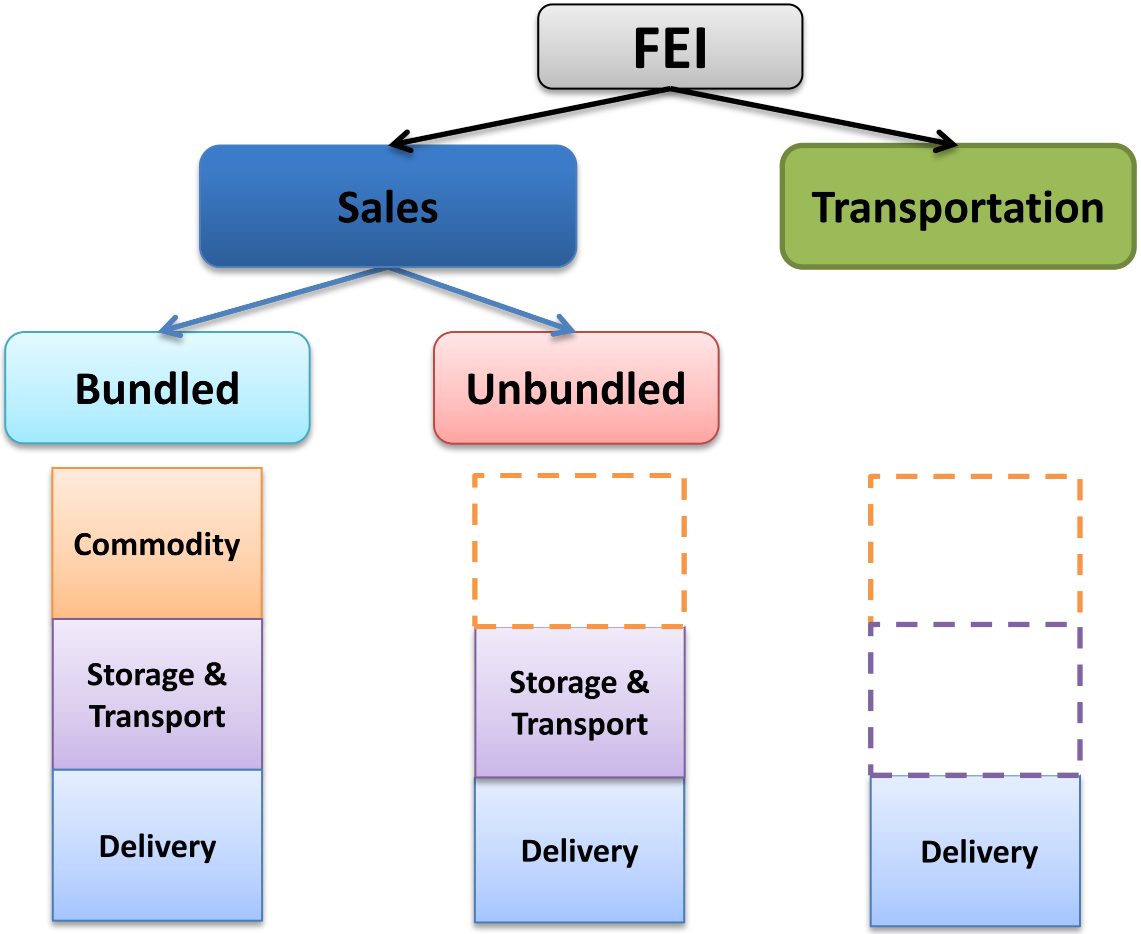
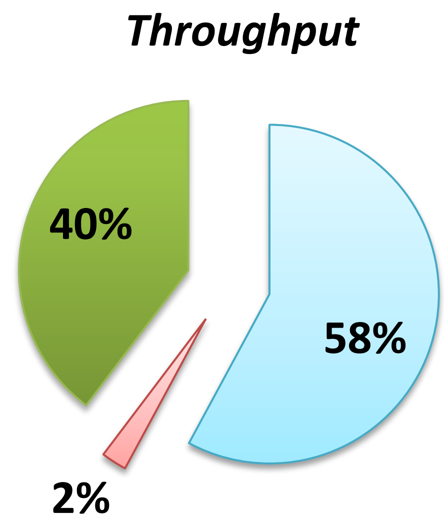
Part II

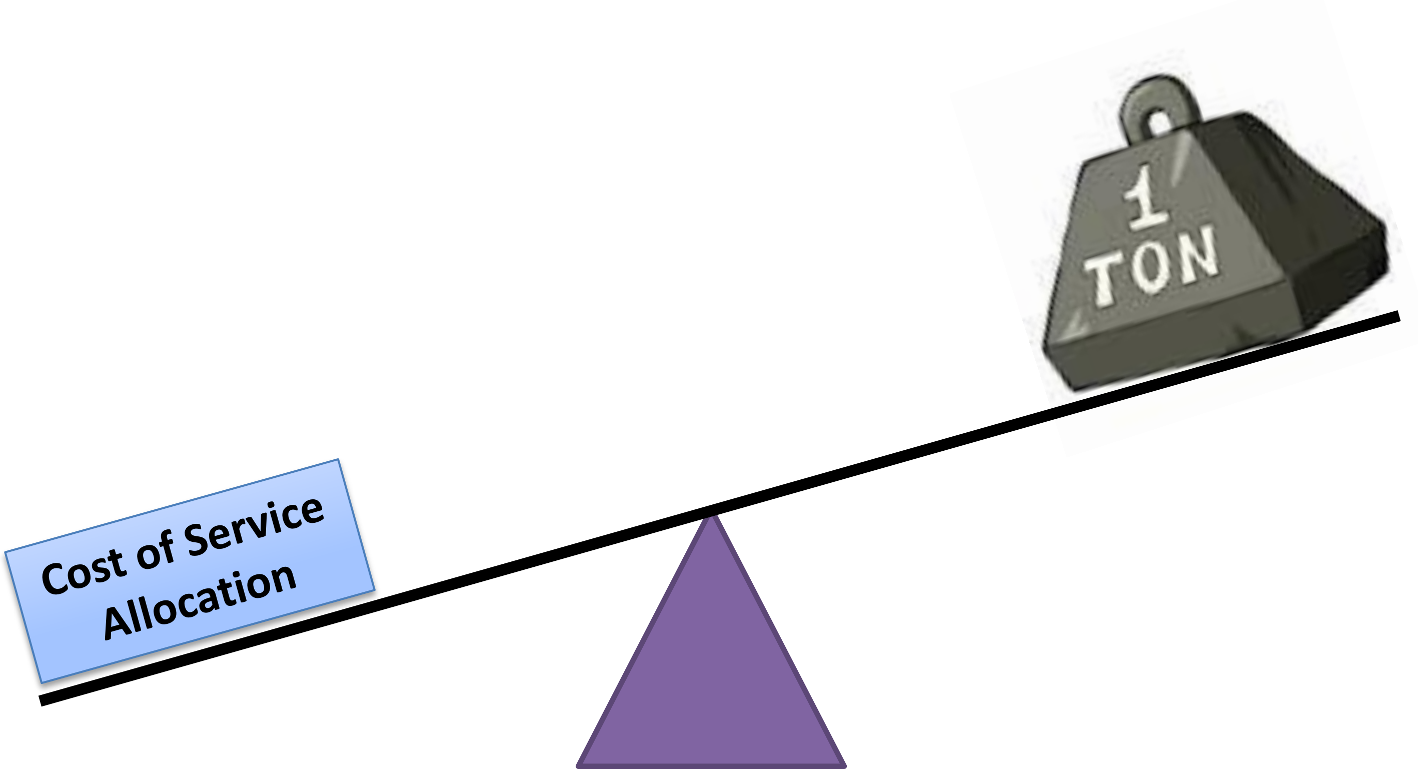
INTRODUCTION

Overview of FEI Services & Rates



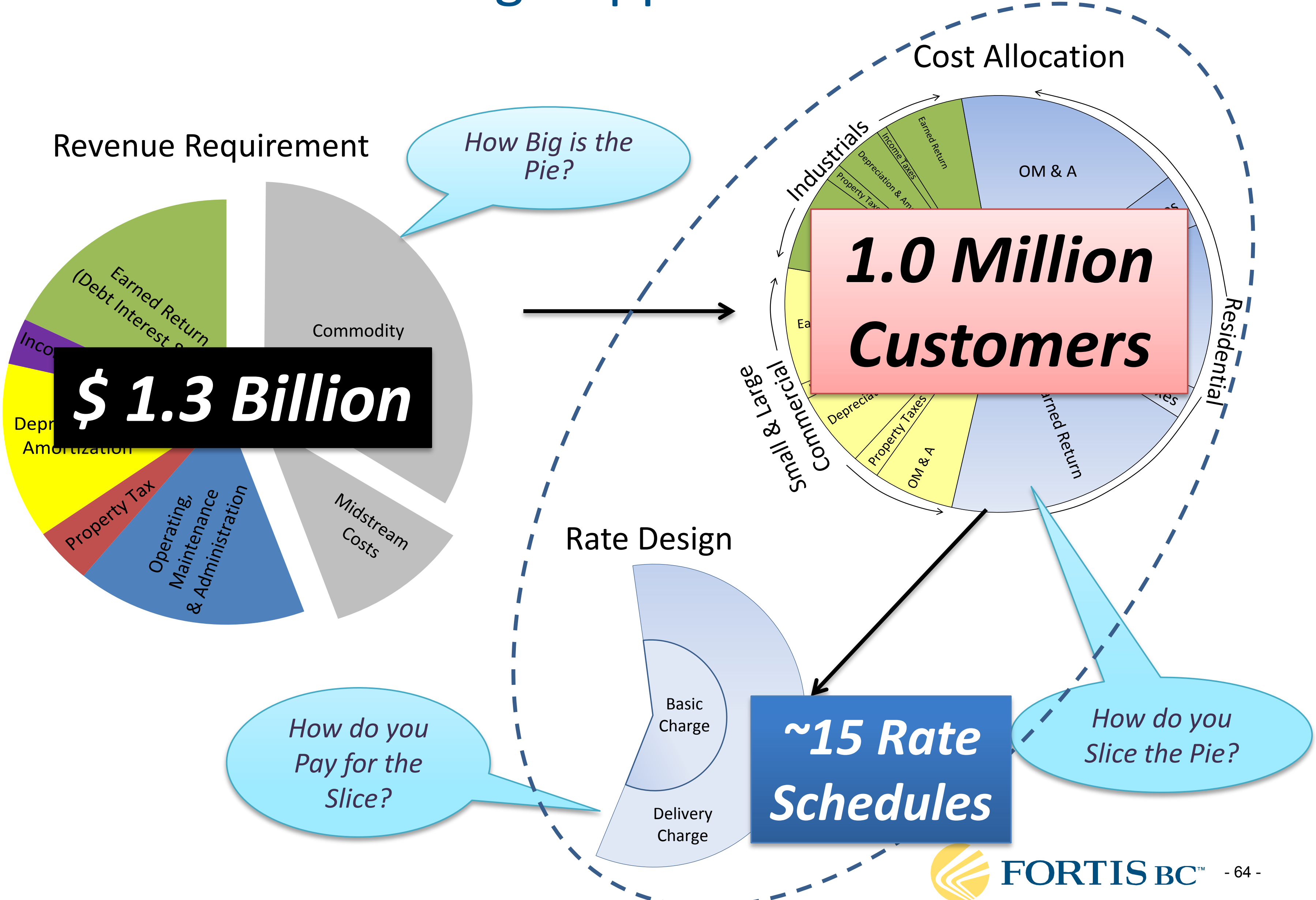


"Storage and Transport" also referred to as "Midstream"



COST OF SERVICE, SEGMENTATION & RATE DESIGN CONCEPTS

What is a Rate Design Application



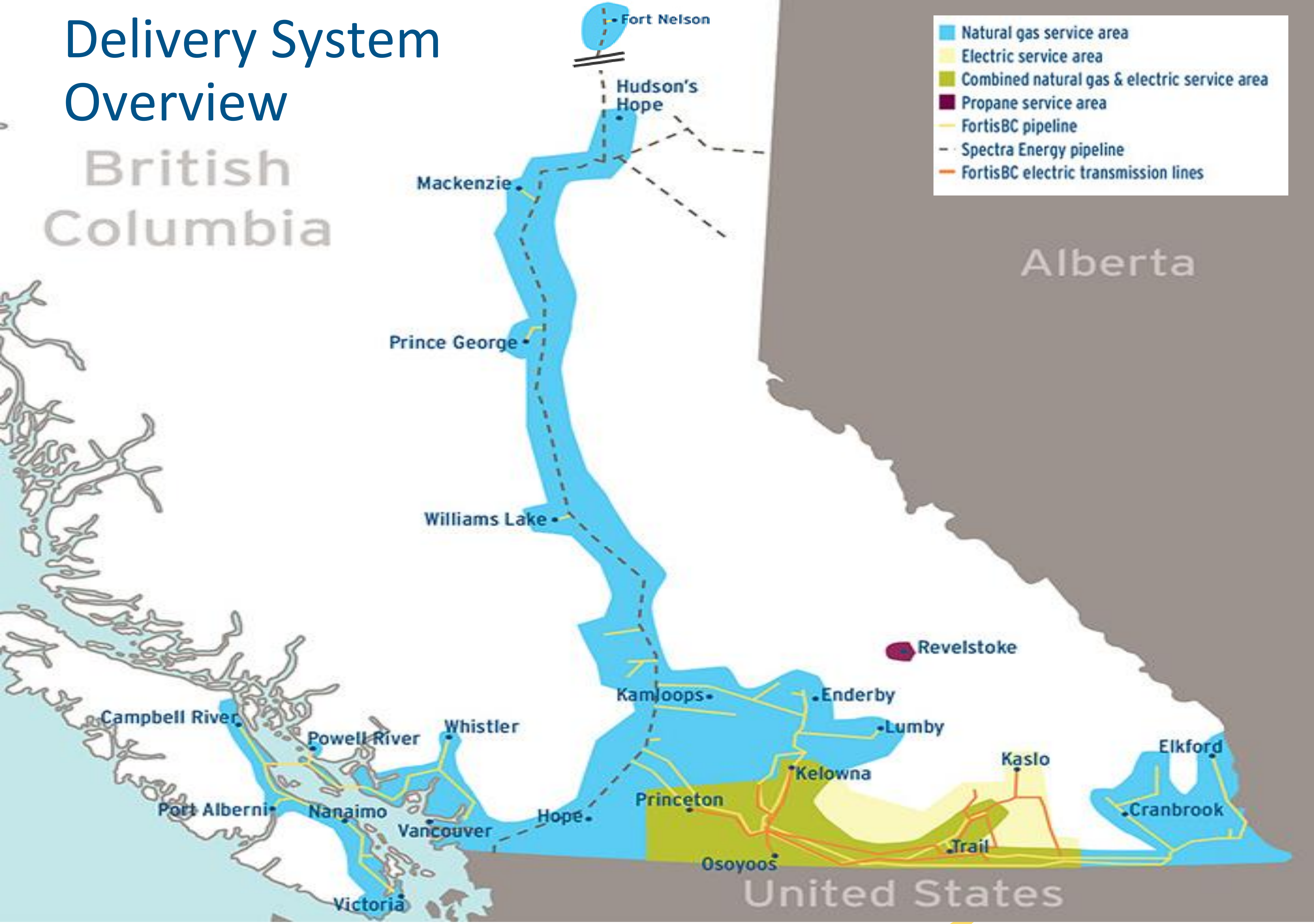
How we split up our Revenue Requirement amongst our customers

How we design our customers rates

Overview

- Delivery System Overview
- Rate Design Principles
- Customer Segmentation
- Cost of Service Allocation (COSA) Terminology
- COSA – Methods and Example
- Rate Design Concepts
- Summary

Delivery System Overview



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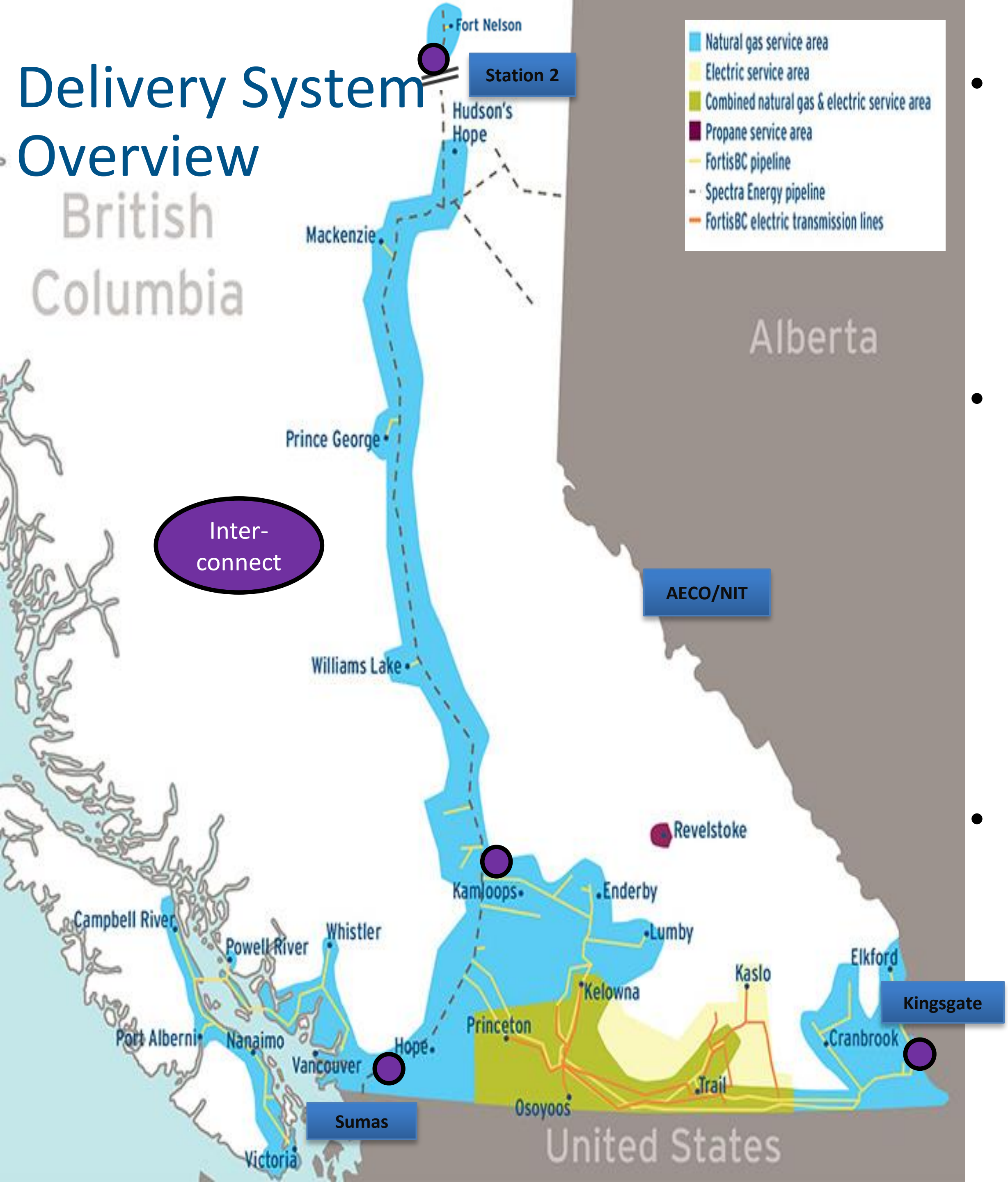
Delivery System Overview



- Essential Services Model (ESM) in place to ensure Gas gets from supply hubs to our service territory
- Transportation Services Model allows customers to bring gas to the FEI system (Interconnect points) whereby we receive gas for delivery to customers
- Delivery Model (COSA) picks up the gas that ESM and Transport models deliver to Interconnect points and moves it to customers premises

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Rate Design Principles

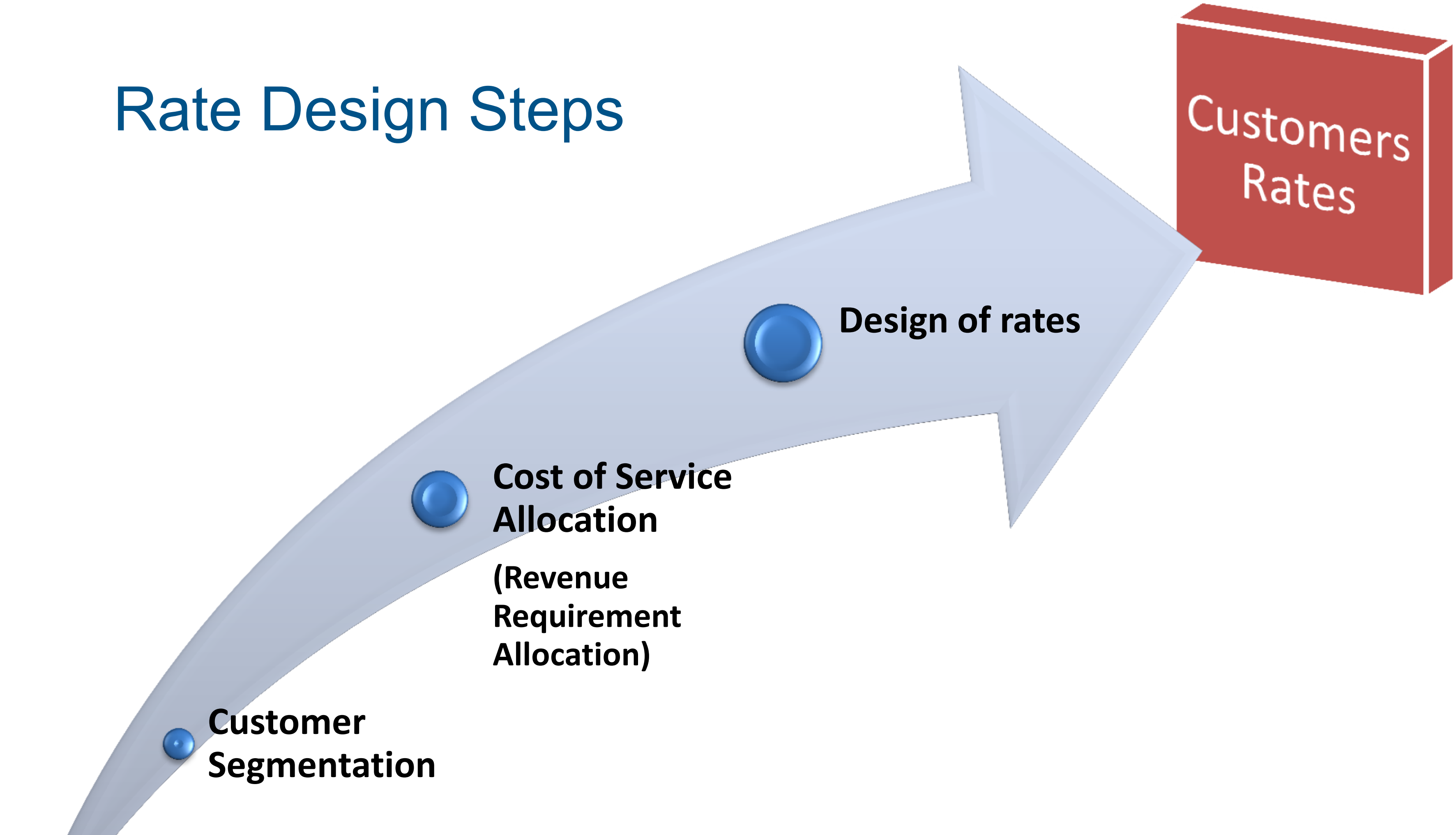
Based on Dr. Bonbright's commonly accepted work "Principles of Public Utility Rates'

The seven principles include:

- Customer Impact;
- Fairness;
- Economic Efficiency;
- Stability/Predictability;
- Ease of Understandability;
- Competitiveness; and
- Recovering the Cost of Service.

The weight placed on each of these principles is not always equal

Rate Design Steps



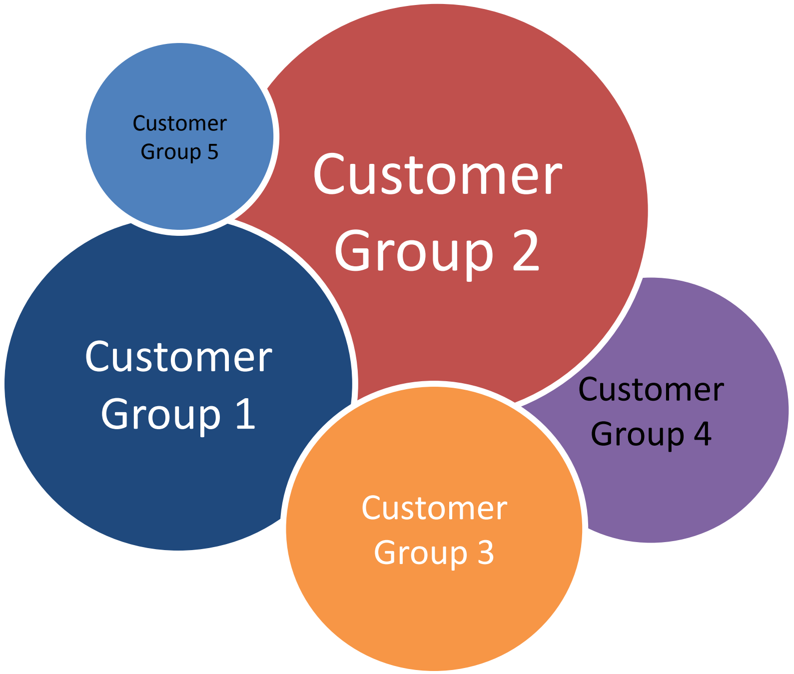
In its simplest form, it is the determination of the most appropriate Rate to charge a Customer Group that recovers the costs of serving them

Customer Segmentation

Analyze customers to separate them into groups where the customers in a particular group use the system in a similar way

Statistical tools are used including:

- Bill Frequency analysis
- Consumption patterns
- Clustering
- Load Factor analysis



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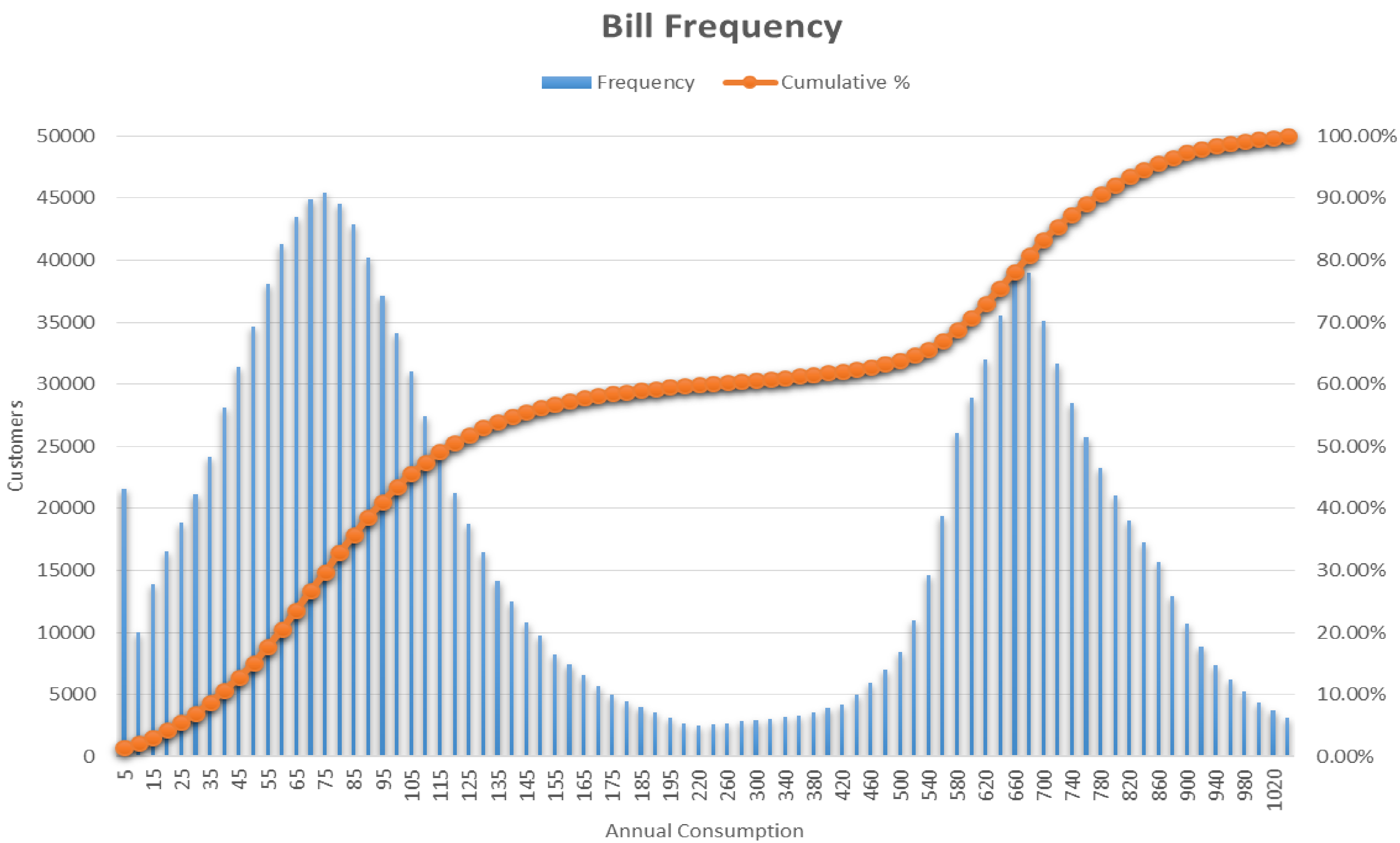
Customer Segmentation Example Approach



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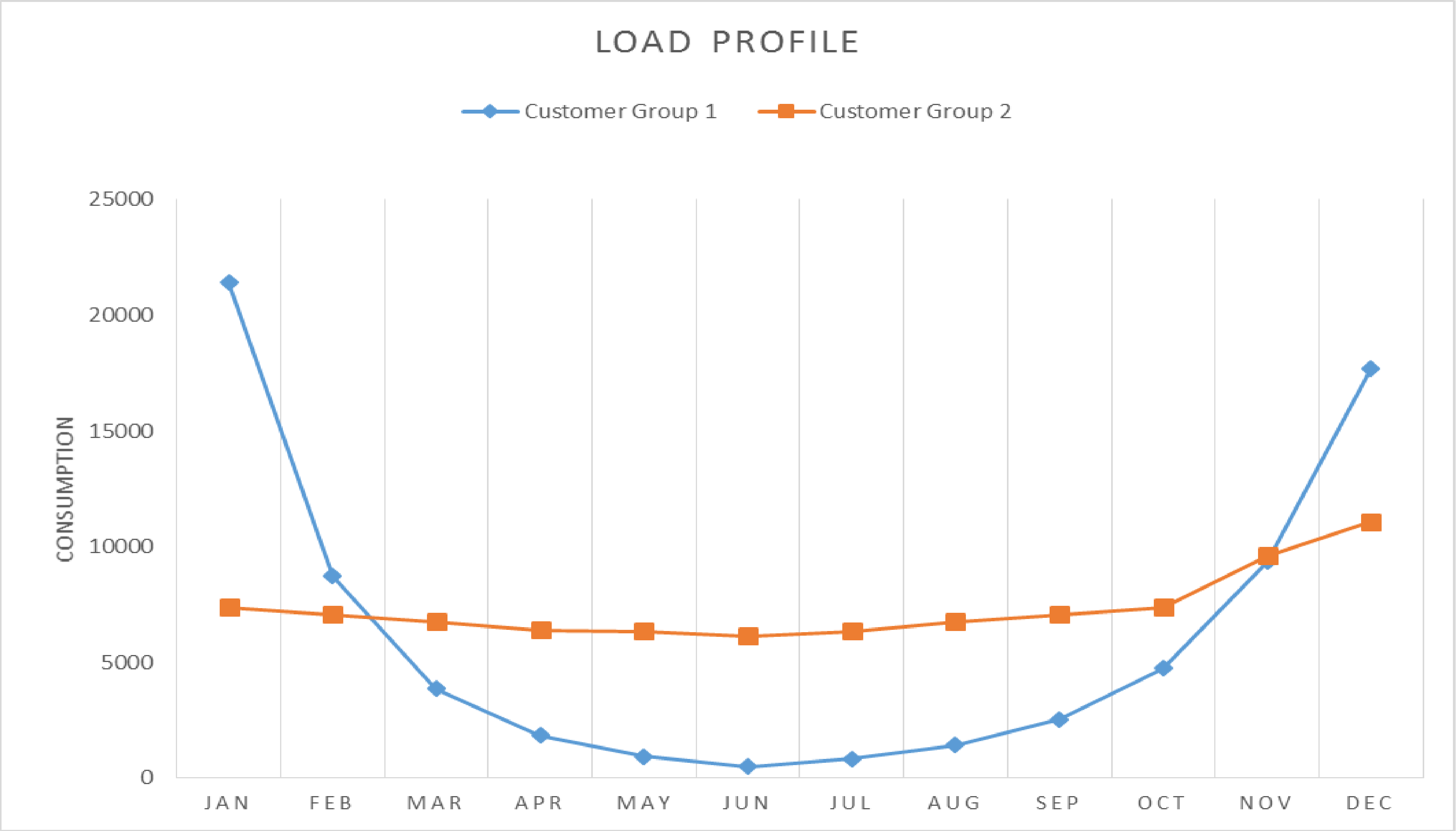
Customer Segmentation Example Approach

Customer Segmentation Example Approach



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How is the Delivery System built?

Design Day

- Our delivery system is built to be able to meet our customers demand on the coldest day in 20 years (design day)

Pipeline

- To do this, we place pipe and other assets in service that are large enough to meet the design day load

Normal Day

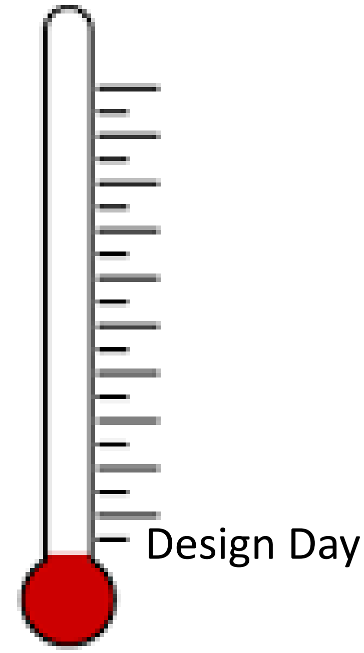
- On a normal temperature day, customers will not fully use our system capacity

Use of System

- Customer Groups use this system differently and as such some costs are allocated according to how each type of customer uses the system

Peak Day

- To do this we use Load Factor to derive a customer group's Peak Day (Design Day) demand



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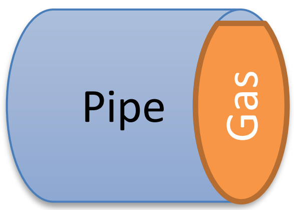
COSA Terminology - Load Factor

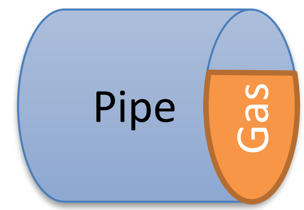
Load Factor is a measure of how a customer group uses the pipeline assets. Equal to average use / peak use.

<u>Customer Group 1</u>
1,000 GJ Consumption
30% Load Factor

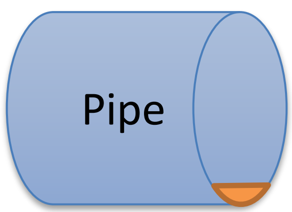
<u>Customer Group 2</u>
1,000 GJ Consumption
60% Load Factor

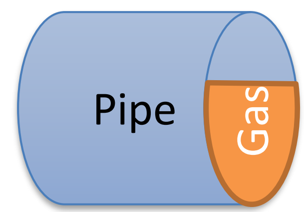
Winter

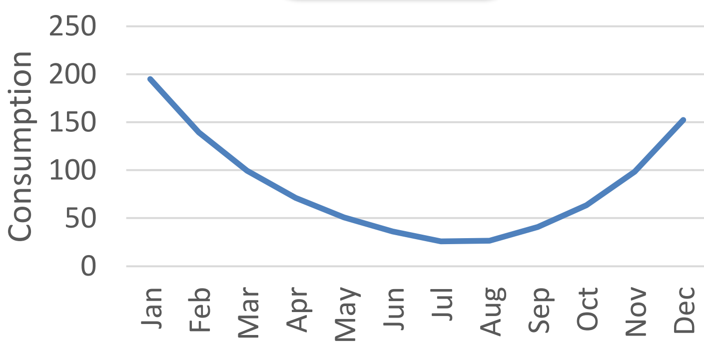


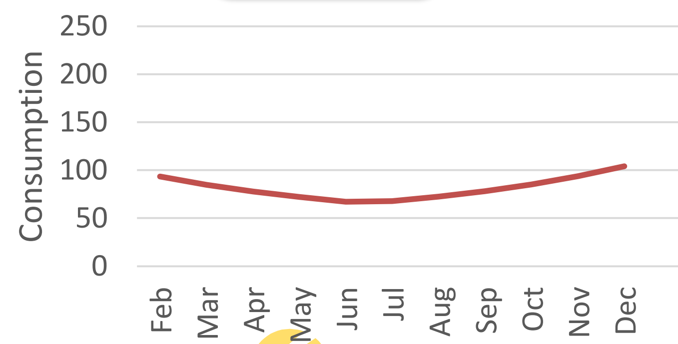


Summer









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COSA Terminology – Peak Day

- Peak Day
- Load factor adjusted volume

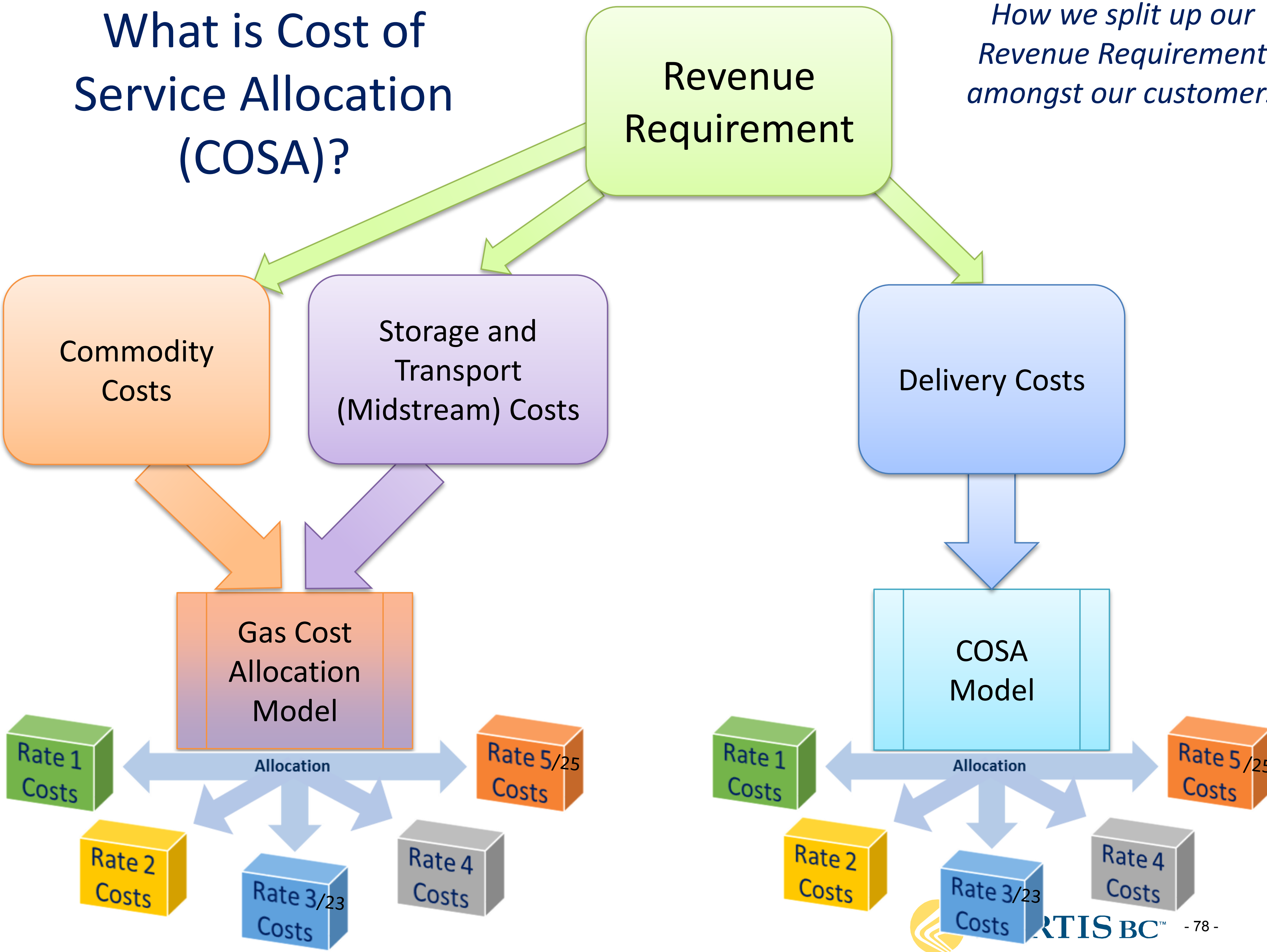
$$Peak\ Day = \frac{Annual\ Consumption}{Load\ Factor\ x\ 365}$$

	Customer Group 1	Customer Group 2
Load Factor	30%	60%
Annual Consumption (GJ)	1,000	1,000
Peak Day (GJ)	9.1	4.6
Peak Day Allocation %	67%	33%

		Customer Group 1	Customer Group 2
Cost to Allocate	$1,000		
Allocation using Peak Day (GJ)		$670	$330
Allocation using Consumption (GJ)		$500	$500

What is Cost of Service Allocation (COSA)?

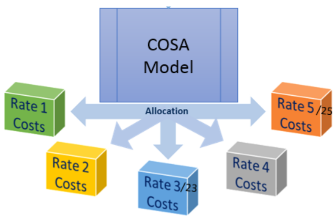
How we split up our Revenue Requirement amongst our customers

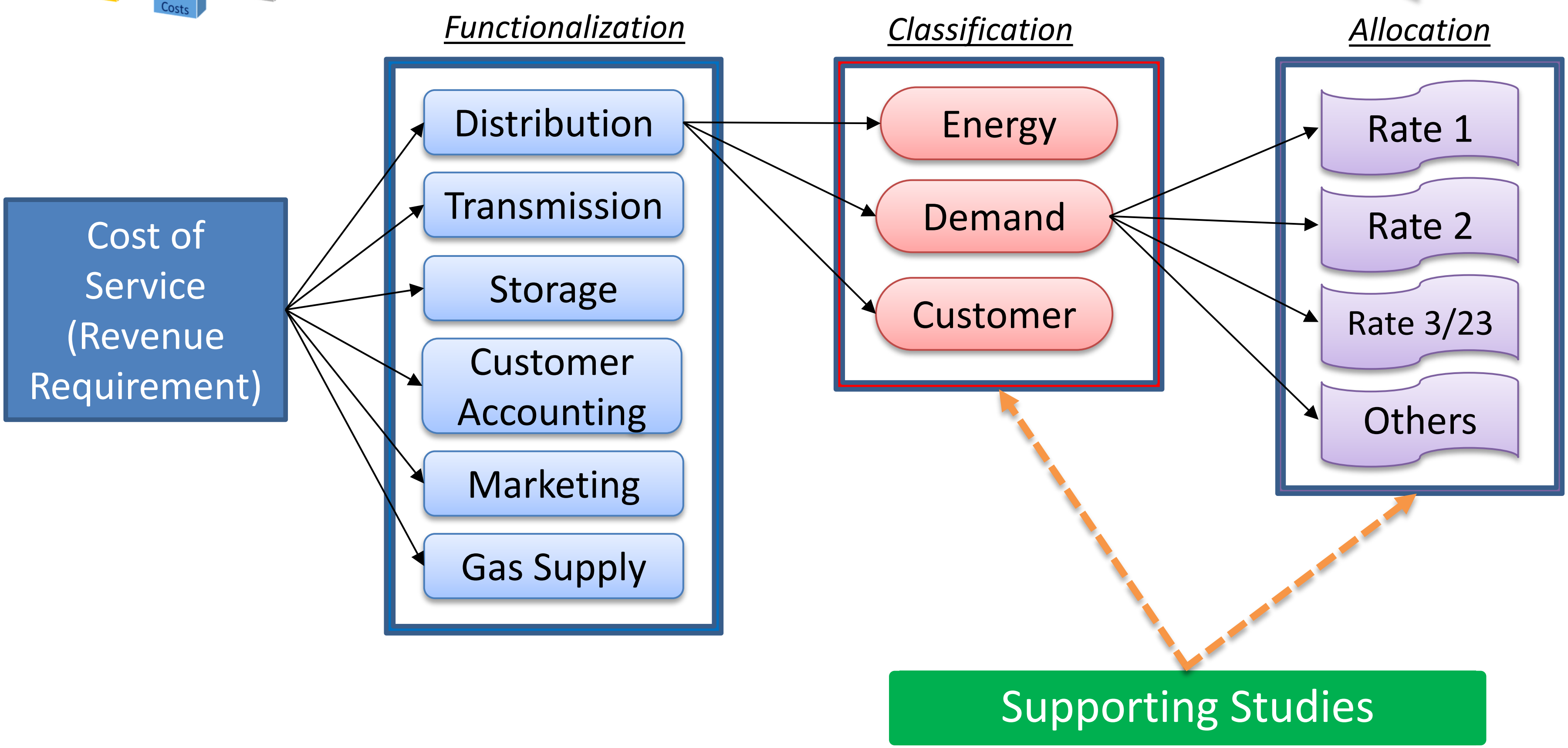


Commodity and Storage and Transport Costs

- Commodity Costs includes all costs to acquire gas and is divided by the total energy demand
  - All customers that purchase gas from FEI pay the same gas cost $/GJ
- Midstream Costs are those incurred to shape the load and are allocated based on load factor adjusted demand (peak demand)
  - Customers that purchase gas from FEI and unbundled customers pay midstream costs
- Transport Customers do not pay for Commodity or Midstream costs
- Gas costs are allocated to Fort Nelson and form part of the bundled rates applicable in Fort Nelson

Cost of Service Allocation (COSA)





How we split up our Revenue Requirement amongst our customers

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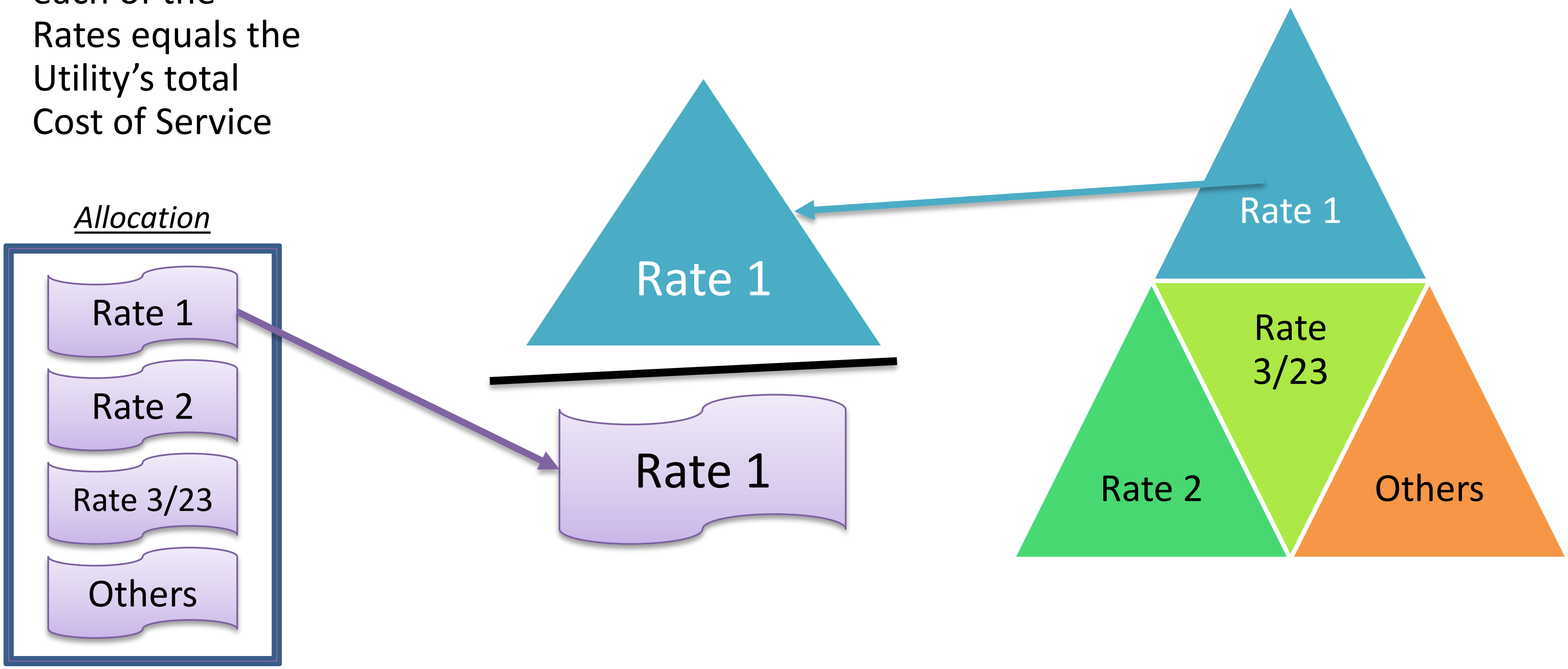
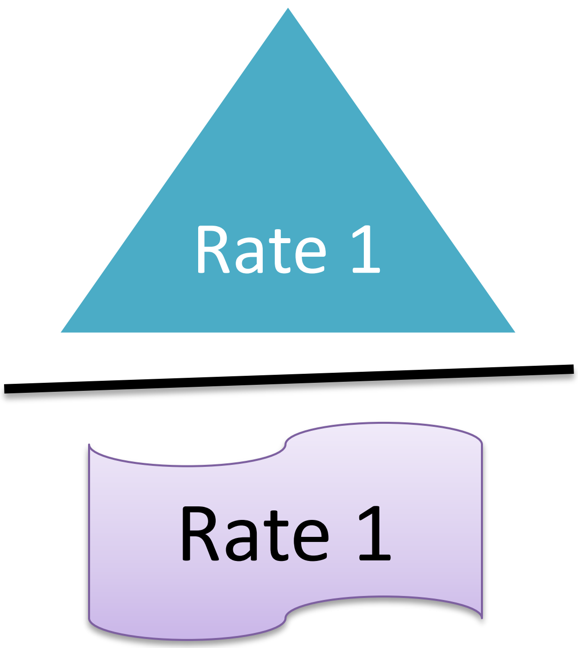
Revenue to Cost Ratio (R/C)

- Sum of all costs allocated to each of the Rates equals the Utility's total Cost of Service

- Total Revenue Collected by Rate Schedule



Revenue to Cost Ratio



- If a customer group R/C is within range, their rates are assumed to be fair and reasonable
- A range is appropriate given the subjective and short term nature of inputs, classifications and allocations
- Some times rebalancing may be required
  - Shift revenue required between customer groups

    (Reduce one Customer Group's rates and increase another group's)

COSA Supporting Studies

Study	Description	Why Is It Required?
1) **Minimum System Study**	• Classifies distribution costs into customer and demand components	• Ensures appropriate allocation of costs to each rate schedule
2) **Customer Weighting Factors Study**	• Assigns weighting factor to the average number of customers for each rate schedule	• Ensures appropriate allocation of customer related costs to various rate schedules

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COSA Minimum System Study (MSS)

- 26,000 KM of distribution mains
  - Diameter of 15 mm – 800 mm
  - Varying cost per meter
- Some portion of these mains are in place just to connect our customers to the system, this is the minimum system
- MSS basically prices 26,000 KM of pipe as if it were 60 mm
  - Generally all new pipe is no less than 60 mm PE pipe
- The value of the minimum system divided by the actual value of all the pipe is the percentage classified as 'Customer'
- The balance is classified as 'Demand'

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COSA Customer Weighting Factor

- Study differentiates the cost to connect small customers and large customers
- Calculated as a ratio to the cost to connect a residential customer
- Ratio used to scale upwards the average number of customers in a customer group

COSA- Example- Functionalization

Assume a two cost system, with two functions and three customer groups

Distribution operations role is to connect customers and deliver gas through DP pipe. Transmission operations role is to ensure gas is brought to the distribution system through TP pipe at the right time, quantity and pressure.

Cost 1: Distribution Operating Costs	$2,000
Cost 2: Transmission Operating Costs	$4,000
Total	**$6,000**

	FUNCTION	
	Distribution Operations	**Transmission Operations**
Distribution Operating Costs	$2,000	
Transmission Operating Costs		$4,000

Classification

Energy

Demand

Customer

COSA- Example - Classification

Distribution costs are incurred in part from customers joining the system and in part from the demand they place on the system

Minimum System Study quantifies the split of the Distribution system between Customer and Demand.

Assume 30% of Distribution system in place because a customer connects and 70% to serve them their demand.

Transmission system is 100% demand related.

	FUNCTION		CLASSIFICATION	
	Distribution Operations	Transmission Operations	Customer	Demand
Distribution Operating Costs	$2,000		$600	$1,400
Transmission Operating Costs		$4,000		$4,000

Allocation

Rate 1

Rate 2

Rate 3/23

Others

COSA – Example - Allocation

Allocation of costs requires an allocator that causes the cost to incur

Number of Customers works well to allocate customer costs. Peak Day Demand works well for demand related costs

Customer Group	Peak Day Demand	Customers
Rate 1	700	1,100
Rate 2	200	300
Rate 3	100	100
Total	**1,000**	**1,500**

Rate 1	Rate 2	Rate 3/23
$1,400 x 700 / 1,000	$1,400 x 200 / 1,000	$1,400 x 100 / 1,000
$600 x 1,100 / 1,500	$600 x 300 / 1,500	$600 x 100 / 1,500
$4,000 x 700 / 1,000	$4,000 x 200 / 1,000	$4,000 x 100 / 1,000

	CLASSIFICATION	Allocation Amount	ALLOCATION: Rate 1 Allocation	ALLOCATION: Rate 2 Allocation	ALLOCATION: Rate 3/23 Allocation	Total
Distribution Operating Costs	Demand	$1,400	$980	$280	$140	$1,400
	Customer	$600	$440	$120	$40	$600
Transmission Operating Costs	Demand	$4,000	$2,800	$800	$400	$4,000
Total		**$6,000**	**$4,220**	**$1,200**	**$580**	**$6,000**

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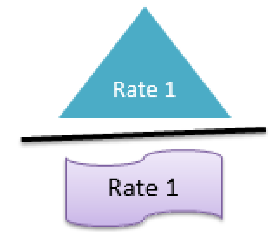
COSA – Example – Revenue to Cost



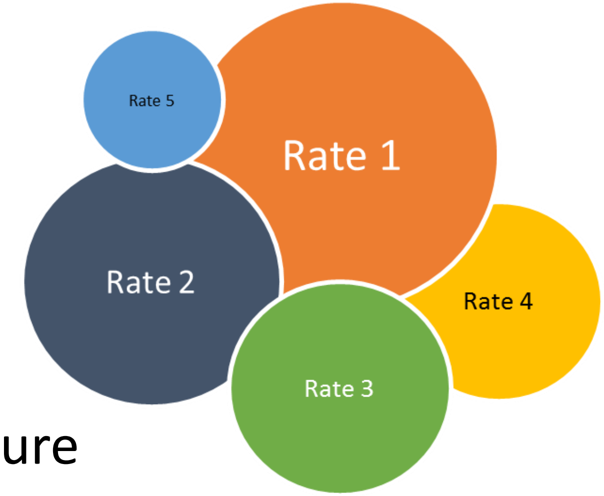
Once costs are allocated, revenue collected from each customer group is divided by the allocated cost to calculate the Revenue to Cost (R/C) ratio

	ALLOCATION			
	Rate 1 Allocation	Rate 2 Allocation	Rate 3/23 Allocation	Total
	$980	$280	$140	$1,400
	$440	$120	$40	$600
	$2,800	$800	$400	$4,000
Total Allocated Costs	**$4,220**	**$1,200**	**$580**	**$6,000**
Revenue at Existing Rates	**$4,150**	**$1,200**	**$650**	**$6,000**
R/C Ratio	**98.3%**	**100.0%**	**112.0%**	**100.0%**

If R/C ratios are far from 100%, rebalancing may be required

How we split up our Revenue Requirement amongst our customers

Designing Rates



- Often premised on allocated costs
- Customer related costs tend to be fixed in nature
- Demand related costs are based on the demand a customer places on the system, however a great portion is also fixed (capital cost of infrastructure like pipe and compression)
- Energy related costs tend to be variable with total consumption
- Balance recovery of fixed costs through fixed charges with the customers desire to control energy costs through consumption patterns

Rates should be understandable, stable, fair

and recover the cost of service

Designing Rates – Cost Classifications

- Fixed (cost caused from customer joining the system)
- Demand (cost caused from peak day demand)
- Variable (cost caused from consumption of commodity)

Rate 1 Delivery Costs	COSA	Rates
Fixed	61%	27%
Demand	39%	0%
Variable	0%	73%

Designing Rates

Fixed (Customer) Costs

- Basic Charge
- Administration Charge
- Minimum Charge

Capacity (Demand) Costs

- Demand Charge
- Firm Delivery Charge

Variable (Energy) Charges

- Delivery Charge
- Interruptible Charge
- Block Charge

Summary

2012 Amalgamation Application Revenue to Cost Ratios

FEI Rate Schedule*	R:C Ratio
Rate 1	93%
Rate 2	105%
Rate 3/23	108%
Rate 5/25	110%

Fort Nelson Rate Schedule	R:C Ratio
Rate 1	81%
Rate 2.1	116%
Rate 2.2	129%
Rate 25	126%

**Amalgamated Mainland, Vancouver Island, Whistler*

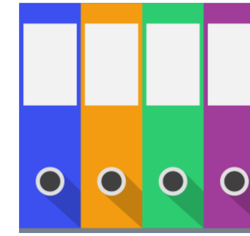
Summary

- COSA methods are consistent with 2012 application
- Midstream allocations consistent with past decisions
- Commodity costs are derived using total CCRA costs / sales volume
- COSA results are one of the many considerations when designing rates

TARIFF RATE SCHEDULES AND SERVICES OVERVIEW

FEI Tariff Rate Schedules and Services

Overview



- **A Tariff is a British Columbia Utilities Commission (BCUC) approved rate schedule of rates that can be charged by a utility to its customers**
  - Includes Sales and Transportation rate schedules, in addition to other specific rate schedules that offer other services
- **The FEI General Terms and Conditions (GT&Cs) of Service**
  - Outline the terms and conditions under which FEI (including the Fort Nelson Service Area) operates
  - Includes the Standard Fees and Charges Schedule, which includes fees and charges such as:
    - *Application Fees*
    - *Reactivation Charges*

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FEI Tariff Service Areas

FEI Tariff Service Areas

- Mainland (including Revelstoke)
- Vancouver Island
- Whistler
- Fort Nelson

Common Rates

<u>Effective January 1, 2018 –></u>
removal of phase-in delivery rate riders for Mainland, Whistler and Vancouver Island

FEI Sales and Transportation Services

FEI Tariff Rate Schedules 1 to 27

Customer Groups	Bundled Service	Unbundled Service*	Transportation Service
Residential	Rate Schedules 1/1B*	Rate Schedule 1U	Not Applicable
Small Commercial (<2,000 GJ/Yr)	Rate Schedules 2/2B*	Rate Schedule 2U	Not Applicable
Large Commercial (>2,000 GJ/Yr)	Rate Schedules 3/3B*	Rate Schedule 3U	Rate Schedule 23
Seasonal	Rate Schedule 4	Not Applicable	Not Applicable
General Firm	Rate Schedules 5/5B*	Not Applicable	Rate Schedule 25
Natural Gas Vehicle	Rate Schedules 6/6P	Not Applicable	Rate Schedule 26
General Interruptible	Rate Schedule 7	Not Applicable	Rate Schedule 27
Large Industrial	Not Applicable	Not Applicable	Rate Schedules 22/22A/22B

The Renewable Natural Gas (Biomethane Service) and Customer Choice (Unbundling Service) Programs are voluntary

Sales and Transportation Services

Sales Services

Bundled Service

Rate Schedules

- 1
- 2
- 3
- 4
- 5
- 6
- 6A
- 6P
- 7

Unbundled Service

Rate Schedules

- 1U
- 2U
- 3U

Biomethane Service

Rate Schedules

- 1B
- 2B
- 3B
- 5B

*Interruptible Service – transportation service which may be interrupted or curtailed by FEI, pursuant to the applicable sections in the applicable rate schedule and the FEI GT&Cs.

Transportation Services

Interruptible Service*

Rate Schedules

- 22 *(with option to negotiate some firm load)*
- 27

Firm Service**

Rate Schedules

- 23
- 25
- 26

Combination of Firm and Interruptible Service

Rate Schedules

- 22A (Closed)
- 22B (Closed)
- 50

**Firm Service – transportation service in which FEI is obligated to provide, only subject to interruption or curtailment pursuant to sections Default/Bankruptcy and/or Force Majeure as per the applicable rate schedule and the FEI GT&Cs.

Sales Service

FEI Tariff Rate Schedules 1 to 7

Description of Charges

Delivery Related Charges	**Basic Charge per Day or Month**	
	Demand Charge per Month per Gigajoule of Daily Demand	*Applicable to Rate Schedules 5 and 5B*
	Delivery Charge per Gigajoule	
Commodity Related Charges	**Storage and Transport per Gigajoule**	*The former Midstream charge*
	Commodity Cost Recovery Charge per Gigajoule	*Not Applicable to Commodity Unbundled Customers*
	Biomethane Energy Recovery Charge per Gigajoule	*Only Applicable to Rate Schedules 1B, 2B, 3B, and 5B*
	Rate Rider 1 per Gigajoule (Revelstoke only - Propane surcharge)	

Sales Rate Schedules

Bundled Service – FEI Rate Schedules 1 to 7

Rate Schedule 1/1B/1U	• Residential Service • ***2016 Forecast Average Number of Customers – 886,652***
Rate Schedule 2/2B/2U	• Small Commercial Service (<2,000 GJ) • ***2016 Forecast Average Number of Customers – 84,737***
Rate Schedule 3/3B/3U	• Large Commercial Service (>2,000 GJ) • ***2016 Forecast Average Number of Customers – 5,040***
Rate Schedule 4	• Seasonal Firm Service • ***2016 Forecast Average Number of Customers - 18***
Rate Schedule 5/5B	• General Firm Service • ***2016 Forecast Average Number of Customers – 230***
Rate Schedule 6*	• Natural Gas Vehicle Service • ***2016 Forecast Average Number of Customers – 15***
Rate Schedule 6P	• Natural Gas Refueling Service (Surrey Ops) • ***2016 Forecast Average Number of Customers – n/a***
Rate Schedule 7	• General Interruptible Service • ***2016 Forecast Average Number of Customers – 5***

***Also includes Rate Schedule 6A – Natural Gas Refueling Service (Compression) – zero customers in this rate class**

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Transportation Service

FEI Tariff Rate Schedules 22, 22A, 22B, 23, 25, 26, and 27

Description of Charges

Delivery Related Charges	**Basic Charge per Month**	
	Administration Charge per Month	
	Demand Charge per Month per Gigajoule of Daily Demand	*Applicable to firm load* *Applicable to Rate Schedules 22A, 22B and 25*
	Delivery Charge per Gigajoule	
Transportation Service Related Charges	**Charge per Gigajoule of Balancing Gas Supplied**	
	Charge per Gigajoule for Backstopping Gas	
	Charge per Gigajoule of Replacement Gas	
	Charge per Gigajoule for Unauthorized Overrun Charges	

Transportation Rate Schedules

FEI Tariff Rate Schedules 22, 22A, 22B, 23, 25, 26, 27, and 50

Rate Schedule 22	• Large Volume Transportation Service • ***2016 Forecast Average Number of Customers – 26***
Rate Schedule 22A	• Transportation Service - Inland Service Area (Closed) • ***2016 Forecast Average Number of Customers – 9***
Rate Schedule 22B	• Transportation Service - Columbia Service Area (Closed) • ***2016 Forecast Average Number of Customers – 5***
Rate Schedule 23	• Commercial Transportation Service (>2,000 GJ) • ***2016 Forecast Average Number of Customers – 1,669***
Rate Schedule 25	• General Firm Transportation Service • ***2016 Forecast Average Number of Customers – 566***
Rate Schedule 26	• Natural Gas Vehicle Transportation Service • ***2016 Forecast Average Number of Customers – nil***
Rate Schedule 27	• General Interruptible Transportation Service • ***2016 Forecast Average Number of Customers – 108***
Rate Schedule 50	• Large Volume Industrial Transportation Service • ***2016 Forecast Average Number of Customers – nil***

Other Services and Rate Schedules

FEI Tariff Rate Schedules 11B, 14A, 36, 40, and 46

Rate Schedule 11B	• Biomethane Large Volume Interruptible Sales
Rate Schedule 14A	• Term and Spot Gas Sales
Rate Schedule 36	• Commodity Unbundling Service (Terms and Conditions)
Rate Schedule 40	• West to East Southern Crossing Pipeline Transportation Service
Rate Schedule 46	• LNG Sales, Dispensing and Transportation Service

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Fort Nelson Service Area

Sales Services

Bundled Service

Applicable Rates

- Rate 1
- Rate 2.1
- Rate 2.2
- Rate 2.3
- Rate 3.1
- Rate 3.2
- Rate 3.3

Transportation Services

Firm Service

Applicable Rate

Rate 25

Fort Nelson Service Area Sales Service

Fort Nelson Rates 1, 2.1, 2.2, and 2.3

Description of Charges

Rates 1, 2.1, 2.2, and 2.3

Rate 1 used as an example

- **Minimum Daily Charge, which includes the first 2 Gigajoules per month prorated on a daily basis**
- **Variable Charge for the next 28 Gigajoules in the month**
- **Variable Charge for excess of 30 Gigajoules in the month**

- **The Minimum Daily Charge and the Variable Charges are inclusive of:**
  - ***Delivery charge per day/Gigajoule***
  - ***Revenue Stabilization Adjustment Amount per Day/Gigajoule***
  - ***Gas Cost Recovery Charge per Day/Gigajoule***

Fort Nelson Service Area Sales Rates

Fort Nelson Rates 1, 2.1, 2.2, 2.3, 3.1, 3.2, and 3.3

Rate 1	• Domestic Service • ***2016 Forecast Average Number of Customers – 1,980***
Rate 2.1	• General Service (<6,000 GJ) • ***2016 Forecast Average Number of Customers – 468***
Rate 2.2	• General Service (=or>6,000 GJ) • ***2016 Forecast Average Number of Customers – 34***
Rate 2.3*	• Natural Gas Vehicle Fuel Service • ***2016 Forecast Average Number of Customers – nil***
Rate 3.1	• Industrial Service (<96,000 GJ) • ***2016 Forecast Average Number of Customers – nil***
Rate 3.2	• Industrial Service (=or>96,000 GJ< 360,000 GJ) • ***2016 Forecast Average Number of Customers – nil***
Rate 3.3	• Industrial Service (=or>360,000 GJ) • ***2016 Forecast Average Number of Customers – nil***

Rate 2.4 provides Compression/Dispensing Service (Rates to be filed with BCUC for approval) – zero customers in this rate class

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Fort Nelson Service Area

Rate 25 General Firm Transportation Service – 2 Customers

Description of Charges

Delivery Related Charges	**Delivery Charge per Gigajoule of Monthly Transportation Quantity**	*Delivery Charge for first 20 GJ* *Next 260 GJ* *Excess of 280 GJ*
	Minimum Delivery Charge per Month	
	Administration Charge per Month	
	Revenue Stabilization Adjustment Charge per Gigajoule	*Rate Rider 5*
Transportation Service Related Charges	**Charge per Gigajoule of Authorized Overrun Gas**	
	Charges for Unauthorized Overrun Gas	

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Applicable Customer Fees and Charges

FEI Standard Fees and Charges Schedule

Application Fee	• *Existing Installation*	**$25.00**
	• *New Installation*	**$25.00**
Late Payment Charge	• ***1.5%*** *per month (**19.56%** per annum) on the outstanding balance*	
Dishonoured Cheque Charge	• *Current Fee*	**$20.00**
Interest on Cash Security Deposits	• *FEI's **Prime Interest Rate**[1] **minus 2%***	
Disputed Meter Testing Fees	• *Meters rated ≤ 14.2 m3/Hour*	**$60.00**
	• *Meters rated > 14.2 m3/Hour*	**Actual Costs**
Reactivation Charges	• *Performed During Regular Working Hours*	**$90.00/Hr**
	• *Performed After Regular Working Hours*	**$115.00/Hr**

[1] *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.*

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Bypass Agreements

Negotiated agreements that provide mutual benefits to the bypass customer and all other customers on the system

Characteristics

- Typically, the customer is within close proximity to connect directly to the upstream pipeline system if they so choose
- FEI has 11 agreements in place, all of which have been reviewed and approved by the BCUC
- Agreements are negotiated in good faith and are evaluated based on the expected cost of direct connection for the bypass customer as well as the impacts on other FEI customers
- A discounted cash flow analysis is used to derive the rates
- Typical initial 10 year term, with extension clauses subject to BCUC approval
- Typically, a negotiated inflation rate is applied to the bypass rate each year (ex. CPI) to account for changes in operating costs over time

Summary

The FEI GT&Cs, including the Standard Fees and Charges Schedule

- *Will be reviewed as part of the Rate Design Application*

Current Rate Schedules

- *Working well for FEI and customers*
- *Will be reviewed as part of the Rate Design Application*

Website Link

- https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasTariffs/FortisBCEnergyInc/Pages/default.aspx

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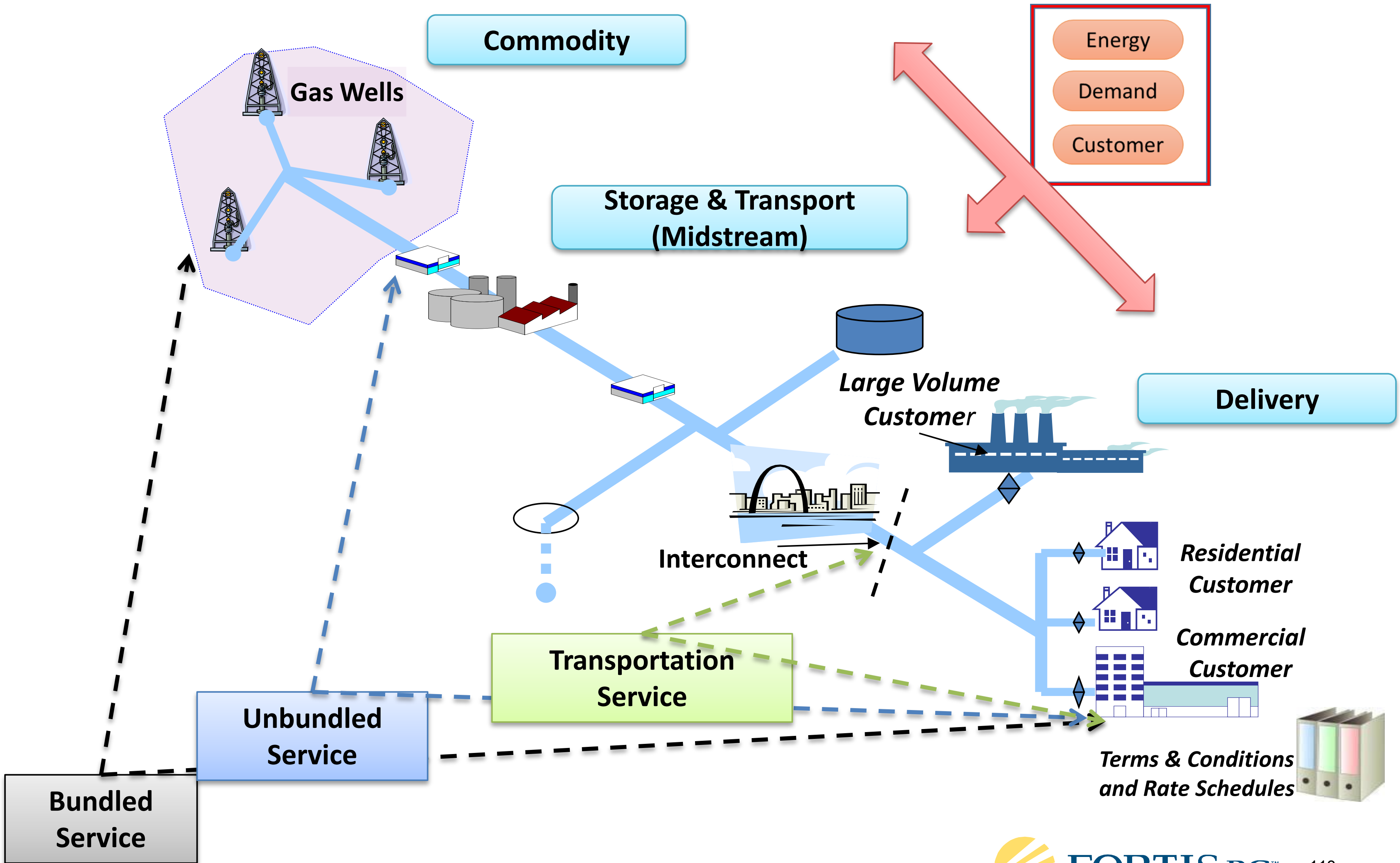
CONCLUDING REMARKS

Services, Cost Allocation and Rate Design



Next Steps

Documentation

- FEI will distribute and post notes and material from today's session by Friday, May 27th

Communication

- Website is now available: www.fortisbc.com/ratedesign

Workshop 1

- Anticipated to occur late June/early July
- Focus on results from preliminary COSA study
- Discussion guide will be circulated 2 weeks in advance of workshop

For further information, please contact:

Gas.Regulatory.Affairs@fortisbc.com

www.fortisbc.com/ratedesign

Find FortisBC at:

Fortisbc.com

604-576-7000

Load Factor Calculation Steps
(generally calculated at the region and rate level)

i. Normalized Monthly Use Per Customer (UPC)
ii. Sum the above 12 months and divide by 365 to get a Daily Average UPC

A. Actual Monthly UPC
B. Divide above by number of days in corresponding month to get Daily Actual UPC
C. Regress Monthly Average Temperature (x) and above daily UPC (y) to derive slope and intercept of daily UPC to temperature
D. Use slope and intercept in linear equation with Peak Day Temperature to calculate peak day UPC
   - Peak Day Temperature = Coldest Day that is expected to occur once every 20 years based on weather data from the last 60 years.

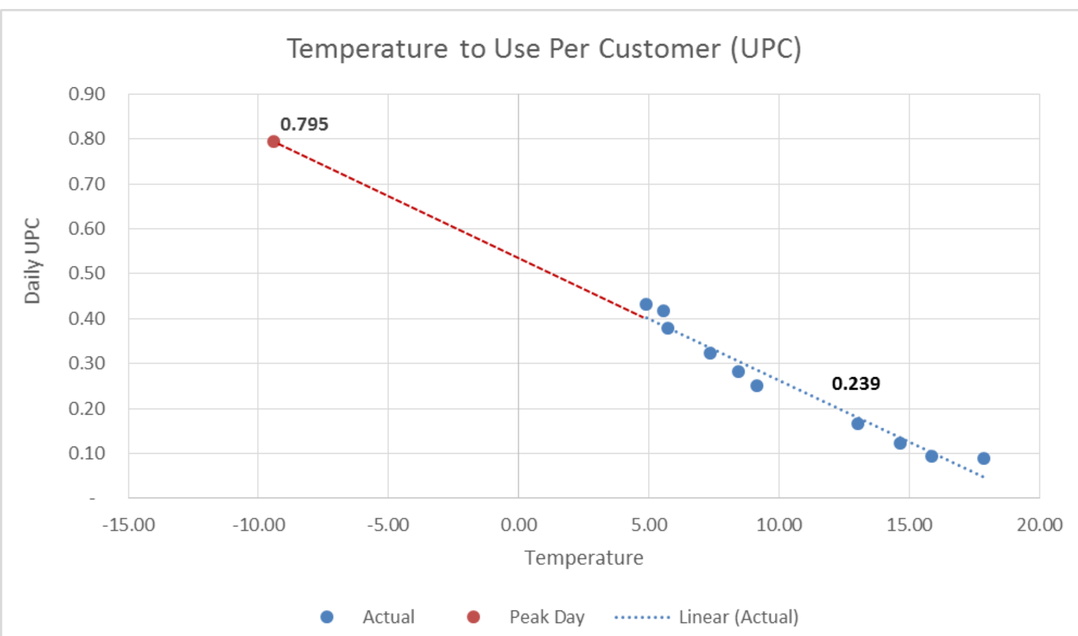
Load Factor = ii / D

- The pipe assets were put in place to serve peak day load (coldest day in 20 years)
- Most days are not peak days so Customers typically use the assets to a lesser degree
- The load factor represents the normal

Example

Normalized monthly consumption converted to an average daily UPC equals ii. 0.239

Using actual data, regress temperature and daily UPC to develop the slope and intercept. Check R^2 value for fit. Use regression equation to derive Peak Day UPC equaling D. 0.795 (see graph below)



Load Factor = 0.239 / 0.795 = 30.0%

Summary

Meeting:	Stakeholder Information Session (Number 2)
Date:	May 19, 2016
Time:	9 am to 3:30 pm
Location:	BCUC Hearing Room, 12th Floor, 1125 Howe Street, Vancouver
Facilitator:	Michelle Carman, FEI
Participants:	Morrow , Kirby (Absolute Energy); Kresnyak, Peter (Absolute Energy); Quail, Susanna (AQW); Roy, Rachel (AQW); Andrews, Bill (BCSEA); Hackney, Tom (BCSEA); Ashley, Jackie (BCUC); Marr, Cathy (BCUC); South, Errol (BCUC); Sue, Suzanne (BCUC); Wruck, Patrick (BCUC); Braithwaite, Tannis (BCPIAC); Feeney, Kate (BCPIAC); Caumanns, Nick (Cascadia Energy); Connelly, Steve (Cascadia Energy); Craig, David (CEC); Rhodes, Janet (CEC); Weafer, Chris (CEC); Vandersteen, Bev (Fort Nelson & District Chamber of Commerce [FNDCC]); Bursey, David (ICG/Sentinel Energy); Langley, Jim (Sentinel Energy); Berkhout, Tom (MEM); Quail, Jim (MoveUP); McCordic, Mary (Shell Energy); Bonin, Kevin (Translink);
FEI Attendees:	Ahmed, Tariq; Bevacqua, Ilva; Carman, Michelle; Gosselin, Rick; Gravel, Colleen; Hill, Shawn; Hill, Song; Hodgins, Kevin; Hopping, Uschi; Joly, Janice; Lang, Mary; Mason, Matt; Moore, Ed; Noel, Brian; Pala, Rohit; Salbach, Stephanie; Sinclair, Corey; Tabone, Gail; Toky, Atul;
Material Provided	Presentation attached following notes.
Agenda:	1. Welcome and Introductions 2. Gas Supply Basics and Fundamentals • FEI Services & Bill Components • Commodity Unbundling & Essential Services Model • Overview of Region & FEI's Resources 3. Transportation Model Overview • General Background • Key Components of Transport Model • Administering the Tariff and Applicable Charges • Summary 4. Cost of Service, Segmentation and Rate Design Concepts • Delivery System Overview • Rate Design Principles • Customer Segmentation • Cost of Service Allocation Terminology • COSA- Methods and Example • Rate Design Concepts • Summary 5. Tariff, Rate Schedules and Services Overview

Summary

	• Sales and Transportation Services Overview • Sales Rate Schedules and Description of Charges • Transportation Rate Schedules and Description of Charges • Other Services and Rate Schedules • Fort Nelson Rate Schedules and Description of Charges • Applicable Customer Fees and Charges • Bypass Agreements 6. Concluding Remarks

Meeting Summary and Notes

	Question/Comment	FEI Response and Discussion Summary
GAS SUPPLY BASICS AND FUNDAMENTALS- SUMMARY OF QUESTIONS/COMMENTS DURING PRESENTATION		
1.	What has been the frequency of a marketer not being able to deliver the gas to the designated hubs under the ESM on behalf of their customer? (slide 21)	Infrequent and minor; however, safeguards and process must be in place to ensure that customers continue receive safe and reliable service.
2.	Where are most of our supply resources sourced from? (slide 25)	Gas supply is primarily purchased from Stn2 and AECO(NIT), which are more liquid and have more counterparties that trade at those points (compared to Sumas/Kingsgate). Storage Aitken Creek (seasonal supply – winter), Jackson Prairie, MIST (shorter duration storage). On-system LNG storage Mt. Hayes, Tilbury (high volume gas on demand). Resources support the winter oriented load in BC.

Summary

	Question/Comment	FEI Response and Discussion Summary
3.	Is the 1-10 days of peaking typical? (slide 27)	1-10 day period is from the planning perspective and it is based on design load. Design load is a peak day core demand that could occur on the system based on the maximum coldest day ever that can be expected in the region from a planning perspective. The design day demand forecast is derived by first establishing the relationship between weather and consumption on the expected coldest forecasted temperature scenario which has a one in twenty (5%) chance of occurrence. Although we plan based on the design load, we are also concerned about the normal use and the duration of asset. It is also important to recognize that access to certain resources in this region is limited and we need access at peak times. Finally, we try to match resources as best we can. Generally, resources in the portfolio have stayed consistent over time. The demand curve is typically highest between Dec-Feb, but it is possible to use all available resources in November for a short or prolonged duration should the region encounter extreme weather in that month instead of the typical expected coldest months. The availability of certain resources should be accessible by the utility in months that go beyond the winter months of Nov-Mar should cold weather overlap in months such as April/May. We are trying to have a resource portfolio that meets not only the peak design day but also be available over a sustained basis that allows us to meet normal winter weather. In addition, the resources should not only be available in the winter months of Nov-Mar but also be accessible in some capacity in the shoulder months around the winter season. As a result, each resource ranging from piped gas supply (baseload & seasonally contracted) to storage contracts of varying capacity/deliverability and duration to low duration but high deliverability LNG plays a role in the portfolio based on the Load Duration Curve under both Design and Normal weather conditions. Since gas is bought prior to actual gas day, resources we contract for must have flexibility, so storage facilities must have that flexibility.

	Question/Comment	FEI Response and Discussion Summary
4.	How frequently is curtailment exercised? (slide 28)	There are two types of curtailment- supply and capacity. Supply curtailments have been imposed when necessary and capacity curtailment can occur every year, particularly in certain locations during peak or certain winter weather conditions. A rough historical estimate of capacity curtailment for interruptible rate schedule customers would be approximately one day per year. Given the past few warm winters there may be downward pressure on the one day per year rule of thumb. The Industrial curtailment referred to in the slides is specifically about the curtailment under Rate Schedule 22A which allows for up to 5 one-half days of curtailment. Under Rate 22A, FEI can hold the customers to consume only half of their firm DTQ but they are required to deliver supply to match their full DTQ and FEI can use the supply for firm core sales customers.
5.	What are core customers?	For gas supply purposes, core customers are defined as rate schedules 1 through 7 (i.e. sales customers) and include customers in the customer choice program
6.	General follow-up discussion	Although system capacity is designed based on geography and 1 in 20 year event, certain regions are constrained for other reasons. Generally the existence of the commodity isn't the issue (i.e. the supply) it is the delivery of the supply that is the challenge (i.e. the capacity). That is, the supply is in one or two key areas and all users in the region need to bring that supply to another location which leads to constraints on the delivery and the necessity for diversity and flexibility.

	Question/Comment	FEI Response and Discussion Summary
7.	Is CCRA & MCRA in scope and what is the dividing line?	We believe that the system and the overall business models are working well and do not need to be revisited; however, we will be digging into the allocation of costs between commodity, midstream and delivery to validate that they are appropriate and identify any need for change or improvement. With respect to the dividing line between CCRA and MCRA, the CCRA relates to all baseload gas purchased by FEI on behalf of customers staying with FEI (i.e. the gas purchased at the supply hubs) and is the amount of gas that is purchased 365 days per year from the supply hubs. Once commodity is bought at the two hubs, then it is transported through the MCRA assets to the locations of the load on FEI's system.
8.	Is there an option for Customer Choice customers to go with another midstream provider?	Not for Residential and Small Commercial customers. If you're a big enough customer (large commercial or high volume firm), you can go to transport model and you have to procure your own resources. Customer Choice allows R1, 2, 3 to buy their commodity baseload under the ESM model from a marketer but FEI still performs the midstream role.
9.	With the ESM model, what were some of the other alternatives considered?	The ESM model was chosen based on the underlying infrastructure of the region. For residential and small commercial customers, FEI is in a better position to collectively manage the infrastructure to achieve safe and reliable service. There is a fundamental difference between a residential customer whose marketer has failed to provide supply vs a transport customer whose marketer has failed to provide supply. Supply must be covered 365 days a year and the system has to be balanced between the amount of gas coming in and the amount used during the day. We contract not just per day, but for resources that allow us to balance the system intraday.

Summary

	Question/Comment	FEI Response and Discussion Summary
10.	Is there a rule of thumb for how load relates to temperature and how much time does it take to get gas from the Aitken Creek Storage facility?	There is an approximate high level rule of thumb in the winter months whereby the average load on FEI's system can move with temperature changes. We can expect the load to change about 25,000 GJ or 30,000 GJ with every one degree change in temperature as an approximate rule of thumb. The nomination cycles cover a gas day and there are three cycles per day and those cycles help with the ability to match the supply and demand. We try to get on the first nomination cycle of the day, so the gas can make its way down. We might access a physical resource, but there is another pipeline in between there and the need of the resources to move that gas and that capacity could already be full. The molecules themselves aren't making their way down to the burnertip, it's just keeping the pipeline full on both ends.
11.	Depending on what the Westcoast system looks like (low pressure), do you have a situation where gas from Aitken Creek won't be enough to meet the demand and Spectra won't authorize?	We have a contract for firm capacity so the pipeline is obligated to deliver; however it's possible in an extreme case (that's where the resources in the portfolio crystalize) – we may need to use LNG immediately to alleviate certain operational conditions. That is, if low line pack has occurred, and pipe is really pulling hard on the bottom end, under those situations, Gas Control staff will make a call to use LNG. Within 4 hours, LNG can provide a very high volume of supply in the load centre directly and help stabilize gas in the pipeline and also system pressure at the bottom end of the pipeline. We have approximately 40 min to act to resolve an imbalance on the intraday in the intraday 2 nomination cycle. Midstream assets balance the system on behalf of all customer groups on the day.

	Question/Comment	FEI Response and Discussion Summary
12.	What portion of the market at supply hubs does FEI hold?	Stn2 – 2.1 bcf and compares to interior capacity and lower mainland of 550-600 TJs (25% of load at Stn2). Total market at AECO is 14bcf so Station 2 is approximately 15% of AECO. With respect to portfolio, 75%-25% at Stn2-AECO respectively is reflected in the baseload.
13.	How does Fort Nelson fit into the portfolio?	Fort Nelson is part of the same portfolio and is allocated cost based on getting commodity to that location (small portion of transport and allocation from AECO). Fort Nelson gets the benefit of being part of the system. Fort Nelson is not part of the CCRA and MCRA rate structure because they are separately regulated with a different and bundled rate structure.
14.	Is the Southern Crossing Pipeline operating as expected?	SCP was put in place to access gas from Alberta to serve Okanagan. It connects to the old 12" line Oliver to Kingsvale for delivery down on Westcoast. The pipeline is being used as expected and is operating well. Contracts underpinning its use from Northwest Natural and FEI Midstream. It's an important part of the diversified portfolio to bring gas from Alberta, to get gas into the interior and also to Huntingdon.
15.	How do we balance on the Westcoast system?	We have an OBA contract (not public) that outlines certain tolerances with each interconnecting point. Conditions have tightened over time and the system is daily balanced.

	Question/Comment	FEI Response and Discussion Summary
TRANSPORTATION MODEL OVERVIEW- SUMMARY OF QUESTIONS/COMMENTS DURING PRESENTATION		
16.	Do you charge Transport customers for holding inventory? (slide 47)	No. Marketers have paid for that gas. If they over-deliver, the gas is banked on that given day. The extra gas may go into line pack or storage somewhere along the line.
17.	Isn't the intent for Transport customers to deliver on that day and do all Transport customers use a marketer? (slide 48)	Yes, gas is delivered and balanced daily. However, customers in monthly balanced groups balance by month-end. Thus, the working relationship with those groups becomes very important. No, not all Transport customers use a marketer, some source their own gas supply and capacity on their own behalf. There are 12 marketers participating and FEI has a rate schedule (14A) that supports customers that require a short term transport service that is limited to index and is not longer than one year in duration for any fixed price contracts. Generally the numbers are small under 14A and it is regarded as an option to customers that want to return to FEI within the current contract year or for customers that marketers no longer want to serve.
18.	What is the logic and rationale for the 20% band? (slide 53)	This tolerance band is one of the things we will be looking at in context of changes. It is a legacy number. Historically, pipeline systems were monthly balanced and perhaps this is one of the factors in the determination of this band. Under cold weather, this band goes to 5% balancing for daily and monthly groups.
19.	How often do charges occur? (slide 57)	They can happen anytime during curtailment. The demand surcharge is extremely rare and has never been applied.
20.	Has Fortis staff grown to manage the growth in the transport group?	No, staff has declined and stayed at about one to manage the administrative aspects of the transport model largely as a result of advancement of technology and the use of the WINS nomination system

	Question/Comment	FEI Response and Discussion Summary
COST OF SERVICE, SEGMENTATION AND RATE DESIGN CONCEPTS- SUMMARY OF QUESTIONS/COMMENTS DURING PRESENTATION		
21.	How do the Bonbright principles apply? How is competiveness related to allocating costs? Does economic efficiency apply to EEC programs?	The principles guide decisions on rate design and competitiveness is an important consideration in setting natural gas rates. From the perspective of delivery, energy consumption and energy efficiency is addressed through EEC programs. With respect to the principles guiding allocations and rate design, economic efficiency refers to economically assigning resources. Some of the principles are contradictory to each other and they are balanced depending on several factors (such as policy and external environment, etc.).
22.	Is a single peak used? (slide 75)	Yes- it is the estimated daily usage and is derived by a monthly peak that regresses to the day.
23.	Does Bonbright provide guidance on a framework for functionalization, classification and allocation and are their alternatives that other utilities may use? Why is there a need to functionalize or classify?	Yes, Bonbright does provide some discussion on allocation methods. As an alternative to embedded cost studies (which require some form of functionalization, classification and allocation) some utilities may use marginal costs. For embedded cost studies, this approach to allocation (i.e. the three step approach) is widely adopted and there is a need to functionalize and classify because the majority of costs are common or shared costs that are largely fixed in nature.
24.	Is distribution piping all the same size?	It ranges from 15mm to 900mm. Minimum today is 60mm poly.
25.	How often is rate re-balancing conducted?	For FEI, only during a rate design application and the last rebalancing was conducted in 2001. We did not propose any shifting of revenue responsibilities, but the rate design in 2001 was a Negotiated Settlement approved by the Commission that shifted revenue from interruptible Large Industrial Rate Schedule 22 to Residential.

	Question/Comment	FEI Response and Discussion Summary
26.	What does the minimum system study cover? (slide 84)	The minimum system study is trying to estimate the distribution costs that are driven by the fact that a customer has been added. That is, without some type of analysis like this, distribution related costs would be classified as demand related and allocated based on peak day which fails to recognize that there is some portion of distribution costs that may be attributed to attaching the next customer.
TARIFF, RATE SCHEDULES AND SERVICES OVERVIEW - SUMMARY OF QUESTIONS/COMMENTS DURING PRESENTATION		
27.	Why are RS22A & 22B closed rate schedules?	They are legacy rate schedules. The closing of these rate schedules comes from the 1993 rate design- these customers are on a specific part of the system (Inland and Columbia regions). They are firm service customers that are served off of the transmission system.
28.	Why is biomethane not available to Fort Nelson customers? (slide 105)	Fort Nelson rates are not set up similar to FEI in order to offer biomethane service, or to administer the service. The first step would be to unbundle rates because it's a voluntary program.

GENERAL QUESTIONS/COMMENTS		
29.	What is the goal of this working group?	The goal of the working group is to provide feedback on FEI proposals and analysis prior to filing. Two weeks in advance of each of the workshops (to begin in late June/early July) a discussion guide will be sent out. The intent of the workshops was expected to be about helping FEI put forward an application that identifies and addresses the concerns of the group, but may not necessarily be an application that puts forward a resolution(s). This is because everyone here has a different perspective and varying interests. Regardless of what we achieve through these workshops, we will still have to file an application and have an IR process. Today's session was to get a common vocabulary and set a foundation for the workshops to follow. Going forward, the best value of these discussions may be to narrow down the issues.

Action Items and Next Steps

	Item	Responsibility
1.	Notes from session circulated by May 27	FEI
2.	Identify key issues & topics that were addressed since the last comprehensive rate design in the 90's (i.e. note proceedings where decisions were made with respect to the business models).	FEI- for discussion at the first workshop
3.	Reach out to FEI with thoughts, concerns, if you want to meet.	All participants

2016 FEI Rate Design Application

Workshop 1 – FEI COSA

Atul Toky – Manager, Rate Design and Tariffs
Richard Gosselin – Manager, Cost of Service

July 11, 2016

FORTIS BC™

Introduction
Objectives for Today

- Inform & Review Results of Current COSA
- Starting Point for Discussion
- Agreement on Key Issues List
- Efficient and Cost Effective Regulatory Process

Workshop Guidelines

Participate

Respect other participants and presenters

Keep discussion topics/issues relevant to Rate Design

Questions as we go / if need be - add them to an 'Issues List'

Issues list to be compiled and revisited following presentation

One speaker at a time

Documentation:

- Meeting Notes
- Issues List
- FortisBC Responses to Issues
- Issues List Items not Addressed During Workshop

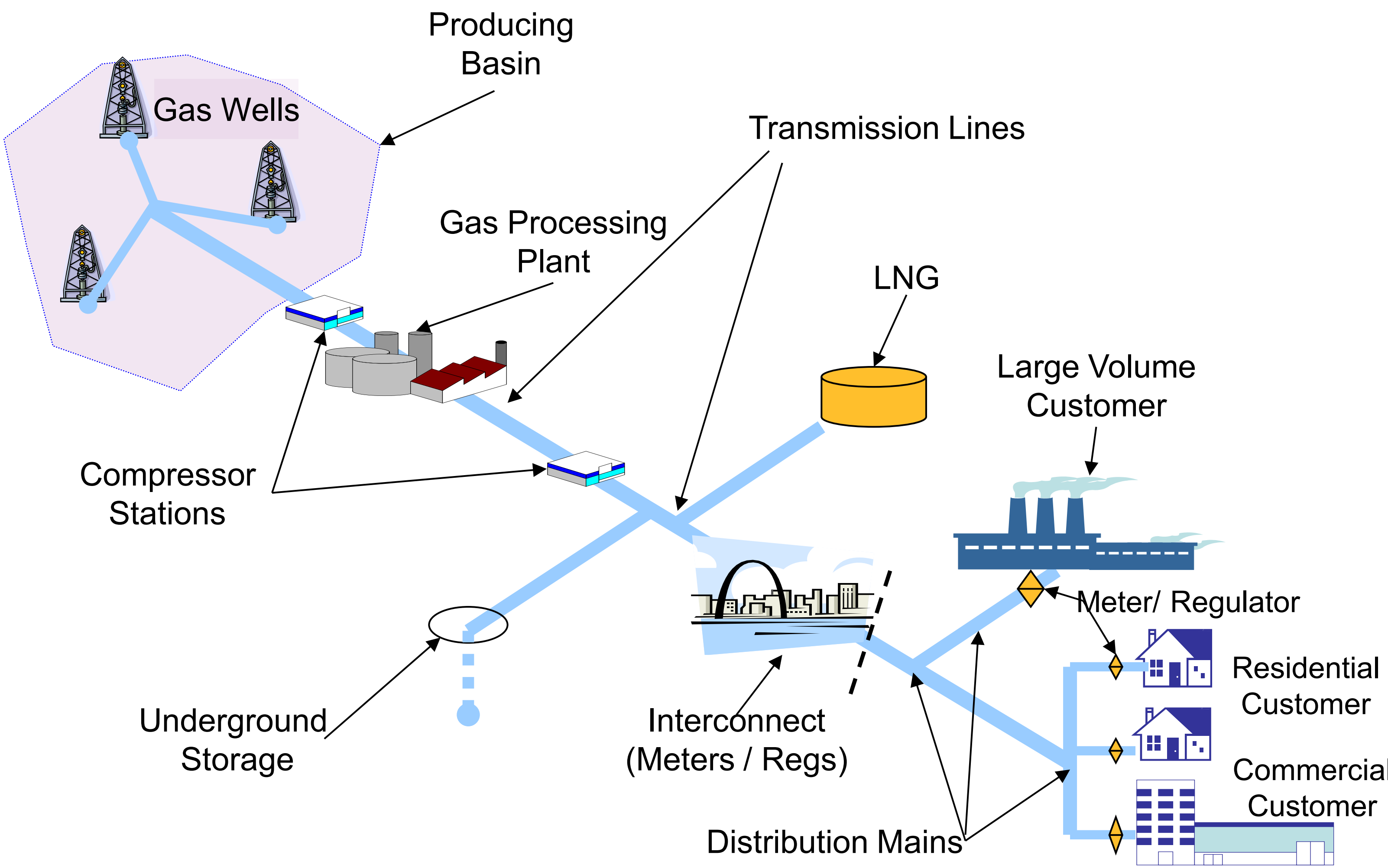
Agenda

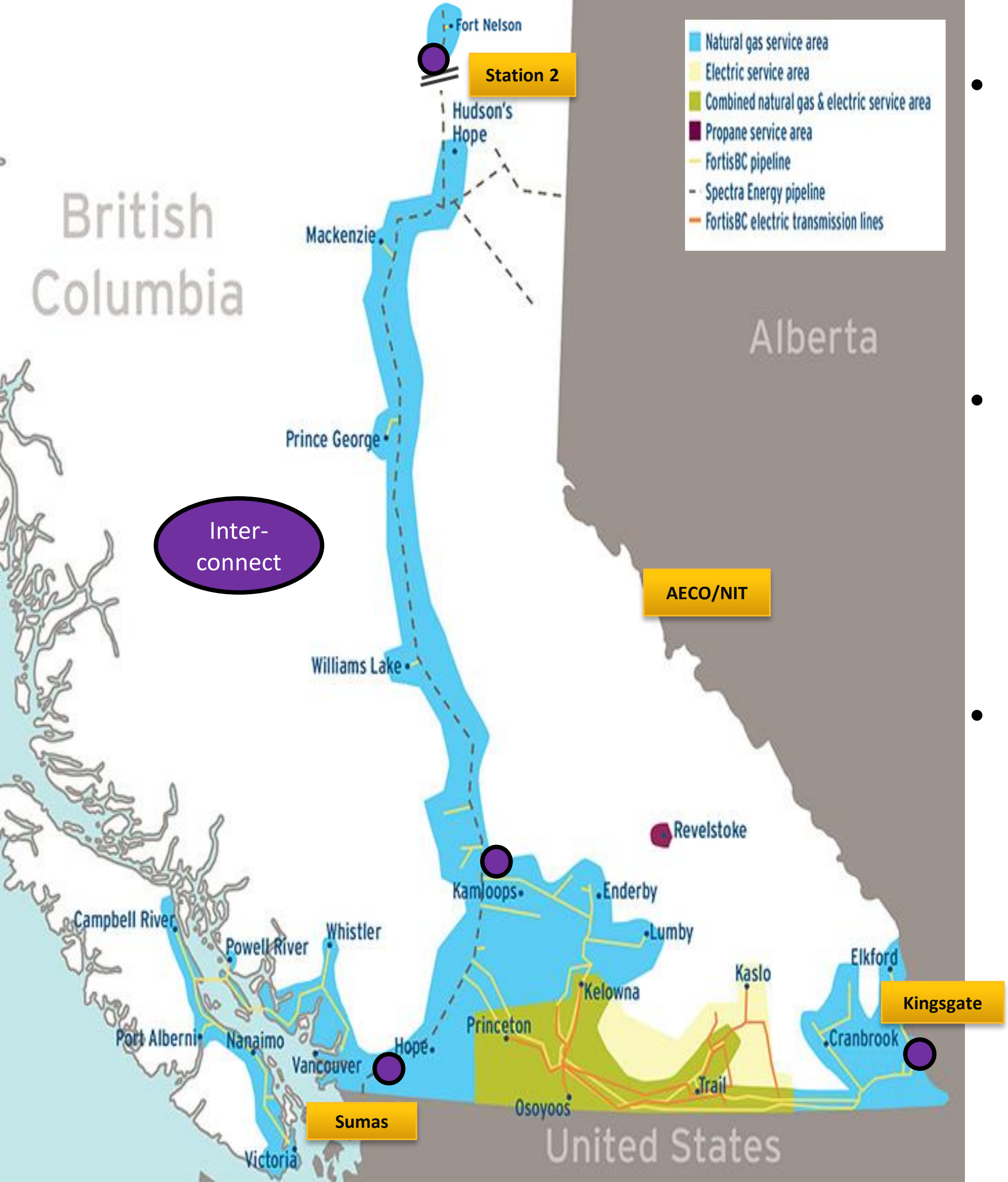
Discussion Guide	Gas Cost Allocation
	Delivery Cost Allocation
	Functionalization, Classification and Allocation Review
Key Discussion Topics	Tilbury Expansion Project
	Eagle Mountain – Woodfibre Pipeline Project
	Mt Hayes Cost Allocation
	Southern Crossing Pipeline
	Load Factors for Allocation
	Other Discussion Topics
Next Steps	Concluding Remarks
	Compile Key Issues List
	Workshop 1 – Fort Nelson

Part I

DISCUSSION GUIDE

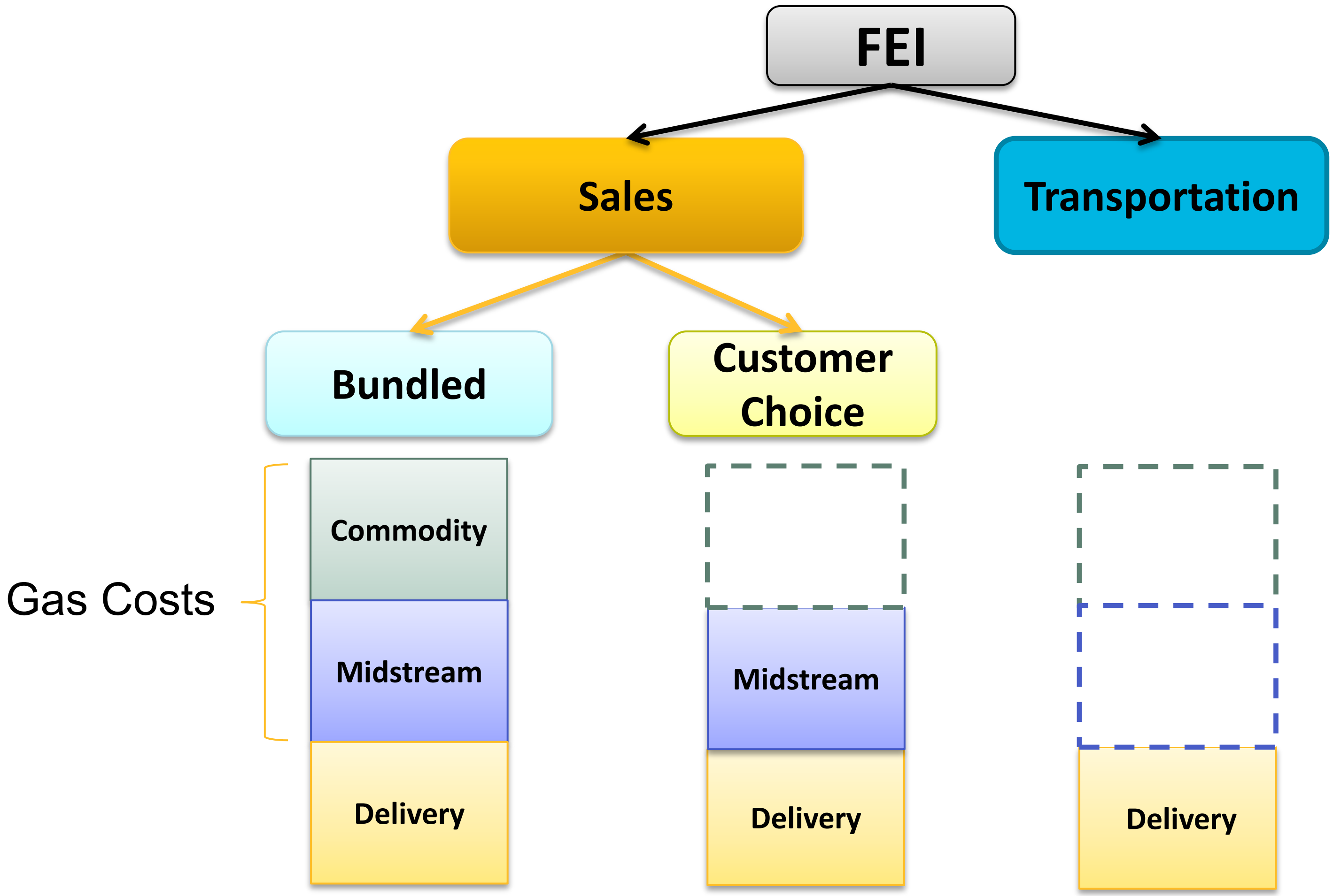
All Components Affect Rate Design





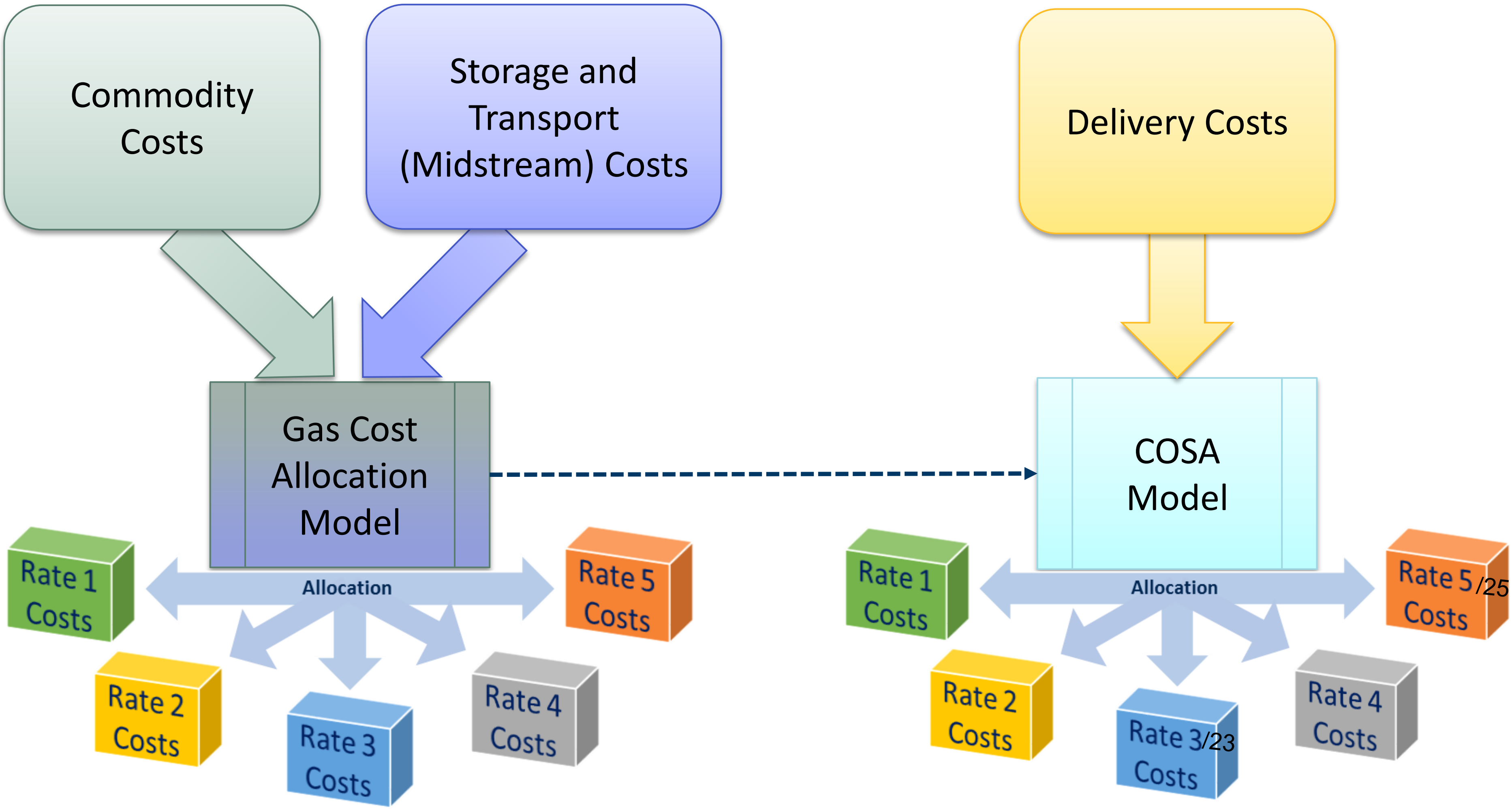
- The **Essential Services Model (ESM**) is in place to ensure Gas gets from supply hubs to our service territory
- **Sales service** picks ups the gas that the ESM delivers and moves it through the system to customers
- **Transportation service** allows customers to bring gas to our system at specific points whereby we take possession and deliver

Overview of FEI Services & Rates



"Midstream" also referred to as "Storage and Transport"
1 PJ = 1,000 TJ = 1,000,000 GJ

What is Cost of Service Allocation (COSA)?



COSA Model: Cost Assumptions

Test Year: Costs from 2016 Annual Review used in COSA

Delivery Costs

- Based on the forecast delivery costs approved in the 2016 Annual Review
- Known & Measurable costs for major projects are included

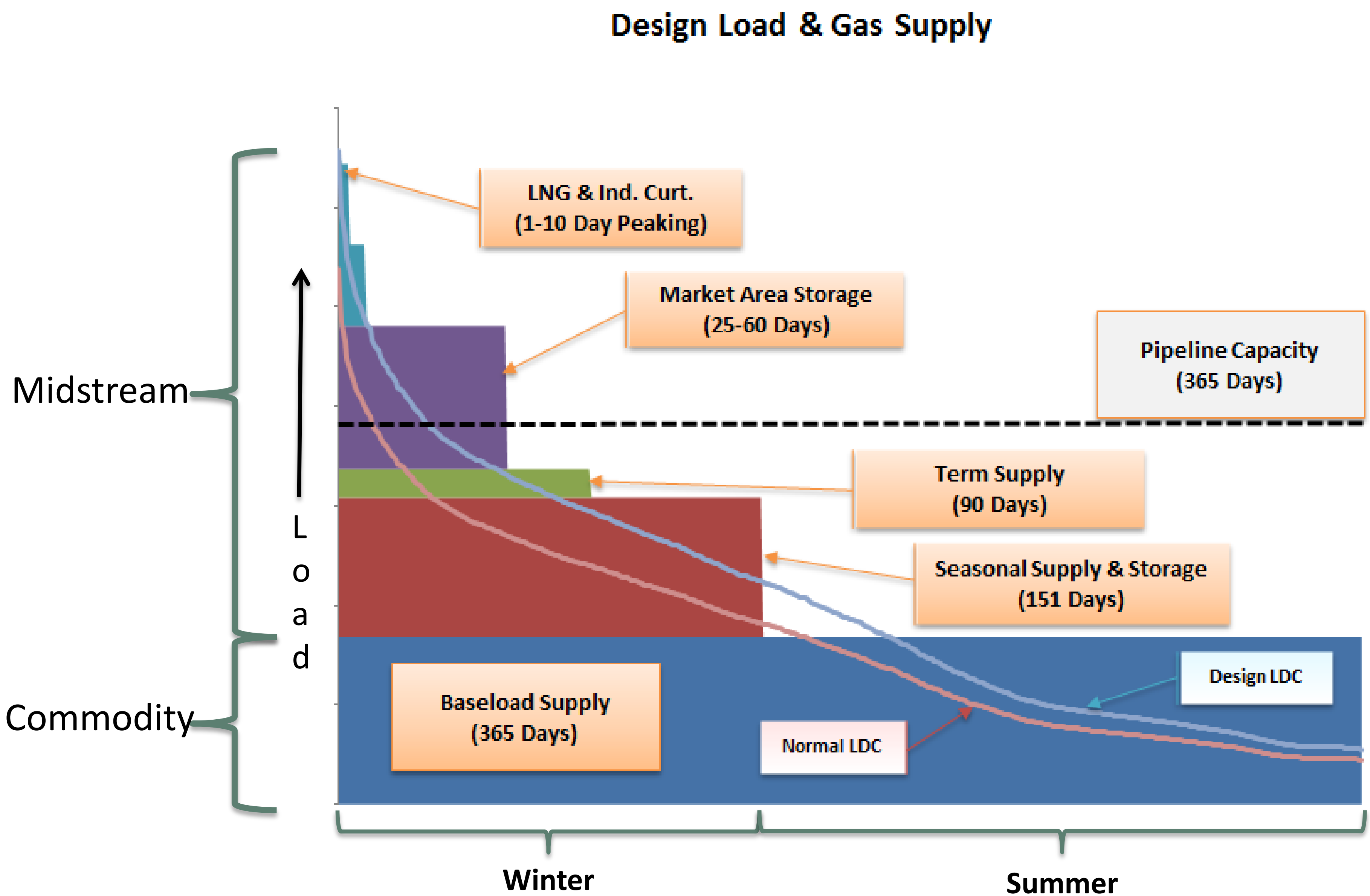
Gas Costs

- Gas cost (Commodity & Midstream) recovery charges are established via the quarterly gas cost review process
- Test year gas costs based on multiplying forecast sales volumes times the existing commodity & midstream charges for each rate schedule

Gas Cost Allocation

Key Components, Allocation Method & Results

Gas Supply Resources



Gas Supply Portfolio

Commodity

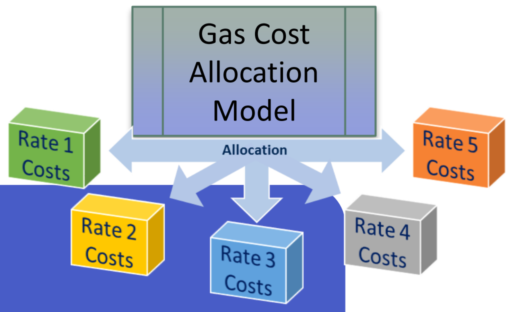
- Market priced annual baseload commodity purchases
- Costs flow through to rates with no markup
- Reviewed quarterly & subject to quarterly resetting

Storage & Transport (Midstream)

- Transportation capacity on external pipelines
- Seasonal storage capacity
- Market Area & On-System LNG storage
- Winter seasonal commodity
- Load balancing for entire system
- Mitigation of resources (short term basis)
- Costs flow through to rates with no markup
- Reviewed quarterly but normally reset annually

Discussion Guide - Section 2.1, page 2 and 3

Gas Cost Allocation Method



Gas supply costs separated between Commodity & Midstream

Commodity costs – classified as energy-related & allocated based on throughput

Midstream costs - classified as demand-related & allocated based on peak day demand

- Rolling three year average load factors used in midstream cost allocations, with exception that load factor for RS 5 midstream cost allocations set at 50% (1996 RDA Negotiated Settlement Agreement)

Discussion Guide - Section 2.3, page 6

Results

2016 Test Year		Total	RATE 1	RATE 2	RATE 3	RATE 4	RATE 5	RATE 6	RATE 7
Midstream Sales Volume	(TJ)	120,882	72,399	27,942	18,037	130	2,173	47	155
Midstream Costs	(000's)	163,374	101,214	39,035	21,049	109	1,819	20	129
Midstream Cost Recovery Charges [1]	($/GJ)		**$ 1.398**	**$ 1.397**	**$ 1.167**	**$ 0.837**	**$ 0.837**	**$ 0.417**	**$ 0.837**
Commodity Sales Volume - FEI	(TJ)	107,522							
Commodity Costs	(000's)	267,299							
Commodity Cost Recovery Charge	($/GJ)		**$ 2.486**	**$ 2.486**	**$ 2.486**	**$ 2.486**	**$ 2.486**	**$ 2.486**	**$ 2.486**

[1] Load Factor adjusted volumetric basis.

	Rate 1	Rate 2	Rate 3	Rate 4	Rate 5	Rate 6	Rate 7
Percent of Midstream Costs Allocation	62%	23%	13%	0%	2%	0%	0%

Discussion Guide- Section 2.4, page 6 and 7

Gas Cost Allocation Summary

FEI believes existing allocation approach is reasonable

- Commodity - driven by energy consumed, classified as energy-related and allocated based on throughput
- Storage and Transport - driven by capacity requirements, classified as demand-related and allocated based on peak day demand

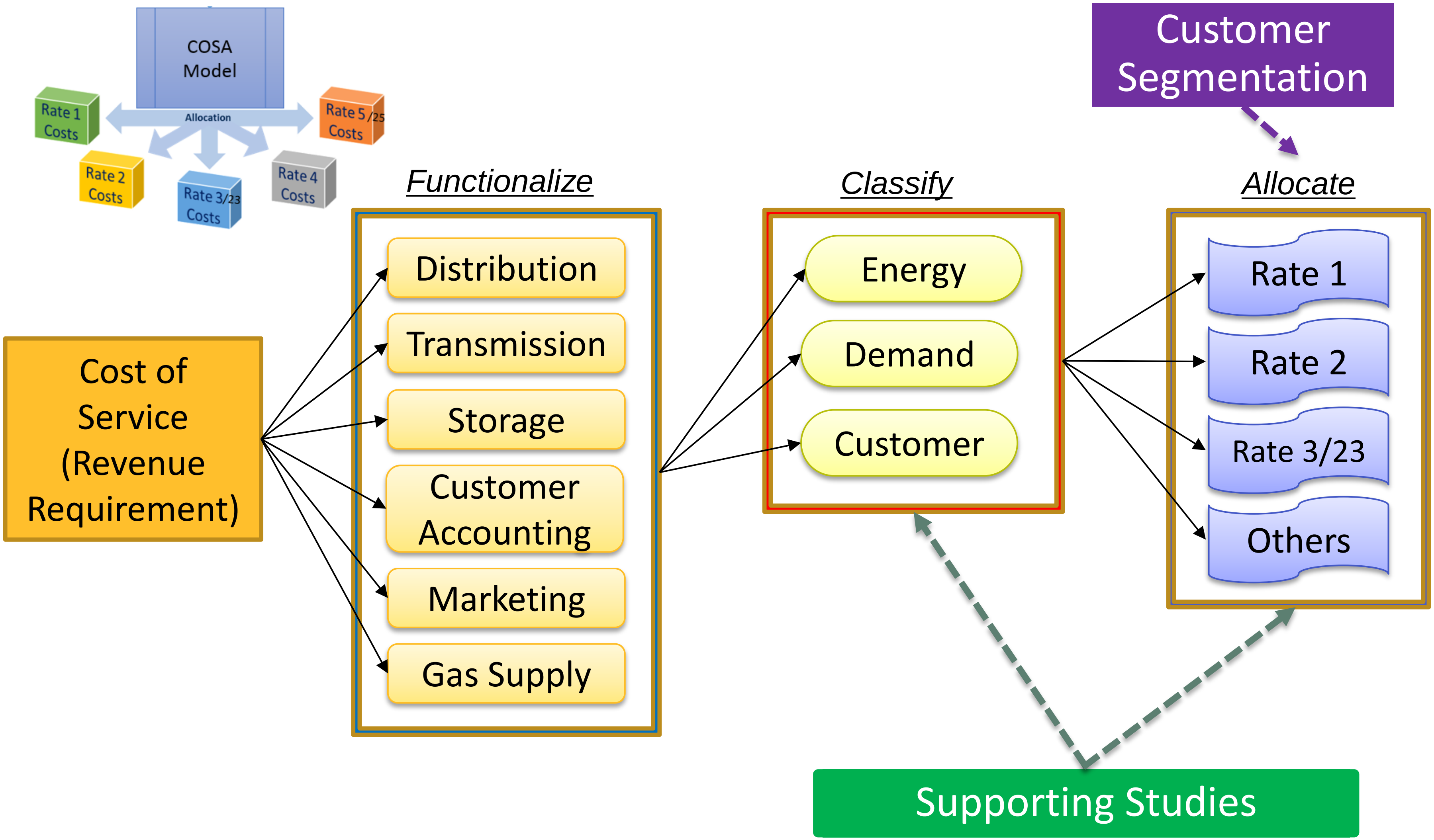
Consistent with Delivery cost allocation methodology and principles

Functionalization, classification and allocation consistent with industry practices

Delivery Cost Allocation

Allocation Method & Results

Delivery Cost: Allocation Method



How we split up our Revenue Requirement amongst our customers

Functionalize – Rate Base

Functionalize Order	Method	Notes
Transmission, Distribution, Storage Plant	Direct to Function	Considered Direct Plant
General & Intangible Plant	Based on Direct Plant Functionalization	Supports Direct Plant therefore functionalization based on the direct plant results
Contribution in Aid of Construction	Direct to Function	
Unamortized Deferrals	Various	Dependent on nature of deferral
Working Capital	Direct to Function	

Operating and Maintenance Costs

- Activity View of O&M provides indication of function and cost causation
- While in PBR no Activity View of O&M
- Split O&M into an Activity view based on historical Actuals

Example

Line No	O&M Activity	Actual O&M Total	Actual O&M Percentage
1	Distribution	51,000	44.7%
2	Transmission	20,000	17.5%
3	Facilities	8,000	7.0%
4	Customer Service	35,000	30.7%
5	**Total**	**114,000**	**100.0%**
6	Formulaic O&M		120,000

	O&M Activity	Reference	Activity View of O&M for COSA
7	Distribution	Line 1 x Line 6	53,684
8	Transmission	Line 2 x Line 6	21,053
9	Facilities	Line 3 x Line 6	8,421
10	Customer Service	Line 4 x Line 6	36,842
11	**Total**	Sum of Lines 7 through 1	**120,000**

Functionalize – Cost of Service

Functionalize Order	Method	Notes
Operating and Maintenance (most)	Direct to Function	
O&M activities supporting Gross Plant	Based on Gross Plant	Facilities, Property Services Engineering, System Planning
O&M activities supporting entire Utility	Based on Functionalized categories above	IS costs, Finance & Regulatory, HR, Environment Health & Safety, Legal, Shared Services
Property Taxes	Based on value of Land, Structures and Pipe in Function	
Depreciation & Amortization	Follows functionalized Plant	
Income Tax & Earned Return	Based on Functionalized Rate Base	Both Income Taxes and Earned Return are determined by Rate Base

Discussion Guide - Section 3.3.1

Functionalize

Customer Information System (CIS) Costs

- Costs are included with all other General Plant
- Directly functionalized ‘Customer Accounting’
- Allocate using Number of Customers
- Results in similar treatment as when costs were outsourced

Classify & Allocate

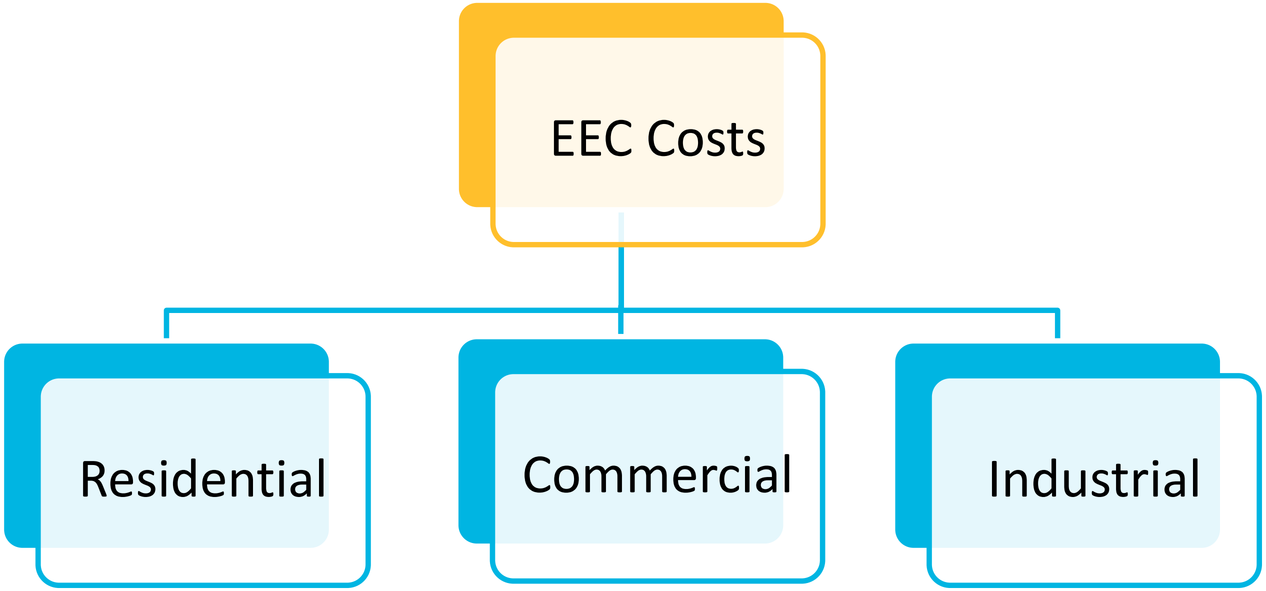
Function	Classify	Allocate
Gas Supply	Energy Demand	Sales Volumes Peak Day Demand
Storage • Tilbury • Mt Hayes	 Demand Demand	 Peak Day Demand Peak Day Demand
Transmission	Demand	Peak Day Demand
Distribution	Customer Demand	Number of Customers Peak Day Demand
Marketing	Customer	Number of Customers
Customer Accounting	Customer	Number of Customers

Discussion Guide - Section 3.3.2 and 3.3.3

Allocate

Energy Efficiency Costs

1. Split between Residential, Commercial, Industrial
2. Allocated to Rate Schedules based on Number of Customer



Part II

KEY DISCUSSION TOPICS

COSA Model - known and measurable changes

Start with test year (2016 Annual Review)

- Revenue = Costs

Add in known and measurable changes

- Creates deficiency/surplus
- Deficiency/Surplus applied to all Rate Schedules based on Revenue Margin
- Revenue = Costs

Perform Cost Allocation

- Produces Revenue to Cost Ratios
- Rebalance if necessary

Tilbury Expansion Project

- Liquefaction capacity and LNG tank expansion at FEI's existing Tilbury site
- Built to serve Natural Gas for Transportation market
- Entering rate base 2017

Special Direction No. 5, Discussion Guide - Section 3.1.3 & 4.1.1

Tilbury Expansion Project – COSA treatment

- Functionalize as Storage
- Direct Cost and Revenue Allocation to Rate Schedule 46
- Net difference allocated to all customers on margin
  - The same will occur in FEI's 2016 Annual Review for 2017 Rates
- *Recommend including in COSA using 10 years levelized costs and revenues*

COSA Treatment	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Level 10 years costs and revenue	96%	101%	102%	105%	135%
2018	96%	101%	102%	105%	136%
Exclude	96%	101%	103%	105%	135%

Rate Schedule 46 included in Special Direction No. 5 and endorsed with Order G-211-13

Eagle Mountain-Woodfibre Pipeline Project (EGP)

Transmission Pipeline from North Coquitlam to Squamish and Compression facilities

Would be built to serve large volume long term customer (Woodfibre LNG)

Costs and Revenue uncertainty

Will not be constructed until customer has contracted with FEI for service

EGP – Addition to COSA

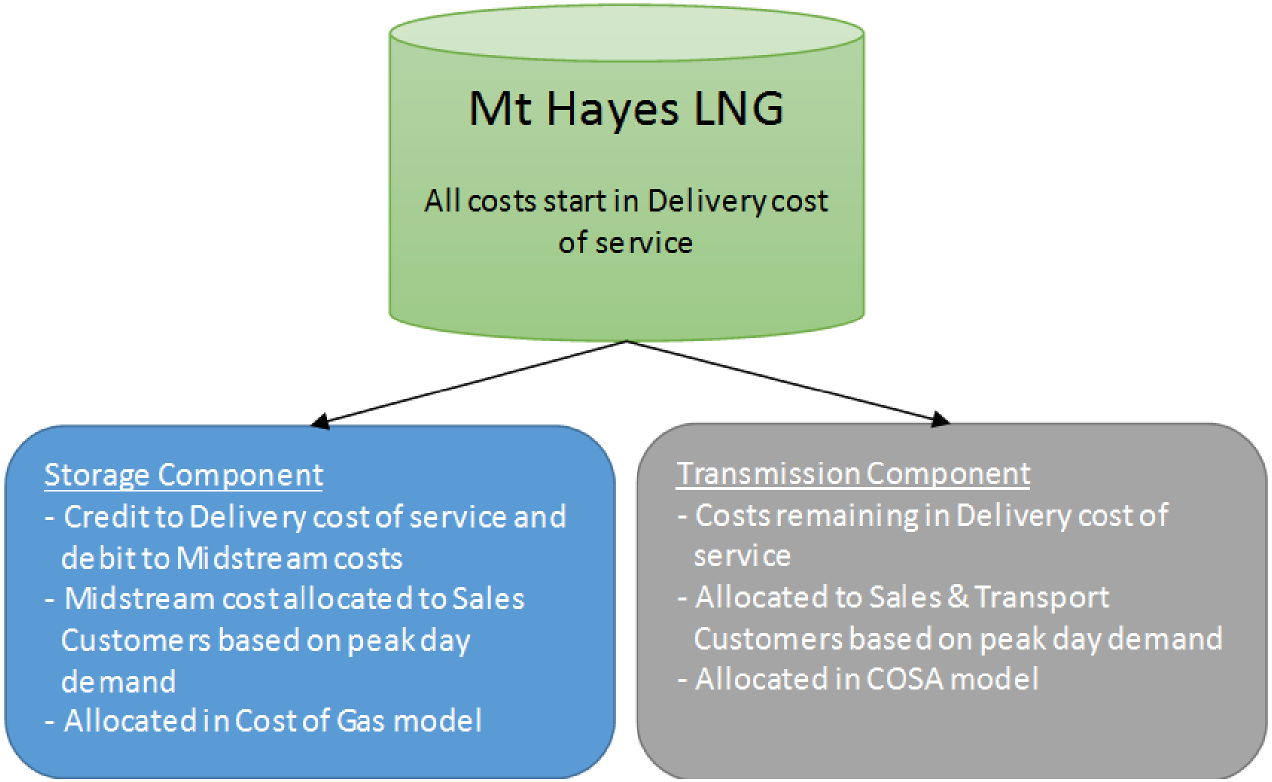
- Functionalize as Transmission
- Allocate using Peak Day
- Revenue credit allocated to all customers on margin
  - The same will occur when enters rate base
- *Recommend excluding from COSA until contracted with Woodfibre*

COSA Treatment	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Excluded	96%	101%	102%	105%	135%
Included	96%	101%	102%	105%	134%

Rate Schedule 50 included in Special Direction No. 5 and endorsed with Order G-10-15

Mt. Hayes - Cost Allocation

- Continues to serve a dual purpose
- Storage Component in Midstream costs
- Transmission Component in Delivery costs



Discussion Guide – Section 3.1.2.2 and 4.2

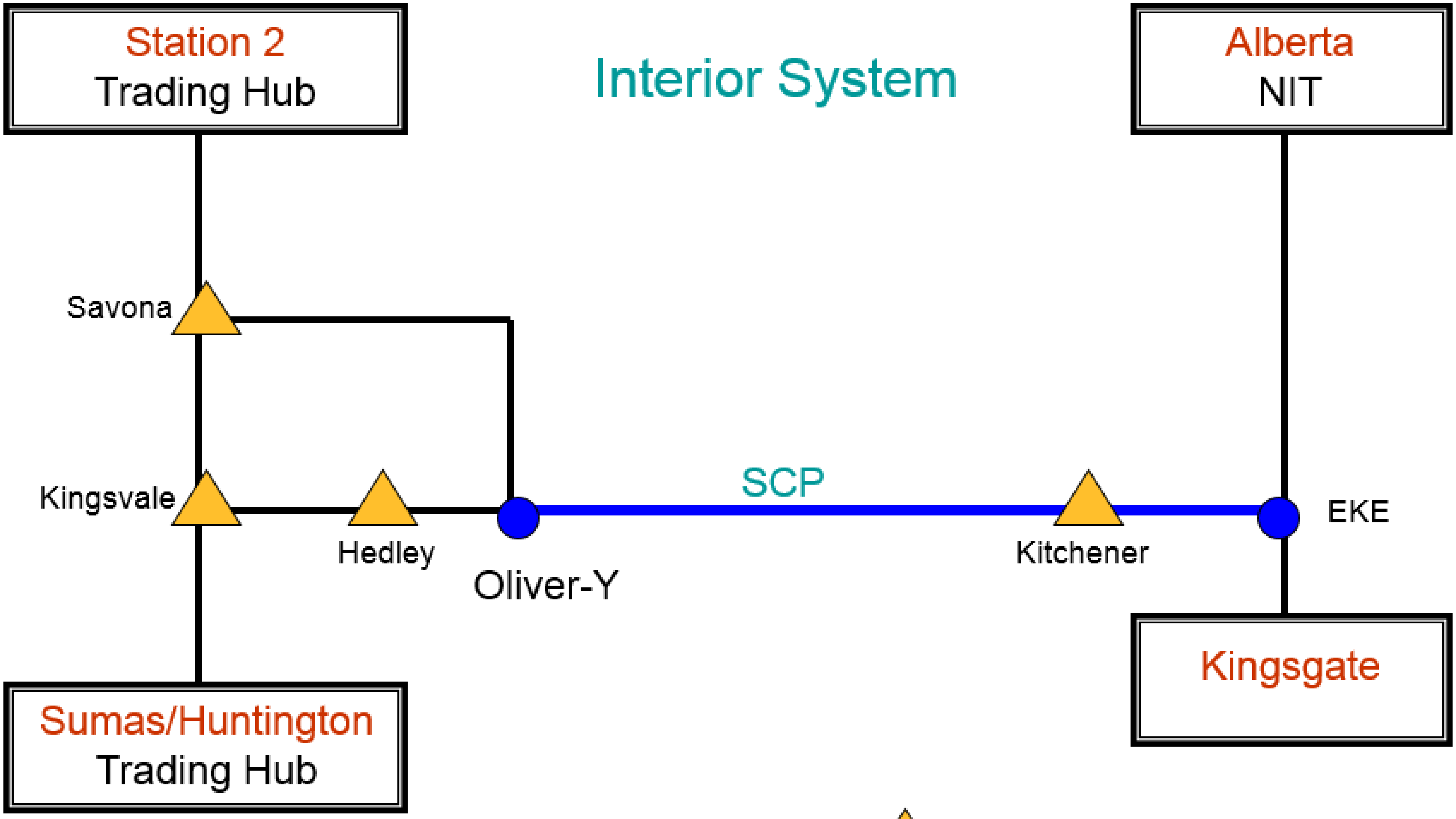
Mt. Hayes – Optional COSA treatment

- Aligns treatment with Tilbury costs
- Functionalize as Storage
- Ignores dual purpose for cost allocation purposes
- Allocates costs to customers on Peak Day
- Slight shifting of costs from Sales to Transportation customers
- *Recommend continued Storage and Transmission treatment*

COSA Treatment	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Dual Purpose	96%	101%	102%	105%	135%
Align with Tilbury	96%	100%	102%	104%	136%

Discussion Guide – Section 3.1.2.2 and 4.2

Southern Crossing Pipeline



Southern Crossing Pipeline

Working as designed

- Providing supply to Interior and Lower Mainland
- Increased liquidity at Sumas market
- Reduced gas supply risk with another pipeline to Huntingdon
- Continued third party revenue (PG&E, Hydro, NWN, FEI)
- Ability to offer firm to customers in Lower Mainland
- *Recommend including with all other Transmission Pipe*

Alternative Treatment: Regional Transmission Pipe in COSA

- Allocate costs to fewer customers

COSA Treatment	Rate 1	Rate 2	Rate 3/23	Rate 5/25	Rate 6
Treat like all other TP	96%	101%	102%	105%	135%
Regional TP	96%	101%	102%	105%	135%

Load Factors for Allocation

Recommend using calculated load factor for midstream cost allocation to RS5 customers

Alignment of Load Factors between Delivery and Midstream allocations is consistent

Results

- Increased midstream charge to Rate Schedule 5 customers
- Decrease in midstream charge to other Rate Schedule customers

Other Discussion Topics

Part III

CLOSING REMARKS & NEXT STEPS

Next Steps

Documentation

- FEI will distribute key issues list and post notes from today's workshop by July 25

Communication

- Website: www.fortisbc.com/ratedesign

Workshop 1 – Fort Nelson

- Scheduled July 27-28
- Focus on results from preliminary COSA study for Fort Nelson
- Discussion guide will be circulated in advance of the workshop

For further information, please contact:

Gas.Regulatory.Affairs@fortisbc.com

www.fortisbc.com/ratedesign

Find FortisBC at:

Fortisbc.com

604-576-7000

COSA Workshop July 11, 2016
Summary

Meeting:	COSA Workshop
Date:	July 11, 2016
Time:	9 am to 3:30 pm
Location:	BCUC Hearing Room, 12th Floor, 1125 Howe Street, Vancouver
Facilitator:	Atul Toky, FEI
Participants:	Kresnyak, Peter (Absolute Energy); Andrews, Bill (BCSEA); Hackney, Tom (BCSEA); Ashley, Jackie (BCUC); Marr, Cathy (BCUC); South, Errol (BCUC); Sue, Suzanne (BCUC); Chong, Doug (BCUC); Braithwaite, Tannis (BCPIAC); Feeney, Kate (BCPIAC); Caumanns, Nick (Cascadia Energy); Connelly, Steve (Cascadia Energy); Craig, David (CEC); Weafer, Chris (CEC); Vandersteen, Bev (Fort Nelson & District Chamber of Commerce [FNDCC] – via Audio Broadcast); Bursey, David (ICG/Sentinel Energy); Langley, Jim (Sentinel Energy); McCordic, Mary (Shell Energy); Bonin, Kevin (Translink); Chung, Alan (BC Hydro); Hastings, Calvin (BC Hydro)
FEI Attendees:	Bevacqua, Ilva; Carman, Michelle; Gosselin, Rick; Gravel, Colleen; Hill, Shawn; Hill, Song; Hodgins, Kevin; Hopping, Uschi; Joly, Janice; Lang, Mary; Moore, Ed; Noel, Brian; Salbach, Stephanie; Sinclair, Corey; Tabone, Gail; Toky, Atul; Sanderson, Ron; Dall'Antonia, Roger; Bystrom, Chris
Material Provided	Presentation attached following notes.
Agenda:	***Agenda:*** 1. Part I: Discussion Guide • Welcome and Introduction • Gas Cost and Delivery Cost Allocation • Delivery Cost Allocation 2. Part II: Key Discussion Topics • Tilbury Expansion Project • Eagle Mountain – WoodFibre Pipeline Project • Mt Hayes Cost Allocation • Southern Crossing Pipeline • Load Factors for Allocation • Other Discussion Topics 3. Part III: Next Steps • Closing Remarks & Next Steps

Meeting Summary and Notes

DISCUSSION GUIDE - SUMMARY OF QUESTIONS/COMMENTS DURING PRESENTATION		
Reference Slide No.	**Summary of Question/Comment**	**FEI Response and Discussion Summary**
3	• On issues list, will there be an ongoing opportunity to add to the issues list?	• Yes. FEI will circulate the issues list two weeks after the workshop and will offer an opportunity for everyone to provide written comments and raise additional issues at that time. The objective for today is not to resolve key issues but to consider and address them to focus the scope of the RDA.
8	• What did FEI change in its cost allocation methodology from last rate design 20 years ago and why? What is FEI doing differently this time and why?	• Generally, the cost allocation methodology has been kept the same as it is working well. FEI is recommending to make a few changes in its cost allocation model which will be discussed later in the presentation.
9	• Does COSA model only deal with delivery costs?	• No, FEI's COSA model also takes into account the inputs from the Gas Cost allocation model. FEI has a separate Gas Cost allocation model, as the rates for gas costs are set quarterly.
12	• Could you please explain design load curve? • Is there any information with respect to unit cost of each of the midstream resources? • What supply resources does FEI use to bridge the small triangle between baseload and seasonal? • Why is pipeline capacity shown as a flat line? Isn't there a material difference throughout the year? E.g. repair, line pack issues?	• Design load curve is based on peak or design day, which in simple terms is the peak of the coldest day in 20 years. • Yes, some costs are for the fixed cost storage contracts, and some for the transport. Transport charges are public information, while some of storage assets are negotiated rates and confidential. Quarterly gas cost filings provide some of this cost information.

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Reference Slide No.	**Summary of Question/Comment**	**FEI Response and Discussion Summary**
		• It could be resources at Aitken Creek or other storage assets or seasonal supply that FEI might use to meet that demand. The design day load curve is just an illustration of how FEI stacks its resources to meet the peak day demand. • The pipeline capacity shown on the curve is upstream of the interconnection. We hold fixed amount on a year to year basis, but like any pipeline, maintenance is done on a daily/monthly basis, which customers on those pipelines are accustomed to. These pipelines are NEB regulated and FEI pays a tariff just as all other shippers do.
15	• How is load factor calculated? • What does FEI mean by three year average? • Could FEI provide details of the calculation?	• Load factor is calculated by taking the average usage divided by the peak day. E.g., if a customer uses 1 GJ per day on average and would use 3 GJ per day on the peak day, then the load factor is 33%. If the average use is 1 GJ per day and the customer would use 2GJ on the peak day, then the Load Factor would be 50%. • FEI calculates load factor on a yearly basis and then takes a three year average. FEI takes a three year rolling average as an average use to calculate the load factors for allocation purposes in the COSA model. •
21	• With respect to the General and Intangible plant, to what extent is there ambiguity between functionalization of Transmission, Distribution and Storage direct plant. i.e., are there any assets or	• Assets and costs in each of these functions (Transmission, Distribution and Storage) are fairly clear. • 10% of the total direct plan is considered general and intangible plant based on 2016 Annual Review information.

DISCUSSION GUIDE - SUMMARY OF QUESTIONS/COMMENTS DURING PRESENTATION		
Reference Slide No.	**Summary of Question/Comment**	**FEI Response and Discussion Summary**
	costs under each of these direct plant functions that should be considered as general plant? • How much of the total direct plant for FEI is considered general and intangible plant? • How does FEI differentiate between the Distribution and Transmission assets? Can you classify your plant by pressures?	• Yes, pressure is one way by which FEI can classify its plant as Transmission or Distribution. FEI's Transmission pipe pressure is 2,400 kPa (450 Psig) and greater. FEI's distribution pressure pipe is less than the aforementioned pressure.
22	• What is the reason for the change for Customer accounting related costs? Why were those taken out of general plant and now functionalized as Customer accounting? • What is the impact (directionally) of making this change in the COSA model?	• Previously, these costs were O&M costs and were outsourced and treated as General costs. Since then, FEI has brought the Customer accounting in house and therefore these types of costs are now functionalized directly to Customer Accounting. These costs are still allocated using number of customers which is consistent with past methodology. FEI believes that this approach is reasonable and is consistent with the cost causation principles. •
23	• Hasn't the Mt Hayes cost allocation been impacted by the Amalgamation?	• FEI will discuss the Mt. Hayes cost allocation under the key discussion topics later in the presentation. For Mt. Hayes, there is a component that is classified as midstream and some component is allocated to transmission (i.e. left in delivery costs) as the asset serves the dual purpose of serving as a storage facility and providing additional transmission system capacity to serve customers similar to a transmission pipeline.
24	• With respect to EEC costs, does FEI classify those costs as energy or demand related?	• EEC costs are classified as customer related costs in the current COSA model.

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DISCUSSION GUIDE - SUMMARY OF QUESTIONS/COMMENTS DURING PRESENTATION		
Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
	• What is the impact of making this change in classification in the COSA model for EEC costs?	• FEI can look at EEC costs being classified as energy related and allocated based on volumes. It is important to note that by classifying this as energy related, the costs will not be allocated to transport customers or another option could be a direct assignment to all customer classes including transportation customers. • FEI needs to run this through the COSA model. However, conceptually it should not make a material impact on the R:C ratios and the rates.
26	• How are Bypass Customers treated in the COSA model?	• The bypass customers' revenues are treated as a credit to the cost of service and allocated based on other rate schedules' margin, i.e revenues minus cost of gas.
27/28	Tilbury Expansion Project: • Could FEI provide data that shows usage forecast for Tilbury Facility? • How much spare capacity is available for FEI to use? Does this spare capacity alter any other resources to meet peak day demand? • If using a 10 year levelized mechanism, is it not equivalent of a deferral account being put in COSA? • Could you show the revenue to cost ratios for all other rate schedules? And also show the decimal points? • What is the absolute dollar amount on the net difference between cost of service and forecast revenues for two options considered? • 10 years to match next time until next rate design	• Yes, FEI can provide the forecast for usage. • There is no spare capacity for FEI to use on a peak day. It is important to note that the costs related to this asset are not allocated based on peak day demand. This is because this LNG asset is constructed to serve the North American NGT market. • No, the levelized approach just changes the net difference between costs and revenues allocated to customers. The net difference between the forecast revenues and cost of service is a revenue requirement issue. Therefore, to separate the revenue requirement issue from the cost allocation issue, FEI is proposing to use 10 year levelized costs

Discussion Guide - Summary of Questions/Comments During Presentation		
Reference Slide No.	**Summary of Question/Comment**	**FEI Response and Discussion Summary**
	just seems convenient. What are some good economic options? • What happens if there is a significant difference in the forecast to what is happening now to what actually happens? As the years roll by and actuals are realized, and there is a difference in the forecast to what you have now, how would that new information be picked up if ever at all?	and revenues instead of another option to take a 2018 view of cost of service and forecast revenues. For cost allocation methodology, the net difference between the revenues and cost of service is allocated based on margin. FEI's analysis suggests that the amount of this difference does not impact the revenue to cost ratios for other rate schedules, suggesting that the cost allocation methodology for this asset is appropriate for both options. Yes, FEI can show the R:C ratios for all other rate schedules including decimal points. • The option using the 10 year levelized approach has about $7 million on net basis that gets allocated to other customers. The option using 2018 cost of service and forecast revenues has about $25 million on net basis that gets allocated to other customers. As can be seen in the summary table, even though there is a significant difference (on net basis) between these two options, the R:C ratios have minimal impact. • Even though the 10 year levelized approach is not a standard methodology used in COSA models, FEI believes that it is a reasonable approach to separate out the revenue requirement issue and cost allocation issue as the levelized approach minimizes the net difference between the cost of service and forecast revenues. The results show that using both options would not impact the revenue to cost ratio and therefore, using a levelized approach is more appropriate for cost allocation purposes.

DISCUSSION GUIDE - SUMMARY OF QUESTIONS/COMMENTS DURING PRESENTATION		
Reference Slide No.	**Summary of Question/Comment**	**FEI Response and Discussion Summary**
		• The COSA results suggest that even if the gap between cost of service and revenues is significant, it has minimal impact to R:C ratios. This means that the cost allocation methodology will remain appropriate even if there is a significant difference from forecast.
29/30	Eagle Mountain-Woodfibre Pipeline (EGP) Project: • If included in the COSA model, the costs related to the project will be allocated to all rate schedules, so revenues won't change but cost (i.e. denominator in R: C ratio) would change. Is that correct understanding? • Is Rate Schedule 50 approved with established rates? • What is the estimated cost of project?	• No, the revenues from this project are credited to all customers. For the EGP project, the revenues are expected to outweigh the costs and therefore there will be a net benefit to all customers. If costs of the EGP Project are included in the COSA model, it will change the R:C ratios only to a decimal point. So, it will have a minimal impact whether it's included or excluded from the COSA model. FEI believes that the EGP Project related costs should be excluded from the COSA model until the customer has contracted with FEI for service. The results of the COSA model show that it doesn't impact the R:C ratios, suggesting that the cost allocation methodology is appropriate whether this project is included or excluded from the COSA model. • The methodology to establish rates under Rate Schedule 50 is approved under Order in Council (OIC) by amendments to Special Direction No. 5. More information is available on the BCUC website: *http://www.bcuc.com/Documents/SpecialDirections/2014/12-19-2014_OIC749-Amendment-Dir5BCReg245-2013.pdf* • The latest cost estimate is about $500 million CAD.

COSA Workshop July 11, 2016
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Discussion Guide - Summary of Questions/Comments During Presentation		
Reference Slide No.	**Summary of Question/Comment**	**FEI Response and Discussion Summary**
31/32	Mt Hayes LNG: • Are any costs for Mt. Hayes allocated to RS46? How does the use of it affect RS46? • What is the practical difference between Tilbury and Mt. Hayes LNG facility usage on a day to day basis? Is Mt. Hayes in vaporization mode daily? Does it fluctuate with the load? • Is FEI taking any LNG out of Mt Hayes for NGT market? • Could FEI provide a forecast for the NGT market on Vancouver Island? What about ferries fueling on island? • Is FEI planning to export LNG from its facilities? What about the Phase 2 of Tilbury expansion for Hawaiian Electric?	• No Mt Hayes costs are allocated to RS46 in the COSA model, the current COSA model only allocates costs related to the Tilbury Expansion only to RS46. • In the load duration curve, the resources FEI has in place are shown from a planning perspective. What resources are used on a day to day basis depends on various factors such as weather conditions, supply constraints in marketplace and physical capacity of FEI's transmission system. On a daily basis, FEI optimizes the use of each resource to meet the demand for the system. The Tilbury LNG is primarily used as a storage facility providing peaking gas supply during cold weather, whereas Mt. Hayes serves the dual purpose of a storage facility as well as a transmission facility providing additional capacity on the Vancouver Island transmission system. • Yes, FEI is supplying some LNG from the Mt. Hayes facility. This has not been factored in the COSA model as it is a very small amount. • We can provide what we have for the forecast for Vancouver Island. Currently the marine transportation market is fueling on the Mainland side with some expectation that there will be growth of LNG sales into the marine market in the future as well as growth in the on-land LNG demand. • FEI is planning to supply LNG to North American domestic customers from its current LNG facilities

COSA Workshop July 11, 2016
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DISCUSSION GUIDE - SUMMARY OF QUESTIONS/COMMENTS DURING PRESENTATION		
Reference Slide No.	**Summary of Question/Comment**	**FEI Response and Discussion Summary**
		including the Tilbury Expansion project under construction. The Phase 2 of Tilbury expansion project for Hawaiian Electric is still in very early stages of planning. For now Fortis Hawaii, an indirect wholly-owned subsidiary of Fortis Inc. has entered into a 20 year fuel supply agreement with Hawaiian Electric Company. To support the agreement, a further expansion is required at Tilbury facility, which will not be owned by the Utility. The further expansion project will take natural gas transportation service from FEI (i.e. RS50 customer of FEI) and is expected to provide net benefits to existing customers.
33/34	Southern Crossing Pipeline: • What about the R:C ratio for Rate 22B? Should Rate 22B customers get an allocation of SCP costs? • What is the reason for change in treatment of SCP in the COSA model? • How is firm capacity to customers in Lower Mainland linked to the SCP?	• When SCP costs functionalized on their own, Rate 22B customers do not receive an allocation since they are at the East end of the pipeline and do not have access to it. • The SCP is simply another transmission pipe (asset) that is used to provide FEI customers gas. FEI has transmission pipe throughout the province and the cost of that pipe is allocated to all customers based on peak day demand. FEI believes that treating the SCP transmission pipe in the same way as the rest of its transmission pipe is fair and reasonable.
35	Load Factors for Allocation: • What is the actual load factor for RS5 customers? What is the impact of aligning the load factors for RS5 customers? • Is the load factor based on actual peak or forecast	• The calculated load factor for RS5 customers is 45%. The impact of making this change will be minimal. RS5 midstream cost would go up by about \$0.05/GJ. • The peak day demand is a theoretical concept (1 in

DISCUSSION GUIDE - SUMMARY OF QUESTIONS/COMMENTS DURING PRESENTATION		
Reference Slide No.	**Summary of Question/Comment**	**FEI Response and Discussion Summary**
	peak? • Is NGV 100% load factor? • Is FEI recommending this change for the duration of this rate design? • Could FEI provide a table showing R:C ratios that combines all of the recommendations?	20 year event) which is used for planning purposes. The load factor is calculated by dividing the normalized actual average usage by the theoretical peak day usage. • Yes, NGV customers are not heat sensitive. • Yes, FEI expects that the change if approved would last for the duration of rate design. That is, the recommended change will be in place until FEI applies to change it. • Yes, Appendix C, Schedule 1 of the discussion guide shows the R:C ratios after combining all of the recommendations.

COSA Workshop July 11, 2016
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OTHER DISCUSSION TOPICS - SUMMARY OF QUESTIONS/COMMENTS		
Reference Slide No.	**Summary of Question/Comment**	**FEI Response and Discussion Summary**
Page 13-14 of Discussion guide	Load factor Calculation methodology • Why did FEI use three year average? • Could FEI provide more details and some alternative approaches for load factor calculation methodology? • Could FEI provide data and calculation on how load factor is calculated and used in the COSA model? • Since FEI has only 2500 demand meters, how exactly are you figuring out the peak day and average demand for other customers?	• FEI used three-year average as it provides a better understanding of the usage pattern, instead of just using a single year average, as it takes into account the changes in usage from one year to another. FEI believes that this approach is appropriate, reasonable and also consistent with what has been done since the 1996 rate design. • FEI will endeavor to provide more details around the load factor calculation methodology and also provide some alternative approaches and how those would impact the results of COSA model. • Yes, FEI can provide data. • FEI will provide more information on how peak day is determined and normalized average demand is calculated.
Page 8-9 of Discussion Guide	• Would it make any difference by departing from what was approved and using O&M from actual results? • Could FEI provide allocation data and material used to split the formulaic O&M?	• FEI is not using the actual O&M but is using the formulaic O&M and splitting that into the activity view by using proportion from actuals percentages. • FEI will provide the data used to split the formulaic O&M.
Page 3-4 of discussion guide	Rate Design History • Would FEI be providing history on the delivery rates as provided for gas costs in the discussion guide? • General Comment: When writing the application, it will be great if FEI can include how FEI's proposed assumptions compare to previous assumptions that	• Yes, the history for both gas cost and delivery rates will be provided in the application.

COSA Workshop July 11, 2016
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OTHER DISCUSSION TOPICS - SUMMARY OF QUESTIONS/COMMENTS		
Reference Slide No.	**Summary of Question/Comment**	**FEI Response and Discussion Summary**
	have been approved and differences in results, if any.	
Page 14-15 of discussion guide	Minimum System Study & PLCC adjustment • Has FEI conducted any other studies? • Could FEI provide a copy of the distribution system standards for better understanding of background and pipe sizing to understand the minimum system study? • Could FEI provide more details to the PLCC calculation?	• Yes, FEI looked at the zero intercept study but didn't find that to be a good alternative since there was not a good correlation between pipe diameter and installation cost. As an alternative, FEI looked at adjustment to the minimum system which adjusts the amount that is classified as demand related and customer related and this is called the Peak Load Carrying Capacity (PLCC) adjustment. The PLCC adjustment was made in response to increasing the minimum size pipe used in the study to better reflect standard practice at the utility. With a larger minimum pipe, there is a higher capacity component associated with that pipe and the PLCC adjustment was considered appropriate to reflect that higher level of capacity. • Yes, FEI can provide copy of distribution system standard. • Yes, FEI will provide details around the PLCC calculation and how it is used in the COSA model.
Page 16 of discussion guide	Customer Weighting Factor and Admin factor Study • Could FEI share the calculations for these studies?	• Yes.
Page 16 of the discussion guide	Bypass & Special Contract Customers • How are costs allocated to bypass customers? Could FEI provide what costs are being bypassed? • Are special contract customers' rates evaluated as	• To be clear, it's not that the Bypass Customers are bypassing costs, rather they have the ability to bypass the system entirely. That is why Bypass

OTHER DISCUSSION TOPICS - SUMMARY OF QUESTIONS/COMMENTS		
Reference Slide No.	**Summary of Question/Comment**	**FEI Response and Discussion Summary**
	part of rate design application?	customers are on a negotiated rate which is not set as part of the rate design application process. It is important to note that the rates are set at the time when these customers entered into an agreement with FEI and that the rates would be greater than the incremental cost to serve the customer but less than the tariff rate that was available to them at the time. Therefore, consistent with past practice, bypass customers are not allocated any costs in the COSA model and revenues from these customers are credited back to all customers who are notionally paying for those costs. • Yes, the special contract customer rates are evaluated as part of this rate design application. This workshop however deals with the cost allocation methodology.
Page 17 of discussion guide	Interruptible Customers • Why interruptible customers aren't allocated demand related costs? Should there be any other costs (such as storage etc.) allocated to these customers?	• Interruptible customers are allocated customer related costs in the COSA model. The reason the COSA model doesn't allocate demand related costs to these customers is because these customers' service can be stopped (interrupted) at any time. Generally, these customers could be interrupted as the weather gets colder and FEI's system nears its peak capacity. Since we do not have to serve these customers when the system is peaking, FEI has incurred no demand (capacity) related cost on their behalf. The interruptible customers provide benefits to all other customers by improving the utilization

OTHER DISCUSSION TOPICS - SUMMARY OF QUESTIONS/COMMENTS		
Reference Slide No.	**Summary of Question/Comment**	**FEI Response and Discussion Summary**
		on non-peak days. Storage costs are also in place to meet the peak day demand, so based on the aforementioned reasons; FEI has not incurred any storage costs on behalf of interruptible customers.
Page 17 of discussion guide; Sec 3.2.5	Biomethane and Natural Gas for Transportation • Can FEI provide cost details for these?	• It is possible for NGT but not for Biomethane customers as they follow other rate schedules (1, 2, 3, 4). FEI doesn't segregate them as they are not different customers.
Page 19, table 3-5	• Could FEI explain the difference between Tilbury and Mt. Hayes delivery cost of service i.e. $35 million vs $7 million?	• This difference is because the Mt. Hayes delivery cost of service is reduced by about $18 million which is the amount FEI reclassifies and included as a midstream cost. Tilbury cost of service includes the Tilbury expansion cost of service, and although this is the case FEI has directly allocated the Tilbury Expansion costs and RS46 revenues to RS46 and only the net difference is allocated to all other customers. • The other option could be to treat Mt. Hayes similar to Tilbury, which is presented as option B in the key discussion topics for Mt. Hayes cost allocation.
Page 21 of discussion guide table 3-7	• Can you break the cost of service allocation down by customer, demand and energy.	• Yes, it is already done and shown in the financial schedules attached to the discussion guide.
Page 21-24 of the discussion	Revenue to Cost Ratios • Is FEI planning to stick with 90-110% as a range of reasonableness?	• Yes. • Uncertainty discussion is around peak demand. For

OTHER DISCUSSION TOPICS - SUMMARY OF QUESTIONS/COMMENTS		
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guide	• FEI stated that "gas systems have some degree uncertainty". How does the range of reasonableness deal with uncertainty? • Is it possible to get the historical COSA studies for the last number of years since the last rate design? Presumably FEI runs these on a regular basis. Trying to apply the same methodology across historic costs to see what has changed over time. • Over the last 20 years, shouldn't there be more certainty in collecting demand date with new meters for residential and commercial and due to technological improvements? • How do gas costs impact R:C ratios? Can FEI provide margin to cost ratios? • How difficult is it to set a different range of reasonableness? • Does FEI expect R:C ratios to stay where they are today for the next little while, or would FEI expect that they would deviate over a period of time? Adding big projects doesn't seem to move R:C ratios too much, which suggests that the COSA study is reasonable, so why not reset or rebalance everyone closer to unity or 100%? • Does FEI consider 135% outside the range of reasonableness? If yes, should it be rebalanced?	electric utilities' COSA model, there's more information around the hourly peak. FEI on the other hand doesn't have demand meters on most of the volume going through the meters, so there is a bit more cost allocation uncertainty. You could say the allocations are a little more subjective in the gas model, so that is why a larger range may be more reasonable. • The most recent COSA study was done in 2012 at the time FEI filed its Amalgamation Application. • Uncertainty and R:C ratio has 2 parts Uncertainty in loads is one part, and that can potentially be reduced by using demand meters on a sample of customer to collect load research. The other uncertainty is related to the different methods available to use in a COSA and the inherent uncertainty associated with spreading shared costs among customer classes. We believe the margin of error is equally distributed above and below a 100% revenue to cost ratio. In other words, we do not expect the results to be skewed in either direction. • Yes, margin to cost ratios can be provided. • It should be noted that the range of reasonableness is used as a guide to rebalance the rates. It is not difficult to do a math exercise and rebalance the rates for customer groups outside the range of reasonableness. However, while doing the rebalancing FEI would have to take into consideration other rate design principles such as

OTHER DISCUSSION TOPICS - SUMMARY OF QUESTIONS/COMMENTS		
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		rate shock and competitiveness. FEI doesn't expect R:C ratios to stay the same over time but it is expected that those R:C ratios would stay within the range of reasonableness. If R:C ratios are outside the range, FEI could bring those back into the range. As mentioned above, rebalancing to a different range or unity would depend on other rate design considerations as well. • Yes, 135% is outside the range. Rebalancing this would virtually have no impact to other customers because it such a small customer group.
2012 Application	• Did FEI get an approval for Rate Design in its 2012 Rate Design Application?	• The Commission approved FEI's proposed rate design for the amalgamated entity, stating: "There is little disagreement among the parties with respect to implementing FEI's existing rate design methodologies on a transitional basis. The Commission Panel agrees and accepts the proposal put forward by the FEU for the temporary rate design once the amalgamation is legally effective."

Action Items and Next Steps

Item		Responsibility	Target Completion
1.	Notes and issues list from session circulated	FEI	July 25
2.	Review notes and issues list and reach out to FEI with thoughts, concerns, if you want to meet.	All others	August 2
3.	Provide details for the load factor calculation methodology used in current COSA and other alternatives	FEI	With Application
4.	Provide impact to R:C ratios if EEC costs are classified as energy related	FEI	With Application
5.	Provide forecast of NGT market	FEI	With Application
6.	Show R:C ratios to three decimal places for alternatives/options on Tilbury Expansion and EGP Project	FEI	With Application
7.	Provide allocation data and material used to split the formulaic O&M	FEI	With Application
8.	Provide history for delivery rates	FEI	With Application
9.	Provide FEI's proposed assumptions compare to previous assumptions that have been approved and differences in results, if any.	FEI	With Application
10.	Provide more details to the PLCC calculation	FEI	With Application
11.	Provide details for Customer Weighting Factor and Customer Admin factor study	FEI	With Application
12.	Provide cost details for NGT customers	FEI	With Application
13.	Provide Margin to Cost ratios	FEI	With Application
14.	Discuss rate design and customer segmentation results and key issues	FEI	Workshop 2 – August 11
15.	Discuss Transportation service model and key issues	FEI	Workshop 3 – August 12

Key Issues

Issues List	
1.	EEC costs Classification - energy related or customer related
2.	Tilbury Expansion project costs and revenues - 2018 cost of service and forecast revenues or 10 year levelized costs and revenues
3.	Treatment of SCP in the COSA model. Why do the recommended changes make sense?
4.	Treatment of Bypass Customers – is it possible to quantify and allocate bypassed costs to these customers?
5.	Treatment of interruptible customers – does it make sense to allocate any demand related costs?
6.	Revenue to Cost Ratios – range of reasonableness? If outside the range, rebalancing to unity or within the range of reasonableness given other rate design considerations?

2016 Rate Design Application

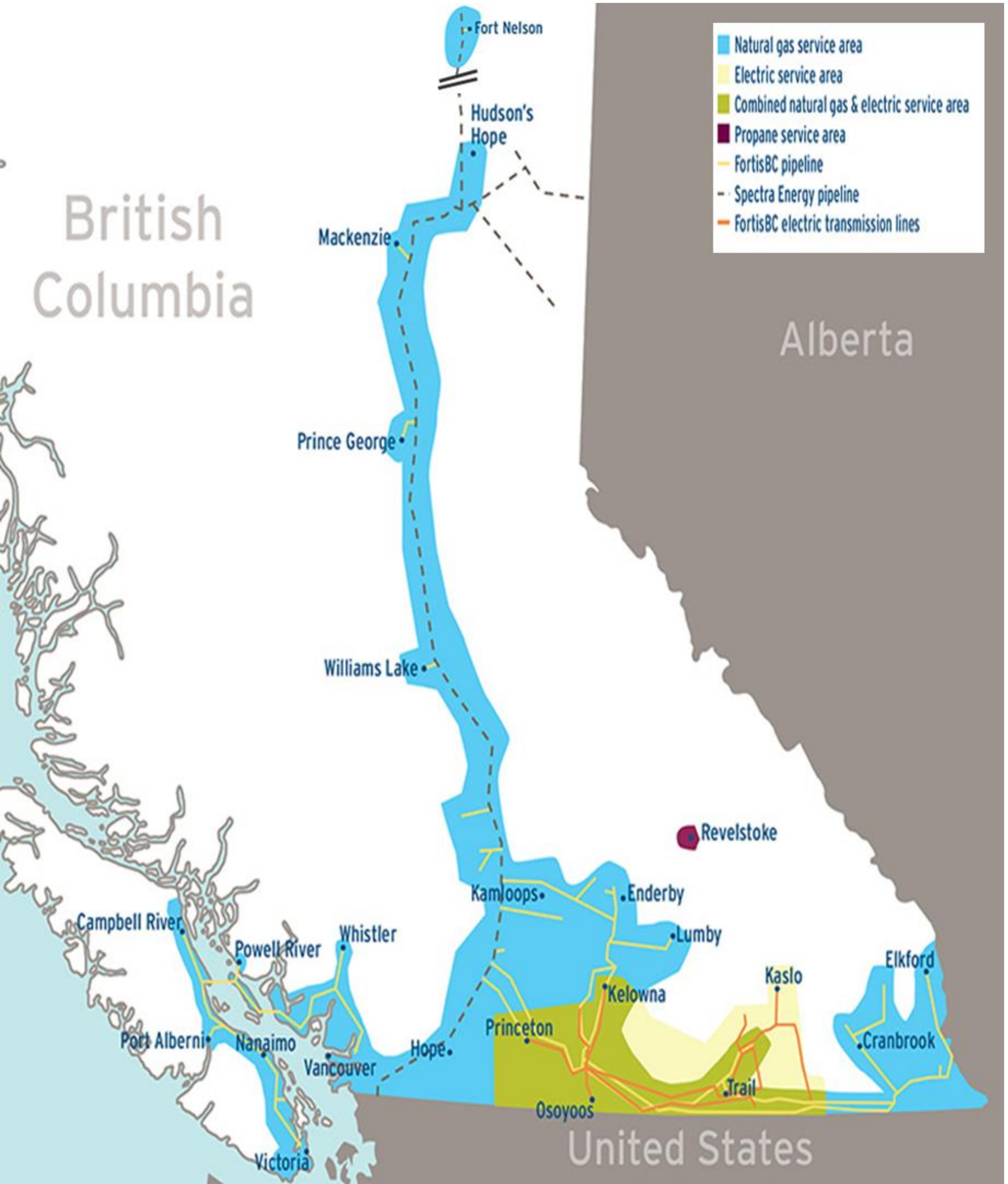
Workshop 1 – Fort Nelson Service Area

Atul Toky – Manager, Rate Design and Tariffs
Richard Gosselin – Manager, Cost of Service
Matt Mason – Community & Aboriginals Relations Manager

July 27 2016

FORTIS BC™

FortisBC, Who we are:



- 100% Canadian owned, and part of the largest investor owned utility in Canada
- Provider of Natural Gas, Electricity and Propane
- 135 communities more than 1 million customers in BC

Introduction - *Objectives for Today*

- Provide context and Information in support of Rate Design
- Inform & Review Results of Current Cost of Service Allocation
- Discussion on Key Topics related to Rate Design
- Agreement on Key Issues List
- Inform Proposals of Revenue Requirement Application 2017-18

Workshop Guidelines

Participate

Respect other participants and presenters

Questions as we go / if need be - add them to an ‘Issues List’

Issues list to be compiled and revisited following presentation

One speaker at a time

Documentation:

- Meeting Notes
- Issues List
- FortisBC Responses to Issues
- Issues List Items not Addressed During Workshop

Agenda

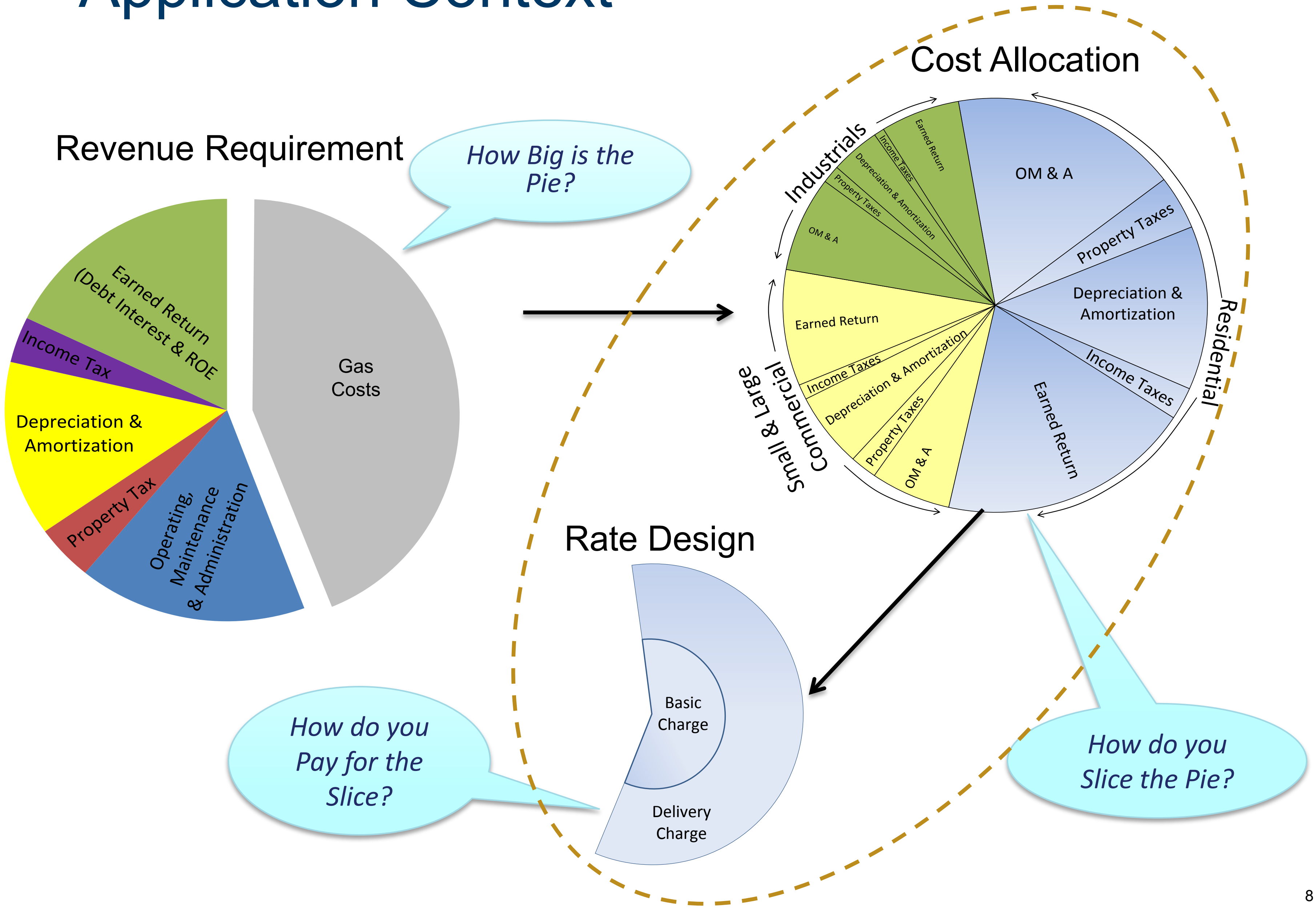
Information Session	Rate Design Application Context and Fundamentals
	Cost of Service, Segmentation and Rate Design Concepts
	Tariff Overview
Discussion Guide	Gas Cost Allocation
	Functionalization, Classification and Allocation Review
	Key Discussion Topics
Revenue Requirement 2017-2018	Proposed Rate Changes
	Primary Reasons for Changes
Next Steps	Concluding Remarks
	Compile Key Issues List

Part I

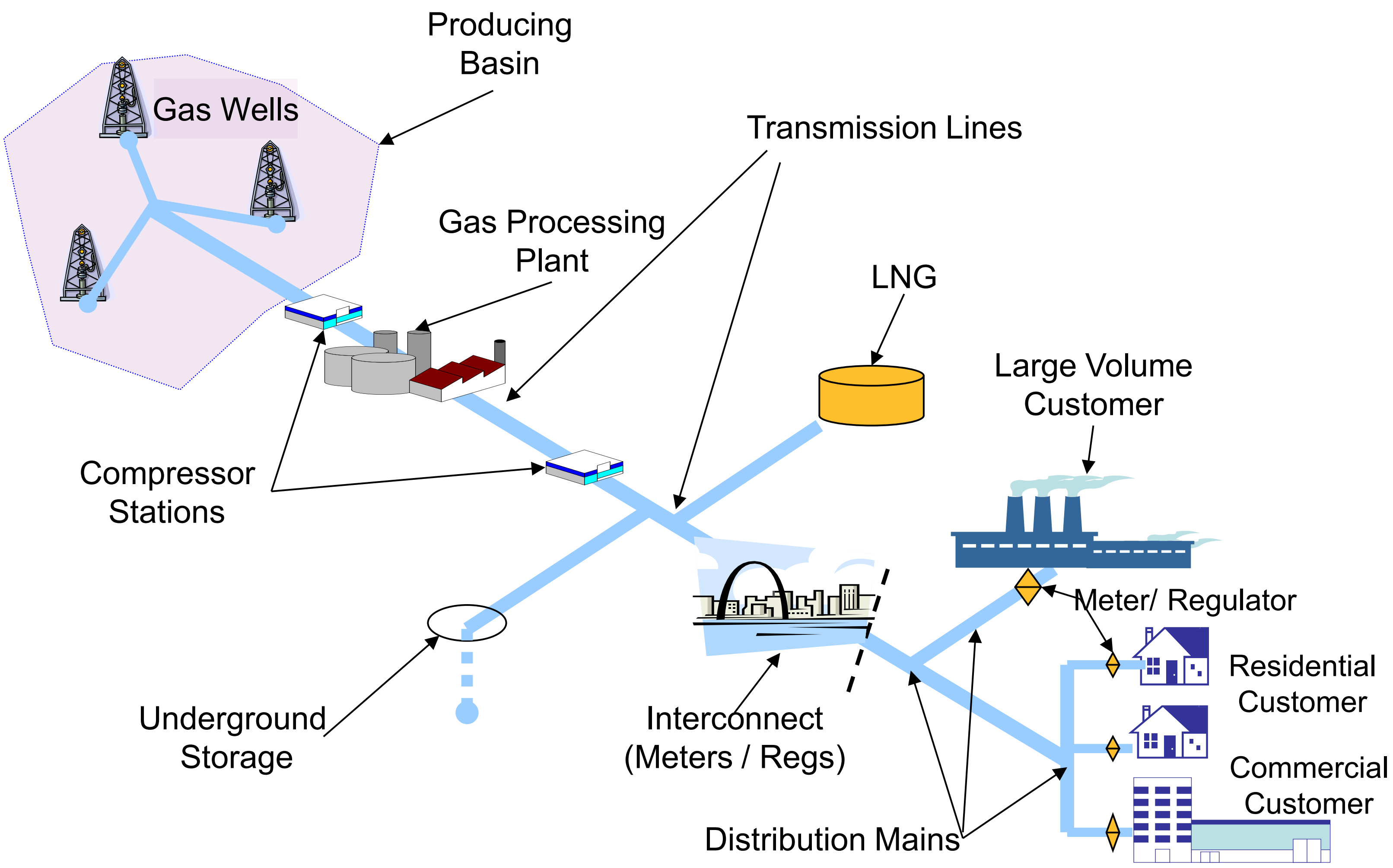
INFORMATION SESSION

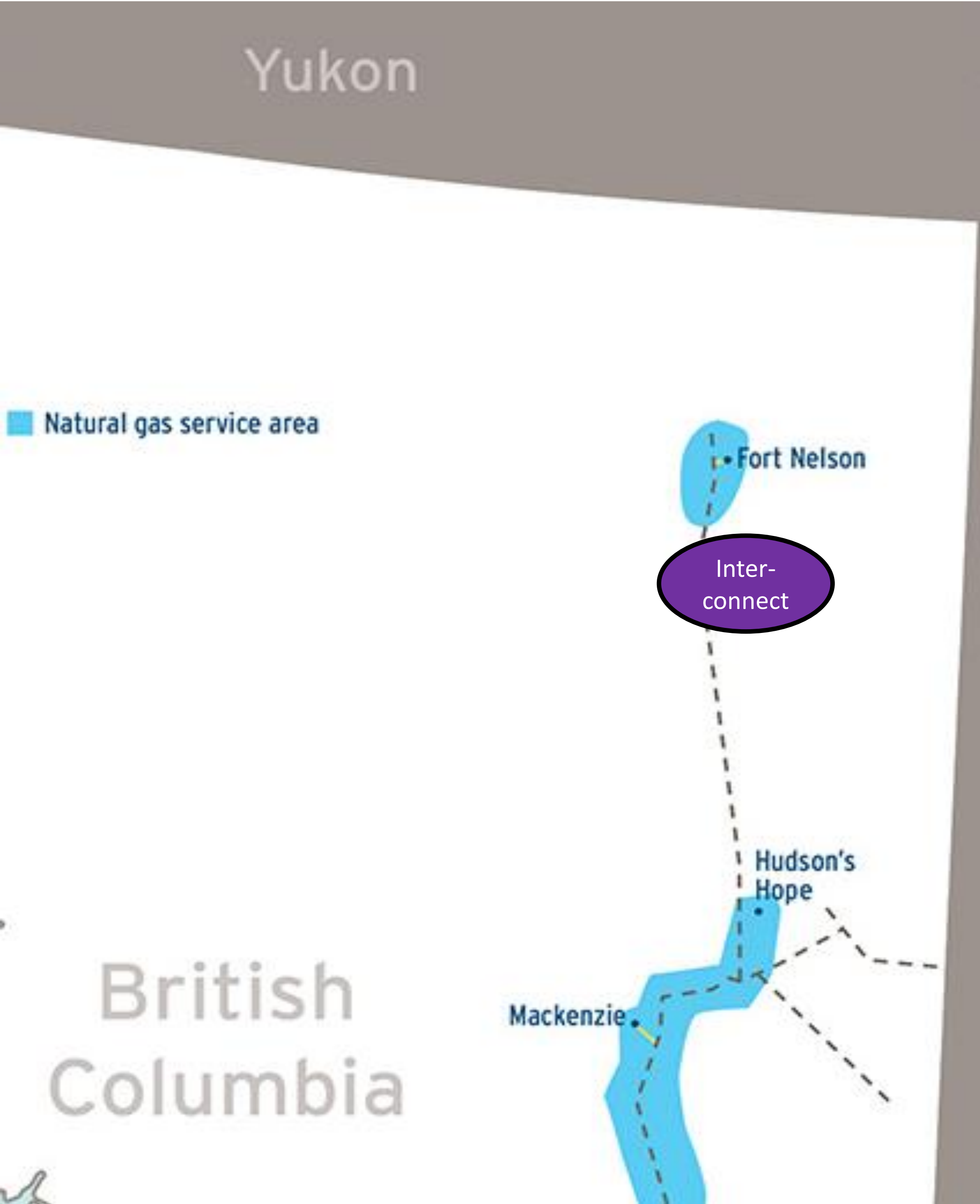
Rate Design Application Context & Fundamentals

Application Context



All Components Affect Rate Design

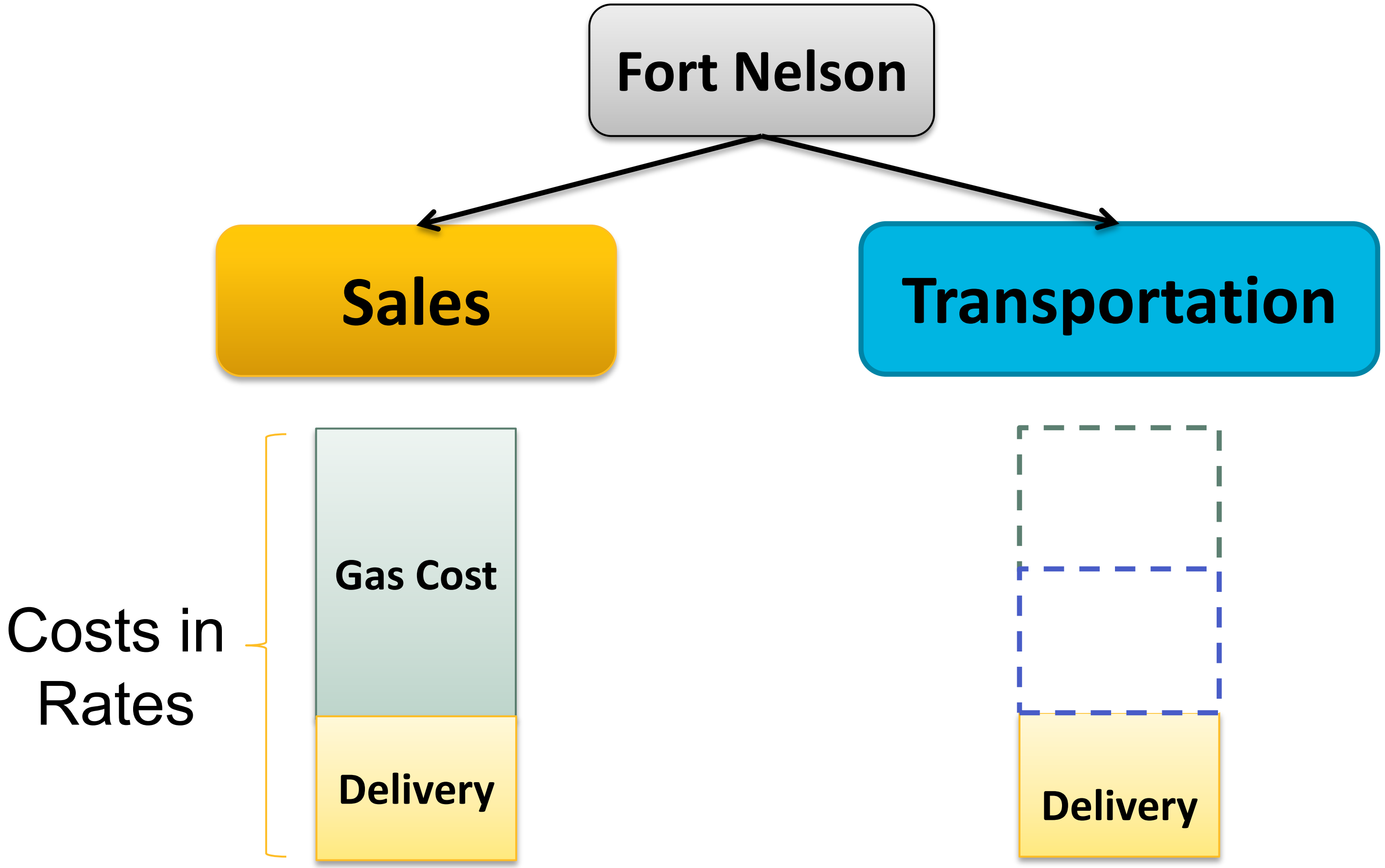




- **Sales service** brings gas to Fort Nelson interconnect moves it through the system to customers

- **Transportation service** allows customers to bring gas to interconnect whereby Utility take possession and delivers it to customers

Overview of Fort Nelson Services & Costs



Sales Service Components – Gas Costs

Consists of:

Gas Cost

Delivery

<u>Commodity Costs</u>

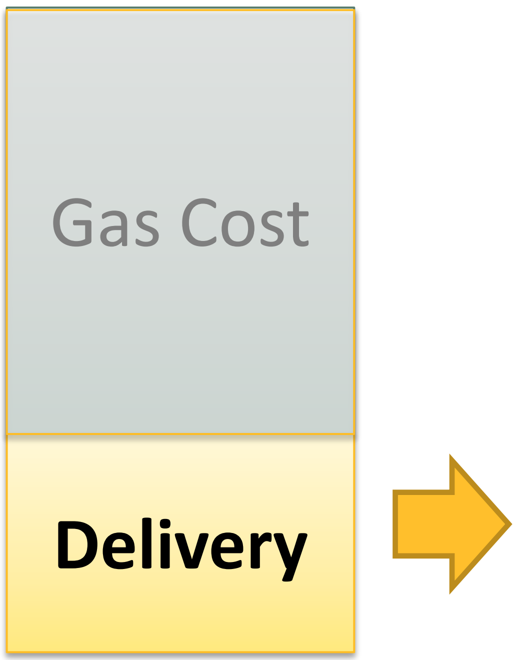
- Market based rate
- Station 2 supply
- Allocation of summer priced gas (physical storage)

<u>Midstream</u>

- Upstream pipeline capacity on external pipeline systems
- T North short-haul

Sales Service Components – Delivery

Consists of:



- Charges for Fort Nelson operations and delivering gas through Fort Nelson’s system
- Includes variable and fixed costs
- Costs generally determined by RRA and CPCN

Sales Service Bill Components – Description of Charges*

Rate 1
(example)

Minimum Daily Charge, which includes the *first 2 Gigajoules* per month prorated on a daily basis

Variable Charge for the *next 28 Gigajoules* in the month

Appears as "Charge for gas used" on the customer's bill

Variable Charge for *excess of 30 Gigajoules* in the month

Appears as "Charge for gas used" on the customer's bill

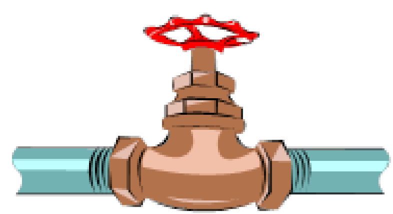
The Minimum Daily Charge and the Variable Charges are inclusive of:

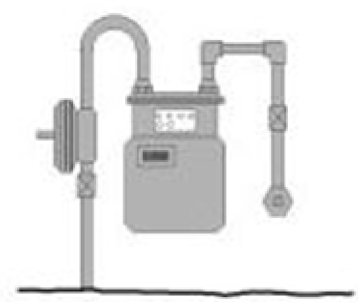
- ***The Delivery charge per day/Gigajoule***
- ***The Revenue Stabilization Adjustment Amount per Day/Gigajoule***
- ***The Gas Cost Recovery Charge per Day/Gigajoule***

Description of Charges and general structure is applicable to Rate 1, 2.1 and 2.2.

Transportation Service Overview

- Designed to give larger customers “choice” in who they to procure their gas supply from
- Transportation service customers can make supply arrangements on their own behalf, or through Marketers participating in the transport model
- Natural gas supply is delivered to Fort Nelson at the interconnect and Fort Nelson transports and delivers it to the customer’s premise
- Transportation Rate Schedules set terms and conditions of service offering





Cost of Service, Segmentation and Rate Design Concepts

Overview

- Rate Design Principles
- Customer Segmentation
- Cost of Service Allocation (COSA) Terminology
- COSA – Methods and Example
- Rate Design Concepts

Rate Design Principles

Based on Dr. Bonbright’s commonly accepted work “Principles of Public Utility Rates’

- Customer Impact;
- Fairness;
- Economic Efficiency;
- Stability/Predictability;
- Ease of Understandability;
- Competitiveness; and
- Recovering the Cost of Service

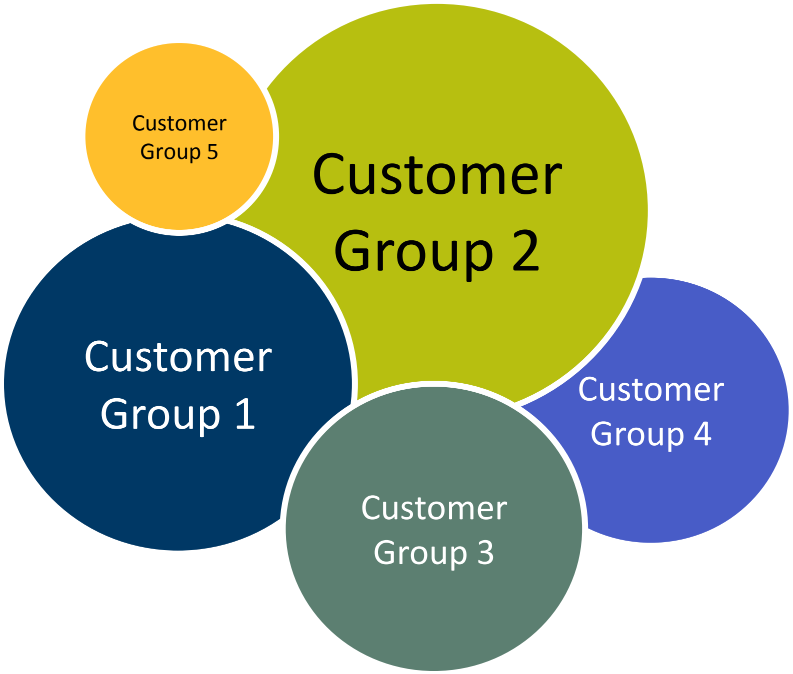
The weight placed on each of these principles is not always equal

Customer Segmentation

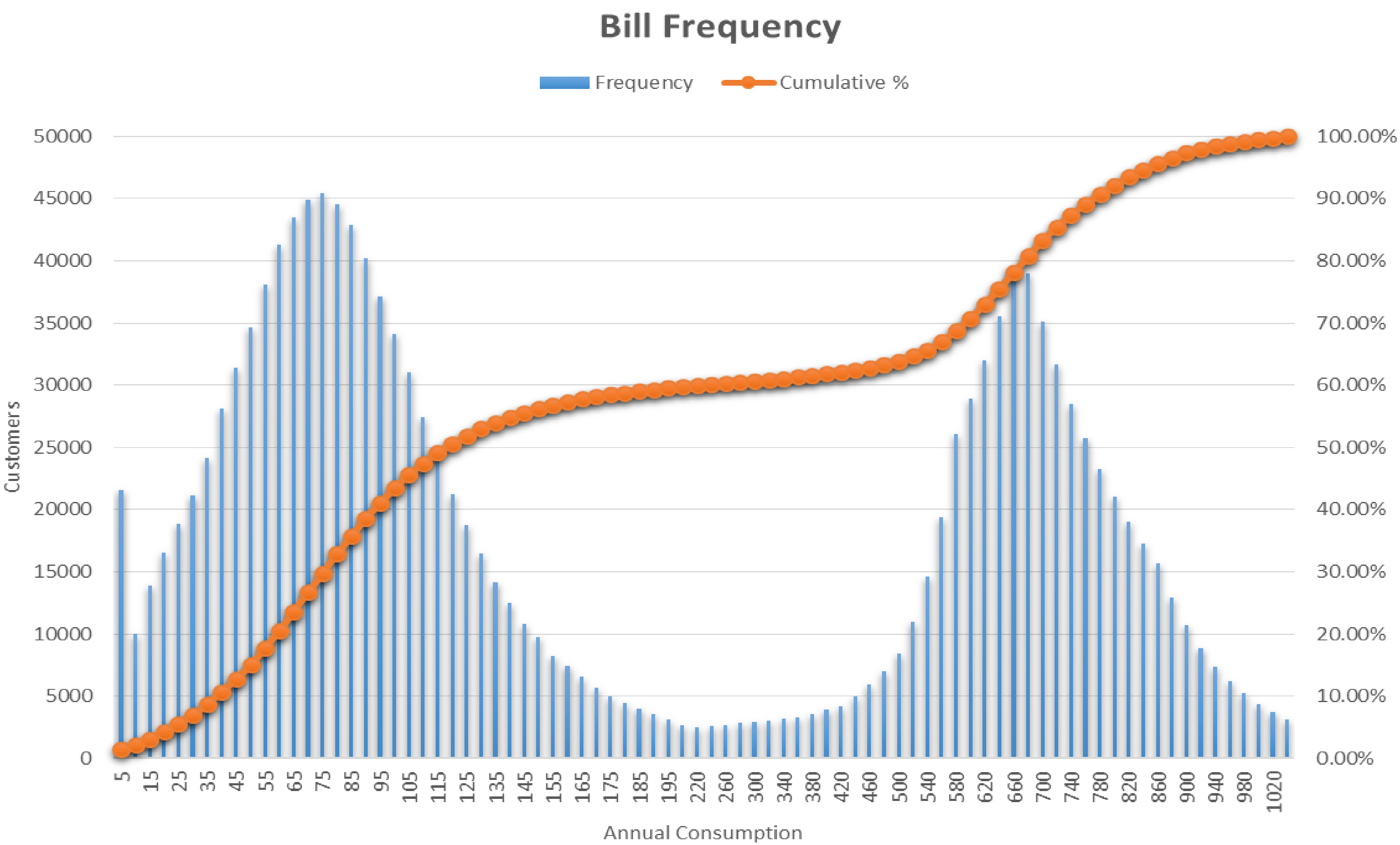
Analyze customers to separate them into groups where the customers in a particular group use the system in a similar way

Statistical tools are used including:

- Bill Frequency analysis
- Consumption patterns



Customer Segmentation Example Approach



How is the Delivery System built

Design Day

- Our delivery system is built to be able to meet our customers demand on the coldest day in 20 years (design day)

Pipeline

- To do this, we place pipe and other assets in service that are large enough to meet the design day load

Normal Day

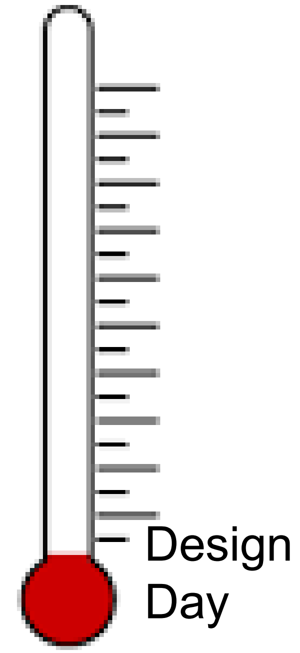
- On a normal temperature day, customers will not fully use our system capacity

Use of System

- Customer Groups use this system differently and as such some costs are allocated according to how each type of customer uses the system

Peak Day

- To do this we use Load Factor to derive a customer group's Peak Day demand

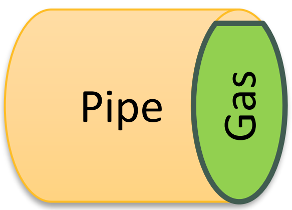


COSA Terminology - Load Factor

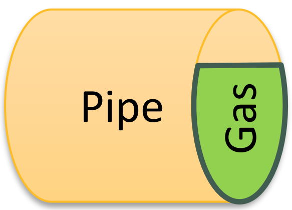
Load Factor is a measure of how a customer group uses the pipeline assets. Equal to "*average use divided by peak day use*".

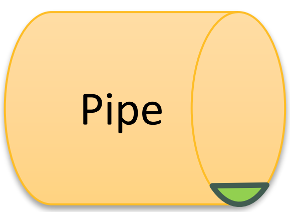
Customer Group 1
1,000 GJ Consumption
30% Load Factor

Customer Group 2
1,000 GJ Consumption
60% Load Factor

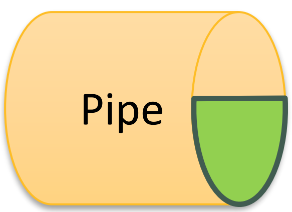


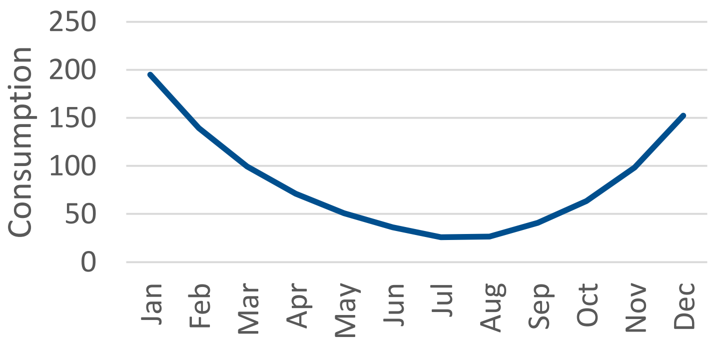
Winter

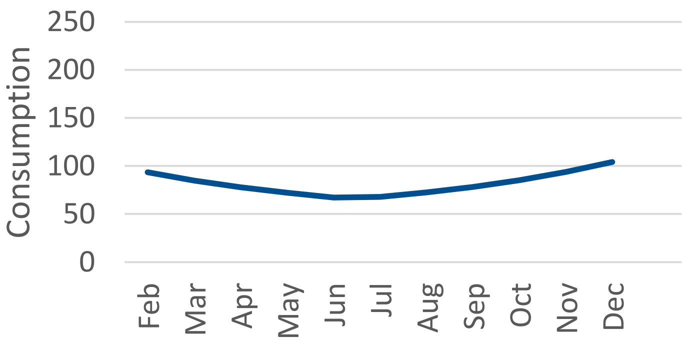




Summer







COSA Terminology – Peak Day

- Peak Day

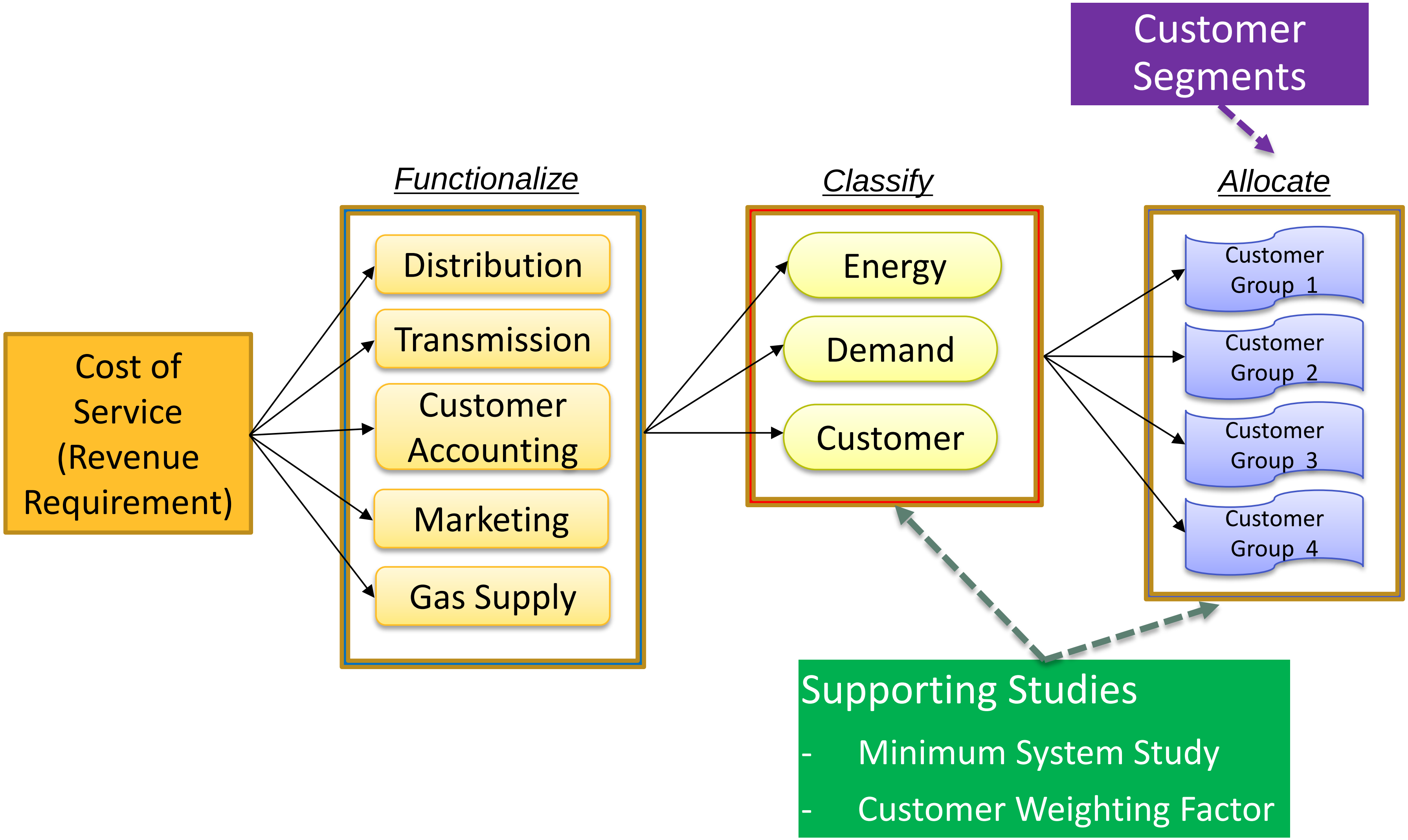
- Load factor adjusted volume

$$Peak\ Day = \frac{Annual\ Consumption}{Load\ Factor\ x\ 365}$$

	Customer Group 1	Customer Group 2
Load Factor	30%	60%
Annual Consumption (GJ)	1,000	1,000
Peak Day (GJ)	9.1	4.6
Peak Day Allocation %	67%	33%

		Customer Group 1	Customer Group 2
Cost to Allocate	$1,000		
Allocation using Peak Day (GJ)		$670	$330
If Allocating using Consumption (GJ)		$500	$500

Cost Allocation Method



How we split up our Revenue Requirement amongst our customers

COSA Supporting Studies

Study	Description	Why Is It Required?
1) **Minimum System Study**	• Classifies distribution costs into customer and demand components	• Ensures appropriate allocation of costs to each rate schedule
2) **Customer Weighting Factors Study**	• Assigns weighting factor to the average number of customers for each rate schedule	• Ensures appropriate allocation of customer related costs to various rate schedules

COSA Minimum System Study (MSS)

- 116 KM of distribution mains
  - Diameter of 26 mm – 168 mm
  - Varying cost per meter
- Some portion of these mains are in place just to connect our customers to the system, this is the minimum system
- MSS basically prices 116 KM of pipe as if it were 60 mm
  - Generally all new pipe is no less than 60 mm PE pipe
- The value of the minimum system divided by the actual value of all the pipe is the percentage classified as ‘Customer’
- The balance is classified as ‘Demand’

COSA Customer Weighting Factor

- Study differentiates the cost to connect small customers and large customers
- Calculated as a ratio to the cost to connect a residential customer
- Ratio used to scale upwards the average number of customers in a customer group

COSA- Example- Functionalization

Assume a two cost system, with two functions and three customer groups

Distribution operations role is to connect customers and deliver gas through DP pipe. Transmission operations role is to ensure gas is brought to the distribution system through TP pipe at the right time, quantity and pressure.

Cost 1: Distribution Operating Costs	$2,000
Cost 2: Transmission Operating Costs	<u>$4,000</u>
Total	**$6,000**

	FUNCTION	
	Distribution Operations	**Transmission Operations**
Distribution Operating Costs	$2,000	
Transmission Operating Costs		$4,000

Classify

Energy

Demand

Customer

COSA- Example - Classification

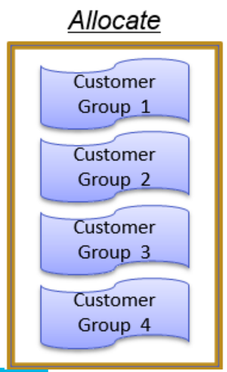
Distribution costs are incurred in part from customers joining the system and in part from the demand they place on the system

Minimum System Study quantifies the split of the Distribution system between Customer and Demand.

Assume 30% of Distribution system in place because a customer connects and 70% to serve them their demand.

Transmission system is 100% demand related.

	FUNCTION		CLASSIFICATION	
	Distribution Operations	**Transmission Operations**	**Customer**	**Demand**
Distribution Operating Costs	$2,000		$600	$1,400
Transmission Operating Costs		$4,000		$4,000



COSA – Example - Allocation

Allocation of costs requires an allocator that causes the cost to incur

Number of Customers works well to allocate customer costs. Peak Day Demand works well for demand related costs.

Customer Group	Peak Day Demand	Customers
1	700	1,100
2	200	300
3	100	100
Total	**1,000**	**1,500**

Customer Group 1	Customer Group 2	Customer Group 3
$1,400 x 700 / 1,000	$1,400 x 200 / 1,000	$1,400 x 100 / 1,000
$600 x 1,100 / 1,500	$600 x 300 / 1,500	$600 x 100 / 1,500
$4,000 x 700 / 1,000	$4,000 x 200 / 1,000	$4,000 x 100 / 1,000

	CLASSIFICATION	Allocation Amount	ALLOCATION: Customer Group 1 Allocation	ALLOCATION: Customer Group 2 Allocation	ALLOCATION: Customer Group 3 Allocation	Total
Distribution Operating Costs	**Demand**	$1,400	$980	$280	$140	$1,400
	Customer	$600	$440	$120	$40	$600
Transmission Operating Costs	**Demand**	$4,000	$2,800	$800	$400	$4,000
Total		**$6,000**	**$4,220**	**$1,200**	**$580**	**$6,000**

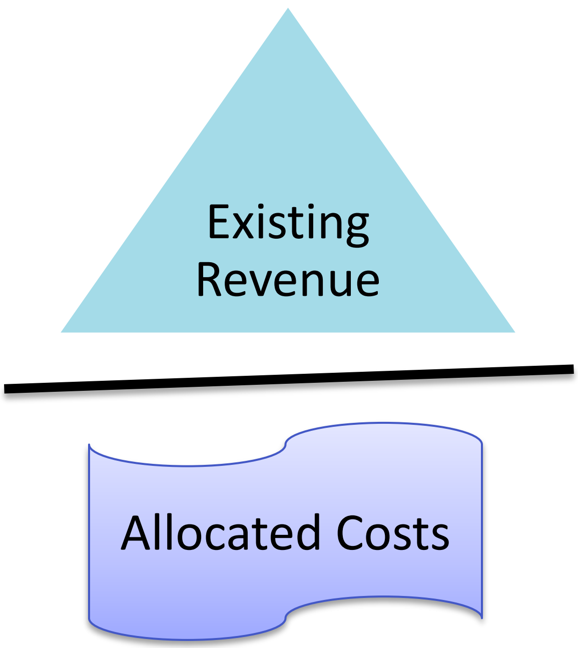
COSA Example – Revenue to Cost

	ALLOCATION			
	Customer Group 1 Allocation	Customer Group 2 Allocation	Customer Group 3 Allocation	Total
	$980	$280	$140	$1,400
	$440	$120	$40	$600
	$2,800	$800	$400	$4,000
Total Allocated Costs	**$4,220**	**$1,200**	**$580**	**$6,000**
Revenue at Existing Rates	**$4,150**	**$1,200**	**$650**	**$6,000**
R/C Ratio	**98.3%**	**100.0%**	**112.0%**	**100.0%**

If R/C ratios are far from 100%, rebalancing may be required

How we split up our Revenue Requirement amongst our customers

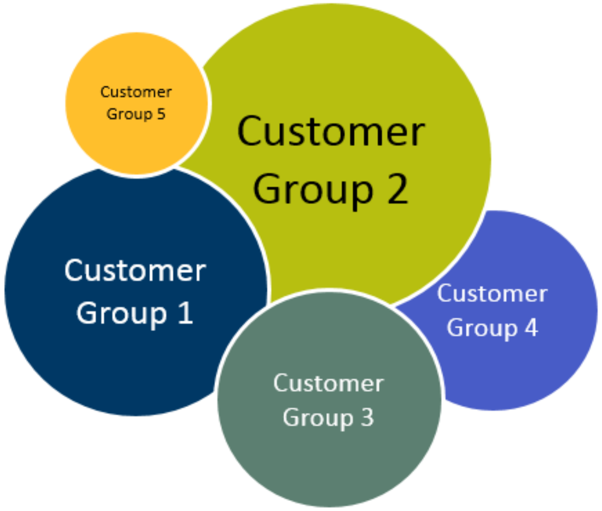
Revenue to Cost Ratio



- If a customer group R/C is within range, their rates are assumed to be fair and reasonable
- A range is appropriate given the subjective and short term nature of inputs, classifications and allocations
- Some times rebalancing may be required
  - Shift revenue required between customer groups

    (Reduce one Customer Group's rates and increase another group's)

Designing Rates



- Often premised on allocated costs
- Customer related costs tend to be fixed in nature
- Demand related costs are based on the demand a customer places on the system, however a great portion is also fixed (capital cost of infrastructure like pipe)
- Energy related costs tend to be variable with total consumption
- Balance recovery of fixed costs through fixed charges with the customers desire to control energy costs through consumption patterns

Rates should be understandable, stable, fair

and recover the cost of service

Tariff Overview

Fort Nelson Service Offerings

Sales Services	Transportation Services
Bundled Service	Firm Service
Applicable Rates	**Applicable Rate**
Rate 1	Rate 25
Rate 2.1	
Rate 2.2	
Rate 2.3	
Rate 3.1	
Rate 3.2	
Rate 3.3	

Fort Nelson Gas Tariff Rates

Rate 1	• Domestic Service • *1,980 Customers*
Rate 2.1	• General Service (<6,000 GJ) • *468 Customers*
Rate 2.2	• General Service (=or>6,000 GJ) • *34 Customers*
Rate 2.3*	• Natural Gas Vehicle Fuel Service • *0 Customers*
Rate 3.1	• Industrial Service (<96,000 GJ) • *0 Customers*
Rate 3.2	• Industrial Service (=or>96,000 GJ< 360,000 GJ) • *0 Customers*
Rate 3.3	• Industrial Service (=or>360,000 GJ) • *0 Customers*
Rate Schedule 25	• General Firm Transportation Service • *2 Customers*

Rate 2.4 provides Compression/Dispensing Service – 0 customers

Part II

DISCUSSION GUIDE

COSA Model: Cost Assumptions

Test Year: Costs from 2015-2016 Revenue Requirements and Rates application used in COSA

Delivery Costs

- Based on the costs approved from Fort Nelson 2015-2016 Revenue Requirements and Rates Application

Gas Costs

- Gas cost (Commodity & Midstream) recovery charges are established via the quarterly gas cost review process
- Test year gas costs based on multiplying forecast sales volumes times the existing gas cost recovery charges for each rate schedule

Gas Cost Allocation Method

Gas costs include Commodity & Midstream costs

Both commodity and midstream costs are classified as energy-related & allocated based on throughput

Discussion Guide - Section 2.2.1, page 3

Delivery Cost Allocation

Functionalization, Classification and Allocation Results and Review

Functionalize

Functionalize Order	Method	Notes
Rate Base	Based on Functions that the costs support	Includes capital assets like Pipe, Regulators, Meters, Buildings, Information Systems
Deferrals	Various	Dependent on nature of deferral
Operating and Maintenance	Based on Functions that the costs support	Includes costs like preventative maintenance, meter exchanges, training, emergency management
Property Taxes	Based on value of Land, Structures and Pipe in Function	
Depreciation & Amortization	Follows functionalized Assets	
Income Tax & Earned Return	Based on Functionalized Rate Base	Both Income Taxes and Earned Return are determined by Rate Base

Classify & Allocate

Function	Classify	Allocate
Gas Supply	Energy	Throughput
Transmission	Demand	Peak Day Demand
Distribution	Customer Demand	Number of Customers Peak Day Demand
Marketing	Customer	Number of Customers
Customer Accounting	Customer	Number of Customers

Cost Allocation Summary

FEI believes existing allocation approach for commodity costs is reasonable

- Commodity - driven by energy consumed, classified as energy-related and allocated based on throughput

FEI proposes to unbundle rate structure and change the midstream costs allocation approach

- Midstream – driven by capacity requirements, classified as demand-related and allocated based on peak demand

Delivery Cost allocation methodology is reasonable and consistent with industry practices

COSA RESULTS

Rates	Revenue to Cost Ratio (no rebalancing)
Rate 1	92%
Rate 2.1	113%
Rate 2.2	121%
Rate 25	59%

Key Discussion Topics

interruptible

Bundled or Unbundled Rates

- Current rates are bundled together as one charge
  - Delivery Costs
  - Gas Costs
  - Storage & Transport Costs

Grouped as one charge (per block) on your bill

- Bundled rates decline with more consumption

- Unbundled rates would separate the three components
  - Delivery Costs
  - Gas Costs
  - Storage & Transport Costs

Individually visible on your bill

Bundled or Unbundled Rates

Rate Structure	Current Rates	Annual Bill
Bundled Rates		
Min incl. 1st 2 GJ per month	$0.4898	$179
Next 28 GJ per month	$4.432	$491
Excess over 30 GJ per month	$4.342	$0
TOTAL		**$669**
Unbundled Rates		
Basic Charge per day	$0.4047	$148
Delivery Charge $/GJ	$2.579	$347
Commodity Charge $/GJ	$1.275	$172
Storage and Transport Charge $/GJ	$0.019	$3
TOTAL		**$669**

Gas Cost Allocation Methodology

- Propose to allocate the midstream component embedded in rates based on demand
- Follows cost causation
- Minimal change to customer bills

	Current Method	Proposed Method	Difference per GJ	Annual Bill Change
Residential	$1.294	$1.293	-$0.001	-$0.14
Small Commercial	$1.294	$1.296	+$0.002	+$0.94
Large Commercial	$1.294	$1.292	-$0.002	-$7.12

Commercial Customers Segmentation

- Rates 2.1 and 2.2 currently segmented based on 6,000 GJ per year separation point
- New separation point of 2,000 GJ based on analysis
  - Separation point of 2,000 GJ aligns with FEI's other service territories
  - Twelve existing Rate 2.1 customers would move to Rate 2.2
  - All other customers stay in existing Rates categories
- No bill impact when rate structures are held constant between Rates 2.1 and 2.2

Rebalancing Options

Option 1: Rebalance rate schedules to 90-110% range

	Rate 1	Rate 2.1	Rate 2.2
Rebalanced Amount (in $000)	+ $130	- $47	- $83
Burner Tip Change (%)	+ 7.7%	- 1.4%	- 7.9%
R:C ratio after rebalancing	98%	110%	110%

Option 2: No Rebalancing

Rate	Revenue to Cost Ratio
Rate 1 – Domestic (Residential) Service	92%
Rate 2.1 – General (Small Commercial) Service	113%
Rate 2.2 – General (Large Commercial) Service	121%
Rate Schedule 25 – General Firm Transportation Service	59%

Common Rates Suitability

BCUC Order G-21-14 (Page 19) :

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.

Common Rates Suitability

Rate 1: Domestic Service (Residential)	Fort Nelson Current Rates January 1, 2016		FEI Current Rate Schedule 1 Rates April 1, 2016	
Basic Charge per day	$	0.4047	$	0.3890
Delivery Charge per GJ	$	2.579	$	4.370
Cost of Gas Charge per GJ	$	1.275	$	1.141
Storage and Transport per GJ	$	0.019	$	1.117
Average annual use per customer of 135 GJ				
Annual Cost	**$**	**669**	**$**	**1,035**
Percentage Change				**55%**

Rate 2.1: General Service (Small Commercial)	Fort Nelson Current Rates January 1, 2016		FEI Current Rate Schedule 2 Rates April 1, 2016	
Basic Charge per day	$	1.1781	$	0.8161
Delivery Charge per GJ	$	3.298	$	3.523
Cost of Gas Charge per GJ	$	1.275	$	1.141
Storage and Transport per GJ	$	0.019	$	1.133
Average annual use per customer of 443 GJ				
Annual Cost	**$**	**2,464**	**$**	**2,866**
Percentage Change				**16%**

Part III

REVENUE REQUIREMENT 2017-18

Agenda

Proposed Rate Changes & Impacts

- Proposed rate increases for 2017 & 2018
- Approximate annual bill impacts

Key Drivers of the Rate Change

- Customer demand reduction & rate base growth

Key Driver of Rate Increase

- Approximate 7% increase in delivery rates in each of 2017 and 2018 with rate smoothing
- The rate increases are mainly driven by the decrease in use per customer resulting in a lower overall forecast of volume
- Other factors include:
  - Rate base growth and increased O&M; offset by
  - Reduction in depreciation & amortization, lower interest rates and reduction in taxes

(Above two net to almost zero change in rates)

Rate Smoothing

- Proposed to keep delivery rate increases stable over 2017 and 2018
- Without smoothing, delivery rate increase would be approximately 14% in 2017 and a decrease of approximately 7% in 2018
- **Same total revenue recovered over two years with or without smoothing**

Rate Smoothing Example

		Revenue Requirement		
		2017	2018	Total
Required Revenue		$114	$107	$221
Smoothing Rate Changes	**2016 Rates**	+ 7%	+ 7%	
Revenue Collected	$100	$107	$114	$221
Unsmoothed Rate Changes	**2016 Rates**	+ 14%	- 7%	
Revenue Collected	$100	$114	$107	$221

Bill Impacts for 2017 & 2018

- Average increase to residential customer bill of $59 in 2017 and another $35 in 2018

- 2017 bill impacts also include increase in recovery of Revenue Stabilization Adjustment Mechanism (RSAM) deferral.

  Approximately $26 of the $59 residential customer increase is related to the recovery of the RSAM account

		2017		2018	
Rate Category	GJ	Annual $ Increase	% of Previous Annual Bill	Annual $ Increase	% of Previous Annual Bill
Rate 1 - Domestic (Residential) Service	135	$59	8.68%	$35	4.70%
Rate 2.1 - General (Commercial) Service	440	$215	8.60%	$131	4.83%
Rate 2.2 - General (Commercial) Service	8,100	$3,511	8.88%	$1,964	4.56%
Rate 25 - Transportation Service	19,850	$9,403	14.60%	$5,532	7.50%

Revenue Requirement

- Separate process from Rate Design
- Filed with the BCUC on June 30, 2016
- Link to BCUC website

    http://www.bcuc.com/

Part IV

CLOSING REMARKS & NEXT STEPS

Next Steps

Documentation

- FEI will distribute key issues list and post notes from today's workshop by Aug 4

Customer Research

- FEI is planning to conduct an online survey for FEI & Fort Nelson residential customers

Communication

- Website: www.fortisbc.com/ratedesign

For further information, please contact:

Gas.Regulatory.Affairs@fortisbc.com

www.fortisbc.com/ratedesign

Find FortisBC at:

Fortisbc.com

604-576-7000

Workshop 1: Fort Nelson Service Area July 27, 2016
Summary

Meeting:	FEI 2016 Rate Design Workshop 1: Fort Nelson Service Area
Date:	July 27, 2016
Time:	9:15 am to 4:30 pm
Location:	Northern Rockies Recreation Facility Community Centre (Viewing Activity Room 1), 5500 Alaska Highway, Fort Nelson BC
Facilitator:	Atul Toky, FEI
Participants:	Mitchell, Michelle (Lakeview Inn & Suites); Neville, Abigail (Fort Nelson News); Roy, Richard (Northern Rockies Regional Municipality Planner); Smith, Kathy (Fort Nelson News); Smith, Peter (BC Oil and Gas Commission); Streeper, Bill (Northern Rockies Regional Municipality Mayor); Vandersteen, Bev (Fort Nelson Chamber of Commerce); Wall, Ben, (NexGen Homes & General Contractors a division of BKT Wall Contracting Ltd.); Belanger, Al (FortisBC Employee); Jodouin, Kyle (FortisBC Employee)
FEI Attendees:	Gosselin, Rick; Gravel, Colleen; Hill, Song; Mason, Matt; Toky, Atul; Bemister, Keith (BCUC Hearing Officer, Allwest Reporting)
Material Provided	Presentation attached following notes.
Agenda:	***Agenda:*** 1. Information Session • Rate Design Application Context and Fundamentals • Cost of Service, Segmentation and Rate Design Concepts • Tariff Overview 2. Discussion Guide • Gas Cost Allocation • Functionalization, Classification and Allocation Review • Key Discussion Topics 3. Revenue Requirement 2017-2018 • Proposed Rate Changes • Primary Reasons for Changes 4. Next Steps • Concluding Remarks • Compile Key Issues List

Meeting Summary and Notes

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
Information Session - Summary of Questions/Comments		
Slide 9	Cost of Gas • What is included in the cost of gas?	• The cost of gas includes two components: ○ Commodity costs – This is a market based rate and consists of primarily Station 2 supply ○ Midstream costs – This includes costs associated with T North short-haul capacity from Spectra.
Slide 12	Storage and Transportation • Is there any transportation or storage included? • Fort Nelson should not be paying for storage. • There should be no third-party storage. • What classification is Spectra to Fort Nelson – Delivery or transportation? • Midstream costs are they for all of FEI or just Station 2?	• Rick: No storage costs included in the midstream; With respect to transportation, there is a small component from T-North included. We will look into this further. • Atul: Storage and transportation is a term we use for midstream. • Will include a description of the physical gas flow and related commercial transactions to bring gas to the delivery system for Fort Nelson Service Area in the Rate Design Application
Slide 9	LNG • LNG is not applicable to Fort Nelson, why is it on the graph?	• Atul: Fort Nelson is not allocated any costs for LNG, it is just a general slide showing the value chain for natural gas system.
Slide 8	Rate Design vs. Revenue Requirements • Rate Design and Revenue Requirements distinction.	• Atul: Two separate applications and processes. Revenue requirements are the costs to serve you, what drives the costs. Rate Design is how those costs are split up among the different types of customers. • Rick: Rate Design does not impact total revenues.
	Common Rates • Are you looking at going back to common rates?	• Atul: Common rate is a key discussion topic that will be covered later today. The objective for today's workshop to discuss the key issues, and get inputs from you.
	Asset Costs • Do you use replacement costs or depreciated values in your model? What are the depreciated values of the pipeline?	• Rick: we use depreciated values. • Forecast 2017 ending net book value of all plant assets in Fort Nelson is $11.5 million

Workshop 1: Fort Nelson Service Area July 27, 2016
Summary

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
Slides 35, 36, 44	Rate Schedule 25 • Rate Schedule 25 is the biggest controversial issue in Ft. Nelson. • There is line sizing/demand that is not being used. • As a municipality, could we go on RS25 and purchase our own gas from Spectra? • What was done with Hydro's revenue from the former natural gas general plant 15 years ago?	• There are currently two customers in RS25, one of which has ceased taking natural gas and the other one is using natural gas for space heating purposes only. This is the reason why the revenue to cost ratio for RS25 is outside the range of reasonableness. We will go over the rebalancing options to address this shortfall in revenues. • RS25 is designed to serve process load customers and therefore, it is not suitable for Fort Nelson as a municipality to go on RS25 as the municipality has mainly residential customers with different load characteristics and end use. • BC Hydro's generation plant and Fort Nelson Gas Ltd. had a wheeling agreement in place until 1996. The agreement provided revenue to Fort Nelson Gas while in effect. When the wheeling agreement expired the loss of that revenue, all else being equal, would have created a revenue deficiency for Fort Nelson Gas. That deficiency would have been made up by all other gas consumers in the Fort Nelson service area..
	Basic Charge, Delivery Charge • What are the components of the basic charge and delivery charge?	• We will go through the current charges and rate structure for Fort Nelson Service Area in our slides. What people see on their bills today are Basic charge and Charge of Gas used. Both of these charges covers cost of gas and delivery costs that Fortis incurs to deliver natural gas to the customers in Fort Nelson Service Area.

Workshop 1: Fort Nelson Service Area July 27, 2016
Summary

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
Key Discussion Topics - Summary of Questions/Comments		
Slide 46	Bundled vs. Unbundled Rates • Rate transparency, why now? • Is there an efficiency gain for the billing system? • Is there a cost to make the change?	• Rick: We will be filing a comprehensive rate design application in fall this year and that's why we are now looking at every aspect of rate design. Unbundled rate structure is more transparent, easy to understand and will remove inconsistency. Fort Nelson Service Area customers are the only FEI customers with bundled rates; all other FEI service area customers have an unbundled rate structure. • Rick: Confirmed that service areas encompass general areas and try to capture locations within these general areas • The Fort Nelson Service Area currently serves approximately 2,450 customers. Operations in the Fort Nelson Service Area consist of a transmission lateral from the Spectra Energy Corporation processing plant to Fort Nelson, together with the gas distribution system within Fort Nelson, as well as the gas distribution system in Prophet River. Prophet River has been part of the Fort Nelson Service Area since the amalgamation of Fort Nelson Gas Ltd. with BC Gas Ltd. In 1989. • Rick: Confirmed that Rates 2.1 and 2.2 applies to schools, municipal buildings etc. and that one customer equals one meter. • We expect very minor efficiency gain on billing system but will confirm and get back to you on this one. However, the efficiency gain is not the reason why we are considering to have unbundled rate structure for customers residing in Fort Nelson Service Area. • We will confirm what it would cost to make this change. However, we don't expect these costs to be significant.
Slide 50	Rebalancing Options • If RS 2.1 and 2.2 customers had to pay RS 25's shortfall of 59%, that would not be good. • Residential is 92% still within range. • Instead of shifting the revenue to residential, shift it to RS25, that way the rates won't go up for residential customers. • RS25 customer should get allocated the costs, not represented here. • Residents cannot afford an increase.	• We could look at another rebalancing option where the revenues from other rate schedules could be shifted to RS25 to bring it in the range of reasonableness (90-100%). However, it is important to note that if we push all the rate increase to RS25, it could force that customer to leave the FortisBC system, which would have some implications to all other customers as the revenues provided by the RS25 customer will then be recovered from all other rate schedules.

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
Slides 51-52	Common Rates Suitability • Most of the difference is based on transportation (delivery) charges (Victoria is farther away from Spectra than Fort Nelson), so it is not apples to apples, it is apples to oranges. • What kind of capital projects are you envisioning for Ft. Nelson for the next five years? • What if use rates continue to decline, maybe amalgamation would be a good thing?	• Rick: we will get back to you with respect to the capital projects envisioned for Fort Nelson for next 5 years. If I had to estimate (subject to confirmation), it would be in the range of $200,000 per year. • Rick: The 2017 – 2018 revenue requirement includes capital additions for Fort Nelson of $601 thousand and $624 thousand respectively. Distribution mains (pipe) equals $262 thousand and $424 thousand respectively. FEI anticipates distribution mains additions similar to 2017 and 2018 in year 2019 – 2021. • Rick: As shown in the slides, today the difference between FEI and Fort Nelson rates is 55% on burner-tip (annual bill), but a major portion of that difference is due to lower midstream costs allocated to Fort Nelson Service Area. There are benefits of amalgamating Fort Nelson Service Area and moving the customers on the common rates. For e.g. rate increases due to capital projects or other major upgrades in Fort Nelson Service Area will not be as high if customers in Fort Nelson Service Area are on common rates as compared to on standalone basis. As can be seen in the slides, the gap between Fort Nelson Service Area and FEI in terms of annual bill for customers is getting smaller and therefore at some point in future it would make sense for Fort Nelson to move onto common rates. At this time, FEI is not considering moving customers in Fort Nelson Service Area to common rates.

Workshop 1: Fort Nelson Service Area July 27, 2016
Summary

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
FORT NELSON 2017-2018 REVENUE REQUIREMENTS AND RATES DISCUSSION - SUMMARY OF QUESTIONS/COMMENTS		
Slide 58	• 2017 Revenue Requirement – can you prepare a slide for 2016 and 2018? • We have to cut costs, why doesn't FEI? • Has consumption dropped from 140 GJ to 135GJ?	• A slide breaking out the 2016 approved and 2017 – 2018 forecast delivery costs of the revenue requirement has been included as an attachment. The details do not include cost of gas as this is a flow through to customers and also leaves of the rate smoothing mechanism FEI is proposing in the 2017 – 2018 revenue requirements application. The purpose of the side by side comparison was to show the differences in costs from year to year and it is for that reason that the rate smoothing mechanism (cost of service component) was left out of the slide. • Song: We are only allowed to recover what is reasonably or prudently incurred; that can be part of the BCUC process to determine revenue requirements. • Rick: yes, drop in consumption can be a factor of warmer weather or other factors

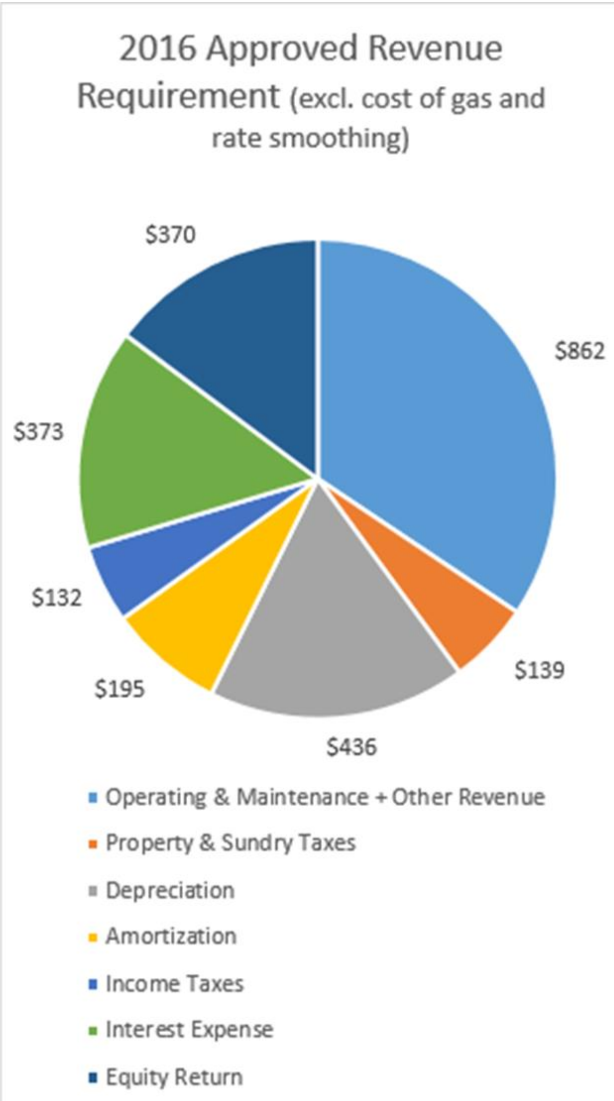
Action Items and Next Steps

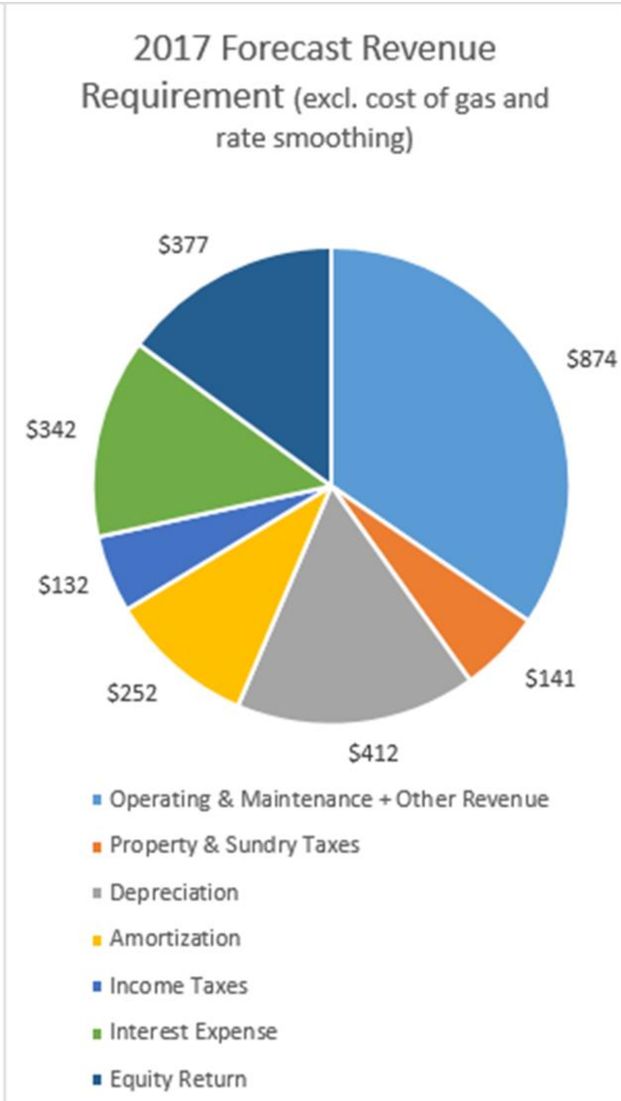
	Item	Responsibility	Target Completion
Rate Design			
1.	Confirm What is included in gas costs? Confirm if there is any transportation and storage included.	FEI	Within the Rate Design application
2.	Provide the depreciated value of the pipeline used in the model.	FEI	Included in the notes
3.	What are the estimated costs for CIS and Customer Service Group to implement the unbundled rate structure for Fort Nelson's customer bills?	FEI	Within the Rate Design application
Revenue Requirements and Rates			
4.	What are all the relevant costs that go into the Fort Nelson Cost of Service for delivery rates? (list)	FEI	Details included in the 2017 – 2018 Revenue Requirement
5.	Confirm the capital projects being envisioned for Fort Nelson for the next five years.	FEI	TBD
6.	Would the Fort Nelson municipality be able to purchase their own natural gas commodity and just pay delivery?	FEI	TBD
7.	Prepare a slide showing the Fort Nelson 2016 and 2018 Revenue Requirement.	FEI	A slide breaking out the 2016 approved and 2017 – 2018 forecast delivery costs of the revenue requirement has been included as an attachment. The details do not include cost of gas as this is a flow through to customers and also leaves of the rate smoothing mechanism FEI is proposing in the 2017 – 2018 revenue requirements application. The purpose of the side by side comparison was to show the differences in costs from year to year and it is for that reason that the rate smoothing mechanism (cost of service component) was left out of the slide.

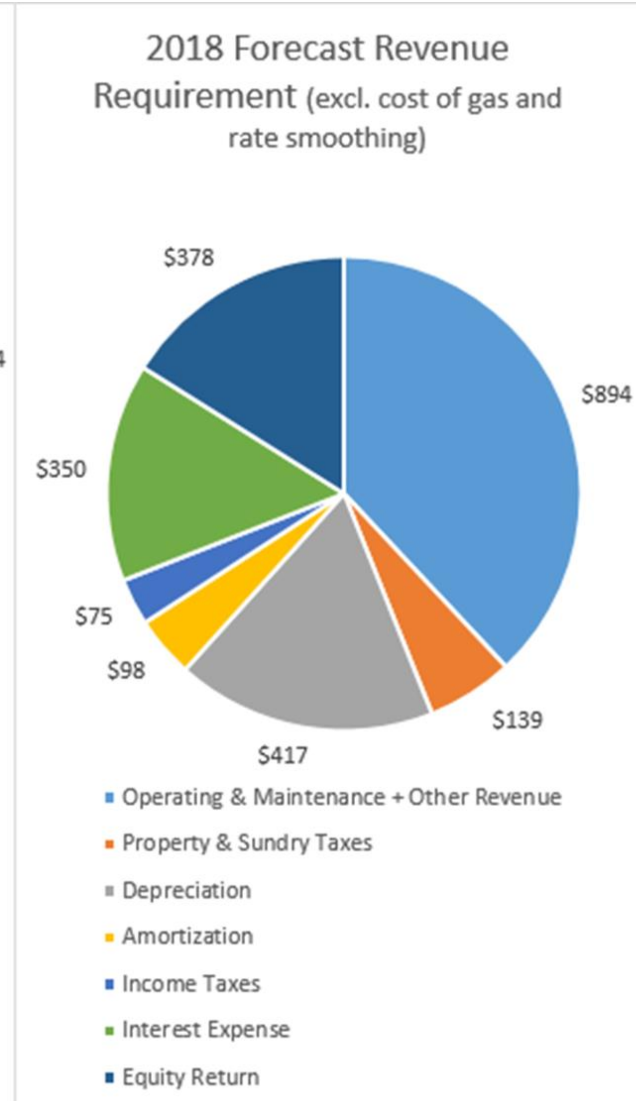
Key Issues

Issues List	
1.	Common Rates: • Confirmation that FEI will not be proposing the adoption of common rates for Fort Nelson in the 2016 RDA.
2.	Rebalancing • New "Option 3": shift revenues to Rate Schedule 25 to rebalance Rate 2.1 and 2.2 and Rate Schedule 25 (leave Rate 1 at 92% R:C ratio).
3.	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, as suggested by the attendees?

COSA Workshop in Fort Nelson July 27, 2016
Summary







2016 Rate Design Application

Workshop 2 – Transportation Review

Atul Toky – Manager, Rate Design and Tariffs
Rohit Pala – Resource Development Manager
Stephanie Salbach – Transportation Services Manager
Ronald J. Amen – Black & Veatch Management Consulting LLC

August 12 2016

Introduction - *Objectives for Today*

Provide Services Overview and Background

Inform & Review services within Transportation Model

Discussion on Key Topics related to Transportation Model

Summarize Key Issues List

Workshop Guidelines

Participate

Respect other participants and presenters

Questions & responses as we go / if needed - add to an ‘Issues List’

Issues list to be compiled and revisited following presentation

One speaker at a time

Documentation:

- Meeting Notes
- Issues List
- FortisBC Responses to Issues
- Issues List Items not Addressed During Workshop

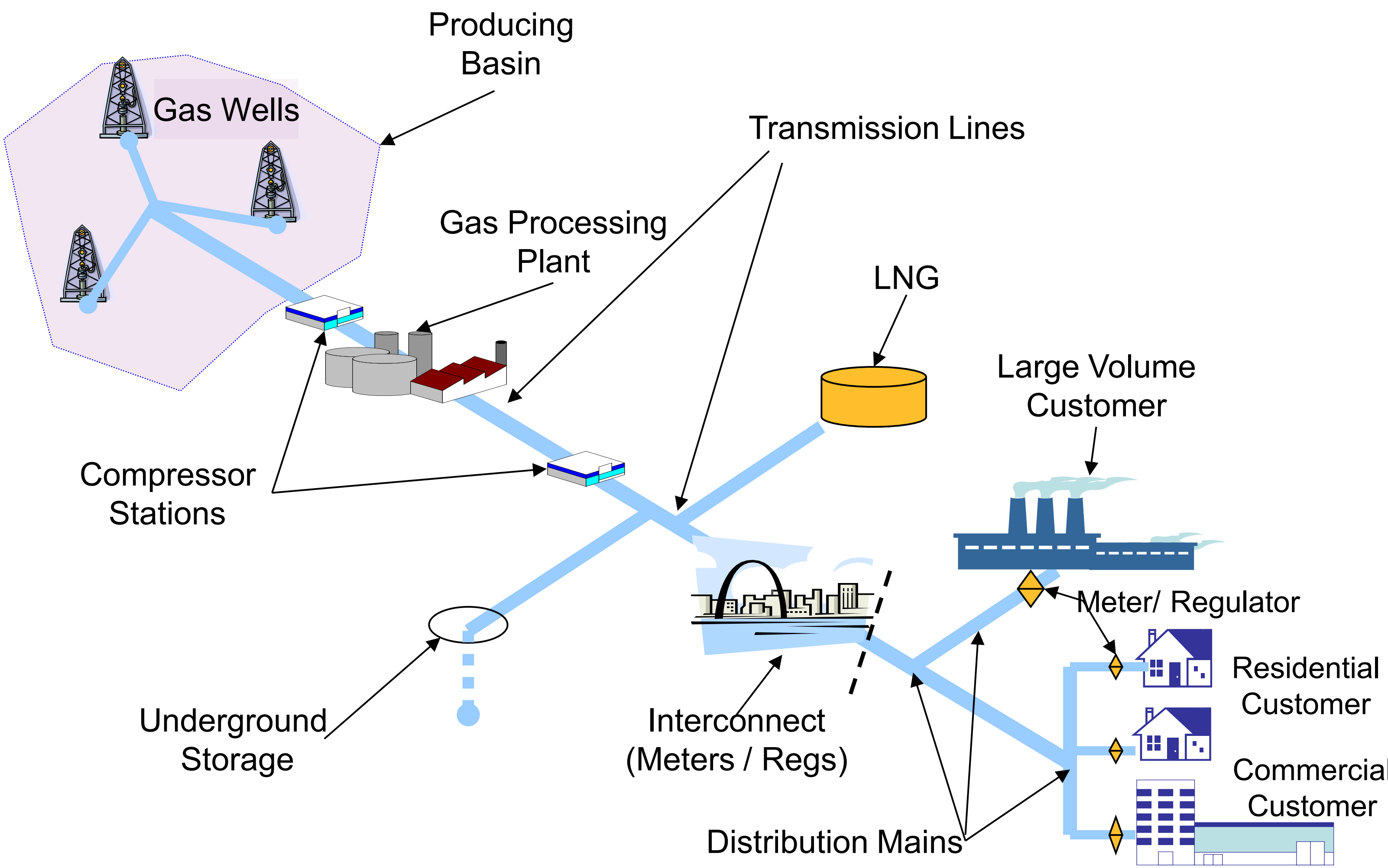
Agenda

Discussion Guide	Services Overview and Background
	Services within the Transportation Model
Key Discussion Topics	Monthly vs Daily Balancing
	Balancing Tolerance and Value
	Additional T-South Capacity
	Other Discussion Topics
Next Steps	Concluding Remarks
	Compile Key Issues List
	Workshop 3 – Rate Design and Segmentation

Part I

DISCUSSION GUIDE

All Components Affect Rate Design



Services Overview and Background

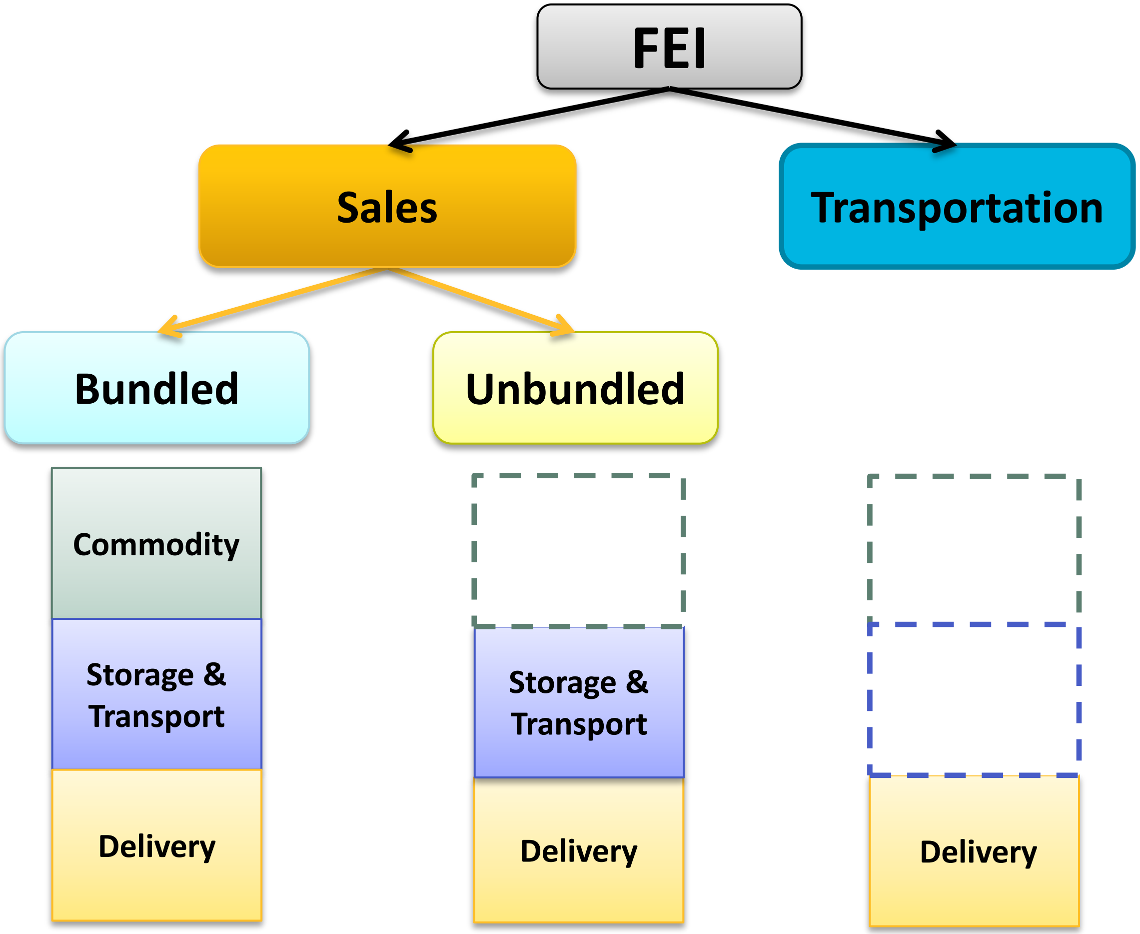
Sales Service

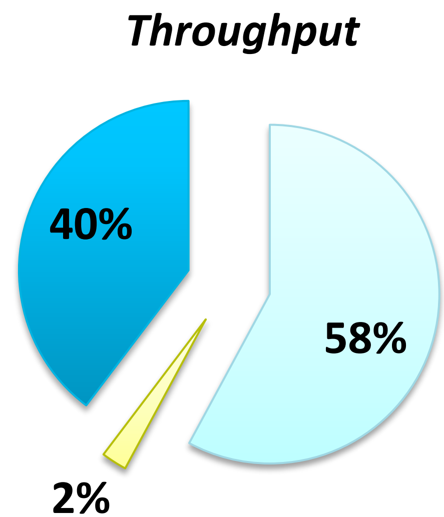
- Receives gas from supply hubs & storage and transports it to the FEI system for delivery to customers
- Managed by the contracting of midstream resources under the ESM

Transportation Service

- allows customers to bring gas to FEI system at specific points whereby FEI take possession and deliver it to customers' premises

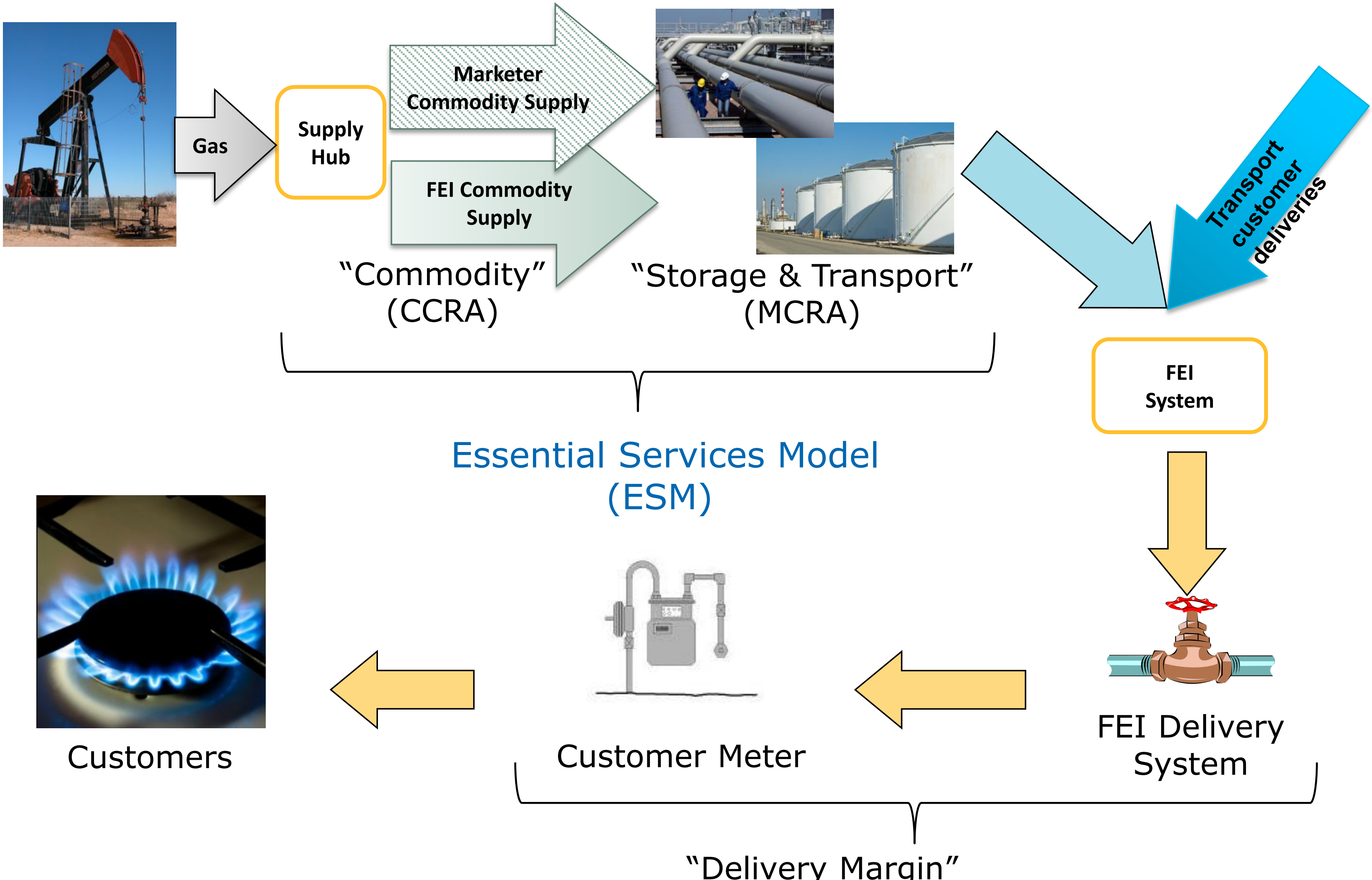
Overview of FEI Services & Rates



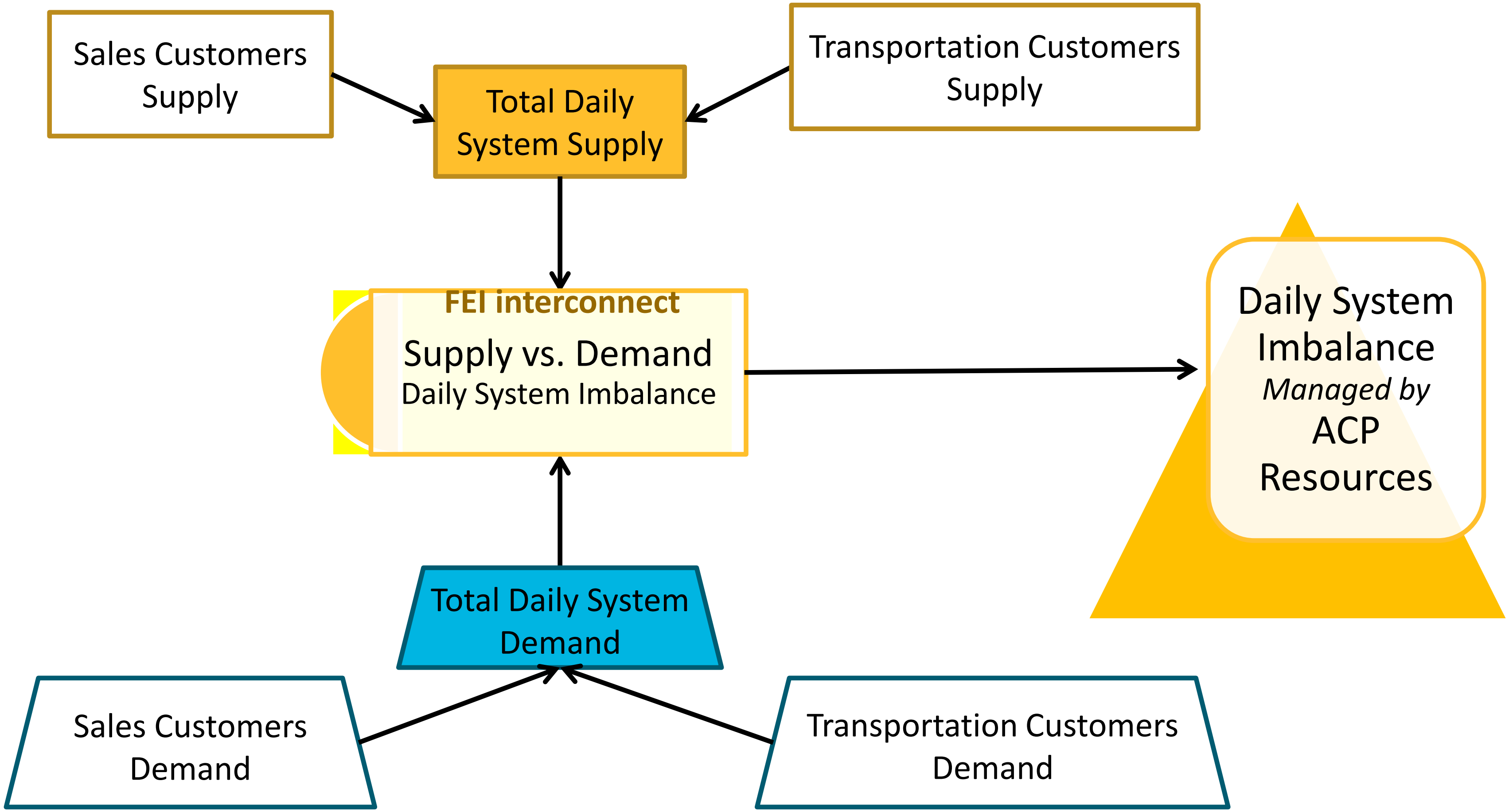


"Storage and Transport" also referred to as "Midstream"
1 PJ = 1,000 TJ = 1,000,000 GJ

From Wellhead to Burnertip



Daily System Load Balancing Overview

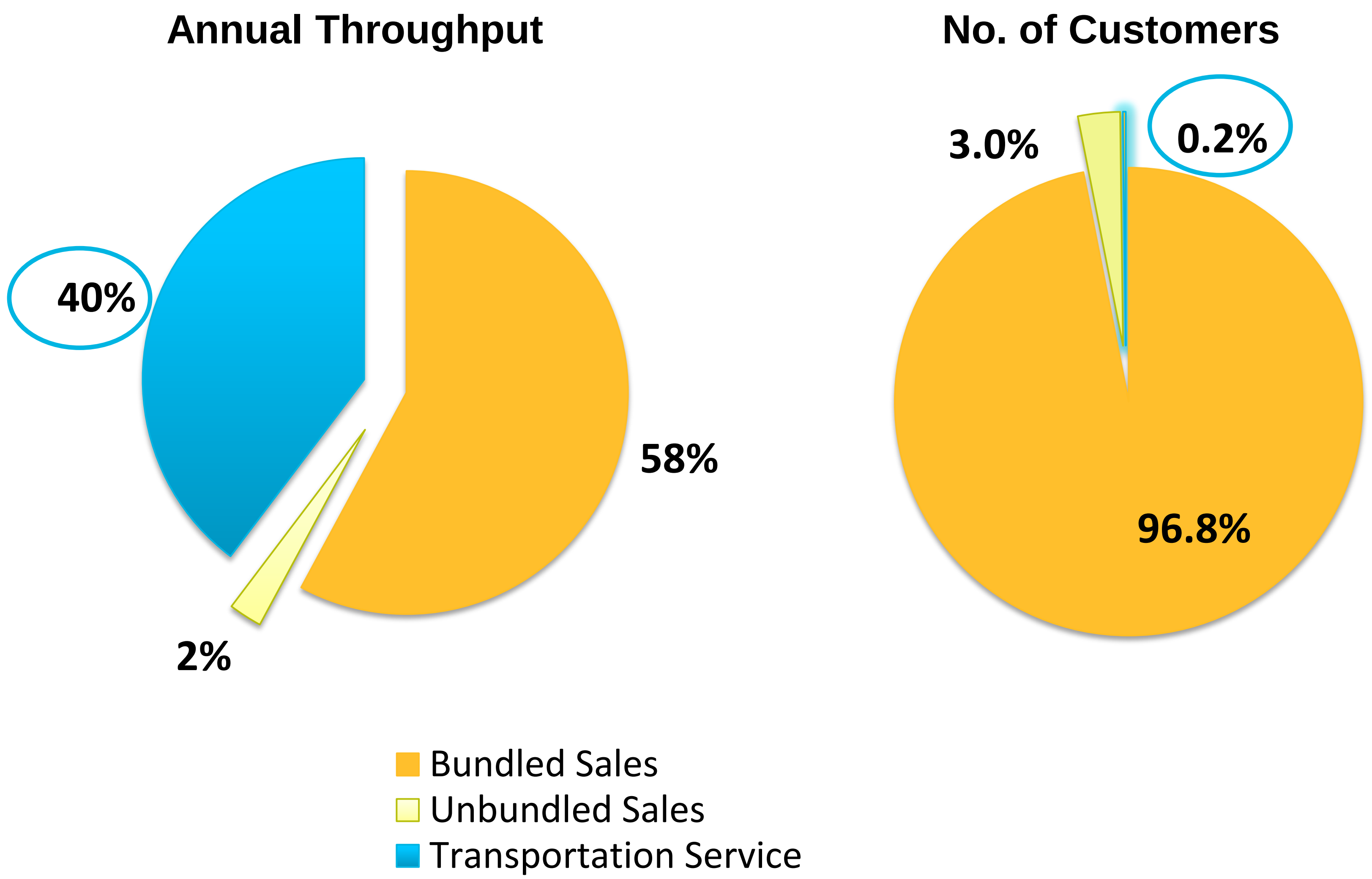


Services within Transportation Model

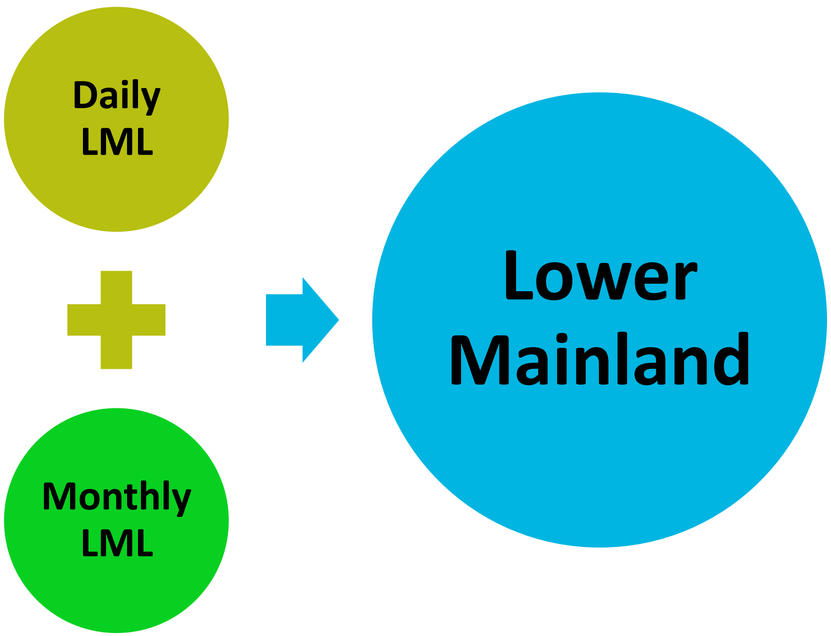
Transportation Model

- System Throughput
- Customer Pooling
- Imbalance Return
- Balancing Tolerance and System Inventory
- Charges as defined in the FEI Transportation Rate Schedules

FEI System Throughput & Customers



Customer Pooling



- Marketers may pool their customers in daily and monthly balanced groups at specific interconnects
- Majority of customers and load are at LML and INT interconnects
- 2,400+ customers
  - 16 Daily groups and 34 Monthly groups
  - 600 customers in Daily Balanced groups / Load ~ 40 PJ/year in 2015
  - 1,865 customers in Monthly Balanced groups / Load ~ 33 PJ/year

Imbalance Return

Imbalance Return – Lower Mainland and Interior

Tool for daily balanced groups only

FEI adjusts as needed

Balancing Tolerance and System Inventory

DAILY Balanced Groups

20% Tolerance

MONTHLY Balanced Groups

No Requirement

FEI can reduce the balancing tolerance to 5%

System Inventory Levels

Charges – Transportation Rate Schedules

- Backstopping and replacement gas
- Daily balancing gas and balancing premium charges
- Monthly balancing gas
- Unauthorized Overrun (under and over 5%)
- Demand Surcharge

Part II

KEY DISCUSSION TOPICS

Topic #1 – Monthly vs Daily Balancing

Monthly vs Daily Balancing

FEI recommends all customers to be daily balanced

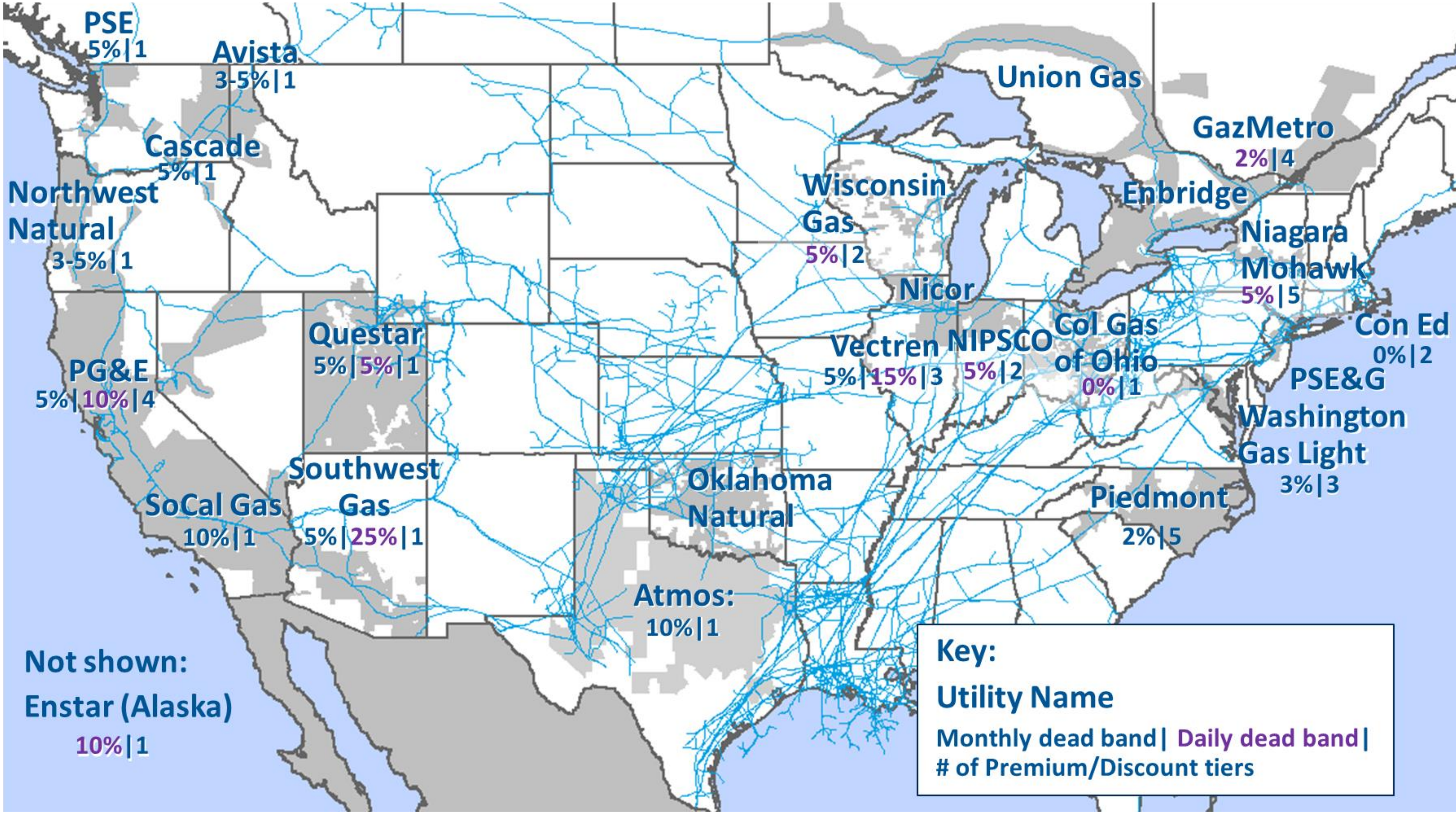
Marketers have tools available to manage fluctuation in demand in the day

Marketers with daily balanced groups currently effectively balance

FEI balances the total system daily at major interconnects

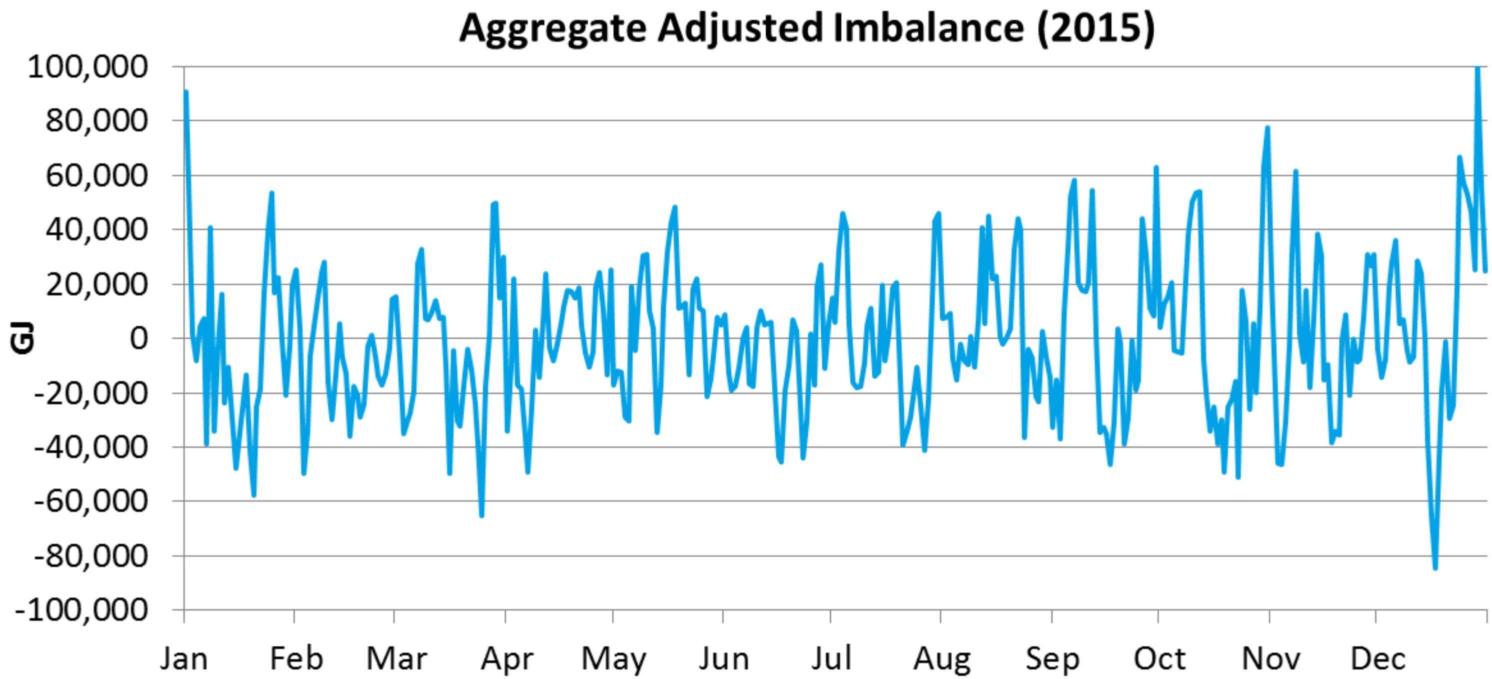
Topic #2 – Balancing Tolerance and Value

A Sampling of Common Industry Practices



LDC balancing provisions are a product of their position on the interstate pipeline grid and proximity to market hubs

Issues Related to Current Balancing Provisions



- Aggregate daily imbalances fluctuate widely on FEI's system due to daily under-supply by monthly balanced marketer pools and the flexible 20% balancing threshold currently allowed
- Imbalances require the utilization of resources on FEI's system (i.e., injecting or withdrawing storage gas), which are funded by sales customers
- This creates a mismatch between services received by transportation customers & the underlying resources paid for by sales customers

Assumptions used to value current Balancing Services

- A methodology was developed by Black & Veatch to calculate the estimated replacement cost of the balancing services provided by FEI

- Analysis reviewed five years of daily system balancing data; selected daily imbalance and delivered volumes for all marketers from 2015 as an indicative year

- Considered costs of contracting for storage and transportation assets at Jackson Prairie Storage, Mist Storage, and Northwest Pipeline

  - These facilities were selected because of their significant intraday nomination activity relative to other assets, indicating their importance in balancing the system

  - Max tariff rates for all of the capacity resources were used

Cost / Risk Trade-off Associated with Replacing Balancing Services

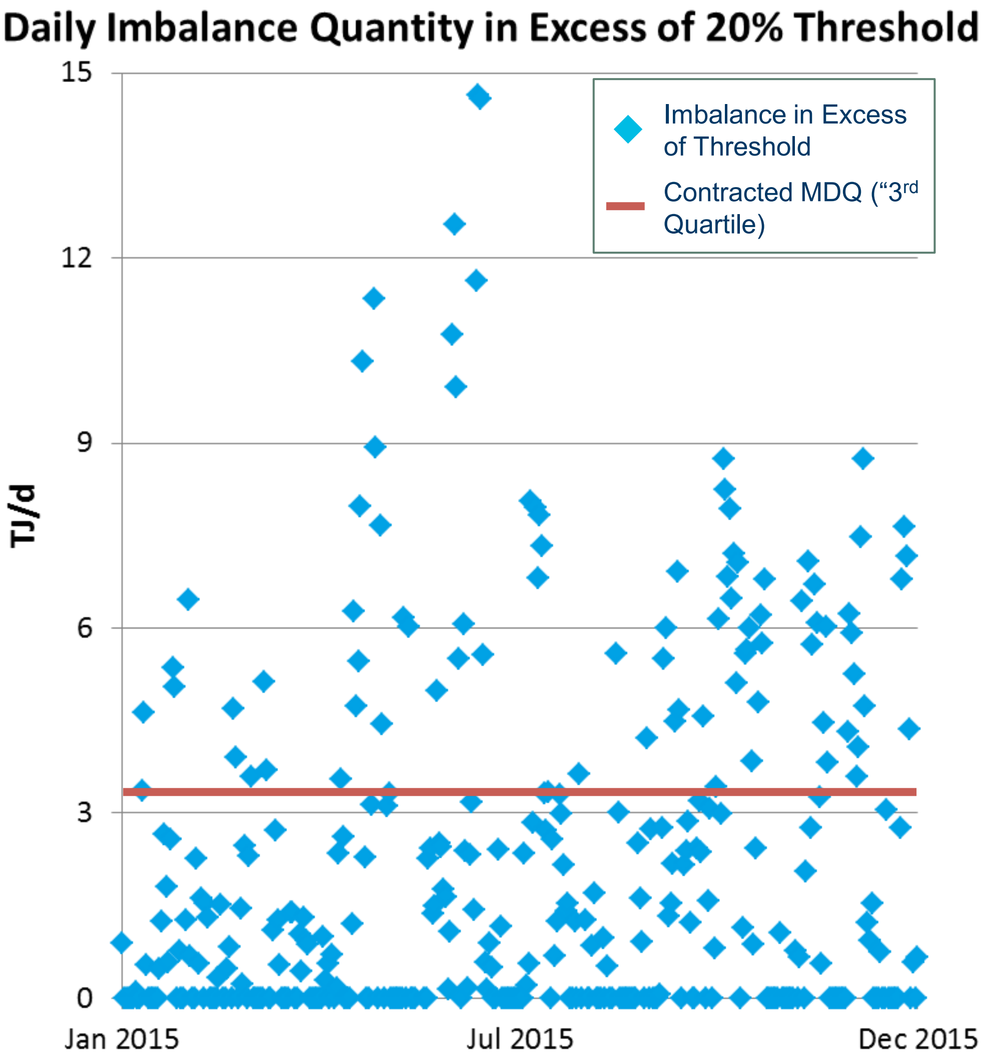


Chart depicts an individual "indicative" marketer; analysis was conducted using all marketers on the FEI system

- Analysis examined the marketer's position when considering how to address its anticipated daily imbalances with firm contracted capacity for a given year
  - Contracting for a high MDQ* would leave a marketer paying high demand charges, even on days it is not using the capacity (see blue dots below the red line)
  - Contracting for a low MDQ would leave a marketer with large volumes on which it must pay imbalance charges (see blue dots above the red line)
- Analysis is based on a "3rd quartile" approach, an assumption selected that adequately balanced firm reservation charges with the risk of incurring imbalance charges

** MDQ – Maximum Daily Quantity*

Results – Base Case

Total Charges for Volumes in Excess of Threshold (Excluding Imbalance Charges)

	Total Charges	$/GJ
5%	$15,100,000	$0.21
10%	$11,600,000	$0.16
15%	$8,600,000	$0.12
20%	$6,500,000	$0.09

Subtract

Replacement Costs Relative to a 5% Balancing Threshold

	Replacement Cost	$/GJ
10%	$3,500,000	$0.05
15%	$6,500,000	$0.09
20%	$8,600,000	$0.12

- Calculated by adding reservation & volumetric charges, then dividing by transportation customer throughput
- Lower balancing tolerances require marketers to contract for more capacity to manage imbalances, resulting in higher costs

- Calculated by taking difference between “industry median” 5% threshold result and 10%, 15%, or 20% threshold result
- Higher thresholds require more resources and more costs to replace; current replacement cost of FEI’s service is $0.12

Sensitivities

- Three sensitivity cases were performed to assess how certain key assumptions would impact the results

Replacement Cost: "Exclude Imbalance Return" Case

	$/GJ	Δ to Base Case
10%	$0.05	$0.001
15%	$0.09	$0.004
20%	$0.13	$0.015

- Under a 20% threshold, the implied value of imbalance return service is $0.015/GJ

Replacement Cost: "Include Imbalance Charges" Case

	$/GJ	Δ to Base Case
10%	$0.05	($0.002)
15%	$0.09	($0.001)
20%	$0.13	$0.009

- Based on a 3rd quartile portfolio balancing decision, there is virtually no difference when including imbalance charges

Replacement Cost: "0% Threshold" Case

	$/GJ	Δ to Base Case
5%	$0.05	$0.048
10%	$0.10	$0.048
15%	$0.14	$0.048
20%	$0.17	$0.048

- When replacement costs are assessed relative to a 0% threshold, costs increase by amount equal to the 5% threshold replacement value case

All sensitivity cases examined indicate replacement cost estimates remain within a relatively close range

Summary of Balancing Tolerance and Value

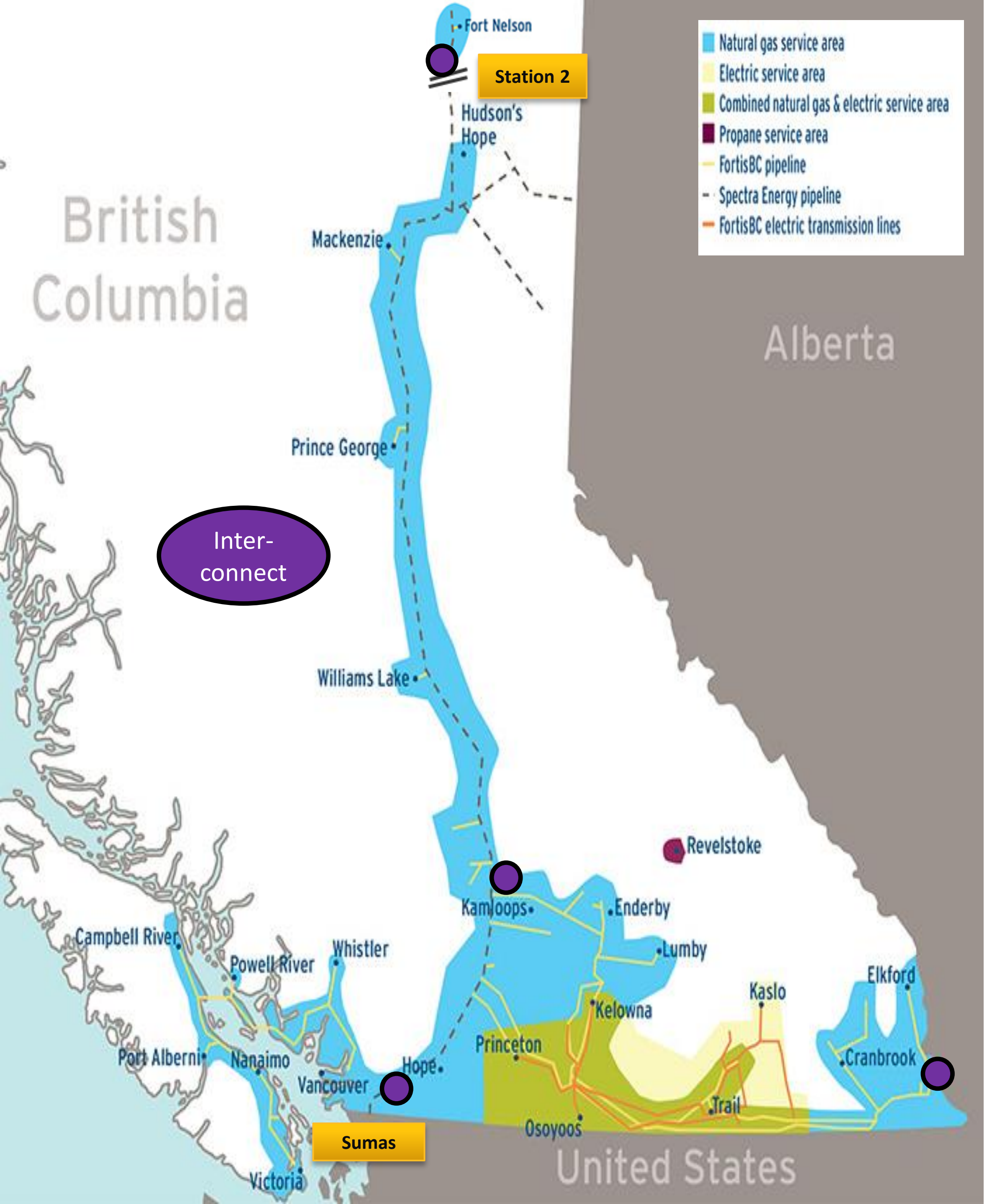
- FEI should continue to balance the system as a whole for both Sales and Transportation Customers.

- There is a value associated with the current balancing provisions and tolerances that FEI provides to its Transportation Customers
  - Different value for different balancing tolerance levels

FEI would like to consider inputs on:

1. Balancing Tolerance: 20%, 15%, 10% or 5%?
2. Appropriate Balancing Charges for different tolerance levels?
3. How should FEI account for these balancing Charges
   - Captured in R:C ratios for Transportation Customers?
   - Derive a Midstream Fee?

Topic #3 – Additional T-South Capacity



- Current T-South constraints
- FEI secured additional T-South capacity for Transportation customers
- To protect the customer and manage risk from buying at Sumas

Additional T-South Capacity

FEI received BCUC approval to contract for additional T-South capacity

FEI collaborated with marketers to allocate the capacity to transportation customers

Requests received exceeded capacity available

FEI is working with marketers to have contracts in place for the start of the 2016/17 gas year

Update on 2016/17 Gas Year

This capacity is administered through Gas EDI with marketers on behalf of their customers

Capacity uptake is fully allocated to marketers/customers

Net Benefit to Midstream costs (IT rate vs Toll)

- Could change year to year based on uptake of capacity

Additional T-South capacity: Options to Manage

<u>OPTION A</u>

Managed in Midstream Group under RS30

<u>OPTION B</u>

Included in Transportation Rate Schedules

Considerations for these options

	Option A	**Option B**
Cost Recovery *(Impact to Midstream)*	√	√
Long term commitment		√
Transparency		√
Administration Flexibility	√	

Other Discussion Topics

Part III

CLOSING REMARKS & NEXT STEPS

Next Steps

Documentation & Communication

- FEI distributed key issues list and meeting notes for Workshop 1 (FEI COSA and Fort Nelson Service Area)
- FEI will distribute key issues list and post notes from today's workshop by Aug 26
- Website: www.fortisbc.com/ratedesign

Customer Research

- Customer survey for FEI & Fort Nelson Residential Customers

Workshop 3 – Rate Design & Segmentation

- Rate Design and Segmentation Workshop is scheduled for Aug 31
- FEI will distribute the discussion guide for Rate Design & Segmentation Workshop two weeks in advance

For further information, please contact:

Gas.Regulatory.Affairs@fortisbc.com

www.fortisbc.com/ratedesign

Find FortisBC at:

Fortisbc.com

604-576-7000

Transportation Review Workshop August 12, 2016
Summary

Meeting:	Transportation Review Workshop
Date:	August 12, 2016
Time:	9 am to 3:30 pm
Location:	Best Western Plus Chateau Granville – 1100 Granville St, Vancouver
Facilitator:	Atul Toky, FEI
Participants:	Suzanne Sue (BCUC), Lejla Uzicanin (BCUC), Cathy Marr (BCUC), Doug Chong (BCUC), Errol South (BCUC), Chris Weafer (CEC), David Craig (CEC), Janet Rhodes (CEC), Kirby Morrow (Absolute Energy), Susan Juilfs (Absolute Energy), Tom Hackney (BCSEA), Bill Andrews (BCSEA), Kevin Bonin (Translink), Steve Connelly (Cascadia Energy), Tannis Braithwaite (BCOAPO), James Langley (Sentinel Energy), David Bursey (Industrial Customers), Tom Dixon (Access Gas), Rachel Roy (MoveUP), Susanna Quail (MoveUP), Sharon Singh (Bennett Jones)
FEI Attendees:	Christopher Bystrom, Michelle Carman, Colleen Gravel, Shawn Hill, Song Hill, Kevin Hodgins, Brenden Hunter, Janice Joly, Mary Lang, Ed Moore, Brian Noel, Rohit Pala, Stephanie Salbach, Gail Tabone, Atul Toky, Sean Willoughby (B&V), Ron Amen (B&V), Ron Sanderson (Contractor)
Material Provided	Presentation attached following notes.
Agenda:	***Agenda:*** 1. Part I: Discussion Guide • Welcome and Introduction • Services Overview and Background • Services within the Transportation Model 2. Part II: Key Discussion Topics • Monthly vs Daily Balancing • Balancing Tolerance and Value • T-South Capacity • Other Discussion Topics 3. Part III: Next Steps • Closing Remarks & Next Steps • Compile Key Issues List

Meeting Summary and Notes

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
Discussion Guide - Summary of Questions/Comments		
Slide 2	1. Discussions are piece meal and there may be an opportunity to influence what you put in the application. Are you going to change your application, or is this just notice of what you are going to put in your application? 2. You refer to the B&V study but you don't give us the B&V study. We leave with information and more questions. Concern is missing opportunity – how we consolidate the workshops to get to shaping of the application and issues.	1. This is all about understanding the key issues related to the rate design application. We have identified key discussion topics for today's workshop and are open to other discussion topics or issues you may have. These key issues will help focus the scope of the RDA. We will work towards addressing those key issues at the time when we file the application. 2. We will go over B&V's methodology today, which is also included in the discussion guide. B&V is still working to complete its final study and report. This is the first step i.e. going through the methodology and approach that B&V has used to value FEI's balancing provisions. We thought that the process we had last time in Workshop 1 was informative and got us through the key items that all of us would like to focus in the RDA. The purpose of these Stakeholders Workshops is to inform, collaborate in understanding and compiling key issues list. We will address most of the questions as we go in these workshops and will make a note of the ones that couldn't be answered or would need more discussion and time to address.

Transportation Review Workshop August 12, 2016
Summary

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
Slide 11	1. Are you able to tell us what your tolerances are with Spectra? 2. Interior OBA separate? 3. We are talking about the balancing function, but is it a backstopping function by the day for the marketer using Fortis midstream assets? 4. What is the correlation between transportation and bypass customers in terms of getting the balancing service? 5. Does FortisBC have a marketing entity as well? If yes, is FEI a material player in the market? 6. How does the daily nomination process work? Fixed amount each day? 7. If transport customers provide gas at interconnecting points precisely, is Fortis needed? Trying to understand how tight the balancing is. 8. The previous slide shows a breakdown of throughput and transportation customers represent 40%. What would be the split for standard, special rate, and bypass customers? 9. Customer served off of Foothills, this discussion doesn't apply to them at all. Does Foothills require daily balancing? We don't know the rules and are just trying to understand things as marketers, to get a better understanding of these balancing provisions. We look to Fortis to apply judgment. More on the record of what is available; transparency will cut out more process.	1. We have different tolerances at different interconnects. About 20TJs at each interconnect but manage them in total on a daily basis. The key thing about our operational balancing agreement with Spectra is that we cannot rely on the ability to give or take 20TJ each day. When we are not balanced, how do we treat the difference? FEI executes resources to minimize the impact on a daily basis. The OBA is not a firm physical resource. 2. The Interior OBA is separate from the one at the Lower Mainland. While they are separate, we work with Westcoast collectively to manage our overall or collective imbalance on a day by day basis. They are separate from a tracking perspective as there is a different toll to get the gas to one point versus another. Sometimes there is more or less flexibility with the OBA, but to emphasize, it is not a firm physical resource that can be relied upon. a. If pressures on Huntingdon go into red, the OBA isn't going to help us i.e. it's not a supply source; it's a structure that allows for balancing between pipeline to pipeline on a daily basis. 3. In terms of balancing, FEI balances the system as a whole on a daily basis using core resources under the ACP. In terms of backstopping, FEI is the supplier of last resort. Similar to balancing, core resources under the ACP are used for backstopping when a shortfall occurs.

Transportation Review Workshop August 12, 2016
Summary

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
		4. Bypass customers are served through the Transportation business model. 5. Yes, FEI has Rate Schedule14. Customers can be on a transport rate schedule but choose to purchase from Fortis instead of electing a marketer. No, FEI is not a material player in the market but there is nothing restricting transportation customers to be on Rate Schedule 14. 6. Under the Customer Choice model, marketers are required to nominate and deliver a fixed amount of supply each day. The transportation model is different; marketers serving transportation customers are obligated to make supply arrangements and adjust their nomination based on what they estimate or forecast their customers to burn or consume on a daily basis. Mechanisms are available to estimate the amount of supply required. The marketer should know what the customer plans to burn. Marketers nominate daily for both daily and monthly balanced groups. Monthly balanced groups must be balanced at the end of the month. The Industry is moving to daily balancing. 7. If transport customers delivered exactly or precisely their daily volume requirement, then there would be no

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
		need for Fortis to balance. Given supply from both transport and FEI serving core will never be perfectly matched, FEI balances the system collectively and will do what is required to keep the system in order and balanced. 8. FEI will provide the breakdown of the 40%. 9. FEI's system interconnects with three pipelines - Northwest Pipeline, Spectra and TransCanada - and therefore FEI is bound by the different rules of those pipelines behind those interconnects. On FEI's system, our position is that rules should be similar across the province so that rules and guidelines are easier to administer. Foothills has a monthly balancing tolerance, however nomination changes occur throughout the day and operationally shippers are required to trend to zero on a daily basis. FEI believes that as long as we develop the rules that everyone understands, there are benefits to the whole group and less risk e.g. given the challenges to secure capacity resource infrastructure, can those resources be funded. It's just a matter of knowing what the rules are so we can account for the dollars needed. FEI recognizes that different interconnects are a concern. We have to reflect some of these comments in our application as

Transportation Review Workshop August 12, 2016
Summary

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		well. This discussion today, once we hear all the issues, maybe we can come back to say we've heard the points, here's our position to reflect Mary's (McCordic) position, here's what we did to accommodate it. We are trying to point out issues to people.
Slide 17	1. How the decision is made, who's in the daily and monthly balancing group? 2. What is Fortis' reason for requiring Rate 22s to be daily balanced? 3. 20% tolerance, handout pg. 8, less than 20% of consumption. Please clarify. 4. Restriction of 5% is when you curtail groups? How often does the 5% restriction happen? Maybe a couple of days? When you do the statistics it would be helpful to show us not just last year but last 5 years, how many times you've curtailed/restricted flows to the daily balancing customers – that will inform us what the daily and monthly balancing means on your system? 5. Alluding to being able to restrict the daily groups. How many days FEI restrict daily balanced groups, when monthly balanced groups were not restricted?	1. The marketer can pool their customers in either daily or monthly balanced groups at their discretion at the major receipt points on our system. Rate Schedule 22 customers however must be managed in a daily balanced group. The rest of the rate schedules, 23, 25, and 27 are not required to be daily balanced but can be monthly balanced. 2. Rate Schedule 22 customers are typically large volume burners and are more volatile. Based on this Fortis requires them to be managed on a daily basis. Other customers may have heat sensitive load characteristics or have a more consistent daily load so those customers tend to be pooled in a monthly balanced group. 3. The handout should be clarified to read: If under-deliveries exceed the 20% tolerance or allowance, charges will apply. 4. When a restriction of 5% is imposed, all groups must bring on enough supply to meet demand or unauthorized overrun charges will apply. The frequency of this restriction varies. We haven't imposed a supply restriction over the past few years. Last December

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		(2015), we thought we may need to impose a restriction. We put a notice out, but then retracted it. FEI can probably get statistics for 5-10 years subject to the availability of data. FEI needs to follow up. 5. On normal days, daily groups are held to a 20% tolerance whereas monthly balanced groups are not held to any tolerances. When a supply restriction is imposed and the balancing tolerance is reduced to 5%, all groups both daily and monthly balanced must adhere to this tolerance. In normal operating conditions, FEI has resources in place under the ACP to help balance the system as a whole. The resources are in place to provide flexibility to serve core customers under rate schedules 1-7. Transportation customers also benefit from these resources as FEI balances the system as a whole.

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KEY DISCUSSION TOPICS - SUMMARY OF QUESTIONS/COMMENTS		
Slide 21	(Kirby Morrow)We are one of the marketers that at one point had both monthly and daily balancing. We now hold a daily balanced group at the Lower Mainland and Interior locations. Loads are highly volatile so makes sense to move into the daily balancing. Smaller marketers may want monthly balancing. Seems there is some arbitrage. Our position is that we are happy with daily balancing. 1. Is FEI going to look at costs and benefits for the two groups/quantitatively as we are concerned about evaluating rate payers and rate payer groups? This is something we'd like to see in the application. FEI looked at three options. 1st is status quo, but there has been some decisions already issued with reliance with resources. 2nd option is tweak the monthly balancing and just change the terms and conditions. 3rd option is what you propose. This purpose of this consultation is for the utility to hear from the marketers. From the affected marketers, would be nice to know if they are in favour or oppose. They can let the utility know and the utility can address that in the application. Should focus on rate payers first. The commission issued a decision on the balancing charges, and it is consistent with what has been presented. That resource is a core resource that is at times may be used by the transport customers. Let's hear the rest of the feedback in the room. Kirby ok, Mary ok. Tom Dixon – we'd like to see it stay as it is, although we know it likely it's not going to stay that way,	1. At this point we are moving toward daily balancing from a principle perspective. We would have to do some work to evaluate both options and account for that in the overall rate design. The tools are in place to manage on a daily basis. Industry standard is daily basis. a. We went through this with the Commission in 2014. At that time, we proposed to make a change to the monthly balancing charge. We had a lengthy record on that one. We can do more analysis, but how efficient and how much work do we want to do vs adopting industry practice. Our justification wouldn't be numbers based; it would be a fairness issue. At a principle based level, the tools are in place and it is accepted industry practice, so why spend money and time investigating that. If marketers want the monthly balancing option, we have to look at it. If we move exclusively to daily, it's one less thing we have to examine.. 2. Everyone has a different perspective on how they do business. If there is a monthly balanced group, sure there is arbitrage going on. Our position regarding the potential for arbitrage was indicated in the 2014 balancing gas application. In this application our position is to go to daily balancing to eliminate the need to figure out all those arbitrage opportunities and how to value

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	but we have no problem with daily balancing if our customers are going to have to pay for that service. Asking to allocate a cost to using the monthly balancing. If that's the case, daily balancing works. Kirby Morrow – we were never extracting value out of our customers in the monthly balancing group – it's advantageous to have daily balancing. Tom Dixon – just to be clear, we'd prefer it to stay the same. 2. Regarding arbitrage – is there arbitrage going on? There's no new evidence of it, but it's a reality There were also far fewer large customers so less arbitrage to worry about. 3. Does FEI fit the description of a local distribution company? 4. If the industry norm is to not have monthly balancing, for those that do have it, why is that? Do they perceive a benefit? Is there a historical aspect? 5. If monthly were to be done away with on a principle basis why would FEI keep monthly? 6. Your position is that it should be daily only. Other utilities have monthly. Allowing for the fact that they have different connections and tolls, isn't it reasonable to ask what is it about their circumstances that warrant having monthly?	that. The industry has moved forward since the monthly balancing provisions were originally introduced. 3. FortisBC Energy Inc. is a local distribution company. 4. For those that have monthly balancing it is related to fundamentals of the infrastructure the LDC is connected to. Different LDCs have different tariffs and different physical resource connections. There are lots of different ways to do things. It's about how to account for those things in your rate design. It's not that daily or monthly balancing is wrong. It's that there is a cost associated with it. 5. Most of the LDCs in the western part of the US including NWN, California Utilities, Questar, Soutwest Gas, they have their own underground storage resources, so they have affiliates that can handle the balancing through their underground storage resources for third parties and large transportation customers. Northwest Pipeline has liberal pipeline balancing provisions, large underground storage of their own, so the LDCs are served off of those pipelines, can therefore have more liberal balancing provisions of their own. Their transportation customers pay a fee on all the volume they move, for monthly balancing. They have no daily restrictions, but they do balance monthly and pay a balancing charge for every volume of gas transported.

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	More liberal balancing options have greater storage – whereas Fortis doesn't have storage within their distribution system and have to rely on nominating. 7. Are there any marketers on FEI's pipeline that have underground storage? 8. For utilities that own their own storage do they recover the cost of that utility margin from transportation services? Access Gas operates on monthly balancing; still doing a manual nomination, we don't get data from our customers. Whereas certain pipes don't provide us any burn data. So we are providing service on an estimate. Technology has eliminated the need for monthly balancing. 9. Does Fortis have any tolerances from Westcoast? A lot of utilities are moving to zero tolerances anyway. Steve Connelly – no issue with the concept of daily balancing. So the purpose of doing an evaluation is to see if the customer has to pay. 10. Is FEI planning to do further investigation? It's an appropriate question to ask to do the valuation.	6. We don't know if marketers with other utilities hold underground storage resources, where capacity is so constrained, they are held to strict balancing. 7. We are not aware of any marketers holding underground storage connected to FEI's system. 8. Some utilities recover the cost through their cost of service allocation methodologies; it's embedded in the rates, otherwise their delivery service rates. 9. Our tolerance with Westcoast is to trend to zero every day. We do our best to match our demand, but there are no charges for that. WEI doesn't provide a balancing service. 10. At times the interstate pipelines account for costs embedded in their tariff, whether daily or monthly its accounted for somewhere. We propose eliminating the monthly. If we still wanted to have the monthly balancing service, we'd have to account for it in the rate design. FEI's approach to daily balancing is a principle based evaluation, but it can also be supported by numbers if there a value attached to it. We can use some of the evidence from the previous proceeding if it makes sense to stay with

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		monthly balancing. The more we can talk through these issues and focus the scope of the RDA the better. We also want to do a valuation for the daily balancing services.
Slide 23	1. In your report do you summarize those factors?	1. We do give some examples. One of the things we noticed that occurred some time ago in the Mid-West during an extended cold snap had a tremendous impact the Chicago hub. Delivering under those conditions, marketers were delivering to those LDCs with the lowest penalties. This resulted in utilities adjusting their penalties and then that began the implementation of various balancing options.
Slide 25	1. Is Aitken Creek relevant to their balancing activities? 2. Imbalances are all year, so there are times when T-South is open. So Aitken Creek would be valid. 3. Max Tariff Rates – does that cause a bias toward the high end of the evaluation for capacity? Is there a max rate in the tariff? 4. So if we didn't have balancing service, the assumption is that we as marketers would have to contract for Jackson Prairie and MIST?	1. In the ACP, the Aitken Creek resource is in place to serve our core load and does help to balance the system under different conditions. In the analysis provided by Black & Veatch, we chose to use one or two assets and price that out for balancing. The assets chosen are the only physical assets you can access at the Interconnect on a 365 day basis. In the winter, T-South could be full, so the only assets in this analysis that we could price as part of this service are assets that we can access all the time which is JPS and Mist 2. I agree but there are different ways to look at this analysis. All of those assets are firm fixed costs. So whether we use it or not, we are paying for it as part of the ACP, they are there for design peak day. The balancing is using non-peak day to help provide an auxiliary service.

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		3. No, we don't think that causes a bias toward the high end of the valuation for capacity. One has to assume that any person trying to contract would be paying a maximum rate. For example, for Northwest Pipeline there is no capacity, so it would go for full/maximum toll (no discount) or negotiated rates. 4. Yes, you would have to choose some level of resource that you would contract on your own to deal with the cost/risk trade off to meet the demand of your transportation customers. JPS and MIST have posted tariff rates, and helps with transparency. Provisions in the FERC regulations, if there is an increase in capacity through increasing pressure or building more pipe, the rates would be on an incremental basis as opposed to rolled in to existing shippers.
Slide 26	1. Can you explain what each point represents, daily? 2. So is that a problem only on the coldest day? Is there offsetting? 3. Explain more about the red line. If a marketer has a tight tolerance, what would happen to the red line? 4. This is an illustrative example, not a real alternative for a transport customer? 5. What is the 75%, number of days or absolute value of	1. Each point represents a daily imbalance for each day of the year. So on a daily basis, there is an imbalance on what they nominated. B&V took an average, and there is a lot of diversity on burn vs supply. If transportation customers were to balance this on their own, resources would be required to balance each of those days. 2. Imbalances exist on normal days and colder days as well. 3. The red line represents 75% of their balancing resource needs. If they had a lower risk tolerance, would

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	the size of the imbalance? 6. Have you done an analysis on the daily balanced groups? We just had a discussion about eliminating the monthly balancing, wouldn't it make sense to analyse the daily balancing? So the tolerances would be tighter, so if you eliminate monthly balancing, this data is moot. If FEI is trying to get to zero tolerances, marketers would have to decide how much risk to take. Because there is currently access to monthly balancing, they can access balancing services up to 20%, no cost to marketer. If no monthly balancing, marketers would have an incentive. 7. Is monthly balancing of significant portion? 8. Sales customers are doing the same thing. Presumably the transport customers are helping out the sales customers and vice versa. Is this net of the sales customers? Or transport in isolation? If you didn't have transport customers at all, the sales customers can't leave it imbalanced. The transport customers are benefiting but you don't leave the assets. We are using it, but talking about charges to customers on your system. You're borrowing the assets but there is no fee for them. The underlying physical demand charges are paid by the core. If you didn't have the balancing service, where would you get the gas from?	contract for more firm capacity to mitigate potential for imbalance charges. You can run the risk of not contracting for firm resources, but then you risk not having the capacity available. If their risk tolerance was lower, they would contract for more firm resources such as underground storage and pipeline capacity together year round. The red line is an assumption that represents adequate balance of the marketer's tolerance for risk. If no tolerance for risk, the red line would move to 12 TJ/day. B&V used an assumption of an adequate balance for risk tolerance and that is 75% on a daily basis. We made an assumption based on the imbalances that the marketers would hold above the 20% balancing threshold. That assumption was the marketers would hold enough capacity to meet their imbalances in excess of the threshold on 75% of days out of the year. 4. This is a typical chart, focused on the larger marketers. 5. The 75% represents the number of days. B&V is assuming they are covering off a fixed number of days. You could put the red line up to the top and that would drive your costs up. We are trying to understand the value that is being provided by Fortis by a replacement cost point of view of the value. 6. Looking at daily balancing exclusively is another angle. 7. Monthly balancing customers represented 77% or 1865

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	Westcoast has no penalties on daily balancing. FEI contracts for assets for the core market and they pay for them. The transport customers get use of them when FEI can afford. When FEI can't afford it, the transport customers don't get it. The point is to use the valuation for how you use the assets. 9. Jim is asking while evaluating the methodology, we should consider the offsetting effect between transportation customers and core customers. And look at the benefit that transportation offer core customers. 10. This example is based on firm service, but that's not how the system is used. 11. So you have a right to call on the service. 12. The idea of being able to balance to zero is unrealistic. Necessary that there is balancing. 13. Where Fortis holds fixed resources that are not used, they are mitigating such that the benefit goes back to core customers. 14. One of the concepts to value is if Fortis wasn't supplying any of this daily balancing service, the transportation customers would need resources to manage it themselves. Then on the other side, Fortis contracts the resources to serve the core customers, and has a suite of	of the total transport customers and approximately 33PJ of load per year. There are about 600 daily balanced customers which account for approximately 40PJ of load per year. 8. The analysis is transport in isolation. Sales customers are already paying 100% of the costs. 9. We have taken into account the transportation customers imbalances, can't rely on how those transport customers would offset the imbalances, however we may attempt to evaluate that service. There is value in transportation customer having access to balancing service that the residential customers have, but not on peak days 10. If you are interruptible, then you do not have a firm right to the service. 11. Yes, we have a right to reduce the service to 5% when deemed necessary. 12. We can't count on what marketers are doing on a daily basis vs what the core customers do. The monthly balanced customers tend to trend differently than the daily balanced customers. There are three different kinds of behavior groups (daily, monthly, and daily with some monthly). Fortis balances all groups. Our position is that everyone in the room understands the tradeoffs.

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	resources to supply those resources.	This is B&V's attempt to try to value that balancing threshold. The revenue stream is in the midstream bucket. There is line pack but it's very small. 13. Those costs and mitigation options are going back to rate schedules 1-7 customers. We are saying there could be another revenue stream flowing into that midstream rate. We tried to evaluate the potential cost to acquire those resources on their own. So some may be able to handle that risk on their own. It doesn't change the fact that there is value to customers today using those mitigation services included in the midstream rate. To clarify that mitigation charges that Fortis incurs are fixed costs. 14. We need the underlying fixed assets. The contracted assets from the ACP are there whether you use it or not. If you didn't have a balancing provision, how would you provide gas? You need a physical resource. The point is the ACP has the physical resources to provide this service. There are two issues: firm and interruptible. We balance our system as a whole every day. Interruptions are very limited. Most of the days we balance for those customers as well. Then this idea of where the red line should be. This is an assumption to evaluate. Tolerance levels on colder days still have a value attached. But most of the days, our customers are allowed to

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<tr><td></td><td></td><td>have a 20% tolerance level. Even under cold weather days or operating restrictions they have 5% tolerance levels. What is the value proposition for those different tolerance levels (how many days in a year am I getting the 20% tolerance level). That's why the floor is the 5% threshold when calculating value. We don't assume the floor is 0%.</td></tr>
<tr><td>Slide 27</td><td>1. Is there another way of looking at it, your lost revenue?

2. The term "charges", these are notional charges from whom to whom?

3. So these are notional costs for transportation customers if they had acquired MIST resources to handle balancing on their own. This is one valuation at 75%. Relative magnitude of 10% in the table on the right hand side?

4. If you reduce the balancing window to 10%, you would change all transport customer $0.05, if over 10%, still paying.

Based on the fact that there are monthly balancing groups today. The greatest volatility is in those monthly balanced groups.

5. If you eliminated the red bar, the monthly balancing comes down? Regarding slide 26, if we are held to a 20% tolerance, wouldn't it all be zero?</td><td>The narrower (lower) the tolerance level, the less valuable the service is because the customers have to secure services on their own. We are not proposing that transport customers go out and contract their own services; we just need to use a way of valuing it.

1. Most of our mitigation efforts are around pipeline capacity, we haven't factored it into the replacement cost calculation.

2. Transportation customers would be paying the charges, calculated by using fixed reservation charges and dividing by throughput. Firm transport and commodity charges would be paid to the storage and pipelines (Mist, JPS, and NWP). The imbalance charges would be paid to FEI.

3. The current Midstream rate of about $0.92/GJ already has mitigation embedded in it. With no mitigation, it's around $1.25/GJ. We are saying is there another revenue stream. This is our starting point as a way of looking at it.</td></tr>
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	Fortis is using a bunch of assumptions for how a marketer would behave, because there is no other way to create a valuation. There is no precise method. 6. I understand Fortis' argument, I suggest you are looking at one element of the transportation customers and need to look at all of the elements.	4. If you tighten the tolerance, the marketer has to go out and manages this and have costs associated with balancing. 5. The previous chart on slide 26 is based on having 20% (so that's zero). This is rate design. Our starting point is to move to daily balancing. On this one, we've operated on a 20% tolerance. We can leave that as is, we just need to be able to value it. The tighter the tolerance, the less gaming influences we have to worry about. What's the number we are going to start with for tolerances? If we are debating the tolerance level, the value goes to different permutations. 6. We have a placeholder to discuss that, let's move on and come back to this after lunch.
Slide 28	1. What is the order of magnitude for a customer what would be the impact on an end-use customer?	1. It's 73PJ as a whole. Based on 22,000GJ per year, impact would $2640 (22,000x$0.12)
Slide 28/29	Values perceived to be too costly, could cause them (marketers) to say, we'll look for other options. One depends on the other. It depends on marketers costs. What's being proposed is a cost allocation implementation of this value. 1. On slide 27, talking cost allocation, not charge. On slide 27 – bottom, should it be a charge or cost allocation, but	We do agree there is a value. We agree as a group that the methodologies are used to value that balancing service. 1. Slide 27 shows a possible valuation based on the methodology we used, table on the right shows the value. Question to the whole group – the table on the right shows the

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	the point is that assuming FEI should continue to balance is the wrong assumption. Depends on Transportation Customers' choices for their balancing options. 2. Should Fortis continue to balance the system – my view is it should. Is that a genuine question? Is there any way Fortis would not? Question should be should it continue to balance for transportation customers? So those options exist and they can't answer the question, should Fortis continue to balance the whole system, but they can't test that until they go see if they can contract on their own. Transportation doesn't have the same peaks. Balancing together is a good idea. Still some different approaches, pulling out the monthly balancing, what does that look like? What will you do with the revenue-cost ratio? On principle it makes sense (efficiency and economy). Fortis already has to balance the system for core customers. 3. Assuming we agree on the value, what would happen to bypass customers? Would they get free balancing? 4. If Fortis dropped the bandwidth to 10%, would you be willing to charge $0.05 in order to move to a 10% window? 5. Should Fortis continue to balance the system, if the answer was zero, is that equivalent to a balancing	value using the methodology that we used. Do we believe that FEI should not continue to balance the system as a whole for both transportation and sales customers? Is that a big enough number that transport customers will say, don't balance – I'll do it on my own. 2. Rules with Westcoast are they only provide OBAs with interconnections so the individual marketers cannot balance with Westcoast on their own. It's not an option. The amount of resources a marketer may be willing to secure on behalf of their customers is tied to the tolerance level. They can go secure the underlying infrastructure they need to meet their customers' needs. 3. Bypass customers are still tied to balancing. That's just their delivery rate. 4. I'm not sure. We have to figure out what the appropriate bandwidth is. 5. Close to zero, yes. 6. Foothills is balanced directly off pipeline, so Fortis has opted (very few assets to serve off of that pipeline), so the supplier has to manage it. It's on Fortis' system but Foothills notifies if there is a problem. 7. If we had to balance the tolerance, it would be 1TJ

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	tolerance of zero? 6. Is this what is happening on Foothills? They are not balancing? 7. Your question should Fortis continue to balance is a moot question. Until they can get an imbalance on the Westcoast system, you can't do it. 8. Balancing tolerance, if the valuation of the tolerance, it makes no difference if you decrease the tolerance and increase the cost or vice versa. Fair to say that some customers have a better ability than others to manage their load. Does that lead to a question, should there be a single tolerance? Would there be a way to sort it out so there are not a lot of IT costs. We've heard the 20% tolerance is out of sync with industry standard. Three options, split the difference and say 10%, with some valuation, would the marketers like it, which ones would say 15%, 5%? There are great differences between other jurisdictions. The answer to 1 depends on the answer to 2. For 3, midstream fee may get adjusted more often. 9. Did B&V collect info on other jurisdictions on how they deal with costs? 10. Bigger question on the need to change the tolerance level.	8. This is an option but has to be traded off with having the IT system to manage this on a real time basis and this has costs. Further, we are the supplier of last resort. If we went to a model where marketers were balancing their own, we would still need resources to balance in case you didn't provide enough supply on the day. Another challenge on the bypass customers on how we deal with them. 9. We have available charges that are published. How to get to underlying costs related to those charges is harder. Cost of Service Studies are not available unless you were part of the proceeding. Resources may be embedded in their distribution system. The capacity costs are within their transmission and distribution system, or like Fortis, acquiring the resources from third parties. Other than the examples whereby you go to third party providers and estimate the cost, it's different when using resources embedded in their system. It is a Cost allocation exercise, there's no charge that's visible. 10. The tolerance would apply to a pool of customers, and currently it's 20% on those customers as a whole. The company isn't stuck on any, but would like to tighten the tolerances, but then it gets to valuation. 11. Our measurement system is as it is. We've made improvements. In the past a good deal of sites were

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	11. Is Fortis prepared to give us better burn data? We get burn data that is a few days old from Fortis, verses live data? 12. Daily metering does exist. Would be worth looking at. I understand where you're going and why, I just think you're looking at this in isolation as one of the factors. I'm not convinced at this point you should change anything. So option 4 would be not to change anything.	without meters and were manually read. All sites are now metered daily and some marketers have access to our hourly SCADA system. You have the historical consumption of your customers to predict what they will burn going forward. We don't have the ability to give you data in real time. 12. We will take this under consideration. To summarize. We need to settle on a methodology.
Slide 31	1. Concern that transportation customers might not step up for capacity. Did the transportation customers ask Fortis to help them or did you just step in to help? Question about how much to contract. Fortis has provided the information to the BCUC. 2. So Fortis just assumed and jumped in to protect them. Were there costs incurred? Did you fully recover the$9.86? We did have a stakeholder meeting last November where we discussed the transportation model. I remember being in the meeting and recommending that Fortis should be moving on it. 3. In GT&C, a Rate 23 customer could come back to the utility as a rate 3 customer. We have the ability to not	1. We proactively managed the T-South capacity and did the analysis around that. It was not a clear cut scenario. We looked at total throughput for transport customers as a whole and came up with a number we thought was reasonable we could secure on behalf of them. 2. At the time it was an open bid process. We believed that many of them could not underwrite to secure their capacity. There was a period where capacity went from unsecured and secured. We had to make it confidential because it was submitted before we made the bid to Westcoast. It's in the Midstream rates 1-7 sales customers. Since we secured that capacity in open season Nov 1, firm toll then we mitigate that on the open market and in the end net no cost for the 2015-16 year. No net impact to the midstream, now working with many parties in the room here on behalf of their customers. The cost is at the toll. Recovery is at the IT

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	accept those customers coming back and charge them an additional rate. Multiple reasons why we did this, trying to protect the customer. If you hadn't done that, who would be impacted? 4. Is this a rate design question; is this a service in the rate design? 5. To what extent is this for sales customers? If you had called it wrong and taken on this extra capacity you didn't need for 20 years, this is a cost we would all incur? 6. Since Fortis unbundles essential services model, it's the first time the utility has bought assets not deemed necessary for the core. 7. In the rate design would you look at whether this is something you want to see continued to be contracted?	rate, net benefit for the 2016/17 year. 3. We wouldn't have any service to offer to marketers who represent those customers and it would be a Sumas based price. This is a bit of a hybrid model between transport customers and core customers. We would hope that starting Nov1, 2016, that those benefits start to flow through to those customers they represent. 4. When we started this, we had to move on this capacity. We've secured this capacity, now we need to know how to run with this. We secured 20 year capacity - underlying bid. In overall portfolio we've secured some firm capacity but also have some that we can roll out on a year by year basis. 5. If capacity was unutilized, then we would mitigate it. It's a one year cost assuming we couldn't mitigate any of it back. We might need more capacity for Rate 1-7 customers over time. You can't step in and out of assets just because your load dropped this year. Always long for short for resources. 6. This is the first time yes. 7. For 16/17 the net benefit is positive. Interruptible rate to Westcoast is a net benefit to them. From our perspective, the question is how should it be offered on a long term basis rather than on just a yearly basis.

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Slide 34	Options to Manage T-south Capacity: 1. How is overall capacity determined every year? Set amount or change? Is it assumed that the pricing is as it is here? It might not even be the IT rate. 2. We'd like to provide as much long term commitment as possible to make Option A look better. In terms of long term commitment, why a check mark on B but not A? We would put that in front of our customers and encourage them to take it. 3. Option B seems like it is going back to rebundling sales, Fortis getting back into the business of transportation. The argument was always that you had to unbundled, then rebundled in a way that was more customized. 4. Does Fortis plan to offer this to Interior based customers? Should they be creating different rates? They went generic postage stamp rates and now wanting to split it up? 5. If we could pick up T-South on long haul we would do that but it is currently not available. 6. Is there a difference between the 2 options that one would be more firm? Option B would be where you design the tariff differently.	1. We secured a certain amount of capacity for it. Subject of how much capacity is being secured here. Would have to make a decision to take away from this service. Pricing is another factor yes. 2. If handled in Midstream the uptake could vary year by year creating uncertainty. We didn't envision you (Marketers) would step forward with an addendum to lock in for 5 years for example. Creates more certainty for Fortis. 3. We have a Marketer in the background who is obligated to provide to the customers. If handled in the rate schedules they would be amended, whether you want to call it getting back to bundled/unbundled. 4. At present we looked at Lower Mainland, is that T-South is competing with the whole Northwest. There are other alternatives right now such as open Interior capacity. If we didn't justify to the Commission to secure capacity, we wouldn't have done it in the first place. 5. Fortis has picked it up on your behalf. 6. Either option could be considered firm. You can accomplish security in both ways. Trying to protect r1-7 long term. What's the best way to do this? In the tariff, or the customer acknowledges they pick up the capacity?

Transportation Review Workshop August 12, 2016
Summary

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
	7. What does Fortis see as an advantage for Option B? Option B is 100% load factor and can't use it in the summer. Can you market that? A lot of our smaller customers only use 10GJ/day. Does Option A or Option B change the delivery point? If in a pool, we might not be able to utilize it. Is this assigned capacity?	Either works. 7. Want the customer to know the value of it. Better under the tariff for transparency. But Kirby has brought up another option to send the customer a letter, just not engrained in the tariff. I don't think so. In both cases would put it into a pool. Capacity would be assigned for the 16/17 year.
Slide 35	Other Discussion Topics: As far as tolerances, Fortis hasn't substantiated the reasons for changing. Second point, the charges are too high. There should be other options to look at. Instead of fixed firm assets, balance Sumas day to day price and Station 2. And unless anyone has anything else, at least one item that transport brings to the sales customer. Page 9 of the Discussion Guide, Figure 3-1. 1. The $20 price at Sumas on the day price. Can you re-evaluate the $20 in this market? It raises the index price for all of us. You've said there is gas available even in winter. 2. The Demand Surcharge gets ridiculous results. Ever charged it? You don't think it's an unreasonable charge? I just know historically that it was a very high number. And it's 20 years later. It's intended to be unreasonable. 3. Will you look at peaking resources?	1. How do we get the Station 2 gas to Interior? Sumas based price that we are protecting against too. It's the lowest cost utility that runs out of gas. 2. We have never applied the Demand Surcharge. 3. Regarding peaking resources, you come up with some ideas. We'll have to look at outcomes to look at methodologies.

Transportation Review Workshop August 12, 2016
Summary

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
CLOSING REMARKS AND NEXT STEPS - SUMMARY OF QUESTIONS/COMMENTS		
Slide 36		Closing Remarks: Everyone seems to be in agreement with eliminating monthly balancing based on the principles as discussed at today's workshop. There was a question from one stakeholder on whether FEI should do financial evaluation for daily balancing versus monthly balancing. One of the marketers commented that they would like to see balancing stay as it is. However, that marketer acknowledged that they have no problem with moving to daily balancing only if their customers are going to pay for that price. Based on the response from everyone at the workshop and considering the time and cost for doing any financial evaluation between daily and monthly balancing, FEI would propose every customer to be daily balanced in its RDA. With respect to balancing tolerance and value, FEI needs to do further work and come up with alternative methodology to evaluate balancing services for different tolerance levels. The group needs to understand the value of balancing services for each tolerance levels. Two options were discussed to account for the value of FEI's balancing services (i.e. balancing value captured in revenue to cost ratios for transportation customers or a midstream fee). Both options have merits and challenges. FEI will look at both and see how best it can be addressed in the application. In Other Discussion Topics, there was a discussion on Demand Surcharge – whether it is right amount or not? FEI believes that

Transportation Review Workshop August 12, 2016
Summary

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
		the demand surcharge should remain high as the charge serves as a heavy penalty in very serious circumstances where FEI requires a customer to comply. FEI would not recommend changing the demand surcharge in its RDA. There was an argument that Transport Customers provide benefits to sales customers by providing more peaking gas during cold weather (interruptible) and if FEI has to pay for that gas what value would that be? We will consider this in our evaluation.
Slide 37	Closing Remarks and Next Steps: 1. Did Fortis agree that B&V would do the study on day prices at Sumas, too? 2. Is there an opportunity to talk about interruptible customers? Will it fit in with other workshops? Heard last workshop that interruptible customers are not charged any demand charges. I would like to see it considered and needs further discussion.	1. FEI need to take it back and think through using price at Sumas to be an alternative. Other than the methodology presented today, FEI needs to come up with some alternatives for evaluating the balancing services. When we talk about bookends, what's the best way to capture those bookends related to value of balancing services? 2. FEI in its next workshop will talk about rate design options for interruptible customers. COSA workshop showed how interruptible customers are treated in the current COSA model. Going forward what should be the appropriate rate? FEI generally received positive feedback at the workshop. There were some comments about seeing the application first and

Transportation Review Workshop August 12, 2016
Summary

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
		having separate information sessions with each group. However, FEI believes that these workshops provide an opportunity for everyone to collaborate together and understand key issues/concerns from each stakeholder in compiling a consolidated issues list that will help focus the scope of RDA.

Transportation Review Workshop August 12, 2016
Summary

Action Items and Next Steps

	Item	Responsibility	Target Completion
1.	Can FEI provide breakdown of 40% what would be the split for standard, special rate, bypass customers	FEI	73.1 PJ annually transportation customers, Rate Schedule 22 = 13 PJ Bypass – 9 PJ Rate Schedule 22A = 9.5 PJ Rate Schedule 22B = 6 PJ Rate Schedule 23 = 8 PJ Rate Schedule 25 = 12.8 PJ Rate Schedule 27 = 7.3 PJ Contract/Others = 7.5 PJ
2.	How often does the 5% restriction happen? Maybe a couple of days? When you do the statistics helpful to show us not just last year but last 5 years, how many times you've curtailed/restricted flows to the daily balancing customers	FEI	Since January 2010, Fortis has issued a supply restriction for 23 days which applied to all groups, both daily and monthly balanced. We have layered in temperature data into the days (23) a supply restriction was imposed. The last supply restriction period was for three days from December 1-3, 2014.
3.	How many days FEI restricted daily balanced, when monthly balances were allowed?	FEI	On a normal daily basis, daily balanced groups are held to a 20% tolerance. If this tolerance is exceeded charges will apply. While daily groups are held to this tolerance, monthly balanced groups are not held to any tolerances. When a supply restriction of 5% is imposed, this restriction applies to both daily and monthly balanced groups. Since January 2010, FEI has imposed a supply restriction 23 times to both daily and monthly balanced groups.

Transportation Review Workshop August 12, 2016
Summary

Item		Responsibility	Target Completion
4.	To the extent that FEI has never charged demand surcharge, has FEI ever had an instance where it should have been applied but FEI chose not to?	FEI	FEI confirms that demand surcharge has never been charged.
5.	Could FEI confirm if Transport Customers provide benefits to sales customers by providing more peaking gas during cold weather (interruptible) and if FEI has to pay for that gas what value that be?	FEI	With the Application

Transportation Review Workshop August 12, 2016
Summary

Key Issues

Issues List	
1.	Monthly versus Daily Balancing: • Confirmation that FEI will be proposing to have all customers be daily balanced based on principles and reasons as mentioned at the workshop • Confirmation that FEI will not be doing financial evaluation for the value of daily vs monthly balancing
2.	Balancing Tolerance and Value: • Everyone is in agreement that some value exists for FEI's balancing services. B&V methodology as presented at the workshop is one option to value FEI balancing services for different tolerance levels. However, FEI needs to show alternative method to value these balancing services • FEI would recommend appropriate tolerance levels based on further evaluation. • FEI would need to come up with an appropriate mechanism to capture the balancing service value for transportation customers.

2016 Rate Design Application

Workshop 3 – Rate Design and Segmentation

Atul Toky – Manager, Rate Design and Tariffs
Richard Gosselin – Manager, Cost of Service
Kevin Hodgins – Manager, Industrial Accounts

August 31 2016

Introduction - *Objectives for Today*

- **Inform and Review Residential Rate Design**
- **Inform & Review Commercial Rate Design**
- **Inform and Review Industrial Rate Design**
- **Discussion on Key Topics**
- **Summarize Key Issues List**

Workshop Guidelines

Participate

Respect other participants and presenters

Questions & responses as we go / if needed - add to an ‘Issues List’

Issues list to be compiled and revisited following presentation

One speaker at a time

Documentation:

- Meeting Notes
- Issues List
- FortisBC Responses to Issues
- Issues List Items not Addressed During Workshop

Agenda

Discussion Guide	Rate Design Principles
	COSA Results
	Residential, Commercial and Industrial Rate Design
Key Discussion Topics	Recovery of Fixed Costs through Fixed Charges for Residential Customers
	Daily Demand Methodology & Demand Charge Adjustment for RS 5 & 25
	Rate Design options for RS22 and Large Industrial Contract Customers
	Other Discussion Topics
Closing Remarks & Next Steps	Compile and Circulate Consolidated Key Issues List
	Customer Research Survey Results
	File the Application

Part I

DISCUSSION GUIDE

Rate Design Principles

Principle 1: Recovering the cost of service

Principle 2: Fair apportionment of costs among customers

Principle 3: Price signals that encourage efficient use

Principle 4: Customer understanding and acceptance

Principle 5: Practical and cost-effective to implement

Principle 6: Rate stability

Principle 7: Revenue stability

Principle 8: Avoidance of undue discrimination

Existing Customer Segmentation

Residential Group

Residential

Rate Schedules 1/1U/1B

Commercial Group

Small Commercial

Rate Schedules 2/2U/2B

(<2,000 GJ/Yr)

Large Commercial

Rate Schedules 3/3U/3B/23

(>2,000 GJ/Yr)

Industrial Group

Rate Schedule 4

Rate Schedules 5/25

Rate Schedule 6

Rate Schedules 7/27

Rate Schedules 22/22A*/22B*

Rate Schedule 50

Contract Customers JV and BCH ICP

Other

Rate Schedule 6P

Rate Schedule 46

Closed Rate Schedules

COSA Assumptions

Test year 2016 Annual Review – approved

Add in known and measurable changes

- Tilbury Expansion Project
- Lower Mainland Intermediate Pressure System Upgrade
- Coastal Transmission System Upgrades (Special Direction 5)
- Elimination of Burrard Thermal Revenues (contract expiration)

Cost of Service Credits allocated to all other rate schedules

- Bypass Customers
- Joint Venture
- BCH ICP

COSA Assumptions

Revenue to Cost Range of Reasonableness 90% - 110%

Cost of Service Allocation Study

- Involves assumptions, estimates, judgment and generalizations
- Supports fairness principle of rate design

COSA Results and Rebalancing Considerations

- Numerical exercise in cost allocation

Basis for Revenue and Rates

Following Rate Schedules use COSA results directly to inform revenue required from the rate schedule and rate design within the rate schedule

RS	Current basis for revenue and rate design	Other Notes
1	COSA	Changes with revenue requirement
2	COSA	Changes with revenue requirement
3/23	COSA	Changes with revenue requirement
5/25	COSA	Changes with revenue requirement
6	COSA	Changes with revenue requirement
22A	COSA Rate design: 1996 NSA	Changes with revenue requirement
22B	COSA Rate design: 1996 NSA	Changes with revenue requirement

Basis for Revenue and Rates

Following Rate Schedules use other means to inform revenue required from the rate schedule and rate design within the rate schedule

RS	Current basis for revenue and rate design	Other Notes
4	COSA: Based on RS5 and RS27	Changes with revenue requirement
7/27	COSA: Based on RS 5/25 @ 80% Load Factor	Changes with revenue requirement
22	COSA: Based on RS 5/25 @ 100% Load Factor	Changes with revenue requirement
Joint Venture	Negotiated Rate	
BCH ICP	Negotiated Rate	Formerly based on FEVI COSA

COSA @ 90 - 110%

For Discussion Purposes

Rate Schedule	Current		Rebalanced		Rebalance Amount ($000)	Approximate Avg. Annual Bill Change
	R:C	M:C	R:C	M:C		
RS 1 – Residential	95.8	93.4	96.2	94.1	$3,587	+0.5%
RS 2 – Small Commercial	99.9	99.8	99.9	99.8		
RS 3/23 – Large Commercial (Sales & Transportation Service)	101.5	103.0	101.5	103.0		
RS 5/25 – General Firm Service (Sales & Transportation Service)	104.2	110.4	104.2	110.4		
RS 6 – Natural Gas Vehicle Service	135.6	169.9	110.0	119.6	($71)	-19.0%
RS 22A (Closed) – Transportation Service Inland Service Area	180.1	183.2	110.0	110.4	($3,517)	-39.0%
RS 22B (Closed) – Transportation Service Columbia Service Area	105.0	105.1	105.0	105.1		

COSA @ 95 - 105%

For Discussion Purposes

Rate Schedule	Current		Rebalanced		Rebalance Amount ($000)	Approximate Avg. Annual Bill Change
	R:C	M:C	R:C	M:C		
RS 1 – Residential	95.8	93.4	96.3	94.1	$3,852	+0.5%
RS 2 – Small Commercial	99.9	99.8	99.9	99.8		
RS 3/23 – Large Commercial (Sales & Transportation Service)	101.5	103.0	101.5	103.0		
RS 5/25 – General Firm Service (Sales & Transportation Service)	104.2	110.4	104.2	110.4		
RS 6 – Natural Gas Vehicle Service	135.6	169.9	105.0	109.8	($84)	-22.6%
RS 22A (Closed) – Transportation Service Inland Service Area	180.1	183.2	105.0	105.2	($3,767)	-41.7%
RS 22B (Closed) – Transportation Service Columbia Service Area	105.0	105.1	105.0	105.1		

COSA @ 100% (unity)

For Discussion Purposes

Rate Schedule	Current		Rebalanced		Rebalance Amount ($000)	Approximate Avg. Annual Bill Change
	R:C	M:C	R:C	M:C		
RS 1 – Residential	95.8	93.4	97.1	95.4	$10,453	+1.4%
RS 2 – Small Commercial	99.9	99.8	100.0	100.0	$257	+0.1%
RS 3/23 – Large Commercial (Sales & Transportation Service)	101.5	103.0	100.0	100.0	($2,917)	-1.4%
RS 5/25 – General Firm Service (Sales & Transportation Service)	104.2	110.4	100.0	100.0	($3,551)	-4.0%
RS 6 – Natural Gas Vehicle Service	135.6	169.9	100.0	100.0	($98)	-26.2%
RS 22A (Closed) – Transportation Service Inland Service Area	180.1	183.2	100.0	100.0	($4,018)	-44.5%
RS 22B (Closed) – Transportation Service Columbia Service Area	105.0	105.1	100.0	100.0	($126)	-4.8%

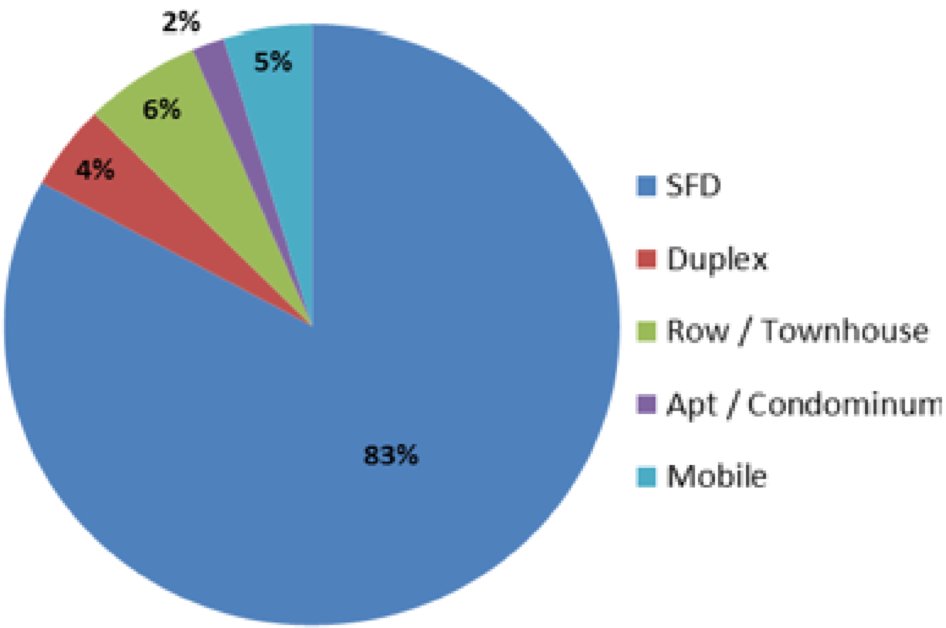
Residential Rate Design

Residential Customer Characteristics

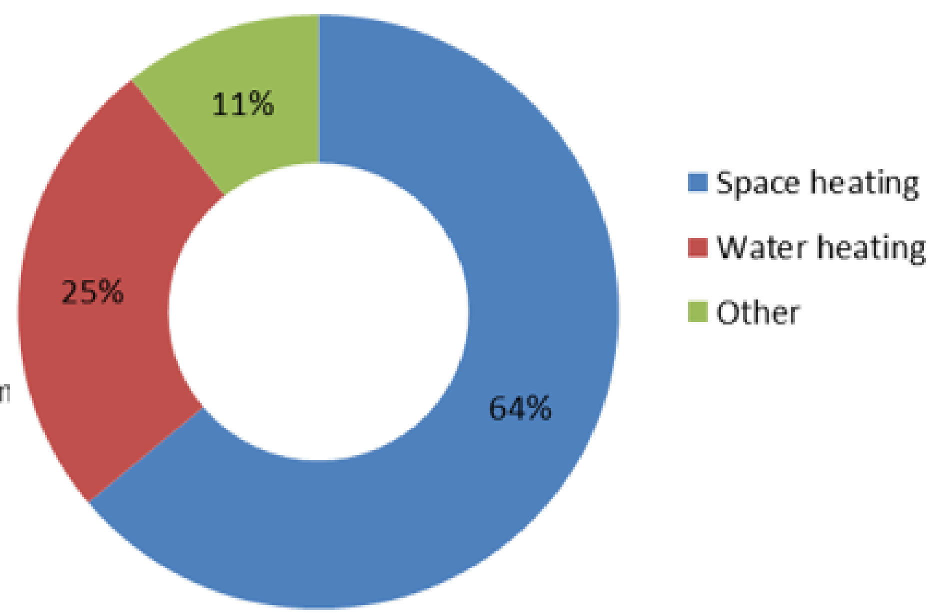
Rate Schedule 1: *single family residences, separately metered single family townhouses, row houses and apartments*

Customer Profile by Demand		**Percentage**
	74.1 PJ	**35.5%**
Customer Profile by Revenue	**$ 773.3 million**	**59.1%**

Customer Mix

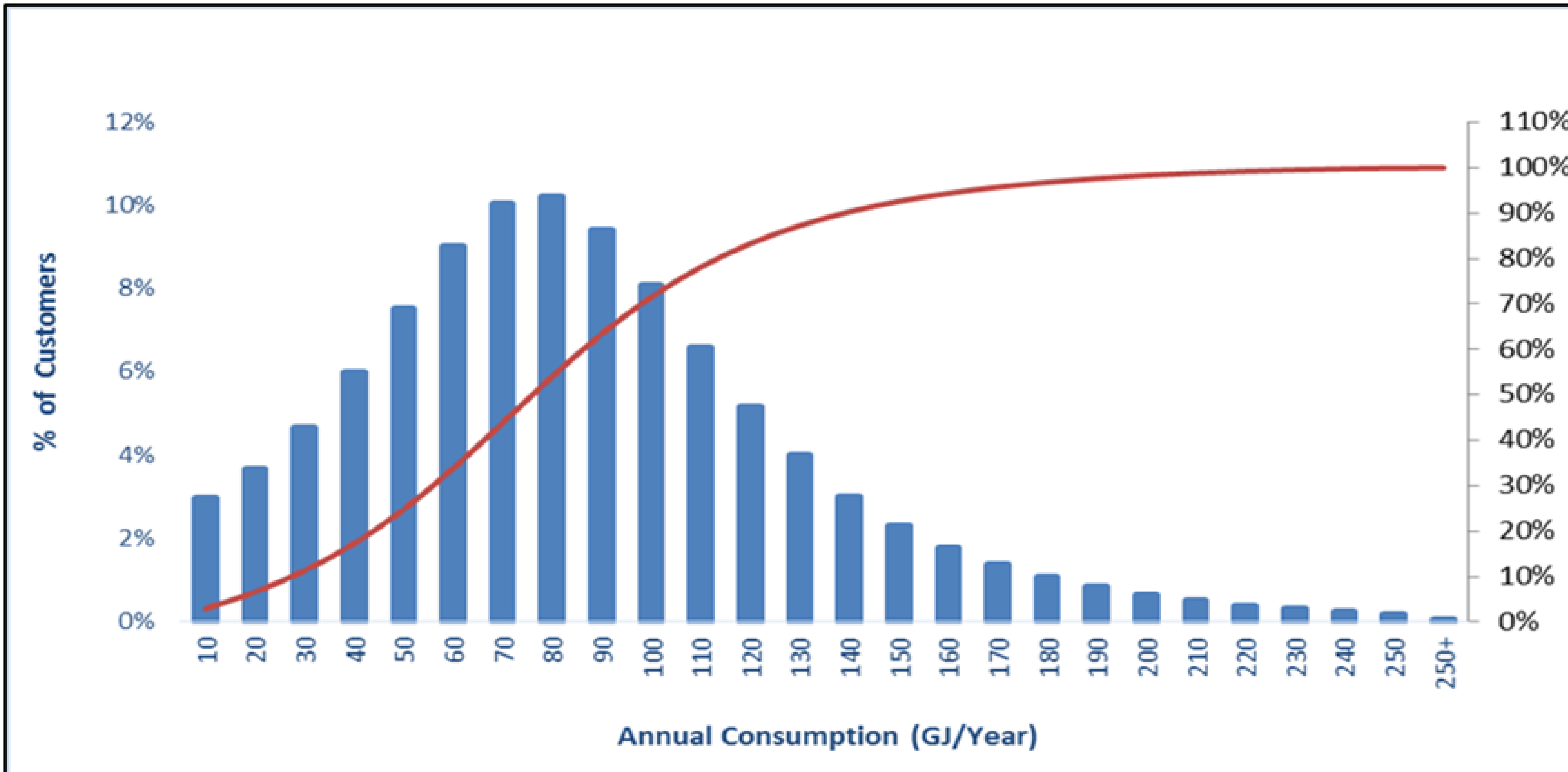


End Use

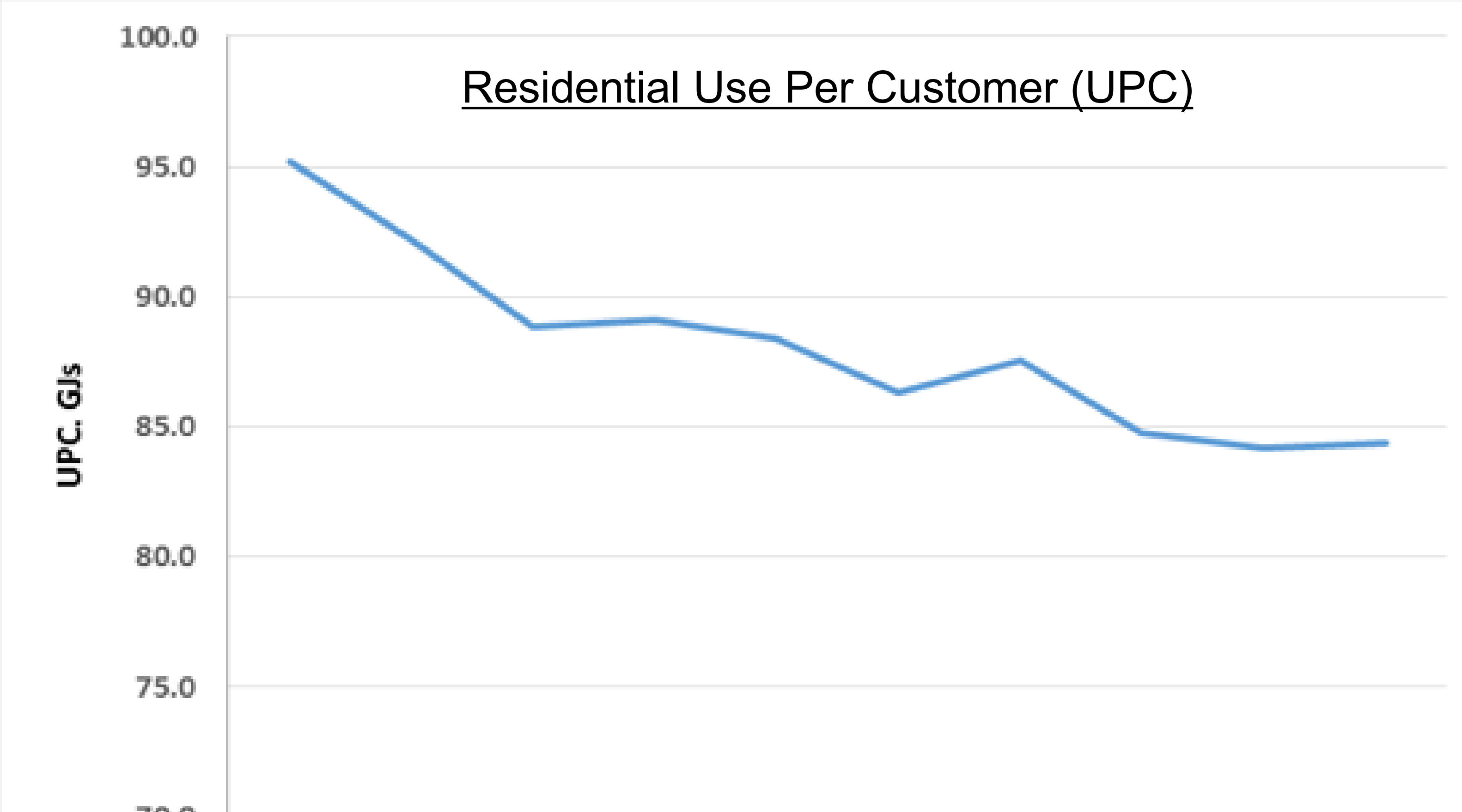


Residential Customer Characteristics

Distribution of Residential Consumption (2015)

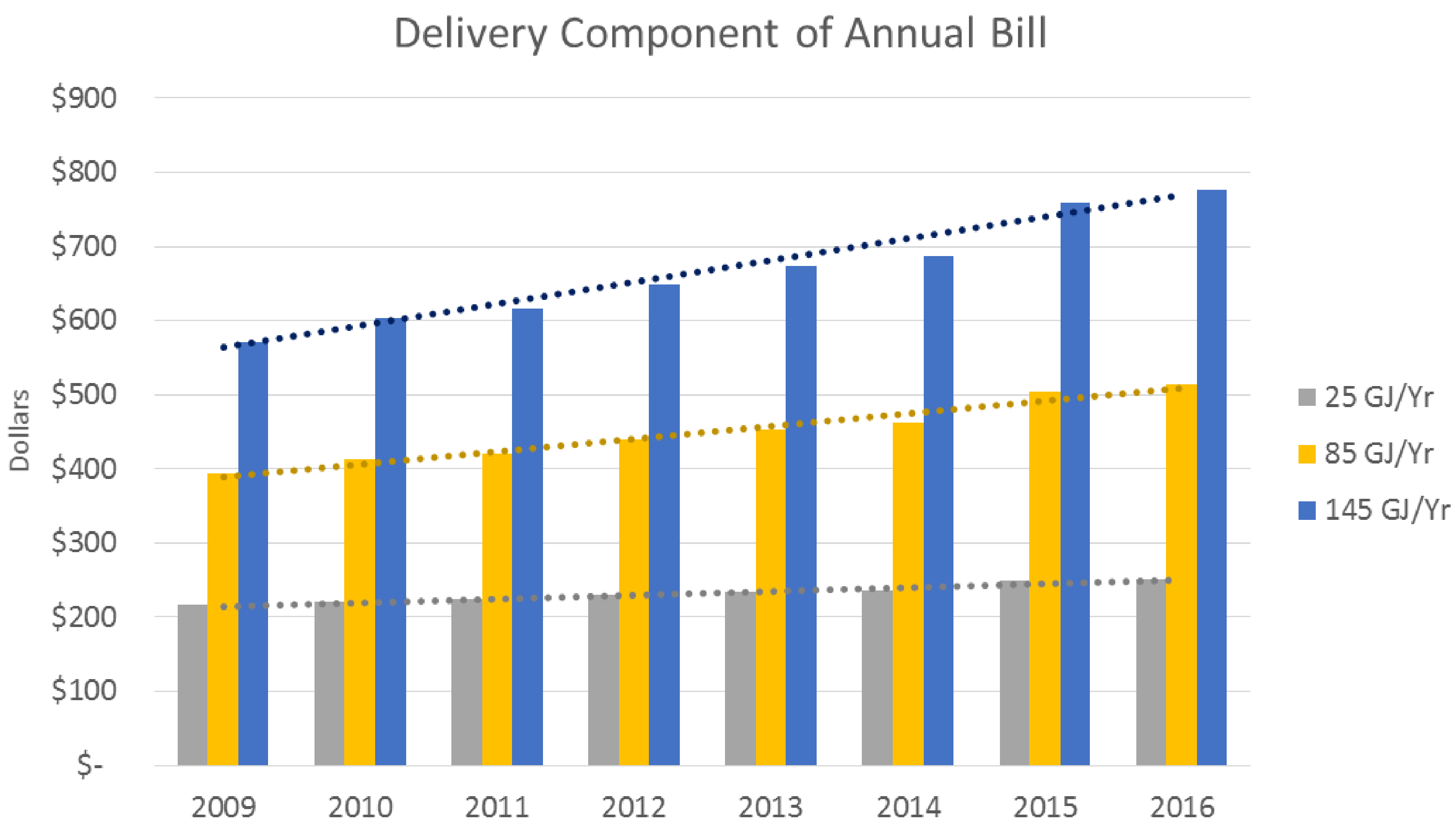


Residential Customer Characteristics



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
RS 1	95.2	92.2	88.8	89.1	88.4	86.3	87.6	84.7	84.2	84.4

Effect of holding Basic Charge Flat on Revenue Margin given different UPC



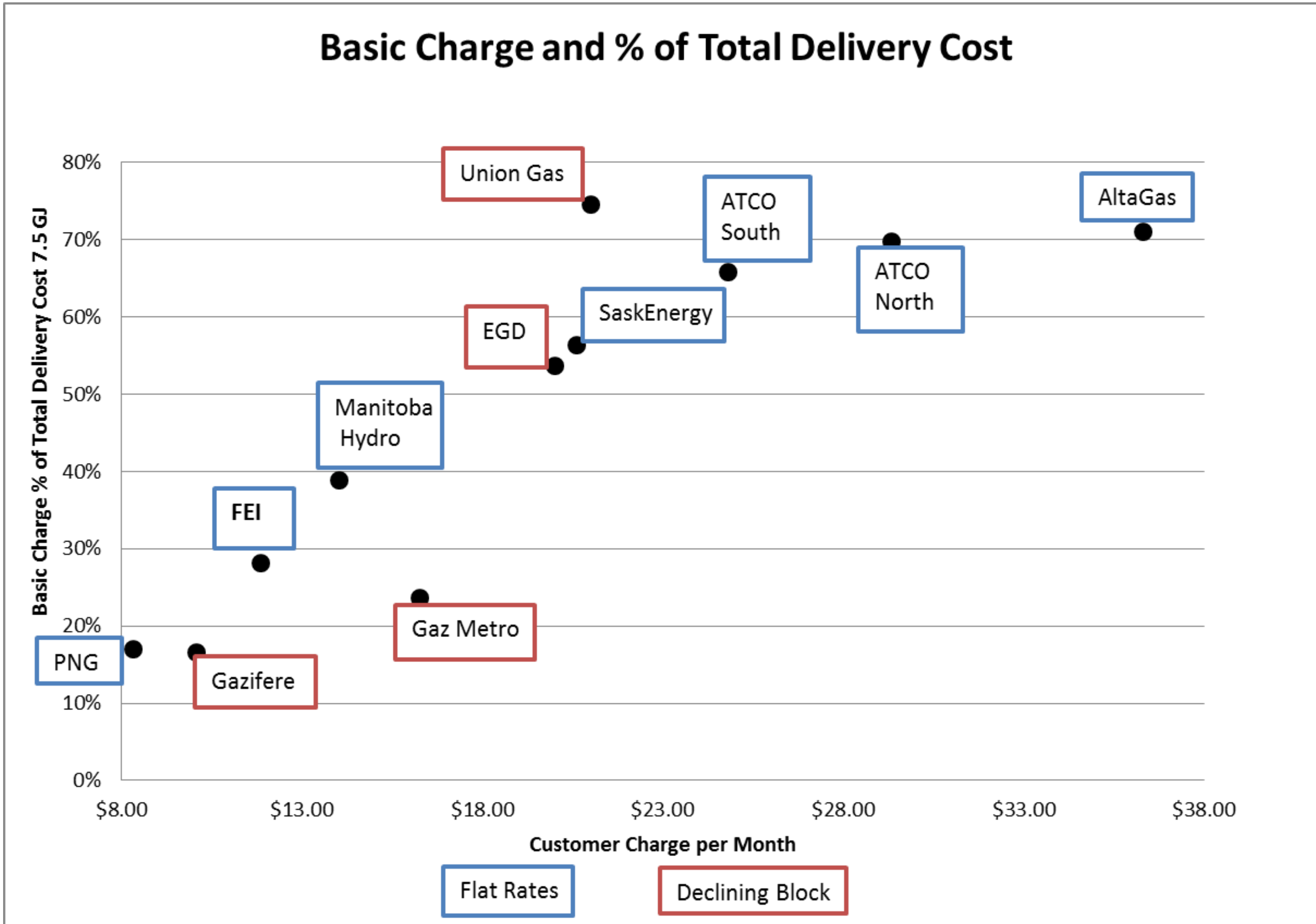
Recovery of Fixed Costs through Fixed Charges

Current Basic Charge Recovers	about 43% of the customer-related allocated costs to residential rate schedule; and
	about 26% of customer & demand related costs allocated to residential rate schedule.

FEI is considering a residential rate design that:

- Maintains the current flat rate structure with a fixed basic charge and a volumetric charge
- Improves the alignment between the allocated fixed costs and the fixed charges
- Minimizes customer impact

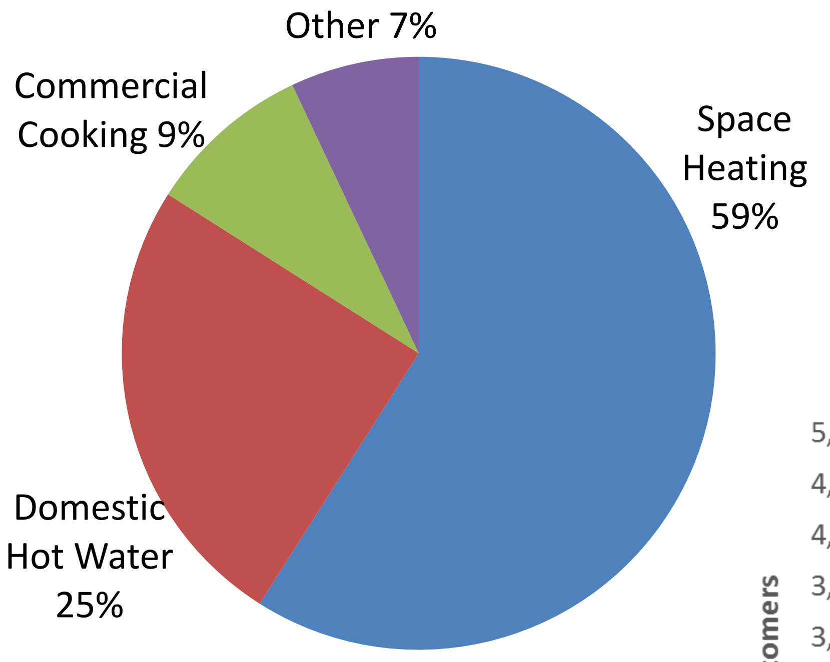
Jurisdictional Comparison



Commercial Rate Design

Commercial Customers Characteristics

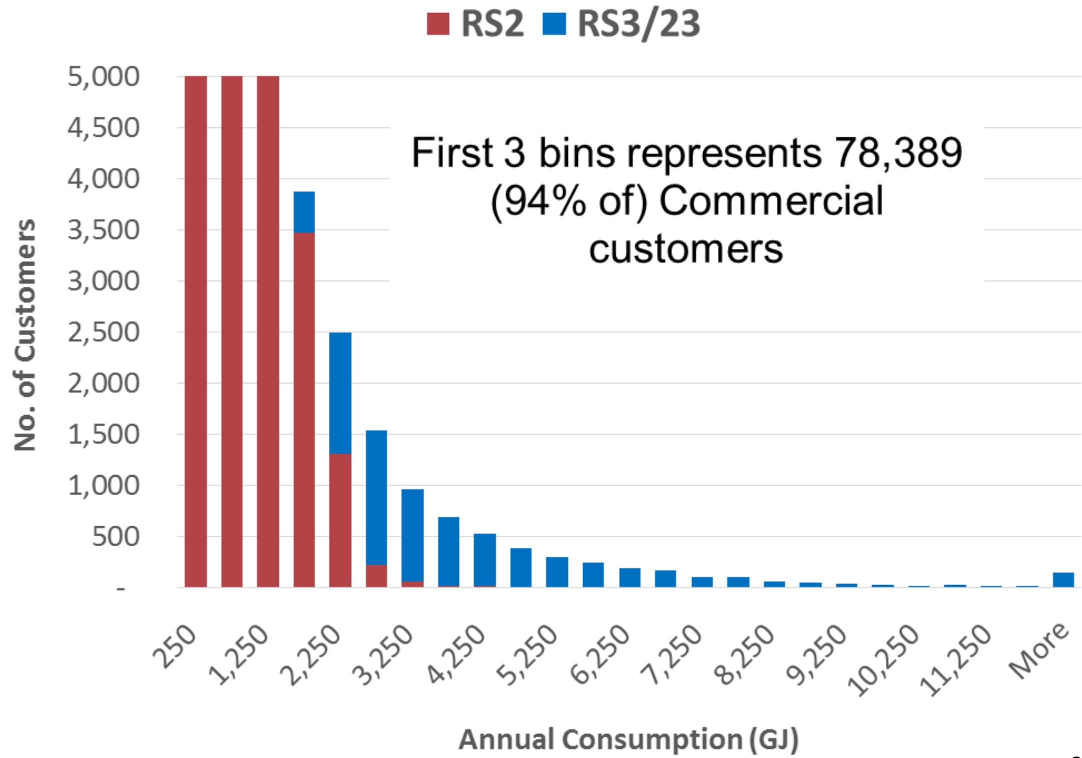
% of Type of End Use



End Use	Percent
Heating	84%
Other	16%

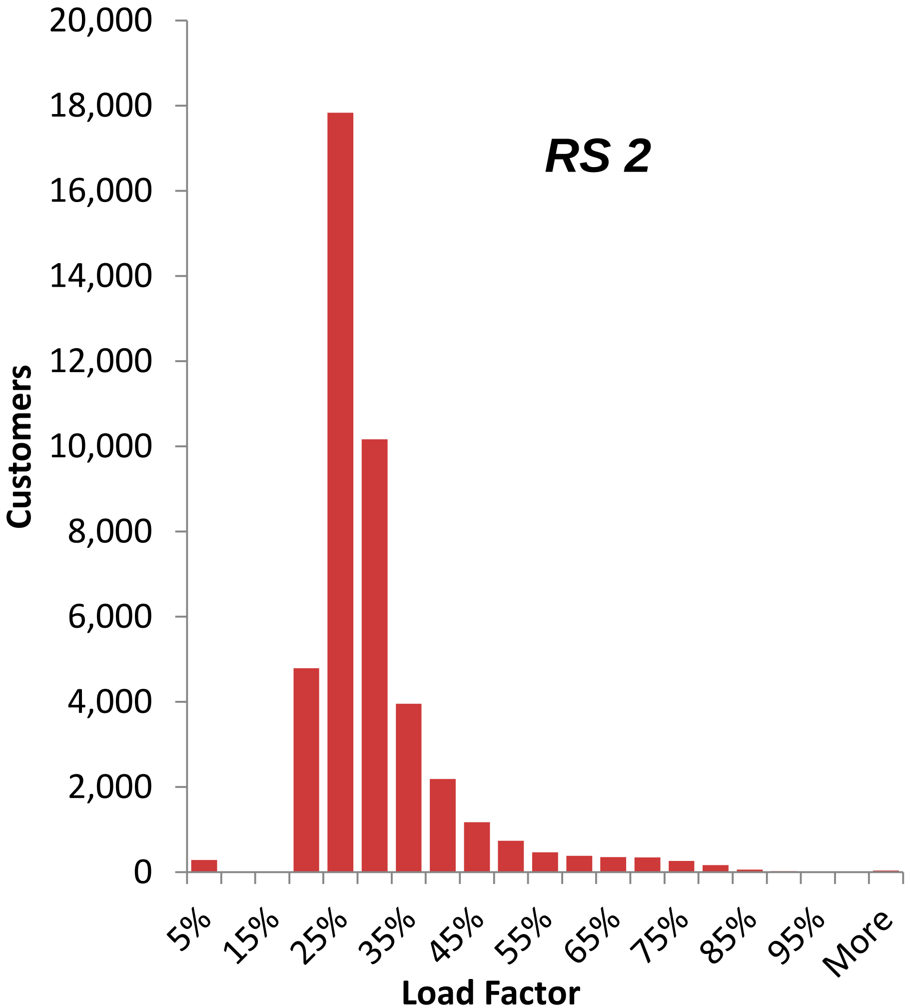
Customers	90,000	9%
Revenue	$395 million	32%
Throughput	55 PJ	26%

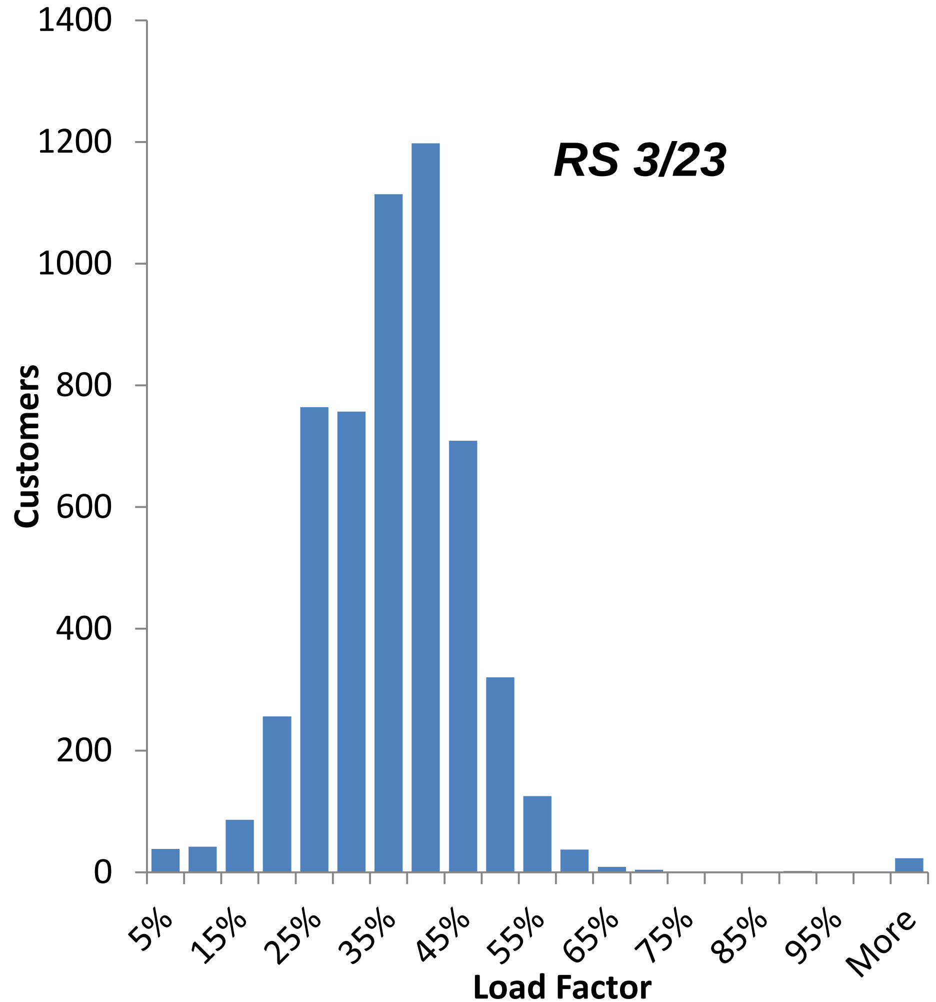
2015 Bill Frequency



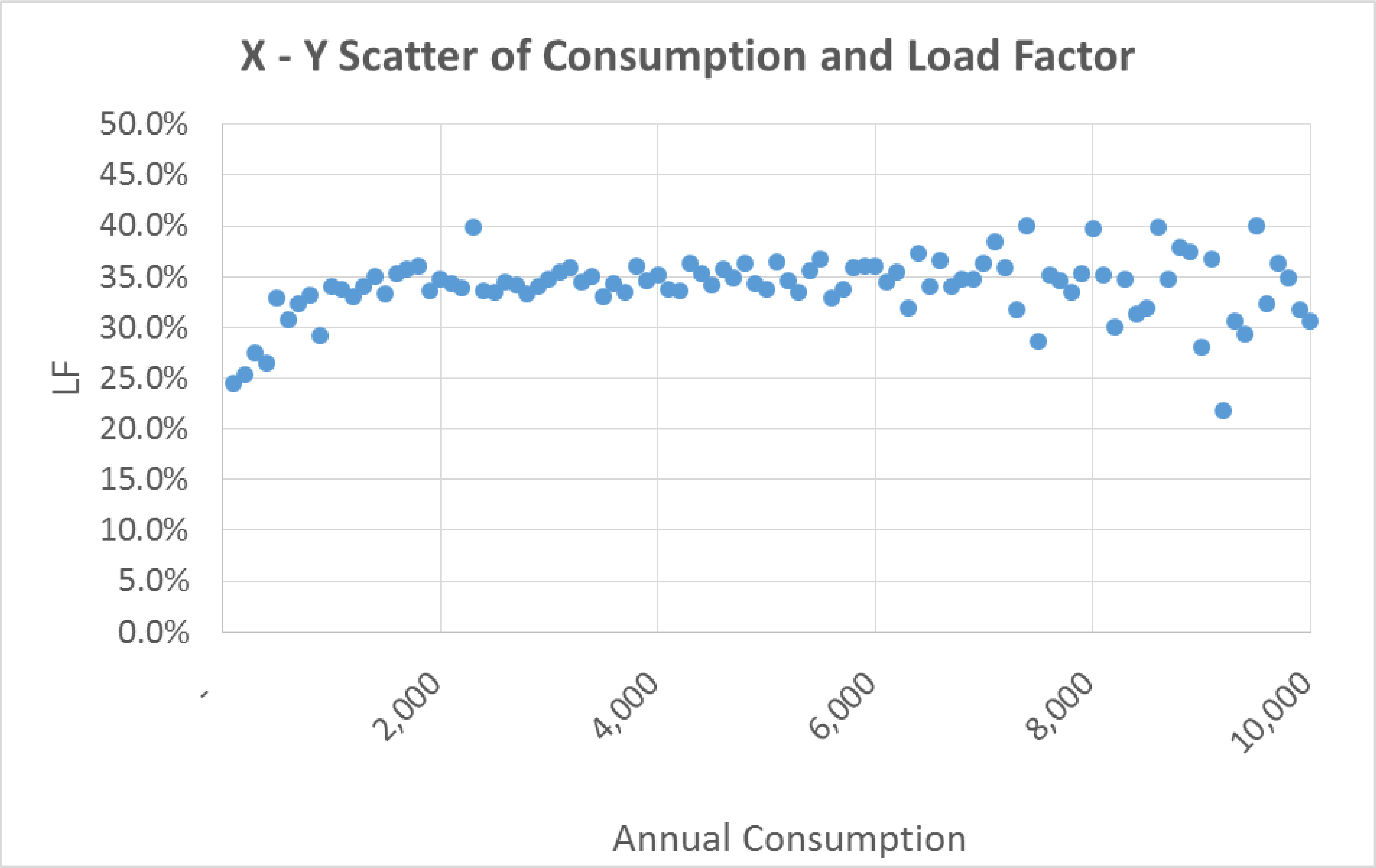
Commercial Customers Characteristics

Histogram of # of Customers by Load Factors

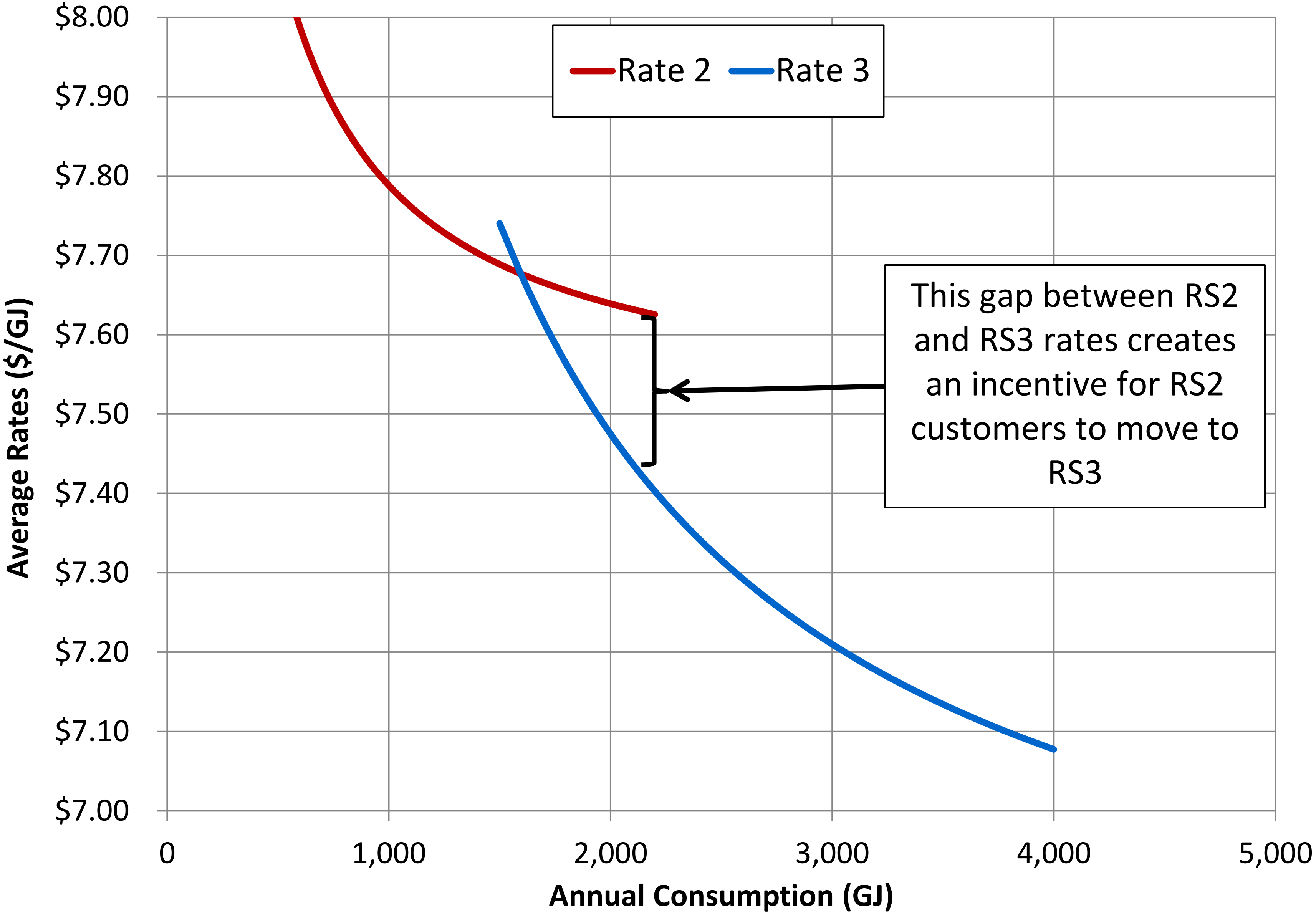




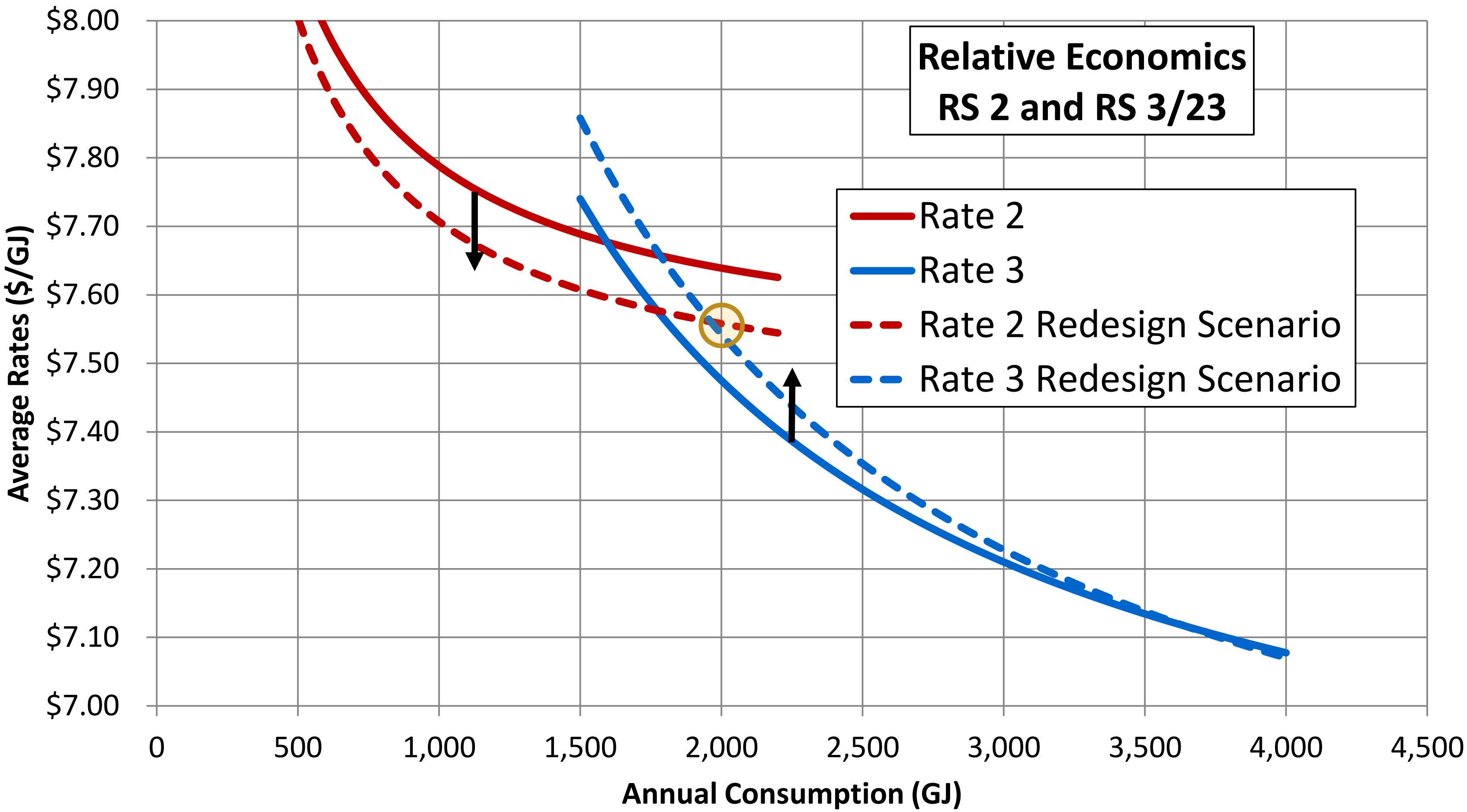
Commercial Customers Characteristics



Rate Schedule 2 and 3 Economic Gap



Commercial Rate Design



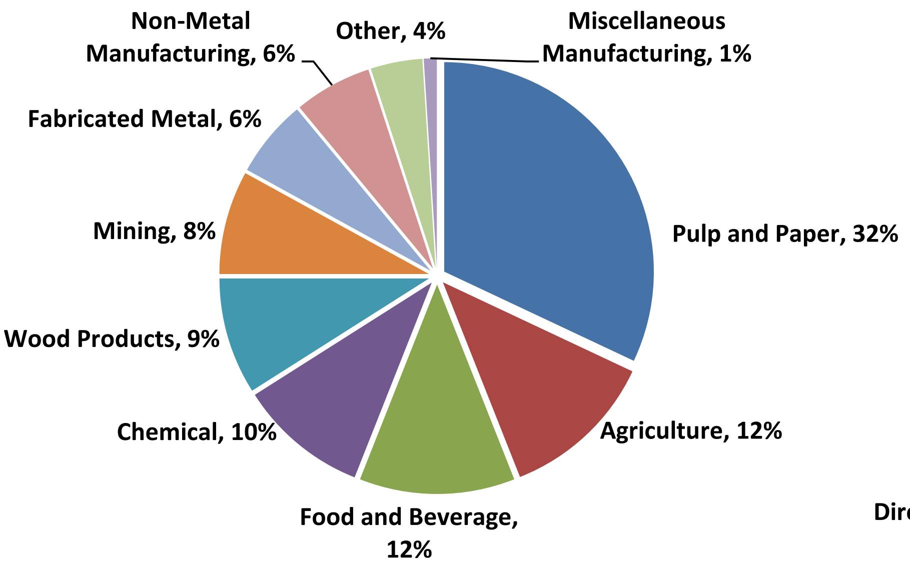
FEI is considering a commercial rate design that:

- Maintains the existing threshold of 2,000 GJ between Rate Schedules 2 and Rate 3
- Adjusts Rate Schedules 2 and 3 to close the economic gap

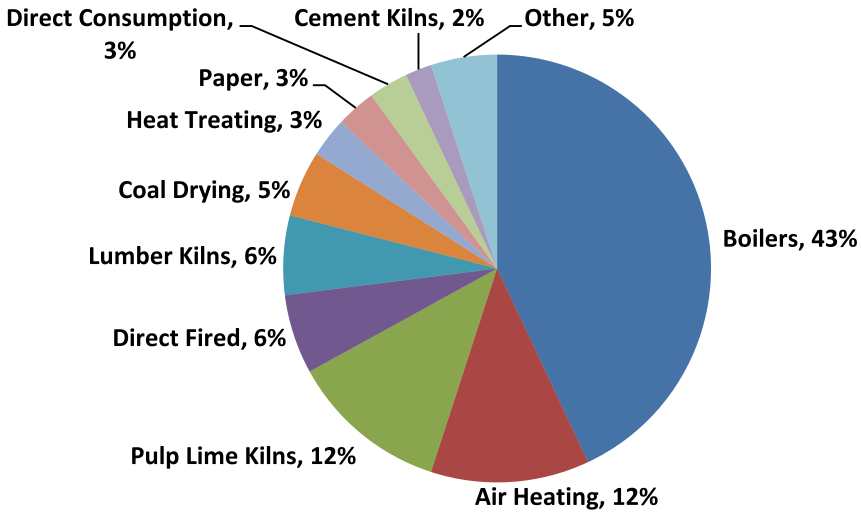
Industrial Rate Design

Industrial Customers Characteristics

Industrial Sectors



Industrial Customers End Use



Industrial Customers: Existing Rate Design

Many Industrial Rate Schedules are linked and changes can have potential ripple effect

RS 5/25	General Firm Service Rate based on COSA results
RS 7/27	Interruptible Rate = RS 5/25 adjusted by an 80% Load Factor
RS 22	Interruptible Rate = *RS 5/25 adjusted by 100% Load Factor *(RS 5/25 less $700k per 2001 Rate design) Firm Rate (Creative Energy) = RS 5/25 adjusted by 100% Load Factor
RS 4 (seasonal)	Off Peak Rate = RS 5/25 , Extended Period Rate = 1.5*RS 7/27
JV & BCH ICP	Negotiated Rates
RS 22A/22B	Grandfathered – Closed to any new customers

Rate Schedule 5/25: Key Considerations

Daily Demand Methodology	The current method to estimate daily demand uses a formula and monthly consumption data.
	Should we use daily consumption data?
Load Factor Price Signals	RS 5/25 was intended for higher load factor customers (~ 50% Load Factor).
	Currently there is an economic incentive for lower load factor RS 3/23 (~ 35% Load Factor) customers to move to RS 5/25
	Should RS5/25 price signals target 50% Load Factor?

RS 5/25: Daily Demand Methodologies

Current Formula: Daily Demand is equal to 1.25 x greater of:

a) Customer's highest avg daily consumption of any month during the winter period, or

b) ½ Customer's highest avg daily consumption of any month during the summer period

Option 2: **FEI System Max Day Send Out**	Use customer's daily consumption on FEI's max day sendout in last year
Option 3: **Avg. Consumption on Coldest Days**	Use customer's daily avg consumption over either 3 or 5 coldest days in their region
Option 4: **Modified Formula** - use greater of:	Customer's daily avg consumption on 3 or 5 coldest days in their region or
	1/2 of avg daily consumption of any month during summer period

RS 5/25 – Load Factor Price Signals

Annual Volume	Load Factor	+ $5 Demand Charge Load Factor
5,000	64.51%	80.57%
7,750	46.80%	58.46%
10,000	42.08%	52.56%
15,000	37.71%	47.10%
20,000	35.85%	44.78%
25,000	34.82%	43.49%
50,000	32.92%	41.12%
75,000	32.34%	40.39%
100,000	32.05%	40.03%
125,000	31.88%	39.82%
150,000	31.77%	39.68%

Example: RS 23 customer with 35% Load Factor

Current rates: RS23 incented to switch to RS25 with annual volume of ~25,000 GJ/Yr.

+$5 Demand Charge: No incentive, need annual volume of over 150,000 GJ/yr

Large Volume Transportation & Contract Customers: Customer Characteristics

RS 22A	- 9 Customers and 9,535 TJ in 2015 - Located in Interior region - Peaking Gas service provided to Gas Supply for Sales customers - Primarily Firm service with intermittent IT service
RS 22B	- 6 Customers and 6,013 TJ in 2015 - Located in Columbia region off Transcanada Foothills System - Elkview has discounted rates as recognized that they could have been bypass - Primarily Firm service with intermittent IT service - Different balancing provisions
RS 22	- 26 customers and 12,775 TJ in 2015 - Located in LML and Interior regions - Primarily IT service but one customer has special negotiated firm rate
Contract Customers	- 2 Customers, JV & BC Hydro ICP - Located in VI region - JV - 5 Pulp & Paper Mills , 13 TJ/d Firm, Agreement expires end 2017 - BC Hydro ICP - Generation facility, 40-50 TJ/d Firm, Agreement expires in 2022

Large Volume Transportation & Contract Customers: Rate Design Considerations

Minimize regional differences

JV Agreement expires end of 2017;

BC Hydro ICP Agreement until 2022

Need to review the Firm Rate methodology for RS 22 (Creative Energy) within this Rate Design Process as directed by the BCUC.

- Other RS 22 customers have expressed interest in a Firm Rate

Large Volume Transportation & Contract Customers: Rate Design Options

Rate Schedule	Option 1	Option 2
22A	Grandfathered; Rebalanced to 110%	Same as Option 1
22B	Grandfathered; No Rebalancing	
22	22 Interruptible & Firm Offering	Single RS 22 Includes RS 22 Interruptible and Firm offerings, JV and BCH/ICP
Joint Venture	Negotiated Rate	
BCH ICP	Negotiated Rate	

Part II

KEY DISCUSSION TOPICS

Discussion Topic #1: Fixed Costs & Charges

Majority of FEI's delivery costs are:

- Fixed in nature
- Do not vary by changes in the consumption levels

Majority of FEI's delivery revenue recovered through variable charges

Discussion Points

- Increase in Basic Charge ?
  - *Last time basic charge increased was in 2009*
- Level of increase to the basic charge? 5%, 10% or 15%?
  - *FEI will consider Bill Impact to low use customers in determining the level of increase to the basic charge*

Discussion Topic #1: Customer Bill Impact to RS 1

Impact from changes in ratio of basic to variable charge:

	All rates are approximate				
	COSA Pre-Rebalancing	COSA Post-Rebalancing	**Percent increase in Basic Charge**		
			5%	10%	15%
Basic Charge ($/Day)	$ 0.3890	$ 0.3890	$ 0.4085	$ 0.4279	$ 0.4474
Volumetric Charge ($/GJ)	$ 4.720	$ 4.758	$ 4.671	$ 4.586	$ 4.500

Annual Consumption	Annual Bill impact due to 15% increase in the Basic Charge	
	Dollar Amount	Percentage of Annual Bill
0-5 GJ	$21	13.9%
40-45 GJ	$10	2.4%
60-65 GJ	$5	0.9%
80-85 GJ	$0	0% *
120-125 GJ	$(10)	-1.0%

* No bill impact to average use customer

Discussion Topic #2:
Daily Demand Methodology for RS 5/25

Method	Pros	Cons
Current Formula	▪ Used since 1994, provides estimate of peak day when daily measurement not available	▪ For the Majority of customers, > 50% Load Factor, formula overestimates peak day ▪ RS 5/25 have daily measurement
System Max Day Send-Out	▪ Customer's coincident demand at time of utility's max day send-out	▪ Can give anomalous results (13 cust had zero demand – 2015) ▪ Not region specific ▪ New customers to RS5/25 still need daily demand estimate
Avg. Consumption on Coldest Days	▪ Not reliant on single day result, but avg consumption on multiple coldest days in various regions ▪ Doesn't penalize for consumption on non peak days	▪ Customers' cold day consumption dependent on factors other than cold weather (ie holiday/weekend) ▪ Doesn't consider heavy Summer users ▪ New customers to RS5/25 still need daily demand estimate
Modified Formula	▪ Not reliant on single day result, but avg consumption on multiple coldest days in various regions ▪ Doesn't penalize for consumption on non peak days ▪ Captures customers with Summer peak	▪ Customers' cold day consumption dependent on factors other than cold weather (ie holiday/weekend) ▪ New customers to RS5/25 still need daily demand estimate

Should we move to Daily Meter Data from Monthly Data?

Discussion Topic #2:
Demand Charge Adjustment for RS 5/25

Annual Volume	Load Factor	+ $5 Demand Charge Load Factor
5,000	64.51%	80.57%
7,750	46.80%	58.46%
10,000	42.08%	52.56%
15,000	37.71%	47.10%
20,000	35.85%	44.78%
25,000	34.82%	43.49%
50,000	32.92%	41.12%
75,000	32.34%	40.39%
100,000	32.05%	40.03%
125,000	31.88%	39.82%
150,000	31.77%	39.68%

Example: RS 23 customer with 35% Load Factor

Current rates: RS23 incented to switch to RS25 with annual volume of ~25,000 GJ/Yr.

+$5 Demand Charge: No incentive, need annual volume of over 150,000 GJ/yr

Should RS5/25 price signals target 50% Load Factor?

Discussion Topic #2: Potential Impact to RS 5/25

Example of Potential Impact of Changes	Amount $Millions
Adjust Daily Demand Method (Modified Formula) Reduction in Daily Demand @ Current Rates	**$(3.9)**
Adjust Load Factor Price Signals $5 Demand Charge increase (161 customers move to RS 3/23)	**$ 3.0**
Rate Change Impact on RS 4, 7 / 27 Delivery Charge	**$ 0.2**
Total Impact	**$(0.7)**

Discussion Topic #3: Large Volume Transportation & Contract Customers Rate Design Options

Rate Schedule	Effective Rate per GJ	Option 1	Option 2
22A	$0.73 per GJ Interruptible (premium to 22A firm)	Grandfathered; Rebalanced to 110%	Same as Option 1
22B	$0.41 per GJ Interruptible (tariff supplement and premium to 22B firm)	Grandfathered; No Rebalancing	
22	$1.03 per GJ Interruptible = RS 25 adjusted to 100% Load Factor	22 Interruptible & Firm Offering	Single RS 22 Includes RS 22 Interruptible and Firm offerings, JV and BCH/ICP
Joint Venture	$0.967 per GJ Interruptible = 3 levels (1) Firm rate (13-20 TJ) (2) Discount to firm (20- 30 TJ) (3) Firm x 1.1 (30+ TJ)	Negotiated Rate	
BCH ICP	$0.958 per GJ Interruptible = 2 levels (1) Winter = Premium to Firm (2) Summer = Firm	Negotiated Rate	

Discussion Topic #3: Option 2

Treating JV, BCH and RS 22 as one to derive allocated costs per GJ

Firm requirements 45, 13 and 11 TJ/Day respectively (Total 69 TJ/Day)

Allocations of both Transmission and Distribution system based on 69 TJ/Day

Allocated Costs / Firm volume

(69TJ/Day x 365) = $0.995

At 110% R:C, $3.6 million shifted to other rate schedules

($1 million shift to RS 1 is a 0.2% increase delivery rates for residential customers)

Other Discussion Topics?

Part III

CLOSING REMARKS & NEXT STEPS

Next Steps

Documentation & Communication

- FEI distributed key issues list and meeting notes for Workshop 1 and 2
- FEI will distribute key issues list and post notes from today's workshop by Sep 14
- FEI will summarize and distribute consolidated key issues list to focus scope of RDA
- Website: www.fortisbc.com/ratedesign

Customer Research Survey

- Customer survey for FEI completed
  - *Reviewing preliminary results*
- Customer Survey for Fort Nelson Residential Customers to be in field soon

File the Application

- FEI will be working to finalize proposals for RDA
- FEI to file the application later this year

For further information, please contact:

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Find FortisBC at:

Fortisbc.com

604-576-7000

Rate Design & Segmentation Workshop August 31, 2016
Summary

Meeting:	Rate Design & Segmentation Workshop
Date:	August 31, 2016
Time:	9 am to 3:30 pm
Location:	Best Western Plus Chateau Granville – 1100 Granville St, Vancouver
Facilitator:	Atul Toky, FEI
Participants:	Suzanne Sue (BCUC), Lejla Uzicanin (BCUC), Cathy Marr (BCUC), Doug Chong (BCUC), Errol South (BCUC), Jackie Ashley (BCUC), Chris Weafer (CEC), David Craig (CEC), Kirby Morrow (Absolute Energy), Tom Hackney (BCSEA), Bill Andrews (BCSEA), Kevin Bonin (Translink), Tannis Braithwaite (BCOAPO), Tom Dixon (Access Gas), Carla Del Monte (Catalyst Paper), Mary McCordic (Shell Energy), Tom Loski (BC Hydro), Nick Caumanns (Cascadia Energy), Peter Kresnyak (Absolute Energy), Gordon Doyle (BC Hydro), Kate Feeney (BCPIAC), Calvin Hastings (BC Hydro), David Bursey (Industrial Customers), James Langley (Sentinel Energy)
FEI Attendees:	Diane Roy, Shawn Hill, Tariq Ahmed (Faskens), Rouzbeh Mehrazma, Brenden Hunter (Faskens), Dave Perttula, Ed Moore, Kevin Hodgins, Atul Toky, Rick Gosselin, Janice Joly, Gail Tabone (Contractor), Ron Sanderson (Contractor), Colleen Gravel, Roger Dall'Antonia, Jason Wolfe
Material Provided	Presentation attached following notes.
Agenda:	***Agenda:*** 1. Part I: Discussion Guide • Welcome and Introduction • Rate Design Principles • COSA Results • Residential, Commercial and Industrial Rate Design 2. Part II: Key Discussion Topics • Recovery of fixed costs through fixed charges for Residential Customers • Daily Demand Methodology & Demand Charge Adjustment for RS 5 and 25 • Rate Design Options for RS 22 and Large Industrial Contract Customers • Other Discussion Topics 3. Part III: Next Steps • Compile and circulate consolidated Key Issues list • Customer Research Survey • File the Application

Meeting Summary and Notes

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
DISCUSSION GUIDE - SUMMARY OF QUESTIONS/COMMENTS		
INTRODUCTION		
6	1. Could you explain why FEI believes that customer rates should be competitive with other fuel alternatives as mentioned in the discussion guide under rate design principles? 2. Are you asking for stakeholders to agree, or informing? We would like to see how this rate design consideration has been applied in the RDA to adjust rates as FEI could also design rates to be lower for that service so it's lower than it otherwise would be to build load in terms of competiveness. We would want to see an example of how it is being applied.	1. In addition to the eight rate design principles mentioned in the discussion guide, FEI has looked at other rate design considerations such as competitiveness and government's energy policy objectives. We think that our rates today are competitive. We consider competitiveness not from the perspective of increasing sales or attaching more customers but from the perspective that if we lose customers because our rates are not competitive, the cost of delivery will now be shared by everyone else as the costs (mainly fixed in nature) have to be divided now between fewer customers. 2. Informing. May not necessarily agree with why competitiveness as a rate design consideration is relevant for the RDA at this time.
COSA ASSUMPTIONS AND RESULTS		
8/9	1. When does Burrard Thermal Contract Expire? 2. Are bypass customers separate from other rate schedules? 3. We are surprised you are sticking with 90-110. Earlier workshop discussion around COSA discussed that the rate payers have challenge with 20% range with one class over another. Has the company given this any thought?	1. Burrard Thermal contract expires at the end of October 2016. 2. No. Bypass customers are across three different rate schedules. We have RS 25 Bypass, RS 22 Bypass and RS 22A Bypass customers. 3. In next few slides, we present other options with respect to range of reasonableness. Not a big difference between them.

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	4. If not much difference, why not aim for the middle? If I have an inaccurate scope, I aim for the middle of the target. You multiply the variation with all that uncertainty. 5. How do you reconcile R:C ratios for transport customers and non-transport customers? And it is susceptible to gas price change? 6. Is the peak day methodology the best you have? Will you show us alternatives? 7. Fairness principle – what other fairness principles are you applying? What else is included? 8. Are there principles underlying? Are rate schedules a mishmash, random? 9. Do you look at demand rather than volume? Load factor is not necessarily your demand. Would rate schedules change? 10. Range of reasonableness. You refer to the 1990s Commission approach 90-110. Do you consider there is a difference between gas and electricity? If so, what would be the basis for that?	4. Half of FEI's costs are allocated on peak day demand. Peak day demand is load required under the coldest conditions. To determine that, we look at existing conditions and regress to show correlation. If 50% or better, reasonable predictor of demand, but not precise. We take those actual and normal conditions and try to estimate extreme conditions. As soon as you estimate, you introduce variability into the peak day calculation. About half of the delivery costs are allocated based on the rate schedules demands under extreme weather conditions. By using a larger range of reasonableness FEI will not 'accidentally' rebalance a rate schedule by relying on a demand allocation that is based on imperfect information. There is history where the Commission has been comfortable with 90-110. 5. We impute a gas cost for RS 23, 25 and 27. We do this because customers in these rate schedules can switch back and forth between these and RS 3, 5, 7 and so in the COSA we treat the Sales and Transport rate schedules as one 3/23, 5/25 and 7/27. Consequently to be able to calculate revenue to cost ratio for each pair FEI imputes a gas cost for the transport customers that is equivalent to the sales customers. Yes, the R:C ratios are susceptible to gas price changes. 6. Yes, FEI feels that the peak day demand methodology and range of reasonableness used for R:C ratios are reasonable and consistent with past practice. 7. Cost allocation fairness. Other Bonbright principles support other reasons to structure rates in other ways.

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		8. We wouldn't consider it random. Residential RS1 serves residential customers where end use is to heat, cook, etc. Commercial class has a split between small and large. The rate schedules are in place and distinct from one another based mainly on how customers cause costs in the system and use gas. 9. Yes. We do look at demand for segmentation. We calculate the peak day demand. Using peak day and average day we calculate a load factor and then apply the load factor to normalized annual energy use to create a load factor adjusted annual energy use which is essentially a peak day demand for each rate schedule. 10. Electric utilities use peak demand based on normal year. Measure every hour, more accuracy than around extreme weather conditions that are used in gas. So, we do believe that there is a difference between gas and electricity.
11	1. Regarding the discounting off of Rate Schedule 5/25, what is the treatment going forward? If so, discount applied? 2. Can you provide a history on the level of curtailment for interruptible customers? 3. What is the value of curtailment to the utility?	1. FEI is still proposing to set the delivery charge for Rate Schedules 7 and 27 at a discount off the Rate Schedule 5 / 25 Demand and Delivery Charges. The discount that has been applied in the past is not simply a mark down from the RS 5/25 rates, FEI instead determines the rates that would apply to RS 5/25 if they had an 80% load factor (RS 5/25 existing load factor is between 50% – 55%). Regarding Rate Schedule 22, under Option 1 the interruptible rate would be priced at a discount from the Rate Schedule 5 / 25 Demand and Delivery Charges using the same methodology as described for RS 7/27 except using 100% load factor. Under Option 2, FEI will complete its

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		evaluation of how the firm and interruptible charges will be determined. 2. Yes, we will look into providing that information. General rule of thumb is approximately 1 day per year. 3. FEI will investigate whether System Planning can estimate the costs to provide firm capacity to interruptible customers.
12	1. Explain marginal vs revenue ratio, and how it fits in your approach? 2. Is that revenue to cost based on a firm customer or interruptible customer? 3. Bypass customers stripped out? How did RS 22A R:C ratio get to this level? History? 4. If RS22A is closed – where would a new customer in the interior go? 5. Could you please provide a background on why RS 22 A rates are closed? 6. Are these customers happy? 7. Have we done a schedule of interruptions for RS22? What is the level of interruptibility? So in IRs, will look for the frequency and duration of the interruption. 8. What is the value to the interruptibility of those customers being able to be interrupted?	1. Rate 1, revenue to cost total revenue from the rate schedules divided by total allocated cost of delivery plus storage and transport (formerly referred to as midstream) plus gas they take. The storage and transport plus gas that the customer pays are the same in both the numerator and the denominator. The margin to cost is just the delivery component of the revenue and allocated cost, it ignores the storage and transport and gas component. 2. Firm. 22A and 22B are primarily firm service, with intermittent use of interruptible capacity. 3. Correct. We pull out the revenues, customers and demand. We can look into providing history with respect to RS 22A R:C ratio. 4. They would go to RS 22. If they want firm, we would have to apply to the BCUC to get a firm rate approved. 5. This goes back to 1993 Rate Design Decision. At that time the Commission recognized that the large industrial customers are served in the Lower Mainland off the distribution system.

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	9. Is there one ratio that Fortis favors (range of reasonableness)? 10. We should be looking at your margins to cost. In terms of focus it should be on margin to cost ratio? Margin to cost numbers are what the utility can control. Gas commodity costs in revenues are not in the utility's control. 11. The Rate Schedule 22A has a high R:C ratio, about 180, how did it get there? If any IT transportation revenue is not included in that ratio?	Whereas, Interior customers are served off transmission laterals. Nature of the service was quite a bit different. The Commission's decision was to park those existing Interior customers into separate closed Rate Schedules. Other existing customers cannot receive service under Rate Schedules 22A or 22B. Existing customers in RS 22A or 22B can leave, but new customers cannot get in. 6. Don't seem to be any issues. 7. We haven't done schedule of interruptions for RS 22. We had talked about it last time. It depends on the region, but the general rule of thumb was that it was averaging about 1 day per year. It may be slightly less than that now as we haven't had very cold weather in the past 5 years, so it has brought that number down. In capacity constrained regions of our system partial curtailment happens every year and the greenhouses out in Delta are an example of that. 8. Gas capacity modelling for interruptible customers are that they have been fully curtailed for interruptible capacity as we reach peak weather conditions in the modelling. We haven't undertaken the actual cost in this RDA to do that, but we could consider if we could determine a value with our System Planning. As we don't hold firm capacity for interruptible customers, the revenue that is received from interruptible customer groups is some of the value of having these types of customers on the system as they utilize excess capacity and don't require the utility to build firm assets that aren't often needed.

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		9. Revenue to cost ratio in the range of 90-110%. 10. For RS 5 and RS 23 yes. There's no sales equivalent for what you have to look at. When we look at 99.9 and 99.8 it's pretty close. Same for residential RS 1. We could focus on margin to cost ratio. It would make little difference, but we could do that. 11. FEI checked and the R:C for Rate Schedule 22A included both firm and interruptible revenues.
13	1. When doing it 100% to R:C why does RS 1 R:C not come to 100%? Allocated based on unity?	1. For the COSA results where FEI balanced to unity FEI balanced rate schedules 2, 3/23, 5/25, 6, 22A and 22B to 100% and the rebalancing was shifted to RS1. However, since rate schedules 4, 7/27 and 22 are interruptible and not directly related to the allocated costs in the COSA, FEI left the revenues for these rate schedules as is. Since RS 4, 7/27 and 22 revenues are greater than the allocated costs (by design) the excess revenue credit falls to RS1 therefore the R:C ratio for RS1 is less that 100%. FEI could spread the RS 4, 7/27 and 22 excess revenue to all rate schedules (RS 1, 2, 3/23, 5/25, 6, 22A, 22B) to produce an R:C that is equivalent for these rate schedules but did not do that for this exercise.

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RESIDENTIAL AND COMMERCIAL RATE DESIGN		
17	1. Has the average customer use changed much? 2. Typical usage of a house is around 80-85 GJ per year. Compared with usage by BC Hydro customer, correspond with 22,000 kWh per year. Higher than typical usage compared to BC Hydro. Any reasons for why typical user is using more? BC Hydro looked at multi-family dwellings mostly.	1. Coming down over the years. 2. The average is slowly coming down. As housing stock turns over, it turns to multi-family dwellings and more efficient appliances. You have to look at segment of BC Hydro that has electric heat. You can't compare average gas user and average electricity user. There is a greater challenge getting gas into multi-family dwellings.
19	1. Have you considered an inclining block structure for reducing carbon emissions? 2. Is price elasticity for gas lower than for electricity? 3. Include in the application, the comparison of variable rate of the residential margin cost comparison verses marginal cost? To see whether the existing rate structure has a price signal that is in excess? 4. We want further information on the impact on low income customers. ECAP customers are probably older people in single family dwellings but not representative of low income segment.	1. We looked at the inclining block structure. It's a much more complex rate structure to understand for our customers. They might not get the right signal when customers roll into higher blocks. We typically found with price elasticity studies, price elasticity for natural gas consumption is quite low. Parties don't respond to a price signal in an inclining block. This is also corroborated by analyzing the trends in residential use per customer and natural gas price competitiveness. During last 10 years the price competitiveness of natural gas versus electricity has consistently improved and the natural gas prices are at record low levels however the residential use per customer has continued to decline which indicates a disconnect between price and consumption. Inclining block structure is not the most effective structure to use. Demand side management programs are the best way to deal with consumption levels and evidence shows they are working as planned.

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		2. Yes, lower. 0.2 – 0.4 price elasticity. If the elasticity is greater than 1, it is considered to be price-elastic. The closer to zero the more inelastic it is. Gas customers are less elastic. Please note that the short term elasticity can be even lower than the longer term elasticity. Research in other jurisdictions suggests that inclining block rates are not used in Canadian natural gas utilities. Inclining block rates are sometimes used in electric rates, although the differential is primarily driven by the cost of new generating resources. On the gas side for Fortis, there is generally surplus capacity available of the Transmission & Distribution system, so not a strong signal for inclining rates on the delivery side. 3. We looked at the marginal cost of adding resources in the system extension proceeding. That analysis conducted by EES Consulting indicated that historical incremental cost for new customers added between 2008 to 2014 is lower than the historical embedded cost. This is in line with economic theory since the natural gas distribution business is widely considered to enjoy the economies of scale; that is as company grows the average cost declines. 4. ECAP customers are vetted low income customers enrolled in the low income Energy Conservation Assistance Program. Although they might not represent the totality of low income customers in FEI's service territory they do represent a segment of low income customers. It is important to understand that low income customers living in MFDs may also be participants in the ECAP program however the ECAP histogram presented in the discussion guide only covers RS 1 customers. Those low income

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		customers living in MFDs with a single meter are not RS 1 customers and therefore not included in the histogram (The ECAP database contains the information on approximately 1750 individual Rate Schedule 1 customers). Nevertheless, the results seem to be logical. For instance, a low income customer is more likely to live in older and less efficient homes with less efficient appliances (the programs such as ECAP are designed to improve this issue) leading to higher natural gas usage for space heating. In addition to ECAP database, FEI's REUS also provides the same conclusion that low use customers are not necessarily low income customers.
21	1. Information in discussion guide on impact of change on low income customers. Is there analysis done on customers that are representative of those people actually are low-income? The ECAP customers are primarily home-owners with disproportionately high gas use.	1. Please refer to the response above.
MORNING BREAK		
	1. Regarding lower volume residential customers, what is the issue? Is there any tariff solution?	1. In any rate schedule that has rates that are cost based and a volumetric component to their rates, higher (than average) consumers pay more of the allocated costs than lower (than average) consumers. The tariff solution will be discussed in the key discussion topics section, but it is basically an increase in the basic charge to better align the recovery of customer caused fixed costs through fixed charges.
24	1. Customers with <5% load factor, who are they or do they only use it because they are on geo-exchange?	1. Don't know if they are on geo-exchange or not, will follow up.
25	1. How do customers move between small and large commercial	1. We look back every year and review the usage by account.

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	rate schedules? Do you look at past year's consumption? 2. Can you produce a load factor scatter drawing for the residential class in a similar way to that shown for commercial customers? 3. Is the beak point between small and large commercial customers not clear? 4. Can you provide the data supporting these graphs? So interveners can make their own judgment.	There will be that subset of customers whose usage hovers around that 2,000 GJ threshold after adjusting for weather. We look for customers around that band, and look at multiple-year average for a trend. Data is looked at and then judgment is applied depending on whether they should be moved back and forth. 2. Yes, we will provide that. 3. The breakpoint between large and small commercial customers is not precise. When plotting the load factors against volume, the graph suggests that 2000 GJ per year continues to be a reasonable breakpoint. However, the results are open to interpretation. 4. Yes.
27	1. Explain what is the process for moving a customer back and forth? Is it the customer's choice or Fortis' choice? Mollify or persuade the customer, as opposed to simply allocating the customer depending on the right category. As I understand it for RS2 customers to stay in RS2, they are peakier users so they should be charged a higher rate. 2. If they are causing more costs, can you just say no you can't switch. 3. So are you just aligning up rates with reality? 4. In the application can you discuss rate stability perspective options?	1. Tariff says we will do periodic reviews. To align with 2000 GJ threshold. The tariff wants you to go that way, but the financial break-even point needs to align. 2. Correct. The tariff stipulates 2000 GJ but it is weather adjusted, so there is bit of a grey area. 3. Correct. The customers closer to the 2000 GJ threshold, they are getting closer to RS3 or RS23. Getting closer to that cusp. Their costs are at parity. Realigning the rate structure. Right now if you are near that cut off as a Rate 2 customer, you are paying more than you should. 4. Yes.

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	5. Have you evaluated the pros and cons of changing the threshold from 2000 down to the 1,600 GJ economic indifference point? Eyeball threshold in slide 25 – weak.	5. The scatter analysis and the data suggest that the threshold should be around 2000 GJ. We don't believe 1600 is the right level where there should be split between the RS 2 and 3. We need to do further analysis on that. We believe the 2000 GJ threshold is reasonable. In the application we will consider the option of a lower threshold such as 1600 GJ.
INDUSTRIAL RATE DESIGN		
30	1. Are Interruptible customers across separate rate schedules? Or rates within the general firm rate class? How is the size of the discount determined? 2. Does Fortis have purely interruptible customers? What typically is difference between some firm and some interruptible? 3. Who are the RS 22A/22B partly firm and partly interruptible customers, manufacturers? 4. Regarding the fairness principle – why for these customers (interruptible customers) are we now abandoning the COSA results and instead using a rate derived from a firm customer instead of a rate derived for this customer? Fair from a design day only. But on a typical day they are using the system just as much as anyone else. O&M follows the plant and rate base. If they are allocated zero rate base, then they are allocated zero O&M. 5. What is the price elasticity of the industrials?	1. Along with firm charges, there are interruptible charges embedded in RS 22A and 22B however, most of our interruptible customers are served under RS 7/27 and RS 22 and unless the customer has a tariff supplement all volumes under these rate schedules are 100% interruptible. FEI is still proposing to set the delivery charge for Rate Schedules 7 and 27 at a discount off the Rate Schedule 5 / 25 Demand and Delivery Charges. The discount that has been applied in the past is not simply a mark down from the RS 5/25 rates, FEI instead determines the rates that would apply to RS 5/25 if they had an 80% load factor (RS 5/25 existing load factor is between 50% – 55%). Regarding Rate Schedule 22, under Option 1 the interruptible rate would be priced at a discount from the Rate Schedule 5 / 25 Demand and Delivery Charges using the same methodology as described for RS 7/27 except using 100% load factor. Under Option 2, FEI will complete its evaluation of how the firm and interruptible charges will be determined. 2. Yes, RS 7/27, RS 22 is 100% curtailable interruptible service. Those with firm service we can only curtail them to that level. Interruptible customers can be curtailed all the way back. In interruptible rate classes, customer examples are hospitals

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	I would think if there is one group of customers who are elastic it would be industrials. Transportation has now become significant chunk of gas bill. 6. There is a difference between RS 22 and RS 27 interruptible rates. Why treated differently? RS22 get a bigger bang for their buck. That maybe the justification for giving larger customers a different rate 7. You identified that Creative Energy has firm? 8. So, any of their additional gas needed is interruptible?	and greenhouses as they have backup fuels, asphalt plants is another example but they don't pave in peak weather days so don't need to have backup fuels to the same extent. 3. Yes. Some examples are coal mines, pulp mills, general manufacturing. 4. When we design the system capacity, the interruptible customers do not cost more. They are interruptible and they have backup. They can go to zero load when we need the capacity back. We don't think that we are abandoning the COSA results. COSA is looking at cost causality to allocate costs to different rate schedules. For interruptible customers no demand related costs are allocated but they do get an allocation of customer related costs. The rates for these interruptible customers are therefore not based on their R:C ratios but is derived from the RS 5/25 adjusted to the appropriate load factor. So, it is a matter of how we come up with methodology for the appropriate revenue for these customers. Across industry there is no acceptance that using zero allocation in a COSA represents fairness. Most non-firm rates are set on a discount on firm rates. Cost of service doesn't fully capture their costs on the system. They are using the system, just not on that peak design day. So not fair for them to pay zero. The truth is somewhere in between that. No standard process to capture both of those. 5. FEI can confirm that industrial customers are generally more elastic than residential and commercial customers. The elasticity of industrial customers may change from industry to

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		industry and from customer to customer. The responsiveness of demand to price may vary greatly depending on factors such as ability to hedge against price volatility, degree of fuel substitution possibilities, reduction in production levels, etc. 6. RS 22 are a larger size of customer so there would be more value in having them interruptible as compared to a smaller RS 7/27. 7. Yes, under RS22, Creative Energy is the only customer with a firm component to their demand. 8. Yes, anything over 2000 GJ per day is interruptible.
31	1. How closely is it linked, moving away from monthly balancing issue? 2. Do you have a similar scatter drawing for RS 5/25 produced in a way similar to that for RS 2 and 3? As an alternative, could we look at the load factor each year and move customers around accordingly?	1. Not linked at all. 2. We don't have it now but we can look at it if it can be produced.
32	1. Only difference between Options 3 and 4, is that customers with mostly a summer load would have no demand. So, Option 4 is better than 3. When filing the application, clearly identify the problem that the current rate design is causing. E.g., efficiency problem. 2. Can you eliminate demand charge? Make the rate simpler based on actual load factor instead of complicated economics.	1. Yes, that is the main difference. 2. We haven't looked at that but we would have to look at another way to ensure that only the appropriate load factor customers would be allowed into the rate class as a totally variable rate structure would not allow the rate schedule to economically police itself.

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33	1. Could you produce a chart with frequency of customers – who are high load factor customers? The way the current structure is set up high volume/low load factor? What about high volume/high load factor? Seems like your solution was to raise the demand charge by $5. Would this not penalize the high volume/high load factor? Is there a model we can run this through? When identifying the problem in you r application be more specific e.g., do they waste gas or become more peakier?	1. That's part of the key consideration for daily demand. First consideration is demand volume. Second is load factor signal. We will be doing bill impacts at different consumption levels. We want to move customers out of the rate class back to RS 3/23 that do not belong but need to recover the costs of serving the rate class. If we increase the fixed charges in RS 5/25 we may need to reduce the variable charges.
34	1. RS 22A is $3.5 million shift? 2. Can you explain how RS 22A provides a peaking gas service? 3. When looking at using the RS 22A peaking capability to take them to half, it's the utility's choice whether to interrupt or not. Do you have internal set of rules in making that decision? Specific rules for LNG and then using the RS 22A supply. It would be useful if those internal procedures are documented. 4. Given the history of Tilbury and Mt Hayes, would be good to see history of what has been used. Do the economics support using it instead of curtailing industrials? Is there a limit that says there's a commercial argument 5. 22B – As they are mostly owned by one company, are RS22B customers allowed to share their Firm quantity like Joint Venture or do they each have their own firm DTQ?	1. Yes 2. Under their service we have options up to 5 days we can curtail them to half of their firm. They still need to provide supply for their full firm demand. Half supply to cover their customer burn and other half gas supply can use to serve core customers. There are other options under the tariff where customers can elect to provide up to 10 days of peaking supply if they don't want to be held to half½ firm. 3. This RS 22A peaking supply is part of the ACP to serve the core. In the ACP, it's the highest stack above LNG. 5 day service. LNG is 10 day service. Also, this is specific to the interior. Yes, we have internal set of rules. 4. LNG is there to send out as we need it as part of the ACP. LNG isn't always on standby for immediate sendout. Point regarding possibly using LNG for industrials is more complicated and is more of a site specific issue whether we are trying to address a capacity or supply issue.

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Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
		5. Each has their own firm DTQ
36	1. Regarding bypass customers, still room for better understanding. Needs more transparency, number of customers, usage and explanation of rates. 2. This rate design, is it intended that it would be in effect past 2022? Largest magnitude impact is if the contract expires in 2022 with BC Hydro. In the event that doesn't get renewed from a revenue rate rebalancing issue?	1. We can explain treatment of bypass customers in the COSA model. Also, can include other information such as customers, usage and explanation of their rates as a part of the Application to address transparency. 2. Yes. We can look at it in the COSA and estimate the impact to all our customers as if the revenues did not exist today..
LUNCH BREAK		
ATUL TOKY – KEY DISCUSSION TOPICS		
38	**Fixed Costs and Charges** 1. Current status quo is continual change? No change in rate design? 2. What percentage of residential customers cost is covered by the basic charge?	1. FEI is considering making a one-time adjustment to the basic charge and will again hold the basic charges constant through revenue requirements however notes that it is a reasonable statement that if you move both the basic and volumetric charges over time, the relationship between large and small customers would remain stable. 2. Twenty-six percent of the customer and demand-related costs are covered by the basic charge.
39	1. What is the ratio between basic charge and customer cost? 2. Could you compare that against the marginal cost in the application? 3. Volumetric charge change per GJ makes Fortis rates more competitive?	1. Basic charge recovers 43% of the customer related (caused) costs and, 26% of the sum of the customer and demand related costs. 2. FEI has not done marginal cost study/analysis. FEI could consider looking at the marginal cost analysis in the Application.

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Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
	4. Did Fortis consider a minimum charge as an option? Doesn't change the basic charge but addressed other issues regarding basic charge. In the Application, consider in the context if it is covering your marginal cost, if there is a fairness problem. And maybe if there is a problem, minimum build or extension policy as a solution. Is there a problem with the fixed charge? Also, identify very clearly whether it is an efficiency issue, fairness issue, etc. 5. Under 5 GJ per year, any analysis, as to the customers here? Single appliance? Or does it include disconnections part way through the year? 6. Regarding low income customers – representative of all low income customers? Do you have other ways of analyzing consumption patterns, methodologies, different data? 7. What is the uptake? Is the survey after they have been enrolled or upon enrollment? Do you know what the uptake is? 8. What is the problem with status quo? What kind of behavior are you trying to incent? 9. Has there been anything done for low volume customers? I for an example pay a basic charge and use very little gas, use gas only for two months in a year. 10. 2009 decision to hold the fixed charge steady and why that was made. Could Fortis look at what has changed between then and now, and what it would have been. To what extent the problem	3. No. Average use customer; that is a customer with annual consumption of 80-85 GJ has zero impact. We are not talking about competitiveness issue here. This is about the level of fixed costs and how we recover those fixed costs through fixed charges. Directionally, it makes sense to adjust the ratio of basic charge and volumetric charge to improve how we recover fixed costs through fixed charges. 4. Replacing the basic charge with a minimum charge like the one that exists for Fort Nelson customers has no significant advantage and they both serve a similar function. In addition, the customer research result shows that the majority of FEI's customers are aware of the basic charge and its role in recovery of fixed costs, therefore it is probably unwise to change that to minimum charge. 5. Lower use are generally single-appliance. The 0 to 5 GJ histogram bin includes around 2 percent of FEI's residential customers. FEI can only assume that these include but not limited to customers with convenience load (such as those with natural gas barbeques .. The consumption histogram is for all the residential customers, including those with less than a full year consumption. 6. See response above (slide 19, response to question #4) 7. The uptake of the ECAP program is available through FEI's annual EEC reports. The ECAP database used in the discussion guide contains the information on approximately 1750 individual Rate Schedule 1 customers who were part of this

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
	was addressed?	program since its initial launch in 2012. To study the low income customers' consumption, FEI examined the 2015 normalized consumption for each residential premise number that was recorded in the database. 8. The adjustment to the basic and volumetric charges FEI is considering is primarily the notion that we are collecting about 43% of customer related cost through basic charge, so it is more about the fairness principle and less about incenting behavior. You have a point on the other principles and how it might affect people's behavior. 9. Low use customers incur the same fixed costs to attach and require the same level of effort for meter reading, c=billing and customer service. Therefore there is no cost basis for doing anything special for low volume customers. And the extension policies already account for the different revenues from different volume customers so they would make different contribution when they connect. 10. In 2001 rate design proceeding, the Commission decided to change the ratio of fixed to variable charge to improve the alignment of fixed costs and fixed charge. With the 2001 Decision, the basic charge was increased from $8.66 per month to $10 per month and FEI was able to recover close to 50% of customer related costs with fixed basic charge. However as part of the 2010-2011 revenue requirement negotiated settlement, it was decided that in order to promote energy conservation any incremental increases in revenue requirement should only be allocated to variable charge. This led to a gradual decrease in ratio of cost recovery between fixed and variable charges. As demonstrated in slide 19 of the workshop, by holding the basic

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
		charge constant, higher use customers are bearing a greater share of the revenue requirement increases. The trend line slope in the graph shows that the Delivery Margin Change from 2009 to 2016 has been about 16% for 25 GJ Customers and 30% for 85 GJ customers (36% for 145 GJ customers). A small one-time increase can help to improve the alignment of fixed costs with fixed charges and improve the economic fairness for average use customers. However any change should only happen in consideration of other rate design principles. To add to the point, back in 1990s, we had revenue decoupling account, RSAM. The logic was that it would ensure that we recover our delivery revenues from residential and commercial rate classes and wouldn't discourage pursuing DSM. We still have that account in effect today. Other thing is we do have small use customers, if they are discouraged from being on the gas system we will lose them and lose the revenues from them and would drive other customers' rates up. It's a balance and we need to encourage appropriate cost recovery from these different customers. Not something that drives these customers away from the system. Costs are substantially fixed.
40	**Daily Demand Methodology** 1. What does bottom question mean? Do we think daily is more appropriate than monthly meter reads to set demand charge? If I had to pick from that list the modified formula seems that it would be fairest. 2. You want to use coldest day as that is most closely tied to	1. We currently don't base demand charge off daily meter reads. Today it is off monthly consumption. Our question to you is should we change our methodology to something different? But have noted the previous suggested comment of something less confusing to the customer. 2. Correct. Coldest day in each customer's region. What are these

Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
	demand related costs? It would be helpful to see a list of pros and cons of these options to status quo. Look at alternative options from Bonbright, what does it do for fairness, change in build and change in modified cost, high level piece. Useful for administrative examples, what type of customers would be winners and options?	customers actually consuming on the coldest day. Within COSA we typically allocate costs based upon peak weather conditions. Don't want to penalize someone for peaking on non-peak day when capacity is available.
41	**Demand Charge Adjustment for RS5/25** 1. What is Fortis asking the stakeholders to do? All interveners may not all have an interest in that issue. The lack of comment shouldn't be considered lack of concern. 2. $5 increase to demand charge seems arbitrary. Does Fortis have any concerns regarding shifting all costs to fixed charges? Even customers with correct load factor may not want to commit to such rate schedule. 3. Does FEI provide an annual analysis of customers whether they are better off in which rate, 23 or 25? We have a lot of high rise customers, margin is slim either way. They would just need to be notified if any changes would shift the economics of what rate class to be in. 4. If you do add the $5, is it also that the variable charge would be adjusted also? 5. Instead of $5, it could be another number to get you closer to zero impact of other rate classes?	1. There is an issue we have identified and we would like to discuss with you all what our considerations are to resolve that issue. It will be good to have your input on some of the options being presented. We want your feedback and would like to hear if you have any concerns. 2. It is not arbitrary. We looked at what does it take to move a load factor up to 40% as a base line. We created RS 5/25 back in 1993. Average load factor of all the customers. Adding $5 to existing charges creates that load factor. 3. We don't perform a mass mail out every year, but when we meet or talk with customers, rate analysis would be a discussion topic. 4. Correct. If we increased the demand charge by $5 per GJ we would have to look at what change downward may be required to the variable charge. 5. We can look into how we minimize overall impact. Demand charge could be adjusted by taking that into consideration. Correct, it could be another number than $5.

Rate Design & Segmentation Workshop August 31, 2016
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Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
43/44	**Large Volume Transportation & Contract Customers Rate Design Options** 1. Contracts with BC Hydro and Joint venture, what is option 2? 2. When it's up for renewal? 3. The effective rates, were those filed publicly with the Commission? 0.967 4. With the contracts coming up for renewal while you are doing this rate design. How does it fit in public forum? Especially with possible private negotiations. What would be process? This would be an issue on the table that may need some reporting back to. How do we determine what's the value of service for these contracts? Not taking a position just saying. 5. Will there be 3 industrial rate schedules for natural gas service in the province? Bonbright discriminatory principles for 22 and 22A and B, rate class based on rate class versus discount given is reflected in marginal cost differences. Also previous rates usually been determined by the Commission are not discriminatory. 6. Can you provide the revenue to cost ratio for the Joint Venture and BC Hydro? RS 22A customers are part of the reason for the reduction.	1. Option 2 is setting firm rates for all RS 22, BC Hydro and Joint Venture as a combined customer class. The tolls for the BCH and Joint Venture agreements would be tied to RS22. 2. No. Joint Venture had a rate that was set escalating. BC Hydro was set by the COSA and frozen, and as part of amalgamation remained frozen. We said we would look at what rate would apply to BC Hydro in the Rate Design. 3. Yes they have always been filed with Revenue Requirements. 4. If they become special negotiated rates then that would be part of application but the agreements and rates would be subject to BCUC review and approval. 5. Yes there could be three industrial rates. Two closed legacy rates and all other existing and new industrials would be under Rate Schedule 22. 6. Slide for Option 2 to lump RS 22 with BC Hydro and Joint Venture together will show the costs to serve that group of customers. Costs determined amount of firm we could offer and group was allocated transmission and distribution costs to serve that group as a whole.

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	Nature of customers, differences. Very similar to mills in the Interior as on Vancouver Island. Historic rate 20 years ago. Judgment applied by the company to make sure you tell the story so people can make an assessment as to what is fair and right. Explain the history in the application. Still puzzled as to why the rates are the way they are. Island Co-Gen. Double hit. There is another impact and every one of your customers also buys electricity as well. Sounds like one item to address at high level is pros and cons of reopening legacy rates as a concept. Should we start from scratch, or tweak some but not others. Which get adjusted and which don't. 7. Burrard Thermal – how big an impact is their termination? For RS 22AR:C ratio, helpful to have the background, how did it get to 180. Bypass customers, more background context.	7. FEI collects about $9 million per year, born by all other non-bypass customers as a loss in revenue, end of October. The filing will assume that's happened.
45	**Other Discussion Topics** 1. Marginal costing updated study for long run cost, status? Fortis also may have some information from the DSM? 2. Do either of the Tilbury expansion projects attract RS 50? 3. RS 50 and 46 revenue cost ratios – can you provide those?	1. FEI has not completed a long run marginal cost study and FEI hadn't intended on doing one. Long run marginal cost focuses on incremental generation/supply. Generation (gas cost supply) is a market based price for us already this is a third of the cost on the annual bill. FEI might be able to use the data from the main extension test application to derive marginal costs. 2. Current Tilbury expansion does not attract RS 50, however RS

Rate Design & Segmentation Workshop August 31, 2016
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Reference Slide No.	Summary of Question/Comment	FEI Response and Discussion Summary
		46 was derived assuming a transportation cost that is similar to RS 50. Further Tilbury expansions whether regulated or not, would attract RS50 as they would need to move gas across the FEI system. 3. We showed in the COSA workshop that R50 has no customers at this point. RS 46 – will take it under consideration. All of the Tilbury components are functionalized as Tilbury Storage and then bring in RS46 assuming 100% capacity to reduce the cost to Tilbury Storage bucket. We also showed that even if you take that out, there is little impact to revenue to cost ratio.

Rate Design & Segmentation Workshop August 31, 2016
Summary

Action Items and Next Steps

	Item	Responsibility	Target Completion
1.	Can you provide a history on the level of curtailment for interruptible customers?	FEI	FEI checked and it is consistent with what we indicated as a general rule of thumb. For the past 20 years there has been approximately 19.5 days of capacity curtailment so it is averaging about 1 day per year. This number is based upon cold weather days where all interruptible customers in the region are curtailed and does not include capacity constrained regions of our system where partial curtailment happens every year and the greenhouses out in Delta are an example of that. This also does not include capacity curtailment or interruptions for maintenance work.
2.	History of RS 22A R:C ratio? Why is that so high?	FEI	With the Application
3.	Value of interruptibility (to be able to curtail interruptible customers)	FEI	With the Application
4.	Any IT revenues included in R:C ratio for RS22A?	FEI	FEI checked and the R:C for Rate Schedule 22A included both firm and interruptible revenues.
5.	Comparison of variable rate of the residential margin cost comparison verses marginal cost? To see whether the existing rate structure has a price signal that is in excess?	FEI	With the Application
6.	Provide data for scatter plot used for RS2 and 3 discussions.	FEI	With the Application
7.	Provide scatter plot for RS 5/25 and RS 1	FEI	With the Application

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	Item	Responsibility	Target Completion
8.	Can you eliminate demand charge? Make the rate simpler based on actual load factor instead of complicated economics.	FEI	With the Application
9.	1600 GJ threshold for RS 2 and Rs3/23 to be looked as an option.	FEI	With the Application
10.	Largest magnitude impact is if the contract expires in 2022 with BC Hydro. In the event that doesn't get renewed from a revenue rate rebalancing issue?	FEI	With the Application
11.	Why different rates for RS 22 and RS 27?	FEI	With the Application
12.	Why it makes sense to grandfather RS 22A and RS 22B? History?	FEI	With the Application
13.			
14.	Customer Research Survey results	FEI	With the Application
15.	Notes to be reviewed by all stakeholders	Stakeholders	September 30, 2016

Rate Design & Segmentation Workshop August 31, 2016
Summary

Key Issues

Issues List	
1.	Application Approach: • As discussed during the workshop, there are no major issues raised. However, FEI has identified few adjustments to residential, commercial and industrial rate design. Prior to making any final proposals, FEI to consider why a change is required from status quo. So using rate design principles to clearly identify the problem that exists (if any) and evaluate the options to resolve the problem and make recommendations/proposals based on those rate design principles.
2.	Rebalancing: • FEI to consider looking at margin to cost ratios for rebalancing.
3.	Residential Rate Design: • Confirmation that FEI will be considering to adjust the ratio of basic charge to the variable charge.
4.	Commercial Rate Design: • Confirmation that FEI will be evaluating changing the threshold to 1600 GJ between RS 2 and RS 3/23 as an alternative option.
5.	Industrial Rate Design: • For RS 5/25, FEI to consider if any adjustments are required at this time as changes made to the rates for RS 5/25 will have a ripple effect on rates for other rate schedules such as RS 7/27, RS 22 and RS 1.

Key Issues

Key Issues List	
Workshop 1 – FEI COSA : July 11, 2016	
1.	EEC Costs Classification – should it be energy related or customer related?
2.	Tilbury Expansion project costs and revenues - 2018 cost of service and forecast revenues or 10 year levelized costs and revenues
3.	Treatment of SCP in the COSA model. Why do the recommended changes make sense?
4.	Treatment of Bypass customers – is it possible to quantify and allocate bypassed costs to these customers?
5.	Treatment of interruptible customers – does it make sense to allocate any demand related costs?
6.	Revenue to Cost Ratios – range of reasonableness? If outside the range, rebalancing to unity or within the range of reasonableness given other rate design considerations?
Workshop 1 – Fort Nelson : July 27, 2016	
7.	Common Rates: Confirmation that FEI will not be proposing the adoption of common rates for Fort Nelson in the 2016 RDA.
8.	Rebalancing: New "Option 3": shift revenues to Rate Schedule 25 to rebalance Rate 2.1 and 2.2 and Rate Schedule 25 (leave Rate Schedule 1 at 92% R:C ratio).
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, as suggested by the attendees?
Workshop 2 – Transportation Service Review : August 12, 2016	
10.	Monthly versus Daily Balancing: • Confirmation that FEI will be proposing to have all customers be daily balanced based on principles and reasons as mentioned at the workshop • Confirmation that FEI will not be doing financial evaluation for the value of daily vs monthly balancing
11.	Balancing Tolerance and Value: • Everyone is in agreement that some value exists for FEI's balancing services. B&V 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 would recommend appropriate tolerance levels based on further evaluation. • FEI would need to come up with an appropriate mechanism to capture the balancing service value for transportation customers.

Key Issues List	
Workshop 3 – Rate Design & Segmentation : August 31, 2016	
12.	Application Approach: • FEI identified a few 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.
13.	Rebalancing: • FEI will consider margin to cost ratios for rebalancing.
14.	Residential Rate Design: • Confirmation that FEI will be considering adjusting the ratio of the basic charge to the variable charge.
15.	Commercial Rate Design: • Confirmation that FEI will be evaluating changing the threshold to 1600 GJ between Rate Schedule 2 and Rate Schedule 3/23 as an alternative option.
16.	Industrial Rate Design: • For Rate Schedule 5/25, FEI will consider if any adjustments are required at this time considering that changes made to the rates for Rate Schedule 5/25 will have a ripple effect on rates for other rate schedules such as Rate Schedules 7/27, 22 and 1.

Appendix 4-3

DISCUSSION GUIDES

FortisBC Energy Inc.

2016 Rate Design Application

Workshop 1: COSA
Discussion Guide

June 27, 2016

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Appendix F: Fully Distributed COSA Study 2016 Test Year Schedules including discussion of Mt Hayes Cost Allocation

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1. INTRODUCTION

FortisBC Energy Inc. (FEI or the Company) is planning to hold a series of Workshops over the next three months for the purpose of working towards an efficient and cost effective regulatory process once the 2016 FEI Rate Design Application (Application or RDA) is filed later this year. This section discusses the objectives of Workshop 1 - Cost of Service Allocation (COSA or COSA Workshop) that FEI will be holding on July 11, 2016.

The key objectives or goals of the COSA workshop are to inform and review the results of the cost allocations and engage all stakeholders in compiling a key issues list, which will then be used to focus the scope of the RDA. FEI has updated its COSA model and has prepared this discussion guide that summarizes key assumptions, allocation methodologies and results for both Gas Costs and Delivery Costs. FEI regards these assumptions, methodologies and allocations as a starting point for discussion and will consider the input of stakeholders prior to the filing of Application.

FEI is circulating this discussion guide in advance of the COSA workshop so that all Stakeholders can review the materials and prepare to participate effectively at the COSA Workshop and contribute to the development of the key issues list. While FEI does not expect that all parties will be in agreement on all the issues, and that some may well have to be settled through the regulatory process, we anticipate that it will be useful to hear the various positions that parties may have so that they may be considered as we move toward filing the RDA in the fall of 2016.

2. PART A: GAS COST ALLOCATIONS

In this section, FEI will discuss the key components of gas costs and provide a brief history related to the gas cost rate design methodologies since the 1991 Rate Design (also referred to as the 1991 Phase A Application). This section will also discuss the classification and allocation of gas costs currently in place. Although a number of changes have been made within the gas supply portfolio since the early 1990s, the gas supply cost allocation methodologies established during the 1991 Rate Design proceeding remain largely unchanged today.

2.1 GAS COST – KEY COMPONENTS

The gas costs are split between commodity and midstream costs, which correlate with the two key components on a customer's bill. Commodity costs correlate with the Cost of Gas component of a customer' bill (also called the Commodity Cost Recovery Charge within the gas tariffs, or more simply referred to as the commodity charge) and midstream costs correlate with the Storage and Transport component of a customer's bill (Storage and Transport charges, also simply referred to as midstream charges).

Both the commodity costs and midstream 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. Transport customers do not pay commodity or midstream charges.

This section will further discuss what is included in the commodity and midstream costs.

2.1.1 Commodity

Commodity costs consist of market priced annual baseload[1] 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 British Columbia Utilities Commission (the Commission) and adjusted if required. For cost allocation purposes, gas purchased by marketers on behalf of their customers under the Customer Choice Program is not included in the commodity costs or the determination of the FEI Cost of Gas charge. This is because these costs are negotiated between a customer and gas marketer directly.[2]

2.1.2 Midstream

Midstream costs are mainly for resources contracted by FEI to facilitate the flow of gas into FEI's service territory each day so that the demand of the core customers can be served and

[1] Baseload is 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 Essential Services Model.

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

the pipeline system stays in balance on a daily basis. Midstream resources are used each day to balance FEI's total gas distribution system by either supplementing it with gas supply when demand is greater or removing excess gas supply out of the system when the demand is lower. 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.

In addition, the midstream portfolio of assets available to service the daily load for the sales customers and balance the total system as a whole daily also includes some company owned assets such as the Southern Crossing Pipeline system, the Tilbury LNG and Mt. Hayes LNG facilities. The operational uses and cost allocations for the Southern Crossing Pipeline, and the Tilbury and Mt. Hayes LNG facilities are discussed under section 3.1.2 of this discussion guide.

Midstream portfolio 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 like Southern Crossing Pipeline and the Mt. Hayes LNG plant which is discussed later under section 3.1.2.

The total cost of the midstream resources are partially offset by revenues collected from mitigation activities such as selling off a portion of the midstream resources on a short term basis in the marketplace when they are not required to meet the requirements of sales customers or manage the requirements of the system as a whole. Examples of mitigation activities include selling 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 pipeline by releasing a portion of contracted pipeline capacity to third parties in the summer months.

The Storage and Transport charges are reviewed quarterly by the Commission, but are normally reset annually using a January 1 effective date. Although the Storage and Transport charges are only charged to sales customers, the resources utilized each day balance the system as a whole, which benefits both sales and transport customers.

2.2 GAS COST - RATE DESIGN HISTORY

Highlights of the major approved rate design methodologies for FEI's gas costs over the past approximately 25 years are summarized in Table 2-1 below and are discussed further in this Section.

Table 2-1: Summary of FEI Gas Cost Rate Design Methodologies Approved Over Time

FEI Application	Key Rate Design Methodologies Approved
1991 Rate Design (Phase A Rate Design)	• Gas cost allocation methodology responding to the deregulation of the gas supply environment. • Development of regional Core Market gas cost recovery charges for each of the three FEI regions (Lower Mainland, Inland, and Columbia). • Development of the Gas Cost Reconciliation Account (GCRA) deferral account.
2004 Customer Choice (Commodity Unbundling) Program	• Implementation of the Essential Services Model and unbundling of the gas supply portfolio to facilitate commodity unbundling for low volume consumers. • Separation of the GCRA into two deferral accounts, the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA). • Gas supply portfolio components and costs assigned to either the commodity portfolio or the midstream portfolio. • Unbundling of the gas cost recovery charges to form commodity and midstream cost recovery charges. • Retained the gas cost allocation methodologies from the 1991 Rate Design. • Commercial customer unbundling implemented in 2004, and residential customer unbundling implemented in 2007.
2012 Common Rates, Amalgamation and Rate Design (2012 RDA) and 2013 Reconsideration on the 2012 RDA	• Commodity costs to be allocated on an energy-related basis; maintain CCRA deferral account across the amalgamated entity. • Midstream costs to be allocated on a demand-related basis; maintain MCRA deferral account across the amalgamated entity. • Postage-stamped commodity and midstream charges throughout the amalgamated service area.

2.2.1 1991 Rate Design

FEI's current rate design methodology has its origins in a two phase rate design process that occurred in 1991 (referred to as "Phase A") and in 1993 (referred to as "Phase B").[3] The first phase addressed gas costs, and the second phase addressed the remainder of the rate design, including delivery charges.

The 1991 Phase A Rate Design dealt principally with gas supply cost allocation methodology for Lower Mainland, Columbia and Inland service regions and responded to the deregulation of the gas supply environment.

By Order G-22-92 and the accompanying Decision, both dated February 21, 1992, the Commission approved the methodology to classify costs associated with commodity purchases within the gas supply portfolio on an energy-related basis and allocated based on throughput,

[3] Commission Order G-92-91 dated September 23, 1991 established the two-phase rate design review process.

while classifying fixed costs associated with upstream pipeline capacity and storage[4] on a demand-related basis and allocating those costs to customer classes based on coincident peak day demand methodology (also referred to as a load factor adjusted volumetric basis).

2.2.2 2004 Customer Choice (Commodity Unbundling) Program

The Essential Services Model and business rules for Commodity Unbundling were approved pursuant to Appendix A to Commission Letter L-25-03, dated June 6, 2006. On January 16, 2004, the Company filed a cost allocation application for commodity unbundling. Commission Order G-25-04, dated March 12, 2004, and the Reasons for Decision attached as Appendix A to the Order, provided the cost allocation approvals. The implementation of the Customer Choice Program resulted in a number of changes to the structure of the gas supply portfolio. A few of the key changes are as follows:

- The implementation of the Essential Services Model[5] in 2004 to support the Customer Choice Program;
- The gas supply portfolio was divided into the commodity portfolio and midstream portfolio;
- The GCRA deferral account was divided into the CCRA deferral account and the MCRA deferral account; and
- All components and costs of the pre-unbundling gas supply portfolio and GCRA deferral account were assigned to either the commodity portfolio and CCRA, or the midstream portfolio and MCRA.

Although the implementation of the Customer Choice Program resulted in changes to the structure of the gas supply portfolio, the classification and allocation of the gas supply costs remained consistent with the cost allocation approved in the 1991 Rate Design.

2.2.3 2012 Common Rates, Amalgamation and Rate Design Application (2012 RDA) and 2013 Reconsideration on the 2012 RDA

As a result of the 2012 RDA and 2013 Reconsideration on the 2012 RDA, the Commission approved the use of the FEI rate structures as the foundation for proposed postage stamp rates across the amalgamated entity (excluding the Fort Nelson Service Area). With respect to gas supply costs, the cost allocation methodologies established in the 1991 Rate Design were applied as much as possible to the gas cost allocation approach for the amalgamated entity. Thus, for the amalgamated entity, commodity costs continue to be allocated on an energy-

[4] Also includes the fixed cost component of any commodity supply netback contracts then in place.

[5] The Essential Services Model supported the delivery of baseload commodity by FEI and unbundling marketers to the regional supply hubs, from where FEI midstream would manage the supply available to the customer demand using its storage and transportation resources.

related basis and midstream costs were to be allocated on a demand-related basis, with midstream charges postage stamped throughout the amalgamated service area.

2.3 *GAS COST – CURRENT ALLOCATION METHODOLOGY*

As discussed above, the current gas cost allocation methodology includes classifying the commodity costs as energy-related and allocating those costs to sales customers based on throughput. The midstream costs are classified as demand-related and allocated on a load factor adjusted volumetric basis. Although, there have been changes to the gas supply portfolio over the last 25 years, the gas cost allocation methodology remains largely consistent with what was approved in the 1991 Rate Design.

The midstream costs are allocated to sales customers using a three year rolling average load factor, such that the basis of the allocation of the midstream costs are the load factor adjusted volumes (i.e. the peak day volume). Interruptible (Rate Schedule 7) and Seasonal (Rate Schedule 4) 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. However, for Interruptible and Seasonal service customers, the Storage and Transport charge is set equal to the rate for General Firm Sales Service (Rate Schedule 5). An exception to the rolling three year average load factor is for General Firm Sales Service customers, whose load factor has been set at 50%. Setting the load factor at 50% was part of the 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.

2.4 *RESULTS*

The following two tables show results:

The following table presents the midstream cost allocation, as a percentage of the cost, based on the load factor adjusted volumes and FEI's current approach of using a three year average load factor for rate schedules 1, 2, 3 and a deemed 50% load factor for rate schedule 5.

Table 2-2: Midstream Cost Allocation

Rate Schedule	Midstream Cost Allocation
1	62%
2	23%
3	13%
5	2%

1 The following table presents the midstream and commodity charges by rate class.

2 **Table 2-3: Midstream and Commodity Charges by Rate Class**

2016 Test Year		Total	RATE 1	RATE 2	RATE 3	RATE 4	RATE 5	RATE 6	RATE 7
Midstream Sales Volume	(TJ)	120,882	72,399	27,942	18,037	130	2,173	47	155
Midstream Costs	(000's)	163,374	101,214	39,035	21,049	109	1,819	20	129
Midstream Cost Recovery Charges [1]	($/GJ)		**$ 1.398**	**$ 1.397**	**$ 1.167**	**$ 0.837**	**$ 0.837**	**$ 0.417**	**$ 0.837**
Commodity Sales Volume - FEI	(TJ)	107,522							
Commodity Costs	(000's)	267,299							
Commodity Cost Recovery Charge	($/GJ)		**$ 2.486**	**$ 2.486**	**$ 2.486**	**$ 2.486**	**$ 2.486**	**$ 2.486**	**$ 2.486**

3 [1] Load Factor adjusted volumetric basis.

4 Please refer to Appendix A that includes schedules showing the commodity and midstream
5 charges by rate class.

3. PART B: DELIVERY COST ALLOCATIONS

3.1 *KEY ASSUMPTIONS*

3.1.1 Test Year Used

FEI is using approved costs from its 2016 Annual Review (Order G-193-15) for allocation within the Cost of Service Allocation (COSA) model. FEI chose 2016 as the base for allocation because it reflects the current operating conditions, reflects the amalgamation of FEI, FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW), and is the closest in time to the expected implementation date of the Rate Design Application (RDA) decision. In addition to the 2016 approved costs, FEI has included forecast costs of some major projects expected to be in service, these projects are discussed further in section 3.1.2.

FEI's 2016 approved costs have not been escalated to attempt to estimate 2018 costs and revenues. The COSA model uses the approved numbers as is. However, with this rate design FEI is endeavouring to put in place rates that will be functional for both the present and for the future. Consequently, in addition to the 2016 approved costs, FEI has included in the COSA model major projects expected to be in-service or close to their in-service dates at the time that rates from the rate design are put in place.

3.1.1.1 O&M

The COSA model uses an activity view of O&M as part of the cost allocation. In 2016, FEI is under performance based ratemaking (PBR) whereby gross O&M is escalated using a formula[6]. Since the formulaic O&M is not derived using a bottom up approach, there is no bottom up (or activity) view to use in the COSA model. To allocate the formulaic O&M for the COSA model, FEI first divided the formulaic O&M into components that mirror the costs to operate and maintain the utility. To do this, FEI has used the 2014 O&M activity view from FEI, FEVI and FEW's annual reports. The costs for each account were summed for the three utilities, then the sums of all the accounts were totalled and a ratio of the summed accounts to the total was developed and applied to the 2016 approved formulaic O&M. That is, the ratio was applied to the formulaic O&M so that the gross amount could be split up for allocation within the COSA model. The following table is an excerpt of the process used to derive the ratio (percentage) that is used to allocate the formulaic O&M.

[6] Order G-138-14

Table 3-1: Excerpt of Formulaic O&M Allocation

Particulars	Reference	FEI 2014	FEVI 2014	FEW 2014	Total 2014	Percentage
Distribution Supervision	110-11	11,236	2,082	72	13,391	5.19%
Operation Centre - Distribution	110-21	11,179	777	160	12,117	4.70%
Preventative Maintenance - Distribution	110-22	2,688	157	20	2,866	1.11%
Operations - Distribution	110-23	6,060	1,156		7,215	2.80%
Emergency Management - Distribution	110-24	5,329	1,133		6,461	2.51%
Field Training - Distribution	110-25	3,191	230		3,421	1.33%
Meter Exchange - Distribution	110-26	2,482	285		2,767	1.07%
Corrective - Distribution	110-31	4,998	508		5,507	2.14%
Account Services - Distribution	110-41	1,439	245	16	1,700	0.66%

In addition to the activity view O&M, property taxes are also included and allocated within the COSA model.

3.1.1.2 Rate Base

The COSA model also uses test year rate base for functionalization and allocation. Rate base is predominantly comprised of the mid-year balance of net plant assets, net contribution in aid of construction, unamortized deferrals and transmission line pack.

3.1.1.3 Customers and Load Information

The number of customers and annual demand (load) by rate schedule from FEI's test year are both used within the COSA model. These two inputs are used to develop many of the allocators within the COSA model. Generally, FEI's delivery system has been constructed to meet 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 for each rate schedule. The peak day demand is used to allocate much of FEI's system costs that are classified as demand. In addition to system costs in place to meet peak day demand, FEI has costs caused by the connection of customers to FEI's delivery system. The number of customers in each rate schedule is used to allocate the customer costs that are caused from a customer joining FEI's delivery system.

3.1.2 Cost Allocations for Existing Major Assets: Tilbury LNG, Mt. Hayes LNG, and Southern Crossing Pipeline

3.1.2.1 Tilbury LNG

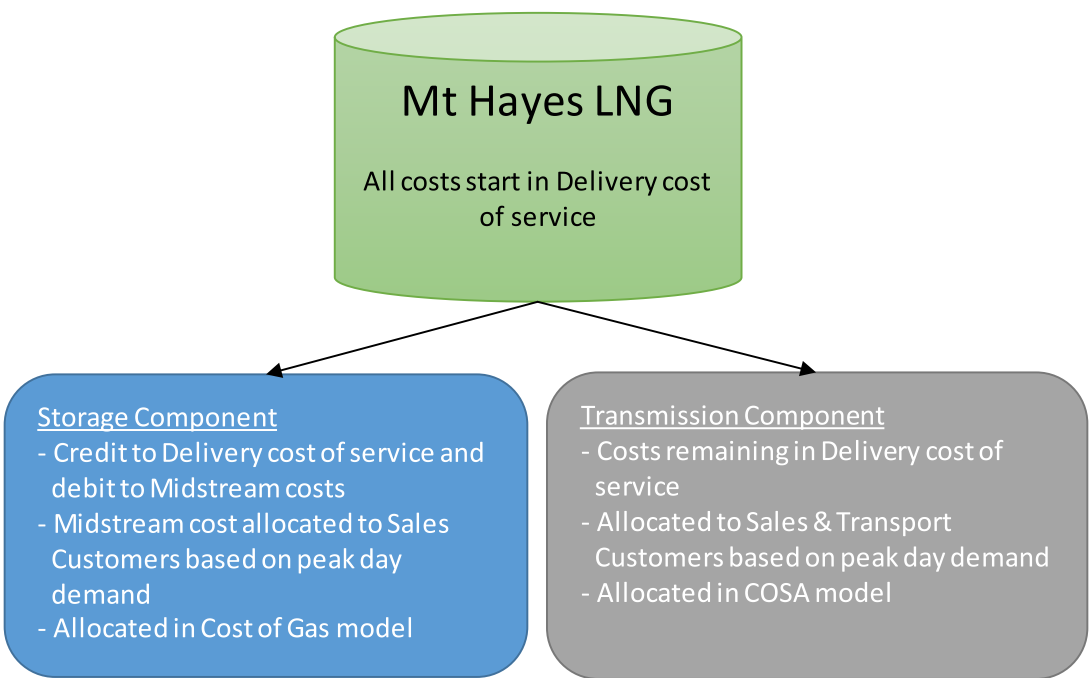
The Tilbury LNG Storage facility was constructed in 1971 principally to serve as a needle peaking resource for the supply of gas on extreme cold days. The Tilbury LNG Storage facility also supports transmission and distribution operations during maintenance and repair activities. Since the 1993 Phase 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 (Rate Schedule 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 (Rate Schedule 7 and 27) and Large Industrial (Rate Schedule 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.

3.1.2.2 Mt. Hayes LNG

The Mt. Hayes LNG facility went into service in 2011. The Mt. Hayes 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 would provide such capacity. The avoided cost of third party storage and transportation is approximately $18 million per year, which is the value reclassified to FEI's midstream and allocated as all other midstream costs are allocated. The cost of the Mt. Hayes 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. The following diagram depicts how Mt Hayes costs are split between Delivery and Midstream and the allocation method of each.

Figure 3-1: Mt Hayes Storage and Transmission Costs



3.1.2.3 Southern Crossing Pipeline (SCP)

The SCP transmission pipeline entered into service in November 2000 and allowed for a greater diversity of gas supply to be sourced from Alberta through the TransCanada West system. The pipeline and compressor stations equipment were designed to allow the flow of gas to be bi-directional, i.e. east to west and west to east. At the time of going into service, part of the support for the pipeline was the contracting of capacity by Pacific Gas and Electric (PG&E) and BC Hydro. Since then the capacity held by PG&E and BC Hydro have been taken up by Northwest Natural and FEI Gas Supply (Midstream). The valuation of SCP costs included in the Gas Supply Midstream is reviewed and approved by the Commission. The midstream component of the SCP costs is allocated to all sales customers on a peak day demand basis. The value of the midstream is credited to the cost of service in FEI's revenue requirements and in FEI's COSA model. The remaining 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.

3.1.3 Cost Assumptions for Major Projects and CPCNs

With this rate design FEI is endeavouring to put in place rates that will be functional for both the present (test year) and for the foreseeable future. Consequently, in addition to test year inputs, FEI has also 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 the rate design are put in place. Following is a list of these projects and their expected in-service dates.

Table 3-2: Expected Project In-Service Dates

Project	Expected In-Service Date	Mid-Year Rate Base included in COSA ($millions)	Cost of Service included in COSA ($millions)
Lower Mainland Intermediate Pipe System Upgrade	October 2018	$256	$25
Coastal Transmission System Upgrades	December 2017	$159	$13
Tilbury Expansion Project	January 2017	$399	$47

The Lower Mainland Intermediate Pipe System Upgrade (LMIPSU) CPCN was filed on December 19, 2014 and was an application to construct and operate two IP pipeline segments in the Lower Mainland of British Columbia that will replace existing pipeline segments. It was approved by BCUC Order C-11-15. The LMIPSU costs are comprised predominantly of distribution mains.

The Coastal Transmission System upgrades (CTS) includes projects to expand FEI's transmission facilities at Cape Horn valve assembly and the Coquitlam Gate Station; between the Nichol Valve Assembly and Port Mann Crossover Station; between the Nichol Valve Assembly and Roebuck Valve Assembly; and between the Tilbury Gate Station and Tilbury LNG

Facility. The approval for the CTS projects and recovery from all customers through rates is prescribed by Order in Council No. 749, as an amendment to Direction No. 5 to the BCUC.

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 North American LNG demand. Approval for the Tilbury Expansion project and recovery from all customers through rates is prescribed by Order in Council No. 557, Direction No. 5 to the BCUC. The Tilbury Expansion project is intended to serve the North American LNG market, to provide net benefits to FEI customers over the life of the asset and will be added into FEI's rate base in FEI's Annual Review for 2017 rates. The initial demand for LNG from the Tilbury Expansion will be lower than the total LNG production capacity of the asset, but FEI expects demand to increase to the assets full capacity over time. Consequently, FEI has included in the COSA model the present value of the Tilbury Expansion costs and revenues over the first ten years of its service life so as to not distort allocations in the COSA model. Ten years was selected as the rate design is intended to provide rate structures that will be fair and appropriate for greater than one year and FEI expects that rate design decisions from this application to be in place for at least ten years.

In addition to the projects referenced in the previous table, FEI may also include the Eagle Mountain - Woodfibre Gas Pipeline (EGP) Project and accompanying Rate schedule 50 revenue as an option in the COSA model. The EGP project is an expansion of FEI's transmission facilities at and between the Eagle Mountain Compressor Station in Coquitlam and an LNG Facility (near Squamish), and a new Squamish area compressor station located in the vicinity of the District of 19 Squamish (V2). The EGP project is included in Order in Council No. 749, as an amendment to Direction No. 5 to the BCUC. Although this project has been approved, FEI is still in negotiations with Woodfibre LNG (WLNG) so has not yet begun construction of the expansion. Until this project is considered highly likely to proceed, FEI will exclude it from the COSA model.

As the above projects are added into the COSA model they create an adjustment to the test year revenue margin that is also brought into the COSA model. This adjustment is made within the COSA model to be consistent with the change that these projects would have on customer's rates when they are placed into service and appear in FEI's revenue requirement.

3.1.4 Existing Customer Segmentation

The COSA model uses FEI's existing Rate Schedules as the basis for cost allocations and calculating revenue to cost ratios. The following table shows by rate schedule the number of customers and annual demand in TJ from FEI's 2016 Annual Review.

Table 3-3: Customers and Annual Demand (TJ) by Rate Schedule

Rate Schedule	Customers	Annual Demand (TJ)
1	886,652	72,466
2	84,737	28,012
3/23	6,709	27,090
4	18	130
5/25	796	15,663
6	15	47
7/27	113	6,691
22[7]	26	13,189
Total	**979,066**	**163,288**

3.2 METHODOLOGY

3.2.1 Peak Day Demand Calculation Method

Consistent with FEI's 1993, 1996, 2001 and 2012 RDAs, the coincident peak demand approach was used in this rate design to allocate the demand related costs to each customer group. The coincident peak approach continues to be appropriate as it allocates demand-related costs to the customer groups that drive system capacity requirements based on the share of system capacity used by each of those customer groups.

The coincident peak of a particular rate schedule is the demand required to serve that group of customers when the system wide demand is at its highest (on the peak (coldest) day. The coincident peak for each rate schedule is also referred to as the load factor adjusted volume and is calculated in the following way:

Coincident Peak = (Annual Volume) / (Load Factor x 365)

As indicated in the formula above, a load factor must be calculated to calculate the coincident peak for each rate schedule. While there are exceptions, lower load factors are generally associated with increasingly heat sensitive load (i.e. residential and commercial customers) while higher load factors are normally indicative of process oriented load.

Consistent with the 2012 and 2001 RDAs, the load factors for the heat sensitive rate schedules (Rates 1, 2, 3/23, and 5/25) are calculated using a three step linear regression methodology, for each region and rate schedule separately. The peak day (coldest day) temperature is varied across FEI's service regions. To develop a peak day demand that is representative of the entire

[7] Excludes Rate Schedules 22A and 22B

utility, FEI uses regional temperature data to calculate the peak day demand. The method FEI uses is as follows:

1. Calculate the Peak Day Consumption:
   - Regress 10 months of actual demand data against average monthly temperatures to establish the linear model parameters.
   - Enter the resulting linear model with the regional peak day temperature to establish the peak day consumption.
2. Calculate the Average Daily Consumption:
   - The average daily consumption is the normalized annual actual use per customer ("UPC") divided by 365.
3. Calculate the Load Factor:
   - The load factor is the ratio of the average daily consumption to the peak day consumption.

As described in the coincident peak formula above, these load factors are applied to the volumes of the applicable rate schedule for the test period to calculate the peak day demand.

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

The sum of the rate schedules peak day demand determines total system demand which is then utilized to calculate the demand allocator for each of the functionalized and classified categories of the cost of service.

3.2.2 Minimum System Study

The Minimum System Study ("MSS") examines the various mains in place 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. Consistent with past practice, FEI has included an updated MSS within this COSA model.

To determine how distribution costs should be split between demand and customer related components, the costs of the overall distribution system are compared to the costs of a hypothetical minimum system where the minimum pipe diameter is used to serve customers, so that the cost of increases to pipe diameter to meet demand are removed. Specifically, the hypothetical minimum system is one in which the actual pipe diameters of the FEI's system are replaced with the existing minimum distribution system standard (60 mm PE). The cost of the minimum system is calculated by multiplying the unit cost of 60 mm PE by the length of all distribution mains. The cost of the minimum system is then divided by the total cost of the distribution system. The percentage derived represents the minimum system and is the percentage of costs of the distribution system that are classified as customer-related in the COSA. The remaining per cent is classified as demand-related in the COSA. The MSS results classify FEI's distribution related costs as 30% customer and 70% demand. This is an important cost allocation step due to the significant size of the distribution system costs.

3.2.1 Peak Load Carrying Capacity Adjustment

The Peak Load Carrying Capacity ("PLCC") adjustment is intended to recognize that there is capacity built into the minimum system and that this capacity component of the minimum system should be classified as demand related and not as customer related. For the Distribution function, the demand related allocator is calculated by applying the PLCC adjustment to the coincident peak demand for each of the customer classes.

The PLCC adjustment in the COSA involves determining the theoretical capacity of each of FEI distribution systems assuming a 60 mm diameter main. The capacity of the minimum sized distribution systems was then divided by the number of customers served by each distribution system and an average minimum system capacity per customer was calculated to determine the PLCC adjustment. This PLCC adjustment was then multiplied by the number of customers in each rate class, and the corresponding amount was subtracted from to the peak day demand for that rate class. The use of the PLCC adjustment was included in FEI's 2012 Rate Design COSA model.

The PLCC adjustment for this Application was determined to be 0.205 GJ per day per customer. 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.

3.2.2 Customer Weighting Factor Study and Customer Administration Factor

3.2.2.1 Customer Weighting Factor Study

To ensure that customer-related costs associated with meters and services are allocated based on cost causation, a Customer Weighting Factor Study is conducted. 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. Rate schedule 1 is the basis for comparison because service under rate schedule 1 requires FEI's least cost meter and service. Once the weighting factors have been calculated and assigned to each rate schedule, customer-related costs can be allocated appropriately across all rate schedules. This study helps ensure each rate schedule is assigned the appropriate proportion of customer-related costs based on cost causation.

3.2.2.2 Customer Administration Factor

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

Weighting factors for each rate class were developed which take into consideration: the frequency of meter reading; the use of AMR 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 weighted for customer administration and billing are then used to allocate costs associated with the customer administration to each rate class. The results from the customer weighting factor study and customer administration factor assessment are included in the table below.

Table 3-4: Customer Weighting Factor Study and Customer Administration Factor Assessment Results

Rate Schedule	Customer Weighting Factor	Customer Admin Factor
1	1.0	1.0
2	1.7	1.0
3	7.7	1.2
4	13.6	0.9
5	11.1	43.0
6	13.3	43.0
7	300.2	43.0
22	49.9	75.0
23	10.3	75.0
25	17.6	75.0
27	46.2	75.0

3.2.3 Bypass, Special Contract and Large Industrial Customers

Bypass contracts are service agreements under which larger volume industrial customers, located in close proximity to upstream transmission pipelines, have negotiated with FEI for delivery charges that are reflective of the customer's cost of constructing its own pipeline to bypass the Company's system. With the exception of the specific rate (and related terms and conditions), the terms and conditions of service in bypass contracts generally conform to the standard rate schedule under which the customer will be receiving service. All bypass rates are approved by the Commission. The COSA treats the bypass revenues as Other Revenue, which is credited to the cost of service and allocated to Core Market and non-contract transportation service rate schedules on the basis of revenue margin. This application contemplates no change to the service rates, terms and conditions applicable to bypass customers.

Special contract rate customers are those customers that have historical negotiated rates which are fixed in their respective transportation service agreements. Contract rate customers served from the Vancouver Island transmission system include the Vancouver Island Gas Joint Venture (VIGJV), BC Hydro (for service to Island Cogen Plant). A contract rate customer served in the East Kootenays is Elk Valley Coal Corporation known previously as Fording Coal Mountain or Byron Creek. All contract rates are approved by the Commission.

Large industrial customers include the Inland region Rate Schedule 22A customers and Columbia region Rate Schedule 22B customers. Both of these rate schedules have been closed to new customers since 1993 Phase B Rate Design Application decision.

The current COSA model treats Special contract rate customer and Large Industrial customer revenues as credits to the cost of service and allocates that credit to each Core Market and non-contract transportation service rate schedule on the basis of revenue margin. The Company has adopted this approach to be consistent with its 2012 application however, Special contract customers and Large Industrial rate schedules are being evaluated in consideration of industrial customer segmentation and rate design.

3.2.4 Interruptible Customers

Interruptible customers are those customers who can be curtailed by FEI in the event that capacity is required to serve firm customers. Since service to interruptible customers can be curtailed, these customers do not drive system capacity additions; therefore, no demand-related costs are allocated to these customer classes in the COSA.

For the purposes of this COSA study, interruptible customer classes attract customer-related costs based on the allocated costs to connect them to the system. This approach and methodology is consistent with past practice and allocates a fair portion of costs to interruptible customers. Since no demand-related costs are allocated to these customers, the interruptible rate classes are excluded from the presentation of Revenue to Cost Ratios.

3.2.5 Biomethane and Natural Gas for Transportation

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 biomethane service cost recovery mechanisms that are currently in place. Currently, all biomethane related costs (with the exception of some interconnections)[8] 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

[8] BCUC Letter L-10-14 Response to Request for Clarification.

COSA model for functionalization and allocation are the cost of seven interconnections[9]. These interconnections are functionalized as distribution costs an allocated to all customers who have access to the biomethane program.

FEI's Natural Gas for transportation (NGT) program provides incentives to customers for the purchase of CNG/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 a fuelling station solution. The rate treatment of these expenditures was approved for FEI in Commission Order G-161-12. The costs of FEI's NGT program are included in the delivery charges for all non-bypass customers. The fuelling stations FEI has constructed attract CNG and LNG compression services revenue that is included as Other Revenue and treated as an offset to the cost of service in FEI's COSA model.

3.3 RESULTS

3.3.1 Functionalization Summary

The functionalization step involves separating the costs from the test period revenue requirements 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. FEI functionalized the 2016 test year costs including known and measurable changes into the following categories:

1. Gas Supply: Commodity and Midstream;
2. LNG Storage: Tilbury including Tilbury Expansion Project;
3. LNG Storage: Mt. Hayes;
4. Transmission including CTS Loops and Southern Crossing Pipeline ("SCP");
5. Distribution including LMIPSU Projects;
6. Marketing; and,
7. Customer Accounting.

All of these functional categories were used in FEI's 2012 COSA. The following table summarizes the results of the delivery cost of service functionalization from the COSA model.

[9] Ibid

Table 3-5: Delivery Cost of Service Functionalization Summary

Function	$ millions Functionalized	Percentage of total
Gas Supply Operations	$0.3	0%
Tilbury LNG Storage	$35	5%
Mt Hayes LNG Storage	$7	1%
Transmission	$156	20%
Distribution	$466	60%
Marketing	$47	6%
Customer Accounting	$61	8%
Total	**$772**	**100%**

3.3.2 Classification Summary

Having functionalized the costs, the COSA study then classifies the functionalized costs into cost-causation categories. These cost causation categories are related to consumption behaviours, system demand, energy delivery or number of customers and are called Demand, Energy and Customer respectively.

- **Demand:** Demand-related costs are those associated with plant that is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as transmission and distribution mains. Essentially, they refer to 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 the FEI's requirement for serving peak demand on 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 the FEI's customers, few of the costs to operate the Company's facilities are variable with respect to the volume of gas delivered to customers. Commodity supply expenses are classified as commodity-related costs as a means to apportion the costs to all sales customers.

- **Customer:** Customer-related costs are those that are incurred when attaching a customer to the distribution system, metering the customer's gas usage and maintaining the customer's accounts. They 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. These costs then 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 borne by both customers connecting to the system and by the maximum hourly or daily gas flow requirements. A Minimum System Study with Peak Load Carrying Capability ("PLCC") Adjustment, discussed above, is conducted and employed to aid the classification of distribution mains costs into both customer and demand related costs. The following table summarizes the results of the delivery cost of service classification from the COSA model.

Table 3-6: Delivery Cost of Service Classification Summary

Classification	$ millions Classified	Percentage of total
Demand	$383	50%
Energy	$0.3	0%
Customer	$389	50%
Total	**$756**	**100%**

3.3.3 Allocation Summary

When all forecast costs from the test year including known and measurable changes are functionalized into the major categories and classified by cost causation, they can then be allocated to each customer group. This allocation of costs is based on a customer's (or 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.

Demand-related costs are allocated to a customer group based on their contribution to the peak day demand measurement. Since each customer group possesses different service characteristics, allocation of demand-related costs based on a customer group's contribution to the peak day demand ensures that the appropriate proportion of those costs are allocated to those who require a larger share of the system capacity.

Energy-related costs are allocated based on annual gas throughput for each rate class.

For allocation of customer-related costs the Customer Weighting Factor Study and Customer Administration Factor are used. The Customer Weighting Factor Study aids in the allocation of customer-related costs associated with meters and services, and the customer administration factor aids in the allocation of costs associated with customer administration and billing. Weighting factors are estimated values indicating the total relative value of meter and service assets or customer administration associated with a specific rate class as compared to other rate classes. Once the weighting factors have been calculated and assigned to each rate class, customer-related costs can be allocated appropriately across the company. This study helps ensure each rate class is assigned the appropriate proportion of customer-related costs based on cost causation. The following table summarizes the results of the delivery cost of service allocation to rate schedules from the COSA model.

Table 3-7: Delivery Cost of Service Allocation to Rate Schedules Summary

Rate Schedule	$ millions Allocated	Percentage of total
1	$508	66%
2	$132	17%
3/23	$94	12%
4	$0.1	0%
5/25	$35	5%
6	$0.1	0%
7/27	$2	0%
22 Interruptible	$0.8	0%
Total	**$772**	**100%**

3.3.4 Revenue to Cost Ratios

The COSA study is one of the primary tools used to establish cost guidelines for the evaluation of rate class revenue levels. This evaluation process includes a comparison of the revenue for each customer class with the corresponding cost to serve them. This comparison is referred to as the Revenue to Cost ratio (R:C ratio). The R:C ratio shows whether the rates charged to each rate class adequately recovers their allocated cost of service. For FEI's transport rate schedules that have companion sales rate schedules (Rate schedule 3/23, 5/25 and 7/27) FEI imputes a Cost of Gas so that when the R:C ratios are calculated the final R:C is on the same basis (revenue margin plus cost of gas).

R:C ratios are assessed based on whether or not they fall within an established "range of reasonableness". FEI believes that the appropriate range of reasonableness is 90 per cent to 110 per cent. Ideally, the revenue to cost ratio should equal 100 percent for each rate class, indicating that the rates charged are in fact economically efficient and fair since the revenues recovered from each rate class would exactly equal the indicated cost to serve them. However, achieving unity implies a level of precision that does not exist with any COSA. As a cost of service study necessarily involves assumptions, estimates, simplifications, judgments and generalizations, a "range of reasonableness" is warranted when evaluating the appropriateness of the revenue to cost ratios.

The result of the COSA study for each rate class is considered in light of this "range of reasonableness" and each rate class that falls within that range is deemed to be at unity. If a rate class 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 classes that require re-balancing. Even if all of the rate classes fall within the "range of reasonableness", further re-balancing may be necessary in light of rate class 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."[10] 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."[11] 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."[12]
- 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]."[13] As in the BC Hydro decision, the Commission determined that the appropriate target R:C in each rate class 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 the 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. Such certainty does not exist for natural gas utilities:

- The equivalent load research analysis for natural gas utilities does not draw from hourly system demand data but rather from daily system demand data.

[10] 2007 BC Hydro Rate Design Application Decision p. 71
[11] 2007 BC Hydro Rate Design Application Decision p. 71.
[12] Ibid
[13] 2009 FortisBC Inc. Rate Design Application Decision p. 77.

- 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.

Policy considerations 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 revenue to cost ratio has been 90 per cent to 110 per cent. In Commission Order No. G-42-91 that ruled on Ocelot Chemical's application seeking reconsideration of the Commission's ruling on Pacific Northern Gas's 1991 Rate Design Application (Order No. 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 classes. 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.[14]

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 percent, there is no compelling evidence to determine that the cost of service results indicate rate restructuring is required.[15]

[14] Commission Order G-42-91 p. 29.
[15] Ibid

The Commission also accepted as a guide to rate setting, a "range of reasonableness" of 90 per cent to 110 per cent in the BC Gas 1993 Phase B Rate Design.[16] The same range of reasonableness was used in the BC Gas 1996 Rate Design[17] and in the Terasen Gas Inc. 2001 Rate Design[18] and in FEI's 2012 Amalgamation Application

Consistent with past precedent FEI has applied a "range of reasonableness" of 90 per cent to 110 per cent in this Application.

The table below provides the revenue to cost ratios for each of the amalgamated entity rate classes based on the 2016 Revenue Requirement, known and measurable changes and COSA study.

Table 3-8: Revenue to Cost Ratios

Rate Schedule	Revenue to Cost Ratio
Rate 1 – Residential	96%
Rate 2 – Small Commercial	101%
Rate 3/23 – Large Commercial	102%
Rate 5/25 – Large General Service	105%
Rate 6 – Natural Gas for Vehicles	135%

For those rate classes that include customers who take transportation service (Rate Schedules 23, 25 and 27), an imputed cost of gas was included in the determination of the revenue to cost ratios in accordance with past Commission requests[19], to achieve consistency and a basis for comparison with firm customers.

The table above shows that Rate Schedule 6 is outside of the range of reasonableness. FEI is still in the process of soliciting information from stakeholders and is considering changes to its existing rate schedules. Once stakeholder information has been addressed and rate schedule proposals have been solidified, FEI will rebalance as necessary and include the rebalancing results with its application. Please refer to Appendix C that shows the COSA schedules using 2016 Test Year. Also, attached is Appendix B that shows the COSA schedules using 2013 Test Year.

[16] Order G-101-93, Decision, p.12: "In previous decisions the Commission has accepted a 10 percent band as reasonable."
[17] Order G-98-96 BC Gas Utility Ltd. 1996 Rate Design Proposals
[18] Order G-116-01 BC Gas Utility Ltd. 2001 Rate Design Application
[19] BCUC Order G-42-91 p. 3. Rate Classes 23, 25, and 27 are transportation options for Rate classes 3, 5 and 7 respectively. Since allocated cost for Rates 3, 5 and 7 includes cost of gas, a cost of gas is imputed for Rates Classes 23, 25 and 27 to ensure consistency and to show revenue to cost ratios on combined basis for Rates 3 & 23, Rates 5 & 25 and Rates 7 & 27.

4. KEY DISCUSSION TOPICS

4.1 MAJOR ASSETS ASSUMPTIONS

Section 3.1.3 discusses the cost allocation assumption used in the current COSA model with respect to the Tilbury Expansion project and the EGP project. This section compares the current COSA model assumption to other alternative for the allocation/treatment of these major assets.

4.1.1 Tilbury Expansion Project

FEI's general approach has been to include in its COSA model the approved costs from its 2016 annual review, which represents FEI's costs at a point in time. As described in section 3.1.3, FEI is including ten years of the Tilbury Expansion project's levelized costs and revenues in the COSA model. Another option for the Tilbury Expansion project is to include 2018 forecast cost and revenue in the COSA. This treatment would be consistent with including costs in the COSA based on a point in time.

The following table shows that by including Tilbury Expansion project in the COSA using 2018 forecast cost and revenue creates a small change in the Rate 6 revenue to cost ratio.

Table 4-1: Revenue to Cost Ratios – Tilbury Expansion Project Options

Rate Schedule	R:C Ratio	R:C ratio using 2018 Cost and Revenue for Tilbury Expansion
Rate 1 – Residential	96%	96%
Rate 2 – Small Commercial	101%	101%
Rate 3/23 – Large Commercial	102%	102%
Rate 5/25 – Large General Service	105%	105%
Rate 6 – Natural Gas for Vehicles	135%	136%

As discussed in section 3.1.3, inclusion of projects creates an adjustment to the test year revenue margin that is brought into the COSA model. Including Tilbury Expansion project 2018 forecast cost and revenue in the COSA model when the capacity of Tilbury is not yet fully sold creates a 2.5% larger initial revenue margin adjustment.

Please refer to Appendix D that shows the COSA schedules with Tilbury Expansion using 2018 forecast cost and revenues.

4.1.2 EGP Project

As an alternative to the assumption in the current COSA model, EGP cost and accompanying Rate Schedule 50 revenue can be included in the current COSA model. The following table shows that including the EGP project and accompanying Rate Schedule 50 revenue in the COSA creates a small change in the Rate 6 revenue to cost ratio.

Table 4-2: Inclusion of EGP Project and Rate Schedule 50 Revenue

Rate Schedule	R:C Ratio	R:C including EGP cost and RS50 revenue
Rate 1 – Residential	96%	96%
Rate 2 – Small Commercial	101%	101%
Rate 3/23 – Large Commercial	102%	102%
Rate 5/25 – Large General Service	105%	105%
Rate 6 – Natural Gas for Vehicles	135%	134%

Construction of the EGP project will be accompanied by high levels and demand and revenue. Consequently, when the project is added into the COSA model, the rate change to the test year revenue margin is 2.4% lower than when the project is excluded. As discussed in section 3.1.3, until it is probable that the EGP project will proceed, FEI plans to exclude it from the COSA model.

Please refer to Appendix E that shows the COSA schedules with EGP project cost and associated RS50 revenues included.

4.2 MT. HAYES COST ALLOCATION

Section 3.1.2.2 discusses the purpose of the Mt. Hayes LNG facility and the methodology used in the current COSA model to allocate costs related to this asset (Option A). This section compares the current COSA model allocation methodology to second option for the allocation of Mt. Hayes costs (Option B).

Option B

Option B for Mt. Hayes cost allocation is consistent with the Tilbury cost allocation, whereby all Mt. Hayes costs are allocated to delivery. This approach is more straightforward than Option A and would recognise the system capacity and reliability benefits all customers receive as a result of Mt. Hayes being part of the integrated transmission system. As shown below, the rate impact difference between Options A and B is minimal.

FEI has prepared a comparison of the cost allocation approach under Option A and Option B. Table 4-3 shows how the total cost of service for Mt. Hayes LNG plant is allocated between delivery margin and midstream. Table 4-4 below shows the total percent of costs that are allocated to sales and transport customers under both options through delivery margin and midstream costs.

Table 4-3: Comparison of Mt. Hayes Cost Allocation Approaches – Allocated Between Delivery Margin and Midstream

Allocation Methodology		SALES		TRANSPORT		TOTAL
		Del Margin	Midstream	Del Margin	Midstream	
Allocate Mt Hayes storage costs to Midstream Costs and Delivery margin for FEI	**Option A**	$6,583	$18,039	$886		$25,508
Allocate Mt Hayes storage costs to Delivery margin for FEI	**Option B**	$22,481		$3,027		$25,508

Table 4-4: Comparison of Mt. Hayes Cost Allocation Approaches

Allocation Methodology		SALES	TRANSPORT	TOTAL
Allocate Mt Hayes storage costs to Midstream Costs and Delivery margin for FEI	**Option A**	$24,622 **96.5%**	$886 **3.5%**	$25,508
Allocate Mt Hayes storage costs to Delivery margin for FEI	**Option B**	$22,481 **88.1%**	$3,027 **11.9%**	$25,508

Note: *The numbers in the tables above are in $000's*

The following table shows the impact of Option B on the revenue to cost ratio for core and transport customers.

Table 4-5: Option B Impact on R:C Ratio for Sales and Transport Customers

Rate Schedule	Revenue to Cost Ratio	R:C using Option B of Mt Hayes
Rate 1 – Residential	96%	96%
Rate 2 – Small Commercial	101%	100%
Rate 3/23 – Large Commercial	102%	102%
Rate 5/25 – Large General Service	105%	104%
Rate 6 – Natural Gas for Vehicles	135%	136%

Please refer to Appendix F that shows the COSA schedules for Option B.

4.3 SOUTHERN CROSSING PIPELINE COST ALLOCATION

One of the options with respect to Southern Crossing Pipeline costs allocation is to functionalize these costs separately and allocate to those customers that utilize the transmission asset. The following table show that there is no change in R:C ratios when SCP is allocated separately from other Transmission assets.

Table 4-6: No Change to R:C Ratios when SCP Functionalized Separately

Rate Schedule	Revenue to Cost Ratio	R:C SCP as a separate function
Rate 1 – Residential	96%	96%
Rate 2 – Small Commercial	101%	101%
Rate 3/23 – Large Commercial	102%	102%
Rate 5/25 – Large General Service	105%	105%
Rate 6 – Natural Gas for Vehicles	135%	135%

The primary reason for the negligible change is that when SCP is treated as a separate function, the only customer group that does not attract an allocation are FEI's large transport customers in the lower mainland, predominantly rate schedule 22 customers.

Please refer to Appendix G that shows the COSA schedules with SCP functionalized separately.

4.4 LOAD FACTORS FOR ALLOCATION

As discussed in section 2.3, FEI allocates midstream costs to rate schedule 5 using 50% as the load factor. This was part of the 1996 Rate Design Application Negotiated Settlement Agreement. To align the allocation of midstream costs and delivery costs, FEI is considering changing the deemed load factor of 50% to the calculated load factor of 45%. Forty five percent is derived using the same approach as FEI uses to calculate the load factors for rate schedules 1, 2, and 3 as discussed in section 2.3. The following table shows that changing the deemed rate schedule 5 load factor from 50% to 45% changes the allocation of midstream costs and midstream charges for sales customers.

Table 4-7: Deemed Rate Schedule 5 Load Factor

2016 Test Year RS 5 @ *calculated 45%*		Total	RATE 1	RATE 2	RATE 3	RATE 4	RATE 5	RATE 6	RATE 7
Midstream Sales Volume	(TJ)	120,882	72,399	27,942	18,037	130	2,173	47	155
Midstream Costs	(000's)	163,374	101,072	38,980	21,014	121	2,023	20	144
Midstream Cost Recovery Charge [1]	**($/GJ)**		**1.396**	**1.395**	**1.165**	**0.931**	**0.931**	**0.417**	**0.931**

2016 Test Year RS 5 @ *deemed 50%*		Total	RATE 1	RATE 2	RATE 3	RATE 4	RATE 5	RATE 6	RATE 7
Midstream Sales Volume	(TJ)	120,882	72,399	27,942	18,037	130	2,173	47	155
Midstream Costs	(000's)	163,374	101,214	39,035	21,049	109	1,819	20	129
Midstream Cost Recovery Charge [1]	**($/GJ)**		**1.398**	**1.397**	**1.167**	**0.837**	**0.837**	**0.417**	**0.837**

[1] Load Factor adjusted volumetric basis

Appendix A

GAS COST ALLOCATION SCHEDULES

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_2016 Test Year

Appendix A
Schedule 1

COST OF GAS - COMMODITY & MIDSTREAM BREAKDOWN

Line No.	Particulars	Reference	Total	RATE 1	RATE 2	RATE 3	RATE 4	RATE 5	RATE 6	RATE 7
1	**Energy - 2016 Test Year (TJ)**									
2										
3	**Sales Customers Volume [1]**		**121,103.5**	**72,466.1**	**28,012.1**	**18,121.3**	**129.9**	**2,172.7**	**46.8**	**154.6**
4	Revelstoke Propane Sales Volume		221.6	66.9	70.2	84.5	-	-	-	-
5	Natural Gas Sales Volume	Line 3 - Line 4	120,881.9	72,399.2	27,941.9	18,036.8	129.9	2,172.7	46.8	154.6
6										
7										
8	Commodity Sales Volume - FEI	Line 5 - Line 9	107,521.9	65,258.2	24,244.9	15,514.8	129.9	2,172.7	46.8	154.6
9	Commodity Sales Volume - Cst Choice Marketers		13,360.0	7,141.0	3,697.0	2,522.0	-	-	-	-
10	Midstream Sales Volume	Line 5	120,881.9	72,399.2	27,941.9	18,036.8	129.9	2,172.7	46.8	154.6
11										
12										
13										
14	**Cost of Gas - Commodity & Midstream [2] ($000s)**	Breakdown at Lines 16 to 18	**$ 474,863**	**$ 287,645**	**$ 111,133**	**$ 67,784**	**$ 432**	**$ 7,219**	**$ 136**	**$ 514**
15										
16	Commodity - FEI		$ 267,299	$ 162,232	$ 60,273	$ 38,570	$ 323	$ 5,401	$ 116	$ 384
17	Commodity - Revelstoke Propane & Cst Choice Marketers		$ 44,190	$ 24,199	$ 11,825	$ 8,165	$ -	$ -	$ -	$ -
18	Midstream		$ 163,374	$ 101,214	$ 39,035	$ 21,049	$ 109	$ 1,819	$ 20	$ 129
19										
20										
21										
22	**Commodity & Midstream Cost Recovery Charges ($/GJ)**									
23										
24	Commodity Cost Recovery Charge - FEI	Line 16 / Line 8		**$ 2.486**	**$ 2.486**	**$ 2.486**	**$ 2.486**	**$ 2.486**	**$ 2.486**	**$ 2.486**
25										
26	Midstream (Storage and Transport) Charges [3]	Line 18 / Line 10		**$ 1.398**	**$ 1.397**	**$ 1.167**	**$ 0.837**	**$ 0.837**	**$ 0.417**	**$ 0.837**

Notes:

[1] Energy forecast per Commission Order G-193-15 Compliance Filing - FEI Annual Review for 2016 Rates Application filed on December 11, 2015, Attachment 1, Section 11, Schedule 18, Col. 3.

[2] Cost of Gas (Commodity and Midstream) per Commission Order G-193-15 Compliance Filing - FEI Annual Review for 2016 Rates Application filed on December 11, 2015, Attachment 1, Section 11, Schedule 17, Col. 3.

[3] Excludes Midstream Cost Reconciliation Account (MCRA) Rider 6.

Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_2016 Test Year
COMMODITY COST RECOVERY CHARGE

Appendix A
Schedule 2

Line No.	Particulars	Reference		Total		RATE 1		RATE 2		RATE 3		RATE 4		RATE 5		RATE 6		RATE 7
1	**Commodity Sales Volume[1] (TJ)**			**117,427**														
2																		
3																		
4																		
5	**Cost of Gas - Commodity[1] ($000s)**	Breakdown at Lines 7 to 9	**$**	**291,955.3**														
6																		
7	Baseload Commodity		$	323,766.8														
8	Administration		$	1,541.7														
9	Commodity Cost Reconciliation Account (CCRA) Deferral Balance		$	(33,353.2)														
10																		
11																		
12																		
13	**Commodity Cost Recovery Charge - FEI ($/GJ)**	Line 5 / Line 1 (or Sched. 1, Line 24)	**$**	**2.486**														
14																		
15	Commodity Sales Volume by Rate Class (TJ)					68,869		26,793		18,135		146		3,395		48		41
16	Commodity Cost Recovery Charge ($/GJ)				$	2.486	$	2.486	$	2.486	$	2.486	$	2.486	$	2.486	$	2.486

Notes:
[1] Energy and commodity cost forecast for April 2015 to March 2016 per FEI 2015 First Quarter Gas Cost Report (Section 1, Tab 2, Page 3) and set the Commodity Cost Recovery Charge effective April 1, 2015, approved pursuant to Commission Order G-39-15.

Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_2016 Test Year
MIDSTREAM (STORAGE AND TRANSPORT) CHARGES and MCRA RIDER 6

Appendix A
Schedule 3

Line No.	Particulars	Reference	Total	RATE 1	RATE 2	RATE 3	RATE 4	RATE 5	RATE 6	RATE 7
1	**Midstream Sales Volume [1] (TJ)**		**121,382.9**	**72,390.7**	**27,242.3**	**18,173.2**	**150.9**	**3,336.7**	**46.9**	**42.2**
2										
3										
4	**Load Factor [2]**			29.8%	29.9%	35.8%		50.0%	100.0%	
5										
6	Load Factor Adjusted Volume by Rate Class	Line 1 / Line 4		242,551	91,182	50,769		6,673	47	
7	Load Factor Adjusted Volume Total	Total of Line 6	391,223							
8										
9	Load Factor Adjusted Volumetric Allocation (%)	Line 5 / Total in Line 6	100%	61.98%	23.31%	12.99%		1.71%	0.01%	
10										
11										
12										
13	**Cost of Gas - Midstream [1] ($000s)**	Breakdown at Lines 16 to 20	$ 163,266.1							
14	Load Factor Adjusted Volumetric Allocation of Midstream Costs	Use % at Line 9		$ 101,195.5	$ 38,056.9	$ 21,201.7	$ -	$ 2,792.3	$ 19.5	$ -
15										
16	Commodity Related Costs		$ (9,205.2)	$ (5,705.6)	$ (2,145.7)	$ (1,195.4)	$ -	$ (157.4)	$ (1.1)	$ -
17	Storage Related Costs		$ 76,180.5	$ 47,218.2	$ 17,757.5	$ 9,892.8	$ -	$ 1,302.9	$ 9.1	$ -
18	Transportation Related Costs		$ 91,693.5	$ 56,833.4	$ 21,373.5	$ 11,907.3	$ -	$ 1,568.2	$ 11.0	$ -
19	GSMIP Incentive Sharing		$ 1,000.0	$ 619.8	$ 233.1	$ 129.9	$ -	$ 17.1	$ 0.1	$ -
20	Administration		$ 3,597.3	$ 2,229.7	$ 838.5	$ 467.1	$ -	$ 61.5	$ 0.4	$ -
21										
22										
23	**Midstream (Storage and Transport) Charges [1] ($/GJ)**	Line 14 / Line 1 (or Sched. 1, Line 26)		**$ 1.398**	**$ 1.397**	**$ 1.167**	**$ 0.837**	**$ 0.837**	**$ 0.417**	**$ 0.837**
24										
25										
26										
27										
28	Midstream Cost Reconciliation Account (MCRA) Deferral Balance [3]		**$ (7,410.8)**							
29	Load Factor Adjusted Volumetric Allocation of MCRA	Use % at Line 9		$ (4,593.3)	$ (1,727.4)	$ (962.4)	$ -	$ (126.7)	$ (0.9)	$ -
30	**MCRA Rider 6 [1] ($/GJ)**	Line 29 / Line 1		**$ (0.064)**	**$ (0.063)**	**$ (0.053)**	**$ (0.038)**	**$ (0.038)**	**$ (0.019)**	**$ (0.038)**

Notes:

[1] Energy and midstream cost forecast for January to December 2015 per FEI 2014 Fourth Quarter Gas Cost Report (Tab 2, Page 7) and set the Storage and Transport Charges and MCRA Rider 6 approved effective January 1, 2015, pursuant to Commission Order G-175-14.

[2] Based on the 3-year average load factor for rate schedules 1, 2, 3 and a deemed 50% load factor for rate schedule 5 as used in the FEI 2014 Fourth Quarter Gas Cost Report. Storage and Transport charges and MCRA Rider 6 for rate schedules 4 and 7 are set equal to the rate schedule 5 Storage and Transport charge and MCRA Rider 6.

[3] MCRA deferral balance amortization as filed in the FEI 2014 Fourth Quarter Gas Cost Report (Tab 2, Page 7).

Slight differences in totals due to rounding.

Appendix B

FULLY DISTRIBUTED COSA STUDY
2013 TEST YEAR SCHEDULES

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
SUMMARY (000's)

Schedule 1

L.No.	Particulars	Reference	Total	RATE 1	RATE 2	RATE 4 [2]	RATE 6	RATE 22 [2] NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27 [2]
1	**REVENUES**										
2	Total Revenues at Proposed 2013 FEI Rates	line 3 + line 4	**$ 1,292,794**	**$ 795,934**	**$ 241,068**	**$ 1,074**	**$ 504**	**$ 11,954**	**$ 187,190**	**$ 46,576**	**$ 8,493**
3	Revenue Margin at Proposed 2013 FEI Rates [4]		$ 669,773	$ 414,446	$ 110,258	$ 314	$ 249	$ 11,954	$ 89,436	$ 34,682	$ 8,434
4	Total Cost of Gas [3]		$ 623,020	$ 381,488	$ 130,810	$ 761	$ 255	$ -	$ 97,754	$ 11,894	$ 58
5											
6	**COST OF SERVICE**										
7	Total Utility Cost of Service	line 8 + line 9	**$ 1,351,981**	**$ 891,206**	**$ 239,820**	**$ 812**	**$ 467**	**$ 967**	**$ 178,004**	**$ 39,336**	**$ 1,369**
8	Cost of Service Margin		$ 728,961	$ 509,718	$ 109,009	$ 51	$ 212	$ 967	$ 80,250	$ 27,442	$ 1,311
9	Total Cost of Gas [3]		$ 623,020	$ 381,488	$ 130,810	$ 761	$ 255	$ -	$ 97,754	$ 11,894	$ 58
10											
11	**SURPLUS / DEFICIT**										
12	Total Surplus / Deficit	line 2 - line 7	**$ (59,187)**								
13	% increase to Equal Allocated Cost		8.8%								
14											
15	**REVENUES (adjusted to equal COS)**										
16	Total Adjusted Revenues at Proposed 2013 FEI Rates	line 17 + line 9	**$ 1,351,981**	**$ 832,559**	**$ 250,812**	**$ 1,102**	**$ 526**	**$ 13,010**	**$ 195,093**	**$ 49,641**	**$ 9,238**
17	Total Adjusted Revenue Margin at Proposed 2013 FEI Rates	line 3 x line 13	$ 728,961	$ 451,071	$ 120,001	$ 341	$ 272	$ 13,010	$ 97,339	$ 37,747	$ 9,180
18											
19	REVENUES (adjusted for R/C RATIOS) [1]		**$ 1,474,599**	**$ 832,559**	**$ 250,812**	**$ 1,102**	**$ 526**	**$ 13,010**	**$ 233,741**	**$ 109,766**	**$ 33,083**
20	COST OF SERVICE (adjusted for R/C RATIOS) [1]		**$ 1,474,599**	**$ 891,206**	**$ 239,820**	**$ 812**	**$ 467**	**$ 967**	**$ 216,652**	**$ 99,461**	**$ 25,214**
21											
22	**REVENUE TO COST RATIO**										
23	Revenue to Cost Ratio	line 19 / line 20	**100%**	**93.4%**	**104.6%**		**112.7%**		**107.9%**	**110.4%**	
24											
25	**REVENUE REBALANCING**										
26	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Total Revenues at Proposed Rates [1]	line 28 + line 9	**$ 1,474,599**	**$ 832,559**	**$ 250,812**	**$ 1,102**	**$ 526**	**$ 13,010**	**$ 233,741**	**$ 109,766**	**$ 33,083**
28	Total Revenue Margin at Proposed Rates	line 17 + line 26	$ 728,961	$ 451,071	$ 120,001	$ 341	$ 272	$ 13,010	$ 97,339	$ 37,747	$ 9,180
29											
30	**PROPOSED REVENUE TO COST RATIO**										
31	Revenue to Cost Ratio at Proposed Rates	line 27 / line 20	**100.0%**	**93.4%**	**104.6%**		**112.7%**		**107.9%**	**110.4%**	
32											

Note:

1. The revenues (line 27 and line 19) and cost of service (line 20) include the imputed COG number for Rate 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios. Please note that Rates 23, 25 and 27 do not pay for commodity and midstream charges.
2. Rate 4 is a seasonal service and Rates 22 and Rate7/27 are interruptible customer classes. The revenue to cost ratio for Rate 4, Rate 22 and Rate 7/27 are not shown in the schedule above as these rate classes do not drive system capacity additions and therefore, no demand-related costs are allocated to these customer classes in the COSA Study.
3. Cost of Gas forecast is based on five-day average of the November 1, 2, 3, 4, and 7, 2011 forward prices, and which reflect the forward prices utilized in the various FEU 2011 Fourth Quarter Gas Cost reports.
4. Revenue Margin includes UAF allocation to rate classes.

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
FUNCTIONALIZATION (000's)

Schedule 2

L.No.	Particulars	Total	Gas Supply Operations	LNG Storage Tilbury	LNG Storage Mt. Hayes	Transmission	Transmission SCP	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense	$ 243,770	$ -	$ 2,609	$ 4,236	$ 41,385	$ 7,537	$ 100,365	$ 5,371	$ 82,267
2	BCH Capacity Right	$ 244	$ -	$ -	$ -	$ 244	$ -	$ -	$ -	$ -
3	Property & Sundry Taxes	$ 61,924	$ -	$ 377	$ 1,076	$ 16,378	$ 5,621	$ 38,472	$ -	$ -
4	Depreciation Expense	$ 171,007	$ -	$ 2,349	$ 7,050	$ 34,157	$ 9,766	$ 117,684	$ -	$ -
5	Amortization Expense	$ 12,458	$ (2)	$ 49	$ 158	$ 8,245	$ (1,888)	$ 1,359	$ 4,474	$ 63
6	Other Operating Revenue	$ (77,908)	$ -	$ -	$ (18,039)	$ (38,070)	$ (14,827)	$ (4,412)	$ -	$ (2,560)
7	Other Earned Return Provisions	$ (97)	$ -	$ (1)	$ (4)	$ (24)	$ (8)	$ (59)	$ -	$ -
8	Income Tax	$ 36,742	$ -	$ 502	$ 1,581	$ 9,276	$ 2,907	$ 22,477	$ -	$ -
9	Earned Return	$ 280,821	$ -	$ 3,841	$ 12,081	$ 70,893	$ 22,215	$ 171,791	$ -	$ -
10	**Total Cost of Service Margin**	**$ 728,961**	**$ (2)**	**$ 9,726**	**$ 8,139**	**$ 142,484**	**$ 31,322**	**$ 447,676**	**$ 9,845**	**$ 79,770**
11										
12	Cost of Gas - Commodity	$ 459,919	$ 459,919	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Cost of Gas - Midstream	$ 163,102	$ 163,102	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	**Total Utility Cost of Service**	**$ 1,351,981**	**$ 623,018**	**$ 9,726**	**$ 8,139**	**$ 142,484**	**$ 31,322**	**$ 447,676**	**$ 9,845**	**$ 79,770**

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year

Schedule 3

RATE BASE SUMMARY - CLASSIFICATION (000's)

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Plant in Service										
2	**Total Gas Plant in Service**		**$ 5,204,738**	**$ 3,521,743**	**$ 847,991**	**$ 293**	**$ 751**	**$ 5,564**	**$ 617,167**	**$ 207,362**	**$ 3,867**
3		Demand	$ 2,955,093	$ 1,616,321	$ 593,089	$ -	$ 394	$ 4,632	$ 547,401	$ 193,255	$ -
4		Customer	$ 2,249,645	$ 1,905,422	$ 254,901	$ 293	$ 357	$ 932	$ 69,766	$ 14,107	$ 3,867
5		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	**Total Accumulated Depreciation**		**$ (1,422,596)**	**$ (958,136)**	**$ (232,141)**	**$ (64)**	**$ (190)**	**$ (1,583)**	**$ (171,520)**	**$ (58,132)**	**$ (829)**
7		Demand	$ (838,887)	$ (457,667)	$ (168,711)	$ -	$ (112)	$ (1,383)	$ (155,950)	$ (55,063)	$ -
8		Customer	$ (583,709)	$ (500,469)	$ (63,431)	$ (64)	$ (78)	$ (199)	$ (15,570)	$ (3,070)	$ (829)
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**TOTAL Net Plant**		**$ 3,782,142**	**$ 2,563,607**	**$ 615,849**	**$ 229**	**$ 561**	**$ 3,981**	**$ 445,647**	**$ 149,230**	**$ 3,038**
11		Demand	$ 2,116,206	$ 1,158,654	$ 424,378	$ -	$ 282	$ 3,248	$ 391,451	$ 138,193	$ -
12		Customer	$ 1,665,935	$ 1,404,953	$ 191,471	$ 229	$ 279	$ 733	$ 54,196	$ 11,037	$ 3,038
13		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14											
15	Contribution In Aid of Construction										
16	**Total CIAC**		**$ (425,839)**	**$ (288,967)**	**$ (69,129)**	**$ (24)**	**$ (62)**	**$ (493)**	**$ (50,049)**	**$ (16,793)**	**$ (322)**
17		Demand	$ (238,428)	$ (130,232)	$ (47,894)	$ -	$ (32)	$ (415)	$ (44,237)	$ (15,618)	$ -
18		Customer	$ (187,411)	$ (158,735)	$ (21,235)	$ (24)	$ (30)	$ (78)	$ (5,812)	$ (1,175)	$ (322)
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	**Total Accumulated Amortization**		**$ 118,407**	**$ 81,795**	**$ 18,807**	**$ 8**	**$ 17**	**$ 130**	**$ 13,169**	**$ 4,381**	**$ 99**
21		Demand	$ 60,595	$ 32,829	$ 12,257	$ -	$ 8	$ 106	$ 11,376	$ 4,018	$ -
22		Customer	$ 57,812	$ 48,966	$ 6,550	$ 8	$ 9	$ 24	$ 1,793	$ 363	$ 99
23		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	**Total Net Contribution**		**$ (307,433)**	**$ (207,172)**	**$ (50,322)**	**$ (17)**	**$ (44)**	**$ (362)**	**$ (36,880)**	**$ (12,413)**	**$ (223)**
25		Demand	$ (177,833)	$ (97,403)	$ (35,637)	$ -	$ (24)	$ (309)	$ (32,860)	$ (11,600)	$ -
26		Customer	$ (129,599)	$ (109,769)	$ (14,685)	$ (17)	$ (21)	$ (54)	$ (4,019)	$ (813)	$ (223)
27		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28											
29	Work in Progress, no AFUDC		**$ 19,418**	**$ 12,366**	**$ 3,386**	**$ 1**	**$ 3**	**$ 23**	**$ 2,702**	**$ 928**	**$ 9**
30		Demand	$ 14,074	$ 7,840	$ 2,780	$ -	$ 2	$ 21	$ 2,536	$ 895	$ -
31		Customer	$ 5,344	$ 4,527	$ 606	$ 1	$ 1	$ 2	$ 166	$ 34	$ 9
32		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33											
34	Unamortized Deferred Charges										
35	**Total Unamortized Deferred Charges - Rate Base**		**$ 68,411**	**$ 32,207**	**$ 15,080**	**$ 10**	**$ 158**	**$ 148**	**$ 15,507**	**$ 5,326**	**$ (24)**
36		Demand	$ 86,025	$ 49,469	$ 16,437	$ -	$ 155	$ 155	$ 14,650	$ 5,159	$ -
37		Customer	$ (25,988)	$ (22,323)	$ (3,094)	$ (4)	$ (2)	$ (7)	$ (520)	$ (13)	$ (25)
38		Energy	$ 8,374	$ 5,061	$ 1,737	$ 14	$ 4	$ -	$ 1,378	$ 180	$ 1
39											
40	Cash Working Capital		**$ 10,310**	**$ 6,727**	**$ 1,718**	**$ 6**	**$ 4**	**$ 8**	**$ 1,440**	**$ 391**	**$ 15**
41		Demand	$ 3,537	$ 1,965	$ 700	$ -	$ 0	$ 5	$ 640	$ 226	$ -
42		Customer	$ 3,364	$ 2,701	$ 311	$ 0	$ 2	$ 3	$ 240	$ 92	$ 15
43		Energy	$ 3,410	$ 2,060	$ 707	$ 6	$ 2	$ -	$ 561	$ 73	$ 0
44											
45	Other Working Capital										
46	**Total Other Working Capital**		**$ 101,420**	**$ 56,054**	**$ 20,485**	**$ (0)**	**$ 9**	**$ 170**	**$ 18,325**	**$ 6,417**	**$ (41)**
47		Demand	$ 108,360	$ 61,464	$ 21,048	$ -	$ 14	$ 179	$ 18,970	$ 6,685	$ -
48		Customer	$ (6,940)	$ (5,410)	$ (563)	$ (0)	$ (5)	$ (8)	$ (644)	$ (268)	$ (41)
49		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50											
51	LILO, Capital Efficiency Mechanism, Others		**$ (1,150)**	**$ (867)**	**$ (162)**	**$ (0)**	**$ (0)**	**$ (1)**	**$ (91)**	**$ (28)**	**$ (1)**
52		Demand	$ (304)	$ (150)	$ (66)	$ -	$ (0)	$ (1)	$ (64)	$ (23)	$ -
53		Customer	$ (846)	$ (716)	$ (96)	$ (0)	$ (0)	$ (0)	$ (26)	$ (5)	$ (1)
54		Energy	$ -						$ -	$ -	$ -
55											
56	**Total Utility Rate Base**		**$ 3,673,118**	**$ 2,462,923**	**$ 606,034**	**$ 228**	**$ 690**	**$ 3,968**	**$ 446,651**	**$ 149,851**	**$ 2,773**
57		Demand	$ 2,150,064	$ 1,181,838	$ 429,641	$ -	$ 430	$ 3,299	$ 395,322	$ 139,534	$ -
58		Customer	$ 1,511,270	$ 1,273,963	$ 173,950	$ 209	$ 254	$ 668	$ 49,391	$ 10,063	$ 2,771
59		Energy	$ 11,784	$ 7,121	$ 2,444	$ 19	$ 6	$ -	$ 1,938	$ 253	$ 1

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Schedule 4

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Operating & Maintenance Expense										
2	**Total Operating & Maintenance Expense**		**$ 243,770**	**$ 171,426**	**$ 32,251**	**$ 11**	**$ 92**	**$ 459**	**$ 28,271**	**$ 10,469**	**$ 790**
3		Demand	$ 92,873	$ 50,770	$ 18,479	$ 2	$ 13	$ 312	$ 17,087	$ 6,128	$ 85
4		Customer	$ 150,896	$ 120,656	$ 13,773	$ 10	$ 79	$ 147	$ 11,184	$ 4,342	$ 705
5		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	BCH Capacity Right		**$ 244**	**$ 138**	**$ 47**	**$ -**	**$ 0**	**$ 0**	**$ 43**	**$ 15**	**$ -**
7		Demand	$ 244	$ 138	$ 47	$ -	$ 0	$ 0	$ 43	$ 15	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Property & Sundry Taxes		**$ 61,924**	**$ 41,537**	**$ 10,218**	**$ 4**	**$ 9**	**$ 72**	**$ 7,513**	**$ 2,522**	**$ 49**
11		Demand	$ 35,519	$ 19,313	$ 7,163	$ -	$ 5	$ 60	$ 6,635	$ 2,343	$ -
12		Customer	$ 26,405	$ 22,224	$ 3,055	$ 4	$ 5	$ 12	$ 878	$ 179	$ 49
13		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Depreciation Expense		**$ 171,007**	**$ 118,800**	**$ 27,339**	**$ 17**	**$ 31**	**$ 175**	**$ 18,454**	**$ 5,962**	**$ 228**
15		Demand	$ 79,672	$ 43,929	$ 15,881	$ -	$ 11	$ 119	$ 14,585	$ 5,147	$ -
16		Customer	$ 91,334	$ 74,871	$ 11,458	$ 17	$ 21	$ 55	$ 3,869	$ 815	$ 228
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Amortization Expense		**$ 12,458**	**$ 7,250**	**$ 2,321**	**$ 0**	**$ 44**	**$ 19**	**$ 2,083**	**$ 736**	**$ 4**
19		Demand	$ 11,526	$ 6,501	$ 2,235	$ -	$ 44	$ 18	$ 2,017	$ 711	$ -
20		Customer	$ 934	$ 751	$ 86	$ 0	$ 0	$ 1	$ 66	$ 25	$ 4
21		Energy	$ (2)	$ (1)	$ (0)	$ (0)	$ (0)	$ -	$ (0)	$ (0)	$ (0)
22	Other Operating Revenue		**$ (77,908)**	**$ (45,520)**	**$ (14,604)**	**$ (0)**	**$ (12)**	**$ (94)**	**$ (13,049)**	**$ (4,605)**	**$ (23)**
23		Demand	$ (72,103)	$ (40,810)	$ (14,045)	$ -	$ (9)	$ (89)	$ (12,680)	$ (4,469)	$ -
24		Customer	$ (5,805)	$ (4,710)	$ (559)	$ (0)	$ (3)	$ (5)	$ (369)	$ (135)	$ (23)
25		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Income Tax		**$ 36,742**	**$ 25,009**	**$ 5,953**	**$ 2**	**$ 5**	**$ 39**	**$ 4,275**	**$ 1,428**	**$ 30**
27		Demand	$ 20,212	$ 11,074	$ 4,050	$ -	$ 3	$ 32	$ 3,734	$ 1,318	$ -
28		Customer	$ 16,530	$ 13,934	$ 1,903	$ 2	$ 3	$ 7	$ 540	$ 110	$ 30
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Earned Return		**$ 280,821**	**$ 191,144**	**$ 45,500**	**$ 17**	**$ 42**	**$ 297**	**$ 32,672**	**$ 10,918**	**$ 232**
31		Demand	$ 154,480	$ 84,642	$ 30,958	$ -	$ 21	$ 241	$ 28,542	$ 10,076	$ -
32		Customer	$ 126,341	$ 106,502	$ 14,542	$ 17	$ 21	$ 56	$ 4,130	$ 842	$ 232
33		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34											
35	**Total Cost of Service Margin**		**$ 728,961**	**$ 509,718**	**$ 109,009**	**$ 51**	**$ 212**	**$ 967**	**$ 80,250**	**$ 27,442**	**$ 1,311**
36		Demand	$ 322,371	$ 175,528	$ 64,758	$ 2	$ 86	$ 693	$ 59,953	$ 21,265	$ 85
37		Customer	$ 406,592	$ 334,191	$ 44,251	$ 49	$ 126	$ 274	$ 20,297	$ 6,177	$ 1,226
38		Energy	$ (2)	$ (1)	$ (0)	$ (0)	$ (0)	$ -	$ (0)	$ (0)	$ (0)
39	Cost of Gas - Commodity		**$ 459,919**	**$ 277,933**	**$ 95,389**	**$ 761**	**$ 232**	**$ -**	**$ 75,655**	**$ 9,890**	**$ 58**
40		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42		Energy	$ 459,919	$ 277,933	$ 95,389	$ 761	$ 232	$ -	$ 75,655	$ 9,890	$ 58
43	Cost of Gas - Midstream		**$ 163,102**	**$ 103,555**	**$ 35,421**	**$ -**	**$ 23**	**$ -**	**$ 22,098**	**$ 2,004**	**$ -**
44		Demand	$ 163,102	$ 103,555	$ 35,421	$ -	$ 23	$ -	$ 22,098	$ 2,004	$ -
45		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	**Total Utility Cost of Service**		**$ 1,351,981**	**$ 891,206**	**$ 239,820**	**$ 812**	**$ 467**	**$ 967**	**$ 178,004**	**$ 39,336**	**$ 1,369**
48		Demand	$ 485,473	$ 279,084	$ 100,180	$ 2	$ 109	$ 693	$ 82,052	$ 23,269	$ 85
49		Customer	$ 406,592	$ 334,191	$ 44,251	$ 49	$ 126	$ 274	$ 20,297	$ 6,177	$ 1,226
50		Energy	$ 459,916	$ 277,931	$ 95,388	$ 761	$ 232	$ -	$ 75,655	$ 9,890	$ 58

FORTISBC ENERGY INC. (AMALGAMATED)
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Rate Design Filing_Common Rates_ 2013 Test Year

Schedule 5

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Supply Operations		**$ 11,784**	**$ 7,121**	**$ 2,444**	**$ 19**	**$ 6**	**$ -**	**$ 1,938**	**$ 253**	**$ 1**
2		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Energy	$ 11,784	$ 7,121	$ 2,444	$ 19	$ 6	$ -	$ 1,938	$ 253	$ 1
5											
6	LNG Storage Tilbury		**$ 41,717**	**$ 23,690**	**$ 8,120**	**$ -**	**$ 5**	**$ -**	**$ 7,321**	**$ 2,580**	**$ -**
7		Demand	$ 41,717	$ 23,690	$ 8,120	$ -	$ 5	$ -	$ 7,321	$ 2,580	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ 202,467**	**$ 114,978**	**$ 39,411**	**$ -**	**$ 26**	**$ -**	**$ 35,530**	**$ 12,522**	**$ -**
12		Demand	$ 202,467	$ 114,978	$ 39,411	$ -	$ 26	$ -	$ 35,530	$ 12,522	$ -
13		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 989,048**	**$ 560,740**	**$ 192,204**	**$ -**	**$ 126**	**$ 1,627**	**$ 173,280**	**$ 61,071**	**$ -**
17		Demand	$ 989,048	$ 560,740	$ 192,204	$ -	$ 126	$ 1,627	$ 173,280	$ 61,071	$ -
18		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											
21	Transmission SCP		**$ 305,472**	**$ 173,187**	**$ 59,363**	**$ -**	**$ 39**	**$ 502**	**$ 53,518**	**$ 18,862**	**$ -**
22		Demand	$ 305,472	$ 173,187	$ 59,363	$ -	$ 39	$ 502	$ 53,518	$ 18,862	$ -
23		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25											
26	Distribution		**$ 2,084,865**	**$ 1,561,899**	**$ 297,168**	**$ 209**	**$ 339**	**$ 1,777**	**$ 168,464**	**$ 52,237**	**$ 2,772**
27		Demand	$ 573,489	$ 287,854	$ 123,211	$ -	$ 85	$ 1,108	$ 119,062	$ 42,170	$ -
28		Customer	$ 1,511,376	$ 1,274,045	$ 173,958	$ 209	$ 255	$ 669	$ 49,402	$ 10,068	$ 2,772
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30											
31	Marketing		**$ 41,727**	**$ 24,344**	**$ 7,620**	**$ 0.1**	**$ 153**	**$ 67**	**$ 7,014**	**$ 2,503**	**$ 26**
32		Demand	$ 37,872	$ 21,389	$ 7,332	$ -	$ 149	$ 62	$ 6,610	$ 2,330	$ -
33		Customer	$ 3,855	$ 2,954	$ 289	$ 0.1	$ 3	$ 5	$ 404	$ 173	$ 26
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35											
36	Customer Accounting		**$ (3,962)**	**$ (3,036)**	**$ (297)**	**$ (0.1)**	**$ (3)**	**$ (5)**	**$ (415)**	**$ (178)**	**$ (27)**
37		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Customer	$ (3,962)	$ (3,036)	$ (297)	$ (0.1)	$ (3)	$ (5)	$ (415)	$ (178)	$ (27)
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40											
41	**Total Utility Rate Base**		**$ 3,673,118**	**$ 2,462,923**	**$ 606,034**	**$ 228**	**$ 690**	**$ 3,968**	**$ 446,651**	**$ 149,851**	**$ 2,773**
42		Demand	$ 2,150,064	$ 1,181,838	$ 429,641	$ -	$ 430	$ 3,299	$ 395,322	$ 139,534	$ -
43		Customer	$ 1,511,270	$ 1,273,963	$ 173,950	$ 209	$ 254	$ 668	$ 49,391	$ 10,063	$ 2,771
44		Energy	$ 11,784	$ 7,121	$ 2,444	$ 19	$ 6	$ -	$ 1,938	$ 253	$ 1

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Schedule 6

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Supply Operations		**$ 623,018**	**$ 381,487**	**$ 130,810**	**$ 761**	**$ 255**	**$ -**	**$ 97,754**	**$ 11,894**	**$ 58**
2		Demand	$ 163,102	$ 103,555	$ 35,421	$ -	$ 23	$ -	$ 22,098	$ 2,004	$ -
3		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Energy	$ 459,916	$ 277,931	$ 95,388	$ 761	$ 232	$ -	$ 75,655	$ 9,890	$ 58
5											
6	LNG Storage Tilbury		**$ 9,726**	**$ 5,523**	**$ 1,893**	**$ -**	**$ 1**	**$ -**	**$ 1,707**	**$ 602**	**$ -**
7		Demand	$ 9,726	$ 5,523	$ 1,893	$ -	$ 1	$ -	$ 1,707	$ 602	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ 8,139**	**$ 4,622**	**$ 1,584**	**$ -**	**$ 1**	**$ -**	**$ 1,428**	**$ 503**	**$ -**
12		Demand	$ 8,139	$ 4,622	$ 1,584	$ -	$ 1	$ -	$ 1,428	$ 503	$ -
13		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 142,484**	**$ 80,506**	**$ 27,606**	**$ 2**	**$ 18**	**$ 400**	**$ 24,969**	**$ 8,897**	**$ 85**
17		Demand	$ 142,484	$ 80,506	$ 27,606	$ 2	$ 18	$ 400	$ 24,969	$ 8,897	$ 85
18		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											
21	Transmission SCP		**$ 31,322**	**$ 17,758**	**$ 6,087**	**$ -**	**$ 4**	**$ 52**	**$ 5,488**	**$ 1,934**	**$ -**
22		Demand	$ 31,322	$ 17,758	$ 6,087	$ -	$ 4	$ 52	$ 5,488	$ 1,934	$ -
23		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25											
26	Distribution		**$ 447,676**	**$ 333,456**	**$ 64,653**	**$ 48**	**$ 77**	**$ 390**	**$ 36,990**	**$ 11,416**	**$ 646**
27		Demand	$ 126,666	$ 64,857	$ 26,812	$ -	$ 18	$ 234	$ 25,662	$ 9,083	$ -
28		Customer	$ 321,010	$ 268,599	$ 37,841	$ 48	$ 59	$ 156	$ 11,328	$ 2,333	$ 646
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30											
31	Marketing		**$ 9,845**	**$ 6,717**	**$ 1,211**	**$ 0**	**$ 47**	**$ 15**	**$ 1,308**	**$ 507**	**$ 39**
32		Demand	$ 4,033	$ 2,263	$ 776	$ -	$ 43	$ 7	$ 699	$ 246	$ -
33		Customer	$ 5,812	$ 4,454	$ 435	$ 0	$ 5	$ 8	$ 609	$ 261	$ 39
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35											
36	Customer Accounting		**$ 79,770**	**$ 61,138**	**$ 5,975**	**$ 1**	**$ 63**	**$ 110**	**$ 8,360**	**$ 3,583**	**$ 540**
37		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Customer	$ 79,770	$ 61,138	$ 5,975	$ 1	$ 63	$ 110	$ 8,360	$ 3,583	$ 540
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40											
41	**Total Utility Cost of Service**		**$ 1,351,981**	**$ 891,206**	**$ 239,820**	**$ 812**	**$ 467**	**$ 967**	**$ 178,004**	**$ 39,336**	**$ 1,369**
42		Demand	$ 485,473	$ 279,084	$ 100,180	$ 2	$ 109	$ 693	$ 82,052	$ 23,269	$ 85
43		Customer	$ 406,592	$ 334,191	$ 44,251	$ 49	$ 126	$ 274	$ 20,297	$ 6,177	$ 1,226
44		Energy	$ 459,916	$ 277,931	$ 95,388	$ 761	$ 232	$ -	$ 75,655	$ 9,890	$ 58

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
ALLOCATORS SUMMARY (000's)

Schedule 7

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Billing Determinants										
2											
3	Sales Volume (TJ)		162,502	74,862	26,997	185	56	11,504	28,499	14,579	5,819
4	Midstream Sales Volume (TJ)		162,287	74,800	26,918	185	56	11,504	28,425	14,579	5,819
5	Commodity Sales Volume (TJ)		148,927	67,660	23,221	185	56	11,504	25,903	14,579	5,819
6	Average No. of Customers		971,089	877,036	85,717	18	21	21	7,384	786	105
7											
8	Cost of Service Margin		**$ 728,961**	**$ 509,718**	**$ 109,009**	**$ 51**	**$ 212**	**$ 967**	**$ 80,250**	**$ 27,442**	**$ 1,311**
9		Demand	$ 322,371	$ 175,528	$ 64,758	$ 2	$ 86	$ 693	$ 59,953	$ 21,265	$ 85
10	Unit Demand Charge ($/GJ)			$ 2.34	$ 0.87	$ 0.00	$ 0.00	$ 0.01	$ 0.80	$ 0.28	$ 0.00
11		Customer	$ 406,592	$ 334,191	$ 44,251	$ 49	$ 126	$ 274	$ 20,297	$ 6,177	$ 1,226
12	Unit Customer Charge ($/GJ)			$ 4.46	$ 0.59	$ 0.00	$ 0.00	$ 0.00	$ 0.27	$ 0.08	$ 0.02
13		Energy	$ (2)	$ (1)	$ (0)	$ (0)	$ (0)	$ -	$ (0)	$ (0)	$ (0)
14	Unit Energy Charge ($/GJ)			$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)	$ -	$ (0.00)	$ (0.00)	$ (0.00)
15											
16	Unit Cost of Service Margin ($/GJ)			**$ 6.81**	**$ 4.04**	**$ 0.28**	**$ 3.76**	**$ 0.08**	**$ 2.82**	**$ 1.88**	**$ 0.23**
17											
18	Cost of Gas - Commodity		**$ 459,919**	**$ 277,933**	**$ 95,389**	**$ 761**	**$ 232**	**$ -**	**$ 75,655**	**$ 9,890**	**$ 58**
19		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Energy	$ 459,919	$ 277,933	$ 95,389	$ 761	$ 232	$ -	$ 75,655	$ 9,890	$ 58
22	Unit Cost of Gas - Commodity ($/GJ)			**$ 4.11**	**$ 4.11**	**$ 4.11**	**$ 4.11**	**$ -**	**$ 2.92**	**$ 0.68**	**$ 0.01**
23											
24	Cost of Gas - Midstream		**$ 163,102**	**$ 103,555**	**$ 35,421**	**$ -**	**$ 23**	**$ -**	**$ 22,098**	**$ 2,004**	**$ -**
25		Demand	$ 163,102	$ 103,555	$ 35,421	$ -	$ 23	$ -	$ 22,098	$ 2,004	$ -
26		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Unit Cost of Gas - Midstream ($/GJ)			**$ 1.38**	**$ 1.32**	**$ -**	**$ 0.41**	**$ -**	**$ 0.78**	**$ 0.14**	**$ -**
28											
29	Total Utility Cost of Service		**$ 1,351,981**	**$ 891,206**	**$ 239,820**	**$ 812**	**$ 467**	**$ 967**	**$ 178,004**	**$ 39,336**	**$ 1,369**
30		Demand	$ 485,473	$ 279,084	$ 100,180	$ 2	$ 109	$ 693	$ 82,052	$ 23,269	$ 85
31		Customer	$ 406,592	$ 334,191	$ 44,251	$ 49	$ 126	$ 274	$ 20,297	$ 6,177	$ 1,226
32		Energy	$ 459,916	$ 277,931	$ 95,388	$ 761	$ 232	$ -	$ 75,655	$ 9,890	$ 58
33	Unit Cost of Service ($/GJ)			**$ 11.90**	**$ 8.88**	**$ 4.38**	**$ 8.28**	**$ 0.08**	**$ 6.25**	**$ 2.70**	**$ 0.24**
34											
35	Total Revenues @ Proposed Rates		**$ 1,351,981**	**$ 832,559**	**$ 250,812**	**$ 1,102**	**$ 526**	**$ 13,010**	**$ 195,093**	**$ 49,641**	**$ 9,238**
36	Unit Rate ($/GJ)			**$ 11.12**	**$ 9.29**	**$ 5.95**	**$ 9.33**	**$ 1.13**	**$ 6.85**	**$ 3.40**	**$ 1.59**
37											
38	Total Revenue Margin @ Proposed Rates		**$ 728,961**	**$ 451,071**	**$ 120,001**	**$ 341**	**$ 272**	**$ 13,010**	**$ 97,339**	**$ 37,747**	**$ 9,180**
39	Unit Rate ($/GJ)			**$ 6.03**	**$ 4.44**	**$ 1.84**	**$ 4.81**	**$ 1.13**	**$ 3.42**	**$ 2.59**	**$ 1.58**

Appendix C

FULLY DISTRIBUTED COSA STUDY
2016 TEST YEAR SCHEDULES

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 1

SUMMARY (000's)

Line No.	Particulars	Reference	Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**REVENUE TO COST**										
2	Total Revenue at Proposed 2016 Common Rates	Line 3 + Line 4	$ 1,294,195	$ 730,278	$ 235,076	$ 694	$ 358	$ 13,560	$ 192,992	$ 88,732	$ 32,504
3	Revenue Margin at Proposed 2016 Common Rates		$ 718,924	$ 442,632	$ 123,943	$ 261	$ 223	$ 13,293	$ 91,660	$ 36,698	$ 10,214
4	Total Cost of Gas		$ 575,271	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 101,332	$ 52,034	$ 22,290
5											
6	**COST OF SERVICE**										
7	Total Utility Cost of Service	Line 8 + Line 9	$ 1,347,460	$ 796,138	$ 243,022	$ 490	$ 277	$ 964	$ 195,346	$ 87,309	$ 23,913
8	Cost of Service Margin		$ 772,189	$ 508,492	$ 131,889	$ 57	$ 142	$ 697	$ 94,013	$ 35,275	$ 1,623
9	Total Cost of Gas		$ 575,271	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 101,332	$ 52,034	$ 22,290
10											
11	**SURPLUS / DEFICIT**										
12	Total Surplus / (Deficit)	Line 2 - Line 7	$ (53,265)								
13	% Increase to Equal Allocated Costs	- Line 12 / Line 3	7.4%	Effect of major project additions to COSA model							
14											
15	**REVENUES (adjusted to equal COS)**										
16	Total Adjusted Revenue at Proposed 2016 Common Rates	Line 4 + Line 17	$ 1,347,460	$ 763,073	$ 244,259	$ 713	$ 375	$ 14,545	$ 199,784	$ 91,451	$ 33,261
17	Total Adjusted Revenue Margin at Proposed 2016 Common Rates	Line 3 x (1 + Line 13)	$ 772,189	$ 475,427	$ 133,126	$ 280	$ 240	$ 14,278	$ 98,451	$ 39,417	$ 10,971
18											
19	REVENUES (adjusted for R/C ratio's)	Line 16	$ 1,347,460	$ 763,073	$ 244,259	$ 713	$ 375	$ 14,545	$ 199,784	$ 91,451	$ 33,261
20	COST OF SERVICE (adjusted for R/C ratio's)	Line 7	$ 1,347,460	$ 796,138	$ 243,022	$ 490	$ 277	$ 964	$ 195,346	$ 87,309	$ 23,913
21											
22	**REVENUE TO COST RATIO**										
23	Revenue to Cost Ratio	Line 19 / Line 20	100%	96%	101%		135%		102%	105%	
24											
25	**REVENUE REBALANCING**										
26	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Total Revenue at Proposed Rates	Line 16 + Line 26	$ 1,347,460	$ 763,073	$ 244,259	$ 713	$ 375	$ 14,545	$ 199,784	$ 91,451	$ 33,261
28	Total Revenue Margin at Proposed Rates	Line 17 + Line 26	$ 772,189	$ 475,427	$ 133,126	$ 280	$ 240	$ 14,278	$ 98,451	$ 39,417	$ 10,971
29											
30	**PROPOSED REVENUE TO COST RATIO**										
31	Revenue to Cost Ratio at Proposed Rates		100%	96%	101%		135%		102%	105%	
32											

33 **Note:**
34 1. Lines 2, 7, 16, 19, 20, 27 include the imputed Cost of Gas for Rates 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios
35 Rates 23, 25 and 27 do not pay for commodity and midstream charges.
36 2. Rate 4 is a seasonal service and Rates 22 and Rate7/27 are interruptible customer classes. The revenue to cost ratio for Rate 4, Rate 22 and Rate 7/27 are not shown in the schedule above as
37 these rate classes do not drive system capacity additions and therefore, no demand-related costs are allocated to these customer classes in the COSA Study.
38 3. Revenue Margin includes UAF allocation to rate classes.

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 2**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE FUNCTIONALIZATION (000's)

Line No.	Particulars	Total	Gas Supply Operation	LNG Storage Tilbury	LNG Storage Mt. Hayes	Transmission	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense	$ 243,000	$ 2,380	$ 14,782	$ 3,568	$ 34,454	$ 108,278	$ 31,064	$ 48,474
2	Property & Sundry Taxes	$ 63,840	$ -	$ 1,960	$ 372	$ 21,680	$ 39,828	$ -	$ -
3	Depreciation Expense	$ 181,504	$ -	$ 20,160	$ 6,655	$ 40,501	$ 105,441	$ -	$ 8,746
4	Amortization Expense	$ 42,339	$ (90)	$ 2,497	$ 43	$ 7,734	$ 21,501	$ 9,566	$ 1,089
5	Other Operating Revenue	$ (113,411)	$ -	$ (39,745)	$ (18,039)	$ (47,061)	$ (6,252)	$ -	$ (2,314)
6	Income Tax	$ 44,864	$ (256)	$ 3,228	$ 1,938	$ 12,798	$ 25,693	$ 813	$ 650
7	Earned Return	$ 310,054	$ (1,711)	$ 32,172	$ 12,933	$ 85,418	$ 171,478	$ 5,428	$ 4,337
8	**Total Cost of Service Margin**	**$ 772,189**	**$ 322**	**$ 35,054**	**$ 7,469**	**$ 155,524**	**$ 465,967**	**$ 46,871**	**$ 60,982**
9									
10	Cost of Gas - Commodity & Midstream	$ 477,714	$ 477,714	$ -	$ -	$ -	$ -	$ -	$ -
11	**Total Utility Revenue Requirement**	**$ 1,249,903**	**$ 478,036**	**$ 35,054**	**$ 7,469**	**$ 155,524**	**$ 465,967**	**$ 46,871**	**$ 60,982**

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study

Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 3

RATE BASE SUMMARY - CLASSIFICATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Gas Plant in Service**										
2	Total Gas Plant in Service		**$ 6,470,628**	**$ 3,792,529**	**$ 1,112,819**	**$ 372**	**$ 745**	**$ 5,343**	**$ 786,178**	**$ 298,045**	**$ 7,363**
3		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Demand	$ 4,180,848	$ 1,868,660	$ 852,557	$ 54	$ 445	$ 3,849	$ 707,527	$ 280,520	$ -
5		Customer	$ 2,289,781	$ 1,923,869	$ 260,262	$ 318	$ 299	$ 1,494	$ 78,650	$ 17,524	$ 7,363
6											
7	Total Accumulated Depreciation		**$ (1,815,001)**	**$ (1,116,768)**	**$ (320,227)**	**$ (101)**	**$ (220)**	**$ (1,523)**	**$ (226,870)**	**$ (86,077)**	**$ (1,958)**
8		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Demand	$ (1,131,843)	$ (540,104)	$ (245,280)	$ (17)	$ (128)	$ (1,120)	$ (203,329)	$ (80,609)	$ -
10		Customer	$ (683,158)	$ (576,664)	$ (74,947)	$ (84)	$ (92)	$ (403)	$ (23,542)	$ (5,468)	$ (1,958)
11											
12	TOTAL Net Plant		**$ 4,655,627**	**$ 2,675,761**	**$ 792,592**	**$ 271**	**$ 525**	**$ 3,820**	**$ 559,307**	**$ 211,968**	**$ 5,406**
13		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Demand	$ 3,049,004	$ 1,328,556	$ 607,277	$ 38	$ 317	$ 2,729	$ 504,199	$ 199,911	$ -
15		Customer	$ 1,606,623	$ 1,347,205	$ 185,315	$ 234	$ 207	$ 1,091	$ 55,109	$ 12,056	$ 5,406
16											
17	**Contributions In Aid of Construction**										
18	Total Gas Plant in Service		**$ (424,193)**	**$ (269,741)**	**$ (78,417)**	**$ (28)**	**$ (51)**	**$ (366)**	**$ (54,498)**	**$ (20,574)**	**$ (518)**
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20		Demand	$ (256,248)	$ (128,187)	$ (59,099)	$ (4)	$ (31)	$ (262)	$ (49,167)	$ (19,498)	$ -
21		Customer	$ (167,945)	$ (141,553)	$ (19,319)	$ (24)	$ (20)	$ (104)	$ (5,331)	$ (1,077)	$ (518)
22											
23	Total Accumulated Depreciation		**$ 143,125**	**$ 91,352**	**$ 26,345**	**$ 10**	**$ 17**	**$ 120**	**$ 18,230**	**$ 6,872**	**$ 179**
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Demand	$ 85,149	$ 42,489	$ 19,677	$ 1	$ 10	$ 84	$ 16,388	$ 6,499	$ -
26		Customer	$ 57,976	$ 48,863	$ 6,668	$ 8	$ 7	$ 36	$ 1,842	$ 373	$ 179
27											
28	TOTAL Net Plant		**$ (281,069)**	**$ (178,388)**	**$ (52,072)**	**$ (19)**	**$ (33)**	**$ (246)**	**$ (36,268)**	**$ (13,703)**	**$ (339)**
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Demand	$ (171,099)	$ (85,698)	$ (39,422)	$ (3)	$ (21)	$ (178)	$ (32,780)	$ (12,998)	$ -
31		Customer	$ (109,969)	$ (92,690)	$ (12,651)	$ (16)	$ (13)	$ (68)	$ (3,488)	$ (704)	$ (339)
32											

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
RATE BASE SUMMARY - CLASSIFICATION (000's)

Schedule 3

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
33	**13 Month Adjustment**		**$ 3,685**	**$ 2,187**	**$ 730**	**$ 0**	**$ 0**	**$ 4**	**$ 549**	**$ 212**	**$ 3**
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35		Demand	$ 2,822	$ 1,463	$ 632	$ 0	$ 0	$ 3	$ 518	$ 205	$ -
36		Customer	$ 863	$ 724	$ 97	$ 0	$ 0	$ 1	$ 31	$ 7	$ 3
37											
38	**Work in Process, no AFUDC**		**$ 35,156**	**$ 20,865**	**$ 6,962**	**$ 2**	**$ 4**	**$ 38**	**$ 5,233**	**$ 2,025**	**$ 27**
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Demand	$ 26,924	$ 13,960	$ 6,033	$ 0	$ 3	$ 33	$ 4,939	$ 1,956	$ -
41		Customer	$ 8,232	$ 6,905	$ 930	$ 1	$ 1	$ 6	$ 294	$ 68	$ 27
42											
43	**Unamortized Deferred Charges**		**$ 24,791**	**$ 20,103**	**$ 16,845**	**$ 2**	**$ 17**	**$ (8)**	**$ (3,355)**	**$ (1,931)**	**$ 235**
44		Energy	$ 1,130	$ (369)	$ 95	$ (31)	$ (11)	$ -	$ 2,010	$ (526)	$ (37)
45		Demand	$ 18,434	$ 16,864	$ 16,559	$ 34	$ 24	$ (21)	$ (6,313)	$ (1,812)	$ 218
46		Customer	$ 5,228	$ 3,609	$ 191	$ (1)	$ 5	$ 13	$ 948	$ 406	$ 55
47											
48	**Cash Working Capital**		**$ 2,129**	**$ 1,316**	**$ 429**	**$ 1**	**$ 1**	**$ 1**	**$ 302**	**$ 75**	**$ 4**
49		Energy	$ 1,184	$ 718	$ 267	$ 1	$ 1	$ -	$ 171	$ 24	$ 2
50		Demand	$ 560	$ 289	$ 126	$ 0	$ 0	$ 1	$ 103	$ 41	$ -
51		Customer	$ 385	$ 308	$ 36	$ 0	$ 0	$ 0	$ 28	$ 10	$ 2
52											
53	**Other Working Capital**		**$ 1,567**	**$ 1,085**	**$ 261**	**$ 0**	**$ 0**	**$ 1**	**$ 160**	**$ 58**	**$ 3**
54		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Demand	$ 608	$ 276	$ 150	$ -	$ 0	$ 0	$ 130	$ 52	$ -
56		Customer	$ 959	$ 808	$ 110	$ 0	$ 0	$ 1	$ 30	$ 6	$ 3
57											
58	**LILO, Other Rate Base items**		**$ 56,701**	**$ 30,057**	**$ 12,452**	**$ 2**	**$ 6**	**$ 101**	**$ 10,089**	**$ 3,996**	**$ (2)**
59		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Demand	$ 57,290	$ 30,553	$ 12,520	$ 2	$ 6	$ 101	$ 10,108	$ 3,999	$ -
61		Customer	$ (589)	$ (496)	$ (68)	$ (0)	$ (0)	$ (0)	$ (19)	$ (4)	$ (2)
62											
63	**Total Utility Rate Base**		**$ 4,498,588**	**$ 2,572,985**	**$ 778,199**	**$ 259**	**$ 520**	**$ 3,711**	**$ 536,018**	**$ 202,699**	**$ 5,337**
64		Energy	$ 2,314	$ 349	$ 362	$ (30)	$ (11)	$ -	$ 2,181	$ (502)	$ (36)
65		Demand	$ 2,984,543	$ 1,306,263	$ 603,876	$ 71	$ 330	$ 2,668	$ 480,904	$ 191,354	$ 218
66		Customer	$ 1,511,731	$ 1,266,373	$ 173,961	$ 219	$ 201	$ 1,043	$ 52,933	$ 11,846	$ 5,155

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 4

COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Operating & Maintenance Expense**		**$ 243,000**	**$ 160,487**	**$ 35,379**	**$ 15**	**$ 64**	**$ 266**	**$ 29,198**	**$ 11,130**	**$ 779**
2		Energy	$ 2,380	$ 1,445	$ 537	$ 3	$ 1	$ -	$ 343	$ 48	$ 3
3		Demand	$ 101,136	$ 48,315	$ 21,972	$ 2	$ 12	$ 92	$ 17,940	$ 7,121	$ 3
4		Customer	$ 139,483	$ 110,728	$ 12,871	$ 10	$ 51	$ 174	$ 10,914	$ 3,961	$ 773
5											
6	**Property & Sundry Taxes**		**$ 63,840**	**$ 39,557**	**$ 12,159**	**$ 4**	**$ 8**	**$ 58**	**$ 8,659**	**$ 3,302**	**$ 93**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 41,115	$ 20,621	$ 9,464	$ 1	$ 5	$ 40	$ 7,865	$ 3,119	$ -
9		Customer	$ 22,725	$ 18,936	$ 2,695	$ 4	$ 3	$ 19	$ 793	$ 183	$ 93
10											
11	**Depreciation Expense**		**$ 181,504**	**$ 109,620**	**$ 29,043**	**$ 16**	**$ 26**	**$ 146**	**$ 19,828**	**$ 7,073**	**$ 237**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 99,884	$ 43,047	$ 19,154	$ 1	$ 10	$ 97	$ 15,799	$ 6,261	$ -
14		Customer	$ 81,619	$ 66,573	$ 9,889	$ 14	$ 16	$ 50	$ 4,029	$ 812	$ 237
15											
16	**Amortization Expense**		**$ 42,339**	**$ 24,859**	**$ 9,165**	**$ 6**	**$ 8**	**$ 42**	**$ 4,827**	**$ 1,943**	**$ 67**
17		Energy	$ (90)	$ (55)	$ (20)	$ (0)	$ (0)	$ -	$ (13)	$ (2)	$ (0)
18		Demand	$ 23,347	$ 11,264	$ 4,949	$ 0	$ 3	$ 27	$ 4,069	$ 1,612	$ -
19		Customer	$ 19,082	$ 13,650	$ 4,236	$ 5	$ 6	$ 15	$ 770	$ 333	$ 67
20											
21	**Other Operating Revenue**		**$ (113,411)**	**$ (40,773)**	**$ (15,448)**	**$ (2)**	**$ (9)**	**$ (120)**	**$ (12,401)**	**$ (4,885)**	**$ (28)**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ (107,272)	$ (35,789)	$ (14,840)	$ (1)	$ (8)	$ (114)	$ (12,019)	$ (4,757)	$ -
24		Customer	$ (6,139)	$ (4,984)	$ (608)	$ (1)	$ (2)	$ (6)	$ (382)	$ (128)	$ (28)
25											

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Schedule 4

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
26	**Income Tax**		**$ 44,864**	**$ 28,824**	**$ 8,463**	**$ 2**	**$ 6**	**$ 40**	**$ 6,089**	**$ 2,325**	**$ 62**
27		Energy	$ (256)	$ (156)	$ (58)	$ (0)	$ (0)	$ -	$ (37)	$ (5)	$ (0)
28		Demand	$ 27,938	$ 14,664	$ 6,586	$ 0	$ 3	$ 27	$ 5,445	$ 2,158	$ -
29		Customer	$ 17,183	$ 14,315	$ 1,934	$ 2	$ 3	$ 13	$ 680	$ 172	$ 62
30											
31	**Earned Return**		**$ 310,054**	**$ 185,918**	**$ 53,128**	**$ 17**	**$ 39**	**$ 266**	**$ 37,814**	**$ 14,386**	**$ 414**
32		Energy	$ (1,711)	$ (1,039)	$ (386)	$ (2)	$ (1)	$ -	$ (247)	$ (35)	$ (2)
33		Demand	$ 197,088	$ 91,415	$ 40,605	$ 3	$ 22	$ 180	$ 33,520	$ 13,270	$ -
34		Customer	$ 114,678	$ 95,541	$ 12,909	$ 16	$ 18	$ 86	$ 4,541	$ 1,150	$ 416
35											
36	**Total Cost of Service Margin**		**$ 772,189**	**$ 508,492**	**$ 131,889**	**$ 57**	**$ 142**	**$ 697**	**$ 94,013**	**$ 35,275**	**$ 1,623**
37		Energy	$ 322	$ 196	$ 73	$ 0	$ 0	$ -	$ 47	$ 7	$ 0
38		Demand	$ 383,237	$ 193,537	$ 87,891	$ 6	$ 47	$ 348	$ 72,620	$ 28,785	$ 3
39		Customer	$ 388,631	$ 314,760	$ 43,925	$ 51	$ 95	$ 349	$ 21,347	$ 6,483	$ 1,620
40											
41	**Cost of Gas Sold (Including Gas Lost)**		**$ 475,684**	**$ 287,646**	**$ 111,133**	**$ 433**	**$ 135**	**$ 267**	**$ 67,966**	**$ 7,458**	**$ 646**
42		Energy	$ 475,684	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 67,966	$ 7,458	$ 646
43		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45											
46	**Total Utility Revenue Requir**		**$ 1,247,873**	**$ 796,138**	**$ 243,022**	**$ 490**	**$ 277**	**$ 964**	**$ 161,979**	**$ 42,733**	**$ 2,269**
47		Energy	$ 476,006	$ 287,842	$ 111,206	$ 433	$ 135	$ 267	$ 68,013	$ 7,465	$ 646
48		Demand	$ 383,237	$ 193,537	$ 87,891	$ 6	$ 47	$ 348	$ 72,620	$ 28,785	$ 3
49		Customer	$ 388,631	$ 314,760	$ 43,925	$ 51	$ 95	$ 349	$ 21,347	$ 6,483	$ 1,620

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 5**

Rate Design Filing_Common Rates_ 2016 Test Year

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Gas Supply Operations**		**$ (24,827)**	**$ (15,068)**	**$ (5,598)**	**$ (30)**	**$ (11)**	**$ -**	**$ (3,582)**	**$ (502)**	**$ (36)**
2		Energy	$ (24,827)	$ (15,068)	$ (5,598)	$ (30)	$ (11)	$ -	$ (3,582)	$ (502)	$ (36)
3		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5											
6	**LNG Storage Tilbury**		**$ 466,786**	**$ 36,256**	**$ 14,884**	**$ -**	**$ 8**	**$ -**	**$ 12,022**	**$ 4,757**	**$ -**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 466,786	$ 36,256	$ 14,884	$ -	$ 8	$ -	$ 12,022	$ 4,757	$ -
9		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	**LNG Storage Mt. Hayes**		**$ 187,640**	**$ 99,978**	**$ 41,043**	**$ -**	**$ 21**	**$ 328**	**$ 33,152**	**$ 13,117**	**$ -**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 187,640	$ 99,978	$ 41,043	$ -	$ 21	$ 328	$ 33,152	$ 13,117	$ -
14		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	**Transmission**		**$ 1,239,328**	**$ 660,319**	**$ 271,074**	**$ 34**	**$ 139**	**$ 2,169**	**$ 218,956**	**$ 86,636**	**$ -**
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 1,239,328	$ 660,319	$ 271,074	$ 34	$ 139	$ 2,169	$ 218,956	$ 86,636	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 5**

Rate Design Filing_Common Rates_ 2016 Test Year

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
21	Distribution		**$ 2,487,976**	**$ 1,702,514**	**$ 420,829**	**$ 220**	**$ 311**	**$ 1,093**	**$ 262,869**	**$ 95,283**	**$ 4,857**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ 1,018,020	$ 467,911	$ 249,904	$ 2	$ 134	$ 120	$ 214,638	$ 85,312	$ -
24		Customer	$ 1,469,956	$ 1,234,603	$ 170,925	$ 218	$ 178	$ 973	$ 48,231	$ 9,971	$ 4,857
25											
26	Marketing		**$ 78,754**	**$ 46,350**	**$ 27,406**	**$ 35**	**$ 32**	**$ 60**	**$ 2,809**	**$ 1,801**	**$ 260**
27		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28		Demand	$ 72,770	$ 41,800	$ 26,971	$ 35	$ 29	$ 50	$ 2,135	$ 1,532	$ 218
29		Customer	$ 5,984	$ 4,550	$ 435	$ 0	$ 3	$ 10	$ 673	$ 269	$ 43
30											
31	Customer Accounting		**$ 62,932**	**$ 42,637**	**$ 8,561**	**$ 0**	**$ 20**	**$ 60**	**$ 9,792**	**$ 1,607**	**$ 255**
32		Energy	$ 27,141	$ 15,418	$ 5,960	$ -	$ -	$ -	$ 5,764	$ -	$ -
33		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Customer	$ 35,792	$ 27,220	$ 2,601	$ 0	$ 20	$ 60	$ 4,028	$ 1,607	$ 255
35											
36	**Total Utility Rate Base**		**$ 4,498,588**	**$ 2,572,985**	**$ 778,199**	**$ 259**	**$ 520**	**$ 3,711**	**$ 536,018**	**$ 202,699**	**$ 5,337**
37		Energy	$ 2,314	$ 349	$ 362	$ (30)	$ (11)	$ -	$ 2,181	$ (502)	$ (36)
38		Demand	$ 2,984,543	$ 1,306,263	$ 603,876	$ 71	$ 330	$ 2,668	$ 480,904	$ 191,354	$ 218
39		Customer	$ 1,511,731	$ 1,266,373	$ 173,961	$ 219	$ 201	$ 1,043	$ 52,933	$ 11,846	$ 5,155

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Schedule 6

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Gas Supply Operations		**$ 322**	**$ 196**	**$ 73**	**$ 0**	**$ 0**	**$ -**	**$ 47**	**$ 7**	**$ 0**
2		Energy	$ 322	$ 196	$ 73	$ 0	$ 0	$ -	$ 47	$ 7	$ 0
3		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5											
6	LNG Storage Tilbury		**$ 35,054**	**$ 19,602**	**$ 7,344**	**$ 1**	**$ 4**	**$ -**	**$ 5,818**	**$ 2,284**	**$ -**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 35,054	$ 19,602	$ 7,344	$ 1	$ 4	$ -	$ 5,818	$ 2,284	$ -
9		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ 7,469**	**$ 3,980**	**$ 1,634**	**$ -**	**$ 1**	**$ 13**	**$ 1,320**	**$ 522**	**$ -**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 7,469	$ 3,980	$ 1,634	$ -	$ 1	$ 13	$ 1,320	$ 522	$ -
14		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 155,524**	**$ 82,864**	**$ 34,017**	**$ 4**	**$ 17**	**$ 272**	**$ 27,477**	**$ 10,872**	**$ -**
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 155,524	$ 82,864	$ 34,017	$ 4	$ 17	$ 272	$ 27,477	$ 10,872	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
Schedule 6

COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
21	Distribution		**$ 465,967**	**$ 321,558**	**$ 78,212**	**$ 47**	**$ 61**	**$ 240**	**$ 47,987**	**$ 16,970**	**$ 892**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ 184,258	$ 86,555	$ 44,550	$ 1	$ 24	$ 62	$ 37,978	$ 15,087	$ -
24		Customer	$ 281,709	$ 235,003	$ 33,662	$ 46	$ 37	$ 179	$ 10,009	$ 1,883	$ 892
25											
26	Marketing		**$ 46,871**	**$ 33,916**	**$ 6,177**	**$ 5**	**$ 24**	**$ 69**	**$ 4,502**	**$ 1,883**	**$ 296**
27		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28		Demand	$ 932	$ 535	$ 345	$ 0	$ 0	$ 1	$ 27	$ 20	$ 3
29		Customer	$ 45,939	$ 33,380	$ 5,831	$ 4	$ 24	$ 69	$ 4,475	$ 1,863	$ 293
30											
31	Customer Accounting		**$ 60,982**	**$ 46,377**	**$ 4,432**	**$ 1**	**$ 34**	**$ 102**	**$ 6,864**	**$ 2,738**	**$ 435**
32		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Customer	$ 60,982	$ 46,377	$ 4,432	$ 1	$ 34	$ 102	$ 6,864	$ 2,738	$ 435
35											
36	**Total Utility Cost of Service**		**$ 772,189**	**$ 508,492**	**$ 131,889**	**$ 57**	**$ 142**	**$ 697**	**$ 94,013**	**$ 35,275**	**$ 1,623**
37		Energy	$ 322	$ 196	$ 73	$ 0	$ 0	$ -	$ 47	$ 7	$ 0
38		Demand	$ 383,237	$ 193,537	$ 87,891	$ 6	$ 47	$ 348	$ 72,620	$ 28,785	$ 3
39		Customer	$ 388,631	$ 314,760	$ 43,925	$ 51	$ 95	$ 349	$ 21,347	$ 6,483	$ 1,620

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 7**

Rate Design Filing_Common Rates_ 2016 Test Year

CLASSIFICATION SUMMARY (000's)

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Billing Determinants										
2											
3	Sales Volume (TJ)		163,288	72,466	28,012	130	47	13,189	27,090	15,663	6,691
4	Midstream Sales Volume (TJ)		120,882	72,399	27,942	130	47	-	18,037	2,173	155
5	Commodity Sales Volume (TJ)		107,522	65,258	24,245	130	47	-	15,515	2,173	155
6	Average No. of Customers		979,066	886,652	84,737	18	15	26	6,709	796	113
7											
8	Cost of Service Margin		**$ 772,189**	**$ 508,492**	**$ 131,889**	**$ 57**	**$ 142**	**$ 697**	**$ 94,013**	**$ 35,275**	**$ 1,623**
9		Energy	$ 322	$ 196	$ 73	$ 0	$ 0	$ -	$ 47	$ 7	$ 0
10	Unit Energy Charge ($/GJ)		0.002	0.003	0.003	0.003	0.003	0.000	0.002	0.000	0.000
11		Demand	$ 383,237	$ 193,537	$ 87,891	$ 6	$ 47	$ 348	$ 72,620	$ 28,785	$ 3
12	Unit Demand Charge ($/GJ)		2.347	2.671	3.138	0.047	1.002	0.026	2.681	1.838	0.000
13		Customer	$ 388,631	$ 314,760	$ 43,925	$ 51	$ 95	$ 349	$ 21,347	$ 6,483	$ 1,620
14	Unit Customer Charge ($/Cust/Day)		1.087	0.972	1.419	7.748	17.344	36.779	3.182	8.145	14.335
15											
16	Unit Cost of Service Margin ($/GJ)		4.729	7.017	4.708	0.443	3.035	0.053	3.470	2.252	0.243
17											
18	Cost of Gas - Commodity & Midstream		**$ 475,684**	**$ 287,646**	**$ 111,133**	**$ 433**	**$ 135**	**$ 267**	**$ 67,966**	**$ 7,458**	**$ 646**
19		Energy	$ 475,684	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 67,966	$ 7,458	$ 646
20		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Unit Cost of Gas - Commodity ($/GJ)		2.913	3.969	3.967	3.333	2.885	0.020	2.509	0.476	0.097
23											
24	Total Utility Cost of Service		**$ 1,247,873**	**$ 796,138**	**$ 243,022**	**$ 490**	**$ 277**	**$ 964**	**$ 161,979**	**$ 42,733**	**$ 2,269**
25		Energy	$ 476,006	$ 287,842	$ 111,206	$ 433	$ 135	$ 267	$ 68,013	$ 7,465	$ 646
26		Demand	$ 383,237	$ 193,537	$ 87,891	$ 6	$ 47	$ 348	$ 72,620	$ 28,785	$ 3
27		Customer	$ 388,631	$ 314,760	$ 43,925	$ 51	$ 95	$ 349	$ 21,347	$ 6,483	$ 1,620
28	Unit Cost of Service ($/GJ)		7.642	10.986	8.676	3.776	5.920	0.073	5.979	2.728	0.339
29											
30	Total Revenues @ Proposed Rates		**$ 1,347,460**	**$ 763,073**	**$ 244,259**	**$ 713**	**$ 375**	**$ 14,545**	**$ 199,784**	**$ 91,451**	**$ 33,261**
31	Unit Rate ($/GJ)		8.252	10.530	8.720	5.491	8.003	1.103	7.375	5.839	4.971
32											
33	Total Revenue Margin @ Proposed Rates		**$ 772,189**	**$ 475,427**	**$ 133,126**	**$ 280**	**$ 240**	**$ 14,278**	**$ 98,451**	**$ 39,417**	**$ 10,971**
34	Unit Rate ($/GJ)		4.729	6.561	4.752	2.158	5.118	1.083	3.634	2.517	1.640

Appendix D

FULLY DISTRIBUTED COSA STUDY
2016 TEST YEAR SCHEDULES
INCLUDING DISCUSSION OF
TILBURY EXPANSION PROJECT

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 1

SUMMARY (000's)

Discussion Point: Tilbury Expansion Project included using 2018 Forecast Costs and Revenue

Line No.	Particulars	Reference	Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**REVENUE TO COST**										
2	Total Revenue at Proposed 2016 Common Rates	Line 3 + Line 4	**$ 1,294,195**	**$ 730,278**	**$ 235,076**	**$ 694**	**$ 358**	**$ 13,560**	**$ 192,992**	**$ 88,732**	**$ 32,504**
3	Revenue Margin at Proposed 2016 Common Rates		$ 718,924	$ 442,632	$ 123,943	$ 261	$ 223	$ 13,293	$ 91,660	$ 36,698	$ 10,214
4	Total Cost of Gas		$ 575,271	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 101,332	$ 52,034	$ 22,290
5											
6	**COST OF SERVICE**										
7	Total Utility Cost of Service	Line 8 + Line 9	**$ 1,365,462**	**$ 808,340**	**$ 245,990**	**$ 492**	**$ 280**	**$ 967**	**$ 197,402**	**$ 88,072**	**$ 23,918**
8	Cost of Service Margin		$ 790,191	$ 520,694	$ 134,857	$ 59	$ 145	$ 700	$ 96,070	$ 36,038	$ 1,629
9	Total Cost of Gas		$ 575,271	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 101,332	$ 52,034	$ 22,290
10											
11	**SURPLUS / DEFICIT**										
12	Total Surplus / (Deficit)	Line 2 - Line 7	**$ (71,267)**								
13	% Increase to Equal Allocated Costs	- Line 12 / Line 3	9.9%	Effect of major project additions to COSA model							
14											
15	**REVENUES (adjusted to equal COS)**										
16	Total Adjusted Revenue at Proposed 2016 Common Rates	Line 4 + Line 17	**$ 1,365,462**	**$ 774,156**	**$ 247,363**	**$ 720**	**$ 380**	**$ 14,878**	**$ 202,079**	**$ 92,370**	**$ 33,516**
17	Total Adjusted Revenue Margin at Proposed 2016 Common Rates	Line 3 x (1 + Line 13)	$ 790,191	$ 486,510	$ 136,230	$ 287	$ 245	$ 14,611	$ 100,746	$ 40,336	$ 11,227
18											
19	REVENUES (adjusted for R/C ratio's)	Line 16	**$ 1,365,462**	**$ 774,156**	**$ 247,363**	**$ 720**	**$ 380**	**$ 14,878**	**$ 202,079**	**$ 92,370**	**$ 33,516**
20	COST OF SERVICE (adjusted for R/C ratio's)	Line 7	**$ 1,365,462**	**$ 808,340**	**$ 245,990**	**$ 492**	**$ 280**	**$ 967**	**$ 197,402**	**$ 88,072**	**$ 23,918**
21											
22	**REVENUE TO COST RATIO**										
23	Revenue to Cost Ratio	Line 19 / Line 20	**100%**	**96%**	**101%**		**136%**		**102%**	**105%**	
24											
25	**REVENUE REBALANCING**										
26	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Total Revenue at Proposed Rates	Line 16 + Line 26	**$ 1,365,462**	**$ 774,156**	**$ 247,363**	**$ 720**	**$ 380**	**$ 14,878**	$ 202,079	$ 92,370	$ 33,516
28	Total Revenue Margin at Proposed Rates	Line 17 + Line 26	$ 790,191	$ 486,510	$ 136,230	$ 287	$ 245	$ 14,611	$ 100,746	$ 40,336	$ 11,227
29											
30	**PROPOSED REVENUE TO COST RATIO**										
31	Revenue to Cost Ratio at Proposed Rates		**100%**	**96%**	**101%**		**136%**		**102%**	**105%**	

32

33 **Note:**

34 1. Lines 2, 7, 16, 19, 20, 27 include the imputed Cost of Gas for Rates 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios

35 Rates 23, 25 and 27 do not pay for commodity and midstream charges.

36 2. Rate 4 is a seasonal service and Rates 22 and Rate7/27 are interruptible customer classes. The revenue to cost ratio for Rate 4, Rate 22 and Rate 7/27 are not shown in the schedule above as

37 these rate classes do not drive system capacity additions and therefore, no demand-related costs are allocated to these customer classes in the COSA Study.

38 3. Revenue Margin includes UAF allocation to rate classes.

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 2**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE FUNCTIONALIZATION (000's)

Discussion Point: Tilbury Expansion Project included using 2018 Forecast Costs and Reve

Line No.	Particulars	Total	Gas Supply Operation	LNG Storage Tilbury	LNG Storage Mt. Hayes	Transmission	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense	$ 241,246	$ 2,385	$ 12,413	$ 3,580	$ 34,566	$ 108,589	$ 31,132	$ 48,580
2	Property & Sundry Taxes	$ 66,459	$ -	$ 1,993	$ 387	$ 22,586	$ 41,493	$ -	$ -
3	Depreciation Expense	$ 180,895	$ -	$ 19,486	$ 6,658	$ 40,522	$ 105,483	$ -	$ 8,746
4	Amortization Expense	$ 42,339	$ (90)	$ 2,394	$ 44	$ 7,759	$ 21,561	$ 9,573	$ 1,099
5	Other Operating Revenue	$ (98,205)	$ -	$ (24,539)	$ (18,039)	$ (47,061)	$ (6,252)	$ -	$ (2,314)
6	Income Tax	$ 44,834	$ (250)	$ 4,125	$ 1,892	$ 12,515	$ 25,124	$ 794	$ 635
7	Earned Return	$ 312,623	$ (1,714)	$ 33,991	$ 12,953	$ 85,657	$ 171,956	$ 5,436	$ 4,344
8	**Total Cost of Service Margin**	**$ 790,191**	**$ 332**	**$ 49,864**	**$ 7,475**	**$ 156,544**	**$ 467,953**	**$ 46,934**	**$ 61,090**
9									
10	Cost of Gas - Commodity & Midstream	$ 477,714	$ 477,714	$ -	$ -	$ -	$ -	$ -	$ -
11	**Total Utility Revenue Requirement**	**$ 1,267,905**	**$ 478,046**	**$ 49,864**	**$ 7,475**	**$ 156,544**	**$ 467,953**	**$ 46,934**	**$ 61,090**

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 3

RATE BASE SUMMARY - CLASSIFICATION (000's)

Discussion Point: Tilbury Expansion Project included using 2018 Forecast Costs and Revenue

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Gas Plant in Service**										
2	Total Gas Plant in Service		**$ 6,457,325**	**$ 3,792,592**	**$ 1,112,798**	**$ 372**	**$ 745**	**$ 5,344**	**$ 786,147**	**$ 298,031**	**$ 7,364**
3		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Demand	$ 4,167,299	$ 1,868,516	$ 852,507	$ 54	$ 445	$ 3,850	$ 707,489	$ 280,505	$ -
5		Customer	$ 2,290,026	$ 1,924,076	$ 260,290	$ 318	$ 299	$ 1,494	$ 78,658	$ 17,526	$ 7,364
6											
7	Total Accumulated Depreciation		**$ (1,775,938)**	**$ (1,116,788)**	**$ (320,220)**	**$ (101)**	**$ (220)**	**$ (1,523)**	**$ (226,861)**	**$ (86,073)**	**$ (1,958)**
8		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Demand	$ (1,092,703)	$ (540,058)	$ (245,264)	$ (17)	$ (128)	$ (1,120)	$ (203,317)	$ (80,604)	$ -
10		Customer	$ (683,235)	$ (576,730)	$ (74,956)	$ (84)	$ (92)	$ (403)	$ (23,544)	$ (5,469)	$ (1,958)
11											
12	TOTAL Net Plant		**$ 4,681,387**	**$ 2,675,804**	**$ 792,577**	**$ 271**	**$ 525**	**$ 3,821**	**$ 559,287**	**$ 211,958**	**$ 5,406**
13		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Demand	$ 3,074,597	$ 1,328,457	$ 607,243	$ 38	$ 317	$ 2,730	$ 504,173	$ 199,901	$ -
15		Customer	$ 1,606,791	$ 1,347,347	$ 185,334	$ 234	$ 207	$ 1,091	$ 55,114	$ 12,057	$ 5,406
16											
17	**Contributions In Aid of Construction**										
18	Total Gas Plant in Service		**$ (424,193)**	**$ (269,742)**	**$ (78,417)**	**$ (28)**	**$ (51)**	**$ (366)**	**$ (54,498)**	**$ (20,574)**	**$ (518)**
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20		Demand	$ (256,244)	$ (128,185)	$ (59,098)	$ (4)	$ (31)	$ (262)	$ (49,167)	$ (19,497)	$ -
21		Customer	$ (167,949)	$ (141,557)	$ (19,319)	$ (24)	$ (20)	$ (104)	$ (5,331)	$ (1,077)	$ (518)
22											
23	Total Accumulated Depreciation		**$ 143,125**	**$ 91,353**	**$ 26,344**	**$ 10**	**$ 17**	**$ 120**	**$ 18,230**	**$ 6,872**	**$ 179**
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Demand	$ 85,145	$ 42,487	$ 19,676	$ 1	$ 10	$ 84	$ 16,387	$ 6,499	$ -
26		Customer	$ 57,979	$ 48,866	$ 6,668	$ 8	$ 7	$ 36	$ 1,842	$ 373	$ 179
27											
28	TOTAL Net Plant		**$ (281,069)**	**$ (178,389)**	**$ (52,072)**	**$ (19)**	**$ (33)**	**$ (246)**	**$ (36,268)**	**$ (13,702)**	**$ (339)**
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Demand	$ (171,099)	$ (85,698)	$ (39,422)	$ (3)	$ (21)	$ (178)	$ (32,780)	$ (12,998)	$ -
31		Customer	$ (109,970)	$ (92,691)	$ (12,651)	$ (16)	$ (13)	$ (68)	$ (3,488)	$ (704)	$ (339)
32											

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 3

RATE BASE SUMMARY - CLASSIFICATION (000's)

Discussion Point: Tilbury Expansion Project included using 2018 Forecast Costs and Revenue

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
33	**13 Month Adjustment**		**$ 3,685**	**$ 2,187**	**$ 730**	**$ 0**	**$ 0**	**$ 4**	**$ 548**	**$ 212**	**$ 3**
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35		Demand	$ 2,820	$ 1,462	$ 632	$ 0	$ 0	$ 3	$ 517	$ 205	$ -
36		Customer	$ 865	$ 725	$ 98	$ 0	$ 0	$ 1	$ 31	$ 7	$ 3
37											
38	**Work in Process, no AFUDC**		**$ 35,156**	**$ 20,869**	**$ 6,961**	**$ 2**	**$ 4**	**$ 38**	**$ 5,231**	**$ 2,024**	**$ 27**
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Demand	$ 26,906	$ 13,949	$ 6,029	$ 0	$ 3	$ 33	$ 4,937	$ 1,955	$ -
41		Customer	$ 8,250	$ 6,920	$ 932	$ 1	$ 1	$ 6	$ 294	$ 68	$ 27
42											
43	**Unamortized Deferred Charges**		**$ 29,774**	**$ 20,387**	**$ 16,749**	**$ 2**	**$ 17**	**$ (3)**	**$ (3,491)**	**$ (1,992)**	**$ 239**
44		Energy	$ 1,130	$ (369)	$ 95	$ (31)	$ (11)	$ -	$ 2,010	$ (526)	$ (37)
45		Demand	$ 22,310	$ 16,215	$ 16,336	$ 34	$ 23	$ (17)	$ (6,484)	$ (1,879)	$ 218
46		Customer	$ 6,333	$ 4,541	$ 319	$ (0)	$ 5	$ 14	$ 983	$ 413	$ 59
47											
48	**Cash Working Capital**		**$ 2,129**	**$ 1,316**	**$ 428**	**$ 1**	**$ 1**	**$ 1**	**$ 302**	**$ 75**	**$ 4**
49		Energy	$ 1,183	$ 718	$ 267	$ 1	$ 1	$ -	$ 171	$ 24	$ 2
50		Demand	$ 560	$ 289	$ 126	$ 0	$ 0	$ 1	$ 103	$ 41	$ -
51		Customer	$ 387	$ 309	$ 36	$ 0	$ 0	$ 0	$ 29	$ 10	$ 2
52											
53	**Other Working Capital**		**$ 1,567**	**$ 1,085**	**$ 261**	**$ 0**	**$ 0**	**$ 1**	**$ 160**	**$ 58**	**$ 3**
54		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Demand	$ 608	$ 276	$ 150	$ -	$ 0	$ 0	$ 130	$ 52	$ -
56		Customer	$ 959	$ 808	$ 110	$ 0	$ 0	$ 1	$ 30	$ 6	$ 3
57											
58	**LILO, Other Rate Base items**		**$ 56,701**	**$ 30,057**	**$ 12,452**	**$ 2**	**$ 6**	**$ 101**	**$ 10,089**	**$ 3,996**	**$ (2)**
59		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Demand	$ 57,290	$ 30,553	$ 12,520	$ 2	$ 6	$ 101	$ 10,108	$ 3,999	$ -
61		Customer	$ (589)	$ (496)	$ (68)	$ (0)	$ (0)	$ (0)	$ (19)	$ (4)	$ (2)
62											
63	**Total Utility Rate Base**		**$ 4,529,330**	**$ 2,573,318**	**$ 778,086**	**$ 260**	**$ 520**	**$ 3,717**	**$ 535,859**	**$ 202,628**	**$ 5,341**
64		Energy	$ 2,313	$ 349	$ 361	$ (30)	$ (11)	$ -	$ 2,181	$ (502)	$ (36)
65		Demand	$ 3,013,992	$ 1,305,505	$ 603,615	$ 71	$ 330	$ 2,673	$ 480,704	$ 191,276	$ 218
66		Customer	$ 1,513,026	$ 1,267,464	$ 174,110	$ 219	$ 201	$ 1,044	$ 52,974	$ 11,854	$ 5,159

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 4**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Discussion Point: Tilbury Expansion Project included using 2018 Forecast Costs and Revenue

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Operating & Maintenance Expense**		**$ 241,246**	**$ 160,558**	**$ 35,343**	**$ 15**	**$ 64**	**$ 266**	**$ 29,172**	**$ 11,119**	**$ 780**
2		Energy	$ 2,385	$ 1,448	$ 538	$ 3	$ 1	$ -	$ 344	$ 48	$ 3
3		Demand	$ 99,082	$ 48,148	$ 21,908	$ 2	$ 12	$ 92	$ 17,890	$ 7,101	$ 3
4		Customer	$ 139,778	$ 110,963	$ 12,898	$ 10	$ 51	$ 174	$ 10,938	$ 3,970	$ 774
5											
6	**Property & Sundry Taxes**		**$ 66,459**	**$ 39,786**	**$ 12,082**	**$ 4**	**$ 8**	**$ 61**	**$ 8,549**	**$ 3,253**	**$ 97**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 42,785	$ 20,059	$ 9,275	$ 1	$ 5	$ 42	$ 7,722	$ 3,062	$ -
9		Customer	$ 23,674	$ 19,726	$ 2,807	$ 4	$ 3	$ 19	$ 826	$ 191	$ 97
10											
11	**Depreciation Expense**		**$ 180,895**	**$ 109,624**	**$ 29,041**	**$ 16**	**$ 26**	**$ 146**	**$ 19,826**	**$ 7,072**	**$ 237**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 99,259	$ 43,037	$ 19,151	$ 1	$ 10	$ 97	$ 15,797	$ 6,260	$ -
14		Customer	$ 81,636	$ 66,587	$ 9,891	$ 14	$ 16	$ 50	$ 4,029	$ 812	$ 237
15											
16	**Amortization Expense**		**$ 42,339**	**$ 24,868**	**$ 9,160**	**$ 6**	**$ 8**	**$ 42**	**$ 4,823**	**$ 1,942**	**$ 67**
17		Energy	$ (90)	$ (55)	$ (20)	$ (0)	$ (0)	$ -	$ (13)	$ (2)	$ (0)
18		Demand	$ 23,307	$ 11,241	$ 4,941	$ 0	$ 3	$ 27	$ 4,063	$ 1,610	$ -
19		Customer	$ 19,122	$ 13,682	$ 4,240	$ 5	$ 6	$ 15	$ 773	$ 334	$ 68
20											
21	**Other Operating Revenue**		**$ (98,205)**	**$ (40,773)**	**$ (15,448)**	**$ (2)**	**$ (9)**	**$ (120)**	**$ (12,401)**	**$ (4,885)**	**$ (28)**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ (92,066)	$ (35,789)	$ (14,840)	$ (1)	$ (8)	$ (114)	$ (12,019)	$ (4,757)	$ -
24		Customer	$ (6,139)	$ (4,984)	$ (608)	$ (1)	$ (2)	$ (6)	$ (382)	$ (128)	$ (28)
25											

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 4**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Discussion Point: Tilbury Expansion Project included using 2018 Forecast Costs and Revenue

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
26	**Income Tax**		**$ 44,834**	**$ 28,727**	**$ 8,498**	**$ 2**	**$ 6**	**$ 39**	**$ 6,133**	**$ 2,345**	**$ 61**
27		Energy	$ (250)	$ (152)	$ (56)	$ (0)	$ (0)	$ -	$ (36)	$ (5)	$ (0)
28		Demand	$ 28,285	$ 14,883	$ 6,663	$ 0	$ 3	$ 26	$ 5,504	$ 2,182	$ -
29		Customer	$ 16,800	$ 13,997	$ 1,891	$ 2	$ 3	$ 13	$ 665	$ 168	$ 61
30											
31	**Earned Return**		**$ 312,623**	**$ 197,903**	**$ 56,179**	**$ 18**	**$ 43**	**$ 267**	**$ 39,968**	**$ 15,191**	**$ 415**
32		Energy	$ (1,714)	$ (1,040)	$ (386)	$ (2)	$ (1)	$ -	$ (247)	$ (35)	$ (2)
33		Demand	$ 199,352	$ 103,145	$ 43,622	$ 4	$ 25	$ 181	$ 35,663	$ 14,074	$ -
34		Customer	$ 114,984	$ 95,798	$ 12,944	$ 16	$ 18	$ 86	$ 4,553	$ 1,153	$ 417
35											
36	**Total Cost of Service Margin**		**$ 790,191**	**$ 520,694**	**$ 134,857**	**$ 59**	**$ 145**	**$ 700**	**$ 96,070**	**$ 36,038**	**$ 1,629**
37		Energy	$ 332	$ 201	$ 75	$ 0	$ 0	$ -	$ 48	$ 7	$ 0
38		Demand	$ 400,005	$ 204,724	$ 90,720	$ 8	$ 50	$ 350	$ 74,620	$ 29,532	$ 3
39		Customer	$ 389,854	$ 315,769	$ 44,062	$ 51	$ 95	$ 350	$ 21,402	$ 6,499	$ 1,625
40											
41	**Cost of Gas Sold (Including Gas Lost)**		**$ 475,684**	**$ 287,646**	**$ 111,133**	**$ 433**	**$ 135**	**$ 267**	**$ 67,966**	**$ 7,458**	**$ 646**
42		Energy	$ 475,684	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 67,966	$ 7,458	$ 646
43		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45											
46	**Total Utility Revenue Requir**		**$ 1,265,875**	**$ 808,340**	**$ 245,990**	**$ 492**	**$ 280**	**$ 967**	**$ 164,036**	**$ 43,496**	**$ 2,275**
47		Energy	$ 476,016	$ 287,847	$ 111,208	$ 433	$ 135	$ 267	$ 68,014	$ 7,465	$ 646
48		Demand	$ 400,005	$ 204,724	$ 90,720	$ 8	$ 50	$ 350	$ 74,620	$ 29,532	$ 3
49		Customer	$ 389,854	$ 315,769	$ 44,062	$ 51	$ 95	$ 350	$ 21,402	$ 6,499	$ 1,625

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study

Schedule 5

Rate Design Filing_Common Rates_ 2016 Test Year

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Discussion Point: Tilbury Expansion Project included using 2018 Forecast Costs and Revenue

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Gas Supply Operations		**$ (24,828)**	**$ (15,069)**	**$ (5,598)**	**$ (30)**	**$ (11)**	**$ -**	**$ (3,583)**	**$ (502)**	**$ (36)**
2		Energy	$ (24,828)	$ (15,069)	$ (5,598)	$ (30)	$ (11)	$ -	$ (3,583)	$ (502)	$ (36)
3		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5											
6	LNG Storage Tilbury		**$ 492,473**	**$ 33,558**	**$ 13,776**	**$ -**	**$ 7**	**$ -**	**$ 11,127**	**$ 4,403**	**$ -**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 492,473	$ 33,558	$ 13,776	$ -	$ 7	$ -	$ 11,127	$ 4,403	$ -
9		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ 187,664**	**$ 99,991**	**$ 41,048**	**$ -**	**$ 21**	**$ 328**	**$ 33,156**	**$ 13,119**	**$ -**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 187,664	$ 99,991	$ 41,048	$ -	$ 21	$ 328	$ 33,156	$ 13,119	$ -
14		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 1,241,012**	**$ 661,216**	**$ 271,443**	**$ 34**	**$ 139**	**$ 2,172**	**$ 219,254**	**$ 86,754**	**$ -**
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 1,241,012	$ 661,216	$ 271,443	$ 34	$ 139	$ 2,172	$ 219,254	$ 86,754	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 5**

Rate Design Filing_Common Rates_ 2016 Test Year

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Discussion Point: Tilbury Expansion Project included using 2018 Forecast Costs and Revenue

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
21	Distribution		**$ 2,491,324**	**$ 1,704,635**	**$ 421,451**	**$ 220**	**$ 312**	**$ 1,096**	**$ 263,303**	**$ 95,447**	**$ 4,861**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ 1,020,073	$ 468,941	$ 250,377	$ 2	$ 134	$ 122	$ 215,031	$ 85,468	$ -
24		Customer	$ 1,471,251	$ 1,235,694	$ 171,074	$ 218	$ 178	$ 974	$ 48,272	$ 9,979	$ 4,861
25											
26	Marketing		**$ 78,754**	**$ 46,350**	**$ 27,406**	**$ 35**	**$ 32**	**$ 60**	**$ 2,809**	**$ 1,801**	**$ 260**
27		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28		Demand	$ 72,770	$ 41,800	$ 26,971	$ 35	$ 29	$ 50	$ 2,135	$ 1,532	$ 218
29		Customer	$ 5,984	$ 4,551	$ 435	$ 0	$ 3	$ 10	$ 673	$ 269	$ 43
30											
31	Customer Accounting		**$ 62,932**	**$ 42,637**	**$ 8,561**	**$ 0**	**$ 20**	**$ 60**	**$ 9,792**	**$ 1,607**	**$ 255**
32		Energy	$ 27,141	$ 15,418	$ 5,960	$ -	$ -	$ -	$ 5,764	$ -	$ -
33		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Customer	$ 35,791	$ 27,219	$ 2,601	$ 0	$ 20	$ 60	$ 4,028	$ 1,607	$ 255
35											
36	**Total Utility Rate Base**		**$ 4,529,330**	**$ 2,573,318**	**$ 778,086**	**$ 260**	**$ 520**	**$ 3,717**	**$ 535,859**	**$ 202,628**	**$ 5,341**
37		Energy	$ 2,313	$ 349	$ 361	$ (30)	$ (11)	$ -	$ 2,181	$ (502)	$ (36)
38		Demand	$ 3,013,992	$ 1,305,505	$ 603,615	$ 71	$ 330	$ 2,673	$ 480,704	$ 191,276	$ 218
39		Customer	$ 1,513,026	$ 1,267,464	$ 174,110	$ 219	$ 201	$ 1,044	$ 52,974	$ 11,854	$ 5,159

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study

Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 6

COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Discussion Point: Tilbury Expansion Project included using 2018 Forecast Costs and Revenue

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Gas Supply Operations		**$ 332**	**$ 201**	**$ 75**	**$ 0**	**$ 0**	**$ -**	**$ 48**	**$ 7**	**$ 0**
2		Energy	$ 332	$ 201	$ 75	$ 0	$ 0	$ -	$ 48	$ 7	$ 0
3		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5											
6	LNG Storage Tilbury		**$ 49,864**	**$ 29,799**	**$ 9,725**	**$ 2**	**$ 7**	**$ -**	**$ 7,447**	**$ 2,884**	**$ -**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 49,864	$ 29,799	$ 9,725	$ 2	$ 7	$ -	$ 7,447	$ 2,884	$ -
9		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ 7,475**	**$ 3,983**	**$ 1,635**	**$ -**	**$ 1**	**$ 13**	**$ 1,321**	**$ 523**	**$ -**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 7,475	$ 3,983	$ 1,635	$ -	$ 1	$ 13	$ 1,321	$ 523	$ -
14		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 156,544**	**$ 83,407**	**$ 34,240**	**$ 4**	**$ 18**	**$ 274**	**$ 27,657**	**$ 10,943**	**$ -**
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 156,544	$ 83,407	$ 34,240	$ 4	$ 18	$ 274	$ 27,657	$ 10,943	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 6**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Discussion Point: Tilbury Expansion Project included using 2018 Forecast Costs and Revenue

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
21	Distribution		**$ 467,953**	**$ 322,881**	**$ 78,560**	**$ 47**	**$ 61**	**$ 242**	**$ 48,213**	**$ 17,053**	**$ 896**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ 185,190	$ 87,000	$ 44,774	$ 1	$ 24	$ 62	$ 38,168	$ 15,162	$ -
24		Customer	$ 282,762	$ 235,882	$ 33,786	$ 46	$ 37	$ 180	$ 10,045	$ 1,891	$ 896
25											
26	Marketing		**$ 46,934**	**$ 33,963**	**$ 6,181**	**$ 5**	**$ 25**	**$ 69**	**$ 4,509**	**$ 1,885**	**$ 296**
27		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28		Demand	$ 932	$ 535	$ 345	$ 0	$ 0	$ 1	$ 27	$ 20	$ 3
29		Customer	$ 46,002	$ 33,428	$ 5,836	$ 4	$ 24	$ 69	$ 4,482	$ 1,866	$ 293
30											
31	Customer Accounting		**$ 61,090**	**$ 46,459**	**$ 4,440**	**$ 1**	**$ 34**	**$ 102**	**$ 6,876**	**$ 2,743**	**$ 436**
32		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Customer	$ 61,090	$ 46,459	$ 4,440	$ 1	$ 34	$ 102	$ 6,876	$ 2,743	$ 436
35											
36	**Total Utility Cost of Service**		**$ 790,191**	**$ 520,694**	**$ 134,857**	**$ 59**	**$ 145**	**$ 700**	**$ 96,070**	**$ 36,038**	**$ 1,629**
37		Energy	$ 332	$ 201	$ 75	$ 0	$ 0	$ -	$ 48	$ 7	$ 0
38		Demand	$ 400,005	$ 204,724	$ 90,720	$ 8	$ 50	$ 350	$ 74,620	$ 29,532	$ 3
39		Customer	$ 389,854	$ 315,769	$ 44,062	$ 51	$ 95	$ 350	$ 21,402	$ 6,499	$ 1,625

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 7**

Rate Design Filing_Common Rates_ 2016 Test Year

<u>CLASSIFICATION SUMMARY (000's)</u>

Discussion Point: Tilbury Expansion Project included using 2018 Forecast Costs and Revenue

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Billing Determinants										
2											
3	Sales Volume (TJ)		163,288	72,466	28,012	130	47	13,189	27,090	15,663	6,691
4	Midstream Sales Volume (TJ)		120,882	72,399	27,942	130	47	-	18,037	2,173	155
5	Commodity Sales Volume (TJ)		107,522	65,258	24,245	130	47	-	15,515	2,173	155
6	Average No. of Customers		979,066	886,652	84,737	18	15	26	6,709	796	113
7											
8	Cost of Service Margin		**$ 790,191**	**$ 520,694**	**$ 134,857**	**$ 59**	**$ 145**	**$ 700**	**$ 96,070**	**$ 36,038**	**$ 1,629**
9		Energy	$ 332	$ 201	$ 75	$ 0	$ 0	$ -	$ 48	$ 7	$ 0
10	Unit Energy Charge ($/GJ)		0.002	0.003	0.003	0.003	0.003	0.000	0.002	0.000	0.000
11		Demand	$ 400,005	$ 204,724	$ 90,720	$ 8	$ 50	$ 350	$ 74,620	$ 29,532	$ 3
12	Unit Demand Charge ($/GJ)		2.450	2.825	3.239	0.058	1.070	0.027	2.754	1.885	0.000
13		Customer	$ 389,854	$ 315,769	$ 44,062	$ 51	$ 95	$ 350	$ 21,402	$ 6,499	$ 1,625
14	Unit Customer Charge ($/Cust/Day)		1.090	0.975	1.424	7.773	17.386	36.897	3.190	8.165	14.383
15											
16	Unit Cost of Service Margin ($/GJ)		4.839	7.185	4.814	0.455	3.108	0.053	3.546	2.301	0.243
17											
18	Cost of Gas - Commodity & Midstream		**$ 475,684**	**$ 287,646**	**$ 111,133**	**$ 433**	**$ 135**	**$ 267**	**$ 67,966**	**$ 7,458**	**$ 646**
19		Energy	$ 475,684	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 67,966	$ 7,458	$ 646
20		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Unit Cost of Gas - Commodity ($/GJ)		2.913	3.969	3.967	3.333	2.885	0.020	2.509	0.476	0.097
23											
24	Total Utility Cost of Service		**$ 1,265,875**	**$ 808,340**	**$ 245,990**	**$ 492**	**$ 280**	**$ 967**	**$ 164,036**	**$ 43,496**	**$ 2,275**
25		Energy	$ 476,016	$ 287,847	$ 111,208	$ 433	$ 135	$ 267	$ 68,014	$ 7,465	$ 646
26		Demand	$ 400,005	$ 204,724	$ 90,720	$ 8	$ 50	$ 350	$ 74,620	$ 29,532	$ 3
27		Customer	$ 389,854	$ 315,769	$ 44,062	$ 51	$ 95	$ 350	$ 21,402	$ 6,499	$ 1,625
28	Unit Cost of Service ($/GJ)		7.752	11.155	8.782	3.788	5.993	0.073	6.055	2.777	0.340
29											
30	Total Revenues @ Proposed Rates		**$ 1,365,462**	**$ 774,156**	**$ 247,363**	**$ 720**	**$ 380**	**$ 14,878**	**$ 202,079**	**$ 92,370**	**$ 33,516**
31	Unit Rate ($/GJ)		8.362	10.683	8.831	5.542	8.122	1.128	7.460	5.897	5.009
32											
33	Total Revenue Margin @ Proposed Rates		**$ 790,191**	**$ 486,510**	**$ 136,230**	**$ 287**	**$ 245**	**$ 14,611**	**$ 100,746**	**$ 40,336**	**$ 11,227**
34	Unit Rate ($/GJ)		4.839	6.714	4.863	2.208	5.237	1.108	3.719	2.575	1.678

Appendix E

FULLY DISTRIBUTED COSA STUDY
2016 TEST YEAR SCHEDULES
INCLUDING DISCUSSION OF EGP PROJECT

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 1

SUMMARY (000's)

Discussion Point: EGP Project included

Line No.	Particulars	Reference	Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**REVENUE TO COST**										
2	Total Revenue at Proposed 2016 Common Rates	Line 3 + Line 4	**$ 1,294,195**	**$ 730,278**	**$ 235,076**	**$ 694**	**$ 358**	**$ 13,560**	**$ 192,992**	**$ 88,732**	**$ 32,504**
3	Revenue Margin at Proposed 2016 Common Rates		$ 718,924	$ 442,632	$ 123,943	$ 261	$ 223	$ 13,293	$ 91,660	$ 36,698	$ 10,214
4	Total Cost of Gas		$ 575,271	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 101,332	$ 52,034	$ 22,290
5											
6	**COST OF SERVICE**										
7	Total Utility Cost of Service	Line 8 + Line 9	**$ 1,330,163**	**$ 785,213**	**$ 239,802**	**$ 490**	**$ 275**	**$ 957**	**$ 193,087**	**$ 86,454**	**$ 23,885**
8	Cost of Service Margin		$ 754,892	$ 497,567	$ 128,669	$ 57	$ 140	$ 690	$ 91,754	$ 34,420	$ 1,595
9	Total Cost of Gas		$ 575,271	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 101,332	$ 52,034	$ 22,290
10											
11	**SURPLUS / DEFICIT**										
12	Total Surplus / (Deficit)	Line 2 - Line 7	**$ (35,968)**								
13	% Increase to Equal Allocated Costs	- Line 12 / Line 3	5.0%	Effect of major project additions to COSA model							
14											
15	**REVENUES (adjusted to equal COS)**										
16	Total Adjusted Revenue at Proposed 2016 Common Rates	Line 4 + Line 17	**$ 1,330,163**	**$ 752,423**	**$ 241,277**	**$ 707**	**$ 369**	**$ 14,225**	**$ 197,578**	**$ 90,568**	**$ 33,015**
17	Total Adjusted Revenue Margin at Proposed 2016 Common Rates	Line 3 x (1 + Line 13)	$ 754,892	$ 464,777	$ 130,144	$ 274	$ 234	$ 13,958	$ 96,246	$ 38,534	$ 10,725
18											
19	REVENUES (adjusted for R/C ratio's)	Line 16	**$ 1,330,163**	**$ 752,423**	**$ 241,277**	**$ 707**	**$ 369**	**$ 14,225**	**$ 197,578**	**$ 90,568**	**$ 33,015**
20	COST OF SERVICE (adjusted for R/C ratio's)	Line 7	**$ 1,330,163**	**$ 785,213**	**$ 239,802**	**$ 490**	**$ 275**	**$ 957**	**$ 193,087**	**$ 86,454**	**$ 23,885**
21											
22	**REVENUE TO COST RATIO**										
23	Revenue to Cost Ratio	Line 19 / Line 20	**100%**	**96%**	**101%**		**134%**		**102%**	**105%**	
24											
25	**REVENUE REBALANCING**										
26	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Total Revenue at Proposed Rates	Line 16 + Line 26	**$ 1,330,163**	**$ 752,423**	**$ 241,277**	**$ 707**	**$ 369**	**$ 14,225**	$ 197,578	$ 90,568	$ 33,015
28	Total Revenue Margin at Proposed Rates	Line 17 + Line 26	$ 754,892	$ 464,777	$ 130,144	$ 274	$ 234	$ 13,958	$ 96,246	$ 38,534	$ 10,725
29											
30	**PROPOSED REVENUE TO COST RATIO**										
31	Revenue to Cost Ratio at Proposed Rates		**100%**	**96%**	**101%**		**134%**		**102%**	**105%**	
32											
33	**Note:**										
34	1. Lines 2, 7, 16, 19, 20, 27 include the imputed Cost of Gas for Rates 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios										
35	Rates 23, 25 and 27 do not pay for commodity and midstream charges.										
36	2. Rate 4 is a seasonal service and Rates 22 and Rate7/27 are interruptible customer classes. The revenue to cost ratio for Rate 4, Rate 22 and Rate 7/27 are not shown in the schedule above as										
37	these rate classes do not drive system capacity additions and therefore, no demand-related costs are allocated to these customer classes in the COSA Study.										
38	3. Revenue Margin includes UAF allocation to rate classes.										

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 2**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE FUNCTIONALIZATION (000's)

Discussion Point: EGP Project included

Line No.	Particulars	Total	Gas Supply Operation	LNG Storage Tilbury	LNG Storage Mt. Hayes	Transmission	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense	$ 244,413	$ 2,376	$ 14,546	$ 3,481	$ 37,900	$ 106,735	$ 31,011	$ 48,365
2	Property & Sundry Taxes	$ 66,661	$ -	$ 1,826	$ 341	$ 27,022	$ 37,472	$ -	$ -
3	Depreciation Expense	$ 194,369	$ -	$ 19,896	$ 6,554	$ 55,438	$ 103,740	$ -	$ 8,741
4	Amortization Expense	$ 43,429	$ (91)	$ 2,380	$ 45	$ 9,651	$ 20,802	$ 9,561	$ 1,081
5	Other Operating Revenue	$ (187,689)	$ -	$ (39,745)	$ (18,039)	$ (121,339)	$ (6,252)	$ -	$ (2,314)
6	Income Tax	$ 41,333	$ (211)	$ 2,221	$ 1,584	$ 15,551	$ 20,986	$ 668	$ 534
7	Earned Return	$ 352,376	$ (1,731)	$ 31,304	$ 13,000	$ 127,657	$ 172,277	$ 5,485	$ 4,384
8	**Total Cost of Service Margin**	**$ 754,892**	**$ 343**	**$ 32,427**	**$ 6,966**	**$ 151,881**	**$ 455,758**	**$ 46,724**	**$ 60,791**
9									
10	Cost of Gas - Commodity & Midstream	$ 477,714	$ 477,714	$ -	$ -	$ -	$ -	$ -	$ -
11	**Total Utility Revenue Requirement**	**$ 1,232,606**	**$ 478,057**	**$ 32,427**	**$ 6,966**	**$ 151,881**	**$ 455,758**	**$ 46,724**	**$ 60,791**

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
RATE BASE SUMMARY - CLASSIFICATION (000's)
Discussion Point: EGP Project included

Schedule 3

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Gas Plant in Service**										
2	Total Gas Plant in Service		**$ 7,067,254**	**$ 4,105,273**	**$ 1,245,002**	**$ 387**	**$ 811**	**$ 6,440**	**$ 893,986**	**$ 340,818**	**$ 7,303**
3		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Demand	$ 4,797,199	$ 2,198,030	$ 987,009	$ 72	$ 514	$ 4,958	$ 815,961	$ 323,420	$ -
5		Customer	$ 2,270,055	$ 1,907,243	$ 257,993	$ 315	$ 297	$ 1,482	$ 78,025	$ 17,398	$ 7,303
6											
7	Total Accumulated Depreciation		**$ (1,849,201)**	**$ (1,125,333)**	**$ (324,942)**	**$ (101)**	**$ (222)**	**$ (1,573)**	**$ (231,008)**	**$ (87,751)**	**$ (1,938)**
8		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Demand	$ (1,172,276)	$ (553,923)	$ (250,712)	$ (18)	$ (131)	$ (1,173)	$ (207,664)	$ (82,323)	$ -
10		Customer	$ (676,925)	$ (571,411)	$ (74,230)	$ (83)	$ (91)	$ (399)	$ (23,344)	$ (5,428)	$ (1,938)
11											
12	TOTAL Net Plant		**$ 5,218,052**	**$ 2,979,940**	**$ 920,060**	**$ 286**	**$ 589**	**$ 4,867**	**$ 662,978**	**$ 253,067**	**$ 5,364**
13		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Demand	$ 3,624,922	$ 1,644,107	$ 736,297	$ 55	$ 383	$ 3,784	$ 608,298	$ 241,097	$ -
15		Customer	$ 1,593,130	$ 1,335,832	$ 183,763	$ 232	$ 206	$ 1,082	$ 54,681	$ 11,970	$ 5,364
16											
17	**Contributions In Aid of Construction**										
18	Total Gas Plant in Service		**$ (424,193)**	**$ (269,702)**	**$ (78,430)**	**$ (28)**	**$ (51)**	**$ (366)**	**$ (54,516)**	**$ (20,582)**	**$ (518)**
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20		Demand	$ (256,397)	$ (128,274)	$ (59,129)	$ (4)	$ (31)	$ (263)	$ (49,190)	$ (19,507)	$ -
21		Customer	$ (167,796)	$ (141,428)	$ (19,302)	$ (24)	$ (20)	$ (104)	$ (5,326)	$ (1,076)	$ (518)
22											
23	Total Accumulated Depreciation		**$ 143,125**	**$ 91,320**	**$ 26,356**	**$ 10**	**$ 17**	**$ 121**	**$ 18,245**	**$ 6,878**	**$ 179**
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Demand	$ 85,274	$ 42,562	$ 19,702	$ 1	$ 10	$ 85	$ 16,407	$ 6,507	$ -
26		Customer	$ 57,850	$ 48,757	$ 6,653	$ 8	$ 7	$ 36	$ 1,838	$ 372	$ 179
27											
28	TOTAL Net Plant		**$ (281,069)**	**$ (178,382)**	**$ (52,074)**	**$ (19)**	**$ (33)**	**$ (246)**	**$ (36,271)**	**$ (13,704)**	**$ (339)**
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Demand	$ (171,122)	$ (85,712)	$ (39,426)	$ (3)	$ (21)	$ (178)	$ (32,783)	$ (13,000)	$ -
31		Customer	$ (109,946)	$ (92,671)	$ (12,648)	$ (16)	$ (13)	$ (68)	$ (3,488)	$ (704)	$ (339)
32											

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 3**

Rate Design Filing_Common Rates_ 2016 Test Year

<u>RATE BASE SUMMARY - CLASSIFICATION (000's)</u>

Discussion Point: EGP Project included

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
33	**13 Month Adjustment**		**$ 3,685**	**$ 2,148**	**$ 743**	**$ 0**	**$ 0**	**$ 4**	**$ 567**	**$ 220**	**$ 2**
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35		Demand	$ 2,974	$ 1,551	$ 663	$ 0	$ 0	$ 4	$ 541	$ 214	$ -
36		Customer	$ 711	$ 596	$ 80	$ 0	$ 0	$ 0	$ 26	$ 6	$ 2
37											
38	**Work in Process, no AFUDC**		**$ 35,156**	**$ 20,489**	**$ 7,088**	**$ 1**	**$ 4**	**$ 42**	**$ 5,407**	**$ 2,102**	**$ 22**
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Demand	$ 28,372	$ 14,801	$ 6,323	$ 1	$ 3	$ 37	$ 5,162	$ 2,044	$ -
41		Customer	$ 6,784	$ 5,688	$ 765	$ 1	$ 1	$ 5	$ 245	$ 58	$ 22
42											
43	**Unamortized Deferred Charges**		**$ 23,322**	**$ 20,187**	**$ 16,236**	**$ 2**	**$ 17**	**$ (20)**	**$ (4,016)**	**$ (2,212)**	**$ 246**
44		Energy	$ 1,130	$ (369)	$ 95	$ (31)	$ (11)	$ -	$ 2,010	$ (526)	$ (37)
45		Demand	$ 13,635	$ 14,146	$ 15,569	$ 33	$ 23	$ (35)	$ (7,085)	$ (2,116)	$ 218
46		Customer	$ 8,557	$ 6,410	$ 572	$ (0)	$ 5	$ 16	$ 1,059	$ 430	$ 66
47											
48	**Cash Working Capital**		**$ 2,079**	**$ 1,278**	**$ 421**	**$ 1**	**$ 1**	**$ 1**	**$ 299**	**$ 75**	**$ 4**
49		Energy	$ 1,155	$ 701	$ 261	$ 1	$ 1	$ -	$ 167	$ 23	$ 2
50		Demand	$ 575	$ 299	$ 129	$ 0	$ 0	$ 1	$ 105	$ 42	$ -
51		Customer	$ 349	$ 278	$ 32	$ 0	$ 0	$ 0	$ 27	$ 10	$ 2
52											
53	**Other Working Capital**		**$ 1,567**	**$ 1,085**	**$ 261**	**$ 0**	**$ 0**	**$ 1**	**$ 160**	**$ 58**	**$ 3**
54		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Demand	$ 608	$ 276	$ 150	$ -	$ 0	$ 0	$ 130	$ 52	$ -
56		Customer	$ 959	$ 808	$ 110	$ 0	$ 0	$ 1	$ 30	$ 6	$ 3
57											
58	**LILO, Other Rate Base items**		**$ 56,701**	**$ 30,057**	**$ 12,452**	**$ 2**	**$ 6**	**$ 101**	**$ 10,089**	**$ 3,996**	**$ (2)**
59		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Demand	$ 57,290	$ 30,553	$ 12,520	$ 2	$ 6	$ 101	$ 10,108	$ 3,999	$ -
61		Customer	$ (589)	$ (496)	$ (68)	$ (0)	$ (0)	$ (0)	$ (19)	$ (4)	$ (2)
62											
63	**Total Utility Rate Base**		**$ 5,059,494**	**$ 2,876,800**	**$ 905,186**	**$ 274**	**$ 585**	**$ 4,750**	**$ 639,213**	**$ 243,601**	**$ 5,300**
64		Energy	$ 2,285	$ 332	$ 355	$ (30)	$ (11)	$ -	$ 2,177	$ (502)	$ (36)
65		Demand	$ 3,557,254	$ 1,620,022	$ 732,225	$ 87	$ 396	$ 3,714	$ 584,475	$ 232,332	$ 218
66		Customer	$ 1,499,955	$ 1,256,446	$ 172,606	$ 217	$ 200	$ 1,036	$ 52,561	$ 11,771	$ 5,119

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 4**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Discussion Point: EGP Project included

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Operating & Maintenance Expense**		**$ 244,413**	**$ 160,667**	**$ 35,888**	**$ 15**	**$ 64**	**$ 273**	**$ 29,709**	**$ 11,345**	**$ 771**
2		Energy	$ 2,376	$ 1,442	$ 536	$ 3	$ 1	$ -	$ 343	$ 48	$ 3
3		Demand	$ 104,776	$ 50,356	$ 22,730	$ 2	$ 12	$ 101	$ 18,535	$ 7,356	$ 3
4		Customer	$ 137,260	$ 108,868	$ 12,622	$ 10	$ 51	$ 172	$ 10,831	$ 3,941	$ 765
5											
6	**Property & Sundry Taxes**		**$ 66,661**	**$ 39,387**	**$ 12,338**	**$ 4**	**$ 8**	**$ 67**	**$ 8,874**	**$ 3,395**	**$ 87**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 45,313	$ 21,600	$ 9,806	$ 1	$ 5	$ 49	$ 8,128	$ 3,222	$ -
9		Customer	$ 21,348	$ 17,787	$ 2,532	$ 3	$ 3	$ 17	$ 746	$ 172	$ 87
10											
11	**Depreciation Expense**		**$ 194,369**	**$ 116,253**	**$ 31,928**	**$ 16**	**$ 28**	**$ 172**	**$ 22,204**	**$ 8,020**	**$ 234**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 113,761	$ 50,530	$ 22,157	$ 2	$ 12	$ 123	$ 18,209	$ 7,214	$ -
14		Customer	$ 80,608	$ 65,723	$ 9,772	$ 14	$ 16	$ 49	$ 3,995	$ 805	$ 234
15											
16	**Amortization Expense**		**$ 43,429**	**$ 25,174**	**$ 9,491**	**$ 5**	**$ 8**	**$ 46**	**$ 5,143**	**$ 2,074**	**$ 64**
17		Energy	$ (91)	$ (55)	$ (20)	$ (0)	$ (0)	$ -	$ (13)	$ (2)	$ (0)
18		Demand	$ 25,456	$ 12,437	$ 5,392	$ 0	$ 3	$ 32	$ 4,418	$ 1,750	$ -
19		Customer	$ 18,063	$ 12,792	$ 4,120	$ 5	$ 5	$ 14	$ 737	$ 326	$ 64
20											
21	**Other Operating Revenue**		**$ (187,689)**	**$ (80,348)**	**$ (31,694)**	**$ (4)**	**$ (18)**	**$ (250)**	**$ (25,524)**	**$ (10,077)**	**$ (28)**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ (181,550)	$ (75,364)	$ (31,086)	$ (3)	$ (16)	$ (244)	$ (25,142)	$ (9,949)	$ -
24		Customer	$ (6,139)	$ (4,984)	$ (608)	$ (1)	$ (2)	$ (6)	$ (382)	$ (128)	$ (28)
25											

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
COST OF SERVICE SUMMARY - CLASSIFICATION (000's)
Discussion Point: EGP Project included

Schedule 4

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
26	**Income Tax**		**$ 41,333**	**$ 26,138**	**$ 7,973**	**$ 2**	**$ 5**	**$ 42**	**$ 5,830**	**$ 2,239**	**$ 51**
27		Energy	$ (211)	$ (128)	$ (48)	$ (0)	$ (0)	$ -	$ (30)	$ (4)	$ (0)
28		Demand	$ 27,502	$ 14,568	$ 6,441	$ 0	$ 3	$ 31	$ 5,304	$ 2,102	$ -
29		Customer	$ 14,042	$ 11,698	$ 1,580	$ 2	$ 2	$ 11	$ 557	$ 141	$ 51
30											
31	**Earned Return**		**$ 352,376**	**$ 210,298**	**$ 62,744**	**$ 18**	**$ 44**	**$ 341**	**$ 45,517**	**$ 17,425**	**$ 416**
32		Energy	$ (1,731)	$ (1,051)	$ (390)	$ (2)	$ (1)	$ -	$ (250)	$ (35)	$ (2)
33		Demand	$ 238,837	$ 115,320	$ 50,160	$ 4	$ 27	$ 255	$ 41,197	$ 16,302	$ -
34		Customer	$ 115,270	$ 96,028	$ 12,974	$ 16	$ 18	$ 86	$ 4,570	$ 1,158	$ 419
35											
36	**Total Cost of Service Margin**		**$ 754,892**	**$ 497,567**	**$ 128,669**	**$ 57**	**$ 140**	**$ 690**	**$ 91,754**	**$ 34,420**	**$ 1,595**
37		Energy	$ 343	$ 208	$ 77	$ 0	$ 0	$ -	$ 50	$ 7	$ 0
38		Demand	$ 374,096	$ 189,446	$ 85,600	$ 6	$ 46	$ 347	$ 70,651	$ 27,997	$ 3
39		Customer	$ 380,453	$ 307,913	$ 42,992	$ 50	$ 94	$ 344	$ 21,054	$ 6,415	$ 1,592
40											
41	**Cost of Gas Sold (Including Gas Lost)**		**$ 475,684**	**$ 287,646**	**$ 111,133**	**$ 433**	**$ 135**	**$ 267**	**$ 67,966**	**$ 7,458**	**$ 646**
42		Energy	$ 475,684	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 67,966	$ 7,458	$ 646
43		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45											
46	**Total Utility Revenue Require**		**$ 1,230,576**	**$ 785,213**	**$ 239,802**	**$ 490**	**$ 275**	**$ 957**	**$ 159,720**	**$ 41,878**	**$ 2,241**
47		Energy	$ 476,027	$ 287,854	$ 111,210	$ 433	$ 135	$ 267	$ 68,016	$ 7,465	$ 646
48		Demand	$ 374,096	$ 189,446	$ 85,600	$ 6	$ 46	$ 347	$ 70,651	$ 27,997	$ 3
49		Customer	$ 380,453	$ 307,913	$ 42,992	$ 50	$ 94	$ 344	$ 21,054	$ 6,415	$ 1,592

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
Schedule 5

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Discussion Point: EGP Project included

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Gas Supply Operations**		**$ (24,856)**	**$ (15,086)**	**$ (5,605)**	**$ (30)**	**$ (11)**	**$ -**	**$ (3,587)**	**$ (502)**	**$ (36)**
2		Energy	$ (24,856)	$ (15,086)	$ (5,605)	$ (30)	$ (11)	$ -	$ (3,587)	$ (502)	$ (36)
3		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5											
6	**LNG Storage Tilbury**		**$ 449,470**	**$ 35,060**	**$ 14,393**	**$ -**	**$ 7**	**$ -**	**$ 11,626**	**$ 4,600**	**$ -**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 449,470	$ 35,060	$ 14,393	$ -	$ 7	$ -	$ 11,626	$ 4,600	$ -
9		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	**LNG Storage Mt. Hayes**		**$ 186,660**	**$ 99,456**	**$ 40,829**	**$ -**	**$ 21**	**$ 327**	**$ 32,979**	**$ 13,049**	**$ -**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 186,660	$ 99,456	$ 40,829	$ -	$ 21	$ 327	$ 32,979	$ 13,049	$ -
14		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	**Transmission**		**$ 1,832,929**	**$ 976,592**	**$ 400,911**	**$ 51**	**$ 206**	**$ 3,208**	**$ 323,830**	**$ 128,132**	**$ -**
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 1,832,929	$ 976,592	$ 400,911	$ 51	$ 206	$ 3,208	$ 323,830	$ 128,132	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 5**

Rate Design Filing_Common Rates_ 2016 Test Year

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Discussion Point: EGP Project included

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
21	Distribution		**$ 2,473,589**	**$ 1,691,778**	**$ 418,690**	**$ 218**	**$ 309**	**$ 1,095**	**$ 261,763**	**$ 94,914**	**$ 4,821**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ 1,015,424	$ 467,114	$ 249,121	$ 2	$ 133	$ 129	$ 213,905	$ 85,019	$ -
24		Customer	$ 1,458,165	$ 1,224,664	$ 169,569	$ 217	$ 176	$ 966	$ 47,857	$ 9,895	$ 4,821
25											
26	Marketing		**$ 78,751**	**$ 46,349**	**$ 27,406**	**$ 35**	**$ 32**	**$ 60**	**$ 2,809**	**$ 1,801**	**$ 260**
27		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28		Demand	$ 72,770	$ 41,800	$ 26,971	$ 35	$ 29	$ 50	$ 2,135	$ 1,532	$ 218
29		Customer	$ 5,981	$ 4,549	$ 435	$ 0	$ 3	$ 10	$ 673	$ 269	$ 43
30											
31	Customer Accounting		**$ 62,950**	**$ 42,651**	**$ 8,562**	**$ 0**	**$ 20**	**$ 60**	**$ 9,794**	**$ 1,608**	**$ 255**
32		Energy	$ 27,141	$ 15,418	$ 5,960	$ -	$ -	$ -	$ 5,764	$ -	$ -
33		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Customer	$ 35,810	$ 27,233	$ 2,603	$ 0	$ 20	$ 60	$ 4,030	$ 1,608	$ 255
35											
36	**Total Utility Rate Base**		**$ 5,059,494**	**$ 2,876,800**	**$ 905,186**	**$ 274**	**$ 585**	**$ 4,750**	**$ 639,213**	**$ 243,601**	**$ 5,300**
37		Energy	$ 2,285	$ 332	$ 355	$ (30)	$ (11)	$ -	$ 2,177	$ (502)	$ (36)
38		Demand	$ 3,557,254	$ 1,620,022	$ 732,225	$ 87	$ 396	$ 3,714	$ 584,475	$ 232,332	$ 218
39		Customer	$ 1,499,955	$ 1,256,446	$ 172,606	$ 217	$ 200	$ 1,036	$ 52,561	$ 11,771	$ 5,119

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 6**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Discussion Point: EGP Project included

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Gas Supply Operations		**$ 343**	**$ 208**	**$ 77**	**$ 0**	**$ 0**	**$ -**	**$ 50**	**$ 7**	**$ 0**
2		Energy	$ 343	$ 208	$ 77	$ 0	$ 0	$ -	$ 50	$ 7	$ 0
3		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5											
6	LNG Storage Tilbury		**$ 32,427**	**$ 18,524**	**$ 6,646**	**$ 1**	**$ 4**	**$ -**	**$ 5,214**	**$ 2,039**	**$ -**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 32,427	$ 18,524	$ 6,646	$ 1	$ 4	$ -	$ 5,214	$ 2,039	$ -
9		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ 6,966**	**$ 3,712**	**$ 1,524**	**$ -**	**$ 1**	**$ 12**	**$ 1,231**	**$ 487**	**$ -**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 6,966	$ 3,712	$ 1,524	$ -	$ 1	$ 12	$ 1,231	$ 487	$ -
14		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 151,881**	**$ 80,923**	**$ 33,220**	**$ 4**	**$ 17**	**$ 266**	**$ 26,833**	**$ 10,617**	**$ -**
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 151,881	$ 80,923	$ 33,220	$ 4	$ 17	$ 266	$ 26,833	$ 10,617	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 6**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Discussion Point: EGP Project included

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
21	Distribution		**$ 455,758**	**$ 314,165**	**$ 76,617**	**$ 46**	**$ 60**	**$ 242**	**$ 47,099**	**$ 16,664**	**$ 866**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ 181,889	$ 85,752	$ 43,864	$ 1	$ 23	$ 68	$ 37,346	$ 14,834	$ -
24		Customer	$ 273,869	$ 228,412	$ 32,753	$ 45	$ 36	$ 174	$ 9,754	$ 1,830	$ 866
25											
26	Marketing		**$ 46,724**	**$ 33,804**	**$ 6,166**	**$ 5**	**$ 24**	**$ 69**	**$ 4,485**	**$ 1,876**	**$ 295**
27		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28		Demand	$ 932	$ 535	$ 345	$ 0	$ 0	$ 1	$ 27	$ 20	$ 3
29		Customer	$ 45,792	$ 33,268	$ 5,821	$ 4	$ 24	$ 68	$ 4,458	$ 1,856	$ 292
30											
31	Customer Accounting		**$ 60,791**	**$ 46,232**	**$ 4,418**	**$ 1**	**$ 34**	**$ 102**	**$ 6,842**	**$ 2,729**	**$ 434**
32		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Customer	$ 60,791	$ 46,232	$ 4,418	$ 1	$ 34	$ 102	$ 6,842	$ 2,729	$ 434
35											
36	**Total Utility Cost of Service**		**$ 754,892**	**$ 497,567**	**$ 128,669**	**$ 57**	**$ 140**	**$ 690**	**$ 91,754**	**$ 34,420**	**$ 1,595**
37		Energy	$ 343	$ 208	$ 77	$ 0	$ 0	$ -	$ 50	$ 7	$ 0
38		Demand	$ 374,096	$ 189,446	$ 85,600	$ 6	$ 46	$ 347	$ 70,651	$ 27,997	$ 3
39		Customer	$ 380,453	$ 307,913	$ 42,992	$ 50	$ 94	$ 344	$ 21,054	$ 6,415	$ 1,592

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 7**

Rate Design Filing_Common Rates_ 2016 Test Year

CLASSIFICATION SUMMARY (000's)

Discussion Point: EGP Project included

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Billing Determinants										
2											
3	Sales Volume (TJ)		163,288	72,466	28,012	130	47	13,189	27,090	15,663	6,691
4	Midstream Sales Volume (TJ)		120,882	72,399	27,942	130	47	-	18,037	2,173	155
5	Commodity Sales Volume (TJ)		107,522	65,258	24,245	130	47	-	15,515	2,173	155
6	Average No. of Customers		979,066	886,652	84,737	18	15	26	6,709	796	113
7											
8	Cost of Service Margin		**$ 754,892**	**$ 497,567**	**$ 128,669**	**$ 57**	**$ 140**	**$ 690**	**$ 91,754**	**$ 34,420**	**$ 1,595**
9		Energy	$ 343	$ 208	$ 77	$ 0	$ 0	$ -	$ 50	$ 7	$ 0
10	Unit Energy Charge ($/GJ)		0.002	0.003	0.003	0.003	0.003	0.000	0.002	0.000	0.000
11		Demand	$ 374,096	$ 189,446	$ 85,600	$ 6	$ 46	$ 347	$ 70,651	$ 27,997	$ 3
12	Unit Demand Charge ($/GJ)		2.291	2.614	3.056	0.049	0.981	0.026	2.608	1.787	0.000
13		Customer	$ 380,453	$ 307,913	$ 42,992	$ 50	$ 94	$ 344	$ 21,054	$ 6,415	$ 1,592
14	Unit Customer Charge ($/Cust/Day)		1.064	0.951	1.389	7.572	17.139	36.175	3.138	8.059	14.085
15											
16	Unit Cost of Service Margin ($/GJ)		4.623	6.866	4.593	0.435	2.991	0.052	3.387	2.198	0.238
17											
18	Cost of Gas - Commodity & Midstream		**$ 475,684**	**$ 287,646**	**$ 111,133**	**$ 433**	**$ 135**	**$ 267**	**$ 67,966**	**$ 7,458**	**$ 646**
19		Energy	$ 475,684	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 67,966	$ 7,458	$ 646
20		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Unit Cost of Gas - Commodity ($/GJ)		2.913	3.969	3.967	3.333	2.885	0.020	2.509	0.476	0.097
23											
24	Total Utility Cost of Service		**$ 1,230,576**	**$ 785,213**	**$ 239,802**	**$ 490**	**$ 275**	**$ 957**	**$ 159,720**	**$ 41,878**	**$ 2,241**
25		Energy	$ 476,027	$ 287,854	$ 111,210	$ 433	$ 135	$ 267	$ 68,016	$ 7,465	$ 646
26		Demand	$ 374,096	$ 189,446	$ 85,600	$ 6	$ 46	$ 347	$ 70,651	$ 27,997	$ 3
27		Customer	$ 380,453	$ 307,913	$ 42,992	$ 50	$ 94	$ 344	$ 21,054	$ 6,415	$ 1,592
28	Unit Cost of Service ($/GJ)		7.536	10.836	8.561	3.769	5.875	0.073	5.896	2.674	0.335
29											
30	Total Revenues @ Proposed Rates		**$ 1,330,163**	**$ 752,423**	**$ 241,277**	**$ 707**	**$ 369**	**$ 14,225**	**$ 197,578**	**$ 90,568**	**$ 33,015**
31	Unit Rate ($/GJ)		8.146	10.383	8.613	5.443	7.888	1.079	7.293	5.782	4.934
32											
33	Total Revenue Margin @ Proposed Rates		**$ 754,892**	**$ 464,777**	**$ 130,144**	**$ 274**	**$ 234**	**$ 13,958**	**$ 96,246**	**$ 38,534**	**$ 10,725**
34	Unit Rate ($/GJ)		4.623	6.414	4.646	2.110	5.003	1.058	3.553	2.460	1.603

Appendix F

FULLY DISTRIBUTED COSA STUDY
2016 TEST YEAR SCHEDULES
INCLUDING DISCUSSION OF MT HAYES COST ALLOCATION

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year **Schedule 1**
SUMMARY (000's)

Discussion Point: Eliiminate Mt Hayes Cost Allocation to Midstream

Line No.	Particulars	Reference	Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**REVENUE TO COST**										
2	Total Revenue at Proposed 2016 Common Rates	Line 3 + Line 4	**$ 1,294,195**	**$ 730,278**	**$ 235,076**	**$ 694**	**$ 358**	**$ 13,560**	**$ 192,992**	**$ 88,732**	**$ 32,504**
3	Revenue Margin at Proposed 2016 Common Rates		$ 718,924	$ 442,632	$ 123,943	$ 261	$ 223	$ 13,293	$ 91,660	$ 36,698	$ 10,214
4	Total Cost of Gas		$ 575,271	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 101,332	$ 52,034	$ 22,290
5											
6	**COST OF SERVICE**										
7	Total Utility Cost of Service	Line 8 + Line 9	**$ 1,365,499**	**$ 805,729**	**$ 246,976**	**$ 490**	**$ 279**	**$ 996**	**$ 198,542**	**$ 88,574**	**$ 23,913**
8	Cost of Service Margin		$ 790,228	$ 518,083	$ 135,843	$ 57	$ 144	$ 729	$ 97,209	$ 36,540	$ 1,623
9	Total Cost of Gas		$ 575,271	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 101,332	$ 52,034	$ 22,290
10											
11	**SURPLUS / DEFICIT**										
12	Total Surplus / (Deficit)	Line 2 - Line 7	**$ (71,304)**								
13	% Increase to Equal Allocated Costs	- Line 12 / Line 3	9.9%	Effect of major project additions to COSA model							
14											
15	**REVENUES (adjusted to equal COS)**										
16	Total Adjusted Revenue at Proposed 2016 Common Rates	Line 4 + Line 17	**$ 1,365,499**	**$ 774,179**	**$ 247,369**	**$ 720**	**$ 380**	**$ 14,878**	**$ 202,083**	**$ 92,372**	**$ 33,517**
17	Total Adjusted Revenue Margin at Proposed 2016 Common Rates	Line 3 x (1 + Line 13)	$ 790,228	$ 486,533	$ 136,236	$ 287	$ 245	$ 14,611	$ 100,751	$ 40,338	$ 11,227
18											
19	REVENUES (adjusted for R/C ratio's)	Line 16	**$ 1,365,499**	**$ 774,179**	**$ 247,369**	**$ 720**	**$ 380**	**$ 14,878**	**$ 202,083**	**$ 92,372**	**$ 33,517**
20	COST OF SERVICE (adjusted for R/C ratio's)	Line 7	**$ 1,365,499**	**$ 805,729**	**$ 246,976**	**$ 490**	**$ 279**	**$ 996**	**$ 198,542**	**$ 88,574**	**$ 23,913**
21											
22	**REVENUE TO COST RATIO**										
23	Revenue to Cost Ratio	Line 19 / Line 20	**100%**	**96%**	**100%**		**136%**		**102%**	**104%**	
24											
25	**REVENUE REBALANCING**										
26	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Total Revenue at Proposed Rates	Line 16 + Line 26	**$ 1,365,499**	**$ 774,179**	**$ 247,369**	**$ 720**	**$ 380**	**$ 14,878**	$ 202,083	$ 92,372	$ 33,517
28	Total Revenue Margin at Proposed Rates	Line 17 + Line 26	$ 790,228	$ 486,533	$ 136,236	$ 287	$ 245	$ 14,611	$ 100,751	$ 40,338	$ 11,227
29											
30	**PROPOSED REVENUE TO COST RATIO**										
31	Revenue to Cost Ratio at Proposed Rates		**100%**	**96%**	**100%**		**136%**		**102%**	**104%**	
32											

33 **Note:**
34 1. Lines 2, 7, 16, 19, 20, 27 include the imputed Cost of Gas for Rates 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios
35 Rates 23, 25 and 27 do not pay for commodity and midstream charges.
36 2. Rate 4 is a seasonal service and Rates 22 and Rate7/27 are interruptible customer classes. The revenue to cost ratio for Rate 4, Rate 22 and Rate 7/27 are not shown in the schedule above as
37 these rate classes do not drive system capacity additions and therefore, no demand-related costs are allocated to these customer classes in the COSA Study.
38 3. Revenue Margin includes UAF allocation to rate classes.

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 2**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE FUNCTIONALIZATION (000's)

Discussion Point: Eliiminate Mt Hayes Cost Allocation to Midstream

Line No.	Particulars	Total	Gas Supply Operation	LNG Storage Tilbury	LNG Storage Mt. Hayes	Transmission	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense	$ 243,000	$ 2,380	$ 14,782	$ 3,568	$ 34,454	$ 108,278	$ 31,064	$ 48,474
2	Property & Sundry Taxes	$ 63,840	$ -	$ 1,960	$ 372	$ 21,680	$ 39,828	$ -	$ -
3	Depreciation Expense	$ 181,504	$ -	$ 20,160	$ 6,655	$ 40,501	$ 105,441	$ -	$ 8,746
4	Amortization Expense	$ 42,339	$ (90)	$ 2,497	$ 43	$ 7,734	$ 21,501	$ 9,566	$ 1,089
5	Other Operating Revenue	$ (95,372)	$ -	$ (39,745)	$ -	$ (47,061)	$ (6,252)	$ -	$ (2,314)
6	Income Tax	$ 44,864	$ (256)	$ 3,228	$ 1,938	$ 12,798	$ 25,693	$ 813	$ 650
7	Earned Return	$ 310,054	$ (1,711)	$ 32,172	$ 12,933	$ 85,418	$ 171,478	$ 5,428	$ 4,337
8	**Total Cost of Service Margin**	**$ 790,228**	**$ 322**	**$ 35,054**	**$ 25,508**	**$ 155,524**	**$ 465,967**	**$ 46,871**	**$ 60,982**
9									
10	Cost of Gas - Commodity & Midstream	$ 477,714	$ 477,714	$ -	$ -	$ -	$ -	$ -	$ -
11	**Total Utility Revenue Requirement**	**$ 1,267,942**	**$ 478,036**	**$ 35,054**	**$ 25,508**	**$ 155,524**	**$ 465,967**	**$ 46,871**	**$ 60,982**

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study **Schedule 3**
Rate Design Filing_Common Rates_ 2016 Test Year
RATE BASE SUMMARY - CLASSIFICATION (000's)
Discussion Point: Eliiminate Mt Hayes Cost Allocation to Midstream

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Gas Plant in Service**										
2	Total Gas Plant in Service		**$ 6,470,628**	**$ 3,792,529**	**$ 1,112,819**	**$ 372**	**$ 745**	**$ 5,343**	**$ 786,178**	**$ 298,045**	**$ 7,363**
3		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Demand	$ 4,180,848	$ 1,868,660	$ 852,557	$ 54	$ 445	$ 3,849	$ 707,527	$ 280,520	$ -
5		Customer	$ 2,289,781	$ 1,923,869	$ 260,262	$ 318	$ 299	$ 1,494	$ 78,650	$ 17,524	$ 7,363
6											
7	Total Accumulated Depreciation		**$ (1,815,001)**	**$ (1,116,768)**	**$ (320,227)**	**$ (101)**	**$ (220)**	**$ (1,523)**	**$ (226,870)**	**$ (86,077)**	**$ (1,958)**
8		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Demand	$ (1,131,843)	$ (540,104)	$ (245,280)	$ (17)	$ (128)	$ (1,120)	$ (203,329)	$ (80,609)	$ -
10		Customer	$ (683,158)	$ (576,664)	$ (74,947)	$ (84)	$ (92)	$ (403)	$ (23,542)	$ (5,468)	$ (1,958)
11											
12	TOTAL Net Plant		**$ 4,655,627**	**$ 2,675,761**	**$ 792,592**	**$ 271**	**$ 525**	**$ 3,820**	**$ 559,307**	**$ 211,968**	**$ 5,406**
13		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Demand	$ 3,049,004	$ 1,328,556	$ 607,277	$ 38	$ 317	$ 2,729	$ 504,199	$ 199,911	$ -
15		Customer	$ 1,606,623	$ 1,347,205	$ 185,315	$ 234	$ 207	$ 1,091	$ 55,109	$ 12,056	$ 5,406
16											
17	**Contributions In Aid of Construction**										
18	Total Gas Plant in Service		**$ (424,193)**	**$ (269,741)**	**$ (78,417)**	**$ (28)**	**$ (51)**	**$ (366)**	**$ (54,498)**	**$ (20,574)**	**$ (518)**
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20		Demand	$ (256,248)	$ (128,187)	$ (59,099)	$ (4)	$ (31)	$ (262)	$ (49,167)	$ (19,498)	$ -
21		Customer	$ (167,945)	$ (141,553)	$ (19,319)	$ (24)	$ (20)	$ (104)	$ (5,331)	$ (1,077)	$ (518)
22											
23	Total Accumulated Depreciation		**$ 143,125**	**$ 91,352**	**$ 26,345**	**$ 10**	**$ 17**	**$ 120**	**$ 18,230**	**$ 6,872**	**$ 179**
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Demand	$ 85,149	$ 42,489	$ 19,677	$ 1	$ 10	$ 84	$ 16,388	$ 6,499	$ -
26		Customer	$ 57,976	$ 48,863	$ 6,668	$ 8	$ 7	$ 36	$ 1,842	$ 373	$ 179
27											
28	TOTAL Net Plant		**$ (281,069)**	**$ (178,388)**	**$ (52,072)**	**$ (19)**	**$ (33)**	**$ (246)**	**$ (36,268)**	**$ (13,703)**	**$ (339)**
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Demand	$ (171,099)	$ (85,698)	$ (39,422)	$ (3)	$ (21)	$ (178)	$ (32,780)	$ (12,998)	$ -
31		Customer	$ (109,969)	$ (92,690)	$ (12,651)	$ (16)	$ (13)	$ (68)	$ (3,488)	$ (704)	$ (339)
32											

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 3**

Rate Design Filing_Common Rates_ 2016 Test Year

RATE BASE SUMMARY - CLASSIFICATION (000's)

Discussion Point: Eliiminate Mt Hayes Cost Allocation to Midstream

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
33	**13 Month Adjustment**		**$ 3,685**	**$ 2,187**	**$ 730**	**$ 0**	**$ 0**	**$ 4**	**$ 549**	**$ 212**	**$ 3**
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35		Demand	$ 2,822	$ 1,463	$ 632	$ 0	$ 0	$ 3	$ 518	$ 205	$ -
36		Customer	$ 863	$ 724	$ 97	$ 0	$ 0	$ 1	$ 31	$ 7	$ 3
37											
38	**Work in Process, no AFUDC**		**$ 35,156**	**$ 20,865**	**$ 6,962**	**$ 2**	**$ 4**	**$ 38**	**$ 5,233**	**$ 2,025**	**$ 27**
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Demand	$ 26,924	$ 13,960	$ 6,033	$ 0	$ 3	$ 33	$ 4,939	$ 1,956	$ -
41		Customer	$ 8,232	$ 6,905	$ 930	$ 1	$ 1	$ 6	$ 294	$ 68	$ 27
42											
43	**Unamortized Deferred Charges**		**$ 24,791**	**$ 20,103**	**$ 16,845**	**$ 2**	**$ 17**	**$ (8)**	**$ (3,355)**	**$ (1,931)**	**$ 235**
44		Energy	$ 1,130	$ (369)	$ 95	$ (31)	$ (11)	$ -	$ 2,010	$ (526)	$ (37)
45		Demand	$ 18,434	$ 16,864	$ 16,559	$ 34	$ 24	$ (21)	$ (6,313)	$ (1,812)	$ 218
46		Customer	$ 5,228	$ 3,609	$ 191	$ (1)	$ 5	$ 13	$ 948	$ 406	$ 55
47											
48	**Cash Working Capital**		**$ 2,129**	**$ 1,316**	**$ 429**	**$ 1**	**$ 1**	**$ 1**	**$ 302**	**$ 75**	**$ 4**
49		Energy	$ 1,184	$ 718	$ 267	$ 1	$ 1	$ -	$ 171	$ 24	$ 2
50		Demand	$ 560	$ 289	$ 126	$ 0	$ 0	$ 1	$ 103	$ 41	$ -
51		Customer	$ 385	$ 308	$ 36	$ 0	$ 0	$ 0	$ 28	$ 10	$ 2
52											
53	**Other Working Capital**		**$ 1,567**	**$ 1,085**	**$ 261**	**$ 0**	**$ 0**	**$ 1**	**$ 160**	**$ 58**	**$ 3**
54		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Demand	$ 608	$ 276	$ 150	$ -	$ 0	$ 0	$ 130	$ 52	$ -
56		Customer	$ 959	$ 808	$ 110	$ 0	$ 0	$ 1	$ 30	$ 6	$ 3
57											
58	**LILO, Other Rate Base items**		**$ 56,701**	**$ 30,057**	**$ 12,452**	**$ 2**	**$ 6**	**$ 101**	**$ 10,089**	**$ 3,996**	**$ (2)**
59		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Demand	$ 57,290	$ 30,553	$ 12,520	$ 2	$ 6	$ 101	$ 10,108	$ 3,999	$ -
61		Customer	$ (589)	$ (496)	$ (68)	$ (0)	$ (0)	$ (0)	$ (19)	$ (4)	$ (2)
62											
63	**Total Utility Rate Base**		**$ 4,498,588**	**$ 2,572,985**	**$ 778,199**	**$ 259**	**$ 520**	**$ 3,711**	**$ 536,018**	**$ 202,699**	**$ 5,337**
64		Energy	$ 2,314	$ 349	$ 362	$ (30)	$ (11)	$ -	$ 2,181	$ (502)	$ (36)
65		Demand	$ 2,984,543	$ 1,306,263	$ 603,876	$ 71	$ 330	$ 2,668	$ 480,904	$ 191,354	$ 218
66		Customer	$ 1,511,731	$ 1,266,373	$ 173,961	$ 219	$ 201	$ 1,043	$ 52,933	$ 11,846	$ 5,155

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 4**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Discussion Point: Eliiminate Mt Hayes Cost Allocation to Midstream

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Operating & Maintenance Expense**		**$ 243,000**	**$ 160,487**	**$ 35,379**	**$ 15**	**$ 64**	**$ 266**	**$ 29,198**	**$ 11,130**	**$ 779**
2		Energy	$ 2,380	$ 1,445	$ 537	$ 3	$ 1	$ -	$ 343	$ 48	$ 3
3		Demand	$ 101,136	$ 48,315	$ 21,972	$ 2	$ 12	$ 92	$ 17,940	$ 7,121	$ 3
4		Customer	$ 139,483	$ 110,728	$ 12,871	$ 10	$ 51	$ 174	$ 10,914	$ 3,961	$ 773
5											
6	**Property & Sundry Taxes**		**$ 63,840**	**$ 39,557**	**$ 12,159**	**$ 4**	**$ 8**	**$ 58**	**$ 8,659**	**$ 3,302**	**$ 93**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 41,115	$ 20,621	$ 9,464	$ 1	$ 5	$ 40	$ 7,865	$ 3,119	$ -
9		Customer	$ 22,725	$ 18,936	$ 2,695	$ 4	$ 3	$ 19	$ 793	$ 183	$ 93
10											
11	**Depreciation Expense**		**$ 181,504**	**$ 109,620**	**$ 29,043**	**$ 16**	**$ 26**	**$ 146**	**$ 19,828**	**$ 7,073**	**$ 237**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 99,884	$ 43,047	$ 19,154	$ 1	$ 10	$ 97	$ 15,799	$ 6,261	$ -
14		Customer	$ 81,619	$ 66,573	$ 9,889	$ 14	$ 16	$ 50	$ 4,029	$ 812	$ 237
15											
16	**Amortization Expense**		**$ 42,339**	**$ 24,859**	**$ 9,165**	**$ 6**	**$ 8**	**$ 42**	**$ 4,827**	**$ 1,943**	**$ 67**
17		Energy	$ (90)	$ (55)	$ (20)	$ (0)	$ (0)	$ -	$ (13)	$ (2)	$ (0)
18		Demand	$ 23,347	$ 11,264	$ 4,949	$ 0	$ 3	$ 27	$ 4,069	$ 1,612	$ -
19		Customer	$ 19,082	$ 13,650	$ 4,236	$ 5	$ 6	$ 15	$ 770	$ 333	$ 67
20											
21	**Other Operating Revenue**		**$ (95,372)**	**$ (31,161)**	**$ (11,502)**	**$ (2)**	**$ (7)**	**$ (89)**	**$ (9,214)**	**$ (3,624)**	**$ (28)**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ (89,233)	$ (26,177)	$ (10,894)	$ (1)	$ (6)	$ (82)	$ (8,832)	$ (3,496)	$ -
24		Customer	$ (6,139)	$ (4,984)	$ (608)	$ (1)	$ (2)	$ (6)	$ (382)	$ (128)	$ (28)
25											

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 4**

Rate Design Filing_Common Rates_ 2016 Test Year

<u>COST OF SERVICE SUMMARY - CLASSIFICATION (000's)</u>

Discussion Point: Eliiminate Mt Hayes Cost Allocation to Midstream

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
26	**Income Tax**		**$ 44,864**	**$ 28,824**	**$ 8,463**	**$ 2**	**$ 6**	**$ 40**	**$ 6,089**	**$ 2,325**	**$ 62**
27		Energy	$ (256)	$ (156)	$ (58)	$ (0)	$ (0)	$ -	$ (37)	$ (5)	$ (0)
28		Demand	$ 27,938	$ 14,664	$ 6,586	$ 0	$ 3	$ 27	$ 5,445	$ 2,158	$ -
29		Customer	$ 17,183	$ 14,315	$ 1,934	$ 2	$ 3	$ 13	$ 680	$ 172	$ 62
30											
31	**Earned Return**		**$ 310,054**	**$ 185,898**	**$ 53,136**	**$ 17**	**$ 39**	**$ 266**	**$ 37,823**	**$ 14,390**	**$ 414**
32		Energy	$ (1,711)	$ (1,039)	$ (386)	$ (2)	$ (1)	$ -	$ (247)	$ (35)	$ (2)
33		Demand	$ 197,088	$ 91,395	$ 40,613	$ 3	$ 22	$ 180	$ 33,529	$ 13,274	$ -
34		Customer	$ 114,678	$ 95,541	$ 12,909	$ 16	$ 18	$ 86	$ 4,541	$ 1,150	$ 416
35											
36	**Total Cost of Service Margin**		**$ 790,228**	**$ 518,083**	**$ 135,843**	**$ 57**	**$ 144**	**$ 729**	**$ 97,209**	**$ 36,540**	**$ 1,623**
37		Energy	$ 322	$ 196	$ 73	$ 0	$ 0	$ -	$ 47	$ 7	$ 0
38		Demand	$ 401,276	$ 203,128	$ 91,845	$ 6	$ 49	$ 379	$ 75,816	$ 30,050	$ 3
39		Customer	$ 388,631	$ 314,760	$ 43,925	$ 51	$ 95	$ 349	$ 21,347	$ 6,483	$ 1,620
40											
41	**Cost of Gas Sold (Including Gas Lost)**		**$ 475,684**	**$ 287,646**	**$ 111,133**	**$ 433**	**$ 135**	**$ 267**	**$ 67,966**	**$ 7,458**	**$ 646**
42		Energy	$ 475,684	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 67,966	$ 7,458	$ 646
43		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45											
46	**Total Utility Revenue Requir**		**$ 1,265,912**	**$ 805,729**	**$ 246,976**	**$ 490**	**$ 279**	**$ 996**	**$ 165,175**	**$ 43,998**	**$ 2,269**
47		Energy	$ 476,006	$ 287,842	$ 111,206	$ 433	$ 135	$ 267	$ 68,013	$ 7,465	$ 646
48		Demand	$ 401,276	$ 203,128	$ 91,845	$ 6	$ 49	$ 379	$ 75,816	$ 30,050	$ 3
49		Customer	$ 388,631	$ 314,760	$ 43,925	$ 51	$ 95	$ 349	$ 21,347	$ 6,483	$ 1,620

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 5**

Rate Design Filing_Common Rates_ 2016 Test Year

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Discussion Point: Eliiminate Mt Hayes Cost Allocation to Midstream

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Gas Supply Operations		**$ (24,827)**	**$ (15,068)**	**$ (5,598)**	**$ (30)**	**$ (11)**	**$ -**	**$ (3,582)**	**$ (502)**	**$ (36)**
2		Energy	$ (24,827)	$ (15,068)	$ (5,598)	$ (30)	$ (11)	$ -	$ (3,582)	$ (502)	$ (36)
3		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5											
6	LNG Storage Tilbury		**$ 466,786**	**$ 36,256**	**$ 14,884**	**$ -**	**$ 8**	**$ -**	**$ 12,022**	**$ 4,757**	**$ -**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 466,786	$ 36,256	$ 14,884	$ -	$ 8	$ -	$ 12,022	$ 4,757	$ -
9		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ 187,640**	**$ 99,978**	**$ 41,043**	**$ -**	**$ 21**	**$ 328**	**$ 33,152**	**$ 13,117**	**$ -**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 187,640	$ 99,978	$ 41,043	$ -	$ 21	$ 328	$ 33,152	$ 13,117	$ -
14		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 1,239,328**	**$ 660,319**	**$ 271,074**	**$ 34**	**$ 139**	**$ 2,169**	**$ 218,956**	**$ 86,636**	**$ -**
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 1,239,328	$ 660,319	$ 271,074	$ 34	$ 139	$ 2,169	$ 218,956	$ 86,636	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 5**

Rate Design Filing_Common Rates_ 2016 Test Year

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Discussion Point: Eliiminate Mt Hayes Cost Allocation to Midstream

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
21	Distribution		**$ 2,487,976**	**$ 1,702,514**	**$ 420,829**	**$ 220**	**$ 311**	**$ 1,093**	**$ 262,869**	**$ 95,283**	**$ 4,857**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ 1,018,020	$ 467,911	$ 249,904	$ 2	$ 134	$ 120	$ 214,638	$ 85,312	$ -
24		Customer	$ 1,469,956	$ 1,234,603	$ 170,925	$ 218	$ 178	$ 973	$ 48,231	$ 9,971	$ 4,857
25											
26	Marketing		**$ 78,754**	**$ 46,350**	**$ 27,406**	**$ 35**	**$ 32**	**$ 60**	**$ 2,809**	**$ 1,801**	**$ 260**
27		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28		Demand	$ 72,770	$ 41,800	$ 26,971	$ 35	$ 29	$ 50	$ 2,135	$ 1,532	$ 218
29		Customer	$ 5,984	$ 4,550	$ 435	$ 0	$ 3	$ 10	$ 673	$ 269	$ 43
30											
31	Customer Accounting		**$ 62,932**	**$ 42,637**	**$ 8,561**	**$ 0**	**$ 20**	**$ 60**	**$ 9,792**	**$ 1,607**	**$ 255**
32		Energy	$ 27,141	$ 15,418	$ 5,960	$ -	$ -	$ -	$ 5,764	$ -	$ -
33		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Customer	$ 35,792	$ 27,220	$ 2,601	$ 0	$ 20	$ 60	$ 4,028	$ 1,607	$ 255
35											
36	**Total Utility Rate Base**		**$ 4,498,588**	**$ 2,572,985**	**$ 778,199**	**$ 259**	**$ 520**	**$ 3,711**	**$ 536,018**	**$ 202,699**	**$ 5,337**
37		Energy	$ 2,314	$ 349	$ 362	$ (30)	$ (11)	$ -	$ 2,181	$ (502)	$ (36)
38		Demand	$ 2,984,543	$ 1,306,263	$ 603,876	$ 71	$ 330	$ 2,668	$ 480,904	$ 191,354	$ 218
39		Customer	$ 1,511,731	$ 1,266,373	$ 173,961	$ 219	$ 201	$ 1,043	$ 52,933	$ 11,846	$ 5,155

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study **Schedule 6**
Rate Design Filing_Common Rates_ 2016 Test Year
COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)
Discussion Point: Eliiminate Mt Hayes Cost Allocation to Midstream

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Gas Supply Operations		**$ 322**	**$ 196**	**$ 73**	**$ 0**	**$ 0**	**$ -**	**$ 47**	**$ 7**	**$ 0**
2		Energy	$ 322	$ 196	$ 73	$ 0	$ 0	$ -	$ 47	$ 7	$ 0
3		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5											
6	LNG Storage Tilbury		**$ 35,054**	**$ 19,582**	**$ 7,352**	**$ 1**	**$ 4**	**$ -**	**$ 5,827**	**$ 2,288**	**$ -**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 35,054	$ 19,582	$ 7,352	$ 1	$ 4	$ -	$ 5,827	$ 2,288	$ -
9		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ 25,508**	**$ 13,591**	**$ 5,579**	**$ -**	**$ 3**	**$ 45**	**$ 4,507**	**$ 1,783**	**$ -**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 25,508	$ 13,591	$ 5,579	$ -	$ 3	$ 45	$ 4,507	$ 1,783	$ -
14		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 155,524**	**$ 82,864**	**$ 34,017**	**$ 4**	**$ 17**	**$ 272**	**$ 27,477**	**$ 10,872**	**$ -**
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 155,524	$ 82,864	$ 34,017	$ 4	$ 17	$ 272	$ 27,477	$ 10,872	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 6**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Discussion Point: Eliiminate Mt Hayes Cost Allocation to Midstream

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
21	Distribution		**$ 465,967**	**$ 321,558**	**$ 78,212**	**$ 47**	**$ 61**	**$ 240**	**$ 47,987**	**$ 16,970**	**$ 892**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ 184,258	$ 86,555	$ 44,550	$ 1	$ 24	$ 62	$ 37,978	$ 15,087	$ -
24		Customer	$ 281,709	$ 235,003	$ 33,662	$ 46	$ 37	$ 179	$ 10,009	$ 1,883	$ 892
25											
26	Marketing		**$ 46,871**	**$ 33,916**	**$ 6,177**	**$ 5**	**$ 24**	**$ 69**	**$ 4,502**	**$ 1,883**	**$ 296**
27		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28		Demand	$ 932	$ 535	$ 345	$ 0	$ 0	$ 1	$ 27	$ 20	$ 3
29		Customer	$ 45,939	$ 33,380	$ 5,831	$ 4	$ 24	$ 69	$ 4,475	$ 1,863	$ 293
30											
31	Customer Accounting		**$ 60,982**	**$ 46,377**	**$ 4,432**	**$ 1**	**$ 34**	**$ 102**	**$ 6,864**	**$ 2,738**	**$ 435**
32		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Customer	$ 60,982	$ 46,377	$ 4,432	$ 1	$ 34	$ 102	$ 6,864	$ 2,738	$ 435
35											
36	**Total Utility Cost of Service**		**$ 790,228**	**$ 518,083**	**$ 135,843**	**$ 57**	**$ 144**	**$ 729**	**$ 97,209**	**$ 36,540**	**$ 1,623**
37		Energy	$ 322	$ 196	$ 73	$ 0	$ 0	$ -	$ 47	$ 7	$ 0
38		Demand	$ 401,276	$ 203,128	$ 91,845	$ 6	$ 49	$ 379	$ 75,816	$ 30,050	$ 3
39		Customer	$ 388,631	$ 314,760	$ 43,925	$ 51	$ 95	$ 349	$ 21,347	$ 6,483	$ 1,620

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 7**

Rate Design Filing_Common Rates_ 2016 Test Year

CLASSIFICATION SUMMARY (000's)

Discussion Point: Eliiminate Mt Hayes Cost Allocation to Midstream

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Billing Determinants										
2											
3	Sales Volume (TJ)		163,288	72,466	28,012	130	47	13,189	27,090	15,663	6,691
4	Midstream Sales Volume (TJ)		120,882	72,399	27,942	130	47	-	18,037	2,173	155
5	Commodity Sales Volume (TJ)		107,522	65,258	24,245	130	47	-	15,515	2,173	155
6	Average No. of Customers		979,066	886,652	84,737	18	15	26	6,709	796	113
7											
8	Cost of Service Margin		**$ 790,228**	**$ 518,083**	**$ 135,843**	**$ 57**	**$ 144**	**$ 729**	**$ 97,209**	**$ 36,540**	**$ 1,623**
9		Energy	$ 322	$ 196	$ 73	$ 0	$ 0	$ -	$ 47	$ 7	$ 0
10	Unit Energy Charge ($/GJ)		0.002	0.003	0.003	0.003	0.003	0.000	0.002	0.000	0.000
11		Demand	$ 401,276	$ 203,128	$ 91,845	$ 6	$ 49	$ 379	$ 75,816	$ 30,050	$ 3
12	Unit Demand Charge ($/GJ)		2.457	2.803	3.279	0.047	1.045	0.029	2.799	1.919	0.000
13		Customer	$ 388,631	$ 314,760	$ 43,925	$ 51	$ 95	$ 349	$ 21,347	$ 6,483	$ 1,620
14	Unit Customer Charge ($/Cust/Day)		1.087	0.972	1.419	7.748	17.344	36.779	3.182	8.145	14.335
15											
16	Unit Cost of Service Margin ($/GJ)		4.839	7.149	4.849	0.442	3.078	0.055	3.588	2.333	0.243
17											
18	Cost of Gas - Commodity & Midstream		**$ 475,684**	**$ 287,646**	**$ 111,133**	**$ 433**	**$ 135**	**$ 267**	**$ 67,966**	**$ 7,458**	**$ 646**
19		Energy	$ 475,684	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 67,966	$ 7,458	$ 646
20		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Unit Cost of Gas - Commodity ($/GJ)		2.913	3.969	3.967	3.333	2.885	0.020	2.509	0.476	0.097
23											
24	Total Utility Cost of Service		**$ 1,265,912**	**$ 805,729**	**$ 246,976**	**$ 490**	**$ 279**	**$ 996**	**$ 165,175**	**$ 43,998**	**$ 2,269**
25		Energy	$ 476,006	$ 287,842	$ 111,206	$ 433	$ 135	$ 267	$ 68,013	$ 7,465	$ 646
26		Demand	$ 401,276	$ 203,128	$ 91,845	$ 6	$ 49	$ 379	$ 75,816	$ 30,050	$ 3
27		Customer	$ 388,631	$ 314,760	$ 43,925	$ 51	$ 95	$ 349	$ 21,347	$ 6,483	$ 1,620
28	Unit Cost of Service ($/GJ)		7.753	11.119	8.817	3.776	5.963	0.075	6.097	2.809	0.339
29											
30	Total Revenues @ Proposed Rates		**$ 1,365,499**	**$ 774,179**	**$ 247,369**	**$ 720**	**$ 380**	**$ 14,878**	**$ 202,083**	**$ 92,372**	**$ 33,517**
31	Unit Rate ($/GJ)		8.363	10.683	8.831	5.542	8.122	1.128	7.460	5.898	5.009
32											
33	Total Revenue Margin @ Proposed Rates		**$ 790,228**	**$ 486,533**	**$ 136,236**	**$ 287**	**$ 245**	**$ 14,611**	**$ 100,751**	**$ 40,338**	**$ 11,227**
34	Unit Rate ($/GJ)		4.839	6.714	4.863	2.209	5.238	1.108	3.719	2.575	1.678

Appendix G

FULLY DISTRIBUTED COSA STUDY
2016 TEST YEAR SCHEDULES
INCLUDING DISCUSSION OF
SCP FUNCTIONALIZATION SEPARATELY

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year **Schedule 1**
SUMMARY (000's)

Discussion Point: SCP as a separate Function

Line No.	Particulars	Reference	Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**REVENUE TO COST**										
2	Total Revenue at Proposed 2016 Common Rates	Line 3 + Line 4	**$ 1,294,195**	**$ 730,278**	**$ 235,076**	**$ 694**	**$ 358**	**$ 13,560**	**$ 192,992**	**$ 88,732**	**$ 32,504**
3	Revenue Margin at Proposed 2016 Common Rates		$ 718,924	$ 442,632	$ 123,943	$ 261	$ 223	$ 13,293	$ 91,660	$ 36,698	$ 10,214
4	Total Cost of Gas		$ 575,271	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 101,332	$ 52,034	$ 22,290
5											
6	**COST OF SERVICE**										
7	Total Utility Cost of Service	Line 8 + Line 9	**$ 1,347,460**	**$ 796,240**	**$ 243,011**	**$ 491**	**$ 277**	**$ 907**	**$ 195,322**	**$ 87,298**	**$ 23,914**
8	Cost of Service Margin		$ 772,189	$ 508,594	$ 131,878	$ 58	$ 142	$ 640	$ 93,990	$ 35,264	$ 1,624
9	Total Cost of Gas		$ 575,271	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 101,332	$ 52,034	$ 22,290
10											
11	**SURPLUS / DEFICIT**										
12	Total Surplus / (Deficit)	Line 2 - Line 7	**$ (53,265)**								
13	% Increase to Equal Allocated Costs	- Line 12 / Line 3	7.4%	Effect of major project additions to COSA model							
14											
15	**REVENUES (adjusted to equal COS)**										
16	Total Adjusted Revenue at Proposed 2016 Common Rates	Line 4 + Line 17	**$ 1,347,460**	**$ 763,073**	**$ 244,259**	**$ 713**	**$ 375**	**$ 14,545**	**$ 199,784**	**$ 91,451**	**$ 33,261**
17	Total Adjusted Revenue Margin at Proposed 2016 Common Rates	Line 3 x (1 + Line 13)	$ 772,189	$ 475,427	$ 133,126	$ 280	$ 240	$ 14,278	$ 98,451	$ 39,417	$ 10,971
18											
19	REVENUES (adjusted for R/C ratio's)	Line 16	**$ 1,347,460**	**$ 763,073**	**$ 244,259**	**$ 713**	**$ 375**	**$ 14,545**	**$ 199,784**	**$ 91,451**	**$ 33,261**
20	COST OF SERVICE (adjusted for R/C ratio's)	Line 7	**$ 1,347,460**	**$ 796,240**	**$ 243,011**	**$ 491**	**$ 277**	**$ 907**	**$ 195,322**	**$ 87,298**	**$ 23,914**
21											
22	**REVENUE TO COST RATIO**										
23	Revenue to Cost Ratio	Line 19 / Line 20	**100%**	**96%**	**101%**		**135%**		**102%**	**105%**	
24											
25	**REVENUE REBALANCING**										
26	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Total Revenue at Proposed Rates	Line 16 + Line 26	**$ 1,347,460**	**$ 763,073**	**$ 244,259**	**$ 713**	**$ 375**	**$ 14,545**	$ 199,784	$ 91,451	$ 33,261
28	Total Revenue Margin at Proposed Rates	Line 17 + Line 26	$ 772,189	$ 475,427	$ 133,126	$ 280	$ 240	$ 14,278	$ 98,451	$ 39,417	$ 10,971
29											
30	**PROPOSED REVENUE TO COST RATIO**										
31	Revenue to Cost Ratio at Proposed Rates		**100%**	**96%**	**101%**		**135%**		**102%**	**105%**	
32											

33 **Note:**
34 1. Lines 2, 7, 16, 19, 20, 27 include the imputed Cost of Gas for Rates 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios
35 Rates 23, 25 and 27 do not pay for commodity and midstream charges.
36 2. Rate 4 is a seasonal service and Rates 22 and Rate7/27 are interruptible customer classes. The revenue to cost ratio for Rate 4, Rate 22 and Rate 7/27 are not shown in the schedule above as
37 these rate classes do not drive system capacity additions and therefore, no demand-related costs are allocated to these customer classes in the COSA Study.
38 3. Revenue Margin includes UAF allocation to rate classes.

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 2**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE FUNCTIONALIZATION (000's)

Discussion Point: SCP as a separate Function

Line No.	Particulars	Total	Gas Supply Operation	LNG Storage Tilbury	LNG Storage Mt. Hayes	Transmission	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense	$ 243,000	$ 2,380	$ 14,782	$ 3,568	$ 29,583	$ 108,278	$ 31,064	$ 48,474
2	Property & Sundry Taxes	$ 63,840	$ -	$ 1,960	$ 372	$ 16,763	$ 39,828	$ -	$ -
3	Depreciation Expense	$ 181,504	$ -	$ 20,160	$ 6,655	$ 31,840	$ 105,441	$ -	$ 8,746
4	Amortization Expense	$ 42,339	$ (90)	$ 2,655	$ 43	$ 7,163	$ 22,514	$ 9,566	$ 1,089
5	Other Operating Revenue	$ (113,411)	$ -	$ (39,745)	$ (18,039)	$ (32,104)	$ (6,252)	$ -	$ (2,314)
6	Income Tax	$ 44,864	$ (256)	$ 3,225	$ 1,938	$ 9,916	$ 25,671	$ 813	$ 650
7	Earned Return	$ 310,054	$ (1,711)	$ 32,149	$ 12,933	$ 66,182	$ 171,332	$ 5,428	$ 4,337
8	**Total Cost of Service Margin**	**$ 772,189**	**$ 322**	**$ 35,185**	**$ 7,469**	**$ 129,344**	**$ 466,813**	**$ 46,871**	**$ 60,982**
9									
10	Cost of Gas - Commodity & Midstream	$ 477,714	$ 477,714	$ -	$ -	$ -	$ -	$ -	$ -
11	**Total Utility Revenue Requirement**	**$ 1,249,903**	**$ 478,036**	**$ 35,185**	**$ 7,469**	**$ 129,344**	**$ 466,813**	**$ 46,871**	**$ 60,982**

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study **Schedule 3**
Rate Design Filing_Common Rates_ 2016 Test Year
RATE BASE SUMMARY - CLASSIFICATION (000's)
Discussion Point: SCP as a separate Function

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Gas Plant in Service**										
2	Total Gas Plant in Service		**$ 6,470,628**	**$ 3,792,921**	**$ 1,112,980**	**$ 372**	**$ 745**	**$ 4,609**	**$ 786,307**	**$ 298,096**	**$ 7,363**
3		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Demand	$ 4,180,848	$ 1,869,051	$ 852,717	$ 54	$ 446	$ 3,115	$ 707,657	$ 280,572	$ -
5		Customer	$ 2,289,781	$ 1,923,869	$ 260,262	$ 318	$ 299	$ 1,494	$ 78,650	$ 17,524	$ 7,363
6											
7	Total Accumulated Depreciation		**$ (1,815,001)**	**$ (1,116,883)**	**$ (320,274)**	**$ (101)**	**$ (220)**	**$ (1,308)**	**$ (226,908)**	**$ (86,092)**	**$ (1,958)**
8		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Demand	$ (1,131,843)	$ (540,218)	$ (245,327)	$ (17)	$ (128)	$ (905)	$ (203,367)	$ (80,624)	$ -
10		Customer	$ (683,158)	$ (576,664)	$ (74,947)	$ (84)	$ (92)	$ (403)	$ (23,542)	$ (5,468)	$ (1,958)
11											
12	TOTAL Net Plant		**$ 4,655,627**	**$ 2,676,038**	**$ 792,706**	**$ 271**	**$ 525**	**$ 3,301**	**$ 559,399**	**$ 212,004**	**$ 5,406**
13		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Demand	$ 3,049,004	$ 1,328,833	$ 607,391	$ 38	$ 317	$ 2,210	$ 504,291	$ 199,948	$ -
15		Customer	$ 1,606,623	$ 1,347,205	$ 185,315	$ 234	$ 207	$ 1,091	$ 55,109	$ 12,056	$ 5,406
16											
17	**Contributions In Aid of Construction**										
18	Total Gas Plant in Service		**$ (424,193)**	**$ (269,741)**	**$ (78,417)**	**$ (28)**	**$ (51)**	**$ (365)**	**$ (54,498)**	**$ (20,574)**	**$ (518)**
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20		Demand	$ (256,248)	$ (128,187)	$ (59,099)	$ (4)	$ (31)	$ (262)	$ (49,168)	$ (19,498)	$ -
21		Customer	$ (167,945)	$ (141,553)	$ (19,319)	$ (24)	$ (20)	$ (104)	$ (5,331)	$ (1,077)	$ (518)
22											
23	Total Accumulated Depreciation		**$ 143,125**	**$ 91,352**	**$ 26,345**	**$ 10**	**$ 17**	**$ 120**	**$ 18,230**	**$ 6,872**	**$ 179**
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Demand	$ 85,149	$ 42,489	$ 19,677	$ 1	$ 10	$ 84	$ 16,388	$ 6,499	$ -
26		Customer	$ 57,976	$ 48,863	$ 6,668	$ 8	$ 7	$ 36	$ 1,842	$ 373	$ 179
27											
28	TOTAL Net Plant		**$ (281,069)**	**$ (178,388)**	**$ (52,072)**	**$ (19)**	**$ (33)**	**$ (246)**	**$ (36,268)**	**$ (13,703)**	**$ (339)**
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Demand	$ (171,099)	$ (85,698)	$ (39,422)	$ (3)	$ (21)	$ (178)	$ (32,780)	$ (12,998)	$ -
31		Customer	$ (109,969)	$ (92,690)	$ (12,651)	$ (16)	$ (13)	$ (68)	$ (3,488)	$ (704)	$ (339)
32											

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 3**

Rate Design Filing_Common Rates_ 2016 Test Year

RATE BASE SUMMARY - CLASSIFICATION (000's)

Discussion Point: SCP as a separate Function

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
33	**13 Month Adjustment**		**$ 3,685**	**$ 2,187**	**$ 730**	**$ 0**	**$ 0**	**$ 3**	**$ 549**	**$ 212**	**$ 3**
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35		Demand	$ 2,822	$ 1,464	$ 632	$ 0	$ 0	$ 3	$ 518	$ 205	$ -
36		Customer	$ 863	$ 724	$ 97	$ 0	$ 0	$ 1	$ 31	$ 7	$ 3
37											
38	**Work in Process, no AFUDC**		**$ 35,156**	**$ 20,868**	**$ 6,964**	**$ 2**	**$ 4**	**$ 32**	**$ 5,234**	**$ 2,025**	**$ 27**
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Demand	$ 26,924	$ 13,963	$ 6,034	$ 0	$ 3	$ 26	$ 4,941	$ 1,957	$ -
41		Customer	$ 8,232	$ 6,905	$ 930	$ 1	$ 1	$ 6	$ 294	$ 68	$ 27
42											
43	**Unamortized Deferred Charges**		**$ 24,791**	**$ 19,883**	**$ 16,913**	**$ 2**	**$ 17**	**$ 7**	**$ (3,257)**	**$ (1,888)**	**$ 233**
44		Energy	$ 1,130	$ (369)	$ 95	$ (31)	$ (11)	$ -	$ 2,010	$ (526)	$ (37)
45		Demand	$ 19,253	$ 17,334	$ 16,721	$ 34	$ 24	$ (6)	$ (6,190)	$ (1,763)	$ 218
46		Customer	$ 4,408	$ 2,918	$ 97	$ (1)	$ 5	$ 13	$ 922	$ 401	$ 53
47											
48	**Cash Working Capital**		**$ 2,129**	**$ 1,316**	**$ 429**	**$ 1**	**$ 1**	**$ 1**	**$ 302**	**$ 75**	**$ 4**
49		Energy	$ 1,184	$ 718	$ 267	$ 1	$ 1	$ -	$ 171	$ 24	$ 2
50		Demand	$ 560	$ 289	$ 126	$ 0	$ 0	$ 1	$ 103	$ 41	$ -
51		Customer	$ 385	$ 308	$ 36	$ 0	$ 0	$ 0	$ 28	$ 10	$ 2
52											
53	**Other Working Capital**		**$ 1,567**	**$ 1,085**	**$ 261**	**$ 0**	**$ 0**	**$ 1**	**$ 160**	**$ 58**	**$ 3**
54		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Demand	$ 608	$ 276	$ 150	$ -	$ 0	$ 0	$ 130	$ 52	$ -
56		Customer	$ 959	$ 808	$ 110	$ 0	$ 0	$ 1	$ 30	$ 6	$ 3
57											
58	**LILO, Other Rate Base items**		**$ 56,701**	**$ 30,057**	**$ 12,452**	**$ 2**	**$ 6**	**$ 101**	**$ 10,089**	**$ 3,996**	**$ (2)**
59		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Demand	$ 57,290	$ 30,553	$ 12,520	$ 2	$ 6	$ 101	$ 10,108	$ 3,999	$ -
61		Customer	$ (589)	$ (496)	$ (68)	$ (0)	$ (0)	$ (0)	$ (19)	$ (4)	$ (2)
62											
63	**Total Utility Rate Base**		**$ 4,498,588**	**$ 2,573,046**	**$ 778,381**	**$ 259**	**$ 520**	**$ 3,199**	**$ 536,209**	**$ 202,779**	**$ 5,334**
64		Energy	$ 2,314	$ 349	$ 362	$ (30)	$ (11)	$ -	$ 2,181	$ (502)	$ (36)
65		Demand	$ 2,985,362	$ 1,307,014	$ 604,153	$ 71	$ 330	$ 2,157	$ 481,120	$ 191,440	$ 218
66		Customer	$ 1,510,912	$ 1,265,682	$ 173,867	$ 219	$ 201	$ 1,043	$ 52,907	$ 11,841	$ 5,152

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 4**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Discussion Point: SCP as a separate Function

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Operating & Maintenance Expense**		**$ 243,000**	**$ 160,494**	**$ 35,382**	**$ 15**	**$ 64**	**$ 252**	**$ 29,200**	**$ 11,131**	**$ 779**
2		Energy	$ 2,380	$ 1,445	$ 537	$ 3	$ 1	$ -	$ 343	$ 48	$ 3
3		Demand	$ 101,136	$ 48,322	$ 21,974	$ 2	$ 12	$ 78	$ 17,943	$ 7,122	$ 3
4		Customer	$ 139,483	$ 110,728	$ 12,871	$ 10	$ 51	$ 174	$ 10,914	$ 3,961	$ 773
5											
6	**Property & Sundry Taxes**		**$ 63,840**	**$ 39,561**	**$ 12,161**	**$ 4**	**$ 8**	**$ 50**	**$ 8,660**	**$ 3,303**	**$ 93**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 41,115	$ 20,626	$ 9,466	$ 1	$ 5	$ 31	$ 7,867	$ 3,119	$ -
9		Customer	$ 22,725	$ 18,936	$ 2,695	$ 4	$ 3	$ 19	$ 793	$ 183	$ 93
10											
11	**Depreciation Expense**		**$ 181,504**	**$ 109,630**	**$ 29,047**	**$ 16**	**$ 26**	**$ 128**	**$ 19,831**	**$ 7,075**	**$ 237**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 99,884	$ 43,056	$ 19,158	$ 1	$ 10	$ 78	$ 15,802	$ 6,263	$ -
14		Customer	$ 81,619	$ 66,573	$ 9,889	$ 14	$ 16	$ 50	$ 4,029	$ 812	$ 237
15											
16	**Amortization Expense**		**$ 42,339**	**$ 24,962**	**$ 9,132**	**$ 6**	**$ 8**	**$ 39**	**$ 4,779**	**$ 1,922**	**$ 68**
17		Energy	$ (90)	$ (55)	$ (20)	$ (0)	$ (0)	$ -	$ (13)	$ (2)	$ (0)
18		Demand	$ 22,955	$ 11,036	$ 4,871	$ 0	$ 3	$ 24	$ 4,009	$ 1,589	$ -
19		Customer	$ 19,474	$ 13,980	$ 4,281	$ 5	$ 6	$ 15	$ 783	$ 335	$ 69
20											
21	**Other Operating Revenue**		**$ (113,411)**	**$ (40,787)**	**$ (15,454)**	**$ (2)**	**$ (9)**	**$ (94)**	**$ (12,405)**	**$ (4,887)**	**$ (28)**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ (107,272)	$ (35,803)	$ (14,845)	$ (1)	$ (8)	$ (88)	$ (12,024)	$ (4,758)	$ -
24		Customer	$ (6,139)	$ (4,984)	$ (608)	$ (1)	$ (2)	$ (6)	$ (382)	$ (128)	$ (28)
25											

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 4**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Discussion Point: SCP as a separate Function

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
26	**Income Tax**		**$ 44,864**	**$ 28,823**	**$ 8,465**	**$ 2**	**$ 6**	**$ 35**	**$ 6,092**	**$ 2,327**	**$ 62**
27		Energy	$ (256)	$ (156)	$ (58)	$ (0)	$ (0)	$ -	$ (37)	$ (5)	$ (0)
28		Demand	$ 27,951	$ 14,674	$ 6,590	$ 0	$ 3	$ 22	$ 5,449	$ 2,160	$ -
29		Customer	$ 17,169	$ 14,304	$ 1,933	$ 2	$ 3	$ 13	$ 680	$ 172	$ 62
30											
31	**Earned Return**		**$ 310,054**	**$ 185,911**	**$ 53,145**	**$ 17**	**$ 39**	**$ 231**	**$ 37,833**	**$ 14,394**	**$ 414**
32		Energy	$ (1,711)	$ (1,039)	$ (386)	$ (2)	$ (1)	$ -	$ (247)	$ (35)	$ (2)
33		Demand	$ 197,177	$ 91,483	$ 40,632	$ 3	$ 22	$ 145	$ 33,541	$ 13,279	$ -
34		Customer	$ 114,588	$ 95,466	$ 12,899	$ 16	$ 18	$ 86	$ 4,539	$ 1,149	$ 416
35											
36	**Total Cost of Service Margin**		**$ 772,189**	**$ 508,594**	**$ 131,878**	**$ 58**	**$ 142**	**$ 640**	**$ 93,990**	**$ 35,264**	**$ 1,624**
37		Energy	$ 322	$ 196	$ 73	$ 0	$ 0	$ -	$ 47	$ 7	$ 0
38		Demand	$ 382,947	$ 193,394	$ 87,847	$ 6	$ 47	$ 291	$ 72,587	$ 28,772	$ 3
39		Customer	$ 388,920	$ 315,004	$ 43,959	$ 51	$ 95	$ 349	$ 21,356	$ 6,485	$ 1,621
40											
41	**Cost of Gas Sold (Including Gas Lost)**		**$ 475,684**	**$ 287,646**	**$ 111,133**	**$ 433**	**$ 135**	**$ 267**	**$ 67,966**	**$ 7,458**	**$ 646**
42		Energy	$ 475,684	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 67,966	$ 7,458	$ 646
43		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45											
46	**Total Utility Revenue Requir**		**$ 1,247,873**	**$ 796,240**	**$ 243,011**	**$ 491**	**$ 277**	**$ 907**	**$ 161,956**	**$ 42,722**	**$ 2,270**
47		Energy	$ 476,006	$ 287,842	$ 111,206	$ 433	$ 135	$ 267	$ 68,013	$ 7,465	$ 646
48		Demand	$ 382,947	$ 193,394	$ 87,847	$ 6	$ 47	$ 291	$ 72,587	$ 28,772	$ 3
49		Customer	$ 388,920	$ 315,004	$ 43,959	$ 51	$ 95	$ 349	$ 21,356	$ 6,485	$ 1,621

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study

Schedule 5

Rate Design Filing_Common Rates_ 2016 Test Year

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Discussion Point: SCP as a separate Function

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Gas Supply Operations**		**$ (24,827)**	**$ (15,068)**	**$ (5,598)**	**$ (30)**	**$ (11)**	**$ -**	**$ (3,582)**	**$ (502)**	**$ (36)**
2		Energy	$ (24,827)	$ (15,068)	$ (5,598)	$ (30)	$ (11)	$ -	$ (3,582)	$ (502)	$ (36)
3		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5											
6	**LNG Storage Tilbury**		**$ 466,456**	**$ 36,080**	**$ 14,812**	**$ -**	**$ 8**	**$ -**	**$ 11,964**	**$ 4,734**	**$ -**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 466,456	$ 36,080	$ 14,812	$ -	$ 8	$ -	$ 11,964	$ 4,734	$ -
9		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	**LNG Storage Mt. Hayes**		**$ 187,640**	**$ 99,978**	**$ 41,043**	**$ -**	**$ 21**	**$ 328**	**$ 33,152**	**$ 13,117**	**$ -**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 187,640	$ 99,978	$ 41,043	$ -	$ 21	$ 328	$ 33,152	$ 13,117	$ -
14		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	**Transmission**		**$ 960,235**	**$ 511,617**	**$ 210,029**	**$ 27**	**$ 108**	**$ 1,681**	**$ 169,648**	**$ 67,126**	**$ -**
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 960,235	$ 511,617	$ 210,029	$ 27	$ 108	$ 1,681	$ 169,648	$ 67,126	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 5

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Discussion Point: SCP as a separate Function

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
21	Transmission SCP		**$ 281,540**	**$ 150,269**	**$ 61,688**	**$ 8**	**$ 32**	**$ -**	**$ 49,828**	**$ 19,716**	**$ -**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ 281,540	$ 150,269	$ 61,688	$ 8	$ 32	$ -	$ 49,828	$ 19,716	$ -
24		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25											
26	Distribution		**$ 2,485,857**	**$ 1,701,183**	**$ 420,440**	**$ 220**	**$ 311**	**$ 1,070**	**$ 262,599**	**$ 95,180**	**$ 4,854**
27		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28		Demand	$ 1,016,721	$ 467,271	$ 249,609	$ 2	$ 133	$ 98	$ 214,393	$ 85,215	$ -
29		Customer	$ 1,469,137	$ 1,233,912	$ 170,831	$ 218	$ 178	$ 973	$ 48,205	$ 9,966	$ 4,854
30											
31	Marketing		**$ 78,754**	**$ 46,350**	**$ 27,406**	**$ 35**	**$ 32**	**$ 60**	**$ 2,809**	**$ 1,801**	**$ 260**
32		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33		Demand	$ 72,770	$ 41,800	$ 26,971	$ 35	$ 29	$ 50	$ 2,135	$ 1,532	$ 218
34		Customer	$ 5,984	$ 4,550	$ 435	$ 0	$ 3	$ 10	$ 673	$ 269	$ 43
35											
36	Customer Accounting		**$ 62,932**	**$ 42,637**	**$ 8,561**	**$ 0**	**$ 20**	**$ 60**	**$ 9,792**	**$ 1,607**	**$ 255**
37		Energy	$ 27,141	$ 15,418	$ 5,960	$ -	$ -	$ -	$ 5,764	$ -	$ -
38		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39		Customer	$ 35,792	$ 27,220	$ 2,601	$ 0	$ 20	$ 60	$ 4,028	$ 1,607	$ 255
40											
41	**Total Utility Rate Base**		**$ 4,498,588**	**$ 2,573,046**	**$ 778,381**	**$ 259**	**$ 520**	**$ 3,199**	**$ 536,209**	**$ 202,779**	**$ 5,334**
42		Energy	$ 2,314	$ 349	$ 362	$ (30)	$ (11)	$ -	$ 2,181	$ (502)	$ (36)
43		Demand	$ 2,985,362	$ 1,307,014	$ 604,153	$ 71	$ 330	$ 2,157	$ 481,120	$ 191,440	$ 218
44		Customer	$ 1,510,912	$ 1,265,682	$ 173,867	$ 219	$ 201	$ 1,043	$ 52,907	$ 11,841	$ 5,152

FORTISBC ENERGY INC.

Fully Distributed Cost of Service Allocation Study **Schedule 6**

Rate Design Filing_Common Rates_ 2016 Test Year

COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Discussion Point: SCP as a separate Function

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Gas Supply Operations		**$ 322**	**$ 196**	**$ 73**	**$ 0**	**$ 0**	**$ -**	**$ 47**	**$ 7**	**$ 0**
2		Energy	$ 322	$ 196	$ 73	$ 0	$ 0	$ -	$ 47	$ 7	$ 0
3		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5											
6	LNG Storage Tilbury		**$ 35,185**	**$ 19,673**	**$ 7,373**	**$ 1**	**$ 4**	**$ -**	**$ 5,841**	**$ 2,293**	**$ -**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 35,185	$ 19,673	$ 7,373	$ 1	$ 4	$ -	$ 5,841	$ 2,293	$ -
9		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ 7,469**	**$ 3,980**	**$ 1,634**	**$ -**	**$ 1**	**$ 13**	**$ 1,320**	**$ 522**	**$ -**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 7,469	$ 3,980	$ 1,634	$ -	$ 1	$ 13	$ 1,320	$ 522	$ -
14		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 129,344**	**$ 68,915**	**$ 28,291**	**$ 4**	**$ 15**	**$ 226**	**$ 22,852**	**$ 9,042**	**$ -**
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 129,344	$ 68,915	$ 28,291	$ 4	$ 15	$ 226	$ 22,852	$ 9,042	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study **Schedule 6**
Rate Design Filing_Common Rates_ 2016 Test Year
COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)
Discussion Point: SCP as a separate Function

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
21	**Transmission SCP**		**$ 25,202**	**$ 13,451**	**$ 5,522**	**$ 1**	**$ 3**	**$ -**	**$ 4,460**	**$ 1,765**	**$ -**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ 25,202	$ 13,451	$ 5,522	$ 1	$ 3	$ -	$ 4,460	$ 1,765	$ -
24		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25											
26	**Distribution**		**$ 466,813**	**$ 322,086**	**$ 78,377**	**$ 47**	**$ 61**	**$ 229**	**$ 48,105**	**$ 17,015**	**$ 893**
27		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28		Demand	$ 184,814	$ 86,839	$ 44,682	$ 1	$ 24	$ 50	$ 38,088	$ 15,131	$ -
29		Customer	$ 281,999	$ 235,247	$ 33,695	$ 46	$ 37	$ 179	$ 10,018	$ 1,885	$ 893
30											
31	**Marketing**		**$ 46,871**	**$ 33,916**	**$ 6,177**	**$ 5**	**$ 24**	**$ 69**	**$ 4,502**	**$ 1,883**	**$ 296**
32		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33		Demand	$ 932	$ 535	$ 345	$ 0	$ 0	$ 1	$ 27	$ 20	$ 3
34		Customer	$ 45,939	$ 33,380	$ 5,831	$ 4	$ 24	$ 69	$ 4,475	$ 1,863	$ 293
35											
36	**Customer Accounting**		**$ 60,982**	**$ 46,377**	**$ 4,432**	**$ 1**	**$ 34**	**$ 102**	**$ 6,864**	**$ 2,738**	**$ 435**
37		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39		Customer	$ 60,982	$ 46,377	$ 4,432	$ 1	$ 34	$ 102	$ 6,864	$ 2,738	$ 435
40											
41	**Total Utility Cost of Service**		**$ 772,189**	**$ 508,594**	**$ 131,878**	**$ 58**	**$ 142**	**$ 640**	**$ 93,990**	**$ 35,264**	**$ 1,624**
42		Energy	$ 322	$ 196	$ 73	$ 0	$ 0	$ -	$ 47	$ 7	$ 0
43		Demand	$ 382,947	$ 193,394	$ 87,847	$ 6	$ 47	$ 291	$ 72,587	$ 28,772	$ 3
44		Customer	$ 388,920	$ 315,004	$ 43,959	$ 51	$ 95	$ 349	$ 21,356	$ 6,485	$ 1,621

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
Schedule 7
CLASSIFICATION SUMMARY (000's)
Discussion Point: SCP as a separate Function

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Billing Determinants										
2											
3	Sales Volume (TJ)		163,288	72,466	28,012	130	47	13,189	27,090	15,663	6,691
4	Midstream Sales Volume (TJ)		120,882	72,399	27,942	130	47	-	18,037	2,173	155
5	Commodity Sales Volume (TJ)		107,522	65,258	24,245	130	47	-	15,515	2,173	155
6	Average No. of Customers		979,066	886,652	84,737	18	15	26	6,709	796	113
7											
8	Cost of Service Margin		**$ 772,189**	**$ 508,594**	**$ 131,878**	**$ 58**	**$ 142**	**$ 640**	**$ 93,990**	**$ 35,264**	**$ 1,624**
9		Energy	$ 322	$ 196	$ 73	$ 0	$ 0	$ -	$ 47	$ 7	$ 0
10	Unit Energy Charge ($/GJ)		0.002	0.003	0.003	0.003	0.003	0.000	0.002	0.000	0.000
11		Demand	$ 382,947	$ 193,394	$ 87,847	$ 6	$ 47	$ 291	$ 72,587	$ 28,772	$ 3
12	Unit Demand Charge ($/GJ)		2.345	2.669	3.136	0.047	1.001	0.022	2.679	1.837	0.000
13		Customer	$ 388,920	$ 315,004	$ 43,959	$ 51	$ 95	$ 349	$ 21,356	$ 6,485	$ 1,621
14	Unit Customer Charge ($/Cust/Day)		1.088	0.973	1.420	7.754	17.350	36.798	3.183	8.147	14.343
15											
16	Unit Cost of Service Margin ($/GJ)		4.729	7.018	4.708	0.443	3.035	0.049	3.470	2.251	0.243
17											
18	Cost of Gas - Commodity & Midstream		**$ 475,684**	**$ 287,646**	**$ 111,133**	**$ 433**	**$ 135**	**$ 267**	**$ 67,966**	**$ 7,458**	**$ 646**
19		Energy	$ 475,684	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 67,966	$ 7,458	$ 646
20		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Unit Cost of Gas - Commodity ($/GJ)		2.913	3.969	3.967	3.333	2.885	0.020	2.509	0.476	0.097
23											
24	Total Utility Cost of Service		**$ 1,247,873**	**$ 796,240**	**$ 243,011**	**$ 491**	**$ 277**	**$ 907**	**$ 161,956**	**$ 42,722**	**$ 2,270**
25		Energy	$ 476,006	$ 287,842	$ 111,206	$ 433	$ 135	$ 267	$ 68,013	$ 7,465	$ 646
26		Demand	$ 382,947	$ 193,394	$ 87,847	$ 6	$ 47	$ 291	$ 72,587	$ 28,772	$ 3
27		Customer	$ 388,920	$ 315,004	$ 43,959	$ 51	$ 95	$ 349	$ 21,356	$ 6,485	$ 1,621
28	Unit Cost of Service ($/GJ)		7.642	10.988	8.675	3.776	5.920	0.069	5.978	2.728	0.339
29											
30	Total Revenues @ Proposed Rates		**$ 1,347,460**	**$ 763,073**	**$ 244,259**	**$ 713**	**$ 375**	**$ 14,545**	**$ 199,784**	**$ 91,451**	**$ 33,261**
31	Unit Rate ($/GJ)		8.252	10.530	8.720	5.491	8.003	1.103	7.375	5.839	4.971
32											
33	Total Revenue Margin @ Proposed Rates		**$ 772,189**	**$ 475,427**	**$ 133,126**	**$ 280**	**$ 240**	**$ 14,278**	**$ 98,451**	**$ 39,417**	**$ 10,971**
34	Unit Rate ($/GJ)		4.729	6.561	4.752	2.158	5.118	1.083	3.634	2.517	1.640

FortisBC Energy Inc.

2016 Rate Design Application

Workshop 1: Fort Nelson Service Area

Discussion Guide

July 14, 2016

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1. INTRODUCTION

FortisBC Energy Inc. (FEI or the Company) is holding a series of workshops over the next three months to consult with customers and stakeholders and to work towards an efficient and cost effective regulatory process for its 2016 FEI Rate Design Application (RDA), which is to be filed in the fall of this year.

The key objective of the Fort Nelson Service Area (Fort Nelson) workshop is to inform customers and stakeholders regarding the cost allocations process and results for the rate design and to engage them in compiling a key issues list, which will then be considered to focus the scope of the RDA. FEI has updated its cost of service allocation (COSA) model for Fort Nelson (the Fort Nelson COSA model), and has prepared this discussion guide that summarizes key assumptions, allocation methodologies and results for both gas costs and delivery costs. In addition, the last section of the discussion guide lists key discussion topics to help focus the discussion during the workshop. These assumptions, methodologies, allocations and key discussion topics reflect FEI's current plan for the 2016 RDA and FEI will consider the input of customers and stakeholders prior to the filing to the Application.

FEI is circulating this discussion guide in advance of the workshop so that all customers and stakeholders can review the materials and prepare to participate effectively at the workshop and to contribute to the development of the key issues list. While FEI does not expect that all parties will be in agreement on all the issues, and that some may well have to be settled through the regulatory process, we anticipate that it will be useful to hear the various issues and positions that parties may have so that they may be considered as we move toward filing the RDA in the fall of 2016.

2. PART A: GAS COST ALLOCATIONS

This section discusses the key components of Fort Nelson's gas costs and discusses the current and proposed methodology to classify and allocate those costs.

2.1 *GAS COST – KEY COMPONENTS*

In Fort Nelson, the gas cost (including the Gas Cost Recovery Charge per gigajoule (GJ)) is bundled with the delivery cost and is not shown separately on most of Fort Nelson's customer's bills. The gas cost consists of commodity related and midstream related cost components, both of which are currently allocated to sales customers. Sales customers, also referred to as the Core Market, are those customers that purchase their commodity from FEI directly. In contrast, transport customers who procure their own gas to be delivered to FEI's interconnecting points do not pay a Gas Cost Recovery Charge.

This section will further discuss what is included in the commodity and midstream costs for Fort Nelson.

2.1.1 Commodity Costs

The commodity cost consists of market-priced annual gas purchased by FEI and flowed through in rates without mark-up. The commodity costs also include an allocation of the gas costs from the Aitken Creek Storage facility. The variable Gas Cost Recovery Charge per GJ is reviewed quarterly by the British Columbia Utilities Commission (the Commission), and adjusted if required.

2.1.2 Midstream Costs

Midstream costs consist of external resources contracted by FEI in order to facilitate the flow of gas each day so that the demand of customers can be served and the pipeline system stays in balance. Midstream resources are used each day to balance FEI's total gas distribution system by either supplementing it with gas supply when demand is greater than supply or removing excess gas supply out of the system when the demand is lower.

The midstream resources that FEI has in place for Fort Nelson are to meet design (peak) day and design year conditions, and are secured in open and competitive marketplace.

Midstream resources procured by FEI for Fort Nelson include transportation capacity on Spectra's pipeline (T-North shorthaul) that delivers gas to Fort Nelson.

2.2 *GAS COST – ALLOCATION METHODOLOGY*

2.2.1 Current Gas Cost Allocation Methodology

Fort Nelson's current gas allocation methodology allocates gas cost on an energy-related throughput basis to sales customers.

2.2.2 Proposed Gas Cost Allocation Methodology

In the 2016 RDA, FEI is planning to unbundle the rates in Fort Nelson to show the daily/monthly fixed and variable delivery charges separately from the variable Gas Cost Recovery Charges. In the FortisBC Energy Inc. Fort Nelson Service Area Gas Tariff (the Fort Nelson Tariff), the Gas Cost Recovery Charge per GJ would be separated into Cost of Gas (Commodity Cost Recovery Charge) per GJ and the Storage and Transport Charge per GJ (also referred to as the midstream charge), consistent with the current FEI rate schedules applicable to the Mainland, Vancouver Island, and Whistler service areas. On a customer's bill, the Cost of Gas per GJ and the Storage and Transport Charge per GJ will still be bundled due to the immaterial nature of the Storage and Transport Charge for Fort Nelson, and will be referred to as the Commodity Charge per GJ.

The proposed gas cost allocation methodology includes classifying the commodity costs as energy-related and allocating those costs to sales customers based on throughput. The midstream costs are proposed to be classified as demand-related and allocated based on peak day demand to all sales customers.

2.3 *RESULTS*

A comparison of the current method of allocating gas costs and the proposed method are provided in Table 2-1 below. As shown on lines 4 and 15 of the table below, the proposed gas cost allocation will have a minimal impact on residential and commercial customers' rates.

Table 2-1: Comparison of the Current and Proposed Gas Cost Allocation[1]

Line No.	Particulars	Total	Residential	Commercial	
				Small	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	2,097,140	884,818	822,353	389,969
12	Midstream Cost (Storage & Transport Cost) [3]	$ 11,347	$ 4,787	$ 4,450	$ 2,110
13	Storage & Transport Cost / GJ (Line 12 / Line 7)	$ 0.019	$ 0.018	$ 0.021	$ 0.017
14					
15	Total Cost of Gas / GJ (Line 9 + Line 13)	$ 1.294	$ 1.293	$ 1.296	$ 1.292
16					
17	Forecast Volume (GJ)	602,200	268,100	209,700	124,400
18	Load Factor %		30.3%	25.5%	31.9%
19	Load Factor Adjusted Volume (Line 17 / Line 18)	2,097,140	884,818	822,353	389,969
20					
21	Total Cost of Gas	$ 779,247			
22	Less: Midstream - Pipeline Costs	(11,347)			
23	Total Commodity	$ 767,900			

Notes to Table 2-1

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 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 cost.
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 19) divide by 365 days.

[1] Residential customers are served under Rate 1: Domestic Service; Small Commercial customers are served under Rate 2.1 General Service and Large Commercial customers are served under Rate 2.2: General Service.

3. PART B: DELIVERY COST ALLOCATIONS

3.1 KEY ASSUMPTIONS

3.1.1 Test Year Used

FEI is using approved costs from its FEI Fort Nelson Service Area 2015-2016 Revenue Requirements and Rates Application, (Fort Nelson 2015-2016 RRA)[2] for allocation within the Fort Nelson COSA model. FEI chose 2016 as the base for allocation because it reflects the current forecast operating conditions, and is the closest in time to the expected implementation date of the RDA decision.

The Fort Nelson 2016 test year approved costs have not been escalated to attempt to estimate 2018 costs and revenues. The COSA model uses the approved numbers as is.

3.1.1.1 O&M and Rate Base

The Fort Nelson COSA model uses the activity view[3] of O&M from the Fort Nelson 2016 test year as part of the cost allocation. In addition to the activity view O&M, property taxes are also included and allocated within the Fort Nelson COSA model.

The Fort Nelson COSA model uses Fort Nelson 2016 test year rate base for functionalization and allocation. Rate base is predominantly comprised of the mid-year balance of net plant assets, net contribution in aid of construction, and unamortized deferrals.

3.1.1.2 Customers and Load Information

The number of customers and annual demand (load) by rate category from Fort Nelson 2016 test year are used to develop many of the allocators within the Fort Nelson COSA model. Generally, Fort Nelson's delivery system has been constructed to meet peak day (coldest day) demand of all its firm service customers. The customer load from Fort Nelson's test year is adjusted by the load factor of each rate category to estimate the peak day demand for each rate category. The peak day demand is used to allocate much of Fort Nelson's system costs that are classified as demand. 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.

2 Approved by G-97-15, issued June 10, 2015.
3 G-97-15 Compliance Filing, Attachment 1, Schedules 22, 23, 24.

3.1.2 Existing Customer Segmentation

The Fort Nelson COSA model uses Fort Nelson's existing rate categories as the basis for cost allocations and calculating revenue to cost ratios. The following table shows by rate category, the number of customers and annual demand in terajoules (TJ) from the Fort Nelson 2015-2016 RRA. Fort Nelson has made an adjustment to the 2016 approved forecast for the number of customers and volumes as one of the Rate Schedule 25 customers has ceased using natural gas as of December, 2015. The impact of this event on the Annual Demand is a reduction of 20 TJ (56 TJ from the approved forecast to 36 TJ).

Table 3-1: Customers and Annual Demand (TJ) by Rate Category [4]

Rate	Customers	Annual Demand (TJ)
1	1,980	268
2.1	468	209
2.2	34	121
2.3	0	0
2.4	0	0
3.1	0	0
3.2	0	0
3.3	0	0
25	1	36
Total	**2,483**	**634**

3.2 *METHODOLOGY*

3.2.1 Peak Day Methodology

Consistent with FEI's methodology, the coincident peak demand (which is explained below) methodology is used in this rate design to allocate the demand-related costs to each customer group. The coincident peak approach continues to be appropriate as it allocates demand-related costs to the customer groups that drive system capacity requirements based on the share of system capacity used by each of those customer groups.

The coincident peak of a particular rate category is the demand required to serve that group of customers when the system wide demand is at its highest (on the peak (coldest) day). The coincident peak for each rate category is also referred to as the load factor adjusted volume and is calculated in the following way:

$$\text{Coincident Peak} = (\text{Annual Volume}) / (\text{Load Factor} \times 365)$$

[4] Fort Nelson does not have any customers served under Rates 2.3, 2.4, 3.1, 3.2, 3.3.

As indicated in the formula above, a load factor must be calculated to calculate the coincident peak for each rate category. While there are exceptions, lower load factors are generally associated with increasingly heat sensitive load (i.e. residential and commercial customers) while higher load factors are normally indicative of process-oriented load. Consistent with the 2012 RDA, the load factors for the heat sensitive rate categories (Rate 1, 2.1, and 2.2) are calculated using a three step linear regression methodology. For Fort Nelson, each rate category is calculated separately:

1. Calculate the Peak Day Consumption:

   Regress 10 months of actual demand data against average monthly temperatures to establish the linear model parameters.

   Enter the resulting linear model with the peak day temperature to establish the peak day consumption.

2. Calculate the Average Daily Consumption:

   The average daily consumption is the normalized annual actual use per customer ("UPC") divided by 365.

3. Calculate the Load Factor:

   The load factor is the ratio of the average daily consumption to the peak day consumption.

As described in the coincident peak formula above, these load factors are applied to the volumes of the applicable rate category for the test period to calculate the peak day demand.

The sum of peak day demand of all rate categories determines total system demand which is then utilized to calculate the demand allocator for each of the functionalized and classified categories of the cost of service.

3.2.1 Minimum System Study

The Minimum System Study (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 total cost per pipe diameter for the entire distribution system. Consistent with past practice, Fort Nelson has included an updated MSS within this Fort Nelson COSA model.

To determine how distribution costs should be split between demand and customer related components, the costs of the overall distribution system are compared to the cost of a hypothetical minimum system where the minimum pipe diameter is used to serve customers, so that the cost of increases to pipe diameter to meet demand are removed. Specifically, the hypothetical minimum system is one in which the actual pipe diameters of Fort Nelson's system are replaced with the existing minimum distribution system standard (60 mm PE). The cost of the minimum system is calculated by multiplying the unit cost of 60 mm PE by the length of all distribution mains. The cost of the minimum system is then divided by the total cost of the distribution system. The percentage derived is the minimum system and is the percentage of costs of the distribution system that are classified as customer-related in the Fort Nelson COSA model. The MSS results classify the Fort Nelson's distribution related costs as 46% customer and 54% as demand. This is an important cost allocation step due to the significant size of the distribution system costs.

3.2.2 Peak Load Carrying Capacity Adjustment

The Peak Load Carrying Capacity ("PLCC") adjustment is intended to recognize that there is capacity built into the minimum system and that this capacity component of the minimum system should be classified as demand-related and not as customer-related. For the distribution function, the demand-related allocator is calculated by applying the PLCC adjustment to the coincident peak demand for each of the customer classes.

The PLCC adjustment in the Fort Nelson COSA model involves determining the theoretical capacity of the distribution systems assuming a 60 mm diameter main. The capacity of the minimum sized distribution systems was then divided by the number of customers served by each distribution system and an average minimum system capacity per customer was calculated to determine the PLCC adjustment. This PLCC adjustment was then multiplied by the number of customers in each rate class, and the corresponding amount was subtracted from the peak day demand for that rate class.

The PLCC adjustment was determined to be 0.205 GJ per day per customer. 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.

3.2.3 Customer Weighting Factor Study and Customer Administration Factor

3.2.3.1 Customer Weighting Factor Study

To ensure that customer-related costs associated with meters and services are allocated based on the principle of cost causation, a Customer Weighting Factor Study is conducted. Weighting factors are estimated values indicating the total relative value of meter and service assets associated with a specific rate category as compared to Rate 1 (Domestic Service (Residential) customers). Rate 1 is the basis for comparison because service under Rate 1 requires FEI's least cost meter and service. Once the weighting factors have been calculated and assigned to each rate category, customer-related costs can be allocated appropriately across all rate categories. This study helps ensure each rate category is assigned the appropriate proportion of customer-related costs based on cost causation.

3.2.3.2 Customer Administration Factor

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

Weighting factors for each rate class were developed, taking into consideration: the frequency of meter reading; the use of Automatic Meter Reading (AMR) 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 weighted for customer administration and billing are then used to allocate costs associated with the customer administration to each rate class. The results from the customer weighting factor study and customer administration factor assessment are included in the table below.

Table 3-2: Customer Weighting Factor Study and Customer Administration Factor Assessment Results

Rate	Customer Weighting Factor	Customer Admin Factor
1	1.0	1.0
2.1	1.6	1.0
2.2	5.7	1.2
25	192.0	75.0

3.2.4 Direct Allocations

Direct allocations within the Fort Nelson COSA model 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 service has been directly assigned to Rate Schedule 25 – General Firm Transportation.

3.2.5 Renewable Natural Gas Program

Renewal Natural Gas (RNG), also known as biomethane, is a renewable and carbon neutral energy source that reduces Greenhouse Gas emissions when used in place of natural gas. Currently, FEI's RNG program[5] is not available to Fort Nelson customers; however, with the unbundling of the Fort Nelson Tariff rates it would be possible to offer this program. FEI's RNG service offering allows customers to purchase blends of RNG and conventional natural gas in percentages from 5% to 100%.

[5] Order G-194-10, issued December 14, 2010 approved FEI begin the RNG program on a 2-year pilot basis. Order G-210-13, issued December 11, 2013 approved (among other things), the continuation of the RNG program on a permanent basis.

3.2.6 Known and Measurable Changes

From the Fort Nelson 2015-2016 RRA, the total mid-year value of the deferral accounts in the Rate Base is $242,000. Two of the deferral accounts are related to the Muskwa River Project (Mid-Year Rate Base value is $236,000) and will be fully amortized by the end of 2017. Consequently, FEI has made an adjustment not to include these items and their related cost of service effect in the Fort Nelson COSA.

3.3 RESULTS

3.3.1 Functionalization Summary

The functionalization step involves separating the costs from the test period revenue requirements 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. FEI functionalized the Fort Nelson 2016 test year costs including known and measurable changes into the following categories:

1. Gas Supply: Commodity and Midstream;
2. Transmission;
3. Distribution;
4. Marketing; and,
5. Customer Accounting.

All of these functional categories were used in the Fort Nelson 2012 COSA model. The following table summarizes the results of the delivery cost of service functionalization from the Fort Nelson COSA model.

Table 3-3: Delivery Cost of Service Functionalization Summary

Function	$ thousands Functionalized	Percentage of total
Gas Supply	$1	0%
Transmission	$651	29%
Distribution	$1,653	72%
Marketing	$3	0%
Customer Accounting	$(28)	-1%
Total	**$2,281**	**100%**

3.3.2 Classification Summary

Having functionalized the costs, the Fort Nelson COSA model then classifies the functionalized costs into categories based on the cost-causation principle. These cost-causation categories are related to consumption behaviours, system demand, energy delivery or number of customers and are called Demand, Energy and Customer respectively.

- **Demand:** Demand-related costs are those associated with plants that are designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as transmission and distribution mains. Essentially, they refer to all costs associated with having peak capacity on standby and available upon peak customer demand. Given this, transmission and distribution capacity are classified as demand-related costs with respect to Fort Nelson's requirement for serving peak demand on the winter peak.

- **Energy:** Energy-related costs are those costs that vary with the volume of gas delivered to customers. In the case of Fort Nelson, other than the commodity supply purchased on behalf of Fort Nelson customers, few of the costs to operate the Company's facilities are variable with respect to the volume of gas delivered to customers. Commodity supply expenses are classified as commodity-related costs as a means to allocate the costs to all sales customers.

- **Customer:** Customer-related costs are those that are incurred when attaching a customer to the distribution system, metering the customer's gas usage and maintaining the customer's accounts. They 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. These costs then 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 borne by both customers connecting to the system and by the maximum hourly or daily gas flow requirements. A Minimum System Study with Peak Load Carrying Capability (PLCC) Adjustment, discussed above, is conducted and employed to aid the classification of distribution mains costs into both customer and demand related costs. The following table summarizes the results of the delivery cost of service classification from the Fort Nelson COSA model.

Table 3-4: Delivery Cost of Service Classification Summary

Classification	$ thousands Classified	Percentage of total
Demand	$1,318	58%
Energy	$1	0%
Customer	$962	42%
Total	**$2,281**	**100%**

3.3.3 Allocation Summary

When all forecast costs from the Fort Nelson 2016 test year including known and measurable changes are functionalized into the major categories and classified by cost causation, they can then be allocated to each customer group. This allocation of costs is based on a customer's (or 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.

Demand-related costs are allocated to a customer group based on their contribution to the peak day demand measurement. Since each customer group possesses different service characteristics, allocation of demand-related costs based on a customer group's contribution to the peak day demand ensures that the appropriate proportion of those costs are allocated to those who require a larger share of the system capacity.

Energy-related costs are allocated based on annual gas throughput to sales customers.

For allocation of customer-related costs the Customer Weighting Factor Study and Customer Administration Factor are used. The Customer Weighting Factor Study aids in the allocation of customer-related costs associated with meters and services, and the customer administration factor aids in the allocation of costs associated with customer administration and billing. Weighting factors are estimated values indicating the total relative value of meter and service assets or customer administration associated with a specific rate class as compared to other rate classes. Once the weighting factors have been calculated and assigned to each rate class, customer-related costs can be allocated appropriately across the company. This study helps ensure each rate class is assigned the appropriate proportion of customer-related costs based on cost causation. The following table summarizes the results of the delivery cost of service allocation to rate classes from the Fort Nelson COSA model.

Table 3-5: Delivery Cost of Service Allocation to Rate Categories Summary

Rate	$ Thousands Allocated	Percentage of total
1	$1,091	48%
2.1	$640	28%
2.2	$247	11%
25	$302	13%
Total	**$2,281**	**100%**

3.3.4 Revenue to Cost Ratios

The Fort Nelson COSA study is one of the primary tools used to establish cost guidelines for the evaluation of rate class revenue levels. This evaluation process includes a comparison of the revenue for each customer class with the corresponding cost to serve them. This comparison is referred to as the Revenue to Cost ratio (R:C ratio). The R:C ratio shows whether the rates charged to each rate class adequately recovers their allocated cost of service.

R:C ratios are assessed based on whether or not they fall within an established "range of reasonableness". FEI believes that the appropriate range of reasonableness is 90 per cent to 110 per cent. As a cost of service study necessarily involves assumptions, estimates, simplifications, judgments and generalizations, a "range of reasonableness" is the right measure when evaluating the appropriateness of the revenue to cost ratios.

The result of the Fort Nelson COSA study for each rate class is considered in light of this "range of reasonableness" and each rate class that falls within that range is deemed to be at unity. If a rate class 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 classes that may require re-balancing. Even if all of the rate classes fall within the "range of reasonableness", re-balancing may be necessary in light of rate class characteristics and rate design objectives.

For natural gas utilities, the long standing precedent for the "range of reasonableness" for the revenue to cost ratio has been 90 per cent to 110 per cent. In Commission Order No. G-42-91 that ruled on Ocelot Chemical's application seeking reconsideration of the Commission's ruling on Pacific Northern Gas's 1991 Rate Design Application (Order No. 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 classes. 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."*[6]

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 percent, there is no compelling evidence to determine that the cost of service results indicate rate restructuring is required."*[7]

The Commission also accepted, as a guide to rate setting, a "range of reasonableness" of 90 per cent to 110 per cent in the BC Gas 1993 Phase B Rate Design.[8] The same range of reasonableness was used in the BC Gas 1996 Rate Design,[9] in the Terasen Gas Inc. (FEI's predecessor) 2001 Rate Design[10] and in FEI's 2012 Amalgamation Application.

Consistent with past precedent, FEI believes that it is reasonable to apply a "range of reasonableness" of 90 per cent to 110 per cent for Fort Nelson COSA model in the 2016 RDA.

The table below provides the revenue to cost ratios for each of the rate classes based on the Fort Nelson 2015-2016 RRA, known and measurable changes in the Fort Nelson COSA model.

Table 3-6: Revenue to Cost Ratios

Rate	Revenue to Cost Ratio
Rate 1 – Domestic (Residential) Service	92%
Rate 2.1 – General (Small Commercial) Service	113%
Rate 2.2 – General (Large Commercial) Service	121%
Rate Schedule 25 – General Firm Transportation Service	59%

The table above shows that R:C ratio for Rate 2.1, 2.2 and Rate Schedule 25 is outside of the range of reasonableness.

As shown in the table above, Rate Schedule 25 has a R:C ratio of only 59%. This is due to the fact that there is only one customer taking service under this rate schedule and this customer is using natural gas for space heating only. This consumption pattern results in a high allocation

6 Commission Order No. G-42-91 p. 29.
7 Ibid.
8 Order G-101-93, Decision, p.12: "In previous decisions the Commission has accepted a 10 percent band as reasonable."
9 Order G-98-96 BC Gas Utility Ltd. 1996 Rate Design Proposals.
10 Order G-116-01 BC Gas Utility Ltd. 2001 Rate Design Application.

of costs when compared to revenues because Rate Schedule 25 was designed to serve process load customers with low heat sensitivity.

FEI is still in the process of soliciting information from its customers and stakeholders in Fort Nelson about issues (if any) related to the Fort Nelson COSA model assumptions, allocation approach and other rate design considerations. Once customer and stakeholder information has been considered and rate design proposals have been solidified, FEI will consider whether to rebalance and include any rebalancing results for Fort Nelson COSA model within its upcoming application. Please refer to Appendix A that shows the Fort Nelson COSA schedules using Fort Nelson 2013 test year, and Appendix B that shows the Fort Nelson COSA schedules using Fort Nelson 2016 test year.

4. PART C: KEY DISCUSSION TOPICS

4.1 *BUNDLED OR UNBUNDLED RATE STRUCTURE*

The Fort Nelson rates for residential and commercial customers are currently bundled with a declining block rate structure. In other words, Fort Nelson customers who take service under Rates 1, 2.1, and 2.2 do not see a separate variable Cost of Gas Charge per GJ, Storage and Transport (midstream) Charge per GJ and Delivery Charge per GJ in the Fort Nelson Tariff and on their bill.

Over 20 years ago, FEI unbundled its rates for customers in the Mainland service area to separate the commodity, midstream and delivery charges. The unbundling of rates allows customers to see the different components outlined in the FEI rate schedules or on a bill (i.e. commodity, midstream and delivery), including changes of a particular component from one period to the next. In addition, by unbundling the rates, FEI has been able to offer optional services, such as the RNG program. These services could not be made available to customers in Fort Nelson because the Fort Nelson Tariff rates have not been unbundled to separate out the variable Delivery Charge from the Gas Cost Recovery Charge.

FEI is considering proposing unbundled rates for Fort Nelson customers, with no declining block structure, consistent with FEI's rates in its other service areas. If Ft. Nelson rates are unbundled, the Fort Nelson Tariff and Fort Nelson customers' bills will outline the following applicable charges: Basic Charge per day, Delivery Charge per GJ, Revenue Stabilization Adjustment Mechanism (RSAM) Rate Rider 5 per GJ[11], Cost of Gas Charge per GJ, and Storage and Transport Charge per GJ[12]. This unbundled rate structure would remove the declining block rate structure that is currently in place. The charges would be set to recover Fort Nelson's cost of service.

Unbundling the rates in this manner would provide transparency into the different components of customer bills and give Fort Nelson customers the option to participate in other services that require unbundled rates, such as the RNG program (subject to Commission approval). The unbundled rates would also be consistent with the rate structures in FEI's other service areas.

Table 4-1 below shows the estimated bill impact to a Fort Nelson residential customer based on an average annual use of 135 GJ with the current bundled rate structure as compared to the unbundled rate structure. It is expected that, under the proposed unbundled rate structure, the annual bill of customers who use more than the average would decrease, while the annual bill of customers who use less than the average would increase.

[11] Consistent with the FEI rate schedules and FEI customers' bill, the RSAM Rate Rider 5 per GJ will be separated in the Fort Nelson Tariff and combined with the applicable Delivery Charge per GJ on Fort Nelson customers' bills.

[12] As referenced in section 2.2.2, the Cost of Gas per GJ and Storage and Transport Charge per GJ will be separated in the Fort Nelson Tariff and combined on Fort Nelson customers' bills as the Commodity Charge per GJ.

Table 4-1: Comparison of Fort Nelson Bundled and Unbundled Rates for Residential Customers

Rate Structure		Current Rates excl RSAM	Days 365 & GJ		Annual Bill
Bundled Rates					
Minimum incl 1st 2 GJ per Month	$	0.4898	365	$	179
Next 28 GJ per Month	$	4.432	111	$	491
Excess over 30 GJ per Month	$	4.342		$	-
Total				**$**	**669**
Unbundled Rates					
Basic Charge / day	$	0.4047	365	$	148
Delivery Charge $ / GJ	$	2.579	135	$	347
Commodity Charge $ / GJ	$	1.275	135	$	172
Storage & Transportation $ / GJ	$	0.019	135	$	3
Total				**$**	**669**

4.2 *GAS COST ALLOCATION METHODOLOGY*

As discussed in section 2.2 above, FEI is considering making the gas cost allocation methodology applicable in Fort Nelson consistent with FEI's gas cost allocation methodology applicable in other service areas. That is, the commodity costs are classified as energy-related and allocated to sales customers based on throughput and the midstream costs are classified as demand-related and allocated to sales customers based on the peak day demand. As noted in sections 2.1.1 and 2.1.2, the midstream resources that FEI has in place for Fort Nelson are to meet the design day also referred to as peak day and therefore should be allocated based on peak day demand. The minimal impact of this change is presented in section 2.3 above.

4.3 *CUSTOMER SEGMENTATION - COMMERCIAL CUSTOMERS*

Fort Nelson's general service (or commercial) customers are currently segmented into Rate 2.1 and 2.2 based on a 6,000 GJ separation point. FEI has completed preliminary analysis on customer segmentation, which suggests that the separation point between general service Rate 2.1 and Rate 2.2 is at 2,000 GJ. This separation point would also be consistent with the customer segmentation in all other FEI service areas.

With this proposed change in customer segmentation, FEI anticipates that there would be approximately 12 customers that would change to large commercial from small commercial, as these 12 customers normalized consumption exceeds 2,000 GJ, but is less than the current 6,000 GJ. The 7 customers in Rate 2.2 and approximately 465 customers in Rate 2.1 would be unaffected.

4.4 OPTIONS FOR REBALANCING

As shown in Table 3-6, based on the current cost allocation results, Rates 2.1, 2.2 and Rate Schedule 25 are outside the range of reasonableness.

FEI is still evaluating the rebalancing options for Fort Nelson rate categories. As explained in section 3.3.4, due to the unique circumstances of the Rate Schedule 25 customer, FEI has not included this rate schedule for rebalancing under Option 1 below. Two rebalancing options are presented below.

Option 1: Rebalancing rates to bring Rates 2.1 and 2.2 inside the range of reasonableness

This option will shift the revenue responsibility from Rates S2.1 and 2.2 to residential customers to bring Rates 2.1 and 2.2 to a R:C ratio of 110%. The resulting R:C ratios and approximate rate impacts are shown below:

Table 4-2: Rebalanced Rates within 90-110%

	Rate 1	Rate 2.1	Rate 2.2
Rebalanced Amount (in $000)	+ $130	- $47	- $83
Burner Tip Change (%)	+ 7.7%	- 1.4%	- 7.9%
R:C ratio after rebalancing	98%	110%	110%

Option 2: No Rebalancing

A second option is not to perform any rebalancing. As shown in Table 4-2, if rates are rebalanced then the cost of rebalancing rates would fall solely on residential customers resulting in a large increase to residential customer rates. The sum of the increase in residential rates due to rebalancing and the increase in rates as proposed in the recently filed Application for 2017 and 2018 Revenue Requirement and Rates for the Fort Nelson Service Area would constitute “rate shock”.

4.5 COMMON RATES SUITABILITY FOR FORT NELSON

In Order G-21-14, dated February 26, 2014, the Commission approved common delivery, commodity and midstream rates for all of FEI service areas, with the exception of Fort Nelson.[13] On page 19 of the Decision accompanying Order G-21-14, the Commission commented on the exclusion of Fort Nelson from common rates as follows:

> 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

[13] Order G-21-14 dated February 26, 2014 related to the FortisBC Energy Utilities (FEU) Application on Reconsideration and Variance of Commission Order G-26-13 on the FEU’s Common Rates, Amalgamation and Rate Design Application.

> 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.

Table below shows the approximate impact on the bill for residential and commercial customer (based on the average use) between Fort Nelson and FEI. For comparability, FEI has used the unbundled rate structure as discussed in section 4.1. The table below assumes no rebalancing or revenue requirement increases and is exclusive of any applicable rate riders.

1 **Table 4-3: Bill Impact and Rate Comparison between Fort Nelson and FEI Using Current Rates**

Rate 1: Domestic Service (Residential)	**Fort Nelson Current Rates January 1, 2016**	**FEI Current Rate Schedule 1 Rates April 1, 2016**
Basic Charge per day	$ 0.4047	$ 0.3890
Delivery Charge per GJ	$ 2.579	$ 4.370
Cost of Gas Charge per GJ	$ 1.275	$ 1.141
Storage and Transport per GJ	$ 0.019	$ 1.117
Average annual use per customer of 135 GJ		
Annual Cost	**$ 669**	**$ 1,035**
Percentage Change		**55%**

Rate 2.1: General Service (Small Commercial)	**Fort Nelson Current Rates January 1, 2016**	**FEI Current Rate Schedule 2 Rates April 1, 2016**
Basic Charge per day	$ 1.1781	$ 0.8161
Delivery Charge per GJ	$ 3.298	$ 3.523
Cost of Gas Charge per GJ	$ 1.275	$ 1.141
Storage and Transport per GJ	$ 0.019	$ 1.133
Average annual use per customer of 443 GJ		
Annual Cost	**$ 2,464**	**$ 2,866**
Percentage Change		**16%**

Rate 2.2: General Service (Large Commercial)	**Fort Nelson Current Rates January 1, 2016**	**FEI Current Rate Schedule 3 Rates April 1, 2016**
Basic Charge per day	$ 1.1781	$ 4.3538
Delivery Charge per GJ	$ 3.408	$ 2.939
Cost of Gas Charge per GJ	$ 1.275	$ 1.141
Storage and Transport per GJ	$ 0.019	$ 0.940
Average annual use per customer of 3,584 GJ		
Annual Cost	**$ 17,283**	**$ 19,581**
Percentage Change		**13%**

2

FEI is in the process of evaluating how it should address the topic of common rates for Fort Nelson in the RDA and invites comments from customers and stakeholders on this topic.

Appendix A

FULLY DISTRIBUTED COSA STUDY
2013 TEST YEAR SCHEDULES

FORTISBC ENERGY INC. (FORT NELSON SERVICE AREA) - LEGACY METHODOLOGY
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_2013 Test Year
SUMMARY (000's)

Schedule 1

L.No.	Particulars	Reference	Total	RATE 1	RATE 2.1	RATE 2.2	RATE 25
1	**REVENUES**						
2	Total Revenues at Proposed 2013 FEFN Rates	line 3 + line 4	**$ 4,388**	**$ 1,942**	**$ 1,572**	**$ 734**	**$ 140**
3	Revenue Margin at Proposed 2013 FEFN Rates		$ 1,927	$ 791	$ 700	$ 296	$ 140
4	Total Cost of Gas [2]		$ 2,461	$ 1,151	$ 872	$ 438	$ -
5							
6	**COST OF SERVICE**						
7	Total Utility Cost of Service	line 8 + line 9	**$ 4,387**	**$ 2,402**	**$ 1,352**	**$ 569**	**$ 63**
8	Cost of Service Margin		$ 1,926	$ 1,251	$ 480	$ 131	$ 63
9	Total Cost of Gas [2]		$ 2,461	$ 1,151	$ 872	$ 438	$ -
10							
11	**SURPLUS / DEFICIT**						
12	Total Surplus / Deficit	line 2 - line 7	**$ 1**				
13	% increase to Equal Allocated Cost		0.0%				
14							
15	**REVENUES (adjusted to equal COS)**						
16	Total Adjusted Revenues at Proposed 2013 FEFN Rates	line 17 + line 9	**$ 4,387**	**$ 1,942**	**$ 1,572**	**$ 734**	**$ 140**
17	Total Adjusted Revenue Margin at Proposed 2013 FEFN Rates	line 3 x line 13	$ 1,926	$ 791	$ 700	$ 296	$ 140
18							
19	REVENUES (adjusted for R/C RATIOS) [1]		**$ 4,618**	**$ 1,942**	**$ 1,572**	**$ 734**	**$ 371**
20	COST OF SERVICE (adjusted for R/C RATIOS) [1]		**$ 4,618**	**$ 2,402**	**$ 1,352**	**$ 569**	**$ 295**
21							
22	**REVENUE TO COST RATIO**						
23	Revenue to Cost Ratio	line 19 / line 20	**100%**	**80.8%**	**116.2%**	**128.9%**	**126.0%**
24							
25	**REVENUE REBALANCING**						
26	Adjustment		$ -	$ -	$ -	$ -	
27	Total Revenues at Proposed Rates [1]	line 28 + line 9	**$ 4,618**	**$ 1,942**	**$ 1,572**	**$ 734**	**$ 371**
28	Total Revenue Margin at Proposed Rates	line 17 + line 26	$ 1,926	$ 791	$ 700	$ 296	$ 140
29							
30	**PROPOSED REVENUE TO COST RATIO**						
31	Revenue to Cost Ratio at Proposed Rates	line 27 / line 20	**100.0%**	**80.8%**	**116.2%**	**128.9%**	**126.0%**

Note:
1. The revenues (line 27 and line 19) and cost of service (line 20) include the imputed COG number for Rate 25. This is shown only for the purposes of presenting the Revenue to Cost Ratios. Please note that Rate 25 does not pay for cost of gas charges.
2. Cost of Gas forecast is based on five-day average forward prices at November 1, 2, 3, 4, and 7, 2011 consistent with the forward pricing utilized in the 2011 Fourth Quarter Gas Cost reports for the various entities/service areas.

FORTISBC ENERGY INC. (FORT NELSON SERVICE AREA) - LEGACY METHODOLOGY
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_2013 Test Year
FUNCTIONALIZATION (000's)

Schedule 2

L.No.	Particulars	Total	Gas Supply Operations	LNG Storage Tilbury	LNG Storage Mt. Hayes	Transmission	Transmission SCP	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense	$ 784	$ -	$ -	$ -	$ (53)	$ -	$ 836	$ -	$ -
2	Property & Sundry Taxes	$ 178	$ -	$ -	$ -	$ 80	$ -	$ 98	$ -	$ -
3	Depreciation Expense	$ 333	$ -	$ -	$ -	$ 121	$ -	$ 212	$ -	$ -
4	Amortization Expense	$ 5	$ -	$ -	$ -	$ 3	$ -	$ 2	$ -	$ -
5	Other Operating Revenue	$ (24)	$ -	$ -	$ -	$ -	$ -	$ (11)	$ -	$ (13)
6	Other Earned Return Provisions	$ (97)	$ -	$ -	$ -	$ (40)	$ -	$ (57)	$ -	$ -
7	Income Tax	$ 28	$ -	$ -	$ -	$ 12	$ -	$ 16	$ -	$ -
8	Earned Return	$ 719	$ -	$ -	$ -	$ 298	$ -	$ 421	$ -	$ -
9	**Total Cost of Service Margin**	**$ 1,926**	**$ -**	**$ -**	**$ -**	**$ 421**	**$ -**	**$ 1,518**	**$ -**	**$ (13)**
10										
11	Cost of Gas	$ 2,461	$ 2,461	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	**Total Utility Cost of Service**	**$ 4,387**	**$ 2,461**	**$ -**	**$ -**	**$ 421**	**$ -**	**$ 1,518**	**$ -**	**$ (13)**

FORTISBC ENERGY INC. (FORT NELSON SERVICE AREA) - LEGACY METHODOLOGY
Fully Distributed Cost of Service Allocation Study **Schedule 3**
Rate Design Filing_2013 Test Year
RATE BASE SUMMARY - CLASSIFICATION (000's)

L.No.	Particulars		Total	RATE 1	RATE 2.1	RATE 2.2	RATE 25
1	Gas Plant in Service						
2	**Total Gas Plant in Service**		**$ 12,760**	**$ 7,942**	**$ 3,336**	**$ 985**	**$ 496**
3		Demand	$ 6,670	$ 3,535	$ 1,958	$ 753	$ 424
4		Customer	$ 6,090	$ 4,407	$ 1,378	$ 232	$ 73
5		Energy	$ -	$ -	$ -	$ -	$ -
6	**Total Accumulated Depreciation**		**$ (2,853)**	**$ (1,969)**	**$ (658)**	**$ (158)**	**$ (69)**
7		Demand	$ (846)	$ (540)	$ (191)	$ (73)	$ (41)
8		Customer	$ (2,007)	$ (1,428)	$ (467)	$ (84)	$ (27)
9		Energy	$ -	$ -	$ -	$ -	$ -
10	**TOTAL Net Plant**		**$ 9,907**	**$ 5,974**	**$ 2,678**	**$ 827**	**$ 428**
11		Demand	$ 5,824	$ 2,995	$ 1,767	$ 679	$ 382
12		Customer	$ 4,083	$ 2,979	$ 911	$ 148	$ 46
13		Energy	$ -	$ -	$ -	$ -	$ -
14							
15	Contribution In Aid of Construction						
16	**Total CIAC**		**$ (1,287)**	**$ (986)**	**$ (247)**	**$ (42)**	**$ (13)**
17		Demand	$ (197)	$ (197)	$ -	$ -	$ -
18		Customer	$ (1,090)	$ (789)	$ (247)	$ (42)	$ (13)
19		Energy	$ -	$ -	$ -	$ -	$ -
20	**Total Accumulated Amortization**		**$ 573**	**$ 439**	**$ 110**	**$ 18**	**$ 6**
21		Demand	$ 88	$ 88	$ -	$ -	$ -
22		Customer	$ 485	$ 351	$ 110	$ 18	$ 6
23		Energy	$ -	$ -	$ -	$ -	$ -
24	**Total Net Contribution**		**$ (714)**	**$ (547)**	**$ (137)**	**$ (23)**	**$ (7)**
25		Demand	$ (109)	$ (109)	$ -	$ -	$ -
26		Customer	$ (605)	$ (437)	$ (137)	$ (23)	$ (7)
27		Energy	$ -	$ -	$ -	$ -	$ -
28							
29	Work in Progress, no AFUDC		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
30		Demand	$ -	$ -	$ -	$ -	$ -
31		Customer	$ -	$ -	$ -	$ -	$ -
32		Energy	$ -	$ -	$ -	$ -	$ -
33							
34	Unamortized Deferred Charges						
35	**Total Unamortized Deferred Charges - Rate Base**		**$ 34**	**$ 7**	**$ 15**	**$ 7**	**$ 4**
36		Demand	$ 56	$ 23	$ 21	$ 8	$ 4
37		Customer	$ (22)	$ (15)	$ (5)	$ (1)	$ (0)
38		Energy	$ -	$ -	$ -	$ -	$ -
39							
40	Cash Working Capital		**$ 58**	**$ 35**	**$ 16**	**$ 5**	**$ 2**
41		Demand	$ 27	$ 14	$ 8	$ 3	$ 2
42		Customer	$ 23	$ 17	$ 5	$ 1	$ 0
43		Energy	$ 8	$ 4	$ 3	$ 1	$ -
44							
45	Other Working Capital						
46	**Total Other Working Capital**		**$ (43)**	**$ (25)**	**$ (13)**	**$ (4)**	**$ (2)**
47		Demand	$ (18)	$ (8)	$ (6)	$ (2)	$ (1)
48		Customer	$ (25)	$ (17)	$ (7)	$ (1)	$ (1)
49		Energy	$ -	$ -	$ -	$ -	$ -
50							
51	LILO, Capital Efficiency Mechanism, Others		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
52		Demand	$ -	$ -	$ -	$ -	$ -
53		Customer	$ -	$ -	$ -	$ -	$ -
54		Energy	$ -				$ -
55							
56	**Total Utility Rate Base**		**$ 9,242**	**$ 5,444**	**$ 2,560**	**$ 812**	**$ 425**
57		Demand	$ 5,780	$ 2,915	$ 1,790	$ 688	$ 387
58		Customer	$ 3,454	$ 2,526	$ 768	$ 123	$ 38
59		Energy	$ 8	$ 4	$ 3	$ 1	$ -

FORTISBC ENERGY INC. (FORT NELSON SERVICE AREA) - LEGACY METHODOLOGY
Fully Distributed Cost of Service Allocation Study **Schedule 4**
Rate Design Filing_2013 Test Year
COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

L.No.	Particulars		Total	RATE 1	RATE 2.1	RATE 2.2	RATE 25
1	Operating & Maintenance Expense						
2	**Total Operating & Maintenance Expense**		**$ 784**	**$ 554**	**$ 173**	**$ 40**	**$ 17**
3		Demand	$ 232	$ 156	$ 48	$ 18	$ 10
4		Customer	$ 552	$ 398	$ 126	$ 21	$ 7
5		Energy	$ -	$ -	$ -	$ -	$ -
6	Property & Sundry Taxes		**$ 178**	**$ 108**	**$ 48**	**$ 15**	**$ 7**
7		Demand	$ 97	$ 50	$ 29	$ 11	$ 6
8		Customer	$ 81	$ 58	$ 19	$ 3	$ 1
9		Energy	$ -	$ -	$ -	$ -	$ -
10	Depreciation Expense		**$ 333**	**$ 198**	**$ 93**	**$ 28**	**$ 14**
11		Demand	$ 169	$ 84	$ 53	$ 20	$ 11
12		Customer	$ 164	$ 114	$ 40	$ 8	$ 3
13		Energy	$ -	$ -	$ -	$ -	$ -
14	Amortization Expense		**$ 5**	**$ 3**	**$ 2**	**$ 1**	**$ 0**
15		Demand	$ 5	$ 2	$ 2	$ 1	$ 0
16		Customer	$ 1	$ 1	$ 0	$ 0	$ 0
17		Energy	$ -	$ -	$ -	$ -	$ -
18	Other Operating Revenue		**$ (24)**	**$ (17)**	**$ (6)**	**$ (1)**	**$ (0)**
19		Demand	$ (2)	$ (2)	$ -	$ -	$ -
20		Customer	$ (22)	$ (15)	$ (6)	$ (1)	$ (0)
21		Energy	$ -	$ -	$ -	$ -	$ -
22	Other Earned Return Provisions		**$ (97)**	**$ (60)**	**$ (25)**	**$ (7)**	**$ (4)**
23		Demand	$ (49)	$ (25)	$ (15)	$ (6)	$ (3)
24		Customer	$ (48)	$ (35)	$ (11)	$ (2)	$ (1)
25		Energy	$ -	$ -	$ -	$ -	$ -
22	Income Tax		**$ 28**	**$ 17**	**$ 7**	**$ 2**	**$ 1**
23		Demand	$ 14	$ 7	$ 4	$ 2	$ 1
24		Customer	$ 14	$ 10	$ 3	$ 0	$ 0
25		Energy	$ -	$ -	$ -	$ -	$ -
26	Earned Return		**$ 719**	**$ 448**	**$ 188**	**$ 55**	**$ 28**
27		Demand	$ 362	$ 188	$ 109	$ 42	$ 24
28		Customer	$ 357	$ 261	$ 79	$ 13	$ 4
29		Energy	$ -	$ -	$ -	$ -	$ -
30							
31	**Total Cost of Service Margin**		**$ 1,926**	**$ 1,251**	**$ 480**	**$ 131**	**$ 63**
32		Demand	$ 828	$ 460	$ 230	$ 88	$ 50
33		Customer	$ 1,098	$ 791	$ 250	$ 43	$ 14
34		Energy	$ -	$ -	$ -	$ -	$ -
35	Cost of Gas		**$ 2,461**	**$ 1,151**	**$ 872**	**$ 438**	**$ -**
36		Demand	$ 162	$ 76	$ 57	$ 29	$ -
37		Customer	$ -	$ -	$ -	$ -	$ -
38		Energy	$ 2,299	$ 1,075	$ 815	$ 409	$ -
39	**Total Utility Cost of Service**		**$ 4,387**	**$ 2,402**	**$ 1,352**	**$ 569**	**$ 63**
40		Demand	$ 990	$ 535	$ 288	$ 117	$ 50
41		Customer	$ 1,098	$ 791	$ 250	$ 43	$ 14
42		Energy	$ 2,299	$ 1,075	$ 815	$ 409	$ -

FORTISBC ENERGY INC. (FORT NELSON SERVICE AREA) - LEGACY METHODOLOGY
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_2013 Test Year
RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Schedule 5

L.No.	Particulars		Total	RATE 1	RATE 2.1	RATE 2.2	RATE 25
1	Gas Supply Operations		$ 8	$ 4	$ 3	$ 1	$ -
2		Demand	$ -	$ -	$ -	$ -	$ -
3		Customer	$ -	$ -	$ -	$ -	$ -
4		Energy	$ 8	$ 4	$ 3	$ 1	$ -
5							
6	LNG Storage Tilbury		$ -	$ -	$ -	$ -	$ -
7		Demand	$ -	$ -	$ -	$ -	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -
10							
11	LNG Storage Mt. Hayes		$ -	$ -	$ -	$ -	$ -
12		Demand	$ -	$ -	$ -	$ -	$ -
13		Customer	$ -	$ -	$ -	$ -	$ -
14		Energy	$ -	$ -	$ -	$ -	$ -
15							
16	Transmission		$ 4,929	$ 2,154	$ 1,734	$ 666	$ 375
17		Demand	$ 4,929	$ 2,154	$ 1,734	$ 666	$ 375
18		Customer	$ -	$ -	$ -	$ -	$ -
19		Energy	$ -	$ -	$ -	$ -	$ -
20							
21	Transmission SCP		$ -	$ -	$ -	$ -	$ -
22		Demand	$ -	$ -	$ -	$ -	$ -
23		Customer	$ -	$ -	$ -	$ -	$ -
24		Energy	$ -	$ -	$ -	$ -	$ -
25							
26	Distribution		$ 4,334	$ 3,305	$ 832	$ 146	$ 51
27		Demand	$ 851	$ 761	$ 56	$ 22	$ 12
28		Customer	$ 3,483	$ 2,544	$ 775	$ 125	$ 38
29		Energy	$ -	$ -	$ -	$ -	$ -
30							
31	Marketing		$ (7)	$ (5)	$ (2)	$ (0)	$ (0)
32		Demand	$ -	$ -	$ -	$ -	$ -
33		Customer	$ (7)	$ (5)	$ (2)	$ (0)	$ (0)
34		Energy	$ -	$ -	$ -	$ -	$ -
35							
36	Customer Accounting		$ (21)	$ (14)	$ (6)	$ (1)	$ (0)
37		Demand	$ -	$ -	$ -	$ -	$ -
38		Customer	$ (21)	$ (14)	$ (6)	$ (1)	$ (0)
39		Energy	$ -	$ -	$ -	$ -	$ -
40							
41	**Total Utility Rate Base**		$ 9,242	$ 5,444	$ 2,560	$ 812	$ 425
42		Demand	$ 5,780	$ 2,915	$ 1,790	$ 688	$ 387
43		Customer	$ 3,454	$ 2,526	$ 768	$ 123	$ 38
44		Energy	$ 8	$ 4	$ 3	$ 1	$ -

FORTISBC ENERGY INC. (FORT NELSON SERVICE AREA) - LEGACY METHODOLOGY
Fully Distributed Cost of Service Allocation Study **Schedule 6**
Rate Design Filing_2013 Test Year
COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

L.No.	Particulars		Total	RATE 1	RATE 2.2	RATE 2.2	RATE 25
1	Gas Supply Operations		**$ 2,461**	**$ 1,151**	**$ 872**	**$ 438**	**$ -**
2		Demand	$ 162	$ 76	$ 57	$ 29	$ -
3		Customer	$ -	$ -	$ -	$ -	$ -
4		Energy	$ 2,299	$ 1,075	$ 815	$ 409	$ -
5							
6	LNG Storage Tilbury		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
7		Demand	$ -	$ -	$ -	$ -	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -
10							
11	LNG Storage Mt. Hayes		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
12		Demand	$ -	$ -	$ -	$ -	$ -
13		Customer	$ -	$ -	$ -	$ -	$ -
14		Energy	$ -	$ -	$ -	$ -	$ -
15							
16	Transmission		**$ 421**	**$ 184**	**$ 148**	**$ 57**	**$ 32**
17		Demand	$ 421	$ 184	$ 148	$ 57	$ 32
18		Customer	$ -	$ -	$ -	$ -	$ -
19		Energy	$ -	$ -	$ -	$ -	$ -
20							
21	Transmission SCP		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
22		Demand	$ -	$ -	$ -	$ -	$ -
23		Customer	$ -	$ -	$ -	$ -	$ -
24		Energy	$ -	$ -	$ -	$ -	$ -
25							
26	Distribution		**$ 1,518**	**$ 1,075**	**$ 336**	**$ 75**	**$ 32**
27		Demand	$ 407	$ 276	$ 82	$ 31	$ 18
28		Customer	$ 1,111	$ 800	$ 254	$ 44	$ 14
29		Energy	$ -	$ -	$ -	$ -	$ -
30							
31	Marketing		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
32		Demand	$ -	$ -	$ -	$ -	$ -
33		Customer	$ -	$ -	$ -	$ -	$ -
34		Energy	$ -	$ -	$ -	$ -	$ -
35							
36	Customer Accounting		**$ (13)**	**$ (8)**	**$ (3)**	**$ (1)**	**$ (0)**
37		Demand	$ -	$ -	$ -	$ -	$ -
38		Customer	$ (13)	$ (8)	$ (3)	$ (1)	$ (0)
39		Energy	$ -	$ -	$ -	$ -	$ -
40							
41	**Total Utility Cost of Service**		**$ 4,387**	**$ 2,402**	**$ 1,352**	**$ 569**	**$ 63**
42		Demand	$ 990	$ 535	$ 288	$ 117	$ 50
43		Customer	$ 1,098	$ 791	$ 250	$ 43	$ 14
44		Energy	$ 2,299	$ 1,075	$ 815	$ 409	$ -

FORTISBC ENERGY INC. (FORT NELSON SERVICE AREA) - LEGACY METHODOLOGY
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_2013 Test Year
ALLOCATORS SUMMARY (000's)

Schedule 7

L.No.	Particulars		Total	RATE 1	RATE 2.1	RATE 2.2	RATE 25
1	Billing Determinants						
2							
3	Sales Volume (TJ)			274	208	104	55
4	Average No. of Customers			1,953	444	28	2
5							
6	**Cost of Service Margin**		**$ 1,926**	**$ 1,251**	**$ 480**	**$ 131**	**$ 63**
7		Demand	$ 828	$ 460	$ 230	$ 88	$ 50
8	Unit Demand Charge ($/GJ)			$ 1.68	$ 0.84	$ 0.32	$ 0.18
9		Customer	$ 1,098	$ 791	$ 250	$ 43	$ 14
10	Unit Customer Charge ($/GJ)			$ 2.88	$ 0.91	$ 0.16	$ 0.05
11		Energy	$ -	$ -	$ -	$ -	$ -
12	Unit Energy Charge ($/GJ)			$ -	$ -	$ -	$ -
13							
14	Unit Cost of Service Margin ($/GJ)			**$ 4.56**	**$ 2.31**	**$ 1.26**	**$ 1.15**
15							
16	**Cost of Gas**		**$ 2,461**	**$ 1,151**	**$ 872**	**$ 438**	**$ -**
17		Demand	$ 162	$ 76	$ 57	$ 29	$ -
18		Customer	$ -	$ -	$ -	$ -	$ -
19		Energy	$ 2,299	$ 1,075	$ 815	$ 409	$ -
20	Unit Cost of Gas ($/GJ)			**$ 4.20**	**$ 4.20**	**$ 4.20**	**$ -**
21							
22	**Total Utility Cost of Service**		**$ 4,387**	**$ 2,402**	**$ 1,352**	**$ 569**	**$ 63**
23		Demand	$ 990	$ 535	$ 288	$ 117	$ 50
24		Customer	$ 1,098	$ 791	$ 250	$ 43	$ 14
25		Energy	$ 2,299	$ 1,075	$ 815	$ 409	$ -
26	Unit Cost of Service ($/GJ)			**$ 8.76**	**$ 6.51**	**$ 5.46**	**$ 1.15**
27							
28	**Total Revenues @ Proposed Rates**		**$ 4,387**	**$ 1,942**	**$ 1,572**	**$ 734**	**$ 140**
29	Unit Rate ($/GJ)			**$ 7.08**	**$ 7.56**	**$ 7.03**	**$ 2.54**
30							
31	**Total Revenue Margin @ Proposed Rates**		**$ 1,926**	**$ 791**	**$ 700**	**$ 296**	**$ 140**
32	Unit Rate ($/GJ)			**$ 2.88**	**$ 3.37**	**$ 2.84**	**$ 2.54**

Appendix B

FULLY DISTRIBUTED COSA STUDY
2016 TEST YEAR SCHEDULES

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 1

SUMMARY (000's)

Line No.	Particulars	Reference	Total	RATE 1	RATE 2.1	RATE 2.2	RATE 25 NON-BYPASS
1	**REVENUE TO COST**						
2	Total Revenue at 2016 Approved Rates	Line 2 + Line 3	**$ 4,914**	**$ 2,033**	**$ 1,706**	**$ 911**	**$ 264**
3	Revenue Margin at 2016 Approved Rates		$ 2,219	$ 894	$ 817	$ 396	$ 112
4	Cost of Gas at 2016 Approved Rates		$ 2,695	$ 1,139	$ 889	$ 515	$ 152
5							
6	**COST OF SERVICE**						
7	Total Utility Cost of Service	Line 7 + Line 8	**$ 4,976**	**$ 2,230**	**$ 1,529**	**$ 762**	**$ 455**
8	Cost of Service Margin		$ 2,281	$ 1,091	$ 640	$ 247	$ 302
9	Total Cost of Gas		$ 2,695	$ 1,139	$ 889	$ 515	$ 152
10							
11	**SURPLUS / DEFICIT**						
12	Total Surplus / (Deficit)	Line 2 - Line 7	$ (62)				
13	% Increase to Equal Allocated Costs	- Line 12 / Line 3	2.8%				
14							
15	**REVENUES (adjusted to equal COS)**						
16	Total Revenue at 2016 Approved Rates - Adjusted	Line 4 + Line 17	**$ 4,976**	**$ 2,058**	**$ 1,729**	**$ 922**	**$ 267**
17	Total Revenue Margin at 2016 Approved Rates - Adjusted	Line 3 x (1 + Line 13)	$ 2,281	$ 919	$ 840	$ 407	$ 115
18							
19	REVENUES (adjusted for R/C ratio's)	Line 16	**$ 4,976**	**$ 2,058**	**$ 1,729**	**$ 922**	**$ 267**
20	COST OF SERVICE (adjusted for R/C ratio's)	Line 7	**$ 4,976**	**$ 2,230**	**$ 1,529**	**$ 762**	**$ 455**
21							
22	**REVENUE TO COST RATIO**						
23	Revenue to Cost Ratio	Line 19 / Line 20	**100%**	**92%**	**113%**	**121%**	**59%**
24							
25	**REVENUE REBALANCING**						
26	Adjustment		$ -	$ -	$ -	$ -	$ -
27	Total Revenue at Proposed Rates	Line 16 + Line 26	**$ 4,976**	**$ 2,058**	**$ 1,729**	**$ 922**	**$ 267**
28	Total Revenue Margin at Proposed Rates	Line 17 + Line 26	$ 2,281	$ 919	$ 840	$ 407	$ 115
29							
30	**PROPOSED REVENUE TO COST RATIO**						
31	Revenue to Cost Ratio at Proposed Rates	Line 27 / Line 20	**100%**	**92%**	**113%**	**121%**	**59%**
32							
33	**Notes:**						
34	1. Lines 2, 7, 16, 19, 20, 27 include the imputed Cost of Gas for Rates 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios.						
35	Rate 25 does not pay a Gas Cost Recovery Charge						

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA

Fully Distributed Cost of Service Allocation Study **Schedule 2**

Rate Design Filing_Common Rates_ 2016 Test Year

FUNCTIONALIZATION (000's)

Line No.	Particulars	Total	Gas Supply Operations	Transmission	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense	$ 882	$ -	$ (55)	$ 937	$ -	$ -
2	Property & Sundry Taxes	$ 139	$ -	$ 72	$ 67	$ -	$ -
3	Depreciation Expense	$ 436	$ -	$ 174	$ 262	$ -	$ -
4	Amortization Expense	$ 38	$ -	$ 19	$ 33	$ 2	$ (16)
5	Other Operating Revenue	$ (20)	$ -	$ -	$ (11)	$ -	$ (9)
6	Income Tax	$ 74	$ 0	$ 40	$ 34	$ 0	$ (0)
7	Earned Return	$ 732	$ 1	$ 400	$ 332	$ 1	$ (3)
8	**Total Cost of Service Margin**	**$ 2,281**	**$ 1**	**$ 651**	**$ 1,653**	**$ 3**	**$ (28)**
9							
10	Cost of Gas - Commodity	$ 2,543	$ 2,543	$ -	$ -	$ -	$ -
11	**Total Utility Revenue Requirement**	**$ 4,824**	**$ 2,544**	**$ 651**	**$ 1,653**	**$ 3**	**$ (28)**

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
Fully Distributed Cost of Service Allocation Study

Schedule 3

Rate Design Filing_Common Rates_ 2016 Test Year

RATE BASE SUMMARY - CLASSIFICATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2.1	RATE 2.2	RATE 25 NON-BYPASS
1	**Gas Plant in Service**						
2	Total Gas Plant in Service		**$ 15,307**	**$ 6,961**	**$ 4,325**	**$ 1,725**	**$ 2,296**
3		Energy	$ -	$ -	$ -	$ -	$ -
4		Demand	$ 9,830	$ 3,308	$ 3,186	$ 1,498	$ 1,839
5		Customer	$ 5,476	$ 3,654	$ 1,139	$ 227	$ 457
6							
7	Total Accumulated Depreciation		**$ (3,992)**	**$ (2,000)**	**$ (1,078)**	**$ (396)**	**$ (517)**
8		Energy	$ -	$ -	$ -	$ -	$ -
9		Demand	$ (1,897)	$ (655)	$ (644)	$ (305)	$ (292)
10		Customer	$ (2,095)	$ (1,345)	$ (433)	$ (92)	$ (225)
11							
12	TOTAL Net Plant		**$ 11,315**	**$ 4,961**	**$ 3,247**	**$ 1,328**	**$ 1,779**
13		Energy	$ -	$ -	$ -	$ -	$ -
14		Demand	$ 7,934	$ 2,652	$ 2,541	$ 1,193	$ 1,547
15		Customer	$ 3,381	$ 2,309	$ 706	$ 135	$ 232
16							
17	**Contributions In Aid of Construction**						
18	Total Gas Plant in Service		**$ (1,319)**	**$ (726)**	**$ (360)**	**$ (125)**	**$ (108)**
19		Energy	$ -	$ -	$ -	$ -	$ -
20		Demand	$ (513)	$ (188)	$ (193)	$ (92)	$ (41)
21		Customer	$ (806)	$ (538)	$ (168)	$ (33)	$ (67)
22							
23	Total Accumulated Depreciation		**$ 682**	**$ 392**	**$ 184**	**$ 62**	**$ 43**
24		Energy	$ -	$ -	$ -	$ -	$ -
25		Demand	$ 219	$ 84	$ 88	$ 42	$ 5
26		Customer	$ 463	$ 309	$ 96	$ 19	$ 39
27							
28	TOTAL Net Plant		**$ (637)**	**$ (333)**	**$ (176)**	**$ (64)**	**$ (65)**
29		Energy	$ -	$ -	$ -	$ -	$ -
30		Demand	$ (294)	$ (104)	$ (104)	$ (50)	$ (36)
31		Customer	$ (343)	$ (229)	$ (71)	$ (14)	$ (29)
32							

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA

Fully Distributed Cost of Service Allocation Study

Schedule 3

Rate Design Filing_Common Rates_ 2016 Test Year

RATE BASE SUMMARY - CLASSIFICATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2.1	RATE 2.2	RATE 25 NON-BYPASS
33	**Work in Process, no AFUDC**		**$ 35**	**$ 14**	**$ 10**	**$ 4**	**$ 7**
34		Energy	$ -	$ -	$ -	$ -	$ -
35		Demand	$ 28	$ 9	$ 9	$ 4	$ 6
36		Customer	$ 7	$ 5	$ 1	$ 0	$ 1
37							
38	**Unamortized Deferred Charges**		**$ 7**	**$ (6)**	**$ 7**	**$ 3**	**$ 2**
39		Energy	$ 3	$ 1	$ 1	$ 1	$ -
40		Demand	$ 28	$ 13	$ 10	$ 3	$ 2
41		Customer	$ (24)	$ (20)	$ (4)	$ 0	$ 0
42							
43	**Cash Working Capital**		**$ 29**	**$ 13**	**$ 10**	**$ 5**	**$ 1**
44		Energy	$ 20	$ 9	$ 7	$ 4	$ -
45		Demand	$ 6	$ 2	$ 2	$ 1	$ 1
46		Customer	$ 3	$ 2	$ 1	$ 0	$ 0
47							
48	**Other Working Capital**		**$ 14**	**$ 8**	**$ 4**	**$ 1**	**$ 1**
49		Energy	$ -	$ -	$ -	$ -	$ -
50		Demand	$ 4	$ 2	$ 2	$ 1	$ -
51		Customer	$ 10	$ 7	$ 2	$ 0	$ 1
52							
53	**Total Utility Rate Base**		**$ 10,763**	**$ 4,657**	**$ 3,102**	**$ 1,278**	**$ 1,726**
54		Energy	$ 23	$ 10	$ 8	$ 5	$ -
55		Demand	$ 7,706	$ 2,574	$ 2,460	$ 1,152	$ 1,520
56		Customer	$ 3,034	$ 2,073	$ 634	$ 121	$ 206

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Schedule 4

Line No.	Particulars		Total	RATE 1	RATE 2.1	RATE 2.2	RATE 25 NON-BYPASS
1	**Operating & Maintenance Expense**		**$ 882**	**$ 473**	**$ 240**	**$ 85**	**$ 84**
2		Energy	$ -	$ -	$ -	$ -	$ -
3		Demand	$ 363	$ 129	$ 130	$ 62	$ 43
4		Customer	$ 519	$ 344	$ 110	$ 23	$ 42
5							
6	**Property & Sundry Taxes**		**$ 139**	**$ 62**	**$ 40**	**$ 16**	**$ 21**
7		Energy	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 93	$ 31	$ 30	$ 14	$ 19
9		Customer	$ 46	$ 31	$ 10	$ 2	$ 3
10							
11	**Depreciation Expense**		**$ 436**	**$ 203**	**$ 125**	**$ 50**	**$ 58**
12		Energy	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 272	$ 92	$ 89	$ 42	$ 48
14		Customer	$ 164	$ 111	$ 36	$ 7	$ 10
15							
16	**Amortization Expense**		**$ 38**	**$ 9**	**$ 13**	**$ 6**	**$ 10**
17		Energy	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 42	$ 14	$ 13	$ 6	$ 9
19		Customer	$ (4)	$ (5)	$ (0)	$ 0	$ 1
20							
21	**Other Operating Revenue**		**$ (20)**	**$ (13)**	**$ (5)**	**$ (1)**	**$ (1)**
22		Energy	$ -	$ -	$ -	$ -	$ -
23		Demand	$ (3)	$ (1)	$ (1)	$ (1)	$ -
24		Customer	$ (17)	$ (12)	$ (3)	$ (0)	$ (1)
25							
26	**Income Tax**		**$ 74**	**$ 33**	**$ 21**	**$ 8**	**$ 12**
27		Energy	$ 0	$ 0	$ 0	$ 0	$ -
28		Demand	$ 51	$ 17	$ 16	$ 7	$ 10
29		Customer	$ 23	$ 16	$ 5	$ 1	$ 2
30							

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Schedule 4

Line No.	Particulars		Total	RATE 1	RATE 2.1	RATE 2.2	RATE 25 NON-BYPASS
31	**Earned Return**		**$ 732**	**$ 324**	**$ 207**	**$ 83**	**$ 118**
32		Energy	$ 1	$ 1	$ 0	$ 0	$ -
33		Demand	$ 500	$ 166	$ 158	$ 74	$ 102
34		Customer	$ 230	$ 157	$ 48	$ 9	$ 16
35							
36	**Total Cost of Service Margin**		**$ 2,281**	**$ 1,091**	**$ 640**	**$ 247**	**$ 302**
37		Energy	$ 1	$ 1	$ 1	$ 0	$ -
38		Demand	$ 1,318	$ 448	$ 434	$ 205	$ 231
39		Customer	$ 962	$ 643	$ 205	$ 42	$ 71
40							
41	**Cost of Gas Sold (Including Gas Lost)**		**$ 2,543**	**$ 1,139**	**$ 889**	**$ 515**	**$ -**
42		Energy	$ 2,543	$ 1,139	$ 889	$ 515	$ -
43		Demand	$ -	$ -	$ -	$ -	$ -
44		Customer	$ -	$ -	$ -	$ -	$ -
45							
46	**Total Utility Revenue Requirement**		**$ 4,824**	**$ 2,230**	**$ 1,529**	**$ 762**	**$ 302**
47		Energy	$ 2,544	$ 1,140	$ 890	$ 515	$ -
48		Demand	$ 1,318	$ 448	$ 434	$ 205	$ 231
49		Customer	$ 962	$ 643	$ 205	$ 42	$ 71

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 5

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2.1	RATE 2.2	RATE 25 NON-BYPASS
1	Gas Supply Operations		**$ 20**	**$ 9**	**$ 7**	**$ 4**	**$ -**
2		Energy	$ 20	$ 9	$ 7	$ 4	$ -
3		Demand	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -
5							
6	Transmission		**$ 5,885**	**$ 1,884**	**$ 1,742**	**$ 810**	**$ 1,450**
7		Energy	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 5,885	$ 1,884	$ 1,742	$ 810	$ 1,450
9		Customer	$ -	$ -	$ -	$ -	$ -
10							
11	Distribution		**$ 4,882**	**$ 2,787**	**$ 1,355**	**$ 464**	**$ 277**
12		Energy	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 1,806	$ 682	$ 712	$ 342	$ 70
14		Customer	$ 3,076	$ 2,105	$ 642	$ 122	$ 207
15							
16	Marketing		**$ 15**	**$ 9**	**$ 6**	**$ 0**	**$ 0**
17		Energy	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 15	$ 9	$ 6	$ 0	$ 0
19		Customer	$ 0	$ 0	$ 0	$ 0	$ 0
20							
21	Customer Accounting		**$ (39)**	**$ (31)**	**$ (7)**	**$ (0)**	**$ (1)**
22		Energy	$ 3	$ 1	$ 1	$ 1	$ -
23		Demand	$ -	$ -	$ -	$ -	$ -
24		Customer	$ (42)	$ (32)	$ (8)	$ (1)	$ (1)
25							
26	**Total Utility Rate Base**		**$ 10,763**	**$ 4,657**	**$ 3,102**	**$ 1,278**	**$ 1,726**
27		Energy	$ 23	$ 10	$ 8	$ 5	$ -
28		Demand	$ 7,706	$ 2,574	$ 2,460	$ 1,152	$ 1,520
29		Customer	$ 3,034	$ 2,073	$ 634	$ 121	$ 206

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 6

COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2.1	RATE 2.2	RATE 25 NON-BYPASS
1	Gas Supply Operations		**$ 1**	**$ 1**	**$ 1**	**$ 0**	**$ -**
2		Energy	$ 1	$ 1	$ 1	$ 0	$ -
3		Demand	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -
5							
6	Transmission		**$ 651**	**$ 208**	**$ 193**	**$ 90**	**$ 160**
7		Energy	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 651	$ 208	$ 193	$ 90	$ 160
9		Customer	$ -	$ -	$ -	$ -	$ -
10							
11	Distribution		**$ 1,653**	**$ 902**	**$ 451**	**$ 158**	**$ 143**
12		Energy	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 667	$ 239	$ 242	$ 115	$ 71
14		Customer	$ 986	$ 662	$ 209	$ 43	$ 72
15							
16	Marketing		**$ 3**	**$ 2**	**$ 1**	**$ 0**	**$ 0**
17		Energy	$ -	$ -	$ -	$ -	$ -
18		Demand	$ -	$ -	$ -	$ -	$ -
19		Customer	$ 3	$ 2	$ 1	$ 0	$ 0
20							
21	Customer Accounting		**$ (28)**	**$ (22)**	**$ (5)**	**$ (0)**	**$ (1)**
22		Energy	$ -	$ -	$ -	$ -	$ -
23		Demand	$ -	$ -	$ -	$ -	$ -
24		Customer	$ (28)	$ (22)	$ (5)	$ (0)	$ (1)
25							
26	**Total Utility Cost of Service**		**$ 2,281**	**$ 1,091**	**$ 640**	**$ 247**	**$ 302**
27		Energy	$ 1	$ 1	$ 1	$ 0	$ -
28		Demand	$ 1,318	$ 448	$ 434	$ 205	$ 231
29		Customer	$ 962	$ 643	$ 205	$ 42	$ 71

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
Fully Distributed Cost of Service Allocation Study

Schedule 7

Rate Design Filing_Common Rates_ 2016 Test Year

CLASSIFICATION SUMMARY (000's)

Line No.	Particulars		Total	RATE 1	RATE 2.1	RATE 2.2	RATE 25 NON-BYPASS
1	Billing Determinants						
2							
3	Sales Volume (TJ)		633	268	209	121	36
4	Midstream Sales Volume (TJ)		597	268	209	121	-
5	Commodity Sales Volume (TJ)		597	268	209	121	-
6	Average No. of Customers		2,483	1,980	468	34	1
7							
8	Cost of Service Margin		**$ 2,281**	**$ 1,091**	**$ 640**	**$ 247**	**$ 302**
9		Energy	$ 1	$ 1	$ 1	$ 0	$ -
10	Unit Energy Charge ($/GJ)			0.002	0.002	0.002	0.000
11		Demand	$ 1,318	$ 448	$ 434	$ 205	$ 231
12	Unit Demand Charge ($/GJ)			1.673	2.082	1.691	6.463
13		Customer	$ 962	$ 643	$ 205	$ 42	$ 71
14	Unit Customer Charge ($/Cust/Day)			0.889	1.201	3.419	194.315
15							
16	Unit Cost of Service Margin ($/GJ)			4.079	3.069	2.045	8.445
17							
18	Cost of Gas - Commodity		**$ 2,543**	**$ 1,139**	**$ 889**	**$ 515**	**$ -**
19		Energy	$ 2,543	$ 1,139	$ 889	$ 515	$ -
20		Demand	$ -	$ -	$ -	$ -	$ -
21		Customer	$ -	$ -	$ -	$ -	$ -
22	Unit Cost of Gas - Commodity ($/GJ)			4.258	4.262	4.256	0.000
23							
24	Total Utility Cost of Service		**$ 4,824**	**$ 2,230**	**$ 1,529**	**$ 762**	**$ 302**
25		Energy	$ 2,544	$ 1,140	$ 890	$ 515	$ -
26		Demand	$ 1,318	$ 448	$ 434	$ 205	$ 231
27		Customer	$ 962	$ 643	$ 205	$ 42	$ 71
28	Unit Cost of Service ($/GJ)			8.337	7.330	6.301	8.445
29							
30	Total Revenues @ Proposed Rates		**$ 4,824**	**$ 2,058**	**$ 1,729**	**$ 922**	**$ 115**
31	Unit Rate ($/GJ)			7.694	8.288	7.621	3.206
32							
33	Total Revenue Margin @ Proposed Rates		**$ 2,281**	**$ 919**	**$ 840**	**$ 407**	**$ 115**
34	Unit Rate ($/GJ)			3.436	4.027	3.365	3.206

FortisBC Energy Inc.

2016 Rate Design Application

Workshop 2: Transportation Service Review
Discussion Guide

August 2, 2016

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1. INTRODUCTION

Starting in the spring of 2016, FortisBC Energy Inc. (FEI or the Company) is holding a series of workshops for the purpose of working towards an efficient and cost effective regulatory process once the 2016 FEI Rate Design Application (Application or RDA) is filed later this year. This document describes the objectives and subject matter of Workshop 2 – Transportation Service Review - that will be held on August 12, 2016.

The key objectives of the Transportation Service Review workshop are to inform and review the areas of the transportation customer business model (or transportation model) and engage all stakeholders in compiling a key issues list. The key issues list will be used by FEI to focus the scope of the RDA. FEI is circulating this discussion guide in advance of the workshop so that all stakeholders can review the materials and prepare to participate effectively and contribute to the development of the key issues list. Included in this discussion guide are three key discussion topics that FEI would like to examine. Topics include monthly versus daily balancing, balancing tolerances and the value of balancing service, and the T-South capacity offering. FEI would like to get feedback on these three topics and encourages comments and opinions on other areas of the transportation model.

Due to the wide range of stakeholders with varying interests involved in this proceeding, FEI does not expect that all parties will be in agreement on all the issues prior to filing the Application and that some may have to be settled through the regulatory process. However, it will be beneficial for all stakeholders involved to hear and understand the positions of the various parties as FEI moves toward the filing of the RDA in the fall of 2016.

2. SERVICES OVERVIEW AND BACKGROUND

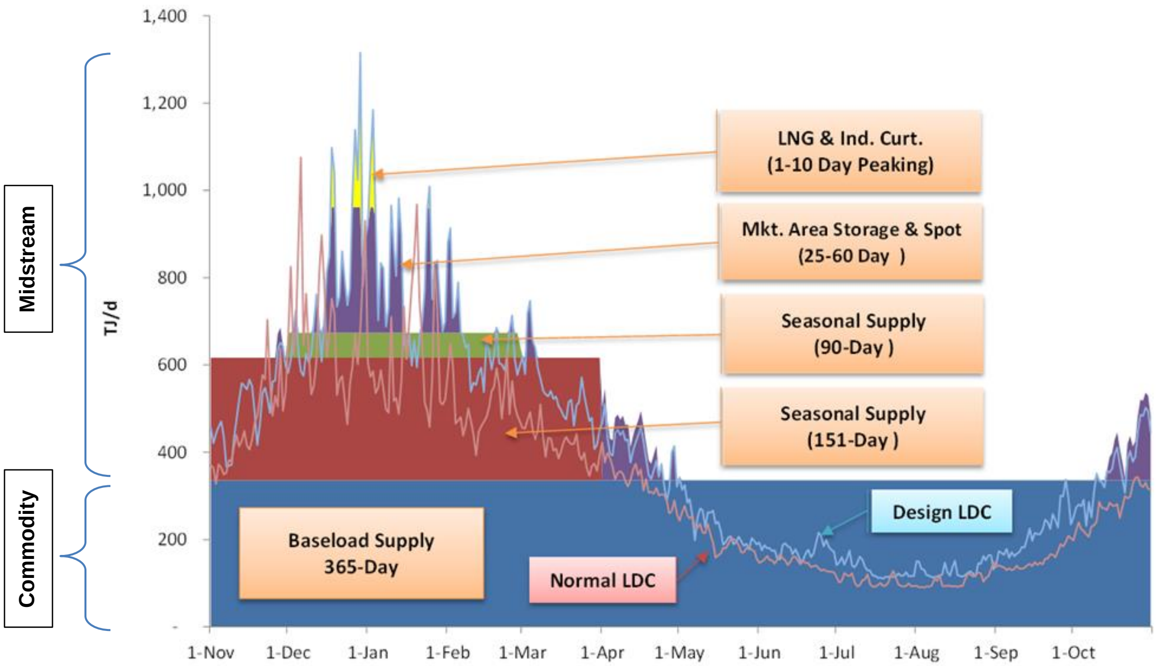
2.1 SALES AND TRANSPORTATION CUSTOMER BUSINESS MODELS

FEI has business models in place that allow customers flexibility in how they choose to source their gas commodity and midstream services. FEI has two primary customer groups: sales customers and transportation customers. Each of these groups has an associated business model, the sales customer business model (sales model or essential services model) for sales customers and the transportation customer business model (transportation model) for transportation customers. These models ensure that the gas supply for the respective customer groups is delivered to FEI each day based on forecasted demand. Sales customers may choose to have their commodity provided by gas marketers or by FEI. Transportation customers may choose to have their commodity provided by themselves or by their marketers.

2.1.1 Sales Customer Business Model

Under the sales model, resources are contracted by FEI to meet the daily load requirements of sales customers under all weather conditions including non-peak load periods (normal load) and peak day load. The contracted resources provide support for balancing the FEI transmission and distribution system (the System) as a whole including balancing the needs of transportation customers or their marketers during non-peak load periods. The regional (external or third-party) pipelines and storage resources contracted by FEI must be available on a firm basis to provide security of supply under all weather conditions or to deal with operational outages planned or unplanned. The contracting of resources comprise of both commodity and midstream, which is illustrated in Figure 2-1 below.

Figure 2-1: Gas Supply for Sales Customers to meet Peak Day and Normal Day Loads



Under the sales model, FEI provides commodity, midstream and delivery services to customers. However, with respect to the commodity service, customers can choose to have the commodity provided by either FEI or a gas marketer under the Customer Choice program at the prescribed supply hubs. The supply hubs are trading points on external pipeline systems where natural gas is transacted for delivery to FEI, namely, at Station 2 and AECO/NIT. Regardless of the provider of the commodity, FEI is responsible for receiving natural gas at the supply hubs for ultimate delivery to customers' premises for consumption (denoted by the Baseload Supply 365-Day bar in the chart).

All other resources above the Baseload Supply 365-Day bar in Figure 2-1 form part of the midstream portfolio which includes seasonal and peaking gas supply, storage capacity and transportation on regional pipelines. These same regional pipelines and storage resources are also accessed by other utilities in and around the Pacific Northwest to meet loads on their systems. Therefore, it is crucial for FEI to contract these midstream resources and to ensure that these resources are available to meet the requirements of its sales customers

The commodity and midstream resources contracted by FEI are discussed in the Annual Contracting Plan (ACP). The ACP is a gas supply planning document that FEI files annually with the British Columbia Utilities Commission (the Commission) for review. The contracted midstream resources provide support for balancing the System as a whole (which also includes balancing the needs of transport customers) during the majority of the year. The exception is those few days of the year during extreme winter weather when these contracted midstream resources are restricted to meet the needs of only sales customers.

2.1.2 Transportation Customer Business Model

Under the transportation model which is available to large commercial and industrial customers, the transportation customers or their marketers source the gas and deliver it directly to FEI's System at a specified location which is usually the point, known as an interconnect, where FEI is connected with external pipelines such as the Spectra or TransCanada Foothills BC systems. Once FEI receives the gas at the specified location from the customer or the customer's marketer, FEI will move the volumes through the System for delivery to the customer's premise for consumption.

Even though the number of transportation customers is very small at approximately 2,500 or 0.2% as a percentage of the total customers, the transportation customers' volumes constitute a significant portion of total annual throughput on FEI's System, equating to about 40% of the total throughput. There are thirteen transportation marketers currently managing the supply and demand requirements of transportation customers.

The transportation model has worked well over the years, as it has allowed customers with different load profiles to manage their gas supply requirements to fit their business needs. However, in this discussion guide, FEI has considered that some amendments to the transportation model are required. As guidelines for the transportation model were developed thirty years ago, FEI believes that the rules within the transportation model need to be revisited and possibly updated in order to reflect the efficiencies and sophistication in today's market, changes to overall industry practices, and revisions to operating practices with third-party pipelines.

2.2 *SYSTEM BALANCING*

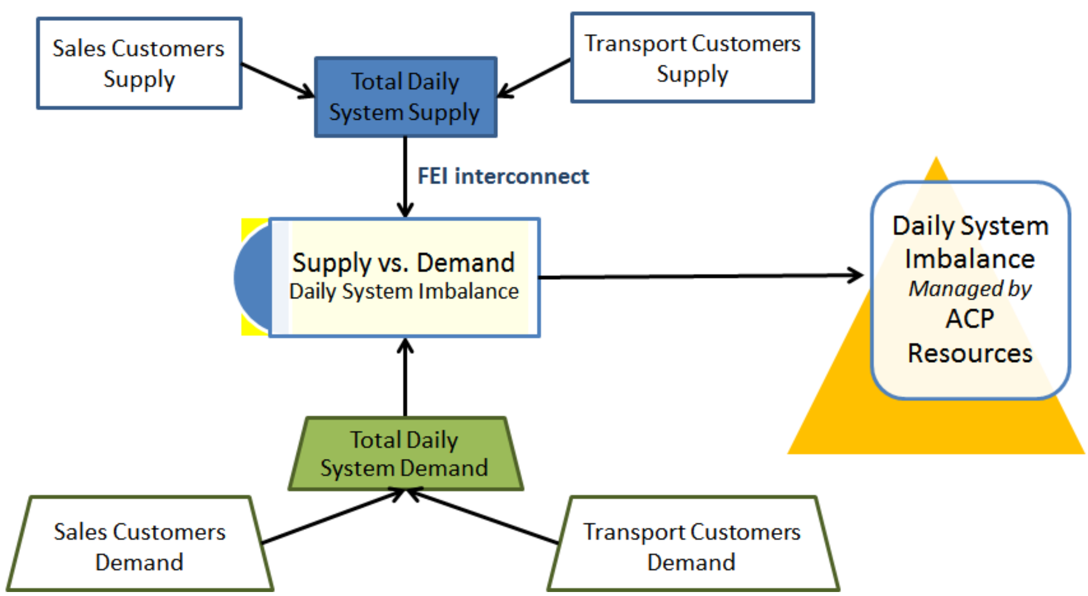
FEI, as the utility, is responsible for monitoring the System on a 24-hour basis each day, with the goal of keeping the System balanced within prescribed tolerance levels and managing the supply and demand for the respective gas day[1]. Factors that influence the System each day include demand from heat sensitive customers, customers who have process load, fluctuations in weather across the Province and the amount of supply coming into the System at various points. If projected demand begins to exceed supply, FEI must ensure that adequate gas supply is available within the day to meet the incremental demand. Conversely, if the projected demand is lower than forecast and excess supply continues to enter the System, then supply reductions must be made to ensure that the System integrity is maintained. Transportation customers or their marketer also have the ability to match their portion of supply vs. demand on the day for their customers through the various available nomination cycles on pipeline systems and an assessment of consumption levels by their customers.

[1] A gas day is defined as any period of twenty-four consecutive hours beginning and ending at 7:00 a.m. Pacific Standard Time.

In keeping with industry practice, FEI must balance daily on a total System basis on behalf of both sales customers and transportation customers or their marketers. However, the pool of resources that is deployed each day to provide the System balancing functions comes from the midstream resources contracted on behalf of sales customers as set out in the ACP in order to meet the design day load. This intraday balancing is conducted mainly by withdrawing from or injecting gas into storage. Movement to and from the storage facilities is managed by contracting pipeline capacity on third-party pipelines that connect the System to the storage facilities.

Figure 2-2 below provides an overview of the daily system load balancing when the total supply does not match the total System demand on FEI's System causing a daily system imbalance. This daily system imbalance is managed by using the ACP resources contracted on behalf of all sales customers.

Figure 1-2: Daily System Load Balancing Overview



The total gas supply that is received at FEI's interconnects from all sources needs to be balanced between interconnecting pipelines. Excess gas left on or gas borrowed from third-party pipelines by FEI due to fluctuations in demand on FEI's System has to trend within operating balancing provisions between FEI and third-party pipeline systems on a daily basis. The total daily imbalances between FEI and third-party pipeline systems and managing the daily long or short positions on FEI's System constitutes FEI's daily balancing functions.

As a result of daily balancing activities undertaken by FEI, transportation customers receive a benefit from the ACP resources. The ACP resources contracted on behalf of sales customers are available almost every day of the year to transportation customers or their marketers except under extreme weather conditions when there is a restriction placed on transportation customers or their marketers according to the service (i.e. imbalance return) being removed or tolerance levels tighten according to the Transportation Terms and Conditions. Under these extreme conditions, transportation customers or their marketers are required to match their daily supply with the anticipated demand of transportation customers or their marketers, and remain within prescribed tolerance levels. In some cases, interruptible transportation customers may be curtailed when there is a capacity constraint on the System during these extreme conditions.

3. SERVICES WITHIN THE TRANSPORTATION MODEL

3.1 CHARGES AS DEFINED IN THE FEI TRANSPORTATION RATE SCHEDULES

As set out in the Transportation Rate Schedules, it is the responsibility of the transportation customers or their marketers to make efforts to match 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 or conditions occur. These charges are laid out in the Table of Charges in each of the Transportation Rate Schedules:

Charges per GJ include the following:

- Backstopping
- Replacement Gas
- Daily Balancing Gas
- Balancing Premium charges (Daily)
- Monthly Balancing Gas
- Unauthorized Overrun (under 5% and over 5%)
- Demand Surcharge

Backstopping is applied when the authorized quantity of gas from the interconnect is less than the nominated quantity. Replacement gas is applied when Southern Crossing Pipeline peaking gas is not returned.

The remaining 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 will be sold to make up for the short-fall.
- If the supply is insufficient beyond the tolerance threshold, balancing premium charges will 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 will apply.
- In the case where a customer is curtailed, demand surcharges will apply if the customer takes gas on the System.

When any of the above charges are incurred, marketers have the ability to pass them directly to the customer(s) or pay on their own behalf.

3.2 CUSTOMER POOLING

FEI's transportation model allows customers to be either daily or monthly balanced, with the exception of customers served under Rate Schedule 22 – Large Volume Transportation service, which must be daily balanced. Marketers are also permitted to pool their customers in daily or monthly balanced groups. Each marketer is permitted to have one daily and one monthly balanced group for each receipt or interconnect point on the System. Grouping or pooling customers helps marketers to operate within the tolerance rules by flattening the overall load of the group.

3.3 IMBALANCE RETURN

Imbalance return is a balancing tool which allows marketers with daily balanced groups to use their stored inventory on FEI's System as a source of supply. Historically, FEI has set a limit of available imbalance return to 40,000 gigajoule (GJ) in the Interior and 40,000 GJ in the Lower Mainland (including Vancouver Island). Marketers submit requests to FEI to use a portion of the available limit, and quantities are allocated equally to all of these marketers. The limit of 40,000 GJ per region is the maximum FEI has deemed operationally manageable during the year under normal weather conditions.

When colder weather or operational restrictions occur, FEI reduces or eliminates the availability of this service as required. FEI provides as much notice as possible when this service is amended in any way.

When imbalance return is eliminated due to colder weather or for operational purposes, daily balanced groups must then bring on enough physical supply to meet demand (and not rely on their inventory) or balancing changes will apply. Conversely, monthly balancing groups do not have the same requirements to balance daily and therefore have the ability to draft the System under these circumstances

3.4 BALANCING TOLERANCE & SYSTEM INVENTORY

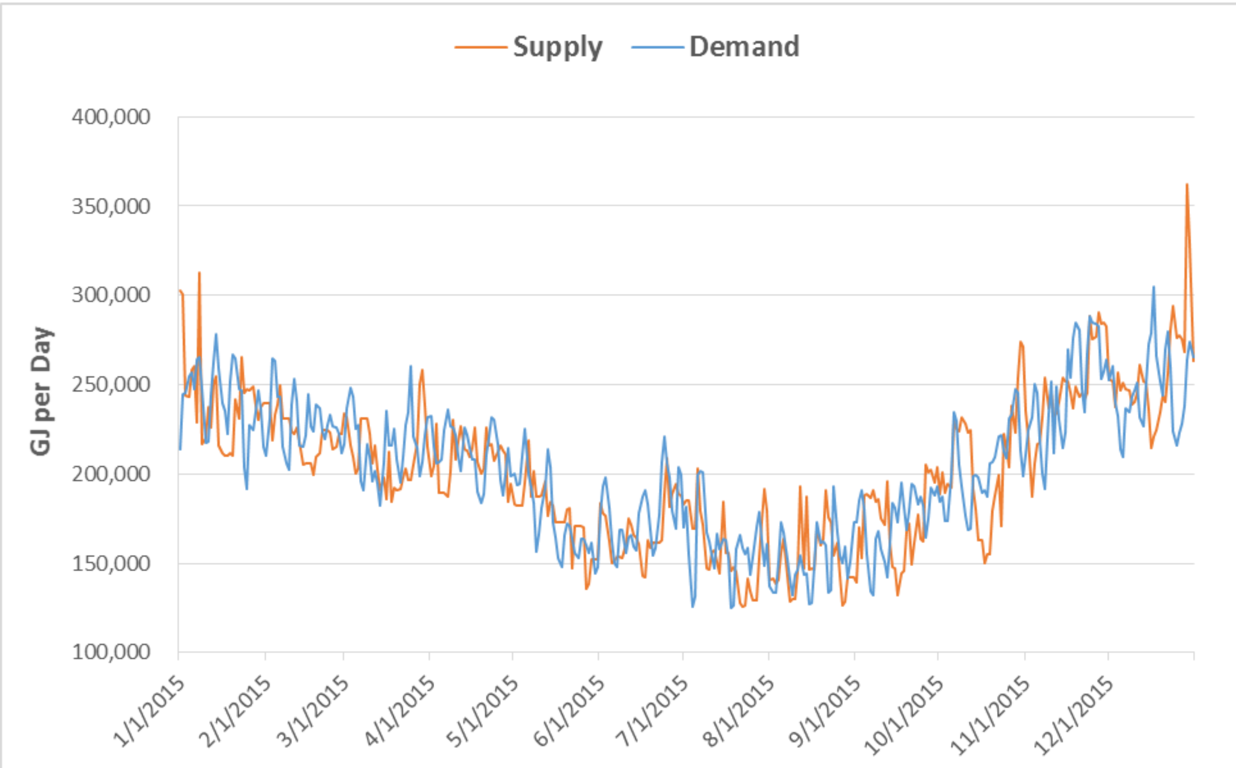
As noted above, customers can be charged a balancing premium charge if imbalance tolerances are exceeded:

- For daily balanced customers, under normal day conditions, the balancing tolerance is 20%. This means that if a customer or marketer delivers less than 20% of the transportation customer's actual consumption, balancing premium charges will apply.
- 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.
- FEI can reduce the balancing tolerance to 5%, which is then applied to both daily and monthly balanced customers. If the 5% tolerance is exceeded, unauthorized over-run charges will apply.

The following Figure 3-1 shows the actual deliveries (or supply) provided by the transportation customers or their marketers relative to the customer demand over 2015. When over deliveries occur (daily supply is greater than daily demand), the excess supply is held in the transportation customer or marketer's account as banked inventory. When under-deliveries occur (daily supply is less than daily demand), customers or marketers draw from the System inventory and may incur charges in doing so.

As seen in Figure 3-1 below, supply can frequently deviate from demand by as much as 50,000 GJ/d. This requires FEI to used midstream resources to withdraw or inject quantities of gas, often on an intraday basis to balance the entire System.

Figure 3-1: 2015 Actual Supply and Demand for Transportation Customers

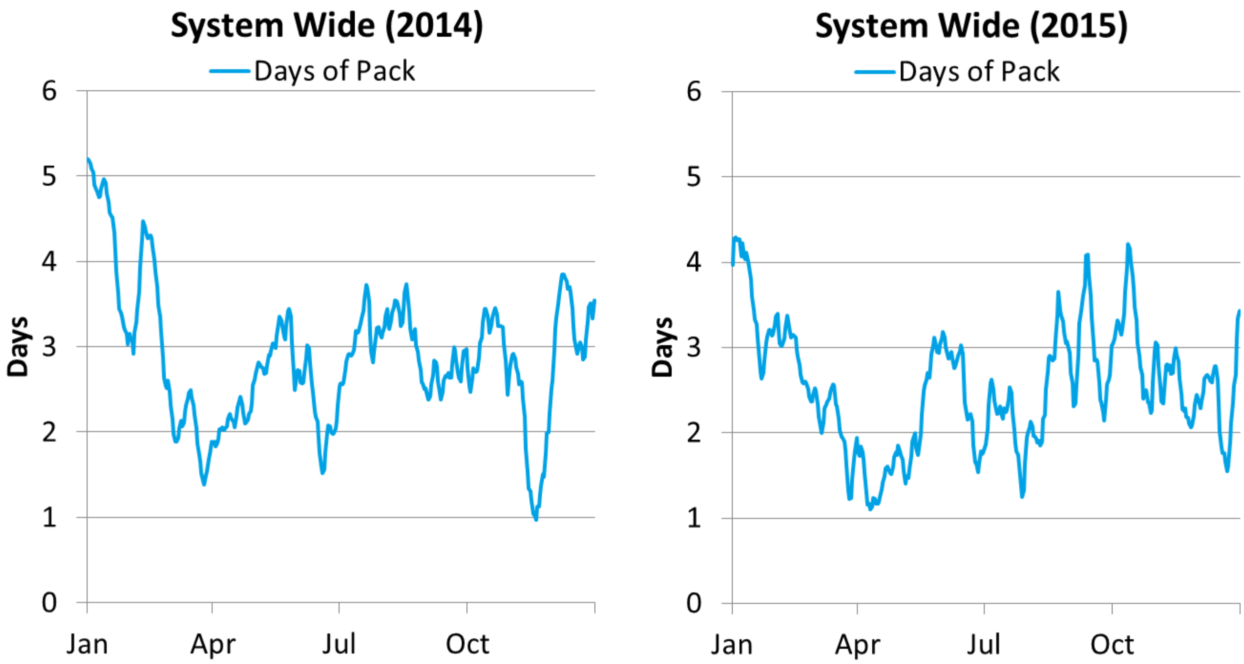


FEI monitors inventories on the System and takes into account both the daily and monthly supply/demand balancing inventory levels combined at a given location. FEI requests that marketers maintain a 2-3 day pack/draft[2] balancing inventory level, which FEI has deemed to be reasonable to manage the System as a whole. The 2-3 days of inventory is based on the average consumption of the daily and monthly balanced customer groups divided by the total inventory held.

[2] On a day when customer demand is greater than the delivered supply, this imbalance results in a "draft" on FEI's System. Conversely, when customer demand is less than the delivered supply, this imbalance results in a "pack" or gas left on FEI's System.

The amount of inventory held on FEI's System can fluctuate on a month-to-month basis. Furthermore, the amount is 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. The graphs below show the variation in the amount of inventory held for the transportation marketers across FEI's entire System during the years 2014 and 2015.

Figure 3-2: Days of Supply Held on Behalf of all Marketers on FEI's System



FEI has developed a good working relationship with the transportation marketers in managing the inventory levels on the System. There are tools within the Transportation Terms and Conditions that allow FEI to assist in managing the inventory positions if necessary. These tools include the ability to limit or reduce inventory, modify the marketer's requested quantities to limit, or adjust their inventory accumulation, and limit or take away marketers' excess inventory and return it at a later date.

4. KEY DISCUSSION TOPICS

FEI believes that the existing transportation model is serving its intended purpose and supports the overall objective of the transportation model, which is to provide customers with options to purchase their gas supply requirements. Marketers have generally adhered to the guidelines of the Transportation Terms and Conditions. FEI has identified some areas of the Transportation Terms and Conditions that should be evaluated for changes which FEI would like to discuss at the workshop.

The following sections review the changes FEI is considering for evaluation in the RDA.

4.1 *MONTHLY VS DAILY BALANCING*

As reviewed in section 3, FEI currently allows customers to be either daily or monthly balanced, with the exception of Rate Schedule 22 customers which must balance daily. The potential charges and balancing tolerances applicable to daily balanced customers provide an incentive to marketers to over-supply daily balanced customers or groups on a daily basis. Conversely as there are no potential charges or balancing tolerances on the day for monthly balanced customers, these customers or their marketers are not given an incentive to balance daily.

Thus, FEI observes that marketers with a daily and monthly balanced group at the same location, such as the Lower Mainland or Interior for example, typically over supply their daily group, and grow a positive inventory through the month to avoid daily charges. They also typically under supply their monthly group, and grow a negative inventory through the month. The marketers then net out or transfer imbalances to avoid imbalance charges at month end.

In today's market, transportation customers or their marketers have access to tools to amend gas requirements on the day to reflect changes in load. Over the past several years, technology improvements such as wireless metering[3] and an increase in gas nomination cycles allow marketers to access and track supply and consumption habits on a tighter scale. This has resulted in greater ability for the gas and pipeline industry to match supply and demand through the use of various technologies, products, and services as compared to when the transportation model was developed.

Given this increased agility, the general industry practice is to require daily balancing. It is industry practice upstream of FEI's System to balance daily and FEI's balancing agreements with third-party pipeline systems require daily balancing downstream[4] as well. The larger Rate Schedule 22 customers on the System are currently required to balance daily. Some marketers hold daily balanced groups exclusively and are able to effectively manage their supply and inventory on the System.

[3] 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.

[4] FEI's OBA to balance daily is discussed further in the following section (4.2).

Given FEI's operational requirement to balance daily, and the capability of transportation customers or their marketers to balance daily as well, FEI would like to discuss eliminating monthly balancing and require all transportation customers or their marketers to balance daily.

4.2 BALANCING TOLERANCE AND VALUE

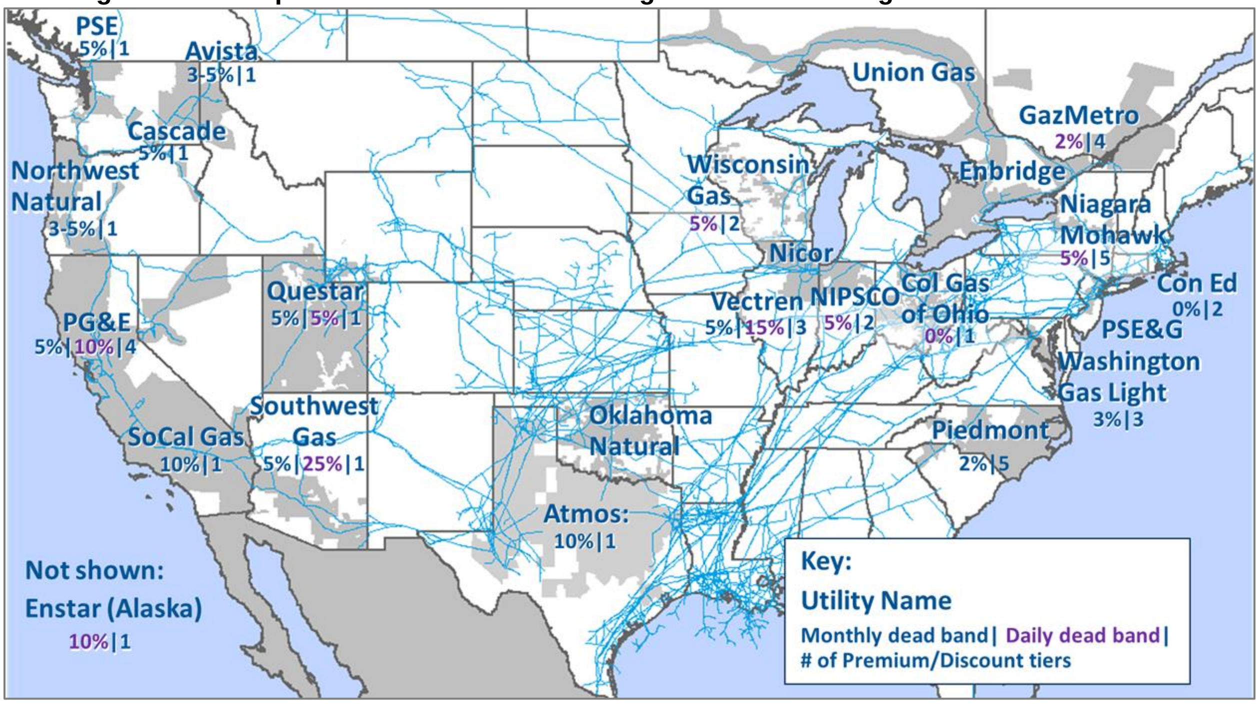
4.2.1 Balancing Provisions: Common Industry Practices

Industry-wide, balancing provisions can differ substantially between local distribution companies (LDCs) based on a given LDC's circumstances. For example, balancing provisions can be relatively stringent for LDCs with service territory adjacent to major natural gas market hubs in order to reduce the possibility for marketers 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 while allowing marketers 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 cashed out 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.

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 see how FEI's balancing provisions compare relative to its peers. 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 below, many LDCs across the U.S. and Canada set balancing thresholds at approximately 5%, a level that applies to both monthly and daily balanced transportation service customers. Thresholds rarely exceed 10%, and sometimes are as low as 0%. All things considered, the analysis shows that FEI's current balancing provisions are substantially more accommodating than its North American LDC peers.

Figure 4-1: Comparison of Selected Balancing Provisions among North American LDCs



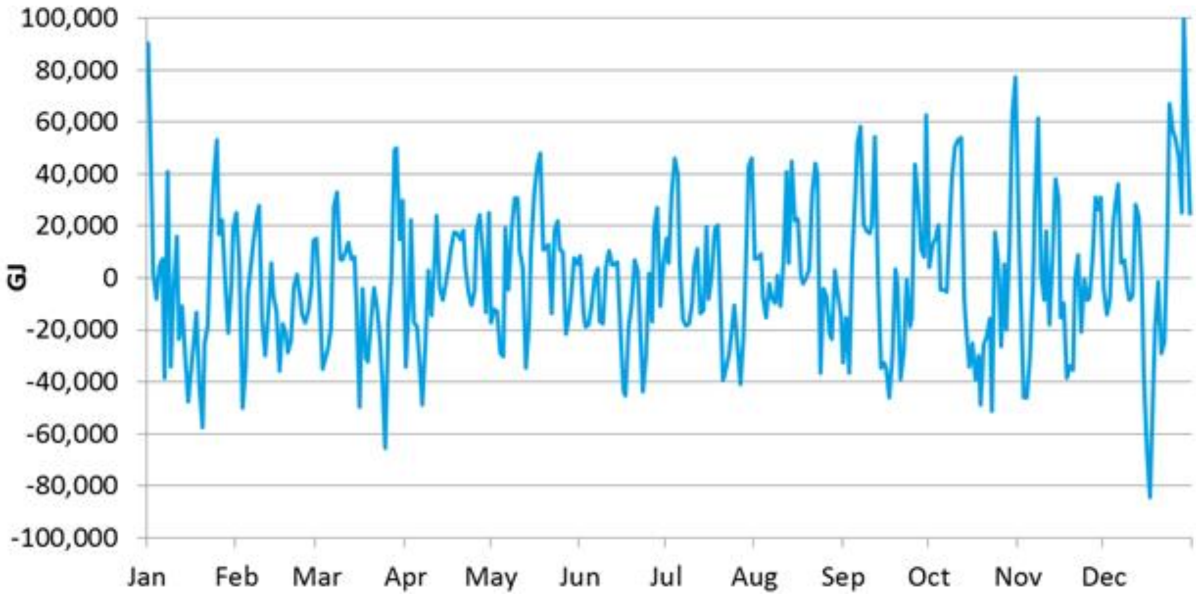
LDCs with monthly and daily dead-bands typically apply both dead-bands to all transport customers.
Enbridge offers services utilizing storage to shift imbalances between customers but does not mention dead-bands in its tariff
Nicor charges a flat per-Dth fee for balancing services in its tariff, but makes no mention of dead-bands
PSE&G charges a balancing fee based on the differential between average winter and average summer throughput differential
No specific balancing provisions were listed in the tariff for Oklahoma Natural and Union Gas

4.2.2 Issues Related to Current Balancing Provisions

Under current balancing provisions and tolerance limits, FEI's System is subject to large fluctuations in gas demand from transportation customers or their marketers that is often not offset by matching gas supply deliveries from marketers. Even after adjusting for monthly true-up transactions (i.e. when a marketer 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's threshold under the Operational Balancing Agreement (OBA) with Spectra requires daily balancing. Imbalances that exceed the threshold at each interconnect point require the utilization of resources on FEI's System, typically by injecting excess gas into storage or withdrawing gas from storage in order to meet the marketers' delivery imbalance swings.

The following chart shows the extent to which the aggregate imbalances vary or fluctuate daily on FEI's System (including transportation customers) throughout the 2015 year.

Figure 4-2: Aggregate Adjusted Imbalance (2015)



These fluctuations occur in part due to the ability for monthly balanced marketers to under-supply FEI's System daily, and also due to the flexible 20% balancing threshold FEI currently allows.

Addressing these frequent fluctuations requires FEI to utilize 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. Therefore, under the current Transportation Terms and Conditions, sales customers are paying for some of the services that are also used by transportation customers or their marketers, which could create a mismatch between services received and services paid for between two major customer groups.

4.2.3 Value of Balancing Services Provided by FEI

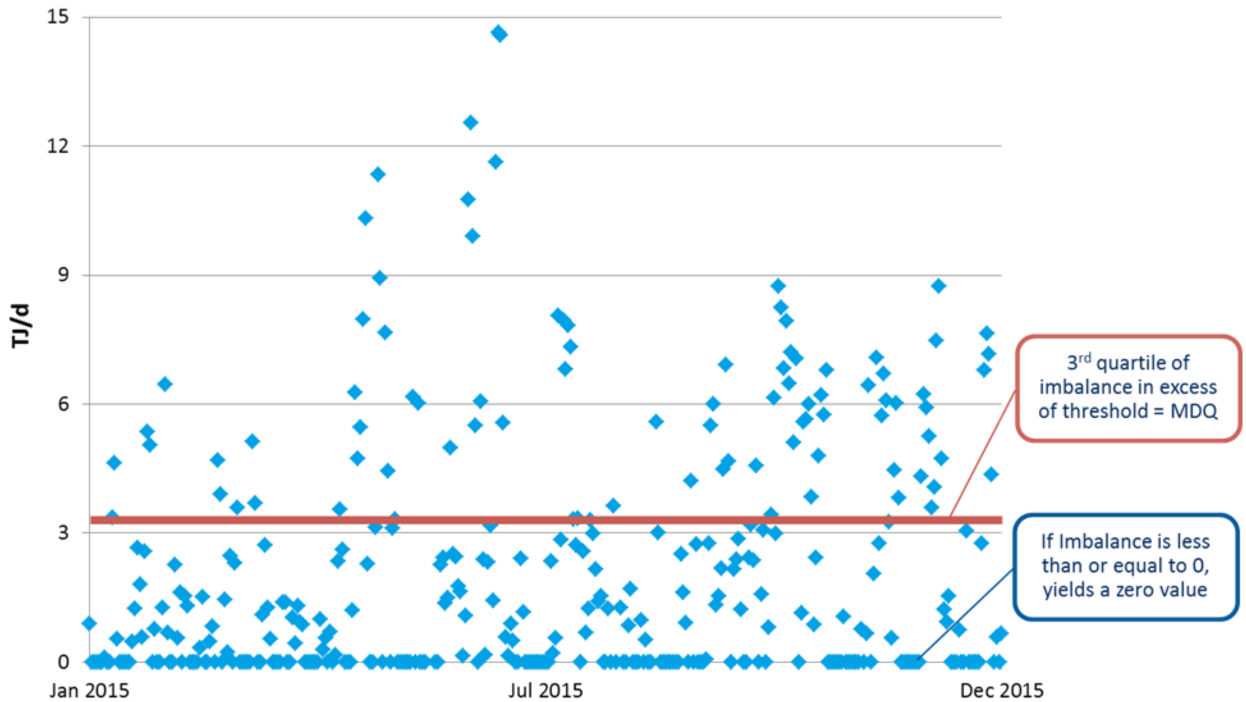
The balancing provisions and tolerance threshold currently set in FEI's Transportation Terms and Conditions provide a great deal of flexibility to transportation customers or their marketers that provide their gas supplies. To provide this level of service, FEI utilizes resources (storage and transportation capacity) that are designed to deliver relatively constant quantities of gas on a day-to-day basis. Since the underlying costs of these resources are recovered from FEI's sales customers, it is reasonable for transportation customers or their marketers to contribute to the recovery of the costs of the resources that provide the related balancing services.

A methodology was developed to calculate the estimated replacement cost of the balancing services provided by FEI. As described in detail below, the calculation shows that the balancing service that FEI provides has significant value in the market.

Using 2015 data as an indicative year, the replacement cost analysis used marketers' daily deliveries (aggregated across all the accounts of each marketer) and adjusted imbalances data (imbalances were adjusted for end-of-month inventory adjustments and allowed imbalance return quantities). The absolute value of the daily imbalance was used, as the analysis needed to show costs associated with both positive and negative imbalances, since both lead to the utilization of the System resources (to inject or withdraw gas, for example). The daily delivered volume was multiplied by an assumed balancing threshold ranging from 5% to 20%, in 5% increments (replicating different balancing threshold levels that FEI could hypothetically set). The difference between these two adjusted figures was determined for each day of 2015. If the difference was negative, it was changed to zero, thereby eliminating any negative values. This amount is referred to as the "volumes in excess of the threshold".

A marketer looking at its projected imbalance volumes in excess of the threshold would likely want to balance its own risk tolerance with cost minimization when deciding what level of contracted firm storage and related pipeline capacity is necessary in order to meet its balancing needs for a given year. Contracting for sufficient firm capacity to meet its highest projected level of daily imbalance would entail over-contracting for capacity on every other day of the year. On the other hand, contracting for lower levels of capacity would leave a marketer subject to potentially expensive imbalance charges or other mitigation measures on a daily basis. To find a balance between these two objectives, the 3rd quartile of the "volumes in excess of the threshold" dataset was assessed in order to arrive at an estimate of the firmly contracted MDQ (the firm transportation quantity delivered during a month), that a marketer might purchase in order to meet its balancing needs. The 3rd quartile represents an MDQ level that could support the balancing required for the volumes in excess of the threshold for 75% of the days in 2015. This assumption is not based on any empirical market observations but provides a reasonable balance between a Marketer paying demand charges or incurring potential imbalance charges. As a sensitivity check, the median of the "volumes in excess of the threshold" was calculated and the results seemed to leave Marketers overly exposed to daily imbalance swings. The chart below shows an example of the "volumes in excess of the threshold" plotted against the 3rd quartile of the data for an indicative marketer.

Figure 4-3: Daily Imbalance Quantity in Excess of 20% Threshold (2015)



From this point, various metrics were calculated to arrive at estimates of how much volume for the year was in excess of the threshold, how much of this volume would be subject to commodity charges on the upstream pipelines, and how much volume would be subject to FEI's applicable imbalance charges. To calculate the annual charges paid by each marketer, these metrics were multiplied by an assumed average portfolio reservation rate or a commodity rate, as applicable. The assumed portfolio consisted of maximum tariff rates for firm transportation service on Northwest Pipeline as well as firm storage service at the Jackson Prairie and Mist storage facilities.

FEI imbalance charges were excluded in the base case version of this analysis in order to reflect the marketers' ability to avoid these charges with mitigation measures and to arrive at a more conservative estimate of balancing costs. A sensitivity case was created to test the impact of including the cost of imbalance charges on FEI's System.

The aggregate total of all marketers' annual balancing costs (consisting of reservation and commodity charges in the base case) was divided by the total transportation throughput on the System (72,381,734 GJ for 2015) to arrive at the average cost of securing balancing resources per GJ under various threshold cases (5-20%). The results are shown below in Table 4-1.

Table 4-1: Average Cost of Securing Balancing Resources (Base Case)

	Total Charges	$/GJ
5%	$15,073,449	$0.21
10%	$11,584,340	$0.16
15%	$8,564,864	$0.12
20%	$6,456,223	$0.09

From this point, one last calculation was made to arrive at the replacement cost of balancing services. As discussed in Section 4.2.1, while balancing thresholds differ widely across LDCs, a 5% threshold is a fairly common "median" threshold often seen across the industry. The analysis measured the incremental value provided by FEI in setting a more flexible 20% threshold by taking the difference between the average cost of securing balancing resources per GJ for the 10%, 15%, and 20% threshold cases and the same metric for the 5% threshold case. The results are shown below in Table 4-2.

Table 4-2: 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 base case analysis shows the current threshold provided by FEI provides $0.119/GJ of value to marketers, as measured by the replacement cost of each marketer securing the service elsewhere. Furthermore, the value of balancing services provided by FEI decreases with more stringent balancing tolerances. The table 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 or their marketers; a more flexible threshold is associated with higher costs.

From the base case analysis, a few sensitivity cases were run whereby certain assumptions were varied to determine the impact on the implied value of balancing services. Each sensitivity case was run in isolation, meaning that only a single assumption was changed in each sensitivity case.

The first sensitivity case examined estimated the impact of excluding the effect of imbalance returns from the "adjusted imbalance" dataset. Given that FEI utilizes the System resources to store the gas held in the marketers' inventory accounts on a daily basis, the sensitivity case was useful in calculating the value of the imbalance return service. The results shown in Table 4-3 that the imbalance return service has an indicative value of about $0.015/GJ for the 20% case, though the value diminishes in the more stringent threshold cases.

Table 4-3: Imbalance Return Case Results

	Total Replacement Costs	$/GJ	Differential from Base Case*
10%	$3,541,598	$0.049	$0.001
15%	$6,821,694	$0.094	$0.004
20%	$9,699,556	$0.134	$0.015

* Comparable Base Case results are found in Table 4-2

As mentioned previously, the effect of including imbalance charges for imbalance volumes that exceed the FEI threshold even after accounting for a marketer's newly contracted capacity was examined. The results show that total charges increase drastically as marketers are subject to fees or imbalance charges due to frequent imbalances exceeding the threshold. However, the imbalance charges have a muted impact on the replacement cost of balancing services since these charges were paid in substantial amounts in all threshold cases. Note that Table 4-4 below includes total charges incurred by all marketers in the first two columns, and then presents the replacement cost figures in the last three columns.

Table 4-4: Imbalance Charges Case Results

	Total Charges	Total Charges $/GJ	Total Replacement Costs	Replacement Costs $/GJ	Differential from Base Case*
5%	$26,167,190	$0.36	N/A	N/A	N/A
10%	$22,847,821	$0.32	$3,319,369	$0.046	($0.002)
15%	$19,720,060	$0.27	$6,447,129	$0.089	($0.001)
20%	$16,908,427	$0.23	$9,258,763	$0.128	$0.009

* Comparable Base Case results are found in Table 4-2

FEI assessed the value of the balancing services it provides on an absolute basis, without taking into account the benchmark 5% threshold. For this sensitivity, a 0% threshold case was used to calculate the cost to procure resources to deal with a hypothetical 0% tolerance threshold. The results are shown below in Table 4-5.

Table 4-5: 0% Threshold Case Results

	Total Charges	Total Charges $/GJ	Total Replacement Costs	Replacement Costs $/GJ	Differential from Base Case*
0%	$18,565,867	$0.26	N/A	N/A	N/A
5%	$15,073,449	$0.21	$3,492,418	$0.048	$0.048
10%	$11,584,340	$0.16	$6,981,527	$0.096	$0.048
15%	$8,564,864	$0.12	$10,001,003	$0.138	$0.048
20%	$6,456,223	$0.09	$12,109,644	$0.167	$0.048

* Comparable Base Case results are found in Table 4-2

Taken as a whole, the replacement cost of balancing services analysis shows that the balancing service FEI provides has significant value in the market. 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 ranges from $0.119/GJ (Table 4-2) to $0.167/GJ (Table 4-5).

4.2.4 Balancing Tolerance and Value Summary

FEI believes that it should continue to balance the System as a whole as this approach provides value for both sales customers and transportation customers or their marketers, and manages the System in a cost effective manner and reduces risk for all customers.

As described in sections above, FEI has reviewed common industry practises with respect to balancing provisions and tolerances. FEI has also listed some of the issues with the current balancing provisions and tolerances and looked at the value for the balancing service that FEI currently provides to its transportation customers or their marketers for various balancing tolerance levels.

As a starting point, FEI would like to discuss how FEI's balancing services and the value associated with those services could evolve as part of the rate design application process.

FEI would like to consider input from stakeholders on the following:

1. What should the balancing tolerance be: 20%, 15%, 10% or 5%?
2. As discussed in section 4.2.3, different balancing tolerance levels derive different balancing charges ($/GJ) for transportation customers or their marketers. What are the appropriate balancing charges for different balancing tolerance levels?
3. How should FEI account for the balancing charges provided to transportation customers?
    - Capture the value of the balancing service in the revenue to cost ratio for transportation customers.
    - Derive a Midstream fee for transportation customers.

4.3 *THIRD-PARTY SERVICE OFFERING*

Another area that FEI has identified as a key discussion topic is related to the Third-Party service offering. The background of this is provided below.

On September 24, 2014, FEI filed a request[5] to amend the 2014/15 ACP that was accepted by the Commission in Letter L-53-14, dated October 2, 2014. The amendment involved the need to contract for an additional Spectra T-South transportation capacity for Rate Schedule 46 – Liquefied Natural Gas Sales, Dispensing and Transportation Service (Rate Schedule 46), and potential industrial transportation customers seeking to return to bundled service. This capacity was secured earlier than it would normally be contracted for because the prospect of new

[5] Request for Approval is included as an attachment to this Discussion Guide – Appendix A.

incremental industrial load in the region could result in capacity being unavailable for Rate Schedule 46 and industrial transportation customers.

On May 2, 2016, FEI filed on a confidential basis its 2016/17 ACP with the Commission. In the 2016/17 ACP, FEI discussed allocating a portion of the additional Spectra T-South Long-Haul transportation capacity that FEI has contracted for FEI's transportation service customers currently under the transportation service model for the 2016/17 gas year. The allocation will be on a temporary basis to marketers that currently have customers under FEI's transportation service model and are interested in obtaining capacity to serve those customers. On May 30, FEI issued a letter to the marketers to respond with a list of their customers interested in this offering and requested capacity. FEI is currently working with the marketers to have contracts in place by November 1, 2016. FEI proposes to allocate a portion of the additional Spectra T-South Long-Haul transportation capacity prior to the implementation of the approved RDA. Currently FEI is awaiting Commission approval of the ACP, including approval to offer the T-South Long-Haul service prior to the conclusion of the RDA for implementation in January 2018.

The Spectra T-South Long-Haul transportation capacity could be managed and administered in Energy Supply under the existing Rate Schedule 30.[6] or this capacity could be included and prescribed specifically in the Transportation Rate Schedules. FEI would like to review these options and is open to alternate suggestions.

[6] Rate Schedule 30 – Off-System Sales and Purchases Rate Schedule and Agreement (Canada and U.S.A.).

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~~CONFIDENTIAL~~

September 24, 2014

Via Email
Original via Mail

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI or the Company)

Amendment to the 2014/2015 Annual Contracting Plan (2014/15 ACP)

~~CONFIDENTIAL~~

On May 1, 2014, FEI filed, on a confidential basis, its 2014/15 Annual Contracting Plan. The Commission accepted the 2014/15 ACP on July 17, 2014.

Due to recent changes in market conditions affecting the future level of firm transportation contracting on the Spectra T-South system, FEI requests approval to amend the 2014/15 ACP in order to secure additional firm T-South transportation capacity for Rate Schedule 46 and industrial transportation customers seeking to return to bundled service.

Changing market conditions are occurring in response to a number of new industrial projects wanting to secure T-South transportation capacity on the Spectra system. In response to this change, Spectra is considering introducing a new service that would allow shippers to secure T-South capacity in the future. This new service will facilitate the orderly marketing of existing uncontracted T-South Huntingdon capacity and provide prospective markets with greater certainty that pipeline capacity will be available for future needs. This new service would provide shippers with another means of securing capacity for future use, in addition to the Bid Week process (13 month service) that is currently available.

It is expected that this new service from Spectra will require parties to make a commitment for a minimum of 10 years to secure T-South capacity and will provide the option to defer the commencement date of the first flow for a period of up to a maximum of 48 months. This commitment level is considerably greater than the two year renewable service that is currently available to parties under the 13 month Bid Week process. This new service should be of interest to shippers who need to secure firm transportation capacity to support industrial projects that will bring significant incremental loads to the region. However, committing to a 10 year contract may be difficult for some industrial customers currently participating in the FEI transportation model given the need to demonstrate credit worthiness that is required to secure firm transportation capacity.

Request for Acceptance

FEI seeks Commission approval to secure an additional 75 TJ/d of firm Spectra T-South transportation capacity for the winter of 2015/16 for Rate Schedule 46 and industrial customers. This new capacity would be secured either entirely during the next Bid Week or in stages over future Bid Weeks depending on developments affecting current market conditions. The next opportunity to bid for firm capacity on T-South is during the Bid Week that commences on October 1, 2014 and ends on October 7, 2014. Following this Bid Week in October, future Bid Weeks start on the first Wednesday of each month.

The total biddable capacity is adjusted for each Bid Week to reflect the amount of non-firm capacity remaining after accounting for firm capacity commitments. The advantage of securing firm capacity during these periods is that it will not start for 13 months. For example, for firm capacity secured during the October 2014 Bid Week, capacity will start to flow on November 1, 2015. Thus, there are no costs until the service starts. Although the service only has a two year commitment in order to secure renewal rights, FEI would secure this capacity for a minimum five year term in order to receive the maximum discount available at this time.

FEI requests an expeditious review of this request and requires a Decision no later than Friday, October 3, 2014. This timing is critical because it would allow FEI to participate in the next Bid Week before it closes (October 7, 2014).

Reasons for the Request

Earlier this month Spectra proposed a new service that involves offering shippers the ability to lock-in existing non-firm T-South Huntingdon capacity for the long term and well before the service commencement date. The offering of this service is driven by new demand from projects either announced or being considered in the Lower Mainland and US PNW that will require pipeline capacity as early as 2016/17.

A significant volume serving industrial customers in the Lower Mainland flows on an interruptible basis today. Any major decrease in the future availability of transportation capacity risks leaving these customers without adequate gas supply or they will need to pay significantly higher commodity prices at Huntingdon before any infrastructure expansions can be completed[1]. Given that these industrial customers may not generally have sufficient credit to secure long term firm transportation capacity, and have not made a commitment to

[1] This industrial load includes Rate Schedule 22, 23, 25, and 27 customers.

hold transportation capacity in the past, FEI faces the potential that these industrial customers will seek to return to it for bundled service. Importantly, this industrial load competes for T-South transportation capacity with industrial load located in the US PNW, which underscores the urgency in being in a position to be able to secure capacity soon.

The availability of sufficient T-South transportation capacity could also affect Rate Schedule 46 customers given the timing of when incremental supply is needed to serve them. The market change driven by Spectra's new service offering requires additional transportation capacity for these customers to be contracted for now rather than waiting. Rate Schedule 46 customers are forecast to require approximately 4 TJ/d by November 2015 and 9 TJ/d by November 2016. This volume is expected to increase as more customers enter into agreements for Rate Schedule 46 service. To serve this new demand, requires FEI to secure the equivalent transportation capacity to match the 35 TJ liquefaction capacity that is being constructed at Tilbury to serve this market.

It is for these reasons that FEI believes it is appropriate to secure new T-South capacity now for these two markets.

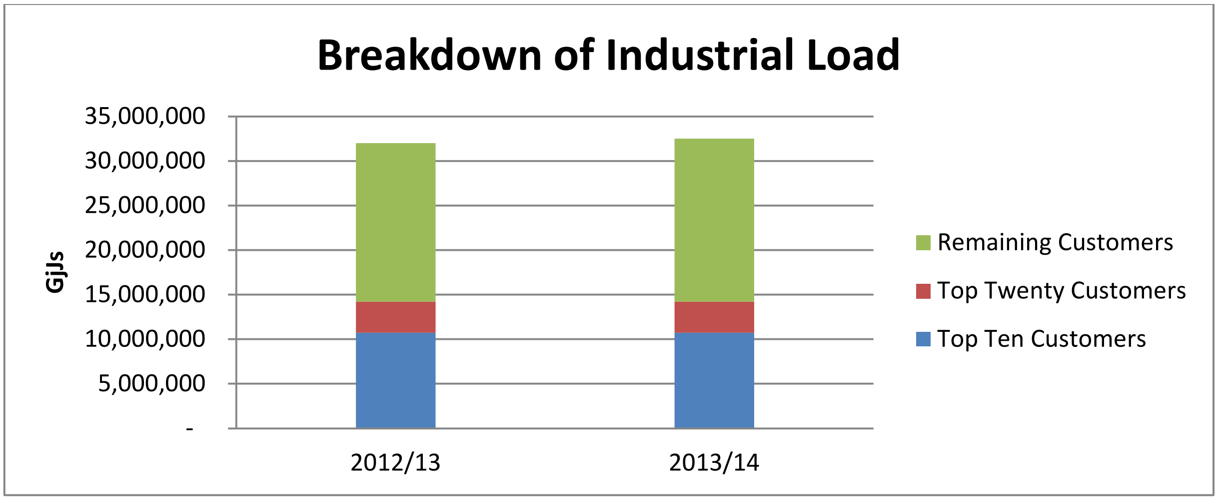
Analysis

The industrial demand under consideration is for Rate Schedule 22, 23, 25 and 27 customers located in the Lower Mainland only. Large industrial customers on Vancouver Island, like the Joint Venture and BC Hydro, are assumed to be directly involved in evaluating Spectra's new service offering and in a position to adequately respond to the pending market change. As a result, FEI has not included their volumes in its analysis.

Interior industrial customers on the FEI system are not at risk because alternatives are in place to serve their loads. Additionally, the competition for T-South Long Haul should not impact their ability to secure additional T-South Interior capacity should they chose to do so.

A review of actual consumption of Rate Schedule 22, 23, 25 and 27 customers located in the Lower Mainland over the last two years indicates that peak demand day occurred on February 5, 2014 when it reached 160 TJ. Although peak demand day reached 160 TJ, FEI does not believe is it necessary to pick up additional firm transportation capacity to match this full amount.

As shown in the following graph, the top 10 Lower Mainland industrial customers consume approximately 11 PJ annually or 30 TJ/d, which accounts for 33 percent of the total load. The combined top 20 industrial customers account for approximately 15 PJ or 40 TJ/d, which accounts for 44 percent of the total load. Given their size, FEI assumes that it is likely that these customers will be proactive in ensuring they have supply secured so that the entire load represented by these customers will not need to be served by FEI. Although these large volume customers are expected to adequately respond to this issue, FEI still faces the possibility that a lack of sufficient credit worthiness by some of these customers will result in them seeking to return to bundled service.



After adjusting the recent peak day demand of 160 TJ for load from larger customers, indicates that a portion of approximately 120 TJ would most likely need to be served. Given the uncertainty in estimating how many industrial customers may elect to return to bundled service, FEI believes it is reasonable to secure firm transportation capacity only for approximately one-third of this industrial demand, or 40 TJ/d, combined with the 35 TJ liquefaction capacity for Rate Schedule 46 service. Combined, these two requirements total 75 TJ/d and would be contracted for on a firm basis for a minimum five year term.

FEI will continue to monitor this situation, and as pointed out earlier, this new capacity would be secured either entirely during the next Bid Week or in stages over future Bid Weeks depending on developments affecting current market conditions. Furthermore, depending on how the market unfolds, FEI may need to secure still further T-South capacity in the future to serve this industrial demand. For now the request for additional T-South capacity is limited and would only serve a portion of the load if all of these customers return to a bundled service from FEI.

Incremental Costs

The following table sets out the total cost and the estimated mitigation value of the 75 TJ/d in incremental T-South transportation.

Cost Analysis for Additional Volume on T-South (Future Increase in T-South Capacity)			
\$0.36/GJ *(Spectra Toll)*	75,000 GJ/d *(Incremental Volume)*	365 *(Days)*	\$9.86 million (Approx. before mitigation)
\$0.36/GJ *(Winter Mitigation)*	75,000 GJ/d *(Incremental Volume)*	151 *(Days)*	\$4.08 million
Net Incremental Cost			\$5.78 million

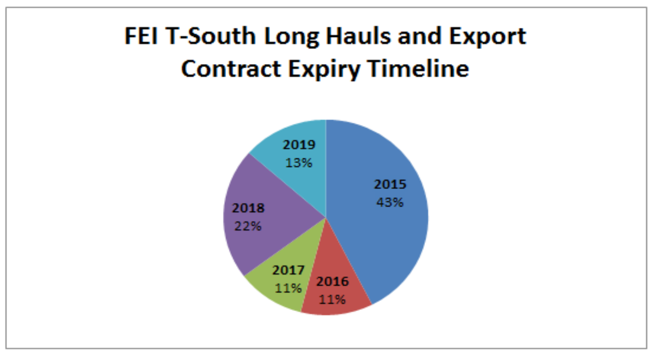
The addition of 75 TJ/d of incremental T-South transportation capacity will result in a total cost of approximately $10 million. FEI expects that T-South will continue to hold value in the winter time so it is reasonable to expect full recovery of the demand charge in the winter period. FEI has not assumed any summer mitigation value, even though some value was realized over the last few summers. Net of the recovery during the winter, the incremental cost of the entire 75 TJ/d in T-South transportation capacity is estimated to be approximately $6 million. The impact of the incremental volume to midstream costs, considering an estimated total volume of 126 PJ, would be approximately 5 cents /GJ.

Additional Capacity Mitigation Options

Should market developments proceed at a pace that do not result in a significant increase in additional firm transportation capacity being contracted, then FEI is able to defer entering into firm contracts and defer this for one or more Bid Weeks. This delay would result in avoiding the payment of firm transportation tolls for one or more months after November 2015.

Alternatively, should industrial customers not return to FEI in sufficient numbers to use the full 75 TJ/d in transportation capacity, FEI's contract portfolio offers the flexibility to either allow existing contracts to roll off, or decrease the contracted amounts once they are up for renewal. The table below shows the existing profile of T-South Long-Haul and Export Contracts, and when they would be renewed.

FEI T-South Contract Expiry Timeline			
Year	10^3M^3	GJ	%
2015	4,126.40	157,835	43%
2016	1,108.70	42,408	11%
2017	1,045.10	39,975	11%
2018	2,109.40	80,685	22%
2019	1,310.10	50,111	14%
Total	9,699.70	371,014	100%



Summary

With the recent changes occurring in the market for firm transportation capacity on T-South, FEI recommends acting proactively by contracting for an additional 75 TJ/d of capacity on T-South for a minimum five year term. Contracting for this capacity may occur as early as during the next Bid Week that is planned to start on October 1, 2014, with the actual contracted volume to be determined by FEI based on evolving market circumstances faced when the Bid Weeks take place. FEI has flexibility in its contracting portfolio to manage this additional transportation capacity by using it to replace expiring future contracts if sufficient demand does not materialize for all of this capacity.

This approach to securing additional firm transportation capacity is appropriate given the changing market conditions faced at this time.

CONFIDENTIALITY

Consistent with past practice, previous discussions and positions on the confidentiality of selected filings (and further emphasized in FEI's January 31, 1994 submission to the Commission), FEI is requesting that this information be filed on a confidential basis pursuant to Section 71(5) of the Utilities Commission Act and requests that the Commission exercise its discretion under Section 6.0 of the Rules for Natural Gas Energy Supply Contracts and allow these documents to remain confidential. FEI believes this will ensure that market sensitive information is protected, and the ability of FEI to obtain favourable commercial terms for future natural gas contracting is not impaired.

FEI further believes that the Core Market could be disadvantaged and may well shoulder incremental costs if utility gas supply procurement strategies as well as contracts are treated in a different manner than those of other gas purchasers, and believes that since it continues to operate within a competitive environment, there is no necessity for public disclosure and risk prejudice or influence in the negotiations or renegotiation of subsequent contracts.

If you require further information or have any questions regarding this submission, please contact Hans Mertins at (604) 592-7856.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

FortisBC Energy Inc.

2016 Rate Design Application

Workshop 3: Rate Design and Segmentation

Discussion Guide

August 19, 2016

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1. INTRODUCTION

Starting in the spring of 2016, FortisBC Energy Inc. (FEI or the Company) is holding a series of workshops for the purpose of working towards an efficient and cost effective regulatory process once the 2016 FEI Rate Design Application (Application or RDA) is filed later this year.

The key objectives of the Rate Design and Segmentation workshop are to inform stakeholders regarding the rate design options that FEI is considering for the RDA and to engage them in compiling a key issues list, which will then be utilized to focus the scope of the RDA. FEI has prepared this discussion guide that summarizes cost of service allocation (COSA) results after rebalancing, rate design and segmentation considerations for residential, commercial and industrial customer groups. In addition, the last section of the discussion guide lists key discussion topics to help focus the discussion during the workshop. These rate design considerations and key discussion topics reflect FEI's current plan for the 2016 RDA, FEI will consider the input of stakeholders prior to the filing to the Application.

FEI is circulating this discussion guide in advance of the workshop so that all stakeholders can review the material and prepare to participate effectively at the workshop and to contribute to the development of the key issues list. While FEI does not expect that all parties will be in agreement on all the key issues, and that some may well have to be settled through the regulatory process, it will be beneficial for everyone involved in the process to hear and understand the position of various parties as FEI moves toward filing the RDA in the fall of 2016.

2. RATE DESIGN PRINCIPLES

2.1 RATE DESIGN PRINCIPLES

FEI applies rate design principles based on those identified by Dr. Bonbright in his widely accepted work, "*Principles of Public Utility Rates.*"[1]

The principles adopted by FEI for rate design, 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; and
- Principle 8: Avoidance of undue discrimination (interclass equity must be enhanced and maintained).

In addition to these rate design principles, FEI takes into account other rate design considerations such as provincial government energy policy objectives. FEI believes that Customer rates should be set at levels that consider competitiveness of natural gas with other fuel alternatives.

FEI continues to follow these rate design principles, which are widely accepted throughout the utility industry for setting rates and have been considered by FEI for many years in its past rate design proceedings. No single rate design can perfectly satisfy all of the rate design principles simultaneously as some principles may contradict with others. Furthermore, different rate design principles may have varying level of importance for different rate classes. Rate design should strive to strike a balance among competing rate design principles based on specific characteristics of customers in each rate schedule.

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

3. CUSTOMER SEGMENTATION

This section describes the existing customer segmentation that FEI has in place to provide natural gas service to its customers.

FEI's customers are segmented based on their load characteristics, which includes their average annual energy consumption, load factor (i.e. how much they consume on average as compared to their peak demand) and in some cases, rate schedules are specific to their end use.

3.1 *EXISTING CUSTOMER SEGMENTATION*

For ease of understanding, FEI has separated its customers into general categories depending upon the customer's type of premise: Residential, Commercial, Industrial and Other. These categories include different types of customers which are segmented according to their load characteristics. Table 3-1 below provides a list of rate schedules that FEI has currently in place representing the customer segmentation under each of these general categories.

FEI has reviewed the load characteristics of its customers and believes that the existing customer segmentation continues to reflect the appropriate load characteristics of its customers. However, FEI has identified some areas of the existing customer rate design that should be evaluated for changes which FEI would like to discuss at the workshop. The following sections review the changes FEI is considering for evaluation in the RDA.

Table 3-1: FEI Existing Customer Segmentation and Their Load Characteristics

Customer Group	FEI Tariff Rate Schedule	Description and Example Customers	Typical Load Characteristics LF[1]	Typical Load Characteristics UPC (GJ)[2]	Number of Customers[3]
RESIDENTIAL	**Rate Schedule 1/1U/1B**	• Residential firm service for use in residential applications - central space heating, water heating, cooking, fireplaces and clothes dryers. • ***Applicable to residential customers only***	32.6%	82	886,652
COMMERCIAL	**Rate Schedule 2/2U/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, apartment buildings**	30.7%	331	84,737
	Rate Schedule 3/3U/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, rec centres, care homes**	36.8%	3,595	5,040
	Rate Schedule 23	• Annual use > 2,000 GJ. • Large commercial firm transportation service.	36.7%	5,374	1,669
INDUSTRIAL	**Rate Schedule 4**	• Seasonal firm service for customers who typically consume gas during off-peak (April to October) periods. • **Example customers: greenhouses and paving companies**	N/A	7,217	18
	Rate Schedule 5	• General firm service with an applicable monthly demand charge per month per GJ of daily demand. • **Example customers: pulp, paper, and lumber operations, manufacturers, apartment buildings**	44.8%	9,447	230
	Rate Schedule 25	• General firm transportation service with an applicable monthly demand charge per month per GJ of daily demand.	55.5%	23,834	566
	Rate Schedule 6	• Natural gas vehicle service (resale for natural gas vehicles). • **Example customers: public fueling stations**	100.0%	3,120	15
	Rate Schedule 7	• General interruptible service. • **Example customers: manufacturers, greenhouses, service industry customers**	N/A	30,920	5
	Rate Schedule 27	• General interruptible transportation service.	N/A	60,525	108
	Rate Schedule 22	• Large volume transportation service with a minimum "take or pay" of 12,000 GJ per month. • **Example customers: greenhouses, educational institutions, cement plants**	N/A	677,554	26
	Rate Schedule 22A *(Closed)*	• Large volume firm and interruptible transportation service for select customers (closed rate schedule). • **Example customers: pulp, paper and lumber operations**	115.2%	N/A	9
	Rate Schedule 22B *(Closed)*	• Large volume firm and interruptible transportation service for select customers (closed rate schedule).Large volume transportation service. • **Example customers: mining and lumber operations**	136.0%	N/A	5
	Rate Schedule 50	• Large volume firm and interruptible transportation service.	100%	NIL	NIL
OTHER	**Rate Schedule 6P**	• Natural gas vehicle refueling service at Surrey Operations. • **Example customers: public customers with natural gas vehicles**	N/A	N/A	N/A
	Rate Schedule 46	• LNG sales, dispensing, and transportation service. • **Example customers: waste hauling companies**	100.0%	51,438	13

1 ***Load Factors*** *are as in the RDA COSA Model.*
2 ***Use per Customer*** *in gigajoules (GJ) is as set out in the FEI Annual Review for 2016 Rates Order G-193-15 Compliance Filing, Section 11, Schedule 19, column 10 divided by column 9.*
3. ***Number of Customers*** *per Rate Schedule is as set out in the FEI Annual Review for 2016 Rates Order G-193-15 Compliance Filing, Section 11, Schedule 19, column 10.*

4. COSA RESULTS

4.1 CURRENT COSA RESULTS

FEI has calculated cost of service allocations using the approved costs from FEI's Annual Review for 2016 Rates (Order G-193-15) in the COSA model, and then included known and measurable changes for major projects expected to be in-service or close to their in-service dates at the time that rate changes from this rate design are put in place. The resulting revenue to cost ratios are shown in the following Table 4-1.

In Table 4-1, FEI has included both the current revenue to cost and margin to cost ratios before rebalancing, and also after rebalancing to the 90-110% range for discussion purposes only. To achieve this, in the following table, FEI has rebalanced Rate Schedule 6 and Rate Schedule 22A to 110% revenue to cost ratio and, for discussion purposes, has shifted the resulting revenue deficiency of approximately $3.6 million to Rate Schedule 1. FEI applied the deficiency to Rate Schedule 1 because it has the lowest revenue to cost ratio of all other rate schedules.

As mentioned above, FEI regards these rebalanced revenue to cost ratios for discussion only. There are other considerations that FEI will take into account, which will impact the revenue to cost ratio proposals and rebalancing approach for the RDA.

Table 4-1: COSA R:C & M:C Ratios, Rebalancing and Bill Change Results[2]

Rate Schedule	Current R:C %	Current M:C %	Rebalanced R:C %	Rebalanced M:C %	Rebalance Amount	Approximate Annual Bill Change
Rate Schedule 1 *Residential Service*	95.8	93.4	96.2	94.1	+$3,587,000	+0.5%
Rate Schedule 2 *Small Commercial Service*	99.9	99.8	99.9	99.8		
Rate Schedule 3/23 *Large Commercial Sales and Transportation Service*	101.5	103.0	101.5	103.0		
Rate Schedule 5/25 *General Firm Sales and Transportation Service*	104.2	110.4	104.2	110.4		
Rate Schedule 6 *Natural Gas Vehicle Service*	135.6	169.9	110.0	119.6	-$71,000	-19.0%
Rate Schedule 22A *Transportation Service (Closed) Inland Service Area*	180.1	183.2	110.0	110.4	-$3,517,000	-39.0%
Rate Schedule 22B *Transportation Service (Closed) Columbia Service Area*	105.0	105.1	105.0	105.1		

FEI has excluded Rate Schedules 4, 22, and 7/27 from the rebalancing as shown in Table 4-1 above. This is because Rate Schedule 4 is a seasonal service (firm in the summer and interruptible in the winter), Rate Schedule 22 is predominantly interruptible[3] and Rate Schedule 7/27 is fully interruptible. These rates do not drive system capacity additions[4], and consequently are not allocated any demand-related costs. The rates within these rate schedules are not set using their allocated costs from the COSA and therefore these rate schedules are not

[2] R:C denotes Revenue to Cost Ratio (includes the Cost of Gas) and M:C denotes Margin to Cost Ratio (excludes the cost of gas)

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

[4] Rate Schedule 4 is winter interruptible and this is when FEI's system peaks

rebalanced. Table 4-2 below shows revenue to cost ratios and margin to cost ratios for Rate Schedule 4, Rate Schedules 7/27 and Rate Schedule 22.

Table 4-2: R:C & M:C Ratio Results for Rates Not Set Using COSA Results[5]

Rate Group	Current R:C %	Current M:C %
Rate Schedule 4 *Seasonal Firm Gas Service*	147.1	542.1
Rate Schedule 7/27 *General Interruptible Sales and Transportation Service*	139.8	731.4
Rate Schedule 22 *Large Volume Transportation Service*	1,496.4	2,025.5

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

5. RESIDENTIAL RATE DESIGN

Rate Schedule 1 (RS 1) includes service to single family residences, separately metered single family townhouses, row houses and apartments. FEI serves more than 886,000 customers in RS 1 which accounts for approximately 91% of the total number of customers in FEI's service territory. Table 5-1 below provides a summary profile of the residential customer class' demand and revenue.

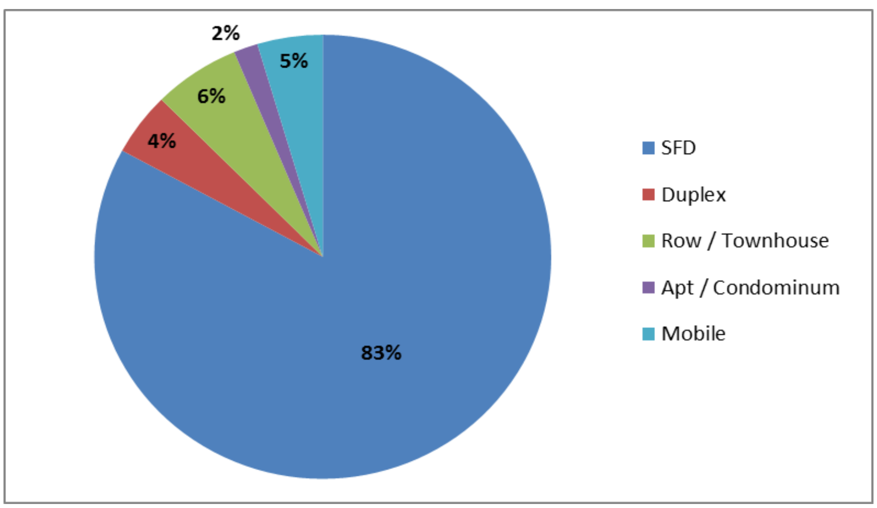
Table 5-1: FEI's Residential Customer Profile for 2015 (Normalized Actuals)

	PJ	Percentage
Customer Profile by Demand	74.1	35.5
	$000's	**Percentage**
Customer Profile by Revenue	773,327	59.1

5.1 *RESIDENTIAL CUSTOMER CHARACTERISTICS*

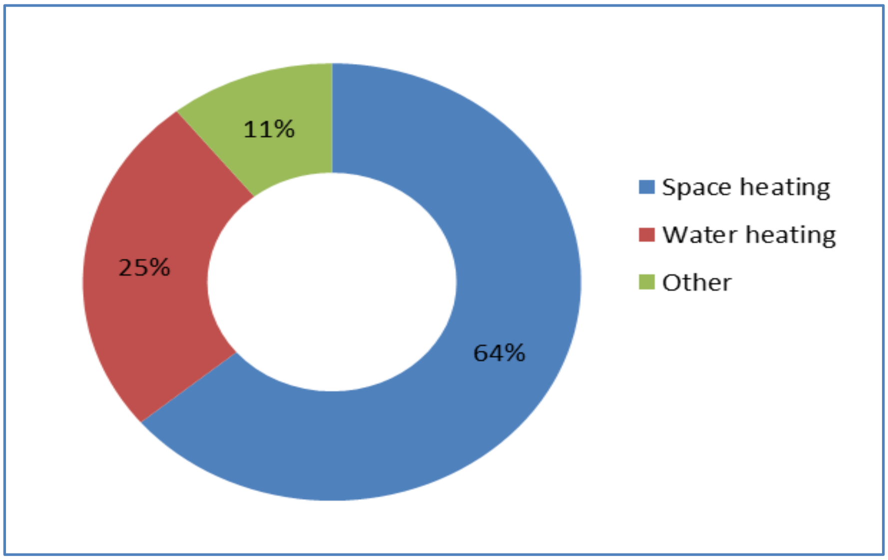
To understand residential customer characteristics, FEI reviewed its most recent Residential End-Use Study (2012 REUS), which suggests that the majority (83%) of residential customers are residing in single family dwellings, although the recent trend shows that the percentage is declining. Figure 5-1 below shows the residential customers by dwelling type.

Figure 5-1: Residential Customers by Dwelling Type from 2012 REUS



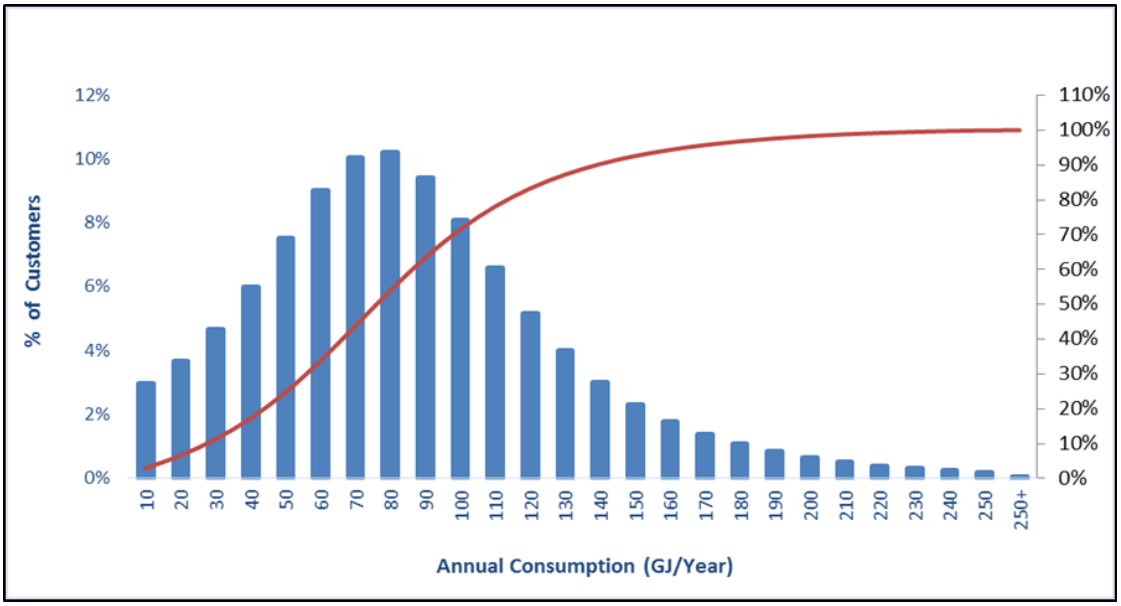
The 2012 REUS also suggests that the majority (64%) of residential customers' demand is used for space heating and water heating. Figure 5-2 below shows the estimated household consumption by end-use.

Figure 5-2: Estimated Household Consumption by End Use from 2012 REUS



In terms of consumption pattern, the residential customers' annual consumption distribution forms an overall bell curve with a slight skew to the right relative to the mean estimated at 81 GJ per year excluding outliers. Figure 5-3 below shows the distribution of residential consumption.

Figure 5-3: Distribution of Residential Consumption (2015)



5.2 *FEI RATE STRUCTURE OPTIONS FOR RESIDENTIAL CUSTOMERS*

5.2.1 FEI Existing and Other Rate Structure Options for Residential Customers

FEI has considered four rate structure options for its residential customers' rate. Each one of these rate structures is defined below.

5.2.1.1 Flat Rate Structure:

In this rate structure, also known as straight line meter rate structure, the variable 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 variable charge calculated based on the monthly natural gas consumption.

5.2.1.2 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 Appendix A, the natural gas utilities in Quebec and Ontario use declining block rate for their residential customers.

5.2.1.3 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 demand charge.

5.2.1.4 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.

5.2.2 Evaluation of different rate structure options

In this section, above mentioned 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. The Table 5-2 below illustrates how each one of the rate structures score against these principles:

1 **Table 5-2: 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 class.	The logic behind 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.	The concepts of peak demand and cost 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.	Similar to declining rates, the inverted rates may not be easy to understand for some customers. Customers may not be able to explain 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 as 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.	Seasonal rate is used as a proxy for demand charge to ensure that the cost of future peaking-related expenditures is allocated to those most responsible for it. Seasonal rates will reduce price competitiveness of natural gas during the winter when natural gas is most valued. Also, seasonal rates introduce a form of regional price differential since the customers in colder environments might be impacted more than others.	The 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 end up being subsidized.
Customer bill impact	Flat rates also help with customer bill impact since there will be no change in average rates 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 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.

5.2.3 Recommended 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 the residential 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' bills.

5.3 FIXED VERSUS VARIABLE RATES AND COSTS FOR RESIDENTIAL CUSTOMERS

FEI's current flat rate structure for the residential rate class consists of a daily basic charge (fixed charge) and a variable charge. The COSA model indicates that the majority of the costs allocated to the residential rate schedule are fixed costs. In the current residential rate structure, as shown in Table 5-3 below, the current basic charge (when calculated as the average fixed monthly amount) recovers about 43%[6] of the customer-related costs and only about 26%[7] of total fixed costs allocated to residential rate schedule.

Table 5-3: Misalignment between Fixed Costs and Fixed Charges[8]

Type of cost	Unit Cost based on COSA results	Current average Monthly basic charge	Differences
Customer-related cost	$27.66 per month		
Demand-related cost	$17.31 per month		
Total fixed costs	$44.98 per month	$11.84 per month	$33.14 per month

Consistent with the fairness principle as discussed in section 2.1, FEI is reviewing the ratio of basic charge to variable charge and would like to discuss with the stakeholders if it is reasonable to adjust this ratio going forward.

5.4 RESIDENTIAL RATE DESIGN RECOMMENDATION

Based on the discussion above, FEI recommends a residential rate design which accomplishes the following:

1. Maintains the current flat rate structure with a fixed basic charge and a variable volumetric charge
2. Improves the alignment between the fixed costs allocated to the residential rate schedule and the fixed charge.

6 $11.84 per month / $27.66 per month
7 $11.84 per month / $44.98 per month
8 FEI's current Rate Schedule 1 (residential) 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 per 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.

5.5 CUSTOMER BILL IMPACTS

Any rate design recommendation should consider customers' ability to pay and should be implemented in a way that avoids rate shocks to customers. The analysis of residential customers' bill impact can be separated into two steps: (1) the impact from rebalancing discussed in section 4 (for discussion purposes only) and (2) the impact from changes in the basic and variable charges.

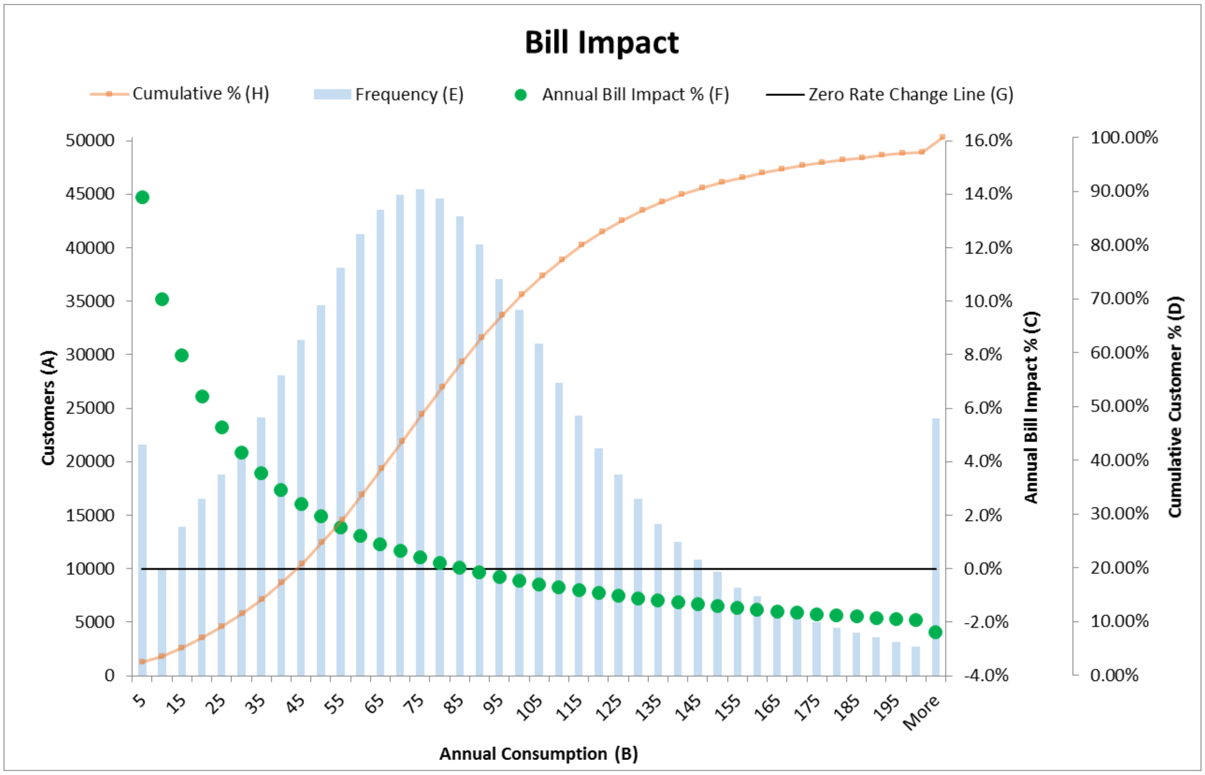
The impact on customers' bills due to rebalancing revenue to cost ratios depend on the individual customers' consumption level (i.e. the higher the consumption, the higher the impact will be). As indicated in Table 4-1, the impact on an average use customer's annual bill is estimated to be around 0.5% (based on 96.2% R/C ratio) or 0.8% on the delivery rate portion of the bill.

The impact from changes in the ratio of basic and variable charges is different. The impact on an average use customer would be zero. This is because the changes are revenue neutral; any increase in the share of basic charge is offset by a similar decrease in the share of the variable delivery charge in revenue recovery.

As referenced in section 5.3 above, the current rate structure has a basic charge of $0.3890 per day (which equates to $11.84 per month, based on 30.44 days in a month). Based on the 2016 COSA model with all known and measurable changes included and after rebalancing, the variable charge is estimated to be $4.758 per GJ. Implementing the rebalancing of fixed and variable charges results in an increase in the basic charge from $11.84 to $13.61 per month (an increase of approximately 15%) and a decrease in the variable delivery charge from the $4.758 per GJ to $4.500 per GJ (a decrease of 5.4%).

The break-even point, that is the point in which the customers experience no bill impact due to changes in the basic charge and delivery charge, is at the 80 to 85 GJ consumption range. Customers with consumption above this range will experience a decrease of 0.1% to 2.4% in their annual bill amounts and customers with consumption below this range will experience an increase of 0.2% to 13.9% in their annual bills depending on their consumption level. Lower use customers (customer with annual consumption less than 30 GJ per year) would experience a slightly higher bill impact (approximately ranging from $14 to $21 annual bill impact depending on the level of annual consumption). In all cases, customers will pay rates more closely matched to their cost of service. The bill impact analysis for the recommended rate structure and fixed versus variable charges is demonstrated in Figure 5-4 and summarized in Table 5-4 below.

Figure 5-4: Customer Bill Impact[9]



The following table describes each of the results that are shown in Figure 5-4 above.

Table 5-4: Bill Impact Explanations

Graph Item	Description
Frequency (E)	These columns show the number of customers whose annual consumption falls within each 5GJ increments. The number of customers can be found on y-axis (A) and the Annual Consumption (GJ) of each 5GJ increments that can be found on x-axis (B).
Cumulative % (H)	This line is the cumulative sum of the number of customers in each 5GJ increments. Sum of the Frequency (E). The cumulative percent can be found on y-axis (D).
Annual Bill Impact (F)	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 (based on the each 5GJ increment into which they fit). The dots line up with Annual Bill Impact % which is the y-axis (C).

The Table 5-5 below provides the dollar amount and percentage of annual bill impact of the recommended rates for various annual consumption levels:

[9] Customer Bill Impact from changes in ratio of basic to variable charges based on 2016 COSA model with all known and measurable changes included and after rebalancing (for discussion purposes).

Table 5-5: Annual Bill Impact of Recommended Rates

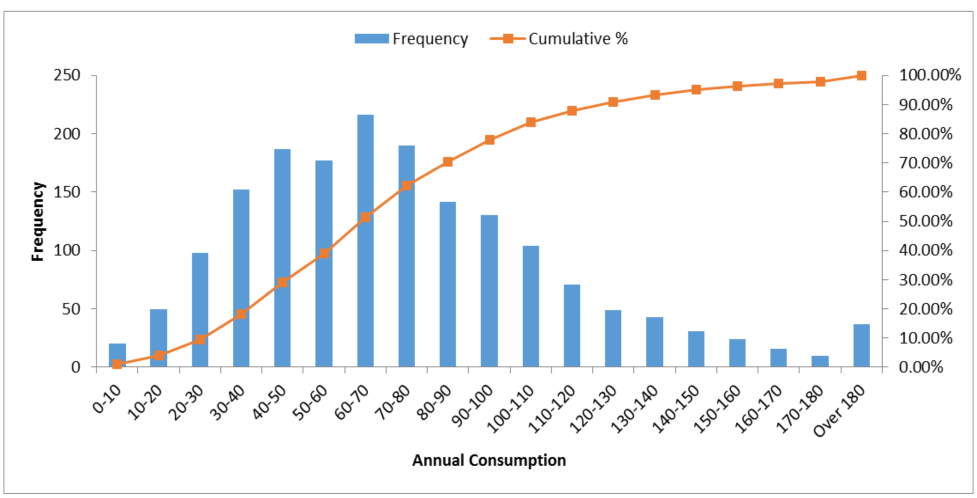
Annual Consumption	Annual Bill impact due to the changes in share of Basic and Delivery Charge	
	dollar amount	Percentage of total bill
0-5 GJ	$21	13.9%
40-45 GJ	$10	2.4%
60-65 GJ	$5	0.9%
80-85 GJ	$0	0%
120-125 GJ	$(10)	-1.0%

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. This is because even though low use customers are more negatively impacted by FEI's proposal (as shown in Table 5-5 above), low income customers do not necessarily equate to low use customers.

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.

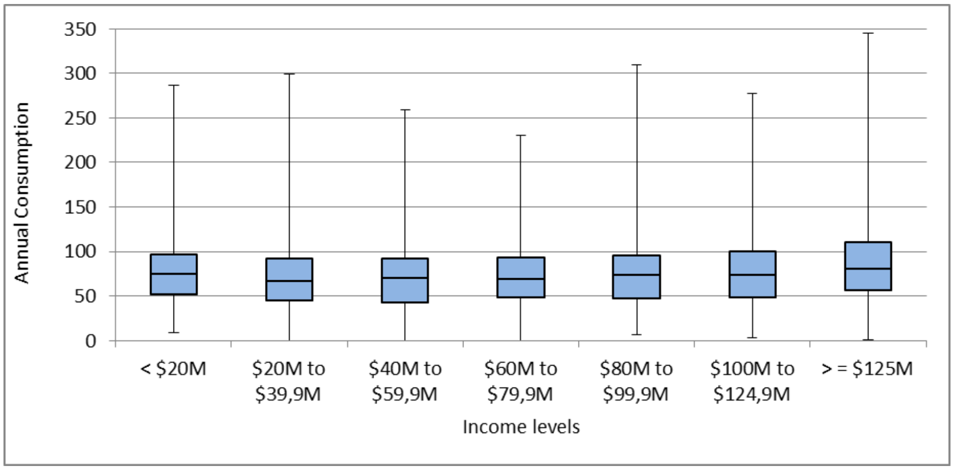
The ECAP is one of FEI's EEC programs designed to provide energy savings for low income households. To be eligible for this program, the applicant must meet the low income requirements and therefore all customers in this program are vetted to be low income customers. The figure below provides a histogram of ECAP customers' annual consumption which shows that the ECAP customers' consumption pattern is similar to FEI's general consumption pattern (as provided in Figure 5-5) with a normal distribution slightly skewed to the right and an S-curve cumulative frequency diagram.

Figure 5-5: The 2015 annual consumption histogram for customers in ECAP program



The second source of information on residential customers' income levels and annual consumption in FEI's service territory is based on the 2012 REUS.

Figure 5-6: Income and consumption levels based on 2012 REUS



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.

Due to the lack of correlation between income levels and consumption as displayed in Figures 5-5 and 5-6 above, FEI believes there are more effective and targeted means to assist low income households than through pricing mechanisms that apply to all customers.

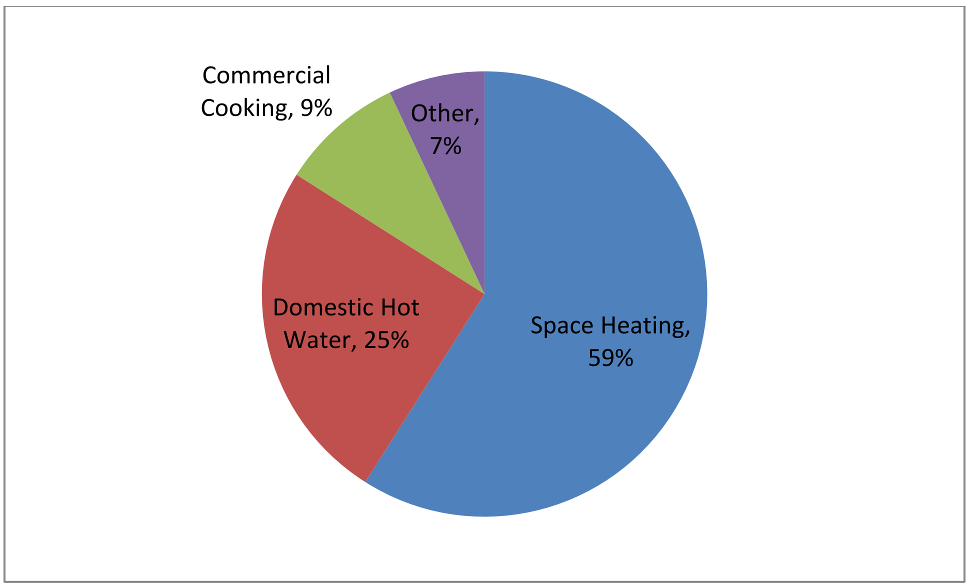
6. COMMERCIAL RATE DESIGN

6.1 COMMERCIAL RATE CLASS CHARACTERISTICS

Commercial customers cover a range of natural gas end users which include restaurants, offices, health care facilities, retail outlets and apartments. 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 petajoules (PJ) of natural gas representing 27% of FEI's total 2016 forecast throughput[10].

Commercial customers end usage from FEI's 2010 Conservation Potential Review study shows in Figure 6-1 that the majority (59%) of end use is for space heating with the second highest end use for domestic hot water (25%).

Figure 6-1: Commercial Customer End Usage Characteristics



6.2 REVIEW OF COMMERCIAL CUSTOMERS SEGMENTATION

6.2.1 Commercial Customer Segmentation

FEI has segmented its commercial customers into three rate schedules: Rate Schedule 2 - Small Commercial Service (normal annual consumption is less than 2,000 GJ), Rate Schedule 3

[10] FEI Compliance filing dated December 11, 2015, Schedules 18 and 19. Sum of forecast demand for Rate Schedules 2, 3 and 23.

- Large Commercial Service[11] (normal annual consumption is 2,000 GJ or greater) and Rate Schedule 23 - Commercial Transportation Service.

The existing customer segmentation of commercial customers is primarily based on their load characteristics (annual demand and load factors). These characteristics are discussed below.

Annual Demand

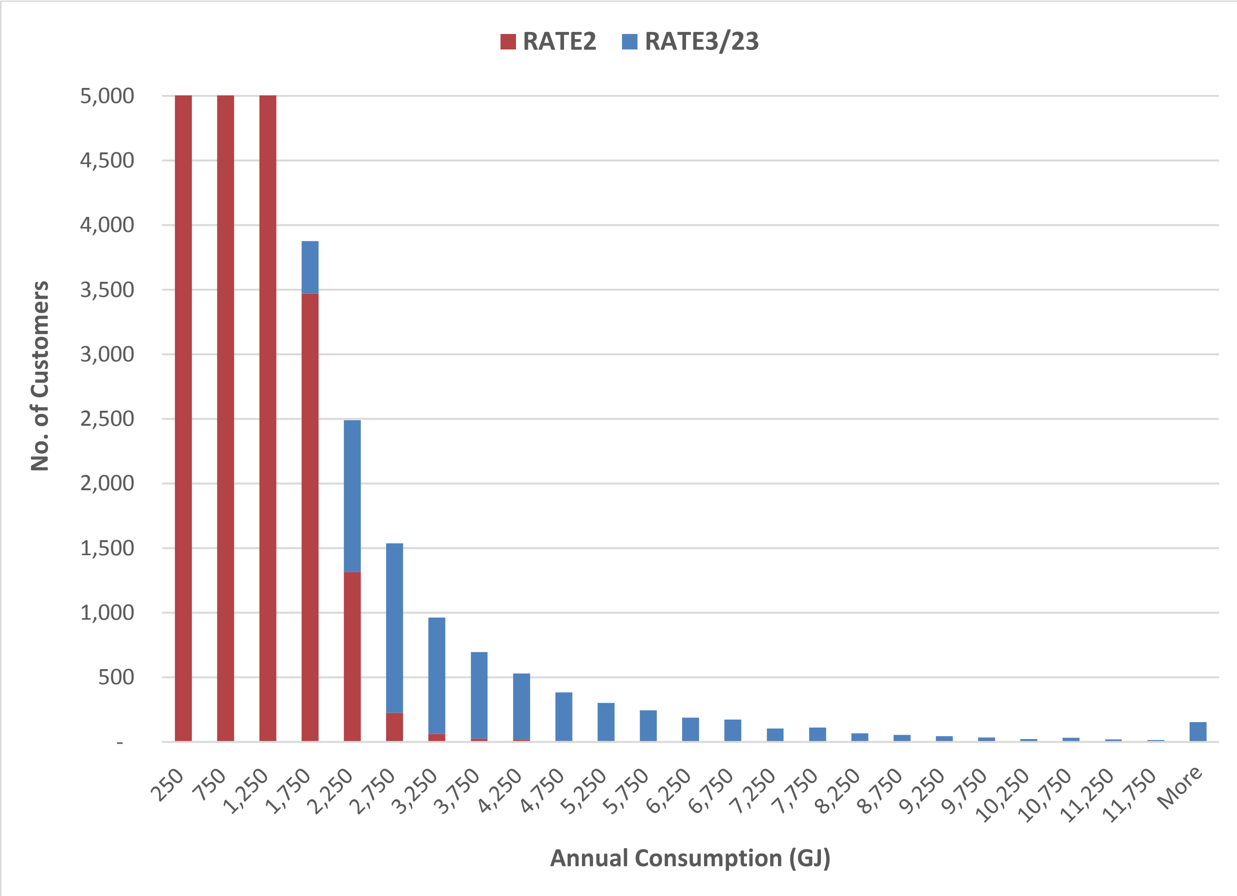
FEI conducted a bill frequency analysis (number of customers for each annual consumption profile) for Rate Schedule 2 and Rate Schedules 3/23. Figure 6-2 below shows the 2015 annual consumption of Rate Schedule 2 and Rate Schedule 3/23 customers. The majority of Rate Schedule 2 customers (78%) use up to 400 GJ per year. FEI also notes that there are a small percentage of Rate Schedule 2 customers (0.4%) whose annual consumption is close to, or even greater than, the 2,000 GJ threshold.

Figure 6-2 below also shows the annual consumption profile of the large commercial sales and transport customers (i.e. Rate Schedules 3 and 23). Based on 2015 data, about 38% of Rate Schedule 3 customers consumed between 2,000 GJ to 3,000 GJ. There were about 19% of customers that had consumption less than 2,000 GJ and about 43% of customers with consumption above 3,000 GJ.

Although Rate Schedule 2 is designed for customers with less than 2,000 GJ and Rate Schedule 3 is designed for customers with greater than 2,000 GJ of annual consumption, occasionally some customers may consume amounts that are more than/less than this threshold, for a variety of reasons. For example, a customer may have ceased operations for a portion of the year, they may have added or changed their equipment or the consumption estimate for a new customer may have not been very accurate. As a result, FEI will periodically review customer consumption data and, after consulting with them, may decide to move them to another rate schedule. When these customers move between rate groups, there will be a resulting bill impact which FEI discusses further below.

[11] Small Commercial and Large Commercial Rate Schedules 2 and 3 respectively can receive their base load commodity from a marketer under the Customer Choice Program. Alternatively, under Rate Schedules 2B and 3B commercial customers can choose to purchase part or all of their commodity as biomethane (Renewable Natural Gas).

Figure 6-2: Commercial Customers' Bill Frequency



Load Factor

FEI investigated the load factors for the existing small and large commercial groups. This analysis is shown in Figure 6-3 and Figure 6-4. These figures illustrate that small commercial customers have a significantly lower load factor, averaging 30.7%. The large commercial customers (Rate Schedule 3 and 23 combined) average 36.7%. This analysis further supports the customer segmentation between small and large commercial customers.

Figure 6-3: Small Commercial Customer Load Factor Distribution

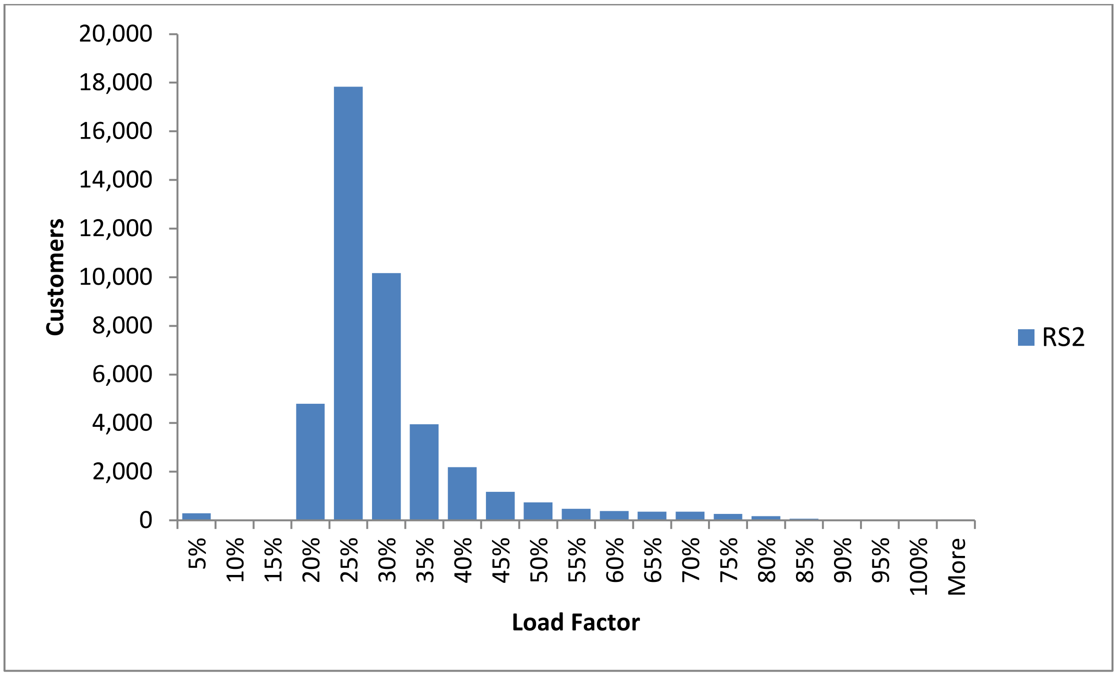
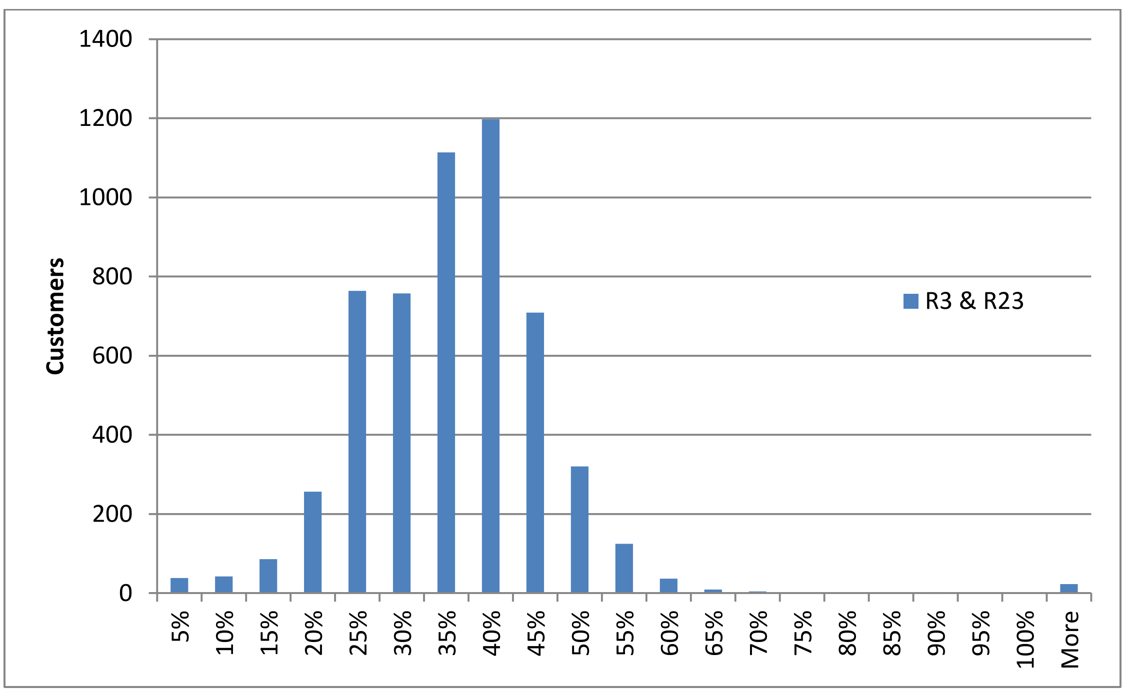


Figure 6-4: Large Commercial Customer Load Factor Distribution



6.2.2 Average Customer Rate

FEI also investigated the annual consumption and the average rate[12] (in $/GJ) for the customers under Rate Schedule 2 and Rate Schedules 3/23. Figure 6-5 below shows that for example, for a customer who consumes 2,000 GJ per year, moving from Rate Schedule 3 to Rate Schedule 2 would raise their average rate by approximately $0.20/GJ. The figure also shows that the point where a customer would be indifferent to moving between Rate Schedule 2 and Rate Schedule 3 (referred to as the economic crossover point) is approximately 1,600 GJ instead of 2,000 GJ. The economic crossover occurs for an annual volume when a customer whether served under Rate Schedule 2 or Rate Schedule 3 would have the same annual total cost. Ideally, an economic crossover point would occur at the threshold value of 2,000 GJ.

Figure 6-5: Relative Economics between Rate Schedules 2 and 3

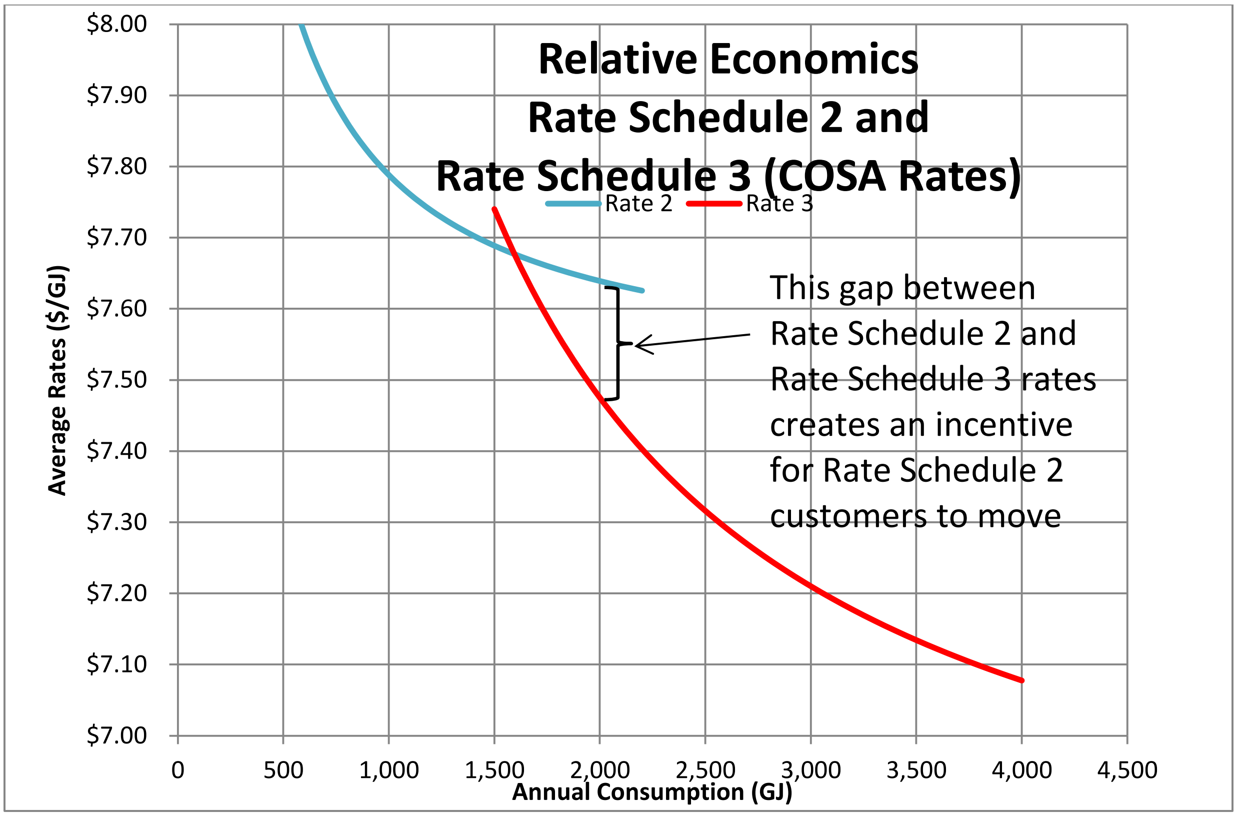


Table 6-1 below show the mathematical derivation of the economic crossover using the basic charges, delivery charges for Rate Schedules 2 and 3, and the average cost of gas from the COSA model. The economic crossover is at 1,595 GJ. What this means as illustrated in Figure 6-5 is that a customer who consumes more than 1,600 GJ and less than 2,000 GJ is better off financially as a large commercial Rate Schedule 3 customer. This results in incenting customers to being classified as large commercial customers when their consumption is in this range.

12 The average rate is calculated by adding up all the annual fixed and variable costs and dividing by their annual consumption.

The economic crossover is calculated by dividing the difference in the basic charge revenue by the difference in the Total Variable Cost ($1,292.14 / $0.810). This means that a small commercial customer and a large commercial customer who consume 1,595 GJ will have the same annual cost.

Table 6-1: Economic Crossover Volume for Rate Schedule 2 and Rate Schedule 3

Line No.	Particulars	Rate Schedule 2	Rate Schedule 3	Difference
1	Basic Charge / Day	$ 0.8161	$ 4.3538	
2	x # of Days	365.25	365.25	
3	Basic Charge Revenue	$ 298.08	$ 1,590.23	$1,292.14
4				
5	Delivery Rate $ / GJ	$ 3.523	$ 2.939	
6	Average Cost of Gas from COSA	$ 3.967	$ 3.741	
7	Total Variable Cost $ / GJ	$ 7.490	$ 6.680	$ 0.810
8				
9	**Economic Crossover GJ Line 3 / Line 7)**			**1,595**

6.2.3 Summary of Commercial Customer Segmentation

As discussed in section 6.2.1, FEI believes that the 2,000 GJ threshold between Rate Schedule 2 and 3 continues to be the appropriate threshold and that the existing customer segmentation should be maintained. However, FEI has identified a mismatch between the customer economics of Rate Schedules 2 and 3/23 for customers whose consumption is near the 2,000 GJ threshold. Therefore, in order to mitigate the customer bill impacts discussed above, existing rates may be adjusted.

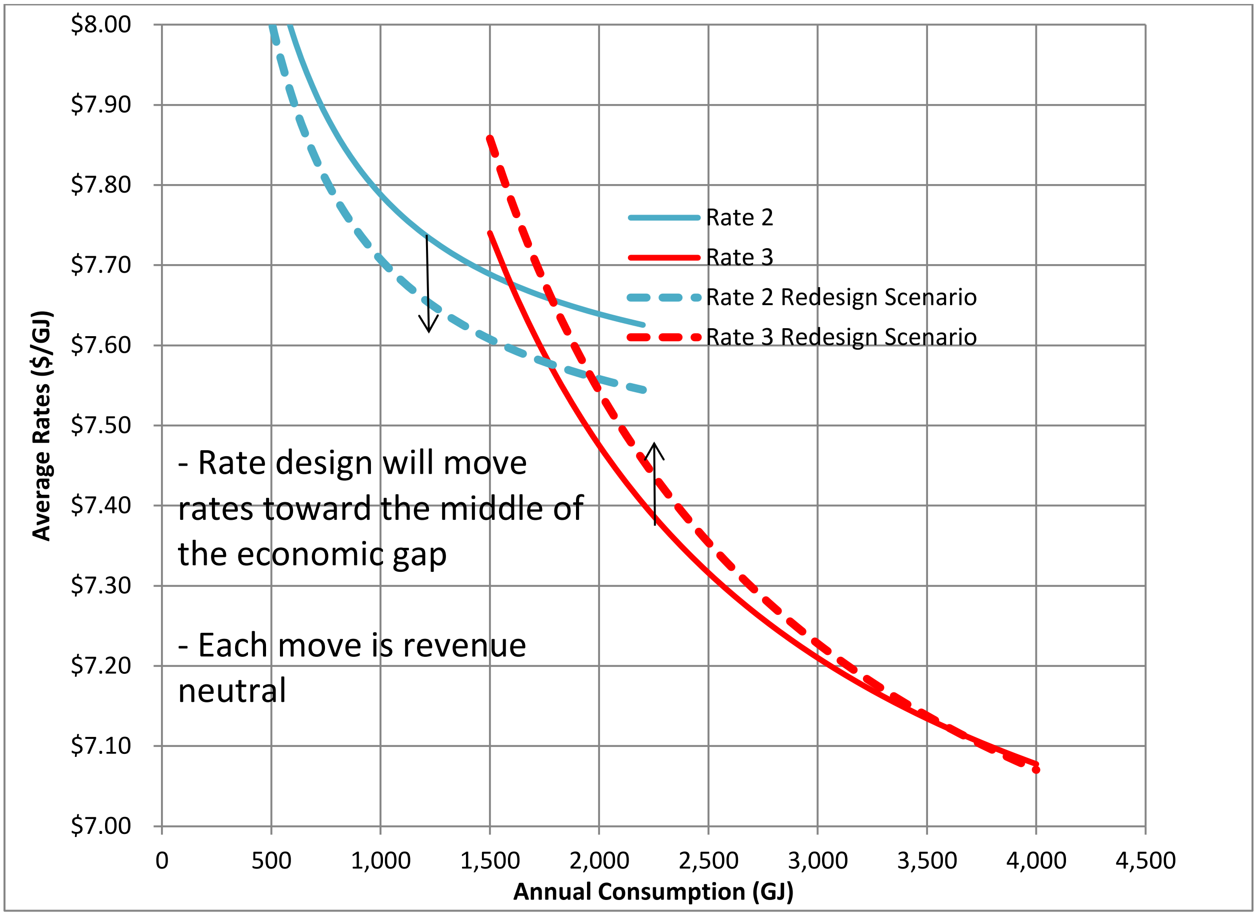
6.2.4 Rate Design Recommendation

FEI believes that the small and large commercial customers' rates may be adjusted to close the gap identified in section 6.2.1 above. This will eliminate the customer bill differential between Rate Schedules 2 and 3 for customers whose annual consumption is close to the 2,000 GJ threshold. The goal is to make the customer economically indifferent between choosing Rate Schedule 2 or 3 if they are near this 2,000 GJ threshold. This will also remove any economic incentive for customers to be misclassified.

The gap identified in Figure 6-5 can be closed by simultaneously raising the basic charge and lowering the delivery charge for Rate Schedule 2 by an amount intended to leave the total revenue generated by Rate Schedule 2 revenue neutral. This is represented by the dashed blue line in Figure 6-6 below. Similarly, the gap can also be closed by raising the basic charge and lowering the delivery charge for Rate Schedule 3, again by an amount intended to leave the rate group revenue neutral. This is represented by the dashed red line. The net effect of these adjustments is for the lines to now cross at the 2,000 GJ threshold.

1 The rate impact for customers at the 2,000 GJ threshold, is a change of approximately $0.10/GJ
2 (a reduction for a Rate Schedule 2 customer and an increase for a Rate Schedule 3 customer)
3 on an average rate of approximately $7.60 GJ (approximately 1%).

4 **Figure 6-6: Rate Schedules 2 and 3 Redesign at 2,000 GJ**

5 

7. INDUSTRIAL RATE DESIGN

7.1 *INDUSTRIAL RATE CLASS CHARACTERISTICS*

The industrial customer group represents a wide range of industries and end uses. The industrial sector makeup is shown in Figure 7-1 and the end usage is shown in Figure 7-2. This data comes from FEI's 2010 Conservation Potential Review study. Figure 7-1 shows that the major gas consuming industries are the pulp and paper, agriculture and food and beverage industries with market shares of 32%, 12% and 12%, respectively. Figure 7-2 shows that the primary end uses are for boilers, air conditioning and pulp lime kilns with market shares of 43%, 12% and 12%, respectively.

Figure 7-1: Industrial Sectors

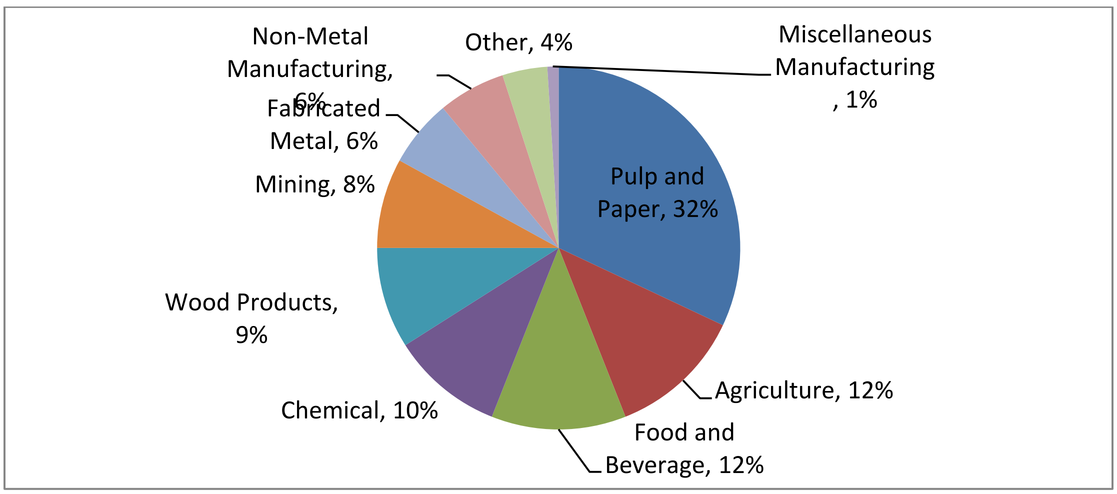
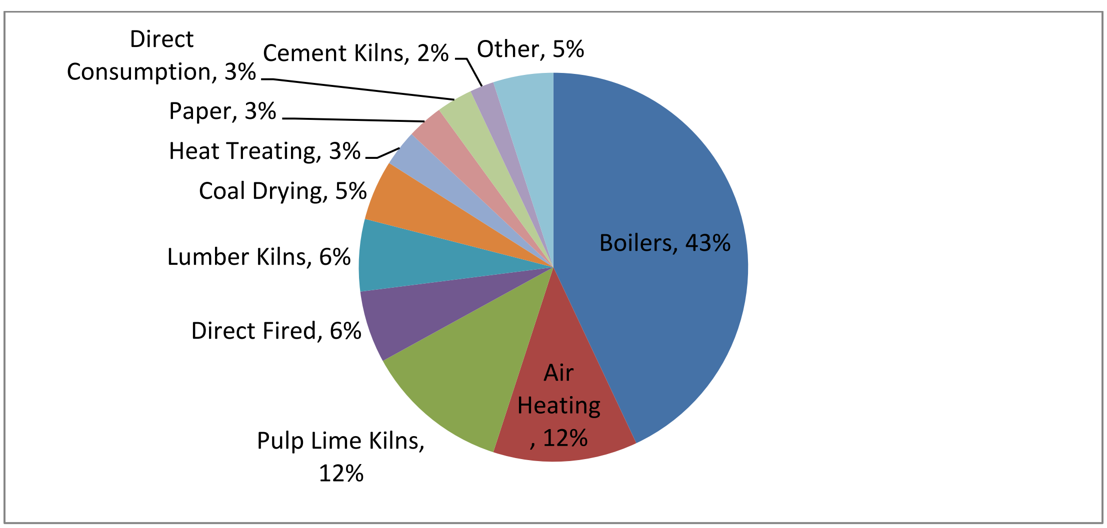
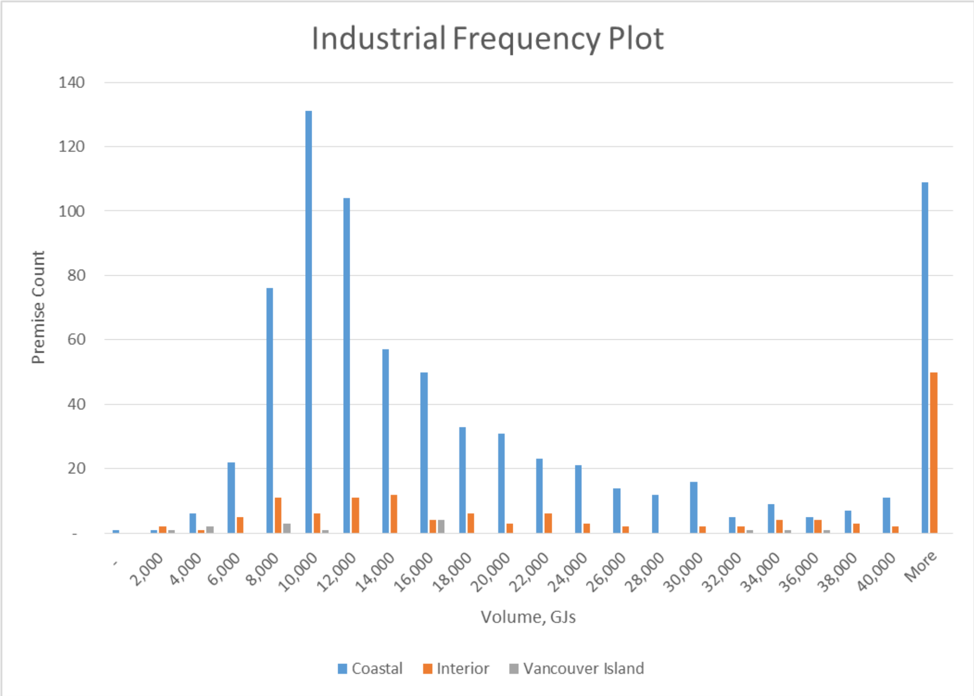


Figure 7-2: End Use by Industrial Customers



Annual usage for Industrial customers varies widely, as shown by Figure 7-3. This bill frequency graph also shows that there is a clustering of customers with annual consumption in the region of 10,000 GJ and another clustering of customers with annual consumption in excess of 40,000 GJ.

Figure 7-3: Industrial Customer Bill Frequency (All Customers)



The wide range of industries, end uses and annual consumption for the industrial customer group requires FEI to customize rate schedules according to the unique characteristics of each market segment. These considerations and market segmentation will be discussed in the next section.

7.2 *INDUSTRIAL CUSTOMERS SEGMENTATION*

The industrial customer group includes customers who have unique demand characteristics that FEI has considered when designing the industrial rate schedules. These characteristics or customer service requirements include the following:

- Firm sales
- Firm transportation
- Interruptible sales
- Interruptible transportation
- Seasonal demand – with summer peaking

- High volume demand (both firm and interruptible service)

FEI has segmented the industrial customers and has existing rate schedules and contracts to match these characteristics, which are listed below in Table 7-1.

1 **Table 7-1: Industrial Customer Groups and Corresponding Rate Schedules**

Industrial Group	FEI Tariff Rate Schedule / Contract	Description
Seasonal Firm Gas Service	Rate Schedule 4	• Seasonal firm service during the off-peak period (April 1to October 31) and interruptible service during the extend period (November 1– March 31).
General Firm Service (Sales)	Rate Schedule 5	• General firm sales service with an applicable monthly demand charge per month per GJ of daily demand. • Firm sales service.
General Firm Transportation Service	Rate Schedule 25	• General firm transportation service with an applicable monthly demand charge per month per GJ of daily demand. • Firm transportation service on FEI's system.
General Interruptible Service (Sales)	Rate Schedule 7	• General interruptible sales service • Sales service is interruptible if there is insufficient capacity or operational restrictions to deliver the gas.
General Interruptible Transportation Service	Rate Schedule 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	Rate Schedule 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	Rate Schedule 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	Rate Schedule 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 Joint Venture	• Contract for firm and interruptible transportation service to five mills on Vancouver Island.
Contract	BC Hydro / Island ICP	• Contract for firm and interruptible transportation service to the Island Cogeneration Facility on Vancouver Island.

2

3 Each of these types of industrial customers is discussed further in the following sections.

7.3 GENERAL FIRM SERVICE: RATE SCHEDULES 5 (SALES) AND 25 (TRANSPORTATION)

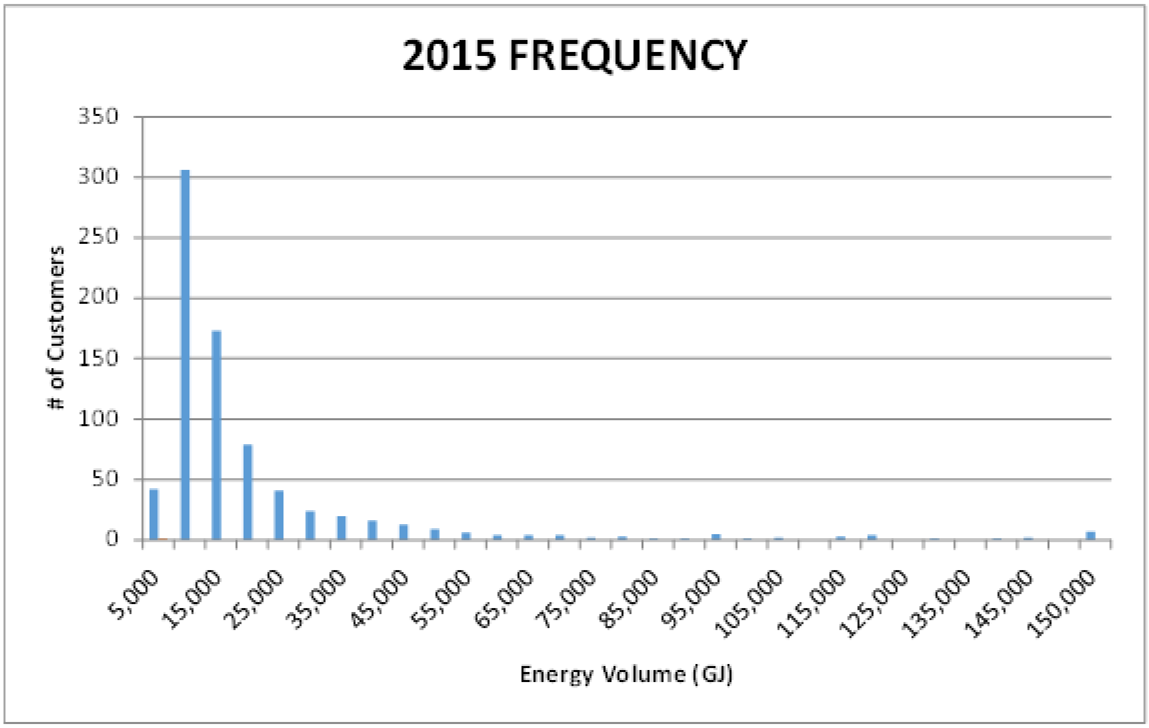
7.3.1 General Firm Service Customer Characteristics

General Firm Service is intended for those commercial and small industrial customers that generally use natural gas for a processing load, as 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 who 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. Therefore, these customers will generally have a relatively constant demand profile throughout the year. This relatively flat demand profile means that these customers will more highly utilize the FEI system than customers who contribute to FEI system peak demand on cold days such as the residential and commercial customers.

FEI offers two related rate schedules to this type of customer – Rate Schedule 5 for General Firm Service (a sales service) and Rate Schedule 25 for General Firm Transportation Service (for customers who choose to purchase their own natural gas from a Marketer). Rate Schedules 5 and 25 are "companion" rate schedules, in that each rate schedule has the same basic and delivery charges (as will be seen in Table 7-2 in section 7.3.2). However, Rate Schedule 25 has an additional administration charge to account for the separate administration and billing for customers who purchases their own gas from a Marketer. As of 2015 year end, there were 774 combined Rate Schedule 5 and 25 customers with a total demand of 15 million GJ.

The following Figure 7-4 shows the annual bill frequency graph for the combined Rate Schedule 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 7-4: Annual Bill Frequency for the Combined Total of Rate Schedule 5 and Rate Schedule 25 Customers



7.3.2 Rate Design Considerations

FEI developed Rate Schedules 5 and 25 to charge General Firm Service customers with high system utilization according to their individual demand profile, as measured by their load factor[13], which reflects their high utilization of the FEI system throughout the year. The demand/variable delivery type of rate structure for Rate Schedule 5 and 25 is more effective at reducing the total costs to high load factor customers. This is because when the demand charge is applied to customers with a higher load factor it results in a lower average cost per GJ of total throughput. In short, customers' more effective use of the system is reflected in lower rates per gigajoule.

FEI designed Rate Schedule 5 to include a basic charge, a delivery charge, a demand charge; a commodity cost Recovery charge and a storage and transport charge. Similarly, Rate Schedule 25 includes a basic charge, an administration charge, a delivery charge and a demand charge. These charges are shown below in Table 7-2.

[13] FEI measures their system utilization by their load factor, which is defined as their average daily demand divided by their peak day demand.

Table 7-2: Rate Schedule 5 and Rate Schedule 25 Description of Charges[14]

Rate Schedule	Basic Charge per Month	Administration Charge per Month[16]	Demand Charge*	Delivery Charge per GJ	Commodity Cost Recovery Charge per GJ	Storage and Transport per GJ
Rate Schedule 5	$587.00	n/a	$20.077	$0.825	$2.486	$0.837
Rate Schedule 25	$587.00	$78.00	$20.077	$0.825	n/a	n/a

**Per Month per GJ of Daily Demand.*

To calculate the demand charge, FEI developed estimates of each customer's peak day demand (referred to as Daily Demand in Rate Schedules 5 and 25). At the time this rate schedule was developed, not all customers on Rate Schedules 5 and 25 had daily demand meters which required FEI to develop a method to estimate a customer's peak demand based on the monthly billing data which was used to calculate the demand portion of their bill. This method is described further below in section 7.3.3.

FEI has noticed that over the years since 1993 a high number of higher volume but lower load factor customers have become either Rate Schedule 5 or Rate Schedule 25 customers. This has caused FEI to review the relative economics of the rate schedules, and whether there is an economic incentive for some customers to be in Rate Schedules 5 or 25 instead of Rate Schedules 3 and 23.

In the sections below, FEI reviews whether or not it is appropriate to:

- Revise the method of estimating the customer's Daily Demand; and
- Adjust for the relative rate economics between Rate Schedules 3/23 and Rate Schedules 5/25.

7.3.3 Customer Peak Demand and Load Factor

The average load factor of the customers on Rate Schedules 5 and 25 is approximately 45% and 55% respectively. These load factors are considerably higher than that noted for residential and commercial customers in sections 5 and 6 respectively. A high load factor signals that the customer uses the gas transmission and distribution facilities more efficiently than lower load factor customers.

The methodology for estimating the Rate Schedule 5 customer demand and calculating the load factor was established when many prospective Rate Schedule 5 customers had older meters and were on traditional monthly billing cycles. Therefore FEI did not have the means to accurately measure the daily usage of most of the Rate Schedule 5 customers and had to establish a "proxy" for this demand. To approximate the customer's peak demand for billing

[14] Rates for the Basic Charge, Demand Charge and Delivery Charge are the current approved rates from the Annual Review for 2016 Rates; the Commodity Charge and Transportation and Storage Charge were approved by the Commission in Order G-39-15, effective April 1, 2015 which were used in the Annual Review for 2016 Rates.

purposes the following formula was developed and approved by the Commission to determine the Daily Demand to which the demand charge would be applied:

> 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).

The 1.25 multiplier is still applied to monthly aggregate demand to estimate the customer's peak day use. However, all Rate Schedules 5 and 25 customers now have meters installed that provide daily measurement to accurately measure their peak demand. Therefore, to improve the cost recovery and cost causality alignment of customer peak demand usage, FEI reviewed a range of options to improve billing of peak customer demand. These options are:

1. Current Formula – Use the method described in the above quote from FEI's tariff.
2. FEI System Maximum Day Send Out – Use the customer's actual consumption that would occur on FEI's maximum day send out (for example, during 2015 the Maximum Day Send Out occurred on December 31, 2015).
3. Average Consumption on Coldest Days – Use the customer's actual average daily consumption over either the 3 or the 5 coldest days.
4. Modified Formula – Use the greater of the customer's average consumption on the three or five coldest days or one half of the average summer maximum day (as in the current formula method).

A principle of rate design is to ensure customers who cause the utility to incur certain costs (such as infrastructure built to meet peak day demand) are allocated their fair share of these costs. Measuring actual peak day demand rather than estimating it will serve this principle well. Therefore, to achieve this principle, FEI has sought to find an appropriate method to determine the customer's Daily Demand that the demand charge would be applied to.

Table 7-3 shows the number of customers who would fall into various load factor segments for each of the options under consideration and discussed above. As shown in the table below, the majority of these customers have a load factor greater than 50%.

A number of customers may not have been operating when FEI experienced a system peak or during the cold days noted below. However, FEI would expect that normally, if the system peak or cold days occurred on a week day, these customers would have exhibited demand. Therefore, when considering the best method of measuring a customer's Daily Demand, FEI would need to consider the possibility that the customer may coincidently not be using gas on one or more of these cold days.

Regardless of which method is utilized for determining peak customer demand, there are many customers whose load factor falls below the 40% threshold – and whose demand characteristics are more likely caused by temperature sensitive demand than processing load demand.

Table 7-3: Number of Customers by Load Factor Segment (Combined Totals for Rate Schedule 5 and Rate Schedule 25 Customers)

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

FEI makes a number of observations from the results shown in Table 7-3:

- Row 3 - shows that there are customers who have no demand at times which may correspond to the particular Daily Demand estimation method used. The column 3 for the System Maximum Send Out method shows that 13 customers have no consumption on the system peak day, which occurred on December 31, 2015 – a day when some customers may have closed their business for the holiday season. Columns 5 and 6, which show the Average Consumption method, show the effect a zero demand reading on any one day will be reduced by averaging the customer's peak day over a longer period. That is, for example, only 4 customers had zero demand during the coldest 5 day period.
- Row 4 – shows that there are between 33 and 55 customers, depending upon the Daily Demand calculation method selected, who would have a less than 40% load factor. Therefore, these customers have a lower effective utilization of the FEI system and based upon this load factor, are candidates to move to Rate Schedules 3 or 23.
- Row 7 – customers shown in this row have the highest load factor, and therefore, utilize the FEI system the most efficiently of all Rate Schedules 5 and 25 customers. Column 3 shows that there are 447 customers who have a load factor greater than 50% by using the Current Formula. Column 7 shows that there are 608 customers with a load factor greater than 50% by using the Modified Formula. Therefore, one can see that the Modified Formula would result in more customers with a higher load factor, and therefore a lower average rate, than the Current Formula.

Table 7-4 below shows the Average Daily Demand (GJ) per customer for each of the methods and for the corresponding load factor ranges as per the table above. Of note is the values shown in Row 6 for customers with a greater than 50% load factor. Under the Current Formula the estimated Daily Demand is 105 GJ. Alternatively, under the Modified Formula, the estimated Daily Demand is 75 GJ, an approximately 29% reduction. However, for customers with a lower load factor, such as those shown in rows 3 and 4, they would have a change to their average Daily Demand: a 13% reduction and increase of 17%, respectively.

Table 7-4: Average Daily Demand (GJ) per Customer by Load Factor Segment (Combined Totals for Rate Schedule 5 and Rate Schedule 25 Customers)

1	2	3	4	5	6	7
2		Current Formula for Daily Demand	FEI System Maximum Day Send Out	Average Consumption on Coldest		Modified Formula with 5 Day Average
				3 Days	*5 Days*	
3	<40% Load Factor	174	160	150	159	152
4	40% to <45% Load Factor	93	89	97	109	109
5	45% to <50% Load Factor	73	82	77	72	72
6	>50% Load Factor	105	25	71	72	75
7	Total	**445**	**356**	**395**	**412**	**408**

A brief explanation and evaluation of the implications of each of these methods is discussed below:

- The Current Formula – uses the customer's highest average daily consumption of any month during the winter period (November 1 through March 31) or one-half of the highest average summer period (April 1 – October 31) and multiplies it by a factor of 1.25 to arrive at an estimate of the customer's Daily Demand. This method does not provide a very precise value for the customer's peak day demand, nor representative of their unique load characteristics, which may influence the demand charge. This method is no longer necessary since all Rate Schedules 5 and 25 customers have daily demand meters.
- FEI system maximum send out – A demand charge based upon the customer demand that coincides with the FEI system peak would ensure that the demand charge was measured only during a coincident peak. However, there are numerous customers who registered zero demand on these days, a situation which may not always apply in the future if system peak does not occur on a weekend when some customers may have their business closed.

- Average consumption on the coldest 3 or 5 days – Using only one day per year to measure a customer's peak demand, FEI may select anomalous days when the customer had unusually high demand that is not representative of future peak demand. To mitigate this risk, FEI would consider using the average consumption over the coldest 3 or 5 days. The 5 day option may be preferred since it serves to further mitigate the risk of selecting an anomalous demand reading.
- Modified formula – by using the greater the customer's average consumption on the three or five coldest days or one-half of the average summer maximum day this method will account for customers with zero demand during the winter and whether they have a summer peak demand when the FEI system demand is low. There were 56 customers in 2015 whose peak for the Modified Formula was in the summer.

In conclusion, the System Maximum Send Out method is likely the most accurate measure of a customer's coincident peak day on a FEI system peak, but the method does not work if the customer has zero demand during the FEI system peak, or the system peak falls on a holiday or weekend. Alternatively, the Modified Formula measure of the customer peak is being averaged over a 3 or 5 day period, but best solves the problem of customers with zero demand during the FEI system peak and will also account for customers with a summer peak load. It is the Daily Demand to which the demand charge is applied to generate revenues to recover the costs to serve this firm service load. FEI will be considering a change to the method for determining the Daily Demand to using the average consumption on the coldest 5 days or using the Modified Formula method discussed above. The following section will discuss the necessity of changing the demand charge.

7.3.4 Review of Rate Schedules 5 and 25 Economics

As discussed in section 7.4.2, FEI has identified a number of customers with particularly high peak day demand and therefore low load factors who have migrated to Rate Schedules 5 and 25 over the past few years, primarily from the large commercial rate group (Rate Schedules 3 and 23). FEI believes this has occurred due to the favourable economics offered to these high volume customers by the current Rate Schedule 5 and 25 charges compared to the Rate Schedule 3 and 23 charges. Using Rate Schedules 23 and 25 as an example, FEI will illustrate these economic factors in the tables below and discuss some potential solutions in section 7.3.5.

The following analysis demonstrates how a large commercial customer with a load factor in the 32% to 40% range may be incented to receive service under Rate Schedule 25.

Table 7-5: Daily Load & Associated Load Factor to be Indifferent between Service Under Rate Schedules 23 and 25 at Current Rates

Rate 23 Charges			Rate 25 Charges		
Basic Charge	$	132.52	Basic Charge	$	587.00
Admin Charge	$	78.00	Admin Charge	$	78.00
			Demand Charge	$	20.077
Delivery Charge	$	2.939	Delivery Charge	$	0.825

Volume	Rate 23 Revenue	Basic + Delivery Revenue	Demand Charge Revenue	Daily Demand	Load Factor
3,000	11,343.24	10,455	888.24	3.687	222.93%
5,000	17,221.24	12,105	5,116.24	21.236	64.51%
7,750	25,303.49	14,374	10,929.74	45.366	46.80%
10,000	31,916.24	16,230	15,686.24	65.109	42.08%
15,000	46,611.24	20,355	26,256.24	108.981	37.71%
20,000	61,306.24	24,480	36,826.24	152.854	35.85%
25,000	76,001.24	28,605	47,396.24	196.727	34.82%
50,000	149,476.24	49,230	100,246.24	416.091	32.92%
75,000	222,951.24	69,855	153,096.24	635.455	32.34%
100,000	296,426.24	90,480	205,946.24	854.818	32.05%
125,000	369,901.24	111,105	258,796.24	1,074.182	31.88%
150,000	443,376.24	131,730	311,646.24	1,293.546	31.77%

- The first step is to calculate the revenues under Rate Schedule 23 charges.
- Second step is to calculate under Rate Schedule 25 what the basic charge plus delivery charge revenue would be.
- Demand charge revenue is the difference Rate Schedule 23 revenue and the basic plus delivery revenue under Rate Schedule 25.
- Daily Demand GJ is the demand charge revenue divided by the demand charge for 12 months.
- Load Factor is the annual volume divided by the product of 365 days times the Daily Demand. (For example, 15,000 GJ / (365 X 108.891 = 37.7% Load Factor).

As can be seen from the table, as the annual volume increases the associated load factors decrease to where the customer is indifferent between Rate Schedules 23 and 25. This means that large commercial customers whose load is temperature sensitive and load factor is approximately 36% or lower would be incented to receive service under Rate Schedule 25. The impact on the Company is a decline in revenues as customers take service under General Firm sales or transport rather than as large commercial. Also, Rate Schedule 25 load factor declines due to the temperature heat sensitive Commercial customers that are now in General Firm Rate

Schedules. The following table shows the impact on the Daily Demand and associated load factor by only changing the demand charge by increasing it by $5 dollars per GJ per month of Daily Demand.

Table 7-6: Daily Load & Associated Load Factor to be Indifferent between Service under Rate Schedules 23 and 25 with a $5 Demand Charge Increase

Rate 23 Charges			Rate 25 Charges		
Basic Charge	$	132.52	Basic Charge	$	587.00
Admin Charge	$	78.00	Admin Charge	$	78.00
			Demand Charge	$	25.077
Delivery Charge	$	2.939	Delivery Charge	$	0.825

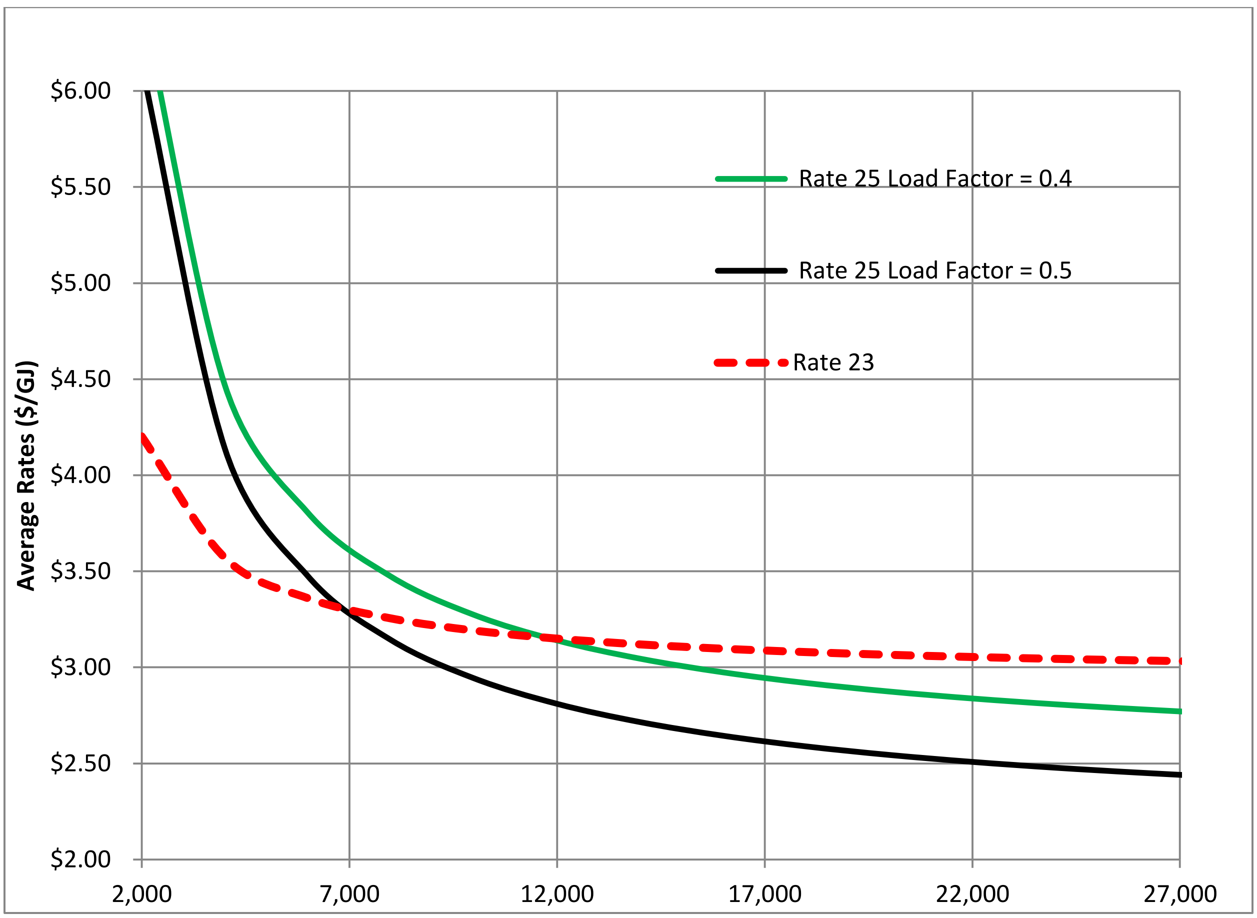
Volume	Rate 23 Revenue	Basic + Delivery Revenue	Demand Charge Revenue	Daily Demand	Load Factor
3,000	11,343.24	10,455	888.24	2.952	278.45%
5,000	17,221.24	12,105	5,116.24	17.002	80.57%
7,750	25,303.49	14,374	10,929.74	36.321	58.46%
10,000	31,916.24	16,230	15,686.24	52.127	52.56%
15,000	46,611.24	20,355	26,256.24	87.252	47.10%
20,000	61,306.24	24,480	36,826.24	122.377	44.78%
25,000	76,001.24	28,605	47,396.24	157.502	43.49%
50,000	149,476.24	49,230	100,246.24	333.128	41.12%
75,000	222,951.24	69,855	153,096.24	508.754	40.39%
100,000	296,426.24	90,480	205,946.24	684.380	40.03%
125,000	369,901.24	111,105	258,796.24	860.005	39.82%
150,000	443,376.24	131,730	311,646.24	1,035.631	39.68%

By increasing the Rate Schedule 25 demand charge by $5 per GJ per month of Daily Demand, the Daily Demand decreases and the associated Load Factor increases to approximately 40% to 60%. The important point from the analysis is that it is the price level variance in the charges applicable to large commercial Rate Schedules 3 and 23 relative to the charges applicable to General Firm Rate Schedules 5 and 25 that is important to incent customers with a load factor of at least 40% to take service under the General Firm Service and to incent commercial customers whose load profile is more temperature sensitive with a load factor less than 40% to take service under Rate Schedules 3 or 23.

To further illustrate the issue the basic charge, delivery charge and demand charge from Table 7-2 are used to create the average rate graph for Rate Schedule 23 and 25 customers at varying demand levels as shown in Figure 7-5. This figure shows how a customer's bill would change as their load factor or annual consumption changes. For example, the solid green line shows how the average rate would change, for a customer with a 40% load factor, over a range of annual consumption levels. Similarly, the solid black line shows the average rate for a customer with a 50% load factor. Comparing these two lines, it is clear that the 50% load factor line is consistently below the 40% line, and therefore a customer with a higher load factor would receive a lower average rate.

To demonstrate how a commercial customer on Rate Schedule 23 may want to move to Rate Schedule 25, the average rate is calculated as above for Rate Schedule 23 and added to Figure 7-5 in the dashed red line. One can see that at lower volumes, e.g. less than about 7,000 GJ, the Rate Schedule 23 customer would have a lower average rate than if the customer were on Rate Schedule 25 – at any level of load factor for Rate Schedule 25. However, as the annual demand for the Rate Schedule 23 customer increases, e.g. to greater than 17,000 GJ, the customer would have a relatively high average rate as a Rate Schedule 23 customer, but would receive a lower average rate as a Rate Schedule 25 customer – even if they have a relatively low 40% load factor. Therefore, these customers have an economic incentive to move to Rate Schedule 25. This outcome is contrary to the intent of the Rate Schedules 5 and 25 design and leads to larger volume, and lower load factor customers moving to Rate Schedules 5 and 25.

Figure 7-5: Comparison of Rate Schedule 23 and Rate Schedule 25 Average Rates at Varying Load Factors



7.3.5 Rate Design Options Considered and Potential Impact

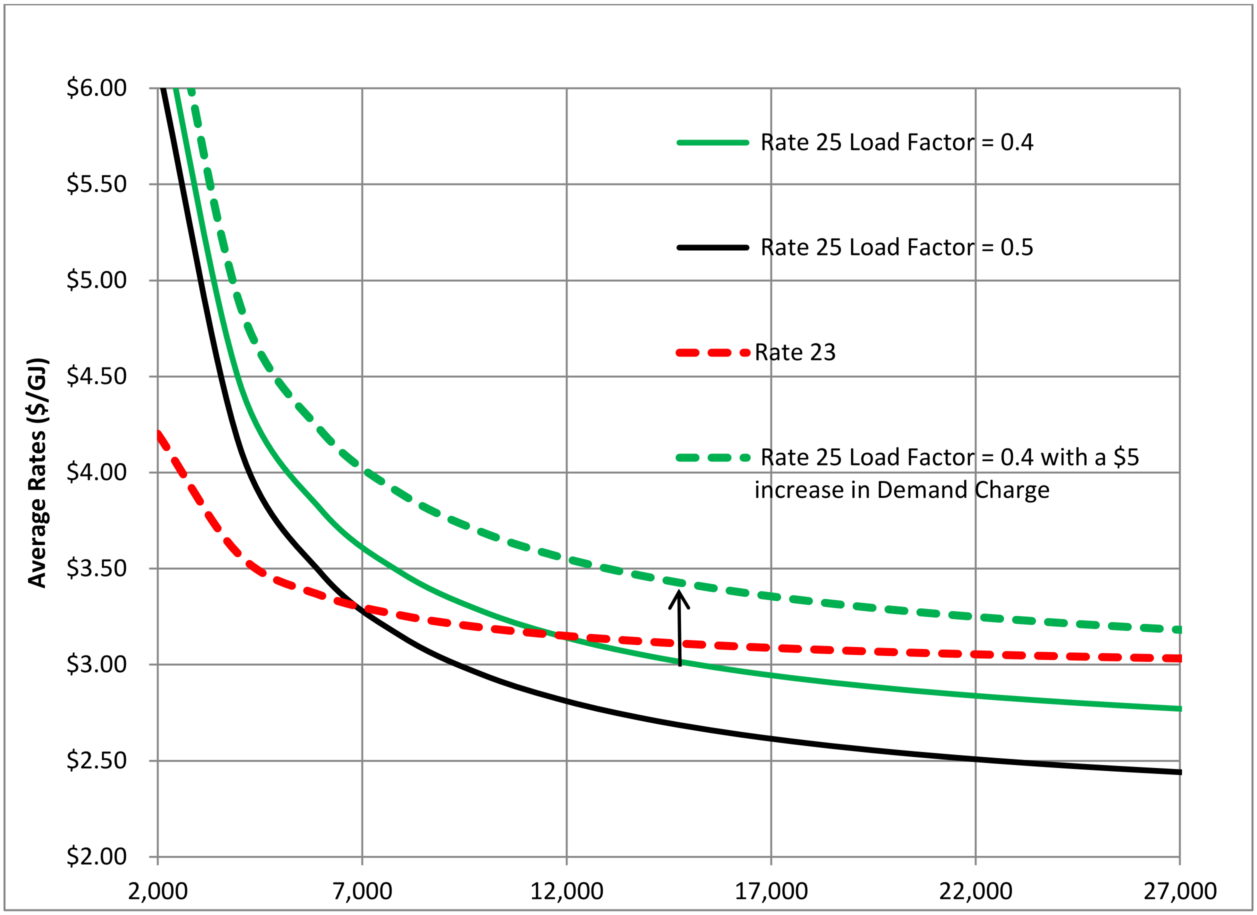
FEI has studied a number of ways to improve the comparative economics between Rate Schedule 23 and Rate Schedule 25[15]. For example, FEI could adjust any of the basic or delivery charges for Rate Schedule 23 or basic, delivery or demand charges for Rate Schedule 25 to adjust the relative economics between these two rates. However, FEI believes that altering any of the Rate Schedule 23 charges would also alter the relative economics with Rate Schedule 2, and so prefers to focus solely on the economics of Rate Schedule 25. FEI believes the best way to improve the relative economics between Rate Schedule 23 and Rate Schedule 25 is to alter the demand/variable components of Rate Schedule 25 and to reduce the attractiveness of this rate for low load factor customers. One way to accomplish this goal is to raise the demand charge for Rate Schedule 25.

To illustrate, FEI shows one such adjustment in Figure 7-6. The green line in this figure shows the average rate for a Rate Schedule 25 customer with a 40% load factor over a range of demand levels. If FEI were to increase the Rate Schedule 25 demand charge by $5.00 the customer's average rate with a 40% load factor would rise to the level of the dashed green line. If the average rate for a Rate Schedule 23 customer, as shown by the dashed red line, is compared to the dashed green line for the 40% load factor customer, the Rate Schedule 23 customer would have a lower average rate for any level of annual demand, and therefore no longer seek to move to Rate Schedule 25.

In conclusion, by raising the demand charge by $5.00, customers with load factors lower than 40% would have a price incentive to receive service under Rate Schedule 23 and not under Rate Schedule 25.

[15] And by association between the companion Rate Schedules 3 and 5.

Figure 7-6: Comparison of Rate Schedule 25 Average Rates to Rate Schedule 23



7.3.6 Rate Design Recommendations

It is clear that the existing rate structure for Rate Schedules 5 and 25 has resulted in larger consuming and lower load factor customers moving into these rate schedules over time. FEI believes one solution to remedy this issue is raising the demand charge for Rate Schedule 5 and Rate Schedule 25 customers by $5.00, from $20.077 per month per gigajoule of Daily Demand to $25.077 as discussed in section 7.4.3.

An offset to this demand charge increase is the revised calculation for the customer's Daily Demand. As discussed in section 7.4.2, FEI is considering a number of options which would remove the 1.25 multiplier currently applied to a customer's highest average Daily Demand in the winter months or 50% of the summer months. As such, raising the demand charge by $5 or about 25% could be offset by a general reduction in the Daily Demand. FEI estimates that those customers who have a greater than 50% load factor would also have an approximately 29%

reduction[16] in their Daily Demand as noted above in section 7.3.3 – offsetting the impact of the demand charge increase.

This analysis is for discussion purposes. FEI will include a more detailed analysis of customer bill impacts for both the revised Daily Demand to which demand charges are applied and the revised demand charge in its RDA.

7.3.7 Rate Schedule 5 and 25 Summary

FEI believes the current rate structure for Rate Schedules 5 and 25 continues to work well in most respects. However, as discussed in section 7.4.2, the rates may be adjusted to improve the economic price signals provided to these customers. FEI has identified two elements to the current Rate Schedules 5 and 25 design for which it seeks input from interested parties. These elements are:

- the method to determine an individual customer's Daily Demand, that the Demand Charge would be applied to, and
- Adjusting the Demand Charge to improve the relative economics between Rate Schedule 3/23 and 5/25 and to create a better cost-causality alignment between individual customer load factor and customer rates.

7.4 GENERAL INTERRUPTIBLE SERVICE: RATE SCHEDULES 7 AND 27 (TRANSPORTATION)

7.4.1 General Interruptible Service Customer Characteristics

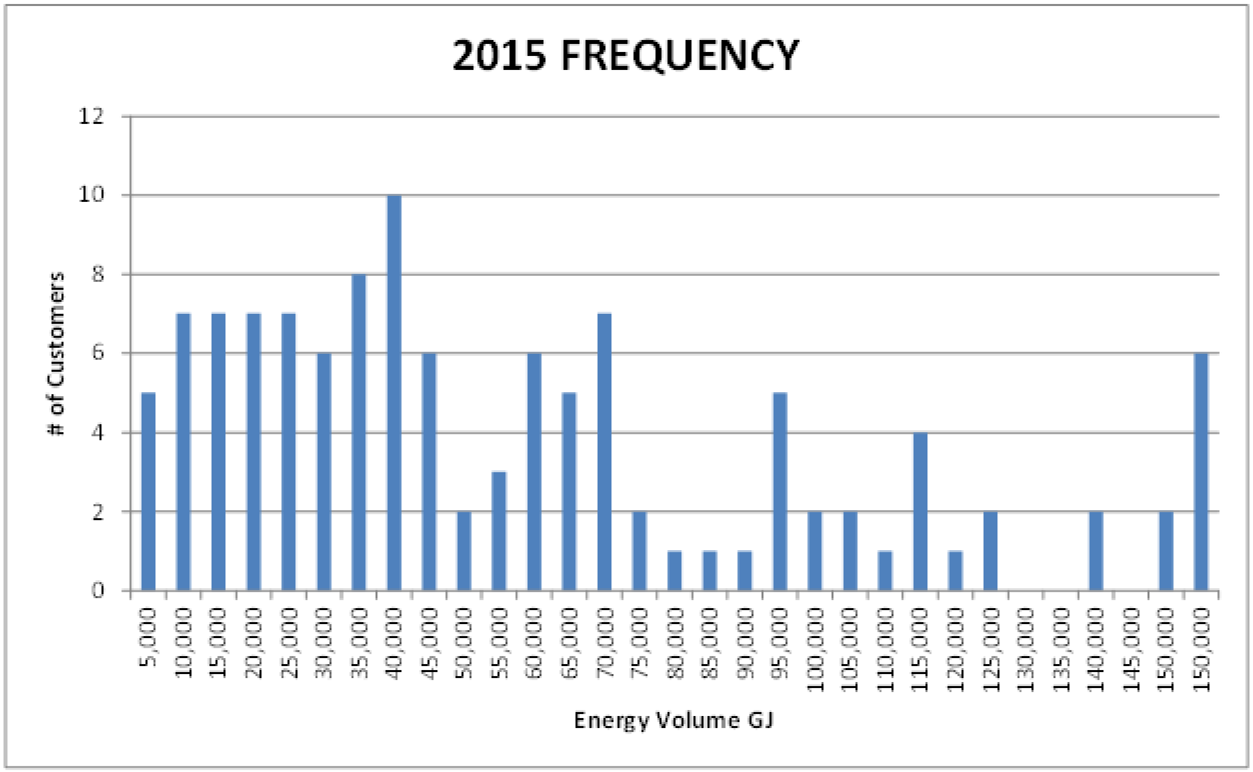
Rate Schedule 7 is an interruptible sales service, and Rate Schedule 27 is the corresponding transportation service available to small industrial and large commercial customers who have the ability to curtail their usage during system capacity constraints. Rate Schedules 7 and 27 are intended for use by small industrial and large commercial transportation customers with gas consumption, generally, of less than 12,000 GJ per month.

As noted above in Table 3-1, 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 7-7 below shows that the annual demand from these customers may range from about 5,000 GJ to 150,000 GJ. However, the key factor for rate design for interruptible rates is not the annual demand, but rather the customer's ability to use interruptible service. During periods of high FEI system demand,

[16] As noted above in section 7.3.3 and row 6 of Table 7-4, the Modified Formula in column 7 has an approximately 29% lower estimate of peak customer demand than the Current Formula shown in column 2.

interruptible customers must be able to curtail their gas usage (by either reducing production or utilizing backup fuel capability) upon short notice.

Figure 7-7: Rate Schedules 7 and 27 Combined Bill Frequency



7.4.2 Review of Current Rate Structures

The rate structure for Interruptible Sales and Transportation Service includes a basic charge (monthly) and a delivery charge. Transportation Service has an additional administration charge. These charges are shown in Table 7-7.

Table 7-7: Current FEI Rates for Interruptible Sales and Transportation Service

Rate Schedule	Basic Charge per Month	Administration Charge per Month	Delivery Charge per GJ	Commodity Cost Recovery Charge per GJ	Storage and Transport per GJ
Rate Schedule 7 ***General Interruptible Sales Service***	$880.00	n/a	$1.353	$1.141	$0.681
Rate Schedule 27 ***General Interruptible Transportation Service***	$880.00	$78.00	$1.353	n/a	n/a

7.4.3 Rate Design Options Considered and Potential Impact

To encourage customers to accept interruptible service, FEI offers the service at a discount to the firm service. This discount considers such factors as:

- the customers 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

The interruptible rate is intended to establish a sufficient discount from the prevailing firm service rate to encourage customers to accept interruptible service. In return, FEI is able to improve the overall system utilization by curtailing the interruptible service during periods of high system demand or for other operational reasons. Interruptible service is of value to FEI since these customers may be curtailed during periods of peak system demand meaning that FEI will not need to build additional capacity and incur related costs to meet their demand.

FEI seeks to find a suitable price discount from firm service to balance a number of objectives. If the discount is too low, this may discourage new customers from considering interruptible service and may also cause existing interruptible customers to revert back 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 – effectively receiving firm service at a discount. Additionally, setting the rate too low may not achieve sufficient recovery of FEI costs

When establishing the interruptible discount from firm service, FEI attempts to balance all of these considerations.

During the 2001 Rate Design Settlement, FEI established an interruptible discount based upon an 80% load factor when compared to the firm rate for Rate Schedule 5. For illustrative purposes, an example of the interruptible delivery charge calculation is provided below in Table 7-8. The table also compares the rates in place in 2001 with the current rates, comparing the firm delivery costs for Rate Schedule 25 customers to interruptible delivery costs for Rate Schedule 27 customers at an 80% load factor.

Table 7-8: Rate Schedule 5 Comparison to Rate Schedule 7 at 80% Load Factor

Rate Schedule	2001	2016 - Current	
Rate Schedule 5 ***General Firm Sales Service***	$0.509	$0.825	*Demand*
	$0.502	$0.825	*Delivery*
	$1.011	**$1.650**	***Total***
Rate Schedule 7 ***General Interruptible Sales Service***	**$0.836**	**$1.353**	***Delivery Charge For Rate Schedule 7***
Differential (per GJ) ***Rate Schedule 5 – Rate Schedule 7***	**$0.175**	**$0.297**	
Discount as a Percentage of Total Firm	**17.3%**	**18.0%**	

As this comparison illustrates in Table 7-8, there has been no deterioration between the avoided cost of firm service and the BCUC approved interruptible delivery charge under which these customers are receiving service. In fact, the value of the discount between the cost of firm and interruptible service has increased, but the relative percentage of the discount to the firm service has remained relatively static (17.3% in 2001 versus 18.0% in 2016). The amount of the discount is viewed as being appropriate as FEI has not experienced movement of customers shifting from interruptible service to firm service or from firm service to interruptible service. FEI concludes the amount of the discount is appropriate relative to the Firm Service.

7.4.4 Rate Design Recommendations

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 customer to stay on interruptible service and to encourage new customers to convert to interruptible service.

FEI is considering to retain the current rate structure and to continue with the existing practise of calculating Rate Schedule 7 and Rate Schedule 27 delivery charges according to an 80% Load Factor. The Company has strived to ensure its interruptible charges are reflective of the value of service provided, and also provide sufficient incentive to encourage customers to remain interruptible or for new customers to consider switching to interruptible service.

7.5 SEASONAL FIRM SERVICE: RATE SCHEDULE 4

7.5.1 Seasonal Customer Characteristics

Customers in this category use natural gas primarily during the summer months, but occasionally may have demand that develops during the winter periods. These customers are served under Rate Schedule 4 - Seasonal Firm Gas Service. This rate group is comprised of 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 terajoules (TJ). These customers require firm gas delivery during the Company's off-peak demand period. Seasonal service is only firm during the Off-Peak Period (April 1 – October 31) and is only available on an interruptible basis during the winter Extension Period (November 1 – March 31).

The unique needs of these customers distinguish them from firm service customers who require firm service year round 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.

7.5.2 Rate Design Considerations

The design of the seasonal rate was established during the 1996 Rate Design with the off peak firm delivery charge set equal to the delivery charged for the Rate Schedule 5 General Firm Service rate. The delivery charge for the seasonal rate during the Extension Period was set at 1.5 times the delivery charge for the Rate Schedule 7 General Interruptible Service rate. The rationale for the extension rate was to set a rate level that would discourage the General Interruptible Service customers from migrating to the seasonal rate. That is, interruptible service customers who use gas throughout the winter period with rare curtailment during Company peak demand periods are not the same as a seasonal customer who does not generally use gas during the winter but may have occasional needs that occur just before or immediately after the summer season.

FEI intends to continue to set the seasonal service rates in the same manner as described in the above paragraph.

7.6 LARGE VOLUME TRANSPORTATION: RATE SCHEDULE 22 AND LARGE INDUSTRIAL CONTRACT CUSTOMERS

7.6.1 Customer Characteristics

Large volume transportation customers are served under Rate Schedules 22, 22A and 22B. The large volume transportation service under Rate Schedule 22 is for customers with a minimum delivery volume of 12,000 GJ per month (take or pay). There is no minimum delivery volume for Rate Schedules 22A and 22B 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. Rate Schedules 22A and 22B are a combination of firm and interruptible service while Rate Schedule 22 is primarily interruptible service.

There are 40 customers in the combined Rate Schedules 22/22A/22B rate group who consumed a total of approximately 27,500 TJ during 2015. Approximately half of this consumption was for interruptible transportation but some was for firm transportation.

7.6.1.1 Rate Schedule 22 – Large Volume Transportation Customers

There are 26 Rate Schedule 22 customers with 25 of the customers being located in the Lower Mainland and 1 customer in the Interior. During 2015, these customers consumed approximately 12,775 TJ. These customers represent industries varying from refineries, manufacturing, cement, forestry, healthcare, education, food beverage and greenhouses. They generally use natural gas to fuel boilers, kilns and dryers. Due to the variety of industry sectors, consumption ranges from approximately 150,000 GJ to 2,000,000 GJ per year. All of these customers are receiving interruptible transportation service, with the exception of one that uses a small amount of firm transportation service. The Rate Schedule 22 tariff allows for firm transportation service however the applicable delivery charges are subject to negotiation and prior approval by the Commission.

7.6.1.2 Rate Schedule 22A (Closed) – Inland Service Area Customers

Rate Schedule 22A is only available to large industrial customers who were receiving transportation service prior to 1993 in the Inland Service Area. There are 9 customers in Rate Schedule 22A who consumed approximately 9,535 TJ during 2015. These customers include mining operations, manufacturing, refineries, pulp mills and forestry companies, which primarily uses firm transportation service with a small amount of interruptible service.

Since the 1993 Phase B Rate Design Decision Rate Schedule 22A customers have been grandfathered in recognition of the unique service offering for the firm and interruptible rates and therefore Rate Schedule 22A is closed to new customers. Rate Schedule 22A non-bypass customers are still subject to general rate changes. However, unlike Rate Schedule 22 customers, Rate Schedule 22A customers have a curtailment of firm service provision that provides peaking gas supplies to sales customers and these quantities are included as part of the Annual Contracting Plan.

7.6.1.3 Rate Schedule 22B (Closed) – Columbia Service Area Customers

Rate Schedule 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 Rate Schedule 22B who consumed approximately 6,013 TJ of natural gas during 2015. These customers include four coal mines and a pulp mill. There is one customer in this rate group which has lower rates than the other four customers. These lower rates were negotiated in the 1994 Columbia Industrial Rate Design, which recognized the customer could be a ‘bypass’ candidate due to its proximity to the TransCanada system and size of load.

Since the Phase B Rate Design Decision and the Columbia Industrial Rate Design Decision in 1994, Rate Schedule 22B customers have been grandfathered in recognition of the unique service offering for setting their firm and interruptible rates and therefore Rate schedule 22B is closed to new customers. Rate Schedule 22B customers rates are still subject to general rate changes. Unlike Rate Schedules 22 and 22A, Rate Schedule 22B allows monthly balancing. Gas delivered to the customers under Rate Schedule 22B is predominantly firm service with a small component that is interruptible.

7.6.1.4 Large Industrial Contract Customers

In addition to the combined Rate Schedules 22/22A/22B rate group, there are two other large industrial contract customers located on Vancouver Island/Sunshine coast: These customers are the Vancouver Island Gas Joint Venture (JV) and BC Hydro's Generation facility (BC Hydro ICP). The JV 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 will be working with the JV on a new agreement as part of this rate design process. The BC Hydro ICP has a firm service contract for 40,000-50,000 GJ per day which expires in 2022.

7.6.2 Existing Rate Design for Large Volume Transportation Customers

The following table shows the rate structure and type of charges currently applicable to Rate Schedules 22, 22A and 22B:

Table 7-9: Large Volume Transportation and Contract Customers' Charges

Rate Schedule	Basic Charge per Month	Administration Charge per Month	Delivery Charge per GJ	Delivery Charge per Month per GJ of Firm DTQ	Delivery Charge per GJ of Firm MTQ	Delivery Charge per GJ of Interruptible MTQ
Rate Schedule 22 ***Large Volume Transportation Service***	$3,664.00	$78.00	$0.982 (Interruptible)[1]	n/a	n/a	n/a
Rate Schedule 22A ***Transportation Service (Closed) Inland Service Area***	$4,810.00	$78.00	n/a	$15.704	$0.110	$1.241
Rate Schedule 22B ***Transportation Service (Closed) Columbia Service Area***	$4,537.00	$78.00	n/a	$10.137	$0.108	$1.011 Apr 1 – Oct 31 $1.455 Nov 1 – Mar 31
Vancouver Island Joint Venture ***Contract***	n/a	n/a	n/a	n/a	$0.9665[2]	***Tier 1 IT*** 13-20 TJ $0.9665 ***Tier 2 IT*** 20-30 TJ $0.7608 ***Tier 3 IT*** 30+ TJ $1.0632
BC Hydro / Island ICP[3] ***Contract***	n/a	n/a	n/a	n/a	$0.958	***Winter IT*** $1.458 ***Summer IT*** $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.*

7.6.2.1 Rate Schedule 22

The interruptible delivery charges in Rate Schedule 22 are based on the firm Rate Schedule 25. The methodology that was applied for Rate Schedules 7/27 (General Interruptible sales and transportation service) to adjust Rate Schedule 25 for an 80% Load Factor is also applicable for Rate Schedule 22 but at a 100% Load Factor and was adjusted as a result of the negotiated settlement in the 2001 Rate Design Application approved by the Commission. If Rate Schedule 22 customers want a portion of their delivery service to be on a firm basis then firm delivery charges are required to be negotiated and approved by the BCUC as a tariff supplement on a contract by contract basis. The one current Rate Schedule 22 customer that has firm service had rates approved by the BCUC but the BCUC concluded that the proposed rates under Tariff Supplement G-21 should be reviewed in the next FEI Rate Design proceeding; therefore FEI will be reviewing firm delivery rates for Rate Schedule 22 as part of this Rate Design process.

7.6.2.2 Rate Schedule 22A

The service under Rate Schedule 22A is primarily firm service with a small component on an interruptible basis. As shown in Table 7-9 above, the firm delivery charges are comprised of a firm demand charge per month per GJ of Firm Daily Transportation Quantity (DTQ) and firm variable delivery charge per GJ of Firm Monthly Transportation Quantity (MTQ) delivered per month. The pricing for interruptible service is variable per GJ on any volumes over the firm MTQ and the interruptible rate is set at a premium of firm service prices to encourage customers to maintain their Firm DTQ.

7.6.2.3 Rate Schedule 22B

Similar, to Rate Schedule 22A, Rate Schedule 22B is primarily a firm service with a small component on an interruptible basis. As shown in Table 7-9 above, the firm delivery charges are comprised of a firm demand charge per month per GJ of Firm DTQ and firm variable delivery charge per GJ of Firm MTQ delivered per month. The pricing for interruptible service is a variable charge per GJ on any volumes over the firm MTQ but has different interruptible rates during the winter and summer periods. The pricing for interruptible service is set at a premium of firm service prices to encourage customers to maintain their firm DTQ.

7.6.2.4 Contract Customers

As mentioned above, BC Hydro ICP and JV are two Large Industrial Contract Customers. The existing rates for BC Hydro ICP and JV are negotiated rates and these agreements are expiring by 2022 and 2017 respectively. Therefore, FEI is considering potential options to derive rates for Rate Schedule 22 and Contract Customers such as JV and BC Hydro ICP. These options are discussed in the following section.

7.6.3 Rate Design Options Considered

For the Large Industrial customers FEI is currently considering two options.

7.6.3.1 Option 1:

The first option that FEI is considering would involve maintaining the current large industrial rate structures. FEI would continue to grandfather Rate Schedule 22A and Rate Schedule 22B as closed service offerings given their unique characteristics and service offerings and would consider rebalancing Rate Schedule 22A to the 110% revenue to cost ratio as discussed above. FEI would seek to determine both firm and interruptible delivery rates for Rate Schedule 22.

Under this option, FEI would use the existing methodology as discussed in section 7.6.2 above to set interruptible delivery charges for Rate Schedule 22 customers. FEI will review existing methodology for setting firm delivery charges for Rate Schedule 22 customers. FEI would propose to continue to maintain BC Hydro ICP and the Joint Venture customers as Large Industrial Contract Customers with negotiated rates. The revenues from BC Hydro ICP and the Joint Venture would continue to be treated as a credit in the COSA model.

7.6.3.2 Option 2:

The second option that FEI is contemplating would be to continue to grandfather Rate Schedule 22A and Rate Schedule 22B as closed service offerings given their unique characteristics and service offerings. Currently, the revenue to cost ratio for Rate Schedule 22A in the COSA is 180% which is outside the range of reasonableness of 90% to 110%. For discussion purposes only, FEI has examined changing the rate levels to achieve revenue to cost ratio of approximately 110%. As shown in Table 4-1, this would result in a $3.5 million revenue responsibility transfer from Rate Schedule 22A to Rate Schedule 1 customers. The revenue to cost ratio in the COSA model for Rate Schedule 22B is 101% which is within the range of reasonableness of 90% to 110%.

As FEI needs to review firm rates for Rate Schedule 22 as part of this Rate Design, FEI is considering changing the rate structure components so that there are both firm and interruptible delivery charges for Rate Schedule 22 approved as part of the RDA process. FEI recommends to group similar type of customers i.e. Rate Schedule 22 customers, BC Hydro ICP and JV to derive firm rates based on the cost of service allocation results. BC Hydro ICP and JV would still be considered Large Industrial Contract Customers given their service characteristics and other terms and conditions included as tariff supplements but their firm rate would be based on the allocated costs from the COSA model.

FEI is still working to come up with a methodology for setting interruptible charges under this option.

7.6.4 Summary of Large Volume Transportation Customers

FEI needs to review the firm rates for Rate Schedule 22 customers as a part of the RDA. FEI will also be working with the JV and BC Hydro ICP as their agreements will be expiring in 2017 and 2022 respectively.

As discussed above, FEI is evaluating potential options to adjust the revenue to cost ratio for Rate Schedule 22A customers and derive a firm and interruptible rate for Rate Schedule 22, BC Hydro and JV. FEI has further work to do in determining the firm and interruptible rate methodology for Rate Schedule 22 but FEI understands that the industrial rate schedules such as Rate Schedule 22, Rate Schedule 27 and Rate Schedule 25 cannot be looked at in isolation but need to be looked at as a suite of service offerings and the appropriate price signals need to be maintained across the rate schedules to support the rate design for those rate schedules.

These options are further discussed in section 8.3.

8. KEY DISCUSSION TOPICS

FEI has identified some areas of the existing rate design and segmentation that should be evaluated for changes which FEI would like to discuss at the workshop.

8.1 MISALIGNMENT BETWEEN FIXED COSTS AND CHARGES FOR RESIDENTIAL CUSTOMERS

As stated in section 5.3, for Residential customers the majority of FEI's delivery costs are fixed and do not vary by the changes in consumption level. This contrasts with the fixed and variable charges in Rate Schedule 1 which result in the majority of FEI's delivery revenue being recovered through variable charges.

FEI would like to discuss with stakeholders the reasonableness of adjusting the ratio of basic charge to variable charge for residential customers so that for an average use customer there is no annual bill impact. The appropriate percentage increase to the basic charge would depend on various factors such as the annual bill impact to the low consumption residential customers and the magnitude of misalignment between fixed costs and charges.

8.2 DEMAND CHARGE APPLICABLE TO RATE SCHEDULE 5 AND RATE SCHEDULE 25 GENERAL SERVICE CUSTOMERS

In section 7.3 above, FEI discusses the two issues which FEI seeks to resolve. These two issues are summarized here for discussion.

1. The method of estimating a customer's peak demand for billing purposes - A 1.25 multiplier was established in the 1993 Phase B Rate Design due to numerous customers that did not have daily demand meters. This multiplier factor was used to adjust a customer's monthly demand, as measured during the monthly billing cycle, into an estimate for their Daily Demand. Today, all these customers have daily meters and so this multiplier is no longer necessary. FEI would like to improve the Daily Demand value for billing purposes by using daily measurement data. The options considered by FEI are discussed above in section 7.3.3.
2. The large number of low load factor customers within Rate Schedule 5 and 25 – The demand/variable delivery rate structure for Rate Schedule 5 and 25 was established for high load factor general firm service customers. However, these schedules have attracted a number of high volume but low load factor customers. This is discussed above in section 7.3.4. FEI would like to adjust the relative economics between Rate Schedules 3/23 and Rate Schedules 5/25 to remove the economic incentive that attracts low load factor customers by raising the Rate Schedule 25 demand charge. By making the rate changes, customers will have price signals that will encourage those with a load profile similar to a large commercial (less than 40% Load Factor) to receive Service under Rate Schedules 3 and 23 for which that Rate Schedule is intended for.

8.3 *LARGE VOLUME TRANSPORTATION AND INDUSTRIAL CONTRACT CUSTOMERS: RATE DESIGN OPTIONS*

As discussed in section 7.6.7, FEI is considering two potential rate design options to address the needs and requirements for its Large Volume Transportation Customers.

Under both of these options, FEI intends to continue to grandfather Rate Schedules 22A and 22B. Based on current COSA results, FEI notes that the revenue to cost ratio for Rate Schedule 22A is outside the range of reasonableness. The appropriate revenue to cost ratio will not only be guided by the range of reasonableness for a rate class but also taking into consideration its cost impact on customers served under different Rate Schedules. In section 4.1, FEI has calculated that adjusting revenues for Rate Schedule 22A to achieve revenue to cost ratio of 110% would shift $3.5 million of revenue responsibility to other rate schedules. For discussion purposes, Table 4-1 in section 4.1 shows the approximate annual bill change if the revenue responsibility is shifted to residential customers. FEI would like to consider inputs on the rebalancing approach at the workshop.

The second point for this discussion topic is to consider inputs on FEI's consideration on rate design options for Rate Schedule 22 customers and the large industrial contract customers such as Joint Venture and BC Hydro ICP. FEI has considered two options as discussed in section 7.6.3.

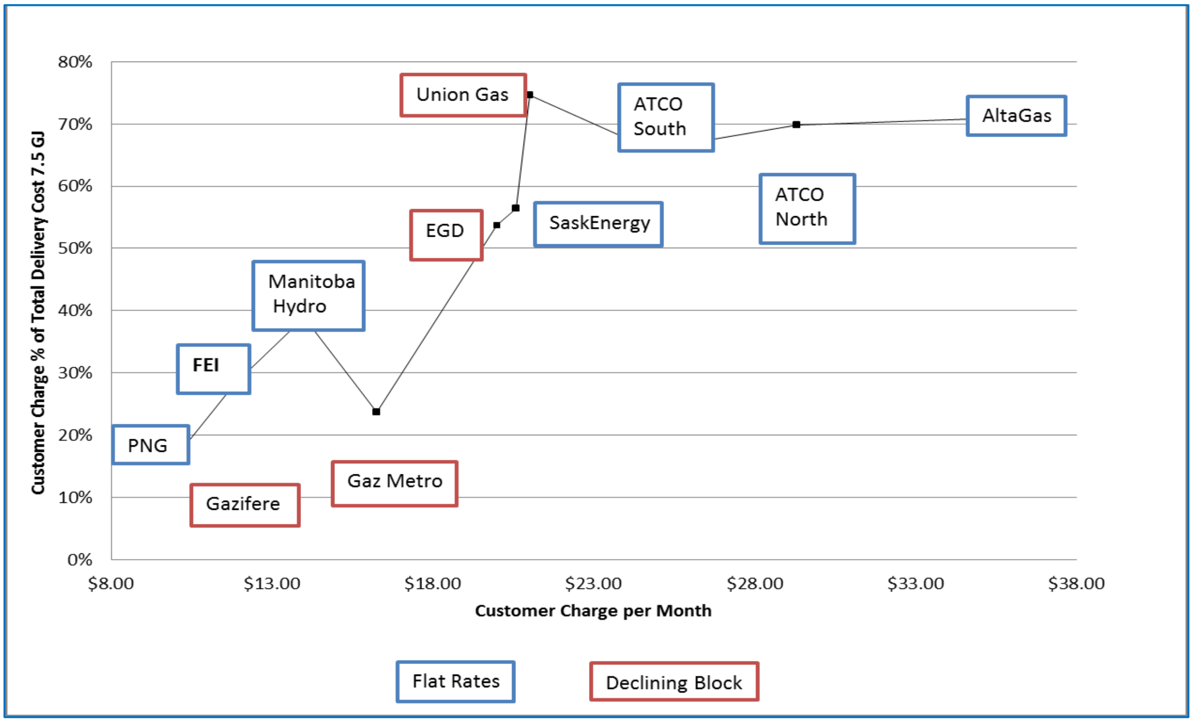
- The first option would be to keep the two large industrial contract customers separate with negotiated rates and for the purposes of the COSA would treat the revenues from these two customers as credits to all other customers. FEI will use existing methodology (i.e. based on Rate Schedule 25 100% load factor adjusted) to set interruptible delivery charges for Rate Schedule 22 customers. FEI will review and determine appropriate methodology to set firm delivery charges.
- The second option would be to include these large industrial contract customers under Rate Schedule 22 for deriving a firm rate based on the allocated costs in the COSA model. The firm delivery charges for these customers would then be based on the results from COSA model. FEI is still working on a methodology to come up with the interruptible rates under this option. Under this option, the contracts with the two large industrial contract customers would be included as Tariff Supplements.

Appendix A

JURISDICTIONAL COMPARISON OF RESIDENTIAL CUSTOMERS

FEI retained the services of EES Consulting to conduct a jurisdictional comparison study and review the applicable rate structures for residential customers in other major Canadian provinces. The summary result of this study is provided in the Figure below.

Figure 1: Rate structures for residential customers in various Canadian natural gas distributors



- 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 class (South Ontario region) is presented.

As can be seen, the Y-axis in the chart presents the percentage of monthly fixed charge (customer or basic charge) to total delivery charges based on a 7.5 GJ consumption per month. The presentation of data with a specific monthly consumption amount will assist the reader to compare the basic charges in each utility on a more meaningful basis.

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[1]. This can partially explain the significantly higher basic charges and percentage of fixed charge to total delivery charge for these utilities as commercial customers traditionally have higher basic charges than separately administered residential rate classes.

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

Appendix 4-4

MARGINAL COST STUDY

FortisBC Energy Inc.
Review of Marginal Cost for Delivery of Natural Gas

December 2016

Prepared by:

EES Consulting

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Kirkland, Washington 98033

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EES Consulting

December 15, 2016

Mr. Atul Toky
Manager, Tariffs, Rate Design and Special Contracts
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, B.C. V4N 0E8

SUBJECT: Review of Marginal Cost for Delivery of Natural Gas

Dear Mr. Toky:

Please find attached the Review of Marginal Cost for Delivery of Natural Gas prepared by EES Consulting. The conclusions and recommendations contained within this report are consistent with industry practice.

This study has been developed independently by EES Consulting, with information provided by FEI staff, as needed. The findings, conclusions and recommendations of this report provide the basis for consideration of the marginal cost associated with the delivery of natural gas when developing the delivery rates for the FEI customer groups.

Thank you for the opportunity to assist FEI in this process. Please contact me directly if there are any questions about the subject analyses.

Very truly yours,

Gary S. Saleba

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President

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Kirkland, WA and Portland, OR

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Executive Summary

This report is provided to Fortis Energy, Inc. (FEI) in support of its 2016 Rate Design Application (RDA). EES Consulting has provided assistance to FEI throughout the process by providing a assistance with COSA and rate design analysis. As part of that assistance, EES Consulting looked at the marginal cost of delivering natural gas for FEI.

The marginal cost analysis developed for FEI is based on appropriate methodologies and takes into account standard practice as well as analysis previously approved by the Commission. Two methods were developed to determine the marginal cost of gas for FEI. The first approach relies on the Rate Impact Analysis (RIA) used for FEI's 2015 System Extension Application. The second approach relies on the results of the 2014 LTRP.

The RIA looked at the total cost to the utility divided by the total system use in GJ with and without the inclusion of 7 years' worth of customer additions. The analysis included all of the capital costs associated with connecting new customers to the system, including meters & regulators, services and mains. Based on this capital amount and the growth in customers, annual costs were calculated and included O&M, return, depreciation and taxes. The RIA shows a marginal cost of $3.77 per GJ, which is 19% below the average system cost for the 2015 revenue requirement. This estimate is appropriate only in the case where sales are based on the addition of new customers and reflects a medium time frame.

To develop the long-run marginal cost for delivery service for FEI, the costs associated with the facilities identified in the 2014 LRTP were considered along with the projected growth on the system. In this case the only item identified was the Okanagan Reinforcement Project. Planning for the 2017 LTRP is currently underway and based on that planning this project has been deferred to a 2020 time frame and a rough estimate of the cost is $140 million. The levelized cost included the O&M, return, depreciation, property taxes and income taxes associated with the project. The resulting long-run marginal cost is $0.20 for the system overall and is based on a 20-year planning horizon. This amount is appropriate for growth in GJ from existing customers.

For the long-run cost associated with growth from new customers, the total system levelized cost of $0.20 would need to be added to this $3.77 per GJ resulting from the RIA. The result in this case is still below the average embedded cost of delivery service.

In both cases the marginal cost is well below the average embedded cost of gas delivery. This would indicate that costs for all customers will be lower as a result of growth in sales and/or customers on the system. In terms of rate design, there is no cost basis for a change in the current rate structure.

Marginal Cost Overview

To assist in assessing the various rate design principles, we have provided a review of the marginal cost of delivery service for the FEI system. Our findings show that in the case of FEI, the marginal cost is below the embedded cost of delivery service. This is consistent with expectations and the fact that FEI is not facing large capital investments in its delivery system to accommodate growth on the system.

While the COSA reflects an embedded approach rather than a marginal cost approach, it is useful to look at the marginal costs of the utility when developing rate design to ensure that customers receive the appropriate price signals. Note that this review is limited to the delivery of natural gas. The COSA and the rate design proposed by FEI are both related solely to the delivery service provided and excludes the cost of gas. Because the cost of gas is collected in a flow-through of costs separate from the delivery rates, it is not appropriate to consider the cost of gas when designing the delivery rates.

FEI charges separately for the cost of gas (including midstream costs) and for the delivery of gas, therefore the marginal cost needs to be looked at separately for the two functions. FEI bases the cost of gas on the price of purchasing gas from the market as it does not develop its own sources of supply. The cost of gas is updated quarterly and is designed as a flow-through of costs. It would be inappropriate to charge more than the actual cost of gas that FEI is actually paying given the flow-through methodology. In the short-term the marginal cost of gas supply is the same as what FEI actually pays for the gas supply from the market, and this price is passed on to the customer. While the cost of gas may be expected to increase in the future, the cost of gas rates will continue to move with the market price of gas and future customers will pay the market price at the time it occurs in the future. Further, expectations about future costs are typically reflected within the market price of natural gas.

For the delivery of gas, it is appropriate to consider the marginal cost of gas as one of many factors in designing the rate structure. However, the overall level of delivery rates is based on an embedded cost approach. This is true both on an overall system basis and for individual customer groups. The level of delivery rates for each group is informed by the COSA results and the resulting revenue to cost ratios for each group. As the COSA for delivery costs is based on an embedded approach, the results will also reflect the embedded cost of gas by customer group. So while the marginal cost of delivery service may be useful in looking at components within the rate design, it would not be appropriate for setting the overall level of rates.

Marginal cost can reflect both short-term and long-term costs. In the short term, the use of additional GJ on the system is unlikely to cause any additional costs to the distribution system as it is already built to meet maximum design day consumption. There would be an additional cost to purchase the equivalent amount of natural gas from the market, and that cost is accounted for in the flow-through to the customer. In the long-term it is necessary to look at the cost of adding capacity to the distribution system to meet additional growth. As with the short-term, the cost of gas and wholesale pipeline capacity would also need to be considered but that would be included in the cost of gas flow-through rather than the delivery rates.

To estimate the marginal cost of delivery service, the approach must be consistent with the time-frame to consider. As mentioned above, in the short-term FEI has sufficient capacity on the delivery system to accommodate additional GJ sales to existing customers. This surplus exists for two reasons. The first reason is that the system is planned for meeting the design day demand level, which far exceeds the daily demand on non-peak days of the year and also exceeds the peak day demand in the majority of years. The second reason is that average use per customer, particularly for the residential rate group, has been steadily declining over time. This frees up capacity on the system for load growth from other customers.

In a medium time frame the addition of new customers' needs to be considered as well as growth in sales to existing customers. There are added costs associated with building new delivery facilities to serve customer additions. This includes the cost of the meter, the service line and new mains that are required for service. These costs were extensively reviewed in the recent 2015 System Extension proceeding where a Rate Impact Analysis (RIA) was included and accepted by the Commission. A detailed discussion of the marginal costs in that context are included below.

In the long term, the marginal cost of delivery needs to consider the long-term projects required to meet the expected load growth on the system. FEI prepared the 2014 Long Term Resource Plan (LTRP) to determine its needs for capacity additions over a 20-year planning horizon. The findings of that LTRP are the appropriate basis for reviewing the long-run marginal cost of delivery service. The results of the approach are discussed below. Using the results of the LTRP is consistent with the approach used to develop the LRMC for electricity for both BC Hydro and FortisBC.

It is important to note the distinctions between the gas and electric industries. On the electric side, the LRMC is currently used as a tool in setting the Residential Inclining Block (RIB) rates for BC Hydro and FortisBC. In this case, the LRMC primarily includes the cost of building new generating resources to provide power to meet the load growth of the utility. This is appropriate because the electric rates include the cost of both the generation and delivery of power. A reduction in power consumption can contribute to the avoidance or delay of new generating resources. In the case of BC Hydro and FortisBC, the marginal cost of power is well above the embedded cost of power.

For the gas utility, load growth will not lead to the addition of new gas production facilities for FEI directly as it does not produce its own gas supplies. Therefore the results will differ considerably from the electric utility because the cost of energy supply is not included in the marginal cost. In our estimates, the marginal cost of delivery service for gas is currently below the embedded cost of delivery service.

Rate Impact Analysis

As part of its application for changes to the system extension policies, as filed in the 2015 System Extension Application, FEI included a Rate Impact Analysis (RIA) to assist in determining whether new customers added to the system were paying their fair share of the cost of extending service. The use of the RIA was approved by the Commission in Order G-147-16.

The RIA looked at the total cost to the utility divided by the total system use in GJ with and without the inclusion of 7 years' worth of customer additions. The analysis included all of the capital costs associated with connecting new customers to the system, including meters & regulators, services and mains. Because customers are often required to make a Contribution in Aid of Construction (CIAC), those costs are born by the new customer and are not included in the RIA. Rather than using the full capital cost added to rate base associated with the new connections, the amount that would be included in the revenue requirements was developed. This reflects the costs that are used in developing rates for delivery service. This meant applying the return, depreciation and taxes applicable to the capital additions, forming the starting point for the incremental costs of adding new customers.

In addition, growth in O&M expenses was included to reflect the additional O&M costs related to customer growth. This was set at 50 percent times the growth rate in the number of customers, consistent with the PBR regulations. Finally, incremental costs associated with growth and sustainment were added based on 50 percent times the growth rate in the number of customers. This addition was based on direction from the Commission in Order G-147-16.

The incremental sales associated with 7 years' worth of customer additions was also determined. The added GJ was based on the actual customer additions multiplied by the weighted average use per customer for those added customers.

The results from the RIA are provided in the table below. To determine the incremental or marginal cost of delivery service, the total incremental costs associated with the 7 years of customer additions ($38.6 million) was divided by the total incremental sales (11.45 million GJ) associated with the 7 years of growth. The result is $3.77 per GJ, as shown in line r of the table. This is 19% below the total system average delivery cost of $4.16 per GJ.

The RIA was developed to demonstrate that customer additions were not leading to higher rates for existing customers. In fact, the analysis showed that existing customers faced lower rates as a result of customer growth. This finding is consistent with marginal costs that are lower than embedded costs. More detailed discussion of the RIA can be found in the Application and resulting Decision.

It is important to note that the RIA was done for the system as a whole and not for individual customer groups. Looking at separate groups was not possible as mains were built for a mix of customers and could not be separated by customer group. The average system cost of $4.16 per GJ and the marginal cost of $3.77 per GJ are therefore for the system as a whole and may be more or less than the costs by customer group. It is important to point out, however, that while the incremental cost may be more or less than the average, the embedded cost by customer group would also be more or less than the average. We would expect the relative difference between the embedded cost and incremental cost to be similar between various rate groups.

Using the RIA is a good representation of the marginal cost over a medium time frame in the case when growth is a result of customer additions. It is not reflective of the marginal cost per GJ for added sales from existing customers when new meters, services and mains are not required.

Table 1
Rate Impacts Associated with Line & Mains Extension

Actual data
Formula driven results based on actual data and general assumptions

Section			2015 With Growth	2015 Without Growth	2008-2014 Growth Amount
This section uses existing actual delivery costs and looks at the impact on revenue requirements without the addition of capital for the new customers added in the past 7 years. (2008 to 2014).	A	2008-14 Meters/Regulators			$16,026,762
	B	2008-14 Services (Company Paid)			$119,082,263
	C	2008-14 Mains (Company Paid)			$58,435,929
	D	2008-2014 SJ and Internal Costs			$7,228,180
		50% Growth Sustainment			$2,775,000
	E	Rate Base	$3,656,399,000	$3,452,850,867	$203,548,133
	F	Return, Depreciation, Taxes	$522,883,000	$494,745,441	$28,137,559
	G	Multiplier for Return, Depreciation, Taxes	13.8%	13.8%	13.8%
	H	O&M Expenses	$238,093,000	$227,622,688	$10,470,312
	I	50% of Customer Growth Rate			4.4%
	J	Other Revenues/Expenses	-$3,942,000	-$3,942,000	$0
	K	Offsetting Bypass Revenues	-$29,802,000	-$29,802,000	$0
	L	Total Revenue Requirement (exc. Cost of Gas)	$757,034,000	$718,426,129	$38,607,871
	M	**Net Revenue Requirement (exc. Cost of Gas)**	**$727,232,000**	**$688,624,129**	**$38,607,871**
This section determines the usage associated with and without customers added to the system in the past 7 years.	N	Customers	970,399	885,051	85,348
	O	Percent Growth in Customers			8.8%
	p	Average GJ/Cust	180	184	134
	q	**Total GJ**	**174,623,400**	**163,169,382**	**11,454,018**
This section calculates the rate impact without the new customers added from 2008 to 2014.	r	**Cost per GJ (exc. Cost of Gas)**	**$4.16**	**$4.22**	**$3.77**

Long Term Resource Plan

On a long run basis, the need for additional capital facilities associated with system growth is the most appropriate method to determine the long-run marginal cost for gas delivery. The 2014 LTRP examines the capital needs for the system over a 20-year period.

System loads are forecast in the LTRP and are expected to increase from 202,346 TJ in 2016 to 233,353 TJ in 2033. To develop a full 20-year forecast we extrapolated the results to the year 2035. The result is a growth of 40,403 TJ, or 20%, over a 20-year period.

Over that time period, the need for capital projects is discussed on a regional basis within the LTRP. The following paragraphs summarize the projects identified in the LTRP.

For the FEVI region a capacity constraint was identified in 2028 with the range being in the period 2024-2031. Because there are operational solutions to manage the constraint, no costs have been assigned to alleviate this constraint.[1]

Capacity needs associated with new Industrial loads were identified in the LTRP, with the potential Woodfibre Plant used as an example.[2] FEI has already developed a process associated with the addition of a new large load through the development of Rate 50. Under Rate 50, the incremental cost of facilities to serve the new customer is included in the rates and a 15-year contract is required. Because the customer is assumed to cover the cost of the incremental facilities, no costs have been assigned as a result of this type of potential project.

In the Coastal system, the LTRP states that the Fraser Valley and Metro Vancouver areas both have sufficient capacity to meet the long term forecast.[3] In the Coquitlam area, the Nichol to Coquitlam line is constrained with gas use at Burrard included. With Burrard phased out, there is no need for capacity reinforcements during the planning horizon.[4]

Finally, within the Interior System, an immediate need for ITA expansion was identified for the Okanagan region within the 2017-2019 period.[5] The "Okanagan Reinforcement Project" has three potential solutions identified in the LTRP. This is the only project identified in the LTRP as needed to meet the capacity increases resulting from load growth over the long run planning horizon.

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[1] 2014 LTRP, page 105
[2] 2014 LTRP, page 106
[3] 2014 LTRP, page 107
[4] 2014 LTRP, page 109
[5] 2014 LTRP, page 116

While FEI also has a Sustainment Program to repair and replace its existing facilities, these costs are not driven by growth and are required on the basis of the existing loads on the system. Therefore, these costs are not included in the LRMC.

To develop the long-run marginal cost for delivery service for FEI, the costs associated with the facilities identified in the LRTP would be considered along with the growth on the system. In this case the only item identified was the Okanagan Reinforcement Project. Planning for the 2017 LTRP is currently underway and based on that planning this project has been deferred to a 2020 time frame and a rough estimate of the cost is $140 million. The levelized cost was determined using a 2% inflation rate, a 5.81% discount rate, a 6.67% rate of return and a 26% income tax rate.

Table 2
Okanagan Reinforcement Project Costs

	Cost (2020 Estimate)
Addition to Rate Base ($000)	$140,000,000
O&M Expense	$136,833
Property Taxes	$290,481
Depreciation Expense	$1,955,599
Income Tax	$2,410,923
Earned Return	$9,272,781
Cost of Service Margin	$14,066,617
20-year Levelized Cost	$8,195,213
20-Year Growth in Sales	40,403 TJ
Levelized Cost per GJ	$0.20

Based on the 2016 costs, the annual amounts for the entire 20-year period were estimated and then the levelized cost was calculated. When the levelized cost was divided by the 20-year growth in sales on the system, the result is an average cost of $0.20 per GJ. Because this reflects the capital requirements to serve growth over a 20-year period, the amount is appropriate to use as the long-run marginal cost for the delivery system when for growth in GJ that is related to growth from existing customers. When growth from new customers is considered, $0.20 per GJ would need to be added to the $3.77 resulting from the RIA. This total of $3.97 would still be below the average cost from the RIA of $4.16 per GJ.

Summary and Conclusions

The marginal cost of gas is something that can be considered when designing rate structures for FEI. Because the cost of gas supply is differentiated from delivery rates, we have looked at the marginal cost for delivery of gas only for use in examining the delivery rate structure. Two methods were developed to determine the marginal cost of gas for FEI. The first approach relies on the Rate Impact Analysis (RIA) used for FEI's 2015 System Extension Application. The second approach relies on the results of the 2012 LTRP.

The RIA shows a marginal cost of $3.77 per GJ, which is 19% below the average system cost for the 2015 revenue requirement. This estimate is appropriate only in the case where sales are based on the addition of new customers and reflects a medium time frame. For the long-run cost associated with growth from new customers, the total system levelized cost of $0.20 would need to be added to this number. The result is still below the average embedded cost of delivery service.

The LTRP shows a long-run marginal cost of $0.20 for the system overall and is based on a 20-year planning horizon. This amount is appropriate for growth in GJ from existing customers.

In both cases the marginal cost is well below the average embedded cost of gas delivery. This would tend to imply that costs for all customers will be lower as a result of growth in sales and/or customers on the system.

Appendix 4-5

SENTIS RESEARCH INC. RESIDENTIAL CUSTOMER RESEARCH SURVEY REPORT

SENTIS®

FORTIS BC™

Residential Customer Research Final Report

Prepared for: **FortisBC Energy Inc.**

November 21, 2016

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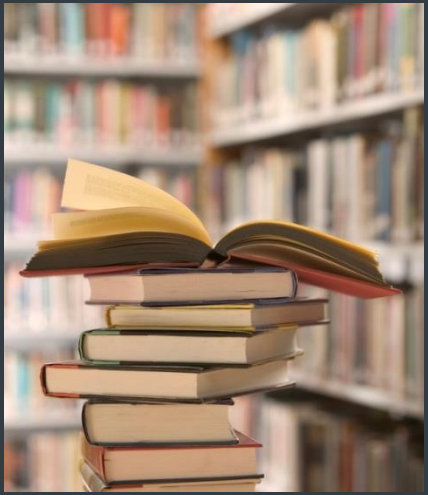

Background and Objectives

Background and Objectives

Research Background and Objectives

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

- FortisBC is also interested in understanding views among its residential customers in Fort Nelson as they do not share the same rates as the rest of the province.

- To this end, FortisBC has determined that a quantitative research survey with residential customers in BC should be undertaken to meet the aforementioned objectives.

About Sentis

Founded in 2011, Sentis Market Research Inc. is a full service market research company owned and operated by senior research professionals. Our office is located in downtown Vancouver.

The Sentis team consist of three senior managers with over 60 years of market search and consulting experience and 16 full-time team members. Together, the Sentis team provides a full range of services including: program design, questionnaire design, sampling, survey programming, data collection, data processing, data analysis, advanced analytics, and reporting.

Background and Objectives (cont.)

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Project Team Members

Adam DiPaula, Sentis Managing Partner

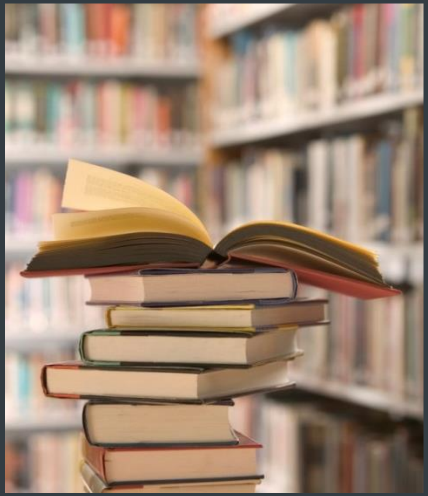
Adam has 16 years of experience designing and conducting customer experience programs, program evaluations and performance measurement studies for a range of crown, government and private sector clients. His recent clients include: FortisBC, go2HR, BC Hydro, Industry Training Authority (ITA), BC Stats, Vancity, the Trucking Safety Council of BC, the Agricultural Land Commission (ALC), Kinder Morgan and Destination BC.

Adam holds a PhD in psychology from UBC.

Tracy Tan, Sentis Project Director

Tracy has eight years of experience managing a wide range of projects for crown, government and private sector clients. These projects include program evaluations, performance measurement studies and usage and attitudes studies. Her recent clients include: FortisBC, BC Safety Authority, BC Stats, TransLink, Destination BC, Industry Training Authority (ITA) and Vancity.

Tracy holds a MSc from the University of Toronto.



Methodology

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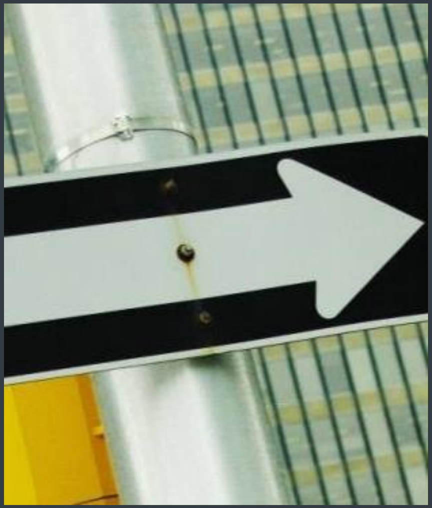
Methodology

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

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

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



Executive Summary

Executive Summary

Natural Gas Bills: Current Customer Behaviour and Clarity of Calculations

Survey results indicate that the majority of customers give their natural gas bills a quick review to ensure everything looks as expected. Furthermore, 25% and 38% of respondents in FEI and Fort Nelson service territories, respectively, claim to "thoroughly review" their bill.

The vast majority of FEI customers (84%) report that they are either very clear (29%) or somewhat clear (55%) regarding how their bill is calculated. Despite being more likely to thoroughly review their natural gas bills, Fort Nelson customers are more likely to report that they are not very clear regarding how their bill is calculated (26%) compared to FEI customers (13%).

Customers who review their bills thoroughly are much more likely to report that they have a very clear understanding of how their bill is calculated. This indicates that customer effort to review the bill in more detail does lead to greater customer understanding. That said, the fact that customers who give their bill a 'quick review' are at least somewhat clear on how their bill is calculated suggests that a high level of effort is not required for customers to feel that they have a relatively clear understanding of their bill.

Awareness of Fixed vs. Variable Charges

Approximately three-quarters of FEI customers were aware of fixed vs. variable charges. In line with their lower level of clarity of how their bill is calculated, Fort Nelson customers are less likely to be aware that their bill is made up of fixed and variable charges with four-in-ten Fort Nelson customers reporting that they were not aware of the two different charges.

Understanding of Bill Components

With the exception of the Storage & Transport charge, a strong majority of FEI customers (eight-in-ten) report understanding each of the charges on their natural gas bill. In contrast, six-in-ten of these customers report understanding the Storage & Transport charge – with only one-quarter reporting that they understand it very well.

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Understanding of Bill Components (cont'd)

Fort Nelson customers are similar to FEI customers in the extent to which they understand each component of their bill. Within each customer group, there is a segment (17% among FEI customers, 22% among Fort Nelson customers) who claim that they understand all of the components of their bill very well.

Fort Nelson Customer Rate Structure Preferences

When Fort Nelson customers are informed that adopting a rate structure that matches the one used in the rest of the province would not impact the annual billing amount for the average customer, only two-in-ten prefer to stay with the current Fort Nelson rate structure. The balance of customers were evenly split between those who prefer adopting the rate structure that matches the rest of the province (42%) and those who do not have a preference either way (37%).

Importance of Rate Setting Principles

The principle that customers believe is the most important one for FortisBC to consider when designing rate structure is that natural gas rates should be easy for the average person to understand.

Fort Nelson and FEI customers differ only in the importance they place on having a rate structure designed to encourage users to use less natural gas and/or avoid high usage during winter months. Fort Nelson customers place much less importance on this principle.

Perceptions of the Impact of Different Rate Structures

Among FEI customers, the flat rate structure is widely perceived to be the easiest to understand. This is the rate structure that is most closely aligned with the principle that customers want to primarily guide FortisBC's rate structure decisions. It is also the structure widely perceived to result in the most stable natural gas prices month-to-month. Opinions are more divided regarding which rate structure would most effectively ensure that higher use customers are not subsidizing low use customers and which rate structure would lead to usage of the system being more evened out throughout the year.

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Perceptions of the Impact of Different Rate Structures (cont'd)

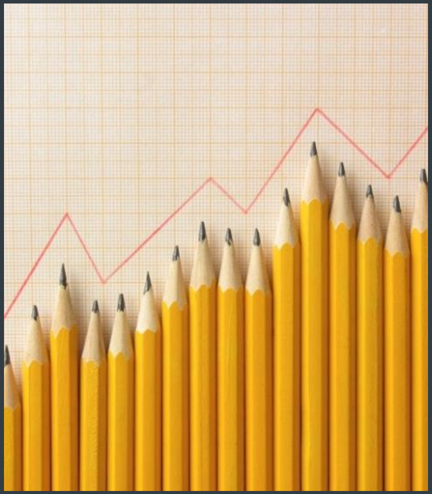
Approximately equal percentages of FEI customers believe that the flat rate structure and the inclining rate structure will minimize the subsidy of low use customers and even out natural gas consumption.

While Fort Nelson customers also think the flat rate structure is the easiest to understand, they do not hold this view as strongly as the rest of the province. Fort Nelson customers are more likely than FEI customers to view the declining rate structure as the easiest to understand and the one that would result in the most stable month-to-month natural gas bills.

Influencers of Overall Impressions of Fortis BC

Impressions of FortisBC are more favourable among FEI customers (four-in-ten have a very favourable impression) than among Fort Nelson customers (two-in-ten have a very favourable impression).

Impressions of FortisBC are influenced strongly by how much customers understand their bill and their assumptions about natural gas prices. Six-in-ten of customers who have a very clear understanding of how their bill is calculated have a very favourable impression of FortisBC, compared to one-quarter who are not clear on how their bill is calculated. Among those who believe (accurately) that natural gas rates have decreased in the past 10 years, six-in-ten have a very favourable impression of FortisBC, compared to just three-in-ten who believe that natural gas prices have increased significantly during this period.



Detailed Findings

Review and Clarity of Natural Gas Bills

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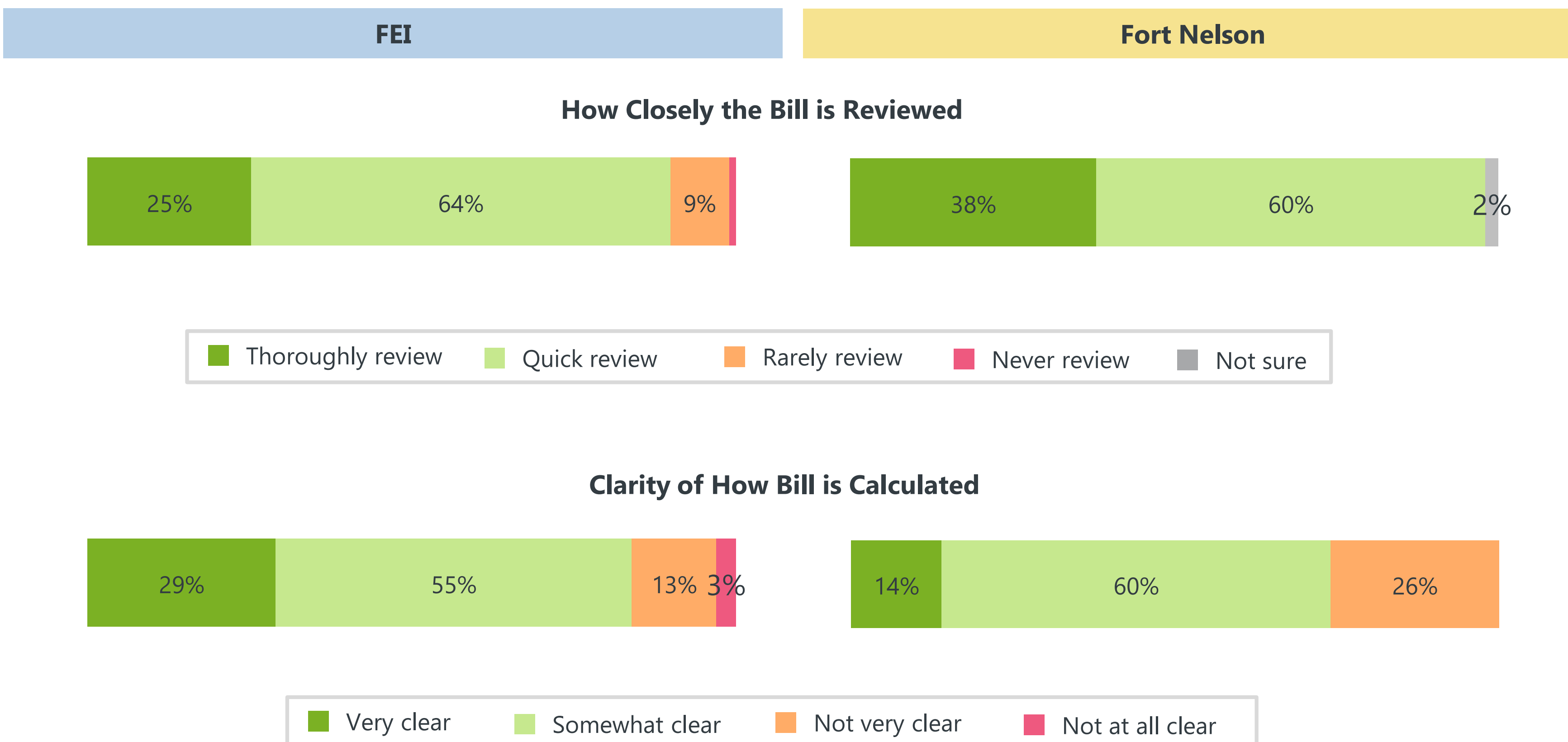
- The most common course of action customers take when they receive their natural gas bill is to give it a quick review to make sure everything looks as expected. Six-in-ten customers give their bill a quick review. Fort Nelson customers are more likely to claim to review their bill thoroughly.
- Over half of customers in both regions report that they are 'somewhat clear' on how their natural gas bill is calculated. However, despite being more likely to report reviewing their bill thoroughly, Fort Nelson customers are twice as likely as FEI customers to report that they are not very clear on how their bill is calculated (26% vs. 13%).



Base: FEI (753); Fort Nelson (65);
Q8. When you get your FortisBC natural gas bill, would you say you…
Q9. And when it comes to how your FortisBC natural gas bill is calculated, would you say you are…

Review and Clarity of Natural Gas Bills (FEI Customers)

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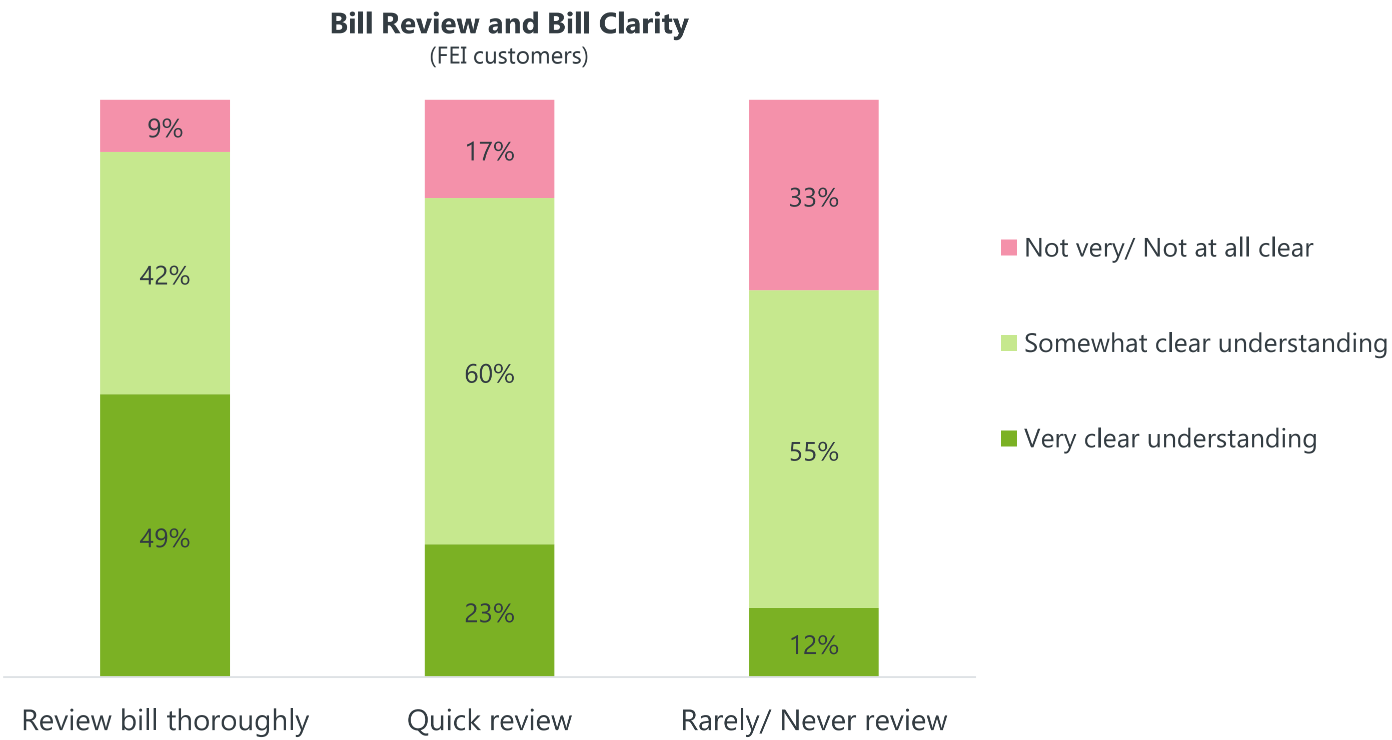
- The degree to which customers review their bill is related strongly to how much they understand it. Among those who review their bill thoroughly, half have a very clear understanding of how it's calculated and nine-in-ten are at least somewhat clear on how it's calculated. In contrast, among those who rarely or never review their bill, only one-in-ten have a very clear understanding of how it's calculated, and one-third are not clear on how their bill is calculated.

- However, the fact that eight-in-ten of customers who only give their bills a 'quick review' are at least somewhat clear on how their bill is calculated suggests that a high level of effort is not required for customers to feel relatively confident in their understanding of their bill.



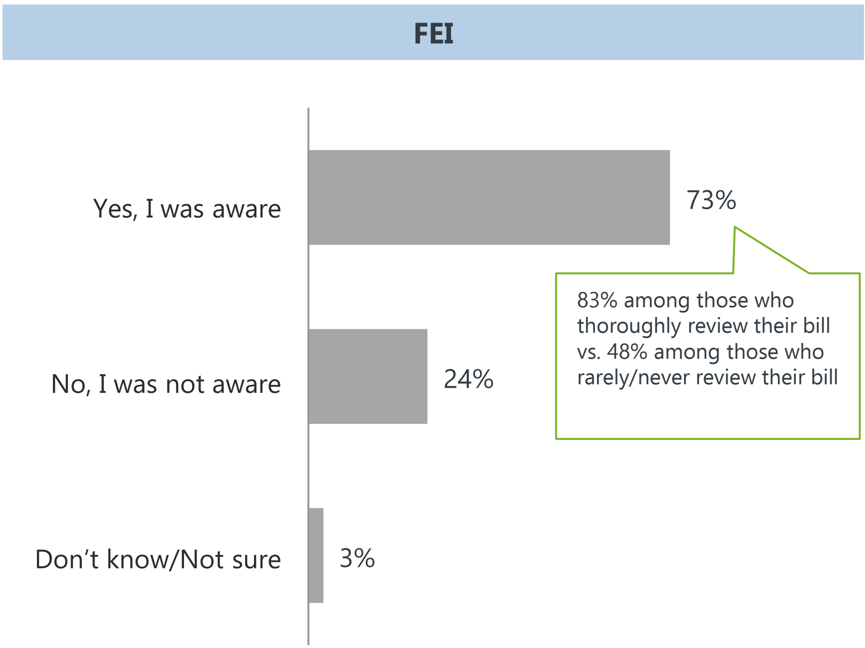
Base: FEI (753)

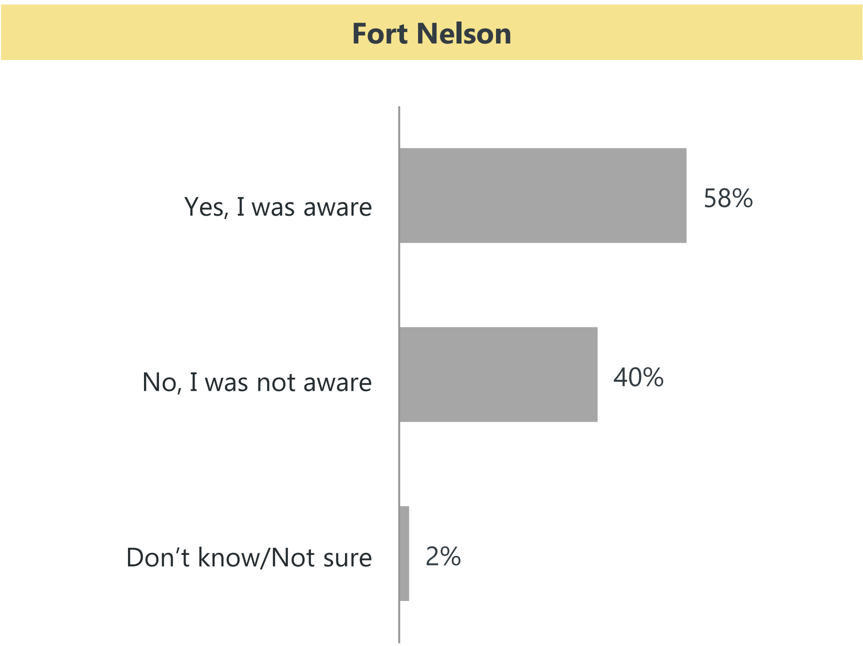
Q8. When you get your FortisBC natural gas bill, would you say you...

Q9. And when it comes to how your FortisBC natural gas bill is calculated, would you say you are...

Awareness of Fixed vs. Variable Charges

- Before they were presented with an example of a natural gas bill, customers were asked if they are aware that their bill is made up of both fixed and variable charges. Three-quarters of FEI customers indicate that they are aware that their bill is made up of fixed and variable charges. Consistent with their somewhat lower levels of understanding regarding how their bill is calculated, Fort Nelson customers are less likely to be aware of the fixed vs. variable distinction – four-in-ten Fort Nelson customers indicate that they are not aware that their bill is made up of these two different charges.





Base: FEI (753); Fort Nelson (65)

Q10. Your natural gas bill is made up of a fixed daily charge – a fixed daily fee that does not change regardless of how much natural gas you use; and variable charges – charges that change each month based on how much natural gas you use. Before this survey, were you aware that your bill is made up of both fixed and variable charges?

Understanding of Bill Components: FEI Customers

Customers outside of Fort Nelson were shown an example of a natural gas bill. It was explained that the bill is made up of the following components:

- The Delivery component which consists of a basic charge and a delivery charge,
- The Commodity component which includes storage and transport charges and the cost of gas charge, and
- Other charges and taxes which cover various fees and taxes collected by the utility on behalf of the different levels of government.

Customers were then asked to rate how much they understood each of these bill components, after being given the following explanations for each:

*The **Basic*** charge *is a fixed daily fee that FortisBC uses to cover a portion of its fixed costs – e.g., meter readings, the call centre, emergency response. All households in your area pay the same Basic charge, and this charge is the same regardless of how much natural gas is used.*

*The **Delivery** charge covers the cost of delivering natural gas to your home. The Delivery charge rate is a fixed dollar amount per unit of natural gas used, so the overall monthly dollar amount a household pays is dependent on how much gas it uses.*

*The **Storage and Transport** charge reflects the price FortisBC pays to other companies to store gas and transport gas through their pipelines. These charges are passed on to customers without a mark-up. All customers pay the same rate for Storage and Transport.*

*The **Cost of Gas** is the price FortisBC pays for natural gas on the open market. These charges are passed on to customers without a mark-up. The cost of natural gas may be adjusted every three months. All customers, unless they have signed a contract with a natural gas marketer, pay the same rate for the Cost of Gas.*

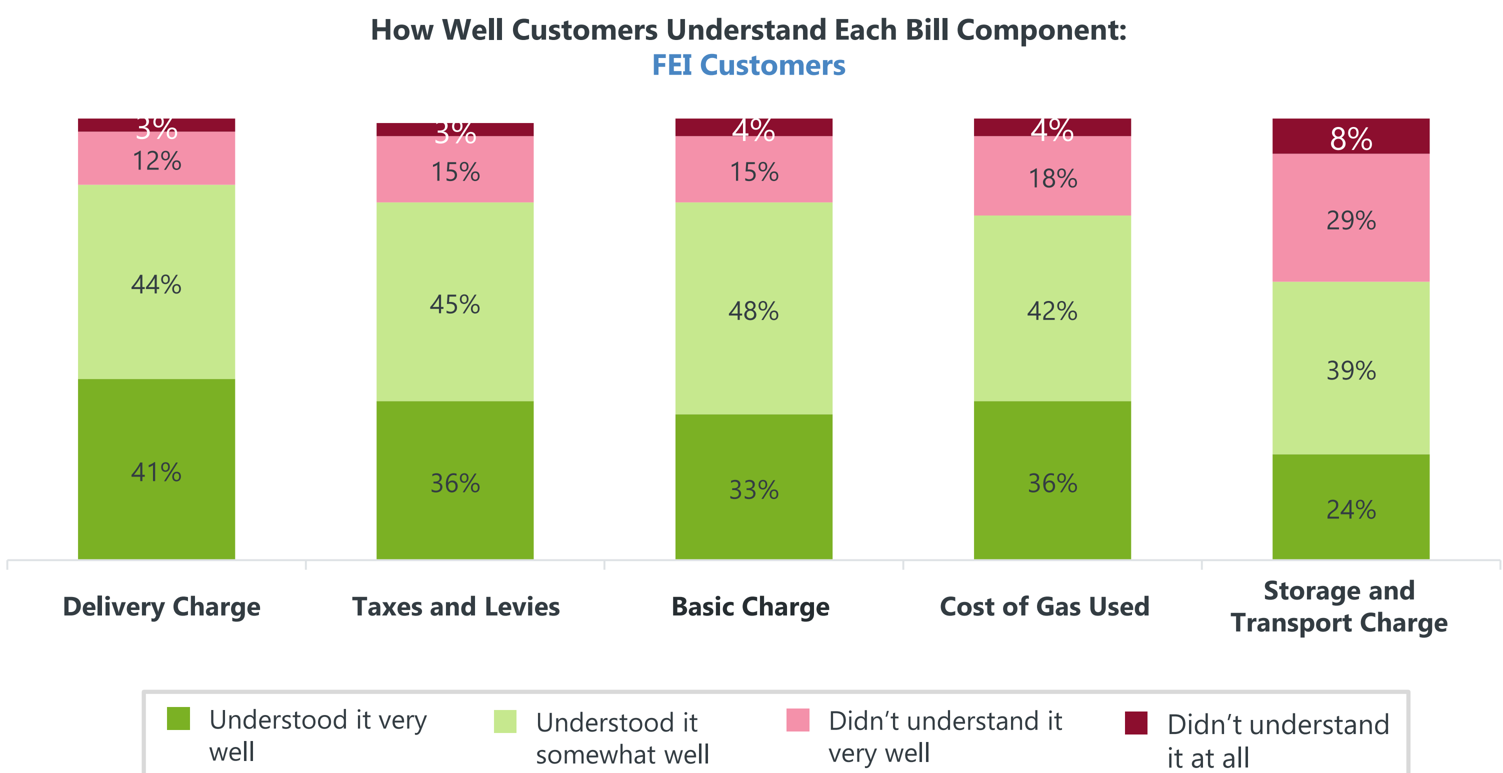
*FortisBC also collects **taxes and levies** on behalf of municipalities, the provincial government and the Canadian Federal Government. The monies collected are remitted directly to the appropriate level of government.*

Understanding of Bill Components: FEI Customers

SENTIS

- While a majority of customers claim to understand each component of their bill either 'somewhat' or 'very' well, they have a clearer understanding of some components more than others. Their level of understanding is highest for the Delivery charge and lowest for the Storage & Transport charge. Four-in-ten customers don't understand the Storage & Transport charge and only one-quarter claim to have a very clear understanding of this charge. Even among those who review their bill thoroughly – only one-third indicated that they understand this component of their bill.

- Less than two-in-ten of customers claim to understand all components of their bill 'very well' and six-in-ten customers report that they understand all components of their bill either 'very' or 'somewhat' well.



Base: FEI (753)

Understanding of Bill Components: Fort Nelson Customers

For Nelson customers were also shown an example of a natural gas bill. It was explained that the bill is made up of the following components:

- Gas charges which consist of a basic charge and a charge for gas used,
- Other charges and taxes which cover various fees and taxes collected by the utility on behalf of the different levels of government.

Customers were then asked to rate how much they understood each of these bill components, after being given the following explanations for each:

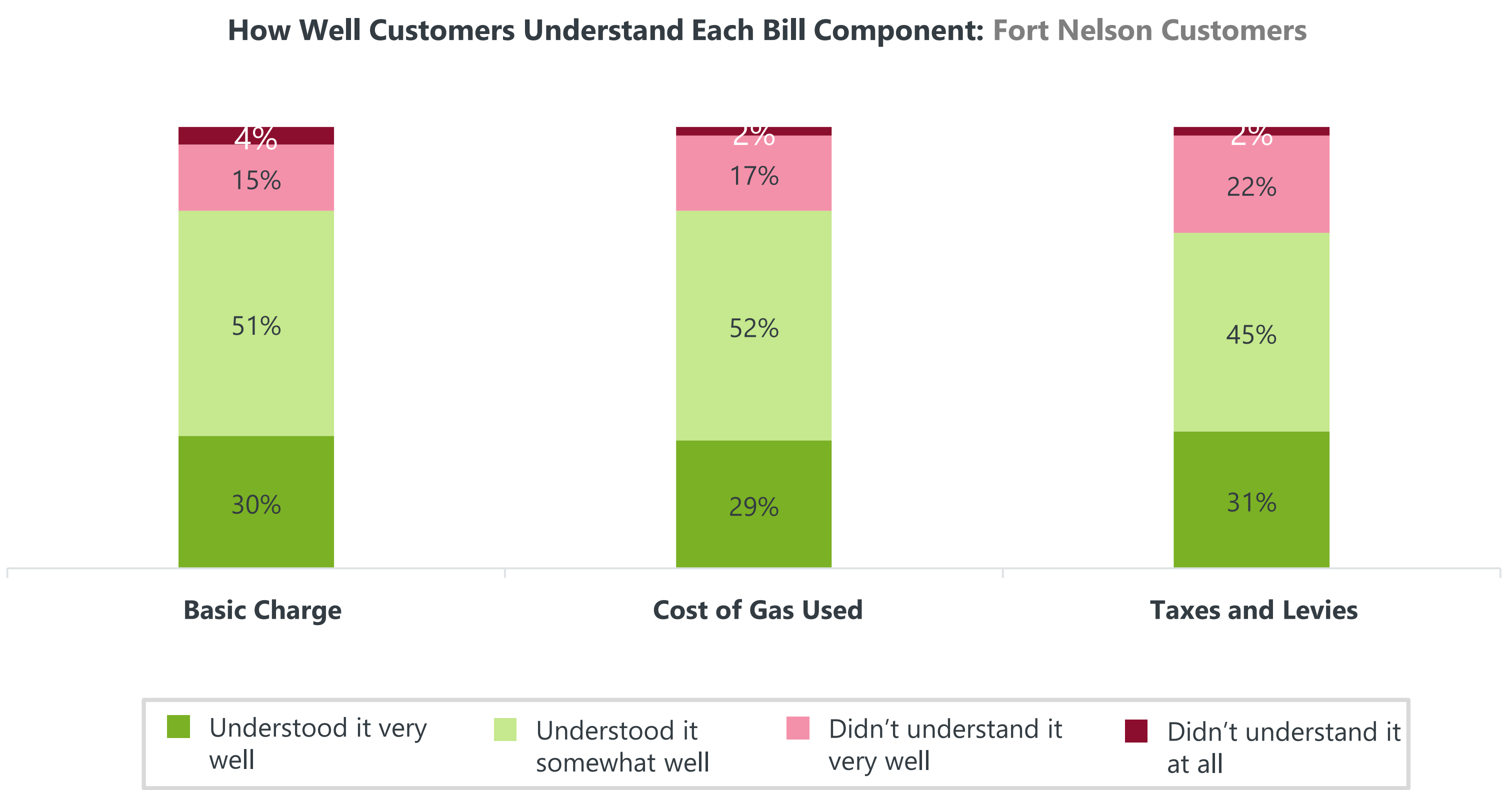
Under the Gas charges there is the Basic Charge and the Charge for gas used. ***The Basic charge*** *is a minimum daily charge, which includes the first 2 GJs (gigajoules) per month of a customer's natural gas consumption. GJs are what FortisBC uses to measure natural gas consumption. All households in your area pay the same Basic charge, and this charge is the same regardless of how much natural gas is used. Before this survey, how well did you understand the Basic charge?*

The ***Charge for gas*** *used is what you pay for any GJs over and above the first 2 GJs. Before this survey, how well did you understand the Charge for gas used part of your bill?*

FortisBC also collects ***taxes and levies*** *on behalf of municipalities, the provincial government and the Canadian Federal Government. The monies collected are remitted directly to the appropriate level of government:*

Understanding of Bill Components: Fort Nelson Customers

- Eight-in-ten of Fort Nelson customers claim to understand each component of their bill either 'somewhat' or 'very' well. Their degree of understanding of these components is comparable to the degree of understanding among FEI customers.
- Two-in-ten Fort Nelson customers report that they understand all components of their bill 'very well' and two-thirds claim that they understand all components of their bill either 'very' or 'somewhat' well.



Base: Fort Nelson (65)

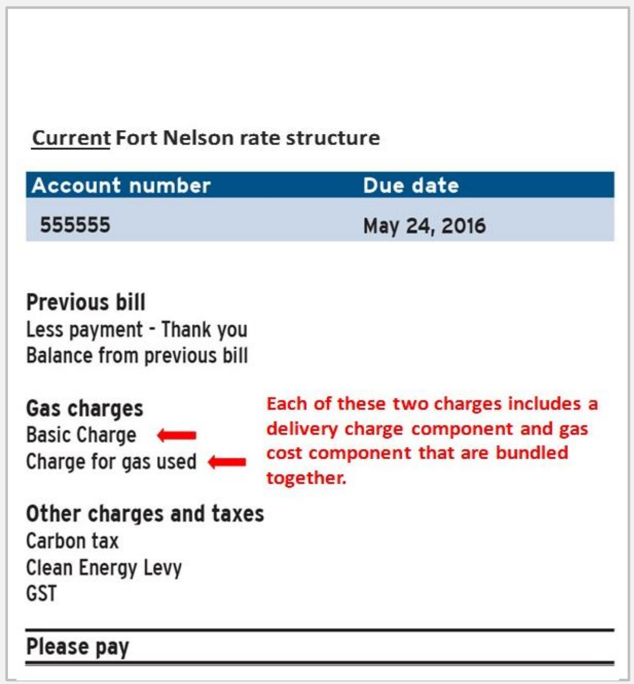
Rate Structure Preferences: Fort Nelson Customers

Before they were asked to indicate their rate structure preference, Fort Nelson customers were provided with the following explanation of how their rate structure differs from the rest of the province.

Fort Nelson's rate structure is currently different than the rest of the province. In Fort Nelson, both the Basic charge and the Charge for gas used include a delivery charge component and a gas cost recovery charge component. Delivery charges, which reflect the costs to deliver gas to homes and businesses; as well as gas cost recovery charges, are bundled together and are not shown separately on a customer's bill. Therefore, a customer only sees two bundled charges in their bill: the Basic charge and the Charge for gas used.

FortisBC is currently reviewing Fort Nelson's rate structure and considering changing it to match the rest of the province so the dollar amount for Delivery charges and gas cost recovery charges can be viewed separately. The new rate structure will not have any impact on the annual billing amount for the average customer.

Customers were also shown these bill images of the current Fort Nelson rate structure and the rate structure for FEI customers.



Current Fort Nelson rate structure

Account number	Due date
555555	May 24, 2016

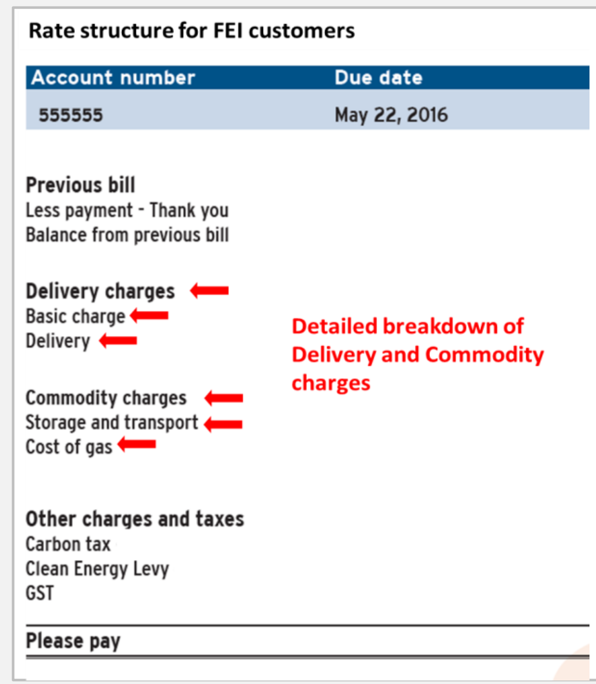
Previous bill
Less payment - Thank you
Balance from previous bill

Gas charges
Basic Charge
Charge for gas used

Each of these two charges includes a delivery charge component and gas cost component that are bundled together.

Other charges and taxes
Carbon tax
Clean Energy Levy
GST

Please pay



Rate structure for FEI customers

Account number	Due date
555555	May 22, 2016

Previous bill
Less payment - Thank you
Balance from previous bill

Delivery charges
Basic charge
Delivery

Commodity charges
Storage and transport
Cost of gas

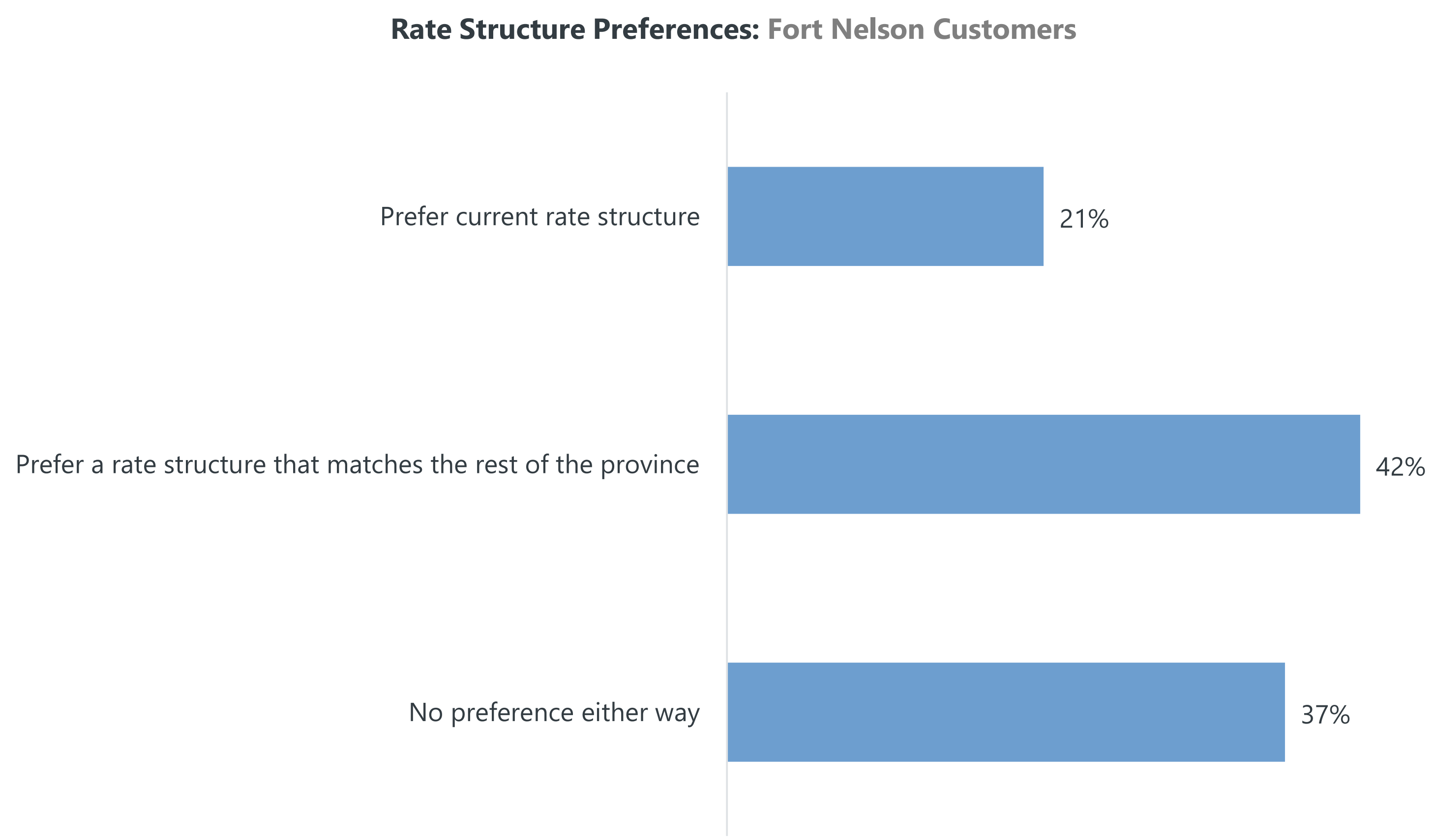
Detailed breakdown of Delivery and Commodity charges

Other charges and taxes
Carbon tax
Clean Energy Levy
GST

Please pay

Rate Structure Preferences: Fort Nelson Customers

- Only two-in-ten Fort Nelson customers prefer the current rate structure. The remainder is divided almost equally between those that prefer a structure that matches FEI and those without a preference either way.



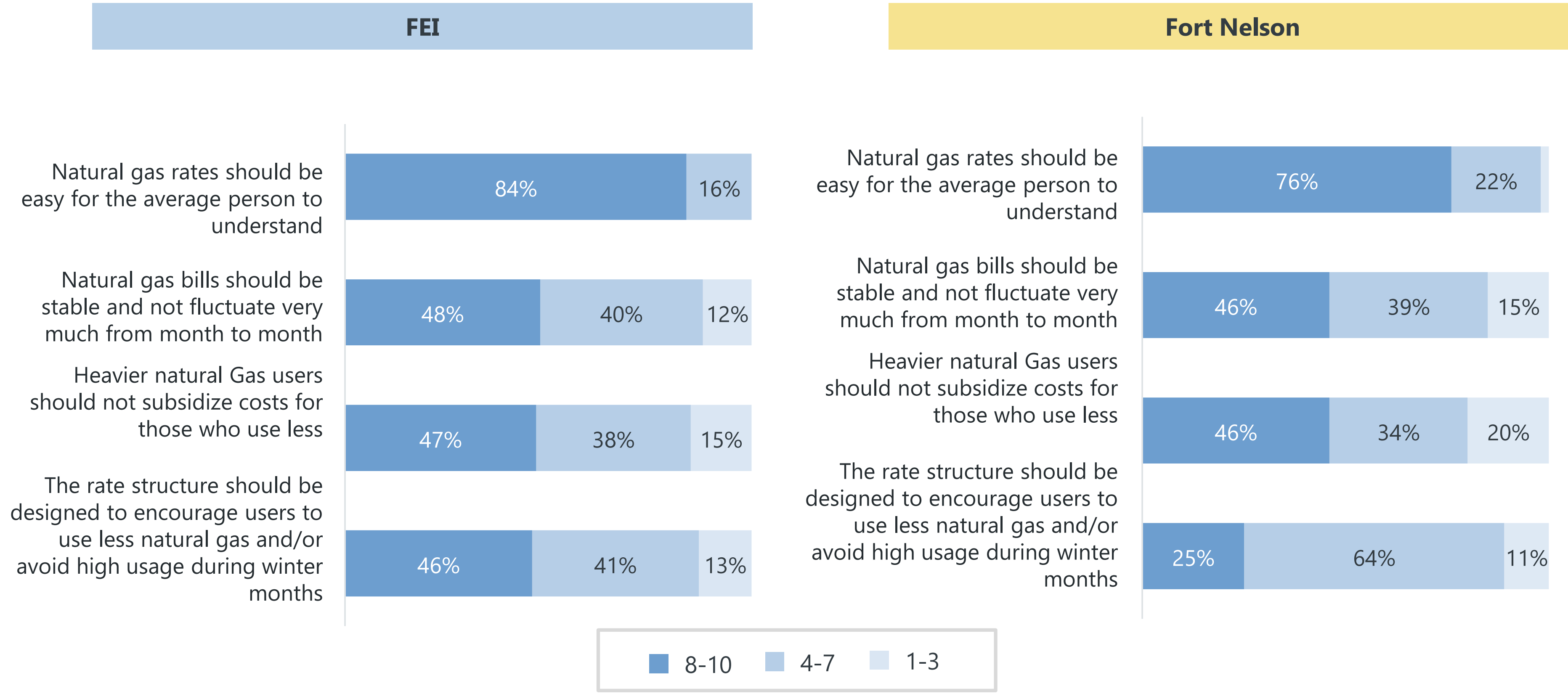
Base: Fort Nelson (65)

Q19new: Fort Nelson's rate structure is currently different than the rest of the province. In Fort Nelson, both the Basic Charge and the Charge for Gas Used include a delivery charge component and a gas cost recovery charge component.... Based on the information above, which rate structure do you prefer?

Importance of Rate Setting Principles

- The most important principle of the four presented to customers is that natural gas rates should be easy for the average person to understand.

- Fort Nelson customers are much less likely to strongly support a rate structure that encourages users to use less natural gas and/or avoid high usage during winter months. In the winter months, the average temperature in Fort Nelson is between -8 and -21 Celsius, whereas it is between +4 and +7 Celsius in Metro Vancouver.



Base: FEI (753); Fort Nelson (65)

Q19. FortisBC has several principles it must consider when setting natural gas rate structures. How important are each of the following principles to you? Please use a scale where 1 is not at all important and 10 is extremely important.

Perceptions of Current and Alternative Rate Structures

SENTIS

Customers were provided with explanations of the current FEI **flat rate** structure as well as two alternative rate structures: **declining** and **inclining.**

*When it comes to the Delivery charges, FortisBC's current residential rate is a **Flat Rate** structure. Customers pay the same dollar per gigajoules of gas used, regardless of how much gas is used. This means that customers will not have a lower or higher rate depending on their usage.*

***Declining Rate Structure:** Customers pay a certain rate for the first set number or block of gigajoules of gas used and then a lower rate for the next set number of gigajoules of gas used. This means that the customers who consume more than the first block of gigajoules, will have a <u>lower overall rate</u>.*

***Inclining Rate Structure:** Customers pay a certain rate for the first set number or block of gigajoules of gas used and then a higher rate for the next set number of gigajoules of gas used. This means that the customers who consume more than the first block of gigajoules will have a <u>higher overall rate</u>.*

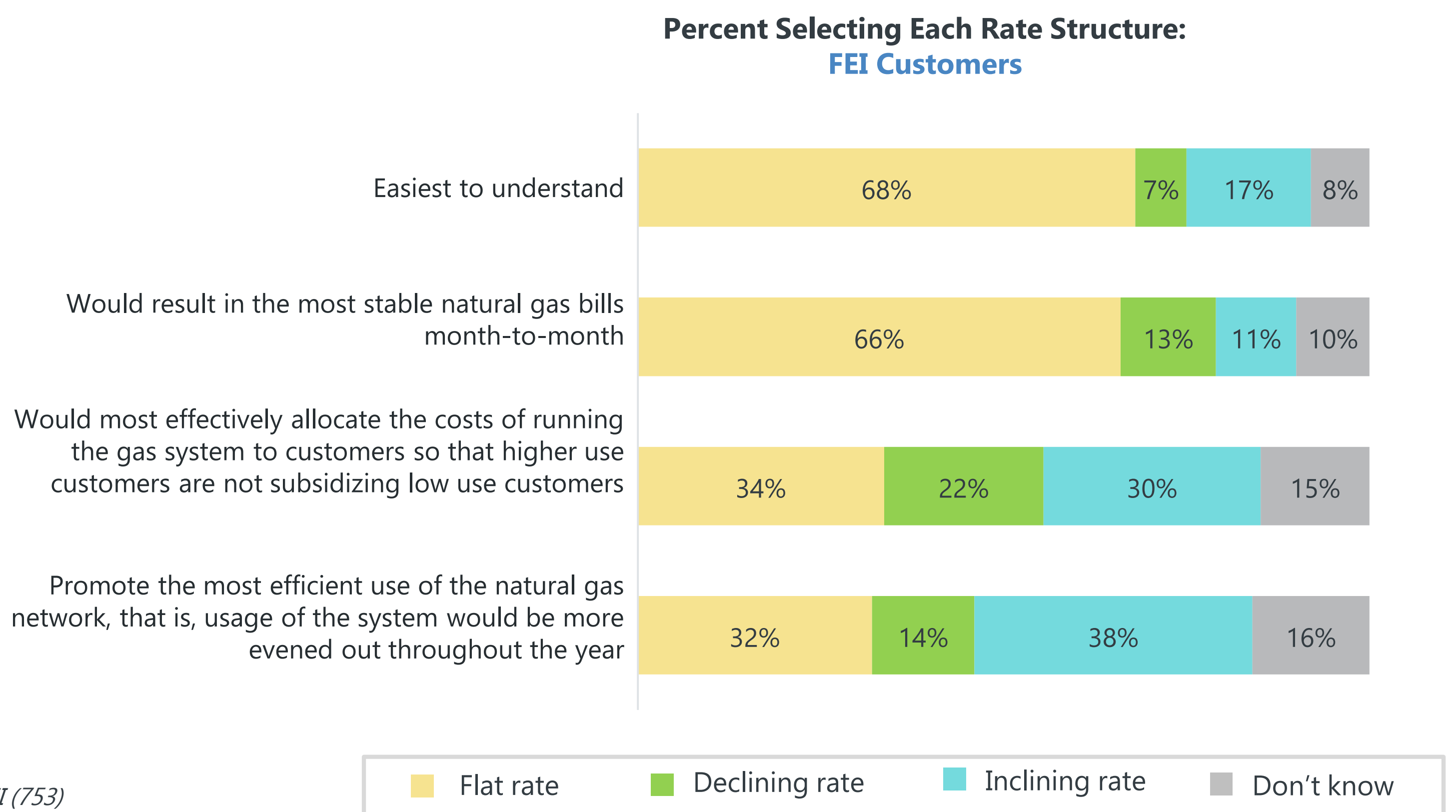
They were then asked to choose which of three:

- Would be the easiest to understand
- Would promote the most efficient use of the natural gas network, that is, usage of the system would be more evened out throughout the year
- Would result in the most stable natural gas bills month-to-month
- Would most effectively allocate the costs of running the gas system to customers so that higher use customers are not subsidizing low use customers

Perceptions of Rate Structures: FEI Customers

SENTIS

- By a wide margin, FEI customers believe that the current flat rate structure is the easiest to understand and is the rate structure that would result in the most stable natural gas bills month-to-month.
- Customers are more divided on whether a flat rate structure or an inclining rate structure would be the one to most effectively allocate the costs of running the system and promote the most efficient use of the natural gas network.
- The vast majority of customers do not believe that a declining rate structure would be the easiest to understand, result in more bill stability month-to-month, would most effectively allocate the costs of running the system, or promote the most efficient use of the natural gas network.

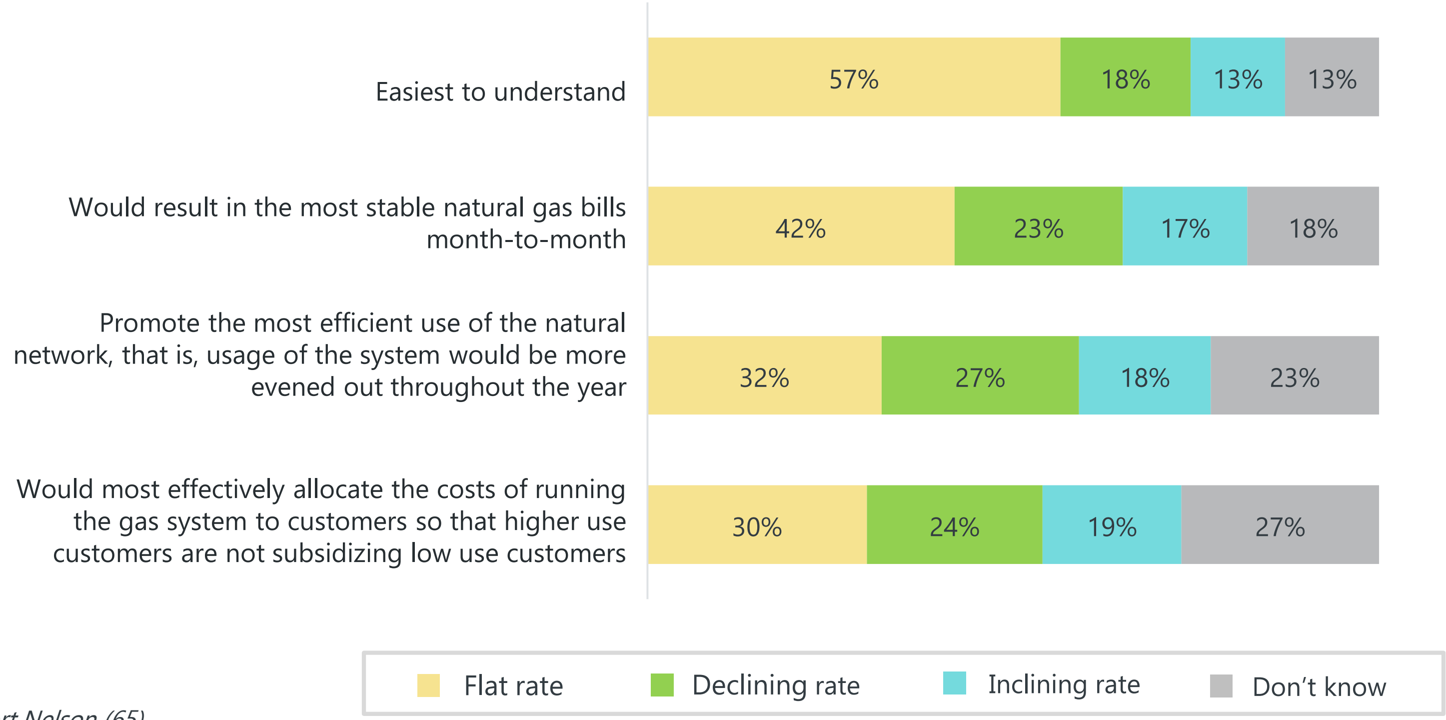


Base: FEI (753)

Perceptions of Rate Structures: Fort Nelson Customers

- Like FEI customers, Fort Nelson customers are most likely to view the flat rate structure as the easiest to understand and the rate structure that would result in the most stable natural gas bills month-to-month.
- However, Fort Nelson customers do not hold this view as strongly as FEI customers. Fort Nelson customers are more likely than FEI customers to choose the declining rate as the easiest to understand (18% for Fort Nelson customers; 7% for FEI customers) and as the rate structure that would result in the most stable natural gas bills month-to-month (23% for Fort Nelson customers; 13% for FEI customers).
- Fort Nelson customers are more likely than FEI customers to express uncertainty regarding which rate structure would promote the most efficient use of the natural gas network and would most effectively allocate the costs of running the gas system so that higher use customers are not subsidizing low use customers.

Percent Selecting Each Rate Structure: Fort Nelson Customers



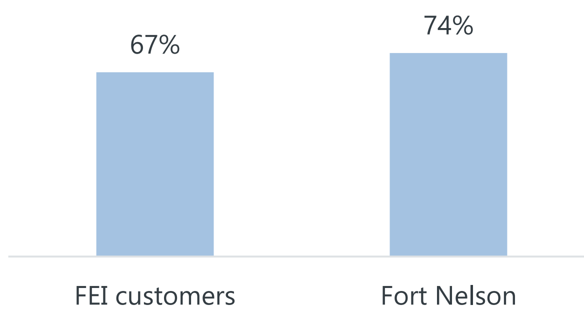
Base: Fort Nelson (65)

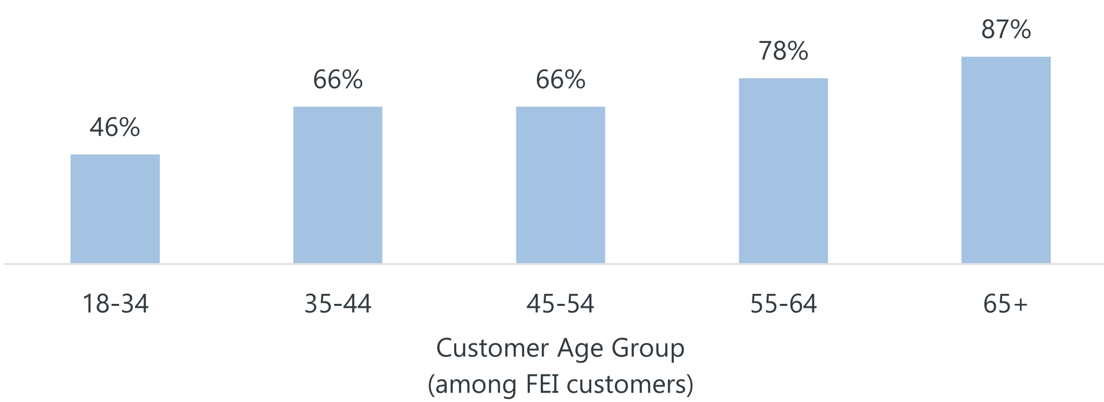
Awareness of BCUC Review and Approval

SENTIS

- Two-thirds of FEI customers, and three-quarters of Fort Nelson customers, claim to be aware that the BC Utilities Commission reviews and approves FortisBC's natural gas rates and charges.
- Awareness of BCUC's role is significantly lower among FEI's youngest customer group.

Percent Aware that FortisBC Rates are Reviewed and Approved by BCUC





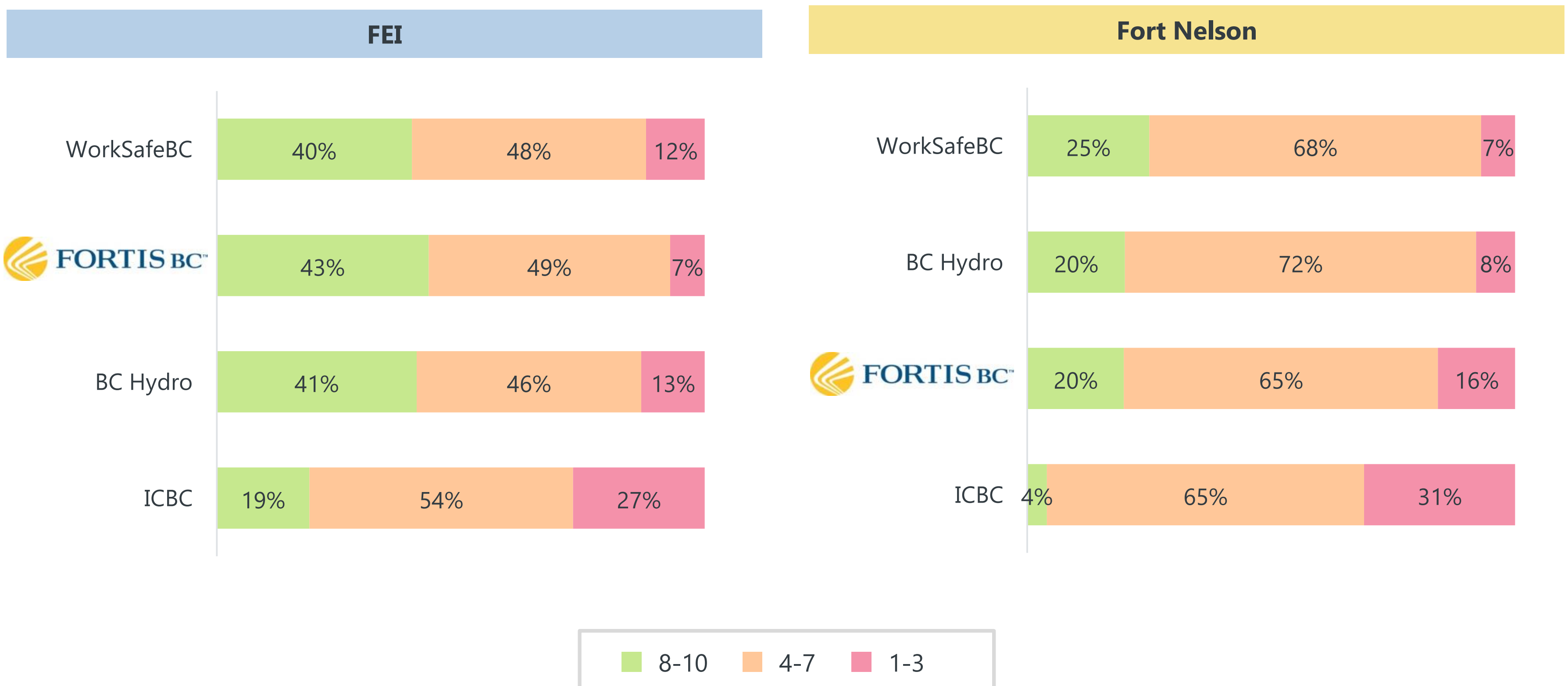
Q21: Before this survey were you aware that FortisBC's natural gas rates and charges are reviewed and approved by the British Columbia Utilities Commission?

Impressions of Organizations

SENTIS

- Within each region, customers' impressions of FortisBC are similar to their impressions of BC Hydro. However, FEI customers have more strongly favourable impressions of both organizations than Fort Nelson customers. Four-in-ten FEI customers have very positive impressions of FortisBC (giving a rating of 8, 9 or 10) compared to two-in-ten Fort Nelson customers.

- Fort Nelson customers have less favourable impressions of all four organizations than FEI customers.



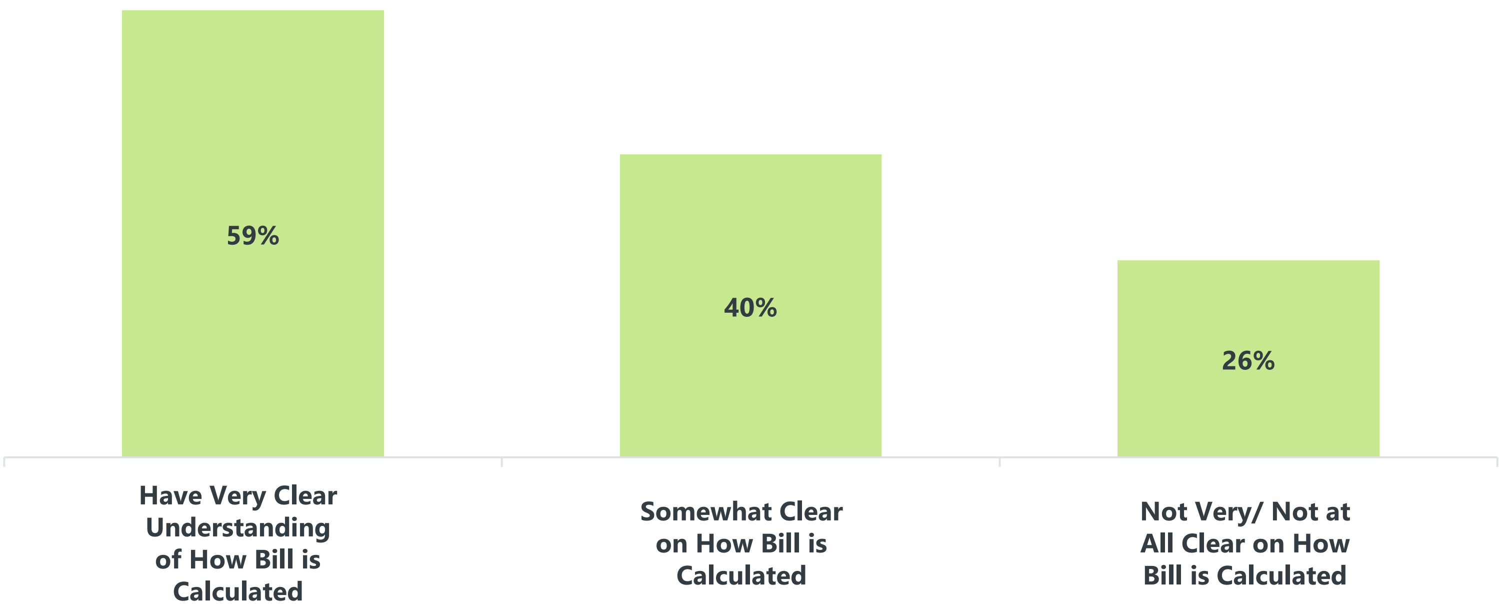
Base: FEI (664-740); Fort Nelson (61-63)

Q1. What is your overall impression of the following organizations? Please rate each on a scale where 1 means 'not at all favourable' and 10 means 'very favourable'.

Bill Understanding & Impressions of FortisBC (FEI Customers)

- Impressions of FortisBC are tied strongly to customers' understanding of how their bill is calculated. Those who report having a very clear understanding of how their bill is calculated are twice as likely to have a very positive view of FortisBC compared to those who report not having a clear understanding of how their bill is calculated.

% of Customers with Very Favourable Impression of FortisBC (rating 8, 9 or 10)



Base: FEI (n=753)

Q1. What is your overall impression of the following organizations? Please rate each on a scale where 1 means 'not at all favourable' and 10 means 'very favourable'.

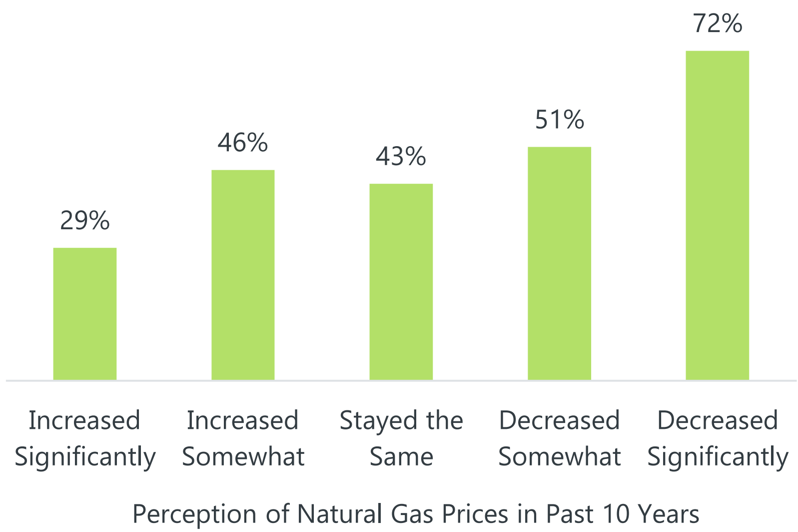
Perceptions of Natural Gas Prices & Impressions of FortisBC (FEI Customers)

- Despite the steady and significant decline in natural gas prices over the past 10 years, 62% of FEI customers, and 88% of Fort Nelson customers believe that prices have increased.
- Customers who report reviewing their bill thoroughly are just as likely to believe that prices have increased (67%) as customers who rarely or never look at their bill (63%).
- Overall impressions of FortisBC are strongly tied to customer assumptions about the price of natural gas over the past 10 years. The more accurate customer perceptions are about how gas prices have changed, the more favourable customers are toward FortisBC.

Perceptions of natural gas prices in the past 10 years

	FEI	Fort Nelson
Increased significantly	21%	43%
Increased somewhat	41%	45%
(Increased, total)	62%	88%
Stayed the same	11%	0%
Decreased somewhat	12%	3%
Decreased significantly	5%	0%
Don't know/ not sure	10%	9%

Percentage of Customers with Very Favourable Impression of FortisBC (ratings of 8 to 10) by Perceptions of Natural Gas Prices in the Past 10 years



Q22: Thinking about the past 10 years, to the best of your knowledge, would you say that natural gas prices have...?

Demographics

SENTIS

	FEI customers	Fort Nelson customers
Base	753 %	65 %
Gender		
Male	49	54
Female	51	46
Age		
18-24	5	-
25-34	23	3
35-44	14	23
45-54	24	55
55-64	14	11
65+	21	7
Annual household income before tax		
Less than $40,000	10	10
$40,000 to less than $60,000	14	15
$60,000 to less than $80,000	17	8
$80,000 to less than $100,000	15	18
$100,000 to less than $150,000	19	14
$150,000 or more	8	8
Prefer not to answer/Don’t know	17	28

Appendix

FORT NELSON CUSTOMERS SCREENED VIA TELEPHONE. ONCE ONLINE, THEY START THE SURVEY AT AGE, GENDER, THEN SKIP TO Q1 THEN SKIP TO Q3

Final

SCREENING QUESTIONS (PART 1)

REGION. In which area is your primary residence?

1. Lower Mainland/ Fraser Valley (includes Whistler and Squamish)
2. Vancouver Island/Sunshine Coast
3. Southern Interior (Kootenays/Okanagan/Thompson)
4. Northern Interior (North of Kamloops)

AGE. Into which of the following categories does your age fall?

1. Under 18 **THANK AND TERMINATE**
2. 18to 24
3. 25 to 34
4. 35 to 44
5. 45 to 54
6. 55 to 64
7. 65 or older

GENDER. Are you?

1. Male
2. Female

S1. Are you or any member of your immediate family or household employed in the following sectors?
Select all that apply

1. Utility company **| THANK AND TERMINATE**
2. Natural gas company or gas marketer **| THANK AND TERMINATE**
3. Electricity company **| THANK AND TERMINATE**
4. Market research company **| THANK AND TERMINATE**
5. Newspaper, radio, or TV network **| THANK AND TERMINATE**
6. Utility regulatory body **| THANK AND TERMINATE**

CORPORATE IMPRESSIONS

Q1. What is your overall impression of the following organizations? Please rate each on a scale where 1 means 'not at all favourable' and 10 means 'very favourable'.

[RANDOMIZE ORDER OF LIST]

A. BC Hydro
B. FortisBC
C. ICBC
D. WorkSafeBC

SCREENING QUESTIONS (PART 2)

S2. Do you receive a **natural gas bill** from FortisBC?

1. Yes, I receive a natural gas bill from FortisBC
2. No, I do not **| THANK AND TERMINATE**
97. Don't know/ not sure **| THANK AND TERMINATE**

S3. Are you the person in your household who is responsible for, or who shares responsibility for making payment decisions for your natural gas bill?

1. Yes, I am responsible or share responsibility
2. No, I am not **| THANK AND TERMINATE**
97. Don't know/ not sure **| THANK AND TERMINATE**

USAGE AND HOME CHARACTERISTICS [ASK ALL]

This survey is about household energy use and how people make payment decisions. Our first set of questions are about some of the characteristics of your home.

Q3. Which of the following natural gas appliances are covered by your FortisBC account?

Please select all that apply.

1. Forced –air furnace
2. Boiler
3. Hot Water Tank
4. Fireplace
5. Cooktop/stove/oven
6. BBQ
7. Clothes dryer

96. Other (specify)
97. None/Don't know/Not sure **THANK AND TERMINATE**

Q4. Are you currently living in …?

1. An apartment or a condominium in a multi-unit building
2. A townhouse, duplex or triplex
3. A single detached home

96. Other (specify)
97. Don't know/ Not sure

Q5. Do you own or rent your home?

1. Own
2. Rent

Q6. Including yourself, how many people live in your home?

1. One
2. Two
3. Three
4. Four or more

Q7. What is the approximate square footage of your home? *An estimate is fine.*

[ ] square feet

ENGAGEMENT/ OVERALL UNDERSTANDING OF NATURAL GAS BILL [ASK ALL]

Q8. When you get your FortisBC natural gas bill, would you say you…

1. Thoroughly review the bill
2. Give the bill a quick review to make sure everything looks as expected
3. Rarely review the bill, or
4. Never review the bill

97. Don't know/ Not sure

Q9. And when it comes to how your FortisBC natural gas bill is calculated, would you say you are…

1. Very clear on how your bill is calculated
2. Somewhat clear on how your bill is calculated
3. Not very clear on how your bill is calculated
4. Not at all clear on how your bill is calculated

AWARENESS OF FIXED VERSUS VARIABLE CHARGES [ASK ALL]

Q10. Your natural gas bill is made up of a fixed daily charge – a fixed daily fee that does not change regardless of how much natural gas you use; and variable charges – charges that change each month based on how much natural gas you use. Before this survey, were you aware that your bill is made up of both fixed and variable charges?

1. Yes, I was aware that my bill is made up of both fixed and variable charges
2. No, I was not aware of this

97. Don't know/ Not sure

NON-FORT NELSON CUSTOMERS [QNS 11-15]

[SHOW NATURAL GAS BILL EXAMPLE]
This is an example of a FortisBC Natural Gas bill. Your bill is made up of three major components:
(1) The Delivery component which consists of a basic charge and a delivery charge,
(2) The Commodity component which includes storage and transport charges and the cost of gas charge, and
(3) Other charges and taxes which cover various fees and taxes collected by the utility on behalf of the different levels of government.

Q11. The Basic charge is a fixed daily fee that FortisBC uses to cover a portion of its fixed costs – e.g., meter readings, the call centre, emergency response. All households in your area pay the same Basic charge, and this charge is the same regardless of how much natural gas is used.

Before this survey, how well did you understand the Basic Charge?

1. Understood it very well
2. Understood it somewhat
3. Didn't understand it very well
4. Didn't understand it at all

Q12. The Delivery charge covers the cost of delivering natural gas to your home. The Delivery charge rate is a fixed dollar amount per unit of natural gas used, so the overall monthly dollar amount a household pays is dependent on how much gas it uses.

Before this survey, how well did you understand the Delivery charge?

1. Understood it very well
2. Understood it somewhat
3. Didn't understand it very well
4. Didn't understand it at all

Q13. The Storage and Transport charge reflects the price FortisBC pays to other companies to store gas and transport gas through their pipelines. These charges are passed on to customers without a mark-up. All customers pay the same rate for Storage and Transport.

Before this survey, how well did you understand the Storage and Transport Charge?

1. Understood it very well
2. Understood it somewhat
3. Didn't understand it very well
4. Didn't understand it at all

Q14. The Cost of Gas is the price FortisBC pays for natural gas on the open market. These charges are passed on to customers without a mark-up. The cost of natural gas may be adjusted every three months. All customers, unless they have signed a contract with a natural gas marketer, pay the same rate for the Cost of Gas.

Before this survey, how well did you understand the Cost of Gas charge?

1. Understood it very well
2. Understood it somewhat
3. Didn't understand it very well
4. Didn't understand it at all

Q15. FortisBC also collects taxes and levies on behalf of municipalities, the provincial government and the Canadian Federal Government. The monies collected are remitted directly to the appropriate level of government:

ONLY SHOW MUNICIPAL OPERATING FEE EXPLANATION FOR THOSE LIVING IN INTERIOR (Q2=2, 3 OR 4)

Municipal operating fee – is collected on behalf of certain local governments and is paid by those customers who consume natural gas or propane in a municipality.

Carbon tax – This is an amount you pay based on the amount of natural gas your household consumes. It is charged to discourage the use of carbon fuels and is remitted to the provincial government

Clean Energy Levy – The funds from the levy are used by the provincial government to support investment in clean energy technology.

GST – this is the federal Goods and Services Tax.

Before this survey, how well did you understand the Other Charges and Taxes part of your bill?

1. Understood it very well
2. Understood it somewhat
3. Didn't understand it very well
4. Didn't understand it at all

FORT NELSON CUSTOMERS [QNS 16-19] [ALL OTHER CUSTOMERS GO TO Q19]
[SHOW NATURAL GAS BILL EXAMPLE FOR FN FOR Q16-18]
This is an example of a FortisBC Natural Gas bill. Your bill is made up of two major components – Gas charges and Other Charges and Taxes.

Q16. Under the Gas charges there is the Basic Charge and the Charge for gas used. The Basic charge is a minimum daily charge, which includes the first 2 GJs (gigajoules) per month of a customer's natural gas consumption. GJs are what FortisBC uses to measure natural gas consumption

All households in your area pay the same Basic charge, and this charge is the same regardless of how much natural gas is used.

Before this survey, how well did you understand the Basic charge?

1. Understood it very well
2. Understood it somewhat
3. Didn't understand it very well
4. Didn't understand it at all

Q17. . The Charge for gas used is what you pay for any GJs over and above the first 2 GJs. Before this survey, how well did you understand the Charge for gas used part of your bill?

1. Understood it very well
2. Understood it somewhat
3. Didn't understand it very well
4. Didn't understand it at all

Q18. FortisBC also collects taxes and levies on behalf of municipalities, the provincial government and the Canadian Federal Government. The monies collected are remitted directly to the appropriate level of government:

Carbon tax – This is an amount you pay based on the amount of natural gas your household consumes. It is charged to discourage the use of carbon fuels and is remitted to the provincial government

Clean Energy Levy – The funds from the levy are used by the provincial government to support investment in clean energy technology.

GST – this is the federal Goods and Services Tax.

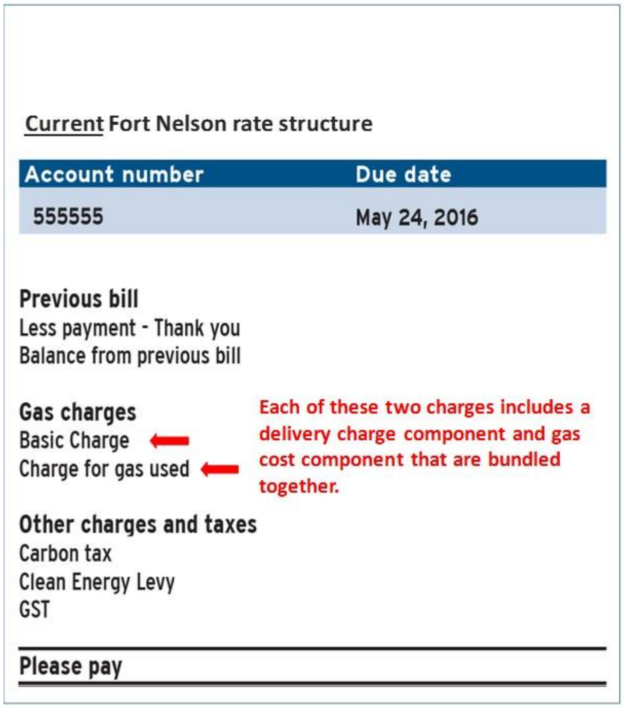
Before today, how well did you understand the Other Charges and Taxes part of your bill?

1. Understood it very well
2. Understood it somewhat
3. Didn't understand it very well
4. Didn't understand it at all

Q19-new. Fort Nelson's rate structure is currently different than the rest of the province. In Fort Nelson, both the Basic charge and the Charge for gas used include a delivery charge component and a gas cost recovery charge component. Delivery charges, which reflect the costs to deliver gas to homes and businesses; as well as gas cost recovery charges, are bundled together and are not shown separately on a customer's bill. Therefore, a customer only sees two bundled charges in their bill: the Basic charge and the Charge for gas used.

FortisBC is currently reviewing Fort Nelson's rate structure and considering changing it to match the rest of the province so the dollar amount for Delivery charges and gas cost recovery charges can be viewed separately. The new rate structure will not have any impact on the annual billing amount for the average customer.

[SHOW A SNIP OF A FN BILL (GAS CHARGES) AND A NON-FN BILL (DELIVERY CHARGES). DO NOT SHOW THE COSTS]



Current Fort Nelson rate structure

Account number	Due date
555555	May 24, 2016

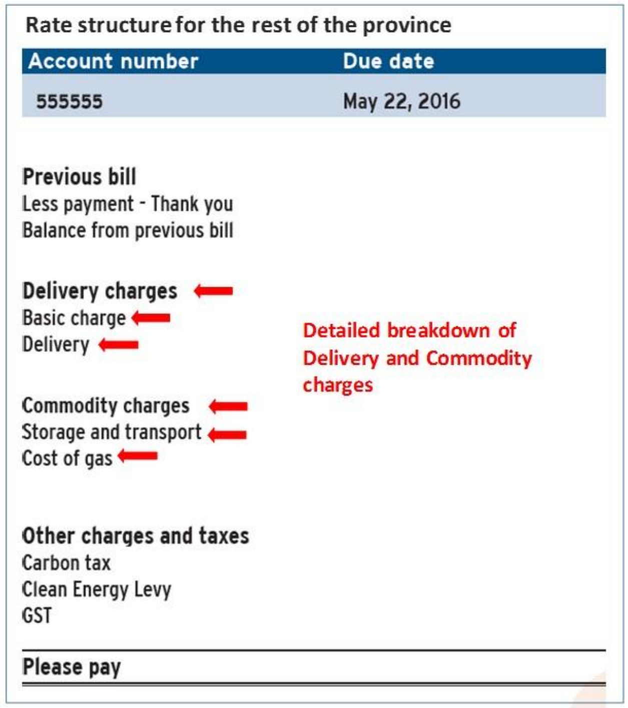
Previous bill
Less payment - Thank you
Balance from previous bill

Gas charges
Basic Charge
Charge for gas used

Each of these two charges includes a delivery charge component and gas cost component that are bundled together.

Other charges and taxes
Carbon tax
Clean Energy Levy
GST

Please pay



Rate structure for the rest of the province

Account number	Due date
555555	May 22, 2016

Previous bill
Less payment - Thank you
Balance from previous bill

Delivery charges
Basic charge
Delivery

Commodity charges
Storage and transport
Cost of gas

Detailed breakdown of Delivery and Commodity charges

Other charges and taxes
Carbon tax
Clean Energy Levy
GST

Please pay

Based on the information above, which rate structure do you prefer?

1. The current Fort Nelson rate structure where Delivery charges and the Charge for gas used are bundled together
2. A rate structure that matches the rest of the province where the various charges are not budled together, but itemized as per the example shown.
3. No preference either way

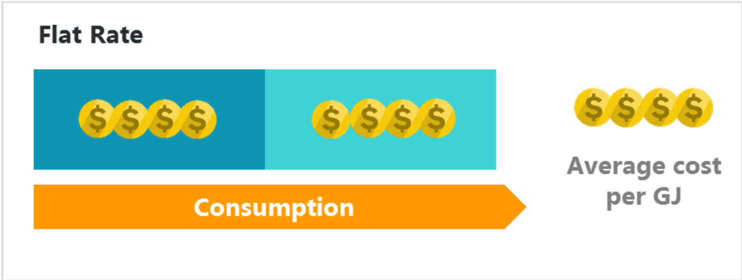
RATE DESIGN CONSIDERATIONS [QN20-22 ASK ALL]

Q19. FortisBC has several principles it must consider when setting natural gas rate structures. How important are each of the following principles to you? RANDOMIZE

[SCALE: 1-NOT AT ALL IMPORTANT TO 10-EXTREMELY IMPORTANT]

a. Natural gas rates should be easy for the average person to understand
b. Heavier natural gas users should not subsidize costs for those who use less
c. The rate structure should be designed to encourage users to use less natural gas and/or to avoid high usage during winter months
d. Natural gas bills should be stable and not fluctuate very much from month to month

Q20. NON-FN WORDING: When it comes to the Delivery charges, FortisBC's current residential rate is a **Flat Rate structure/FN WORDING:** Across the province, when it comes to the Delivery charges, with the exception of Fort Nelson, FortisBC's current residential rate is a **Flat Rate structure**. **EVERYONE:** Customers pay the same dollar per gigajoules of gas used, regardless of how much gas is used. This means that customers will not have a lower or higher rate depending on their usage.



There are **other** ways that FortisBC can structure residential rates: [RANDOMIZE ORDER SHOWN]

Declining Rate Structure: Customers pay a certain rate for the first set number or block of gigajoules of gas used and then a lower rate for the next set number of gigajoules of gas used. This means that the customers who consume more than the first block of gigajoules, will have a lower overall rate.

[NOTE-SEASONAL RATE DELETED-JULY 22/16]

Inclining Rate Structure: Customers pay a certain rate for the first set number or block of gigajoules of gas used and then a higher rate for the next set number of gigajoules of gas used. This means that the customers who consume more than the first block of gigajoules will have a higher overall rate.

[THE 3 RESIDENTIAL RATE EXPLANATIONS WILL STAY ON SCREEN FOR RESPONDENTS TO REFERENCE]

Which of the three residential rates options….**[RANDOMIZE STMTS & RATE OPTIONS SHOWN FOR EACH STATEMENT. DO NOT PUT IN GRID. ORDER OF RATE OPTIONS WILL BE THE SAME FOR A GIVEN RESPONDENT.]**

a. Would be the easiest to understand *Select only one*

1. Flat Rate structure
2. Declining rate strcuture
3. Inclining rate structure
4. Don't Know **[ANCHOR]**

b. Would promote the most efficient use of the natural gas network, that is, usage of the system would be more evened out throughout the year *Select only one*

1. Flat Rate structure
2. Declining rate strcuture
3. Inclining rate structure
4. Don't Know **[ANCHOR]**

c. Would result in the most stable natural gas bills month-to-month *Select only one*

1. Flat Rate structure
2. Declining rate strcuture
3. Inclining rate structure
4. Don't Know **[ANCHOR]**

d. Would most effectively allocate the costs of running the gas system to customers so that higher use customers are not subsidizing low use customers *Select only one*

1. Flat Rate structure
2. Declining rate strcuture
3. Inclining rate structure
4. Don't Know **[ANCHOR]**

AWARENESS OF BCUC ROLE AND NATURAL GAS PRICES [ASK ALL]

Q21. Before this survey, were you aware FortisBC's natural gas rates and charges are reviewed and approved by the British Columbia Utilities Commission (BCUC)? The BCUC is an independent regulatory agency

1. Yes, I was aware that FortisBC's natural gas rates and charges are reviewed and approved by the British Columbia Utilities Commission (BCUC)
2. No, I was not aware of this

Q22. Thinking about the past 10 years, to the best of your knowledge, would you say that natural gas prices have…

1. Increased significantly
2. Increased somewhat
3. Stayed the same
4. Decreased somewhat
5. Decreased significantly

97. Don't know/ Not sure

MANAGING ENERGY COSTS [ASK ALL]

Q23. In the past 5 years, have you changed the primary fuel source you use to heat your home?

1. Yes
2. No
3. Don't Know

[IF Q23=YES ASK Q24]
Q24 And what was the primary fuel source you **previously used** to heat your home?

Please select that last fuel source used

1. Natural Gas
2. Electricity (including air source heat pumps)
3. Wood
4. Bottled Propane
5. Oil
6. Solar
7. Other (specify)

97. Don't know/ Not sure

DEMOGRAPHICS [ASK ALL]

And lastly…

INCOME. What was your approximate household income in 2015 before taxes?

1. Less than $40,000
2. $40,000 to less than $50,000
3. $50,000 to less than $60,000
4. $60,000 to less than $70,000
5. $70,000 to less than $80,000
6. $80,000 to less than $100,000
7. $100,000 to less than $150,000

8. $150,000 or more
97. Don’t know/Not sure
99. Prefer not to answer

Appendix 6

COST OF SERVICE ALLOCATION (COSA)

Appendix 6-1

EES COSA STUDY REPORT

FortisBC Energy, Inc.

FortisBC Energy, Inc.
Natural Gas Cost of Service and Rate Review
December 12, 2016

Prepared by:

EES Consulting

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Kirkland, Washington 98033

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Kirkland, WA and Portland, OR

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EES Consulting

December 12, 2016

Mr. Atul Toky
Manager, Tariffs, Rate Design and Special Contracts
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, B.C. V4N 0E8

SUBJECT: Natural Gas Cost of Service Review

Dear Mr. Toky:

Please find attached the Natural Gas Cost of Service Review prepared by EES Consulting, Inc. (EES). The conclusions and recommendations contained within this report are based upon industry practice and generally accepted rate setting principles.

This study has been developed independently by EES Consulting, with information provided by FEI staff, as needed. The findings, conclusions and recommendations of this report provide the basis for the development of fair and equitable rates for FEI.

Thank you for the opportunity to assist FEI in this rate setting process. Please contact me directly if there are any questions about the subject analyses.

Very truly yours,

Gary S. Saleba
President

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Kirkland, Washington 98033

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Kirkland, WA and Portland, OR

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Executive Summary

This report is provided to FortisBC Energy, Inc. (FEI) in support of its 2016 Rate Design Application (RDA). EES Consulting has provided assistance to FEI throughout the process by providing a review of standard and alternative COSA methodologies, input as to the appropriate methodology to use given the unique circumstance of the utility, review of the COSA model, and recommendations on setting appropriate rates.

The COSA developed by FEI is based on appropriate methodologies and takes into account standard practice, past precedent and cost causation. The COSA is based on the 2016 revenue requirement approved by the Commission, adjusted for certain expected capital projects.

The FEI COSA contains the following functions:

- Gas Supply Operations
- Tilbury LNG Storage
- Mt. Hayes LNG Storage
- Transmission
- Distribution
- Marketing
- Customer Accounting

The three primary classifiers in the COSA are:

- Demand
- Energy
- Customer

Once costs were functionalized and classified using these categories, costs were then allocated across customer groups based on the appropriate allocation factors.

We have reviewed both the COSA methodology and the COSA model itself to determine whether it is correct and appropriate. We find that the COSA follows standard utility practice, is generally consistent with past practice for the utility and the results are acceptable for purposes of setting just and reasonable rates for the utility. There are a few items where it may be beneficial to consider a change in the methodology in future proceedings, which are addressed within this report.

The COSA is intended to provide findings on whether any rebalancing should occur between customer groups and to assist in rate design matters. As the proposed implementation date for new rates is June 2018, it is expected that actual rate levels will be based on the revenue requirement established under the PBR for 2018. The rate design changes proposed in the Application, including rebalancing between various customer groups, will be applied to the rates that are applicable at that time. However, for purposes of the application, the rate adjustments contained in the various sections of the rate application are shown as if they apply to current rate levels.

For the cost of gas the actual rate levels are reviewed and set quarterly based on the actual and projected costs of gas purchases. Midstream rates are generally updated on an annual basis outside of the revenue requirements process. For delivery rates, the actual rate levels are updated annually on the basis of the PBR methodology.

FEI has proposed using a 90% to 110% revenue to cost ratio range of reasonableness for setting proposed rates. We consider this to be a reasonable range for use when considering the revenue to cost ratios for FEI. While this is a broader range than what is currently accepted by the Commission for the electric utilities in B.C., it is consistent with the range previously accepted for gas utilities in the Province and the larger range is appropriate in this particular case. Generally, the greater the level of uncertainty that exists within the COSA, the greater the acceptable revenue to cost range should be. In this particular case, uncertainty exists due to the peak day demand allocators and the uncertainty inherent to the allocation of costs using any selected methodology.

Ratemaking principals are based on many factors besides the COSA results, and rate changes based on COSA results are best made during a time of relative stability. FEI has considered the standard Bonbright principles in proposing the rates contained in the application. We believe that these principles are adequately maintained with the current FEI rate proposal.

FEI has proposed some relatively minor changes in its rate design for the Residential, Commercial and Industrial groups. All of the changes proposed reflect a move towards cost-causation, as demonstrated in the COSA while balancing the other rate design principles. For this reason we conclude that the proposed changes are appropriate.

COSA Overview

EES Consulting was retained by FEI to review and assist the utility in developing its comprehensive cost of service allocation (COSA) and rate design for the natural gas utility. The COSA is one of the major inputs that is used in developing proposed rates for FEI. Basically the COSA takes the revenue requirements established for the utility and allocates costs across the various customer groups, with the results used to ensure that proposed rates are fair, equitable and not unduly discriminatory. EES Consulting worked with FEI staff in assessing the appropriateness of the COSA methodology and rate design, making recommendations for changes where warranted, and reviewing the COSA model created by FEI staff.

In 2012 FEI filed a consolidated COSA as part of its request for Amalgamation of the three separate natural gas utilities. While that COSA was used in support of the Amalgamation, it was not used to make changes in the COSA methodology or specific rate design changes. Since the Amalgamation was approved, FEI has been phasing in the postage stamping of rates with all customers (except Fort Nelson) migrating to the FEI rate schedules.

Prior to Amalgamation, FEI last filed a comprehensive COSA in 2001 and this methodology was considered as the starting point when performing the Amalgamated COSA.

Report Organization

This report is designed as a review of the appropriateness of the proposed COSA methodology for use in the Rate Design Application. Determining the appropriateness of the methodology was based on the specific circumstance of the utility, past practices of the utility, and a review of the methodologies used in other jurisdictions.

This report is organized such that it follows the steps taken in analyzing and developing FEI's COSA. Contained in this section is an overview of the COSA process. This is followed by a jurisdictional review of COSA methods used by gas utilities across Canada and in the Pacific Northwest U.S. The next two sections discuss the functionalization, classification and allocation of costs within the COSA. Next, a jurisdictional review of rates in place is provided. This is followed by a review of the proposed rate design for the utility. The final section provides the summary and recommendations for the COSA and Rate Design.

Overview of the COSA

The setting of natural gas delivery rates that achieve the standard Bonbright principles of fairness and avoidance of undue discrimination is a complex process. This process is directed, however, by generally accepted methodologies that can be used as a guide in developing FEI's natural gas rates. The COSA is the second step in a traditional three-step process for developing service rates. The first step is the development of the test period revenue requirement for the utility, which is the starting input for the COSA. The COSA spreads the revenue requirement across the various customer groups, creating per unit costs by group. In the third step, rates are designed for each rate schedule, with revenue to cost ratios and per unit costs being considered in setting the appropriate rate levels.

As part of the Amalgamation, the Fort Nelson service area was excluded from postage stamped rates. This means that a separate COSA is needed to develop rates for the Fort Nelson service area. Throughout this report the methodology used for the COSA is discussed and the methods apply equally to the FEI COSA and the Fort Nelson COSA, although they are not discussed individually.

The COSA analysis takes the revenue requirement for the utility and attempts to equitably allocate those costs to the various customer groups (e.g., residential, commercial). This analysis provides a determination of the level of revenue responsibility of each customer group and the adjustments required to meet the cost of service.

Because the majority of costs are not incurred by any one type of customer, the COSA becomes an exercise in spreading joint and common costs among the various groups using factors appropriate to each type of expense. The founding principle of cost allocation is the concept of cost-causation. Cost-causation evaluates which customer or group of customers causes the utility to incur certain costs by linking system facility investments and operating costs to serve certain facilities to the services used by different customers.

A COSA can be performed using embedded costs or marginal costs. An Embedded COSA generally reflects the actual costs incurred by the utility, including costs associated with the historical rate base, and closely track the costs kept in its accounting records. A Marginal COSA reflects the costs associated with adding a new customer, and are based on costs of facilities and services as if incurred at the present time. A Marginal COSA often results in costs per customer group that are higher than embedded costs. Therefore, the use of a Marginal COSA usually requires that all costs be scaled back to a level equal to the Embedded revenue requirement established using actual or projected costs from an "accounting" perspective. Note that a Marginal COSA is different than calculating the marginal costs for the utility overall. A Marginal COSA would determine revenue to cost ratios by customer group and the need for rebalancing between groups, while an overall marginal cost is often used as a potential factor in developing rate design. EES has prepared a separate report that addresses marginal delivery costs for FEI but a Marginal COSA has not been completed by either FEI or by EES Consulting.

FEI COSA uses an embedded approach, which is consistent with the accepted practice for the past 20 years. We believe this is the most appropriate methodology. Therefore, FEI's embedded cost revenue requirement and existing rate base investment are used in developing the COSA results.

There are three basic steps to follow in developing a COSA, namely:

- Functionalization
- Classification
- Allocation

Functionalization separates costs into major categories that reflect the utility's plant investment and different services provided to customers. The primary functional categories are gas supply, transmission and distribution. In the case of FEI, additional functions are used to represent storage, marketing and customer accounting.

Classification determines the portion of the cost that is related to specific cost-causal factors, such as those that are demand-related, energy-related, or customer-related. Gas supply costs are related to supplying gas to core customers throughout the year. Storage and transmission costs are related to the bulk transfer of gas to load centers on the system. These storage and transmission facilities are typically designed and operated to meet system peak demand requirement. The distribution system is designed to extend service to all customers attached to the system and to meet the peak load capacity requirement of each customer. Customer accounting and marketing costs are more closely related to the number of customers on the system.

Allocation of costs to specific customer groups is based on the customer's contribution to the specific classifier selected. For instance, demand-related costs are allocated to a customer group using that customer group's contribution to the particular measurement of system demand. An analysis of customer requirements, loads, and usage characteristics is completed to develop allocation factors reflecting each of the classifiers employed within the COSA. The analysis may include an evaluation of the system design and operations, its accounting and physical asset records, customer load data, and special studies.

The overall COSA approach used for FEI COSA follows the standard three-step process that is generally accepted for embedded costs studies.

Overview of Rate Design

While the COSA is complex analysis of various line item expenses and various methodologies to allocate costs among the customer groups, rate design is less driven by detailed analysis. In designing rates the utility must take into account many different factors, of which the COSA results are just one. Rate design is just as complex as the COSA, however the complexity is related to more qualitative issues than quantitative issues.

The first issue in designing rates is to determine the appropriate segmentation of customers into customer groups. While this needs to be decided prior to carrying out the COSA, it is one of the factors in designing rates. In deciding what customer groups are most important the utility must consider factors that impact the costs developed in the COSA, as well as those factors that are more logistical in nature. The following is a list of factors to consider when developing the appropriate rates groups:

- Load Characteristics and Homogeneity
- Ability to Identify Customers Belonging to Each Group
- Different Levels of Service (e.g. sales vs. transport service, firm vs. interruptible)
- Different Uses of Gas Impacting Service Levels
- Ability for Customer to Understand and Accept the Customer Groups
- Ability to Administer the Customer Groups
- Benefits Associated with Attracting and Retaining Customers (e.g. bypass rates)

While the Revenue Requirements establishes the overall rate increase that is needed by the utility, the COSA is used to determine equity among the various customer groups. Within the COSA, revenue to cost ratios are developed to see which customer groups are paying more than their share of costs, and which customer groups are paying less than their share of costs. Because of the inherent uncertainty in any COSA, both because of differences in methodology and uncertainty in load factors and peak demands by rate group, a range of reasonableness is generally applied to determine whether a group is paying its fair share. In the past, a 90% to 110% percent range of reasonableness was applied to the revenue to cost ratios for FEI. Customer groups within that range do not need an adjustment in the overall rate level. Customer groups outside of that range should generally have rebalancing adjustments with a shift in revenues between groups such that revenue to cost ratios move towards the range of reasonableness. For rate schedules that require a rebalancing adjustment, gradualism is often applied rather than making a large adjustment at one time to avoid rate shock to any given customer groups

Once overall revenues for each rate group are established, the rate structure needs to be developed for each customer group. The rate structure needs to take into account the cost causation determined in the COSA, the price signals desired by the utility to promote economic efficiency, the ease of understanding by customers, the ability to administer the rates, rate stability and practices by neighboring and competing utilities. The rate structure includes the following types of factors, although not all of them may apply for any given utility:

- Inclusion of a Customer Charge
- Inclusion of a Minimum Bill
- Inclusion of a Demand Charge
- Inclusion of an Energy Charge
- Whether Rates Differ by Block (Inclining or Declining)

- Whether Demand Charges are Based on Contract Demand, Metered Demand or Demand Ratchet
- Whether the Cost of Gas and Delivery Charges are Separate

Based on the selected rate structure, the level of the rate components can be set. Setting specific rate components are generally driven by current rate components, the unit costs resulting from the COSA, rates for neighboring or competing utilities, acceptability from customers, rate stability and desired price signals.

Jurisdictional Review of COSA Methodology

To assist in determining whether FEI is using accepted methods within its COSA, EES Consulting reviewed the methods used by various other gas utilities across Canada and in the Pacific Northwest U.S. While physical circumstances, intervenor positions, Commission approvals and history all play a role in approved COSA methods for different utilities, it is useful to review what other utilities are using. The review of the methods used by other large gas utilities is based primarily on the Commission Decisions in the most recently approved rate cases. In some cases the Decision is still pending or a settlement was reached among the parties and the methods contained in the rate application were included.

The utilities included in the review are:

- ATCO (Alberta)
- Union Gas (Ontario)
- Enbridge (Ontario)
- Gaz Metro (Quebec)
- Puget Sound Energy (Washington)
- Avista (Washington)
- Northwest Natural Gas (Oregon)

We also spoke to a representative at SaskEnergy, however, they are not regulated in the traditional sense and their COSA is not publicly available.

While we were able to compare specific methods used in the COSA, in some cases it would be difficult to say that there was a true precedent as the Decision is still pending or the results were based on a negotiated settlement.

Table 1 summarizes the status of each rate proceeding and the related dates associated with the Application and Decision.

Table 1 Status of Most Recent Rate Application			
Name of Utility	**Timeline**	**Docket**	**Status**
ATCO	2012 Actuals	Decision 2013-035	Based on COSA method from 2010 settlement, COSA accepted as filed
Union Gas	Uses 2013 Forecast Year	EB-2011-0210	No changes in methodology from 2007, settlement/acceptance on most COSA issues
Enbridge	2014 Forecast	EB-2012-0459	Decision provided July 2014
Gaz Metro	Filed in 2013	R-3867-2013	Black & Veatch provided recommendations to COSA method in Application, no decision as of June 2016
Puget Sound Energy	Filed June 2011	UG-111049	Settlement in January 2012 – settled on rates and specified that they did not all agree on the COSA methodology
Avista	Filed in 2015 using 2014 Actuals	UG-15025	Settlement in January 2016 with no agreement specified on actual COSA
Northwest Natural Gas	Filed December 2011	UG-221	Settlement in October 2012 - COSA based on marginal cost rather than embedded cost

Because the Northwest Natural Gas rates are based on a marginal cost study, they are excluded in the comparison of the COSA methodologies used. They are, however, included in terms of the rate structure comparison included in a later section of this report.

Cost of Gas and Wholesale Transportation

Like FEI, most of the utilities exclude the cost of gas in their COSA and have a separate gas cost recovery mechanism to provide more frequent updates based on the actual cost of gas purchased. The exception to this is Union Gas and Avista where the cost of gas is still included in a combined rate. Union Gas allocated gas costs on the basis of annual energy.

Similarly, the cost of wholesale transportation service was often excluded from the COSA. For Union Gas transportation purchases were included and the base load costs were allocated on average day while remaining costs were allocated on the excess over the average day. Enbridge also included wholesale transportation purchases. For upstream transmission contracted on a 100% load factor basis the costs were allocated on the basis of annual demand. For purchased transportation from Union Gas to move gas into and out of storage the costs were split 40% based on average storage amount and 60% based on the peak day excess over average storage.

Storage

None of the utilities reviewed has internal storage similar to FEI's situation. Storage service was generally purchased on a wholesale basis. Even those utilities that owned storage facilities kept those facilities in their unregulated business. Table 2 summarizes the treatment of storage costs in the COSA of the utilities reviewed.

Table 2 Treatment of Storage	
Name of Utility	**Method Used**
ATCO	Excluded from the delivery COSA.
Union Gas	Took out portion of costs related to unregulated side- only system integrity portion remains in the COSA. Remaining portion classified as peak demand (design day) and allocated based on excess demand over average demand
Enbridge	Develop storage costs and then charge for in-franchise use vs outside use. Three components include annual component for volume (space), variable amount per m3 for injections and withdrawals (space) and peak component for max daily rate (deliverability).
Gaz Metro	Not applicable
Puget Sound Energy	Allocated on Seasonal Demand
Avista	Noted that Commodity storage benefits for gas customers and balancing for all customers

Transmission

Not all of the utilities have facilities that were considered to be transmission. Table 3 summarizes the treatment of transmission costs in the COSA of the utilities reviewed. Because the inclusion of transmission varied so much between the utilities, it is difficult to reach any conclusions about a standard approach.

Table 3 Treatment of Transmission	
Name of Utility	**Method Used**
ATCO	Not included.
Union Gas	Classified as demand-related using design day demand to allocate– except compressor fuel as energy related.
Enbridge	Transmission and high pressure system allocated on peak demand. (considered distribution mains)
Gaz Metro	Was average and excess method. Black & Veatch recommend 100% design day
Puget Sound Energy	Peak and average method
Avista	Not included.

Distribution Mains

Table 4 summarizes the treatment of distribution mains in the COSA of the utilities reviewed. In most cases there was a split of distribution mains between demand and customer, using either a minimum system approach or a fixed percentage split. While Gaz Metro previously used an average and excess method, their COSA consultant recommended a move to a minimum system approach. In Washington, the WUTC generally does not allow the use of the minimum system approach and therefore a peak and average method was used by the two utilities in Washington. However, by exempting large users from an allocation of the small mains, the treatment has some of the same impacts as a minimum system approach.

Table 4
Treatment of Distribution Mains

Name of Utility	Method Used
ATCO	Split 35% customer and 65% non-coincident demand
Union Gas	Minimum System – Demand and Customer
Enbridge	Large customer class excluded from pipes under 6" ordered by the OEB. Low pressure mains use minimum system, with 34% customer-related and 66% demand-related.
Gaz Metro	Was average and excess. Black & Veatch recommended minimum system with NCP demand & customer
Puget Sound Energy	Peak and average method – split by system load factor (33% load factor meant 33% on average demand and 67% on peak demand). Small mains less than 2" not allocated to large commercial or industrial. Medium means of 2" to 3" allocated with one-third allocated to all customers and two-thirds allocated to all but industrial customers.
Avista	CP and Commodity based on peak and average ratio (load factor with 60% peak, 40% commodity) – Commodity Portion segregated into small 2", medium 4"and large 6" with large users getting 0% of small mains and 33% of medium mains. Previously small and large (4") then used peak and average ratio. Only took out usage of large customers not served at all by small mains. Note that WUTC does not allow minimum system.

Compressor/Measuring/Regulating Equipment

Table 5 summarizes the treatment of compressor/measuring and regulating equipment in the COSA of the utilities reviewed. Generally these costs were treated in the same manner as distribution mains.

Table 5 Treatment of Compressor/Measuring/Regulating Equipment	
Name of Utility	**Method Used**
ATCO	Same as distribution mains
Union Gas	Classified as 100% Demand
Enbridge	Same as mains
Gaz Metro	Not discussed.
Puget Sound Energy	Peak and average method
Avista	Peak and average ratio method

Services and Meters

Table 6 summarizes the treatment of services and meters in the COSA of the utilities reviewed. In all cases the costs were classified as customer-related and some form of weighting of customer was used to develop the allocation factor.

Table 6 Treatment of Services and Meters	
Name of Utility	**Method Used**
ATCO	Customer or weighted customers (different for meters and services)- Does have meter reading, billing, customer service.
Union Gas	Classified as 100% Customer (use average customers, service replacement costs and service calls)
Enbridge	Customer-related, meter reading classified to Readings Processed
Gaz Metro	Not discussed.
Puget Sound Energy	Customer-related weighted on cost of installed meters.
Avista	Meters & services based on weighted customer

General Plant

Table 7 summarizes the treatment of general plant in the COSA of the utilities reviewed. There was a wide variation in the treatment of general plant facilities. In some cases specific studies were made for space utilization while in other cases a combination of plant, O&M expenses and labor were used.

Table 7 Treatment of General Plant	
Name of Utility	**Method Used**
ATCO	General Structures based on total space study, tools and equipment – capital and O&M use by function
Union Gas	Functionalize using indirect rate base functionalization factor (50% weighted net plant/50% O&M) or using indirect O&M functionalization factor (O&M less compressor fuel). and service calls)
Enbridge	Structures based on space utilization analysis and office equip follows, tools, computers etc. all have analysis of use.
Gaz Metro	Was based on other distribution plant, recommend some costs be based on labor ratios
Puget Sound Energy	Some based on plant, some based on labor
Avista	4-part allocator- 25% each Direct O&M without resources and labor, direct O&M labor, Customers, Net Plant). Used to be 50% other O&M and 50% throughput

A&G

Table 8 summarizes the Administrative and General (A&G) costs in the COSA of the utilities reviewed. In all cases O&M expenses were used for all or some of the allocation of costs. For the two utilities in Washington, a combination of O&M, plant, revenue and labor was used to allocate the A&G costs.

Table 8 Treatment of A&G	
Name of Utility	**Method Used**
ATCO	Customer and Non-Coincident Demand – based on distribution service costs before billing and call center
Union Gas	Functionalize on the basis of all other O&M – except labor benefits on basis of direct labor.
Enbridge	On the basis of O&M costs – includes 3% of the cost of gas and classified to Distribution
Gaz Metro	
Puget Sound Energy	Some on labor costs, some on plant, some revenue-related and the rest based on all other O&M expenses
Avista	4-part allocator

Sales & Marketing

Table 9 summarizes the treatment of sales and marketing in the COSA of the utilities reviewed. In all cases sales and marketing expenses were assigned as customer-related.

Table 9 Treatment of Sales and Marketing	
Name of Utility	**Method Used**
ATCO	100% Customer
Union Gas	Customer Related
Enbridge	NGV-related costs assigned, rest equally split between distribution costs and number of customers, general promotion used to increase gas utilization so classified as demand-related.
Gaz Metro	
Puget Sound Energy	Customer-related
Avista	Unweighted customers

Customer Accounting

Table 10 summarizes the treatment of customer accounting in the COSA of the utilities reviewed. Customer accounting costs were considered customer-related in all cases.

Table 10 Treatment of Customer Accounting	
Name of Utility	**Method Used**
ATCO	100% Customer
Union Gas	Customer Related
Enbridge	Number of Customers
Gaz Metro	
Puget Sound Energy	Customer-related
Avista	Acctg, customer care, meter reading allocated to unweighted customers

Demand Side Management/Conservation

Table 11 summarizes the treatment of demand side management (DSM) or conservation in the COSA of the utilities reviewed. Not all of the utilities had specific costs related to DSM.

Table 11 Treatment of Demand Side Management/Conservation	
Name of Utility	**Method Used**
ATCO	None
Union Gas	Classified as 100% Demand
Enbridge	Was not discussed – classified as distribution DSM and allocation method is not listed in table with others, less to Rate 1 than both customer, peak or commodity
Gaz Metro	
Puget Sound Energy	No costs identified
Avista	DSM Investment and amortization based on Peak and Average Method

Losses

Table 12 summarizes the treatment of losses in the COSA of the utilities reviewed. In most cases the treatment of losses was not specifically identified in the Application/Decision and was not specified in the tables.

Table 12 Treatment of Losses	
Name of Utility	**Method Used**
ATCO	Not discussed/included in tables.
Union Gas	Commodity related.
Enbridge	Commodity losses classified based on gas costs, storage losses follow storage treatment
Gaz Metro	Should be recovered in transport rates for transporters (by actual delivery after losses) and in cost of gas for purchasers
Puget Sound Energy	Not discussed or shown in COSA
Avista	Not discussed or shown in COSA

Review of COSA Functionalization and Classification Methods

The Adjusted 2016 COSA reflects the revenue requirements and rate base approved by the Commission in the Annual Rate Review. Adjustments have been made to reflect new large projects expected over the next few years so that the COSA can be representative of the utility's costs over the next several years. All items in the revenue requirement are then allocated across the various customer groups. As discussed previously, a separate COSA was performed for Fort Nelson and the methods used apply to both FEI and Fort Nelson.

Both the rate base and revenue requirements for FEI are functionalized and classified within the COSA. The methodology used for these first two steps are discussed in greater detail in this section. All of the functionalization and classification methods used in the COSA reflect both past practices and the specific circumstances of the utility. It is our opinion that they also fall within the range of accepted utility practice and are appropriate for the Adjusted 2016 COSA.

Functionalization

The first step in the COSA is the functionalization of costs. Generally, functionalization follows the various cost categories of items found in the rate base. For FEI, the COSA contains the following functions:

- Gas Supply Operations
- Tilbury LNG Storage
- Mt. Hayes LNG Storage
- Transmission
- Distribution
- Marketing
- Customer Accounting

The functions defined by FEI and the costs that were assigned to each function are appropriate given that they reflect the historic functions and follow the standard system of accounts of the utility. The functions generally differ in terms of usage, cost causation and which customer groups use the function. While Marketing and Customer Accounting are separate categories within the standard system of accounts, and have been treated as separate functions in the past, the current methodology is appropriate. However, they could potentially be combined as they are classified and allocated in the same manner, with no impact on the COSA results.

Costs that are directly related to the defined functions are assigned to those functions. For General plant accounts, facilities related to the Customer Information/Service system have been functionalized to the Customer Accounting function. The remaining assets are functionalized across all of the functions on the basis of the gross plant in service prior to intangible and general plant. Administrative and general (A&G) expenses are functionalized on the basis of all gross O&M before Administrative and General costs. This approach is consistent with standard practice in the industry.

An alternative approach sometimes used for functionalizing A&G, as well as general plant and the associated operating and maintenance (O&M) expense, is to use labor ratios to account for the number of staff assigned to each function. In the case of FEI, staff time is not always easily assigned to the various functions and does not necessarily best represent the level of effort and costs for some of the functions. The decision to use gross plant in service and O&M expense is appropriate at the present time as it spreads the costs among all of the functions and reflects past practice.

Classification of Costs

The second step in performing a COSA is to classify the functionalized expenses to traditional cost-causation categories. These cost-causation categories can be directly related to specific consumption behavior or system configuration measurements including peak day demand, energy, or number of customers. Each classification category will have a specific allocator that, when applied, will distribute those costs among the appropriate customer classes during the allocation phase of the analysis.

The three primary classifiers are:

- Demand
- Energy
- Customer

These three classifiers are standard for both gas and electric utilities and have consistently been used by FEI in past COSAs and best reflect the different cost causation factors. Therefore the classifiers are appropriate for the Adjusted 2016 COSA. Functionalized gas supply costs are generally classified and allocated on the basis of energy. Transmission system costs are generally classified as demand-related. Distribution costs are generally split between demand-related and customer-related components, or directly assigned to a specific customer group.

Within the three categories, there are multiple ways of defining each option as well as varying ways to split costs between two or more classifiers. Customer-related categories can distinguish between actual customer and weighted customer characteristics. Other classifiers sometimes used in the process include revenue-related and direct assignment. In addition, there are many instances where certain expense accounts are not specifically classified to a particular category but rather follow the spilt used for a related rate base account or subtotal of specific expenses or rate base accounts. For example, the depreciation expense associated with distribution is generally classified to demand and customer on the basis of the classification of the total distribution plant.

Classification of Gas Supply, Storage and Transmission Rate Base

FEI has a limited amount of rate base for gas supply, which has been classified as energy-related, consistent with all other gas supply accounts.

Storage facilities include the Tilbury and Mt. Hayes facilities. A portion of the costs for Mt. Hayes are assigned to the midstream portion of the cost of gas, with the residual included in the delivery component of the COSA. This is consistent with previous practice. For Tilbury, 100 percent is included in the delivery component. Those costs are then included in rate base and have all been classified as demand-related. FEI storage facilities differ from upstream and market area storage facilities that are available on a wholesale basis to gas purchasers and are generally considered part of the cost of gas. These wholesale storage options are generally used to provide seasonal storage to take advantage of cost differentials and availability of gas supply by season and require the purchase of additional wholesale transportation to access the facilities. FEI's storage facilities are integrated with the transmission system and are not available to other providers on a wholesale basis. The underlying cost causation for Tilbury and Mt. Hayes differs from wholesale storage as they are used to provide storage to meet short-term peaking needs, to provide reliability in the event of transmission outages, to offset the need for additional transmission facilities, and to assist with balancing daily customer needs of natural gas. These functions are available for both the core sales and transportation customers of FEI and are therefore appropriate to include in the delivery margin for all customers, with the exception of the portion of Mt. Hayes assigned to the midstream function. For that reason, the costs are classified on the basis of demand, consistent with past practice. Because the storage in place at FEI is unique to the system, reliance on the specific cost causation is used rather than widespread industry practice. The bulk of storage facilities in North America are wholesale facilities and their treatment is not relevant in this case.

The cost of providing transmission service to a customer is considered to be directly proportional to the contribution to system peak demand that a customer imposes on the system. All transmission rate base accounts are classified 100 percent demand-related. This is appropriate because it is consistent with past practice and industry standards.

Classification of Distribution Rate Base

Generally, there are two methodologies that can be used to classify distribution costs: 100% demand and minimum system. The 100% demand methodology assumes that the distribution system is built only to meet the peak day demand and are therefore all assigned on the basis of demand. In some cases, while the cost is considered demand-related, the allocator is a peak and average demand number or average and excess number rather than just based on peak day demand. We do not believe that the 100% demand approach is appropriate as the FEI system is built in part to reflect the fact that each customer is connected to the system, regardless of usage level.

Distribution costs can also be split between demand and customer according to a minimum system approach. This approach reflects the philosophy that the system is in place in part because there are customers to serve throughout the service territory expanse, and that a minimally sized distribution system is needed to serve these customers even if they only use 1 joule of energy per year. The concept follows that any costs associated with a system larger than this minimum size are due to the fact that customers “demand” a delivery quantity greater than the minimum unit of gas supply and that therefore, those costs should be treated as demand-related. Because the residential group tends to have a higher share of the number of customers as compared to the share of peak demand, the minimum system methodology tends to allocate more costs to the residential customer group and customer-related unit costs tend to be higher than with the 100% demand methodology.

Distribution facilities include all equipment required to get gas supply from the transmission system to the end user of the natural gas. Classifying distribution costs under the minimum system method requires a special analysis of the nature of the costs. Most distribution costs are appropriately split between demand and customer components. Different accounts within the distribution function are treated separately. For purposes of the COSA, a specialized study termed a “minimum system analysis” was used, which is a theoretical analysis using both engineering and accounting inputs to develop a split of the distribution costs between demand and customer components. The minimum system study was updated by FEI staff to reflect the most current information to be consistent with the COSA test year.

The minimum system analysis is used to theoretically determine the lowest level of plant investment required to serve a utility’s customers compared to the actual facilities in place to meet varying customer demands. FEI staff completed the minimum system study using current 2015 year data. For the consolidated COSA filed in the Amalgamation Proceeding, FEI engineers determined that the minimum size pipe should be 2 inches rather than the 1.25 inches that was used in the past. To better reflect this larger minimum size pipe, an offset to account for the peak load carrying capability (PLCC) of the minimum system was incorporated into the analysis. The PLCC adjustment is discussed in the following section.

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the length of distribution mains in place segregated by size of the pipe. The cost associated with these facilities are then determined. The costs associated with the minimum size facilities were classified as customer-related while the remaining facilities were classified as demand-related.

The result of the minimum system study for FEI was 70% demand-related and 30% customer-related. The result differs from studies prior to this time, in large part because of the change in the minimum size pipe. The calculations and data used in developing the minimum system were reviewed and have been done appropriately and provided reasonable results for the FEI system. The resulting demand/customer split was used for the majority of distribution accounts, including mains, structures and regulating equipment.

Costs associated with Services and Meters differ within the minimum system approach. These costs are directly associated with the number of customers, i.e. there is generally one service and meter per customer. Costs have therefore been classified as 100% customer-related.

The minimum system approach is consistent with past practice of the utility and is generally accepted in the utility industry.

Peak Load Carrying Capability Adjustment (PLCC)

While the minimum system is, in theory, designed to carry only a minimal amount of load, the actual facilities designated as the minimal size are capable of carrying some amount of demand, therefore overstating the level of the customer-related component. The actual amount of demand capability within the minimum system is a function of load density, minimum equipment standards, and other engineering considerations. Under traditional cost allocation techniques, each customer/connection attracts an equal allocation of the minimum system, plus each customer group is allocated demand costs based on the total customer group's peak demand. As such, it has been argued that a customer group peak demand allocator is too large, because a portion of these peak demand-related costs are being covered through the per customer/connection minimum system allocation.

The correction of the problem of over allocating demand can be achieved by the application of a PLCC adjustment. This adjustment recognizes that the minimum sized pipe assigned to the customer-related component has a peak load carrying capability, that is, it is large enough to carry more than just the minimal amount of gas associated with having a customer on the system. The PLCC adjustment is made to the allocation of demand-related costs among customers. Use of the PLCC adjustment has already been approved by the Commission for the FortisBC electric COSA and was included in the COSA for the Amalgamation Proceeding. This adjustment is particularly warranted in light of the change in the minimum size pipe to 2 inches as the new size allows an even greater amount of gas beyond the minimum requirement to flow to the customer.

The precise amount of a PLCC adjustment should match the definition of the minimum system adopted. In FEI's case, it was determined that the average PLCC is 0.205 GJ per customer. The use of the PLCC credit is an enhancement over what was done for COSAs prior to the Amalgamation Proceeding. EES Consulting reviewed the PLCC calculations and concur with the results.

The PLCC adjustment will determine how much demand for a customer group can be met by the minimum system (number of customers/connections x PLCC for minimum system) and will credit this amount against the peak demands by customer group used for determining demand allocators. The adjusted customer group peak demand amounts can then be used to allocate the distribution demand-related costs, eliminating the double-counting.

Other Rate Base Items

The Customer Accounting and Marketing functions were both classified as customer-related as the costs are not based on the usage of each customer. This is appropriate as it reflects cost causation, is consistent with past practice and is the industry standard. In the case of the accounts for Energy Efficiency & Conservation (EEC), currently included in the Marketing function, there is some question as to whether these costs are more closely aligned with customers or if they are in place to avoid gas and transmission facilities. FEI first split the costs by Residential, Commercial and Industrial groups based on the amounts spent for each customer group, similar to a direct assignment. Within each broad customer group, costs were classified as energy-related to allow allocation to specific rate schedule. This reflects both the benefits to the various customer groups as well as the impact of reducing energy use.

General plant was first functionalized to the various functions and then classified using the resulting assignments of gross plant prior to general plant. For example, the portion of general plant assigned to distribution was based on the gross plant functionalized as distribution and then was split between demand and customer in the same manner as the general gross plant amount. Accumulated depreciation accounts and working capital accounts were classified in the same fashion as the corresponding gross plant accounts. Customer contributions were tracked separately for the transmission and distribution functions and then each was classified in the same manner as gross plant for the function. This is appropriate because it allows the customer contributions to be a direct reduction in plant in the same manner it is ultimately allocated to customers.

Classification of Expenses

Gas Supply expenses within the COSA are relatively minor with the exception of the cost of gas and midstream costs. The cost of gas, and other minor gas supply expenses are classified as energy-related, consistent with the Gas Supply rate base accounts. This is consistent with past practice. While rates for the cost of gas are updated more frequently than the costs for gas delivery, they are included within the COSA for comparison purposes.

Midstream costs are updated annually along with the quarter four cost of gas. Midstream costs include charges for the use of upstream pipeline and storage facilities not owned by FEI. Charges for those services are primarily tied to contracted capacity, which is set to cover forecasted peak day demands. The annual midstream cost filings allocate costs by rate group and the results are included in the COSA to allow FEI to calculate revenue to cost ratios and bill comparisons that reflect the entire cost to the customer.

Expenses associated with storage facilities are treated in the same fashion as the storage rate base accounts, with all expenses classified as demand-related. Transmission expenses similarly follow the transmission rate base and are also classified as demand-related.

Some of the distribution expense accounts correspond to a rate base account and follow the treatment of that rate base item. For some items, this means a split between demand and customer using the minimum system split. For other items, rate base accounts are 100% customer-related and therefore the corresponding expenses are classified as customer-related. For more general distribution expenses, the costs are classified on the same basis as the total distribution rate base.

Marketing and Customer Accounting expenses are classified as customer-related. The exception is the expense associated with EEC programs, which is treated in the same manner described above.

A&G was first assigned to each function on the basis of gross plant. These amounts were then classified on the same basis as the plant associated with each of the various functions.

Treatment of Bypass, Interruptible and Other Revenues

In addition to revenues from core and transportation customers subject to tariffs, FEI also receives revenues from customers with bypass and other dedicated contracts as well as other activities. Because the COSA is concerned with collecting revenues from rates for the tariffed customer groups, these other revenues are treated as an offset to the revenue requirement. Specific items within other revenues are treated individually to best reflect the appropriate cost causation, as described below.

Revenues collected from late payment fees are functionalized to the Customer Accounting function and classified as customer-related. Connection fees are functionalized to the distribution function as they are charged in order to offset the cost of new customers hooked up to the distribution system. Other Revenues are then classified in the same manner as all distribution rate base.

A large portion of other revenue comes from customer revenues that are set at negotiated rates. FEI has customers on contract rates that have been negotiated due to the ability of the customer to bypass the system. For bypass customers, rates are set outside of the COSA because the COSA does not capture the benefits these customers provide to the system. For bypass customers, those customers could economically bypass the system when compared to full cost-based rates and they are provided a negotiated discount to connect/retain them as a customer. By continuing to collect revenues from these customers, they are contributing to the fixed cost of the system that is already in place. This is preferable to collecting no revenues from them and means that other customers will not have to make up for the revenues associated with their lost sales. The Commission has approved this rate-setting approach for bypass customers, and once the discount is negotiated, FEI is contractually obligated to sell at the specified rate.

Within the COSA, if bypass customers were allocated a full share of costs based on their peak demand, the revenue to cost ratio would be below 100%. That result would be acceptable given the circumstances, however, it would not recognize the impact on other rate groups. If there is a shortfall in revenues within the COSA from one group that will not be changed through rebalancing, all of the other rate groups will see revenue to cost ratios that are too high. The treatment in the COSA is to place the bypass revenue in the other revenue category, and classify and allocate those revenues in a manner to offset the fixed cost of the system and credit all other classes. This approach is consistent with past practice and follows cost-causation. As the discount for bypass customers is provided because the revenues benefit all other customers by retaining the bypass customer, it is appropriate that those revenues are used as a credit to benefit all other customers.

Bypass revenues are classified as demand, like the transmission and distribution rate base and expenses they offset. Revenues are then allocated to customer groups on the basis of the delivery margin so that the revenues offset the costs assigned to each group.

A similar issue exists for interruptible customers as for bypass customers. For interruptible customers, past studies included them as separate customer groups in the COSA but assigned them zero peak load. As with bypass customers, the COSA results were not used when setting the interruptible rates and instead rates were based on a market driven discount relative to firm rates. This discounting approach was approved by the Commission in its Phase B Rate Design Application Decision from October 1993, and subsequently continued to be used in later negotiated settlement agreements.

The past COSA treatment leads to interruptible customer groups seeing very high revenue to cost ratios, and reflect little or no contribution to the fixed system by interruptible customers as the costs assigned to them generally reflect only those costs that are customer-related. As with bypass customers, rates are set at a discount to reflect some contribution to the fixed cost of the system while also recognizing the fact that all other customers benefit from interruptible sales. Similar to the bypass issue, the revenue to cost ratios in the COSA are misleading because there is no intention to change interruptible rates to match the COSA results. Therefore the revenues from the interruptible group that are above the allocated cost are not used to benefit other customers by offsetting the costs of all other groups, as is the case for bypass revenues. For that reason it would be more appropriate to treat all interruptible revenues in the same manner as bypass revenues. However, interveners have generally asked to see the revenue to cost ratios for the interruptible group in the past.

FEI continued to treat interruptible customers as having zero load in the baseline COSA, consistent with past practice. However, an adjustment was made in the final COSA to exclude interruptible sales and revenues when designing industrial rates to provide revenue to cost ratios that would be more appropriate for the circumstances.

Review of COSA Allocation Methods

The third step in performing a COSA is the allocation of the utility's total functionalized and classified revenue requirement to the customer groups. This is performed through the application of an appropriate allocation methodology.

For each of the primary classifiers discussed above, distinctions have been made within each category to better reflect cost-causation. The following are the specific allocation methods used in the FEI and Fort Nelson natural gas COSA. The specific method of cost classification and allocation for various rate base and expense items is discussed in further detail below.

Demand Allocation Factors

For purposes of this study, demand allocation factors were developed based on peak day demand to represent maximum use during an extreme weather condition. In some cases, the demand allocators were further differentiated to reflect the fact that not all customers use the facilities being allocated, and therefore some customers are excluded when developing specific allocation factors. Given the use of the PLCC adjustment as part of the minimum system treatment of distribution costs, the demand allocation factors are further adjusted by subtracting the PLCC amount times the number of customers in each rate group. This adjusted demand number represents the amount of demand that is not already included in the portion of distribution allocated on the basis of customers.

To be consistent with past COSA studies, the coincident peak day demand numbers were used for all allocation factors. While this is an acceptable methodology, there are cases where both a coincident peak (CP) and non-coincident peak (NCP) allocators are both used within a COSA. This is something that FEI may want to consider for future applications. The following describes both the CP and NCP demand calculations.

- *Coincident Peak Day Demand (CP).* The coincident peak day demand reflects the diversity among customers and reflects the peak day consumption used to develop the amount of gas supply purchased by the utility. Because this peak value better reflects the amount used for facilities closer to the upstream gas supply, it is generally used as the allocator for costs within the storage and transmission functions.

- *Non-Coincident Peak Day Demand Allocation Factor (NCP).* The NCP demand method allocates costs to each rate group based upon their highest non-coincident peak demand regardless of the time of occurrence. This peak reflects the system planning forecast of demand used for planning facilities close to the customer. The NCP is often used for facilities close to the customer, such as distribution.

Energy Allocation Factors

Energy costs vary directly with consumption. Accordingly, energy allocation factors were based upon annual gas sales for each customer group. As the energy allocator is used only for the gas supply function, it includes only the core customer groups that purchase natural gas from FEI. The only exception of energy-related costs being applied to transport customers is the assignment of the cost of gas associated with system losses.

Customer Allocation Factors

Two basic types of customer costs were identified—actual and weighted. This is generally consistent with past practice; however, we recommended a slight modification to reflect three rather than two different customer allocators. In addition to customers weighted for meters and services, we suggested that an allocator using customers weighted for customer accounting was more appropriate to use for some accounts and would better reflect cost causation. FEI therefore added this third allocator to the COSA. EES Consulting reviewed the calculations for both weighted customer allocators and found the results to be reasonable.

- *Actual Customers.* The allocation factor for actual customers was derived from the actual number of customers served in each customer group averaged across the 12 months of the 2016 test period.

- *Customers Weighted for Meters and Services.* The first weighted customer allocation factor considered the relative differences in meter costs among the various customer groups. The cost of actual meters and services installed for each rate group was used as the weighting factor for each group.

- *Customers Weighted for Customer Administration and Billing.* The second weighted customer allocation factor considered the cost of customer administration and billing as well as customer service for each rate group. The weighting factors were developed by FEI staff and were based on the estimated level of effort required per rate group. A standard weighting factor of 1.0 was used for the residential groups, with other groups receiving a weighting factor relative to the level of effort for a residential customer.

Allocation of Rate Base and Revenue Requirements

Gas supply rate base items and expenses were classified as energy-related and were appropriately allocated to customer groups on the basis of annual GJ for core customers.

Transmission and storage rate base and expense items were all classified as demand-related and were allocated on the basis of the CP demand.

Distribution rate base and expense items that were related to metering and services were classified as 100% customer and the customer numbers weighted for meters and services were used for allocation. For the other distribution items that were split between demand and customer, the actual numbers of customers was used as the customer allocator. The demand allocator was equal to the CP demand less the PLCC amount per customer times the actual customers in each rate group.

Customer Accounting and Marketing accounts used the customer allocator weighted for customer accounting. General plant and A&G costs were allocated to rate groups on the same basis as was used for each of the classified components.

Jurisdictional Review of Rates

As with the review of COSA methodologies used in other jurisdictions, EES Consulting reviewed the rates in place for other large gas utilities across Canada and the Pacific Northwest U.S. Rates were reviewed in terms of customer groups used, the structure of the rates, and the level of the customer charge. While the level of rates is interesting, all utilities face different costs and include different items in their delivery charges. For that reason, the level of the rates was not a focus of the review.

In general, there was greater consistency in COSA methods than there was in the actual customer segmentation of rate groups and rate design. More utilities were reviewed in terms of rate design than COSA methodology as utilities with different forms or unpublished COSA results did not need to be excluded. The following utilities were included in the jurisdictional gas rate design review:

- PNG (British Columbia)
- ATCO (Alberta)
- AltaGas (Alberta)
- SaskEnergy (Saskatchewan)
- Manitoba Hydro (Manitoba)
- Union Gas (Ontario)
- Enbridge (Ontario)
- Gaz Metro (Quebec)
- Gazifere (Quebec)
- Puget Sound Energy (Washington)
- Avista (Washington)
- Northwest Natural Gas (Oregon)

Tables showing the comparison of rates can be found in Appendices 7-3, 8-1 and 9-1.

Rate Group Segmentation

The first thing to note in the review is that there is a wide range of segmentation of customer groups between the various utilities. The rates for the utilities were looked at in terms of residential, commercial and industrial and NGV/Other categories, however, the rate groups did not all readily fall into those categories.

While all utilities had some form of service for residential customers, none of the utilities had more than one rate that would be applicable to residential customers. In some cases, there was no distinction between residential and other small users. Examples of this include ATCO, where service was for Low Use customers under 1,200 GJ per year and Union Gas, where the D1 rate applied to anyone with use below 50,000 m3 per year but with declining block rates to accommodate users of various sizes within that rate schedule.

For commercial customers, there were several cases where small and large commercial customers were broken out into two rate groups. This is true for PNG, AltaGas, SaskEnergy, Manitoba Hydro and Avista. For Union Gas and Gaz Metro commercial customers were accommodated with a declining block structure to allow for lower rates for larger commercial customers without the need for different customer groups.

Industrial rates varied quite a bit in terms of offerings. In some cases there was a distinction by size, such as Gazifere that has a moderate, large and very large volume service. Many of the utilities differentiated rates by load factor, such as for Enbridge, Union Gas, Gaz Metro, Puget Sound Energy and Avista. Firm vs. Interruptible rates were offered by Union Gas and Puget Sound Energy. Also the majority of industrial rates were for transport service only.

Only three other utilities had specific rates for NGV service, including PNG, Gazifere and Avista.

Rate Structure

The rate structure of a utility includes such things as whether there are flat or block rates and whether a demand charge is included.

In terms of flat or block rates, the utilities tend to have the same type of structure across the various rate groups. The majority of the Western utilities have flat rates for all or most of their rate schedules while the Eastern utilizes tend to have declining block rates. Note that the declining block rates in many of the cases are used to differentiate large and small users rather than having more rate groups.

Flat rates are used for most or all rate groups by PNG, ATCO, AltaGas, SaskPower, Manitoba Hydro, Puget Sound Energy and Northwest Natural.

Declining block rates are used for all customer groups by Union Gas, Enbridge, and Gaz Metro. Gazifere uses declining block rates for residential and commercial groups but not for industrial customers. SaskEnergy, Puget Sound Energy, Northwest Natural and Avista add declining block rates just for industrial customers.

Only one utility has an inclining block rate. Avista has inclining block rates for residential and small general service customers but has declining block rates for its larger commercial and industrial customers.

For NGV rates, PNG and Avista have flat rates while Gazifere has a declining block rate.

Most utilities use demand charges for industrial rates. Seven of the utilities have demand charges for industrial customers, while five utilities do not. For ATCO, only demand charges are applied and there is no energy rate for High Use customers. None of the utilities have demand charges for residential, commercial or NGV customers.

Customer Charge

The final comparison includes the level of the customer charge in place at the various utilities. While some charges were applied on a daily basis while others were applied on a monthly basis, all customer charges were converted to a monthly basis to allow a more applicable comparison.

For residential customers, the customer charge ranged from $7.00 per month for PNG and Avista to a high of over $36 for AltaGas. The majority of the customer charges were in the range of $10 to $20 per month.

For small commercial customers, the customer charge ranged from $7.00 per month for PNG to a high of $70 for Union Gas and Enbridge. The majority were in the range of $30 to $40 per month. Large commercial customer charges ranged from $77 to $412 per month.

Industrial customer charges per month had the largest range, from $149 for ATCO to $38,000 for one of Northwest Natural rate schedules. Because the eligibility and terms associated with the various types of industrial rates vary considerably, it is not surprising that the customer charge varies so much.

Rate Design

Rate design takes into account many different factors, of which the COSA is a starting point. As can be seen in the jurisdictional review, rate design varies considerable among utilities and must meet the specific needs of the utility in question. History, regulatory precedent, government policy, customer acceptance and understanding, competitiveness and desired price signals all play a role along with the cost circumstances of the utility when designing rates.

As discussed in the jurisdictional review, the segmentation of rate groups, the overall rate structure, and the level of various rate components are all part of the rate design for the utility. Interclass equity resulting from the COSA is also used to assist in determining whether any rebalancing between customer groups is required.

FEI is proposing to make some rebalancing adjustments as well as some rate design changes for certain customer groups. Many of the customer groups will see little change in the overall rate structure. EES Consulting has reviewed the rate design proposed by FEI and that review is discussed in the following sections.

Residential Rates

For the residential class, FEI is proposing to retain the current segmentation and increase the Basic charge per customer while lowering the Delivery charge to retain revenue neutrality. We agree that this proposal is appropriate.

In terms of segmentation, FEI looked at the correlation between load factor and average use and did not find a strong correlation. This makes sense as the convenience appliances used by customers with low consumption typically have a more sporadic usage pattern and may or may not be used on the peak day. In fact, FEI has shown that low users have a much wider range in their load factors than higher users. It is important to note that the load factors are estimated for each customer using regression analysis as the utility does not meter the daily loads of each customer. FEI has not found any evidence that would support further segmentation of the residential customer group.

FEI has proposed to increase the Basic charge by 5% to better reflect cost causation. The COSA results in customer-related costs of approximately $27.00 per month and includes such things as the cost of the meter, meter reading, billing, customer service and a share of the distribution system. A higher Basic charge is also consistent with the practice in other jurisdictions. Changing the Basic charge by 5% would increase it from an average of $11.84 per month to an average of $12.43. This proposal moves the Basic charge towards the cost resulting from the COSA. A much higher Basic charge could be supported by the COSA but has not been proposed based on the other rate design principles.

To retain revenue neutrality, the Delivery rate would decline by roughly 0.02%. While FEI considered alternatives to the flat Delivery charge, it is not proposing to make changes at this time. A declining block rate would be consistent with findings that the marginal cost for delivery is lower than the average delivery rate, and a declining block rate is found in several other jurisdictions in Canada. It does not, however, align with energy policy or customer acceptance. An inverted block rate is counter to marginal cost findings, is not found in other Canadian jurisdictions and is not easy to understand for most customers.

One issue brought up by stakeholders is the issue of Basic charges for low income customers. In our experience, low income customers are not necessarily low users of energy. This is due in part to the lack of capital to install more efficient appliances or weatherization measures. This is consistent with the findings of FEI using actual data for its service area. FEI's approach to deal with low income customers through measures outside of rate design is appropriate.

Finally, FEI is proposing to increase Residential rates to reflect inter-class inequities. The COSA shows that the Residential group is paying less than its cost of service, although the Revenue to Cost ratio is still within the target range of 90% to 110%. To offset the decreases necessary to bring other rate classes into the 90% to 110% range of reasonableness, the Residential class is the only class that is both below 100% and has revenues sufficient to make up for decreases in revenues from other rate groups. We agree that it is appropriate to increase the Residential rate to provide greater interclass equity.

The bill impacts associated with the changes to the Residential rate propose by FEI do not lead to any large impacts. Most customers will see less than a 1% change in their monthly bill as a result of the proposal.

Commercial Rates

For the Commercial class, FEI has separate rates for large and small users. FEI is proposing some minor adjustments to the rates to provide a better transition between the two rates. The overall rate structure is otherwise proposed to remain the same, and the current segmentation is proposed to remain at a 2,000 GJ breakpoint. The FEI proposal is appropriate for this customer group and reflects the rate design principles.

Commercial customers are split between small and large on the basis of annual consumption of 2,000 GJ. FEI looked at the load factors by usage level and the thresholds used for segmentation in other jurisdictions and found no compelling arguments to change the level of the threshold between the small and large Commercial rates. Based on stakeholder feedback, FEI did look at the impacts of changing the threshold to a lower level. The benefits of making such a change was not significant and would lead to disruption and large bill impacts for many customers. Based on all of the relevant factors, we believe it is appropriate to keep the threshold at 2,000 GJ.

Based on the results of the COSA, the revenue to cost ratio for the Commercial group is within the range of reasonableness and no interclass adjustment is required.

For the Commercial rate design, the misalignment of bills for customers close to the 2,000 GJ range was identified by FEI and rate changes were proposed to eliminate this misalignment. The proposal included an increase in the basic charge for both the small and large Commercial rates, a decrease in the Delivery rate for the small Commercial rate and an increase in the Delivery rate for the large Commercial rate. Increasing the Basic charge is appropriate given the higher customer-related costs resulting from the COSA, and is consistent with the change to the Residential group.

The bill impacts associated with the changes to the Commercial rates propose by FEI do not lead to any large impacts. The smallest users may see bill impacts up to 10 percent, but most bill impacts are much less than that.

Industrial Rates

The Industrial group contains several different rate schedules. Changes are being proposed for several of the Industrial rates to better reflect cost causation. No changes in the segmentation of the Industrial group are being proposed. In some cases the rate design is changing, and in some cases an adjustment for interclass equity is proposed.

Industrial rates are segmented into different rate groups on the basis of service type, including sales vs transport service and firm vs interruptible service. Gas volume also provides some segmentation of the group. Finally special circumstances, including NGV and seasonal sales are used for segmentation. These different factors are appropriate for the segmentation as they impact the costs of serving the various sub-groups. Because these rates include a demand charge, rates already take into account differing load factors by rate group and therefore, unlike other groups, load factor is not a factor required to segment the customers even further. The segmentation is consistent with that used in other jurisdictions, although for the Industrial group the factors included are much more specific to the circumstances of the utility and the types of Industrial customers on the system. FEI is not proposing any changes in the current segmentation.

While load factor is not an issue for the segmentation of Industrial customers, it is a significant factor to ensuring that rates are equitable between Industrial rate groups. For Rates 5 and 25 FEI is proposing to adjust the method for calculating the Daily Demand to better reflect actual peak demands and increasing the level of the Demand charge to better reflect the costs associated with peak loads and therefore create better equity among customers within the rate. As the current demand charge is lower than the demand-related costs resulting from the COSA, an increase in the demand charge is consistent with the COSA. FEI looked at several methods to better align the Daily Demand calculation with actual demand and found that applying the current approach but with a different multiplier to balance the ease of understanding and administration along with providing the least anomalous results. The proposed adjustments move the rate closer to cost causation and are appropriate.

FEI is proposing no change to the rate structure for Rates 7 and 27, which are interruptible rates. These rates are not based on the COSA but rather reflect an incentive to encourage interruptible service. We reviewed the approach used by FEI to develop a discount relative to the Rate 5/25 rates and found the approach to be reasonable. Because FEI believes the level of the rate is commensurate with the value provided, maintaining the current rate structure with the proposed discount is appropriate.

For seasonal service under Rate 4, FEI is not proposing any changes in the rate setting approach. Rate 4 has historically been set on the basis of Rate 5/25, and that approach is proposed to continue. The proposed changes to Rate 5/25 have a corresponding impact on the calculations used to develop Rate 4. Because the rate differential between seasonal and standard service is based on differences in value on a seasonal basis, the proposed rate structure is appropriate.

FEI's largest customers are on Rate 22 (including sub-rates 22A and 22B) or under special contract with FEI. Rates 22A and 22B have been closed for some time and FEI proposes to keep these rates closed with grandfathering of the current rate structures and accompanying terms and conditions. There are two special contract customers, including the Joint Venture (JV) and BC Hydro ICP. The JV contract expires at the end of 2017 and the BC Hydro ICP contract expires in 2022. At the time of the contract expiration, FEI proposes to place these customers on Rate 22 to provide consistent rates and service with its other Industrial customers. The Rate 22 rate structure is proposed to remain the same, with a Basic charge, Demand Charge and Delivery Charge for firm service. Rates for interruptible service would exclude the demand charge but results in a volumetric Delivery Charge per GJ that includes demand-related costs. The level of the rate is proposed to change to reflect the unit cost arising from the final COSA.

Summary and Conclusions

FEI prepared the COSA for this RDA to reflect the 2016 Rate Review as filed with the Commission, with several adjustments made to reflect large upcoming capital projects. It follows the three basic steps of functionalization, classification and allocation. We have reviewed both the COSA methodology and the COSA model itself to determine whether it is correct and appropriate. We find that the COSA follows standard utility practice, is generally consistent with past practice for the utility and the results are acceptable for purposes of setting just and reasonable rates for the amalgamated utility. There are a few items where it may be beneficial to consider a change in the methodology in future applications, which are addressed in previous sections of this report.

Use of COSA Results

Results of the COSA provide fully allocated costs for each customer class. Those costs are then compared to the revenues at present rates to determine the revenue to cost ratios.

The COSA is intended to provide findings on whether any rebalancing should occur between customer classes. It is not intended to set the actual rate levels as that is being done outside of this process. For the cost of gas, the actual rate levels are reviewed and set quarterly based on the actual costs of gas purchases. Midstream rates are generally updated on an annual basis outside of the annual revenue requirements process. For delivery rates, the actual rate levels are updated annually on the basis of the RRA. The method for assigning costs by customer class for the cost of gas, midstream costs and delivery costs, including the consolidation of those costs, is included with this COSA. The revenue requirements used for the COSA reflect the forecast of gas for 2016 with several adjustments and are not for the forecast period matching the implementation of the rates. Therefore the COSA is most appropriately used as a tool for looking at interclass equity and unit costs for rate design.

While the COSA reflects a 2016 test year, FEI does not intend to implement the proposed rate changes until June 1, 2018. At that time, the rates will reflect the approved revenue requirements at that time. It is typical to have a lag in implementation due to the time required for the regulatory process. The COSA is being used to examine the need for rebalancing between customer classes in light of the revenue to cost ratio results and adjustments to rate design are proposed that will be applied to the rates that are in place on June 1, 2018.

Revenue to cost ratios that are above 100% reflect a case where customers are paying more than their allocated share of costs, while numbers below 100% apply when customers are paying less than allocated costs. However, use of this 100% mark implies that the results of the COSA are completely accurate. While a COSA is the best method for determining a fair and equitable split of costs among customer classes, it relies on a forecast of both costs and sales that contain uncertainty, it contains methods that reflect the best estimate of cost causation but is subject to some interpretation, and it reflects load factors to determine peak day demands that are not metered in many cases. For all of these reasons, a revenue to cost range, sometimes referred to as a "range of reasonableness", rather than a firm 100% mark is used to determine reasonable revenue to cost ratios.

FEI has proposed using a 90% to 110% revenue to cost ratio "range of reasonableness" for setting proposed rates. We consider this to be a reasonable range for use when considering the adjusted revenue to cost ratios for FEI. While this is a broader range than what is currently accepted by the Commission for the electric utilities in B.C., it is consistent with the range previously accepted for gas utilities in the Province and the larger range is appropriate in this particular case. Anytime there is greater uncertainty in the COSA results, the resulting revenue to cost ratios are less accurate and reliable. This makes it advisable to use +/- 10% to reflect the uncertainty in the COSA. FEI COSA contains uncertainty due to several factors.

Gas utilities use peak days that reflect extreme weather planning conditions compared to the electric utilities that use actual or forecast loads under normal weather conditions. While the loads used in FEI COSA reflect the cost causation of the system, they contain less certainty than the loads used on the electric side. Because a large portion of costs are allocated on the basis of the peak day use per class, having uncertainty in the peak day loads used for allocation among the classes will lead to more uncertainty in the COSA results.

Rate Design Issues

For all of the rate classes, FEI looked at segmentation of the rate classes, the need to rebalance rates on the basis of the revenue to cost ratios in the COSA, and the rate design of each individual rate structure.

FEI did not find the need for further segmentation, or changes in the segmentation of the customer classes. We agree that this finding is appropriate.

In terms of rebalancing, FEI has proposed to increase revenues for the residential class by less than 1% in order to decrease the revenues for Rate 6 and Rate 22 based on the revenue to cost ratios resulting from the COSA. Note that the Rate 22 levels are set on the basis of costs for the group after the two special contract customers are added to the group for ratemaking purposes.

Some rate design changes have also been proposed to meet the various rate design principles of the utility. This includes an increase in the basic charge for the residential rate. For the commercial rate the basic charge would increase and energy charges would change to provide a smooth transition between the two commercial rates. For industrial customers the Rate 22 customers would be combined with two contract customers in the COSA to establish the rates going forward. However, rates for contract customers would not change until the end of the current contract.

After reviewing the various rate design changes, we agree that they are appropriate.

Appendix 6-2

FEI 2016 ANNUAL REVIEW COMPLIANCE FILING

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SUMMARY OF RATE CHANGE Schedule 1
FOR THE YEAR ENDING DECEMBER 31, 2016
($000,000s)

Line No.	Particulars	2016 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ 6.245		
3	Change in Other Revenue	(0.626)	$ 5.619	
4				
5	**O&M CHANGES**			
6	Gross O&M Change	0.780		
7	Capitalized Overhead Change	(0.137)	0.643	
8				
9	**DEPRECIATION EXPENSE**			
10	Plant Depreciation		6.386	
11				
12	**AMORTIZATION EXPENSE**			
13	CIAC	(0.352)		
14	Deferrals	3.467	3.115	
15				
16	**FINANCING AND RETURN ON EQUITY**			
17	Financing Rate Changes	(9.628)		
18	Financing Ratio Changes	5.762		
19	Rate Base Growth	2.243	(1.623)	
20				
21	**TAX EXPENSE**			
22	Property and Other Taxes	2.021		
23	Other Income Taxes Changes	(2.829)	(0.808)	
24				
25				
26	Revenue Deficiency (Surplus)		$ 13.332	Schedule 16, Line 12, Column 4
27				
28	Margin @ Existing Rates		746.492	Schedule 16, Line 16, Column 3
29	Rate Change		1.79%	

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UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 2

Line No.	Particulars	2015 Approved	2016 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 5,356,070	$ 5,517,286	$ 161,216	Schedule 6.2, Line 39, Column 3
2	Opening Balance Adjustment	-	-	-	
3	Net Additions	160,638	152,567	(8,071)	Schedule 6.2, Line 39, Column 4+5+6
4	Plant in Service, Ending	5,516,708	5,669,853	153,145	
5					
6	Accumulated Depreciation Beginning	$ (1,565,971)	$ (1,691,556)	$ (125,585)	Schedule 7.2, Line 39, Column 5
7	Opening Balance Adjustment	-	-	-	
8	Net Additions	(125,576)	(119,574)	6,002	Schedule 7.2, Line 39, Column 6+7
9	Accumulated Depreciation Ending	(1,691,547)	(1,811,130)	(119,583)	
10					
11	CIAC, Beginning	$ (445,070)	$ (425,250)	$ 19,820	Schedule 9, Line 9, Column 2
12	Opening Balance Adjustment	14,550	-	(14,550)	
13	Net Additions	5,269	1,022	(4,247)	Schedule 9, Line 9, Column 4+5
14	CIAC, Ending	(425,251)	(424,228)	1,023	
15					
16	Accumulated Amortization Beginning - CIAC	$ 131,682	$ 139,013	$ 7,331	Schedule 9, Line 19, Column 2
17	Opening Balance Adjustment	(1,548)	-	1,548	
18	Net Additions	8,879	8,447	(432)	Schedule 9, Line 19, Column 4+5
19	Accumulated Amortization Ending - CIAC	139,013	147,460	8,447	
20					
21	Net Plant in Service, Mid-Year	$ 3,514,318	$ 3,560,724	$ 46,406	
22					
23	Adjustment for timing of Capital additions	$ -	$ 3,685	$ 3,685	
24	Capital Work in Progress, No AFUDC	36,377	35,156	(1,221)	
25	Unamortized Deferred Charges	31,570	32,735	1,165	Schedule 11.1, Line 46, Column 10
26	Working Capital	79,936	61,048	(18,888)	Schedule 13, Line 16, Column 3
27	Deferred Income Taxes Regulatory Asset	395,930	388,446	(7,484)	Schedule 15, Line 6, Column 3
28	Deferred Income Taxes Regulatory Liability	(395,930)	(388,446)	7,484	Schedule 15, Line 6, Column 3
29	LILO Benefit	(817)	(651)	166	
30					
31	Mid-Year Utility Rate Base	$ 3,661,384	$ 3,692,697	$ 31,313	

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FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 3

Line No.	Particulars	Reference	2014	2015	2016	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Formula Cost Drivers**					
2	CPI		0.473%	0.879%	0.980%	
3	AWE		2.277%	1.646%	2.050%	
4	Labour Split					
5	Non Labour		45.000%	45.000%	45.000%	
6	Labour		55.000%	55.000%	55.000%	
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	1.460%	1.301%	1.569%	
8	Productivity Factor		-1.100%	-1.100%	-1.100%	
9	Net Inflation Factor for Costs	Line 7 + Line 8	0.360%	0.201%	0.469%	
10						
11	Average Customer Growth		0.260%	0.614%	0.567%	
12	Inflation Factor for Base Capital	(1 + Line 9) x (1 + Line 11)	100.621%	100.816%	101.039%	
13						
14	Customer Growth Factor		-0.688%	-5.615%	16.249%	
15	Inflation Factor for Growth Capital	(1 + Line 9) x (1 + Line 14)	99.669%	94.575%	116.794%	

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CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 4

Line No.	Particulars	Growth CapEx	Other CapEx	Forecast CapEx	Total CapEx	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**2013**					
2	Base	$ 21,881	$ 99,243			
3	**2014**					
4	Net Inflation Factor	99.669%	100.621%			Schedule 3, Line 12 & 15, Column 3
5	FEI Formula Capex	21,809	99,859			
6	Reclassify Pension & OPEB from Formula	(331)	(1,516)			
7	FEI Net Formula Capex	21,478	98,343			
8	FEVI Capex	8,378	11,518			Note 1
9	FEW Capex	258	142			
10	Total	30,114	110,003			
11	**2015**					
12	Net Inflation Factor	94.575%	100.816%			Schedule 3, Line 12 & 15, Column 4
13	Formula Capex	28,479	110,901			
14	**2016**					
15	Net Inflation Factor	116.794%	101.039%			Schedule 3, Line 12 & 15, Column 5
16	Formula Capex	$ 33,262	$ 112,053		$ 145,315	
17						
18	**Capital Tracked Outside of Formula**					
19	Pension & OPEB (Capital Portion)			$ 4,075		
20	Biomethane Upgraders			-		
21	Biomethane Interconnect			1,355		
22	NGT Assets			5,488		
23	Total			$ 10,918	10,918	
24						
25	**Total Capital Expenditures Net of CIAC**				$ 156,233	
26						
27	Contributions in Aid of Construction				6,515	
28	**Total Capital Expenditures before CIAC**				$ 162,748	
29						
30	Notes					
31	1. FEVI growth capex of $8,802 thousand less $424 thousand of pension and OPEBs; FEVI other capex of $13,908 thousand less $2,390 thousand of pension and OPEBs.					

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CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 5

Line No.	Particulars (1)		2016 Formula (2)	Cross Reference (3)
1	**CAPEX**			
2				
3	Growth Capital Expenditures	$	33,262	Schedule 4, Line 16, Column 2
4	Sustainment Capital Expenditures		112,053	Schedule 4, Line 16, Column 3
5	Forecast Capital Expenditures		10,918	Schedule 4, Line 23, Column 4
6	CIAC		6,515	Schedule 4, Line 27, Column 5
7	Total Regular Capital Expenditures	$	162,748	
8				
9	**Special Projects and CPCN's**			
10				
11	LMIPSU	$	28,879	
12	Huntingdon Station		300	
13	CTS		18,224	
14	Tilbury Expansion		80,565	
15	City of Vancouver Biomethane Plant		6,800	
16	Total Regular Capital Expenditures	$	134,768	
17				
18	**Total Capital Expenditures**	$	297,516	
19				
20				
21	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
22				
23	Regular Capital Expenditures	$	162,748	
24	Add - Capitalized Overheads		32,594	Schedule 21, Line 30, Column 4
25	Add - AFUDC		1,918	
26	Gross Capital Expenditures		197,260	
27	Change in Work in Progress		840	
28	**Total Additions to Plant**	$	198,100	
29				
30	Special Projects and CPCN's	$	134,768	
31	Add - AFUDC		26,674	
32	Gross Capital Expenditures		161,442	
33	Change in Work in Progress		(154,072)	
34	**Total Additions to Plant**	$	7,370	
35				
36	**Grand Total Additions to Plant**	$	205,470	

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Section 11

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 6 (2016)

Line No.	Account	Particulars	12/31/15	CPCN's	Additions	Retirements	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1		**INTANGIBLE PLANT**						
2	117-00	Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	
3	175-00	Unamortized Conversion Expense	109	-	-	-	109	
4	175-00	Unamortized Conversion Expense - Squamish	777	-	-	-	777	
5	178-00	Organization Expense	728	-	-	-	728	
6	179-01	Other Deferred Charges	-	-	-	-	-	
7	401-00	Franchise and Consents	297	-	-	-	297	
8	402-00	Utility Plant Acquisition Adjustment	62	-	-	-	62	
9	402-00	Other Intangible Plant	1,907	-	-	-	1,907	
10	431-00	Mfg'd Gas Land Rights	-	-	-	-	-	
11	461-00	Transmission Land Rights	53,068	-	487	-	53,555	
12	461-02	Transmission Land Rights - Mt. Hayes	610	-	-	-	610	
13	461-10	Transmission Land Rights - Byron Creek	16	-	-	-	16	
14	461-13	IP Land Rights Whistler	87	-	-	-	87	
15	471-00	Distribution Land Rights	3,079	-	-	-	3,079	
16	471-10	Distribution Land Rights - Byron Creek	1	-	-	-	1	
17	402-01	Application Software - 12.5%	108,270	-	7,174	(10,931)	104,513	
18	402-02	Application Software - 20%	27,628	-	6,260	(5,632)	28,256	
19			$ 196,639	$ -	$ 13,921	$ (16,563)	$ 193,997	
20								
21		**MANUFACTURED GAS / LOCAL STORAGE**						
22	430-00	Manufact'd Gas - Land	$ 31	$ -	$ -	$ -	$ 31	
23	431-00	Manufact'd Gas - Land Rights	-	-	-	-	-	
24	432-00	Manufact'd Gas - Struct. & Improvements	998	-	-	-	998	
25	433-00	Manufact'd Gas - Equipment	1,095	-	338	-	1,433	
26	434-00	Manufact'd Gas - Gas Holders	2,940	-	-	-	2,940	
27	436-00	Manufact'd Gas - Compressor Equipment	367	-	-	-	367	
28	437-00	Manufact'd Gas - Measuring & Regulating Equipment	875	-	-	-	875	
29	443-00	Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	
30	440/44	Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	15,164	
31	442-00	Structures & Improvements (Tilbury)	4,959	-	-	-	4,959	
32	443-00	Gas Holders - Storage (Tilbury)	16,499	-	-	-	16,499	
33	446-00	Compressor Equipment (Tilbury)	-	-	-	-	-	
34	447-00	Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-	
35	448-00	Purification Equipment (Tilbury)	-	-	-	-	-	
36	449-00	Local Storage Equipment (Tilbury)	29,773	-	2,516	-	32,289	
37	440/44	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	-	-	-	1,083	
38	442-00	Structures & Improvements (Mount Hayes)	17,310	-	-	-	17,310	
39	443-00	Gas Holders - Storage (Mount Hayes)	60,112	-	-	-	60,112	
40	446-00	Compressor Equipment (Mount Hayes)	-	-	-	-	-	
41	447-00	Measuring & Regulating Equipment (Mount Hayes)	-	-	-	-	-	
42	448-00	Purification Equipment (Mount Hayes)	-	-	-	-	-	
43	448-10	Piping (Mount Hayes)	11,488	-	-	-	11,488	
44	448-20	Pre-treatment (Mount Hayes)	28,714	-	-	-	28,714	
45	448-30	Liquefaction Equipment (Mount Hayes)	28,714	-	-	-	28,714	
46	448-40	Send out Equipment (Mount Hayes)	22,960	-	-	-	22,960	
47	448-50	Sub-station and Electric (Mount Hayes)	21,644	-	-	-	21,644	
48	448-60	Control Room (Mount Hayes)	5,900	-	-	-	5,900	
49	449-00	Local Storage Equipment (Mount Hayes)	6,363	-	-	-	6,363	
50			$ 276,989	$ -	$ 2,854	$ -	$ 279,843	

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Section 11

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 6.1 (2016)

Line No.	Account	Particulars	12/31/15	CPCN's	Additions	Retirements	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1		**TRANSMISSION PLANT**						
2	460-00	Land in Fee Simple	$ 10,627	$ 240	$ -	$ -	$ 10,867	
3	461-00	Transmission Land Rights	1	-	-	-	1	
4	462-00	Compressor Structures	29,484	-	-	-	29,484	
5	463-00	Measuring Structures	14,015	-	-	-	14,015	
6	464-00	Other Structures & Improvements	6,485	14	-	-	6,499	
7	465-00	Mains	1,168,483	4,775	14,997	(1,619)	1,186,636	
8	465-00	Mains - INSPECTION	16,054	-	2,570	-	18,624	
9	465-11	IP Transmission Pipeline - Whistler	42,288	-	-	-	42,288	
10	465-30	Mains - Mt Hayes	6,299	-	-	-	6,299	
11	465-10	Mains - Byron Creek	974	-	-	-	974	
12	466-00	Compressor Equipment	178,852	-	2,865	(742)	180,975	
13	466-00	Compressor Equipment - OVERHAUL	3,856	-	-	-	3,856	
14	467-00	Measuring and Regulating Equipment - Mt. Hayes	5,342	-	-	-	5,342	
15	467-00	Measuring & Regulating Equipment	49,540	2,239	-	-	51,779	
16	467-10	Telemetering	13,046	102	362	(21)	13,489	
17	467-31	IP Intermediate Pressure Whistler	313	-	-	-	313	
18	467-20	Measuring & Regulating Equipment - Byron Creek	39	-	-	-	39	
19	468-00	Communication Structures & Equipment	4,245	-	-	-	4,245	
20			$ 1,549,943	$ 7,370	$ 20,794	$ (2,382)	$ 1,575,725	
21								
22		**DISTRIBUTION PLANT**						
23	470-00	Land in Fee Simple	$ 4,207	$ -	$ -	$ -	$ 4,207	
24	471-00	Distribution Land Rights	-	-	-	-	-	
25	472-00	Structures & Improvements	21,577	-	-	-	21,577	
26	472-10	Structures & Improvements - Byron Creek	107	-	-	-	107	
27	473-00	Services	1,064,850	-	45,268	(3,058)	1,107,060	
28	474-00	House Regulators & Meter Installations	197,454	-	-	(494)	196,960	
29	477-00	Meters/Regulators Installations	99,443	-	27,108	-	126,551	
30	475-00	Mains	1,337,895	-	29,955	(1,688)	1,366,162	
31	476-00	Compressor Equipment	1,110	-	-	-	1,110	
32	477-00	Measuring & Regulating Equipment	121,647	-	9,387	(1,084)	129,950	
33	477-00	Telemetering	10,508	-	1,028	-	11,536	
34	477-10	Measuring & Regulating Equipment - Byron Creek	163	-	-	-	163	
35	478-10	Meters	237,085	-	13,866	(7,556)	243,395	
36	478-20	Instruments	11,944	-	-	-	11,944	
37	479-00	Other Distribution Equipment	-	-	-	-	-	
38			$ 3,107,990	$ -	$ 126,612	$ (13,880)	$ 3,220,722	
39								
40		**BIO GAS**						
41	472-00	Bio Gas Struct. & Improvements	$ 652	$ -	$ 193	$ -	$ 845	
42	475-10	Bio Gas Mains – Municipal Land	1,407	-	516	-	1,923	
43	475-20	Bio Gas Mains – Private Land	55	-	-	-	55	
44	418-10	Bio Gas Purification Overhaul	20	-	-	-	20	
45	418-20	Bio Gas Purification Upgrader	8,153	-	-	-	8,153	
46	477-10	Bio Gas Reg & Meter Equipment	2,159	-	970	-	3,129	
47	478-30	Bio Gas Meters	35	-	19	-	54	
48	474-10	Bio Gas Reg & Meter Installations	225	-	35	-	260	
49			$ 12,706	$ -	$ 1,733	$ -	$ 14,439	

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 6.2 (2016)

Line No.	Account	Particulars	12/31/15	CPCN's	Additions	Retirements	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1		**Natural Gas for Transportation**						
2	476-10	NG Transportation CNG Dispensing Equipment	$ 7,581	$ -	$ 2,006	$ -	$ 9,587	
3	476-20	NG Transportation LNG Dispensing Equipment	6,075	-	-	-	6,075	
4	476-30	NG Transportation CNG Foundations	931	-	100	-	1,031	
5	476-40	NG Transportation LNG Foundations	897	-	-	-	897	
6	476-50	NG Transportation LNG Pumps	63	-	-	-	63	
7	476-60	NG Transportation CNG Dehydrator	253	-	-	-	253	
8	476-70	NG Transportation LNG Dehydrator	-	-	-	-	-	
9			$ 15,800	$ -	$ 2,106	$ -	$ 17,906	
10								
11		**GENERAL PLANT & EQUIPMENT**						
12	480-00	Land in Fee Simple	$ 30,082	$ -	$ 385	$ -	$ 30,467	
13	481-00	Land Rights	-	-	-	-	-	
14	482-00	Frame Buildings	16,822	-	-	-	16,822	
15	482-00	Masonry Buildings	118,744	-	6,079	(125)	124,698	
16	482-00	Leasehold Improvement	4,650	-	198	(69)	4,779	
17	483-30	GP Office Equipment	4,686	-	578	(524)	4,740	
18	483-40	GP Furniture	21,543	-	1,951	(1,450)	22,044	
19	483-10	GP Computer Hardware	48,270	-	9,693	(10,421)	47,542	
20	483-20	GP Computer Software	4,519	-	-	(732)	3,787	
21	483-21	GP Computer Software	-	-	-	-	-	
22	483-22	GP Computer Software	-	-	-	-	-	
23	484-00	Vehicles	11,958	-	2,684	-	14,642	
24	484-00	Vehicles - Leased	27,602	-	-	(1,479)	26,123	
25	485-10	Heavy Work Equipment	858	-	-	-	858	
26	485-20	Heavy Mobile Equipment	2,747	-	3,850	-	6,597	
27	486-00	Small Tools & Equipment	50,673	-	3,427	(3,405)	50,695	
28	487-00	Equipment on Customer's Premises	24	-	-	-	24	
29	487-00	VRA Compressor Installation Costs	-	-	-	-	-	
30	488-00	Telephone	5,747	-	-	(1,849)	3,898	
31	488-00	Radio	8,294	-	1,235	(24)	9,505	
32	489-00	Other General Equipment	-	-	-	-	-	
33			$ 357,219	$ -	$ 30,080	$ (20,078)	$ 367,221	
34								
35		**UNCLASSIFIED PLANT**						
36	499-00	Plant Suspense	-	-	-	-	-	
37			$ -	$ -	$ -	$ -	$ -	
38								
39		**Total Plant in Service**	$ 5,517,286	$ 7,370	$ 198,100	$ (52,903)	$ 5,669,853	
40								
41		Cross Reference		Schedule 5, Line 34, Column 2	Schedule 5, Line 28, Column 2			

FORTISBC ENERGY INC.

G-193-15 December 11, 2015

Section 11

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 7 (2016)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/15	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1		**INTANGIBLE PLANT**									
2	117-00	Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	
3	175-00	Unamortized Conversion Expense	109	0.92%	58	1	-	-	-	59	
4	175-00	Unamortized Conversion Expense - Squamish	777	10.04%	657	78	-	-	-	735	
5	178-00	Organization Expense	728	0.96%	414	7	-	-	-	421	
6	179-01	Other Deferred Charges	-	0.00%	-	-	-	-	-	-	
7	401-00	Franchise and Consents	297	2.02%	194	4	-	-	-	198	
8	402-00	Utility Plant Acquisition Adjustment	62	0.00%	62	-	-	-	-	62	
9	402-00	Other Intangible Plant	1,907	2.05%	992	39	-	-	-	1,031	
10	431-00	Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-	-	
11	461-00	Transmission Land Rights	53,068	0.00%	1,766	-	-	-	-	1,766	
12	461-02	Transmission Land Rights - Mt. Hayes	610	0.00%	-	-	-	-	-	-	
13	461-10	Transmission Land Rights - Byron Creek	16	0.00%	19	-	-	-	-	19	
14	461-13	IP Land Rights Whistler	87	0.00%	10	-	-	-	-	10	
15	471-00	Distribution Land Rights	3,079	0.00%	238	-	-	-	-	238	
16	471-10	Distribution Land Rights - Byron Creek	1	0.00%	1	-	-	-	-	1	
17	402-01	Application Software - 12.5%	108,270	12.50%	52,235	13,534	(10,931)	-	-	54,838	
18	402-02	Application Software - 20%	27,628	20.00%	12,365	5,526	(5,632)	-	-	12,259	
19			$ 196,639		$ 69,011	$ 19,189	$ (16,563)	$ -	$ -	$ 71,637	
20											
21		**MANUFACTURED GAS / LOCAL STORAGE**									
22	430-00	Manufact'd Gas - Land	$ 31	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	
23	431-00	Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-	-	
24	432-00	Manufact'd Gas - Struct. & Improvements	998	3.40%	254	34	-	-	-	288	
25	433-00	Manufact'd Gas - Equipment	1,095	6.54%	198	72	-	-	-	270	
26	434-00	Manufact'd Gas - Gas Holders	2,940	2.35%	443	69	-	-	-	512	
27	436-00	Manufact'd Gas - Compressor Equipment	367	5.19%	94	19	-	-	-	113	
28	437-00	Manufact'd Gas - Measuring & Regulating Equipment	875	15.89%	768	139	-	-	-	907	
29	443-00	Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	0.00%	-	-	-	-	-	-	
30	440/44	Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	1	-	-	-	-	1	
31	442-00	Structures & Improvements (Tilbury)	4,959	3.57%	3,320	177	-	-	-	3,497	
32	443-00	Gas Holders - Storage (Tilbury)	16,499	1.93%	11,676	318	-	-	-	11,994	
33	446-00	Compressor Equipment (Tilbury)	-	0.00%	-	-	-	-	-	-	
34	447-00	Measuring & Regulating Equipment (Tilbury)	-	0.00%	-	-	-	-	-	-	
35	448-00	Purification Equipment (Tilbury)	-	0.00%	-	-	-	-	-	-	
36	449-00	Local Storage Equipment (Tilbury)	29,773	4.24%	14,181	1,262	-	-	-	15,443	
37	440/44	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	0.00%	-	-	-	-	-	-	
38	442-00	Structures & Improvements (Mount Hayes)	17,310	4.00%	3,167	692	-	-	-	3,859	
39	443-00	Gas Holders - Storage (Mount Hayes)	60,112	1.67%	4,599	1,004	-	-	-	5,603	
40	446-00	Compressor Equipment (Mount Hayes)	-	0.00%	-	-	-	-	-	-	
41	447-00	Measuring & Regulating Equipment (Mount Hayes)	-	0.00%	-	-	-	-	-	-	
42	448-00	Purification Equipment (Mount Hayes)	-	0.00%	-	-	-	-	-	-	
43	448-10	Piping (Mount Hayes)	11,488	2.50%	1,316	287	-	-	-	1,603	
44	448-20	Pre-treatment (Mount Hayes)	28,714	4.00%	5,263	1,149	-	-	-	6,412	
45	448-30	Liquefaction Equipment (Mount Hayes)	28,714	2.50%	3,289	718	-	-	-	4,007	
46	448-40	Send out Equipment (Mount Hayes)	22,960	2.50%	2,630	574	-	-	-	3,204	
47	448-50	Sub-station and Electric (Mount Hayes)	21,644	2.50%	2,479	541	-	-	-	3,020	
48	448-60	Control Room (Mount Hayes)	5,900	6.68%	1,803	394	-	-	-	2,197	
49	449-00	Local Storage Equipment (Mount Hayes)	6,363	3.03%	6	193	-	-	-	199	
50			$ 276,989		$ 55,487	$ 7,642	$ -	$ -	$ -	$ 63,129	

FORTISBC ENERGY INC.

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Section 11

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 7.1 (2016)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/15	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1		**TRANSMISSION PLANT**									
2	460-00	Land in Fee Simple	$ 10,867	0.00%	$ 503	$ -	$ -	$ -	$ -	$ 503	
3	461-00	Transmission Land Rights	1	0.00%	-	-	-	-	-	-	
4	462-00	Compressor Structures	29,484	3.66%	14,532	1,079	-	-	-	15,611	
5	463-00	Measuring Structures	14,015	3.37%	6,299	472	-	-	-	6,771	
6	464-00	Other Structures & Improvements	6,499	2.84%	2,462	185	-	-	-	2,647	
7	465-00	Mains	1,173,258	1.47%	361,730	17,247	(1,619)	-	-	377,358	
8	465-00	Mains - INSPECTION	16,054	14.72%	6,577	2,363	-	-	-	8,940	
9	465-11	IP Transmission Pipeline - Whistler	42,288	1.43%	3,883	605	-	-	-	4,488	
10	465-30	Mains - Mt Hayes	6,299	1.54%	501	97	-	-	-	598	
11	465-10	Mains - Byron Creek	974	5.03%	1,133	49	-	-	-	1,182	
12	466-00	Compressor Equipment	178,852	2.88%	78,287	5,151	(742)	-	-	82,696	
13	466-00	Compressor Equipment - OVERHAUL	3,856	20.17%	1,886	778	-	-	-	2,664	
14	467-00	Measuring and Regulating Equipment - Mt. Hayes	5,342	3.71%	978	198	-	-	-	1,176	
15	467-00	Measuring & Regulating Equipment	51,779	4.28%	21,374	2,216	-	-	-	23,590	
16	467-10	Telemetering	13,148	0.84%	6,523	110	(21)	-	-	6,612	
17	467-31	IP Intermediate Pressure Whistler	313	4.15%	76	13	-	-	-	89	
18	467-20	Measuring & Regulating Equipment - Byron Creek	39	0.00%	10	-	-	-	-	10	
19	468-00	Communication Structures & Equipment	4,245	11.35%	4,325	482	-	-	-	4,807	
20			$ 1,557,313		$ 511,079	$ 31,045	$ (2,382)	$ -	$ -	$ 539,742	
21											
22		**DISTRIBUTION PLANT**									
23	470-00	Land in Fee Simple	$ 4,207	0.00%	$ (9)	$ -	$ -	$ -	$ -	$ (9)	
24	471-00	Distribution Land Rights	-	0.00%	-	-	-	-	-	-	
25	472-00	Structures & Improvements	21,577	3.30%	7,974	712	-	-	-	8,686	
26	472-10	Structures & Improvements - Byron Creek	107	4.67%	48	5	-	-	-	53	
27	473-00	Services	1,064,850	2.37%	246,171	25,066	(3,058)	-	-	268,179	
28	474-00	House Regulators & Meter Installations	197,454	7.36%	66,166	13,664	(494)	-	-	79,336	
29	477-00	Meters/Regulators Installations	99,443	4.55%	6,951	4,525	-	-	-	11,476	
30	475-00	Mains	1,337,895	1.55%	436,085	20,904	(1,688)	-	-	455,301	
31	476-00	Compressor Equipment	1,110	26.58%	1,265	295	-	-	-	1,560	
32	477-00	Measuring & Regulating Equipment	121,647	4.71%	43,083	5,730	(1,084)	-	-	47,729	
33	477-00	Telemetering	10,508	0.26%	6,104	27	-	-	-	6,131	
34	477-10	Measuring & Regulating Equipment - Byron Creek	163	0.00%	216	-	-	-	-	216	
35	478-10	Meters	237,085	7.82%	113,718	17,953	(7,556)	-	-	124,115	
36	478-20	Instruments	11,944	3.15%	2,427	376	-	-	-	2,803	
37	479-00	Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	
38			$ 3,107,990		$ 930,199	$ 89,257	$ (13,880)	$ -	$ -	$ 1,005,576	
39											
40		**BIO GAS**									
41	472-00	Bio Gas Struct. & Improvements	$ 652	3.78%	$ 31	$ 25	$ -	$ -	$ -	$ 56	
42	475-10	Bio Gas Mains – Municipal Land	1,407	1.25%	23	18	-	-	-	41	
43	475-20	Bio Gas Mains – Private Land	55	2.44%	3	1	-	-	-	4	
44	418-10	Bio Gas Purification Overhaul	20	13.33%	-	3	-	-	-	3	
45	418-20	Bio Gas Purification Upgrader	8,153	6.67%	434	544	-	-	-	978	
46	477-10	Bio Gas Reg & Meter Equipment	2,159	4.72%	134	102	-	-	-	236	
47	478-30	Bio Gas Meters	35	10.00%	4	4	-	-	-	8	
48	474-10	Bio Gas Reg & Meter Installations	225	5.21%	6	12	-	-	-	18	
49			$ 12,706		$ 635	$ 709	$ -	$ -	$ -	$ 1,344	

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Section 11

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 7.2 (2016)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/15	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1		**Natural Gas for Transportation**									
2	476-10	NG Transportation CNG Dispensing Equipment	$ 7,581	4.99%	$ 933	$ 378	$ -	$ -	$ -	$ 1,311	
3	476-20	NG Transportation LNG Dispensing Equipment	6,075	5.01%	414	304	-	-	-	718	
4	476-30	NG Transportation CNG Foundations	931	4.95%	119	46	-	-	-	165	
5	476-40	NG Transportation LNG Foundations	897	5.05%	98	45	-	-	-	143	
6	476-50	NG Transportation LNG Pumps	63	9.52%	18	6	-	-	-	24	
7	476-60	NG Transportation CNG Dehydrator	253	5.15%	36	13	-	-	-	49	
8	476-70	NG Transportation LNG Dehydrator	-	0.00%	-	-	-	-	-	-	
9			$ 15,800		$ 1,618	$ 792	$ -	$ -	$ -	$ 2,410	
10											
11		**GENERAL PLANT & EQUIPMENT**									
12	480-00	Land in Fee Simple	$ 30,082	0.00%	$ 17	$ -	$ -	$ -	$ -	$ 17	
13	481-00	Land Rights	-	0.00%	-	-	-	-	-	-	
14	482-00	Frame Buildings	16,822	5.33%	6,853	897	-	-	-	7,750	
15	482-00	Masonry Buildings	118,744	2.23%	23,153	2,648	(125)	-	-	25,676	
16	482-00	Leasehold Improvement	4,650	9.29%	1,676	432	(69)	-	-	2,039	
17	483-30	GP Office Equipment	4,686	6.67%	3,897	313	(524)	-	-	3,686	
18	483-40	GP Furniture	21,543	5.00%	8,484	1,077	(1,450)	-	-	8,111	
19	483-10	GP Computer Hardware	48,270	20.00%	21,683	9,654	(10,421)	-	-	20,916	
20	483-20	GP Computer Software	4,519	12.50%	2,401	565	(732)	-	-	2,234	
21	483-21	GP Computer Software	-	0.00%	-	-	-	-	-	-	
22	483-22	GP Computer Software	-	0.00%	-	-	-	-	-	-	
23	484-00	Vehicles	11,958	16.04%	4,802	1,918	-	-	-	6,720	
24	484-00	Vehicles - Leased	27,602	9.44%	19,923	2,358	(1,479)	-	-	20,802	
25	485-10	Heavy Work Equipment	858	6.47%	453	56	-	-	-	509	
26	485-20	Heavy Mobile Equipment	2,747	16.44%	2,014	452	-	-	-	2,466	
27	486-00	Small Tools & Equipment	50,673	5.00%	22,433	2,534	(3,405)	-	-	21,562	
28	487-00	Equipment on Customer's Premises	24	8.33%	17	2	-	-	-	19	
29	487-00	VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-	-	
30	488-00	Telephone	5,747	6.67%	3,759	383	(1,849)	-	-	2,293	
31	488-00	Radio	8,294	6.68%	1,962	554	(24)	-	-	2,492	
32	489-00	Other General Equipment	-	0.00%	-	-	-	-	-	-	
33			$ 357,219		$ 123,527	$ 23,843	$ (20,078)	$ -	$ -	$ 127,292	
34											
35		**UNCLASSIFIED PLANT**									
36	499-00	Plant Suspense	-	0.00%	-	-	-	-	-	-	
37			$ -		$ -	$ -	$ -	$ -	$ -	$ -	
38											
39		**Total**	$ 5,524,656		$ 1,691,556	$ 172,477	$ (52,903)	$ -	$ -	$ 1,811,130	
40		Less: Depreciation & Amortization transferred to biomethane BVA				(547)					
41		Less: Vehicle Depreciation Allocated To Capital Projects				(1,582)					
42						$ 170,348					
43											
44		Cross Reference	Schedule 6.2, Line 39, Column 3+4								

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

NON-REG PLANT CONTINUITY SCHEDULE Schedule 8 (2016)
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars			12/31/15	CPCN's	Additions	Retirements	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Non-Regulated Plant**								
2	NRB Depreciation @ 0%			$ 1,054	$ -	$ -	$ -	$ 1,054	
3	NRB Depreciation @ 2.4%			176,594	-	-	-	176,594	
4	Mobile Refueling Station			744	-	-	-	744	
5								-	
6	**Total**			$ 178,392	$ -	$ -	$ -	$ 178,392	
7									
8									
9									

10 **NON-REG PLANT ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE**
11 **FOR THE YEAR ENDING DECEMBER 31, 2016**
12 **($000s)**
13
14

Line No.	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/15	Depreciation Expense	Depreciation Retirements	Cost of Removal	12/31/16	Cross Reference
17	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
18									
19	**Non-Regulated Plant Depreciation**								
20	NRB Depreciation @ 0%	$ 1,054	0.00%	$ 291	$ -	$ -	$ -	$ 291	
21	NRB Depreciation @ 2.4%	176,594	2.40%	112,984	4,238	-	-	117,222	
22	Mobile Refueling Station	744	5.00%	81	37	-	-	118	
23								-	
24	**Total**	$ 178,392		$ 113,356	$ 4,275	$ -	$ -	$ 117,631	

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 9 (2016)

Line No.	Particulars	12/31/15	Adjustment	Additions	Retirements	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2	Distribution Contributions	$ 268,788	$ -	$ 6,056	$ -	$ 274,844	
3	Transmission Contributions	145,125	-	459	-	145,584	
4	Others	722	-	-	-	722	
5	Software Tax Savings - Infrastructure/Custom	5,069	-	-	(2,537)	2,532	
6	FEW Contribution for Whistler Pipeline	-	-	-	-	-	
7	Government Loans Contribution	5,000	-	-	(5,000)	-	
8	Biomethane	546	-	-	-	546	
9	**Total**	$ 425,250	$ -	$ 6,515	$ (7,537)	$ 424,228	
10							
11	**Amortization**						
12	Distribution Contributions	$ (88,605)	$ -	$ (7,768)	$ -	$ (96,373)	
13	Transmission Contributions	(45,594)	-	(2,438)	-	(48,032)	
14	Others	(499)	-	(108)	-	(607)	
15	Software Tax Savings - Infrastructure/Custom	(4,221)	-	(634)	2,537	(2,318)	
16	FEW Contribution for Whistler Pipeline	-	-	-	-	-	
17	Government Loans Contribution	-	-	-	-	-	
18	Biomethane	(94)	-	(36)	-	(130)	
19	**Total**	$ (139,013)	$ -	$ (10,984)	$ 2,537	$ (147,460)	
20							
21	**Net CIAC**	$ 286,237	$ -	$ (4,469)	$ (5,000)	$ 276,768	
22							
23							
24	Total CIAC Amortization Expense per Line 19			$ (10,984)			
25	Less: CIAC Amortization Transferred to Biomethane BVA			36			
26	**Net CIAC Amortization Expense**			$ (10,948)			

FORTISBC ENERGY INC.

G-193-15 December 11, 2015

Section 11

NEGATIVE SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 10 (2016)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/15	Negative Salv Provision	Removal Costs/ Proceeds on Disp.	12/31/16	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**MANUFACTURED GAS / LOCAL STORAGE**							
2	442-00	Structures & Improvements (Tilbury)	$ 4,959	0.36%	$ 72	$ 18	$ -	$ 90	
3	443-00	Gas Holders - Storage (Tilbury)	16,499	0.40%	264	66	-	330	
4	449-00	Local Storage Equipment (Tilbury)	29,773	0.35%	379	104	-	483	
5			$ 51,231		$ 715	$ 188	$ -	$ 903	
6									
7		**TRANSMISSION PLANT**							
8	462-00	Compressor Structures	$ 29,484	0.18%	$ 413	$ 53	$ -	$ 466	
9	463-00	Measuring Structures	14,015	0.08%	129	11	-	140	
10	464-00	Other Structures & Improvements	6,499	0.14%	21	9	-	30	
11	465-00	Mains	1,173,258	0.10%	8,138	1,173	-	9,311	
12	466-00	Compressor Equipment	178,852	0.28%	2,414	501	-	2,915	
13	467-00	Measuring and Regulating Equipment - Mt. Hayes	5,342	0.00%	185	-	-	185	
14	467-00	Measuring & Regulating Equipment	51,779	0.19%	119	98	-	217	
15	468-00	Communication Structures & Equipment	4,245	2.11%	357	90	-	447	
16			$ 1,463,474		$ 11,776	$ 1,935	$ -	$ 13,711	
17									
18		**DISTRIBUTION PLANT**							
19	472-00	Structures & Improvements	$ 21,577	0.16%	$ 152	$ 35	$ -	$ 187	
20	473-00	Services	1,064,850	1.17%	6,981	11,960	(9,548)	9,393	
21	474-00	House Regulators & Meter Installations	197,454	0.75%	(2,886)	1,360	(3,565)	(5,091)	
22	477-00	Meters/Regulators Installations	99,443	0.60%	997	597	-	1,594	
23	475-00	Mains	1,337,895	0.32%	15,502	4,154	(549)	19,107	
24	476-00	Compressor Equipment	1,110	11.43%	584	127	-	711	
25	477-00	Measuring & Regulating Equipment	121,647	0.45%	1,880	547	-	2,427	
26	477-00	Telemetering	10,508	0.00%	(12)	-	-	(12)	
27	478-10	Meters	237,085	0.49%	3,330	1,113	-	4,443	
28			$ 3,091,569		$ 26,528	$ 19,893	$ (13,661)	$ 32,759	
29									
30		**BIO GAS**							
31	475-10	Bio Gas Mains – Municipal Land	$ 1,407	0.33%	$ 6	$ 5	$ -	$ 11	
32	475-20	Bio Gas Mains – Private Land	55	0.01%	1	-	-	1	
33			$ 1,462		$ 7	$ 5	$ -	$ 12	
34									
35		**GENERAL PLANT & EQUIPMENT**							
36	482-00	Frame Buildings	$ 16,822	0.00%	$ (12)	$ -	$ -	$ (12)	
37	482-00	Masonry Buildings	118,744	0.00%	(1)	-	-	(1)	
38			$ 135,566		$ (13)	$ -	$ -	$ (13)	
39									
40		**Total**	$ 4,743,302		$ 39,013	$ 22,021	$ (13,661)	$ 47,372	
41									
42		Cross Reference	Schedule 6 - 6.2, Column 3+4						

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11 (2016)
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	12/31/15	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/16	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related Deferral Accounts										
2	Commodity Cost Reconciliation Account (CCRA)	$ (12,370)	$ -	$ 16,716	$ (4,346)	$ -	$ -	$ -	$ (0)	$ (6,185)	
3	Midstream Cost Reconciliation Account (MCRA)	(9,989)	-	(23,937)	6,224	-	7,493	(1,948)	(22,157)	(16,073)	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	35,953	-	-	-	-	(24,293)	6,316	17,976	26,965	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(4,000)	-	1,372	(357)	149	(161)	42	(2,955)	(3,477)	
6	Revelstoke Propane Cost Deferral Account	(198)	-	268	(70)	-	-	-	0	(99)	
7	SCP Mitigation Revenues Variance Account	(834)	-	-	-	544	-	-	(290)	(562)	
8		$ 8,563	$ -	$ (5,581)	$ 1,451	$ 692	$ (16,961)	$ 4,410	$ (7,426)	$ 569	
9	Energy Policy Deferral Accounts										
10	Energy Efficiency & Conservation (EEC)	$ 61,769	$ 9,633	$ 15,000	$ (3,900)	$ (8,365)	$ -	$ -	$ 74,138	$ 72,770	
11	NGV Conversion Grants	56	-	45	(12)	(16)	-	-	73	65	
12	Emissions Regulations	3	-	-	-	-	-	-	3	3	
13	NGT Incentives	15,664	-	5,498	(1,429)	(1,845)	-	-	17,888	16,776	
14	CNG and LNG Recoveries	(332)	-	-	-	332	-	-	-	(166)	
15		$ 77,160	$ 9,633	$ 20,543	$ (5,341)	$ (9,893)	$ -	$ -	$ 92,102	$ 89,447	
16	Non-Controllable Items Deferral Accounts										
17	Pension & OPEB Variance	$ 6,861	$ -	$ -	$ -	$ (6,771)	$ -	$ -	$ 90	$ 3,476	
18	BCUC Levies Variance	423	-	-	-	(423)	-	-	(0)	211	
19	Customer Service Variance Account	(10,371)	-	-	-	3,456	-	-	(6,915)	(8,643)	
20	Pension & OPEB Funding	(214,316)	-	(10,565)	-	-	-	-	(224,881)	(219,598)	
21	US GAAP Pension & OPEB Funded Status	148,811	-	-	-	-	-	-	148,811	148,811	
22		$ (68,592)	$ -	$ (10,565)	$ -	$ (3,737)	$ -	$ -	$ (82,894)	$ (75,743)	

FORTISBC ENERGY INC.

G-193-15 December 11, 2015 Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 11.1 (2016)

Line No.	Particulars	12/31/15	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/16	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Application Costs Deferral Accounts										
2	2014-2019 PBR Requirements	$ 990	$ -	$ -	$ -	$ (247)	$ -	$ -	$ 743	$ 866	
3	2014 Long Term Resource Plan Application	50	-	-	-	(50)	-	-	(0)	25	
4	AES Inquiry Cost	254	-	-	-	(132)	-	-	123	189	
5	Generic Cost of Capital Application	11	-	-	-	(11)	-	-	(0)	5	
6	2016 Cost of Capital Application	231	-	300	(78)	-	-	-	453	342	
7	Amalgamation and Rate Design Application Costs	522	-	-	-	(490)	-	-	32	277	
8	2015-2019 Annual Review Costs	222	-	200	(52)	(222)	-	-	148	185	
9	2017 Rate Design Application	111	-	500	(130)	-	-	-	481	296	
10	2017 Long Term Resource Plan Application	-	-	505	(131)	-	-	-	374	187	
11	LMIPSU Application Costs	-	1,047	-	-	(349)	-	-	698	873	
12	Huntingdon CPCN Application Costs	-	-	-	-	-	-	-	-	-	
13	2015 System Extension Application	241	-	-	-	(120)	-	-	120	180	
14	BERC Rate Methodology Application	56	-	-	-	(56)	-	-	-	28	
15		$ 2,687	$ 1,047	$ 1,505	$ (391)	$ (1,676)	$ -	$ -	$ 3,172	$ 3,453	
16	Other Deferral Accounts										
17	Whistler Pipeline Conversion	$ 10,151	$ -	$ -	$ -	$ (745)	$ -	$ -	$ 9,406	$ 9,779	
18	2010-2011 Customer Service O&M and COS	14,560	-	-	-	(3,251)	-	-	11,309	12,934	
19	Gas Asset Records Project	1,237	-	1,770	(460)	(516)	-	-	2,031	1,634	
20	BC OneCall Project	840	-	350	(91)	(358)	-	-	741	791	
21	Gains and Losses on Asset Disposition	32,402	-	-	-	(3,986)	-	-	28,416	30,409	
22	Negative Salvage Provision/Cost	(38,589)	-	13,661	-	(22,020)	-	-	(46,948)	(42,769)	
23	TESDA Overhead Allocation Variance	296	-	-	-	(296)	-	-	-	148	
24	PCEC Start Up Costs	920	-	-	-	(88)	-	-	832	876	
25	Huntingdon CPCN Pre-Feasibility Costs	-	360	-	-	(120)	-	-	240	300	
26	LMIPSU Development Costs	-	2,382	-	-	(794)	-	-	1,588	1,985	
27		$ 21,818	$ 2,742	$ 15,781	$ (551)	$ (32,174)	$ -	$ -	$ 7,615	$ 16,087	
28	Residual Deferred Accounts										
29	Depreciation Variance	-	-	-	-	-	-	-	-	-	
30	BFI Costs and Recoveries	$ (193)	$ -	$ -	$ -	$ -	$ -	$ -	$ (193)	$ (193)	
31	Fuelling Stations Variance Account	53	-	-	-	(53)	-	-	-	26	
32	US GAAP Transitional Costs	(70)	-	-	-	70	-	-	-	(35)	
33	Residual Delivery Rate Riders	-	8	-	-	(8)	-	-	-	4	
34	Property Tax Deferral	(1,456)	-	-	-	1,448	-	-	(8)	(732)	
35	Interest Variance	(338)	-	-	-	338	-	-	-	(169)	
36	Interest Variance - Funding benefits via Customer Deposit	40	-	-	-	(40)	-	-	0	20	
37	Tax Variance Account	-	-	-	-	-	-	-	-	-	
38	NGV for Transportation Application	-	-	-	-	-	-	-	-	-	
39	Rate Schedule 16 Application Costs	-	-	-	-	-	-	-	-	-	
40	Gas Cost Variance Account (GCVA)	-	-	-	-	-	-	-	-	-	
41	FEW 2014 Revenue Surplus/Deficiency	-	-	-	-	-	-	-	-	-	
42	Capital Contribution to FEVI	-	-	-	-	-	-	-	-	-	
43	FEI 2014 Rates Deficiency	-	-	-	-	-	-	-	-	-	
44		$ (1,965)	$ 8	$ -	$ -	$ 1,756	$ -	$ -	$ (201)	$ (1,079)	
45											
46	**Total**	$ 39,671	$ 13,431	$ 21,683	$ (4,833)	$ (45,033)	$ (16,961)	$ 4,410	$ 12,368	$ 32,735	

FORTISBC ENERGY INC.

G-193-15 December 11, 2015

Section 11

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 12 (2016)

Line No.	Particulars	12/31/15	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/16	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Non-Rate Base										
2	Biomethane Variance Account	$ 1,096	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,096	$ 1,096	
3	EEC Incentives for AES / TES	-	-	-	-	-	-	-	-	-	
4	KORP Feasibility Costs	479	-	-	-	-	-	-	479	479	
5	EEC-Incentives	9,633	(9,633)	-	-	-	-	-	-	-	
6	US GAAP Uncertain Tax Positions	466	-	-	-	-	-	-	466	466	
7	Mark to Market - Hedging Transactions	11,165	-	-	-	-	-	-	11,165	11,165	
8	Huntingdon CPCN Application Costs	-	-	-	-	-	-	-	-	-	
9	Huntingdon CPCN Pre-Feasibility Costs	360	(360)	-	-	-	-	-	-	-	
10	Amalgamation Regulatory Account	961	-	12	-	-	(656)	170	488	725	
11	2014-2019 Earning Sharing Account	(4,086)	-	(122)	-	4,208	-	-	0	(2,043)	
12	Flow-Through Account	(713)	-	(21)	-	734	-	-	-	(357)	
13	Phase-In-Rider Balancing Account	1,061	-	-	-	-	(1,434)	373	-	531	
14	2016 Cost of Capital Application	-	-	-	-	-	-	-	-	-	
15	LMIPSU Application Costs	1,047	(1,047)	-	-	-	-	-	-	-	
16	LMIPSU Development Costs	2,382	(2,382)	-	-	-	-	-	0	0	
17	PEC Pipeline Development Costs and Commitment Fees	8,479	-	-	-	-	-	-	8,479	8,479	
18	Rate Stabilization Deferral Account (RSDA)	(45,467)	-	(499)	130	-	43,009	(11,182)	(14,009)	(29,738)	
19	FEW Rider B Refund Deferral	8	(8)	-	-	-	-	-	-	-	
20	**Total Non Rate Base Deferral Accounts**	$ (13,128)	$ (13,431)	$ (630)	$ 130	$ 4,943	$ 40,919	$ (10,639)	$ 8,164	$ (9,197)	

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 13

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 11,837	$ 13,263	$ 1,426	Schedule 14, Line 29, Column 5
3					
4	Less: Funds Available				
5	Average Customer Deposits	-	-	-	
6	Reserve for bad debts	(7,927)	(5,597)	2,330	
7	Employee Withholdings	(5,292)	(5,537)	(245)	
8					
9	**Other Working Capital Items**				
10	Construction Advances	(13)	(13)	-	
11	Transmission Line Pack Gas	2,251	2,332	81	
12	Gas In Storage	77,811	55,331	(22,480)	
13	Inventory - Materials and Supplied	1,567	1,567	0	
14	Refundable Contributions	(298)	(298)	-	
15					
16	Total	$ 79,936	$ 61,048	$ (18,888)	

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

CASH WORKING CAPITAL Schedule 14
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2016 at Revised Rates	Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential & Commercial Tariff Revenue	$ 1,094,405	38.4	$ 41,977,040		
4	Industrial Tariff Revenue	86,719	45.1	3,913,235		
5	Other Tariff Revenue	71,371	43.5	3,104,900		
6						
7	**Other Revenue**					
8	Late Payment Charges	2,314	38.3	88,638		
9	Connection Charges	3,060	38.4	117,382		
10	Other Utility Income	21,521	37.4	805,373		
11						
12	Total	$ 1,279,390		$ 50,006,568	39.1	
13						
14	**EXPENSES**					
15	Energy Purchases	$ 477,714	(40.2)	$ (19,204,103)		
16	Operating and Maintenance	238,067	(25.5)	(6,070,709)		
17	Property Taxes	63,043	(2.0)	(126,086)		
18	Franchise Fees	8,279	(420.3)	(3,479,664)		
19	Carbon Tax	181,416	(29.1)	(5,279,212)		
20	GST	10,735	(38.8)	(416,513)		
21	PST	4,539	(37.1)	(168,379)		
22	Income Tax	46,173	(15.2)	(701,830)		
23						
24	Total	$ 1,029,966		$ (35,446,496)	(34.4)	
25						
26	Net Lag (Lead) Days				4.7	
27	Total Expenses				$ 1,029,966	
28						
29	Cash Working Capital				$ 13,263	

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

DEFERRED INCOME TAX LIABILITY / ASSET Schedule 15
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Total DIT Liability- After Tax	$ (293,874)	$ (285,802)	$ 8,072	
2	Tax Gross Up	(103,253)	(100,417)	2,836	
3	DIT Liability/Asset - End of Year	$ (397,127)	$ (386,219)	$ 10,908	
4	DIT Liability/Asset - Opening Balance	(394,733)	(390,672)	4,061	
5					
6	DIT Liability/Asset - Mid Year	$ (395,930)	$ (388,446)	$ 7,484	

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 16

Line No.	Particulars	2015 Approved	2016 Forecast at Existing Rates	2016 Forecast Revised Revenue	2016 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	124,737	121,772		121,772	(2,965)	
3	Transportation Volume (TJ)	82,649	86,003		86,003	3,354	
4		207,386	207,775	-	207,775	389	Schedule 18, Line 25, Column 3
5							
6	**REVENUE AT EXISTING RATES**						
7	Sales	$ 1,267,517	$ 1,102,916	$ -	$ 1,102,916	$ (164,601)	
8	Deficiency (Surplus)	4,488	-	11,610	11,610	7,122	
9	RSAM Revenue		-	-	-	-	
10	Transportation	120,575	121,289	-	121,289	714	
11	Deficiency (Surplus)	642	-	1,722	1,722	1,080	
12	Total	1,393,222	1,224,205	13,332	1,237,537	(156,765)	Schedule 19, Line 31, Column 8
13							
14	**COST OF ENERGY**	640,486	477,714	-	477,714	(162,772)	Schedule 17, Line 25, Column 3
15							
16	**MARGIN**	752,736	746,492	13,332	759,823	7,087	
17							
18	**EXPENSES**						
19	O&M Expense (net)	237,424	238,067	-	238,067	643	Schedule 21, Line 31, Column 4
20	Depreciation & Amortization	189,989	199,490	-	199,490	9,501	Schedule 22, Line 14, Column 3
21	Property Taxes	61,015	63,036	-	63,036	2,021	Schedule 23, Line 8, Column 3
22	Other Revenue	(41,226)	(41,852)	-	(41,852)	(626)	Schedule 20, Line 12, Column 3
23	Utility Income Before Income Taxes	305,534	287,751	13,332	301,082	(4,452)	
24							
25	Income Taxes	49,002	42,706	3,467	46,173	(2,829)	Schedule 24, Line 13, Column 3
26							
27	**EARNED RETURN**	$ 256,532	$ 245,045	$ 9,865	$ 254,909	$ (1,623)	Schedule 26, Line 5, Column 7
28							
29	**UTILITY RATE BASE**	$ 3,661,384	$ 3,692,649		$ 3,692,697	$ 31,313	Schedule 2, Line 31, Column 3
30	**RATE OF RETURN ON UTILITY RATE BASE**	7.01%	6.64%		6.90%	-0.10%	Schedule 26, Line 5, Column 6

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

COST OF ENERGY Schedule 17
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 379,106	$ 287,645	$ (91,461)	
4	Commercial				
5	Rate Schedule 2	146,170	111,133	(35,037)	
6	Rate Schedule 3	95,837	67,784	(28,053)	
7	Rate Schedule 23	111	182	71	
8	Industrial				
9	Rate Schedule 4	674	432	(242)	
10	Rate Schedule 5	15,676	7,219	(8,457)	
11	Rate Schedule 6	212	136	(76)	
12	Rate Schedule 7	192	514	322	
13	Rate Schedule 22 - Firm Service	153	225	72	
14	Rate Schedule 22 - Interruptible Service	154	268	114	
15	Rate Schedule 25	158	241	83	
16	Rate Schedule 27	90	131	41	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	98	125	27	
19	Rate Schedule 25	12	13	1	
20	Rate Schedule 46	1,826	1,662	(164)	
21	Byron Creek	-	-	-	
22	Burrard Thermal	17	4	(13)	
23	BC Hydro ICP	-	-	-	
24	VIGJV	-	-	-	
25	Total	$ 640,486	$ 477,714	$ (162,772)	

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

VOLUME AND REVENUE Schedule 18
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**				
2	Residential				
3	Rate Schedule 1	73,067.8	72,466.1	(601.7)	
4	Commercial				
5	Rate Schedule 2	28,107.6	28,012.1	(95.5)	
6	Rate Schedule 3	19,210.3	18,121.3	(1,089.0)	
7	Rate Schedule 23	8,255.0	8,968.8	713.8	
8	Industrial				
9	Rate Schedule 4	145.7	129.9	(15.8)	
10	Rate Schedule 5	3,394.5	2,172.7	(1,221.8)	
11	Rate Schedule 6	50.5	46.8	(3.7)	
12	Rate Schedule 7	41.5	154.6	113.1	
13	Rate Schedule 22 - Firm Service	10,603.8	9,878.9	(724.9)	
14	Rate Schedule 22 - Interruptible Service	12,535.4	17,616.4	5,081.0	
15	Rate Schedule 25	13,267.2	13,490.2	223.0	
16	Rate Schedule 27	6,636.0	6,536.7	(99.3)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	7,260.0	8,395.8	1,135.8	
19	Rate Schedule 25	895.2	850.9	(44.3)	
20	Rate Schedule 46	719.2	668.7	(50.5)	
21	Byron Creek	2,940.3	375.4	(2,564.9)	
22	Burrard Thermal	1,276.3	186.4	(1,089.9)	
23	BC Hydro ICP	14,600.0	14,945.0	345.0	
24	VIGJV	4,380.0	4,758.0	378.0	
25	Total	207,386.3	207,774.7	388.4	
26					
27	**REVENUE AT EXISTING RATES**				
28	Residential				
29	Rate Schedule 1	$ 814,408	$ 722,183	$ (92,225)	
30	Commercial				
31	Rate Schedule 2	267,664	232,810	(34,854)	
32	Rate Schedule 3	159,270	127,933	(31,337)	
33	Rate Schedule 23	27,692	30,021	2,329	
34	Industrial				
35	Rate Schedule 4	941	689	(252)	
36	Rate Schedule 5	24,991	13,435	(11,556)	
37	Rate Schedule 6	449	354	(95)	
38	Rate Schedule 7	279	773	494	
39	Rate Schedule 22 - Firm Service	9,068	6,149	(2,919)	
40	Rate Schedule 22 - Interruptible Service	13,211	17,857	4,646	
41	Rate Schedule 25	31,453	30,052	(1,401)	
42	Rate Schedule 27	9,991	9,902	(89)	
43	Bypass and Special Rates				
44	Rate Schedule 22 - Firm Service	839	846	7	
45	Rate Schedule 25	703	435	(268)	
46	Rate Schedule 46	4,003	4,739	736	
47	Byron Creek	1,560	44	(1,516)	
48	Burrard Thermal	9,965	8,314	(1,651)	
49	BC Hydro ICP	12,527	13,097	570	
50	VIGJV	4,208	4,572	364	
51	Total	$ 1,393,222	$ 1,224,205	$ (169,017)	

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

MARGIN AND REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 19

Line No.	Particulars	2015 Approved Margin	2016 Forecast Margin at Existing Rates	2016 Forecast Effective Increase	2016 Forecast Margin at Revised Rates	2016 Forecast Revenue at Existing Rates	2016 Forecast Effective Increase	2016 Forecast Revenue at Revised Rates	Average Number of Customers	Terajoules	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON - BYPASS**										
2	Residential										
3	Rate Schedule 1	$ 435,303	$ 434,537	$ 8,095	$ 442,632	$ 722,183	$ 8,095	$ 730,278	886,652	72,466.1	
4	Commercial										
5	Rate Schedule 2	121,494	121,677	2,266	123,943	232,810	2,266	235,076	84,737	28,012.1	
6	Rate Schedule 3	63,434	60,149	1,119	61,268	127,933	1,119	129,052	5,040	18,121.3	
7	Rate Schedule 23	27,580	29,839	553	30,392	30,021	553	30,574	1,669	8,968.8	
8	Industrial										
9	Rate Schedule 4	267	256	5	261	689	5	694	18	129.9	
10	Rate Schedule 5	9,315	6,217	116	6,333	13,435	116	13,551	230	2,172.7	
11	Rate Schedule 6	236	219	4	223	354	4	358	15	46.8	
12	Rate Schedule 7	87	258	5	263	773	5	778	5	154.6	
13	Rate Schedule 22 - Firm Service	8,914	5,925	110	6,035	6,149	110	6,259	14	9,878.9	
14	Rate Schedule 22 - Interruptible Service	13,057	17,590	326	17,916	17,858	326	18,184	26	17,616.4	
15	Rate Schedule 25	31,296	29,812	553	30,365	30,052	553	30,605	566	13,490.2	
16	Rate Schedule 27	9,901	9,771	180	9,951	9,902	180	10,082	108	6,536.7	
17	Total Non-Bypass	$ 720,885	$ 716,250	$ 13,332	$ 729,581	$ 1,192,159	$ 13,332	$ 1,205,491	979,080	177,594.5	
18											
19											
20	**BYPASS & SPECIAL**										
21	Rate Schedule 22 - Firm Service	$ 740	$ 721	$ -	$ 721	$ 846	$ -	$ 846	6	8,395.8	
22	Rate Schedule 25	691	422	-	422	435	-	435	4	850.9	
23	Rate Schedule 46	2,177	3,076	-	3,076	4,739	-	4,739	13	668.7	
24	Byron Creek	1,560	44	-	44	44	-	44	1	375.4	
25	Burrard Thermal	9,948	8,310	-	8,310	8,314	-	8,314	1	186.4	
26	BC Hydro ICP	12,527	13,097	-	13,097	13,097	-	13,097	1	14,945.0	
27	VIGJV	4,208	4,572	-	4,572	4,572	-	4,572	1	4,758.0	
28	Total Bypass & Special	$ 31,851	$ 30,242	$ -	$ 30,242	$ 32,047	$ -	$ 32,047	27	30,180.2	
29											
30											
31	Total	$ 752,736	$ 746,492	$ 13,332	$ 759,823	$ 1,224,205	$ 13,332	$ 1,237,537	979,107	207,774.7	
32											
33	**Effective Increase**			1.79%				1.09%			

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

OTHER REVENUE Schedule 20
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 2,542	$ 2,314	$ (228)	
2	Connection Charge	3,033	$ 3,060	27	
3	NSF Returned Cheque Charges	89	$ 88	(1)	
4	Other Recoveries	202	$ 202	-	
5	SCP Third Party Revenue	15,035	$ 14,957	(78)	
6	NGT Tanker Rental Revenue	215	$ 209	(6)	
7	NGT Overhead and Marketing Recovery	227	$ 263	36	
8	Biomethane Other Revenue	(70)	$ 294	364	
9	LNG Mitigation Revenue from FEI	18,039	$ 18,039	-	
10	CNG & LNG Service Revenues	1,914	$ 2,426	512	
11					
12	Total	$ 41,226	$ 41,852	$ 626	

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 21

Line No.	Particulars	Formula O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**2013**				
2	Base O&M	$ 228,020			
3	Less: O&M tracked outside of Formula	(30,721)			
4	O&M Subject to Formula	197,299			
5	**2014**				
6	Net Inflation Factor	100.621%			Schedule 3, Line 12, Column 3
7	FEI Formula O&M	198,524			
8	Add: FEVI/FEW Base O&M	38,498			
9	Less: FEVI Pension & OPEB's	(2,016)			
10	Less: FEVI Insurance	(1,250)			
11	Less: FEVI NGT Station O&M	(44)			
12	Total	233,712			
13	**2015**				
14	Net Inflation Factor	100.816%			Schedule 3, Line 12, Column 4
15	Formula O&M	235,619			
16	**2016**				
17	Net Inflation Factor	101.039%			Schedule 3, Line 12, Column 5
18	Formula O&M	$ 238,068		$ 238,068	
19					
20	**O&M Tracked Outside of Formula**				
21	Pension & OPEB (O&M Portion)		$ 24,218		
22	Insurance		6,275		
23	Biomethane O&M		1,022		
24	NGT Stations O&M		1,167		
25	LNG Production O&M		870		
26	Total		$ 33,552	33,552	
27					
28	**Total Gross O&M**			$ 271,620	
29	O&M Transferred to Biomethane BVA			(959)	
30	Capitalized Overhead			(32,594)	
31	**Net O&M Expense**			$ 238,067	

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 22

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 165,608	$ 172,477	$ 6,869	Schedule 7.2, Line 39, Column 6
3	Depreciation transferred to BVA	(171)	(547)	(376)	Schedule 7.2, Line 40, Column 6
4	Vehicle Depreciation allocated to Capital Projects	(1,475)	(1,582)	(107)	Schedule 7.2, Line 41, Column 6
5		163,962	170,348	6,386	
6					
7	**Amortization**				
8	Rate Base deferrals	$ 39,522	$ 45,033	$ 5,511	Schedule 11.1, Line 46, Column 6
9	Non-Rate Base deferrals	(2,899)	(4,943)	(2,044)	Schedule 12, Line 20, Column 6
10	CIAC	(10,596)	(10,984)	(388)	Schedule 9, Line 19, Column 4
11	CIAC Amortization transferred to BVA		36	36	Schedule 9, Line 25, Column 4
12		26,027	29,142	3,115	
13					
14	Total	$ 189,989	$ 199,490	$ 9,501	

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 23

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 47,550	$ 49,521	$ 1,971	
2	1% In-Lieu of Municipal Taxes	13,465	13,522	57	
3					
4	Total	$ 61,015	$ 63,043	$ 2,028	
5					
6	Total Property Tax Expense per Line 4		$ 63,043		
7	Less: Property Tax Transferred to Biomethane BVA		(7)		
8	**Net Property Tax Expense**		$ 63,036		

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

INCOME TAXES Schedule 24
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved	2016 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 256,532	$ 254,909	$ (1,623)	Schedule 16, Line 27, Column 5
2	Deduct: Interest on Debt	(133,189)	(130,511)	2,678	Schedule 26, Line 1+2, Column 7
3	Adjustments to Taxable Income	16,123	7,017	(9,106)	Schedule 24, Line 38
4	Accounting Income After Tax	$ 139,466	$ 131,415	$ (8,051)	
5					
6	1 - Current Income Tax Rate	74.00%	74.00%	0.00%	
7	Taxable Income	$ 188,468	$ 177,588	$ (10,880)	
8					
9	Current Income Tax Rate	26.00%	26.00%	0.00%	
10	Income Tax - Current	$ 49,002	$ 46,173	$ (2,829)	
11					
12	Previous Year Adjustment	-	-	-	
13	Total Income Tax	$ 49,002	$ 46,173	$ (2,829)	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Non-tax Deductible Expenses	$ 992	$ 1,000	$ 8	
19	Depreciation	163,962	170,348	6,386	Schedule 22, Line 5, Column 3
20	Amortization of Deferred Charges	36,623	40,090	3,467	Schedule 22, Line 8+9, Column 3
21	Amortization of Debt Issue Expenses	925	879	(46)	
22	Vehicles: Interest & Capitalized Depreciation	1,726	1,791	65	
23	Pension Expense	21,394	18,969	(2,425)	
24	OPEB Expense	10,343	10,938	595	
25	Biomethane Other Revenue	70	(294)	(364)	Schedule 20, Line 8, Column 3
26					
27	Deductions:				
28	Capital Cost Allowance	(156,972)	(174,396)	(17,424)	Schedule 25, Line 24, Column 6
29	CIAC Amortization	(10,596)	(10,948)	(352)	Schedule 22, Line 10+11, Column 3
30	Cumulative Eligible Capital Allowance	(1,815)	(1,736)	79	
31	Debt Issue Costs	(578)	(1,233)	(655)	
32	Vehicle Lease Payment	(2,747)	(2,567)	180	
33	Pension Contributions	(17,285)	(15,903)	1,382	
34	OPEB Contributions	(3,199)	(3,487)	(288)	
35	Overheads Capitalized Expensed for Tax Purposes	(10,819)	(10,865)	(46)	
36	Removal Costs	(14,009)	(13,661)	348	Schedule 11.1, Line 22, Column 4
37	Major Inspection Costs	(1,892)	(1,908)	(16)	
38	Total	$ 16,123	$ 7,017	$ (9,106)	

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 25

Line No.	Class	CCA Rate	12/31/2015 UCC Balance	Adjustments	2016 Additions	2016 CCA	12/31/2016 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1(a)	4%	$ 1,177,103	$ -	$ 2,450	$ (47,133)	$ 1,132,420
2	1(b)	6%	59,176	-	6,436	(3,744)	61,868
3	2	6%	118,369	-	-	(7,102)	111,267
4	3	5%	2,182	-	-	(109)	2,073
5	6	10%	113	-	-	(11)	102
6	7	15%	16,452	-	2,184	(2,632)	16,004
7	8	20%	27,126	-	7,161	(6,141)	28,146
8	10	30%	6,130	-	2,683	(2,242)	6,571
9	12	100%	6,476	-	13,065	(13,009)	6,532
10	13	manual	3,456	-	196	(415)	3,237
11	14	manual	178	-	-	(25)	153
12	17	8%	1,586	-	-	(127)	1,459
13	38	30%	1,359	-	3,850	(985)	4,224
14	39	25%	-	-	-	-	-
15	42	12%				-	-
16	43.2	50%	7,222	-	-	(3,611)	3,611
17	45	45%	38	-	-	(17)	21
18	46	30%				-	-
19	47	8%	125,278	-	419,967	(26,821)	518,424
20	49	8%	127,860	-	5,436	(10,446)	122,850
21	50	55%	12,346	-	9,438	(9,385)	12,399
22	51	6%	621,800	-	104,419	(40,441)	685,778
23							
24	Total		$ 2,314,250	$ -	$ 577,285	$ (174,396)	$ 2,717,139

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

RETURN ON CAPITAL Schedule 26
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 Approved Earned Return	2016 Amount	2016 Ratio	2016 Average Embedded Cost	2016 Cost Component	2016 Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 129,861	$ 2,145,303	58.10%	6.01%	3.49%	$ 128,940	$ (921)	Schedule 27,Line 27+29,Column 5,6,7
2	Short Term Debt	3,328	125,706	3.40%	1.25%	0.04%	1,571	(1,757)	
3	Common Equity	123,343	1,421,688	38.50%	8.75%	3.37%	124,398	1,055	
4									
5	Total	$ 256,532	$ 3,692,697	100.00%		6.90%	$ 254,909	$ (1,623)	
6									
7	Cross Reference		Schedule 2, Line 31, Column 3						

FORTISBC ENERGY INC. G-193-15 December 11, 2015 Section 11

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Schedule 27

Line No.	Particulars	Issue Date	Maturity Date	Net Proceeds of Issue	Average Principal Outstanding	Interest * Rate	Interest Expense	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Series B Purchase Money Mortgage	November 30, 1991	September 30, 2016	$ 164,684	$ 124,500	10.461%	$ 13,024	
2	Medium Term Note - Series 11	September 21, 1999	September 21, 2029	147,710	150,000	7.073%	10,610	
3	2004 Long Term Debt Issue - Series 18	April 29, 2004	May 1, 2034	148,085	150,000	6.598%	9,897	
4	2005 Long Term Debt Issue - Series 19	February 25, 2005	February 25, 2035	148,337	150,000	5.980%	8,970	
5	2006 Long Term Debt Issue - Series 21	September 25, 2006	September 25, 2036	119,216	120,000	5.595%	6,714	
6	2007 Medium Term Debt Issue - Series 22	October 2, 2007	October 2, 2037	247,697	250,000	6.067%	15,168	
7	2008 Medium Term Debt Issue - Series 23	May 13, 2008	May 13, 2038	247,588	250,000	5.869%	14,673	
8	2009 Med.Term Debt Issue- Series 24	February 24, 2009	February 24, 2039	98,766	100,000	6.645%	6,645	
9	2011 Medium Term Debt Issue - Series 25	December 9, 2011	December 9, 2041	98,590	100,000	4.334%	4,334	
10	2015 Medium Term Debt Issue - Series 26 (Series A Renewal)	April 13, 2015	April 13, 2045	148,500	150,000	3.429%	5,144	
11	2016 Medium Term Debt Issue - Series 27	January 1, 2016	January 1, 2046	148,500	150,000	4.562%	6,843	
12	2016 Medium Term Debt Issue - Series 28 (Series B Renewal)	September 30, 2016	September 30, 2046	165,340	42,412	4.562%	1,935	
13								
14	FEVI L/T Debt Issue - 2008	February 16, 2008	February 15, 2038	247,999	250,000	6.109%	15,273	
15	FEVI L/T Debt Issue - 2010	December 6, 2010	December 6, 2040	98,836	100,000	5.278%	5,278	
16								
17	LILO Obligations - Kelowna				19,106	6.511%	1,244	
18	LILO Obligations - Nelson				3,108	8.237%	256	
19	LILO Obligations - Vernon				9,180	9.564%	878	
20	LILO Obligations - Prince George				24,000	8.442%	2,026	
21	LILO Obligations - Creston				2,294	7.541%	173	
22								
23	Vehicle Lease Obligation				6,499	3.216%	209	
24								
25	Sub-Total				$ 2,151,099		$ 129,294	
26	Less: Fort Nelson Division Portion of Long Term Debt				(5,796)		(354)	
27	Total				$ 2,145,303		$ 128,940	
28								
29	Average Embedded Cost					6.01%		
30								
31	* Interest Rate is Effective interest rate as it includes amortization of debt issue costs							

Appendix 6-3

COSA MODEL O&M ALLOCATION PERCENTAGES

FORTISBC ENERGY INC. **Appendix 6-3**

2016 Revenue Requirement O&M Split

			2016	Percentage
1	**Operating & Maintenance Expense**			
2	Distribution Supervision	$	14,376.2	5.29%
3	Operation Centre - Distribution		11,848.4	4.36%
4	Preventative Maintenance - Distribution		2,664.7	0.98%
6	Operations - Distribution		7,104.0	2.62%
8	Emergency Management - Distribution		6,383.3	2.35%
10	Field Training - Distribution		2,825.5	1.04%
12	Meter Exchange - Distribution		3,032.3	1.12%
14	Corrective - Distribution		5,915.3	2.18%
16	Account Services - Distribution		1,432.1	0.53%
18	Bad Debt Management - Distribution		788.6	0.29%
20	**Distribution Total**	**$**	**56,370.5**	
22				
24	Transmission Supervision		1,221.1	0.45%
26	Pipeline / Right of Way Operations		10,896.8	4.01%
28	Compression Operations		3,941.1	1.45%
30	Measurement Control Operations		861.8	0.32%
32	Pipeline / Right of Way - Maintenance		3,390.6	1.25%
34	Compression - Maintenance		2,719.0	1.00%
36	Measurement Control Operations		459.6	0.17%
38	Company Use Gas (Compression & Line Heating)		857.6	0.32%
40	**Transmission Total**	**$**	**24,347.5**	
42				
44				
46	LNG Plant Operations		4,809.1	1.77%
48	LNG Plant Maintenance		1,656.7	0.61%
50	**LNG Plant Total - Tilbury**	**$**	**6,465.8**	
52				
54				
56	Meter Reading		11,776.3	4.34%
58	**Meter Reading Total**	**$**	**11,776.3**	
60				
62	Energy Supply & Resource Development		2,506.9	0.92%
64	Gas Control		2,207.1	0.81%
66	**Energy Supply & Resource Development Total**	**$**	**4,714.1**	
68				
70	Facilities Management		9,961.9	3.67%
72	Supply Chain		4,693.2	1.73%
74	Measurement		7,927.1	2.92%
76	Property Services		1,424.8	0.52%
78	System Planning		7,401.7	2.73%
80	Engineering		8,819.2	3.25%
82	Project Management		887.9	0.33%
84	**General Operations Total**	**$**	**41,115.8**	

FORTISBC ENERGY INC. **Appendix 6-3**

2016 Revenue Requirement O&M Split

			2016	Percentage
86				
88	Energy Solutions & External Relations Supervision		1,014.3	0.37%
90	Energy Solutions		8,037.9	2.96%
92	Energy Efficiency		1,461.3	0.54%
94	Corporate Communications & External Relations		9,246.4	3.40%
96	Resource Plan, Market & Business Development		6,325.8	2.33%
98	**Energy Solutions & External Relations Total**	**$**	**26,085.7**	
100				
102	Customer Service Supervision		299.8	0.11%
104	Customer Assistance		10,960.5	4.04%
106	Customer Billing		12,187.9	4.49%
108	Credit & Collections		2,561.3	0.94%
110	Customer Operations		4,122.9	1.52%
112	**Customer Care Total**	**$**	**30,132.3**	
114				
116	Information Systems Supervision		5,045.2	1.86%
118	Application Management		15,244.2	5.61%
120	Infrastructure Management		9,197.3	3.39%
122	**Business & IT Services Total**	**$**	**29,486.8**	
124				
126	Administration & General		(188.0)	-0.07%
128	Shared Services Agreement		4,680.7	1.72%
130	Retiree Benefits		-	0.00%
132	Legal		1,894.8	0.70%
134	Internal Audit		825.2	0.30%
136	Risk Management/Insurance		6,893.0	2.54%
138	Environment Health & Safety		3,299.8	1.21%
140	Financial & Regulatory Services		14,204.9	5.23%
142	Human Resources		9,514.9	3.50%
144	**Administration & General Total**	**$**	**41,125.2**	
146				
148	**Gross Operating & Maintenance Expense**		**271,620.0**	100.00%
150				
152	O&M Transferred to the BVA		(959.0)	
154	Capitalized Overhead		(32,594.4)	
156				
158	**Net Operating & Maintenance Expense**	**$**	**238,066.6**	

Appendix 6-4

INITIAL COSA FINANCIAL SCHEDULES

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 1

SUMMARY (000's)

Line No.	Particulars	Reference	Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	RATE 22A NON-BYPASS	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1													
2	**REVENUE TO COST**												
3	Revenue at 2016 Existing rates incl. known & measurable changes	Line 4 + Line 5	**$ 1,304,517**	**$ 730,278**	**$ 235,076**	**$ 694**	**$ 358**	**$ 14,266**	**$ 7,160**	**$ 2,456**	**$ 192,992**	**$ 88,732**	**$ 32,504**
4	Revenue Margin at Proposed 2016 Existing rates incl. known & measurable changes		$ 729,022	$ 442,632	$ 123,943	$ 261	$ 223	$ 13,999	$ 6,977	$ 2,415	$ 91,660	$ 36,698	$ 10,214
5	Total Cost of Gas (included imputed amounts for RS 23, 25 and 27)		$ 575,495	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 183	$ 41	$ 101,332	$ 52,034	$ 22,290
6													
7	**COST OF SERVICE**												
8	Total Utility Cost of Service	Line 9 + Line 10	**$ 1,358,342**	**$ 798,301**	**$ 240,995**	**$ 484**	**$ 286**	**$ 1,073**	**$ 7,007**	**$ 2,643**	**$ 196,580**	**$ 87,145**	**$ 23,830**
9	Allocated Cost of Service with all proposals included		$ 782,847	$ 510,655	$ 129,862	$ 51	$ 151	$ 806	$ 6,824	$ 2,602	$ 95,247	$ 35,111	$ 1,540
10	Total Cost of Gas (included imputed amounts for RS 23, 25 and 27)		$ 575,495	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 183	$ 41	$ 101,332	$ 52,034	$ 22,290
11													
12	**SURPLUS / DEFICIT**												
13	Total Surplus / (Deficit)	Line 3 - Line 8	**$ (53,825)**										
14	% Increase to Equal Allocated Costs	- Line 13 / Line 4	7.4%										
15													
16	**REVENUES (adjusted to equal COS)**												
17	Adjusted Revenue at 2016 Rates with known & measurable changes	Line 5 + Line 18	**$ 1,358,342**	**$ 762,958**	**$ 244,227**	**$ 713**	**$ 374**	**$ 15,300**	**$ 7,675**	**$ 2,634**	**$ 199,760**	**$ 91,442**	**$ 33,258**
18	Adjusted Revenue Margin at 2016 rates incl. known & measurable changes	Line 4 x (1 + Line 14)	$ 782,847	$ 475,312	$ 133,094	$ 280	$ 239	$ 15,033	$ 7,492	$ 2,593	$ 98,427	$ 39,407	$ 10,968
19													
20	REVENUES (adjusted for R/C ratio's)	Line 17	**$ 1,358,342**	**$ 762,958**	**$ 244,227**	**$ 713**	**$ 374**	**$ 15,300**	**$ 7,675**	**$ 2,634**	**$ 199,760**	**$ 91,442**	**$ 33,258**
21	COST OF SERVICE (adjusted for R/C ratio's)	Line 8	**$ 1,358,342**	**$ 798,301**	**$ 240,995**	**$ 484**	**$ 286**	**$ 1,073**	**$ 7,007**	**$ 2,643**	**$ 196,580**	**$ 87,145**	**$ 23,830**
22													
23	**REVENUE TO COST RATIO**												
24	Revenue to Cost Ratio before Rebalancing	Line 20 / Line 21	**100.0%**	**95.6%**	**101.3%**	**147.4%**	**131.2%**	**1425.5%**	**109.5%**	**99.7%**	**101.6%**	**104.9%**	**139.6%**
25													
26	**REVENUE REBALANCING**												
27	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Total Adjusted Revenue	Line 17 + Line 27	**$ 1,358,342**	**$ 762,958**	**$ 244,227**	**$ 713**	**$ 374**	**$ 15,300**	**$ 7,675**	**$ 2,634**	$ 199,760	$ 91,442	$ 33,258
29	Total Adjusted Revenue Margin	Line 18 + Line 27	$ 782,847	$ 475,312	$ 133,094	$ 280	$ 239	$ 15,033	$ 7,492	$ 2,593	$ 98,427	$ 39,407	$ 10,968
30													
31	**REVENUE TO COST RATIO AFTER REBALANCING**												
32	Margin to Cost Ratio including known and measurable changes	Line 29 / Line 9	**100.0%**	**93.1%**	**102.5%**	**550.9%**	**159.1%**	**1864.4%**	**109.8%**	**99.7%**	**103.3%**	**112.2%**	**712.3%**
33	Revenue to Cost Ratio including known and measurable changes	Line 28 / Line 21	**100.0%**	**95.6%**	**101.3%**	**147.4%**	**131.2%**	**1425.5%**	**109.5%**	**99.7%**	**101.6%**	**104.9%**	**139.6%**
34													
35													
36	**Note:**												
37	1. Lines 3, 5, 8, 10, 17, 20 ,21, 28 include the imputed Cost of Gas for Rates 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios.												
38	Please note that Rates 23, 25 and 27 do not pay for commodity and midstream charges.												
39	2. Rate 4 is a seasonal service and Rates 22 and Rate7/27 are interruptible customer classes. Their rates are not set based on their allocated costs.												
40	These rate classes do not drive system capacity additions and therefore, no demand-related costs are allocated to these customer classes in the COSA Study.												
41	3. Revenue Margin includes UAF allocation to rate classes.												

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 2

FUNCTIONALIZATION (000's)

Line No.	Particulars	Total	Gas Supply Operations	LNG Storage Tilbury	LNG Storage Mt. Hayes	Transmission	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense	$ 243,000	$ 4,116	$ 15,930	$ 3,593	$ 39,307	$ 104,262	$ 35,029	$ 40,763
2	Property & Sundry Taxes	$ 63,840	$ -	$ 1,956	$ 371	$ 21,757	$ 39,756	$ -	$ -
3	Depreciation Expense	$ 181,504	$ -	$ 20,156	$ 6,654	$ 40,532	$ 105,416	$ -	$ 8,746
4	Amortization Expense	$ 42,339	$ (149)	$ 2,666	$ 159	$ 8,645	$ 22,225	$ 8,822	$ (29)
5	Other Operating Revenue	$ (102,753)	$ -	$ (39,745)	$ (18,039)	$ (36,991)	$ (5,664)	$ -	$ (2,314)
6	Income Tax	$ 44,864	$ (256)	$ 3,217	$ 1,933	$ 12,854	$ 25,656	$ 812	$ 648
7	Earned Return	$ 310,054	$ (1,707)	$ 32,095	$ 12,902	$ 85,787	$ 171,232	$ 5,420	$ 4,326
8	**Total Cost of Service Margin**	**$ 782,847**	**$ 2,004**	**$ 36,274**	**$ 7,573**	**$ 171,890**	**$ 462,883**	**$ 50,084**	**$ 52,140**
9									
10	Cost of Gas - Commodity & Midstream	$ 477,714	$ 477,714	$ -	$ -	$ -	$ -	$ -	$ -
11	**Total Utility Revenue Requirement**	**$ 1,260,561**	**$ 479,718**	**$ 36,274**	**$ 7,573**	**$ 171,890**	**$ 462,883**	**$ 50,084**	**$ 52,140**

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
RATE BASE SUMMARY - CLASSIFICATION (000's)

Schedule 3

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	RATE 22A NON-BYPASS	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Gas Plant in Service**												
2	Total Gas Plant in Service		**$ 6,478,628**	**$ 3,777,628**	**$ 1,079,538**	**$ 371**	**$ 769**	**$ 5,465**	**$ 63,770**	**$ 24,796**	**$ 762,548**	**$ 288,661**	**$ 7,847**
3		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Demand	$ 4,173,666	$ 1,878,298	$ 806,945	$ -	$ 427	$ 3,660	$ 54,410	$ 21,078	$ 673,308	$ 268,306	$ -
5		Customer	$ 2,304,962	$ 1,899,330	$ 272,593	$ 371	$ 342	$ 1,805	$ 9,360	$ 3,718	$ 89,240	$ 20,355	$ 7,847
6													
7	Total Accumulated Depreciation		**$ (1,812,500)**	**$ (1,102,066)**	**$ (311,413)**	**$ (109)**	**$ (234)**	**$ (1,609)**	**$ (20,675)**	**$ (8,227)**	**$ (221,013)**	**$ (83,518)**	**$ (2,378)**
8		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Demand	$ (1,125,078)	$ (540,358)	$ (231,083)	$ -	$ (122)	$ (1,061)	$ (15,766)	$ (6,109)	$ (192,584)	$ (76,736)	$ -
10		Customer	$ (687,421)	$ (561,708)	$ (80,330)	$ (109)	$ (112)	$ (548)	$ (4,909)	$ (2,117)	$ (28,429)	$ (6,782)	$ (2,378)
11													
12	TOTAL Net Plant		**$ 4,666,128**	**$ 2,675,561**	**$ 768,125**	**$ 262**	**$ 535**	**$ 3,856**	**$ 43,095**	**$ 16,570**	**$ 541,535**	**$ 205,143**	**$ 5,469**
13		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Demand	$ 3,048,588	$ 1,337,939	$ 575,862	$ -	$ 305	$ 2,599	$ 38,644	$ 14,969	$ 480,724	$ 191,570	$ -
15		Customer	$ 1,617,540	$ 1,337,622	$ 192,263	$ 262	$ 231	$ 1,257	$ 4,451	$ 1,601	$ 60,811	$ 13,573	$ 5,469
16													
17	**Contributions In Aid of Construction**												
18	Total Gas Plant in Service		**$ (424,193)**	**$ (268,296)**	**$ (76,061)**	**$ (28)**	**$ (52)**	**$ (376)**	**$ (4,397)**	**$ (1,710)**	**$ (52,819)**	**$ (19,899)**	**$ (555)**
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20		Demand	$ (255,076)	$ (128,581)	$ (55,804)	$ -	$ (30)	$ (248)	$ (3,691)	$ (1,430)	$ (46,685)	$ (18,607)	$ -
21		Customer	$ (169,117)	$ (139,715)	$ (20,256)	$ (28)	$ (23)	$ (127)	$ (706)	$ (280)	$ (6,135)	$ (1,292)	$ (555)
22													
23	Total Accumulated Depreciation		**$ 143,125**	**$ 90,877**	**$ 25,579**	**$ 10**	**$ 18**	**$ 124**	**$ 1,432**	**$ 557**	**$ 17,686**	**$ 6,652**	**$ 192**
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Demand	$ 84,745	$ 42,649	$ 18,587	$ -	$ 10	$ 80	$ 1,188	$ 460	$ 15,566	$ 6,205	$ -
26		Customer	$ 58,379	$ 48,228	$ 6,991	$ 10	$ 8	$ 44	$ 244	$ 97	$ 2,120	$ 447	$ 192
27													
28	TOTAL Net Plant		**$ (281,069)**	**$ (177,419)**	**$ (50,482)**	**$ (18)**	**$ (35)**	**$ (252)**	**$ (2,966)**	**$ (1,153)**	**$ (35,133)**	**$ (13,247)**	**$ (363)**
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Demand	$ (170,331)	$ (85,933)	$ (37,217)	$ -	$ (20)	$ (168)	$ (2,503)	$ (970)	$ (31,118)	$ (12,402)	$ -
31		Customer	$ (110,738)	$ (91,487)	$ (13,265)	$ (18)	$ (15)	$ (83)	$ (463)	$ (183)	$ (4,015)	$ (845)	$ (363)
32													

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 3

RATE BASE SUMMARY - CLASSIFICATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	RATE 22A NON-BYPASS	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
33	**13 Month Adjustment**		**$ 3,685**	**$ 2,177**	**$ 699**	**$ 0**	**$ 0**	**$ 4**	**$ 52**	**$ 20**	**$ 526**	**$ 204**	**$ 3**
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35		Demand	$ 2,819	$ 1,464	$ 597	$ -	$ 0	$ 3	$ 48	$ 19	$ 492	$ 196	$ -
36		Customer	$ 866	$ 713	$ 102	$ 0	$ 0	$ 1	$ 3	$ 1	$ 35	$ 8	$ 3
37													
38	**Work in Process, no AFUDC**		**$ 35,156**	**$ 20,765**	**$ 6,670**	**$ 1**	**$ 4**	**$ 37**	**$ 492**	**$ 191**	**$ 5,021**	**$ 1,945**	**$ 29**
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Demand	$ 26,892	$ 13,965	$ 5,699	$ -	$ 3	$ 31	$ 459	$ 178	$ 4,690	$ 1,867	$ -
41		Customer	$ 8,264	$ 6,800	$ 971	$ 1	$ 1	$ 7	$ 33	$ 13	$ 330	$ 78	$ 29
42													
43	**Unamortized Deferred Charges**		**$ 24,791**	**$ 20,284**	**$ 5,254**	**$ (27)**	**$ 55**	**$ 436**	**$ (686)**	**$ (199)**	**$ 9,249**	**$ (2,724)**	**$ 266**
44		Energy	$ 73,900	$ 41,431	$ 14,891	$ (27)	$ (10)	$ 491	$ 336	$ 197	$ 16,320	$ 58	$ 212
45		Demand	$ (54,337)	$ (24,824)	$ (9,807)	$ -	$ 60	$ (68)	$ (1,010)	$ (391)	$ (7,998)	$ (3,182)	$ -
46		Customer	$ 5,228	$ 3,677	$ 170	$ (1)	$ 5	$ 13	$ (13)	$ (4)	$ 927	$ 400	$ 54
47													
48	**Cash Working Capital**		**$ 2,129**	**$ 1,311**	**$ 424**	**$ 1**	**$ 1**	**$ 1**	**$ 10**	**$ 4**	**$ 299**	**$ 74**	**$ 4**
49		Energy	$ 1,188	$ 721	$ 268	$ 1	$ 1	$ -	$ -	$ -	$ 171	$ 24	$ 2
50		Demand	$ 568	$ 294	$ 121	$ -	$ 0	$ 1	$ 10	$ 4	$ 99	$ 40	$ -
51		Customer	$ 373	$ 296	$ 36	$ 0	$ 0	$ 0	$ 1	$ 0	$ 28	$ 10	$ 2
52													
53	**Other Working Capital**		**$ 1,567**	**$ 1,081**	**$ 259**	**$ 0**	**$ 0**	**$ 1**	**$ 4**	**$ 2**	**$ 159**	**$ 57**	**$ 3**
54		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Demand	$ 602	$ 284	$ 144	$ -	$ 0	$ 0	$ 0	$ 0	$ 124	$ 50	$ -
56		Customer	$ 965	$ 798	$ 116	$ 0	$ 0	$ 1	$ 4	$ 2	$ 35	$ 7	$ 3
57													
58	**LILO, Other Rate Base items**		**$ 56,701**	**$ 29,718**	**$ 11,651**	**$ (0)**	**$ 6**	**$ 95**	**$ 1,418**	**$ 550**	**$ 9,488**	**$ 3,777**	**$ (2)**
59		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Demand	$ 57,294	$ 30,208	$ 11,722	$ -	$ 6	$ 96	$ 1,421	$ 551	$ 9,510	$ 3,781	$ -
61		Customer	$ (593)	$ (490)	$ (71)	$ (0)	$ (0)	$ (0)	$ (2)	$ (1)	$ (21)	$ (5)	$ (2)
62													
63	**Total Utility Rate Base**		**$ 4,509,089**	**$ 2,573,478**	**$ 742,601**	**$ 220**	**$ 567**	**$ 4,179**	**$ 41,420**	**$ 15,984**	**$ 531,144**	**$ 195,229**	**$ 5,408**
64		Energy	$ 75,088	$ 42,152	$ 15,159	$ (25)	$ (9)	$ 491	$ 336	$ 197	$ 16,492	$ 82	$ 214
65		Demand	$ 2,912,094	$ 1,273,397	$ 547,120	$ -	$ 354	$ 2,493	$ 37,069	$ 14,358	$ 456,523	$ 181,920	$ -
66		Customer	$ 1,521,907	$ 1,257,929	$ 180,321	$ 245	$ 222	$ 1,194	$ 4,015	$ 1,429	$ 58,130	$ 13,228	$ 5,195

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Schedule 4

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	RATE 22A NON-BYPASS	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Operating & Maintenance Expense**		**$ 243,000**	**$ 161,226**	**$ 34,167**	**$ 15**	**$ 61**	**$ 271**	**$ 1,622**	**$ 639**	**$ 28,049**	**$ 10,539**	**$ 728**
2		Energy	$ 5,577	$ 3,337	$ 1,225	$ 5	$ 2	$ 10	$ 7	$ 4	$ 881	$ 95	$ 11
3		Demand	$ 99,531	$ 48,183	$ 20,205	$ -	$ 11	$ 94	$ 1,394	$ 540	$ 16,752	$ 6,672	$ -
4		Customer	$ 137,892	$ 109,707	$ 12,737	$ 10	$ 49	$ 167	$ 222	$ 95	$ 10,416	$ 3,772	$ 717
5													
6	**Property & Sundry Taxes**		**$ 63,840**	**$ 39,767**	**$ 11,666**	**$ 4**	**$ 8**	**$ 57**	**$ 582**	**$ 226**	**$ 8,282**	**$ 3,167**	**$ 81**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 40,988	$ 20,737	$ 8,958	$ -	$ 5	$ 38	$ 563	$ 218	$ 7,485	$ 2,983	$ -
9		Customer	$ 22,852	$ 19,030	$ 2,708	$ 4	$ 3	$ 19	$ 19	$ 8	$ 797	$ 184	$ 81
10													
11	**Depreciation Expense**		**$ 181,504**	**$ 109,208**	**$ 27,950**	**$ 14**	**$ 26**	**$ 142**	**$ 1,910**	**$ 688**	**$ 19,036**	**$ 6,794**	**$ 220**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 99,637	$ 43,086	$ 18,082	$ -	$ 10	$ 91	$ 1,359	$ 527	$ 14,995	$ 5,973	$ -
14		Customer	$ 81,866	$ 66,123	$ 9,868	$ 14	$ 16	$ 51	$ 551	$ 161	$ 4,041	$ 822	$ 220
15													
16	**Amortization Expense**		**$ 42,339**	**$ 24,379**	**$ 7,759**	**$ 2**	**$ 20**	**$ 91**	**$ 484**	**$ 196**	**$ 6,128**	**$ 1,798**	**$ 60**
17		Energy	$ 8,216	$ 4,715	$ 1,667	$ 0	$ 0	$ 56	$ 39	$ 23	$ 1,623	$ 64	$ 28
18		Demand	$ 24,958	$ 12,120	$ 5,013	$ -	$ 19	$ 27	$ 409	$ 158	$ 4,141	$ 1,649	$ -
19		Customer	$ 9,165	$ 7,544	$ 1,078	$ 1	$ 1	$ 7	$ 37	$ 15	$ 364	$ 85	$ 32
20													
21	**Other Operating Revenue**		**$ (102,753)**	**$ (37,394)**	**$ (11,551)**	**$ (2)**	**$ (10)**	**$ (62)**	**$ (1,031)**	**$ (399)**	**$ (9,036)**	**$ (3,495)**	**$ (28)**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ (96,950)	$ (32,752)	$ (10,965)	$ (1)	$ (8)	$ (56)	$ (1,015)	$ (392)	$ (8,650)	$ (3,365)	$ -
24		Customer	$ (5,804)	$ (4,641)	$ (586)	$ (1)	$ (2)	$ (6)	$ (16)	$ (7)	$ (387)	$ (130)	$ (28)
25													

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Schedule 4

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	RATE 22A NON-BYPASS	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
26	**Income Tax**		**$ 44,864**	**$ 28,797**	**$ 8,183**	**$ 2**	**$ 6**	**$ 40**	**$ 424**	**$ 163**	**$ 5,885**	**$ 2,248**	**$ 62**
27		Energy	$ (256)	$ (155)	$ (58)	$ (0)	$ (0)	$ -	$ -	$ -	$ (37)	$ (5)	$ (0)
28		Demand	$ 27,853	$ 14,748	$ 6,241	$ -	$ 3	$ 26	$ 381	$ 148	$ 5,187	$ 2,066	$ -
29		Customer	$ 17,267	$ 14,204	$ 1,999	$ 3	$ 3	$ 14	$ 43	$ 16	$ 735	$ 187	$ 63
30													
31	**Earned Return**		**$ 310,054**	**$ 184,671**	**$ 51,688**	**$ 15**	**$ 39**	**$ 267**	**$ 2,833**	**$ 1,089**	**$ 36,904**	**$ 14,059**	**$ 416**
32		Energy	$ (1,707)	$ (1,036)	$ (385)	$ (2)	$ (1)	$ -	$ -	$ -	$ (246)	$ (34)	$ (2)
33		Demand	$ 196,521	$ 90,907	$ 38,730	$ -	$ 20	$ 171	$ 2,543	$ 985	$ 32,245	$ 12,847	$ -
34		Customer	$ 115,241	$ 94,800	$ 13,344	$ 18	$ 20	$ 96	$ 290	$ 104	$ 4,904	$ 1,246	$ 418
35													
36	**Total Cost of Service Margin**		**$ 782,847**	**$ 510,655**	**$ 129,862**	**$ 51**	**$ 151**	**$ 806**	**$ 6,824**	**$ 2,602**	**$ 95,247**	**$ 35,111**	**$ 1,540**
37		Energy	$ 11,831	$ 6,861	$ 2,450	$ 3	$ 1	$ 66	$ 45	$ 27	$ 2,221	$ 119	$ 37
38		Demand	$ 392,539	$ 197,028	$ 86,264	$ (1)	$ 59	$ 392	$ 5,633	$ 2,183	$ 72,156	$ 28,826	$ -
39		Customer	$ 378,478	$ 306,766	$ 41,148	$ 49	$ 90	$ 348	$ 1,146	$ 392	$ 20,870	$ 6,165	$ 1,503
40													
41	**Cost of Gas Sold (Including Gas Lost)**		**$ 475,908**	**$ 287,646**	**$ 111,133**	**$ 433**	**$ 135**	**$ 267**	**$ 183**	**$ 41**	**$ 67,966**	**$ 7,458**	**$ 646**
42		Energy	$ 475,908	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 183	$ 41	$ 67,966	$ 7,458	$ 646
43		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45													
46	**Total Utility Revenue Require**		**$ 1,258,755**	**$ 798,301**	**$ 240,995**	**$ 484**	**$ 286**	**$ 1,073**	**$ 7,007**	**$ 2,643**	**$ 163,213**	**$ 42,569**	**$ 2,186**
47		Energy	$ 487,739	$ 294,507	$ 113,583	$ 436	$ 136	$ 333	$ 228	$ 68	$ 70,187	$ 7,577	$ 683
48		Demand	$ 392,539	$ 197,028	$ 86,264	$ (1)	$ 59	$ 392	$ 5,633	$ 2,183	$ 72,156	$ 28,826	$ -
49		Customer	$ 378,478	$ 306,766	$ 41,148	$ 49	$ 90	$ 348	$ 1,146	$ 392	$ 20,870	$ 6,165	$ 1,503

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RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Schedule 5

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	RATE 22A NON-BYPASS	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Gas Supply Operations		**$ (24,823)**	**$ (15,066)**	**$ (5,597)**	**$ (30)**	**$ (11)**	**$ -**	**$ -**	**$ -**	**$ (3,582)**	**$ (502)**	**$ (36)**
2		Energy	$ (24,823)	$ (15,066)	$ (5,597)	$ (30)	$ (11)	$ -	$ -	$ -	$ (3,582)	$ (502)	$ (36)
3		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5													
6	LNG Storage Tilbury		**$ 466,757**	**$ 37,104**	**$ 14,423**	**$ -**	**$ 7**	**$ -**	**$ -**	**$ -**	**$ 11,707**	**$ 4,655**	**$ -**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 466,757	$ 37,104	$ 14,423	$ -	$ 7	$ -	$ -	$ -	$ 11,707	$ 4,655	$ -
9		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10													
11	LNG Storage Mt. Hayes		**$ 187,625**	**$ 98,857**	**$ 38,428**	**$ -**	**$ 20**	**$ 311**	**$ 4,623**	**$ 1,791**	**$ 31,191**	**$ 12,404**	**$ -**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 187,625	$ 98,857	$ 38,428	$ -	$ 20	$ 311	$ 4,623	$ 1,791	$ 31,191	$ 12,404	$ -
14		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15													
16	Transmission		**$ 1,247,585**	**$ 657,334**	**$ 255,523**	**$ -**	**$ 133**	**$ 2,069**	**$ 30,741**	**$ 11,912**	**$ 207,399**	**$ 82,476**	**$ -**
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 1,247,585	$ 657,334	$ 255,523	$ -	$ 133	$ 2,069	$ 30,741	$ 11,912	$ 207,399	$ 82,476	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20													

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Schedule 5

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	RATE 22A NON-BYPASS	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
21	Distribution		**$ 2,490,203**	**$ 1,706,297**	**$ 416,034**	**$ 244**	**$ 328**	**$ 1,238**	**$ 5,695**	**$ 2,070**	**$ 259,660**	**$ 93,739**	**$ 4,897**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ 1,010,062	$ 480,102	$ 238,746	$ -	$ 129	$ 114	$ 1,705	$ 655	$ 206,227	$ 82,385	$ -
24		Customer	$ 1,480,141	$ 1,226,194	$ 177,288	$ 244	$ 199	$ 1,125	$ 3,991	$ 1,415	$ 53,433	$ 11,354	$ 4,897
25													
26	Marketing		**$ 78,828**	**$ 46,354**	**$ 15,232**	**$ 5**	**$ 70**	**$ 501**	**$ 340**	**$ 198**	**$ 14,984**	**$ 852**	**$ 292**
27		Energy	$ 72,770	$ 41,800	$ 14,797	$ 5	$ 2	$ 491	$ 336	$ 197	$ 14,310	$ 583	$ 249
28		Demand	$ 65	$ -	$ -	$ -	$ 65	$ -	$ -	$ -	$ -	$ -	$ -
29		Customer	$ 5,993	$ 4,554	$ 435	$ 0	$ 3	$ 10	$ 3	$ 2	$ 674	$ 269	$ 43
30													
31	Customer Accounting		**$ 62,914**	**$ 42,598**	**$ 8,557**	**$ 0**	**$ 20**	**$ 60**	**$ 21**	**$ 11**	**$ 9,786**	**$ 1,605**	**$ 255**
32		Energy	$ 27,141	$ 15,418	$ 5,960	$ -	$ -	$ -	$ -	$ -	$ 5,764	$ -	$ -
33		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Customer	$ 35,773	$ 27,181	$ 2,598	$ 0	$ 20	$ 60	$ 21	$ 11	$ 4,023	$ 1,605	$ 255
35													
36	**Total Utility Rate Base**		**$ 4,509,089**	**$ 2,573,478**	**$ 742,601**	**$ 220**	**$ 567**	**$ 4,179**	**$ 41,420**	**$ 15,984**	**$ 531,144**	**$ 195,229**	**$ 5,408**
37		Energy	$ 75,088	$ 42,152	$ 15,159	$ (25)	$ (9)	$ 491	$ 336	$ 197	$ 16,492	$ 82	$ 214
38		Demand	$ 2,912,094	$ 1,273,397	$ 547,120	$ -	$ 354	$ 2,493	$ 37,069	$ 14,358	$ 456,523	$ 181,920	$ -
39		Customer	$ 1,521,907	$ 1,257,929	$ 180,321	$ 245	$ 222	$ 1,194	$ 4,015	$ 1,429	$ 58,130	$ 13,228	$ 5,195

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Schedule 6

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	RATE 22A NON-BYPASS	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Gas Supply Operations		**$ 2,004**	**$ 1,216**	**$ 452**	**$ 2**	**$ 1**	**$ -**	**$ -**	**$ -**	**$ 289**	**$ 41**	**$ 3**
2		Energy	$ 2,004	$ 1,216	$ 452	$ 2	$ 1	$ -	$ -	$ -	$ 289	$ 41	$ 3
3		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5													
6	LNG Storage Tilbury		**$ 36,274**	**$ 19,823**	**$ 7,706**	**$ -**	**$ 4**	**$ -**	**$ -**	**$ -**	**$ 6,254**	**$ 2,487**	**$ -**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 36,274	$ 19,823	$ 7,706	$ -	$ 4	$ -	$ -	$ -	$ 6,254	$ 2,487	$ -
9		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10													
11	LNG Storage Mt. Hayes		**$ 7,573**	**$ 3,990**	**$ 1,551**	**$ -**	**$ 1**	**$ 13**	**$ 187**	**$ 72**	**$ 1,259**	**$ 501**	**$ -**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 7,573	$ 3,990	$ 1,551	$ -	$ 1	$ 13	$ 187	$ 72	$ 1,259	$ 501	$ -
14		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15													
16	Transmission		**$ 171,890**	**$ 87,834**	**$ 36,030**	**$ (1)**	**$ 16**	**$ 321**	**$ 4,576**	**$ 1,775**	**$ 29,523**	**$ 11,816**	**$ -**
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 171,890	$ 87,834	$ 36,030	$ (1)	$ 16	$ 321	$ 4,576	$ 1,775	$ 29,523	$ 11,816	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20													

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Fully Distributed Cost of Service Allocation Study
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Schedule 6

COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	RATE 22A NON-BYPASS	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
21	Distribution		**$ 462,883**	**$ 321,954**	**$ 75,417**	**$ 48**	**$ 61**	**$ 252**	**$ 1,962**	**$ 699**	**$ 45,601**	**$ 16,044**	**$ 845**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ 176,786	$ 85,381	$ 40,977	$ -	$ 22	$ 58	$ 870	$ 336	$ 35,119	$ 14,022	$ -
24		Customer	$ 286,097	$ 236,573	$ 34,440	$ 48	$ 39	$ 194	$ 1,092	$ 362	$ 10,482	$ 2,022	$ 845
25													
26	Marketing		**$ 50,084**	**$ 36,220**	**$ 4,920**	**$ 1**	**$ 38**	**$ 134**	**$ 69**	**$ 39**	**$ 6,457**	**$ 1,884**	**$ 320**
27		Energy	$ 9,826	$ 5,644	$ 1,998	$ 1	$ 0	$ 66	$ 45	$ 27	$ 1,932	$ 79	$ 34
28		Demand	$ 16	$ -	$ -	$ -	$ 16	$ -	$ -	$ -	$ -	$ -	$ -
29		Customer	$ 40,241	$ 30,576	$ 2,922	$ 1	$ 22	$ 67	$ 23	$ 13	$ 4,525	$ 1,805	$ 287
30													
31	Customer Accounting		**$ 52,140**	**$ 39,617**	**$ 3,786**	**$ 1**	**$ 29**	**$ 87**	**$ 30**	**$ 17**	**$ 5,863**	**$ 2,339**	**$ 372**
32		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Customer	$ 52,140	$ 39,617	$ 3,786	$ 1	$ 29	$ 87	$ 30	$ 17	$ 5,863	$ 2,339	$ 372
35													
36	**Total Utility Cost of Service**		**$ 782,847**	**$ 510,655**	**$ 129,862**	**$ 51**	**$ 151**	**$ 806**	**$ 6,824**	**$ 2,602**	**$ 95,247**	**$ 35,111**	**$ 1,540**
37		Energy	$ 11,831	$ 6,861	$ 2,450	$ 3	$ 1	$ 66	$ 45	$ 27	$ 2,221	$ 119	$ 37
38		Demand	$ 392,539	$ 197,028	$ 86,264	$ (1)	$ 59	$ 392	$ 5,633	$ 2,183	$ 72,156	$ 28,826	$ -
39		Customer	$ 378,478	$ 306,766	$ 41,148	$ 49	$ 90	$ 348	$ 1,146	$ 392	$ 20,870	$ 6,165	$ 1,503

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
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Schedule 7

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON-BYPASS	RATE 22A NON-BYPASS	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Billing Determinants												
2													
3	Sales Volume (TJ)		177,595	72,466	28,012	130	47	13,189	9,030	5,277	27,090	15,663	6,691
4	Midstream Sales Volume (TJ)		120,882	72,399	27,942	130	47	-	-	-	18,037	2,173	155
5	Commodity Sales Volume (TJ)		107,522	65,258	24,245	130	47	-	-	-	15,515	2,173	155
6	Average No. of Customers		979,080	886,652	84,737	18	15	26	9	5	6,709	796	113
7													
8	Cost of Service Margin		**$ 782,847**	**$ 510,655**	**$ 129,862**	**$ 51**	**$ 151**	**$ 806**	**$ 6,824**	**$ 2,602**	**$ 95,247**	**$ 35,111**	**$ 1,540**
9		Energy	$ 11,831	$ 6,861	$ 2,450	$ 3	$ 1	$ 66	$ 45	$ 27	$ 2,221	$ 119	$ 37
10	Unit Energy Charge ($/GJ)		0.067	0.095	0.087	0.024	0.024	0.005	0.005	0.005	0.082	0.008	0.005
11		Demand	$ 392,539	$ 197,028	$ 86,264	$ (1)	$ 59	$ 392	$ 5,633	$ 2,183	$ 72,156	$ 28,826	$ -
12	Unit Demand Charge ($/GJ)		2.210	2.719	3.080	-0.011	1.266	0.030	0.624	0.414	2.664	1.840	0.000
13		Customer	$ 378,478	$ 306,766	$ 41,148	$ 49	$ 90	$ 348	$ 1,146	$ 392	$ 20,870	$ 6,165	$ 1,503
14	Unit Customer Charge ($/Cust/Day)		1.058	0.947	1.329	7.483	16.451	36.692	348.567	214.606	3.111	7.746	13.304
15													
16	Unit Cost of Service Margin ($/GJ)		4.408	7.047	4.636	0.392	3.216	0.061	0.756	0.493	3.516	2.242	0.230
17													
18	Cost of Gas - Commodity & Midstream		**$ 475,908**	**$ 287,646**	**$ 111,133**	**$ 433**	**$ 135**	**$ 267**	**$ 183**	**$ 41**	**$ 67,966**	**$ 7,458**	**$ 646**
19		Energy	$ 475,908	$ 287,646	$ 111,133	$ 433	$ 135	$ 267	$ 183	$ 41	$ 67,966	$ 7,458	$ 646
20		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Unit Cost of Gas - Commodity ($/GJ)		2.680	3.969	3.967	3.333	2.885	0.020	0.020	0.008	2.509	0.476	0.097
23													
24	Total Utility Cost of Service		**$ 1,258,755**	**$ 798,301**	**$ 240,995**	**$ 484**	**$ 286**	**$ 1,073**	**$ 7,007**	**$ 2,643**	**$ 163,213**	**$ 42,569**	**$ 2,186**
25		Energy	$ 487,739	$ 294,507	$ 113,583	$ 436	$ 136	$ 333	$ 228	$ 68	$ 70,187	$ 7,577	$ 683
26		Demand	$ 392,539	$ 197,028	$ 86,264	$ (1)	$ 59	$ 392	$ 5,633	$ 2,183	$ 72,156	$ 28,826	$ -
27		Customer	$ 378,478	$ 306,766	$ 41,148	$ 49	$ 90	$ 348	$ 1,146	$ 392	$ 20,870	$ 6,165	$ 1,503
28	Unit Cost of Service ($/GJ)		7.088	11.016	8.603	3.725	6.101	0.081	0.776	0.501	6.025	2.718	0.327
29													
30	Total Revenues @ Proposed Rates		**$ 1,358,342**	**$ 762,958**	**$ 244,227**	**$ 713**	**$ 374**	**$ 15,300**	**$ 7,675**	**$ 2,634**	**$ 199,760**	**$ 91,442**	**$ 33,258**
31	Unit Rate ($/GJ)		7.649	10.528	8.719	5.491	8.001	1.160	0.850	0.499	7.374	5.838	4.970
32													
33	Total Revenue Margin @ Proposed Rates		**$ 782,847**	**$ 475,312**	**$ 133,094**	**$ 280**	**$ 239**	**$ 15,033**	**$ 7,492**	**$ 2,593**	**$ 98,427**	**$ 39,407**	**$ 10,968**
34	Unit Rate ($/GJ)		4.408	6.559	4.751	2.158	5.117	1.140	0.830	0.491	3.633	2.516	1.639

Appendix 6-5

MINIMUM SYSTEM STUDY RESULTS AND PEAK LOAD CARRYING CAPACITY STUDY RESULTS

MINIMUM SYSTEM AND PEAK LOAD CARRYING CAPACITY STUDIES

The following appendix discusses the purpose and results of the Minimum System Study and Peak Load Carrying Capacity ("PLCC") Study. Each study was developed to support the Cost of Service Allocation study and the results produced by the two studies aid in the classification of costs associated with distribution mains.

1.1. PURPOSE OF MINIMUM SYSTEM STUDY

Distribution mains costs have been classified as demand or customer related components based on the results of the Minimum System Study.

As described in Section 6.3.5.4 of the Application, the Minimum System Study assumes that a certain level of plant investment is required to serve the minimum loading requirements of customers throughout the service territory. To estimate the value of mains required from a customer connection vs. the demand component FEI follows the steps outlined below:

1. Obtain the length of mains by diameter and material included in all of FEI's service areas,
2. Estimate the replacement cost of mains by diameter and material using zone based geo-pricing and inflating prices to 2016 dollars using PBR approved inflation rates,
3. Value FEI's mains at their estimated replacement cost,
4. Value FEI's mains at the minimum standard size and material (60mm PE),
5. Calculate the customer-related component of FEI's mains by dividing number 4 above by number 3 above,
6. Calculate the demand-related component as one minus number 5 above

The percentages calculated in steps 5 and 6 above are applied to FEI's distribution mains embedded costs to split those costs into customer and demand related components. However, in the Minimum System Study, the proportion of costs determined to be customer related is overstated since the 60 mm pipe (customer related portion) also has the ability to carry some demand. As a result, an adjustment to account for the PLCC of the minimum system is required and together the two studies better represent the demand and customer related components of the distribution system.

1.1 MINIMUM SYSTEM RESULTS

To determine the demand versus customer related proportion, the steel and plastic weighted costs are summed for each pipe diameter and then the summed weighted costs for the minimum distribution system are compared to the total weighted costs for the entire distribution system.

The following tables present the Minimum System Study results for the entire distribution system. The first table summarizes the combined minimum weighted cost per diameter results for all mains, as well as the customer and demand related component percentages. The subsequent tables show the results per material type (steel and plastic/polyethylene). In all three tables the mains have been separated by pipe diameter and each diameter has been allocated length of pipe installed and unit costs per length to determine the actual total weighted cost per pipe diameter.

Table 1: Minimum System Results for All Mains

COMBINED STEEL & PLASTIC MAINS

Line No.	Diameter		Length in Meters	Unit Cost / Length ($/m)	Weighted Cost	Minimum Size Cost (All Pipe Valued at 60mm PE)
	Inches	mm				
	(1)	(2)	(3)	(4)	(5)	(6)
1	0.6	15	201,739	$ 57.55	$ 11,610,076	$ 11,233,200
2	0.8	21	38,914	$ 149.85	$ 5,831,225	$ 2,166,832
3	1.0	26	1,491,415	$ 122.19	$ 182,236,170	$ 83,044,874
4	1.3	33	17,750	$ 149.61	$ 2,655,635	$ 988,357
5	1.7	42	8,176,149	$ 81.16	$ 663,565,704	$ 455,263,903
6	1.9	48	41,693	$ 150.18	$ 6,261,307	$ 2,321,558
7	2.4	60	9,344,973	$ 103.43	$ 966,547,294	$ 520,346,273
8	0.6	15.0	0		$ -	$ -
9	0.8	21.0	200	$ 150.34	$ 30,058	$ 11,132
10	1.0	26.0	2,303	$ 150.34	$ 346,222	$ 128,230
11	1.3	33.0	2	$ 150.34	$ 345	$ 128
12	1.7	42.0	9,481	$ 150.34	$ 1,425,364	$ 527,913
13	1.9	48.0	0		$ -	$ -
14	2.4	60.0	48,205	$ 150.34	$ 7,247,235	$ 2,684,161
15	2.9	73	585	$ 274.33	$ 160,579	$ 32,594
16	3.5	88	1,629,167	$ 167.72	$ 273,236,425	$ 90,715,168
17	4.0	101	592	$ 275.56	$ 163,058	$ 32,949
18	4.5	114	2,714,754	$ 208.66	$ 566,447,291	$ 151,162,769
19	6.6	168	1,190,799	$ 449.10	$ 534,788,514	$ 66,306,001
20	8.6	219	292,284	$ 1,876.21	$ 548,386,780	$ 16,274,967
21	10.7	273	49,070	$ 2,274.10	$ 111,590,603	$ 2,732,323
22	12.7	323	125,597	$ 2,274.19	$ 285,631,012	$ 6,993,472
23	16.0	406	33,359	$ 2,274.22	$ 75,866,002	$ 1,857,498
24	18.0	457	1,947	$ 2,274.22	$ 4,428,391	$ 108,424
25	20.0	508	57,658	$ 6,171.01	$ 355,805,428	$ 3,210,485
26	24.0	609	1,466	$ 6,171.01	$ 9,045,949	$ 81,623
27	30.0	762	11,779	$ 6,171.01	$ 72,687,404	$ 655,869
28	36.0	914	0		$ -	$ -
29	42.0	1066	0		$ -	$ -
32	**TOTAL**		**25,481,880**		**$ 4,685,994,070**	**$ 1,418,880,702**
33						
34	**Customer Related Component**			Line 32, Column (6) / Line 32, Column (5)		**30%**
35	**Demand Related Component**			1 - Line 34, Column (6)		**70%**

1 **Table 2: Steel Mains Weighted Cost per Diameter**

STEEL MAINS

Line No.	Diameter Inches	Diameter mm	Length in Meters	Unit Cost / Length ($/m)	Weighted Cost	Minimum Size Cost (All Pipe Valued at 60mm PE)
1	0.6	15	3,981	$ 150.34	$ 598,568	$ 221,692
2	0.8	21	38,711	$ 150.34	$ 5,819,919	$ 2,155,526
3	1.0	26	1,047,877	$ 150.34	$ 157,539,117	$ 58,347,821
4	1.3	33	17,613	$ 150.34	$ 2,648,031	$ 980,752
5	1.7	42	2,200,542	$ 150.34	$ 330,832,271	$ 122,530,471
6	1.9	48	41,620	$ 150.34	$ 6,257,250	$ 2,317,500
7	2.4	60	4,713,757	$ 150.34	$ 708,672,209	$ 262,471,188
8	0.6	15.0	0	$ 150.34	$ -	$ -
9	0.8	21.0	200	$ 150.34	$ 30,058	$ 11,132
10	1.0	26.0	2,303	$ 150.34	$ 346,222	$ 128,230
11	1.3	33.0	2	$ 150.34	$ 345	$ 128
12	1.7	42.0	9,481	$ 150.34	$ 1,425,364	$ 527,913
13	1.9	48.0	0	$ 150.34	$ -	$ -
14	2.4	60.0	48,205	$ 150.34	$ 7,247,235	$ 2,684,161
8	2.9	73	579	$ 276.19	$ 159,940	$ 32,246
9	3.5	88	612,942	$ 276.19	$ 169,285,772	$ 34,129,794
10	4.0	101	590	$ 276.19	$ 162,839	$ 32,830
11	4.5	114	1,660,501	$ 276.19	$ 458,606,773	$ 92,459,953
12	6.6	168	734,566	$ 591.88	$ 434,775,260	$ 40,902,039
13	8.6	219	235,675	$ 2,274.22	$ 535,977,075	$ 13,122,827
14	10.7	273	49,067	$ 2,274.22	$ 111,589,967	$ 2,732,161
15	12.7	323	125,595	$ 2,274.22	$ 285,630,569	$ 6,993,360
16	16.0	406	33,359	$ 2,274.22	$ 75,866,002	$ 1,857,498
17	18.0	457	1,947	$ 2,274.22	$ 4,428,391	$ 108,424
18	20.0	508	57,658	$ 6,171.01	$ 355,805,428	$ 3,210,485
19	24.0	609	1,466	$ 6,171.01	$ 9,045,949	$ 81,623
20	30.0	762	11,779	$ 6,171.01	$ 72,687,404	$ 655,869
21	36.0	914	0	$ -	$ -	$ -
22	42.0	1066	0	$ -	$ -	$ -
25	TOTAL		11,650,017		3,735,437,956	648,695,623

2

Table 3: Plastic Mains Weighted Cost per Diameter

PLASTIC MAINS

Line No.	Diameter Inches	Diameter mm	Length in Meters	Unit Cost / Length ($/m)	Weighted Cost	Minimum Size Cost (All Pipe Valued at 60mm PE)
1	0.6	15	197,757	$ 55.68	$ 11,011,508	$ 11,011,508
2	0.8	21	203	$ 55.68	$ 11,306	$ 11,306
3	1.0	26	443,538	$ 55.68	$ 24,697,053	$ 24,697,053
4	1.3	33	137	$ 55.68	$ 7,604	$ 7,604
5	1.7	42	5,975,607	$ 55.68	$ 332,733,433	$ 332,733,433
6	1.9	48	73	$ 55.68	$ 4,058	$ 4,058
7	2.4	60	4,631,215	$ 55.68	$ 257,875,085	$ 257,875,085
8	2.9	73	6	$ 102.29	$ 639	$ 348
9	3.5	88	1,016,225	$ 102.29	$ 103,950,653	$ 56,585,374
10	4.0	101	2	$ 102.29	$ 219	$ 119
11	4.5	114	1,054,252	$ 102.29	$ 107,840,518	$ 58,702,816
12	6.6	168	456,233	$ 219.22	$ 100,013,255	$ 25,403,962
13	8.6	219	56,610	$ 219.22	$ 12,409,705	$ 3,152,139
14	10.7	273	3	$ 219.22	$ 636	$ 162
15	12.7	323	2	$ 219.22	$ 443	$ 112
16	16.0	406	0		$ -	$ -
17	18.0	457	0		$ -	$ -
18	20.0	508	0		$ -	$ -
19	24.0	609	0		$ -	$ -
20	30.0	762	0		$ -	$ -
21	36.0	914	0		$ -	$ -
22	42.0	1066	0		$ -	$ -
25	**TOTAL**		**13,831,863**		**950,556,114**	**770,185,079**

1.2 *PURPOSE OF PEAK LOAD CARRYING CAPACITY STUDY*

In the Minimum System Study the proportion of costs determined to be customer related is overstated since the customer related portion also has the ability to carry some demand. As a result an adjustment to account for the PLCC of the minimum system is required.

The PLCC adjustment involves the FEI System Capacity Planning Department determining the theoretical capacity of each distribution system in the Province assuming a 60 mm (2 inch) main diameter. The 60 mm main diameter is the minimum size normally installed by the Company as specified by the FEI installation standard[1]. The capacities of the minimum sized distribution systems are then divided by the number of customers served by each distribution system and an average minimum system capacity per customer (the "PLCC Adjustment") is calculated. This PLCC Adjustment is then multiplied by the number of customers in each rate class, and the corresponding amount is subtracted from the peak demand for that rate class to get the PLCC

[1] Appendix 6-6

adjusted peak demand. This PLCC adjusted peak demand is then used to allocate the demand related costs for the Distribution function.

The Minimum System approach with PLCC Adjustment more closely matches the theoretical demand and customer related components of the distribution system, and is important to consider with the increase in the Company's minimum installation size of mains to 60 mm.

1.3 *PLCC ADJUSTMENT*

Table 4 presents the total PLCC Adjustment for the FEI (*0.205 GJ/day/customer*) and details associated with the PLCC calculation, which was calculated through the following steps:

1. The System Planning Department calculates the load capacity of each distribution network in the Province for the Amalgamated Entity assuming only 60 mm mains are used.
2. Since each network serves a different number of customers, the average system capacity is calculated by summing the network capacities and dividing by the total number of customers.

Table 4: PLCC Summary – Capacity Calculation of Each Distribution System with 60 mm Mains

Network Area Model	Design Degree Day	Heating Value (MJ/m³)	Network Capacity for PLCC (m³/h)	Customers	Total Network Capacity (GJ/d)
Coquitlam	31.0	38.601	11,162	55,810	10,341
N. Van.-W. Van.	31.0	38.601	8,623	45,591	7,988
Richmond	31.0	38.601	5,837	48,645	5,408
700 kPa - Annacis	31.0	38.601	1,035	681	959
700 kPa - Metro	31.0	38.601	1,502	1,043	1,391
Squamish-Brackendale	35.0	38.601	1,207	4,311	1,118
Vancouver-Burnaby-New West	31.0	38.601	28,372	158,494	24,962
Whistler	41.3	38.601	503	2,875	466
Chilliwack	38.0	38.601	3,924	29,956	3,635
Del-Abb	31 & 34	38.601	34,632	231,803	32,084
Hope	38.0	38.601	844	2,612	782
Kent	38.0	38.601	989	2,651	916
Maple Ridge	31.0	38.601	6,823	28,913	6,321
Mission	34.0	38.601	2,830	11,128	2,622
100 Mile-Clinton	55.0	38.241	2,836	4,836	2,603
Cache Creek-Ashcroft	49.0	38.241	1,825	1,378	1,675
Chetwynd	60.0	38.241	1,201	1,483	1,102
Fort Nelson	62.0	37.559	3,261	2,496	2,939
Greater Kamloops	49.0	38.241	13,489	34,856	12,380
Greater Salmon Arm	45.0	38.008	5,894	12,564	5,376
Hudson Hope	60.0	38.241	978	388	898
Mackenzie	60.0	38.241	984	1,741	903
Merritt-Logan Lake	49.0	38.241	3,559	4,588	3,267
Prince George-Hixon	58.0	38.241	7,890	30,580	7,241
Quesnel	57.0	38.241	2,819	7,949	2,587
Revelstoke	43.0	93.540	127	1,647	285
Williams Lake	55.0	38.241	2,364	7,387	2,170
Castlegar	40.0	37.990	2,884	4,629	2,630
Central Kootenay	40.0	37.990	2,685	7,777	2,448
Cranbrook-Kimberley	51.0	37.990	4,400	13,553	4,012
Creston	40.0	37.990	1,146	3,098	1,045
East Kootenay	51.0	37.990	1,296	6,848	1,182
Greater Kelowna	45.0	38.008	11,689	60,850	10,662
Nelson	40.0	37.990	459	5,310	418
North Okanagan	45.0	38.008	6,923	26,403	6,315
Princeton	45.0	38.008	889	1,532	811
South Okanagan	40.0	38.008	5,035	23,616	4,593
West Kootenay	40.0	37.990	3,139	3,566	2,862
Campbell River and Comox-Courtenay-Cumberland	32.4 & 28.5	38.601	5,800	18,711	5,374
Chemainus-Crofton	30.4	38.601	655	1,284	607
CRD-Victoria	28.7	38.601	9,172	44,405	8,498
Duncan-Shawnigan Lake	30.4	38.601	1,066	5,610	987
Gibson-Roberts Creek-Sechelt	28.6	38.601	1,998	6,468	1,851
Ladysmith	30.4	38.601	1,010	1,906	936
Nanaimo-Harmac	30.4	38.601	4,104	17,098	3,802
Parksville-Qualicum	30.4	38.601	1,599	8,885	1,482
Port Alberni	30.4	38.601	1,408	3,274	1,304
Powell River	28.6	38.601	2,292	3,696	2,123
				1,004,925	**206,360**

Average consumption per Customer (Average GJ/d Customer) **0.205**

1.4 *SUMMARY*

The Minimum System study with PLCC Adjustment classifies costs associated with distribution mains into customer and demand related components. Along with the use of the PLCC Adjustment, the two studies produce results that closely match the theoretical demand and customer related components of the distribution system.

Appendix 6-6

SIZING OF DISTRIBUTION PIPE STANDARDS

Sizing of Distribution Pipe - Mains and Services

DOCUMENT NUMBER: **1345**
DOCUMENT TYPE: **SPECIFICATION**
Owner: **Loge, Andrew**
SML: **Penner, Terry**
CATEGORY: **ENGINEERING - DESIGN (GAS) - DISTRIBUTION (LESS THAN 30% SMYS)**

Utility: **Gas**
Approved Date: **May 04, 2011**
Effective Date: **May 04, 2011**

Document History: This document replaces DES 04-01-08 on the Standards site.

Summary of Changes

This document was migrated to the CRL.

Overview

This specification describes the process used to determine the appropriate size of any new steel or polyethylene (PE) main or service line in distribution pressure (DP) service.

Audience

This document is intended for Planning and Design Technologists, System Capacity Planning Technologists, and others involved in distribution system design.

Contents

References 2
Responsibility 2
Main Sizing 2
General 2
System Improvements 3
Service Line Sizing 3
Communication and Enforcement 8
Related Information 8

References

- **IB 2008-43** Elimination of 88 mm PE pipe and restricted use of 42 mm PE Pipe

Responsibility

Planning and Design Technologists are responsible for sizing services.

System Capacity Planning Technologists are responsible for the final determination of service header size.

The System Capacity Planning Technologists are responsible for all main sizing including the following:

- evaluating alternative designs
- formulating guidelines and procedures to be used in sizing mains and services
- providing technical advice, information and direction in order to achieve consistent and standard sizing techniques
- the final determination of main size

Main Sizing

General

A new main must be sized and installed to suit the FBC (Gas) needs. For routine main extensions or replacement, Planning and Design Technologists must use the Weymouth Computer Program for preliminary sizing and budget estimating.

Planning and Design Technologists must forward preliminary MCO's and SHO's to System Capacity Planning for review to facilitate final sizing of mains.

System Capacity Planning Technologists must size the main with consideration of the following design factors:

- current and future operating pressures and adjacent system configurations
- potential renewal or integrity based replacement programs
- current and forecast loads
- Net Present Value (NPV) cost of replacing the main
- NPV cost of main extension and system improvement versus the five year net revenue
- immediate and long term (20 year) system improvement plan
- any relevant special studies

System Capacity Planning Technologists will use current hydraulic simulation software based on the principles of conservation of mass and energy for pipe sizing. Models used for sizing assessments will be newly built, or have been reviewed and assessed to be still valid, within the most recent capacity planning annual cycle.

System Capacity Planning must analyze the proposed main to determine if the proposed size, location, and operating pressure accommodate the immediate and long term (20 yr) development plan for the area. The System Capacity Planning Technologist must then provide a recommended pipe size to the Planning and Design Technologist to finalize cost estimates, route selection, and general construction planning requirements.

For main extensions, the Planning and Design Technologist must run the Economic Test using the main sizing information provided by System Capacity Planning to determine contribution requirements.

- Refer to **CUS 07-08** *Main Extensions*.

Effective Nov 3, 2008 (per IB 2008-43 Elimination of 88 mm PE pipe and restricted use of 42 mm PE Pipe) 88 mm PE is no longer being used for new installations and 42 mm PE will be restricted to single services without branches. Where these 88 mm and 42 mm material would have been selected in the past the next larger pipe size, 114 mm and 60 mm respectively, must be used.

System Improvements

For significant load additions a **Form 1425** *Load Information Memo* (LIM) must be forwarded to System Capacity Planning to confirm existing and proposed main sizing. Refer to **CRL #1341** *New Loads and Changes to Existing Loads* for further details.

Where a potential new customer requires an extension, and the extension “triggers” a system improvement, System Capacity Planning will size the system improvement. The sizing of the system improvement will depend on customer load demand and future development plans for the surrounding area.

Service Line Sizing

Planning and Design Technologists will use the CAFÉ application to determine the service size. CAFÉ relies on the Weymouth equation to determine the service size. The current process for using the CAFÉ Pipe Sizing Calculator is available in the Install Centre Knowledge Base and is included below.

To determine the size of the service line, proceed as follows:

1. Determine the equivalent length of the proposed service in metres.
   - Use Table 1 when a PE service with standard parts is installed. If other than a standard PE service, add the equivalent lengths in Table 2 and Table 3 to the total service length.

2. Estimate the load the service will be required to supply in cubic metres per hour using the Load Diversity Chart (Figure 2).
3. Use a main pressure of 70 kPa to determine the service size except when:
   - sizing for an industrial meter set, then use 140 kPa (70kPa for propane)
   - sizing a line pressure meter set, in which case, the main pressure must be provided by the System Capacity Planning Manager

4. Follow the CAFÉ Pipe sizing process that follows.

NOTE: When sizing larger commercial/industrial service applications, contact System Capacity Planning for load diversity and/or alternate main pressure recommendations.

Figure 1: Calculating Pipe Size

Title

Title: Calculating Pipe Size

Role:

- OSR, IC1, IC2, IC1 Workleader

Purpose:

- To describe how the pipe size calculator works in CAFE
- To explain how to populate a chosen pipe size in the variant questions of the service product.

Prerequisite:

- A Project or Scenario must be created in CAFE.
- An Attachment Service Product must be added to the Project/Scenario.
- The Attachment must be on a Natural Gas DP system.
- The User must be on the Variant Questions tab of the Service Project.

Step	Action / Desk level Procedure	Details/Notes/Context
1.	**The pipe size calculator is designed to recommend a pipe size based on the flow rate, upstream pressure and pipe length of the attachment. It uses the Weymouth Calculation. This is accurate for attachments on Natural Gas DP systems. Propane and LP systems will need to be calculated separately.** **Open the Pipe Size Calculator Window.** • From the Variants tab, click on the Icon	The pipe size calculator is built in for when you are unsure or want to confirm a new service pipe size. If you have a pipe size determined, you can select it from the pull down in the variant questions

FIELD	DEFINITION	Details/Notes/Context
Flow Rate	Default is Total Connected Load of all premises on the attachment. Change to Diversified Load when required. Can be entered in BTU/h or m^3/h.	
Upstream Pressure (kPa) Minimum Pressure on LIM Report	Pressure in the Gas Main at the tie-in of the service. Received from System Capacity Planning via the Load Information Memo (LIM)	NOTE: Upstream Pressure must be between 69kPa and 9999 kPa. This formula is not accurate for Propane and Low Pressure Systems
Max Allowable Drop (kPa)	10 KPA for New 35 KPA for Existing	
Pipe Length (m)	Length of service from the tie-in location to the gas meter	NOTE: The Pipe Length doesn't automatically take into account equivalent pipe lengths for fittings, bends etc. This field can be overwritten with a length that includes them.
Equivalent Pipe Lengths		*Link to Equivalent Lengths Table*
Delta Pressure (kPa)	Maximum Allowable Change in Pressure (as chosen by the user)	
Pipe Material	Radio Button. Choose PE or Steel for Service Pipe Size.	

Step	Action / Desk level Procedure	Details/Notes/Context
2.	**Enter in Data for Calculation** **Rules:** • Flow, Pipe Length and Delivery Pressure will be populated if those fields are filled out in the variant questions. • Flow, Pipe Length and Upstream Pressure require numeric values. • Delivery Pressure is a pull-down and will default to 1.75 kPa if it is not populated from the variant questions. • Pipe Material is two radio buttons and will default to PE if it is not populated from the variant questions.	

Title

	Results: The Pipe Size and Pressure table below will populate as you enter or edit the data.		
1.	**View calculation results and select a pipe size.** The pipe size and pressure table updates automatically as you update the entry fields.		
	FIELD	**DEFINITION**	
	Pipe Size	Service Pipe Size	
	Downstream Pressure	Pressure at Meter (Service Side)	
	?P^2	Change in Pressure from Main to Meter	Minimum pressure drop allowed in PE on a existing service up to 35kPa on a new pipe up to 10kPa
	Message	Pipe Size Selection Note.	The message field recommends to you what pipe size to select given what you have entered. Possible messages are: -Pipe Size is not available! -Recommended -Pressure Change is too big!
	• Click on the line item of the pipe size you are selecting. • Click on the Icon. **Results:** The selected pipe size will populate in the variant questions.		NOTE: Although the calculator recommends the pipe size, it does not control the choice. You are able to select any available size if you feel it is justified.

NOTE: Please view PDF if figure is difficult to read.

Figure 2: Load Diversity Chart

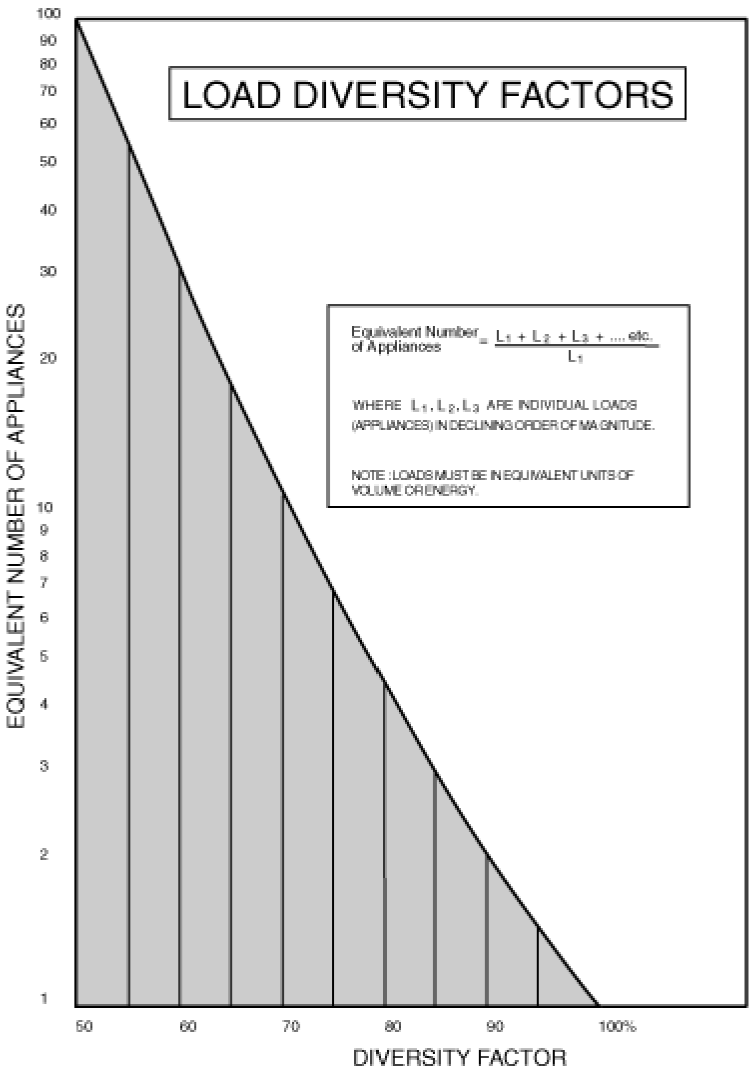


Table 1: Equivalent Lengths of Components for a Standard PE Service

Services (mm	Equivalent Length (m)
15	6
26	9
42	30

Table 2: Equivalent Lengths of Fittings

	Pipe Sizes (mm)					
	114	88	60	42	26	15
PE Fittings						
tee (flow through run)	1.9	1.5	1.0	0.7	1.5	0.2
tee (flow through branch)	5.7	4.4	3.0	2.1	1.2	0.7
90 degree elbow	5.4	4.2	2.8	1.9	1.2	0.6
45 degree elbow	1.6	1.2	n/a	n/a	n/a	n/a
PE valve	7.0	6.0	5.0	4.0	1.6	0.5
15-26 riser	n/a	n/a	n/a	n/a	36.3	1.5
26-26 riser	n/a	n/a	n/a	12.8	1.5	1.0
42-42 riser	n/a	n/a	12.0	1.5	1.0	1.0
Steel Fittings						
tee (flow through run)	2.1	1.6	1.1	0.7	0.4	0.3
tee (flow through branch)	6.3	4.9	3.1	2.1	1.3	0.9
90 degree elbow	3.1	2.4	1.6	1.1	0.6	0.5
45 degree elbow	1.7	1.3	0.8	0.6	0.3	0.2
NST No-Blo Service Tee	n/a	n/a	20.7	20.7	9.8	9.8
FST Flanged Stopper Tee	30.5	24.4	n/a	n/a	n/a	n/a

Table 3: Equivalent Lengths of Electro and Butt Fusion Poly Tapping Tees

Saddle Size (mm)	Outlet Size (mm)	Equivalent Length (m)*
42	15	2.1
42	26	3.7
60	15	2.1
60	26	3.7
60	42	14.8
60	60	23.5
88 and larger	15	2.1
88 and larger	26	3.7
88 and larger	42	14.8
88 and larger	60	19.8

* greater of calculated or vendor provided values

Communication and Enforcement

As outlined as per the specification above.

Related Information

Related Policies:

- 1341 New Loads and Changes to Existing Loads

Related Specifications:

- 1238 Main Extensions
- 1696 Distribution System Piping Design
- 1344 Distribution System Set and Delivery Pressures

Other References:

- Form 1425 Load Information Memo (LIM)

Appendix 6-7

DETAILED LOAD FACTOR CALCULATIONS

Detailed Load Factor Calculations

As discussed in Section 6.3.6.1 of the Application FEI uses the three-year average load factor to derive the Load Factor Adjusted Annual Volume (or coincident peak day demand) for the heat sensitive rate schedules to allocated demand-related costs in the COSA. The following content reiterates the process as described in section 6.3.6.1 and provides supporting details for the derivation of the load factor for RS 1 in the Lower Mainland.

Load factors are calculated in the following manner each year as FEI is preparing for its Quarter 4 Gas Cost filing where FEI requests approval of its Storage & Transport (Midstream) charges for the upcoming year, as such the data that FEI uses in the first step of the calculation is a mix of end of year 2014 and beginning of year 2015 consumption and temperatures to calculate the temperature vs. consumption regression equation. The details below are for Lower Mainland RS 1 unless otherwise noted.

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[1] 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.

Year	Month Number	Monthly Average Temperature	Monthly Actual Consumption	Days in Month	Daily Actual Use Rate
(1)	(2)	(3)	(4)	(5)	(6)
2014	9	15.86	2.81	30	0.09
2014	10	13.04	5.13	31	0.17
2014	11	5.74	11.37	30	0.38
2014	12	4.90	13.39	31	0.43
2015	1	5.58	12.95	31	0.42
2015	2	7.36	9.07	28	0.32
2015	3	8.43	8.73	31	0.28
2015	4	9.16	7.51	30	0.25
2015	5	14.66	3.83	31	0.12
2015	6	17.89	2.67	30	0.09

<u>Parameters for a linear regression equation</u>

Intercept: 0.5373 = Excel function INTERCEPT using column (G) as known y's and column (3) as known x's

Slope: (0.0275) = Excel function SLOPE using column (G) as known y's and column (3) as known x's

<u>Notes</u>

Column (4) equals the monthly average consumption of an RS 1 customer in the Lower Mainland

Column (6) equals column (4) divided by column (5)

This method is creating a regression equation that determines how daily consumption (column 6) relates to daily temperature (column 3)

[1] July and August are excluded

b. Enter the regional design day temperature into the estimated linear models to establish the peak day demand for each region and rate schedule.

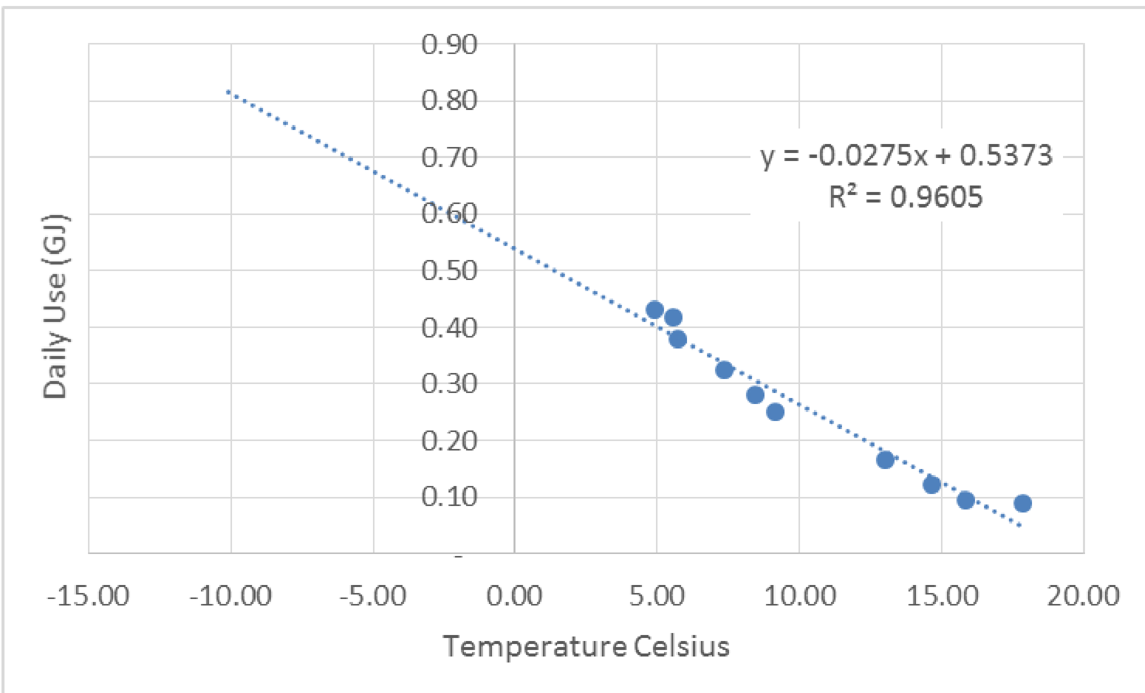
Peak Day Temp:	Intercept	Slope
(9.40)	0.5373	(0.0275)

Peak Day Demand Equation

Peak Day Demand = 0.5373 + (-9.4 x -0.0275)

Peak Day Demand: 0.7954

Figure 1: Graph of Daily Consumption vs. Daily Temperature with regression line



2) Calculate the **Average Daily Consumption** for each region and rate schedule:

a. Rate schedules 1/2/3/23:

i. The Average Daily Consumption is the normalized[2] annual actual use per customer (UPC) divided by 365 days/year.

Month / Year	Normal Monthly UPC
Jan-15	14.9
Feb-15	11.7
Mar-15	10.5
Apr-15	7.6
May-15	4.9
Jun-15	3.8
Jul-15	2.8
Aug-15	2.4
Sep-15	3.1
Oct-15	6.3
Nov-15	10.8
Dec-15	15.3
Total	94.2
Days	365
Avg Normal Daily UPC	**0.258**

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

Load Factor = Average Daily Consumption / Peak Day Demand

Load Factor = **0.258 / 0.7954**

Load Factor = **32.4%**

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

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.

Region	RS 1 LF by Region	Customer Weighting	Weighted LF
Lower Mainland	**32.4%**	61.3%	19.9%
Inland	32.0%	24.7%	7.9%
Columbia	34.2%	2.4%	0.8%
Vancouver Island	36.1%	11.4%	4.1%
Whistler	34.3%	0.3%	0.1%
Total		**100.0%**	**32.8%**

	2013	2014	2015	Three Year Average
RS 1 WAvg Load Factor	29.6%	31.3%	32.8%	**31.2%**

Rate Schedule 1 three year average load factor of 31.2%, along with the load factor of other heat sensitive rate schedules, can be found in Table 6-13 of the application.

Appendix 6-8

CUSTOMER WEIGHTING AND CUSTOMER ADMINISTRATION FACTOR STUDY RESULTS

CUSTOMER WEIGHTING FACTOR STUDY

PURPOSE OF CUSTOMER WEIGHTING FACTOR STUDY

To allocate customer related costs, customer weighting factors must be developed and assigned to each rate schedule. Weighting factors are estimated values indicating the total relative value of meter and service assets or customer administration costs associated with a specific rate schedule as compared to other rate schedules. For the purposes of this analysis, weighting factors were calculated for each rate schedule relative to the residential rate schedule as it represents the lowest cost per customer rate schedule[1].

Two types of customer weighting factors have been calculated:

1. Customer Weighting Factors for Meters and Services: This weighting factor examines the various types of meters and services used throughout FEI and uses current costs associated with meters and services for each customer group. These factors are used to weight customers for allocation of meter and service related costs to the various rate schedules.

2. Customer Weighting Factors for Customer Administration and Billing: Large customers generally require a greater level of administrative effort or customer service than the average residential customer, therefore customer weighting factors are required to properly allocate customer administration, marketing and billing related costs to the various rate schedules.

CUSTOMER WEIGHTING FACTORS

The following tables present the customer weighting factors for FEI for both Meters and Services, and Customer Administration & Billing.

[1] The residential rate schedule has historically been used by FEI as the base weighting factor since the average cost for meter and service equipment is lowest for the residential class. The customer weighting factor study results for this application support the continuation of this method.

Table 1: FEI Customer Weighting Factors for Meters & Services

Rate schedule	2016 Weighting Factors
Rate 1 - Residential	1.0
Rate 2 - Small Commercial	1.7
Rate 3 - Large Commercial	7.0
Rate 4 - Seasonal	13.6
Rate 5 - General Firm	11.1
Rate 6 - NGV Service	13.3
Rate 7 - General Interruptible	132.5
Rate 22 - Large Industrial Interruptible	49.9
Rate 23 - Large Commercial Transportation	10.3
Rate 25 - General Firm Transportation	17.6
Rate 27 - General Interruptible	46.2

Table 2: FEI Customer Weighting Factors for Administration & Billing

Rate schedule	2016 Weighting Factors
Rate 1 - Residential	1.0
Rate 2 - Small Commercial	1.0
Rate 3 - Large Commercial	1.2
Rate 4 - Seasonal	0.9
Rate 5 - General Firm	43.0
Rate 6 - NGV Service	43.0
Rate 7 - General Interruptible	43.0
Rate 22 - Large Industrial Interruptible	75.0
Rate 23 - Large Commercial Transportation	75.0
Rate 25 - General Firm Transportation	75.0
Rate 27 - General Interruptible	75.0

Appendix 6-9

2013 TEST YEAR COSA FINANCIAL SCHEDULES

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
SUMMARY (000's)

Schedule 1

L.No.	Particulars	Reference	Total	RATE 1	RATE 2	RATE 4 [2]	RATE 6	RATE 22 [2] NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27 [2]
1	**REVENUES**										
2	Total Revenues at Proposed 2013 FEI Rates	line 3 + line 4	**$ 1,292,794**	**$ 795,934**	**$ 241,068**	**$ 1,074**	**$ 504**	**$ 11,954**	**$ 187,190**	**$ 46,576**	**$ 8,493**
3	Revenue Margin at Proposed 2013 FEI Rates [4]		$ 669,773	$ 414,446	$ 110,258	$ 314	$ 249	$ 11,954	$ 89,436	$ 34,682	$ 8,434
4	Total Cost of Gas [3]		$ 623,020	$ 381,488	$ 130,810	$ 761	$ 255	$ -	$ 97,754	$ 11,894	$ 58
5											
6	**COST OF SERVICE**										
7	Total Utility Cost of Service	line 8 + line 9	**$ 1,351,981**	**$ 891,207**	**$ 239,820**	**$ 812**	**$ 467**	**$ 967**	**$ 178,004**	**$ 39,336**	**$ 1,369**
8	Cost of Service Margin		$ 728,961	$ 509,719	$ 109,009	$ 51	$ 212	$ 967	$ 80,250	$ 27,442	$ 1,311
9	Total Cost of Gas [3]		$ 623,020	$ 381,488	$ 130,810	$ 761	$ 255	$ -	$ 97,754	$ 11,894	$ 58
10											
11	**SURPLUS / DEFICIT**										
12	Total Surplus / Deficit	line 2 - line 7	**$ (59,187)**								
13	% increase to Equal Allocated Cost		8.8%								
14											
15	**REVENUES (adjusted to equal COS)**										
16	Total Adjusted Revenues at Proposed 2013 FEI Rates	line 17 + line 9	**$ 1,351,981**	**$ 832,559**	**$ 250,812**	**$ 1,102**	**$ 526**	**$ 13,010**	**$ 195,093**	**$ 49,641**	**$ 9,238**
17	Total Adjusted Revenue Margin at Proposed 2013 FEI Rates	line 3 x line 13	$ 728,961	$ 451,071	$ 120,001	$ 341	$ 272	$ 13,010	$ 97,339	$ 37,747	$ 9,180
18											
19	REVENUES (adjusted for R/C RATIOS) [1]		**$ 1,474,599**	**$ 832,559**	**$ 250,812**	**$ 1,102**	**$ 526**	**$ 13,010**	**$ 233,741**	**$ 109,766**	**$ 33,083**
20	COST OF SERVICE (adjusted for R/C RATIOS) [1]		**$ 1,474,599**	**$ 891,207**	**$ 239,820**	**$ 812**	**$ 467**	**$ 967**	**$ 216,652**	**$ 99,461**	**$ 25,214**
21											
22	**REVENUE TO COST RATIO**										
23	Revenue to Cost Ratio	line 19 / line 20	**100%**	**93.4%**	**104.6%**		**112.7%**		**107.9%**	**110.4%**	
24											
25	**REVENUE REBALANCING**										
26	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Total Revenues at Proposed Rates [1]	line 28 + line 9	**$ 1,474,599**	**$ 832,559**	**$ 250,812**	**$ 1,102**	**$ 526**	**$ 13,010**	**$ 233,741**	**$ 109,766**	**$ 33,083**
28	Total Revenue Margin at Proposed Rates	line 17 + line 26	$ 728,961	$ 451,071	$ 120,001	$ 341	$ 272	$ 13,010	$ 97,339	$ 37,747	$ 9,180
29											
30	**PROPOSED REVENUE TO COST RATIO**										
31	Revenue to Cost Ratio at Proposed Rates	line 27 / line 20	**100.0%**	**93.4%**	**104.6%**		**112.7%**		**107.9%**	**110.4%**	

Note:
1. The revenues (line 27 and line 19) and cost of service (line 20) include the imputed COG number for Rate 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios.
   Please note that Rates 23, 25 and 27 do not pay for commodity and midstream charges.
2. Rate 4 is a seasonal service and Rates 22 and Rate7/27 are interruptible customer classes. The revenue to cost ratio for Rate 4, Rate 22 and Rate 7/27 are not shown in the schedule above as these rate classes do not drive system capacity additions and therefore, no demand-related costs are allocated to these customer classes in the COSA Study.
3. Cost of Gas forecast is based on five-day average of the November 1, 2, 3, 4, and 7, 2011 forward prices, and which reflect the forward prices utilized in the various FEU 2011 Fourth Quarter Gas Cost reports.
4. Revenue Margin includes UAF allocation to rate classes.

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
FUNCTIONALIZATION (000's)

Schedule 2

L.No.	Particulars	Total	Gas Supply Operations	LNG Storage Tilbury	LNG Storage Mt. Hayes	Transmission	Transmission SCP	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense	$ 243,770	$ -	$ 2,609	$ 4,236	$ 41,385	$ 7,537	$ 100,365	$ 5,371	$ 82,267
2	BCH Capacity Right	$ 244	$ -	$ -	$ -	$ 244	$ -	$ -	$ -	$ -
3	Property & Sundry Taxes	$ 61,924	$ -	$ 377	$ 1,076	$ 16,378	$ 5,621	$ 38,472	$ -	$ -
4	Depreciation Expense	$ 171,007	$ -	$ 2,349	$ 7,050	$ 34,157	$ 9,766	$ 117,684	$ -	$ -
5	Amortization Expense	$ 12,458	$ (2)	$ 49	$ 158	$ 8,245	$ (1,888)	$ 1,359	$ 4,474	$ 63
6	Other Operating Revenue	$ (77,908)	$ -	$ -	$ (18,039)	$ (38,070)	$ (14,827)	$ (4,412)	$ -	$ (2,560)
7	Other Earned Return Provisions	$ (97)	$ -	$ (1)	$ (4)	$ (24)	$ (8)	$ (59)	$ -	$ -
8	Income Tax	$ 36,742	$ -	$ 502	$ 1,581	$ 9,276	$ 2,907	$ 22,477	$ -	$ -
9	Earned Return	$ 280,821	$ -	$ 3,841	$ 12,081	$ 70,893	$ 22,215	$ 171,791	$ -	$ -
10	**Total Cost of Service Margin**	**$ 728,961**	**$ (2)**	**$ 9,726**	**$ 8,139**	**$ 142,484**	**$ 31,322**	**$ 447,676**	**$ 9,845**	**$ 79,770**
11										
12	Cost of Gas - Commodity	$ 459,919	$ 459,919	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Cost of Gas - Midstream	$ 163,102	$ 163,102	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	**Total Utility Cost of Service**	**$ 1,351,981**	**$ 623,018**	**$ 9,726**	**$ 8,139**	**$ 142,484**	**$ 31,322**	**$ 447,676**	**$ 9,845**	**$ 79,770**

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
RATE BASE SUMMARY - CLASSIFICATION (000's)

Schedule 3

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Plant in Service										
2	**Total Gas Plant in Service**		**5,204,738**	**3,521,746**	**847,992**	**293**	**751**	**5,564**	**617,168**	**207,357**	**3,867**
3		Demand	2,955,093	1,616,324	593,090	-	394	4,632	547,402	193,250	-
4		Customer	2,249,645	1,905,422	254,901	293	357	932	69,766	14,107	3,867
5		Energy	-	-	-	-	-	-	-	-	-
6	**Total Accumulated Depreciation**		**(1,422,596)**	**(958,137)**	**(232,142)**	**(64)**	**(190)**	**(1,583)**	**(171,521)**	**(58,131)**	**(829)**
7		Demand	(838,887)	(457,668)	(168,711)	-	(112)	(1,383)	(155,950)	(55,061)	-
8		Customer	(583,709)	(500,469)	(63,431)	(64)	(78)	(199)	(15,570)	(3,070)	(829)
9		Energy	-	-	-	-	-	-	-	-	-
10	**TOTAL Net Plant**		**3,782,142**	**2,563,609**	**615,850**	**229**	**561**	**3,981**	**445,647**	**149,226**	**3,038**
11		Demand	2,116,206	1,158,656	424,379	-	282	3,248	391,452	138,189	-
12		Customer	1,665,935	1,404,953	191,471	229	279	733	54,196	11,037	3,038
13		Energy	-	-	-	-	-	-	-	-	-
14											
15	Contribution In Aid of Construction										
16	**Total CIAC**		**(425,839)**	**(288,967)**	**(69,129)**	**(24)**	**(62)**	**(493)**	**(50,049)**	**(16,793)**	**(322)**
17		Demand	(238,428)	(130,233)	(47,894)	-	(32)	(415)	(44,237)	(15,618)	-
18		Customer	(187,411)	(158,735)	(21,235)	(24)	(30)	(78)	(5,812)	(1,175)	(322)
19		Energy	-	-	-	-	-	-	-	-	-
20	**Total Accumulated Amortization**		**118,407**	**81,795**	**18,807**	**8**	**17**	**130**	**13,169**	**4,380**	**99**
21		Demand	60,595	32,829	12,257	-	8	106	11,376	4,018	-
22		Customer	57,812	48,966	6,550	8	9	24	1,793	363	99
23		Energy	-	-	-	-	-	-	-	-	-
24	**Total Net Contribution**		**(307,433)**	**(207,172)**	**(50,322)**	**(17)**	**(44)**	**(362)**	**(36,880)**	**(12,412)**	**(223)**
25		Demand	(177,833)	(97,403)	(35,637)	-	(24)	(309)	(32,861)	(11,600)	-
26		Customer	(129,599)	(109,769)	(14,685)	(17)	(21)	(54)	(4,019)	(813)	(223)
27		Energy	-	-	-	-	-	-	-	-	-
28											
29	Work in Progress, no AFUDC		**19,418**	**12,366**	**3,386**	**1**	**3**	**23**	**2,702**	**928**	**9**
30		Demand	14,074	7,840	2,780	-	2	21	2,536	895	-
31		Customer	5,344	4,527	606	1	1	2	166	34	9
32		Energy	-	-	-	-	-	-	-	-	-
33											
34	Unamortized Deferred Charges										
35	**Total Unamortized Deferred Charges - Rate Base**		**68,411**	**32,207**	**15,080**	**10**	**158**	**148**	**15,507**	**5,325**	**(24)**
36		Demand	86,025	49,469	16,437	-	155	155	14,650	5,158	-
37		Customer	(25,988)	(22,323)	(3,094)	(4)	(2)	(7)	(520)	(13)	(25)
38		Energy	8,374	5,061	1,737	14	4	-	1,378	180	1
39											
40	Cash Working Capital		**10,310**	**6,727**	**1,718**	**6**	**4**	**8**	**1,440**	**391**	**15**
41		Demand	3,537	1,965	700	-	0	5	640	226	-
42		Customer	3,364	2,701	311	0	2	3	240	92	15
43		Energy	3,410	2,060	707	6	2	-	561	73	0
44											
45	Other Working Capital										
46	**Total Other Working Capital**		**101,420**	**56,054**	**20,485**	**(0)**	**9**	**170**	**18,325**	**6,417**	**(41)**
47		Demand	108,360	61,464	21,048	-	14	179	18,970	6,685	-
48		Customer	(6,940)	(5,410)	(563)	(0)	(5)	(8)	(644)	(268)	(41)
49		Energy	-	-	-	-	-	-	-	-	-
50											
51	LILO, Capital Efficiency Mechanism, Others		**(1,150)**	**(867)**	**(162)**	**(0)**	**(0)**	**(1)**	**(91)**	**(28)**	**(1)**
52		Demand	(304)	(150)	(66)	-	(0)	(1)	(64)	(23)	-
53		Customer	(846)	(716)	(96)	(0)	(0)	(0)	(26)	(5)	(1)
54		Energy	-						-	-	-
55											
56	**Total Utility Rate Base**		**3,673,118**	**2,462,925**	**606,035**	**228**	**690**	**3,968**	**446,652**	**149,847**	**2,773**
57		Demand	2,150,064	1,181,841	429,642	-	430	3,299	395,323	139,530	-
58		Customer	1,511,270	1,273,963	173,950	209	254	668	49,391	10,063	2,771
59		Energy	11,784	7,121	2,444	19	6	-	1,938	253	1

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Schedule 4

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Operating & Maintenance Expense										
2	**Total Operating & Maintenance Expense**		**$ 243,770**	**$ 171,426**	**$ 32,251**	**$ 11**	**$ 92**	**$ 459**	**$ 28,271**	**$ 10,469**	**$ 790**
3		Demand	$ 92,873	$ 50,770	$ 18,479	$ 2	$ 13	$ 312	$ 17,087	$ 6,127	$ 85
4		Customer	$ 150,896	$ 120,656	$ 13,773	$ 10	$ 79	$ 147	$ 11,184	$ 4,342	$ 705
5		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	BCH Capacity Right		**$ 244**	**$ 138**	**$ 47**	**$ -**	**$ 0**	**$ 0**	**$ 43**	**$ 15**	**$ -**
7		Demand	$ 244	$ 138	$ 47	$ -	$ 0	$ 0	$ 43	$ 15	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Property & Sundry Taxes		**$ 61,924**	**$ 41,537**	**$ 10,218**	**$ 4**	**$ 9**	**$ 72**	**$ 7,513**	**$ 2,522**	**$ 49**
11		Demand	$ 35,519	$ 19,313	$ 7,163	$ -	$ 5	$ 60	$ 6,635	$ 2,343	$ -
12		Customer	$ 26,405	$ 22,224	$ 3,055	$ 4	$ 5	$ 12	$ 878	$ 179	$ 49
13		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Depreciation Expense		**$ 171,007**	**$ 118,801**	**$ 27,339**	**$ 17**	**$ 31**	**$ 175**	**$ 18,455**	**$ 5,962**	**$ 228**
15		Demand	$ 79,672	$ 43,929	$ 15,881	$ -	$ 11	$ 119	$ 14,585	$ 5,147	$ -
16		Customer	$ 91,334	$ 74,871	$ 11,458	$ 17	$ 21	$ 55	$ 3,869	$ 815	$ 228
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	Amortization Expense		**$ 12,458**	**$ 7,250**	**$ 2,321**	**$ 0**	**$ 44**	**$ 19**	**$ 2,083**	**$ 736**	**$ 4**
19		Demand	$ 11,526	$ 6,501	$ 2,235	$ -	$ 44	$ 18	$ 2,017	$ 711	$ -
20		Customer	$ 934	$ 751	$ 86	$ 0	$ 0	$ 1	$ 66	$ 25	$ 4
21		Energy	$ (2)	$ (1)	$ (0)	$ (0)	$ (0)	$ -	$ (0)	$ (0)	$ (0)
22	Other Operating Revenue		**$ (77,908)**	**$ (45,520)**	**$ (14,604)**	**$ (0)**	**$ (12)**	**$ (94)**	**$ (13,049)**	**$ (4,605)**	**$ (23)**
23		Demand	$ (72,103)	$ (40,810)	$ (14,045)	$ -	$ (9)	$ (89)	$ (12,680)	$ (4,469)	$ -
24		Customer	$ (5,805)	$ (4,710)	$ (559)	$ (0)	$ (3)	$ (5)	$ (369)	$ (135)	$ (23)
25		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Income Tax		**$ 36,742**	**$ 25,009**	**$ 5,953**	**$ 2**	**$ 5**	**$ 39**	**$ 4,275**	**$ 1,428**	**$ 30**
27		Demand	$ 20,212	$ 11,074	$ 4,050	$ -	$ 3	$ 32	$ 3,734	$ 1,318	$ -
28		Customer	$ 16,530	$ 13,934	$ 1,903	$ 2	$ 3	$ 7	$ 540	$ 110	$ 30
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Earned Return		**$ 280,821**	**$ 191,144**	**$ 45,500**	**$ 17**	**$ 42**	**$ 297**	**$ 32,672**	**$ 10,917**	**$ 232**
31		Demand	$ 154,480	$ 84,643	$ 30,958	$ -	$ 21	$ 241	$ 28,543	$ 10,076	$ -
32		Customer	$ 126,341	$ 106,502	$ 14,542	$ 17	$ 21	$ 56	$ 4,130	$ 842	$ 232
33		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34											
35	**Total Cost of Service Margin**		**$ 728,961**	**$ 509,719**	**$ 109,009**	**$ 51**	**$ 212**	**$ 967**	**$ 80,250**	**$ 27,442**	**$ 1,311**
36		Demand	$ 322,371	$ 175,529	$ 64,758	$ 2	$ 86	$ 693	$ 59,954	$ 21,265	$ 85
37		Customer	$ 406,592	$ 334,191	$ 44,251	$ 49	$ 126	$ 274	$ 20,297	$ 6,177	$ 1,226
38		Energy	$ (2)	$ (1)	$ (0)	$ (0)	$ (0)	$ -	$ (0)	$ (0)	$ (0)
39	Cost of Gas - Commodity		**$ 459,919**	**$ 277,933**	**$ 95,389**	**$ 761**	**$ 232**	**$ -**	**$ 75,655**	**$ 9,890**	**$ 58**
40		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42		Energy	$ 459,919	$ 277,933	$ 95,389	$ 761	$ 232	$ -	$ 75,655	$ 9,890	$ 58
43	Cost of Gas - Midstream		**$ 163,102**	**$ 103,555**	**$ 35,421**	**$ -**	**$ 23**	**$ -**	**$ 22,098**	**$ 2,004**	**$ -**
44		Demand	$ 163,102	$ 103,555	$ 35,421	$ -	$ 23	$ -	$ 22,098	$ 2,004	$ -
45		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	**Total Utility Cost of Service**		**$ 1,351,981**	**$ 891,207**	**$ 239,820**	**$ 812**	**$ 467**	**$ 967**	**$ 178,004**	**$ 39,336**	**$ 1,369**
48		Demand	$ 485,473	$ 279,084	$ 100,180	$ 2	$ 109	$ 693	$ 82,052	$ 23,268	$ 85
49		Customer	$ 406,592	$ 334,191	$ 44,251	$ 49	$ 126	$ 274	$ 20,297	$ 6,177	$ 1,226
50		Energy	$ 459,916	$ 277,931	$ 95,388	$ 761	$ 232	$ -	$ 75,655	$ 9,890	$ 58

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Schedule 5

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Supply Operations		**$ 11,784**	**$ 7,121**	**$ 2,444**	**$ 19**	**$ 6**	**$ -**	**$ 1,938**	**$ 253**	**$ 1**
2		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Energy	$ 11,784	$ 7,121	$ 2,444	$ 19	$ 6	$ -	$ 1,938	$ 253	$ 1
5											
6	LNG Storage Tilbury		**$ 41,717**	**$ 23,690**	**$ 8,120**	**$ -**	**$ 5**	**$ -**	**$ 7,321**	**$ 2,580**	**$ -**
7		Demand	$ 41,717	$ 23,690	$ 8,120	$ -	$ 5	$ -	$ 7,321	$ 2,580	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ 202,467**	**$ 114,978**	**$ 39,411**	**$ -**	**$ 26**	**$ -**	**$ 35,530**	**$ 12,522**	**$ -**
12		Demand	$ 202,467	$ 114,978	$ 39,411	$ -	$ 26	$ -	$ 35,530	$ 12,522	$ -
13		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 989,048**	**$ 560,742**	**$ 192,205**	**$ -**	**$ 126**	**$ 1,627**	**$ 173,281**	**$ 61,067**	**$ -**
17		Demand	$ 989,048	$ 560,742	$ 192,205	$ -	$ 126	$ 1,627	$ 173,281	$ 61,067	$ -
18		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											
21	Transmission SCP		**$ 305,472**	**$ 173,187**	**$ 59,363**	**$ -**	**$ 39**	**$ 502**	**$ 53,518**	**$ 18,862**	**$ -**
22		Demand	$ 305,472	$ 173,187	$ 59,363	$ -	$ 39	$ 502	$ 53,518	$ 18,862	$ -
23		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25											
26	Distribution		**$ 2,084,865**	**$ 1,561,899**	**$ 297,168**	**$ 209**	**$ 339**	**$ 1,777**	**$ 168,464**	**$ 52,237**	**$ 2,772**
27		Demand	$ 573,489	$ 287,854	$ 123,211	$ -	$ 85	$ 1,108	$ 119,062	$ 42,169	$ -
28		Customer	$ 1,511,376	$ 1,274,045	$ 173,958	$ 209	$ 255	$ 669	$ 49,402	$ 10,068	$ 2,772
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30											
31	Marketing		**$ 41,727**	**$ 24,344**	**$ 7,620**	**$ 0.1**	**$ 153**	**$ 67**	**$ 7,014**	**$ 2,503**	**$ 26**
32		Demand	$ 37,872	$ 21,390	$ 7,332	$ -	$ 149	$ 62	$ 6,610	$ 2,329	$ -
33		Customer	$ 3,855	$ 2,954	$ 289	$ 0.1	$ 3	$ 5	$ 404	$ 173	$ 26
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35											
36	Customer Accounting		**$ (3,962)**	**$ (3,036)**	**$ (297)**	**$ (0.1)**	**$ (3)**	**$ (5)**	**$ (415)**	**$ (178)**	**$ (27)**
37		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Customer	$ (3,962)	$ (3,036)	$ (297)	$ (0.1)	$ (3)	$ (5)	$ (415)	$ (178)	$ (27)
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40											
41	**Total Utility Rate Base**		**$ 3,673,118**	**$ 2,462,925**	**$ 606,035**	**$ 228**	**$ 690**	**$ 3,968**	**$ 446,652**	**$ 149,847**	**$ 2,773**
42		Demand	$ 2,150,064	$ 1,181,841	$ 429,642	$ -	$ 430	$ 3,299	$ 395,323	$ 139,530	$ -
43		Customer	$ 1,511,270	$ 1,273,963	$ 173,950	$ 209	$ 254	$ 668	$ 49,391	$ 10,063	$ 2,771
44		Energy	$ 11,784	$ 7,121	$ 2,444	$ 19	$ 6	$ -	$ 1,938	$ 253	$ 1

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Schedule 6

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Supply Operations		**$ 623,018**	**$ 381,487**	**$ 130,810**	**$ 761**	**$ 255**	**$ -**	**$ 97,754**	**$ 11,894**	**$ 58**
2		Demand	$ 163,102	$ 103,555	$ 35,421	$ -	$ 23	$ -	$ 22,098	$ 2,004	$ -
3		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Energy	$ 459,916	$ 277,931	$ 95,388	$ 761	$ 232	$ -	$ 75,655	$ 9,890	$ 58
5											
6	LNG Storage Tilbury		**$ 9,726**	**$ 5,523**	**$ 1,893**	**$ -**	**$ 1**	**$ -**	**$ 1,707**	**$ 602**	**$ -**
7		Demand	$ 9,726	$ 5,523	$ 1,893	$ -	$ 1	$ -	$ 1,707	$ 602	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ 8,139**	**$ 4,622**	**$ 1,584**	**$ -**	**$ 1**	**$ -**	**$ 1,428**	**$ 503**	**$ -**
12		Demand	$ 8,139	$ 4,622	$ 1,584	$ -	$ 1	$ -	$ 1,428	$ 503	$ -
13		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 142,484**	**$ 80,506**	**$ 27,606**	**$ 2**	**$ 18**	**$ 400**	**$ 24,970**	**$ 8,896**	**$ 85**
17		Demand	$ 142,484	$ 80,506	$ 27,606	$ 2	$ 18	$ 400	$ 24,970	$ 8,896	$ 85
18		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											
21	Transmission SCP		**$ 31,322**	**$ 17,758**	**$ 6,087**	**$ -**	**$ 4**	**$ 52**	**$ 5,488**	**$ 1,934**	**$ -**
22		Demand	$ 31,322	$ 17,758	$ 6,087	$ -	$ 4	$ 52	$ 5,488	$ 1,934	$ -
23		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25											
26	Distribution		**$ 447,676**	**$ 333,456**	**$ 64,653**	**$ 48**	**$ 77**	**$ 390**	**$ 36,990**	**$ 11,416**	**$ 646**
27		Demand	$ 126,666	$ 64,857	$ 26,812	$ -	$ 18	$ 234	$ 25,662	$ 9,083	$ -
28		Customer	$ 321,010	$ 268,599	$ 37,841	$ 48	$ 59	$ 156	$ 11,328	$ 2,333	$ 646
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30											
31	Marketing		**$ 9,845**	**$ 6,717**	**$ 1,211**	**$ 0**	**$ 47**	**$ 15**	**$ 1,308**	**$ 507**	**$ 39**
32		Demand	$ 4,033	$ 2,263	$ 776	$ -	$ 43	$ 7	$ 699	$ 246	$ -
33		Customer	$ 5,812	$ 4,454	$ 435	$ 0	$ 5	$ 8	$ 609	$ 261	$ 39
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35											
36	Customer Accounting		**$ 79,770**	**$ 61,138**	**$ 5,975**	**$ 1**	**$ 63**	**$ 110**	**$ 8,360**	**$ 3,583**	**$ 540**
37		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Customer	$ 79,770	$ 61,138	$ 5,975	$ 1	$ 63	$ 110	$ 8,360	$ 3,583	$ 540
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40											
41	**Total Utility Cost of Service**		**$ 1,351,981**	**$ 891,207**	**$ 239,820**	**$ 812**	**$ 467**	**$ 967**	**$ 178,004**	**$ 39,336**	**$ 1,369**
42		Demand	$ 485,473	$ 279,084	$ 100,180	$ 2	$ 109	$ 693	$ 82,052	$ 23,268	$ 85
43		Customer	$ 406,592	$ 334,191	$ 44,251	$ 49	$ 126	$ 274	$ 20,297	$ 6,177	$ 1,226
44		Energy	$ 459,916	$ 277,931	$ 95,388	$ 761	$ 232	$ -	$ 75,655	$ 9,890	$ 58

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study **Schedule 7**
Rate Design Filing_Common Rates_ 2013 Test Year
ALLOCATORS SUMMARY (000's)

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Billing Determinants										
2											
3	Sales Volume (TJ)		162,502	74,862	26,997	185	56	11,504	28,499	14,579	5,819
4	Midstream Sales Volume (TJ)		162,287	74,800	26,918	185	56	11,504	28,425	14,579	5,819
5	Commodity Sales Volume (TJ)		148,927	67,660	23,221	185	56	11,504	25,903	14,579	5,819
6	Average No. of Customers		971,089	877,036	85,717	18	21	21	7,384	786	105
7											
8	Cost of Service Margin		**$ 728,961**	**$ 509,719**	**$ 109,009**	**$ 51**	**$ 212**	**$ 967**	**$ 80,250**	**$ 27,442**	**$ 1,311**
9		Demand	$ 322,371	$ 175,529	$ 64,758	$ 2	$ 86	$ 693	$ 59,954	$ 21,265	$ 85
10	Unit Demand Charge ($/GJ)			$ 2.34	$ 0.87	$ 0.00	$ 0.00	$ 0.01	$ 0.80	$ 0.28	$ 0.00
11		Customer	$ 406,592	$ 334,191	$ 44,251	$ 49	$ 126	$ 274	$ 20,297	$ 6,177	$ 1,226
12	Unit Customer Charge ($/GJ)			$ 4.46	$ 0.59	$ 0.00	$ 0.00	$ 0.00	$ 0.27	$ 0.08	$ 0.02
13		Energy	$ (2)	$ (1)	$ (0)	$ (0)	$ (0)	$ -	$ (0)	$ (0)	$ (0)
14	Unit Energy Charge ($/GJ)			$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)	$ -	$ (0.00)	$ (0.00)	$ (0.00)
15											
16	Unit Cost of Service Margin ($/GJ)			**$ 6.81**	**$ 4.04**	**$ 0.28**	**$ 3.76**	**$ 0.08**	**$ 2.82**	**$ 1.88**	**$ 0.23**
17											
18	Cost of Gas - Commodity		**$ 459,919**	**$ 277,933**	**$ 95,389**	**$ 761**	**$ 232**	**$ -**	**$ 75,655**	**$ 9,890**	**$ 58**
19		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Energy	$ 459,919	$ 277,933	$ 95,389	$ 761	$ 232	$ -	$ 75,655	$ 9,890	$ 58
22	Unit Cost of Gas - Commodity ($/GJ)			**$ 4.11**	**$ 4.11**	**$ 4.11**	**$ 4.11**	**$ -**	**$ 2.92**	**$ 0.68**	**$ 0.01**
23											
24	Cost of Gas - Midstream		**$ 163,102**	**$ 103,555**	**$ 35,421**	**$ -**	**$ 23**	**$ -**	**$ 22,098**	**$ 2,004**	**$ -**
25		Demand	$ 163,102	$ 103,555	$ 35,421	$ -	$ 23	$ -	$ 22,098	$ 2,004	$ -
26		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Unit Cost of Gas - Midstream ($/GJ)			**$ 1.38**	**$ 1.32**	**$ -**	**$ 0.41**	**$ -**	**$ 0.78**	**$ 0.14**	**$ -**
28											
29	Total Utility Cost of Service		**$ 1,351,981**	**$ 891,207**	**$ 239,820**	**$ 812**	**$ 467**	**$ 967**	**$ 178,004**	**$ 39,336**	**$ 1,369**
30		Demand	$ 485,473	$ 279,084	$ 100,180	$ 2	$ 109	$ 693	$ 82,052	$ 23,268	$ 85
31		Customer	$ 406,592	$ 334,191	$ 44,251	$ 49	$ 126	$ 274	$ 20,297	$ 6,177	$ 1,226
32		Energy	$ 459,916	$ 277,931	$ 95,388	$ 761	$ 232	$ -	$ 75,655	$ 9,890	$ 58
33	Unit Cost of Service ($/GJ)			**$ 11.90**	**$ 8.88**	**$ 4.38**	**$ 8.28**	**$ 0.08**	**$ 6.25**	**$ 2.70**	**$ 0.24**
34											
35	Total Revenues @ Proposed Rates		**$ 1,351,981**	**$ 832,559**	**$ 250,812**	**$ 1,102**	**$ 526**	**$ 13,010**	**$ 195,093**	**$ 49,641**	**$ 9,238**
36	Unit Rate ($/GJ)			**$ 11.12**	**$ 9.29**	**$ 5.95**	**$ 9.33**	**$ 1.13**	**$ 6.85**	**$ 3.40**	**$ 1.59**
37											
38	Total Revenue Margin @ Proposed Rates		**$ 728,961**	**$ 451,071**	**$ 120,001**	**$ 341**	**$ 272**	**$ 13,010**	**$ 97,339**	**$ 37,747**	**$ 9,180**
39	Unit Rate ($/GJ)			**$ 6.03**	**$ 4.44**	**$ 1.84**	**$ 4.81**	**$ 1.13**	**$ 3.42**	**$ 2.59**	**$ 1.58**

Appendix 6-10

HISTORY OF GAS COSTS AND DELIVERY RATES

RS 1 Lower Mainland

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-9-08	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10
Basic Charge	$ 11.12	$ 11.16	$ 10.94	$ 10.94	$ 11.13	$ 11.13	$ 11.13	$ 11.13	$ 11.13	$ 11.99	$ 11.84	$ 11.84	$ 11.84
Delivery Charge	$ 2.781	$ 2.791	$ 2.736	$ 2.736	$ 2.783	$ 2.783	$ 2.783	$ 2.783	$ 2.783	$ 2.998	$ 2.961	$ 2.961	$ 3.179
Commodity Cost Recovery Charge	$ 9.774	$ 7.662	$ 7.662	$ 6.926	$ 6.926	$ 6.926	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953
Storage and Transport per GJ	$ 0.613	$ 0.613	$ 0.859	$ 0.859	$ 1.209	$ 1.209	$ 1.209	$ 1.209	$ 1.209	$ 0.942	$ 0.942	$ 0.942	$ 1.642

RS 1 Inland

Order Number	G-132-05	G-25-06	G-109-06	G-160-06	G-66-07	G-105-07	G-153-07	G-9-08	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09
Effective Date	1-Jan-06	1-Apr-06	1-Oct-06	1-Jan-07	1-Jul-07	1-Oct-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09
Basic Charge	$ 11.12	$ 11.16	$ 11.16	$ 10.94	$ 10.94	$ 10.94	$ 11.13	$ 11.13	$ 11.13	$ 11.13	$ 11.13	$ 11.99	$ 11.84
Delivery Charge	$ 2.781	$ 2.791	$ 2.791	$ 2.736	$ 2.736	$ 2.736	$ 2.783	$ 2.783	$ 2.783	$ 2.783	$ 2.783	$ 2.998	$ 2.961
Commodity Cost Recovery Charge	$ 9.774	$ 7.662	$ 7.662	$ 7.662	$ 7.662	$ 6.926	$ 6.926	$ 6.926	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962
Storage and Transport per GJ	$ 0.556	$ 0.556	$ 0.556	$ 0.850	$ 0.850	$ 0.850	$ 1.186	$ 1.186	$ 1.186	$ 1.186	$ 1.186	$ 0.903	$ 0.903

RS 1 Columbia

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-9-08	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10
Basic Charge	$ 11.12	$ 11.16	$ 10.94	$ 10.94	$ 11.13	$ 11.13	$ 11.13	$ 11.13	$ 11.13	$ 11.99	$ 11.84	$ 11.84	$ 11.84
Delivery Charge	$ 2.781	$ 2.791	$ 2.736	$ 2.736	$ 2.783	$ 2.783	$ 2.783	$ 2.783	$ 2.783	$ 2.998	$ 2.961	$ 2.961	$ 3.179
Commodity Cost Recovery Charge	$ 9.774	$ 7.662	$ 7.662	$ 6.926	$ 6.926	$ 6.926	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953
Storage and Transport per GJ	$ 0.642	$ 0.642	$ 0.912	$ 0.912	$ 1.265	$ 1.265	$ 1.265	$ 1.265	$ 1.265	$ 0.981	$ 0.981	$ 0.981	$ 1.681

RS 2 Mainland

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-9-08	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10
Basic Charge	$ 23.33	$ 23.42	$ 22.96	$ 22.96	$ 23.35	$ 23.35	$ 23.35	$ 23.35	$ 23.35	$ 25.15	$ 24.84	$ 24.84	$ 24.84
Delivery Charge	$ 2.328	$ 2.337	$ 2.291	$ 2.291	$ 2.330	$ 2.330	$ 2.330	$ 2.330	$ 2.330	$ 2.510	$ 2.479	$ 2.479	$ 2.643
Commodity Cost Recovery Charge	$ 9.797	$ 7.673	$ 7.673	$ 6.928	$ 6.928	$ 6.928	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953
Storage and Transport per GJ	$ 0.630	$ 0.630	$ 0.865	$ 0.865	$ 1.303	$ 1.303	$ 1.303	$ 1.303	$ 1.303	$ 0.947	$ 0.947	$ 0.947	$ 1.636

RS 1 Lower Mainland

Order Number	G-42-10	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13
Effective Date	1-Apr-10	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13
Basic Charge	$ 11.84	$ 11.84	$ 11.84	$ 11.84	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890
Delivery Charge	$ 3.179	$ 3.179	$ 3.275	$ 3.275	$ 3.559	$ 3.559	$ 3.488	$ 3.790	$ 3.663	$ 3.663
Commodity Cost Recovery Charge	$ 5.609	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272
Storage and Transport per GJ	$ 1.642	$ 1.642	$ 1.340	$ 1.340	$ 1.424	$ 1.424	$ 1.424	$ 1.274	$ 1.274	$ 1.274

RS 1 Inland

Order Number	G-74-09	G-105-09	G-141-09	G-42-10	G-106-10	G-187-10	G-105-11	G-156-11	G-177-11	G-26-12
Effective Date	1-Jul-09	1-Oct-09	1-Jan-10	1-Apr-10	1-Jul-10	1-Jan-11	1-Jul-11	1-Oct-11	1-Jan-12	1-Apr-12
Basic Charge	$ 11.84	$ 11.84	$ 11.84	$ 11.84	$ 11.84	$ 11.84	$ 11.84	$ 11.84	$ 0.3890	$ 0.3890
Delivery Charge	$ 2.961	$ 2.961	$ 3.179	$ 3.179	$ 3.179	$ 3.275	$ 3.275	$ 3.275	$ 3.559	$ 3.559
Commodity Cost Recovery Charge	$ 5.962	$ 4.953	$ 4.953	$ 5.609	$ 4.976	$ 4.568	$ 4.568	$ 4.005	$ 4.005	$ 2.977
Storage and Transport per GJ	$ 0.903	$ 0.903	$ 1.621	$ 1.621	$ 1.621	$ 1.315	$ 1.315	$ 1.315	$ 1.398	$ 1.398

RS 1 Columbia

Order Number	G-42-10	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13
Effective Date	1-Apr-10	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13
Basic Charge	$ 11.84	$ 11.84	$ 11.84	$ 11.84	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890
Delivery Charge	$ 3.179	$ 3.179	$ 3.275	$ 3.275	$ 3.559	$ 3.559	$ 3.488	$ 3.790	$ 3.663	$ 3.663
Commodity Cost Recovery Charge	$ 5.609	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272
Storage and Transport per GJ	$ 1.681	$ 1.681	$ 1.355	$ 1.355	$ 1.433	$ 1.433	$ 1.433	$ 1.248	$ 1.248	$ 1.248

RS 2 Mainland

Order Number	G-42-10	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13
Effective Date	1-Apr-10	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13
Basic Charge	$ 24.84	$ 24.84	$ 24.84	$ 24.84	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161
Delivery Charge	$ 2.643	$ 2.643	$ 2.714	$ 2.714	$ 2.928	$ 2.928	$ 2.874	$ 3.009	$ 3.006	$ 3.006
Commodity Cost Recovery Charge	$ 5.609	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272
Storage and Transport per GJ	$ 1.636	$ 1.636	$ 1.327	$ 1.327	$ 1.410	$ 1.410	$ 1.410	$ 1.265	$ 1.265	$ 1.265

Amalgamation - ALL REGIONS

RS 1 Lower Mainland												
Order Number	G-150-13/G-201-13	G-37-14	G-133-14	G-138-14/G-164-14	G-21-14/G-178-14	G-39-15	G-99-15	G-86-15/G-106-15	G-145-15	G-188-15/G-193-15	G-37-16/G-33-16	G-145-16
Effective Date	1-Jan-14	1-Apr-14	1-Oct-14	1-Nov-14	1-Jan-15	1-Apr-15	1-Jul-15	1-Aug-15	1-Oct-15	1-Jan-16	1-Apr-16	1-Oct-16
Basic Charge	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890
Delivery Charge	$ 3.741	$ 3.741	$ 3.741	$ 3.761	$ 4.216	$ 4.216	$ 4.216	$ 4.258	$ 4.258	$ 4.370	$ 4.370	$ 4.370
Commodity Cost Recovery Charge	$ 3.272	$ 4.640	$ 3.781	$ 3.781	$ 3.781	$ 2.486	$ 2.486	$ 2.486	$ 2.486	$ 1.719	$ 1.141	$ 2.050
Storage and Transport per GJ	$ 1.385	$ 1.385	$ 1.385	$ 1.385	$ 1.398	$ 1.398	$ 1.398	$ 1.398	$ 1.398	$ 1.117	$ 1.117	$ 1.117

RS 1 Inland										
Order Number	G-44-12	G-117-12	G-179-12	G-75-13/G-94-13	G-147-13	G-150-13/G-201-13	G-37-14	G-79-14	G-133-14	G-138-14/G-164-14
Effective Date	1-Jun-12	1-Oct-12	1-Jan-13	1-Jul-13	1-Oct-13	1-Jan-14	1-Apr-14	1-Jul-14	1-Oct-14	1-Nov-14
Basic Charge	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890
Delivery Charge	$ 3.488	$ 3.488	$ 3.790	$ 3.663	$ 3.663	$ 3.741	$ 3.741	$ 3.741	$ 3.741	$ 3.761
Commodity Cost Recovery Charge	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272	$ 3.272	$ 4.640	$ 4.640	$ 3.781	$ 3.781
Storage and Transport per GJ	$ 1.398	$ 1.398	$ 1.241	$ 1.241	$ 1.241	$ 1.301	$ 1.301	$ 1.301	$ 1.301	$ 1.301

RS 1 Columbia				
Order Number	G-150-13/G-201-13	G-37-14	G-133-14	G-138-14/G-164-14
Effective Date	1-Jan-14	1-Apr-14	1-Oct-14	1-Nov-14
Basic Charge	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890
Delivery Charge	$ 3.741	$ 3.741	$ 3.741	$ 3.761
Commodity Cost Recovery Charge	$ 3.272	$ 4.640	$ 3.781	$ 3.781
Storage and Transport per GJ	$ 1.288	$ 1.288	$ 1.288	$ 1.288

Amalgamation - ALL REGIONS

RS 2 Mainland												
Order Number	G-150-13/G-201-13	G-37-14	G-133-14	G-138-14/G-164-14	G-21-14/G-178-14	G-39-15	G-99-15	G-86-15/G-106-15	G-145-15	G-188-15/G-193-15	G-37-16/G-33-16	G-145-16
Effective Date	1-Jan-14	1-Apr-14	1-Oct-14	1-Nov-14	1-Jan-15	1-Apr-15	1-Jul-15	1-Aug-15	1-Oct-15	1-Jan-16	1-Apr-16	1-Oct-16
Basic Charge	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161
Delivery Charge	$ 3.064	$ 3.064	$ 3.064	$ 3.079	$ 3.411	$ 3.411	$ 3.411	$ 3.442	$ 3.442	$ 3.523	$ 3.523	$ 3.523
Commodity Cost Recovery Charge	$ 3.272	$ 4.640	$ 3.781	$ 3.781	$ 3.781	$ 2.486	$ 2.486	$ 2.486	$ 2.486	$ 1.719	$ 1.141	$ 2.050
Storage and Transport per GJ	$ 1.392	$ 1.392	$ 1.392	$ 1.392	$ 1.397	$ 1.397	$ 1.397	$ 1.397	$ 1.397	$ 1.133	$ 1.133	$ 1.133

RS 2 Inland

Order Number	G-132-05	G-25-06	G-109-06	G-160-06	G-66-07	G-105-07	G-153-07	G-9-08	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09
Effective Date	1-Jan-06	1-Apr-06	1-Oct-06	1-Jan-07	1-Jul-07	1-Oct-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09
Basic Charge	$ 23.33	$ 23.42	$ 23.42	$ 22.96	$ 22.96	$ 22.96	$ 23.35	$ 23.35	$ 23.35	$ 23.35	$ 23.35	$ 25.15	$ 24.84
Delivery Charge	$ 2.328	$ 2.337	$ 2.337	$ 2.291	$ 2.291	$ 2.291	$ 2.330	$ 2.330	$ 2.330	$ 2.330	$ 2.330	$ 2.510	$ 2.479
Commodity Cost Recovery Charge	$ 9.797	$ 7.673	$ 7.673	$ 7.673	$ 7.673	$ 6.928	$ 6.928	$ 6.928	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962
Storage and Transport per GJ	$ 0.570	$ 0.570	$ 0.570	$ 0.856	$ 0.856	$ 0.856	$ 1.279	$ 1.279	$ 1.279	$ 1.279	$ 1.279	$ 0.907	$ 0.907

RS 2 Columbia

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-9-08	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10
Basic Charge	$ 23.33	$ 23.42	$ 22.96	$ 22.96	$ 23.35	$ 23.35	$ 23.35	$ 23.35	$ 23.35	$ 25.15	$ 24.84	$ 24.84	$ 24.84
Delivery Charge	$ 2.328	$ 2.337	$ 2.291	$ 2.291	$ 2.330	$ 2.330	$ 2.330	$ 2.330	$ 2.330	$ 2.510	$ 2.479	$ 2.479	$ 2.643
Commodity Cost Recovery Charge	$ 9.797	$ 7.673	$ 7.673	$ 6.928	$ 6.928	$ 6.928	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953
Storage and Transport per GJ	$ 0.656	$ 0.656	$ 0.918	$ 0.918	$ 1.359	$ 1.359	$ 1.359	$ 1.359	$ 1.359	$ 0.986	$ 0.986	$ 0.986	$ 1.676

RS 3 Mainland

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-9-08	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10
Basic Charge	$ 124.50	$ 124.95	$ 122.48	$ 122.48	$ 124.58	$ 124.58	$ 124.58	$ 124.58	$ 124.58	$ 134.20	$ 132.52	$ 132.52	$ 132.52
Delivery Charge	$ 2.007	$ 2.014	$ 1.974	$ 1.974	$ 2.008	$ 2.008	$ 2.008	$ 2.008	$ 2.008	$ 2.163	$ 2.136	$ 2.136	$ 2.264
Commodity Cost Recovery Charge	$ 9.699	$ 7.627	$ 7.627	$ 6.916	$ 6.916	$ 6.916	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953
Storage and Transport per GJ	$ 0.559	$ 0.559	$ 0.761	$ 0.761	$ 1.115	$ 1.115	$ 1.115	$ 1.115	$ 1.115	$ 0.830	$ 0.830	$ 0.830	$ 1.289

RS 3 Inland

Order Number	G-132-05	G-25-06	G-109-06	G-160-06	G-66-07	G-105-07	G-153-07	G-9-08	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09
Effective Date	1-Jan-06	1-Apr-06	1-Oct-06	1-Jan-07	1-Jul-07	1-Oct-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09
Basic Charge	$ 124.50	$ 124.95	$ 124.95	$ 122.48	$ 122.48	$ 122.48	$ 124.58	$ 124.58	$ 124.58	$ 124.58	$ 124.58	$ 134.20	$ 132.52
Delivery Charge	$ 2.007	$ 2.014	$ 2.014	$ 1.974	$ 1.974	$ 1.974	$ 2.008	$ 2.008	$ 2.008	$ 2.008	$ 2.008	$ 2.163	$ 2.136
Commodity Cost Recovery Charge	$ 9.699	$ 7.627	$ 7.627	$ 7.627	$ 7.627	$ 6.916	$ 6.916	$ 6.916	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962
Storage and Transport per GJ	$ 0.510	$ 0.510	$ 0.510	$ 0.756	$ 0.756	$ 0.756	$ 1.096	$ 1.096	$ 1.096	$ 1.096	$ 1.096	$ 0.796	$ 0.796

RS 2 Inland

Order Number	G-74-09	G-105-09	G-141-09	G-42-10	G-106-10	G-187-10	G-105-11	G-156-11	G-177-11	G-26-12
Effective Date	1-Jul-09	1-Oct-09	1-Jan-10	1-Apr-10	1-Jul-10	1-Jan-11	1-Jul-11	1-Oct-11	1-Jan-12	1-Apr-12
Basic Charge	$ 24.84	$ 24.84	$ 24.84	$ 24.84	$ 24.84	$ 24.84	$ 24.84	$ 24.84	$ 0.8161	$ 0.8161
Delivery Charge	$ 2.479	$ 2.479	$ 2.643	$ 2.643	$ 2.643	$ 2.714	$ 2.714	$ 2.714	$ 2.928	$ 2.928
Commodity Cost Recovery Charge	$ 5.962	$ 4.953	$ 4.953	$ 5.609	$ 4.976	$ 4.568	$ 4.568	$ 4.005	$ 4.005	$ 2.977
Storage and Transport per GJ	$ 0.907	$ 0.907	$ 1.615	$ 1.615	$ 1.615	$ 1.301	$ 1.301	$ 1.301	$ 1.385	$ 1.385

RS 2 Columbia

Order Number	G-42-10	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13
Effective Date	1-Apr-10	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13
Basic Charge	$ 24.84	$ 24.84	$ 24.84	$ 24.84	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161
Delivery Charge	$ 2.643	$ 2.643	$ 2.714	$ 2.714	$ 2.928	$ 2.928	$ 2.874	$ 3.099	$ 3.006	$ 3.006
Commodity Cost Recovery Charge	$ 5.609	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272
Storage and Transport per GJ	$ 1.676	$ 1.676	$ 1.342	$ 1.342	$ 1.419	$ 1.419	$ 1.419	$ 1.239	$ 1.239	$ 1.239

RS 3 Mainland

Order Number	G-42-10	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13
Effective Date	1-Apr-10	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13
Basic Charge	$ 132.52	$ 132.52	$ 132.52	$ 132.52	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538
Delivery Charge	$ 2.264	$ 2.264	$ 2.318	$ 2.318	$ 2.483	$ 2.483	$ 2.442	$ 2.617	$ 2.543	$ 2.543
Commodity Cost Recovery Charge	$ 5.609	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272
Storage and Transport per GJ	$ 1.289	$ 1.289	$ 1.018	$ 1.018	$ 1.097	$ 1.097	$ 1.097	$ 0.999	$ 0.999	$ 0.999

RS 3 Inland

Order Number	G-74-09	G-105-09	G-141-09	G-42-10	G-106-10	G-187-10	G-105-11	G-156-11	G-177-11	G-26-12
Effective Date	1-Jul-09	1-Oct-09	1-Jan-10	1-Apr-10	1-Jul-10	1-Jan-11	1-Jul-11	1-Oct-11	1-Jan-12	1-Apr-12
Basic Charge	$ 132.52	$ 132.52	$ 132.52	$ 132.52	$ 132.52	$ 132.52	$ 132.52	$ 132.52	$ 4.3538	$ 4.3538
Delivery Charge	$ 2.136	$ 2.136	$ 2.264	$ 2.264	$ 2.264	$ 2.318	$ 2.318	$ 2.318	$ 2.483	$ 2.483
Commodity Cost Recovery Charge	$ 5.962	$ 4.953	$ 4.953	$ 5.609	$ 4.976	$ 4.568	$ 4.568	$ 4.005	$ 4.005	$ 2.977
Storage and Transport per GJ	$ 0.796	$ 0.796	$ 1.274	$ 1.274	$ 1.274	$ 0.999	$ 0.999	$ 0.999	$ 1.077	$ 1.077

RS 2 Inland

Order Number	G-44-12	G-117-12	G-179-12	G-75-13/G-94-13	G-147-13	G-150-13/G-201-13	G-37-14	G-79-14	G-133-14	G-138-14/G-164-14
Effective Date	1-Jun-12	1-Oct-12	1-Jan-13	1-Jul-13	1-Oct-13	1-Jan-14	1-Apr-14	1-Jul-14	1-Oct-14	1-Nov-14
Basic Charge	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161
Delivery Charge	$ 2.874	$ 2.874	$ 3.099	$ 3.006	$ 3.006	$ 3.064	$ 3.064	$ 3.064	$ 3.064	$ 3.079
Commodity Cost Recovery Charge	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272	$ 3.272	$ 4.640	$ 4.640	$ 3.781	$ 3.781
Storage and Transport per GJ	$ 1.385	$ 1.385	$ 1.232	$ 1.232	$ 1.232	$ 1.307	$ 1.307	$ 1.307	$ 1.307	$ 1.307

RS 2 Columbia

Order Number	G-150-13/G-201-13	G-37-14	G-133-14	G-138-14/G-164-14
Effective Date	1-Jan-14	1-Apr-14	1-Oct-14	1-Nov-14
Basic Charge	$ 0.8161	$ 0.8161	$ 0.8161	$ 0.8161
Delivery Charge	$ 3.064	$ 3.064	$ 3.064	$ 3.079
Commodity Cost Recovery Charge	$ 3.272	$ 4.640	$ 3.781	$ 3.781
Storage and Transport per GJ	$ 1.294	$ 1.294	$ 1.294	$ 1.294

RS 3 Mainland

					Amalgamation - ALL REGIONS							
Order Number	G-150-13/G-201-13	G-37-14	G-133-14	G-138-14/G-164-14	G-21-14/G-178-14	G-39-15	G-99-15	G-86-15/G-106-15	G-145-15	G-188-15/G-193-15	G-37-16/G-33-16	G-145-16
Effective Date	1-Jan-14	1-Apr-14	1-Oct-14	1-Nov-14	1-Jan-15	1-Apr-15	1-Jul-15	1-Aug-15	1-Oct-15	1-Jan-16	1-Apr-16	1-Oct-16
Basic Charge	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538
Delivery Charge	$ 2.587	$ 2.587	$ 2.587	$ 2.599	$ 2.854	$ 2.854	$ 2.854	$ 2.877	$ 2.877	$ 2.939	$ 2.939	$ 2.939
Commodity Cost Recovery Charge	$ 3.272	$ 4.640	$ 3.781	$ 3.781	$ 3.781	$ 2.486	$ 2.486	$ 2.486	$ 2.486	$ 1.719	$ 1.141	$ 2.050
Storage and Transport per GJ	$ 1.184	$ 1.184	$ 1.184	$ 1.184	$ 1.167	$ 1.167	$ 1.167	$ 1.167	$ 1.167	$ 0.940	$ 0.940	$ 0.940

RS 3 Inland

Order Number	G-44-12	G-117-12	G-179-12	G-75-13/G-94-13	G-147-13	G-150-13/G-201-13	G-37-14	G-79-14	G-133-14	G-138-14/G-164-14
Effective Date	1-Jun-12	1-Oct-12	1-Jan-13	1-Jul-13	1-Oct-13	1-Jan-14	1-Apr-14	1-Jul-14	1-Oct-14	1-Nov-14
Basic Charge	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538
Delivery Charge	$ 2.442	$ 2.442	$ 2.617	$ 2.543	$ 2.543	$ 2.587	$ 2.587	$ 2.587	$ 2.587	$ 2.599
Commodity Cost Recovery Charge	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272	$ 3.272	$ 4.640	$ 4.640	$ 3.781	$ 3.781
Storage and Transport per GJ	$ 1.077	$ 1.077	$ 0.972	$ 0.972	$ 0.972	$ 1.113	$ 1.113	$ 1.113	$ 1.113	$ 1.113

RS 3 Columbia

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-9-08	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10
Basic Charge	$ 124.50	$ 124.95	$ 122.48	$ 122.48	$ 124.58	$ 124.58	$ 124.58	$ 124.58	$ 124.58	$ 134.20	$ 132.52	$ 132.52	$ 132.52
Delivery Charge	$ 2.007	$ 2.014	$ 1.974	$ 1.974	$ 2.008	$ 2.008	$ 2.008	$ 2.008	$ 2.008	$ 2.163	$ 2.136	$ 2.136	$ 2.264
Commodity Cost Recovery Charge	$ 9.699	$ 7.627	$ 7.627	$ 6.916	$ 6.916	$ 6.916	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953
Storage and Transport per GJ	$ 0.596	$ 0.596	$ 0.817	$ 0.817	$ 1.175	$ 1.175	$ 1.175	$ 1.175	$ 1.175	$ 0.873	$ 0.873	$ 0.873	$ 1.332

RS 4 Mainland

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09	G-42-10
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10	1-Apr-10
Basic Charge	$ 412.00	$ 414.00	$ 406.00	$ 406.00	$ 413.00	$ 413.00	$ 413.00	$ 413.00	$ 445.00	$ 439.00	$ 439.00	$ 439.00	$ 439.00
Off-Peak Period*	$ 0.717	$ 0.719	$ 0.705	$ 0.705	$ 0.717	$ 0.717	$ 0.717	$ 0.717	$ 0.772	$ 0.762	$ 0.762	$ 0.827	$ 0.827
Peak Period**	$ 1.446	$ 1.451	$ 1.422	$ 1.422	$ 1.446	$ 1.446	$ 1.446	$ 1.446	$ 1.558	$ 1.539	$ 1.539	$ 1.604	$ 1.604
Commodity Cost Recovery Charge													
Off-Peak Period*	$ 9.587	$ 7.575	$ 7.575	$ 6.902	$ 6.902	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953	$ 5.609
Peak Period**	$ 9.587	$ 7.575	$ 7.575	$ 6.902	$ 6.902	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953	$ 5.609
Storage and Transport per GJ	$ 0.477	$ 0.477	$ 0.614	$ 0.614	$ 0.823	$ 0.823	$ 0.823	$ 0.823	$ 0.670	$ 0.670	$ 0.670	$ 0.960	$ 0.960

RS 4 Inland

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09	G-42-10
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10	1-Apr-10
Basic Charge	$ 412.00	$ 414.00	$ 406.00	$ 406.00	$ 413.00	$ 413.00	$ 413.00	$ 413.00	$ 445.00	$ 439.00	$ 439.00	$ 439.00	$ 439.00
Off-Peak Period*	$ 0.717	$ 0.719	$ 0.705	$ 0.705	$ 0.717	$ 0.717	$ 0.717	$ 0.717	$ 0.772	$ 0.762	$ 0.762	$ 0.827	$ 0.827
Peak Period**	$ 1.446	$ 1.451	$ 1.422	$ 1.422	$ 1.446	$ 1.446	$ 1.446	$ 1.446	$ 1.558	$ 1.539	$ 1.539	$ 1.604	$ 1.604
Commodity Cost Recovery Charge													
Off-Peak Period*	$ 9.587	$ 7.575	$ 7.575	$ 6.902	$ 6.902	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953	$ 5.609
Peak Period**	$ 9.587	$ 7.575	$ 7.575	$ 6.902	$ 6.902	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953	$ 5.609
Storage and Transport per GJ	$ 0.442	$ 0.442	$ 0.615	$ 0.615	$ 0.812	$ 0.812	$ 0.812	$ 0.812	$ 0.644	$ 0.644	$ 0.644	$ 0.950	$ 0.950

RS 3 Columbia

Order Number	G-42-10	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13
Effective Date	1-Apr-10	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13
Basic Charge	$ 132.52	$ 132.52	$ 132.52	$ 132.52	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538
Delivery Charge	$ 2.264	$ 2.264	$ 2.318	$ 2.318	$ 2.438	$ 2.438	$ 2.442	$ 2.617	$ 2.543	$ 2.543
Commodity Cost Recovery Charge	$ 5.609	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272
Storage and Transport per GJ	$ 1.332	$ 1.332	$ 1.036	$ 1.036	$ 1.109	$ 1.109	$ 1.109	$ 0.979	$ 0.979	$ 0.979

RS 4 Mainland

Order Number	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13	G-150-13/G-201-13
Effective Date	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13	1-Jan-14
Basic Charge	$ 439.00	$ 439.00	$ 439.00	$ 14.4230	$ 14.4230	$ 14.4230	$ 14.4230	$ 14.4230	$ 14.4230	$ 14.4230
Off-Peak Period*	$ 0.827	$ 0.854	$ 0.854	$ 0.940	$ 0.940	$ 0.919	$ 1.011	$ 0.973	$ 0.973	$ 1.000
Peak Period**	$ 1.604	$ 1.631	$ 1.631	$ 1.727	$ 1.727	$ 1.696	$ 1.788	$ 1.750	$ 1.750	$ 1.777
Commodity Cost Recovery Charge										
Off-Peak Period*	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272	$ 3.272
Peak Period**	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272	$ 3.272
Storage and Transport per GJ	$ 0.960	$ 0.764	$ 0.764	$ 0.839	$ 0.839	$ 0.839	$ 0.765	$ 0.765	$ 0.765	$ 0.862

RS 4 Inland

Order Number	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13	G-150-13/G-201-13
Effective Date	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13	1-Jan-14
Basic Charge	$ 439.00	$ 439.00	$ 439.00	$ 14.4230	$ 14.4230	$ 14.4230	$ 14.4230	$ 14.4230	$ 14.4230	$ 14.4230
Off-Peak Period*	$ 0.827	$ 0.854	$ 0.854	$ 0.940	$ 0.940	$ 0.919	$ 1.011	$ 0.973	$ 0.973	$ 1.000
Peak Period**	$ 1.604	$ 1.631	$ 1.631	$ 1.727	$ 1.727	$ 1.696	$ 1.788	$ 1.750	$ 1.750	$ 1.777
Commodity Cost Recovery Charge										
Off-Peak Period*	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272	$ 3.272
Peak Period**	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272	$ 3.272
Storage and Transport per GJ	$ 0.950	$ 0.749	$ 0.749	$ 0.824	$ 0.824	$ 0.824	$ 0.743	$ 0.743	$ 0.743	$ 0.812

RS 3 Columbia				
Order Number	G-150-13/G-201-13	G-37-14	G-133-14	G-138-14/G-164-14
Effective Date	1-Jan-14	1-Apr-14	1-Oct-14	1-Nov-14
Basic Charge	$ 4.3538	$ 4.3538	$ 4.3538	$ 4.3538
Delivery Charge	$ 2.587	$ 2.587	$ 2.587	$ 2.599
Commodity Cost Recovery Charge	$ 3.272	$ 4.640	$ 3.781	$ 3.781
Storage and Transport per GJ	$ 1.100	$ 1.100	$ 1.100	$ 1.100

RS 4 Mainland				Amalgamation - ALL REGIONS					
Order Number	G-37-14	G-133-14	G-138-14/G-164-14	G-21-14/G-178-14	G-39-15	G-86-15/G-106-15	G-188-15/G-193-15	G-37-16	G-145-16
Effective Date	1-Apr-14	1-Oct-14	1-Nov-14	1-Jan-15	1-Apr-15	1-Aug-15	1-Jan-16	1-Apr-16	1-Oct-16
Basic Charge	$ 14.4230	$ 14.4230	$ 14.4230	$ 14.4230	$ 14.4230	$ 14.4230	$ 14.4230	$ 14.4230	$ 14.4230
Off-Peak Period*	$ 1.000	$ 1.000	$ 1.008	$ 1.165	$ 1.165	$ 1.179	$ 1.217	$ 1.217	$ 1.217
Peak Period**	$ 1.777	$ 1.777	$ 1.785	$ 1.942	$ 1.942	$ 1.956	$ 1.994	$ 1.994	$ 1.994
Commodity Cost Recovery Charge									
Off-Peak Period*	$ 4.640	$ 3.781	$ 3.781	$ 3.781	$ 2.486	$ 2.486	$ 1.719	$ 1.141	$ 2.050
Peak Period**	$ 4.640	$ 3.781	$ 3.781	$ 3.781	$ 2.486	$ 2.486	$ 1.719	$ 1.141	$ 2.050
Storage and Transport per GJ	$ 0.862	$ 0.862	$ 0.862	$ 0.837	$ 0.837	$ 0.837	$ 0.681	$ 0.681	$ 0.681

RS 4 Inland			
Order Number	G-37-14	G-133-14	G-138-14/G-164-14
Effective Date	1-Apr-14	1-Oct-14	1-Nov-14
Basic Charge	$ 14.4230	$ 14.4230	$ 14.4230
Off-Peak Period*	$ 1.000	$ 1.000	$ 1.008
Peak Period**	$ 1.777	$ 1.777	$ 1.785
Commodity Cost Recovery Charge			
Off-Peak Period*	$ 4.640	$ 3.781	$ 3.781
Peak Period**	$ 4.640	$ 3.781	$ 3.781
Storage and Transport per GJ	$ 0.812	$ 0.812	$ 0.812

RS 4 Columbia

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09	G-42-10
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10	1-Apr-10
Basic Charge	$ 412.00	$ 414.00	$ 406.00	$ 406.00	$ 413.00	$ 413.00	$ 413.00	$ 413.00	$ 445.00	$ 439.00	$ 439.00	$ 439.00	$ 439.00
Off-Peak Period*	$ 0.717	$ 0.719	$ 0.705	$ 0.705	$ 0.717	$ 0.717	$ 0.717	$ 0.717	$ 0.772	$ 0.762	$ 0.762	$ 0.827	$ 0.827
Peak Period**	$ 1.446	$ 1.451	$ 1.422	$ 1.422	$ 1.446	$ 1.446	$ 1.446	$ 1.446	$ 1.558	$ 1.539	$ 1.539	$ 1.604	$ 1.604
Commodity Cost Recovery Charge													
Off-Peak Period*	$ 9.587	$ 7.575	$ 7.575	$ 6.902	$ 6.902	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953	$ 5.609
Peak Period**	$ 9.587	$ 7.575	$ 7.575	$ 6.902	$ 6.902	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953	$ 5.609
Storage and Transport per GJ	$ 0.527	$ 0.527	$ 0.676	$ 0.676	$ 0.887	$ 0.887	$ 0.887	$ 0.887	$ 0.720	$ 0.720	$ 0.720	$ 1.005	$ 1.005

RS 5 Mainland

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-9-08	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10
Basic Charge	$ 551.00	$ 553.00	$ 542.00	$ 542.00	$ 551.00	$ 551.00	$ 551.00	$ 551.00	$ 551.00	$ 594.00	$ 587.00	$ 587.00	$ 587.00
Demand Charge	$ 13.766	$ 13.816	$ 13.543	$ 13.543	$ 13.776	$ 13.776	$ 13.776	$ 13.776	$ 13.776	$ 14.840	$ 14.655	$ 14.655	$ 15.554
Delivery Charge	$ 0.557	$ 0.559	$ 0.548	$ 0.548	$ 0.557	$ 0.557	$ 0.557	$ 0.557	$ 0.557	$ 0.600	$ 0.593	$ 0.593	$ 0.629
Commodity Cost Recovery Charge	$ 9.587	$ 7.575	$ 7.575	$ 6.902	$ 6.902	$ 6.902	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953
Storage and Transport per GJ	$ 0.477	$ 0.477	$ 0.614	$ 0.614	$ 0.823	$ 0.823	$ 0.823	$ 0.823	$ 0.823	$ 0.670	$ 0.670	$ 0.670	$ 0.960

RS 5 Inland

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-9-08	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10
Basic Charge	$ 551.00	$ 553.00	$ 542.00	$ 542.00	$ 551.00	$ 551.00	$ 551.00	$ 551.00	$ 551.00	$ 594.00	$ 587.00	$ 587.00	$ 587.00
Demand Charge	$ 13.766	$ 13.816	$ 13.543	$ 13.543	$ 13.776	$ 13.776	$ 13.776	$ 13.776	$ 13.776	$ 14.840	$ 14.655	$ 14.655	$ 15.554
Delivery Charge	$ 0.557	$ 0.559	$ 0.548	$ 0.548	$ 0.557	$ 0.557	$ 0.557	$ 0.557	$ 0.557	$ 0.600	$ 0.593	$ 0.593	$ 0.629
Commodity Cost Recovery Charge	$ 9.587	$ 7.575	$ 7.575	$ 6.902	$ 6.902	$ 6.902	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953
Storage and Transport per GJ	$ 0.442	$ 0.442	$ 0.615	$ 0.615	$ 0.812	$ 0.812	$ 0.812	$ 0.812	$ 0.812	$ 0.644	$ 0.644	$ 0.644	$ 0.950

RS 4 Columbia										
Order Number	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13	G-150-13/G-201-13
Effective Date	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13	1-Jan-14
Basic Charge	$ 439.00	$ 439.00	$ 439.00	$ 14.423	$ 14.423	$ 14.423	$ 14.423	$ 14.423	$ 14.423	$ 14.423
Off-Peak Period*	$ 0.827	$ 0.854	$ 0.854	$ 0.940	$ 0.940	$ 0.919	$ 1.011	$ 0.973	$ 0.973	$ 1.000
Peak Period**	$ 1.604	$ 1.631	$ 1.631	$ 1.727	$ 1.727	$ 1.696	$ 1.788	$ 1.750	$ 1.750	$ 1.777
Commodity Cost Recovery Charge										
Off-Peak Period*	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272	$ 3.272
Peak Period**	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272	$ 3.272
Storage and Transport per GJ	$ 1.005	$ 0.785	$ 0.785	$ 0.853	$ 0.853	$ 0.853	$ 0.750	$ 0.750	$ 0.750	$ 0.800

RS 5 Mainland										
Order Number	G-42-10	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13
Effective Date	1-Apr-10	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13
Basic Charge	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00
Demand Charge	$ 15.554	$ 15.554	$ 15.943	$ 15.943	$ 16.996	$ 16.996	$ 16.820	$ 18.063	$ 17.531	$ 17.531
Delivery Charge	$ 0.629	$ 0.629	$ 0.645	$ 0.645	$ 0.702	$ 0.702	$ 0.680	$ 0.731	$ 0.722	$ 0.722
Commodity Cost Recovery Charge	$ 5.609	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272
Storage and Transport per GJ	$ 0.960	$ 0.960	$ 0.764	$ 0.764	$ 0.839	$ 0.839	$ 0.839	$ 0.765	$ 0.765	$ 0.765

RS 5 Inland										
Order Number	G-42-10	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13
Effective Date	1-Apr-10	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13
Basic Charge	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00
Demand Charge	$ 15.554	$ 15.554	$ 15.94	$ 15.94	$ 16.996	$ 16.996	$ 16.820	$ 18.063	$ 17.531	$ 17.531
Delivery Charge	$ 0.629	$ 0.629	$ 0.645	$ 0.645	$ 0.702	$ 0.702	$ 0.680	$ 0.731	$ 0.722	$ 0.722
Commodity Cost Recovery Charge	$ 5.609	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272
Storage and Transport per GJ	$ 0.950	$ 0.950	$ 0.749	$ 0.749	$ 0.824	$ 0.824	$ 0.824	$ 0.743	$ 0.743	$ 0.743

RS 4 Columbia			
Order Number	G-37-14	G-133-14	G-138-14/G-164-14
Effective Date	1-Apr-14	1-Oct-14	1-Nov-14
Basic Charge	$ 14.423	$ 14.423	$ 14.423
Off-Peak Period*	$ 1.000	$ 1.000	$ 1.008
Peak Period**	$ 1.777	$ 1.777	$ 1.785
Commodity Cost Recovery Charge			
Off-Peak Period*	$ 4.640	$ 3.781	$ 3.781
Peak Period**	$ 4.640	$ 3.781	$ 3.781
Storage and Transport per GJ	$ 0.800	$ 0.800	$ 0.800

RS 5 Mainland					**Amalgamation - ALL REGIONS**					
Order Number	G-150-13/G-201-13	G-37-14	G-133-14	G-138-14/G-164-14	G-21-14/G-178-14	G-39-15	G-86-15/G-106-15	G-188-15/G-193-15	G-37-16	G-145-16
Effective Date	1-Jan-14	1-Apr-14	1-Oct-14	1-Nov-14	1-Jan-15	1-Apr-15	1-Aug-15	1-Jan-16	1-Apr-16	1-Oct-16
Basic Charge	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00
Demand Charge	$ 17.850	$ 17.850	$ 17.850	$ 17.925	$ 19.742	$ 19.742	$ 19.910	$ 20.077	$ 20.077	$ 20.077
Delivery Charge	$ 0.736	$ 0.736	$ 0.736	$ 0.738	$ 0.813	$ 0.813	$ 0.819	$ 0.825	$ 0.825	$ 0.825
Commodity Cost Recovery Charge	$ 3.272	$ 4.640	$ 3.781	$ 3.781	$ 3.781	$ 2.486	$ 2.486	$ 1.719	$ 1.141	$ 2.050
Storage and Transport per GJ	$ 0.862	$ 0.862	$ 0.862	$ 0.862	$ 0.837	$ 0.837	$ 0.837	$ 0.681	$ 0.681	$ 0.681

RS 5 Inland				
Order Number	G-150-13/G-201-13	G-37-14	G-133-14	G-138-14/G-164-14
Effective Date	1-Jan-14	1-Apr-14	1-Oct-14	1-Nov-14
Basic Charge	$ 587.00	$ 587.00	$ 587.00	$ 587.00
Demand Charge	$ 17.850	$ 17.850	$ 17.850	$ 17.925
Delivery Charge	$ 0.736	$ 0.736	$ 0.736	$ 0.738
Commodity Cost Recovery Charge	$ 3.272	$ 4.640	$ 3.781	$ 3.781
Storage and Transport per GJ	$ 0.812	$ 0.812	$ 0.812	$ 0.812

RS 5 Columbia

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-9-08	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10
Basic Charge	$ 551.00	$ 553.00	$ 542.00	$ 542.00	$ 551.00	$ 551.00	$ 551.00	$ 551.00	$ 551.00	$ 594.00	$ 587.00	$ 587.00	$ 587.00
Demand Charge	$ 13.766	$ 13.816	$ 13.543	$ 13.543	$ 13.776	$ 13.776	$ 13.776	$ 13.776	$ 13.776	$ 14.840	$ 14.655	$ 14.655	$ 15.554
Delivery Charge	$ 0.557	$ 0.559	$ 0.548	$ 0.548	$ 0.557	$ 0.557	$ 0.557	$ 0.557	$ 0.557	$ 0.600	$ 0.593	$ 0.593	$ 0.629
Commodity Cost Recovery Charge	$ 9.587	$ 7.575	$ 7.575	$ 6.902	$ 6.902	$ 6.902	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953
Storage and Transport per GJ	$ 0.527	$ 0.527	$ 0.676	$ 0.676	$ 0.887	$ 0.887	$ 0.887	$ 0.887	$ 0.887	$ 0.720	$ 0.720	$ 0.720	$ 1.005

RS 6 Mainland

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-9-08	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10
Basic Charge	$ 58.00	$ 58.00	$ 57.00	$ 57.00	$ 58.00	$ 58.00	$ 58.00	$ 58.00	$ 58.00	$ 62.00	$ 61.00	$ 61.00	$ 61.00
Delivery Charge	$ 3.192	$ 3.203	$ 3.140	$ 3.140	$ 3.194	$ 3.194	$ 3.194	$ 3.194	$ 3.194	$ 3.441	$ 3.398	$ 3.398	$ 3.571
Commodity Cost Recovery Charge	$ 9.438	$ 7.505	$ 7.505	$ 6.883	$ 6.883	$ 6.883	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953
Storage and Transport per GJ	$ 0.369	$ 0.369	$ 0.420	$ 0.420	$ 0.452	$ 0.452	$ 0.452	$ 0.452	$ 0.452	$ 0.471	$ 0.471	$ 0.471	$ 0.466

RS 6 Inland

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-9-08	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10
Basic Charge	$ 58.00	$ 58.00	$ 57.00	$ 57.00	$ 58.00	$ 58.00	$ 58.00	$ 58.00	$ 58.00	$ 62.00	$ 61.00	$ 61.00	$ 61.00
Delivery Charge	$ 3.192	$ 3.203	$ 3.140	$ 3.140	$ 3.194	$ 3.194	$ 3.194	$ 3.194	$ 3.194	$ 3.441	$ 3.398	$ 3.398	$ 3.571
Commodity Cost Recovery Charge	$ 9.438	$ 7.505	$ 7.505	$ 6.883	$ 6.883	$ 6.883	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953
Storage and Transport per GJ	$ 0.352	$ 0.352	$ 0.424	$ 0.424	$ 0.431	$ 0.431	$ 0.431	$ 0.431	$ 0.431	$ 0.446	$ 0.446	$ 0.446	$ 0.464

RS 6 Columbia

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-9-08	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10
Basic Charge	$ 58.00	$ 58.00	$ 57.00	$ 57.00	$ 58.00	$ 58.00	$ 58.00	$ 58.00	$ 58.00	$ 62.00	$ 61.00	$ 61.00	$ 61.00
Delivery Charge	$ 3.192	$ 3.203	$ 3.140	$ 3.140	$ 3.194	$ 3.194	$ 3.194	$ 3.194	$ 3.194	$ 3.441	$ 3.398	$ 3.398	$ 3.571
Commodity Cost Recovery Charge	$ 9.438	$ 7.505	$ 7.505	$ 6.883	$ 6.883	$ 6.883	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953
Storage and Transport per GJ	$ 0.352	$ 0.352	$ 0.424	$ 0.424	$ 0.431	$ 0.431	$ 0.431	$ 0.431	$ 0.431	$ 0.446	$ 0.446	$ 0.446	$ 0.464

RS 5 Columbia

Order Number	G-42-10	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13
Effective Date	1-Apr-10	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13
Basic Charge	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00
Demand Charge	$ 15.554	$ 15.554	$ 15.94	$ 15.94	$ 16.996	$ 16.996	$ 16.820	$ 18.063	$ 17.531	$ 17.531
Delivery Charge	$ 0.629	$ 0.629	$ 0.645	$ 0.645	$ 0.702	$ 0.702	$ 0.680	$ 0.731	$ 0.722	$ 0.722
Commodity Cost Recovery Charge	$ 5.609	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272
Storage and Transport per GJ	$ 1.005	$ 1.005	$ 0.785	$ 0.785	$ 0.853	$ 0.853	$ 0.853	$ 0.750	$ 0.750	$ 0.750

RS 6 Mainland

Order Number	G-42-10	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13
Effective Date	1-Apr-10	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13
Basic Charge	$ 61.00	$ 61.00	$ 61.00	$ 61.00	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041
Delivery Charge	$ 3.571	$ 3.571	$ 3.648	$ 3.648	$ 3.878	$ 3.878	$ 3.825	$ 4.056	$ 3.967	$ 3.967
Commodity Cost Recovery Charge	$ 5.609	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272
Storage and Transport per GJ	$ 0.466	$ 0.466	$ 0.353	$ 0.353	$ 0.421	$ 0.421	$ 0.421	$ 0.396	$ 0.396	$ 0.396

RS 6 Inland

Order Number	G-42-10	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13
Effective Date	1-Apr-10	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13
Basic Charge	$ 61.00	$ 61.00	$ 61.00	$ 61.00	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041
Delivery Charge	$ 3.571	$ 3.571	$ 3.648	$ 3.648	$ 3.878	$ 3.878	$ 3.825	$ 4.056	$ 3.967	$ 3.967
Commodity Cost Recovery Charge	$ 5.609	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272
Storage and Transport per GJ	$ 0.464	$ 0.464	$ 0.346	$ 0.346	$ 0.413	$ 0.413	$ 0.413	$ 0.382	$ 0.382	$ 0.382

RS 6 Columbia

Order Number	G-42-10	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13
Effective Date	1-Apr-10	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13
Basic Charge	$ 61.00	$ 61.00	$ 61.00	$ 61.00	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041
Delivery Charge	$ 3.571	$ 3.571	$ 3.648	$ 3.648	$ 3.878	$ 3.878	$ 3.825	$ 4.056	$ 3.967	$ 3.967
Commodity Cost Recovery Charge	$ 5.609	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272
Storage and Transport per GJ	$ 0.464	$ 0.464	$ 0.346	$ 0.346	$ 0.413	$ 0.413	$ 0.413	$ 0.382	$ 0.382	$ 0.382

RS 5 Columbia

Order Number	G-150-13/G-201-13	G-37-14	G-133-14	G-138-14/G-164-14
Effective Date	1-Jan-14	1-Apr-14	1-Oct-14	1-Nov-14
Basic Charge	$ 587.00	$ 587.00	$ 587.00	$ 587.00
Demand Charge	$ 17.850	$ 17.850	$ 17.850	$ 17.925
Delivery Charge	$ 0.736	$ 0.736	$ 0.736	$ 0.738
Commodity Cost Recovery Charge	$ 3.272	$ 4.640	$ 3.781	$ 3.781
Storage and Transport per GJ	$ 0.800	$ 0.800	$ 0.800	$ 0.800

RS 6 Mainland

					Amalgamation - ALL REGIONS					
Order Number	G-150-13/G-201-13	G-37-14	G-133-14	G-138-14/G-164-14	G-21-14/G-178-14	G-39-15	G-86-15/G-106-15	G-188-15/G-193-15	G-37-16	G-145-16
Effective Date	1-Jan-14	1-Apr-14	1-Oct-14	1-Nov-14	1-Jan-15	1-Apr-15	1-Aug-15	1-Jan-16	1-Apr-16	1-Oct-16
Basic Charge	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041
Delivery Charge	$ 4.029	$ 4.029	$ 4.029	$ 4.048	$ 4.403	$ 4.403	$ 4.436	$ 4.521	$ 4.521	$ 4.521
Commodity Cost Recovery Charge	$ 3.272	$ 4.640	$ 3.781	$ 3.781	$ 3.781	$ 2.486	$ 2.486	$ 1.719	$ 1.141	$ 2.050
Storage and Transport per GJ	$ 0.467	$ 0.467	$ 0.467	$ 0.467	$ 0.417	$ 0.417	$ 0.417	$ 0.340	$ 0.340	$ 0.340

RS 6 Inland

Order Number	G-150-13/G-201-13	G-37-14	G-133-14	G-138-14/G-164-14
Effective Date	1-Jan-14	1-Apr-14	1-Oct-14	1-Nov-14
Basic Charge	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041
Delivery Charge	$ 4.029	$ 4.029	$ 4.029	$ 4.048
Commodity Cost Recovery Charge	$ 3.272	$ 4.640	$ 3.781	$ 3.781
Storage and Transport per GJ	$ 0.442	$ 0.442	$ 0.442	$ 0.442

RS 6 Columbia

Order Number	G-150-13/G-201-13	G-37-14	G-133-14	G-138-14/G-164-14
Effective Date	1-Jan-14	1-Apr-14	1-Oct-14	1-Nov-14
Basic Charge	$ 2.0041	$ 2.0041	$ 2.0041	$ 2.0041
Delivery Charge	$ 4.029	$ 4.029	$ 4.029	$ 4.048
Commodity Cost Recovery Charge	$ 3.272	$ 4.640	$ 3.781	$ 3.781
Storage and Transport per GJ	$ 0.442	$ 0.442	$ 0.442	$ 0.442

RS 7 Mainland

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09	G-42-10
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10	1-Apr-10
Basic Charge	$ 826.00	$ 829.00	$ 813.00	$ 813.00	$ 827.00	$ 827.00	$ 827.00	$ 827.00	$ 891.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00
Delivery Charge	$ 0.930	$ 0.933	$ 0.915	$ 0.915	$ 0.931	$ 0.931	$ 0.931	$ 0.931	$ 1.003	$ 0.990	$ 0.990	$ 1.048	$ 1.048
Commodity Cost Recovery Charge	$ 9.587	$ 7.575	$ 7.575	$ 6.902	$ 6.902	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953	$ 5.609
Storage and Transport per GJ	$ 0.477	$ 0.477	$ 0.614	$ 0.614	$ 0.823	$ 0.823	$ 0.823	$ 0.823	$ 0.670	$ 0.670	$ 0.670	$ 0.960	$ 0.960

RS 7 Inland

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09	G-42-10
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10	1-Apr-10
Basic Charge	$ 826.00	$ 829.00	$ 813.00	$ 813.00	$ 827.00	$ 827.00	$ 827.00	$ 827.00	$ 891.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00
Delivery Charge	$ 0.930	$ 0.933	$ 0.915	$ 0.915	$ 0.931	$ 0.931	$ 0.931	$ 0.931	$ 1.003	$ 0.990	$ 0.990	$ 1.048	$ 1.048
Commodity Cost Recovery Charge	$ 9.587	$ 7.575	$ 7.575	$ 6.902	$ 6.902	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953	$ 5.609
Storage and Transport per GJ	$ 0.442	$ 0.442	$ 0.615	$ 0.615	$ 0.812	$ 0.812	$ 0.812	$ 0.812	$ 0.644	$ 0.644	$ 0.644	$ 0.950	$ 0.950

RS 7 Columbia

Order Number	G-132-05	G-25-06	G-160-06	G-105-07	G-153-07	G-38-08	G-94-08	G-127-08	G-191-08	G-23-09	G-105-09	G-141-09	G-42-10
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Oct-07	1-Jan-08	1-Apr-08	1-Jul-08	1-Oct-08	1-Jan-09	1-Apr-09	1-Oct-09	1-Jan-10	1-Apr-10
Basic Charge	$ 826.00	$ 829.00	$ 813.00	$ 813.00	$ 827.00	$ 827.00	$ 827.00	$ 827.00	$ 891.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00
Delivery Charge	$ 0.930	$ 0.933	$ 0.915	$ 0.915	$ 0.931	$ 0.931	$ 0.931	$ 0.931	$ 1.003	$ 0.990	$ 0.990	$ 1.048	$ 1.048
Commodity Cost Recovery Charge	$ 9.587	$ 7.575	$ 7.575	$ 6.902	$ 6.902	$ 8.287	$ 9.780	$ 7.536	$ 7.536	$ 5.962	$ 4.953	$ 4.953	$ 5.609
Storage and Transport per GJ	$ 0.527	$ 0.527	$ 0.676	$ 0.676	$ 0.887	$ 0.887	$ 0.887	$ 0.887	$ 0.720	$ 0.720	$ 0.720	$ 1.005	$ 1.005

RS 22 Mainland

Order Number	G-132-05	G-14-06	G-160-06	G-153-07	G-38-08	G-191-08	G-23-09	G-141-09	G-187-10	G-177-11	G-44-12	G-179-12	G-75-12
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Jan-08	1-Apr-08	1-Jan-09	1-Apr-09	1-Jan-10	1-Jan-11	1-Jan-12	1-Jun-12	1-Jan-13	1-Jul-13
Basic Charge	$ 3,442.00	$ 3,454.00	$ 3,386.00	$ 3,444.00	$ 3,444.00	$ 3,710.00	$ 3,664.00	$ 3,664.00	$ 3,664.00	$ 3,664.00	$ 3,664.00	$ 3,664.00	$ 3,664.00
Delivery Charge	$ 0.689	$ 0.691	$ 0.677	$ 0.689	$ 0.689	$ 0.742	$ 0.733	$ 0.773	$ 0.790	$ 0.844	$ 0.830	$ 0.887	$ 0.863
Administration Charge per Month	$ 73.00	$ 73.00	$ 72.00	$ 73.00	$ 73.00	$ 79.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

RS 7 Mainland										
Order Number	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13	G-150-13/G-201-13
Effective Date	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13	1-Jan-14
Basic Charge	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00
Delivery Charge	$ 1.048	$ 1.073	$ 1.073	$ 1.148	$ 1.148	$ 1.129	$ 1.209	$ 1.175	$ 1.175	$ 1.195
Commodity Cost Recovery Charge	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272	$ 3.272
Storage and Transport per GJ	$ 0.960	$ 0.764	$ 0.764	$ 0.839	$ 0.839	$ 0.839	$ 0.765	$ 0.765	$ 0.765	$ 0.862

RS 7 Inland										
Order Number	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13	G-150-13/G-201-13
Effective Date	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13	1-Jan-14
Basic Charge	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00
Delivery Charge	$ 1.048	$ 1.073	$ 1.073	$ 1.148	$ 1.148	$ 1.129	$ 1.209	$ 1.175	$ 1.175	$ 1.195
Commodity Cost Recovery Charge	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272	$ 3.272
Storage and Transport per GJ	$ 0.950	$ 0.749	$ 0.749	$ 0.824	$ 0.824	$ 0.824	$ 0.743	$ 0.743	$ 0.743	$ 0.812

RS 7 Columbia										
Order Number	G-106-10	G-187-10	G-156-11	G-177-11	G-26-12	G-44-12	G-179-12	G-75-13/G-94-13	G-147-13	G-150-13/G-201-13
Effective Date	1-Jul-10	1-Jan-11	1-Oct-11	1-Jan-12	1-Apr-12	1-Jun-12	1-Jan-13	1-Jul-13	1-Oct-13	1-Jan-14
Basic Charge	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00
Delivery Charge	$ 1.048	$ 1.073	$ 1.073	$ 1.148	$ 1.148	$ 1.129	$ 1.209	$ 1.175	$ 1.175	$ 1.195
Commodity Cost Recovery Charge	$ 4.976	$ 4.568	$ 4.005	$ 4.005	$ 2.977	$ 2.977	$ 2.977	$ 3.913	$ 3.272	$ 3.272
Storage and Transport per GJ	$ 1.005	$ 0.785	$ 0.785	$ 0.853	$ 0.853	$ 0.853	$ 0.750	$ 0.750	$ 0.750	$ 0.800

RS 22 Mainland			Amalgamation - ALL REGIONS		
Order Number	G-150-13	G-138-14/G-164-14	G-21-14/G-178-14	G-86-15/G-106-15	G-188-15/G-193-15
Effective Date	1-Jan-14	1-Nov-14	1-Jan-15	1-Aug-15	1-Jan-16
Basic Charge	$ 3,664.00	$ 3,664.00	$ 3,664.00	$ 3,664.00	$ 3,664.00
Delivery Charge	$ 0.877	$ 0.880	$ 0.957	$ 0.964	$ 0.982
Administration Charge per Month	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

Amalgamation - ALL REGIONS

RS 7 Mainland									
Order Number	G-37-14	G-133-14	G-138-14/G-164-14	G-21-14/G-178-14	G-39-15	G-86-15/G-106-15	G-188-15/G-193-15	G-137-16	G-145-16
Effective Date	1-Apr-14	1-Oct-14	1-Nov-14	1-Jan-15	1-Apr-15	1-Aug-15	1-Jan-16	1-Apr-16	1-Oct-16
Basic Charge	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00
Delivery Charge	$ 1.195	$ 1.195	$ 1.200	$ 1.315	$ 1.315	$ 1.325	$ 1.353	$ 1.353	$ 1.353
Commodity Cost Recovery Charge	$ 4.640	$ 3.781	$ 3.781	$ 3.781	$ 2.486	$ 2.486	$ 1.719	$ 1.141	$ 2.050
Storage and Transport per GJ	$ 0.862	$ 0.862	$ 0.862	$ 0.837	$ 0.837	$ 0.837	$ 0.681	$ 0.681	$ 0.681

RS 7 Inland			
Order Number	G-37-14	G-133-14	G-138-14/G-164-14
Effective Date	1-Apr-14	1-Oct-14	1-Nov-14
Basic Charge	$ 880.00	$ 880.00	$ 880.00
Delivery Charge	$ 1.195	$ 1.195	$ 1.200
Commodity Cost Recovery Charge	$ 4.640	$ 3.781	$ 3.781
Storage and Transport per GJ	$ 0.812	$ 0.812	$ 0.812

RS 7 Columbia			
Order Number	G-37-14	G-133-14	G-138-14/G-164-14
Effective Date	1-Apr-14	1-Oct-14	1-Nov-14
Basic Charge	$ 880.00	$ 880.00	$ 880.00
Delivery Charge	$ 1.195	$ 1.195	$ 1.200
Commodity Cost Recovery Charge	$ 4.640	$ 3.781	$ 3.781
Storage and Transport per GJ	$ 0.800	$ 0.800	$ 0.800

RS 22 Mainland
Order Number
Effective Date
Basic Charge
Delivery Charge
Administration Charge per Month

RS 22 Inland

Order Number	G-132-05	G-14-06	G-160-06	G-153-07	G-38-08	G-191-08	G-23-09	G-141-09	G-187-10	G-177-11	G-44-12	G-179-12	G-75-12
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Jan-08	1-Apr-08	1-Jan-09	1-Apr-09	1-Jan-10	1-Jan-11	1-Jan-12	1-Jun-12	1-Jan-13	1-Jul-13
Basic Charge	$ 3,442.00	$ 3,454.00	$ 3,386.00	$ 3,444.00	$ 3,444.00	$ 3,710.00	$ 3,664.00	$ 3,664.00	$ 3,664.00	$ 3,664.00	$ 3,664.00	$ 3,664.00	$ 3,664.00
Delivery Charge	$ 0.689	$ 0.691	$ 0.677	$ 0.689	$ 0.689	$ 0.742	$ 0.733	$ 0.773	$ 0.790	$ 0.844	$ 0.830	$ 0.887	$ 0.863
Administration Charge per Month	$ 73.00	$ 73.00	$ 72.00	$ 73.00	$ 73.00	$ 79.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

RS 22 Columbia

Order Number	G-132-05	G-14-06	G-160-06	G-153-07	G-38-08	G-191-08	G-23-09	G-141-09	G-187-10	G-177-11	G-44-12	G-179-12	G-75-12
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Jan-08	1-Apr-08	1-Jan-09	1-Apr-09	1-Jan-10	1-Jan-11	1-Jan-12	1-Jun-12	1-Jan-13	1-Jul-13
Basic Charge	$ 3,442.00	$ 3,454.00	$ 3,386.00	$ 3,444.00	$ 3,444.00	$ 3,710.00	$ 3,664.00	$ 3,664.00	$ 3,664.00	$ 3,664.00	$ 3,664.00	$ 3,664.00	$ 3,664.00
Delivery Charge	$ 0.689	$ 0.691	$ 0.677	$ 0.689	$ 0.689	$ 0.742	$ 0.733	$ 0.773	$ 0.790	$ 0.844	$ 0.830	$ 0.887	$ 0.863
Administration Charge per Month	$ 73.00	$ 73.00	$ 72.00	$ 73.00	$ 73.00	$ 79.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

RS 23 Mainland

Order Number	G-132-05	G-14-06	G-160-06	G-153-07	G-9-08	G-38-08	G-191-08	G-23-09	G-141-09	G-187-10	G-177-11	G-44-12	G-179-12
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jan-09	1-Apr-09	1-Jan-10	1-Jan-11	1-Jan-12	1-Jun-12	1-Jan-13
Basic Charge	$ 124.50	$ 124.95	$ 122.48	$ 124.58	$ 124.58	$ 124.58	$ 134.20	$ 132.52	$ 132.52	$ 132.52	$ 132.52	$ 132.52	$ 132.52
Delivery Charge	$ 2.007	$ 2.014	$ 1.974	$ 2.008	$ 2.008	$ 2.008	$ 2.163	$ 2.136	$ 2.264	$ 2.318	$ 2.483	$ 2.442	$ 2.617
Administration Charge	$ 73.00	$ 73.00	$ 72.00	$ 73.00	$ 73.00	$ 73.00	$ 79.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

RS 23 Inland

Order Number	G-132-05	G-14-06	G-160-06	G-153-07	G-9-08	G-38-08	G-191-08	G-23-09	G-141-09	G-187-10	G-177-11	G-44-12	G-179-12
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jan-09	1-Apr-09	1-Jan-10	1-Jan-11	1-Jan-12	1-Jun-12	1-Jan-13
Basic Charge	$ 124.50	$ 124.95	$ 122.48	$ 124.58	$ 124.58	$ 124.58	$ 134.20	$ 132.52	$ 132.52	$ 132.52	$ 132.52	$ 132.52	$ 132.52
Delivery Charge	$ 2.007	$ 2.014	$ 1.974	$ 2.008	$ 2.008	$ 2.008	$ 2.163	$ 2.136	$ 2.264	$ 2.318	$ 2.483	$ 2.442	$ 2.617
Administration Charge	$ 73.00	$ 73.00	$ 72.00	$ 73.00	$ 73.00	$ 73.00	$ 79.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

RS 22 Inland		
Order Number	G-150-13	G-138-14/G-164-14
Effective Date	1-Jan-14	1-Nov-14
Basic Charge	$ 3,664.00	$ 3,664.00
Delivery Charge	$ 0.877	$ 0.880
Administration Charge per Month	$ 78.00	$ 78.00

RS 22 Columbia		
Order Number	G-150-13	G-138-14/G-164-14
Effective Date	1-Jan-14	1-Nov-14
Basic Charge	$ 3,664.00	$ 3,664.00
Delivery Charge	$ 0.877	$ 0.880
Administration Charge per Month	$ 78.00	$ 78.00

RS 23 Mainland				**Amalgamation - ALL REGIONS**		
Order Number	G-75-13	G-150-13	G-138-14/G-164-14	G-21-14/G-178-14	G-86-15/G-106-15	G-188-15/G-193-15
Effective Date	1-Jul-13	1-Jan-14	1-Nov-14	1-Jan-15	1-Aug-15	1-Jan-16
Basic Charge	$ 132.52	$ 132.52	$ 132.52	$ 132.52	$ 132.52	$ 132.52
Delivery Charge	$ 2.543	$ 2.587	$ 2.599	$ 2.854	$ 2.877	$ 2.939
Administration Charge	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

RS 23 Inland			
Order Number	G-75-13	G-150-13	G-138-14/G-164-14
Effective Date	1-Jul-13	1-Jan-14	1-Nov-14
Basic Charge	$ 132.52	$ 132.52	$ 132.52
Delivery Charge	$ 2.543	$ 2.587	$ 2.599
Administration Charge	$ 78.00	$ 78.00	$ 78.00

RS 22 Inland
Order Number
Effective Date
Basic Charge
Delivery Charge
Administration Charge per Month

RS 22 Columbia
Order Number
Effective Date
Basic Charge
Delivery Charge
Administration Charge per Month

RS 23 Mainland
Order Number
Effective Date
Basic Charge
Delivery Charge
Administration Charge

RS 23 Inland
Order Number
Effective Date
Basic Charge
Delivery Charge
Administration Charge

RS 23 Columbia

Order Number	G-132-05	G-14-06	G-160-06	G-153-07	G-9-08	G-38-08	G-191-08	G-23-09	G-141-09	G-187-10	G-177-11	G-44-12	G-179-12
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jan-09	1-Apr-09	1-Jan-10	1-Jan-11	1-Jan-12	1-Jun-12	1-Jan-13
Basic Charge	$ 124.50	$ 124.95	$ 122.48	$ 124.58	$ 124.58	$ 124.58	$ 134.20	$ 132.52	$ 132.52	$ 132.52	$ 132.52	$ 132.52	$ 132.52
Delivery Charge	$ 2.007	$ 2.014	$ 1.974	$ 2.008	$ 2.008	$ 2.008	$ 2.163	$ 2.136	$ 2.264	$ 2.318	$ 2.483	$ 2.442	$ 2.617
Administration Charge	$ 73.00	$ 73.00	$ 72.00	$ 73.00	$ 73.00	$ 73.00	$ 79.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

RS 25 Mainland

Order Number	G-132-05	G-14-06	G-160-06	G-153-07	G-9-08	G-38-08	G-191-08	G-23-09	G-141-09	G-187-10	G-177-11	G-44-12	G-179-12
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jan-09	1-Apr-09	1-Jan-10	1-Jan-11	1-Jan-12	1-Jun-12	1-Jan-13
Basic Charge	$ 551.00	$ 553.00	$ 542.00	$ 551.00	$ 551.00	$ 551.00	$ 594.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00
Demand Charge	$ 13.766	$ 13.816	$ 13.543	$ 13.776	$ 13.776	$ 13.776	$ 14.840	$ 14.655	$ 15.554	$ 15.943	$ 16.996	$ 16.820	$ 18.063
Delivery Charge	$ 0.557	$ 0.559	$ 0.548	$ 0.557	$ 0.557	$ 0.557	$ 0.600	$ 0.593	$ 0.629	$ 0.645	$ 0.702	$ 0.680	$ 0.731
Administration Charge	$ 73.00	$ 73.00	$ 72.00	$ 73.00	$ 73.00	$ 73.00	$ 79.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

RS 25 Inland

Order Number	G-132-05	G-14-06	G-160-06	G-153-07	G-9-08	G-38-08	G-191-08	G-23-09	G-141-09	G-187-10	G-177-11	G-44-12	G-179-12
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jan-09	1-Apr-09	1-Jan-10	1-Jan-11	1-Jan-12	1-Jun-12	1-Jan-13
Basic Charge	$ 551.00	$ 553.00	$ 542.00	$ 551.00	$ 551.00	$ 551.00	$ 594.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00
Demand Charge	$ 13.766	$ 13.816	$ 13.543	$ 13.776	$ 13.776	$ 13.776	$ 14.840	$ 14.655	$ 15.554	$ 15.943	$ 16.996	$ 16.820	$ 18.063
Delivery Charge	$ 0.557	$ 0.559	$ 0.548	$ 0.557	$ 0.557	$ 0.557	$ 0.600	$ 0.593	$ 0.629	$ 0.645	$ 0.702	$ 0.680	$ 0.731
Administration Charge	$ 73.00	$ 73.00	$ 72.00	$ 73.00	$ 73.00	$ 73.00	$ 79.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

RS 25 Columbia

Order Number	G-132-05	G-14-06	G-160-06	G-153-07	G-9-08	G-38-08	G-191-08	G-23-09	G-141-09	G-187-10	G-177-11	G-44-12	G-179-12
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Jan-08	1-Feb-08	1-Apr-08	1-Jan-09	1-Apr-09	1-Jan-10	1-Jan-11	1-Jan-12	1-Jun-12	1-Jan-13
Basic Charge	$ 551.00	$ 553.00	$ 542.00	$ 551.00	$ 551.00	$ 551.00	$ 594.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00
Demand Charge	$ 13.766	$ 13.816	$ 13.543	$ 13.776	$ 13.776	$ 13.776	$ 14.840	$ 14.655	$ 15.554	$ 15.943	$ 16.996	$ 16.820	$ 18.063
Delivery Charge	$ 0.557	$ 0.559	$ 0.548	$ 0.557	$ 0.557	$ 0.557	$ 0.600	$ 0.593	$ 0.629	$ 0.645	$ 0.702	$ 0.680	$ 0.731
Administration Charge	$ 73.00	$ 73.00	$ 72.00	$ 73.00	$ 73.00	$ 73.00	$ 79.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

RS 23 Columbia			
Order Number	G-75-13	G-150-13	G-138-14/G-164-14
Effective Date	1-Jul-13	1-Jan-14	1-Nov-14
Basic Charge	$ 132.52	$ 132.52	$ 132.52
Delivery Charge	$ 2.543	$ 2.587	$ 2.599
Administration Charge	$ 78.00	$ 78.00	$ 78.00

RS 25 Mainland				**Amalgamation - ALL REGIONS**		
Order Number	G-75-13	G-150-13	G-138-14/G-164-14	G-21-14/G-178-14	G-86-15/G-106-15	G-188-15/G-193-15
Effective Date	1-Jul-13	1-Jan-14	1-Nov-14	1-Jan-15	1-Aug-15	1-Jan-16
Basic Charge	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00	$ 587.00
Demand Charge	$ 17.531	$ 17.850	$ 17.925	$ 19.742	$ 19.910	$ 20.077
Delivery Charge	$ 0.722	$ 0.736	$ 0.738	$ 0.813	$ 0.819	$ 0.825
Administration Charge	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

RS 25 Inland			
Order Number	G-75-13	G-150-13	G-138-14/G-164-14
Effective Date	1-Jul-13	1-Jan-14	1-Nov-14
Basic Charge	$ 587.00	$ 587.00	$ 587.00
Demand Charge	$ 17.531	$ 17.850	$ 17.925
Delivery Charge	$ 0.722	$ 0.736	$ 0.738
Administration Charge	$ 78.00	$ 78.00	$ 78.00

RS 25 Columbia			
Order Number	G-75-13	G-150-13	G-138-14/G-164-14
Effective Date	1-Jul-13	1-Jan-14	1-Nov-14
Basic Charge	$ 587.00	$ 587.00	$ 587.00
Demand Charge	$ 17.531	$ 17.850	$ 17.925
Delivery Charge	$ 0.722	$ 0.736	$ 0.738
Administration Charge	$ 78.00	$ 78.00	$ 78.00

RS 23 Columbia
Order Number
Effective Date
Basic Charge
Delivery Charge
Administration Charge

RS 25 Mainland
Order Number
Effective Date
Basic Charge
Demand Charge
Delivery Charge
Administration Charge

RS 25 Inland
Order Number
Effective Date
Basic Charge
Demand Charge
Delivery Charge
Administration Charge

RS 25 Columbia
Order Number
Effective Date
Basic Charge
Demand Charge
Delivery Charge
Administration Charge

RS 27 Mainland

Order Number	G-132-05	G-14-06	G-160-06	G-153-07	G-38-08	G-191-08	G-23-09	G-141-09	G-187-10	G-177-11	G-44-12	G-179-12	G-75-13
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Jan-08	1-Apr-08	1-Jan-09	1-Apr-09	1-Jan-10	1-Jan-11	1-Jan-12	1-Jun-12	1-Jan-13	1-Jul-13
Basic Charge	$ 826.00	$ 829.00	$ 813.00	$ 827.00	$ 827.00	$ 891.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00
Delivery Charge	$ 0.930	$ 0.933	$ 0.915	$ 0.931	$ 0.931	$ 1.003	$ 0.990	$ 1.048	$ 1.073	$ 1.148	$ 1.129	$ 1.209	$ 1.175
Administration Charge	$ 73.00	$ 73.00	$ 72.00	$ 73.00	$ 73.00	$ 79.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

RS 27 Inland

Order Number	G-132-05	G-14-06	G-160-06	G-153-07	G-38-08	G-191-08	G-23-09	G-141-09	G-187-10	G-177-11	G-44-12	G-179-12	G-75-13
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Jan-08	1-Apr-08	1-Jan-09	1-Apr-09	1-Jan-10	1-Jan-11	1-Jan-12	1-Jun-12	1-Jan-13	1-Jul-13
Basic Charge	$ 826.00	$ 829.00	$ 813.00	$ 827.00	$ 827.00	$ 891.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00
Delivery Charge	$ 0.930	$ 0.933	$ 0.915	$ 0.931	$ 0.931	$ 1.003	$ 0.990	$ 1.048	$ 1.073	$ 1.148	$ 1.129	$ 1.209	$ 1.175
Administration Charge	$ 73.00	$ 73.00	$ 72.00	$ 73.00	$ 73.00	$ 79.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

RS 27 Columbia

Order Number	G-132-05	G-14-06	G-160-06	G-153-07	G-38-08	G-191-08	G-23-09	G-141-09	G-187-10	G-177-11	G-44-12	G-179-12	G-75-13
Effective Date	1-Jan-06	1-Apr-06	1-Jan-07	1-Jan-08	1-Apr-08	1-Jan-09	1-Apr-09	1-Jan-10	1-Jan-11	1-Jan-12	1-Jun-12	1-Jan-13	1-Jul-13
Basic Charge	$ 826.00	$ 829.00	$ 813.00	$ 827.00	$ 827.00	$ 891.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00
Delivery Charge	$ 0.930	$ 0.933	$ 0.915	$ 0.931	$ 0.931	$ 1.003	$ 0.990	$ 1.048	$ 1.073	$ 1.148	$ 1.129	$ 1.209	$ 1.175
Administration Charge	$ 73.00	$ 73.00	$ 72.00	$ 73.00	$ 73.00	$ 79.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

RS 27 Mainland			Amalgamation - ALL REGIONS		
Order Number	G-150-13	G-138-14/G-164-14	G-21-14/G-178-14	G-86-15/G-106-15	G-188-15/G-193-15
Effective Date	1-Jan-14	1-Nov-14	1-Jan-15	1-Aug-15	1-Jan-16
Basic Charge	$ 880.00	$ 880.00	$ 880.00	$ 880.00	$ 880.00
Delivery Charge	$ 1.195	$ 1.200	$ 1.315	$ 1.325	$ 1.353
Administration Charge	$ 78.00	$ 78.00	$ 78.00	$ 78.00	$ 78.00

RS 27 Inland		
Order Number	G-150-13	G-138-14/G-164-14
Effective Date	1-Jan-14	1-Nov-14
Basic Charge	$ 880.00	$ 880.00
Delivery Charge	$ 1.195	$ 1.200
Administration Charge	$ 78.00	$ 78.00

RS 27 Columbia		
Order Number	G-150-13	G-138-14/G-164-14
Effective Date	1-Jan-14	1-Nov-14
Basic Charge	$ 880.00	$ 880.00
Delivery Charge	$ 1.195	$ 1.200
Administration Charge	$ 78.00	$ 78.00

RS 27 Mainland
Order Number
Effective Date
Basic Charge
Delivery Charge
Administration Charge

RS 27 Inland
Order Number
Effective Date
Basic Charge
Delivery Charge
Administration Charge

RS 27 Columbia
Order Number
Effective Date
Basic Charge
Delivery Charge
Administration Charge

Appendix 6-11

AVOIDED STORAGE COST CALCULATION

Market Area Storage Cost (Mist)

Source: Natural Gas Price Forecast from GLJA [Jan 2015], Storage and Transport Rates: Gas Supply, FEI

Calendar Year		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
RATE CHARGES												
	Sumas Summer Price ($US/MMBtu)	$ 2.03	$ 2.12	$ 2.43	$ 2.56	$ 2.69	$ 2.81	$ 2.90	$ 3.04	$ 3.19	$ 3.32	$ 3.39
update NWP wi	NWP 15 day storage charge ($US/MMBtu) *	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25
	NWP Injection/Withdrawal Fuel Rate (%)	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%
	NWP TF-1 Transport Demand Charge ($US/MMBtu)	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41
	NWP Transport Fuel Rate (%)	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
	Storage Deliverability Required Mcf/d	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
STORAGE CHARGE ($US 000)												
Demand:	NWP Storage Charge for 150MMcf/d x 15 days	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162
Fuel:	Injection Fuel Charge for 5-day (15-day first year)	$ 6	$ 6	$ 7	$ 8	$ 8	$ 9	$ 9	$ 9	$ 10	$ 10	$ 10
TRANSPORT CHARGE ($US 000)												
Demand:	NWP TF-1@40% Transport Charge for 365 day	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156
Fuel 1:	NWP Transport for 5-day Injection	$ 23	$ 24	$ 28	$ 29	$ 31	$ 32	$ 33	$ 35	$ 37	$ 38	$ 39
Fuel 2:	NWP Transport for 5-day Withdrawal	$ 23	$ 24	$ 28	$ 29	$ 31	$ 32	$ 33	$ 35	$ 37	$ 38	$ 39
TOTAL STORAGE & TRANSPORT												
	($US 000)	$ 14,372	$ 14,374	$ 14,382	$ 14,385	$ 14,389	$ 14,392	$ 14,394	$ 14,398	$ 14,402	$ 14,405	$ 14,407
	($Cdn 000) applying Fx = 0.76 $Cdn/$US	$ 18,910	$ 18,913	$ 18,923	$ 18,928	$ 18,933	$ 18,936	$ 18,939	$ 18,944	$ 18,949	$ 18,954	$ 18,956

Calendar Year		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
RATE CHARGES												
	Sumas Summer Price ($US/MMBtu)	$ 3.46	$ 3.53	$ 3.60	$ 3.67	$ 3.74	$ 3.82	$ 3.89	$ 3.97	$ 3.02	$ 4.13	$ 3.15
update NWP wi	NWP 15 day storage charge ($US/MMBtu) *	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25	$ 2.25
	NWP Injection/Withdrawal Fuel Rate (%)	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%
	NWP TF-1 Transport Demand Charge ($US/MMBtu)	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41	$ 0.41
	NWP Transport Fuel Rate (%)	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%	1.50%
	Storage Deliverability Required Mcf/d	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
STORAGE CHARGE ($US 000)												
Demand:	NWP Storage Charge for 150MMcf/d x 15 days	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162	$ 5,162
Fuel:	Injection Fuel Charge for 5-day (15-day first year)	$ 11	$ 11	$ 11	$ 11	$ 11	$ 12	$ 12	$ 12	$ 9	$ 13	$ 10
TRANSPORT CHARGE ($US 000)												
Demand:	NWP TF-1@40% Transport Charge for 365 day	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156	$ 9,156
Fuel 1:	NWP Transport for 5-day Injection	$ 40	$ 40	$ 41	$ 42	$ 43	$ 44	$ 45	$ 46	$ 35	$ 47	$ 36
Fuel 2:	NWP Transport for 5-day Withdrawal	$ 40	$ 40	$ 41	$ 42	$ 43	$ 44	$ 45	$ 46	$ 35	$ 47	$ 36
TOTAL STORAGE & TRANSPORT												
	($US 000)	$ 14,409	$ 14,410	$ 14,412	$ 14,414	$ 14,416	$ 14,418	$ 14,420	$ 14,422	$ 14,397	$ 14,426	$ 14,400
	($Cdn 000) applying Fx = 0.76 $Cdn/$US	$ 18,959	$ 18,961	$ 18,963	$ 18,966	$ 18,968	$ 18,971	$ 18,974	$ 18,976	$ 18,944	$ 18,982	$ 18,948

Please note Conversion Factors: *GJ/MMBtu 1.055056*
GJ/Mcf 1.07588

STORAGE COST: PRESENT VALUE (Year 2015 $) **NWP TF-1@40%**

	Period (Years)	11	21	11	21
	Discount Rate	6.0%	6.0%	10.0%	10.0%
STORAGE CHARGE ($US 000)					
Demand:	NWP Storage Charge for 150MMcf/d x 15 days	$ 40,746	$ 60,807	$ 33,530	$ 44,648
Fuel:	Injection Fuel Charge for 5-day	$ 65	$ 109	$ 52	$ 77
TRANSPORT CHARGE ($US 000)					
Demand:	NWP TF-1@40% Transport Charge for 365 day	$ 72,269	$ 107,849	$ 59,470	$ 79,189
Fuel 1:	NWP Transport for 5-day Injection	$ 244	$ 407	$ 197	$ 287
Fuel 2:	NWP Transport for 5-day Withdrawal	$ 244	$ 407	$ 197	$ 287
TOTAL STORAGE & TRANSPORT					
	($US 000)	$ 113,567	$ 169,579	$ 93,447	$ 124,489
	($Cdn 000) applying Fx = 0.76 $US/$Cdn	$ 149,431	$ 223,130	$ 122,956	$ 163,801
	Levelized Storage Year Cost ($Cdn 000)	$ 19,689	$ 19,450	$ 19,816	$ 19,604

Unit Charge based on period & discount rate	11yr @ 6%	21yr @ 6%	11yr @ 10%	21yr @ 10%
Fixed unit charge ($Cdn/GJ)	$ 116.74	$ 116.74	$ 116.74	$ 116.74
Variable unit charge ($Cdn/GJ)	$ 0.57	$ 0.64	$ 0.56	$ 0.61
Unit charge ($Cdn/GJ)	$ 117.31	$ 117.38	$ 117.30	$ 117.36

$$NPV = \sum_{i=1}^{n} \frac{\text{unit charge}}{(1 + \text{discount rate})^i}$$

where n is the period (12 year or 22 year) and discount rate is 6.2% or 10%

* *Storage Rate on NWP of $US 2.25/MMBtu = (($0.00347 x capacity x 365-days + $0.04045 x deliverability x 365-days)/capacity)*
where: deliverability = 150,000 MMscf/d; storage days = 15 days; capacity = deliverability x storage days.
capacity charge of $0.00347 and demand charge of $0.04045

Summary of T-South Cost with mitigation payments

Storage Contract Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
GLJA AECO One Year ($Cdn/MMBtu)	$ 2.70	$ 2.76	$ 3.27	$ 3.45	$ 3.63	$ 3.81	$ 3.90	$ 4.10	$ 4.30	$ 4.50	$ 4.60
GLJA AECO One Year ($US/MMBtu) using GLGA Fx 0.85 US/Cdn	$ 2.11	$ 2.10	$ 2.49	$ 2.62	$ 2.76	$ 2.90	$ 2.96	$ 3.12	$ 3.27	$ 3.42	$ 3.50
GLJA AECO One Year ($Cdn/GJ)	$ 2.63	$ 2.62	$ 3.10	$ 3.27	$ 3.44	$ 3.61	$ 3.70	$ 3.89	$ 4.08	$ 4.27	$ 4.36
GLJA AECO Storage Year ($Cdn/GJ)	$ 2.63	$ 2.74	$ 3.14	$ 3.31	$ 3.48	$ 3.63	$ 3.74	$ 3.93	$ 4.12	$ 4.29	$ 4.38
Station-2 Winter Price = 107.46035406174% Storage Year ($Cdn/GJ	$ 2.83	$ 2.94	$ 3.38	$ 3.56	$ 3.74	$ 3.90	$ 4.02	$ 4.23	$ 4.43	$ 4.61	$ 4.71
Station-2 Summer Price = 94.6711756701855% Storage Year ($Cdn	$ 2.49	$ 2.59	$ 2.97	$ 3.14	$ 3.30	$ 3.44	$ 3.54	$ 3.72	$ 3.90	$ 4.06	$ 4.15
Sumas Winter Price (US$/MMBtu)	$ 2.53	$ 2.63	$ 2.99	$ 3.14	$ 3.30	$ 3.43	$ 3.54	$ 3.71	$ 3.88	$ 4.03	$ 4.11
Sumas Summer Price (US$/MMBtu)	$ 2.03	$ 2.12	$ 2.43	$ 2.56	$ 2.69	$ 2.81	$ 2.90	$ 3.04	$ 3.19	$ 3.32	$ 3.39
Sumas Winter Price ($Cdn/GJ)	$ 3.16	$ 3.28	$ 3.73	$ 3.92	$ 4.11	$ 4.28	$ 4.41	$ 4.62	$ 4.84	$ 5.02	$ 5.13
Sumas Summer Price ($Cdn/GJ)	$ 2.54	$ 2.64	$ 3.03	$ 3.20	$ 3.36	$ 3.50	$ 3.61	$ 3.79	$ 3.98	$ 4.14	$ 4.23
T-South Demand Charges ($Cdn/Mcf)	$ 0.35	$ 0.36	$ 0.36	$ 0.37	$ 0.37	$ 0.38	$ 0.39	$ 0.39	$ 0.40	$ 0.40	$ 0.41
T-South Demand Charges, Calendar Year ($Cdn/GJ)	$ 0.33	$ 0.33	$ 0.34	$ 0.34	$ 0.35	$ 0.35	$ 0.36	$ 0.36	$ 0.37	$ 0.38	$ 0.38
T-South Demand Charges, Storage Year ($Cdn/GJ)	$ 0.33	$ 0.33	$ 0.34	$ 0.34	$ 0.35	$ 0.35	$ 0.36	$ 0.37	$ 0.37	$ 0.38	$ 0.38
Station-2 Daily Gas Price = 1.5 times Winter Price ($Cdn/GJ)	$ 4.24	$ 4.41	$ 5.06	$ 5.34	$ 5.61	$ 5.86	$ 6.03	$ 6.34	$ 6.65	$ 6.91	$ 7.06
Sumas Summer/Station-2 Winter daily Differential ($Cdn/GJ)	$ 1.70	$ 1.77	$ 2.03	$ 2.14	$ 2.25	$ 2.35	$ 2.42	$ 2.55	$ 2.67	$ 2.78	$ 2.84
Station-2 Daily Winter T-South Fuel 3.3% ($Cdn/GJ)	$ 0.14	$ 0.15	$ 0.17	$ 0.18	$ 0.19	$ 0.19	$ 0.20	$ 0.21	$ 0.22	$ 0.23	$ 0.23
Fixed cost (150MMcfd x 365days x T-South Demand Charge)(9 months first year)	$ 19,168	$ 19,478	$ 19,794	$ 20,115	$20,441	$20,772	$21,108	$21,450	$21,798	$22,151	$22,510
Variable based on (150 MMcf/d x 5 days) (two days first year)	$ 1,486	$ 1,547	$ 1,776	$ 1,872	$ 1,969	$ 2,053	$ 2,116	$ 2,223	$ 2,330	$ 2,424	$ 2,476
Total before mitigation	$ 20,654	$ 21,025	$ 21,570	$ 21,987	$22,409	$22,825	$23,224	$23,673	$24,128	$24,575	$24,986
Mitigation (4 out of 5 winter months)	-$ 6,039	-$ 6,137	-$ 6,236	-$ 6,338	-$ 6,440	-$ 6,545	-$ 6,651	-$ 6,758	-$ 6,868	-$ 6,979	-$ 7,092
Total after mitigation	$ 14,615	$ 14,888	$ 15,333	$ 15,649	$15,969	$16,280	$16,574	$16,915	$17,260	$17,596	$17,894

Storage Contract Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
GLJA AECO One Year ($Cdn/MMBtu)	$ 4.69	$ 4.79	$ 4.88	$ 4.98	$ 5.08	$ 5.18	$ 5.28	$ 5.39	$ 5.50	$ 5.61	$ 5.72
GLJA AECO One Year ($US/MMBtu) using GLGA Fx 0.85 US/Cdn	$ 3.57	$ 3.64	$ 3.71	$ 3.78	$ 3.86	$ 3.94	$ 4.02	$ 4.10	$ 4.18	$ 4.26	$ 4.35
GLJA AECO One Year ($Cdn/GJ)	$ 4.45	$ 4.54	$ 4.63	$ 4.72	$ 4.81	$ 4.91	$ 5.01	$ 5.11	$ 5.21	$ 5.31	$ 5.42
GLJA AECO Storage Year ($Cdn/GJ)	$ 4.47	$ 4.56	$ 4.65	$ 4.74	$ 4.84	$ 4.93	$ 5.03	$ 5.13	$ 3.91	$ 5.34	$ 4.07
Station-2 Winter Price = 107.46035406174% Storage Year ($Cdn/GJ	$ 4.80	$ 4.90	$ 5.00	$ 5.10	$ 5.20	$ 5.30	$ 5.41	$ 5.52	$ 4.20	$ 5.74	$ 4.37
Station-2 Summer Price = 94.6711756701855% Storage Year ($Cdn	$ 4.23	$ 4.32	$ 4.40	$ 4.49	$ 4.58	$ 4.67	$ 4.77	$ 4.86	$ 3.70	$ 5.06	$ 3.85
Sumas Winter Price (US$/MMBtu)	$ 4.20	$ 4.28	$ 4.36	$ 4.45	$ 4.54	$ 4.63	$ 4.72	$ 4.81	$ 3.73	$ 5.00	$ 3.81
Sumas Summer Price (US$/MMBtu)	$ 3.46	$ 3.53	$ 3.60	$ 3.67	$ 3.74	$ 3.82	$ 3.89	$ 3.97	$ 3.02	$ 4.13	$ 3.15
Sumas Winter Price ($Cdn/GJ)	$ 5.23	$ 5.34	$ 5.44	$ 5.55	$ 5.66	$ 5.77	$ 5.15	$ 5.25	$ 4.00	$ 5.46	$ 4.16
Sumas Summer Price ($Cdn/GJ)	$ 4.31	$ 4.40	$ 4.49	$ 4.58	$ 4.67	$ 4.76	$ 4.48	$ 4.57	$ 3.48	$ 4.75	$ 3.62
T-South Demand Charges ($Cdn/Mcf)	$ 0.42	$ 0.42	$ 0.43	$ 0.44	$ 0.45	$ 0.45	$ 0.46	$ 0.47	$ 0.48	$ 0.48	$ 0.49
T-South Demand Charges, Calendar Year ($Cdn/GJ)	$ 0.39	$ 0.39	$ 0.40	$ 0.41	$ 0.41	$ 0.42	$ 0.43	$ 0.43	$ 0.44	$ 0.45	$ 0.46
T-South Demand Charges, Storage Year ($Cdn/GJ)	$ 0.39	$ 0.40	$ 0.40	$ 0.41	$ 0.42	$ 0.42	$ 0.43	$ 0.44	$ 0.44	$ 0.45	$ 0.34
Station-2 Daily Gas Price = 1.5 times Winter Price ($Cdn/GJ)	$ 7.20	$ 7.35	$ 7.50	$ 7.65	$ 7.80	$ 7.95	$ 8.11	$ 8.28	$ 6.30	$ 8.61	$ 6.55
Sumas Summer/Station-2 Winter daily Differential ($Cdn/GJ)	$ 2.89	$ 2.95	$ 3.01	$ 3.07	$ 3.13	$ 3.19	$ 3.26	$ 3.32	$ 2.53	$ 3.46	$ 2.63
Station-2 Daily Winter T-South Fuel 3.3% ($Cdn/GJ)	$ 0.24	$ 0.24	$ 0.25	$ 0.25	$ 0.26	$ 0.26	$ 0.27	$ 0.27	$ 0.21	$ 0.28	$ 0.22
Fixed cost (150MMcfd x 365days x T-South Demand Charge)(9 months first year)	$22,874	$23,245	$23,621	$24,004	$24,393	$24,788	$25,190	$25,598	$26,012	$26,434	$26,862
Variable based on (150 MMcf/d x 5 days) (two days first year)	$ 2,526	$ 2,576	$ 2,628	$ 2,681	$ 2,734	$ 2,789	$ 2,845	$ 2,901	$ 2,209	$ 3,019	$ 2,298
Total before mitigation	$25,400	$25,821	$26,249	$26,685	$27,127	$27,577	$28,038	$28,503	$28,224	$29,456	$29,163
Mitigation (4 out of 5 winter months)	-$ 7,207	-$ 7,324	-$ 7,442	-$ 7,563	-$ 7,685	-$ 7,810	-$ 7,936	-$ 8,065	-$ 8,196	-$ 8,328	-$ 8,463
Total after mitigation	$18,193	$18,498	$18,807	$19,122	$19,442	$19,767	$48,136	$48,937	$48,249	$50,580	$49,859

Variable cost: This is the 5 day usage charge for fuel and the added cost of summer/winter differential to secure supply.

Please note Conversion Factors: GJ/MMBtu 1.055056
GJ/Mcf 1.07588

WEI TRANSPORT COST: PRESENT VALUE (Year 2015 $)

Period (Years)	11	21	11	21
Discount Rate	6.0%	6.0%	10.0%	10.0%
Fixed cost (150MMcfd x 365days x T-South Demand Charge)	$ 162,640	$ 257,563	$ 133,063	$ 185,419
Variable based on (150 MMcf/d x 5 days) (two days first year)	$ 15,523	$ 25,934	$ 12,537	$ 18,291
Total before mitigation	$ 178,163	$ 283,497	$ 145,600	$ 203,709
Mitigation (4 out of 5 winter months)	-$ 51,243	-$ 81,150	-$ 41,924	-$ 58,420
Total after mitigation	$ 126,920	$ 202,347	$ 103,676	$ 145,290
Levelized Yearly Cost, before mitigatin ($Cdn 000)	$ 22,573	$ 24,069	$ 22,417	$ 23,554
Levelized Yearly Cost, after mitigation ($Cdn 000)	$ 16,080	$ 17,179	$ 15,962	$ 16,799

Unit Charge based on period & discount rate	11yr @ 6%	21yr @ 6%	11yr @ 10%	21yr @ 10%
Before mitigation unit charge ($Cdn/GJ)	$ 139.87	$ 149.14	$ 138.91	$ 145.95
After mitigation unit charge ($Cdn/GJ)	$ 99.64	$ 106.45	$ 98.91	$ 104.09

$$NPV = \sum_{i=1}^{n} \frac{\text{unit charge}}{(1 + \text{discount rate})^i}$$ *where n is the period (12 year or 22 year) and discount rate is 6.2% or 10%*

Appendix 7

RATE DESIGN FOR RESIDENTIAL CUSTOMERS

Appendix 7-1

2012 RESIDENTIAL END-USE STUDY

SAMPSON RESEARCH

Consulting Project

2012 FEU Residential End-use Study

Final

Prepared for:
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By:

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Note to Readers:

All opinions and analyses presented in this report are the responsibility of Sampson Research and do not necessarily represent the views of FortisBC.

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This document is formatted for double sided printing to save paper. Blank pages are inserted where necessary to preserve proper formatting.

Currency Units

All dollar figures presented in this report, unless stated otherwise, are expressed in Canadian funds.

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SAMPSON RESEARCH

1 EXECUTIVE SUMMARY

1.1 Introduction and Background

This report summarizes the results from a Residential End-Use Survey (REUS) of FortisBC Energy Utilities' (FEU) customers conducted in late 2012. Over 3,400 survey responses were received over the Internet or through the mail. Results were analyzed by FEU's five regions (Lower Mainland/Fraser Valley, Vancouver Island/Sunshine Coast, Interior (Inland and Columbia), Whistler and Fort Nelson). Comparisons were made with results from residential end-use studies conducted by FEU in 2008 and 2002. Survey estimates at the utility level for the 2012 REUS are accurate to +/- 2.4%, 19 times out of 20.

The 2012 REUS represents the first time the electric and gas divisions of FortisBC have combined resources to implement a joint REUS of their customers. To do this, the questionnaire and survey sample were structured to accommodate gas-only customers, electric-only customers, and customers who receive both their gas and electric services from FortisBC (i.e., shared services customers). REUS results for FortisBC's electric customers are published in a separate report.

Data from the 2012 FEU REUS and published third party sources were used to explore trends and factors contributing to the decline in residential natural gas use rates. These included developments and trends in new construction, gas appliance stocks and efficiencies, and changes in the demographic composition of FEU's residential customer base. Conditional demand analysis (CDA) modelling using REUS data and gas consumption records were used to derive Unit Energy Consumption (UEC) estimates for key gas end-uses by region and at the utility level. These estimates were compared to those generated by the utility in 2008 and 2002.

1.2 Highlights of the 2012 REUS

Highlights from the 2012 REUS of FEU's gas customers are organized by topic area. Readers are directed to the respective sections in the main report for a detailed presentation and discussion of results by region, dwelling type, and dwelling vintage.

1.2.1 Trends Influencing Residential Natural Gas Consumption

Use rates (weather normalized gas consumption per-household) have been declining across FEU's regions since 1999. Use rates are down 24% since 1999 and 4% since the last REUS (2008). The decline since 2008 is understated somewhat due to a change in the use rate calculation method for 2012.

Declining use rates are attributed to:

- The shift in new residential construction towards smaller, less energy-intensive dwellings including row houses, townhouses, and apartments.
- Improvements in the thermal envelope of all dwelling types (improved insulation, energy-efficient windows, etc.).
- Improvements in the efficiency of larger (thermal) gas end-uses including furnaces, boilers, domestic water heaters, and fireplaces.

EXECUTIVE SUMMARY

- Changes in the penetration rates of gas appliances and equipment (convenience loads) in new and retrofit construction.
- Improvements in the efficiency of appliances that use hot water, including clothes washers and dishwashers.
- The long-term decline in the average number of occupants per-dwelling and an aging customer base.
- Long-run demand response to increases in the price of natural gas.

These trends are being partially offset by the long-run increase in the average size of the new single family detached dwellings.

1.2.2 Dwelling Characteristics and Renovations

- The average FEU residential customer has lived in their home for 17 years, up from 12 years in 2002. This increase is consistent with the aging of FEU's residential customer base. People are less likely to change residences as they get older.
- Average home size (ft^2) varies by dwelling type and vintage. The median size of a single family detached (SFD) dwelling with gas service built since 2005 is 2,900 ft^2, 32% larger than SFDs built in 1950-75 and 53% larger than SFDs constructed before 1950.
- Ceiling heights in newly constructed dwellings continue to increase, with ceilings of nine feet and higher present in 69% of dwellings constructed since 2005 compared to 14% of dwellings constructed during the 1950-75 period. Increased floor space and higher ceilings increase the overall load placed on space heating equipment.
- The likelihood of basements being completely finished has increased from 57% in 2008 to 62% in 2012.
- Consistent with changes to building codes, newer homes are more likely to have average or above average insulation, high efficiency windows, and insulated exterior doors.

1.2.3 Energy-Related Renovation Activities – Past and Planned

- Nearly half (46%) of FEU customers undertook one or more energy-related improvements to their home in the last five years. The top three energy-related renovations include installing programmable thermostats, energy-efficient windows, and weather stripping and caulking.
- Thirty-eight percent (38%) of households plan to undertake one or more energy-related renovations during the next two years. The top three energy-related renovations planned include installing energy-efficient windows, improving insulation, and weather stripping / caulking.
- Nine percent (9%) of FEU customers made changes involving fireplaces or heating stoves during the last five years, and 6% plan to undertake similar renovations in the next two years.

1.2.4 Space Heating

- The proportion of FEU customers using natural gas as either their main or secondary (supplementary) space heating fuel in 2012 is 95%, unchanged from 2008. The role of natural gas as a space heating fuel, however, has shifted somewhat to a secondary or supplementary fuel. This trend was identified in the 2008 REUS. It is due primarily to the long-term decline in the penetration of gas forced air furnaces in new construction (57% of FEU homes built since 2005 compared to 88% of homes constructed between 1950 and 1975), and, to a lesser degree, the increased penetration of air source heat pumps.
- Five percent (5%) of FEU households changed their main space heating fuel during the last five years, not statistically different from the rate observed in 2008.
- The top three main methods of space heating are forced air furnaces (70% of FEU homes), hot water radiant floor heat or air source heat pumps (tied for second place at 6% each), and gas fireplaces (4%). Data gathered elsewhere in the 2012 REUS survey suggest the penetration of air source heat pumps is closer to 12% of FEU homes.
- On average, 78% of FEU homes have a gas forced air furnaces. High efficiency models (AFUE of 90% or higher) account for 37% of gas furnaces in FEU's service region, up from 16% in 2008 while standard efficiency furnace (less than 78% AFUE) shares have fallen to 23% from 44% in 2008. As of 2012, 40% of furnaces were mid-efficiency units (78% to 85% AFUE).
- High efficiency boilers (AFUE of 90% or higher) now make up 36% of all boilers in use, up from 30% in 2008.
- The repair incidence for gas boilers is significantly higher than gas furnaces (31% versus 18% during the last three years); so too, the median cost of the repair ($400 for gas boilers versus $300 for gas furnaces). The incidence of repairs is highest for boilers and furnaces when they are between 15 and 19 years old.

1.2.5 Domestic Water Heating

- Penetration of gas domestic water heaters (any type) is currently estimated at 83%, down from 89% in 2008. The decline is largely attributed to the drop in the penetration of natural gas DWH systems in dwellings constructed since 2005 (66% for gas dwellings constructed since 2005 versus 80% to 88% for older dwellings).
- The incidence of DWH fuel switching among FEU customers during the last five years is low at 2%. Of those who switched, the net effect on natural gas fuel shares is neutral.
- Storage-type hot water tanks (any fuel) are used by 91% of FEU dwellings without centrally provided domestic hot water. On-demand DWH units, including tankless and hybrid versions equipped with a small expansion tank, represent three percent and one percent of all DWH units respectively in 2012.
- Forty-one percent (41%) of FEU customers installed a new DWH heater in the last five years. This proportion has not varied significantly over the last three REUS surveys.
- Two percent (2%) of households use solar energy systems to pre-warm or supplement their domestic water heating.

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1.2.6 Fireplaces and Heating Stoves

- Eighty-four percent (84%) of FEU customers have one or more fireplaces and/or heater stoves, statistically unchanged from 2008.
- The three most popular fireplace types are heater style gas fireplaces (43% of FEU customers), wood burning fireplaces (22%), and decorative gas fireplaces (19%).
- Newer dwellings are more likely to have heater type gas fireplaces (fixed glass front), while older dwellings are more likely to have a decorative gas fireplace or a wood burning fireplace. Electric fireplaces have also become popular in new construction, present in 18% of homes constructed since 2005 compared to 8% for homes constructed during the previous 20 years.

1.2.7 Appliances

- Declines in the penetration of gas furnaces and gas hot water heaters (thermal loads) in new construction are being partially offset by the growing popularity (penetration) of smaller (convenience) gas loads like gas ranges (gas cook top and oven) or dual fuel ranges (gas cook top, electric oven). These appliances are displacing electric ranges (electric cook top and oven) and electric cook tops.
- The penetration of piped gas barbeques has also increased, currently present in 20% of FEU homes, up from 16% in 2008. Nearly half (45%) of gas homes constructed since 2005 have a piped gas barbecue.
- Energy-efficient front loading clothes washers are now present in 42% of FEU households, up from 27% in 2008.

1.2.8 Pools and Hot Tubs

- Three percent (3%) FEU households have a heated pool and 10% have a hot tub.
- The most common fuel used to heat swimming pools is natural gas (68% of heated pools). In contrast, only 10% of hot tubs use natural gas.

1.2.9 Behaviours

The frequency of a limited number of space heating and water heating behaviours were queried in the 2012 REUS.

- Space heating behaviours with the greatest room for improvement include draft proofing / leak sealing, closing vents / turning down the thermostat in unused rooms, and closing window coverings.
- Behaviours impacting domestic water heating with the greatest potential for improvement include turning off the water heater while away, doing laundry with full loads, and running dishwashers only when full.

- The frequency of water heating behaviours (e.g., showers, baths, dishwashing, clothes washing, etc.) is positively correlated with the number of people in the home, and, to a lesser extent, the presence of children or seniors.

1.2.10 Products and Services

- Thirty-seven percent (37%) of 2012 REUS respondents participated in an energy efficiency incentive program offered by a utility or government in the last five years. The proportion of renovations that were completed with assistance varied by renovation type.
- Based on a list of potential products and services designed to reduce energy use, survey respondents expressed the most interest in:
  - furnace or heat pump tune-up to ensure they are working safely and efficiently;
  - home energy audit to determine main energy uses in the home and identify opportunities to save energy; and
  - program to replace standard efficiency water heater with high efficiency water heater.

1.3 Conditional Demand Analysis Highlights

Conditional demand analysis (CDA) using data from the 2012 REUS, gas consumption records, and regional weather stations was used to estimate unit energy consumption (UEC) estimates for each of the major gas end-uses. Gas end-uses modelled included main and secondary space heating, water heaters, fireplaces, cook tops and ranges, pools, hot tubs, and piped gas barbeques.

Highlights from the CDA include:

- Primary and secondary space heating UECs of 52 GJ/year and 25 GJ/year, respectively. The UEC for primary space heating is down 9% from 2008, while secondary space heating UEC is up by 6%. Declines in the primary space heating UEC are consistent with the increasing efficiency of gas space heating equipment stocks and the shift of natural gas from a main to secondary heating fuel.
- UEC estimates for other gas end-uses include domestic water heating (26 GJ/year), decorative fireplaces (18 GJ/year), and heater type fireplaces (15 GJ/year).
- FEU customers in the Lower Mainland have higher UECs for primary space heating and domestic hot water use compared to other regions, most notably the Interior and Vancouver Island. These results are consistent with single family detached homes in the Lower Mainland being larger, on average, compared to other regions, and tending to have more occupants per dwelling compared to other FEU regions.

* * * * *

2 INTRODUCTION

This report presents detailed results and analyses from a comprehensive residential end-use study (REUS) of FortisBC Energy Utilities' (FEU) residential customers based on survey data collected in November of 2012. This study represents the fourth end-use survey of FortisBC's natural gas customers in British Columbia conducted since 1993, and the first to be conducted jointly with FortisBC's electric division (FBC).

Data, information, and analysis from residential end-use studies like the 2012 REUS are used to support a broad range of activities and processes for FortisBC's electric and gas divisions, including:

- Revenue requirement, rate design, and other applications to the British Columbia Utilities Commission
- Preparation and updating long-term resource plans
- Inputs for pricing models and tests for system extensions (mains and services)
- Reviews of conservation potential
- DSM opportunity assessments and program designs
- Inputs for load forecast models
- Development of marketing programs and advertising messaging

2.1 Research Objectives

Research objectives for the 2012 REUS are extensive and cover most aspects of documenting and understanding residential energy use, including equipment stocks, purchases and replacement behaviours, attitudes towards energy conservation, and other variables that influence the residential consumption of natural gas and electricity. Specifically, the research objectives for the 2012 study included:

- Collecting information on appliance end-use stocks including age, efficiency, and usage. End-uses include space heating and cooling, water heating, cooking, refrigeration, dishwashing, laundry, swimming pools, hot tubs, and saunas.
- Determining primary and secondary energy (fuel) sources for space and water heating.
- Determining dwelling characteristics that directly or indirectly influence energy consumption, including building envelope, vintage, heated floor space, number of stories, tenure, length of residency, ceiling heights, window types, and insulation levels.
- Identifying past and planned energy-related renovation activities.
- Understanding the factors that influence end-use fuel choices.
- Detailing energy conserving behaviours that affect energy use associated with heating, cooling, laundry, dishwashing, bathing, showers, draft proofing, furnace maintenance, food storage, lighting, and small appliance use.
- Discerning attitudes and beliefs regarding energy conservation and other energy-related issues.
- Assessing interest in potential utility programs and services and the likelihood of purchasing new appliances, or conducting upgrades to the building envelope.

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- Performing a conditional demand analysis (CDA) to estimate unit energy consumption (UEC) estimates for major appliance and end-uses.
- Analyzing trends in gas end-uses and end-use combinations in new construction versus older housing stock.
- Comparing findings with previous surveys, where applicable, to assess market changes and trends. Analyzing past and future trends in housing type, appliances, efficiency levels, renovations, and demographic shifts.

2.2 Previous Gas REUS Studies

The 2012 REUS of FortisBC's natural gas customers builds upon end-use studies conducted by its predecessor companies Terasen Gas in 2008 and BC Gas in 2002 and 1993.

Regional coverage of the REUS surveys has expanded over time commensurate with expansion of the utility. The 1993 and 2002 studies presented results for three regions: Lower Mainland, Interior, and Fort Nelson. The 2008 and 2012 studies included these plus two additional regions: Vancouver Island/Sunshine Coast and Whistler.

The last three REUS surveys included conditional demand (CDA) analyses that estimated unit-energy consumption (UEC) figures for major gas end-uses. The 2002 and 2008 REUS studies also included psychographic segmentations of residential customers based on self-reported information on attitudes, behaviours, and socio-demographic characteristics.

2.3 Topic Coverage for the 2012 REUS

Topic coverage for FortisBC's residential end-use survey has expanded with each iteration of the study. The questionnaire has evolved over time, reflecting emerging trends in residential end-use equipment, building characteristics, and other market characteristics. Evolution of the questionnaire also reflects the ongoing effort to improve the accuracy and reliability of the results. While changes in topic coverage and/or question wording are sometimes required, considerable attention is paid to maintaining consistency and compatibility with past questionnaire designs. Doing this maximizes FortisBC's ability to identify and follow trends in residential energy use equipment and behaviours.

The 2012 REUS represents the first time the gas and electric divisions of FortisBC have conducted a joint end-use survey. The combined study provides data to each division about its respective residential customers. It also affords a holistic energy view of their shared customers. Achieving this goal meant the end-use questionnaire for shared customers had to be expanded to address the broader range of electrical end-uses and related behaviours, including lighting, air conditioning, and smaller end-uses such as DVD players and computers. Additionally, target number of survey completions was increased to 5,000 compared to 2,715 for the 2008 REUS. While the final number of responses fell below the target, the combined survey approach is considered a success and provides a rich dataset of information on the residential customers for each utility.

2.4 Report Organization

This report is organized into 15 sections plus a bibliography. Following this introduction, the Background and Methodology section addresses the sampling strategy, final sample design, questionnaire design, and final response statistics. Section 3 presents and discusses factors affecting long-run trends in natural gas use rates. The next nine sections address key findings from the 2012 REUS survey, organized by the respective topic areas of the survey instrument. Topic areas addressed are:

- Building Envelope and Renovations
- Space Heating
- Domestic Hot Water
- Fireplaces and Heating Stoves
- Appliances
- Pools, Hot Tubs, and Saunas
- Energy Use Behaviours
- Products and Services
- Demographics

Findings from the conditional demand analysis, including regional-specific Unit Energy Consumption (UEC) estimates by end-use, are provided in Section 14. The results of the gas end-use combinations analysis are summarized in Section 15. A bibliography of referenced research and articles is included in Section 16.

This document is accompanied with two appendices. Appendix A includes the 2012 REUS questionnaire. Appendix B presents background methodology and detailed equations used in the conditional demand analysis.

2.5 Using this Report

This report presents a substantial body of information and data about FortisBC's residential gas customers. Trends in the data are identified through comparisons with past REUS studies and/or using additional information and statistics from third party sources. Considerable effort has been made to ensure the data presented are accurate and statistically representative of the FortisBC's residential customer base. The quality of the analysis and interpretation of the data are dependent, in part, on the accuracy of the information provided by survey respondents. The technical nature of many of the questions in the REUS survey inevitably means that unintentional misclassifications or reporting errors by survey respondents are possible. Where evident, quality issues are identified, implications discussed, and remedies, if possible, provided.

The sheer volume of information contained in this report means its primary purpose is as a reference document; filling gaps in information about residential energy issues. Analyses and conclusions are meant to further discussion and understanding of residential energy trends and the factors influencing them.

3 BACKGROUND & METHODOLOGY

This section discusses the sampling plan, questionnaire topics, survey implementation, survey response, and representativeness of the survey results for the 2012 REUS. This section also provides a list of terms, definitions, and explanatory notes to assist the reader in the interpretation of the reported results.

3.1 Sample Frame and Sampling Plan

The sampling plan for the 2012 REUS was more complex than past studies because of the need to ensure representative samples of residential customers were obtained for both the natural gas (FEU) and electric (FBC) divisions of FortisBC. Additionally, the sampling plan needed to ensure representative samples for regions within each division, including the Interior region where approximately 50% of the customers were common to both divisions (i.e., shared services). Interior region customers were oversampled to ensure these needs were met.

For the FEU REUS, the sample plan required representative samples of natural gas customers from each of the FEU's five regions:

- Lower Mainland (LM)
- Interior (Inland and Columbia) (INT)
- Vancouver Island / Sunshine Coast (VI)
- Whistler (W)
- Fort Nelson (FN)

Customer counts for each of these regions (i.e., the sample frame) are provided in Table 1.

Table 1: FEU Residential Customer Counts (Sample Frame)

Region / Business Unit	Customer Counts	Percent Distribution
Lower Mainland (LM)	528,192	61.7%
Interior (Inland and Columbia) (INT)	231,522	27.0%
Vancouver Island / Sunshine Coast (VI)	92,067	10.8%
Whistler (W)	2,271	0.3%
Fort Nelson (FN)	1,947	0.2%
Total (FEU)	**855,999**	**100%**

For reference purposes, customer counts for FBC's electric customers are provided in Table 2.

Table 2: FBC Residential Customer Counts (Sample Frame)

Region / Business Unit	FBC Direct	FBC Indirect	FBC Total	Percent Distribution
Kelowna / Central Okanagan (KE)	44,378	13,037	57,415	40%
South Okanagan (SO)	20,994	20,542	41,536	29%
Kootenay / Kootenay Boundary (KB)	33,713	10,406	44,119	31%
Total (FBC)	**99,085**	**43,985**	**143,070**	**100%**

BACKGROUND & METHODOLOGY

3.2 Sample Sizes and Sample Preparation

FEU's 2008 REUS had targeted 2,715 survey completions but realized 2,221 completed surveys. The target for the 2012 REUS (gas customers) was set at 5,000 surveys. The decision to increase the target number of survey completions for the 2012 REUS was attributed to FortisBC's desire to:

- reduce the standard errors of point estimates, especially for less common end-uses, behaviours, and building types;
- accommodate analysis of FBC customer results by its three regions ((Central Okanagan, South Okanagan / Similkamee, West Kootenay / Kootenay Boundary), and whether these customers were directly or indirectly served by FBC;
- improve the accuracy and reliability of conditional demand analysis estimates of unit energy consumption (UEC) for each of the major gas regions; and
- accommodate oversampling in regions with a history of low response rates (e.g., Lower Mainland).

Similar to that of past REUS surveys, eligibility for inclusion in the sample was restricted to customers with a minimum of two years of uninterrupted gas billing history. This was a requirement of the conditional demand analysis (CDA). As a result, customers whose residence was constructed since fall of 2010 or who changed residences in the two years leading up to the survey were excluded from the REUS sample frame.

Assuming an average survey response of 20%, achieving 5,000 completed surveys required a mail-out of 25,000 questionnaires. This target was expected to yield an overall accuracy of +/- 1.4% at the combined utility level using a 95% confidence interval. The sampling plan sought to achieve accuracy levels in the major FEU regions of +/- 3% or less.

All customer samples, with the exception of FBC's indirectly served customers[1], were randomly drawn from FEU's customer accounts. For customers in the shared services region, FBC drew a random sample of direct customers which was then merged with FEU's customer accounts to identify customers with a gas account. Finally, a third party sample of households located in areas serviced by municipal (wholesale) utilities was purchased and merged with FEU gas accounts to complete the sample frame for the Interior.

3.3 Questionnaire Design and Topics

The 2012 REUS questionnaire was designed with strong emphasis on ensuring comparability and consistency with past REUS surveys. Any modifications to questions and/or response categories were made to either improve question performance or accommodate trends in residential end-use equipment. Additionally, the order in which some questions were asked on the questionnaire was changed from the previous REUS to improve flow. The 2012 REUS questionnaire expanded its use of graphics and explanatory text boxes to help respondents correctly categorize their equipment and household features. In situations where several different models of a particular end-use are possible (e.g., differing types of domestic hot water heaters), questions were worded using visual clues or identifiers to improve respondents' ability to correctly classify their equipment through observation.

[1] Indirect customers receive their electrical service from a municipal electric utility (e.g., Kelowna, Summerland, Penticton, Grand Forks, or Nelson). These municipal utilities resell electricity supplied by FortisBC.

Table 3 summarizes the major subject areas addressed by the 2012 REUS with comparisons to past FEU and FBC REUS surveys.

Table 3: REUS Survey Topics – Comparisons to Past REUS Surveys

Survey Topic Group	FEU 2012	FEU 2008	FEU 2002	FEU 1993	FBC 2012	FBC 2009
Dwelling characteristics	◆	◆	◆	◆	◆	◆
Space heating	◆	◆	◆	◆	◆	◆
Fireplaces	◆	◆	◆	◆	◆	
Domestic water heating	◆	◆	◆	◆	◆	◆
Appliances	◆	◆	◆	◆	◆	◆
Indoor and outdoor lighting					◆	◆
Pools and hot tubs	◆	◆	◆	◆	◆	◆
Energy-related renovations	◆	◆	◆	◆	◆	
Rates and tariffs			◆			
Energy use behaviours	◆	◆	◆	◆	◆	◆
Products and services	◆	◆	◆	◆	◆	
Communications with FortisBC			◆			
Energy attitudes & preferences	◆	◆	◆		◆	◆
Socio-demographics	◆	◆	◆	◆	◆	◆

3.3.1 New Topics

The following topics were new to the 2012 REUS:

- Part-time or full-time use of the residence for a home-based business
- Value of any repairs made to furnaces or boilers in the last three years
- Hot water tank size
- Proximity of hot water tank to an electrical outlet
- Presence of a drain water heat recovery system
- Faucet aerators and instant hot water dispensers
- Use of high efficiency (ECM) motors for swimming pools
- Presence of saunas and sauna fuels
- Presence of gas outdoor fireplace or fire pit
- Likelihood of purchasing air conditioning in the upcoming year
- Sources of information used for major appliance purchase decisions
- Person(s) in the household making the most effort to conserve energy
- Familiarity with utility energy conservation initiatives
- Respondent’s role in major appliance purchase decisions
- Access to the internet
- Presence of secondary suites, detached garages/workshops, other buildings, and well pumps
- Installation of an ENERCHOICE fireplace in the past five years

3.3.2 Other Questionnaire Changes

Expansions / modifications of existing questions / topics in the 2012 FEI REUS questionnaire included:

- inclusion of electric forced air furnace as a space heating method;

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- inclusion of two types of on-demand hot water heaters (with or without an expansion tank), and hybrid (heat pump) hot water heaters; and
- an expanded appliance section.

Two versions of the REUS questionnaire were developed. Customers identified as having both gas and electric (direct or indirect) service provided by FortisBC or the possibility of shared services received an expanded questionnaire with sections dedicated to electrical end-uses such as lighting. The questionnaire received by gas-only customers excluded these dedicated electric-only sections.

The final version of the 2012 FEU (gas) questionnaire is included in Appendix A.

3.4 Survey Implementation

The Vancouver office of IPSOS Reid was responsible for implementing the survey, data cleaning, tabulating results, and incentive management. The survey was mailed to households in hardcopy form, accompanied by a self-addressed return envelope. Recipients could either complete the hardcopy survey and return by mail, or complete an online version of the survey. Each recipient was assigned a unique entry code which allowed the marketing research firm to control the possibility of duplicate surveys from the same households. Incentives to complete the survey included a chance at winning of one of four $1,000 gift certificates to a home improvement store. To encourage online responses, respondents completing their survey online had their name entered in the prize draw an additional time, effectively doubling their chances of winning.

A total of 25,400 questionnaires were mailed out in the fourth week of November 2012. Reminder cards were mailed out a week later. Respondents were given four weeks to complete the survey.

A total of 3,441 valid surveys were received, of which 41% were completed online. The overall response rate was 13.7%, considerably lower than the 20% achieved in 2008. The lower than expected response rate is attributed to the length of the survey, the technically challenging nature of many of the survey questions, and the timing of the survey's release (last week of November). Survey response rates by region are summarized in Table 4.

Table 4: FEU REUS Survey Response Summary (%)

Region / Business Unit	Surveys Mailed	Completed Surveys	Response Rate (%)	Surveys Completed Online (%)
Lower Mainland (LM)	6,250	793	12.7	45.0
Interior (Inland and Columbia) (INT)	12,171*	1,707	14.0	41.7
Vancouver Island / Sunshine Coast (VI)	3,704	752	20.3	36.7
Whistler (W)	1,650	85	5.2	41.7
Fort Nelson (FN)	1,294	107	8.3	41.0
Total (FEU)	**25,069**	**3,444**	**13.7**	**41.3**

* Joint sample of gas and electric customers

3.5 Weighting of Results

Weights were used to restore the relative proportions of the five regions to that of the FEU customer population. The weights were calculated using equation (1):

$$W^r = (P^r/P^{FEU}) \,/\, (S^r/S^{FEU}) \qquad (1)$$

W = weight
P = population (sample frame)
S = survey returns
r = FEU region
FEU = total of all FEU regions

Table 5 presents the weights calculated using this formula and used in analyses of the 2012 REUS data:

Table 5: FEU 2012 REUS Weights

FEU Region	Weight
Lower Mainland / Fraser Valley	2.6773
Interior / Kootenay	0.5455
Vancouver Island / Sunshine Coast	0.4919
Whistler	0.1053
Fort Nelson	0.0761

3.6 Accuracy of Survey Estimates

The margin of error (accuracy level) for 2012 REUS questions varies by region and the degree of consensus. Table 6 summarizes accuracy levels at the 95% confidence level for a typical range of “yes-no” type questions for each of the five FEU regions and the five region total (FEU). Comparable margins of error at the FEU level for the 2008 REUS survey are provided, as are margins of error for the subset of Lower Mainland, Interior and Fort Nelson regions (FEI) for 2012, 2008 and 2002. The latter are provided to allow comparison with the 2002 REUS which did not include Vancouver Island or Whistler.

Table 6: Accuracy Levels for Proportional Responses by Region (%)
Percent Plus or Minus at the 95% Confidence Level

Accuracy / Proportional Response	LM +/-	INT +/-	VI +/-	W +/-	FN +/-	FEU 2012 +/-	FEU 2008 +/-	FEI 2012 +/-	FEI 2008 +/-	FEI 2002 +/-
50%	3.5	2.4	3.6	10.6	9.6	2.3	3.2	2.5	3.5	2.4
40% or 60%	3.4	2.3	3.5	10.4	9.4	2.2	3.2	2.5	3.4	2.4
30% or 70%	3.2	2.2	3.3	9.7	8.8	2.1	3.0	2.3	3.2	2.2
20% or 80%	2.8	1.9	2.9	8.5	7.7	1.8	2.6	2.0	2.8	2.0
10% or 90%	2.1	1.4	2.1	6.4	5.8	1.4	1.9	1.5	2.1	1.5
Number of respondents (unweighted)	**793**	**1707**	**752**	**85**	**104**	**3441**	**2221**	**2604**	**1446**	**1610**

At the FEU company level, a typical question with a “50-50” response (e.g., 50% answering yes, 50% answering no) will have an accuracy of plus or minus 2.3%, 19 times out of 20. The margin of error varies by region, reflecting differing proportions of completed surveys to the sample population. Regardless of

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region, margins of error decrease as the consensus of the survey estimate increases. Thus, a yes-no type question with 90% answering "yes" will have an accuracy at the FEU level of plus or minus 1.4%, 19 times out of 20.

3.7 Abbreviations, Definitions & Explanatory Notes

The following definitions and notes are included to aid in the interpretation of survey results and the general readability of the report.

Conditional Demand Analysis (CDA) – A statistical method for proportioning total household natural gas consumption by individual gas end-uses (e.g., space heating, domestic hot water, cooking, etc.). CDA requires data on the penetration and saturation of end-uses by customer, matched to their billing consumption data. As an indirect approach to estimating end-use consumption[2], diversity in the penetration, saturation, and usage of the end-uses within the sample population is required for the model to isolate the consumption of any particular end-use.

Data presentation – Data and statistics are presented in a variety of formats, including tabular, graphical, and within descriptive paragraphs. The expression of percentages in the form of ratios (e.g., one-in-ten, one-in-five, etc.) within the text of this report reflects the style preferences of FortisBC.

Don't Know (DK) Responses – Some survey questions include a "don't know" (DK) response category. The relative proportion of respondents who answered DK provides useful information, and often is related to the complexity of question's subject. In some cases, it is legitimate to recalculate proportions for the question excluding DK responses. Effectively, this recalculation assumes the distribution of the DK responses is proportional to those who provided a response. Re-proportioning DK responses is not valid in cases where the "proportionate distribution" assumption does not apply. For example, uncertainty regarding furnace efficiency may be proportionately higher for households with older mid- or standard efficiency furnaces than for those with high efficiency furnaces. In cases such as these, a DK response should be treated as a legitimate response and included in the base for calculating the relative proportions of the other response categories.

DWH – Domestic water heater

FAF – Forced air furnace

FEU (FortisBC Energy Utilities) – Represents the collective name of the three corporate utilities that make up FortisBC's Gas Utility, including FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.

FEU 2008 – Represents data from FortisBC Energy Utilities' (FEU) 2008 residential end-use survey including customers from the Lower Mainland/Fraser Valley, Vancouver Island / Sunshine Coast, Interior and Columbia, Whistler, and Fort Nelson. These data were published in the 2008 REUS report under the designation "2008 TG" (Sampson Research 2009).

[2] As opposed to a more direct method of metering of individual end-uses.

FEU 2012 – Represents data from FEU's 2012 residential end-use survey including gas customers from the Lower Mainland/Fraser Valley, Vancouver Island / Sunshine Coast, Interior and Columbia, Whistler, and Fort Nelson.

FEI (FortisBC Energy Inc.) – Represents a subset of FEU gas customers, including those in the Lower Mainland, Interior, Columbia, and Fort Nelson regions. Excludes customers in Vancouver Island / Sunshine Coast and Whistler.

FEI 2002 – Represents utility level data from FEU's 2002 residential end-use survey for gas customers in the Lower Mainland, Interior, Columbia, and Fort Nelson regions. Excludes customers in Vancouver Island / Sunshine Coast and Whistler. Comparisons to 2002 REUS results use data that were originally published in the 2003 REUS report (Habart 2003). These data were republished in the 2008 REUS report under the designation "2002 TGI" (Sampson Research 2009).

FEI 2008 – Represents utility level data from FEU's 2008 residential end-use survey for gas customers in the Lower Mainland, Interior, Columbia, and Fort Nelson regions. Excludes customers in Vancouver Island / Sunshine Coast and Whistler. These data were published in the 2008 REUS report under the designation "2008 TGI" (Sampson Research 2009).

FEI 2012 – Represents utility level data from FEU's 2012 residential end-use survey for gas customers in the Lower Mainland, Interior, Columbia, and Fort Nelson regions. Excludes customers in Vancouver Island / Sunshine Coast and Whistler.

Footnotes – With the exception of footnotes in data tables, footnotes referenced in the text of the report are found at the bottom of the page. Footnotes pertaining to data in tables are situated immediately below the table in question.

FN – Fort Nelson

Natural Gas vs. Piped Propane – Geographic coverage for the 2012 REUS survey included a small number of customers in areas serviced by piped propane systems (e.g., Revelstoke). Unless otherwise stated, all references to "piped gas" in the report refer to either piped gas or piped propane.

Heating Degree Day (HDD) - Defined as the difference between a reference value of 18°C and the average outside temperature for that day. The number of HDDs reflect the amount by which the outside temperature falls below 18 degrees Celsius and length of time below that temperature. The number of HDDs provides a good indication of the amount of heating required to maintain a comfortable indoor temperature.

Figure 1 (next page) shows the relative severity of a typical winter for each of FEU's five regions, as indicated by 30 year HDD averages. Lower Mainland (LM) and Vancouver Island / Sunshine Coast (VI) regions have the warmest winters (each with approximately 3,000 HDDs per year), while winters in the Interior (INT) and Whistler (W) regions are colder (approximately 3,800 and 4,300 HDDs per year respectively). The northerly Fort Nelson (FN) region is the coldest, recording more than 6,800 HDDs per year.

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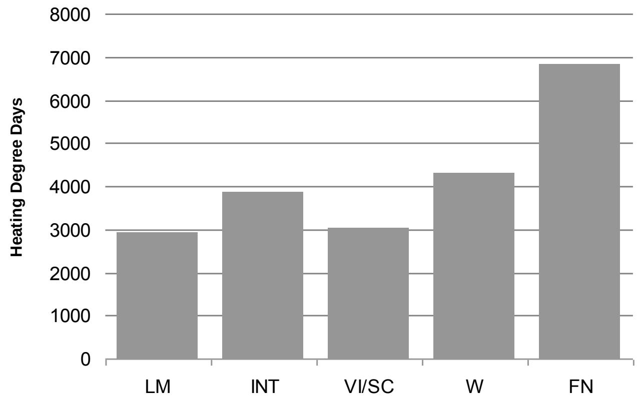
Figure 1: Typical Annual Heating Degree Days by Region



Source: Environment Canada, 1971-2000 Climate Normals

INT –Interior region including Inland and Columbia

LM – Lower Mainland / Fraser Valley

Non-Response (NR) – Sometimes categorized as missing values, they refer to cases where a respondent chose not to answer a question. In these cases, non-responses are treated differently from "Don't Know" (DK) responses as they imply neither uncertainty nor certainty of a response. Indeed, they provide no information from which to extrapolate a response. All calculations in this report, unless stated or otherwise indicated, exclude missing or NR values. This is done to avoid distorting the proportions assigned to the response categories based on those who answered the question.

The 2002 REUS report represents an exception to this assumption. Missing data and Don't Know responses were often reported as a combined statistic and reported as DK/NR. In cases where the 2002 survey questionnaire did not provide a separate DK response category (e.g., check box), it was assumed that all responses in the DK/NR category represented missing values. In these situations, proportions were restated to exclude the missing values, making them consistent to the approach used in the 2008 and 2012 REUS reports. In all other situations, the DK/NR estimate from the 2002 REUS was left unchanged and footnoted in the tables.

Penetration – Defined as the number of households with a particular appliance or end-use divided by the total number of households with or without the appliance or end-use. Penetration is used to understand the proportion of FEU's residential customer base with the appliance or end-use in question. Penetration does not concern itself with how many of the appliances or end-uses an individual household has, only the presence of at least one. Commensurately, the upper limit on any penetration estimate is 100%.

Saturation – Defined as the total number of appliances or end-uses divided by the number of households with and without the appliance or end-use. Saturation provides an estimate of the average number of specific appliances or end-uses per typical FEU residential customer. Saturation estimates are influenced by the number of appliances present in user households and the penetration of the appliance in the general population. For example, the saturation of low flow shower heads is a function of how many households use them <u>and</u> the number installed. As homes may have more than one appliance or end-use there is no theoretical upper limit on saturation estimates.

SFD – Single family detached dwelling

Significant Digit Conventions – Except where otherwise indicated, all data placed in the text of this report have been rounded to the nearest significant digit. To facilitate analyses and calculations by FEU, data presented in tables and figures are expressed to one decimal place, and in some cases (e.g., saturation rates) two decimal places. This also allows tables to accommodate the occasional small response proportion (i.e., penetrations of less than 1%).

Unit Energy Consumption (UEC) – The annual energy consumed by a piped gas or propane end-use in a given year. UECs for gas utilities are estimated by conditional demand analysis. The size of an UEC estimate is determined, in part, by the purpose of the end-use (e.g., cooking, space heating, etc.), the efficiency of the end-use equipment, and its use (occupant behaviours). UECs for some end-uses, particularly space and water heating, are also weather (HDD) dependent.

Unweighted Base – All tables whose data and/or calculations share the same base will have the unweighted base for the statistics indicated. These numbers reflect the actual number of surveys where a valid response to the question was received. The size of the unweighted base is useful to help guide comparisons with other data and understanding the relative accuracy of the estimates. Unless indicated otherwise, unweighted bases indicated in this report exclude non-responses or missing values (see definition of non-response, below). The unweighted base may change somewhat from question to question depending upon the degree of non-response.

VI – Vancouver Island / Sunshine Coast

Weighted Results – All utility level results (FEU, FEI) are based on weighted data to ensure proportionate representation from the respective regions.

W – Whistler

Additional Notes to Tables

n/a Not Applicable – Used when data are unavailable for comparison.

-- No responses were received for the particular category or cell.

0.0* Value less than 0.1 or 0.1%

0.00* Value less than 0.01

4 TRENDS

This section presents and discusses key trends in household formation and composition, end-use penetration rates, equipment efficiency, and construction trends that are influencing natural gas consumption for FortisBC's residential customers. The primary objective of this section is to provide context for understanding and interpreting the findings from the 2012 REUS, particularly when its findings are compared with those from past REUS surveys. Implications of these trends and developments on the residential demand for natural gas over the medium-term are discussed.

4.1 Trends in Natural Gas Consumption

4.1.1 Use Rates

Natural gas consumption on a per-FEU household (per-account) basis, normalized for year-to-year variations due to temperature, is down significantly (24%) since 1999 (Table 7). Since the last REUS (2008), use rates have continued to decline, although the amount of the decline is understated somewhat due to a recent change in the definition of a valid customer account.[3] Declines in use rates have occurred in all FEU regions, most notably Vancouver Island (down 32% since 1999), the Interior (down 27%), and the Lower Mainland (down 19%). Declining residential consumption of natural gas is a North American-wide phenomenon.

Table 7: FEU Weather Normalized Gas Use Rates by Region – 1999-2012

Year	LM	INT	VI	W	FN	FEU
1999	121.9	104.5	71.9	94.8	161.4	114.1
2000	116.9	99.5	68.4	91.8	158.0	109.2
2001	105.2	88.1	66.2	87.9	167.3	98.4
2002	118.4	89.5	66.6	89.4	156.5	107.1
2003	111.5	89.2	61.8	90.6	162.3	102.3
2004	108.3	86.1	59.0	85.7	166.4	99.1
2005	103.6	82.4	58.7	93.4	153.7	95.0
2006	103.2	82.0	60.2	85.6	141.5	94.7
2007	102.6	80.8	57.0	95.7	141.9	93.8
2008	99.5	76.5	56.1	95.2	139.6	90.5
2009	99.8	76.3	52.6	80.0	138.4	88.3
2010	99.3	74.9	51.8	99.1	140.1	87.5
2011	96.7	74.1	51.2	93.6	136.9	85.6
2012 [1]	98.3	76.3	49.0	88.0	138.3	86.9
Change 1999-2012	**-19.4%**	**-27.0%**	**-31.9%**	**-7.2%**	**-14.3%**	**-23.8%**

[1] Increase over 2011 due, in part, to a change in the definition of a valid customer account.

4.1.2 Natural Gas Intensities (GJ/ft²)

Declines in natural gas use rates are consistent with the long-term decline in average gas intensities (GJ consumption per square foot) of residential construction.

[3] Source: Email correspondence from Walter Wright, FEU. This change affects use rate calculations for 2012 going forward.

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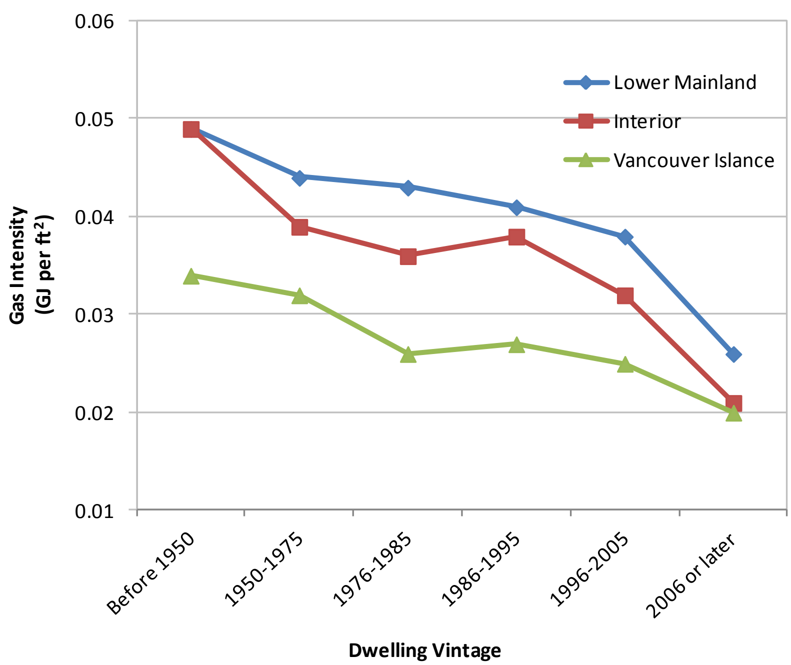
Figure 2 shows the gas intensity (GJ/ft^2) trend for single family detached homes constructed in the Lower Mainland since 2005 is lower by almost half (47%) than homes constructed prior to 1950. The relationship also holds true for more recent vintages. Lower Mainland homes constructed since 2005, as an example, use 40% less natural gas per square foot than homes constructed between 1976 and 1985. Similar trends have occurred in the Interior and, to a lesser extent, on Vancouver Island.

The declines in residential gas intensity per-square foot reflect the net effect of improvements in thermal envelope and end-use equipment efficiency, trends in penetration rates for gas end-uses, the demand response to higher gas prices, plus other factors affecting both new and existing dwellings.

Figure 2: Gas Intensity Trend
Single Family Detached Dwellings – 2012 REUS Data



4.2 Factors Influencing Natural Gas Use and Intensity

Factors influencing natural gas use rates over time include:

- changes in the mix of dwelling types in new construction;
- changes in the penetration rates of gas appliances and equipment in new and retrofit construction;
- increasing efficiency of gas furnaces, boilers, water heaters, and other gas-related appliance stocks;
- improvements in thermal efficiency of the building envelope;
- changing demographic characteristics of FortisBC's residential customer base; and
- other factors, including short- and long-term responses to changes in the price of natural gas (demand elasticities) and cross effects.

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Some trends influencing natural gas consumption are short-term and transient, such as behavioural responses to short-lived increases or decreases in the price of natural gas. Others are long-term and are more sustained, such as long-run trends in new housing construction and legislated improvements in the efficiency of gas furnaces and hot water-using appliances. Some trends partly or wholly offset each other, while other trends complement each other. An example of an offsetting trend is the improvement in the efficiency of natural gas furnaces which is being partially offset by the increase in overall home size (square footage). An example of a complementary trend is the increased efficiency of domestic water heaters and the reduced demand for hot water associated with an aging customer base.

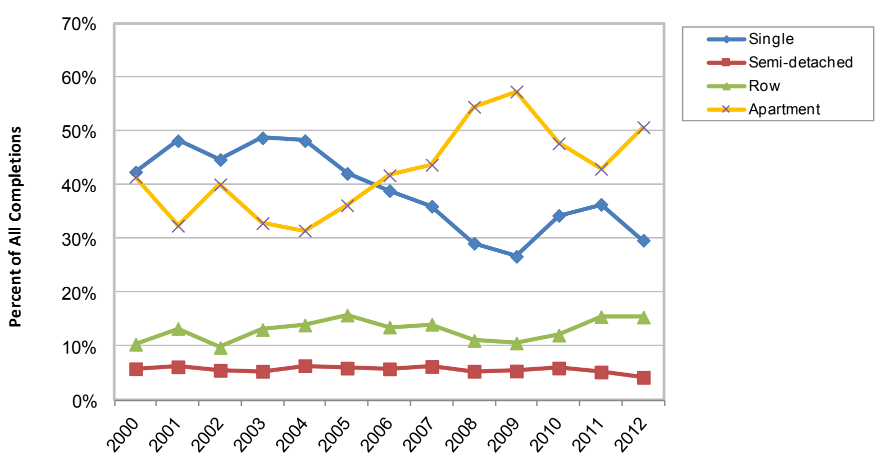
It is not the purpose of this section of the 2012 REUS report to quantify the relative contribution of the factors underpinning the long-run decline in natural gas use rates.[4] Rather, it is to provide an overview of key trends and developments influencing gas use rates for FortisBC's residential natural gas customer base.

Published research on natural gas use trends and influencing factors from other North American jurisdictions are referenced in this section where relevant. Third party research on gas trends, although less voluminous compared to that devoted to understanding the forces driving electricity use, confirms that many of the factors and trends influencing natural gas consumption in British Columbia are occurring across North America.

4.2.1 Trends in New Construction – Dwelling Type Mix

Canada Mortgage and Housing Corporation (CMHC) data show that residential construction in urban areas of British Columbia has been shifting away from single family detached dwellings towards apartments and row/townhouses for the last ten years (Figure 3).

Figure 3: Dwelling Type Shares - Housing Completions in Urban BC



Data source: CMHC

[4] Natural Resources Canada's *Energy Efficiency Trends in Canada, 1990 to 2009*, (Cat. No. M141-1/2009E-PDF), December 2011 provides a good discussion of the relative impact of the various trends and factors influencing energy use in the residential sector. The long-term change in energy use (all fuels) by Canadian homes is explained by quantifying five different contributing factors including changes in the number of households and floor space (activity), changes in the mix of dwelling types (structure), changes in the relative penetration of various appliances and end-uses (service level), differences in heating and cooling degree days (weather), and improvements in appliance efficiency and the thermal envelope of homes (energy efficiency).

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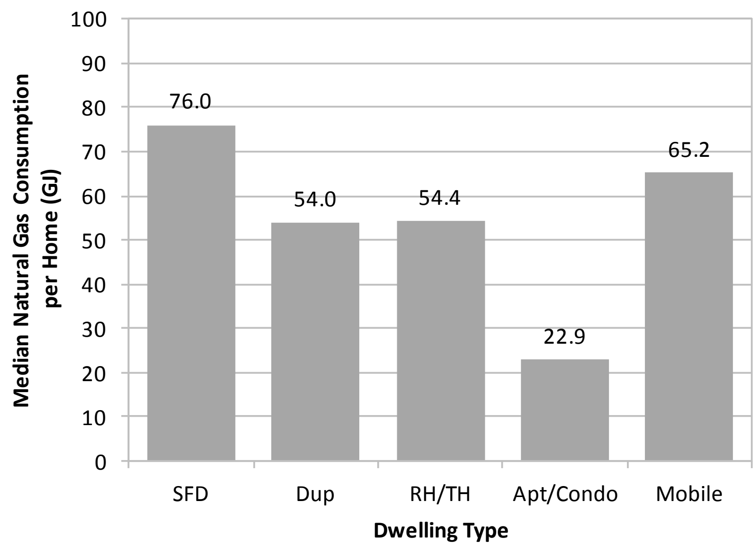
Single family detached dwellings have seen their share of new construction decline from nearly half (49%) of all dwelling completions in 2003 to just three-in-ten (30%) in 2012. In contrast, apartments (CMHC data is for individual apartment units regardless of whether they have gas) represented more than half of all new construction in 2012. As newly built dwellings represent only a one to two percent increase in the total stock of housing in British Columbia in a given year, new construction trends influence the relative composition of the stock of housing relatively slowly over the long-term.

The changing mix of dwelling types constructed in British Columbia will influence natural gas use rates in the long run as the amount of gas consumed by duplexes, townhouses, apartments / condominiums and mobile homes is typically less than single family detached units. Using data from the 2012 REUS, the median annual consumption for single family detached homes in FEU's service region is 76 GJ, compared to 54 GJ for row houses/townhouses, and 23 GJ for individually metered apartments /condominiums (Figure 4).

Figure 4: Median Annual Natural Gas Consumption by Dwelling Type – 2012 REUS

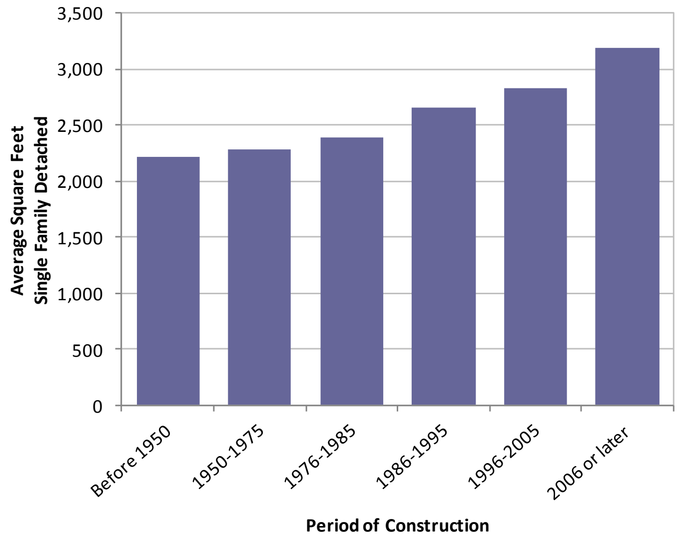


4.2.2 Trends in New Construction - Dwelling Sizes and Ceiling Heights

While the changing mix of dwelling types in new construction is placing downward pressure on gas intensities, the tendency for newer single family detached homes to be larger (greater floor area and internal volumes) is countering this trend to some degree. This increase in interior volume creates more demand for space heating and cooling.

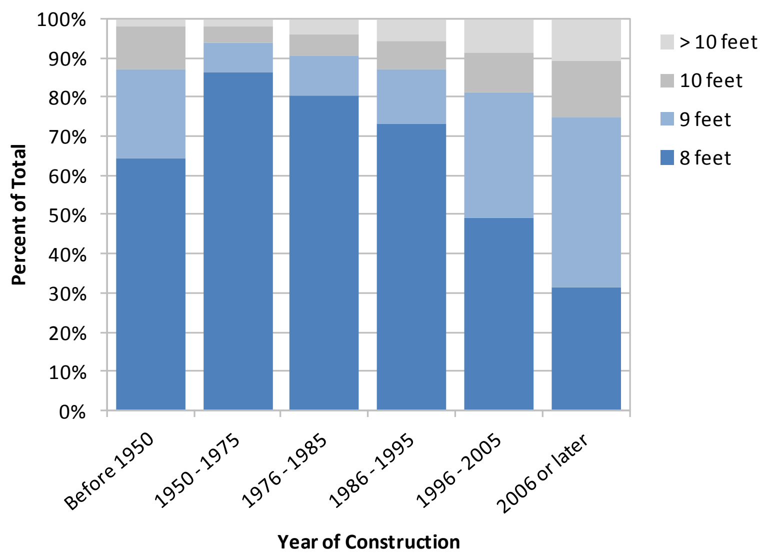
Figure 5 (next page) illustrates the trend towards the increasing square footage of single family detached dwellings as indicated in data collected by the 2012 REUS. Including basements in the calculation of square footage, the average single family detached dwelling constructed since 2005 is 40% larger than those constructed in the 1950-75 period.

Figure 5: Floor Space Trends in New Construction Single Family Detached Dwellings



Accompanying the trend toward increased floor space, average ceiling heights have been increasing, with a shift towards ceilings of nine and ten feet among homes built since 1985 (Figure 6).

Figure 6: Ceiling Height Trends in New Construction



4.2.3 Penetration Rates for Gas Appliances and Equipment

There are several trends in new and retrofit construction affecting penetration rates for gas appliances and equipment. These trends, in turn, impact average gas consumption per home. These trends include:

- a shift away from thermal gas end-uses (e.g., space heating, domestic water heating) to smaller, convenience gas end-uses (e.g., gas cooking, etc.) in newer construction;

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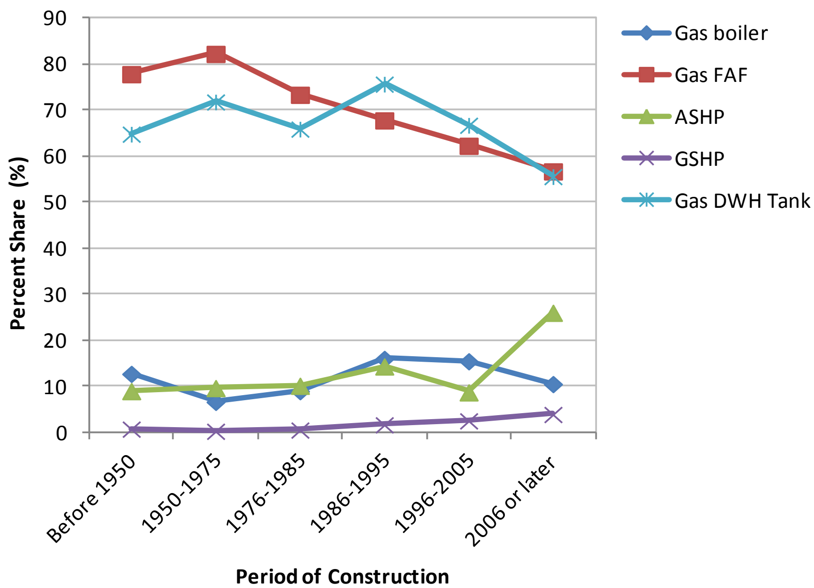
- increasing efficiency of gas furnaces and boilers; and
- increasing popularity of air source heat pumps and, to a lesser degree, ground source heat pumps.

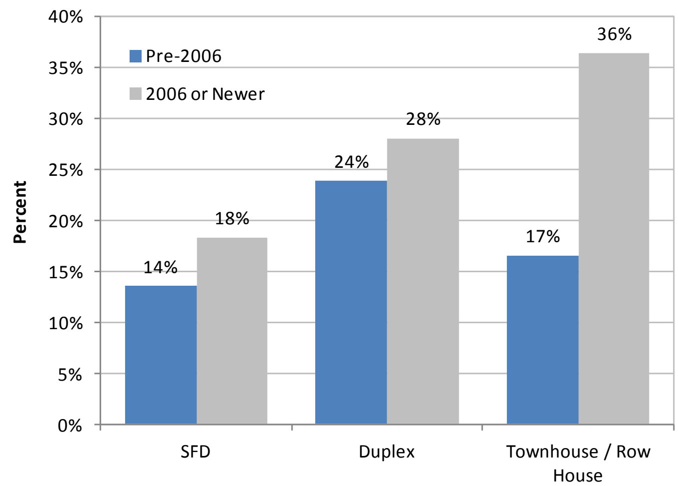
Figure 7 compares penetration rates for major gas space and water heating equipment from the 2012 REUS. The penetration of gas forced air furnaces in homes constructed since 2005 is 25 percentage points lower compared to homes built during the 1950-75 period. Gas hot water tanks have lost share as well, although the decline is more recent (decline in share of 20 percentage points since the mid-1990s). The increase in the penetration of air source heat pumps in homes constructed since 2005 (up 17 percentage points from 1996-2005) is noteworthy, as many of these units are paired with a gas furnace. The net effect is to reduce the amount of gas used for space heating. A modest upward trend in the ground source heat pumps is evident, but penetration is still quite low.

Figure 7: Penetration Rates – Larger Gas End-Uses & Heat Pumps



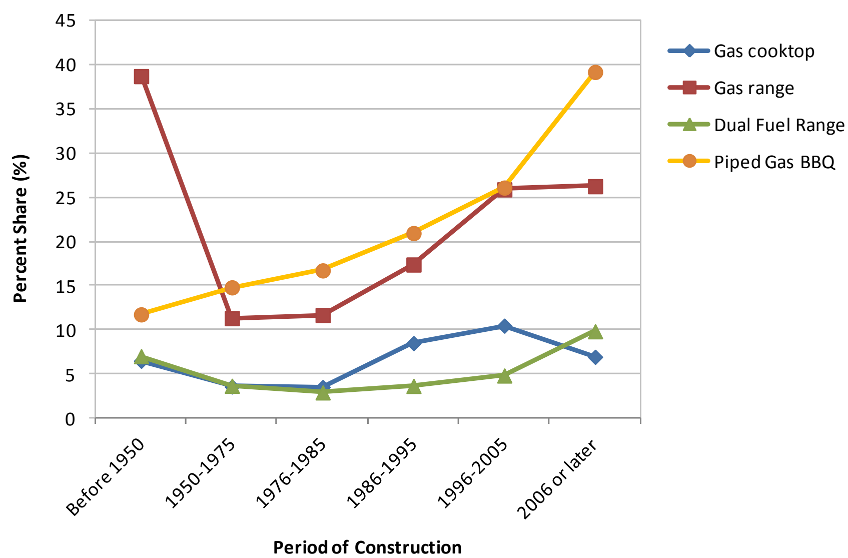
While some of the changes observed in penetration rates will be due to retrofits and renovations, the majority come from decisions taken at the time of new construction. This is evident in Figure 8 (next page) which illustrates the decline of the traditional pairing of gas furnace (or boiler) and gas DWH. Homes constructed since 2006 with a gas furnace or boiler are significantly less likely to use gas for DWH compared to those built prior to 2006. The size of the decline is particularly notable for row/townhouses (17% for homes built before 2006 versus 36% for homes built since this time).

Figure 8: Penetration Rates – Dwellings with Gas Furnaces or Boilers but No Gas DWH



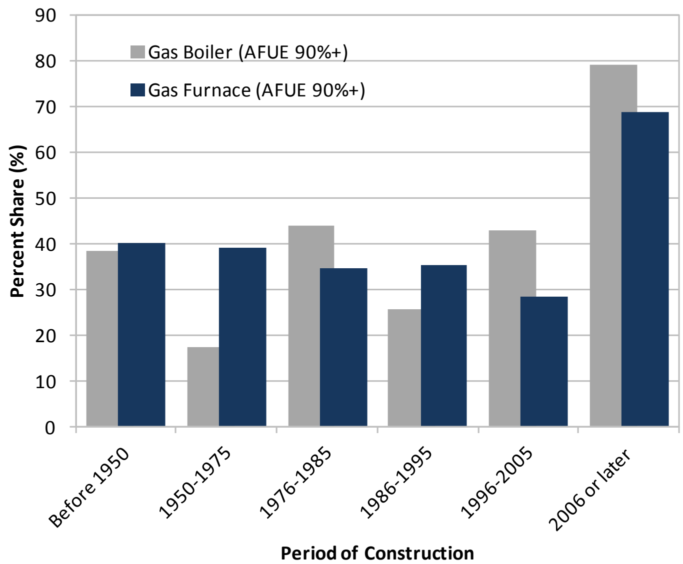
Declines in penetration rates for larger gas end-uses in new construction are being partially offset by increasing penetration of gas end-uses that represent smaller loads for FEU, notably gas ranges (gas cook top and oven), dual fuel ranges (gas cook top and electric oven), and piped gas barbeques (Figure 9).

Figure 9: Penetration Rates – Gas Cooking End-Uses



Legislation mandating the use of higher efficiency furnaces and boilers in new and retrofit construction is transforming the market for gas space heating equipment. When combined with declining penetration rates, this is accentuating the decline in gas load for space heating. Figure 10 (next page) shows the impact of legislated standards for homes constructed since 2005. Stocks of gas furnaces and boilers in older dwellings are gradually becoming more efficient as older, less efficient, units wear out and are replaced with high efficiency units.

Figure 10: Penetration Rates – Energy-Efficient Gas Furnaces and Boilers



4.2.4 Appliance Efficiency Trends

Several developments have influenced improvements in the energy efficiency of major home appliances that either use natural gas directly (e.g., gas furnaces) or indirectly through the demand for hot water heating (e.g., horizontal axis clothes washing machines, dishwashers, etc.). They include:

- legislated minimum efficiency standards for gas and gas related appliances;
- increase in market share captured by ENERGY STAR® appliances; and
- demand-side management initiatives.

Legislated Appliance Efficiency Standards

At the national level, the Energy Efficiency Act (1995) regulates a broad range of energy-using appliances, although the vast majority were initially subject to testing and/or reporting requirements only, rather than minimum energy efficiency criteria. Energy efficiency standards have been also been enacted provincially by British Columbia, most recently under its Energy Efficiency Act (2008).

Table 8 (next page) summarizes past and proposed changes in the energy efficiency standards and regulations for:

- gas furnaces
- gas boilers
- gas water heaters
- gas ranges
- automatic clothes washing machines
- gas fireplaces and free standing stoves
- dishwashers

Table 8: Summary of Energy Efficiency Standards by Appliance Type

Appliance	Energy Efficiency Standards
Gas furnaces of less than 225,000 Btu/hour	Test Standard: CSA P.2-07 Canada: February 3, 1995: minimum AFUE of 78%, all furnaces December 31, 2009: minimum AFUE of 90%, except thru-the-wall furnaces December 31, 2012: minimum AFUE of 90% for thru-the-wall furnaces British Columbia: January 1, 2008: minimum AFUE of 90% for new residential construction December 31, 2009: minimum AFUE of 90% for all furnaces – new construction or existing dwellings Energy Star Models Version 3 in effect February 1, 2012. Furnaces must have an AFUE rating of 95% or higher to qualify as ENERGY STAR. April 1, 2007 to March 1, 2009: Energy Star qualified residential forced air furnaces or boilers (gas-fired and oil-fired), air source heat pumps and ground source heat pumps are eligible for a provincial tax exemption if purchased or leased for residential purposes.
Gas boilers with input rating of less than 300,000 Btu/hour	Test Standard: CSA P.2-07 May 1, 1996: AFUE of 80% for hot water systems – non condensing May 1, 1996: AFUE of 75% for low pressure steam systems September 1, 2010: AFUE of 82% or higher, no constant burning pilot, automatic means for adjusting water temperature Proposed updates to the Energy Efficiency Act affecting boilers can be found at: http://www.empr.gov.bc.ca/EEC/Strategy/EEA/Pages/CurrentConsultations.aspx
Gas water heaters with inputs of less than 75,000 Btu/h or less, and storage capacity of 76 litres to 320 litres.	Test Standard: CAN/CSA P.3-04 September 1, 2004: Minimum efficiency factor (EF) of 0.67 – 0.0005V (where V=rated storage capacity in litres) Energy Star Models: Voluntary participation by manufacturers. Current Energy Star qualified models use 5% less energy than those meeting the minimum federal energy performance standard. January 1, 2009: minimum qualifying EF ≥ 0.62 and first hour rating (FHR) of ≥ 254 litres per hour for gas storage water heaters September 1, 2010: Gas tankless water heaters: EF ≥ 0.82, LPM ≥ 9.5 over 42.8°C rise Condensing gas storage water heater: EF ≥ 0.80, FHR ≥ 254 litres per hour Heat pump water heater: EF ≥ 2.0, FHR ≥ 190 litres per hour
Gas ranges	February 3, 1995: No minimum performance or test standards; regulations govern reporting only. No continuous burning pilot light if product has electrical power source *continued next page…*

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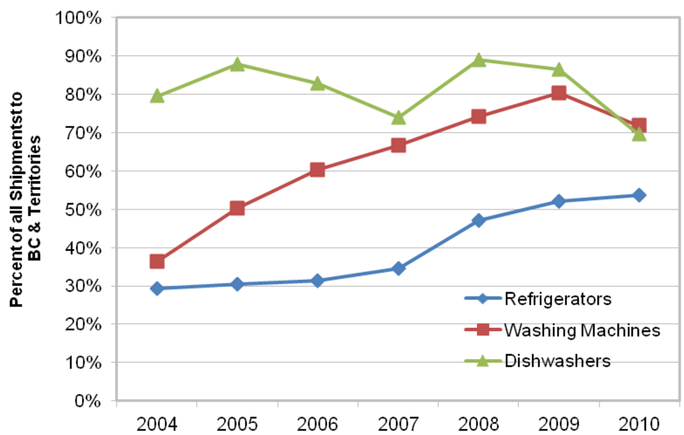
Appliance	Energy Efficiency Standards
Clothes washers – top loading, front loading, and compact	Test Standards: CAN/CSA-C360-M89, CAN/CSA-C360-92, CAN/CSA-C360-03 British Columbia (testing only): May 1, 1991: E = 1.5 V + 30.5, where E=kWh/month and V= volume (litres) May 1, 1995: E = 1.5 V + 30.5, where E=kWh/month and V= volume (litres) Canada: May 1, 1995: testing and EnerGuide label January 1, 2004: • Vertical axis standard (45L or greater): minimum EF of 29.45 (Litres / kWh / cycle) • Horizontal axis: min EF of 29.45 January 1, 2007: • Vertical axis standard (45L or greater): minimum EF of 35.68 (Litres / kWh / cycle) • Horizontal axis: min EF of 35.68 • EnerGuide label required Energy Star Models: Voluntary participation by manufacturers. Current Energy Star qualified models are 36% more efficient than the minimum federal energy performance standard and use 35% to 50% less water. January 1, 2007: modified energy factor (MEF*) of at least 48.45 L/kWh/cycle (1.72 cu. ft./kWh/cycle) and maximum water factor (WF) = 1.07 L/cycle per L of tub capacity (8.0 gal./cycle/cu. ft.) January 1, 2009: MEF ≥ 1.8 cu. ft./kWh/cycle and WF ≤ 7.5 January 1, 2011: MEF ≥ 2.0 cu. ft./kWh/cycle and WF ≤ 6.0
Gas fireplaces including inserts and free standing stoves	Test Standard: CAN/CSA P.4.1-02 September 25, 2003: no minimum performance levels; regulations govern testing and reporting standards only. The Canadian Gas Fireplace Efficiency Standard, CGA-P.4, uses a laboratory procedure similar to the Annual Fuel Utilization Efficiency procedure for furnaces to measure the seasonal performance of gas fireplaces as they are normally installed in Canadian housing. This standard has already been utilized in British Columbia to determine eligibility for their Clean Choice Program, and it has resulted in P.4 efficiencies being developed for a large number of gas fireplaces.
Dishwashers – standard and compact	Test Standards: CAN/CSA-C373-92, CAN/CSA-C373-04 February 3, 1995: testing and EnerGuide label required January 1, 2004: minimum EF (energy factor = cycles per kilowatt hour) of 0.46 for standard dishwashers Energy Star Models: Voluntary participation by manufacturers. Current Energy Star qualified dishwashers must achieve energy efficiency levels at least 41% higher than the minimum regulated Canadian standard. Prior to 2007, ES models were required to be 25% more efficient than the standard at the time. January 1, 2007: minimum EF of 0.65 for standard dishwashers January 1, 2007: minimum EF of 0.65 for standard dishwashers August 11, 2009: maximum TEAC (kWh/yr) of 324, and maximum WF (Litres / cycle) of 21.96 January 1, 2011: maximum TEAC (kWh/yr) of 307, and maximum WF (Litres / cycle) of 18.93
Sources: Natural Resources Canada (http://oee.nrcan.gc.ca) *Energy Efficiency Act of British Columbia*, Energy Efficiency Standards Regulation, B.C. Reg. 389/93	

ENERGY STAR® Appliances

There is no single measure that adequately summarizes the efficiency trends in new appliances, or the general improvement in efficiency of the stock of appliances. The now defunct Canadian Appliance Manufacturers Association (CAMA) tracked shipments of ENERGY STAR qualifying models to British Columbia for three appliances: dishwashers, washing machines, and refrigerators.[5] Summarized in Figure 11, these data show that the proportion of refrigerators shipped to British Columbia that are ENERGY STAR qualified has risen from 29% in 2004 to 54% in 2010. ENERGY STAR qualified shares of washing machines increased from 36% to 72% over the same period. The share of dishwashers rated ENERGY STAR has been generally high, varying between 70% and 89% depending on the year. These data understate the impact on residential energy savings as minimum standards for ENERGY STAR, for some appliances, have been revised upward over time.

Figure 11: ENERGY STAR® Share of Appliance Shipments to British Columbia 2004 - 2010



Data source: NR Canada / CAMA

Demand-Side Management Initiatives

Demand-side management (DSM) initiatives operated by utilities, governments, or others use financial or other incentives to encourage households to adopt energy-efficient equipment and appliances, and/or adopt energy conserving behaviors. Some programs seek to transform the market by working with manufacturers, distributors, and retailers to move the market towards a specific energy efficiency target. Changes to municipal, provincial, and/or federal legislation and regulations governing efficiency standards for equipment and structures are sometimes used to ensure the market cannot retreat from the high efficiency target. Past and present DSM programs targeting British Columbia households have contributed to improvements of household energy use and intensities.

While it is not reasonable to provide a comprehensive list of past and present DSM initiatives that may have impacted energy use of FEU residential customers, FortisBC has operated a number of initiatives directly targeting equipment and appliances that use natural gas either directly (e.g., gas furnaces) or indirectly (e.g., (hot water for dishwashers). These include:

[5] With the opening of a Canadian branch office of the Association of Home Appliance Manufacturers (AHAM) effective July 1st, 2012, Electro-Federation Canada (EFC) announced the closure of its Canadian Appliance Manufacturers Association (CAMA) council.

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- Heating system upgrade programs (various years) - incentives to purchase high efficiency furnaces and boilers
- Fireplace upgrade programs – incentives to upgrade from decorative natural gas fireplaces to EnerChoice energy-efficient fireplaces
- ENERGY STAR® water heaters and clothes washers
- Tune up programs for furnaces and fireplaces
- Home weatherization programs (insulation, air sealing)

Other notable energy efficiency initiatives during the past five years include the federal government's ecoENERGY Retrofit Homes Program[6] and its provincial companion program LiveSmart BC: Efficiency Incentive program.[7]
Other utilities, the Government of British Columbia, and the Government of Canada have, individually or in partnership, implemented market transformation programs to improve the energy efficiency standards for windows and appliances, including dishwashers and front loading clothes washing machines.

While assessing the collective impact of these programs on long-run trends in gas consumption is beyond the scope of this document, the 2012 REUS survey addressed the adoption of energy-efficient equipment, and behaviours affecting the efficient use of energy.

4.2.5 Improvements in Thermal Efficiency - Construction Codes and Standards

Changes to residential construction codes and standards have contributed to declining energy use in new construction.

In British Columbia, residential building codes and standards have expanded their scope over time from the initial focus on health and safety to specific provisions for energy and water efficiency. There are two distinct jurisdictions governing building codes within the province. Within the City of Vancouver, the Vancouver Building Bylaw (VBBL) defines the minimum performance requirements for construction within municipal boundaries. In all other areas of the province, the BC Building Code (BCBC) regulates construction.

In addition to building codes, the BC Energy Efficiency Act[8] and the national Energy Efficiency Act[9] regulate the performance of a broad range of residential energy-using equipment and end-uses.

Recent changes to the British Columbia Building Code (BCBC) and the British Columbia Energy Efficiency Act apply to construction of small buildings and residential detachments (up to 600 square meters or 6,500 square feet). These requirements generally pertain to single family dwellings, duplexes and smaller row houses.

The BCBC defines minimum building practices in all areas of British Columbia except Vancouver. The 2012 BCBC came into effect in December 2012. There are no changes in the 2012 BCBC relative to energy

[6] http://oee.nrcan.gc.ca/residential/6551
[7] http://www.livesmartbc.ca/homes/index.html
[8] http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/00_96114_01
[9] http://laws-lois.justice.gc.ca/eng/acts/E-6.4/page-1.html

compared with the previous version of the Code (defined by the 2006 BCBC plus the Part 10 amendment enacted in September 2008). The 2012 changes pertained primarily to seismic upgrading.

The Province of British Columbia has completed a public review of proposed changes to energy requirements for residential buildings.[10] Due to come into effect in December 2014, they will require new residential construction in British Columbia to meet the requirements of the National Energy Code of Canada for Buildings (NBC), 2011.[11] These changes are expected to provide some increase in energy efficiency across British Columbia. The ventilation requirements in the NBC are expected to be updated to meet the special requirements in British Columbia, and will likely have an impact on energy use in houses, but this change will not be confirmed until 2014. Finally, equipment efficiency requirements will now be embedded in the building code rather than in a separate legislative act.

The City of Vancouver has its own Charter and has not adopted the BC Building Code. New construction within city boundaries is regulated by the Vancouver Building Bylaw (VBBL). Requirements in the City of Vancouver are more stringent than the provincial building code. New homes are required to achieve an EnerGuide 80 rating, in part via increased insulation requirements. The VBBL also requires installation of heat recovery ventilators and, when using gas fireplaces, that they be direct-vented and use electronic ignition.

The City of Vancouver plans to update the VBBL. These changes are expected to be approved late in 2013 with an effective date in early 2014. These additional requirements include:

- increased requirements for insulation (primarily by changing from nominal values to effective values) and operation of heat recovery ventilators
- increased attic insulation from RSI 7.0 to RSI 8.8
- improved window performance from USI 2.0 to 1.4 W/(K•m²)
- skylights with maximum thermal transmittance value of 2.6 W/(K•m²)

In the case of retrofit construction, changes to the VBBL are proposed based on the level of retrofit activity. Acquiring a building permit for retrofits over $5,000 to existing one- and two-family dwellings will require an EnerGuide for Houses (EGH) Report completed in the last 3 years. If the report indicates an air leakage rate greater than six air changes per hour (ACH), retrofits over $25,000 will required a minimum of $800 in weatherisation of the home. If the report indicates less than RSI 5.3 (R 30) thermal insulation in the attic, retrofits exceeding $50,000 will also be required to provide additional attic insulation to a minimum of RSI 8.8 (R 50).

Apartments

Apartment buildings larger than 600 square meters (~6,500 square feet) are generally regulated under Part Three of the BCBC. Since September 5, 2008, new apartments outside the City of Vancouver have been required to meet ASHRAE 90.1-2004.[12] Within the City of Vancouver ASHRAE 90.1-2007 is required. Both the City of Vancouver and the Province of British Columbia have expressed a commitment to adopting ASHRAE 90.1-2010. For the province, this code will come into effect in December 2013, while

[10] http://www.housing.gov.bc.ca/building/green/energy/Part%2010%20code%20change.pdf

[11] http://www.nrc-nrc.gc.ca/eng/publications/codes_centre/2011_national_energy_code_buildings.html

[12] This is a standard developed by the American Society of Heating Refrigeration and Air Conditioning Engineers (ASHRAE), and has been adopted by over 30 states in the USA.

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the City of Vancouver is expecting to approve this change in late 2013 with an effective date in early 2014. The impact of this change will likely result in a savings of 8% to 10% in energy use, relative to current code requirements. In addition, both the City of Vancouver and the Province have adopted an alternate compliance path using the National Energy Code for Buildings (2011).

4.2.6 Demographic Trends

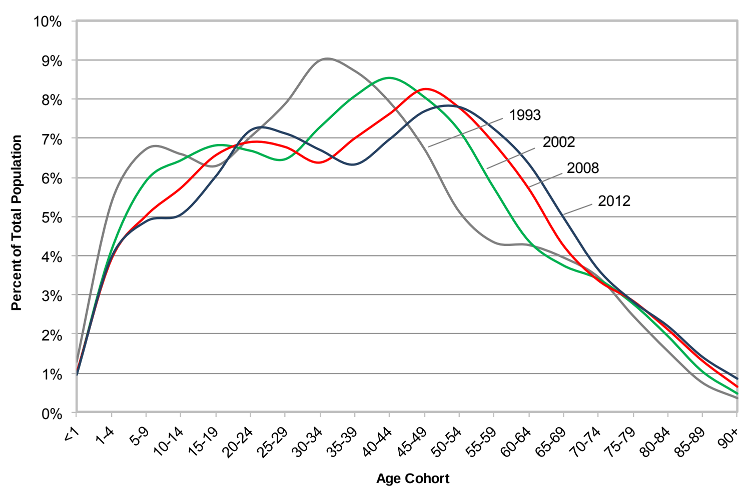
Consistent with trends identified in the 2008 REUS, ForticBC's residential customer base is aging and the number of people per-household is declining. These are two key demographic trends contributing to the decline in natural gas consumption over the long run.

Aging Population

As FortisBC's residential customer base ages, it impacts average household gas consumption. This is because older individuals differ from their younger counterparts in their demands for space heating and domestic water heating. A 2005 US Energy Information Administration (EIA) study found that natural gas use for space heating was 13% higher in homes with seniors compared to those without. Conversely, gas consumption for water heating was 13% lower in homes with seniors than those without. The presence of children between 5 and 16 years of age was found to increase gas consumption for space heating and water heating by 5% and 39% respectively.[13]

The age profiles of British Columbia's population corresponding to each of the past four REUS survey years are illustrated in Figure 12.

Figure 12: British Columbia Age Profiles – 1993 to 2012



Data source: BC Stats

Several trends are evident:

- Individuals between the ages of 25 and 44, the age segment typically associated with household formation (buying their first home, raising a family, etc.) have proportionately decreased since 1993 (27% versus 34% in 1993).

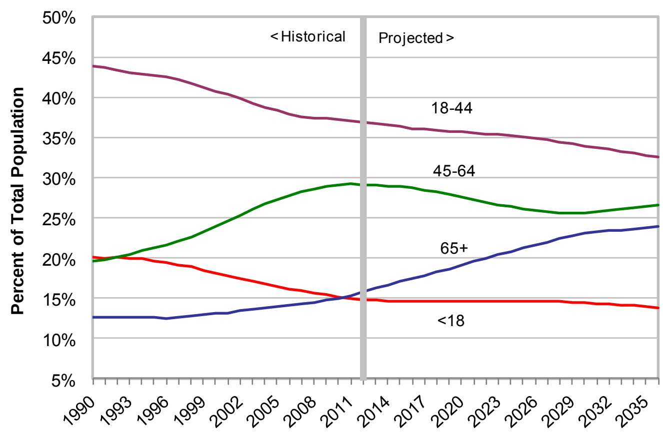
[13] Source: Energy Information Administration, *2005 Residential Energy Consumption Survey*, U.S. Department of Energy.

- The proportion of the population aged 45 to 64 increased over the same period (21% to 29%).
- Individuals now aged 65 years and older has increased (16% versus 13% in 1993).

The aging of the baby boomer generation (individuals born after the Second World War and up to 1966) is clearly evident in the graph. Increasingly, this large age cohort has raised their families and is entering retirement.

Population projections by age group (cohort) made by BC Stats show the cohorts comprised of children and young adults as a share of the total population will continue to decline during the next quarter-century (Figure 13). The relative share of the population made up of seniors (those aged 65 years or older) is expected to increase to nearly one quarter of the population by 2035. These changes will be reflected in FEU's residential customer base.

Figure 13: Population Projections by Age Cohort – British Columbia



Data source: BC Stats

Number of Occupants per Dwelling

The aging of the population is being accompanied by a slow but consistent decline in the number of occupants per dwelling. Fewer people in the home means reduced demand for hot water from activities such as showering, clothes washing, and dishwashing.

Figure 14 (next page) shows the long-run decline in the average number of people per-household for the Census areas corresponding to FEU's regions. Further declines are expected, with rate of decline moderating somewhat towards the end of the current decade.

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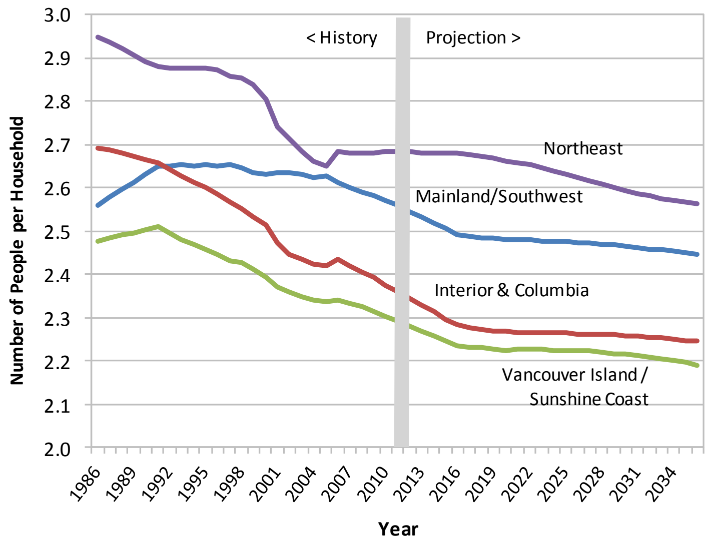
Figure 14: Average Number of People per-Household – History and Projection

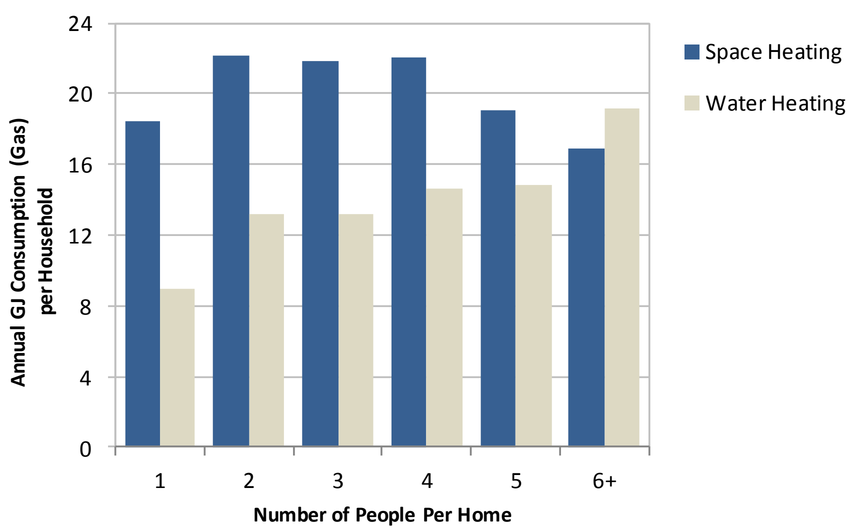


Source: BC Stats

The decline in the average number of people per-household stems, in part, from the long-run societal trend towards smaller family sizes, but also from the growing proportion of older households where the children have grown up and left home.

The decline in the average number of people per household has implications for energy required for space and water heating. Figure 15 summarizes the results from the 2009 US Department of Energy (DOE) residential energy use study that found that natural gas consumption for space and water heating generally increases as the number of people in the home increases.

Figure 15: Gas Consumption by Number of People in the Home



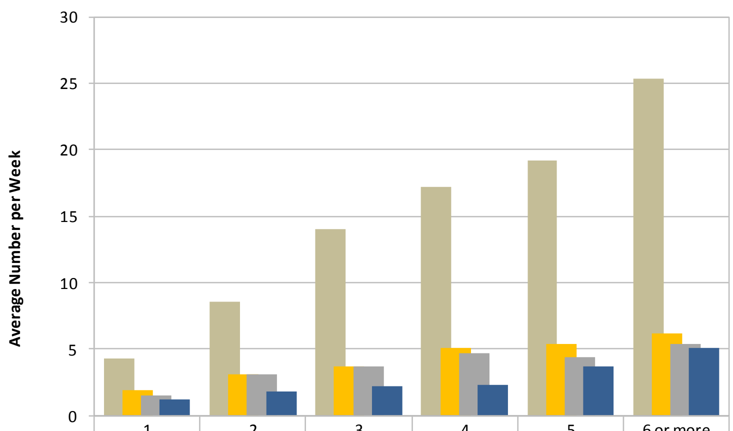
Source: 2009 Residential Endergy Consumption Survey, US DOE

The relationship between space heating and household size is not strictly linear. Indeed, the amount of energy to keep a two person household warm did not vary that much from that of a four person household. Natural gas use for water heating shows a much stronger relationship between household size and consumption, rising from 8 GJ for a one person household to 18 GJ for households with six or more people.

These findings are consistent with the results of a 1999 study on residential water use by the American Water Works Association (AWWA). Their research found that family size influences hot water use as does the mix of age groups present in the home.[14] For example, both the number of people in the home and the presence of children and teens were positively correlated with increased water use for showers, baths, and clothes washing. Faucet use was positively correlated with household size, and the square footage of the home. Interestingly, they found water consumption for showers, baths and dishwashers was positively correlated with the number of persons employed outside the home. These findings strongly suggest that the demand for hot water, and thus energy needed for water heating, will, everything else held constant, decline over time as the baby boom demographic ages, retires, and increasingly live in childless homes.[15]

Data from the 2012 REUS support many of the AWWA findings, including the relationship between the number of occupants per home and the demand for hot water. Figure 16 shows that as the number of people per household increases, so does the number of showers, laundry loads, dishwasher loads and baths. Additional discussion is provided in Section 11 of this report.

Figure 16: Effect of Household Size on Hot Water Using Activities



	1	2	3	4	5	6 or more
Showers	4.3	8.5	14.0	17.2	19.2	25.3
Laundry Loads	1.9	3.1	3.7	5.1	5.4	6.2
Dishwasher Loads	1.5	3.1	3.7	4.6	4.4	5.4
Baths	1.2	1.8	2.2	2.3	3.7	5.1

Household Size (People)

4.2.7 Demand Response to Price Changes

The trend towards declining natural gas use rates is, in part, the result of the demand response to changes in the real price of natural gas (nominal prices adjusted for inflation).

[14] Mayer, P.W., W.B. DeOreo et al. (1999).

[15] According to the AWWA website, an update to this research is expected by late 2013.

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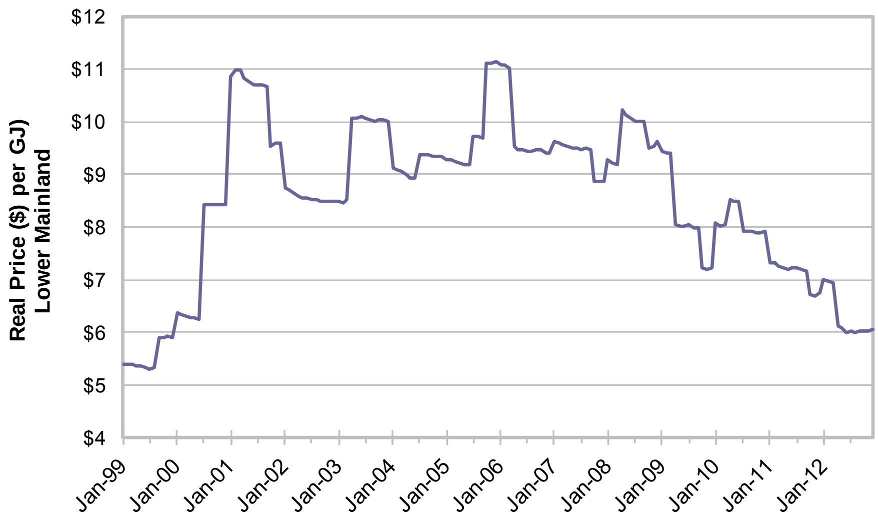
Figure 17 illustrates the inflation-adjusted price of natural gas (variable rate component) for FEU's Lower Mainland residential customers from January 1999 to December 2012. A significant increase in prices occurred in late 2000, followed by a period of variable but consistently high prices, after which prices begin to decline around the spring of 2008.[16] By the end of 2012, inflation-adjusted natural gas prices were at levels last experienced in December 1999.[17] Price trends in the other FEU regions have followed a similar trajectory.

Figure 17: Inflation-Adjusted Residential Natural Gas Prices Variable Rate Portion ($/GJ) – FEU Lower Mainland



Reactions to changes in the real price of natural gas differ in the short-term from the long-term. Short-term reactions to a change in the price of natural gas will be mostly behavioural: changes to thermostat settings, hot water temperatures, and use of alternative fuel space heating options (e.g., fireplaces, portable electric space heaters, etc.). Long-term reactions to a sustained increase or decrease in price includes sustained (ingrained) changes in behaviour and structural changes affecting the home's thermal envelope (e.g., whether or not to improve insulation, upgrade windows, etc.), appliance purchases (e.g., efficiency decisions for furnaces, washing machines, dishwashers, etc.), and fuel switching (e.g., from gas to electric hot water heating, etc.). Structural changes permanently reduce the energy requirements of a home.

The strength and nature of the reaction to price changes depends on other factors including household income and prices of competing fuels. Lower income households are restricted by the lack of financial resources in their ability to undertake structural improvements to reduce exposure to higher energy prices. Changes in the price of competing fuels (e.g., electricity), everything else held constant, can influence both short term and longer term fuel switching decisions.

[16] The variable rate portion of the FEU tariff for residential customers reflects the price of natural gas purchased at prices set by the market and does not include any mark-up.

[17] Prices were adjusted for inflation using the consumer price index (CPI) for the Greater Vancouver areas. Data source: Statistics Canada CANSIM.

Generally speaking, there is a paucity of published research into the price elasticity of natural gas for the residential sector. Of the few published studies, short-term price elasticities for natural gas are generally quite low, in the order of -0.3 or smaller.[18] A 2006 study by the Colorado-based National Renewable Energy Laboratory (NREL) estimated the short-run price elasticity for natural gas in the Pacific Coast region of the U.S. (Washington and Oregon) to be -0.18 and the long-run price elasticity to be -0.63.[19] A more recent (2012) study by the University of Ottawa estimated the long-run price elasticity for natural gas in British Columbia to be -0.67.[20]

While natural gas prices in the short-term may increase or decrease, expectations regarding the future direction of prices will influence major appliance purchases over the medium term. In particular, recent declines in the price of natural gas for FEU residential customers have come after an extended period of high and volatile prices. The medium to longer term response to lower prices will depend, in part, on whether they are sustained enough to change expectations formed by the past decade of high and volatile prices. Changes to building codes and regulations governing the efficiency choices available to consumers, combined with structural improvements already made by households, will limit upward pressure on natural gas use rates from an extended period of low gas prices.

4.2.8 Cross Effects / Interaction Effects

Cross effects (also known as interaction effects) affecting space heating refer to the heating penalty associated with the adoption of energy-efficient technologies that, due to their more efficient use of energy, produce less waste heat than their inefficient counterparts. As a result, space heating systems compensate, to some degree, for the lost heat. For homes with natural gas space heating, this lost heat represents an offsetting factor to declining use rates.

The displacement of incandescent lighting with compact fluorescent lighting is one example where the heating penalty may be significant. The extent of the heating penalty is subject to considerable debate, and published estimates vary greatly.[21] The need for replacement heat has also been identified with the increased penetration of variable speed motors with high efficiency condensing gas furnaces. Variable speed motors, known as electronically commutated motors (ECM), give off significantly less waste heat than their lesser-efficient fixed-speed counterparts.[22]

[18] Interpreted as a 0.3% decline in gas consumption per every 1% increase in real prices. An overview of short- and long-term price elasticities for natural gas can be found in Wade, Steven, H., *Price Responsiveness in the AEO2003 NEMS Residential and Commercial Building Sector Models*, Energy Information Administration, U.S. Department of Energy.

[19] Bernstein, M.A., and Griffin, J. (2006)

[20] Ryan, D, and Razek, N.A (2012)

[21] A 2004 study using Natural Resources Canada's test houses found that during the heating season, 80% to 96% of the energy savings from replacing incandescent lighting with CFLs was offset by the increased need for space heating. (CANMET (2004). In contrast, the Washington-based New Buildings Institute estimated the cross effects of lighting at 13% for the Pacific Northwest (New Buildings Institute (2003).

[22] The operating temperature of a variable speed or ECM motor is constant and typically at or near ambient temperature, whereas the operating temperature of a fixed speed or PSC motor can range from 32 to 77 degrees Celsius.

5 DWELLING CHARACTERISTICS

This section provides detail on the dwelling characteristics of FEU residential homes including:

- Dwelling type, size, vintage, number of stories, tenure, maintenance fees, and length of residency;
- Characteristics of the building envelope including insulation levels, window glazing and frame material, and exterior door materials;
- Renovations undertaken during the past five years, and planned for the next two years, by type of renovation; and
- Who performs the renovations – homeowner, contractor, or a combination of the two.

5.1 Dwelling Characteristics

5.1.1 Dwelling Types and Vintages

Single family detached (SFD) dwellings dominate the residential customer base for FEU, accounting for over eight-in-ten (82%) of all dwelling types in 2012 (Table 9). This proportion is unchanged from previous REUS surveys (i.e., differences are not statistically significant). Shares for other dwelling types in 2012 also remained effectively the same as those in the 2008 REUS. Changes in shares for FEI over the 2002 to 2012 period show some minor fluctuations, all of which fall within the accuracy bounds of the survey estimates.

Notable differences in dwelling type shares between FEU's five regions include:

- proportionately more row / townhouses in the Lower Mainland (11%) and Whistler (29%);
- proportionately more single family detached homes Interior and Vancouver Island regions; and
- significantly more mobile homes in the Fort Nelson and the Interior regions (25% and 7% respectively).

Table 9: Residential Dwelling Types by Region (%)

Dwelling Type	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*793*	*1,707*	*752*	*85*	*104*	*3441*	*2217*	*2604*	*1444*	*1610*
Single Family Detached	80.3	84.3	85.9	54.2	67.4	81.9	83.0	81.5	83.0	80.7
Duplex	5.5	3.7	4.8	12.0	2.8	5.0	5.0	5.0	4.9	4.5
Row / Townhouse	11.1	3.1	5.2	28.9	5.1	8.4	8.2	8.7	8.3	10.5
Apt / Condominium	0.8	2.2	1.5	2.4	0.0	1.2	1.1	1.2	1.0	0.4
Mobile Home / Other	2.3	6.7	2.6	2.4	24.7	3.6	2.7	3.7	2.8	3.8
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

Table 10 (next page) summarizes the distribution of residential gas customers by dwelling vintage (period of construction). Data from past REUS studies are not provided as the age of the two studies makes

DWELLING CHARACTERISTICS

comparisons with the current survey invalid.[23] Overall, nearly six-in-ten (55%) of dwellings were built prior to 1986, over one-quarter (27%) built between 1950 and 1975 and one-tenth (11%) built prior to 1950. Slightly more than one-fifth (22%) of all gas homes were built since 1995.[24] Comparing the regions shows that the Lower Mainland and the Interior regions have the largest shares of older homes (those built prior to 1996) (79% and 77% respectively). Regions with the newest housing stock (i.e., 1996 or newer) include Whistler and Vancouver Island (63% and 31% of dwellings). The latter reflects the relatively more recent arrival of natural gas service on the island.

Table 10: Residential Dwelling Stocks by Period of Construction (%)

Year of Construction	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*777*	*1685*	*731*	*82*	*104*	*3379*
Before 1950	10.6	10.4	12.0	0.0	4.8	10.6
1950-1975	26.1	30.4	23.1	6.2	28.5	26.9
1976-1985	17.9	18.8	11.5	13.6	23.7	17.5
1986 -1995	24.2	17.3	21.5	17.3	13.3	22.0
1996 -2005	14.3	15.0	20.9	56.8	23.1	15.3
2006 or later	5.3	6.6	10.4	6.2	3.8	6.2
DK	1.7	1.5	0.5	0.0	2.8	1.5
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Built prior to 1996	78.8	76.9	68.1	37.0	70.2	77.0
Built since 1995	19.6	21.6	31.3	63.0	26.9	21.5

Totals may not sum due to rounding.

5.1.2 Residency and Tenure

The vast majority (99%) of respondents to the 2012 REUS survey indicated their home was their principal residence (Table 11). This share is statistically unchanged from that recorded in 2008. Whistler had the lowest percentage of homes as a principal residence (82%).

Table 11: Principal Residence by Region (%)

Principal Residence?	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*775*	*1674*	*732*	*83*	*103*	*3367*	*2221*	*2514*	*1444*	*1610*
Yes	99.2	98.2	99.5	81.7	96.8	98.9	98.5	98.9	98.7	98.3
No	0.8	1.8	0.5	18.3	3.2	1.1	1.5	1.1	1.3	1.6
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

Table 12 (next page) summarizes FEU's residential customers according to whether they rent or own their residence. The vast majority (97%) of FEU residential customers owned their home in 2012, statistically unchanged from 2008 (96%). Renters made up three percent of FEU residential customers. Comparing

[23] The 2002 REUS included only residences constructed prior to, or including, 2000. The 2008 REUS included only dwellings constructed prior to, or including, 2006. Each survey excluded the two most recent years of construction due to the billing requirements of the conditional demand analyses.

[24] The relative proportion of homes built since 2005 understates the true (FEI population) proportion because the REUS sample excludes residences with a minimum of two years of uninterrupted billing history. The latter was a requirement for the conditional demand analysis conducted using the 2012 REUS results.

results from the past three REUS surveys suggests a downward trend in the proportion of customers renting homes (3% of FEI customers in 2012 compared to 7% in 2002).

Table 12: Ownership Status by Region (%)

	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*758*	*1652*	*713*	*81*	*102*	*3306*	*2211*	*2574*	*1439*	*1578*
Own	97.3	97.7	97.3	96.4	98.1	97.4	95.6	97.4	95.4	93.4
Rent	2.7	2.3	2.7	3.6	1.9	2.6	4.4	2.6	4.6	6.6
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

Data on home ownership by dwelling type are summarized in Table 13. The proportion of dwellings that are rented is highest for apartments/condominiums and duplexes (15% and 11% respectively).

Table 13: Ownership Status by Dwelling Type (%)

	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2,792*	*154*	*207*	*55*	*118*	*59*
Own	98.4	89.2	94.9	85.1	99.1	92.0
Rent	1.6	10.8	5.1	14.9	0.9	8.0
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

5.1.3 Secondary Suites

Twelve percent (12%) of respondents to the 2012 REUS indicated their home has a secondary suite (Table 14). Regionally, Whistler and Lower Mainland customers are more likely to have a secondary suite (20% and 14% respectively). The incidence of secondary suites is likely underreported as some survey respondents with secondary suites may not want to share this information.[25]

Table 14: Homes with Secondary Suites by Region (%)

	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*793*	*1707*	*752*	*84*	*105*	*3441*
Secondary Suite	14.0	7.8	10.0	20.3	6.2	11.9

Totals may not sum due to rounding.

5.1.4 Length of Residency

FEU residential customers have lived an average of 16.5 years in their current residence, up from 15.2 years in 2008 (Table 15, next page). Average length of residence for customers in the FEI service regions increased from 12.4 years in 2002 to 16.8 years in 2012. Both trends are consistent with the aging of the population and the reduced tendency for older individuals to change homes.

[25] A 2009 study by the City of Vancouver estimated that 35% of single family dwellings in Vancouver had a secondary suite. Vancouver (2009), p.17.

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Consistent with the findings from the 2008 REUS, the 2012 survey found highest average length of residence to be among LM customers (17 years), while Whistler and Fort Nelson has the lowest (12 years).

Table 15: Average Length of Residence (Years) by Region

Length of Residence (years)	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*793*	*1707*	*752*	*84*	*105*	*3441*	*2180*	*2605*	*1419*	*1610*
Mean	17.2	16.0	14.5	12.1	12.3	16.5	15.2	16.8	15.0	12.4
Standard Deviation	20.7	9.0	8.0	2.5	2.7	12.4	12.3	13.6	12.4	11.7

The average length of residence varies with the type of dwelling (Table 16). FEU customers living in single family detached dwellings have the longest average tenure (17.9 years), whereas customers in row houses / townhouses and apartments/condominiums have average tenures of 9.7 years and 6.6 years respectively. There is a relationship between length of tenure, dwelling type, and resident age.

Table 16: Average Length of Residence (Years) by Dwelling Type

Length of Residence (years)	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2723*	*150*	*198*	*55*	*116*	*57*
Mean	17.9	11.6	9.7	6.6	11.0	12.3
Standard Deviation	12.8	9.0	8.1	4.5	6.5	8.7

Data supporting the relationship between dwelling type and resident ages are summarized in Table 17. Of note, respondents 55 years of age or older are significantly more likely to live in SFDs, duplexes, or mobile homes (66%, 68% and 81% respectively). Respondents under 35 are more likely to live in row houses/townhouses and apartments/condominiums (7% and 13% respectively). Typically, younger customers are more likely to reside in townhouses and apartments/condominiums, while older adults reside in single family detached dwellings or mobile homes.[26]

Table 17: Age of Respondents by Dwelling Type (%)

Age of Respondent (years)	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other	2012 FEU
Unweighted base	*2723*	*150*	*198*	*55*	*116*	*57*	*3299*
24 yrs or less	0.3	0.0	1.0	0.0	0.0	0.0	0.3
25 to 34	3.4	3.7	6.0	12.9	4.6	6.2	3.8
35 to 44	10.0	12.5	14.7	10.4	6.0	2.0	10.3
45 to 54	20.6	16.1	19.9	23.7	8.6	9.4	20.0
55 to 64	28.6	23.0	22.4	11.4	28.0	16.7	27.4
65 & older	37.1	44.7	35.9	41.6	52.8	65.6	38.2
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
34 yrs and younger	3.7	3.7	7.0	12.9	4.6	6.2	4.1
55 yrs and older	65.7	67.7	58.4	53.0	80.8	82.3	65.6

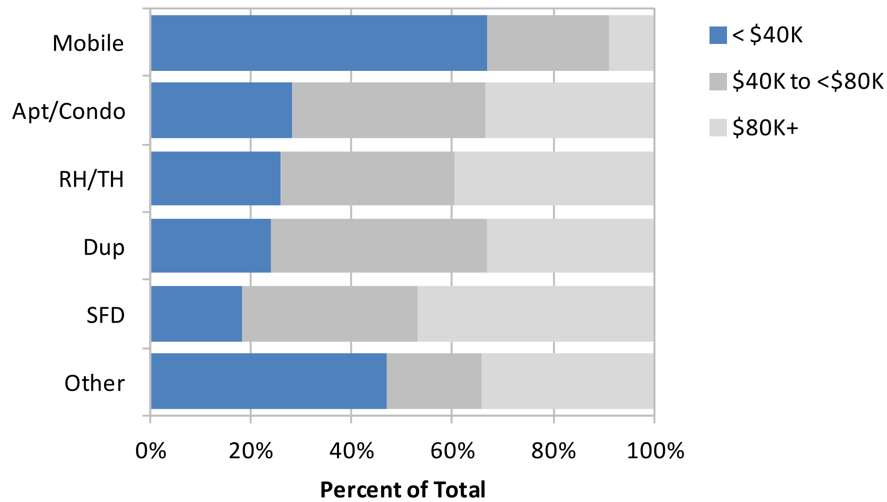
Totals may not sum due to rounding.

Dwelling type and household income are also related, especially when low income and high income households are compared. Figure 18 (next page) illustrates how respondents with household incomes of

[26] The 2008 REUS found that, as individuals age, the average length of residency increases and the likelihood of changing residences decreases. Source: REUS (2008), p. 4-5.

less than $40,000 are significantly more likely to live in a mobile home. Conversely, respondents with annual household incomes of $80,000 or more are most likely to live in single family detached dwellings.

Figure 18: Household Income by Dwelling Type



5.1.5 Rent and Maintenance Fees

Nearly one-in-five (18%) respondents to the 2012 REUS indicated they either pay rent or maintenance fees (Table 18). Regional variations in this percentage are consistent with the proportion of respondents living in rental accommodations, condominiums, or co-operative housing. For example, 43% of Whistler respondents paid rent or maintenance fees, the highest of the five regions, but consistent with the high proportion of row / townhouses. Differences between the 2012 REUS and 2008 REUS results are not statistically significant.

Table 18: Households Paying Rent or Maintenance Fees by Region (%)

	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*755*	*1617*	*724*	*82*	*95*	*3273*	*2211*	*2467*	*1,439*	*1,578*
Pay rent or maintenance fee	20.1	14.7	15.2	42.9	16.5	18.1	17.3	18.4	17.7	14.3

Respondents paying rent or maintenance fees were asked to indicate which services (heat, hot water, electricity) and fuels (i.e., for gas fireplaces, gas clothes dryers, gas cooking) are included in these fees. The results are summarized in Table 19 (next page). Previous REUS surveys did not ask about electricity so historical comparisons regarding this service are not possible.

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Table 19: Services and Fuels Covered by Rent / Maintenance Fees by Region (%)
Percent of respondents paying rent or maintenance fees

	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base [1]	*161*	*256*	*113*	*37*	*20*	*587*	*765*	*437*	*502+*	*n/a*
Heat	17.0	25.1	20.2	5.5	40.3	19.0	6.4	19.0	6.2	2.1
Hot water	17.6	29.1	23.7	5.5	40.3	20.6	8.8	20.4	8.7	3.0
Fuel for gas fireplace	10.1	8.4	10.5	5.5	5.7	9.7	5.1	9.6	5.0	1.9
Fuel for gas cooking	5.7	5.2	3.5	2.8	11.5	5.4	2.1	5.6	2.2	n/a
Fuel for gas clothes drying	0.6	4.0	1.8	--	5.7	1.5	3.2	1.5	2.5	n/a
Electricity	13.8	22.7	18.4	8.3	28.8	16.2	n/a	16.0	n/a	n/a
DK	0.6	0.8	0.9	--	--	0.7	n/a	0.7	n/a	n/a

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only

Among the base of those paying rent or maintenance fees, the three most common services covered by rent or maintenance fees include hot water (21% of those paying rent or fees), heat (19%), and electricity (16%). These percentages are influenced, in part, by whether the service or end-use is present in the suite or dwelling. This would explain, in part, the relatively lower percentages of respondents indicating that their rent or maintenance fees include fuel for gas fireplaces, gas cooking or gas dryers.

Comparing the results of the 2012 REUS survey with previous REUS surveys highlights a discrepancy in the data series, with most percentages being considerably lower than those recorded in 2012. The 2008 dataset was reviewed, and the components and weighting of the calculations confirmed as correct. The remaining possible reason for the discrepancy rests with a change to the order of the rent and maintenance fee questions in the 2012 REUS.

5.2 Dwelling Size

Dwelling size is defined as the total floor area of the dwelling including the basement and any unfinished areas, but excluding garages or carports. As the data include a small number of responses considered unrealistically high or low, an outlier analysis was used to remove the bottom 0.5% and top 0.5% of the estimates, ranked from lowest to highest. This affected 1% of the unweighted sample.

Average dwelling size in the 2012 REUS is 2,209 square feet, statistically unchanged from the average recorded in the 2008 survey (Table 20). Differences between the means for 2008 and 2002 are not statistically significant at the 95% confidence level.

Table 20: Dwelling Sizes (Square Feet) by Region

	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*755*	*1617*	*724*	*82*	*95*	*3273*	*2044*	*2467*	*1305*	*1416*
Mean [1]	2395	2181	2116	2311	1952	2209 [2]	2220	2235	2239	2199
Median	2200	2100	2000	2000	1800	2100	1800	2200	1800	n/a
Standard Deviation	2107	839	651	493	258	1221	806	1355	950 [3]	950 [4]

[1] Mean excludes the 0.5% largest and smallest values
[2] Untrimmed mean is 2394 square feet.
[3] The standard deviation of 949.9 square feet.
[4] Standard deviation of 949.8 square feet.

Table 21 (next page) summarizes key floor space statistics by dwelling type. On average, single family detached dwellings are the largest (average of 2,347 ft^2) and mobile homes the smallest (1,076 ft^2). The median size for single family detached homes is 2,200 ft^2, compared to 1,500 ft^2 for row / townhouses and 1,200 ft^2 for apartments / condominiums.

Table 21: Dwelling Sizes (Square Feet) by Type of Dwelling

	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2723*	*150*	*198*	*55*	*116*	*57*
Mean [1]	2347	1980	1613	1379	1076	1964
Median	2200	1765	1500	1200	1024	1750
Standard Deviation	1182	1775	618	901	197	2085

[1] Mean excludes the 0.5% largest and smallest values

The average size of new single family detached dwellings has been increasing over time (Table 22). For example, the median size for a SFD built before 1950 was 1,900 ft^2. During the mid-1970s to mid-1980s this increased to 2,200 ft^2. The median size of dwellings constructed since 2005 is 2,900 ft^2, up 21% from 1986-95 and up 53% from those built prior to 1950.

Table 22: Floor Space of Single Family Detached Dwellings by Vintage

	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known
Unweighted base[1]	*314*	*786*	*462*	*486*	*419*	*170*	*27*
Mean [2]	1958	2180	2293	2486	2661	2920	2534
Median	1900	2200	2200	2400	2560	2900	2000
Standard Deviation	1334	937	1142	1333	1016	1489	776

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only
[2] Mean excludes the 0.5% largest and smallest values

5.2.1 Number of Heated Floors

The number of heated floors for a residential dwelling provides important information to understand the space conditioning load per square foot, with multi-story dwellings having different space heating and cooling profiles than their single story counterparts.

The 2012 REUS queried the number of floors of heated living space, including basements if heated. Past REUS surveys tended to ask respondents to indicate the number of “stories” in the home, sometimes including basements and at other times not. Counting a basement as a story has been problematic in the past as respondents’ interpretations of what constitutes the basement level of a home varies. In particular, some consider the first floor of their home as the basement, although it may be fully above ground.[27] Detailed information regarding the characteristics of basements for REUS 2012 respondents is presented later in this section.

Table 23 (next page) summarizes the number of heated floors including heated basements for residential gas dwellings in the five FEU regions.

[27] The categorization of the first floor of a house as the “basement” is particular to Lower Mainland respondents, and is likely associated with the popularity of some residential building types (e.g., “Vancouver Specials”).

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Table 23: Number of Heated Floors Including Basements by Region (%)

	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*793*	*1707*	*752*	*84*	*105*	*3441*
Distribution (%)						
One floor	14.1	19.8	29.4	8.3	36.4	17.3
Two floors	53.7	61.3	56.4	33.3	49.8	56.0
Three floors	30.2	16.2	12.1	50.0	12.8	24.4
More than three floors	2.0	2.7	2.1	8.3	1.0	2.3
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

Overall, the majority of FEU homes have two heated floors (56% of all FEU dwellings), but 24% have three. Seventeen percent (17%) of dwellings have one heated floor.

Table 24 summarizes the number of heated floors by dwelling type for FEU residential dwellings, regardless of region. SFDs and duplexes are most likely to have two heated floors, while townhouses are equally likely to have two or three heated floors. Apartments, condominiums and mobile homes, not surprisingly, are most likely to have only one heated floor. Data that suggest more than two floors for apartments / condominiums and, notably, mobile homes should be treated as suspect.

Table 24: Number of Heated Floors Including Basements by Dwelling Type (%)

	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2796*	*154*	*207*	*56*	*119*	*59*
Distribution (%)						
One floor	14.9	11.1	19.4	76.6	86.8	31.6
Two floors	58.8	68.4	39.2	15.0	2.7	47.2
Three floors	24.4	15.2	39.3	7.1	0.9	19.1
More than three floors	2.0	5.3	2.1	1.4	9.6	2.0
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

5.3 Basements and Crawlspaces

Eight-in-ten (81%) of FEU households indicated their home has a basement or crawlspace, statistically unchanged from the proportion recorded during the 2008 REUS (79%) (Table 25, next page). Basements or crawlspaces are most common in dwellings in the Interior region (91% of Interior dwellings), followed by Vancouver Island (83%) and Whistler (80%). Dwellings in Whistler and Vancouver Island are more likely than other regions to have a crawlspace (53% and 37% respectively).

Table 25: Incidence of Basements and Crawlspaces by Region (%)

	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2108*	*2604*	*1357*
Full basement	47.0	60.6	38.2	15.7	55.0	49.7	52.0	51.2	53.6
Partial basement	9.7	12.7	8.2	10.8	5.1	10.3	12.2	10.6	12.1
Crawlspace	19.0	17.2	36.6	53.0	12.3	20.5	15.0	18.5	13.7
No basement or crawlspace	24.3	9.5	17.1	20.5	27.5	19.5	20.8	19.8	20.6
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Basement or crawlspace	75.7	90.5	82.9	79.5	72.5	80.5	79.2	80.2	79.4

Totals may not sum due to rounding.

Table 26 summarizes the incidence of basements and crawlspaces by dwelling type. Single family detached homes and duplexes were most likely to have a basement or crawlspace (86% and 72% respectively), compared to row / townhouses (55%), and apartments / condominiums (57%). The numbers suggest that some apartments or condominiums do not strictly adhere to the conventional definition of being part of a mid-rise or high-rise building.

Table 26: Incidence of Basements and Crawlspaces by Dwelling Type (%)

	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2796*	*154*	*207*	*56*	*119*	*59*
Full basement	54.2	41.7	28.0	16.7	0.9	37.4
Partial basement	11.1	7.2	9.5	0.0	0.0	8.1
Crawlspace	20.6	23.1	17.8	7.7	34.9	14.9
No basement or crawlspace	14.2	27.9	44.7	75.6	64.1	39.6
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Basement or crawlspace	85.8	72.1	55.3	24.4	35.9	60.4

Totals may not sum due to rounding.

Basements, if present, can be completely below ground, partially above ground or completely above ground (Table 27, next page). Topography, soil conditions, and the dwelling design often influence vertical positioning of the basement. Of FEU dwellings with basements:

- Three-quarters (73%) have a basement that is partially above ground;
- Over one-in-eight either have a basement completely below ground (14%), or have a basement completely above ground 13%;
- Regionally, homes with basements in Whistler, Lower Mainland, and Vancouver Island were the most likely to have basements situated completely above ground (17% to 18%); and
- Homes in the Interior and Fort Nelson regions were most likely to have basements completely below ground (17% and 21% respectively).

There are no significant differences between 2008 and 2012 data for either FEU or FEI totals. Data from 2002 are not presented due to differences in question wording

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Table 27: Basement Elevation by Region (%)

Homes with basements	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI
Unweighted base [1]	*440*	*1233*	*340*	*23*	*62*	*2098*	*1055*	*1735*	*753*
Completely below ground	13.4	17.4	6.2	4.5	20.5	14.2	14.0	14.9	14.5
Partially above ground	69.3	76.8	77.4	77.3	77.9	72.5	69.7	72.1	69.6
Completely above ground	17.3	5.8	16.5	18.2	1.6	13.3	16.3	13.1	15.9
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only
Totals may not sum due to rounding.

Six-in-ten (61%) of FEU residential dwellings with a basement have fully finished basements (Table 28). Another three-in-ten (31%) have partially finished basements. The remainder (8%) of basements are unfinished. Although some of the survey to survey changes are small, the trend has been towards finishing the basement level.

Table 28: Basement Finishing by Region (%)

Homes with basements	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base [1]	*440*	*1233*	*340*	*23*	*62*	*2098*	*1272*	*1735*	*894*	*1089*
Unfinished	6.9	8.1	9.1	18.2	4.8	7.5	8.9	7.3	8.5	10.8
Partially finished	26.4	38.0	40.6	13.6	32.1	31.4	33.7	30.6	33.2	32.4
Completely finished	66.7	53.9	50.3	68.2	63.1	61.1	57.3	62.1	58.3	56.8
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only
Totals may not sum due to rounding.

Eight-in-ten (80%) of FEU dwellings with a basement or crawlspace usually heat these spaces during the heating season, up from 2008 (74%) (Table 29). Regionally, dwellings on Vancouver Island are least likely to heat their basement or crawlspace (69% heated), while dwellings in the Fort Nelson region are most likely to heat these spaces (89% heated).

Table 29: Heating of Basements and Crawlspaces by Region (%)

Basement/Crawlspace Heating	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI
Unweighted base [1]	583	1516	605	67	74	2845	1473	*2173*	*934*
Usually heated during heating season	79.9	82.3	68.9	83.3	89.4	79.5	74.2	80.8	75.3
Not heated	20.1	17.7	31.1	16.7	10.6	20.5	25.8	19.2	24.7
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.
[1] Excludes homes without basements.

Table 30 (next page) summarizes the above data by basements versus crawlspaces. Of note, slightly less than half (49%) of crawl spaces are heated during the heating season, up from 2008 (42%). Crawl spaces are least likely to be heated in the Fort Nelson and Interior regions (38% and 44% respectively). In comparison, 90% of basements are heated, up from 82% in 2008. The increase in the proportion of basements that are heated is consistent with the longer term trend towards finishing the basement level.

Table 30: Heating of Basements vs. Crawlspaces (%)

Basement /Crawlspace Heating	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Percent of basements heated	89.4	91.3	86.1	90.9	100.0	89.8	81.6
Percent of crawl spaces heated	51.7	43.5	47.2	79.6	38.5	49.2	41.5

Totals may not sum due to rounding.
[1] Excludes homes without basements or crawlspaces.

5.4 Ceiling Heights

Ceiling heights affect the total interior volume of the home that needs to be heated or cooled. Survey respondents were asked to indicate the proportions of their dwelling that have 8, 9, 10 and more than 10 foot ceiling heights. These data, summarized in Table 31 show that 8 foot ceilings continue to be most common ceiling height, accounting for seven-in-ten (71%) of all ceilings in a typical residence. Next most common are 9 foot ceilings and 10 foot ceilings (17% and 7% respectively). Five percent (5%) of ceilings were greater than 10 feet. Dwellings in Whistler are notable in that they have a significantly higher incidence of ceilings exceeding 8 feet (56%). All differences between the 2012 and 2008 results are not statistically significant.

Table 31: Ceiling Heights by Region (Mean %)

Ceiling Height	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*1952*
8 feet	69.5	74.5	68.1	43.9	79.2	70.7	71.8
9 feet	17.9	14.8	19.1	20.8	9.4	17.1	17.5
10 feet	7.4	6.8	8.0	13.2	6.9	7.3	6.5
More than 10 feet	5.2	3.9	4.8	22.0	4.6	4.8	4.0

Totals may not sum due to rounding.

Ceiling heights in new construction have been increasing. Table 32 illustrates this trend by summarizing the data on ceiling heights by dwelling vintage. Indeed, ceiling heights in new homes have been increasing since the mid-1970s. Ceilings of nine feet or higher account for seven-in-ten (69%) of ceilings in dwellings constructed since 2005 compared to just slightly over one-in-eight (14%) of dwellings constructed during the 1950-75 period. Indeed, one-quarter (25%) of all ceilings in homes built since 2005 are 10 feet high or higher.

Table 32: Ceiling Heights by Dwelling Vintage (Mean %)

Ceiling Height	Before 1950	1950 - 1975	1976 - 1985	1986 – 1995	1996 - 2005	2006 or later	Age Un-known
Unweighted base	*346*	*904*	*569*	*648*	*582*	*234*	*346*
8 feet	64.2	86.2	80.3	73.0	49.2	31.2	68.9
9 feet	22.9	7.9	10.3	14.0	32.2	43.7	8.3
10 feet	10.8	4.1	5.3	7.4	9.9	14.2	11.8
More than 10 feet	2.0	1.9	4.1	5.6	8.7	10.9	11.0

5.5 Insulation

Collecting credible data on home insulation levels using self-reported methods is challenging. Respondents' ability to accurately describe insulation levels is hindered by the fact that many of the areas

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of a home that are traditionally insulated are not accessible. Additionally, knowing the insulating value (R-value) is challenging for many. The 2012 REUS survey and past REUS surveys have tried to address this latter issue by categorizing insulation levels by both R-value and wall thickness. Despite efforts to improve the ability of respondents to answer this question, up to one-quarter (25%) of respondents to the 2012 REUS survey did not know the insulation level in their dwelling's walls, attic, or basement. As a result, caution is advised in the interpretation of these data.

The 2012 REUS survey first asked whether insulation was present in each of three areas of the home (attics, walls, basements or crawlspaces). If present, respondents were asked to indicate the level or amount of insulation present in each area using one of the following three categorizations:

- Below average (about R6 or 1.75 inches of insulation or less)
- Average (about R12 or 3.5 inches of insulation)
- Above average (about R18 or 5.25 inches of insulation or more)

Those who indicated an area was not insulated or were unsure whether it was insulated were not asked to rate the insulation level.

This approach differs from past REUS surveys which did not query the presence (yes or no) of insulation. Past REUS surveys implicitly included respondents without insulation as part of the "below average" insulation category. As a result of this difference, comparisons with past REUS survey results were not made.

Insulation levels for attics are summarized by region in Table 33. The "Don't Knows" are included in the presentation of results because it cannot be assumed that they are proportionately distributed among those who indicated one of the three insulation levels.[28]

Table 33: Attic Insulation Levels by Region (%)

Attics	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*760*	*1640*	*721*	*83*	*100*	*3304*
Attic not insulated	3.7	1.6	1.1	3.7	2.1	2.8
Unsure attic is insulated	6.5	5.1	3.7	6.1	6.2	5.8
Insulated:						
Below average	5.2	4.3	3.4	3.7	4.1	4.7
Average	30.8	26.4	30.6	20.7	29.8	29.6
Above average	31.1	44.9	38.6	48.8	42.1	35.7
DK	22.7	17.6	22.7	17.1	15.8	21.3
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

As standards for insulating homes have improved over time, newer homes are expected to be better insulated than older homes. Table 34 (next page) summarizes insulation levels for attics by dwelling vintage and the data confirm that attics are less likely to be insulated if built before 1950, and insulation levels are generally higher in newer homes than older homes. The relationship between insulation levels and dwelling vintage also reflects the likelihood that older homes may have upgraded their attic insulation.

[28] For example, respondents who are unsure of their home's insulation levels may be more likely to have below average insulation levels.

Table 34: Attic Insulation Levels by Dwelling Vintage (%)

Attics	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known
Unweighted base [1]	*350*	*919*	*576*	*664*	*586*	*238*	*46*
Attic not insulated	5.0	2.9	2.2	2.6	2.0	0.8	16.9
Unsure attic is insulated	6.9	4.7	4.1	7.5	5.1	5.1	28.2
Insulated:							
Below average	31.1	28.1	35.0	31.1	28.4	16.8	15.5
Average	28.5	38.6	33.7	32.5	39.8	49.1	18.0
Above average	19.1	17.5	21.0	22.8	24.5	26.8	20.3
DK	11.9	7.6	6.3	10.1	7.1	5.9	45.1
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

Table 35 summarizes the data for wall insulation for the five FEU regions and the overall utility average.

Table 35: Exterior Wall Insulation Levels by Region (%)

Exterior Walls	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*760*	*1640*	*721*	*83*	*100*	*3304*
Walls not insulated	3.3	1.1	2.0	0.0	1.0	2.6
Unsure walls are insulated	8.7	6.6	6.1	4.9	6.0	7.8
Insulated:						
Below average	5.9	6.1	5.0	4.9	8.1	5.8
Average	42.9	40.4	40.3	31.7	39.2	41.9
Above average	12.4	24.2	21.8	40.2	26.2	16.7
DK	26.8	21.6	24.9	18.3	19.5	25.2
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

Exterior wall insulation levels by dwelling vintage are summarized in Table 36 (next page). Compared to attic insulation levels, the relationship between dwelling vintage and exterior wall insulation levels is much more pronounced. This is likely due to the degree of difficulty to upgrade wall insulation once construction of the dwelling is complete. Thirteen percent (13%) of respondents with dwellings built before 1950 indicated their walls are not insulated plus another one-in-ten (10%) indicated they are unsure whether the walls were insulated. The proportion of respondents unsure whether their walls are insulated tends to decline with newer dwellings, as does the likelihood that walls are not insulated. The higher rates of uncertainty associated with older homes may reflect the tendency for these homes to have had multiple owners, meaning that the current owner may be unaware of past efforts to improve insulation levels.

For homes with some form of wall insulation, the proportion of dwellings with below average insulation in their walls increases with the age of the dwelling. For example, nearly one-half (47%) of respondents living in dwellings constructed between 1950 and 1975 indicated their home has below average wall insulation, compared to almost one-quarter (23%) of respondents living in dwellings constructed since 2006. Conversely, only one-in-ten (10%) of homes built prior to 1950 were felt to have average wall insulation levels compared to nearly one-half (45%) of homes built since 2005.

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Table 36: Exterior Wall Insulation Levels by Dwelling Vintage (%)

Exterior Walls	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known
Unweighted base[1]	*350*	*919*	*576*	*664*	*586*	*238*	*46*
Walls not insulated	12.5	2.8	0.5	1.6	0.5	--	1.0
Unsure walls are insulated	9.6	9.4	5.7	7.8	6.4	5.4	22.9
Insulated:							
Below average	32.0	46.9	54.1	40.0	36.9	22.6	33.9
Average	10.1	7.5	10.8	19.3	30.3	45.0	6.8
Above average	21.3	22.9	25.4	27.8	25.4	26.8	33.1
DK	22.1	12.2	6.2	9.4	7.0	5.4	23.9
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

Basements without insulation can account for 20% to 35% of the total heat loss of a house.[29] Insulation for basements and crawl spaces by FEU region are summarized in Table 37.

Table 37: Basement or Crawl Space Insulation Levels by Region ((%)

Basements or Crawl Space	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*760*	*1640*	*721*	*83*	*100*	*3304*
Basement / crawl space not insulated	19.9	14.4	18.1	6.3	11.9	18.1
Unsure basement / crawl space is insulated	11.0	7.1	8.4	5.1	10.8	9.6
Insulated:						
Below average	5.4	8.0	5.5	5.1	5.4	6.1
Average	31.8	35.2	31.5	27.9	37.9	32.7
Above average	11.2	18.8	17.6	35.4	21.7	14.1
DK	20.7	16.5	19.0	20.3	12.3	19.4
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

Table 38 (next page) summarizes basement and crawl space insulation by dwelling vintage. Similar to data on attic and wall insulation levels, newer homes are more likely than older homes to have insulation in their basement or crawl space and have insulation that is average or above average. As an example, just one percent of homes constructed since 2005 have below average amounts of insulation compared to one-in-ten (11%) of homes built prior to 1950. Similarly, four-in-ten (41%) of homes built since 2005 have above average insulation compared to one-in-eight (13%) of those built prior to 1950.

[29] Natural Resources Canada, *Keeping the Heat In – EnerGuide*, 2004.

Table 38: Basement or Crawl Space Insulation Levels by Dwelling Vintage (%)

Basement or Crawl Space	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known
Unweighted base	*350*	*919*	*576*	*664*	*586*	*238*	*46*
Basement / crawl space not insulated	25.9	17.4	18.8	22.7	10.7	9.8	19.9
Unsure basement / crawl space is insulated	8.7	9.1	9.4	10.7	9.8	7.0	27.9
Insulated:							
Below average	11.2	8.1	6.0	5.8	1.0	1.1	7.0
Average	28.9	40.5	34.5	29.4	30.2	18.9	15.5
Above average	12.6	6.9	8.7	12.8	26.1	41.1	1.4
DK	12.8	18.0	22.6	18.7	22.0	22.1	28.2
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

5.6 Draft Proofing Effectiveness

Draft proofing / leak sealing is an activity best performed at least once a year, and is especially important in older homes. When asked how successful their draft proofing is for their residence, slightly less than one-half (48%) of respondents indicated their home was sometimes or always drafty, slightly higher than 2008 (44%) (Table 39). Regionally, the results are likely influenced by climate, the age and composition of the dwelling stock. For example, homes on Vancouver Island and Whistler are considered the least drafty (40% and 44%) while the draftiest homes are in Fort Nelson (63%).

Table 39: Draftiness of the Home by Region (%)

How effective is your draft proofing?	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base	*793*	*1707*	*752*	*84*	*105*	*3441*	*2182*[1]
Not at all drafty	49.1	54.2	59.9	56.1	37.1	51.6	55.6
Sometimes drafty	45.5	41.0	37.7	43.9	54.2	43.5	41.1
Always drafty	5.4	4.7	2.4	--	8.7	4.9	3.3
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Sometimes or always drafty	50.9	45.8	40.1	43.9	62.9	48.4	44.4

[1] Rebased to exclude DK responses
Totals may not sum due to rounding.

5.7 Windows

Respondents to the 2012 REUS were asked to specify the percentage of their windows that matched the following descriptions:

- Single pane regular (clear) glass
- Double pane regular (clear) glass
- Double pane low-e
- Triple pane regular (clear) glass
- Triple pane low-e
- Other

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Respondents with double and/or triple glazed windows were also asked whether the windows had argon gas fill between the panes. These window descriptions are the same as those used in the 2008 REUS. The 2002 REUS also used similar window categories but did not ask for percentages. Rather, the survey asked respondents to indicate which of the window types were in the majority of window openings. This prevents direct comparison of the 2002 data with 2008 and 2012.

Average (mean) percentages for the five window types and "other" by FEU region are provided in Table 40. Highlights include:

- double pane regular glass windows continue to be most common window type present in FEU residential dwellings in 2012 (62% of all windows in 2012 versus 66% in 2008);
- the share of double pane windows with low-e coating is highest in the Interior and Fort Nelson regions (27% and 26% respectively);
- consistent with the 2008 REUS, residential dwellings in the Lower Mainland region continue to have significantly more single pane windows than other regions (18%); and
- triple pane windows, with or without low-e coatings, represent a very small percentage of windows, regardless of region.

Table 40: Window Glazing - Mean % of all Windows by Region

Window Type	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base	*781*	*1662*	*738*	*80*	*101*	*3362*	*1993*
Single pane regular glass	17.7	8.8	10.0	0.8	11.2	14.5	18.2
Double pane regular glass	62.0	60.7	68.3	72.6	59.7	62.3	66.3
Double pane with low-e coat	18.5	26.9	19.3	23.4	25.5	20.9	13.5
Triple pane regular glass	0.4	0.7	0.5	0.1	1.1	0.5	0.5
Triple pane with low-e coat	0.6	1.5	0.4	0.1	--	0.8	0.4
Other	0.8	1.4	1.4	3.0	2.5	1.0	0.7

Of note, the percentage of double pane windows with low-e coating increased from 2008 (14% versus 21% in 2012). This result is attributable to both newer homes in the 2012 REUS but also due to significant home renovation activity during the past four years, in part, due to rebate programs offered by governments and utilities.

Data on window types by dwelling vintage are summarized in Table 41 (next page). Unsurprisingly, the data show that the older the dwelling, the more likely it has single pane windows. Homes constructed in the 1986-95 period are most likely to have double pane windows with regular glass, and this percentage decreases with dwellings that are both older and newer. The effects of renovation activity among the older housing stock are evident from the percentage of windows for homes constructed prior to 2006 that have double pane windows with low-e coating (ranges from 14% to 24%).

Table 41: Window Glazing - Mean % of all Windows by Dwelling Vintage

Window Type	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 – 2005	2006 or later	Age Un-known
Unweighted base [1]	*343*	*903*	*563*	*654*	*574*	*230*	*46*
Single pane regular (clear) glass	34.8	24.1	12.5	5.1	3.3	1.2	23.7
Double pane regular (clear) glass	46.9	48.5	63.3	80.1	71.5	61.2	54.7
Double pane with low-e coat	15.4	24.1	22.8	13.6	23.3	33.3	14.5
Triple pane regular (clear) glass	0.7	0.2	0.2	0.4	0.9	1.7	0.5
Triple pane with low-e coat	0.9	1.4	0.4	0.3	0.4	2.3	0.5
Other	1.3	1.7	0.9	0.5	0.6	0.3	6.0

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

The presence of argon gas fill in double or triple glazed windows is summarized in Table 42. The likelihood of double or triple pane windows having argon gas fill increases with the presence of low-e coatings. For example, one-in-ten (11%) of respondents indicated their double paned windows (no low e coating) were equipped with argon gas compared to over one-half (54%) of respondents with double paned windows that had a low-e coating. These data are remarkable because of the high degree of respondents who were unsure (answered “don’t know”). Don’t know responses ranged from one-third (31 %) for “other” windows to over one-half (53%) for triple pane windows with clear glass.

Table 42: Windows with Argon Gas Fill by Window Type
Percent (%) Share Across

	Filled with Argon Gas?				
Window Type	Yes	No	Don’t Know	Total	*Un-weighted Base* [1]
Double pane regular (clear) glass	10.8	37.9	51.3	100.0	*2108*
Double pane with low-e coat	53.8	13.5	32.7	100.0	*928*
Triple pane regular (clear) glass	23.2	23.5	53.3	100.0	*35*
Triple pane with low-e coat	47.1	14.2	38.7	100.0	*46*
Other	4.2	64.5	31.3	100.0	*36*

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

5.7.1 Window Frames

Each respondent to the 2012 REUS was asked to estimate the percentage of their dwelling’s windows by frame material (e.g., aluminum, wood, vinyl, and/or fibreglass). An open ended “other” frame category was also provided. Averages by frame type, by region, are summarized in Table 43. The data show that vinyl framed windows are most common, accounting for nearly one-half (47%) of all windows, followed by aluminum (31%), and wood (20%).

Table 43: Window Frame Material - Mean % of all Windows by Region

Window Frame Material	LM	INT	VI	W	FN	2012 FEU
Unweighted base	781	1670	741	83	102	3377
Aluminum	50.0	20.5	34.8	33.1	17.3	30.6
Wood	11.1	27.6	10.8	40.5	26.8	20.4
Vinyl	37.1	49.7	52.9	25.4	54.8	47.1
Fibreglass	1.3	1.6	1.1	--	0.2	1.3
Other	0.5	0.6	0.4	1.0	1.0	0.6

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The popularity of different window frame materials tends to vary by when the home was built (Table 44).

- Homes built prior to 1950 are most likely to have wood window frames (46% of windows).
- Window frames in homes constructed from the mid-1970s to mid-1990s are more likely to be made from aluminum (40% to 43%).
- Homes constructed since the mid-1990s are most likely to have vinyl window frames (66% to 72%).

While some homes continue to use their original window frames, evidence of the use of newer style vinyl windows in older homes (those built prior to the mid-1990s) is consistent with window upgrades to existing structures.

Table 44: Window Frame Material - Mean % of all Windows by Dwelling Vintage

Window Frame Material	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known
Unweighted base [1]	*343*	*903*	*570*	*655*	*574*	*230*	*43*
Aluminum	17.7	29.7	40.2	43.2	19.5	15.6	54.5
Wood	45.7	21.5	19.7	18.9	11.2	8.9	12.8
Vinyl	35.2	47.3	38.2	36.9	66.4	71.7	28.5
Fibreglass	0.8	1.1	1.1	0.8	2.0	3.0	4.2
Other	0.6	0.4	0.8	0.4	0.8	0.7	--

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

5.8 Exterior Doors

REUS 2012 respondents were asked to itemize (count) their exterior (outside) doors by door material and design. Table 45 (next page) summarizes the relative popularity of door materials including wood, steel, fibreglass and glass. Insulated steel or fibreglass doors are the most common outer door materials for FEU customers, representing four-in-ten (39%) of all exterior doors in 2012, up from 2008 (34%). Wood doors (23%) and aluminum framed doors with glass (13%) are the next two most popular door types. Commensurate with the increased share represented by insulated steel or fibreglass doors, the shares for wood and aluminum framed glass doors has declined relative to 2008.

Notable regional differences include a significantly higher share for insulated steel or fibreglass doors in the Fort Nelson and Interior regions (55% and 44% respectively). Dwellings in Whistler and the Lower Mainland are significantly more likely to use exterior doors made of wood compared to the other regions. In Whistler's case, the use of wood exterior doors is likely influenced the architectural conventions common to the resort's housing stock. The use of wood for exterior doors in the Lower Mainland is attributable to the mix of older homes and newer, character style homes.

Table 45: Exterior Door Material by Region (%)

Exterior Door Type	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base	*778*	*1655*	*741*	*83*	*102*	*3359*	*2074*
Wood doors	28.2	19.8	21.4	34.4	17.8	22.5	27.2
Wood doors with aluminum storm doors	6.4	7.0	4.8	1.6	7.7	6.2	7.7
Insulated steel or fibreglass doors	30.7	43.5	37.4	15.8	55.2	38.6	33.8
Glass doors with wooden frames	7.1	9.5	9.4	28.7	8.7	9.4	8.5
Glass doors with aluminum frames	18.5	10.1	15.8	14.8	5.2	13.4	16.7
Glass doors with vinyl frames	9.0	10.1	11.3	4.7	5.2	9.8	6.2
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

Table 46 summarizes the popularity of different exterior door types by dwelling vintage. As expected, wooden exterior doors are typical of older dwellings (e.g., 40% of exterior doors in homes built before 1950). However, wooden doors have shown some signs of resurgence in newer dwellings (16% of dwellings constructed since 2005). Despite this, newer homes are most likely to use insulated steel or fibreglass doors and glass doors with vinyl frames. Wooden doors with aluminum storm doors are most common among homes constructed prior to 1975 and are present in only three percent of homes constructed since 2005.

Table 46: Exterior Door Material by Dwelling Vintage (%)

Exterior Door Type	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known
Unweighted base [1]	342	906	568	649	565	224	44
Wood doors	39.6	31.6	21.2	13.3	12.5	16.3	29.3
Wood doors with aluminum storm doors	8.4	9.4	5.3	5.3	2.6	3.2	10.0
Insulated steel or fibreglass doors	28.5	32.6	40.0	44.9	46.5	39.0	29.3
Glass doors with wooden frames	10.9	6.3	7.7	11.0	10.6	15.4	6.4
Glass doors with aluminum frames	8.4	12.2	16.0	15.8	14.0	11.7	14.3
Glass doors with vinyl frames	4.3	8.0	9.8	9.6	13.8	14.5	10.7
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

Table 47 summarizes the average number of exterior doors per dwelling, by door material.

Table 47: Average Number of Exterior Doors per Dwelling

Exterior Door Type	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base	*778*	*1655*	*741*	*83*	*102*	*3359*	*2074*
Wood doors	1.0	0.7	0.8	1.3	0.5	0.8	1.0
Wood doors with aluminum storm doors	0.2	0.2	0.2	0.1	0.2	0.2	0.3
Insulated steel or fibreglass doors	1.1	1.5	1.3	0.6	1.5	1.3	1.2
Glass doors with wooden frames	0.3	0.3	0.3	1.1	0.2	0.3	0.3
Glass doors with aluminum frames	0.7	0.3	0.6	0.6	0.1	0.5	0.6
Glass doors with vinyl frames	0.3	0.3	0.4	0.2	0.1	0.3	0.2
Average # per dwelling (all types)	**3.6**	**3.4**	**3.6**	**3.8**	**2.8**	**3.5**	**3.6**

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5.9 Energy-Related Renovations

Respondents to the 2012 REUS were provided a list of renovations that could affect energy use. They were asked to indicate whether they had undertaken the renovation in the last five years. Additionally, they were asked whether they undertook the renovation with the help of a government or utility rebate. For renovations where no government or utility rebate was available, respondents only had to indicate whether they had undertaken the activity in the last five years. All respondents were also asked whether they planned to undertake any or all of the renovations during the next two years. Analysis of the results from the 2008 REUS had found a strong relationship between stated renovation intentions and actions.[30] Thus, activities indicated for the next two years from the 2012 REUS, while speculative, are considered reasonable indicators as to which renovations are most likely to be undertaken by FEU residential customers.

Past (rebate and no-rebate) and planned (expected) renovations for FEU customers are summarized in Table 48. Of note, nearly one-half (46%) undertook at least one of the listed renovation activities. The three most frequently undertaken renovations were: installing programmable thermostats (undertaken by 21% of REUS 2012 respondents); installing energy-efficient windows (20%), and weather stripping or caulking (19%). Appliance specific renovations included: installed a high efficiency hot water tank (10%), and installed an on-demand hot water heater (3%).

Table 48: Renovation Activity - Last Five Years and Next Two Years (%)

Type of Renovation	Last Five Years				Plan to do This – Next Two Years
	Did This – With or Without Rebate	Did This - With Rebate	Did This - Without Rebate	Percent Using Rebate	
Install programmable thermostat(s)	20.5	3.6	16.9	17.5	4.6
Install energy-efficient window(s)	20.1	7.2	12.9	35.6	9.2
Install weather stripping or caulking	18.6	2.6	16.0	13.8	8.4
Install low flow showerhead(s)	16.7	2.1	14.6	12.5	4.6
Improve insulation in walls, attic, basement, or crawlspace	16.2	5.2	11.0	31.8	9.0
Install insulated exterior door(s) or storm doors	13.6	3.8	9.9	27.7	5.6
Completed EcoENERGY or LiveSmart BC energy audit	10.4	n/a	10.4	n/a	2.9
Install high efficiency hot water tank	10.1	2.5	7.6	24.4	7.0
Install pipe wrap	9.4	1.0	8.4	10.6	4.8
Install on-demand (tankless or hybrid) water heater	3.0	0.8	2.2	28.0	5.2
Install hot water heater blanket	2.9	0.6	2.4	18.9	5.9
Install hot tub	1.8	n/a	1.8	n/a	1.5
Install drain pipe waste heat recovery system	0.9	0.3	0.6	29.2	2.1
Install a sauna	0.8	n/a	0.8	n/a	0.7
Install heated swimming pool	0.5	n/a	0.5	n/a	0.6
At least one of the above (%)	46.3			n/a	38.4

Calculated using weighted base of n = 3,341
n/a = not applicable

The percent of renovations completed with the aid of a government or utility rebate, where available, ranged from one-in-ten (11%) for installing pipe wrap to nearly four-in-ten (36%) for installing energy-efficient windows. One-in-ten (10%) of respondents indicated they completed an ecoENERGY / LiveSmart BC home energy audit.

[30] Terasen Gas (2008), p. 4-20.

The percent of respondents that undertook one or more energy-related renovations to their home in the last five years varies, in part, with the vintage of their home (Table 49).

Table 49: Renovations in Last Five Years by Dwelling Vintage
Percent of Respondents

Energy-Related Renovation – Last Five Years	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known
Unweighted base	*350*	*919*	*576*	*664*	*586*	*238*	*46*
Improve insulation in walls, attic, basement, or crawlspace	27.0	22.6	15.2	11.3	8.0	6.0	16.8
Install energy-efficient window(s)	25.1	32.2	27.9	10.3	4.8	4.3	16.6
Install insulated exterior door(s) or storm doors	18.7	20.6	16.1	8.1	6.2	3.9	4.1
Install low flow showerhead(s)	19.3	19.7	22.1	15.3	8.6	7.7	10.4
Install programmable thermostat(s)	22.6	23.5	21.6	22.7	13.5	9.4	9.4
Install pipe wrap	13.4	12.4	8.4	4.1	4.2	1.6	5.2
Install weather stripping or caulking	28.5	23.1	20.2	12.7	14.4	5.9	6.3
Install hot water heater blanket	3.6	4.6	3.1	1.4	2.4	1.0	2.0
Install drain pipe waste heat recovery system	1.3	1.0	1.3	0.6	0.7	0.1	0.0
Install on-demand (tankless or hybrid) water heater	5.1	3.6	3.8	2.2	1.1	2.1	0.0
Install high efficiency hot water tank	8.8	10.3	12.5	11.1	9.2	2.4	4.3
Completed EcoENERGY or LiveSmart BC energy audit	12.9	13.1	11.1	11.3	4.8	2.7	1.1
Install a sauna	2.1	0.3	0.6	0.1	2.0	0.5	0.0
Install heated swimming pool	0.7	0.2	0.6	0.1	1.0	0.5	0.0
Install hot tub	1.3	2.4	1.2	1.7	1.7	3.2	0.0
At least one of the above	51.0	55.4	54.2	44.6	33.3	21.6	37.4

The data confirm that the older the home, the more likely it received one or more energy-related renovations during the past five years. For example, one-half (51%) of homes built before 1950 had at least one energy-related renovation compared to only one-in-five (22%) of homes constructed since 2005. The likelihood of any specific renovation activity being completed during the last five years typically increased with the age of the dwelling, although there is a commonality of renovation incidence for windows, doors, programmable thermostats, and weather stripping for homes built prior to 1986. This group of homes were also comparable in terms of their likelihood of having an ecoENERGY / LiveSmart BC energy audit.

Overall, four-in-ten (38%) households plan to undertake one or more energy-related renovations during the next two years. The top three energy-related renovations planned include installing energy-efficient windows, improving insulation and weather stripping / caulking.

Table 50 (next page) shows the likelihood undertaking one or more energy impacting renovations in the next two years also varies, in part, with the vintage of the home.

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Table 50: Renovations in Next Two Years by Dwelling Vintage
Percent of Respondents

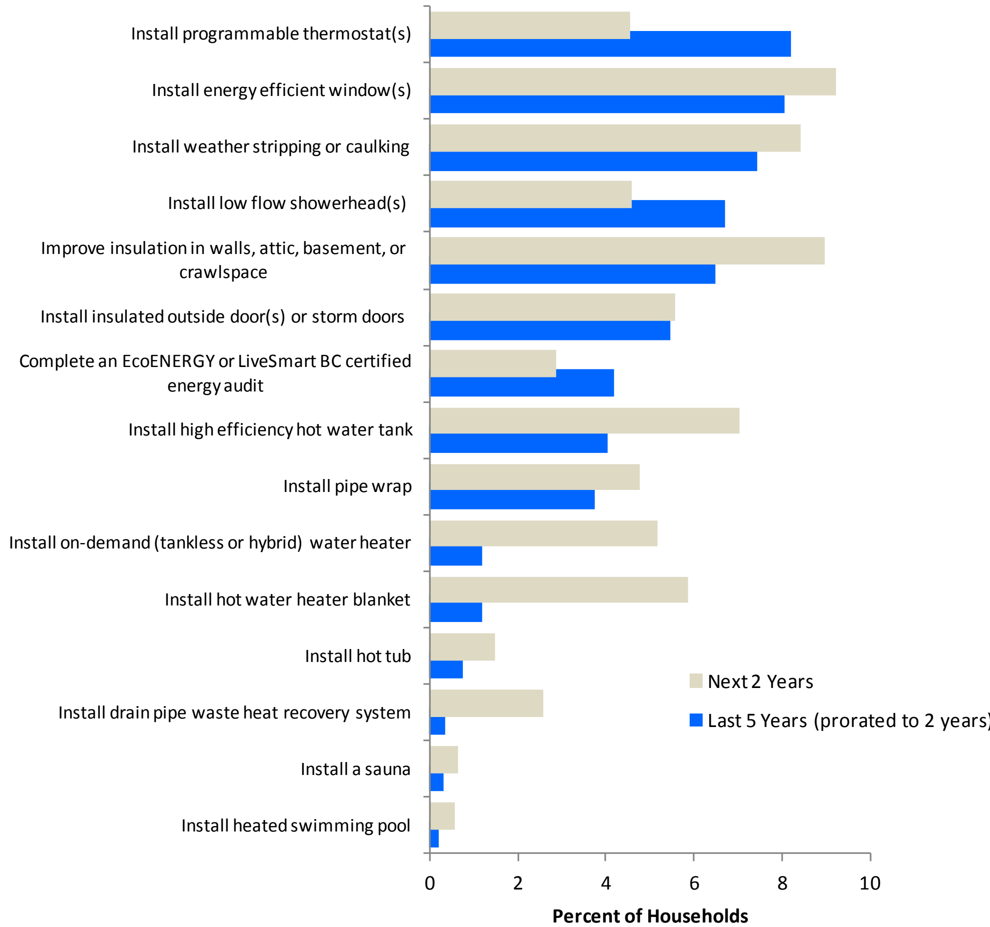
Energy-Related Renovation – Next Two Years	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known
Unweighted base	*350*	*919*	*576*	*664*	*586*	*238*	*46*
Improve insulation in walls, attic, basement, or crawlspace	14.7	11.2	11.5	7.1	4.5	4.6	0.1
Install energy-efficient window(s)	13.7	12.6	13.4	6.8	2.8	3.1	6.4
Install insulated exterior door(s) or storm doors	7.2	7.5	5.8	5.8	2.5	1.0	6.4
Install low flow showerhead(s)	5.5	5.5	4.0	4.3	4.3	3.9	1.1
Install programmable thermostat(s)	2.4	5.3	4.4	5.0	3.8	4.9	6.3
Install pipe wrap	5.8	6.0	4.1	5.7	3.2	2.2	0.0
Install weather stripping or caulking	9.2	7.3	7.9	11.9	6.6	8.3	5.2
Install hot water heater blanket	8.6	6.0	7.4	6.6	3.5	2.0	0.0
Install drain pipe waste heat recovery system	1.2	4.1	3.0	2.5	1.8	1.0	0.0
Install on-demand (tankless or hybrid) water heater	4.5	7.1	5.4	4.4	5.0	2.5	1.0
Install high efficiency hot water tank	5.6	8.3	6.5	7.3	9.4	1.0	6.2
Have an EcoENERGY or LiveSmart BC energy audit	1.5	3.5	2.7	4.2	1.9	1.6	2.0
Install a sauna	0.2	1.1	0.3	1.0	0.3	0.5	0.0
Install heated swimming pool	0.3	1.0	0.4	0.7	0.2	0.5	0.0
Install hot tub	2.8	2.4	0.9	1.0	0.5	1.0	1.1
At least one of the above	40.8	42.5	46.3	36.9	31.6	27.7	23.2

Over four-in-ten respondents living in dwellings built prior to 1986 are planning to undertake at least one energy-related renovation, compared to three-in-ten of respondents living in homes built since 1995. Additionally, the nature of the renovations planned varies by vintage, with respondents in older dwellings planning to install energy-efficient windows, insulated doors, hot water heater blankets, and pipe wrap. Respondents with newer homes are more likely to upgrade weather stripping and caulking, improve insulation levels, install programmable thermostats, and install low flow shower heads. Of particular note, homes constructed during the mid-1970s to mid-1980s (28 to 38 years old) are expected to undergo the most renovation activity during the next two years, with nearly half (46%) of households in these homes planning at least one energy-related renovation.

Figure 19 (next page) compares the frequency of past energy-related renovations with planned renovations, ordered by renovations undertaken during the past five years. Data for the latter variable have been prorated to two years to allow comparison with the planned renovations.

Some renovations undertaken in the past are less likely to occur in the next two years. These include installing programmable thermostats and low flow showerheads. Some renovations are more likely to occur in the next two years than they did in the past, including installing a high efficiency hot water tank or on-demand water heater, installing a hot water heater blanket, and improving insulation. There also appears to be some interest in drain pipe waste heat recovery systems.

Figure 19: Comparison of Past and Planned Energy-Related Renovations



5.9.1 Renovations Involving Fireplaces and Heater Stoves

One-in-eight (14%) of REUS 2012 respondents indicated they had either undertaken renovations or changes to their fireplaces or heater stoves during the last five years or planned to do so in the next two years (Table 51). Regionally, residents of Fort Nelson and Whistler were less likely to make or plan changes but the small samples for these regions mean the differences are not statistically significant.

Table 51: Renovations / Changes to Fireplaces or Heating Stoves (%)

Fireplace or Heater Stove Renovations	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*769*	*1624*	*717*	*81*	*104*	*3295*
Yes - Renovations / changes last 5 years or next 2 years	14.2	13.4	13.4	11.2	8.5	13.9

Past and planned renovations involving fireplaces or heating stoves, by type of renovation, are summarized in Table 52 (next page). Respondents having made a renovation involving fireplaces or heating stoves in the last five years were asked whether the renovation(s) were done with or without a government or utility rebate.

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Table 52: Fireplace or Heating Stove Renovations - Last Five Years and Next Two Years (Population %)

Type of Fireplace or Heating Stove Renovation	Did This – With or Without Rebate	Did This - With Rebate	Did This - Without Rebate	Percent Using Rebate	Plan to do this – Next 2 Years
Install gas heater type fireplace insert in an existing wood fireplace	3.6	0.7	2.9	20.6	1.2
Install free standing gas fireplace or heating stove	1.8	0.5	1.3	28.8	0.9
Replace decorative gas fireplace with gas heater type insert	1.5	0.9	0.7	55.1	0.8
Remove wood fireplace or wood stove	1.0	n/a	1.0	n/a	0.2
Install decorative gas fireplace	1.0	n/a	1.0	n/a	0.2
Install wood stove	0.9	0.1	0.7	16.4	0.5
Install electric fireplace	0.9	n/a	0.9	n/a	0.4
Remove or disconnect gas fireplace	0.5	n/a	0.5	n/a	0.2
At least one of the above (population)	8.9			n/a	6.2

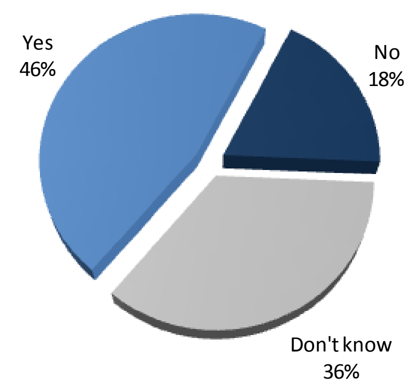
n/a = not applicable

Overall, one-in-ten (9%) of FEU residential customers undertook one of the listed renovations to a fireplace or heater stove during the last five years. The top three renovations were: installing a gas heater type fireplace insert in an existing wood fireplace (3.6% of respondents); installing a free standing gas fireplace or heater stove (1.8%), and replacing a decorative gas fireplace with a gas heater type insert (1.5%). Over one-half (55%) of decorative gas fireplace replacements were done with a government or utility rebate.

Only six percent (6%) of FEU customers indicated they plan to undertake one or more of the eight listed fireplace or heater stove renovations during the next two years with the most frequently planned renovation is to install a gas heater type fireplace insert into an existing wood fireplace (1.2% of the respondents).

Respondents who installed a gas fireplace or heater stove during the last five years were asked whether the unit was an EnerChoice model. The EnerChoice logo and a brief description were provided to help with recognition. The results, summarized in Figure 20, show that less than one-half (46%) of those who installed a fireplace or heater stove indicated it was EnerChoice model; however, over one-in-three (35%) were unsure whether it was an EnerChoice model. Regional results are not presented due to small sample sizes.

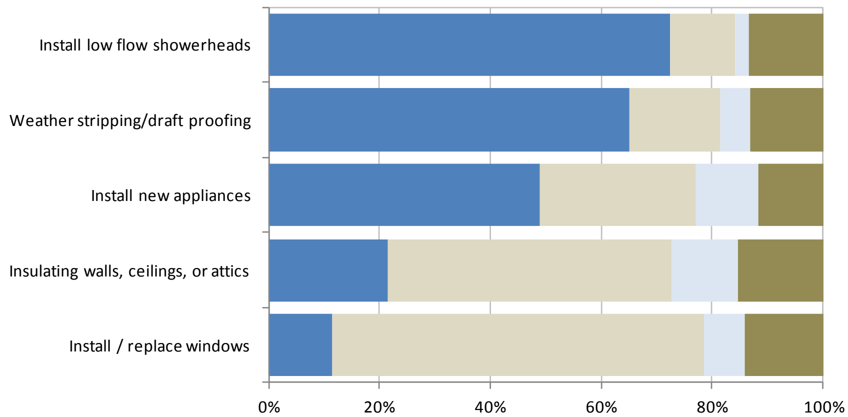
Figure 20: Was Fireplace or Heater Stove an EnerChoice Model?



5.10 Energy-Related Home Improvements – DIY Versus Using Contractors

Respondents to the 2012 REUS survey were asked to indicate who typically performs a variety of common energy-related improvements to their home, including installing new appliances, installing/replacing windows, installing low flow showerheads, weather stripping and draft proofing, and improving insulation in walls, ceilings, and attics. The results, summarized in Figure 21, show that the more complex the task, the greater likelihood that a contractor would undertake the task.

Figure 21: Who Typically Completes Energy-Related Home Improvements?



	Install / replace windows	Insulating walls, ceilings, or attics	Install new appliances	Weather stripping/draft proofing	Install low flow showerheads
Homeowner	11.4	21.6	48.8	65.0	72.3
Contractor	67.3	51.2	28.2	16.6	11.8
Both	7.2	11.9	11.4	5.3	2.5
Not Applicable / No Answer	14.1	15.3	11.6	13.1	13.4

Percent of Respondents (n=3,441)

Between 12% to 15% of respondents indicated the home improvement in question was not applicable to them or did not answer the question. Some may not have made the improvement in question or someone else may be responsible for these improvements in their home. This latter would be typical for condominiums and rental properties where many renovations and capital upgrades are responsibility of someone other than the resident.

6 SPACE HEATING

This section presents and analyzes data on space heating fuels and methods (appliances and equipment), fuel switching behaviours, furnace and boiler efficiencies, heating equipment replacement, repair and maintenance behaviours, and furnace fan operating behaviours.

6.1 Determining How Dwellings are Heated

Determining how people heat their homes requires identifying two components: fuels and methods (equipment and appliances). As some space heating methods (e.g., forced air furnaces) may be used with a number of different fuels depending upon their design, the 2012 REUS and all previous FortisBC REUS surveys asked respondents to identify space heating fuels separately from the methods. An alternative approach is to provide a list of space heating equipment and fuel combinations (e.g., electric forced air furnace, natural gas forced air furnace, combination wood and electric forced air furnace, etc.) and have respondents pick their system(s) from this list. The drawback to this approach has always been the sheer number of equipment-fuel combinations that exist and need to be listed to be comprehensive. Each approach has merits and weaknesses. While accurately cataloguing heating methods and fuels is important, it equally important to understand how homeowners and renters use their heating systems. This includes whether they have switched from one to another as their preferred heating method (i.e., in homes with more than one method of space heating) or through equipment replacement.

6.2 Space Heating Fuels

Respondents to the 2012 REUS survey were asked to identify the main space heating fuel used to heat their home, all other fuels used for space heating, and the most used secondary or other fuel used for space heating. The main space heating fuel was described as the fuel “that provides most of the heat in the home during a typical year”. The following sections discuss main fuels and secondary fuels separately, and then summarize all fuels used regardless of whether they are main or secondary.

6.2.1 Main Space Heating Fuel

Natural gas is the main (primary) space heating fuel for nine-in-ten (87%) of FEU residential customers, down from 91% in 2008 (Table 53, next page). The loss of natural gas share corresponds with an increase in the use of electricity as the main fuel (11% versus 7% in 2008) .All other space heating fuels have not experienced a statistically significant increase or decrease compared to 2008.

Regionally, the use of natural gas as a main space heating fuel is highest in the Fort Nelson (96%) and the Lower Mainland (92%) regions, and lowest in Whistler (57%).

The decline in the share of natural gas as a main space heating fuel at the utility level may have occurred because of changes to the stock of space heating equipment in FEU homes (e.g., permanent replacement of one system for another, or via new construction trends) and/or because of a switch in the role of natural gas as the main fuel to a secondary space heating fuel in homes that have more than one space heating equipment-fuel option. These two possible effects are explored further throughout this section.

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Table 53: Main Space Heating Fuel by Region (%)

Main Space Heating Fuel	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI [1]
Unweighted base	*786*	*1695*	*752*	*85*	*102*	*3420*	*2209*	*2583*	*1439*	*1610*
Electricity	7.4	11.3	33.8	38.1	1.9	11.4	6.9	8.6	4.7	3.5
Natural gas	91.5	84.7	63.0	57.1	96.1	86.5	91.1	89.4	93.6	92.9
Piped propane	--	0.2	--	--	--	0.0*	0.4	0.1	0.2	0.6
Bottled propane	--	0.9	--	--	--	0.3	0.1	0.3	0.1	--
Oil	--	--	1.5	--	--	0.2	0.2	--	0.0	0.1
Wood	0.4	2.2	0.9	4.8	1.0	0.9	0.9	0.9	0.9	1.4
Other	0.6	0.6	0.8	--	--	0.7	0.2	0.6	0.2	0.3
DK [1]	0.1	--	--	--	1.0	0.1	0.3	0.1	0.3	1.8
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**--**

[1] Data for 2002 included multiple responses on the main space heating fuel. Data may also include non-responses (missing values).
* Value less than 0.1%
Totals may not sum due to rounding.

Main space heating fuel shares by dwelling type are summarized in Table 54. The percentage of dwellings using natural gas as the main space heating fuel varies from a high of nine-in-ten (91%) for duplexes and mobile homes to seven-in-ten (69%) for apartments / condominiums. The vast majority (87%) of single family detached dwellings use natural gas as their main space heating fuel.

Table 54: Main Space Heating Fuel by Dwelling Type (%)

Main Space Heating Fuel	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2796*	*154*	*207*	*56*	*119*	*59*
Electricity	10.9	8.4	16.5	31.2	3.2	6.8
Natural gas	87.0	90.9	81.6	68.8	91.2	81.9
Piped propane	0.0*	--	--	--	0.8	--
Bottled propane	0.2	--	--	--	3.2	3.1
Oil	0.2	--	--	--	--	0.9
Wood	1.1	--	--	--	1.6	1.0
Other	0.6	0.6	1.9	--	--	1.0
DK	0.0*	--	--	--	--	5.1
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

* Value less than 0.1%
Totals may not sum due to rounding.

6.2.2 Supplementary Space Heating Fuel

After identifying their main space heating fuel, respondents were asked to indicate all other fuels used for space heating. Of these other space heating fuels, respondents were asked which one they use the most (i.e., which fuel they use the most after their primary or main space heating fuel).

Six-in-ten (58%) of respondents indicated they have a supplementary space heating fuel, meaning that four-in-ten (42%) of FEU customers use only one fuel to heat their home (Table 55, next page). The difference in incidence of supplementary heating fuel between 2012 and 2008 is not statistically significant at the 95% confidence interval.

Regionally, Whistler customers are most likely to use a supplementary heating fuel (91% of respondents), while Fort Nelson residents are the least likely to use a supplementary fuel (46%).

Table 55: Supplementary Space Heating Fuel Use by Region (%)

	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2221*	*2604*	*1439*	*1610*
Use supplementary fuel(s)	57.0	57.0	68.1	90.5	45.9	58.3	55.6	57.0	54.6	52.8

When analyzed by dwelling type, the incidence of secondary space heating fuels is highest among duplexes (62%), followed by single family detached (59%) and apartments/condominiums (58%) (Table 56).

Table 56: Supplementary Space Heating Fuel Use by Dwelling Type (%)

	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2796*	*154*	*207*	*56*	*119*	*59*
Use supplementary fuel(s)	59.0	62.3	53.3	57.5	46.6	50.6

Detailed data on all space heating fuels supplementing the main space heating fuel are provided in Table 57. Electricity represents the most common supplementary heating fuel, used by three-quarters (73%) of FEU customers who use a supplementary fuel. The next most common supplementary fuels are wood (17%) and natural gas (16%). For natural gas, the decline in its use as a main space heating fuel appears to have been accompanied by its increased use as a supplementary fuel (up from 12% in 2008). The use of wood as a supplementary heating fuel appears relatively stable at 17%, statistically unchanged from 2008 (18%).

Table 57: Supplementary Space Heating Fuel(s) by Region (%)
Dwellings Using More than One Heating Fuel
Multiple Responses Allowed

Supplementary Space Heating Fuels	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base [1]	*452*	*973*	*512*	*76*	*48*	*2061*	*1319*	*1473*	*765*	*850*
Electricity	79.2	69.6	49.8	56.6	79.3	72.9	70.8	76.3	73.0	57.9
Natural gas	10.6	14.9	45.1	38.2	2.1	16.2	11.9	11.9	9.0	27.0
Piped propane	0.4	0.9	0.8	2.6	--	0.6	0.1	0.6	0.0	0.5
Bottled propane	0.4	1.2	0.2	--	2.1	0.6	0.3	0.7	0.4	0.3
Oil	0.2	0.4	0.8	--	2.1	0.3	0.6	0.3	0.7	0.3
Wood	16.6	21.8	10.7	17.1	18.6	17.2	18.2	18.2	18.5	23.5
Other	0.7	1.1	0.4	1.3	--	0.8	0.8	0.8	0.8	1.4 [1]
DK	2.2	2.1	0.6	--	6.2	2.0	6.1	2.2	6.7	4.5

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Columns do not sum to 100% because of multiple responses.

Table 58 (next page) summarizes data on which supplementary or other fuels are the most used supplementary space heating fuel. Of note, electricity remains the most used supplementary fuel at seven-in-ten (70%) of households using a supplementary space heating fuel, statistically unchanged from 2008 (i.e., within the margins of error for the estimates). Sixteen percent (16%) of dwellings with a supplementary heating fuel identified natural gas as their most used supplementary fuel, up from 11% in 2008. These data, combined with the main space heating fuel shares, appear to confirm a modest shift in the use of natural gas in space heating.

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Electricity's share of supplementary fuels varies regionally from Vancouver Island (45%) to the Lower Mainland (74%). Use of natural gas as the most used supplementary fuel ranged from four-in-ten (44%) of Vancouver Island customers to just three percent of Fort Nelson customers. One-in-ten (11%) of FEU customers indicated wood is the most used supplementary fuel used for space heating.

Table 58: Most Used Supplementary Space Heating Fuel by Region (%)
Dwellings Using More than One Heating Fuel

Most Used Supplementary Space Heating Fuel	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base [1]	*296*	*622*	*354*	*51*	*33*	*1356*	*1293*
Electricity	76.4	65.2	47.1	56.2	76.3	69.7	67.1
Natural gas	10.5	14.2	43.9	38.4	2.2	15.8	11.1
Piped propane	0.5	0.6	0.8	1.4	--	0.6	0.1
Bottled propane	--	0.8	--	--	--	0.2	0.4
Oil	0.2	0.3	0.8	--	2.2	0.3	0.5
Wood	9.4	16.5	6.6	4.1	15.1	10.9	14.2
Other	0.5	0.6	0.4	--	--	0.5	0.4
DK	2.5	1.7	0.4	--	4.3	2.0	6.3
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

Data on most used supplementary space heating fuel by dwelling types are summarized in Table 59. Electricity is their most used supplementary fuel but the shares range from nine-in-ten (91%) of mobile homes using a supplementary heating fuel to six-in-ten (59%) for apartments / condominiums. The incidence of natural gas as the most used supplementary fuel ranges from of single family detached dwellings (15%) to apartments / condominiums (39%). Single family detached dwellings are notable in that one-in-eight (13%) with supplementary space heating fuels use wood as the most used supplementary space heating fuel. Sample sizes for apartments, condominiums, mobile homes and others are small so caution is advised on interpreting the supplemental fuel data for these dwelling types.

Table 59: Most Used Supplementary Space Heating Fuel by Dwelling Type (%)
Dwellings Using More than One Heating Fuel

Most Used Supplementary Space Heating Fuel	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base [1]	*1146*	*50*	*69*	*21*	*37*	*15*
Electricity	69.3	78.2	64.3	59.0	91.0	76.1
Natural gas	14.8	13.2	26.7	38.6	--	21.7
Piped propane	0.5	--	1.9	--	--	--
Bottled propane	0.2	--	--	--	1.7	--
Oil	0.2	--	1.8	--	--	--
Wood	12.7	2.1	1.8	--	5.5	2.3
Other	0.4	3.2	--	--	--	--
DK	1.9	3.2	3.6	2.5	1.7	--
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

6.2.3 Net Space Heating Fuels

Fuels used for space heating, regardless of whether they are used as the main or supplemental heating fuel, are summarized in Table 60. These data confirm that while there has been a moderate decline in the percentage of customers using natural gas as their primary heating fuel, the proportion of FEU gas customers using natural gas as either a main or supplemental space heating fuel (95%), is statistically unchanged from 2008. Similarly, the proportion of households in FEI regional grouping using natural gas for space heating in 2012 also remains unchanged when compared to 2008 and 2002 (all within the margins of error).

Table 60: Net Space Heating Fuel(s) by Region (%)
Multiple Responses Allowed

Main or Supplementary Space Heating Fuel	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2221*	*2604*	*1446*	*1610*
Electricity	52.5	50.9	67.7	89.4	37.5	53.7	41.1	51.9	40.9	36.1
Natural gas	96.7	92.6	93.7	91.8	95.2	95.3	96.3	95.5	97.0	96.0
Piped propane	0.3	0.7	0.5	2.3	--	0.4	0.0*	0.4	0.0*	0.8
Bottled propane	0.3	1.6	0.1	--	1.0	0.6	0.2	0.7	0.2	--
Oil	0.1	0.2	2.0	--	1.0	0.4	0.4	0.2	0.4	0.0*
Wood	9.8	14.6	8.2	20.0	9.6	11.0	10.1	11.3	10.1	13.5
Other	1.0	1.3	1.1	1.2	--	1.1	0.4	1.1	0.4	0.7
DK	2.1	1.9	0.4	--	4.8	1.9	3.4	2.1	3.7	3.8

Columns do not sum to 100% because of multiple responses.
* Value less than 0.1%.

On a regional basis, natural gas usage for space heating by FEU customers is lowest in the Whistler region (92%), and highest in the Lower Mainland (97%). The relatively few dwellings that do not use natural gas for space heating, must, by default, use natural gas for some other end-use or end-uses in the home (e.g., hot water heating, cooking, etc.).

6.2.4 Change in Space Heating Fuel – Last Five Years

All survey respondents were asked whether they had changed from one main space heating fuel to another during the last five years. Those who indicated yes to this question were asked to identify the previous main space heating fuel. The primary purpose of these two questions is to understand the incidence and outcomes of space heating fuel switching behaviors.

Table 61 (next page) shows that only one-in-twenty (5%) of FEU customers reported a change in their main space heating fuel in the last five years. This is statistically unchanged from the three percent who changed in the five years prior to the 2008 REUS survey. Regionally, one-in-three (36%) of Whistler respondents changed their fuel, consistent with the community's system-wide conversion from piped propane to natural gas. Respondents from Vancouver Island also had an above average rate of change (8%). Of the remaining three regions, the Interior was on par with the FEU average (5%) while the Lower Mainland and Fort Nelson regions were below average (3% and 1% respectively).

A change in main space heating fuel may come about because of the installation of a new or different space heating equipment, a decision to use one fuel-specific system more than another (e.g., switch to using a wood stove more while using less electric baseboard heat), or because access to a fuel not previously available in the area.

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Table 61: Change in Main Space Heating Fuel in Last Five Years (%)

Changed Main Fuel used for Space Heating?	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*785*	*1687*	*750*	*85*	*101*	*3408*	*2179*	*2943*	*1416*	*1610*
Yes	3.3	5.3	8.4	35.7	1.0	4.5	2.8	3.9	1.9	4.1
No	96.7	94.7	91.6	64.3	99.0	95.5	97.2	96.1	98.1	93.2
DK/NR	--	--	--	--	--	--	--	--	--	2.7
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

Continuing a trend observed in the 2008 REUS[31], there has been a gradual move from natural gas to electricity as the main space heating fuel (Table 62). One-half (49%) of FEU customers who changed their main space heating fuel in the last five years switched from natural gas to another fuel. In 2008, less than six-in-ten (57%) of fuel switchers had moved away from natural gas. In comparison, one-quarter (26%) of fuel switchers in 2012 moved away from electricity as their main space heating fuel during the last five years.

Table 62: Previous Main Space Heating Fuel by Region (%)

Previous Main Space Heating Fuel	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI [2]
Unweighted base [1]	*25*	*88*	*61*	*29*	*1*	*204*	*82*	*114*	*29*	*74*
Electricity	28.0	26.1	24.6	6.9	--	26.3	16.8	27.2	19.7	41.6
Natural gas	52.0	52.3	42.6	3.4	--	49.2	56.5	52.1	72.7	28.5
Piped propane	--	--	--	89.6	--	1.8	0.1	--	--	2.0
Bottled propane	--	2.3	--	--	--	0.7	1.0	0.9	--	0.8
Oil	8.0	4.5	26.2	--	100.0	10.5	19.2	6.6	--	13.9
Wood	4.0	11.4	6.6	--	--	6.8	6.5	7.1	7.6	20.2
DK	4.0	1.1	--	--	--	2.2	--	2.8	--	1.2
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**--**

Totals may not sum due to rounding.
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] Multiple responses recorded so total does not sum to 100%.

The relative movement away from natural gas varies between regions due, in part, to regional-specific circumstances. For example, Vancouver Island continues its switch from heating oil (26% of fuel switchers) and wood (7%). Ninety-percent (90%) of Whistler households that switched, moved from piped propane to natural gas, consistent with the system-wide conversion for their community. Regional sample sizes are small so caution is advised in the interpretation of their data.

6.3 Space Heating Methods

There are a variety of methods (equipment) used to provide space heating for the residential sector. Respondents to the 2012 REUS were asked to identify their main space heating method, their second most used method, and all other methods used to heat their home. Methods differ from fuels in that they refer to an appliance or technology (e.g., portable electric heaters, air source heat pumps, etc.) regardless of the fuel used. Respondents selected their responses from a list of space heating equipment.

[31] Sampson Research (2008), p. 5-5.

6.3.1 Number of Space Heating Methods

The majority (73%) of respondents to the 2012 REUS indicated they use more than one space heating method (Table 63). Nearly one-half (45%) use two space heating methods and another one-quarter (24%) use three methods. A further five percent of respondents use more than three or more methods to heat their home. The overall average is 2.0 methods per household. Regionally, homes in the Whistler region are the most likely to use more than one method (average of 2.5 methods per dwelling) versus dwellings in Fort Nelson which were the least likely (average of 1.8 methods).

Table 63: Number of Space Heating Methods Used by Region (%)

Number of Space Heating Methods	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*782*	*1684*	*736*	*83*	*103*	*3388*
1	27.0	29.2	17.9	4.9	46.0	26.6
2	43.7	44.0	53.3	47.6	30.7	44.8
3	24.6	22.1	23.2	32.9	19.5	23.8
4	4.0	3.4	4.5	12.2	3.8	3.9
5	0.6	1.0	1.0	2.4	--	0.8
6	0.1	0.2	0.1	--	--	0.2
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Two or more methods	73.0	70.8	82.1	95.1	54.0	73.4
Average	2.1	2.0	2.1	2.5	1.8	2.0
Standard Deviation	1.5	0.7	0.6	0.3	0.2	0.9

Totals may not sum due to rounding.

As expected, the number of space heating methods varies by type of dwelling. Single family detached dwellings are more likely to use more than one method (76%), while mobile homes are the least likely (53%). Data on the number of different space heating methods for these and the other dwelling types are presented in Table 64.

Table 64: Number of Space Heating Methods Used by Dwelling Type (%)

Number of Space Heating Methods	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2750*	*152*	*206*	*56*	*119*	*58*
1	24.4	37.4	34.3	42.4	46.8	27.9
2	44.8	41.9	42.6	52.5	41.6	49.7
3	25.5	20.3	19.3	5.1	11.6	16.1
4	4.3	0.4	2.8	--	0.1	6.3
5	0.9	--	0.9	--	--	--
6	0.2	--	--	--	--	--
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Two or more methods	75.6	62.6	65.7	57.6	53.2	72.1
Average	2.1	1.8	1.9	1.6	1.7	2.0
Standard Deviation	0.9	0.8	1.0	0.5	0.5	0.8

Totals may not sum due to rounding.

Finally, the number of space heating methods was examined by dwelling vintage (Table 65, next page). The results show only relatively modest variations between vintages. Dwellings constructed since 2005, however, are significantly more likely to use two or more heating methods (79%) compared to other vintages (71% to 76%).

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Table 65: Number of Space Heating Methods Used by Dwelling Vintage (%)

Number of Space Heating Methods	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known
Unweighted base [1]	*340*	*903*	*569*	*656*	*580*	*236*	*46*
1	24.2	28.6	25.6	26.4	27.2	21.3	39.2
2	39.5	41.3	48.7	44.5	45.9	51.5	44.0
3	29.5	24.3	21.3	24.5	24.1	21.5	16.8
4	4.9	4.4	3.7	4.0	2.2	5.2	--
5	1.2	1.2	0.6	0.6	0.4	0.5	--
6	0.8	0.1	0.1	0.1	0.1	--	--
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Two or more methods	75.8	71.4	74.4	73.6	72.8	78.7	60.8
Average	2.2	2.1	2.1	2.1	2.0	2.1	1.8
Standard Deviation	0.9	0.9	0.8	0.4	0.7	0.7	0.8

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

6.3.2 Main Space Heating Methods

Main space heating methods used by FEU residential customers are summarized by region in Table 66.

Table 66: Main Space Heating Method by Region (%)

Main Heating Method	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*782*	*1681*	*734*	*83*	*102*	*3382*	*2175*	*2565*	*1043*	*1610*
Central forced air furnace	69.8	78.3	48.1	36.6	93.8	69.8	73.4	72.5	76.0	76.2
Multi-fuel forced air furnace	0.4	0.8	0.3	--	--	0.5	n/a	0.5	n/a	n/a
Wired-in electric heater (baseboards)	2.8	3.0	18.5	30.5	--	4.6	2.6	2.9	1.7	1.6 [1]
Wired-in electric wall heater (fan forced)	0.1	0.1	1.0	--	--	0.2	0.7	0.1	0.4	n/a
Heat pump - air source	4.2	6.4	10.6	--	--	5.5	3.0	4.9	2.4	0.6 [2]
Heat pump - ground source (geothermal)	0.4	1.4	0.8	2.4	--	0.7	0.2	0.7	0.2	
Hot water baseboards	7.3	1.9	2.7	1.2	1.0	5.3	5.0	5.6	5.0	4.8
Hot water radiant floor heat	8.7	1.6	2.5	9.8	1.0	6.1	7.1	6.5	7.5	6.1
Electric radiant heat	0.4	0.2	1.2	2.4	--	0.4	1.1	0.3	1.0	0.3
Gas wall heater	0.5	0.4	0.3	--	--	0.5	0.5	0.5	0.6	2.1
Portable electric heaters	0.5	0.5	0.3	--	--	0.5	0.2	0.5	0.2	0.8
Gas fireplace	4.0	2.0	9.8	12.2	1.3	4.1	3.9	3.4	3.1	
Gas heater stove	0.1	0.4	2.0	1.2	--	0.4	0.6	0.2	0.3	n/a
Wood stove	0.4	2.1	0.8	2.4	1.9	0.9	0.7	0.9	0.7	1.5
Wood burning fireplace	0.1	0.1	0.1	1.2	--	0.1	0.2	0.1	0.2	5.6 [3]
Electric fireplace	--	0.1	--	--	1.0	0.0*	0.1	0.0*	0.1	
Other	0.3	0.7	1.0	--	--	0.4	0.6	0.4	0.6	0.4
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.
[1] Adjusted for multiple reporting (Habart 2003)
[2] Not differentiated in 2002 REUS. Includes both air source and ground source heat pumps.
[3] Not differentiated in 2002 REUS. Includes wood, electric, and gas fireplaces.
[*] Value less than 0.1%.

Central forced air furnaces are the most common main heating method, used by seven-in-ten (70%) of respondents, down from 2008 (73%). Next most common methods include hot water radiant floor heat and air source heat pumps (6% each), and wired-in electric and hot water baseboard heaters (5% each). Gas fireplaces are used by four percent of FEU households as their main space heating method.

Regional differences in main space heating methods are evident. Whistler and Vancouver Island customers are significantly more likely than other regions to use electric baseboard heaters (31% and 19% respectively). These two regions are also notable for their use of gas fireplaces as the main space heating method (12% and 10% respectively). Vancouver Island and Interior homes are most likely to use air source heat pumps as their main method of space heating (11% and 6% respectively).

The main space heating methods by dwelling type are summarized in Table 67. The data show that single family detached dwellings predominately use forced air furnaces (71% of all single family detached dwellings), followed by air source heat pumps or hot water baseboards (6% each), and hot water radiant floor heat (5%). Forced air furnaces are used as the main method in duplexes (63%) and row/townhouses (67%). These two dwelling types, plus apartments/condominiums, are more likely than single family detached dwellings to use hot water radiant floor heat and wired-in electric baseboard heaters. Over three-in-ten (32%) apartments / condominiums use a gas fireplace as their main space heating method. A similar finding for apartments/condominiums was noted in the 2008 REUS.[32]

Table 67: Main Space Heating Method by Dwelling Type (%)

Main Space Heating Method	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2744*	*152*	*206*	*56*	*119*	*58*
Central forced air furnace	70.7	62.6	67.3	30.9	90.5	54.1
Multi-fuel forced air furnace	0.4	0.3	0.9	--	1.6	--
Wired-in electric heater (baseboards)	3.5	6.1	12.0	21.8	1.5	2.9
Wired-in electric wall heater (fan forced)	0.2	--	--	--	--	0.9
Heat pump - air source	6.3	1.5	2.1	1.3	1.6	1.0
Heat pump - ground source (geothermal)	0.8	1.3	--	--	0.8	0.9
Hot water baseboards	5.8	4.8	0.9	2.6	--	12.2
Hot water radiant floor heat	5.3	11.5	10.6	8.7	--	17.4
Electric radiant heat	0.5	--	0.2	1.2	--	--
Gas wall heater	0.4	--	0.9	--	0.8	1.0
Portable electric heaters	0.4	2.3	--	--	--	2.1
Gas fireplace	3.4	9.2	4.8	32.2	--	5.1
Gas heater stove	0.5	0.3	--	--	--	0.2
Wood stove	1.1	--	--	--	1.6	1.0
Wood burning fireplace	0.1	--	--	--	--	--
Electric fireplace	0.0*	--	--	--	0.8	--
Other	0.5	--	0.2	1.3	0.8	0.9
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

* Value less than 0.1%
Totals may not sum due to rounding.

The main space heating method used by single family detached dwellings was explored by dwelling vintage in Table 68 (next page).

[32] Sampson Research (2008), p. 5-7.

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Table 68: Main Space Heating Method by Dwelling Vintage – Single Family Detached Dwellings (%)

Main Space Heating Method	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known
Unweighted base[1]	*340*	*898*	*569*	*655*	*580*	*236*	*31*
Central forced air furnace	76.3	81.2	70.1	64.7	60.7	49.6	72.4
Wired-in electric heater (baseboards)	4.5	1.6	5.6	3.0	4.3	4.5	9.6
Heat pump-air source	4.7	4.8	4.6	7.0	7.8	20.4	1.7
Heat pump - ground source (geothermal)	--	0.1	0.1	0.6	1.7	6.4	--
Hot water baseboards	8.7	4.4	7.3	8.0	3.0	1.8	1.7
Hot water radiant floor heat	1.1	0.5	1.1	9.3	15.9	13.3	--
Gas fireplace	0.6	3.3	6.1	3.3	3.6	1.0	1.5
All other methods	4.0	4.1	5.1	4.2	3.0	2.9	13.1
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

Central forced air furnaces (CFAF), as a percent of all main space heating methods, is highest among homes constructed during the 1950-75 period (81%) and declines successively with newer construction. Notably, CFAF's are the main space heating method in only one half (50%) of the SFDs constructed since 2005. The role of furnaces as a main method is being eroded by air source and ground source heat pumps, and hot water radiant heat. In particular, air source heat pumps are used as a main method in five percent of homes built prior to 1986 but two-in-ten (20%) of homes constructed since 2005. Ground source heat pumps are used as main method in six percent of homes constructed since 2005, but less than one percent of homes constructed before this. Additional developments of note include the decline of hot water baseboard heat and gas fireplaces as main methods. For additional discussion of heat pumps, including their underreporting, please see Sections 6.3.4 and 9.4.1.

6.3.3 Secondary Space Heating Methods

Respondents were asked about the use of secondary space heating methods, including which one is used the most. This approach was followed in the 2012 and 2008 REUS surveys. Secondary methods were queried in the 2002 REUS but without qualification as to which are used more than others. As a result, comparisons with 2002 were not made.

The most used secondary space heating methods are summarized in Table 69 (next page). The three most commonly used secondary methods are: gas fireplaces (25% of all FEU customers); electric baseboard heaters (13%), and portable electric heaters (11%). These methods were also the top three methods identified in the 2008 REUS, although the percentage of homes using gas fireplaces is significantly less in 2012 than in 2008 (25% versus 29%).

The proportion of dwellings using gas fireplaces as the most used secondary method is highest on Vancouver Island (40%) and lowest in Fort Nelson (16%). Electric baseboard heaters are an important secondary space heating method for Whistler (32%), Vancouver Island (16%), and the Lower Mainland (14%).

Data on the most used secondary heating methods are summarized by dwelling type in Table 70 (next page). Of note, the use of gas fireplaces as a secondary space heating method is highest in row/townhouses and apartments /condominiums (28% and 29% respectively). The use of portable electric space heaters is highest in mobile homes (20%) compared to just one percent of apartments/condominiums.

Table 69: Second Most Used Space Heating Method by Region (%)

Second Most Used Heating Method	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base	*782*	*1681*	*734*	*83*	*102*	*3382*	*2175*
Central forced air furnace	4.0	5.2	3.1	1.2	1.0	4.2	3.1
Multi-fuel forced air furnace	0.8	0.2	0.4	--	1.0	0.6	n/a
Wired-in electric heater (baseboards)	13.9	8.9	15.9	31.7	3.9	12.8	10.7
Wired-in electric wall heater (fan forced)	1.0	1.6	2.6	1.2	--	1.3	4.2
Heat pump - air source	1.0	3.5	1.0	--	--	1.7	0.8
Heat pump - ground source (geothermal)	--	0.2	--	--	--	0.0*	0.1
Hot water baseboards	1.0	0.2	0.3	--	1.0	0.7	0.9
Hot water radiant floor heat	1.7	0.5	0.7	2.4	2.9	1.2	0.3
Electric radiant heat	2.8	2.4	2.6	14.6	2.3	2.7	1.6
Gas wall heater	0.1	0.6	0.5	--	--	0.3	0.2
Portable electric heaters	11.9	10.4	5.2	1.2	9.7	10.7	10.0
Gas fireplace	23.5	20.5	40.2	32.9	15.5	24.5	28.9
Gas heater stove	0.5	1.7	2.2	1.2	1.0	1.0	1.1
Wood stove	2.2	4.8	1.6	1.2	3.9	2.8	2.1
Wood burning fireplace	3.7	3.4	2.0	4.9	2.9	3.4	5.9
Electric fireplace	1.8	3.4	1.6	1.2	6.8	2.2	2.2
Other	0.8	1.0	0.5	1.2	1.0	0.8	0.9
No second method	**29.3**	**31.6**	**19.5**	**4.9**	**47.4**	**28.9**	**27.0**
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

* Value less than 0.1%
Totals may not sum due to rounding.

Table 70: Second Most Used Space Heating Method by Dwelling Type (%)

Second Most Used Heating Method	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2744*	*152*	*206*	*56*	*119*	*58*
Central forced air furnace	4.8	1.6	2.1	1.3	1.6	1.0
Multi-fuel forced air furnace	0.5	--	2.1	--	--	--
Wired-in electric heater (baseboards)	12.2	19.4	16.6	16.8	4.2	10.3
Wired-in electric wall heater (fan forced)	1.4	0.9	1.1	--	0.8	0.9
Heat pump - air source	2.0	0.3	--	--	0.8	--
Heat pump - ground source (geothermal)	0.1	--	--	--	--	--
Hot water baseboards	0.8	--	0.2	--	--	5.1
Hot water radiant floor heat	1.4	--	--	--	--	5.1
Electric radiant heat	2.7	1.6	2.1	7.7	--	5.1
Gas wall heater	0.3	0.6	0.2	--	1.5	--
Portable electric heaters	11.2	7.7	7.4	1.3	20.4	15.4
Gas fireplace	24.5	20.8	28.3	29.2	12.2	25.1
Gas heater stove	1.2	--	0.2	--	0.1	--
Wood stove	3.4	0.3	--	--	1.7	1.0
Wood burning fireplace	4.0	0.9	0.9	--	0.8	--
Electric fireplace	2.1	2.6	2.1	1.3	7.4	--
Other	0.9	0.3	0.2	--	0.8	1.0
No second method	**26.5**	**42.8**	**36.5**	**42.4**	**47.7**	**30.0**
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

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Table 71 summarizes the relative popularity of all secondary space heating methods. Comparable data from 2008 and 2002 are provided. Caution is advised in the interpretation of the 2002 data, as this study found that households over-reported their forced air furnaces as either primary or secondary heat sources (Habart 2003).

Table 71: All Secondary Space Heating Methods by Region (%)

All Secondary Space Heating Methods	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base [1]	*782*	*1681*	*734*	*83*	*102*	*3382*	*2175*	*2565*	*1043*	*1610*
Central forced air furnace	4.6	5.6	3.8	1.2	1.0	4.8	3.2	4.9	3.0	19.7
Multi-fuel forced air furnace	1.0	0.5	0.4	--	1.0	0.8	3.2	0.9	n/a	n/a
Wired-in electric heater (baseboards)	17.5	12.6	19.6	37.8	7.1	16.4	12.8	16.0	12.2	16.6
Wired-in electric wall heater (fan forced)	1.7	2.4	5.4	7.3	1.0	2.3	5.5	1.9	5.2	n/a
Heat pump-air source	1.4	3.8	1.4	--	--	2.0	0.9	2.1	1.0	0.6[2]
Heat pump - ground source (geothermal)	0.3	0.2	--	--	--	0.2	0.1	0.2	0.1	
Hot water baseboards	1.3	0.2	0.3	--	1.0	0.9	1.0	1.0	1.1	2.5
Hot water radiant floor heat	2.3	0.8	1.0	2.4	3.9	1.7	0.4	1.8	0.4	2.9
Electric radiant heat	5.8	4.8	5.9	28.1	3.3	5.6	2.9	5.5	2.9	1.1
Gas wall heater	0.6	0.8	1.0	--	1.0	0.7	0.6	0.7	0.5	3.6
Portable electric heaters	19.4	17.1	11.3	9.8	20.3	17.9	16.8	18.7	17.3	16.8
Gas heater stove	0.9	2.4	2.9	2.4	1.9	1.5	1.3	1.3	1.2	n/a
Wood stove	3.8	6.7	3.0	4.9	4.8	4.5	2.7	4.7	2.7	5.0
Gas fireplace	36.1	30.4	52.0	51.2	20.3	36.2	39.2	34.3	38.4	37.1[3]
Wood burning fireplace	9.8	6.8	5.7	9.8	2.9	8.6	10.0	8.9	9.9	
Electric fireplace	4.1	7.6	3.5	3.6	10.6	5.0	3.5	5.2	3.4	
Other (Specify)	1.3	1.6	1.1	1.2	2.9	1.4	1.8	1.4	1.7	**2.3**
No Secondary Heating	**29.3**	**31.6**	**19.5**	**4.9**	**47.4**	**28.9**	**27.0**	**30.0**	**28.0**	**23.7**

Columns do not sum to 100% because of multiple responses.
[1] All customers answering QB5 (main space heat).
[2] Not differentiated in 2002 REUS. Includes both air source and ground source heat pumps.
[3] Not differentiated in 2002 REUS. Includes wood, electric, and gas fireplaces.

6.3.4 Heat Pump Underreporting

The presence of heat pumps (both air source and ground source) was addressed in the space heating methods and appliance sections of the 2012 REUS questionnaire. A review of the data on heat pumps from the two sections of the report strongly suggests that heat pumps are underreported as a main or secondary space heating method.

Data on air source heat pumps from the appliance section of the REUS survey indicate that 12% of FEU households have an ASHP, in contrast to 8% of households from the space heating methods section of the survey. The lower estimate from the space heating section may be because some households consider their ASHP a space cooling (air conditioning) method rather than a space heating method. It may also be due to the nature in which the questions were posed in the two sections of the REUS questionnaire. Based on the discussion in Section 9.4, page 125 of this report, it is likely that the incidence of ASHPs, as suggested by the space heating method section of the 2012 REUS, understates the true incidence of heat pumps among FEU's residential customer base. The more accurate estimate of the penetration of ASHPs is assumed to be 12% of FEU households.

6.4 Furnaces and Boilers

In addition to the space heating method questions, respondents to the 2012 REUS were asked whether their home had a natural gas furnace, natural gas boiler, electric furnace, or neither of these three systems. Respondents with gas furnaces and boilers were then asked to provide additional information on the efficiency of their equipment, repair costs, and replacement behaviours.

Upon review of the data, it was noted that the proportion of dwellings with a gas furnace in the 2012 survey was significantly below that recorded by the 2008 survey. While a decline in the use of furnaces as a space heating method in newer dwellings has been noted, the data suggest a broad-based decline across most other dwelling vintages. This is confounding. Major renovations that eliminate the gas furnace for some other form of space heating method are possible but other data from the 2012 REUS did not support this as an explanation for the significant drop in furnace shares among older dwellings. Further investigation was conducted to understand whether this was a legitimate trend, an underreporting bias, or other misclassification issue.

6.4.1 Adjustments to Furnace and Boiler Data

Data on furnaces and boilers for each 2012 REUS respondent (question B6) were reviewed and compared with the space heating fuels (questions B1, B4a, and B4b) and methods (questions B5a, B5b, and B5c). The purpose of the comparison was to assess the likelihood that a gas furnace, gas boiler, or electric furnace, if indicated, was correct. The comparison also assessed the likelihood that a gas furnace, gas boiler, or electric furnace was present in the home but not reported in question B6. Specifically, the assessment considered the following:

- whether natural gas was indicated as either a main or secondary space heating fuel (consistency with either gas boilers or gas forced air furnaces);
- whether a central forced air furnace or multi-fuel forced air furnace was identified as either a main, secondary, or other space heating method (indicator of a gas, electric, oil, or propane forced air furnace);
- whether hot water baseboards or hot water radiant in-floor/under-floor heat was identified as either a main, secondary, or other space heating method (indicator of a gas boiler); and
- whether an air source or ground source heat pump was identified as a main, secondary, or other space heating method (heat pumps in northern climates are often paired with an electric or gas forced air furnace).

As no method based on self-reported survey data can conclusively confirm whether a respondent has a gas furnace, electric furnace or gas boiler, the data combinations were analyzed on the basis of the most likely heating method. In all cases, the respondent's original answer to question B6 was retained unless compelling evidence suggested a different method. All results were expressed in terms of two likelihoods – probable (strong likelihood of being the correct answer) or possible (a moderate likelihood of being the correct response). In cases where the respondent's data suggested that more than one method might be present (e.g., gas furnace and a gas boiler), one of the two methods was typically assigned as the probable result.

The results of the analysis, summarized in Table 72 (next page), confirmed the majority of gas furnaces (97%), gas boilers (87%), and electric furnaces (89%) were most likely correct. The analysis found that some methods were most likely misclassified or unspecified. For example, approximately 13% of

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respondents who indicated they had a gas boiler most likely have a gas forced air furnace. It may be that these respondents confused their gas domestic water heater with being a gas boiler. A similar issue was believed to have occurred in the 2002 REUS.[33] The analysis also found that over one-quarter (27%) of respondents who did not answer question B6 most likely have a gas forced air furnace (FAF) and another five percent of non-responders likely have a gas boiler. There were situations where a natural gas forced air furnace and a natural gas boiler were both suggested which is possible for larger homes. However, this combination is unlikely to be present in significant quantities.

Table 72: Reclassification Results for Furnaces and Boilers – 2012 REUS

2012 REUS	Original Classification			
Reclassified Results	Gas Boiler	Gas FAF	Electric FAF	No Answer
Unweighted base	*258*	*2430*	*138*	*615*
Electric FAF	0.1	--	89.4	0.5
Electric – Multi-fuel FAF	--	--	3.2	--
Gas Boiler	87.1	1.9	7.4	5.3
Gas FAF	12.7	97.3	--	27.5
Gas – Multi-fuel FAF	--	0.8	--	0.1
Oil FAF	--	--	--	0.8
Propane FAF	--	--	--	0.2
No Answer	--	--	--	65.6
Total	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

To ensure compatibility with the previous REUS, survey data for furnaces and boilers from the 2008 REUS were similarly reviewed and reclassified using the same algorithm and assumptions applied to the 2012 REUS dataset. The degree of misclassification for the two surveys is similar. Highlights from the reclassification, summarized in Table 73, include:

- 97% of gas forced air furnaces confirmed
- 89% of gas boilers were confirmed
- 11% of gas boilers misclassified

Table 73: Reclassification Results for Furnaces and Boilers – 2008 REUS

2008 REUS	Original Classification			
Reclassified Results	Gas Boiler	Gas FAF	Electric FAF	No Answer
Unweighted base	*241*	*1463*	--	*478*
Electric FAF	--	--	--	5.8
Gas Boiler	88.9	2.7	--	6.4
Gas FAF	11.1	97.3	--	13.0
No Answer	--	--	--	74.8
Total	**100.0**	**100.0**	--	**100.0**

Totals may not sum due to rounding.

Electric forced air furnaces were not specifically queried in the 2008 REUS although an estimated six percent (6%) of the non-responses most likely represented dwellings with electric furnaces.

[33] Habart (2003)

The findings of the two analyses were used to reclassify the 2012 and 2008 REUS data for gas furnaces and gas boilers. Data for electric furnaces from the 2012 REUS were also reclassified but this did not affect the 2008 results as they were not specifically queried in the 2008 survey.

6.4.2 Reclassified Boiler and Furnace Data

After analysis and reclassification, an estimated three-quarters (76%) of FEU customers in 2012 had a gas furnace, down slightly from 2008 (79%). As shown in Table 74, the incidence of gas furnaces is highest in the Interior (86%) and Fort Nelson (85%) and lowest in Whistler (37%). One-in-eight (12%) of FEU customers have a gas boiler, unchanged from 2008 (within the margins of error). Gas boilers are most common in the Lower Mainland (17%) and Whistler (13%). Only three percent (3%) of FEU customers have an electric furnace and almost one-in-ten (9%) indicated they had something other than a gas furnace, gas boiler, or electric furnace. All results are based on revised furnace and boiler data.

Table 74: Furnaces and Boilers by Region (%)
Using Reclassified Data for 2012 and 2008

	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2221*	*2604*	*1446*	*1610*
Gas boiler	16.8	4.3	6.9	13.1	5.7	12.3	13.1	12.9	13.4	27.7 [1]
Gas furnace	76.3	85.5	50.4	36.9	85.4	75.9	79.3	79.1	81.6	85.7
Electric furnace	1.6	3.6	7.0	2.4	6.6	2.8	n/a	2.3	n/a	n/a
None of the above	5.3	6.6	35.6	47.6	2.3	9.0	7.6	5.7	5.0	--
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Data for 2008 and 2012 adjusted for misclassification error.
Totals may not sum due to rounding.
[1] Overstated as some respondents confused boilers with hot water tanks (Habart 2003).

The incidence of furnaces and boilers by dwelling type is presented in Table 75. Mobile homes are the most likely to have a gas furnace (95%) and apartments/condominiums the least likely (19%). Apartments/condominiums are also the most likely to indicate some method other than a furnace or boiler (41%). The incidence of gas boilers ranges from a zero for mobile homes to a high of almost one-in-five for duplexes (18%) and apartment / condominiums (19%). Gas boilers are present in one-in-eight (12%) of single family detached dwellings.

Table 75: Furnaces and Boilers by Dwelling Type (%)
Using Reclassified Data for 2012

	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2796*	*154*	*207*	*56*	*119*	*59*
Gas boiler	11.9	18.1	12.0	19.0	--	30.4
Gas furnace	77.5	67.9	70.1	29.6	94.3	58.7
Electric furnace	2.8	2.5	1.5	10.3	2.6	0.9
None of the above	7.7	11.4	16.3	41.1	3.1	10.0
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

Table 76 (next page) summarizes the incidence of restated furnaces and boilers by dwelling vintage. Of note, homes constructed since 1975 are progressively less likely to have a gas furnace. Indeed, only six-in-ten (57%) of FEU dwellings constructed since 2005 have a gas furnace, compared to over three-quarters

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(77%) of homes constructed during 1976-85. This trend is partly explained by the increasing share of row/townhomes in new construction but the decline in furnace shares has occurred across all dwelling types.

Table 76: Furnaces and Boilers by Dwelling Vintage (%)
Using Reclassified Data for 2012

	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Year Un-known
Unweighted base [1]	*350*	*919*	*576*	*664*	*586*	*238*	*46*
Gas boiler	13.0	5.1	9.4	16.8	20.8	15.4	1.1
Gas furnace	80.0	88.1	76.8	72.5	64.2	56.5	71.8
Electric furnace	0.3	1.9	3.1	1.3	3.8	10.3	11.5
None of the above	6.7	4.8	10.7	9.3	11.3	17.7	15.6
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

6.4.3 Gas Boiler Efficiencies

Respondents to the 2012 REUS who indicated they had a gas boiler or gas furnace were asked to indicate the efficiency of their gas heating system. Respondents with boilers were asked to indicate their boiler's efficiency based on the following descriptions:

- Low efficiency (60% efficient)
- Mid-efficiency (80% to 85% efficient)
- High efficiency (90% efficient or higher)

Additional information on the typical characteristics of gas boilers by efficiency type was provided to survey respondents on the survey questionnaire (hardcopy and online) to improve the likelihood they would correctly identify their boiler's efficiency (example provided in Figure 22).

Figure 22: Gas Boiler Types

Gas Boiler Types

Low Efficiency Gas Boilers:
- 13 years old or older
- 60% efficient
- uses a standing pilot light

Mid-Efficiency Gas Boilers:
- 80% to 85% efficient
- no pilot light, uses igniter instead
- uses induced draft fan or damper

High Efficiency Gas Boilers:
- 90% efficient or higher
- no pilot light, uses igniter instead
- uses plastic exhaust pipe that exits the roof or side of house

The efficiency breakdowns using the reclassified boiler data for 2012 are summarized in Table 77. The breakdown is almost neatly divided into quarters: low efficiency (25%); mid-efficiency (23%); high efficiency (27%); Don't Know (25%). Caution is advised with interpreting regional results as all samples are small.

Table 77: Natural Gas Boiler Efficiency by Region Including DK Responses (%)
Using Reclassified Gas Boiler Data for 2012

Boiler Efficiency	LM	INT	VI	W	FN	2012 FEU
Unweighted base [1]	*109*	*54*	*34*	*9*	*5*	*211*
Low efficiency (60%)	23.9	40.7	17.6	22.2	40.0	25.0
Mid-efficiency (80% to 85%)	22.9	16.7	29.4	22.2	20.0	22.7
High efficiency (90% or higher)	27.5	25.9	20.6	33.4	20.0	27.1
DK	25.7	16.7	32.4	22.2	20.0	25.2
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

To allow comparisons of boiler efficiency among regions using a common base, and to improve the ability to compare with 2008 and 2002 data, Table 78 removes respondents who were unsure of their boiler's efficiency and rebases the results.[34] Note, 2008 and 2002 REUS surveys provided only two efficiency categories (standard and high efficiency), thereby making direct comparisons with anything other than high efficiency boilers difficult.

The incidence of high efficiency boilers in 2012 (36%) is up over 2008 (30%). Caution is advised when interpreting regional differences as sample sizes are small for most regions.

Table 78: Natural Gas Boiler Efficiency by Region Excluding DK Responses (%)
Using Reclassified Gas Boiler Data for 2012 and 2008

<table>
<tr><th>Boiler Efficiency</th><th>LM</th><th>INT</th><th>VI</th><th>W</th><th>FN</th><th>2012 FEU</th><th>2008 FEU</th><th>2012 FEI</th><th>2008 FEI</th><th>2002 FEI</th></tr>
<tr><td>Unweighted base [1]</td><td>81</td><td>45</td><td>23</td><td>7</td><td>4</td><td>160</td><td>111</td><td>130</td><td>64</td><td>236</td></tr>
<tr><td>Low efficiency (60%)</td><td>32.1</td><td>48.9</td><td>26.1</td><td>28.5</td><td>50.0</td><td>33.5</td><td rowspan="2">69.8 [2]</td><td>33.8</td><td rowspan="2">69.9 [2]</td><td rowspan="2">69.6 [2]</td></tr>
<tr><td>Mid-efficiency (80% to 85%)</td><td>30.9</td><td>20.0</td><td>43.5</td><td>28.5</td><td>25.0</td><td>30.4</td><td>29.8</td></tr>
<tr><td>High efficiency (90% or higher)</td><td>37.0</td><td>31.1</td><td>30.4</td><td>42.9</td><td>25.0</td><td>36.2</td><td>30.2</td><td>36.4</td><td>30.1</td><td>30.4</td></tr>
<tr><td>Total</td><td>100.0</td><td>100.0</td><td>100.0</td><td>100.0</td><td>100.0</td><td>100.0</td><td>100.0</td><td>100.0</td><td>100.0</td><td>100.0</td></tr>
</table>

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] As no low efficiency category was provided in 2008 REUS, this value captures both low and mid efficiency boilers.
Totals may not sum due to rounding.

6.4.4 Gas Boiler Ages

Table 79 summarizes the median and mean (average) ages of gas boilers by region. The average age of gas boilers is 14 years, while the median age is 13 years. Caution is advised in the interpretation of differences among regions, particularly outside of the Lower Mainland, as sample sizes are small.

Table 79: Ages of Gas Boilers by Region (Years)
Using Reclassified Gas Boiler Data

Age of Gas Boiler (years)	LM	INT	VI	W	FN	2012 FEU
Unweighted base [1]	*102*	*51*	*33*	*9*	*4*	*199*
Median	13.0	14.0	11.0	11.0	15.0	13.0
Mean	14.2	15.7	12.3	10.3	15.0	14.2
Standard deviation	17.6	9.3	6.6	2.2	0.2	13.7

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

6.4.5 Gas Furnace Efficiencies

Respondents with a gas furnace were asked to indicate whether the furnace was a low efficiency, mid-efficiency or high efficiency unit. Respondents were provided with the following responses categories:

- Low (standard) efficiency – less than 78% efficient
- Mid-efficiency – 78% to 85% efficient
- High efficiency – 90% efficient or higher

[34] Rebasing by excluding "don't know" responses implicitly assumes that the mix of boiler efficiencies for those unsure of their boiler's efficiency is comparable to those who knew their unit's efficiency. This assumption will be invalid if the mix of boiler efficiencies within the don't know response differs from those who knew the efficiency of their furnace.

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To assist survey respondents in correctly classifying their furnace by efficiency level, additional information on the characteristics of furnaces in each of the three efficiency categories was provided on the survey questionnaire. A copy of this additional information is provided in Figure 23.

The distribution of gas furnaces by efficiency level using restated furnace data are summarized in Table 80. Highlights include.

- One-in-five (19%) of households with a gas furnace in 2012 indicated it was a low efficiency unit, down significantly from two-in-five (39%) in 2008.
- The proportion of households with a high efficiency gas furnace more than doubled from 2008 (14%) to 2012 (32%).

Figure 23: Gas Furnace Types

Gas Furnace Types

Low (Standard) Efficiency Gas Furnaces:
- 18 years old or older
- less than 78% efficient
- typically uses a pilot light
- uses metal flue that exits the roof

Mid-Efficiency Gas Furnaces:
- 78% to 85% efficient
- no pilot light, uses igniter instead
- uses a metal flue that exits the roof

High Efficiency Gas Furnaces:
- 90% efficient or higher
- no pilot light, uses igniter instead
- uses plastic exhaust pipe that exits the side of the house.
- ENERGY STAR qualified

Table 80: Furnace Efficiency by Region Including DK Responses (%)
Using Reclassified Furnace Data for 2012 and 2008

Gas Furnace Efficiency	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base [1]	*549*	*1350*	*342*	*27*	*83*	*2351*	*1411*	*1982*	*1056*	*1279*
Low (standard) efficiency (< 78% AFUE)	21.5	16.1	11.1	--	28.9	19.1	38.6	19.7	40.3	40.1
Mid-efficiency (78% to 85% AFUE)	33.3	34.7	35.7	25.9	33.7	33.9	34.3	33.8	33.3	21.3
High efficiency (90% AFUE or higher)	29.1	37.0	30.7	51.9	18.1	31.7	14.1	31.7	13.6	12.2
DK	16.0	12.1	22.5	22.2	19.3	15.3	13.0	14.7	12.8	26.4
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

It was noted in the 2008 REUS report that the proportion of high efficiency furnaces was likely understated[35], so this may have exaggerated the increase in high efficiency shares between 2008 and 2012. Regardless, the increase in high efficiency shares is consistent with the high incidence of furnace replacements that has occurred in the last four years (see Section 6.4.7). It is also consistent with the retirement of older, low efficiency furnaces as part of the replacement cycle.

Comparable to 2008, over one-in-seven (15%) of respondents in 2012 were unsure of their furnace efficiency level. Regionally this proportion varied between one-in-eight (12%) in the Interior to nearly one-quarter (23%) on Vancouver Island making regional comparisons difficult. To address this, the data was rebased excluding these don't know responses. These data are summarized in Table 81 (next page).

Excluding respondents who did not know the efficiency of their gas furnace, the proportion of FEU customers with a high efficiency furnace in 2012 (37%) is more than double the proportion in 2008 (16%). Regionally, high efficiency furnaces represented anywhere between less than a quarter (22%) of homes with gas furnaces in Fort Nelson to two-thirds (67%) of gas furnaces in Whistler. Conversely, the share of homes with low efficiency furnaces ranged from nil (Whistler) to somewhat more than two-thirds (36%) of Fort Nelson households with a gas furnace.

[35] Sampson Research (2009), p 5-13.

Table 81: Furnace Efficiency by Region excluding DK Responses (%)
Using Reclassified Furnace Data for 2012 and 2008

Gas Furnace Efficiency	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base [1]	*461*	*1187*	*265*	*21*	*67*	*2001*	*1210*	*1715*	*913*	*942*
Low (standard) efficiency (< 78% AFUE)	25.6	18.4	14.3	--	35.8	22.5	44.4	23.1	46.2	54.5
Mid-efficiency (78% to 85% AFUE)	39.7	39.5	46.0	33.3	41.8	40.0	39.4	39.6	38.2	28.9
High efficiency (90% AFUE or higher)	34.7	42.1	39.6	66.7	22.4	37.4	16.2	37.2	15.6	16.6
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

The median and average age of gas furnaces by region are provided in Table 82. The average age is 12 years old but the median age is 10 years. Regionally, the oldest furnaces are in the Lower Mainland (13 years old on average).

Table 82: Age of Gas Furnaces by Region
Using Reclassified Furnace Data for 2012

Age of Gas Furnace (years)	LM	INT	VI	W	FN	2012 FEU
Unweighted base [1]	*452*	*1096*	*284*	*22*	*59*	*1913*
Median	8.0	9.0	12.0	10.5	8.0	10.0
Mean	12.7	11.4	11.7	8.9	11.0	12.2
Standard deviation	13.8	6.5	4.3	1.8	2.5	10.2

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Furnace vintages are summarized by dwelling vintage in Table 83. The data reflect the replacement cycle for furnaces. For example, the average age of furnaces in homes constructed between 1986 and 1995 is 13 years, but the median age is 17 years, suggesting a significant proportion of furnaces for these dwellings have replaced a furnace (i.e., the distribution of furnace ages is skewed towards younger furnaces).

Table 83: Age of Gas Furnaces by Dwelling Vintage
Using Reclassified Furnace Data for 2012

Age of Gas Furnace (years)	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 – 2005	2006 or later	Year Un-known
Unweighted base [1]	*182*	*571*	*313*	*377*	*315*	*115*	*12*
Median	10.0	9.0	7.0	17.0	11.0	5.0	4.0
Mean	11.9	12.8	13.3	13.0	11.1	5.1	6.1
Standard deviation	10.1	12.2	12.4	9.0	3.8	1.6	5.8

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

6.4.6 ENERGY STAR® Furnaces & Boilers

Table 84 (next page) summarizes the proportion of gas furnaces rated ENERGY STAR® as indicated by survey respondents. On average, over one-third (36%) of FEU customers indicated their furnace is ENERGY STAR rated, while another three-in-ten (31%) indicated they were unsure.

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Table 84: Incidence of ENERGY STAR Gas Furnaces by Region (%)

Is Gas Furnace ENERGY STAR?	LM	INT	VI	W	FN	2012 FEU
Unweighted base [1]	*563*	*1343*	*344*	*27*	*78*	*2355*
Yes	35.9	36.4	32.0	48.2	28.2	35.8
No	35.2	31.1	23.8	29.6	35.9	33.1
DK	29.0	32.5	44.2	22.2	35.9	31.1
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

ENERGY STAR shares for gas boilers are summarized in Table 85. As was the case with gas furnaces, the proportion of respondents unsure whether their gas furnace is ENERGY STAR qualified is high (37%). Regional comparisons are provided but small sample sizes are noted for most regions.

Table 85: Incidence of ENERGY STAR Gas Boilers by Region (%)

Is Gas Boiler ENERGY STAR?	LM	INT	VI	W	FN	2012 FEU
Unweighted base [1]	*122*	*66*	*41*	*9*	*8*	*246*
Yes	29.5	27.3	31.7	33.3	37.5	29.4
No	33.6	39.4	29.3	33.3	37.5	33.9
DK	36.9	33.3	39.0	33.3	25.0	36.6
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

6.4.7 Furnace & Boiler Replacement Behaviours

On average, nearly one-third (31%) of FEU customers reported installing a gas furnace or boiler in the last five years, up significantly from one-in-five (22%) who indicated they did so in the five years prior to the 2008 REUS. Lower Mainland dwellings experienced the highest installation rates (33%), followed by the Interior (29%) and Whistler (28%).

Table 86: Installed Gas Furnace or Boiler in Last Five Years by Region (%)

Installed last five years?	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base [1,2]	*568*	*1365*	*346*	*27*	*83*	*2389*	*1665*	*2016*	*1225*	*1550*
Yes	32.7	28.5	22.6	27.8	20.9	30.8	21.7	31.4	22.1	19.5
No	65.4	69.7	75.3	69.4	78.0	67.3	76.5	66.7	76.0	77.4
DK	1.9	1.8	2.1	2.8	1.1	1.9	1.7	1.9	1.8	3.1
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] Asked only of those with a gas furnace or boiler.
Totals may not sum due to rounding.

Reasons why a furnace or boiler was installed during the last five years are summarized in Table 87 (next page).

As was the case in 2008 and 2002, three reasons dominate: wanting a more efficient furnace or boiler (mentioned by 38% of 2012 REUS respondents replacing a furnace or boiler in last five years), failure of the existing furnace or boiler (24%), and anticipation that the furnace or boiler would fail (16%).

Table 87: Reason for Installing Gas Furnace or Boiler by Region (%)

	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base [1,2]	*219*	*403*	*85*	*10*	*18*	*735*	*310*	*640*	*237*	*312*
Wanted more efficient furnace or boiler	37.0	42.7	20.0	10.0	22.2	37.6	44.3	38.5	45.2	25.7
Furnace or boiler had failed	26.5	17.1	25.9	40.0	22.2	24.0	21.8	23.9	22.0	35.6
Anticipated furnace or boiler failure	15.5	18.1	11.8	10.0	33.4	16.0	18.2	16.3	18.4	20.8
New home	10.0	8.7	20.0	10.0	11.1	10.2	8.6	9.7	8.4	15.3
Wanted a lower cost fuel	1.8	5.5	--	--	--	2.7	0.8	2.8	0.8	6.5
Wanted to change to gas	--	0.7	16.5	10.0	--	1.0	1.2	0.2	--	5.9
Wanted an environmentally friendly fuel	0.5	0.7	2.4	--	--	0.6	2.2	0.5	2.3	1.9
House was too cold	--	--	--	--	--	--	1.1	--	1.1	3.1
Heated floor area increased	--	--	--	--	--	--	0.6	--	0.7	1.4
Other	8.7	6.5	3.5	19.9	11.1	7.9	1.2	8.1	1.1	1.2
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] Asked only of those with a gas furnace or boiler.
Totals may not sum due to rounding.

The efficiency of the furnaces installed during the last five years is summarized in Table 88. When compared to the 2008 results, the proportion of high efficiency models installed is, as expected, significantly higher (65% for 2012 versus 40% for 2008). Efficiency levels for boilers installed in the last five years are not reported due to small sample sizes.

Table 88: Efficiency of Gas Furnace Installed in Last Five Years by Region (%)

Efficiency of New Furnace	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base [1]	*186*	*383*	*72*	*7*	*16*	*664*	*264*
Low (standard) efficiency (< 78% AFUE)	4.3	1.6	1.4	--	--	3.4	0.8
Mid-efficiency (78% to 85% AFUE)	30.1	23.5	19.4	--	56.2	27.8	51.3
High efficiency (90% AFUE or higher)	61.8	71.8	69.4	100.0	43.8	65.0	39.5
Efficiency unknown	3.8	3.1	9.7	--	--	3.9	8.4
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

6.4.8 Furnace & Boiler Repairs and Maintenance

The 2012 REUS survey queried respondents with furnaces and boilers about repairs and repair costs during the last three years, and the frequency of common maintenance procedures. Table 89 (next page) shows nearly one-in-five (18%) of respondents made repairs to their gas furnace during the last three years. Regionally, Whistler stands out, with three-in-ten (29%) indicating they repaired their furnace, considerably higher than the five region average, and likely attributable to the conversion from piped propane to natural gas.[36] For homes with gas boilers, three-in-ten (31%) on average, indicated they had to repair their boiler in the last five years. Fort Nelson households had the highest incidence (37%).

[36] While any modifications to furnaces required to convert from piped propane to natural gas were paid by FortisBC, the question did not specifically state that repairs had to be paid by the homeowner.

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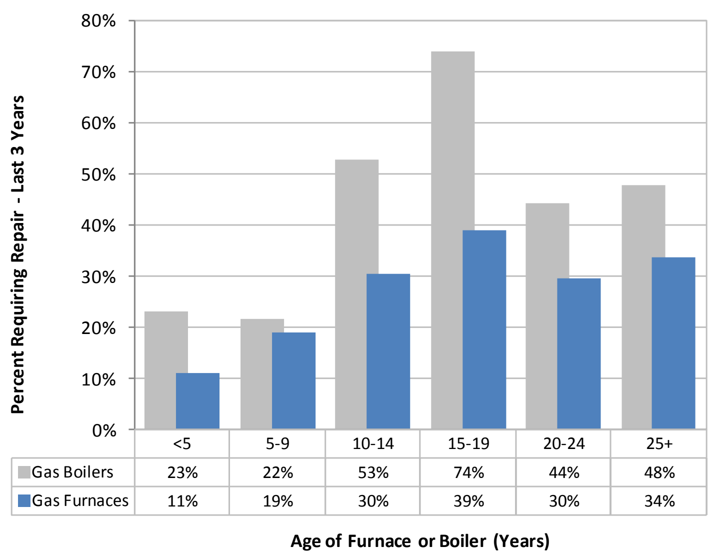
Table 89: Made Repairs to Gas Furnaces in the Last Three Years by Region (%)

	LM	INT	VI	W	FN	2012 FEU
Yes – Gas furnaces [1]	19.1	15.9	17.0	28.6	21.7	18.0
Yes – Gas boilers [2]	32.3	24.3	19.6	20.0	37.4	30.7

[1] Base – households with gas furnaces (Base =2,430).
[2] Base – households with gas boilers (Base = 258)

Figure 24 shows that unsurprisingly the likelihood of gas furnaces and gas boilers needing repair increases with the age of the space heating unit. While only one-in-ten (11%) of gas furnaces less than 5 years old had some form of repair during the last 3 years, the repair rate for for furnaces 5 to 9 years old was two-in-ten (19%), and three-in-ten (30%) for furnaces that are 10 to 14 years old. The need for repairs peaks for gas furnaces aged 15 and 19 years, with four-in-ten (39%) of furnaces in this age group having had repairs in the last three years. Possibly because they already incurred repairs that extended their lifespan, the likelihood of repair declines somewhat for furnaces 20 years and older. All calculations use the revised furnace and gas boiler data.

Figure 24: Incidence of Gas Furnace and Boiler Repairs by Equipment Vintage Repairs Made Within the Last Three Years



	<5	5-9	10-14	15-19	20-24	25+
Gas Boilers	23%	22%	53%	74%	44%	48%
Gas Furnaces	11%	19%	30%	39%	30%	34%

Compared to gas furnaces, the incidence of repairs for gas boilers is higher, in some cases considerably higher, for most equipment age ranges. Almost one-quarter (23%) of gas boilers less than 10 years of age required repairs during the last three years. The incidence of repair jumps for boilers aged 10-14 years (53%) and 15-19 years (74%). Similar to gas furnaces, the incidence of repair for boilers in their third decade of service declines.

Furnace and Boiler Repair Costs

Respondents with gas furnaces or gas boilers that required repair during the last three years were asked to indicate how much was spent on repairs during that period.

A first pass of the data for gas furnaces show expenditures ranging from a low of a few dollars to thousands of dollars. Further review of the data by age of furnace strongly suggested that some respondents had counted the installation cost for a new furnace as a repair cost. To counter this, Tukey's method was used to determine outliers in the repair cost data set. The result of this analysis led to the exclusion of amounts exceeding $1,500 from the analysis.

Median and mean (average) repair costs, excluding outliers, for gas furnaces are summarized in Table 90. The average cost of furnace repairs during the last three years for FEU customers was $377, with the median repair cost being $300.

Table 90: Repair Costs Last Three Years – Gas Furnaces ($)

Repair Costs	LM	INT	VI	W	FN	2012 FEU
Unweighted base [1,2]	*157*	*228*	*80*	*8*	*24*	*994*
Median	$300	$300	$300	$350	$300	$300
Mean	$395	$334	$357	$380	$402	$377
Standard deviation	$496	$186	$203	$47	$98	$306

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] Excludes extreme outliers (expenditures exceeding $1,500)

Repair costs for gas boilers were analyzed for outliers in a manner consistent with that used for gas furnaces. Extreme outliers (expenditures of $2,000 or more based on Tukey's method of outlier determination) were removed. Median and mean (average) repair costs, excluding outliers, for gas furnaces are summarized in Table 91. The average cost of gas boiler repairs during the last three years was $588, with the median repair cost being $400. Regional results are not provided due to small sample sizes.

Table 91: Repair Costs Last Three Years – Gas Boilers ($)

Repair Costs	2012 FEU
Unweighted base [1,2]	*82*
Median	$400
Mean	$588
Standard deviation	$652

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] Excludes extreme outliers (expenditures exceeding $2,000)

Heating System Maintenance Behaviours

The frequency with which households undertake several common maintenance behaviours for gas furnaces were queried:

- changing the furnace filter regularly
- servicing the heating system annually using a contractor
- servicing the heating system annually without using a contractor (homeowner)

Respondents were asked to indicate whether they always, usually, occasionally or never did each of the three behaviours. Respondents were allowed to specify "don't know" or "not applicable". The findings are summarized in Table 92 (next page).

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Table 92: Frequency of Heating System Maintenance Behaviours (%)
Rows Sum Across

Heating System Maintenance	Always	Usually	Occasion-ally	Never	DK	Total
Change furnace filter regularly	62.1	22.9	9.9	3.9	1.2	100.0
Service heating system annually by contractor	24.0	19.5	30.6	23.5	2.4	100.0
Service heating system annually myself	14.5	10.1	14.0	59.8	1.6	100.0

A minority of respondents (39%) had their heating system serviced annually, either by a contractor (24%) or by servicing the equipment themselves (15%). Over one-in-seven (15%) never had the equipment serviced.

6.4.9 Furnace Fan Blower Motors – Types and Operations

Respondents with gas furnaces were asked a series of questions about their furnace blower motors to better understand both the type of blower motors in use and how they are used during the year.

Three-in-ten (29%) of FEU respondents with a natural gas furnace indicated their furnace has a variable speed or electronically controlled blower motor (Table 93). Of note, four-in-ten (41%) did not know the type of blower motor on their furnace.

Table 93: Incidence of Variable Speed Furnace Fan Motors by Region (%)

Does furnace have a VSD blower motor?	LM	INT	VI	W	FN	2012 FEU
Unweighted base [1,2]	*554*	*1332*	*337*	*27*	*82*	*2332*
Yes	29.8	31.7	16.3	22.2	17.1	29.4
No	30.3	28.6	31.2	18.5	29.3	29.8
DK	39.9	39.7	52.5	59.3	53.7	40.8
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] Asked only of those with a gas furnace or boiler.

Regardless of whether they knew the furnace blower motor type, respondents with gas furnaces were asked about how often their furnace blower motor operates (runs). Respondents were asked to choose the best answer from the following list:

- only when furnace is operating
- only when furnace or air conditioning is operating
- continuously during the heating season
- continuously during the heating and cooling season
- continuously year round

The results, summarized in Table 94 (next page), show that a majority (63%) of respondents with gas furnaces only operate their furnace blower motors when the furnace is providing heat. The next most frequent response was when either the furnace or the air conditioner (AC) is operating (19%). Six percent (6%) indicated their furnace fan operates continuously all year. Some regional variations are worth noting, particular for the Interior and Fort Nelson regions where the higher incidence of central air conditioning is evident.

Table 94: Furnace Fan Blower Motor Operating Behaviours by Region (%)
Gas Furnaces Only

When does your furnace fan operate?	LM	INT	VI	W	FN	2012 FEU
Unweighted base[1]	*567*	*1353*	*345*	*27*	*82*	*2374*
Only when furnace is operating	70.2	45.6	78.8	81.5	69.5	63.4
Only when furnace or AC is operating	9.7	39.7	8.7	3.7	15.8	18.7
Continuously during the heating season	3.9	2.1	1.4	3.7	7.3	3.2
Continuously during heating and cooling season	3.4	2.8	2.9	--	1.2	3.1
Continuously year round	6.5	5.5	3.8	7.4	2.4	6.0
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

Those respondents who indicated the blower fan on their gas furnace did not operate continuously all year were asked whether they sometimes turned on the furnace fan to provide ventilation in the house. Those who indicated they did this were then asked to indicate the approximate number of weeks in the year that they manually used their fan to provide ventilation. The findings for these two questions are summarized in Table 95 and Table 96.

Approximately one-in-five (18%) of households with a gas furnace sometimes turn on their furnace blower motor to provide ventilation for part of the year.

Table 95: Use of Furnace Fan for Ventilation for Part of the Year by Region (%)
Gas Furnaces Only

Furnace fan used for ventilation?	LM	INT	VI	W	FN	2012 FEU
Unweighted base [1]	*567*	*1353*	*345*	*27*	*82*	*2374*
Yes	17.3	20.2	21.4	23.1	18.3	18.4
No	76.0	74.2	74.8	69.3	79.3	75.4
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding.

Respondents with gas furnaces used their furnace fans to provide ventilation for an average of one-quarter (13 weeks) of the year. The median value was 8 weeks. Average usage is similar among all regions (12 to 14 weeks) with the exception of Whistler (very small sample).

Table 96: Use of Furnace Fan for Ventilation by Region (Number of Weeks)
Gas Furnaces

Furnace fan used for ventilation (weeks)	LM	INT	VI	W	FN	2012 FEU
Unweighted base [1]	*94*	*255*	*69*	*6*	*15*	*439*
Median	8.0	8.0	5.0	4.0	10.0	8.0
Mean	13.9	12.3	12.9	6.0	12.3	13.3
Standard deviation	24.0	9.8	11.8	1.4	3.6	14.2

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

6.5 Programmable Thermostats

Six-in-ten (61%) of FEU residential customers use a programmable thermostat in their home, up from 2008 (55%) (Table 97). Regionally, usage is highest in the Interior and Lower Mainland (63% and 62%), while Whistler has the lowest use of programmable thermostats (44%).

Table 97: Use of Programmable Thermostats by Region (%)

Use programmable thermostat?	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base	*778*	*1689*	*727*	*83*	*103*	*3380*	*2188*
Yes	62.2	62.9	53.1	43.9	47.9	61.3	54.6
No	36.8	36.2	46.1	52.4	51.1	37.7	44.2
DK	1.0	0.9	0.8	3.7	1.0	1.0	1.2
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

Data on programmable thermostat use by dwelling type and tenancy status (own versus rent) is summarized in Table 98. Usage among the six dwelling types is highest among single family detached homes (63%) while apartments / condominiums have proportionately fewer units with programmable thermostats (29%). Owners are significantly more likely than renters to use a programmable thermostat (62% versus 33%). The incidence of programmable thermostats is influenced, in part, by the type of heating system present.

Table 98: Use of Programmable Thermostats by Dwelling Type and Tenancy Status (%)

Use programmable thermostat?	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other	Own	Rent
Unweighted base	*2746*	*151*	*205*	*54*	*118*	*58*	*3250*	*84*
Yes	63.1	54.3	60.7	28.7	48.6	38.7	62.1	33.1
No	35.9	42.4	39.3	69.9	49.8	60.3	36.9	63.2
DK	1.0	3.3	--	1.4	1.6	1.0	0.9	3.7
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

7 DOMESTIC HOT WATER

Domestic water heating (DWH) represents the system of providing hot water for domestic uses such as clothes washing, dish washing, showers, baths, and the like. Respondents to the 2012 REUS were asked a series of questions regarding their hot water heating system, including type and age of equipment, fuels, and replacement and fuel switching behaviours. Findings from past FEU REUS surveys strongly suggested that some survey respondents had difficulty in accurately identifying the fuel used for domestic water heating and the type of hot water heater equipment used to provide hot water. Given this, the DWH section of the 2012 REUS questionnaire was restructured and refined to improve the ability of respondents to accurately describe their DWH systems. As will be discussed, the results show that improvements to this end have been made but the topic remains a difficult one for some survey respondents.

7.1 Penetration and Saturation

The proportion of households with in-home DWH systems (any fuel), including penetration and saturation rates for domestic water heaters, are summarized in Table 99. Over nine-in-ten (93%) of respondents indicated their dwelling has a domestic water heater. The remainder (7 %) have their domestic hot water centrally provided (i.e., from outside their unit). This proportion of centrally provided hot water is significantly higher than that recorded in 2008 (4%), but comparable to the proportion recorded in the 2002 survey. Differences in the proportion of households without a domestic hot water heater between 2008 and 2012 may be due to differences in the sample plan for the two surveys and/or differences in the proportion of non-responses for the two surveys.[37]

Table 99: Hot Water Heater (Any Fuel) Penetration and Saturation by Region

	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base [1]	*793*	*1707*	*752*	*85*	*104*	*3441*	*2186*	*2604*	*1423*	*1610*
Penetration (%)	92.1	94.3	96.1	97.6	94.3	93.1	96.5	92.7	96.3	94.6
Saturation [2]	1.03	1.04	1.05	1.35	1.03	1.04	1.03	1.03	1.03	1.03
Households with >1 water heater (%) [2]	2.7	3.7	5.0	31.7	3.0	3.3	3.1	3.0	3.0	2.7
Installed new water in past five years (%) [2]	41.0	37.8	43.8	53.8	28.2	40.5	38.3	40.0	37.6	37.2
No hot water heater in residence (%)	7.9	5.7	3.9	2.4	5.7	6.9	3.5	7.3	3.7	5.4 [3]

[1] Treats missing responses as zeros. This ensures consistency with past surveys.
[2] Excludes missing responses and respondents living in apartments, row houses and townhouses where hot water is centrally provided.
[3] Treated non-response as zero. When non-responses are excluded, the percentage of FEI customers with no water heater decreases to 4.9%.

Regionally, Vancouver Island customers have statistically significant higher penetration of DWH heaters than the Lower Mainland (96% versus 92%). All other differences in penetration between regions are not statistically significant.

Saturation rates for households with at least one DWH heater are comparable to those observed in 2008 (1.04 units, on average, per home in 2012 versus 1.03 in 2008). The saturation rates reflect a small

[37] The 2008 REUS survey treated non-responses the same as if the respondent had indicated domestic hot water was centrally provided. In contrast, the 2002 REUS treated non-responses as non-responses (i.e., did not assume it meant centrally provided domestic hot water). It is not possible to isolate non-responses from the "no water heater" responses in the 2008 REUS dataset.

DOMESTIC HOT WATER

proportion of homes that have more than one DWH unit three percent of FEU residential customers). As observed in the 2008 REUS, Whistler dwellings are significantly more likely to have multiple DWH units (32%). In 2008, this was attributed to the high proportion of homes in the community that have a secondary suite.[38] Indeed, one-in-five (20%) of Whistler respondents to the 2012 REUS indicated their dwelling has a secondary suite, significantly higher than other regions. Saturation rates for FEI customers in 2012 are unchanged from 2002.

Four-in-ten (41%) of FEU residential customers installed a domestic hot water heater in the last five years, not significantly different from the 2008 REUS (38%). This is equivalent to an average replacement rate of 8% per year, and an average water heater life of over 13 years.

Penetration and saturation rates for hot water heaters (any fuel) by dwelling type are presented in Table 100. As was the case in the 2008 REUS, a small percentage of respondents (5%) in single family detached dwellings indicated they do not have a hot water heater in their residence.[39]A similar result was observed for mobile homes (8%). In some cases, this may be due to the presence of combination boilers (a single unit providing both heat and domestic hot water).

In contrast to SFDs and mobile homes, it was expected that a proportion of apartments / condominiums, row and townhouses, and to a much lesser degree, duplexes, would not have a DWH heater in their residence. Indeed, six-in-ten (58%) of apartments / condominiums and one-in-eight (12%) of row / townhouses indicated their unit does not have a DWH heater. Of note, over one-in-eight (14%) of respondents living in duplexes indicated they do not have a domestic hot water heater. The latter, like that of SFDs, may reflect a degree of misclassification by the survey respondent.

Table 100: Hot Water Heater (Any Fuel) Penetration and Saturation by Dwelling Type

	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base [1]	*2796*	*154*	*207*	*56*	*119*	*59*
Penetration (%)	94.9	86.0	87.9	42.2	91.7	84.9
Saturation [2]	1.04	1.03	1.00	1.00	1.02	1.04
Households with >1 water heater (%) [2]	3.8	3.1	0.0	0.0	1.7	3.6
Installed new water in past five years (%) [2]	40.9	40.0	38.2	53.7	32.0	29.1
No hot water heater in residence (%)	5.1	14.0	12.1	57.8	8.3	15.1

[1] Treats missing responses as zeros. This ensures consistency with past surveys.
[2] Excludes missing responses and respondents living in apartments, row houses and townhouses where hot water is centrally provided.

*

Questions about domestic hot water equipment and fuels from this point on in the survey were directed only to households with an in-home DWH system. Respondents living in apartments, townhouses and other complexes where DWH is provided centrally were skipped forward in the survey and, for obvious reasons, not asked questions about their DWH equipment or fuels.

38 Sampson Research (2008), p. 7-1.

39 The 2008 REUS survey had 3% of respondents in SFDs that reported not having a hot water heater in the dwelling.

7.2 Average Age of Hot Water Heaters

Table 101 summarizes the mean (average) age of the first and second hot water heaters, regardless of type or fuel. The average age of the first water heater in the FEU service region is 6.6 years, with regional variations from a low of 5.0 years for Whistler customers to a high of 7.4 years for Fort Nelson customers.

Table 101: Average Age of Hot Water Heaters (Any Fuel) by Region (Years)

DWH Age	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base[1]	*634*	*1384*	*649*	*76*	*76*	*2819*	*1656*	*2094*	*1026*	*1528*
Average age of first water heater (years)	6.4	7.1	6.0	5.0	7.4	6.6	7.1	6.7	7.3	7.5
Average age of second water heater (years)	11.9	7.5	7.3	5.3	7.3	8.1	6.7	8.2	6.2	8.5

[1] Unweighted base for first water heater only.

The mean (average) age of the first water heater is significantly lower than the average from the 2008 REUS.

7.3 Water Heater Fuels

Results from the 2008 REUS strongly suggested that some respondents with conventional storage tank hot water heaters either incorrectly specified the fuel used by their DWH tank, or the type of tank (vented or not vented).[40] The 2012 REUS questionnaire was redesigned to improve the quality of the fuel and equipment data collected for DWH equipment by asking about tank venting in a question separate from the type (shape) of DWH equipment. Specifically, respondents who indicated their home had a conventional storage-style DWH tank were asked to indicate whether the tank had one of the following venting configurations:

- vent through the side wall
- vent through the roof
- no vent (electric tank)

The no vent category description deliberately included the term “electric tank” because tanks using natural gas, propane, or oil require a vent to exhaust combustion gases, whereas electric tanks do not. A similar question was asked of respondents who indicated they had on-demand (tankless or hybrid) water heaters. Again, if no vent was present, the default assumption is that the water heater uses electricity.

When data on fuels and equipment characteristics for water heaters were compared on a respondent-by-respondent basis, some degree of fuel misspecification for storage style tanks, like that identified in the 2008 REUS, was apparent. The misspecification took the form of a mismatch between fuel (e.g., electricity versus natural gas) and equipment (vent or no vent) for conventional storage (tank) style DWH heaters. In situations where the dwelling had more than one domestic water heater, extra caution was used to compare first, second and third units in the order specified in the survey.[41]

[40] Sampson Research (2008), p.7-5.

[41] To improve the pairings of fuels with equipment for homes with more than one water heater, the 2012 REUS questionnaire asked respondents to treat the water heater that provides most of the hot water for the home as the main water heater. All subsequent questions provided response categories for multiple units organized by heater 1 (main), heater 2, and heater 3.

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Assuming the information provided on the presence (or lack) of a vent was the most likely to be correct because it could be observed by the survey respondent, data on water heater fuels for conventional storage tanks were adjusted for two types of misspecification:

- Specifying natural gas, piped propane, or oil as the DWH fuel but indicating the tank did not have a vent (i.e., it is an electric tank).
- Specifying electricity as the DWH fuel but indicating their tank had either a vent through the roof or side wall of the dwelling (tank uses natural gas, oil or propane).

In situations where a vent was present and electricity was indicated as the fuel, the reassignment of the fuel to natural gas, propane or oil was first confirmed by the presence of the same fuel for space heating. In situations where an electric tank (no vent) was indicated but natural gas, piped propane, oil, or geothermal specified as the fuel, the DWH fuel was changed to electricity. In the end, 63 cases had their DWH fuel changed from electricity to natural gas, 16 cases had their DWH fuel changed from natural gas to electricity, four cases changed from geothermal to electricity, and one case changed from a non-response to electricity.

The soundness of this adjustment methodology depends entirely upon the assumption that respondents were able to correctly classify their hot water heating equipment based on its outward appearance. The fact that some respondents could not answer the question regarding the venting of their storage tank (e.g., answered “don’t know”) suggests they either could not easily view their DWH equipment, or chose not to, while completing the survey.

7.3.1 Restated Domestic Hot Water Heater Fuels

Data on DWH fuels, with adjustments, are summarized in Table 102. No adjustments were made to 2008 or 2002 data because the questions are not directly comparable between surveys, making the reclassification methodology unsuitable for these datasets. As a result, caution is advised in comparing past REUS data with the 2012 adjusted results.

Table 102: Hot Water Heater Fuels (Corrected) by Region (%)
First DWH Unit

	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*730*	*1609*	*723*	*83*	*98*	*3243*	*2026*	*2437*	*1291*	*1528*
Electricity	10.5	25.8	28.8	64.6	13.5	16.9	10.8	15.3	9.7	14.3
Natural gas	89.0	73.3	70.5	34.1	86.5	82.5	88.8	84.2	90.1	84.7
Piped propane	0.1	--	--	--	--	0.1	0.1	0.1	0.0*	0.2
Other [1]	--	0.4	0.4	1.2	--	0.2	0.2	0.1	0.2	--
NR	0.3	0.5	0.3	--	--	0.3	--	0.3	--	0.9
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

* Value less than 0.1%
[1] Includes bottled propane, solar, geothermal, and oil.
Totals may not sum due to rounding.

Natural gas is the most common DWH fuel for FEU customers (83% of first DWH heaters). Natural gas shares by region vary from Whistler (34%) to the Lower Mainland (89%). One-in-six (17%) of FEU customers use electricity for DWH. Fuels other than electricity or natural gas, included piped propane, bottled propane, oil, solar, and geothermal, individually and collectively. These other fuels accounted for one percent (1%) or less of all DWH heaters.

To better understand whether DWH fuel shares are changing in new construction, the relationship between dwelling vintage and DWH fuel shares were explored for single family detached (SFD) dwellings in Table 103. The proportion of SFDs that use natural gas as their DWH fuel (first unit) is highest for SFDs constructed between 1986 and 2005 (87%). Over eight-in-ten SFDs constructed prior to this time use natural gas for their DWH; however, SFDs constructed since 2005 are significantly less likely to use natural gas (66%) for DWH heating and more likely to use electricity (33%). DWH fuel shares by dwelling vintage for dwelling types other than SFDs are not reported because of small sample sizes.

Table 103: Hot Water Heater Fuels (Corrected) for First DWH Unit – SFDs by Vintage (%)

	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known
Unweighted base [1]	329	782	473	497	367	140	*29*
Electricity	19.5	15.4	19.8	12.2	15.2	33.2	23.9
Natural gas	80.2	84.5	79.7	87.7	84.7	65.8	76.1
Piped propane	--	--	0.5	--	--	--	--
Other [2]	0.3	0.1	--	0.1	0.1	1.0	--
NR	0.1	0.6	0.1	0.4	0.2	0.3	--
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only
[2] Includes bottle propane, solar, geothermal, and oil.
Totals may not sum due to rounding

7.3.2 Solar Pre-Warming and DWH

A very small percentage (2%) of FEU customers (any DWH fuel) use solar energy to pre-warm or supplement their main DWH water heating process (Table 104). A similarly small percentage was recorded in 2008. Differences between the regions are not significant at the 95% confidence level.

Table 104: Solar Assist for Pre-Warming the First DWH Unit (Any Fuel) by Region (%)

	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base	*718*	*1562*	*701*	*82*	*96*	*3159*	*1928*
Use solar assist	2.2	1.2	1.3	--	--	1.8	0.8
No assist	97.8	98.8	98.7	100.0	100.0	98.2	99.2
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

7.4 Fuel Switching

All respondents with DWH equipment in their home or suite were asked whether they switched the fuel used to provide domestic hot water in the last five years. In past end-use surveys, the proportion that switched fuels was small (typically 5% or less). The 2012 REUS, however, recorded an incidence of switching several magnitudes greater than the historical estimates, suggesting a problem with the question wording and/or its interpretation by respondents.

All respondents who switched fuels were asked to indicate their previous DWH fuel. This allowed comparison with the current DWH fuel to see whether a change had occurred. These comparisons confirmed that the vast majority of respondents who reported a fuel change did not change their DWH fuel. It is not clear why the question was misinterpreted. Its wording was the same as the 2008 questionnaire although placement of the question in the DWH section in the 2012 questionnaire was changed. The data on fuel switching were adjusted to exclude respondents whose current and past fuels were the same.

Table 105 summarizes the restated data on DWH fuel switching. Two percent (2%) of FEU customers switched DWH fuels in the last five years, up from one percent (1.1%) in 2008. Regionally, the percent that switched DWH fuels varies from a low of two percent in the Lower Mainland, Interior, and Fort Nelson to one-in-five (21%) in Whistler. The higher percentage for Whistler is most likely due to the town's recent switch to natural gas from piped propane. Four percent of Vancouver Island gas customers reported switching DWH fuels in the last five years.

Table 105: Change in DWH Fuel Last Five Years by Region (%)
Restated Data

Changed DWH Fuel Last Five Years?	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*728*	*1595*	*715*	*82*	*97*	*3217*	*2004*	*2420*	*1278*	*1516*
Yes	1.9	2.3	3.9	21.0	2.0	2.3	1.1	2.0	0.5	5.7
No	98.1	97.7	96.1	79.0	98.0	97.7	98.9	98.0	99.5	94.3
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.
* Value less than 0.1%

The relative proportions of current versus previous DWH fuels for households who switched DWH fuel in the last five years are summarized in Table 106. All data are expressed as a percent of all respondents who changed DWH fuels in the last five years.

Table 106: Change in Water Heating Fuel during Past Five Years (%)

Previous fuel ▶ / Current fuel ▼	Electricity	Natural Gas	Piped Propane	Oil	All Previous Fuels
Unweighted base [1]	*42*	*34*	*11*	*2*	*89*
Electricity	--	42.2	0.3	--	42.5
Natural gas	52.7	--	1.5	1.6	55.8
Oil	--	0.8	--	--	0.8
Other	0.9	--	--	--	0.9
All Current Fuels	53.6	43.0	1.9	1.6	100.0

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Fifty-four percent (54%) of households who changed DWH fuels switched from electricity to something else. Of these, almost all (53%) switched from electricity to natural gas. In comparison, over four-in-ten (43%) switched from natural gas to something else with the majority (42%) switching to electricity. All remaining current and previous fuel combinations are small (representing 2% or less of DWH fuel switchers). While the number of fuel switchers is low (n=89), the data show the proportion switching from natural gas to something else only somewhat outweighed the proportion switching to natural gas. The data suggest the impact of fuel switching for DWH is effectively neutral.

7.5 Water Heater Equipment

Respondents to the 2012 REUS were asked to identify the equipment used to provide their domestic hot water. A list of common and less common DWH equipment types was provided. These included:

- Conventional storage (tank)

- On-demand (tankless)
- Hybrid on-demand (uses small storage tank)
- Combined space and water heater
- Hybrid heat pump water heater (tank)

To help in the correct classification of some newer DWH equipment types, participants in the 2012 REUS were provided with additional information about on-demand water heaters and hybrid heat pump water heaters (Figure 25).

Respondents with conventional storage (tank) water heaters (first, second and/or third units) were asked whether the units had a vent (metal or plastic) and where the vent discharged (roof or sidewall).

Figure 25: Explanatory Text Box – Water Heater Types

Tankless & Hybrid On-Demand Water Heaters

On-demand (tankless) water heaters, also known as instantaneous water heaters, are compact units that provide hot water on demand. Hybrid on-demand models use a small storage tank to reduce temperature fluctuations during use.

Hybrid heat pump water heaters combine a heat pump with an electric hot water tank to improve energy efficiency.

7.5.1 Penetration Rates

Penetration rates for domestic hot water heater equipment, regardless of whether they are the household's main, secondary or tertiary unit, are summarized in Table 107 with comparison to 2008 data. Slight differences between the two surveys exist so some caution is advised in the interpretation of changes between the two years.

Table 107: Hot Water Heater Type Penetration Rates by Region (%)
Includes First, Second and Third Water Heaters

	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base	*730*	*1609*	*723*	*83*	*98*	*3243*	*1963*
Conventional storage tank ▼	90.6	93.6	91.0	91.8	96.1	91.4	82.9
Vent through side-wall	15.0	9.6	16.8	12.0	10.4	12.3	12.4 [1]
Vent through roof	51.8	48.4	37.3	14.8	62.5	45.7	56.5
No vent (electric)	9.2	24.2	27.4	57.5	12.3	22.0	14.0
DK	14.5	11.3	9.5	7.4	12.3	11.4	n/a
On-demand (tankless)	3.5	2.4	5.0	2.7	1.2	3.4	2.7 [2]
Hybrid on-demand (small tank)	0.8	0.5	0.9	--	--	0.7	
Combined space and water heater	1.3	0.4	0.7	0.9	--	1.0	0.7
Hybrid heat pump heater (tank)	0.4	0.4	0.1	0.9	--	0.4	n/a
DK [3]	3.4	2.6	2.3	3.7	1.2	3.0	13.6
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Includes condensing hot water heaters
[2] On-demand water heaters with and without small tanks not differentiated in the 2008 REUS
[3] Represents uncertainty across all DWH types, including conventional storage tanks.
Totals may not sum due to rounding.

Over nine-in-ten (91%) FEU customers had a conventional storage tank. This style of water heater dominates in all regions. When detail on the presence and type of vent is considered, just under one-half (46%) have a traditional roof vent; one-in-eight (12%) have a side vent, and over one-in-five (22%) have no vent (electric tank implied). One-in-ten (11%) of respondents with a conventional storage tank did not know whether their tank was vented.

Tankless on-demand units (3%) and hybrid (1%) versions equipped with a small expansion tank represent a tiny portion of the overall DWH market. Venting data for on-demand water heaters are not reported due to the small number of responses received. Data from the 2008 REUS indicated on-demand units (no differentiation by tankless or small expansion tank) represented less than three percent (2.7%) of units in 2008, suggesting only a slight increase in the penetration of these units in the last four years

7.5.2 Saturation Rates by Type of Water Heater

Saturation rates for hot water heaters, by water heater type, are summarized in Table 108 with comparisons to 2008. As the 2008 REUS identified difficulties that respondents had in correctly identifying the venting for the conventional tanks, caution is advised in comparing the 2012 results with those of 2008.

Table 108: Hot Water Heater Type Saturation by Region Includes First, Second and Third Water Heaters

	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base [5]	*698*	*1543*	*695*	*80*	*96*	*3112*	*1692*
Conventional storage tank ▼	0.96	1.00	0.97	1.27	1.01	0.97	0.97
Vent through side-wall	0.19	0.12	0.20	0.18	0.12	0.15	0.15 [1]
Vent through roof	0.66	0.59	0.45	0.22	0.74	0.56	0.67
No vent (electric)	0.12	0.29	0.33	0.86	0.15	0.27	0.17
On-demand (tankless)	0.04	0.03	0.05	0.04	0.02	0.04	0.03 [2]
Hybrid on-demand (small tank)	0.01	0.01	0.01	--	--	0.01	
Combined space and water heater	0.01	0.00*	0.01	0.01	--	0.01	0.01
Hybrid heat pump heater (tank)	0.00*	0.00*	0.00*	0.01	--	0.00*	n/a

* Saturation less than 0.01
[1] Includes condensing hot water heaters
[2] On-demand water heaters with and without small tanks not differentiated in the 2008 REUS
Totals may not sum due to rounding.

The saturation rate for conventional storage style tanks is 0.97, unchanged from 2008. Saturation rates for conventional tanks by region, varies from a low of 0.96 for Lower Mainland to 1.27 for Whistler. Saturation rates for on-demand water heaters remain low (less than 0.05).

7.5.3 Water Heater Sizes

Table 109 summarizes the distribution of conventional storage water heater tank sizes by units with either a side or roof vent, no vent (electric) and those not specifying their tank's vent specifics. Respondents were asked to answer this question thinking about the largest tank in the house.

Table 109: DWH Tank Sizes – Largest Tank in the Home (%)

	With Roof Vent	With Side-Wall Vent	No Vent (Electric)	Venting Unknown	2012 FEU
Unweighted base	*1476*	*379*	*661*	*351*	*2867*
10 imperial gallons (46 litres)	0.6	3.2	1.1	1.5	1.2
33 imperial gallons (150 litres)	28.0	21.7	11.5	16.7	22.8
40 imperial gallons (182 litres)	49.7	42.6	47.8	22.3	44.4
60 imperial gallons (273 litres)	10.3	12.5	15.3	7.5	11.0
Other	2.7	5.4	5.7	3.4	3.7
DK	8.7	14.5	18.7	48.6	16.9
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

The most common size is 40 gallons (44% of all responses), followed by 33 gallon tanks (23%), and 60 gallon tanks (11%). Of note, nearly one-in-five (17%) of respondents did not know the size of their tank.

7.6 Water Heater Installations

Table 110 shows that the proportion of households installing domestic hot water heaters during the last five years (41%) is statistically unchanged from that recorded during the last two REUS surveys (38% - 39%).

Table 110: New DWH Heater Installations Last Five Years by Region (%)

Installed Water Heater Last Five Years?	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*727*	*1588*	*714*	*81*	*98*	*3208*	*2011*	*2413*	*1283*	*1525*
Yes	41.0	37.8	43.8	53.8	28.2	40.5	38.3	40.0	37.6	39.3
No	59.0	62.2	56.2	46.2	71.8	59.5	61.7	60.0	62.4	57.5
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.
* Value less than 0.1%

Reasons for installing a water heater are summarized in Table 111. Consistent with past REUS surveys in 2008 and 2002, the most common reasons are water heater failure (60% of respondents who installed a hot water heater in the last five years), and anticipation that the water heater would fail (23%).

The proportion (9%) installing a new water heater because they wanted a more efficient unit remained the same as in 2008 and 2002. The 2002 REUS data includes multiple responses so comparisons with 2008 and 2012 data should be made with caution.

Table 111: Reasons for Installing a New Water Heater in Last Five Years (%)

	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base[1]	*296*	*595*	*311*	*42*	*27*	*1271*	*730*	*918*	*421*	*583*
Water heater had failed	61.1	58.2	56.6	52.4	55.6	59.8	65.1	60.3	66.1	67.3
Anticipated water heater failure	22.0	23.4	24.1	33.3	25.9	22.6	17.5	22.4	17.5	16.8
Wanted more efficient water heater	9.1	8.7	5.1	--	11.1	8.5	9.2	9.0	9.6	3.7
New home	2.4	3.4	4.8	7.1	3.7	2.9	4.4	2.7	4.1	6.7
Needed more hot water	1.0	1.2	1.3	--	--	1.1	0.8	1.1	0.7	2.9
Wanted to change to gas	0.3	0.3	1.9	--	--	0.5	1.5	0.3	0.6	2.3
Wanted faster hot water recovery	0.3	0.2	--	--	--	0.3	0.3	0.3	0.3	1.0
Wanted an environmentally friendly fuel	--	0.3	0.6	--	--	0.2	--	0.1	--	0.5
Wanted a cheaper fuel	--	0.3	0.3	2.4	--	0.1	0.2	0.1	0.1	0.8
Other	3.7	4.0	5.1	4.8	3.7	4.0	1.0	3.8	0.9	2.8
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**--**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only
Totals may not sum due to rounding.

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7.7 Showerheads, Aerators, and Miscellaneous Hot Water Appliances

The 2012 REUS asked respondents to indicate how many showerheads, low flow showerheads, water heater blankets, instant hot water dispensers, and bathroom and kitchen aerators are installed in their home. The results, expressed in terms of penetration and saturation rates, are summarized in Table 112.

Table 112: Hot Water Appliances by Region (%)

Hot Water Appliance	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2187*	*2604*	*1423*	*1610*
Showerheads										
Penetration (%)	98.4	98.1	98.4	97.6	99.0	98.3	99.4	98.3	99.4	98.6
Saturation	2.23	2.01	2.05	2.57	1.84	2.15	2.15	2.16	2.16	1.95
Low flow showerheads										
Penetration (%)	37.1	43.5	43.0	35.7	28.8	39.4	46.9	39.0	46.4	61.6
Saturation	0.69	0.80	0.82	0.68	0.53	0.74	0.85	0.73	0.84	1.08
Water heater blankets										
Penetration (%)	5.2	6.8	5.1	3.6	0.9	5.6	6.4	5.7	6.1	15.2
Saturation	0.06	0.07	0.06	0.05	0.03	0.06	0.08	0.06	0.08	0.16
Instant Hot Water Dispensers										
Penetration (%)	3.2	1.9	3.3	7.1	7.6	2.8	n/a	n/a	n/a	n/a
Saturation	0.05	0.03	0.05	0.07	0.14	0.05	n/a	n/a	n/a	n/a
Bathroom & Kitchen Aerators										
Penetration (%)	45.5	46.3	47.1	45.2	45.0	45.9	n/a	n/a	n/a	n/a
Saturation	1.46	1.35	1.45	1.49	1.42	1.43	n/a	n/a	n/a	n/a

Data for instant hot water dispensers and aerators were new to the 2012 REUS so no data are available for 2008 or 2002 survey years. Additionally, respondents to the 2002 REUS with more than four showerheads, low flow shower heads, and/or water heater blankets could only indicate this by checking a box labelled “4+”. The 2008 and 2012 surveys did not constrain respondents’ answers. As a result, the 2002 REUS saturation estimates may be understated.

There are no statistically significant differences between survey years for showerhead (any type, including low flow) penetration and saturation. Data on low flow showerheads are provided but are considered to be less reliable than other data as the interpretation of “low flow” showerhead is subjective.[42]

The penetration of water heater blankets has not varied significantly for the past three surveys. The relatively low incidence of water heater blankets is consistent with the gradual replacement of older water heaters with more efficient units. Newer water heaters are built with higher insulation levels and, as a result, the addition of a water heater blanket is not as cost-effective as it was with older units.

The penetration of instant hot water dispensers is low at three percent (3%) of households. Bathroom and kitchen faucet aerators were identified in almost half (46%) of homes. Like that of low flow shower heads, the penetration and saturation rates for aerators are considered less reliable as most new faucets come equipped with aerators. There may also be an awareness issue for some households as to what is an aerator.

[42] The other issue confounding the interpretation of what is a low flow showerhead is that the volume of new and replacement showerheads has been declining over time, effectively altering what constitutes a low flow model.

7.7.1 Drain Water Heat Recovery Systems

Three percent (3%) of REUS 2012 respondents indicated their home has a drain water heat recovery (DWHR) system (Table 113). These systems typically use small diameter copper piping wrapped around the main or most used drain pipe to capture heat from activities requiring hot water (e.g., baths, showers, dishwashing, etc.). The re-captured heat is then used to reduce the energy needed by DWH water. As these systems are relatively new, the 2012 REUS questionnaire included both a photograph and brief description to aid the respondents.

The incidence of DWHR is highest in the Lower Mainland (4%) and lowest in Fort Nelson (1%). A significant proportion of respondents were uncertain (18%) as to whether their home has such a system.

Table 113: Drain Water Heat Recovery Systems by Region (%)

Drain Water HR?	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*718*	*1562*	*708*	*80*	*97*	*3165*
Yes	3.9	1.9	2.3	1.3	1.0	3.1
No	76.9	83.6	81.9	89.9	77.6	79.3
DK	19.2	14.5	15.8	8.9	21.3	17.5
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

8 FIREPLACES AND HEATER STOVES

This section summarizes data on the penetration, saturation, and use of fireplaces and heater stoves. Up to seven fireplace and heater stove types were queried in the 2012 REUS. They included:

- Gas (decorative)
- Gas (heater type)
- Gas (free standing)
- Electric
- Wood burning fireplace
- Wood burning stoves
- Other

To assist respondents in correctly identifying the type(s) of fireplaces and heater stoves in their home, the survey questionnaire included the following descriptions:

- **Decorative fireplaces** – Provide ambiance but have little or no heating ability. The firebox is typically steel or masonry, and the hearth is often open to the room or equipped with opening glass doors.
- **Heater type fireplaces (built-ins and inserts)** – These fireplaces are efficient heaters with fixed glass fronts and may have features such as fans and thermostatic control. They may be built-in at the time of construction, or inserted into an existing masonry or other fireplace as an upgrade.
- **Free standing fireplaces and heater stoves** – These are stand-alone units that that can be used for both ambiance and heating. Gas heater stoves resemble wood stoves in appearance but use gas instead of wood.

The same fireplace and heater stove types were queried in the 2008 REUS.

8.1 Penetration and Saturation – Any Fuel

Past REUS studies based the penetration and saturation of fireplaces and heater stoves on only households with a fireplace or heater stove. Penetration and saturation statistics for fireplaces and heater stoves in the 2012 REUS are now calculated using the total population regardless of whether or not they have a fireplace or heater stove. This places penetration and saturation data on a basis comparable to other end-uses discussed and analyzed in this report. Data for fireplaces and heater stoves from the 2008 REUS survey were restated to ensure consistency.[43]

Table 114 (next page) summarizes the penetration and saturation rates for all fireplaces and heater stoves regardless of type or fuel. Overall, over four-in-five (84%) of FEU residential customers have at least one fireplace or heater stove, statistically unchanged from 2008. Regional data show that penetration is highest in Whistler (100% of respondents), followed by Vancouver Island (89%), and the Lower Mainland (88%).

[43] As a result, penetration and saturation rates for fireplaces and heater stoves for 2008 will differ from those reported in the 2008 REUS report.

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Table 114: Fireplaces and Heater Stoves by Region
Any Type, Any Fuel

	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	783	1684	732	84	101	3384	2167	*2568*	1960	1610
Penetration (%)	87.7	72.4	89.1	100.0	56.0	83.7	84.8	83.0	84.5	81.0
Saturation	1.65	1.44	1.44	1.36	1.23	1.58	1.52	1.60	1.50	1.31

Table 115 summarizes the penetration and saturation of fireplaces and heater stoves (any type, any fuel) by dwelling type. With the exception of mobile homes for which only one-third reported having a fireplace or heater stove, the penetration rate for all other dwelling types exceeds eight-in-ten (80%) with single family detached dwellings and row houses / townhouses being the most likely to have at least one unit (86%).

Table 115: Fireplaces and Heater Stoves by Dwelling Type
Any Type, Any Fuel

	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2750*	*152*	*206*	*53*	*118*	*57*
Penetration (%)	85.0	80.1	86.3	81.5	33.0	77.5
Saturation	1.39	1.14	1.09	1.02	0.35	1.30

Table 116 provides detail on the distribution of FEU customers on the basis of the number of fireplaces and heating stoves per dwelling. Sixteen percent (16%) of FEU residential customers do not have a fireplace or heating stove. Regionally, the proportion of customers without this end-use was highest in Fort Nelson (46%).

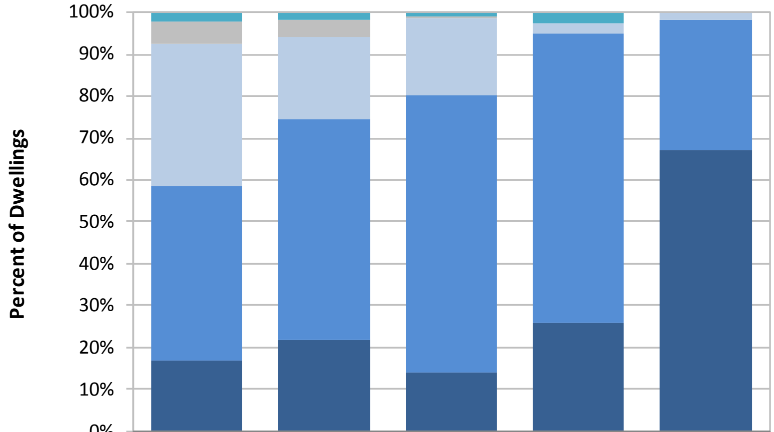
Table 116: Number of Fireplaces and Heater Stoves per Dwelling by Region (%)
Any Type, Any Fuel

	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*783*	*1684*	*732*	*84*	*101*	*3384*
None	12.3	27.6	10.9	0.0	43.9	16.3
1 unit	43.2	45.0	56.7	75.3	45.3	45.2
2 units	36.5	22.9	26.7	16.0	9.8	31.7
3 units	5.7	3.5	4.4	3.7	--	4.9
More than 3 units	2.3	1.0	1.2	4.9	1.0	1.8
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding

Figure 26 (next page) summarizes the number of fireplaces and heater stoves by dwelling type. The data show that four-in-ten (42%) of single family detached dwellings have only one fireplace or heater stove, while over three-in-ten (34%) have two, and under one-in-ten (8%) have three or more units. By comparison approximately two-thirds of row / townhouses (66%) and apartments / condominiums (69%) have only one unit.

Figure 26: Number of Fireplaces / Heater Stoves by Dwelling Type



	SFD	Dup	RH/TH	Apt/Condo	Mobile
>3	2.0	1.9	0.9	2.6	0.0
3	5.5	3.9	0.4	0.0	0.0
2	33.8	19.8	18.3	2.6	1.6
1	41.7	52.6	66.3	69.1	31.4
None	16.9	21.8	14.0	25.7	67.0

8.2 Penetration and Saturation – by Fuel

Penetration and saturation rates for gas fireplaces and heater stoves are summarized in Table 117. The data show that over four-in-ten (43%) FEU homes have heater type gas fireplaces, statistically unchanged from 2008. Decorative gas fireplaces are present in one-in-five (19%) of homes. Finally, less than one-in-ten (7%) of homes reported having a free standing gas model. Regionally, dwellings in Vancouver Island and Whistler have the highest penetration of heater type units (60% and 59% of homes respectively). In both regions one-in-ten use their fireplaces as the primary heat source. Older, gas decorative models are most common in the Lower Mainland (23%).

Table 117: Gas Fireplace and Heater Stove Details by Region
Base includes all households with and without a fireplace or heater stove

Fireplace / Heater Stove Type	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base	*783*	*1684*	*732*	*84*	*101*	*3384*	*2167*
Gas (decorative)							
Penetration (%)	23.0	12.8	12.0	10.8	8.8	19.0	18.3
Saturation	0.30	0.15	0.14	0.16	0.10	0.24	0.35
Gas (heater type)							
Penetration (%)	44.2	34.2	60.4	59.0	21.9	43.2	42.5
Saturation	0.59	0.42	0.71	0.73	0.23	0.56	0.61
Gas (free standing)							
Penetration (%)	5.6	7.2	12.4	8.4	4.9	6.8	6.0
Saturation	0.07	0.08	0.14	0.10	0.05	0.08	0.08

Table 118 (next page) presents gas fireplace and heater stove penetration and saturation rates by dwelling type. For gas units, decorative fireplaces are most common among row houses/townhouses

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(32%), followed by duplexes (25%) and single family dwellings (18%). Conversely, heater type gas fireplaces are most common in apartments / condominiums (61%).

Table 118: Gas Fireplace and Heater Stove Details by Dwelling Type
Base includes all households with and without a fireplace or heater stove

Fireplace / Heater Stove Type	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2750*	*152*	*206*	*53*	*118*	*57*
Gas (decorative)						
Penetration (%)	17.8	24.9	32.2	18.9	0.0*	16.5
Saturation	0.23	0.30	0.35	0.19	--	0.30
Gas (heater type)						
Penetration (%)	44.3	42.4	40.1	61.4	9.4	38.9
Saturation	0.58	0.52	0.45	0.64	0.10	0.54
Gas (free standing)						
Penetration (%)	7.6	5.2	1.4	5.6	6.4	2.2
Saturation	0.09	0.06	0.01	0.08	0.06	0.02

* Value less than 0.01

Table 119 presents penetration and saturation rates of gas fireplaces by dwelling vintage. The data show that gas heater type fireplaces are more common in newer dwellings. For example, heater type fireplaces are present in approximately one-third (31%) of homes built before 1950 and two-thirds (67%) of homes constructed since 2005. Conversely, the popularity (penetration) of decorative gas fireplaces is declining from 34% for dwellings constructed during 1986-95 to 15% for those constructed since 2005. These data reflect both new construction trends and retrofits to existing dwellings.

Table 119: Gas Fireplace and Heater Stove Details by Dwelling Vintage
Base includes all households with and without a fireplace or heater stove

Fireplace / Heater Stove Type	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Year Un-known
Unweighted base[1]	350	919	576	664	586	238	46
Gas (decorative)							
Penetration (%)	8.4	12.1	12.6	33.6	26.4	15.0	12.7
Saturation	0.08	0.15	0.15	0.44	0.32	0.20	0.30
Gas (heater type)							
Penetration (%)	30.6	33.2	40.4	47.4	61.0	66.9	13.7
Saturation	0.38	0.41	0.48	0.63	0.85	0.84	0.30
Gas (free standing)							
Penetration (%)	6.6	7.6	7.5	5.5	6.2	5.6	15.9
Saturation	0.07	0.08	0.09	0.06	0.07	0.07	0.37

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Table 120 (next page) summarizes penetration and saturation rates for fireplaces and heater stoves that use fuels other than natural gas. Wood burning fireplaces are the most common non-gas type, present in over one-in-five (22%) of FEU homes in 2012, with penetration of wood fireplaces highest in the Lower Mainland (27%). After wood fireplaces, the next most common non-gas fireplace or heater stove types are electric units (8% of homes) and wood stoves (5%). There has been a statistically significant increase in the penetration and saturation of electric fireplaces since 2008.

Table 120: Fireplace and Heater Stove Details by Region – Fuels Other Than Natural Gas
Base includes all households with and without a fireplace or heater stove

Fireplace / Heater Stove Type	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base	*783*	*1684*	*732*	*84*	*101*	*3384*	*2167*
Electric							
Penetration (%)	7.5	9.9	6.7	1.2	13.7	8.1	5.6
Saturation	0.10	0.11	0.10	0.01	0.14	0.10	0.08
Wood burning fireplace							
Penetration (%)	26.7	16.1	11.5	22.9	12.7	22.2	24.0
Saturation	0.34	0.19	0.14	0.25	0.13	0.28	0.33
Wood burning stove							
Penetration (%)	3.8	7.8	4.4	9.6	4.9	5.0	4.7
Saturation	0.04	0.08	0.05	0.11	0.05	0.05	0.06
Other							
Penetration (%)	0.6	1.2	0.7	--	--	0.8	0.6
Saturation	0.01	0.01	0.01	--	--	0.01	0.00*

* Value less than 0.01

Dwelling type specific data for fireplaces and heater stoves using fuels other than natural gas are provided in Table 121. Among non-gas fireplaces and heater stoves, single family detached dwellings are most likely to have a wood burning fireplace (25% of all SFDs), followed by other (18%), and duplexes (13%). Electric fireplaces are notable in their penetration in row/townhouses (14%) and mobile homes (13%). The absence of a venting requirement and portability has made them an attractive choice.

Table 121: Fireplace and Heater Stove Details by Dwelling Type – Fuels Other Than Natural Gas
Base includes all households with and without a fireplace or heater stove

Fireplace / Heater Stove Type	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2750*	*152*	*206*	*53*	*118*	*57*
Electric						
Penetration (%)	7.4	8.1	14.3	4.3	13.1	7.1
Saturation	0.09	0.09	0.19	0.04	0.14	0.07
Wood burning fireplace						
Penetration (%)	25.0	12.5	7.8	1.4	1.6	17.7
Saturation	0.31	0.14	0.08	0.01	0.02	0.33
Wood burning stove						
Penetration (%)	5.9	2.2	0.0*	1.4	1.7	3.3
Saturation	0.06	0.02	--	0.01	0.02	0.03
Other						
Penetration (%)	0.9	0.3	0.2	1.4	0.8	--
Saturation	0.01	0.00*	0.00*	0.03	0.01	--

* Value less than 0.01

Finally, penetration and saturation rates for non-gas fireplaces and heater stoves by dwelling vintage are summarized in Table 122 (next page). The data show a decline in penetration of wood burning fireplaces, driven by municipal by-laws, and heater stoves (present in only 1% to 2% of homes built since 2005) and a jump in the penetration of electric fireplaces (18% of homes built since 2005).

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Table 122: Fireplace and Heater Stove Details by Dwelling Vintage – Fuels other than Natural Gas
Base includes all households with and without a fireplace or heater stove

Fireplace / Heater Stove Type	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Year Un-known
Unweighted base[1]	350	919	576	664	586	238	46
Electric							
Penetration (%)	11.6	5.7	6.9	7.7	8.1	17.8	8.3
Saturation	0.17	0.07	0.08	0.09	0.10	0.24	0.25
Wood burning fireplace							
Penetration (%)	30.5	35.8	31.7	11.8	3.6	1.7	24.3
Saturation	0.36	0.45	0.40	0.15	0.05	0.02	0.45
Wood burning stove							
Penetration (%)	4.8	7.7	6.4	3.6	2.4	1.3	8.5
Saturation	0.05	0.08	0.07	0.04	0.02	0.02	0.24
Other							
Penetration (%)	1.2	1.3	1.3	0.2	0.3	0.3	--
Saturation	0.01	0.01	0.02	0.00	0.00	0.01	--

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

8.3 Gas Fireplaces - Ages and Features

Respondents with gas fireplaces were asked to indicate the ages of their fireplaces and whether the fireplaces had a fixed glass front, glass doors that open, or an open hearth (no glass). These data help assess the efficiency level of the fireplace unit, with newer, more efficient units having fixed glass fronts.

Data on the age of the first gas fireplace are summarized in Table 123. The average (mean) age of gas fireplaces for FEU customers is 13 years. Only slight differences in mean age between regions are observed, with fireplaces in Whistler and Vancouver Island tending to be younger (11 years on average for both) and fireplaces in Lower Mainland tending to be somewhat older (13 years).

Table 123: Age of First Gas Fireplace (Years)

Age of Gas Fireplace (years)	LM	INT	VI	W	FN	2012 FEU
Unweighted base [1]	*429*	*693*	*455*	*49*	*24*	*1650*
Mean	13.4	12.9	11.4	11.2	12.4	13.0
Standard deviation	12.3	5.2	4.0	1.6	1.6	7.4

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Age statistics for second gas fireplaces are provided in Table 124. Samples are smaller due to the lower incidence of homes with second gas fireplaces or heater stoves so caution is advised when making regional comparisons. Overall, the average age of the second gas fireplace is 14 years.

Table 124: Age of Second Gas Fireplace (Years)

Age of Gas Fireplace (years)	LM	INT	VI	W	FN	2012 FEU
Unweighted base [1]	*153*	*163*	*107*	*12*	*3*	*438*
Mean	14.5	12.8	12.1	11.7	16.0	14.0
Standard deviation	12.1	5.2	4.0	2.0	0.3	8.1

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Of the three possible designs for gas fireplaces, three-quarters (76%) of fireplaces have a fixed glass front, significantly higher than fireplaces with glass doors that open (16%) , and open hearth models (8%). As suggested by their design, these latter two types are older, less efficient units. These data are summarized in Table 125.

Table 125: Gas Fireplace Characteristics by Region
Percent of All Gas Fireplaces[1]

	LM	INT	VI	W	FN	2012 FEU
Fixed glass front	72.3	79.7	89.8	86.7	93.2	76.2
Glass doors that open	16.2	16.8	10.1	8.3	6.8	15.5
No glass (open hearth)	11.5	3.4	0.2	5.0	--	8.2
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Includes homes with more than one gas fireplace
Totals may not sum due to rounding

8.4 Usage Behaviours

Household use of fireplaces and heater stoves was explored in the 2012 REUS from a number of perspectives including weekly hours-of-use by season, role (heating, ambiance, or combination of heating and ambiance), and contribution to the home's space heating load.

8.4.1 Hours-of-Operation

Average weekly hours-of-use for fireplaces and heater stoves by season and region are summarized in Table 126, with comparisons to 2008 and 2002. The data are consistent with past surveys and show that usage is highest during the fall and winter and lowest during the spring and summer. Winter usage averages 18 hours per week and fall usage averages 14 hours per week. Compared to 2008, fall usage is higher while winter and spring usage estimates are lower. Overall, average operating hours for fireplaces and heater stoves is 472 hours per year, statistically unchanged from 2008 (460).

Table 126: Weekly Average Hours of Fireplace / Heater Stove Operation by Region

Season [1]	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*673*	*1177*	*634*	*82*	*56*	*2622*	*2167*	*1906*	*1960*	*1259*
Summer	0.2	0.7	0.3	0.4	0.9	0.3	0.3	0.3	0.3	0.6
Fall	11.8	16.1	20.9	15.7	25.2	13.8	7.6	12.9	7.3	10.1
Winter	15.0	21.6	26.0	31.8	33.6	17.9	20.1	16.8	20.1	20.8
Spring	3.6	4.3	8.5	7.0	6.6	4.3	7.4	3.7	7.0	9.3
Annual Average Hours [2]	**397**	**555**	**725**	**713**	**862**	**472**	**460**	**439**	**451**	**530**

[1] Assumes each season is 13 weeks long.
[2] Average hours of operation per year

Regionally, customers in Fort Nelson have the highest average annual operating hours (862 hours), followed by Vancouver Island (725), and Whistler (713). Lower Mainland homes with fireplaces or heater stoves used them the least (397 hours).

Respondents to the 2012 REUS were not asked to provide hours-of-use estimates for individual fireplaces or heater stove types because the request it was considered onerous, particularly for homes with more than one fireplace or heater stove. However, over three-quarters (77%) of all dwellings with a fireplace or heater stove in the 2012 REUS survey have only one unit, implying the hours of operation, by season, for these dwellings can be solely attributable to one particular type of fireplace or heater stove. Data for this subset of households are summarized in Table 127.

Table 127: Average Weekly Hours of Fireplace / Heater Stove Operation by Fireplace Type
Dwellings with only one fireplace or heater stove

Fireplace Type [1]	Summer	Fall	Winter	Spring	Annual Average Hours [2]
Gas (decorative)	0.2	6.8	10.5	1.5	248
Gas (heater type)	0.4	16.9	21.5	6.5	590
Gas (free standing)	0.3	26.3	32.5	6.7	855
Electric	0.3	10.9	13.9	2.5	358
Wood burning fireplace	0.0	7.4	9.0	0.9	225
Wood burning stove	0.4	31.0	41.0	4.9	1004
Other	0.0	19.2	34.8	13.4	877

[1] Dwellings with only one of any fireplace / heater stove type (n=2016)
[2] Annual hours of operation

As expected, wood stoves are used the most, averaging 1,004 hours per year, followed by free standing gas heater stoves at 855 hours per year. Gas heater type fireplaces are used 590 hours per year and decorative gas fireplaces, consistent with a design oriented to ambiance rather than heating, are used 248 hours per year. As a reminder, these data are only for dwellings with only one fireplace or heating stove. Operating hours for homes with more than one fireplace or heater stove type will likely be higher.

8.4.2 Fireplace and Heater Stoves - Uses

Fireplaces and heater stoves can be used to provide heat, ambiance, and for many of these units, a combination of heating and ambiance. For each fireplace or heater stove type, respondents to the 2012 REUS were asked to indicate the unit's primary purpose. The results, by fireplace / heater stove type are summarized in Figure 27 (next page).

For gas units, heater type fireplaces and stand-alone units are used considerably more for space heating (85% heating or heating and ambiance for gas heater type fireplaces, and 80% for stand-alone gas units) than the traditional decorative gas fireplaces (38%). Wood burning fireplaces are used very little for heating (35%). Wood burning stoves, in contrast, are specifically designed for space heating and the data confirm they are used for that purpose (88%).

The 2012 REUS asked households with a fireplace or heater stove to estimate the contribution of their fireplace or heater stove to their dwelling's space heating requirements. Answering this question was expected to be challenging for respondents with more than one space heating method, so the response categories were selected to improve response rates while explicitly acknowledging that precise estimates are not reasonable given the challenging nature of the question.

- 0% (none)
- Up to 10%
- Up to 25%
- Up to 50%
- Up to 75%
- Up to 100%

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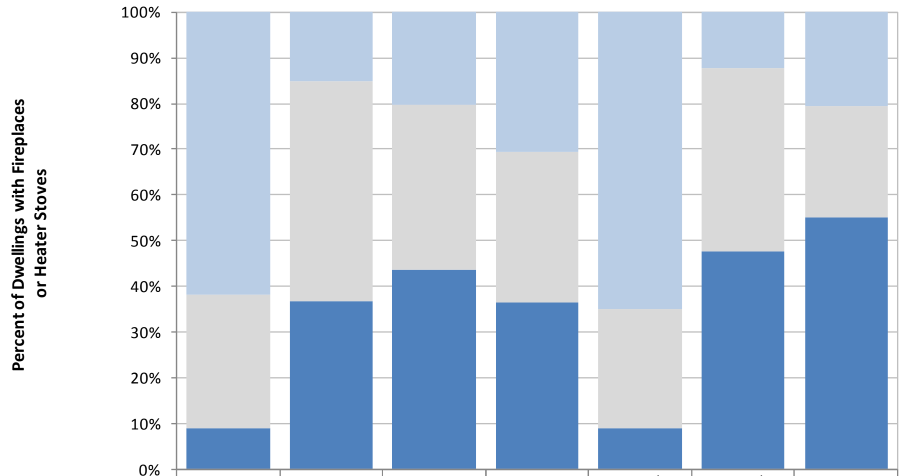
Figure 27: Primary Purpose of Fireplaces and Heater Stoves



	Gas (decorative)	Gas (heater type)	Gas (free standing)	Electric	Wood burning fireplace	Wood burning stove	Other
Ambiance	61.9	15.1	20.2	30.6	65.0	12.1	20.4
Heating & Ambiance	29.3	48.1	36.1	32.9	26.1	40.2	24.5
Heating	8.8	36.8	43.7	36.5	8.9	47.6	55.1

Fireplace / Heater Stove Type

Table 128 summarizes the results for this question. One-third (33%) of FEU gas customers with a fireplace or heater stove indicated the unit(s) do not contribute to their home's heating requirements. A further third (31%) indicated their fireplace or heater stove contributed as much as ten percent (10%) of their home's space heating load, while one-in-six (16%) indicated it was as much as 25% percent. Smaller numbers of respondents indicated the contribution to space heating was higher than this. However, one-in-six (15%) of REUS respondents with a fireplace or heater stove indicated their unit(s) met anywhere from one-half to their dwelling's entire space heating load.

Table 128: Fireplace and Heater Stove Contribution to Space Heating Load by Region (%)

Share of Space Heating Load	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*686*	*1202*	*646*	*83*	*56*	*2673*
0%	37.5	29.2	17.5	13.4	27.9	33.2
Up to 10%	30.3	33.4	29.4	30.5	27.9	30.9
Up to 25%	14.4	16.7	24.1	19.5	26.2	16.1
Up to 50%	6.1	8.9	11.1	17.1	7.0	7.4
Up to 75%	3.4	4.2	7.6	8.5	4.1	4.1
Up to 100%	2.6	3.2	6.0	9.8	5.2	3.2
DK	5.7	4.4	4.2	1.2	1.7	5.2
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding

Regional differences are apparent and consistent with other data on fireplaces and heater stoves collected in the 2012 REUS. For example, Vancouver Island and Whistler households were most likely to indicate their units contributed to their home's space heating load and to indicate contributions of up to 50% or more. Lower Mainland customers were the most likely to indicate no contribution to space heating at all (38%), but the proportion of customers in this region with contributions of up to 10% and

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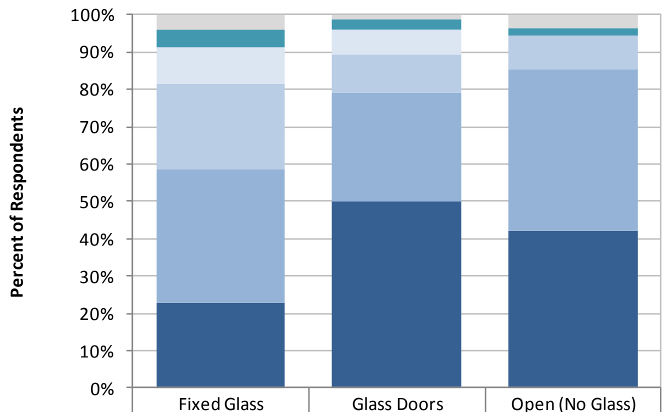
25% were comparable to those in the Interior. The proportion of respondents that could not answer the question averaged one-in-twenty.

This question was not asked in previous REUS surveys so comparisons with past data are not possible.

Figure 28 explores the relationship between the design of gas fireplaces and heater stoves and their use to provide heat to the home. While the presence of a fixed glass front does not ensure the fireplace is energy-efficient, these units are more likely to be used to provide heat compared to those with opening glass doors or no glass (open).

Figure 28: Contribution to Space Heating by Gas Fireplace Type

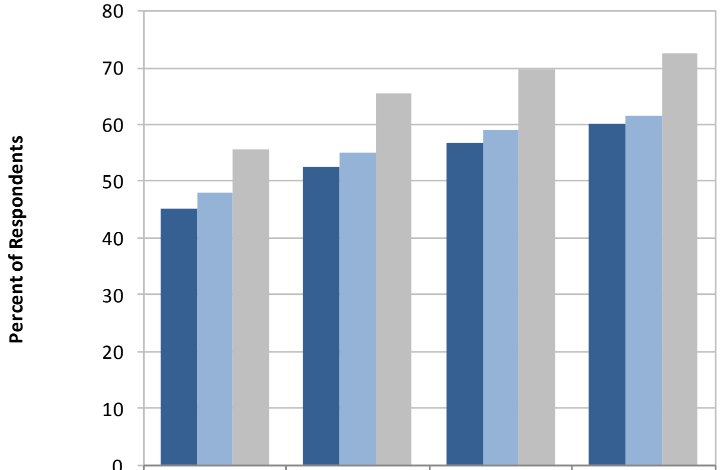


	Fixed Glass	Glass Doors	Open (No Glass)
Up to 100%	3.6	1.3	3.4
Up to 75%	4.5	2.6	1.9
Up to 50%	9.4	6.3	0.0
Up to 25%	21.6	9.9	8.4
Up to 10%	33.8	28.3	40.2
0%	21.4	47.9	38.9

It is reasonable to expect that as the number of fireplaces or heater stoves within a home increases, their overall contribution to space heating would increase. To explore the validity of this hypothesis, data on the number of fireplaces and heater stoves per home (any fuel) were compared to respondents' assessments of their contribution to space heating. The results, visually summarized in Figure 29 (next page), suggests that there is very little difference in the contribution made to space heating between homes with one fireplace or heater stove versus those with two units.

There are two possible explanations for this result. The first is that homes with two fireplaces and/or heater stoves split the contribution to space heating relatively equally between the two units. The second explanation is that one of the two units is used more than the other. This could be because one unit is more suited to space heating than the other or because one of the two units is located in a room or area of the home that is used relatively more than where the other unit is located. While representing considerably fewer homes, the presence of three gas fireplaces / heater stoves results in a modest increase in contribution to space heating load. Clearly, the relationship between the number of gas fireplaces and heating stoves in the home, and the contribution to space heating load, is not linear.

Figure 29: Contribution to Space Heating by Number of Fireplaces / Heater Stoves



	1 to 25%	Up to 50%	Up to 75%	Up to 100%
1 Fireplace	45.1	52.4	56.7	60.2
2 Fireplaces	48.0	55.1	59.0	61.6
3 Fireplaces	55.7	65.6	69.7	72.6

Data on the contribution of fireplaces and heater stoves to space heating requirements were explored by dwelling type. These data are summarized in Table 129. They show that the proportion of homes that indicated their fireplace contributes up to 50% of their space heating requirements does not vary greatly between the dwelling types. However, apartment dwellers are more likely to say their fireplace contributes up to 100% of their space heating. This latter outcome is consistent with the findings of the 2008 REUS which showed that fireplaces and heater stoves play an important role in space heating for apartments / condominiums and, to a lesser extent, row and townhouses.[44]

Table 129: Fireplace and Heater Stove Details by Dwelling Type (%)

Share of Space Heating Load	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base [1]	*2227*	*109*	*170*	*44*	*45*	*38*
0%	32.2	40.3	44.7	10.5	10.7	27.4
Up to 10%	32.1	24.0	22.3	24.2	13.1	37.3
Up to 25%	16.6	13.5	12.9	8.3	25.1	16.0
Up to 50%	7.4	4.5	8.5	13.7	6.8	8.1
Up to 75%	3.8	4.1	4.0	10.5	19.4	9.5
Up to 100%	2.6	6.9	3.4	31.1	5.5	0.3
DK	5.3	6.7	4.1	1.8	19.3	1.4
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

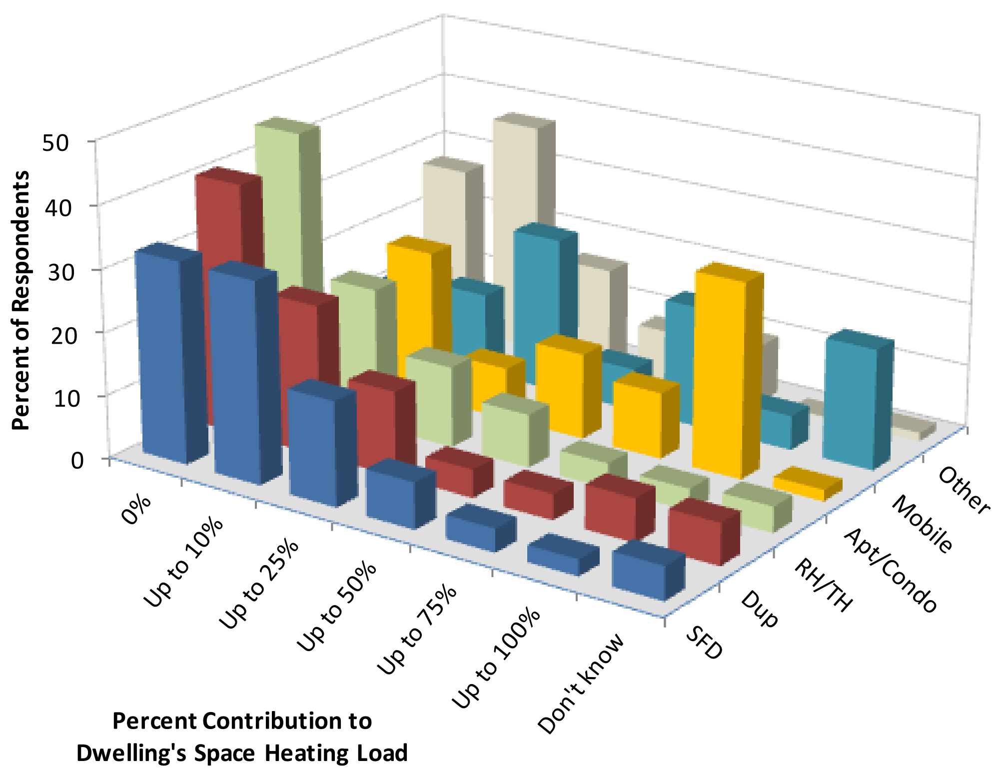
[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding

[44] The 2008 REUS found that 28% of vertical subdivision homes (apartments) considered their gas fireplace as their primary method of space heating. Another 39% indicated the fireplace was their second most used method of space heating. Source: Sampson Research (2008), pp 5-6 to 5-9.

FIREPLACES AND HEATER STOVES

Figure 30 visually compares the contribution of fireplaces and heater stoves to space heating load of the different dwelling types.

Figure 30: Fireplace and Heater Stove Contribution to Space Heating Load by Dwelling Type



8.5 Pilot Lights

Over nine-in-ten (93%) of respondents with either one or two gas fireplaces indicated the fireplaces have a pilot light (Table 130). Approximately two to three percent did not know whether their fireplace had a pilot light.

Table 130: Percent of Gas Fireplaces with a Pilot Light by Region (%)

	LM	INT	VI	W	FN	2012 FEU
First fireplace	91.5	93.8	96.7	98.3	96.6	92.7
Second fireplace	91.9	93.1	96.8	84.6	100.0	92.6
Third fireplace	87.1	82.4	90.9	75.1	--	86.8

Seven-in-ten (68%) of households with a gas fireplace equipped with a pilot light indicated they turned off the pilot light at least one month during the year (Table 131, next page). This compares to six-in-ten (61%) who reported this behaviour in the 2008 REUS. Regionally, FEU customers in the Fort Nelson (small sample) and Lower Mainland are the least likely to turn off their pilot lights (56% and 65% respectively), while Interior and Vancouver Island customers are most likely (74% and 73% respectively). Including those who do not turn off their fireplace pilot light, the pilot lights for fireplaces are turned off an average of 4.2

months per year. For just those households who turn off their pilot lights, the lights are turned off an average of 6.5 months per year. The latter value is significantly lower than that calculated from the 2008 REUS. There are slight differences in question structure and wording between the two surveys so this may explain some the difference. Regardless, caution is advised in attributing the decrease to changes in household behaviour.

Table 131: Gas Fireplace Pilot Light Behaviours by Region (%)

Gas Fireplace Pilot Light Usage	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base [1]	466	772	532	61	27	1858	1314
Never turn off (%)	34.6	25.0	26.3	32.8	43.6	31.4	28.2
Turn off, one or more months per year (%)	64.8	74.2	73.0	67.2	56.4	67.9	60.7
Average # of months turned off (All fireplaces with pilots)	3.9	4.9	4.2	3.7	3.4	4.2	4.7
Average # of months turned off (Fireplaces turned off at least one month)	6.5	6.8	5.8	5.7	6.3	6.5	8.5

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Lighting a pilot light on a gas fireplace, furnace or hot water tank can be intimidating for some households. The 2012 REUS asked respondents with fireplaces that have a pilot light who typically relights the pilot light. Table 132 summarizes whether it is the survey respondent, another member in the household, contractor, or someone else.

Table 132: Who Typically Lights the Fireplace Pilot Light by Region (%)

	LM	INT	VI	W	FN	2012 FEU
Unweighted base [1]	*297*	*561*	*379*	*39*	*16*	*1292*
Myself	81.5	80.6	80.7	76.9	62.5	81.1
Contractor	1.7	4.6	5.3	2.6	12.5	2.9
Other member of the household	13.1	10.3	9.5	18.0	25.0	12.0
Other	3.0	4.3	4.2	2.6	--	3.5
DK	0.7	0.2	0.3	--	--	0.5
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
Totals may not sum due to rounding

Eighty-one percent (81%) of respondents indicated they did it themselves, while another 12% indicated someone else in the household relit the pilot light. Only three percent indicated they use a contractor.

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Respondents to the 2012 REUS were provided with a list of cooking, refrigeration, cleaning, space heating, and space cooling appliances, and asked to indicate the number (quantity), and ages for each present in the home. The list of appliances queried in the 2012 survey is more extensive than the 2008 and 2002 surveys, so a multi-year analysis of penetration and saturation trends is not possible for all appliances.

9.1 Cooking Appliances

Penetration and saturation rates for cooking appliances are summarized in Table 133.

Table 133: Penetration and Saturation of Cooking and Related Appliances by Region

Cooking Appliances	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI [2]
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2213*	*2604*	*1439*	*1610*
Electric range (cook top & oven)										
Penetration (%)	67.6	74.9	69.3	50.0	73.4	69.7	75.5	69.8	76.1	81.8
Saturation	0.77	0.82	0.76	0.55	0.77	0.78	0.86	0.79	0.87	0.92
Gas range (cook top & oven)										
Penetration (%)	21.4	15.0	18.0	22.6	20.9	19.3	17.6	19.5	16.8	15.7
Saturation	0.23	0.16	0.18	0.23	0.21	0.21	0.19	0.21	0.19	0.17
Dual fuel range (gas cook top, electric oven)										
Penetration (%)	5.0	3.1	4.5	19.0	2.8	4.5	n/a	4.4	n/a	n/a
Saturation	0.05	0.03	0.05	0.19	0.03	0.05	n/a	0.05	n/a	n/a
Electric cook top										
Penetration (%)	9.8	8.8	9.0	10.7	5.7	9.5	12.7	9.5	12.9	16.6
Saturation	0.11	0.09	0.10	0.11	0.06	0.10	0.13	0.10	0.14	0.19
Gas cook top										
Penetration (%)	7.1	4.8	6.9	15.5	3.8	6.4	9.6	6.4	9.6	7.0
Saturation	0.08	0.05	0.07	0.15	0.04	0.07	0.11	0.07	0.11	0.07
Electric wall oven										
Penetration (%)	14.9	10.1	11.7	23.8	3.8	13.3	13.5	13.4	13.6	n/a
Saturation	0.16	0.11	0.13	0.32	0.04	0.15	0.16	0.15	0.16	n/a
Gas wall oven										
Penetration (%)	0.9	0.8	1.2	1.2	0.9	0.9	2.6	0.9	2.7	n/a
Saturation	0.01	0.01	0.01	0.01	0.02	0.01	0.04	0.01	0.04	n/a
Microwave oven										
Penetration (%)	82.0	83.2	82.7	82.1	72.5	82.4	86.4	82.3	86.4	92.7
Saturation	0.93	0.91	0.91	0.92	0.81	0.92	0.98	0.92	0.98	1.01
Gas barbeque (piped gas) [1]										
Penetration (%)	16.4	24.1	25.7	45.2	15.2	19.6	15.5	18.7	14.5	9.7
Saturation	0.17	0.24	0.26	0.46	0.16	0.20	0.16	0.19	0.15	0.10
Gas barbeque (bottled gas) [2]										
Penetration (%)	48.0	46.6	41.6	34.5	56.0	47.0	48.8	47.6	49.6	63.0
Saturation	0.50	0.48	0.43	0.36	0.56	0.49	0.51	0.49	0.52	0.65
Commercial grade range hood										
Penetration (%)	15.9	15.1	17.8	20.2	16.1	15.9	n/a	15.7	n/a	n/a
Saturation	0.17	0.16	0.18	0.20	0.16	0.17	n/a	0.17	n/a	n/a

[1] This category was described as "NG barbeque" in the 2002 REUS questionnaire.
[2] This category was described as "propane barbeque" in the 2002 REUS questionnaire.
n/a = appliance not queried

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Data from the 2008 REUS survey strongly suggested that some respondents had trouble differentiating between ranges (both cook top and oven) and cook tops and ovens as separate items.[45] The 2012 REUS clarified the category descriptions for ranges to include the words "cook top and oven" next to the category (e.g., "electric range (cook top and oven)" and "gas range (cook top and oven)"). Other changes made to the 2012 survey included the addition of dual fuel ranges consisting of a gas cook top and an electric oven. Despite introducing some inconsistencies with past REUS results, these changes provide a more accurate profile of gas cooking appliances.

Reviewing the 2012 results confirms a number of trends observed in 2008. Notably, the penetration of electric ranges (electric cook top and oven) continues to decline in FEI homes (70% versus 76% in 2008 and 82% in 2002). Electric cook tops are also experiencing a similar decline in popularity, (10% in 2008 versus 17% in 2002). The decline in penetration of electric ranges and electric cook-tops appears to have been a direct result of the increasing popularity of gas ranges (gas cook top and gas oven) which are now present in one-in-five of both FEU and FEI homes.. Dual fuel ranges (gas cook top and an electric oven) are present in 5% of FEU households. While their relatively popularity over time is not known, their inclusion in the 2012 REUS for the first time likely means that some of the decline observed in the penetration of gas cook tops and electric ranges may reflect more accurate classification of the respective appliances.

Other noteworthy findings from the cooking appliance data include:

- continuing decline in the popularity of microwave ovens (currently present in 82% of FEI homes, versus 93% in 2002), and
- continuing growth in the penetration of piped gas barbeques (currently 19% of FEI customers, versus 10% in 2002)

Sixteen percent (16%) of FEU customers indicated they have a commercial grade range hood, a question added to the REUS for the first time in 2012. At first glance, the penetration rate for this appliance is surprisingly high. While home improvement shows, new housing development promotions, and the DIY movement in general have associated the use commercial grade kitchen appliances as the *de rigueur* for premium kitchen design, the result likely overstates the true penetration rate for range hoods with the air flow capacity and designs comparable to those of a commercial kitchen.

9.1.1 Cooking Appliances by Dwelling Vintage

To explore how trends in new construction and renovation activity might be influencing the popularity of different cooking appliances, data on the penetration and saturation of cooking and related appliances are summarized by dwelling vintage in Table 134 (next page).

The data show that homes constructed since 1995 are more likely than older homes to have a gas range (cook top and oven) or dual fuel range (gas cook top, electric oven) and commensurately less likely to have an electric range. Finally, the penetration of piped gas barbeques increases with the newness of the home.

[45] A detailed review of the data from the 2008 REUS found some respondents with gas ranges (gas cook top with either a gas or electric oven below) indicated having a both a gas cook top (standalone) and gas range. It was strongly suspected that these respondents did not have a gas cook top in addition to their gas range, but rather were unclear as to which category best represented their cooking appliance.

Smaller samples for some vintages, particularly homes constructed since 2005, mean that some differences in penetration rates between construction periods that appear counterintuitive are not statistically significant (i.e., within the margins of error of the estimates). This is the case with the penetration of gas cook tops for homes constructed since 2005 compared to homes constructed during the previous ten years (7.9% versus 11.9%).

Table 134: Penetration and Saturation of Cooking and Related Appliances by Dwelling Vintage

Cooking Appliances	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Unknown
Unweighted base[1]	*350*	*919*	*576*	*664*	*586*	*238*	*46*
Electric range (cook top & oven)							
Penetration (%)	60.2	76.3	79.1	72.8	57.9	55.6	65.3
Saturation	0.71	0.84	0.86	0.79	0.66	0.74	0.77
Gas range (cook top & oven)							
Penetration (%)	37.8	11.5	11.4	15.6	29.4	29.9	26.4
Saturation	0.42	0.12	0.12	0.16	0.30	0.34	0.32
Dual fuel range (gas cook top, electric oven)							
Penetration (%)	6.9	3.7	2.9	3.3	5.5	11.2	5.2
Saturation	0.07	0.04	0.03	0.03	0.05	0.11	0.10
Electric cook top							
Penetration (%)	2.5	11.0	8.8	9.3	8.8	11.8	27.2
Saturation	0.03	0.12	0.09	0.10	0.09	0.16	0.32
Gas cook top							
Penetration (%)	6.4	3.6	3.5	7.6	11.9	7.9	11.5
Saturation	0.06	0.04	0.03	0.08	0.12	0.08	0.17
Electric wall oven							
Penetration (%)	9.9	11.8	10.4	15.5	16.5	11.3	15.7
Saturation	0.11	0.13	0.12	0.18	0.18	0.12	0.21
Gas wall oven							
Penetration (%)	1.0	0.8	1.0	0.1	0.7	0.8	15.7
Saturation	0.01	0.01	0.01	0.00*	0.01	0.01	0.21
Microwave oven							
Penetration (%)	77.4	82.5	82.2	84.2	83.3	85.5	88.2
Saturation	0.89	0.90	0.89	0.92	0.97	1.05	0.95
Gas barbeque (piped gas)[2]							
Penetration (%)	11.5	15.0	16.3	18.8	29.6	44.6	12.7
Saturation	0.11	0.15	0.16	0.19	0.30	0.45	0.18
Gas barbeque (bottled gas)[3]							
Penetration (%)	45.8	49.3	54.5	48.3	37.9	36.2	42.9
Saturation	0.47	0.51	0.56	0.51	0.38	0.37	0.48
Commercial grade range hood							
Penetration (%)	39.2	27.2	30.4	29.4	25.4	19.5	35.5
Saturation	0.55	0.35	0.40	0.40	0.33	0.26	0.53

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] This category was described as "NG barbeque" in the 2002 REUS questionnaire.
[3] This category was described as "propane barbeque" in the 2002 REUS questionnaire.
n/a = appliance not queried
* Value less than 0.01

Table 135 (next page) presents the average ages of the different cooking appliances. In the interest of brevity, age data for second or third appliances are not reported.

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The average age of the appliance stock reflects the rate of stock turnover due to failure (influenced by the durability and typical lifespan of the appliance[46]) but also the relative popularity of the appliance in renovations and new construction. For example, the recent popularity of dual fuel ranges (gas cook top, electric oven) is reflected by the relatively young age of the appliance stock (average of 5.6 years versus 11.6 years for electric cook tops). Similarly, the relatively young stock of gas ranges (cook top and oven) is consistent with their recent popularity in renovations and new construction.

Table 135: Average Age (Years) of Cooking and Related Appliances by Region
First Appliance Only

Cooking Appliances	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Electric range (cook top & oven)	11.0	9.6	9.4	11.2	8.3	10.4	9.8	10.5	9.9	10.6
Gas range (cook top & oven)	8.7	9.0	8.6	11.0	6.4	8.7	8.5	8.7	8.6	9.2
Dual fuel range (gas cook top, electric oven)	5.4	6.0	6.0	6.5	5.7	5.6	n/a	5.5	n/a	n/a
Electric cook top	11.7	11.4	10.8	13.8	14.9	11.6	9.2	11.6	9.0	10.0
Gas cook top	9.2	10.2	7.8	11.4	6.8	9.3	7.0	9.4	6.8	8.5
Electric wall oven	11.2	10.2	8.8	10.3	17.0	10.8	9.7	11.0	9.7	n/a
Gas wall oven	8.0	7.1	7.9	1.0	--	7.8	6.4	7.8	5.8	n/a
Microwave oven	7.6	7.1	7.7	8.4	5.9	7.4	6.9	7.4	6.9	7.9
Gas barbeque (piped gas) [1]	5.4	6.5	6.0	6.2	5.6	5.8	6.5	5.8	6.7	5.6
Gas barbeque (bottled gas) [2]	6.2	5.9	5.3	4.9	5.5	6.0	5.4	6.1	5.4	6.7
Commercial grade range hood	10.2	9.8	9.8	9.3	11.3	10.1	n/a	10.1	n/a	n/a

[1] This category was described as “NG barbeque” in the 2002 REUS questionnaire.
[2] This category was described as “propane barbeque” in the 2002 REUS questionnaire.
n/a = appliance not queried

9.2 Refrigerators and Freezers

Table 136 (next page) summarizes penetration and saturation rates for manual and automatic defrost refrigerators, and chest and upright stand-alone freezers. Manual defrost refrigerators are considerably less common than auto-defrost models. Chest-style freezers are more common than upright models, and the penetration of freezers (any type) is highest in the Interior and Fort Nelson and lowest in Whistler.

The 2008 and 2002 surveys did not query refrigerators by defrost method (e.g., auto defrost versus manual defrost, etc.). While the 2012 data for the two styles of refrigerators and freezers have been summed to allow comparison with previous survey years, caution should be advised in comparing the 2012 aggregate results with previous years due to differences in the question design.

[46] For example, the average age of ranges and refrigerators will be higher than that of microwave ovens, in part, because they last longer.

Table 136: Penetration and Saturation of Refrigerators and Freezers by Region

Refrigerators & Freezers	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2213*	*2604*	*1439*	*1610*
Refrigerator – manual defrost										
Penetration (%)	16.0	14.4	10.8	17.9	26.6	15.0	n/a	n/a	n/a	n/a
Saturation	0.20	0.17	0.13	0.21	0.31	0.19	n/a	n/a	n/a	n/a
Refrigerator – auto defrost										
Penetration (%)	87.6	88.3	89.2	83.3	73.4	87.9	n/a	n/a	n/a	n/a
Saturation	1.14	1.13	1.11	1.06	0.83	1.13	n/a	n/a	n/a	n/a
Refrigerator – any type										
Penetration (%)[1]	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	97.7
Saturation	1.34	1.29	1.24	1.27	1.14	1.32	1.34	1.36	1.33	1.32
Stand-alone freezer – upright										
Penetration (%)	20.6	27.4	25.5	14.3	23.7	22.9	n/a	n/a	n/a	n/a
Saturation	0.21	0.29	0.27	0.14	0.27	0.24	n/a	n/a	n/a	n/a
Stand-alone freezer – chest style										
Penetration (%)	47.4	56.7	51.2	23.8	60.1	50.3	n/a	n/a	n/a	n/a
Saturation	0.53	0.67	0.56	0.26	0.69	0.57	n/a	n/a	n/a	n/a
Stand-alone freezer – any type										
Penetration (%)	68.0	84.1	76.7	38.1	83.9	73.2	66.7	67.1	72.9	69.4
Saturation	0.74	0.96	0.83	0.40	0.95	0.81	0.76	0.77	0.80	0.76

n/a = appliance not queried
[1] 100% is the default penetration

The average ages of refrigerators and stand-alone freezers are summarized by region in Table 137.

Table 137: Average Age (Years) of Refrigerators and Freezers by Region
First Appliance Only

Refrigerators & Freezers	LM	INT	VI	W	FN	2012 FEU
Refrigerator – manual defrost	12.8	13.4	12.3	14.7	6.7	12.9
Refrigerator – auto defrost	9.0	8.3	8.1	9.3	7.4	8.7
Stand-alone freezer – upright	10.0	8.0	8.0	11.6	6.8	9.1
Stand-alone freezer – chest style	14.3	13.5	12.2	13.5	10.9	13.9

n/a = appliance not queried

9.3 Cleaning Appliances

Cleaning appliances are defined to include automatic dishwashers; top loading and front loading (horizontal axis) clothes washers; and electric and gas clothes dryers. Penetration and saturation rates for these appliances for the 2012, 2008, and 2002 survey years are summarized in Table 138 (next page).

The penetration of front loading (horizontal axis) clothes washers has increased from one-in-ten (9%) of all FEI customers in 2002 to four-in-ten (41%) in 2012.[47] Commensurate with this increase, the penetration of top loading clothes washers has declined from nearly nine-in-ten (88%) of FEI households

[47] ENERGY STAR clothes washers use about 75 percent less water than a standard washer used 20 years ago. Source: US EPA (2012).

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in 2002 to under six-in-ten (57%) in 2012. Traditionally, top loading clothes washers have not been energy-efficient. However, ENERGY STAR® qualified high efficiency top loading clothes washers have come onto the market since the last REUS. While still considerably less efficient than horizontal axis washers, their presence means that implying efficiency shares for clothes washers based on differentiating top versus front loading models is now less reliable than it was in 2008.[48]

Table 138: Penetration and Saturation of Cleaning Appliances by Region

Cleaning Appliances	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2213*	*2604*	*1439*	*1610*
Dishwasher										
Penetration (%)	87.4	83.2	86.7	95.2	73.4	86.2	81.9	86.1	81.4	81.2
Saturation	0.93	0.86	0.91	1.08	0.74	0.91	0.87	0.91	0.86	0.83
Clothes washer - top loading										
Penetration (%)	58.4	54.7	50.8	58.3	52.6	56.6	70.7	57.3	71.0	88.3
Saturation	0.61	0.56	0.52	0.64	0.53	0.59	0.74	0.60	0.75	0.90
Clothes washer - front loading										
Penetration (%)	40.6	42.6	45.9	45.2	43.6	41.7	27.4	41.2	26.8	9.4
Saturation	0.43	0.44	0.47	0.48	0.46	0.43	0.30	0.43	0.29	0.10
Electric clothes dryer										
Penetration (%)	88.0	89.6	87.0	90.5	86.7	88.3	87.1	88.5	87.7	89.6
Saturation	0.93	0.93	0.90	1.04	0.90	0.93	0.91	0.93	0.92	0.91
Gas clothes dryer										
Penetration (%)	4.5	4.0	7.2	3.6	9.5	4.7	5.9	4.4	5.1	5.3
Saturation	0.05	0.04	0.08	0.04	0.09	0.05	0.07	0.05	0.06	0.05

The average ages of cleaning appliances (first unit only) are summarized by appliance and region in Table 139.

Table 139: Average Age (Years) of Cleaning Appliances by Region
First Appliance Only

Cleaning Appliances	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Dishwasher	8.4	7.8	8.1	8.8	6.0	8.2	7.7	8.2	7.8	8.4
Clothes washer - top loading	10.8	9.9	10.2	11.0	9.0	10.5	9.6	10.6	9.5	8.7
Clothes washer - front loading	4.8	5.2	5.2	5.4	4.5	4.9	4.7	4.9	4.8	5.0
Electric clothes dryer	8.9	8.4	8.3	8.2	7.0	8.7	8.8	8.8	8.7	9.4
Gas clothes dryer	12.5	11.4	10.5	14.0	10.1	12.0	9.2	12.3	9.2	8.9

Table 140 (next page) summarizes the average number of clothes washing, drying, and dishwashing loads per household during a typical week. Specifically, the number of loads per week per household are provided for dishwashing, clothes washing (any temperature and using cold water wash and rinse, laundry loads dried in the dryer, on a clothes line or rack (summer versus winter). All averages are calculated using the base of all REUS respondents. All six activities will be influenced, in part, by the number of occupants of the house.

[48] While the accuracy of self-reported data on appliance efficiency using the presence or lack thereof of the ENERGY STAR logo in past surveys has been suspect, a return to using this method to differentiate high efficiency units from standard efficiency units may be required in future REUS surveys.

Table 140: Dishwasher and Laundry Loads per Week

Average number of loads per week per household	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*
Dishwasher loads	3.4	3.2	3.5	3.5	3.1	3.4
Loads of laundry – any temp	3.6	3.5	3.5	3.6	4.1	3.6
Loads of laundry – cold water wash and rinse	2.3	2.0	1.9	1.8	2.8	2.2
Dryer loads	4.0	3.8	3.9	3.8	5.3	3.9
Loads dried on clothes line or rack – Summer	1.4	1.4	1.4	1.2	1.2	1.4
Loads dried on clothes line or rack – Winter	0.8	0.7	0.6	0.7	0.5	0.7

9.4 Heating Appliances

Penetration and saturation rates for a range of space heating equipment and appliances are presented in Table 141. Specific equipment types queried included heat pumps (both air source and ground source), heat recovery ventilators (make-up air units), outdoor heaters (bottled and piped gas), and gas outdoor fireplaces or fire pits. The latter are a relatively new trend in home design and were not queried in past REUS surveys.

Table 141: Penetration and Saturation of Heating Related Appliances by Region

Heating Appliances	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2213*	*2604*	*1439*	*1610*
Air source heat pump										
Penetration (%)	10.6	13.9	13.3	1.2	4.8	11.8	4.2	11.6	3.7	1.2
Saturation	0.12	0.14	0.13	0.01	0.05	0.12	0.04	0.12	0.04	0.01
Ground source heat pump										
Penetration (%)	1.5	1.7	0.7	2.4	0.9	1.5	0.3	1.6	0.2	1.1
Saturation	0.02	0.02	0.01	0.05	0.01	0.02	0.00*	0.02	0.00*	0.01
Heat recovery ventilator / make-up air unit										
Penetration (%)	1.9	2.9	4.5	8.3	2.8	2.5	1.9	2.2	1.6	1.8
Saturation	0.02	0.03	0.05	0.11	0.03	0.03	0.02	0.02	0.02	0.02
Portable electric heaters										
Penetration (%)	31.8	25.0	22.1	19.0	29.4	28.9	n/a	29.7	n/a	n/a
Saturation	0.43	0.33	0.27	0.27	0.39	0.39	n/a	0.40	n/a	n/a
Gas outdoor heater (piped gas) [1]										
Penetration (%)	1.5	1.8	2.1	2.4	0.9	1.7	1.3	1.6	1.3	0.9
Saturation	0.02	0.02	0.02	0.02	0.01	0.02	0.02	0.02	0.02	0.01
Gas outdoor heater (bottled gas) [2]										
Penetration (%)	4.8	2.8	3.5	5.9	0.9	4.1	1.6	4.2	1.5	1.1
Saturation	0.05	0.03	0.04	0.06	0.02	0.04	0.02	0.04	0.02	0.01
Gas outdoor fire pit or fireplace										
Penetration (%)	3.2	1.9	2.9	5.9	1.9	2.8	n/a	2.8	n/a	n/a
Saturation	0.04	0.02	0.03	0.06	0.02	0.03	n/a	0.03	n/a	n/a

* Value smaller than 0.01
[1] Queried as natural gas outdoor heater in the 2002 REUS.
[2] Queried as propane outdoor heater in the 2002 REUS.
n/a = appliance not queried

The data indicate that one-in-eight (12%) of FEU households have an ASHP, up from four percent in 2008. On a regional basis, penetration of ASHP is highest in the Interior (14% of FEU customers), Vancouver Island (13%) and Lower Mainland (11%). The proportion of households with a ground source heat pump

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(GSHP), also referred to as a geothermal system, remains low at one and a half percent of households. The penetration was less than one percent in 2008.

Residential building codes now require tighter building envelopes than in the past, meaning that there is considerably less opportunity for outside air to enter through seams, joints, and other areas of the building shell. Heat recovery ventilators (HRVs)[49] allow pre-heated fresh air to be introduced to the home, preventing depressurization of the home by range hoods and exhaust fans. HRVs are present in three percent (3%) of FEU homes, statistically unchanged from two percent (2%) of FEU homes in 2008.

The penetration rate for gas outdoor heaters (piped gas) among FEU residential customers is low at two percent (1.7%). Gas outdoor fire pits or fireplaces are estimated at three percent (2.8%) of FEU households.

Penetration and saturation rates for heating equipment by dwelling vintage are summarized in Table 142.

Table 142: Penetration and Saturation of Heating Equipment by Dwelling Vintage

Heating Appliances	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Unknown
Unweighted base	*350*	*919*	*576*	*664*	*586*	*238*	*46*
Air source heat pump							
Penetration (%)	8.8	9.8	10.0	12.9	9.9	29.6	18.8
Saturation	0.09	0.10	0.10	0.15	0.10	0.32	0.24
Ground source heat pump							
Penetration (%)	0.7	0.3	0.5	1.5	2.9	4.5	10.5
Saturation	0.01	0.00*	0.01	0.02	0.03	0.05	0.16
Heat recovery ventilator / make-up air unit							
Penetration (%)	2.3	0.5	0.8	3.3	4.4	6.9	10.6
Saturation	0.02	0.00*	0.01	0.03	0.05	0.07	0.16
Portable electric heaters							
Penetration (%)	39.2	27.2	30.4	29.4	25.4	19.5	10.5
Saturation	0.55	0.35	0.40	0.40	0.33	0.26	0.21
Gas outdoor heater (piped gas)							
Penetration (%)	1.9	1.3	0.7	1.1	2.4	3.1	10.5
Saturation	0.03	0.01	0.01	0.01	0.02	0.06	0.21
Gas outdoor heater (bottled gas)							
Penetration (%)	3.0	2.8	5.6	2.2	7.6	3.6	6.3
Saturation	0.04	0.03	0.06	0.02	0.08	0.04	0.12
Gas outdoor fire pit or fireplace							
Penetration (%)	2.5	1.5	3.1	1.3	4.8	9.0	5.2
Saturation	0.02	0.02	0.03	0.01	0.05	0.12	0.10

* Value less than 0.01

Of note:

- the penetration of ASHPs is highest among dwellings constructed since 2005 (26% of dwellings);
- the penetration of ground source heat pumps, while still relatively small, also shows a greater penetration among newer dwellings (4% of homes constructed since 2005 versus less than 1% for homes constructed prior to 1986);

[49] Also known as make up air units or mechanical ventilation.

- HRVs are also more likely to be present in newer homes (6% of homes built since 2005 compared to less than one percent of homes constructed prior to 1986); and
- gas outdoor fireplaces or fire pits also appear to be more common among newer dwellings (8% of homes constructed since 2005).

Dwelling-specific detail on air source heat pumps, ground source heat pumps and heat recovery ventilators is provided in Table 143. Sample sizes for some dwelling types, particularly apartments / condominiums, are small, so caution is advised in the interpretation of these data. The data show the penetration of air source heat pumps is highest among single family detached dwellings and row / townhouses (13% and 10% respectively). The penetration of ground source heat pumps (GSHPs) among these and other dwelling types is considerably lower. Differences in the penetration of GSHPs between the dwelling types are not statistically significant at the 95% confidence level.

Table 143: Penetration and Saturation of Heat Pumps and Make-Up Air Units by Dwelling Type

Heat Pumps & HRVs	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base [1]	*2796*	*154*	*207*	*56*	*119*	*59*
Air source heat pump						
Penetration (%)	12.8	4.4	10.0	3.9	4.9	2.1
Saturation	0.14	0.04	0.10	0.04	0.05	0.02
Ground source heat pump						
Penetration (%)	1.5	2.9	1.1	--	--	1.0
Saturation	0.02	0.03	0.01	--	--	0.01
Heat recovery ventilator / make-up air unit						
Penetration (%)	2.7	0.4	2.1	--	0.9	7.0
Saturation	0.03	0.00*	0.02	--	0.01	0.07

* Value less than 0.01

The average ages of the different heating equipment are summarized in Table 144. Comparable data, where it exists, from the 2002 and 2008 REUS surveys are provided. Differences between the current and past surveys are expected, as the average age of the heating equipment stock reflects both the aging of the stock present in 2008 and the introduction of new stock via replacements or new construction.

Table 144: Average Age (Years) of Heating Equipment by Region

Heating Appliances	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Air source heat pump	8.3	6.8	6.5	--	11.4	7.5	4.4	7.7	3.7	1.2
Ground source heat pump	7.8	7.2	4.0	3.0	10.0	7.5	14.2	7.7	14.2	8.6
Heat recovery ventilator / make-up air unit	12.9	7.4	11.8	13.0	12.5	10.9	9.1	10.6	8.4	6.5
Portable electric heater	4.6	4.9	4.4	4.1	4.7	4.7	n/a	4.7	n/a	n/a
Gas outdoor heater (piped gas) [1]	10.0	8.5	8.9	5.0	--	9.3	8.7	9.4	9.2	4.4
Gas outdoor heater (bottled gas) [2]	5.9	4.9	4.8	9.0	--	5.7	4.0	5.7	4.2	2.1
Gas outdoor fire pit or fireplace	4.1	4.2	7.1	1.5	-- [3]	4.5	n/a	4.1	n/a	n/a

[1] Queried as natural gas outdoor heater in the 2002 REUS.
[2] Queried as propane outdoor heater in the 2002 REUS.
[3] Data not reported due to insufficient sample

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9.4.1 ASHPs – Additional Discussion

While data from the appliance section of the survey, as reported in Table 141, page 125, indicate that 12% of FEU households have an ASHP, only 8% of households indicated they use an ASHP as either a main or secondary space heating method under the space heating section of the survey (Sections 6.3.2 and 6.3.1, page 74). The lower penetration rate under the space heating section may be that some households associate an ASHP with space cooling (air conditioning) rather than space heating and thus underreport these units when asked about space heating methods. It may also be due to the nature in which the questions in the two sections were posed. In the space heating section of the survey, respondents were asked to indicate the main, secondary, and any other methods used to heat the home from a list of several possible space heating methods including ASHPs. In contrast, the appliance section of the survey asked respondents to indicate the quantity, including none, for each of 26 different appliances, including ASHPs. Being required to indicate the presence or quantity of individual end-uses may have improved the likelihood that respondents would indicate the presence of an ASHP regardless of its role in providing heating or cooling.

In light of these findings, the incidence of ASHPs is considered to be underreported in the space heating methods section of the report. The more accurate estimate of the penetration of ASHPs is assumed to be 12% of FEU households.

9.5 Cooling and Miscellaneous Appliances

Penetration and saturation rates for a variety of common household cooling appliances ranging from central air conditioners to ceiling fans are presented in Table 145 (next page). Data are also provided for miscellaneous end-uses including humidifiers and dehumidifiers.

Three types of air conditioning equipment were queried: central systems (typically paired with a forced air furnace); portable air conditioners, and room window air conditioners. Slight differences exist in the descriptions used for air conditioners between the 2012 REUS and previous REUS surveys, so caution in comparing the 2012 results with earlier years is advised.

The data show that homes in the Interior are most likely to have air conditioning, either in the form of central air conditioning or room window air conditioners (50% and 11% of Interior households respectively).

Research on residential new construction trends conducted for FEU in 2010[50] identified an underreporting issue for air conditioning for homes with heat pumps (either air source or ground source). In particular, some respondents did not indicate their home had air conditioning despite having a heat pump; the latter, by the nature of its technology, can provide both heating and cooling. A review of the 2012 REUS data revealed a similar underreporting of air conditioning in homes with heat pumps. To address this issue in the 2012 REUS, penetration and saturation data for central air conditioners are presented two ways. The first as supplied by respondents (which may or may not include air conditioning provided by air source or ground source heat pumps). The second includes air conditioning provided by traditional central air conditioning units or via air source and ground source heat pumps. As it is not possible to identify air source heat pumps by type (i.e., paired with a forced air furnace or stand-alone mini-split units, etc.), the

[50] Sampson Research (2011).

amended central air conditioning data may somewhat overstate the penetration of "central" air conditioning.[51]

Table 145: Penetration and Saturation of Cooling Equipment by Region

Cooling Equipment	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2213*	*2604*	*1439*	*1610*
Central air conditioner [1]										
Penetration (%)	9.1	50.4	9.3	4.8	13.3	20.3	15.2	21.7	16.7	15.1
Saturation	0.10	0.52	0.10	0.05	0.14	0.21	0.15	0.23	0.17	0.16
Central air conditioning including heat pumps [2]										
Penetration (%)	15.8	55.1	15.4	5.9	18.0	26.3	18.6	n/a	n/a	n/a
Saturation	0.16	0.57	0.16	0.06	0.19	0.27	0.19	n/a	n/a	n/a
Portable air conditioner										
Penetration (%)	13.5	8.3	7.7	2.4	12.3	11.4	10.4	11.9	10.9	n/a
Saturation	0.16	0.10	0.08	0.02	0.14	0.14	0.12	0.14	0.13	n/a
Room window air conditioner [3]										
Penetration (%)	8.3	10.6	2.8	1.2	8.5	8.3	10.3	9.0	10.5	9.1
Saturation	0.10	0.14	0.04	0.01	0.11	0.10	0.16	0.11	0.16	0.13
Portable Fan										
Penetration (%)	59.6	42.4	52.1	38.1	55.0	54.1	n/a	54.4	n/a	n/a
Saturation	1.10	0.69	0.84	0.62	0.99	0.96	n/a	0.97	n/a	n/a
Humidifier										
Penetration (%)	4.3	11.9	2.5	13.1	21.8	6.2	4.8	6.6	5.0	7.0
Saturation	0.05	0.13	0.03	0.19	0.26	0.07	0.05	0.07	0.05	0.07
Dehumidifier										
Penetration (%)	4.9	4.3	7.4	3.6	3.8	5.0	4.4	4.7	4.1	n/a
Saturation	0.05	0.04	0.08	0.05	0.04	0.05	0.05	0.05	0.05	n/a

[1] Queried as "electric central air conditioner" in 2002 and 2008
[2] Includes air conditioning provided by air source and ground source heat pumps
[3] Queried as "electric wall unit" in 2002 and 2008
n/a = appliance not queried

9.6 Cooling and Miscellaneous Appliances – Operating Hours

REUS 2012 respondents were asked to indicate the average daily operating hours for each of the nine cooling appliances. These averages are presented in Table 146 (next page) and refer to the units only when in use (e.g., air conditioners will only be used in the cooling months).

[51] Ductless or mini-split air source heat pumps consist of an outdoor compressor/condenser and an indoor air-handling unit (head). They are typically installed in dwellings or rooms within dwellings where ductwork is not available. For larger dwellings, ductless units with multiple "heads" are available and allow greater cooling coverage. Regardless, ductless ASHPs are not typically considered to provide "central" air conditioning. Central air conditioning usually refers to a dedicated air conditioning unit paired with a ducted furnace or a heat pump paired with a ducted furnace.

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Table 146: Cooling Equipment Average Daily Hours of Use by Region

Cooling Equipment	LM	INT	VI	W*	FN*	2012 FEU
Central air conditioner [1]	7.7	7.8	6.9	9.2	13.8	7.7
Portable air conditioner	5.2	5.7	6.6	5.5	11.9	5.4
Room window air conditioner [2]	5.7	6.6	4.1	10.0	8.0	6.0
Portable Fan	5.4	6.4	5.7	6.1	7.5	5.7
Humidifier	4.7	12.0	6.4	12.9	13.7	8.6
Dehumidifier	9.1	7.5	6.8	2.5	18.7	8.4
Portable electric heater	4.6	4.9	4.4	4.1	4.7	4.7

* Small samples – caution is advised
[1] Queried as “electric central air conditioner” in 2002 and 2008
[2] Queried as “electric wall unit” in 2002 and 2008

10 POOLS, HOT TUBS & SAUNAS

This section presents and discusses the incidence of swimming pools, hot tubs, and saunas among FEU households. Information is provided on their heating fuels, months of operation, and energy saving behaviours such as the use of pool and hot tub covers. As in the 2008 REUS, the 2012 survey asked detailed questions about fuels and behaviours only for households that had exclusive use of the facilities. Respondents who shared a swimming pool, hot tub, and/or sauna with other residences, as is the case in some condominium or townhouse complexes, were skipped past this section of the survey. The 2012 REUS represents the first FEU REUS survey to collect details (albeit limited) on exclusive-use saunas.

10.1 Penetration Rates

Penetration rates of exclusive-use only pools, hot tubs and saunas are provided in Table 147. Saturation figures are not presented, as homes with more than one of any of these end-uses would be very uncommon.

Four percent (4%) of FEU gas customers, on average, reported having a swimming pool for their exclusive use. Compared to 2008, the incidence is unchanged (difference between 2008 and 2012 is not statistically significant at the 95% confidence level). Regionally, customers in the Interior had the highest incidence of an exclusive-use pool (8%).

Table 147: Penetration of Pools, Hot Tubs, and Saunas by Region (%)

Exclusive use only	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2189*	*2604*	*1426*	*1610*
Swimming pool	3.2	7.9	1.8	--	2.0	4.3	5.2	4.6	5.6	n/a
Hot tub	7.3	15.3	9.2	39.0	6.8	9.7	13.3	9.7	13.5	n/a
Sauna	3.8	4.1	2.5	12.2	2.0	3.8	n/a	3.9	n/a	n/a

n/a =data not available

On average, one-in-ten (10%) of FEU customers have a hot tub for their exclusive use. Regionally, Whistler, and to a lesser extent the Interior, stand out as having a significantly higher proportion of households with an exclusive hot tub compared to the other regions (39% and 15% respectively). The incidence of hot tubs in other regions varied from 7% (Lower Mainland and Fort Nelson) to 9% (Interior).

Four percent (4%) of FEU customers reported having a sauna that was for their exclusive use. As with the case for hot tubs, the incidence of saunas was highest for Whistler customers (12%). The 2008 and 2002 surveys did not query the presence of saunas.

Table 148 (next page) summarizes the penetration of exclusive-use pools, hot tubs, and saunas by dwelling type. Not surprisingly, penetration for the three end-uses was highest among single family detached homes and lowest among apartments / condominiums.

Table 148: Penetration of Pools, Hot Tubs, and Saunas by Dwelling Type (%)

Exclusive use only	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base [1]	*2796*	*154*	*207*	*56*	*119*	*59*
Swimming pool	5.2	--	1.0	1.4	0.9	0.0

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Hot tub	11.5	3.2	0.7	--	4.3	2.0
Sauna	4.2	2.6	0.2	--	--	7.8

10.2 Heating Fuels – Pools, Hot Tubs, and Saunas

Respondents to the 2012 REUS were asked to indicate the fuel(s) used to heat their exclusive-use heated pools, hot tubs and/or saunas. In the case of pools and hot tubs, fuel use is compared with 2002 and 2008 REUS results.

Table 149 summarizes the fuels used to heat exclusive-use swimming pools. Natural gas is the most common fuel used to heat pools, heating almost seven-in-ten (68%) of all exclusive-use pools. The next most common heating fuel is solar (27%). More than one-quarter (27%) indicated their pool is not heated. Regional comparisons are not presented due to small sample sizes.

Table 149: Fuels used to Heat Swimming Pools by Region (%)
Exclusive-use pools only

Main pool heater fuel	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI [2]
Unweighted base [1]	*169*	*63*	*156*	*50*	*98*
Solar	26.5	15.0	18.8	14.6	20.7
Natural gas	68.3	43.4	50.6	43.6	56.0
Electric	4.7	5.2	3.2	3.9	1.4
Other	0.4	--	0.4	--	--
Not heated	27.2	36.4	27.0	37.9	24.1
DK/NR	--	--	--	--	2.6
Total	**100.0**	**100.0**	**100.0**	**100.0**	**--**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] includes non-responses (NR)
Totals may not sum due to rounding

Households that use either natural gas, electricity or some other fuel to heat their pool were asked whether they supplement the primary fuel with solar energy. The results by fuel type are summarized in Table 150.

Table 150: Use of Solar Heating to Supplement Heating for Swimming Pools
Percent using solar heating by fuel type

	2012 FEU
Unweighted base [1]	*24*
Natural gas	25.9
Electric	44.9
Other	100.0

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

One-quarter (26%) of respondents who use natural gas indicated they also use solar heating. Nearly half (45%) of respondents using electricity to heat their pools reported using solar heating as a supplementary heating source. Regional results are not presented due to insufficient sample.

The vast majority of hot tubs (90%) are heated using electricity (Table 151). The remainder (10%) use natural gas. Regionally, small sample sizes mean that regional differences are not significant with the exception of the Interior and Lower Mainland (96% of Interior hot tubs use electricity versus 84% in the

Lower Mainland). Differences in fuel use between the 2012 and 2008 REUS are statistically different using a 90% confidence interval but not at the 95% confidence level.

Table 151: Hot Tub Fuels by Region (%)

Exclusive use only	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI [2]
Unweighted base [1]	*56*	*246*	*66*	*32*	*7*	*407*	*269*	*309*	*142*	*185*
Natural gas	16.1	3.7	4.5	3.1	14.3	9.6	15.0	10.2	16.2	13.1
Electric	83.9	96.3	95.5	96.9	85.7	90.4	83.4	89.8	82.2	86.3
Other	--	--	--	--	--	--	1.6	--	1.6	1.2
DK/NR	--	--	--	--	--	--	--	--	--	0.9
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**--**

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] includes non-responses (NR)
Totals may not sum due to rounding

Data on sauna fuels are summarized in Table 152. Predominately, saunas are heated using electricity (95% of all exclusive use saunas). A very small proportion use natural gas or some other fuel (1% each).Regional results are not presented due to small samples in all regions except the Interior.

Table 152: Sauna Fuels (%)

Exclusive use only	2012 FEU
Unweighted base	*122*
Natural gas	1.1
Electric	95.4
Other	0.9
DK	2.6
Total	**100.0**

Totals may not sum due to rounding0

10.3 Heating Behaviours – Pools and Hot Tubs

Table 153 (next page) summarizes the mean number of months that pools and hot tubs are heated. Data for pools are for heated pools only. On average, exclusive use swimming pools are heated 3.5 months of the year. This average is not statistically different than that recorded in 2008. Four percent (4%) of gas customers indicated they heat their pool year round.

Hot tubs are heated, on average, 9 months of the year. Nearly half (46%) heat them all year round.

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Table 153: Pools and Hot Tubs – Average Number of Months Heated

Pool and Hot Tub Heating	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Heated Pools((*Unweighted base* [1])	*20*	*80*	*8*	--	*2*	*110*	*45*
Months heated (mean)	3.5	3.4	4.6	--	4.5	3.5	3.7
Heated all year (%)	5.0	1.2	12.5	--	--	3.7	7.1
Hot tubs (*Unweighted base* [1])	*56*	*245*	*65*	*32*	*7*	*405*	*261*
Months heated (mean)	7.6	9.4	8.2	9.5	9.9	8.5	8.2
Heated all year (%)	41.1	51.8	41.5	62.5	71.5	45.9	42.4

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.

Using some sort of insulated cover on a pool or hot tub when it is not in use (heating season only) saves energy by minimizing heat losses.[52] On average, three-quarters (75%) of FEU households with heated pools use a cover when not in use (i.e., during the months when the pool is heated). This proportion has varied somewhat during the past three REUS surveys (Table 154). However, the small number of homes with heated pools in the 2008 and 2012 surveys (n=45 and n=115 respectively) means the difference between the 2008 and 2012 estimates is not statistically significant at the 95% confidence level.

Table 154: Use of Pool and Hot Tub Covers by Region (%)
Heated Pools and all Hot Tubs

	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Cover pool when not in use	60.0	95.2	55.6	--	50.0	75.2	68.5	76.1	66.7	79.7
Cover hot tub when not in use	92.7	99.2	95.3	96.8	85.7	95.8	94.7	95.8	94.3	95.3

The incidence of covering a hot tub when not in use is considerably higher than that for pools. Almost all (96%) households with a hot tub cover their hot tub when not in use. Differences among the regions are not statistically significant, nor are differences at the utility level between the 2008 and 2012 surveys.

Data on the incidence of high efficiency motors (i.e., variable speed or electrically controlled) for pool pumps are summarized in Table 155 (next page). Nearly two-in-five (18%) indicated their pool was equipped with a high efficiency pump motor. However, more than one-quarter (27%) were unsure. Three percent (3%) indicated the question was not applicable (i.e., pool not heated and/or no method of circulating the water). Regional results are not provided due to small sample sizes. This question was not asked in the 2008 or 2002 surveys.

Table 155: Incidence of High Efficiency Pool Pump Motors (%)

Have HE Pool Pump Motor?	2012 FEU
Unweighted base	*166*
Yes	17.8
No	52.0
DK	27.2
Not applicable	3.0
Total	**100.0**

Totals may not sum due to rounding

[52] According to the US Department of Energy (DOE), evaporation accounts for 70% of the energy loss from outdoor swimming pools, while radiation to the sky (temperature differential between the pool temperature and the outside air) accounts for another 20%. Ground and other losses account for the remaining 10%. Using a pool cover, especially one that continues to permit solar gain, can reduce energy losses by 50% to 70%. Source: http://energy.gov/energysaver/articles/swimming-pool-covers

11 ENERGY USE BEHAVIOURS

This section summarizes a series of questions posed to 2012 REUS respondents regarding the behaviours they take or not take to conserve energy associated with natural gas end-uses in the home. This information is supplemented with additional information on the frequency of a number of common behaviours affecting the demand for space and hot water heating. Developing a comprehensive understanding of behaviours influencing natural gas use and the myriad of factors that influence these behaviours requires a considerably more involved research process than that allowed by the 2012 REUS. Limitations to survey length restricted the number of behaviours that could be queried and the degree to which barriers and opportunities for saving energy were explored. Information presented in this section is intended to provide a broad baseline of key energy use behaviours only.

11.1 Behaviours Influencing Natural Gas Consumption

To better understand the potential for energy savings in natural gas consumption through changes in behaviours in the home, respondents to the 2012 REUS were asked to rate their frequency of undertaking a variety of behaviours related to space heating and domestic hot water consumption. Respondents were asked to indicate how often they did each behaviour using a four point scale including always, usually, occasionally and never. Each behaviour also allowed respondents to answer “don’t know” or indicate the behaviour was “not applicable”. The latter response category is required, as not all behaviours will apply to all households (e.g., ability to use storm windows is specific to homes with older style single pane windows that accept storm windows).

Behaviours were analyzed from two perspectives. The first perspective was the proportion of households that already do the behaviour (i.e., indicated “always” or “usually”). These households are the least likely to deliver incremental energy savings from undertaking (increasing) these behaviours. The second perspective is the proportion of households that occasionally or never undertake the energy saving behaviour, or are unsure how often they undertake the behaviour. The latter defines the outstanding market potential for behavioural change in terms of the proportion of residential customers that could contribute energy savings from a sustained change in their behaviours. Market potential figures exclude those who indicated the behavioural was not applicable (e.g., storm windows). Some respondents, however, may have selected “never” rather than the more appropriate “not applicable” for some behaviours, so the reader is cautioned that the market potential may be somewhat overstated for some behaviours. This is more likely to be the case where the behaviour is linked to a technology that has less than 100% penetration.[53]

No attempt has been made to estimate or otherwise quantify the energy savings associated with any specific behaviour, nor the amount of the outstanding market that could be realistically captured through utility programming. These are issues outside of the scope of the 2012 REUS.

[53] As an example, respondents who do not have an automatic dishwasher may choose “never” for how often they undertake conserving behaviours associated with the use of automatic dishwashers rather than selecting “not applicable”. In this case, their answer would be included with other households who suggest there is room for improvement.

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11.1.1 Space Heating Behaviours

Respondents were asked to indicate the temperature they usually keep their residence in the winter (heating) season for three common situations:

- When someone is at home
- When no one is at home
- During the night

The results (averages) are summarized in Table 156. All data reported are for FEU households that undertake the set-back behaviours during winter, either occasionally or regularly. Data on how many households undertake set-back behaviours, are reported further on in this section. The results show that respondents turn down their thermostat by an average of 3.1 degrees Celsius when no one is at home. During the night, the average turn down in thermostat is 2.9 degrees. There are no statistically significant differences in the averages between electrically heated versus gas (natural gas or piped propane).[54]

Table 156: Winter (Heating Season) Room Temperatures (Degrees Celsius)

							Main SH Fuel	
	LM	INT	VI	W	FN	2012 FEU	Electric	Gas
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*538*	*2779*
When someone is at home	20.4	20.7	20.2	20.0	20.9	20.5	20.4	20.5
When no one is at home	17.3	17.6	16.9	16.3	18.8	17.3	17.3	17.3
During the night	17.6	17.7	16.8	17.1	18.9	17.5	17.7	17.5
Daytime set-back[1]	3.1	3.1	3.3	3.8	2.1	3.1	3.1	3.1
Night time set-back[2]	2.8	3.0	3.4	2.9	2.0	2.9	2.8	3.0

[1]Difference in daytime temperature when someone is at home versus no one is at home
[2]Difference between night-time temperature and daytime temperature when someone is at home

Most FEU households (81%) have the ability to reduce the temperature in unused rooms by turning down individual room thermostats or by closing registers or vents (Table 157). As expected, FEU homes that use electricity as their main space heating fuel are more able to control the temperature in individual rooms than homes where natural gas is their main space heating fuel (89% versus 79%). This is consistent with the tendency for electric space heat to be provided by baseboard heaters that have zoned temperature control (either via a wall-mounted rheostat or at the register itself).

Table 157: Ability to Reduce Temperature in Unused Rooms by Region (%)

							Main SH Fuel	
	LM	INT	VI	W	FN	2012 FEU	Electric	Gas
Unweighted base	773	1652	739	83	104	3351	*538*	*2779*
Yes	79.8	80.3	85.5	93.9	73.4	80.6	89.0	79.4
No	17.7	17.2	13.3	6.1	24.7	17.1	9.0	18.2
DK	2.5	2.5	1.2	--	1.9	2.3	2.0	2.4
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding

[54] Data for main space heating fuels other than natural gas, piped propane, and electricity are not reported due to very small sample sizes.

Table 158 summarizes the percentage of REUS respondents who answered always or usually to eight different behaviours that save energy associated with space heating. The frequency of leaving windows open during the winter, an action sometimes used to improve ventilation, was also queried. Results are presented by each of the five FEU regions, the overall FEU average, and by main space heating fuel (electric versus natural gas or piped propane). Results for renters versus owners were reviewed but are not presented because the sample of renters (n=85) is too small to provide meaningful results for a majority of the questions (i.e., most differences between renters and owners will not be statistically significant). The base for all responses is the same which means that behaviours that are not applicable to all residential customers (e.g., storm windows) will have, by default, lower percentages of respondents indicating they always or usually undertake these behaviours.

Table 158: Space Heating Behaviours
Percent who always or usually undertake the behaviour

							Main SH Fuel	
Behaviours Impacting Space Heating	**LM**	**INT**	**VI**	**W**	**FN**	**2012 FEU**	**Electric**	**Gas**
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*538*	*2779*
Turn down heat - at night	80.4	86.3	86.5	79.5	71.2	82.6	78.1	83.6
Turn down heat - no one at home	77.7	83.0	82.2	79.5	67.1	79.6	75.5	80.3
Close window coverings	70.7	71.9	68.3	69.5	66.7	70.7	67.2	71.4
Close vents / turn down thermostats in unused rooms	61.0	62.4	68.4	74.7	50.7	62.2	72.2	61.3
Draft proof at least once a year	33.5	46.0	35.6	38.6	45.5	37.1	37.5	37.0
Install plastic window coverings during winter months	6.8	12.4	4.8	5.0	23.9	8.1	5.2	8.4
Install storm windows (single pane windows only)	4.2	7.7	3.4	1.3	6.0	5.0	4.5	5.1
Leave one or more windows open during winter [1]	78.2	83.6	79.5	86.7	96.2	79.8	82.4	79.4

[1] Respondents who occasionally, never, or unsure they leave windows open

When ranked by the percentage of households reporting they always or usually undertake the behaviour, the top ranked behaviours are:

- turning down the heat at night (83% always or usually);
- turning down the heat when no one is home (80%), and
- closing window coverings to keep in the heat (71%).

Interior and Fort Nelson respondents are more likely to conduct annual draft proofing compared to other regions (46% each compared to the five region average of 37%). While the sample is small, Fort Nelson scores lower on many behaviours with the exception of draft proofing (already mentioned), installing storm windows, and using plastic window coverings.

When responses are expressed according to main space heating fuel (electricity versus natural gas or piped propane), some differences appear:

- Respondents using electricity as their main space heating fuel are more likely to say they always or usually close vents or turn down room thermostats than homes using natural gas (72% versus 61%).

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- Homes using gas as their main space heating fuel are somewhat more likely than electrically heated homes to turn down the thermostat at night or when no one is at home (significantly different at the 90% confidence level).

The difference in frequency of window opening between gas versus electric main space heating is not statistically significant at the 95% confidence interval.

Table 159 summarizes the market potential for each of the seven space heating behaviours. Behaviours with the largest remaining potential include:

- draft proofing (60% of respondents could do more);
- installing plastic window coverings (46%), and
- closing vents or turning down thermostats in unused rooms (30%).

Homes whose main space heating fuel is natural gas have less remaining potential than their electric counterparts for closing window coverings and turning down the heat at night, but have greater potential to close vents / turn down the thermostat in unused rooms, and installing storm windows.

Table 159: Space Heating Behaviours – Remaining Potential
Percent who occasionally, never or are unsure they undertake the behaviour

							Main SH Fuel	
Behaviours Impacting Space Heating	**LM**	**INT**	**VI**	**W**	**FN**	**2012 FEU**	**Electric**	**Gas**
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*538*	*2779*
Draft proof at least once a year	64.1	51.0	60.2	60.2	53.6	60.2	59.5	60.4
Install plastic window coverings during winter months	50.3	38.1	41.7	41.2	49.2	46.1	46.6	46.5
Close vents / turn down thermostats in unused rooms	30.5	31.6	25.4	20.5	44.5	30.3	23.7	31.1
Close window coverings	26.1	25.8	28.2	28.0	27.5	26.2	29.3	25.8
Install storm windows (single pane windows only)	28.6	19.1	20.6	7.6	22.1	25.1	18.0	26.2
Leave one or more windows open during winter [1]	21.3	15.3	19.9	13.3	3.8	19.5	17.2	19.8
Turn down heat - no one at home	20.2	15.2	15.1	16.9	29.1	18.3	22.6	18.0
Turn down heat - at night	18.2	12.6	12.0	20.5	26.0	16.1	20.6	15.2

[1] Respondents who always or usually leave windows open during winter

One-in-five (20%) of FEU customers indicated they always or usually leave one or more windows open during the winter. Regionally, this behaviour was most prevalent in the Lower Mainland (21%) and Vancouver Island (20%), but less so in regions where the winters are colder. The provision of fresh air via other means (heat recovery ventilators or make up air units, etc.) represents an area of opportunity for these households.

11.1.2 Laundry and Other Domestic Hot Water Use Behaviours

A number of activities directly affect the amount of energy associated with heating water for domestic use. They include baths, showers, clothes washing, dish washing, and general faucet use. A study of hot water use in Seattle homes (Mayer 2000) provides interesting insight into the relative contribution of these activities to overall hot water consumption. The study found that general faucet use, showers, and baths used the most hot water on a per-capita basis, and approximately three-quarters (73% to 78%) of the water used by these activities was hot water (Table 160). Hot water used on a per-capita basis by clothes washers was comparable to that of bathing. Twenty-eight percent (28%) of the water used for clothes washing is unheated.

Table 160: Household Per Capita Hot Water Use by Activity

	Per Capita Hot Water Use (L/day)	Hot Water Portion (%)
Faucets	32.6	72.7
Showers	23.8	73.1
Baths	15.9	78.2
Clothes Washers	14.8	27.8
Leaks	4.5	26.8
Dishwashers	3.4	100.0

Source: Mayer, P.W., DeOreo, W.B.(1999)

Due to limitations on survey length, the 2012 REUS limited domestic hot water behavioural potential questions to:

- Turning off the water heater or use its "vacation setting" when no one is home for more than 2 or 3 days
- Doing laundry with full loads
- Doing laundry using cold water
- Running the dishwasher when full

Additionally, the survey collected data on the number of showers, average length of showers, baths, dishwasher loads, and laundry loads (by water temperature) per week.

Table 161 summarizes the percent of respondents who always or usually turn off their water heaters when away, only do laundry with full loads, and only run the dishwasher when full.

Table 161: Domestic Hot Water Behaviours
Percent who always or usually undertake the behaviour

							Main DWH Fuel	
Behaviours Impacting DWH	LM	INT	VI	W	FN	2012 FEU	Electric	Gas
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*538*	*2779*
Turn off water heater when away	35.0	42.8	37.2	34.9	26.0	37.3	31.2	39.6
Only do laundry with full loads	91.0	93.4	93.1	86.7	89.6	91.9	93.8	91.4
Only run dishwasher when full	86.1	83.1	87.1	90.4	70.6	85.4	85.9	85.7

The results show the majority (92%) of households always or usually do laundry with full loads and run the dishwasher when full (85%). While 37% of households turn off the water heater when no one is at home for a few days, homes with gas hot water heaters are significantly more likely than those with electric hot water heaters to turn off the water heater when away for more than a couple of days (40% versus 31%).

Consistent with the proportion of households who already do the hot water saving activities, Table 162 (next page) shows the market potential for saving energy from changes to hot water use behaviours are:

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- turning off the water heater while away (53%);
- doing laundry with full loads (8%), and
- running dishwashers only when full (3%).

Table 162: Domestic Hot Water Behaviours – Remaining Potential
Percent who occasionally, never or are unsure they undertake the behaviour

							Main DWH Fuel	
Behaviours Impacting DWH	LM	INT	VI	W	FN	2012 FEU	Electric	Gas
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*538*	*2779*
Turn off water heater when away	55.7	47.9	52.4	59.0	66.4	53.3	61.6	52.2
Only do laundry with full loads	8.3	6.2	6.4	12.0	9.5	7.6	5.9	8.0
Only run dishwasher when full	2.6	1.8	2.4	3.6	3.8	2.4	1.2	2.4

Again, these estimates represent the potential market for a behavioural program, not the potential energy savings from implementing the programming.

Table 163 summarizes the frequency of a number of hot water-using activities including dishwashing, laundry, bathing, and showering. All data are expressed per average household. Some behaviours occur more frequently than others. For example, showers are considerably more common than baths (average of 11.4 showers per-week versus 2.1 baths). On average, FEU households do 3.6 loads of laundry per-week, of which 2.2 or 61% are done using cold water wash and rinse.

Table 163: Hot Water Use Activities – Number Per-Household

							Main DWH Fuel	
Behaviours Impacting DWH	LM	INT	VI	W	FN	2012 FEU	Electric	Gas
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*538*	*2779*
Average # of people per home	2.9	2.4	2.4	2.7	2.6	2.7	2.6	2.7
Dishwasher loads per week	3.4	3.2	3.5	3.5	3.1	3.4	3.3	3.5
Laundry loads per week (any temperature)	3.6	3.5	3.5	3.6	4.1	3.6	3.5	3.6
Laundry loads using cold water	2.3	2.0	1.9	1.8	2.8	2.2	2.4	2.2
Baths per week	2.3	1.9	1.8	1.4	2.6	2.1	2.4	2.1
Showers per week	12.4	9.6	10.0	11.0	12.9	11.4	10.2	11.6
Average shower duration (minutes)	23.9	18.0	17.7	19.8	26.9	21.6	16.7	20.5

One-in-five (20%) respondents felt they could do more cold water wash and rinse than they do at present (Table 164). These households felt they could 2.5 more laundry loads in cold water, on average, per week.

Table 164: Clothes Washing Behaviours – Cold Water Wash Potential

							Main DWH Fuel	
Cold Water Wash and Rinse	LM	INT	VI	W	FN	2012 FEU	Electric	Gas
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*538*	*2779*
Able or willing to do more (% of households)	20.2	19.6	18.4	15.5	16.1	19.8	18.7	20.2
Average number of extra loads (per week) [1]	2.7	2.3	2.2	1.8	3.9	2.5	2.7	2.4

[1] Based on small samples for Whistler and Fort Nelson

The number and frequency of most hot water use activities for a household typically varies with the number of people in the home. Table 165 (next page) restates data on hot water using behaviours on a per-person basis.

Table 165: Hot Water Usage Behaviours – Per Person

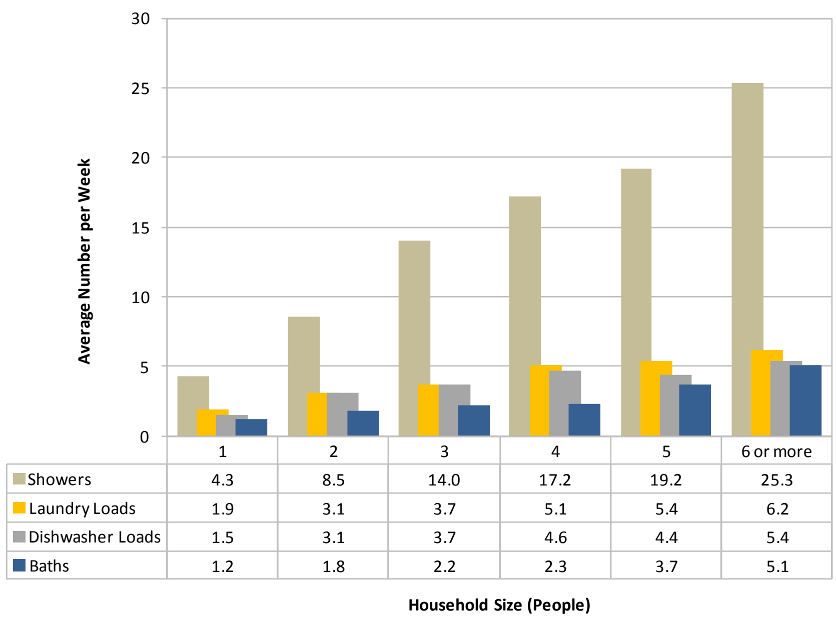
							Main DWH Fuel	
Behaviours Impacting DWH	**LM**	**INT**	**VI**	**W**	**FN**	**2012 FEU**	**Electric**	**Gas**
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*538*	*2779*
Average # of people per home	2.9	2.4	2.4	2.7	2.6	2.7	2.6	2.7
Dishwasher loads per week	1.2	1.4	1.5	1.3	1.2	1.3	1.3	1.3
Laundry loads per week (any temperature)	1.3	1.5	1.5	1.3	1.6	1.3	1.4	1.3
Laundry loads using cold water	0.8	0.9	0.8	0.7	1.0	0.8	0.9	0.8
Baths per week	0.8	0.8	0.8	0.5	1.0	0.8	0.9	0.8
Showers per week	4.3	4.0	4.3	4.1	4.9	4.2	3.9	4.3
Average shower duration (minutes)	8.2	7.5	7.5	7.3	10.2	8.0	6.5	7.6

The relationship between the frequency and duration of these activities and the number of occupants in the home is explored in the next section.

11.1.3 Household Characteristics Influencing Domestic Hot Water Use

Figure 31 shows the relationship between the number of people in the household and the average number of showers, laundry loads, dishwasher loads and baths per week. As expected, household size affects how many of each activity is performed and the demand for hot water. The rate of increase in the activity as household size increases varies by activity.

Figure 31: Effect of Household Size on Hot Water Using Activities



The results are largely consistent with the 1999 AWWA study on residential water use that found family size and the presence of children and teens increased water consumption associated with showers, baths, faucet use, and clothes washing.[55] The study also found water consumption for showers, baths and

[55] Mayer, P.W., W.B. DeOreo et al. (1999).

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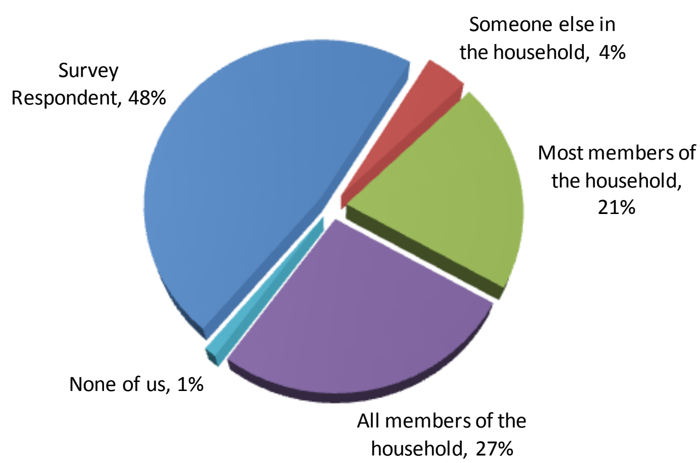
dishwashers was positively correlated with the number of persons employed outside the home. The 2012 REUS did not ask about employment so similar relationships using the 2012 REUS were not possible. Water use associated with dishwashers was found to be positively correlated with household size but not necessarily the presence of teenagers or children. The AWWA data are presented to place scale and scope of energy use associated with a variety of common household water use behaviours. Comparable numbers for FortisBC customers are not available but could vary from these estimates for a variety of reasons including, but not exclusive of, differences in the stock and efficiency of end-use equipment, retail prices of natural gas, and cultural factors.

11.1.4 Contribution of Household Members to Conserving Energy

Energy conserving behaviours may vary by household member. Some members may be energy conscious and diligent while others are less so. To explore this dynamic, respondents were asked to indicate who in their household makes the most effort to conserve energy. The results, illustrated in Figure 32, show nearly half (48%) indicated it was themselves and one-in-five (21%) indicating it was most members of their household. Approximately, three-in-ten (27%) indicated it was all members of their household.

Figure 32: Who in the Household Makes the Most Effort at Conserving Energy?



12 PRODUCTS AND SERVICES

This section summarizes the results of a series of questions regarding awareness of utility and government energy efficiency brand names, participation in utility and government energy efficiency programs; interest in energy-related products and services, and various energy-related attitudes and beliefs. This section also summarizes data on access to the Internet, comfort navigating the Internet, and who most influences decisions for major appliance purchases.

12.1 Awareness of Utility and Government Energy Brand Names

Simple awareness of four different energy efficiency related brand names was tested using a five point scale where one meant "not at all familiar" and five meant "very familiar". The distribution of responses for each brand is presented in Table 166. When the top two response categories (4 or 5) are summed, respondents were most familiar ENERGY STAR® (63% scoring either a 4 or 5), followed by BC Hydro's Power Smart initiative (61%), and in third place, FortisBC's PowerSense brand (37%). Last place is occupied by the LiveSmart BC brand. While this question tests recall of brand names, it does not test the respondent's understanding, depth of knowledge or experience with the brand. Typically, the proportion recalling initiative brand will be higher, sometimes considerably higher, than the proportion that have a solid understanding of the brand's offerings and other attributes.

Table 166: Awareness of Energy Efficiency Initiatives

Energy Efficiency Initiative	Not at all familiar (1)	(2)	(3)	(4)	Very Familiar (5)	Very or Somewhat Familiar (4 or 5)
ENERGY STAR®	12.2	7.0	17.8	21.5	41.5	63.0
Power Smart (BC Hydro)	11.3	8.7	19.0	20.8	40.1	60.9
PowerSense (FortisBC)	26.5	14.9	21.7	16.0	21.0	37.0
LiveSmart BC	39.0	17.2	19.8	11.4	12.7	24.1

The average familiarity score of the five energy efficiency brands in each of the five FEU regions is provided in Table 167. The familiarity score is calculated as the simple average of the 1 to 5 scores, with the lowest possible score being 1 (i.e., no one is familiar with the brand). The highest possible score is 5 (everyone is very familiar with the brand). This type of scoring incorporates all responses, not just those most familiar with the brand. ENERGY STAR and BC Hydro's Power Smart brand names tied with each having a familiarity score of 3.6 out of 5.0. PowerSense ranked third with a 2.9 score. LiveSmart BC took fourth place with a score of 2.0 out of 5.0. Power Smart had the highest region to region variability.

Table 167: Awareness Score for Energy Efficiency Brands by Region
Score (Min = 1, Max = 5)

Energy Efficiency Initiative	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*
ENERGY STAR®	3.7	3.4	3.5	3.4	3.1	3.6
Power Smart (BC Hydro)	3.8	3.0	3.7	3.8	3.1	3.6
PowerSense (FortisBC)	2.8	3.1	2.8	2.5	2.6	2.9
LiveSmart BC	2.0	2.1	2.1	1.8	1.5	2.0

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12.2 Past Participation in Energy Efficiency Rebate Programs

Respondents to the 2012 REUS were asked to indicate whether their household had, over the last five years, participated in energy efficiency programs offered by either BC Hydro (Power Smart), ecoENERGY / LiveSmart BC, FortisBC Energy (formerly Terasen Gas), or FortisBC Electric (PowerSense). The results, summarized in Table 168, should be interpreted with caution as they reflect a wide range of influencing factors, including, but not exclusive of:

- overall geographic coverage of the utility's programs (e.g., FortisBC Electric's PowerSense program is offered only to their electric customers in the Interior region);
- the range of different residential programs offered by the utility (e.g., the number of different programs available to households and whether these programs were offered in one or more of the last five years);
- awareness of the utility or government program (influenced, in part, by the amount of marketing); and
- relative popularity of the program (influenced by a range of factors, including the amount of the incentive relative to the energy-efficient appliance or activity promoted).

Table 168: Participation in Energy Efficiency Rebate Programs in the Last Five Years by Region (%)

Energy Efficiency Rebate Program	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*745*	*1601*	*716*	*81*	*101*	*3244*
Power Smart (BC Hydro)	20.8	7.7	21.8	19.0	9.5	17.3
ecoENERGY/LiveSmart BC	13.9	12.1	10.0	7.1	0.9	12.9
FortisBC Energy (formerly Terasen Gas)	9.1	11.0	6.2	7.1	2.8	9.3
PowerSense (FortisBC Electric)	3.5	9.2	2.4	1.2	0.0	4.9
None of the above	61.2	65.6	64.4	69.0	85.8	62.8

Multiple responses allowed.

The largest share of respondents participating in a rebate program said they had participated in a BC Hydro Power Smart program (17% in the last five years), followed by the ecoENERGY / LiveSmart BC program (13%), and FortisBC Energy (formerly Terasen Gas)(9%). Regional results reflect, in part, the utility service coverage. For example, participation in BC Hydro's Power Smart program is lowest in the Interior region (8% versus 17% overall) while participation in a FortisBC Electric PowerSense program is highest in the Interior (9%). Interestingly, small percentages of customers in regions outside of the Interior reported participating in a FortisBC Electric program. This result may reflect some incorrect association of another utility's program with the FortisBC Electric program. Notably, two-thirds (63%) of respondents to the 2012 REUS did not participate in any of the programs during the past five years.

Table 169 (next page) explores the participation in utility or government rebate programs by the vintage of the respondent's dwelling. The results suggest that, regardless of program, participation does not necessarily depend upon whether the home is older or newer.

Table 169: Participation in Energy Efficiency Rebate Programs in the Last Five Years by Dwelling Vintage (%)

Energy Efficiency Rebate Program	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known
Unweighted base	*350*	*919*	*576*	*664*	*586*	*238*	*46*
Power Smart (BC Hydro)	11.8	16.4	19.5	17.8	19.0	18.1	14.6
ecoENERGY/LiveSmart BC	14.9	13.8	16.8	13.2	7.5	10.2	2.1
FortisBC Energy (formerly Terasen Gas)	11.7	9.1	7.7	12.8	6.5	6.9	2.1
PowerSense (FortisBC Electric)	4.8	5.9	4.0	3.6	6.1	5.9	5.3
None of the above	64.9	61.5	59.4	61.0	66.8	68.6	80.0

Multiple responses allowed. Totals may not sum to 100%

12.3 Interest in Products and Services

Interest in a number of products and services that could be offered by FortisBC was queried using a four point scale where one meant “not at all interested” and a four meant “very interested”. The results, ranked by the proportion that indicated an interest level of 3 or 4, are summarized in Table 170. As no financial obligation or commitment is implied or associated with a respondent’s answer, caution is advised in over-interpreting interest in any particular product or service as indicative of program uptake that would occur if the product or service was offered.

Table 170: Interest in Products and Services (%)
Ordered by % Very or Somewhat Interested

Product / Service	Not at all Interested (1)	(2)	(3)	Very Interested (4)	Interested (3 or 4)
Furnace or heat pump tune-up to ensure they are working safely and efficiently	31.3	16.3	26.8	25.6	**52.4**
Home energy audit to determine main energy uses in the home and identify opportunities to save energy	29.2	20.6	24.2	26.0	**50.2**
Program to replace standard efficiency water heater with high efficiency water heater	35.8	15.8	22.6	25.8	**48.4**
Program to install an in-home display that allows you to monitor your home’s energy usage	34.9	19.2	21.9	24.0	**45.9**
Program to compare your home’s energy use with homes of comparable size and type	33.9	20.3	24.9	21.0	**45.8**
Program to improve draft proofing	35.4	19.3	24.4	20.9	**45.3**
Do-it-yourself online energy audit	32.9	22.1	24.6	20.4	**45.0**
Program that allows you to pay for energy-efficient improvements to your home via instalments on your utility bill	39.2	19.9	23.7	17.2	**40.9**
Program to upgrade attic and wall insulation	43.3	17.7	18.4	20.7	**39.1**
Program to replace a low efficiency furnace with a high efficiency furnace	48.3	12.9	16.6	22.1	**38.8**
Program to replace standard efficiency clothes washer with high efficiency clothes washer	48.2	17.3	18.0	16.5	**34.5**
Program to install high efficiency gas fireplace	53.8	13.6	14.6	18.1	**32.7**
Program to install programmable thermostats	57.1	14.5	14.3	14.1	**28.4**
Program to purchase an electric automobile	56.7	16.1	14.1	13.1	**27.1**

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The top three programs include a furnace tune-up program, a program offering home energy audit, and a program to encourage replacement of standard efficiency hot water heaters.

12.4 Attitudes toward Energy Use

Attitudes and behaviours can influence how households use energy or respond to programming designed to reduce energy consumption. Table 171 represents the first of two tables that summarize the relative agreement or disagreement of REUS 2012 respondents with a broad range of statements. Agreement with the statement is represented by those who indicated either a 4 or 5, while disagreement is represented by either a 1 or 2 on the scale. Those undecided, unsure or with no strong opinion (neutral) are represented by a 3. The responses to these questions can be used in psychographic segmentation studies.

Table 171: Attitudes and Beliefs (%) – Part I

Attitudes and Beliefs – Part I	Strongly Disagree (1)	(2)	Neither Agree or Disagree (3)	(4)	Strongly Agree (5)	Disagree (1 or 2)	Agree (4 or 5)
There are many ways that a person can save energy. When you add them up, they result in substantial savings	1.0	2.7	13.3	37.8	45.2	3.7	83.0
By making my home more energy-efficient, I am helping to do my part for the environment	1.1	2.6	12.8	34.8	48.6	3.7	83.5
I think natural gas is a clean and efficient energy source	1.1	2.7	16.2	35.2	44.8	3.8	80.0
Members of my household regularly limit the length of their showers to save energy	5.9	12.2	32.2	28.2	21.5	18.1	49.7
I don't want to think about natural gas or electricity, I just want it to work	18.4	17.9	28.9	19.3	15.5	36.3	34.8
I consider natural gas to be a safe energy source	1.2	3.1	19.6	36.2	39.8	4.3	76.0
When something needs to be done around home, I usually hire someone	23.2	21.5	27.8	16.4	11.1	44.6	27.5
I almost always have a home renovation on the go	32.4	23.7	23.9	13.3	6.7	56.1	20.0
It is cheaper to heat a home with natural gas than it is with electricity	2.7	4.1	32.5	24.8	35.8	6.9	60.7
Our household has reduced its energy use by as much as reasonably possible	3.3	12.2	30.2	33.7	20.5	15.5	54.3
I am a busy person with little or no time to research ways to save energy	15.9	20.8	42.4	14.8	6.1	36.6	20.9
I conserve energy because it saves money, not because it helps the environment	12.7	17.2	36.0	20.8	13.2	29.9	34.0

Notable observations include:

- somewhat more than eight-in-ten (83%) respondents agree that natural gas is a clean and efficient energy source;
- approximately equal proportions of customers wish not to think about their natural gas or electrical service as those that do (35% and 36% respectively); and
- six-in-ten (61%) feel that is cheaper to heat a home with natural gas than it is with electricity.

Table 172 presents the results for the second set of attitude and behaviour questions. As before, respondents were asked to rate their agreement or disagreement with a series of statements.

Table 172: Attitudes and Beliefs (%) – Part II

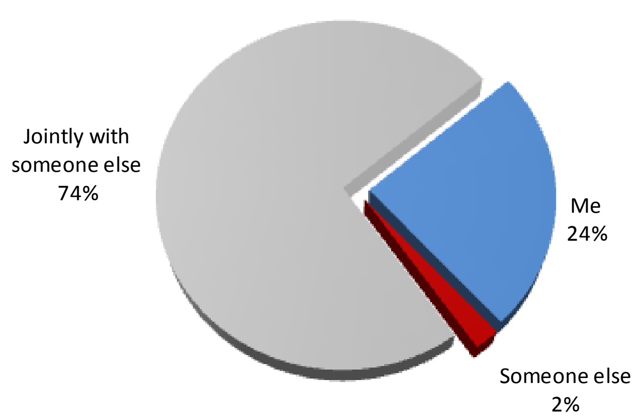
Attitudes and Beliefs – Part II	Strongly Disagree (1)	(2)	Neither Agree or Disagree (3)	(4)	Strongly Agree (5)	Disagree (1 or 2)	Agree (4 or 5)
I am usually the first one to try new products	14.5	16.3	47.8	14.6	6.9	30.8	21.4
I am usually willing to pay more for brand name items	14.7	16.5	31.6	29.1	8.1	31.2	37.2
I prefer dealing with British Columbia based companies	2.2	4.9	28.6	37.1	27.2	7.1	64.3
I always look for the best price when buying products or services	1.9	5.1	19.8	37.2	36.0	7.0	73.2
I usually take time to research issues thoroughly before making a decision	1.7	3.6	19.1	42.7	33.0	5.3	75.7
I am the type of person to have good insurance coverage	1.7	2.4	12.4	37.6	45.9	4.1	83.5

12.5 Major Appliance Purchases – Factors Influencing Decisions

The 2012 REUS explored a small number of factors that can influence decisions for major appliance purchases, including who in the home makes the purchase decision, access to the Internet, comfort navigating the Internet, and sources of information used to make a decision.

When asked who in their household makes major appliance purchase decisions, nearly three-quarters (74%) of survey respondents indicated it was them along with someone else in the home, and one-quarter (24%) said they, alone, make the major appliance purchase decisions (Figure 33). Only two percent (2%) said someone else in the household makes the decisions.

Figure 33: Who Makes the Decision Regarding Major Appliance Purchases?



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12.6 Internet Access & Comfort Navigating the Internet

The vast majority (92%) of FEU residential customers responding to the 2012 REUS indicated they have high speed access to the Internet from their residence, while another two percent (1.7%) have access via dial up modem (Table 173). On average, under one-in-ten (7%) of respondents indicated they do not have Internet access at their residence.

Table 173: Residential Internet Access by Region (%)

Type of Access	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*776*	*1664*	*740*	*85*	*103*	*3368*
High speed	92.9	88.8	91.8	94.1	92.3	91.7
Dial-up modem	1.5	2.3	1.4	--	--	1.7
No Internet Access	5.5	8.9	6.9	5.9	7.7	6.6
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

Respondents were asked to rate their comfort with navigating the Internet as either "very comfortable", "somewhat comfortable", "not very comfortable", or "not at all comfortable". The distribution of responses by the five regions, presented in Table 174, shows the majority (61%) of FEU residential customers are comfortable with navigating the Internet, while another one-quarter (25%) are somewhat comfortable. One-in-eight (13%) indicated they were either not very comfortable or not at all comfortable. Regionally, Whistler has the smallest proportion of customers that are either not very or not at all comfortable (7%), while the Interior has the highest (16%).

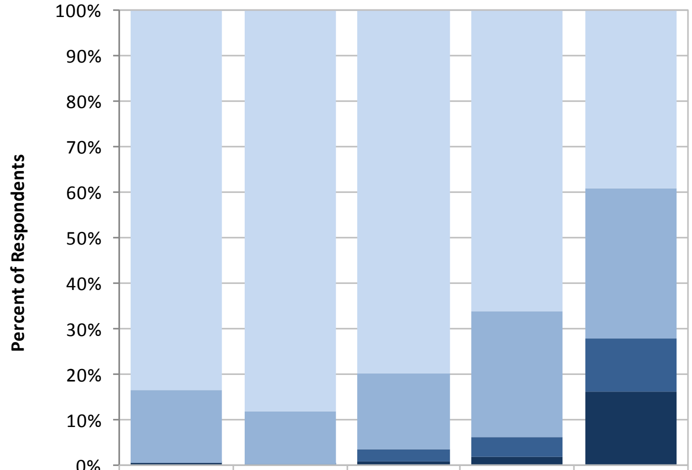
Table 174: Comfort with Navigating the Internet by Region (%)

Comfort Level	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*774*	*1641*	*728*	*84*	*103*	*3330*
Not at all comfortable	6.2	8.6	6.0	2.4	6.7	6.8
Not very comfortable	6.1	7.6	5.6	4.8	5.8	6.4
Somewhat comfortable	24.4	27.2	26.6	14.5	28.1	25.4
Very comfortable	63.3	56.6	61.7	78.3	59.4	61.4
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

Figure 34 (next page) shows the proportion of respondents that are very comfortable with navigating the Internet progressively shrinks as the respondent age increases. For example, nine-in-ten (88%) of those in the 35-44 age cohort indicated they were very comfortable with navigating the Internet compared to just four-in-ten (39%) of those aged 65 or older.

Figure 34: Comfort with Navigating the Internet – By Age Group



	< 35 years	35-44 years	45-54 years	55-64 years	65 years +
Very comfortable	83.4	88.0	79.8	66.3	39.3
Somewhat comfortable	16.1	11.8	16.5	27.6	32.8
Not very comfortable	0.1	0.0	2.9	4.2	11.9
Not at all comfortable	0.4	0.2	0.8	1.9	16.0

There are no statistically significant differences in relative comfort navigating the Internet based on respondent gender (data not shown).

12.6.1 Sources of Information Used in Appliance Purchase Decisions

To better understand what sources of information are used to make a purchase decision for a major appliance, respondents to the 2012 REUS were asked to rate the influence different (potential) information sources using a five point scale, where one meant "not at all influential" and five meant "very influential". Respondents were asked to rate seven sources of information, including:

- Contractors / tradespersons
- Customer ratings
- Expert reviews (e.g., magazines, websites, TV)
- Electric or gas utilities
- Government
- Appliance salespeople
- Knowledgeable family member, friend, or neighbour

Table 175 (next page) summarizes respondent answers by three metrics: not influential (either a 1 or 2 on the five point scale), influential (4 or 5), and the weighted average influence score (maximum score of 5). Generally speaking, the relative influence that an individual source of information has will be related to the trustworthiness of the information source.

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Table 175: Influential Sources of Information for Purchasing a Major Appliance

Sources of Information	Not Influential (1 or 2) %	Influential (4 or 5) %	Average Score (max=5)
Customer ratings	16.6	56.9	3.6
Knowledgeable family member, friend, or neighbour	16.3	55.8	3.5
Expert reviews (e.g., magazines, websites, TV)	20.6	52.8	3.4
Electric or gas utilities	32.8	37.7	3.0
Contractors / tradespersons	43.7	29.2	2.7
Appliance salespeople	42.1	22.7	2.7
Government	54.5	19.8	2.4

Customer ratings, knowledgeable family members, friends or neighbours, and expert reviews are considered the most influential of the seven sources, with weighted average influence scores ranging from 3.4 to 3.6. Least influential are appliance salespeople and government (scores of 2.7 and 2.4 respectively). Electric or gas utilities were in the middle, with four-in-ten (38%) of respondents indicating they are influential in their appliance choice decision (score of 3.0).

While the question design and presentation of data evaluate each source individually, it is realistic to assume that appliance purchase decisions may require input from more than one source of information.

When average influence scores were analyzed by age and gender of the survey respondent (Table 176), there were no significant differences by age or age grouping. When compared on the basis of gender, women were more likely to rate all sources of information as being more influential to their decisions than their male counterparts.

Table 176: Influential Sources of Information for Purchasing a Major Appliance – Gender Differences Average Influence Score (Max =5)

	Average Score (Max = 5)	
Sources of Information	Women	Men
Unweighted base	*1,443*	*1,898*
Customer ratings	4.3	4.1
Knowledgeable family member, friend, or neighbor	4.3	3.8
Expert reviews (e.g., magazines, websites, TV)	4.1	4.0
Electric or gas utilities	3.9	3.7
Contractors / tradespersons	3.6	3.2
Appliance salespeople	3.4	3.1
Government	3.3	3.1

13 DEMOGRAPHICS

This section summarizes demographic and socio-demographic characteristics of respondents to the 2012 REUS and their households, with comparisons to the 2008 and 2002 REUS surveys.

13.1 Survey Respondent Characteristics

13.1.1 Age Cohorts

The distribution of survey respondents by age cohort is summarized in Table 177. Comparisons are provided with the 2008 and 2002 surveys. Of note, the proportion of respondents 45 years or older responding to the REUS surveys has increased from slightly greater than seven-in-ten (72%) in 2002 to nearly nine-in-ten (85%) in 2012. This is consistent with the aging of the general population base (see Section 3).

Table 177: REUS Respondents by Age Group by Region (%)

Age Cohort	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*773*	*1658*	*726*	*82*	*102*	*3341*	*2186*	*2533*	*1424*	*1491*
18 yrs or younger	--	0.1	--	--	--	0.0*	--	0.0*	--	0.1
19 – 24 yrs	0.4	0.1	--	--	--	0.3	0.4	0.3	0.5	0.6
25 – 34 yrs	4.0	3.5	3.2	1.2	10.6	3.8	4.2	3.9	4.5	8.1
35 – 44 yrs	11.1	9.5	7.9	13.6	19.3	10.4	13.7	10.6	14.5	19.6
45 – 54 yrs	21.1	18.5	15.0	25.9	31.9	19.8	20.4	20.3	20.3	25.6
55 – 64 yrs	27.3	27.8	27.1	28.4	25.2	27.4	28.9	27.4	29.0	21.6
65 yrs and older	36.1	40.6	46.8	30.9	12.9	38.4	32.4	37.4	31.1	24.3
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
44 yrs or younger	15.5	13.1	11.0	14.8	30.0	14.4	18.3	14.8	19.5	28.4
45 yrs or older	84.5	86.9	89.0	85.2	70.0	85.6	81.7	85.2	80.5	71.6

Totals may not sum due to rounding.
* Value less than 0.01%

13.1.2 Gender

The gender of the survey respondents, by region, is provided in Table 178. Overall, more males than females responded to the 2012 survey (57% versus 40%). Significantly more males in the Lower Mainland and Whistler regions responded to the survey.

Table 178: Survey Respondent Gender by Region (%)

Gender	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*
Female	38.3	43.2	43.2	29.8	49.7	40.2
Male	59.0	54.0	53.3	67.9	48.4	57.0
No answer	2.6	2.9	3.5	2.4	1.9	2.8
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

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13.1.3 Marital Status

A summary of the survey respondents by marital status is provided in Table 179. There are no significant differences when compared to those who responded to the 2008 REUS.

Table 179: Marital Status by Region (%)

Marital Status	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2174*	*2604*	*1415*	*1481*
Single	6.1	6.3	4.3	12.2	14.5	6.0	6.7	6.2	6.8	6.8
Married / common law	82.1	76.7	77.6	75.6	71.0	80.1	79.7	80.4	79.9	79.9
Divorced / separated	5.5	7.3	6.6	7.3	11.6	6.1	5.8	6.1	5.6	7.3
Widowed	6.4	9.7	11.6	4.9	2.9	7.8	7.8	7.4	7.7	6.0
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

13.1.4 Educational Attainment

The distribution of survey respondents by the highest level of educational attainment is provided in Table 180. Changes from 2008 include significantly more respondents with a post-graduate degree (13% in 2012 versus 10% in 2008), and proportionately fewer respondents with a high school degree as their highest educational attainment (13% versus 17%).

Table 180: Respondent Education Status by Region (%)
Highest Level of Education Achieved

Education	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2221*	*2604*	*1446*	*1610*
Some high school	4.8	6.7	4.9	1.2	4.8	5.3	4.7	5.4	4.6	9.2
Completed high school	12.2	15.9	14.1	5.9	19.9	13.4	16.9	13.4	16.7	14.4
Some trade / technical school	5.9	7.7	5.6	5.9	10.4	6.4	7.4	6.5	7.7	15.4
Completed trade / technical school	12.4	15.5	12.4	8.3	18.0	13.2	14.4	13.3	14.7	14.9
Some university / college	18.4	18.4	19.0	10.7	17.1	18.4	18.0	18.4	17.9	7.3
Completed university / college	28.5	24.7	25.3	38.1	19.3	27.1	25.8	27.3	25.9	23.7
Post graduate	14.9	8.6	14.8	27.4	8.5	13.2	9.8	12.9	9.6	6.1
No response	2.9	2.5	4.0	2.4	1.9	2.9	3.1	2.8	3.0	9.0
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

13.2 Household Characteristics

13.2.1 Number of Occupants per-Dwelling

Table 181 (next page) summarizes the average number of occupants per dwelling, including the proportion of homes with two occupants or less, between three and five occupants, and six or more occupants. Overall, the average is 2.8 occupants per-dwelling. Household sizes tend to be larger in the Lower Mainland (average of 2.9 occupants per dwelling) and smaller in the Interior and Vancouver Island (2.4 occupants each). At the utility level, there is no statistically significant change in the overall average between 2012 and 2008.

Table 181: Average Number of Occupants per Dwelling by Region (%)

Number of Occupants per-Dwelling	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2174*
Average per home	2.9	2.4	2.4	2.7	2.6	2.8	2.8
Standard Deviation	2.34	0.84	0.81	0.58	0.36	1.22	1.60
Homes by size:							
2 occupants or less (%)	51.9	69.8	72.5	60.5	58.0	58.9	55.3
3 - 5 occupants (%)	43.2	28.5	25.6	34.6	39.1	37.3	39.1
6 occupants or more (%)	4.9	1.7	1.9	4.9	2.9	3.7	5.6
Total (%)	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

When analyzed by the number of occupants, homes with two people or less represent the majority (59%) of all FEU households, followed by those with between three and five people (37%). Homes with six or more people are significantly less common (4% of households) and are more likely to occur in the Lower Mainland. Homes in the Interior and Whistler regions are more likely than other regions to have two occupants or less.

The composition of FEU homes by age of the home's occupants is provided in Table 182. The data are expressed in terms of the number of occupants by age group per the base of all homes in the region. To illustrate using an example, there are an average of 0.11 occupants five years of age or younger per FEU household in 2012, compared to 0.46 occupants per-household for those aged 25 to 44 years.

Table 182: Average Number of Occupants in the Home by Age Cohort and Region

Age Cohort	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*
5 years or younger	0.12	0.08	0.07	0.12	0.16	0.11
6 – 12 yrs	0.17	0.11	0.10	0.16	0.19	0.15
13 – 18 yrs	0.20	0.13	0.11	0.12	0.24	0.17
19 – 24 yrs	0.21	0.13	0.11	0.22	0.14	0.18
25 – 44 yrs	0.55	0.32	0.33	0.49	0.71	0.46
45 – 64 yrs	0.99	0.91	0.80	1.14	0.98	0.95
65 yrs and older	0.66	0.71	0.83	0.47	0.22	0.69

The incidence of occupants by age cohort is summarized in Table 183 (next page). The data show that, on average, less than one-in-ten (7%) of FEU households have at least one pre-school aged child (five years of age or younger), one-in-ten have pre-teens, and one-in-eight (13%) have teenagers at home. Regionally, FEU households in the Lower Mainland and Fort Nelson are more likely to have children (any age under 19 years old) compared to the other regions. Consistent with a population dominated by the aging baby boom cohort, over four-in-ten (44%) of FEU households have at least one household member who is 65 years or older (e.g., a senior). Vancouver Island households have the highest incidence of seniors (53%) versus Fort Nelson with the lowest (16%).

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Table 183: Incidence of Household Members by Age Cohort by Region (%)

Age Cohort of Home's Occupants	LM	INT	VI	W	FN	2012 FEU
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*
5 years or younger	8.3	5.8	5.1	8.6	9.8	7.3
6 – 12 yrs	12.2	7.5	7.3	13.6	11.7	10.4
13 – 18 yrs	15.1	9.5	8.5	7.4	17.6	12.9
19 – 24 yrs	15.9	9.2	8.3	11.1	9.8	13.2
25 – 44 yrs	33.8	21.0	19.1	30.9	43.0	28.8
45 – 64 yrs	58.2	56.1	50.0	65.4	59.6	56.8
65 yrs and older	42.4	45.2	53.0	32.1	16.0	44.2
Households with children (<19 yrs) %	27.7	18.0	16.6	21.4	32.3	23.9
Households without children (<19 yrs) %	72.3	82.0	83.4	78.6	67.7	76.1

Columns do not sum to 100%

To explore the relationship between dwelling type and occupant characteristics, the incidence of individuals by age cohort by dwelling type is provided Table 184. While sample sizes for some dwelling types, especially apartments /condominiums, are small, the data show relatively few differences among the dwelling types. Apartments/condominiums and mobile homes are notable in that they are the least likely to have children at home (0% and 10% respectively). Mobile homes tend to have older residents, including the highest incidence of seniors (55%).

Table 184: Incidence of People in the Home by Age Cohort by Dwelling Type (%)

Age Cohort of Home's Occupants	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2,792*	*154*	*207*	*55*	*118*	*59*
5 years or younger	7.4	6.5	8.7	0.0	1.8	15.6
6 – 12 yrs	10.4	11.4	13.0	0.0	2.5	11.3
13 – 18 yrs	13.5	10.7	13.7	0.0	6.7	12.5
19 – 24 yrs	14.3	8.9	8.8	0.0	8.0	22.6
25 – 44 yrs	28.5	32.9	31.8	23.7	16.1	35.0
45 – 64 yrs	59.0	51.1	47.2	36.8	45.0	52.0
65 yrs and older	43.1	50.8	41.1	45.9	55.2	71.8
Households with children (<19 yrs)	24.4	24.2	27.8	0.0	10.2	28.5
Households without children (<19 yrs)	75.6	75.8	72.2	100.0	89.8	71.5

As discussed in Section 3, the number of occupants in the home affects household energy use particularly for domestic hot water uses (clothes washing, dishwashing, showers, etc.). Table 185 (next page) summarizes the proportion of FEU households that saw an increase, decrease, or a combination of increase and decrease in the number of occupants during the last two years.

Table 185: Changes in the Number of People in the Home by Region (%)
Change in Number of Occupants during the Last 2 Years

Number of Occupants	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	2181	*2604*	1420	1610
Yes – changed in last two years	21.9	20.0	17.7	14.6	32.2	21.0	32.2	21.4	33.2	32.1
Yes – more people in the past	12.1	11.2	10.7	8.5	15.6	11.7	17.8	11.8	18.4	19.3
Yes – fewer people in the past	7.0	6.2	4.5	2.4	11.7	6.5	7.1	6.8	7.3	11.9
Yes – both fewer and more people in the past	1.9	2.4	1.9	3.7	2.9	2.1	7.1	2.1	7.2	4.6

One-in-five (21%) of FEU customers indicated the number of people in the home had changed in the last two years, down from two-thirds (32%) of households in 2008. One-in-eight (12%) had experienced a decrease in household size during the last two years and under one-in-ten (7%) had experienced an increase in household size in the last two years. Two percent (2%) said their home had experienced both an increase and decrease. These results are consistent with aging of the population and the commensurate decline of household size due, in part, to adult children leaving home.

13.2.2 Household Income

The distribution of 2012 REUS respondents by annual household income is provided in Table 186. The data are useful in providing context to income-driven differences between consumers regarding behaviours, attitudes, and equipment purchase decisions. The proportion of respondents who chose to not answer the question is higher than in past surveys (31% in 2012 versus 25% in 2008). The dataset was not rebased to show only those who answered the question. This was done primarily because there is no a priori reason non-responses would be distributed across the income categories in the same relative proportions as responses. Regional comparisons can be made, but with caution as the proportion choosing not to answer the question does vary from region to region.

Table 186: Annual Household Income before Taxes by Region (%)

Household Income	LM	INT	VI	W	FN	2012 FEU	2008 FEU	2012 FEI	2008 FEI	2002 FEI
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2221*	*2604*	*1446*	*1610*
Less than $20,000	2.9	4.2	1.7	1.2	2.8	3.1	3.7	3.3	3.8	6.1
$20,000 to $29,999	3.9	7.7	4.8	3.6	1.9	5.0	16.7[1]	5.0	16.6[1]	17.2[1]
$20,000 to $39,999	4.9	8.7	8.1	--	2.8	6.3		6.1		
$40,000 to $49,999	5.9	7.7	7.0	2.4	4.8	6.5	17.6[2]	6.5	17.5[2]	17.6[2]
$50,000 to $59,999	6.6	7.3	8.2	3.6	6.6	6.9		6.8		
$60,000 to $79,999	9.7	13.1	10.4	4.8	8.5	10.7	15.1	10.7	15.5	14.9
$80,000 to $99,999	10.0	9.4	9.3	9.5	6.6	9.7	10.8	9.8	10.7	10.8
$100,000 to $124,999	9.1	9.0	8.5	11.9	12.3	9.0	11.5	9.1	11.8	6.7
$125,000 or more	13.9	7.5	10.1	23.8	17.4	11.8	9.6	11.9	9.5	7.3
No response / Prefer not to answer	33.2	25.4	31.8	39.3	36.1	30.9	24.6	30.8	24.2	19.2
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Households with less than $40K	11.7	20.6	14.6	4.8	7.6	14.4	20.4	14.4	20.4	23.3
Households with less than $60K	24.2	35.6	29.9	10.7	19.0	27.9	38.0	27.7	37.9	40.9
Households with $100K or more	23.0	16.5	18.6	35.7	29.8	20.8	21.1	21.0	21.3	14.0

[1] Represents household incomes of $20,000 to $39,999
[2] Represents household incomes of $40,000 to $59,999
Totals may not sum due to rounding.

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Household incomes by dwelling type are summarized in Table 187. Occupants of mobile homes stand out as having proportionately lower household income compared to occupants in other dwelling types.

Table 187: Annual Household Income before Taxes by Dwelling Type (%)

Household Income	Single Family Detached	Duplex	Row / Town-house	Apt / Condo-minium	Mobile Home	Other
Unweighted base	*2792*	*154*	*207*	*55*	*118*	*59*
Less than $20,000	2.4	2.5	8.3	7.9	11.0	4.0
$20,000 to $29,999	4.0	4.7	6.1	7.8	27.0	23.2
$30,000 to $39,999	6.1	11.4	3.1	8.9	12.8	9.0
$40,000 to $49,999	6.6	9.9	4.9	9.0	5.1	2.1
$50,000 to $59,999	7.0	9.1	4.2	7.7	6.6	9.1
$60,000 to $79,999	10.3	14.7	14.1	16.9	6.7	3.1
$80,000 to $99,999	9.8	8.6	11.5	10.2	5.7	10.4
$100,000 to $124,999	9.2	10.5	9.0	5.1	0.9	2.9
$125,000 or more	13.0	6.9	6.2	13.8	0.2	13.1
No response / Prefer not to answer	31.7	21.8	32.5	12.7	23.9	23.0
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Households with less than $40K	12.5	18.6	17.6	24.6	50.9	36.3
Households with less than $60K	26.0	37.6	26.7	41.3	62.6	47.5
Households with $100K or more	22.2	17.4	15.2	18.9	1.1	16.0

Totals may not sum due to rounding.

13.2.3 Spoken Languages

The majority (92%) of respondents to the 2012 REUS indicated that English was the main language spoken in the home (Table 188). Mandarin and Cantonese are second and third most common, representing 3.1% of households. All other languages each represented less than one percent of REUS respondents.

Table 188: Main Language Spoken in the Home by Region (%)

	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2221*
English	88.5	97.1	94.3	94.1	95.2	91.5	88.8
Mandarin	1.5	0.1	--	--	--	0.9	1.4
Cantonese	3.5	0.1	0.1	--	--	2.2	3.6
Hindi	--	--	--	1.2	--	0.0	0.3
Punjabi	0.6	0.2	0.3	--	0.9	0.5	0.4
Tagalog	0.1	0.1	--	--	--	0.1	1.0
Farsi (Persian)	0.6	--	--	--	--	0.4	--
French	0.4	0.4	0.7	--	0.9	0.4	0.4
German	--	0.2	0.4	--	--	0.1	0.6
Other	0.9	0.4	0.3	--	0.9	0.7	2.1
No response	3.8	1.5	4.0	4.8	1.9	3.2	1.4
Total	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

Totals may not sum due to rounding.

Other languages spoken in the home are listed in Table 189. All responses are expressed as a percent of the base of REUS respondents and include multiple responses.

Table 189: All Other Languages Spoken in the Home – by Region
Multiple Responses Allowed

	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2174*
English	5.4	0.2	2.4	--	--	3.7	3.7
Mandarin	2.6	0.1	0.5	--	--	1.7	0.7
Cantonese	2.6	0.1	1.1	--	--	1.8	1.4
Hindi	0.9	--	0.8	--	--	0.6	0.5
Punjabi	1.1	0.1	0.8	--	--	0.8	0.7
Tagalog	0.6	0.1	0.5	--	--	0.5	0.6
Farsi (Persian)	0.2	--	0.8	--	--	0.3	0.0*
French	4.8	2.7	12.7	11.3	--	5.1	4.3
German	3.8	1.3	10.5	11.3	--	3.8	2.4
Other	6.5	1.2	9.7	--	--	5.4	2.9

* Value less than 0.01%

14 CONDITIONAL DEMAND ANALYSIS

FortisBC Energy Utilities (FEU) use information on end-use gas consumption for power system planning, load forecasting, marketing and demand side management. End-use consumption refers to the energy used for space heating, water heating, cooking and other specific uses, as opposed to total consumption. The Unit Energy Consumption (UEC) for an end-use is defined as the quantity of energy consumed by that end-use in a given period of time.

This section summarizes the results of a Conditional Demand Analysis (CDA) applied to the 2012 REUS data to estimate UEC values for major residential gas end-uses. CDA is a multivariate regression technique which combines utility billing data with weather information and customer survey data. A detailed presentation of the methodology, equation specifications, and equation results for the CDA are included in Appendix B.

14.1 Research Objectives

The objectives of the 2012 CDA analysis for FEU natural gas customers are to:

- estimate weather-normalized UEC values for major residential gas end-uses, including space heating, water heating, fireplaces, cooking and other specific uses;
- estimate UEC values for each of the following regions: Lower Mainland, Interior, Vancouver Island, Whistler and Fort Nelson;
- disaggregate UECs for key end-uses by the following dwelling types: single family dwellings, multi-family dwellings and vertical subdivisions; and
- compare the results with past CDA studies.

Gas end-uses modelled include:

- Primary space heating
- Secondary space heating (excluding fireplaces)
- Domestic water heating
- Fireplaces (heater type, free standing, and decorative)
- Cooking (gas range, cook top, oven, duel fuel range)
- Gas clothes dryers
- Hot tubs
- Piped gas BBQs
- Swimming pools

Attempts were made to model piped gas outdoor heaters and gas saunas. However, these end-uses were not retained in the conditional demand analysis because they produced unreasonable results, likely due to the small number of households possessing these end-uses.

14.2 CDA Sample

The sample used for the gas CDA consisted of households in FEU's service territory who participated in the 2012 Residential End-use Study. Consistent with the 2008 CDA, customers living in mobile homes or

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"other" dwelling types, as well as customers who have not lived in their residence for at least two years, were excluded from the analysis. There were a total of 3,109 customers in the resulting sample (Table 190).

Table 190: Sample used in the 2012 FEU Conditional Demand Analysis

	LM	INT	VI	W	FN	2012 FEU
Single family detached	608	616	1382	43	69	2718
Semi-detached	122	71	109	32	7	341
Apartments / Condominiums	5	9	34	2	--	50
Total 2012 CDA Sample	**735**	**696**	**1525**	**77**	**76**	**3109**

The survey data from these customers were used in combination with two year's worth of monthly billing data for each customer and regional specific weather data for the same period. The two-year period used was December 2010 to November 2012. Customers with missing billing data were not used in the estimation of the conditional demand models.

The conditional demand models were estimated using ordinary least squares. The regression models performed well. The adjusted R-squared values were high, and most of the regression coefficients had the correct sign and were significant at the five percent level or better (see Appendix B for the detailed regression outputs).

The regression coefficients were used to calculate Unit Energy Consumption (UEC) values for major residential end-uses. UECs were calculated for each household possessing the end-use by substituting household variables into the end-use equations. Normal heating degree days were substituted to generate weather-normalized UECs for space heating, fireplaces and water heating. Weighted average UECs were then calculated across all households possessing the end-use (weighted by region).

14.3 Utility Level UECs

An overall conditional demand model was constructed to estimate UECs for FEU's service territory. The weather-normalized, weighted UECs are shown in Table 191 (next page). As expected, the main end-uses are primary space heating at 52.4 GJ per year and water heating at 26.3 GJ per year. Other key end-uses are decorative fireplaces (17.7 GJ per year), heater type fireplaces (14.6 GJ per year) and gas cooking appliances (12.5 GJ per year). Secondary gas space heating (excluding fireplaces), gas heated pools and hot tubs are also heavy users of natural gas, but they have lower penetration rates than other major end-uses.

The average energy consumption per household (HEC) is calculated by multiplying each end-use's UEC by its penetration rate and summing across end-uses. The HEC is a measure of the average consumption of a household in FEU's service territory. The weather-normalized, weighted HEC was estimated to be 81.2 GJ per year. In comparison, the actual weighted consumption for the sample was 89.5 GJ per year. Part of the reason that estimated, weather-normalized consumption is lower than actual consumption levels is because normal weather conditions were warmer than during the two-year period from December 2010 to November 2012. However, Conditional Demand Analysis tends to underestimate actual consumption levels.[56]

Table 191: Penetration Rates and Unit Energy Consumption by End-use – Overall Service Area

	Sample Size (unweighted)	Penetration (% presence)	Unit Energy Consumption (GJ/year)	Avg. Consumption per Household (GJ/year)		UECs in 2008 (GJ/year)	UECs in 2002 (GJ/year)
Primary Space Heating	2511	86%	52.4	44.9	55%	57.8	67.8
Secondary Space Heating	111	3%	24.5	0.7	1%	23.2	-
Water Heating	2259	78%	26.3	20.6	25%	19.8	20.8
Decorative Fireplace	469	19%	17.7	3.4	4%	20.9	16.8^
Heater Fireplace	1331	43%	14.6	6.3	8%	17.4	15.8^^
Free Standing Fireplace	252	7%	7.0	0.5	1%	-	-
Range, Cook Top, Oven	826	29%	12.5	3.6	4%	5.4	8.5
BBQ	734	20%	0.3	0.1	<1%	8.1	3.1
Dryer	159	5%	**	**	**	3.9	4.0
Pool	56	2%	43.1	0.9	1%	38.5	53.5
Hot Tub	21	1%	21.3*	0.2*	<1%	19.5	17.9
Household Consumption							
Estimated				**81.2**		**85.8**	**96.1**
Actual				**89.5**		**98.9**	**104.9**

* Small sample size (less than 30 households with end-use present). These results should be interpreted with caution.
** An attempt was made to include gas dryers in the CDA, but it was not retained in the model because the estimated UEC value was negative.
^ 2002 data represents log fireplaces
^^ 2002 data represents inserts

The table also shows a comparison between this study's UEC estimates and those produced in two previous conditional demand analyses, conducted as part of the 2002 and 2008 Residential End-Use Studies.[57] It is important to note the service territory analyzed in the 2002 study excluded Vancouver Island and Whistler. Vancouver Island now forms a sizable portion of FEU's service territory, but has lower natural gas consumption than the Lower Mainland or the Interior (e.g. space and water heating consumption tends to be lower for Vancouver Island). As a result, comparisons with the 2002 study may not be entirely valid.

The weather-normalized UEC for primary space heating has dropped from 57.8 GJ per year in the 2008 study to 52.4 GJ per year in this study. This decrease can be explained by improvements in heating efficiency over time.

In contrast, the weather-normalized UEC for water heating has increased from 19.8 GJ per year in the 2008 study to 26.3 GJ per year in the current analysis. This is mainly due to a higher UEC value estimated for the Lower Mainland region (see the following section for an explanation).

The UECs for many of the other end-uses are relatively consistent between studies, with the exception of gas cooking and BBQs. The UEC for gas cooking appliances (gas ranges, cook tops, ovens and duel fuel

[56] In CDA, the model's intercept term is forced to be zero to ensure it does not capture the effects of the individual end-uses. However, forcing the intercept to zero often results in underestimated total household consumption because non-modelled end-uses (e.g. outdoor heaters) and behaviours (e.g. heating use in the summer) are not captured.

[57] Habart (2003), Sampson Research (2009).

ranges) appears to be over-estimated and BBQs appears to be under-estimated in the current study. This may be due to the fact these two end-used provide the same service (i.e., cooking). It may be more meaningful to consider these end-uses in the aggregate when comparing the results.[58]

Finally, an attempt was made to include gas dryers in the CDA, but it was not retained in the final model because the estimated UEC value was negative.

14.4 Regional UECs

Individual CDA models were estimated for the Lower Mainland, Vancouver Island and Interior regions. For the two smaller regions of Whistler and Fort Nelson, the overall conditional demand model constructed at the utility level was used to estimate UECs. The results are presented in the following sections.

14.4.1 Lower Mainland

Table 192 shows the weather-normalized UECs for the Lower Mainland region. The major end-uses are primary space heating at 55.0 GJ per year and water heating at 29.9 GJ per year. For both these end-uses, the UEC values are greater than in the Vancouver Island or Interior regions. One reason the demand for space and water heating is higher in the Lower Mainland is that dwellings are larger on average. As well, the average number of people living in the household is greater in the Lower Mainland compared to the other regions, which particularly affects the demand for water heating (see Section 11.1.3).

Table 192: Penetration Rates and Unit Energy Consumption by End-use – Lower Mainland

	Sample Size	Penetration (% presence)	Unit Energy Consumption (GJ/year)	Avg. Consumption per Household (GJ/year)		UECs in 2008 (GJ/year)	UECs in 2002 (GJ/year)
Primary Space Heating	664	90%	55.0	49.7	56%	62.0	65.3
Secondary Space Heating	15	2%	41.5*	0.8*	1%	18.1	-
Water Heating	610	83%	29.9	24.8	28%	20.4	21.0
Decorative Fireplace	171	23%	12.9	3.0	3%	21.4	16.2^
Heater Fireplace	321	44%	10.5	4.6	5%	18.3	14.9^^
Free Standing Fireplace	41	6%	5.3	0.3	<1%	-	-
Range, Cook Top, Oven	236	32%	9.2	3.0	3%	5.6	8.6
BBQ	122	17%	5.2	0.9	1%	8.1	3.4
Dryer	36	5%	**	**	**	4.2	4.0
Pool	18	2%	37.1*	0.9*	1%	38.5	53.6
Hot Tub	8	1%	21.6*	0.2*	<1%	19.5	17.8
Household Consumption							
Estimated				**88.2**		**92.1**	**93.8**
Actual				**98.1**		**108.9**	**109.0**

* Small sample size (less than 30 households with end-use present). These results should be interpreted with caution.
** An attempt was made to include gas dryers in the CDA, but it was not retained in the model because the estimated UEC value was negative.
^ 2002 data represents log fireplaces
^^ 2002 data represents inserts

[58] In the 2008 study, these two end-uses were also challenging to model, with the gas cooking UEC underestimated and BBQs overestimated. However, the sum of the UECs appears to be consistent between studies.

The estimated UEC for secondary gas space heating is also high, but this value appears to be over-estimated. Only 15 households in the Lower Mainland sample used gas for secondary space heating (excluding fireplaces). Due to the small sample size, this UEC estimate may not be reliable.

The UECs for gas cooking appliances and BBQs appear to be more reasonable than in the overall model. An attempt was made to include gas dryers in the CDA, but it was not retained in the final model because the estimated UEC value was negative.

The weather-normalized annual energy consumption per household (HEC) was estimated to be 88.2 GJ per year. In comparison, the actual average consumption for the sample was 98.1 GJ per year.

The UEC for primary space heating decreased from 62.0 GJ per year in the 2008 study to 55.0 GJ per year in this study. Such a drop is consistent with improvements in heating efficiency, as well as a trend towards smaller households in the region. In contrast, the UEC for water heating in this study was significantly greater than in the 2008 study. Some of this change may be due to a rise in average dwelling size over time, though efficiency improvements and smaller households are thought to counteract this trend overall.

One explanation for the higher water heating UEC value is the methodological differences between studies. In the 2008 study, UEC estimates for the individual regions were derived from the overall conditional demand model constructed at the utility level. With this approach, the overall model was able to capture some regional variation in water heating by including variables that naturally varied by region (e.g., weather, household size, etc.) Still, the UEC estimates for water heating did not vary much between regions. In contrast, the individual condition demand models estimated for each region in the current study were better able to capture regional variation in end-use demand. Though the water heating UEC may be somewhat overestimated in the current analysis, it is likely more robust than in past studies.

UEC estimates for fireplaces are significantly lower than in the 2008 study. As with water heating, this change is mainly due to methodological differences between the studies. In the 2008 study, the overall model assumed a constant UEC specification for fireplaces across all regions based simply on the number of fireplaces in use. The resulting UEC estimates were very similar between regional subgroups. By developing individual conditional demand models for each region, and by incorporating data on heating degree days into the specifications, the current UEC estimates for fireplaces are considered to be more credible than in past studies.

14.4.2 Vancouver Island

Table 193 (next page) shows the weather-normalized UECs for the Vancouver Island region. The major end-uses are primary space heating at 43.0 GJ per year and water heating at 18.3 GJ per year. For both these end-uses, the estimated UECs are lower than in the Lower Mainland or Interior regions. Compared to the Lower Mainland, customers in Vancouver Island tend to have lower demand for space and water heating because dwellings are smaller, and because there are fewer people per-household on average. Weather conditions largely explain the difference in heating demand between Vancouver Island and the Interior, since the average size of homes and the number of household members is similar.

The weather-normalized annual energy consumption per household (HEC) was estimated to be 51.9 GJ per year. In comparison, the actual average consumption for the sample was 56.1 GJ per year.

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Table 193: Penetration Rates and Unit Energy Consumption by End-use – Vancouver Island

	Sample Size	Penetration (% presence)	Unit Energy Consumption (GJ/year)	Average Consumption per Household (GJ/year)		UECs in 2008 (GJ/year)
Primary Space Heating	445	64%	43.0	27.5	53%	43.0
Secondary Space Heating	25	4%	6.9*	0.2*	<1%	19.9
Water Heating	476	68%	18.3	12.5	3%	18.8
Decorative Fireplace	81	12%	12.0	1.4	12%	19.7
Heater Fireplace	406	58%	10.6	6.2	3%	16.1
Free Standing Fireplace	89	13%	12.8	1.6	24%	-
Range, Cook Top, Oven	193	28%	5.7	1.6	3%	4.7
BBQ	181	26%	1.1	0.3	1%	8.1
Dryer	49	7%	3.7	0.3	1%	3.4
Pool	4	1%	**	**	**	38.5
Hot Tub	3	<1%	***	***	***	19.5
Household Consumption						
Estimated				**51.9**		**64.8**
Actual				**56.1**		**67.2**

* Small sample size (less than 30 households with end-use present). These results should be interpreted with caution.
** Insufficient sample to produce meaningful estimates (less than 5 households with end-use present).
*** An attempt was made to include hot tubs in the CDA, but it was not retained in the model because the estimated UEC value was negative.

The UECs for space and water heating did not change significantly from the 2008 study. Even with a trend towards larger dwellings, one would expect UECs for these end-uses to decrease over time because of efficiency improvements and smaller household sizes. As noted in the previous section, comparisons between years are complicated by the methodological differences between studies. In general, the estimates for space and water heating in the current study are considered to be more robust.

UEC estimates for fireplaces were significantly less than in the 2008 study, again because of key methodological differences. The current UEC estimates for fireplaces are thought to be more credible than in the 2008 study. In the current analysis, UECs for fireplaces were similar between Vancouver Island and the Lower Mainland, but lower than in the Interior.

As with the Lower Mainland, the sample used for Vancouver Island did not contain many households from vertical subdivisions. Consequently, the UEC values may be somewhat overestimated for end-uses that are influenced by dwelling type. Note the sample used in the 2008 study also under-represented vertical subdivisions in Vancouver Island.

14.4.3 Interior

Table 194 shows the weather-normalized UECs for the Interior region. The main end-uses are primary space heating at 53.0 GJ per year and water heating at 21.3 GJ per year. For both these end-uses, unit energy consumption is less than in the Lower Mainland, but greater than in Vancouver Island. Heater fireplaces (19.2 GJ per year) and decorative fireplaces (18.7 GJ per year) are also major users of natural gas in the Interior. These UEC values are higher than in the Lower Mainland or Vancouver Island regions.

The UECs for space and water heating were slightly larger than in the 2008 study. As noted in the previous sections, the current estimates for space and water heating are considered to be more robust because of the methodological approach used.

The weather-normalized annual energy consumption per household (HEC) was estimated to be 75.4 GJ per year. In comparison, the actual average consumption for the sample was 79.2 GJ per year.

Table 194: Penetration Rates and Unit Energy Consumption by End-use – Interior

	Sample Size	Penetration (% presence)	Unit Energy Consumption (GJ/year)	Avg. Consumption per Household (GJ/year)		UECs in 2002 (GJ/year)	UECs in 2008 (GJ/year)
Primary Space Heating	1287	84%	53.0	44.7	59%	74.1	51.6
Secondary Space Heating	68	4%	18.5	0.8	1%	-	39.3
Water Heating	1081	71%	21.3	15.1	20%	20.3	18.8
Decorative Fireplace	201	13%	18.7	2.5	3%	18.6^	19.8
Heater Fireplace	543	36%	19.2	6.8	9%	18.3^^	15.9
Free Standing Fireplace	113	7%	10.8	0.8	1%	-	-
Range, Cook Top, Oven	333	22%	11.1	2.4	3%	7.8	5.1
BBQ	386	25%	1.9	0.5	1%	2.8	8.1
Dryer	63	4%	11.1	0.5	1%	4.0	3.6
Pool	34	2%	58.6	1.3	2%	53.3	38.5
Hot Tub	8	<1%	*	*	*	17.9	19.5
Household Consumption							
Estimated				**75.4**		**101.7**	**78.5**
Actual				**79.2**		**96.7**	**86.7**

* An attempt was made to include hot tubs in the CDA, but it was not retained in the model because the estimated UEC value was unreasonable.
^ 2002 data represents log fireplaces
^^ 2002 data represents inserts

14.4.4 Whistler

The overall conditional demand model constructed at the utility level was used to estimate UECs for the Whistler region. Table 195 (next page) shows the resulting UEC values. These results should be interpreted with caution because of the small sample size and the low penetration rates for many of the end-uses. As well, applying the overall model to a small region like Whistler may produce misleading results because the model parameters are so heavily affected by the larger regions. For example, the high UEC estimate for water heating is largely influenced by the effect of the Lower Mainland data on the overall model.

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The weather-normalized annual energy consumption per household (HEC) was estimated to be 67.4 GJ per year. In comparison, the actual average consumption for the sample was 75.4 GJ per year. The significant drop in gas consumption from the 2008 study is mainly from a decline in penetration rates for many of the end-uses.

Table 195: Penetration Rates and Unit Energy Consumption by End-use – Whistler

	Sample Size	Penetration (% presence)	Unit Energy Consumption (GJ/year)	Average Consumption per Household (GJ/year)		UECs in 2008 (GJ/year)
Primary Space Heating	44	57%	60.5	34.6	51%	66.9
Secondary Space Heating	2	3%	**	**	**	33.6
Water Heating	25	32%	34.8*	11.3*	17%	18.5
Decorative Fireplace	8	10%	26.2*	2.7*	4%	22.2
Heater Fireplace	46	60%	17.8	10.6	16%	15.8
Free Standing Fireplace	6	8%	10.2*	0.8*	1%	-
Range, Cook Top, Oven	42	55%	11.5	6.3	9%	4.8
BBQ	34	44%	0.3	0.1	<1%	7.9
Dryer	2	3%	***	***	***	3.3
Pool	0	0%	-	-	-	-
Hot Tub	1	1%	**	**	**	19.5
Household Consumption						
Estimated				**67.4**		**92.6**
Actual				**75.4**		**96.6**

* Small sample size (less than 30 households with end-use present). These results should be interpreted with caution.
** Insufficient sample to produce meaningful estimates (less than 5 households with end-use present).
*** An attempt was made to include gas dryers in the CDA, but it was not retained in the model because the estimated UEC value was negative.

14.4.5 Fort Nelson

The overall conditional demand model constructed at the utility level was used to estimate UECs for the Fort Nelson region. Table 196 (next page) shows the weather-normalized UECs. These results should be interpreted with caution because of the small sample size and the low penetration rates for many of the end-uses, as well as the methodological approach used. In particular, the UEC value for water heating appears to be over-estimated, due to the effect of the Lower Mainland data on the overall model.

The weather-normalized average annual energy consumption per household (HEC) was estimated to be 143.7 GJ per year. In comparison, the actual average consumption for the sample was 150.7 GJ per year. Average gas consumption was similar to the 2008 study.

Table 196: Penetration Rates and Unit Energy Consumption by End-use – Fort Nelson

	Sample Size	Penetration (% presence)	Unit Energy Consumption (GJ/year)	Average Consumption per Household (GJ/year)		UECs in 2008 (GJ/year)
Primary Space Heating	71	93%	94.6	88.4	62%	113.4
Secondary Space Heating	1	1%	**	**	**	-
Water Heating	67	88%	48.4	42.5	30%	22.7
Decorative Fireplace	8	10%	28.5*	3.0*	2%	19.3
Heater Fireplace	15	20%	22.3*	4.5*	3%	14.7
Free Standing Fireplace	3	4%	**	**	**	-
Range, Cook Top, Oven	22	29%	13.2*	3.8*	3%	5.3
BBQ	11	14%	0.3*	0.04*	<1%	7.9
Dryer	9	12%	***	***	***	3.3
Pool	0	0%	-	-	-	-
Hot Tub	1	1%	**	**	**	-
Household Consumption						
Estimated				**143.7**		**130.2**
Actual				**150.7**		**150.4**

* Small sample size (less than 30 households with end-use present). These results should be interpreted with caution.
** Insufficient sample to produce meaningful estimates (less than 5 households with end-use present).
*** An attempt was made to include gas dryers in the CDA, but it was not retained in the model because the estimated UEC value was negative.

14.5 UECs by Dwelling Type

Exogenous variables were incorporated into the CDA models for primary space heating and water heating to disaggregate by the following dwelling types: single family dwellings, multi-family dwellings (duplexes, row houses, townhouses) and apartments/condominiums.

14.5.1 Primary Space Heating

Table 197 shows estimated weather-normalized UECs for primary gas space heating by geographic region and housing type. Note that estimates could not be produced for apartments/condominiums due to the small sample sizes.

Table 197: Primary Gas Space Heating UECs (GJ/year) by Dwelling Type

	Lower Mainland^	Vancouver Island^	Interior^	Whistler^^	Fort Nelson^^	Overall (weighted)
Single Family Dwelling	57.2	44.9	55.5	80.1*	97.6	54.4
Multi-Family Dwelling	43.3	23.4	21.8	34.9*	**	38.8
Apts/Condos	**	**	**	**	**	**
Overall	**55.0**	**43.0**	**53.0**	**60.5**	**94.6**	**52.4**

* Small sample size (less than 30 households with end-use present). These results should be interpreted with caution.
** Insufficient sample to produce meaningful estimates.
^ UECs estimated from individual regional conditional demand model.
^^ UECs estimated from overall conditional demand model.

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14.5.2 Water Heating

Table 198 shows estimated weather-normalized UECs for water heating by region and dwelling type. Reasonable estimates could not be produced for vertical subdivisions because of the small sample sizes.

Table 198: Water Heating UECs (GJ/year) by Dwelling Type

	Lower Mainland^	Vancouver Island^	Interior^	Whistler^^	Fort Nelson^^	Overall (weighted)
Single Family Dwelling	30.0	18.4	21.5	33.7*	48.5	26.5
Multi-Family Dwelling	29.3	17.7	19.9	**	**	25.0
Apts/Condos	**	**	**	**	**	**
Overall	**29.9**	**18.3**	**21.3**	**34.8***	**48.4**	**26.3**

* Small sample size (less than 30 households with end-use present). These results should be interpreted with caution.
** Insufficient sample to produce meaningful estimates.
^ UECs estimated from individual regional conditional demand model.
^^ UECs estimated from overall conditional demand model.

14.6 UECs for Newer Homes (Constructed Since 1995)

The larger sample sizes in the 2012 REUS allowed exploration of UECs for newer homes. This is of particular interest as findings elsewhere in the 2012 REUS clearly indicated significant changes in the penetration and efficiency of gas space heating and domestic water heating equipment for newer homes. While many of these developments are evident in homes constructed since 2005, the available sample of homes constructed since this time was too small to develop a conditional demand model. The decision was made to expand the analysis to include homes constructed since 1995. While the final specification of the model with this expanded sample (n=734) was able to capture some regional variation in the key space and DWH end uses, constant UEC specifications were assumed for most other end uses.

A specific objective of the analysis of newer homes was to explore the effect of high efficiency gas furnaces, high efficiency boilers, and high efficiency domestic water heaters (e.g., condensing and on-demand) on annual gas consumption.[59]

14.6.1 Utility Level Results

Table 199 (next page) shows the weather-normalized, weighted UECs for newer homes in FEU's service territory, with comparison made to UEC estimates for the overall stock of homes, taken from Table 191. Unit energy consumption for primary space heating in newer homes is estimated at 40.5 GJ per year and consumption associated with domestic water heating is estimated at 29.4 GJ per year. Heater fireplaces (21.0 GJ per year) and decorative fireplaces (17.1 GJ per year) are also major users of natural gas in newer homes. Overall, the weather-normalized, weighted energy consumption per household (HEC) was estimated to be 78.1 GJ per year. In comparison, the actual weighted consumption for the sample of newer homes was 84.1 GJ per year. As expected, the average gas consumption per household is lower for newer homes than for the overall stock of residential gas dwellings.

[59] Despite attempts to model the effect of high-efficiency gas water heaters including on-demand (tankless) water heaters. These variables were not retained in the conditional demand analysis because they were not statistically significant or produced unreasonable results.

Table 199: Penetration Rates and Unit Energy Consumption by End-use – Newer Homes

	Sample Size	Penetration (% presence)	Unit Energy Consumption (GJ/year)	Average Consumption per Household (GJ/year)		UECs – All Dwelling Vintages (GJ/year)
Primary Space Heating	520	78%	40.5	31.6	40%	52.4
Secondary Space Heating	27	3%	23.9*	0.7*	1%	24.5
Water Heating	504	75%	29.4	21.9	28%	26.3
Decorative Fireplace	148	24%	17.1	4.1	5%	17.7
Heater Fireplace	453	63%	21.0	13.2	17%	14.6
Free Standing Fireplace	50	6%	11.0	0.7	1%	7.0
Range, Cook Top, Oven	299	46%	10.8	5.0	6%	12.5
BBQ	313	35%	1.1	0.4	<1%	0.3
Dryer	40	5%	***	***	***	**
Pool	11	1%	29.5*	0.4*	<1%	43.1
Hot Tub	3	1%	**	**	**	21.3*
Household Consumption						
Estimated				**78.1**		**81.2**
Actual				**84.1**		**89.5**

* Small sample size (less than 30 households with end-use present). These results should be interpreted with caution.
** Insufficient sample to produce meaningful estimates (less than 5 households with end-use present).
*** An attempt was made to include gas dryers in the CDA, but it was not retained in the model because the estimated UEC value was negative.

The lower space heating UEC is explained, in part, to improvements in space heating equipment efficiency and improvements in the building envelope (more efficient windows, better insulation in walls, ceilings, and doors). Improved furnace efficiencies are due to the higher penetration of mid-efficiency furnaces in newer homes compared to the overall stock of homes (53% versus 40%) rather than the relatively higher penetration of high efficiency furnaces (39% for newer homes versus 37% for the stock). Information from the 2012 REUS strongly suggests that the lower space heating UEC for newer homes is attributable, in part, to the presence of air source heat pumps. Of note, 16% of newer homes have an ASHP compared to 12% of the stock of homes.[60] This equipment appears to be offsetting some of the space heating load borne by traditional systems.

Newer homes also have a higher penetration of heater style gas fireplaces relative to the stock of homes (63% versus 43%). Heater style fireplaces (fixed glass front) are much more likely than traditional decorative style fireplaces to be used for space heating (e.g., annual hours of use for heater style fireplaces is 2.4 times that of decorative units).[61] The relatively higher incidence and use of heater style fireplaces is consistent with the higher UEC obtained for heater fireplaces in newer homes (21.0 GJ per year versus 14.6 GJ per year for the stock).

While not quantified, the tendency for newer single family detached homes to be larger (more square feet, higher ceilings) will offset some of the decline attributable to improvements in equipment efficiency and changes in the mix of space heating equipment. In effect, newer single family detached dwellings have larger volume of interior required for space heating compared to older detached dwellings.[62]

[60] Even more notable is the fact that 30% of FEU homes constructed since 2005 are equipped with an ASHP.
[61] Section 8.4.
[62] Exogenous variables were incorporated into the conditional demand model for newer homes in an attempt to estimate the UEC for high-efficiency gas furnaces. Among the 159 households in the newer home CDA sample that indicated they had a high

The UEC for water heating is slightly larger for newer homes (29.4 GJ per year) than for the overall stock of homes (26.3 GJ per year). Water heating demand may be higher in newer homes because of differences in household size and composition. Notably, average household size is larger for newer homes than for the overall stock of homes (2.9 individuals versus 2.7). Residents in newer homes are also more likely to have children or teenagers at home. These two demographic characteristics are associated with higher (hot) water use.

UECs for all other end-uses are relatively consistent between newer homes and the overall sample.

14.6.2 Regional Results – Newer Homes

Interpretation of the results presented in this section should be made with caution as sample sizes are small. Results are to be considered directional in nature only.

Primary Space Heating

Table 200 shows estimated weather-normalized UECs for primary gas space heating by region and dwelling type for the newer home sample. Note that estimates could not be produced for apartments / condominiums due to small sample sizes.

Table 200: Primary Gas Space Heating UECs (GJ/year) – Newer Homes

	Lower Mainland^	Vancouver Island^	Interior^	Whistler^	Fort Nelson^	Overall (weighted)
Single Family Dwelling	42.7	34.5	42.3	76.1*	78.3*	42.0
Multi-Family Dwelling	36.9*	32.6*	36.4*	45.0*	**	36.7
Apts/Condos	**	**	**	**	**	**
Overall	**41.2**	**33.3**	**40.7**	**60.9***	**78.5***	**40.5**

* Small sample size (less than 30 households with end-use present). These results should be interpreted with caution.
** Insufficient sample to produce meaningful estimates.
^ UECs estimated from conditional demand model developed for newer homes.

Water Heating

Table 201 (next page) shows estimated weather-normalized UECs for water heating by region and dwelling type for the newer home sample. Reasonable estimates could not be produced for apartments / condominiums because of the small sample sizes.

efficiency furnace, their weather-normalized, weighted UEC for primary space heating was 32.2 GJ per year. As the analysis of space heating in newer homes has suggested that furnace consumption is being influenced by the presence of air source heat pumps and heater style fireplaces, it is reasonable to assume that the UEC estimate for high efficiency furnaces is also being influenced, to some degree, by this equipment.

Table 201: Water Heating UECs (GJ/year) – Newer Homes

	Lower Mainland^	Vancouver Island^	Interior^	Whistler^	Fort Nelson^	Overall (weighted)
Single Family Dwelling	29.7	25.1	32.4	38.3*	62.4*	29.7
Multi-Family Dwelling	25.9*	26.8*	30.9*	36.9*	**	26.9
Apts/Condos	**	**	**	**	**	**
Overall	**29.2**	**25.3**	**32.3**	**37.9***	**62.2***	**29.4**

* Small sample size (less than 30 households with end-use present). These results should be interpreted with caution.
** Insufficient sample to produce meaningful estimates.
^ UECs estimated from conditional demand model developed for newer homes.

14.7 Limitations

The results of these conditional demand analyses should be interpreted with some caution due to several important limitations:

- The estimated consumption levels of high-penetration end-uses may mask the effects of other end-uses and/or partially capture the base consumption load of a household.
- The effects of low-penetration end-uses (e.g. gas dryers or hot tubs) are difficult to estimate because of small sample sizes.
- The effects of certain end-uses (e.g. gas cooking appliances and BBQs) may be confounded because of a high correlation of ownership.
- Unit energy consumption values could not be accurately estimated for some regions and dwelling types due to small sample sizes.
- Some information collected through the self-reported customer surveys may be unreliable.
- The rich model specifications originally developed for some end-uses had to be simplified because of unreasonable regression results.
- The composition of the sample used to develop the conditional demand model may skew the results (e.g. under-representation of vertical subdivisions, especially in the Lower Mainland).

15 GAS END-USE COMBINATIONS

This section presents and discusses the findings from an analysis of gas end-use pairings (combinations). Results are compared to a similar analysis conducted using data from the 2010 Residential New Homes Survey (2010 RNHS) and the 2008 Residential End-use Survey (2008 REUS). The main purpose of the analysis in this report is to explore the number and types of gas end-uses present in the homes of FortisBC's residential customers and how they vary by dwelling type, vintage, and square footage. As a word of caution, discussion about losses or gains in gas end-use penetrations apply only to residential dwellings with gas service. They do not address the loss or gain of gas market share in new residential construction or retrofits.

15.1 Methodology and Data Preparations

The 2012 REUS dataset was used to identify nine different gas end-use groupings present in survey respondent's dwellings. They include space heating, domestic water heating, fireplaces and heater stoves, indoor cooking, outdoor cooking (piped gas BBQs), clothes drying, heated pools, hot tubs, and miscellaneous outdoor applications (outdoor heaters and fire pits). Table 202 provides greater detail on the composition of each group with corresponding data sources from the 2012 REUS identified.

Table 202: Gas End-use Groupings – 2012 REUS

Gas End-Use Short Name	Gas End-Use Long Name	Detailed Description	Question Number: 2012 REUS
SH	Gas space heating	Natural gas furnace, boiler, or wall heater	B6, B5-10
DWH	Gas domestic water heating	Natural gas domestic water heater – any type	D2
FP	Gas fireplace or heater stove	Gas fireplace or heater stove	C2
C-I	Gas indoor cooking	Gas range (gas cook top and oven), dual fuel gas range (gas cook top, electric oven), gas cook top, and/or gas wall oven	F1-2, F1-3, F1-5, F1-7
C-O	Gas outdoor cooking	Piped gas barbeque	F1-9
CD	Gas clothes dryer	Gas clothes dryer	F1-20
Pool	Gas heated pool	Indoor or outdoor pool heated by natural gas	E-2
HT	Piped gas hot tub	Indoor or outdoor hot tub heated with natural gas	E9-1
OTH	Piped gas outdoor heater or fire pit	Outdoor heater or fire pit heated via piped natural gas	F1-24, F1-26

The analysis was concerned with the presence of gas-end-use rather than the quantities of the end-use. For example, homes with two gas fireplaces are treated the same as those with only one gas fireplace. While it was possible that a dwelling could have all nine gas end-uses, nine-in-ten had between one and four end-uses.

The presence of gas space heating was initially defined based on specification of natural gas as either the main or supplementary space heating fuel. This approach was rejected in favour of the presence of a gas furnace, gas boiler or gas wall heater. This was required because some survey respondents with gas fireplaces and no other gas space heating method indicated that gas was either their main or supplemental space heating fuel. In these cases, it is likely that the gas fireplace is being treated as a space heating method (and fuel). Since gas fireplaces are treated distinctly from space heating in the combination analysis, using space heating fuel as an indicator of gas space heating would double count the number of gas end-uses for these respondents.

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15.1.1 Comparisons with Previous Combination Analyses

Analysis of gas end-use combinations was first conducted using data from the 2008 REUS and 2010 RNHS surveys.[63] To allow comparison with the 2012 results, end-use data for these earlier studies were restated using the current nine end-use definitions. This was required because the 2008 and 2010 studies treated gas cooking appliances as individual gas end-uses (gas cook top, gas range, gas wall oven, etc.). In contrast, the 2012 analysis defined only two cooking categories – indoor cooking appliances (gas range, gas cook top, gas wall oven, dual fuel range, etc.) and outdoor cooking appliances (piped gas barbeque). All data from the 2008 and 2010 studies presented in this report reflect reclassification of the end-use categories to the 2012 definitions.

15.2 Findings

15.2.1 Gas End-Use Counts by Region

Table 203 summarizes the distribution of FEU residential customers by number of gas end-uses, the overall average, and the upper and lower bounds of the average based on a 95% confidence interval. Data are summarized by FortisBC region and the utility aggregate (FEU 2012). The table also includes comparable data at the utility level from the 2008 REUS.

Table 203: Average Number of Gas End-uses by Region
Percent Share of All Dwelling Types

Number of Gas End-Uses	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Unweighted base	*793*	*1707*	*752*	*85*	*104*	*3441*	*2221*
1	7.6	15.6	14.8	25.6	13.9	10.6	8.9
2	24.6	32.1	30.4	15.9	38.7	27.3	36.3
3	37.6	29.8	31.1	29.3	25.2	34.7	36.2
4	20.9	15.4	16.2	14.6	16.4	18.9	14.2
5	6.9	5.2	6.1	12.2	3.9	6.3	3.9
6+	2.4	1.9	1.3	2.4	1.9	2.2	0.5
Total (%)	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**
Average Number per-Dwelling	**3.0**	**2.7**	**2.7**	**2.8**	**2.6**	**2.9**	**2.7**
Standard Deviation	1.8	0.9	0.8	0.5	0.3	1.2	1.0
Lower conf. interval (95%)	2.9	2.6	2.7	2.7	2.6	2.9	2.7
Upper conf. interval (95%)	3.2	2.7	2.8	2.9	2.7	2.9	2.7

Totals may not sum due to rounding.

Overall, the average FEU residential customer in 2012 had 2.9 gas end-uses, up slightly from an average of 2.7 in 2008. Compared to 2008, the number of homes with 4 or more end-uses increased and the proportion with three or less declined.

Regional differences in the distribution of gas-end-use counts and overall averages are evident in the 2012 data. Of note, residential gas customers in the Lower Mainland have more gas end-uses on average (3.0) compared to the other regions (2.6 to 2.7). FEU residential customers in the Lower Mainland are less likely to have only one gas end-use and more likely to have three or four gas end-uses compared to FEU

[63] Sampson Research (2011).

customers in the Interior and Vancouver Island regions. Approximately one-in-seven (15%) of homes in these regions have only one gas end-use, double the rate of Lower Mainland homes.

The average number of gas end-uses varies by type of dwelling, construction period, and size (square footage). These data are discussed next.

15.2.2 Gas End-Use Counts by Dwelling Type

The average number of gas end-uses for single family detached dwellings, duplexes, and row houses / townhouses is summarized in Table 204. Regardless of region, single family detached dwellings have more gas end-uses than duplexes or row houses/townhouses (average of 3.0 versus 2.7 and 2.8 respectively). Regionally, single family detached dwellings in the Lower Mainland have a higher average number of gas end-uses (3.1) than comparable dwellings in the Interior, Vancouver Island and Fort Nelson regions (average of 2.8 each). SFDs in Whistler represent an exception with an average of 3.3 gas end-uses.

Table 204: Average Number of Gas End-uses by Dwelling Type

Selected Dwelling Types	LM	INT	VI	W	FN	2012 FEU	2008 FEU
Single Family Detached							
Average	3.1	2.8	2.8	3.3	2.8	3.0	2.7
Std Deviation	1.9	0.9	0.8	0.4	0.3	1.1	1.2
Duplex							
Average	3.0	2.5	2.4	3.1	2.3	2.7	2.8
Std Deviation	1.9	0.7	0.8	0.4	0.2	0.5	0.8
Townhouse / Row House							
Average	2.6	2.8	2.3	1.8	1.9	2.8	2.7
Std Deviation	1.6	0.9	0.8	0.4	0.3	0.7	0.4
All Dwellings							
Average	3.0	2.7	2.7	2.8	2.6	2.9	2.7
Std Deviation	1.8	0.9	0.8	0.5	0.3	1.2	1.0

At the utility level, the average number of gas end-uses for SFDs increased from 2.7 to 3.0 since the 2008 REUS. This increase is statistically significant at the 95% confidence level. The difference is attributed to the tendency for newer SFDs (those constructed since 2005) to have more gas end-uses than older SFDs. Differences in the average number of end-uses for duplexes and townhouses between the 2008 and 2012 studies are not statistically significant.

The tendency for SFDs to have more gas end-uses than duplexes and row houses/townhouses is consistent with their tendency to be larger in square footage terms. Indeed, the number of gas end-uses typically increases as the square footage of the dwelling increases. This relationship for single family detached dwellings is shown in Figure 35 (next page). Of note, the relative number of homes with four or more gas end-uses begins to increase once the dwelling size exceeds 3,000 square feet. Similar relationships exist for duplexes (not shown) and row houses / townhouses (Figure 36, next page). There were no row houses / townhouses in the 2012 REUS survey exceeded 3,500 square feet.

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Figure 35: Number of Gas End-Uses by Square Footage
Single Family Detached Dwellings

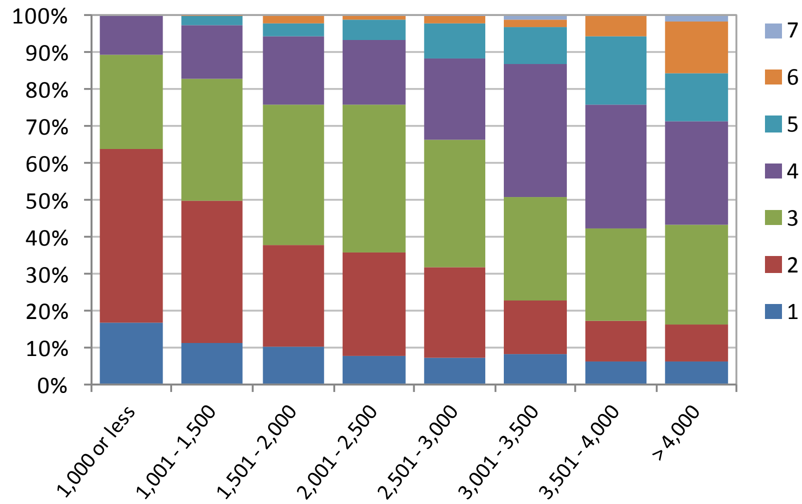


Figure 36: Number of Gas End-Uses by Square Footage
Townhouses / Row Houses

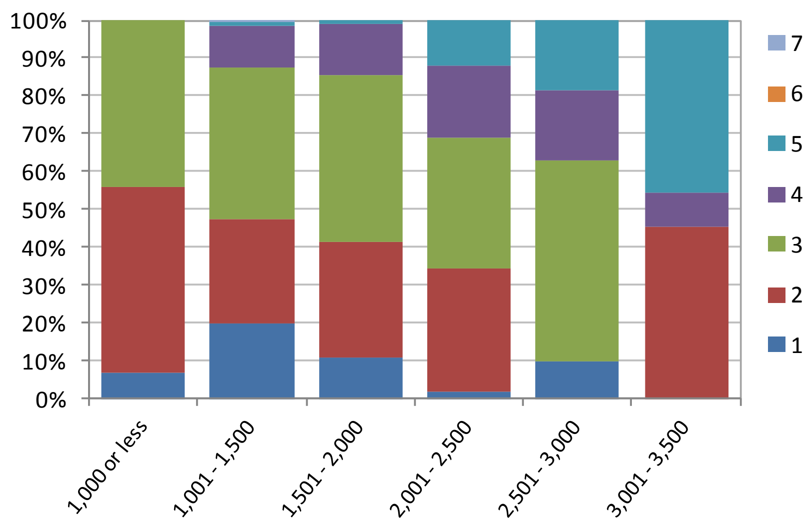


Table 205 (next page) expresses these data in terms of average number of end-uses for each of the three detachment types. The data show the average number of gas end-uses for single family detached dwellings ranges from a low of 2.1 for homes with 1,000 square feet or less, to a high of 3.6 for homes exceeding 4,000 square feet. Townhouses range from 1.8 gas end-uses on average for the smallest units to 3.7 for units exceeding 3,000 square feet.

For all dwelling types including single family detached, duplexes, row houses / townhouses, apartments and mobile homes, the average number of end-uses ranges from a low of 1.9 for those with 1,000 square feet or less to a high of 3.5 for those 4,000 square feet or greater.

Table 205: Average Number of Gas End-Uses by Size (ft^2) of Dwelling

	1,000 or less	1,001 - 1,500	1,501 - 2,000	2,001 - 2,500	2,501 - 3,000	3,001 - 3,500	3,501 - 4,000	> 4,000
Unweighted base	*185*	*590*	*765*	*746*	*502*	*232*	*129*	*124*
Single Family Detached								
Average	2.1	2.5	2.7	2.8	3.0	3.3	3.4	3.6
Std Deviation	0.8	1.0	1.1	1.1	1.2	1.2	1.3	1.4
Duplex								
Average	2.2	2.4	2.6	3.3	3.1	2.8	4.0	3.3
Std Deviation	0.9	1.2	1.1	1.2	1.0	0.4	0.0	0.5
Townhouse / Row House								
Average	1.8	2.4	2.5	3.1	3.0	3.7	--	--
Std Deviation	0.8	1.1	1.0	1.2	1.4	1.5	--	--
All Dwellings								
Average	1.9	2.4	2.7	2.9	3.0	3.3	3.4	3.5
Std Deviation	0.8	1.0	1.1	1.1	1.2	1.2	1.3	1.4

15.2.3 Gas End-Use Counts by Dwelling Vintage

Table 206 summarizes the average number of gas end-uses for all dwelling types by period of construction, with additional detail for single family detached dwellings, duplexes, and townhouses/row houses. The data show the average home constructed during 1950-1985 has between 2.6 and 2.8 gas end-uses. Homes built during the next 20 years have a higher number of gas end-uses (average of 3.0 to 3.4 end-uses). The number of gas end-uses in homes constructed during the 2006-2010 period declined somewhat (average of 3.2 end-uses).

Table 206: Average Number of Gas End-Uses by Dwelling Vintage

	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known
Unweighted base	*350*	*919*	*576*	*664*	*586*	*238*	*46*
Single Family Detached							
Average	2.8	2.7	2.7	3.2	3.6	3.3	2.7
Std Deviation	1.2	1.0	1.1	1.2	1.1	1.2	1.5
Duplex							
Average	3.3	2.5	2.3	3.0	3.1	3.2	5.0
Std Deviation	1.8	1.2	1.3	1.2	0.9	1.0	0.8
Townhouse / Row House							
Average	3.0	2.1	2.3	2.7	2.9	2.5	--
Std Deviation	--	1.0	1.0	1.2	1.1	1.6	1.2
All Dwellings							
Average	2.8	2.7	2.6	3.0	3.4	3.2	2.7
Std Deviation	1.2	1.0	1.1	1.2	1.1	1.2	1.4

Totals may not sum due to rounding.

The decline in gas end-uses for gas homes constructed since 2005 is attributed in large part to the increased share of new home construction represented by townhouses / row houses. Prior to 2006, the ratio of gas townhouses to gas single family dwellings was one in ten. In the period since 2005, this ratio increases to an average of 1.7 gas townhouses per every ten gas SFD homes. This is consistent with the trend observed in CMHC new construction data. Their data show the ratio of new row houses /

GAS END-USE COMBINATIONS

townhouses to new SFDs in British Columbia more than doubling between 2000 and 2012.[64] While the average number of gas end-uses for SFDs increased to 3.5 during this period compared to 3.0 for older SFDs, the increased market share of townhouses / row houses in new construction, along with their corresponding smaller number of gas end-uses, brought the overall average down.

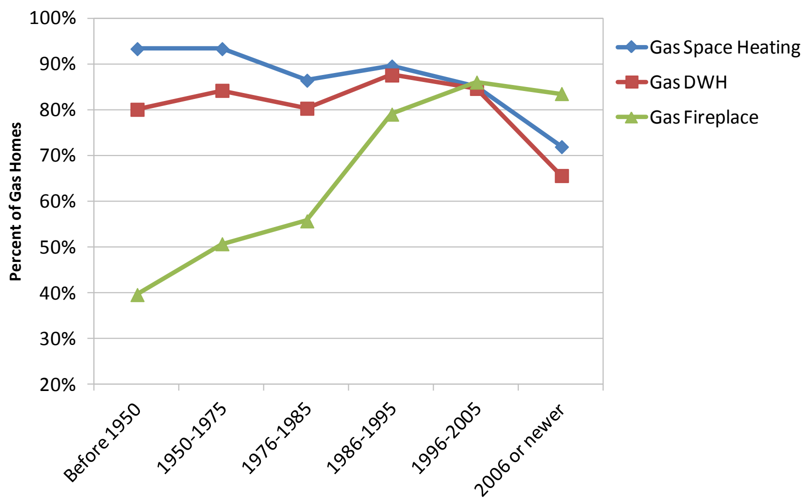
Of particular note, the time trend in gas end-use counts masks the shift away from traditional gas end-uses of space and domestic water heating towards smaller gas loads such as indoor and outdoor gas cooking appliances. This is discussed in detail in the next section.

15.2.4 Trends in End-Use Penetration

Figure 37 summarizes the penetration of thermal residential gas end-uses by period of construction. Thermal end-uses or loads include space heating, domestic water heating, and fireplaces.

Figure 37: Gas End-Use Penetrations by Dwelling Vintage – Thermal Loads

All Dwelling Types



The data show a decline in the penetration of gas space heating (furnaces, boilers or wall heaters) and gas domestic water heaters, most notably among dwellings constructed since 2005. The decline in gas DWH is more severe than that of space heating, falling from just under 80% of homes in 1996-2005 to 56% of homes in the post-2005 period.[65] The penetration of gas space heating end-uses declined from 85% to 72% over the same period but, at its peak in homes constructed prior to 1976, penetration exceeded 90%.

In contrast to the other thermal loads, gas fireplaces have become increasing common over the last fifty years. Their penetration has risen from just under 40% of residential gas dwellings constructed prior to 1950, to 86% of gas homes built during 1996-2005. The slight decline for homes built since 2005 is not statistically significant. Data from the 2012 conditional demand analysis (CDA) strongly suggests that gas fireplaces are increasingly being used as a method of space heating. This is consistent with the shift from

[64] From 2.4 row houses / townhouses per ten SFDs to 5.2 per ten SFDs. Source: CMHC urban housing construction statistics for British Columbia, 2002-2012

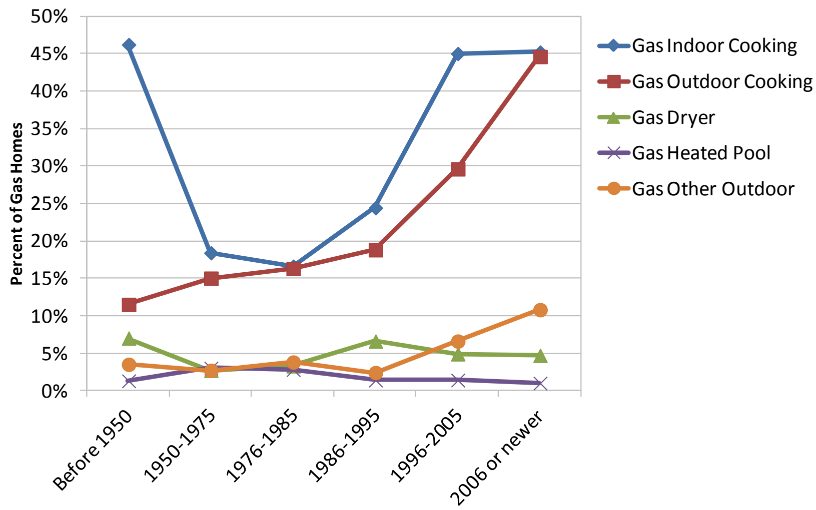
[65] To maintain consistency with how penetration rates are calculated for other gas end-uses, the base for DWH penetration rates in this analysis includes dwellings where domestic hot water is centrally provided (i.e., no DWH equipment in the unit). Penetration and saturation data reported in Chapter 7, in contrast, exclude these dwellings from the calculation base. Correspondingly, DWH penetration rates reported here are somewhat higher than stated in Chapter 7.

decorative to heater style fireplace models in new and retrofit construction and their higher hours of use (2.8 times that of decorative gas fireplace models). Some gas fireplaces for FEU customers may have been original to the house, added, or retrofitted sometime after the construction of the home was complete.

Figure 38 summarizes the penetration of gas “convenience” end-uses by period of construction. Convenience end-uses or loads include gas indoor and outdoor cooking appliances, gas dryers, gas heated swimming pools, and miscellaneous other outdoor gas end-uses (e.g., space heaters and fire pits).

Figure 38: Gas End-Use Penetrations by Dwelling Vintage – Convenience Loads

All Dwelling Types



Indoor and outdoor gas cooking end-uses (cook tops, ranges, wall ovens, dual fuel ranges, piped gas BBQs) have increased in popularity since the 1980s. Penetration of indoor and outdoor gas cooking appliances in new construction is tied at 45%. Penetration of outdoor heaters and fire pits in newer construction is currently 11%, up from low single digits for homes constructed prior to 1996.

Single family detached homes are similar to row houses / townhouses in that the two dwelling types share similar trends in the penetration of space and domestic water heating in new construction. However, the decline in DWH penetration for new townhouses began in the mid-1990s compared to a decade later for SFDs. Also, the penetration of gas fireplaces declined in townhouses built since 2005 while the penetration rate for this end-use held steady for new single family detached dwellings.

15.2.5 Common Gas End-Use Combinations

Analysis of gas end-use combinations by dwelling type, region, and vintage reveals considerable diversity. When all dwelling types are considered, over 112 unique combinations of the nine gas end-use groups are recorded. Fifty-five unique combinations are present in homes constructed since 2005. These counts likely underestimate the total number of unique gas appliance combinations due to the grouping of space heating, cooking, and miscellaneous outdoor gas equipment.

The next two tables present the ten most common end-use combinations for gas homes by region, based on their proportion (percentage) of all gas end-use combinations present. Depending upon the region, these ten combinations represent 68% to 83% of all combinations.

GAS END-USE COMBINATIONS

The top two most common end-use combinations for all regions, except Whistler, is the traditional pairing of gas space heating (SH), gas DWH, and gas fireplaces.

Table 207: Top Ten Gas End-Use Combinations by Region – Part I (%)
Lower Mainland, Interior, Vancouver Island

Lower Mainland		Interior		Vancouver Island	
Combination	%	Combination	%	Combination	%
SH DWH FP	28.0	SH DWH	23.3	SH DWH FP	16.8
SH DWH	17.9	SH DWH FP	18.0	DWH FP	10.8
SH DWH FP C-I	11.3	SH	10.9	FP	10.5
SH	5.6	SH DWH FP C-O	6.4	SH DWH	7.9
SH DWH FP C-O	4.4	SH FP	4.1	SH DWH FP C-O	4.7
SH DWH C-I	3.8	SH DWH FP C-I C-O	3.6	SH FP	4.4
SH DWH FP C-I C-O	3.7	SH DWH FP C-I	3.3	SH DWH FP C-I	3.3
SH FP	3.0	FP	2.9	SH	3.1
SH FP C-I	1.8	SH DWH C-O	2.4	FP C-O	3.1
FP	1.6	SH DWH C-I	2.3	DWH FP C-I C-O	2.9
Total (%)	**81.2**	**Total (%)**	**77.2**	**Total (%)**	**67.6**

LEGEND:
SH = space heating (gas boiler or gas furnace)
DWH = gas domestic water heater
FP = gas fireplace
C-I = indoor gas cooking
C-O = outdoor gas cooking (BBQ)
CD = gas clothes dryer
OTH = outdoor gas fire pit or gas heater

Totals may not sum due to rounding

Table 208: Top Ten Gas End-Use Combinations by Region – Part II (%)
Whistler, Fort Nelson, FEU Total

Whistler		Fort Nelson		All Regions (FEU 2012)	
Combination	%	Combination	%	Combination	%
FP	20.7	SH DWH	32.9	SH DWH FP	24.0
SH DWH FP C-I C-O	9.8	SH DWH FP	13.5	SH DWH	18.3
FP C-I C-O	9.8	SH	7.7	SH DWH FP C-I	8.2
SH FP C-I C-O	7.3	SH DWH C-I	7.7	SH	6.7
SH FP C-I	4.9	SH DWH FP C-I	4.8	SH DWH FP C-O	5.0
SH DWH FP	3.7	SH DWH C-I CD	3.9	SH DWH FP C-I C-O	3.5
SH DWH	3.7	SH DWH FP C-O	3.9	SH FP	3.5
FP OTH	3.7	OTH	2.9	SH DWH C-I	3.3
SH C-I C-O	3.7	SH FP	2.9	FP	3.0
DWH FP	2.4	SH DWH C-O	2.9	DWH FP	1.7
Total (%)	**69.5**	**Total (%)**	**83.2**	**Total (%)**	**77.3**

LEGEND:
SH = space heating (gas boiler or gas furnace)
DWH = gas domestic water heater
FP = gas fireplace
C-I = indoor gas cooking
C-O = outdoor gas cooking (BBQ)
CD = gas clothes dryer
OTH = outdoor gas fire pit or gas heater

Totals may not sum due to rounding

Table 209 (next page) presents the top ten gas end-use combinations for the three main dwelling types – single family detached, duplexes, and row houses / townhouses. The data show that single family dwellings and duplexes share similar gas end-use profiles with the traditional combinations of space heating, DWH, and fireplaces dominating the ten most common end-use combinations. The top ten combinations for row houses / townhouses are more likely to exclude gas DWH.

Table 209: Top Ten Gas End-Use Combinations by Dwelling Type (%)

Single Family Detached		Duplexes		Row Houses / Townhouses		All Dwelling Types	
Combination	%	Combination	%	Combination	%	Combination	%
SH DWH FP	24.3	SH DWH FP	22.3	SH DWH FP	32.5	SH DWH FP	24.0
SH DWH	18.8	SH DWH	13.4	SH DWH	14.3	SH DWH	18.3
SH DWH FP C-I	8.6	SH DWH FP C-I	10.7	SH DWH FP C-I	7.0	SH DWH FP C-I	8.2
SH	5.6	SH	9.1	SH	6.5	SH	6.7
SH DWH FP C-O	5.5	SH DWH FP C-O	5.8	FP	6.4	SH DWH FP C-O	5.0
SH DWH FP C-I C-O	3.9	SH DWH FP C-I CD	4.9	SH FP	6.4	SH DWH FP C-I C-O	3.5
SH DWH C-I	3.6	FP	3.8	SH FP C-I	4.7	SH FP	3.5
SH FP	2.8	DWH FP	3.7	DWH FP	4.2	SH DWH C-I	3.3
FP	2.5	SH FP C-I	3.6	FP C-I	2.9	FP	3.0
SH DWH C-I C-O	1.6	SH DWH C-I	2.9	SH DWH FP C-I C-O	2.9	DWH FP	1.7
Total (%)	**77.1**	**Total (%)**	**80.3**	**Total (%)**	**87.9**	**Total (%)**	**77.3**

LEGEND:
SH = space heating (gas boiler or gas furnace)
DWH = gas domestic water heater
FP = gas fireplace
C-I = indoor gas cooking
C-O = outdoor gas cooking (BBQ)
CD = gas clothes dryer
OTH = outdoor gas fire pit or gas heater

Totals may not sum due to rounding

Table 210 summarizes the top ten end-use combinations for gas dwellings constructed prior to 2006 and homes constructed during 2006 to 2010. Compared to older homes, the top ten end-use combinations for newer homes reflect the higher penetration of indoor and outdoor gas cooking, and gas fireplaces. They also highlight the reduced incidence of gas DWH and the increased prevalence of single end-uses (e.g., fireplace only, space heating only, etc.).

Table 210: Top Ten Gas End-Use Combinations (%) – Newer versus Older Homes

Older Homes (2005 or older)		New Homes (2006 - 2010)		All Vintages	
Combination	%	Combination	%	Combination	%
SH DWH FP	25.1	SH DWH FP	12.0	SH DWH FP	24.0
SH DWH	19.0	SH DWH FP C-O	8.3	SH DWH	18.3
SH DWH FP C-I	8.3	SH DWH FP C-I C-O	8.2	SH DWH FP C-I	8.2
SH	6.9	SH DWH FP C-I	8.0	SH	6.7
SH DWH FP C-O	4.9	FP	6.8	SH DWH FP C-O	5.0
SH FP	3.5	SH	5.2	SH DWH FP C-I C-O	3.5
SH DWH C-I	3.4	SH FP	3.8	SH FP	3.5
SH DWH FP C-I C-O	3.2	SH FP C-I C-O	3.6	SH DWH C-I	3.3
FP	2.7	FP C-I	3.3	FP	3.0
DWH FP	1.8	DWH FP C-I C-O	3.0	DWH FP	1.7
Total (%)	**78.8**	**Total (%)**	**62.1**	**Total (%)**	**77.3**

LEGEND:
SH = space heating (gas boiler or gas furnace)
DWH = gas domestic water heater
FP = gas fireplace
C-I = indoor gas cooking
C-O = outdoor gas cooking (BBQ)
CD = gas clothes dryer
OTH = outdoor gas fire pit or gas heater

Totals may not sum due to rounding

GAS END-USE COMBINATIONS

15.2.6 Additional Analysis - Incidence of Gas Space Heat and Gas DWH Pairings

The analysis up to this point has provided insight into trends in the number and penetration of gas end-uses and end-use combinations. This section explores trends in the traditional pairing of gas space heat and gas DWH.

Table 211 summarizes the incidence of homes with gas furnaces or boilers paired with gas DWH or electric DWH for SFDs, row houses/townhouses, and all dwellings.[66] Data for homes with electric space heat and DWH are also provided. These data confirm there has been a significant reduction in the number of new homes that are using gas for domestic water heating. For example, 56% of SFDs constructed since 2005 have the traditional pairing of gas space heat and gas DWH, down from 81% for SFDs built prior to this. Seventy-three percent (73%) of townhouses / row houses built prior to 2006 have gas space heat (gas furnace or boiler) and gas DWH, compared to 54% of townhouses / row houses constructed since. Overall, the proportion of FEU residential dwellings with gas space and domestic water heating for new construction has fallen to 48%.

Table 211: Gas Space Heat and DWH Combinations by Dwelling Type and Vintage (%)

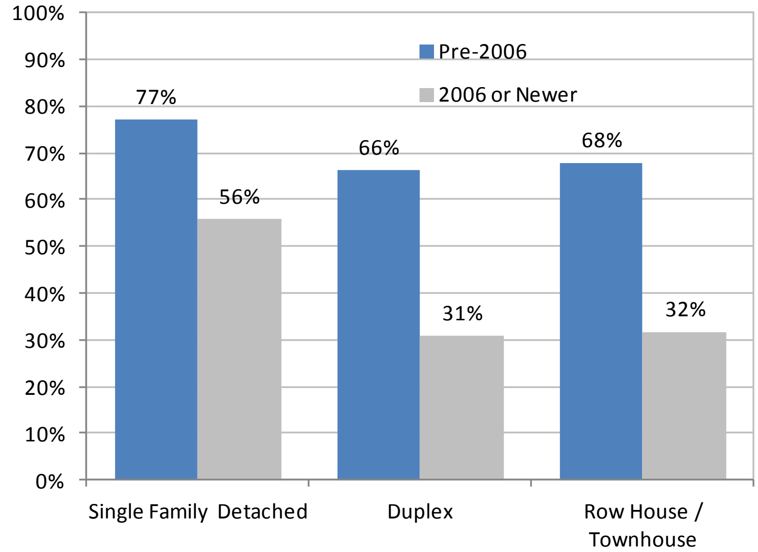
	Before 1950	1950 - 1975	1976 - 1985	1986 - 1995	1996 - 2005	2006 or later	Age Un-known	2012 FEU
Unweighted base[1,2]	*343*	*903*	*563*	*654*	*574*	*230*	*46*	*3441*
Single Family Detached								
Gas space heat & gas DWH	74.7	77.4	74.9	77.9	80.1	55.8	70.8	75.9
Gas space heat & electric DWH	19.8	15.8	11.0	12.6	7.4	18.3	13.1	13.5
Electric space heat & gas DWH	3.1	3.2	4.6	4.9	7.7	7.4	1.5	4.6
Electric space heat & electric DWH	2.4	3.6	9.5	4.6	4.8	18.5	14.6	6.0
Townhouse / Row House								
Gas space heat & gas DWH	--	73.2	64.2	74.3	57.4	31.7	--	63.4
Gas space heat & electric DWH	100.0	22.5	20.3	9.9	23.4	36.3	19.9	16.6
Electric space heat & gas DWH	--	--	--	6.6	8.7	12.7	--	5.9
Electric space heat & electric DWH	--	4.3	15.5	9.2	10.5	19.3	80.1	14.1
All Dwellings								
Gas space heat & gas DWH	73.1	75.8	72.1	75.9	71.8	48.4	55.9	72.4
Gas space heat & electric DWH	20.2	17.5	14.4	13.6	13.2	23.5	16.1	15.6
Electric space heat & gas DWH	3.9	2.9	3.8	5.3	7.4	7.5	1.0	4.7
Electric space heat & electric DWH	2.8	3.8	9.7	5.2	7.6	20.6	27.0	7.3

[1] Caution is advised in interpreting data for samples of less than 50. Results are directional only.
[2] All dwelling types.
Totals may not sum due to rounding.

Figure 39 (next page) compares the percentages of detachments with gas space heating and gas DWH for two periods – homes constructed prior to 2006 and those built afterwards. The data show the decline in this traditional pairing of gas end-uses.

[66] These homes may have other gas end-uses. However, this analysis concentrates on the largest gas loads which traditionally have been space and domestic water heating.

Figure 39: Share of FEU Dwellings with Gas Space Heating and Gas DWH



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Appendix A

2012 REUS Questionnaire

FORTIS BC™

Residence (Site) Address

& ID Code

November 5, 2012

Dear Customer,

At FortisBC, we're committed to providing a range of energy services to meet your needs today and tomorrow. Planning for your future needs means understanding how residential customers like you currently use energy and if you plan to change how you use energy in the future.

This survey is an important tool for understanding how energy is used in homes, the types of space and water heating appliances installed, how those appliances are used, the energy efficiency of homes and attitudes about energy issues.

This information is used to:

- forecast future demand for natural gas
- design energy efficiency programs to help you save money on your energy bills
- protect the environment by lowering greenhouse gas emissions

How to complete the survey

This survey should be completed by the person most responsible for the maintenance and repair of your home. Also please ensure that the survey responses refer to the residence located at the address shown above.

1. You can complete the enclosed survey and return it in the postage paid envelope provided; or

2. You can complete the survey online at, www.websurveys.ca/fbcreus by entering the survey id included at the top of this page.

You could win a $1,000 home improvement gift certificate

Return your completed survey by **December 24, 2012** and you'll be entered into a draw to **win one of four $1,000 gift certificates to a home improvement store near you.**

Complete the survey online and double your chances of winning. Full contest rules are at the back of the survey.

Privacy

The survey will tell us how you use energy in your home. To meet the goals of this survey, FortisBC will also analyze how much natural gas your home has used over the past two years.*

To protect your privacy, Ipsos, the national market research company that is conducting this survey on behalf of FortisBC, will not have access to your account information. As well, FortisBC will not see your individual responses. The information collected will be treated confidentially and in accordance with the provisions of the *Personal Information Protection* Act (British Columbia). The information collected will not be used for any marketing or sales purpose.

If you have any questions, please contact Walter Wright, Market Research, at 604-592-7653 or walter.wright@fortisbc.com.

Yours truly,

Tom Loski
Vice-President, Customer Service
FortisBC

**FortisBC Energy Inc. is administering this survey on behalf of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. By participating in this survey, I agree that the aforementioned FortisBC utilities may use and disclose between the FortisBC utilities, the consumption information for my home for the past two years.*

Instructions for Completing the Mail Survey
Some questions require you to place an “X” in the appropriate box, for example:

Do you rent or own this residence? Rent ☒ Own ☐

Some questions require you to fill in a number, for example: “ 23 ” years

Some questions allow you to check several answers. These questions will have the instruction “check all that apply.”

When you have completed the survey, please put the questionnaire in the enclosed envelope. No postage is needed. Surveys are due by December 24, 2012.

If you have mislaid the return envelope, please mail the questionnaire to:

Ipsos
200 - 1285 West Pender
Vancouver, BC V6E 4B1

Dear Participant:

Throughout this questionnaire, when we ask about your home or residence, we are referring to area covered by your FortisBC bill**.** If you live in an apartment or townhouse complex, please do not include building hallways or outside lighting which are not covered by your own bill.

A. About This Residence

A1. Do you own or rent this residence?

- ☐ 1 Own/co-op → **CONTINUE**
- ☐ 2 Rent → **GO TO QUESTION A3**

A2. Do you pay maintenance fees?

- ☐ 1 Yes
- ☐ 2 No → **GO TO QUESTION A4**

A3. Which of the following are included in your rent or maintenance fees?

- ☐ 1 Heat
- ☐ 2 Hot water
- ☐ 3 Fuel for gas fireplace
- ☐ 0 None of the above
- ☐ 9 Don't know
- ☐ 4 Fuel for gas cooking
- ☐ 5 Fuel for gas clothes drying
- ☐ 6 Electricity

A4. Is this residence a…

- ☐ 1 Single family dwelling (detached)
- ☐ 2 Duplex
- ☐ 3 Row/townhouse (3 or more units attached each with separate entrance)
- ☐ 4 Apartment / Condominium
- ☐ 5 Mobile home
- ☐ 6 Other (please specify): __________

A5. When was this residence built?

- ☐ 1 Before 1950
- ☐ 2 1950-1975
- ☐ 3 1976-1985
- ☐ 4 1986-1995
- ☐ 5 1996-2005
- ☐ 6 2006 or later
- ☐ 9 Don't know

A6. Is this your principal residence?

- ☐ 1 Yes
- ☐ 2 No

A7. How many weeks per year is this residence occupied?

______ weeks ☐ 1 Always occupied

A8. How many years have you lived in this residence?

______ years

A9. What are the heights of the ceilings in this residence, excluding the basement? Please indicate the percentage of the residence with each ceiling height. Choose the closest height. Your answers should sum to 100%.

8 feet	______
9 feet	______
10 feet	______
More than 10 feet	______
TOTAL	**100%**

A10. What type of basement does your residence have?

- ☐ 1 No basement → **GO TO QUESTION A14**
- ☐ 2 Full basement
- ☐ 3 Crawl space → **GO TO QUESTION A13**
- ☐ 4 Partial basement

A11. Is the basement area of this residence…

- ☐ 1 Completely below ground
- ☐ 2 Completely above ground
- ☐ 3 Partially above ground

A12. Is the basement area of this residence unfinished, partly finished, or completely finished?

☐ 1 Unfinished ☐ 2 Partly finished ☐ 3 Completely finished

A13. During the heating season, is your basement or crawl space usually heated?

☐ 1 Yes ☐ 2 No

A14. What is the total floor area of this residence, including the basement and unfinished areas but excluding the garage or carport?

_________ Square feet OR _________ Square meters

A15. How many floors of heated living space does this residence have? (include basement if heated)

☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5+

A16. Does the electric bill for this residence cover any of the following, and if so, how many:

	Yes	No	Don't Know	Number			
Secondary suite(s)	☐ 1	☐ 2	☐ 9	☐ 1	☐ 2	☐ 3	☐ 4+
Detached garage / workshop	☐ 1	☐ 2	☐ 9	☐ 1	☐ 2	☐ 3	☐ 4+
Other buildings (e.g., sheds, farm buildings)	☐ 1	☐ 2	☐ 9	☐ 1	☐ 2	☐ 3	☐ 4+
Pumps (e.g., wells, irrigation, etc.)	☐ 1	☐ 2	☐ 9	☐ 1	☐ 2	☐ 3	☐ 4+

A17. Please indicate which areas of this residence have insulation and if you know whether the insulation is below average, average or above average.

Location	Have insulation? Yes	No	Don't Know	Below Average (R6 or 1.75" fiberglass or less)	Average (R12 or 3.5" fiberglass or less)	Above Average (R20 or 6" fiberglass or more)	Don't know
In the attic	☐ 1	☐ 2	☐ 9	☐ 1	☐ 2	☐ 3	☐ 9
In your walls	☐ 1	☐ 2	☐ 9	☐ 1	☐ 2	☐ 3	☐ 9
In your basement / crawl space	☐ 1	☐ 2	☐ 9	☐ 1	☐ 2	☐ 3	☐ 9

A18. How effective is the draft proofing in this residence?

☐ 1 Not at all drafty ☐ 2 Sometimes drafty ☐ 3 Always drafty

A19. Please estimate what percentage of your windows are:

	% of Total Windows	Argon Gas Filled?		
Single pane regular (clear) glass	_______%			
Double pane regular (clear) glass	_______%	☐ 1 Yes	☐ 2 No	☐ 9 Don't know
Double pane low-E*	_______%	☐ 1 Yes	☐ 2 No	☐ 9 Don't know
Triple pane regular (clear) glass	_______%	☐ 1 Yes	☐ 2 No	☐ 9 Don't know
Triple pane low-E*	_______%	☐ 1 Yes	☐ 2 No	☐ 9 Don't know
Other – Specify: ______________________	_______%	☐ 1 Yes	☐ 2 No	☐ 9 Don't know
	Total 100%			

** Low-E coated glass has a slight shading or tint when compared to standard windows.*

A20. Please estimate the percentage of your windows that have the following frames:

	% of Total Windows
Aluminum frames	________%
Wood frames	________%
Vinyl frames	________%
Fiberglass frames	________%
Other (please specify): _______________	________%
Total	100%

A21. Please indicate the number of outside doors in this residence. If this residence is an apartment or condominium, please count only doors in your unit that open directly to the outdoors.

	Number		Number
Wood doors	____ 1	Glass doors with wooden frames	____ 4
Wood doors with aluminum storm doors	____ 2	Glass doors with aluminum frames	____ 5
Insulated steel or fibreglass doors	____ 3	Glass doors with vinyl frames	____ 6

A22. Do you or anyone in your household use part of this residence as a full-time or part-time office from which they conduct a business?

☐ 1 Yes, full-time business ☐ 2 Yes, part-time business ☐ 3 No

B. Space Heating

B1. What is the main fuel used to heat this residence? The main fuel is the one that provides most of the heat in the home during a typical year. (Check one fuel only.)

Electricity ☐ 1	Bottled propane ☐ 4	Other ☐ 7
Natural gas ☐ 2	Oil ☐ 5	Don't know ☐ 9
Piped propane ☐ 3	Wood ☐ 6	

Do I have piped natural gas or piped propane service?

If you are a gas customer of FortisBC and live anywhere in British Columbia *other than Revelstoke*, your residence uses *natural gas*. Customers in Revelstoke receive their gas service in the form of piped propane. Propane from a refillable tank is considered "bottled" propane.

B2. Have you changed from one main fuel to another to heat this residence over the past five years?

Yes ☐ 1 → **CONTINUE**
No ☐ 2 → **GO TO QUESTION B4**

B3. What was the previous main space heating fuel? (check one fuel only)

Electricity ☐ 1	Bottled propane ☐ 4	Other ☐ 7
Natural gas ☐ 2	Oil ☐ 5	Don't know ☐ 9
Piped propane ☐ 3	Wood ☐ 6	

B4. Please indicate any OTHER fuel(s) used to heat this residence (check all that apply) and which OTHER fuel is used the most (check one only). Note: both air source and ground source (geothermal) heat pumps require electricity to operate.

	All OTHER Fuels *(check all that apply)*	**Most commonly used OTHER Fuel** *(check one only)*
Electricity	☐ 1	☐ 1
Natural gas	☐ 2	☐ 2
Piped propane	☐ 3	☐ 3
Bottled propane	☐ 4	☐ 4
Oil	☐ 5	☐ 5
Wood	☐ 6	☐ 6
Other	☐ 7	☐ 7
Don't know	☐ 9	☐ 9

UNLESS OTHERWISE STATED, ANY REFERENCES TO "GAS" FROM THIS POINT FORWARD IN THE SURVEY MEAN EITHER NATURAL GAS OR PROPANE GAS.

B5. There are several methods that can be used to heat a home. Please check the main method used to heat this residence, then the second most used method, and then all other methods used to heat this residence.

	Main method *(check one only)*	**Second most used method** *(check one only)*	**All other methods** *(check all that apply)*
Central forced air furnace	☐ 1	☐ 1	☐ 1
Multi-fuel forced air furnace	☐ 2	☐ 2	☐ 2
Wired-in electric heater (baseboards)	☐ 3	☐ 3	☐ 3
Wired-in electric wall heater (fan forced)	☐ 4	☐ 4	☐ 4
Heat pump–air source	☐ 5	☐ 5	☐ 5
Heat pump – ground source (geothermal)	☐ 6	☐ 6	☐ 6
Hot water baseboards	☐ 7	☐ 7	☐ 7
Hot water radiant in-floor / underfloor heat	☐ 8	☐ 8	☐ 8
Electric radiant heat (floors, walls, and/or ceilings)	☐ 9	☐ 9	☐ 9
Gas wall heater	☐ 10	☐ 10	☐ 10
Portable electric heaters	☐ 11	☐ 11	☐ 11
Gas fireplace	☐ 12	☐ 12	☐ 12
Gas heater stove	☐ 13	☐ 13	☐ 13
Wood stove	☐ 14	☐ 14	☐ 14
Wood burning fireplace	☐ 15	☐ 15	☐ 15
Electric fireplace	☐ 16	☐ 16	☐ 16
Other (Specify) _______________	☐ 17	☐ 17	☐ 17

IF THIS RESIDENCE DOES NOT HAVE A GAS FURNACE, ELECTRIC FURNACE, OR GAS BOILER, GO TO QUESTION B18

B6. Which of the following does this residence have?

☐ 1 Gas boiler → **GO TO QUESTION B7**
☐ 2 Gas furnace → **GO TO QUESTION B8**
☐ 3 Electric furnace → **GO TO QUESTION B12**
☐ 0 None of the above → **GO TO QUESTION B18**

B7. Boiler efficiency refers to how much useful heat your boiler extracts from the gas. The higher the efficiency of the boiler, the less fuel is required to heat your house. Boilers are categorized as low efficiency, mid-efficiency, or high efficiency.

What is the efficiency of your boiler?

☐ 1 Low efficiency – 60% efficient
☐ 2 Mid-efficiency – 80% to 85% efficient
☐ 3 High efficiency – 90% efficient or higher
☐ 9 Don't know

→ **GO TO QUESTION B9**

B8. Furnace efficiency refers to how much useful heat your furnace extracts from the gas. The higher the efficiency of the furnace, the less fuel is required is to heat your house. Furnaces are categorized as low (standard) efficiency, mid-efficiency, or high efficiency.

What is the efficiency of your gas furnace?

☐ 1 Low (standard) efficiency – less than 78% efficient
☐ 2 Mid-efficiency – 78% to 85% efficient
☐ 3 High efficiency – 90% efficient or higher
☐ 9 Don't know

Gas Boiler Types

Low Efficiency Gas Boilers:
- 13 years old or older
- 60% efficient
- uses a standing pilot light

Mid-Efficiency Gas Boilers:
- 80% to 85% efficient
- no pilot light, uses igniter instead
- uses induced draft fan or damper

High Efficiency Gas Boilers:
- 90% efficient or higher
- no pilot light, uses igniter instead
- uses plastic exhaust pipe that exits the roof or side of house

Gas Furnace Types

Low (Standard) Efficiency Gas Furnaces:
- 18 years old or older
- less than 78% efficient
- typically uses a pilot light
- uses metal flue that exits the roof

Mid-Efficiency Gas Furnaces:
- 78% to 85% efficient
- no pilot light, uses igniter instead
- uses a metal flue that exits the roof

High Efficiency Gas Furnaces:
- 90% efficient or higher
- no pilot light, uses igniter instead
- uses plastic exhaust pipe that exits the side of the house.
- ENERGY STAR qualified

B9. Is your gas furnace or boiler an ENERGY STAR® qualified model?

☐ 1 Yes ☐ 2 No ☐ 9 Don't Know

ENERGY STAR® qualified products are some of the most energy-efficient products that you can buy today. ENERGY STAR products will display the ENERGY STAR logo on the product or its packaging when new.

B10. Has a gas furnace or gas boiler been installed in this residence in the past five years?

Yes ☐ 1 → **CONTINUE**
No ☐ 2
Don't know ☐ 9 } → **GO TO QUESTION B12**

B11. What was the main reason for installing a natural gas furnace or natural gas boiler? (Check one reason only)

☐ 1 New home
☐ 2 Wanted to change to gas
☐ 3 Wanted more efficient furnace or boiler
☐ 4 Existing furnace or boiler had failed
☐ 5 Anticipated furnace or boiler failure
☐ 6 Wanted an environmentally friendly fuel
☐ 7 Wanted a lower cost fuel
☐ 8 Other (please specify): ___________________

B12. How old is your furnace or boiler? _____ years ☐ 9 Don't know

RESIDENCES WITH GAS OR ELECTRIC FURNACES

B13. How often does your furnace fan blower operate? Choose the best answer.

☐ 1 Only when furnace is operating
☐ 2 Only when furnace or air conditioning is operating
☐ 3 Continuously during the heating season
☐ 4 Continuously during the heating and cooling season
☐ 5 Continuously year round → **GO TO QUESTION B15**
☐ 9 Don't know

B14. In addition to the above, do you also turn on the furnace fan to provide ventilation for part of the year?

☐ 1 Yes → **How many weeks per year does the furnace fan operate in this mode?** ______ weeks
☐ 2 No

B15. Does your furnace have a high efficiency blower motor (often called a variable speed motor or electronically controlled motor (ECM))?

☐ 1 Yes ☐ 2 No ☐ 9 Don't know

B16. Have you undertaken any repairs to your furnace or boiler during the past three years?

Yes ☐ 1
No ☐ 2
Don't know ☐ 9 } → **GO TO QUESTION B18**

B17. In total, how much did you spend on repairs to your furnace or boiler over the past three years?

$ ______ ☐ 999 Don't know

B18. Please indicate whether you always, usually, occasionally or never do the following (check one box per row).

	Always	Usually	Occasion -ally	Never	Don't know	Not Applicable
Change the furnace filter regularly	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
Have the heating system serviced annually by a contractor	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
Service the heating system annually myself	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6

B19. How many rooms in this residence are heated? (Exclude bathrooms, closets and hallways)

Number of rooms that are always heated _____
Number of rooms that are sometimes heated _____
Number of rooms that are rarely or never heated _____

B20. Do you use programmable thermostat(s) in this residence? ☐ 1 Yes ☐ 2 No ☐ 9 Don't Know

C. Fireplaces and Heater Stoves

Many homes are equipped with fireplaces or heater stoves. Some provide ambiance but little or no heat, while others can be used to heat one or more rooms.

C1. Do you have a fireplace or heating stove in this residence?

Yes ☐ 1 → **CONTINUE**
No ☐ 2 → **GO TO SECTION D**

Gas Fireplace and Stove Types

Decorative fireplaces – Provide ambiance but have little or no heating ability. The firebox is typically steel or masonry, and the hearth is often open to the room or equipped with opening glass doors.

Heater type fireplaces (built-ins and inserts) – These fireplaces are efficient heaters with fixed glass fronts and may have features such as fans and thermostatic control. They may be built-in at the time of construction, or inserted into an existing masonry or other fireplace as an upgrade.

Free standing fireplaces and heater stoves – These are stand alone units that that can be used for both ambiance and heating. Gas heater stoves resemble wood stoves in appearance but use gas instead of wood.

C2. How many of the following types of fireplaces and heater stoves do you have? For each type, please indicate whether they are used primarily for heating, ambiance or both.

	Number (Check one) type that you have)				Used primarily for:		
	1	2	3	4+	Heating	Ambiance	Both
Gas (decorative)	☐ 1	☐ 2	☐ 3	☐ 4	☐ 1	☐ 2	☐ 3
Gas (heater type)	☐ 1	☐ 2	☐ 3	☐ 4	☐ 1	☐ 2	☐ 3
Gas (free standing)	☐ 1	☐ 2	☐ 3	☐ 4	☐ 1	☐ 2	☐ 3
Electric	☐ 1	☐ 2	☐ 3	☐ 4	☐ 1	☐ 2	☐ 3
Wood burning fireplace	☐ 1	☐ 2	☐ 3	☐ 4	☐ 1	☐ 2	☐ 3
Wood burning stove	☐ 1	☐ 2	☐ 3	☐ 4	☐ 1	☐ 2	☐ 3
Other: _______________	☐ 1	☐ 2	☐ 3	☐ 4	☐ 1	☐ 2	☐ 3

C3. How many hours are the fireplaces and heater stoves in use during a typical week in each of the following seasons? Please sum the total hours for ALL fireplaces and heater stoves used in a typical week in each season.

Summer (July – September) _____ hours per week
Fall (October – December) _____ hours per week
Winter (January – March) _____ hours per week
Spring (April – June) _____ hours per week

C4. Approximately, what share of this residence's space heating requirements are provided by your fireplace or heater stove? Please include all fireplaces and heater stoves at this residence in your answer.

0% (none) ☐ 0
Up to 10% ☐ 1
Up to 25% ☐ 2
Up to 50% ☐ 3
Up to 75% ☐ 4
Up to 100% ☐ 5
Don't know ☐ 9

IF THIS RESIDENCE DOES NOT HAVE A GAS FIREPLACE, GO TO SECTION D

C5. How old is (are) your gas fireplace(s)?

Gas fireplace 1 _____ years Don't know ☐ 99
Gas fireplace 2 _____ years Don't know ☐ 99
Gas fireplace 3 _____ years Don't know ☐ 99

C6. For each gas fireplace you have, please indicate whether it has a fixed glass front, glass doors that open, or an open hearth design (no glass) by checking the appropriate box.

	Gas Fireplace 1	Gas Fireplace 2	Gas Fireplace 3
Fixed glass front	☐ 1	☐ 1	☐ 1
Glass doors that open	☐ 2	☐ 2	☐ 2
No glass (open hearth)	☐ 3	☐ 3	☐ 3

C7. For each gas fireplace you have, please indicate whether it has a pilot light? The pilot light is a small flame that is used to ignite the fireplace.

	Gas Fireplace 1	Gas Fireplace 2	Gas Fireplace 3
Yes	☐ 1	☐ 1	☐ 1
No	☐ 2	☐ 2	☐ 2
Don't know	☐ 3	☐ 3	☐ 3

C8. GAS FIREPLACES WITH PILOT LIGHTS ONLY: Do you typically turn off your fireplace pilot light? If yes, how many months is the pilot light typically turned off?

Yes ☐ 1 → **Number of months per year pilot light off: ______**
No ☐ 2 } → **GO TO SECTION D**
Don't know ☐ 9 }

C9. Who typically re-lights the pilot light for your gas fireplace?

☐ 1 Myself
☐ 2 Contractor
☐ 3 Some other member of my household
☐ 4 Other: __________________
☐ 9 Don't' Know

D. Domestic Water Heating

D1. How many water heaters are there in this residence? If you live in an apartment, townhouse, or row house where hot water is centrally provided to all units (from outside your unit), please check "none".

1 ☐
2 ☐
3 ☐
None ☐ → **GO TO QUESTION D15**

D2. What type of fuel does your water heater(s) use? Homes with more than one water heater usually have one water heater that provides more hot water than the others. For classification purposes, consider this unit your main water heater.

	Heater 1 (Main Unit)	Heater 2	Heater 3
Electricity	☐ 1	☐ 1	☐ 1
Natural gas	☐ 2	☐ 2	☐ 2
Piped propane	☐ 3	☐ 3	☐ 3
Bottled propane	☐ 4	☐ 4	☐ 4
Solar	☐ 5	☐ 5	☐ 5
Oil	☐ 6	☐ 6	☐ 6
Geothermal	☐ 7	☐ 7	☐ 7
Other	☐ 8	☐ 8	☐ 8

Water Heater Fuels: Hint

Most hot water heaters use gas, oil or electricity. If your hot water heater has a flue/vent then it uses gas or oil. If there is no vent then it uses electricity. Please consider the fuels used in your house when completing this question.

D3. Please indicate whether the water heater(s) uses solar energy to pre-warm or supplement the water heating process.

	Heater 1 (Main Unit)	Heater 2	Heater 3
Yes	☐ 1	☐ 1	☐ 1
No	☐ 2	☐ 2	☐ 2

D4. Have you changed the water heating fuel at this residence within the past five years?

Yes ☐ 1 → **CONTINUE** No ☐ 2 → **GO TO QUESTION D6**

D5. What was the previous water heater fuel?

	Heater 1 (Main Unit)	Heater 2	Heater 3
Electricity	☐ 1	☐ 1	☐ 1
Natural gas	☐ 2	☐ 2	☐ 2
Piped propane	☐ 3	☐ 3	☐ 3
Bottled propane	☐ 4	☐ 4	☐ 4
Solar	☐ 5	☐ 5	☐ 5
Oil	☐ 6	☐ 6	☐ 6
Geothermal	☐ 7	☐ 7	☐ 7
Other	☐ 8	☐ 8	☐ 8

D6. What types of water heater(s) are there in this residence?

	Heater 1 (Main Unit)	Heater 2	Heater 3
Conventional storage (tank)	☐ 1	☐ 1	☐ 1
On-demand (tankless)	☐ 2	☐ 2	☐ 2
Hybrid on-demand (uses small storage tank)	☐ 3	☐ 3	☐ 3
Combined space and water heater	☐ 4	☐ 4	☐ 4
Hybrid heat pump water heater (tank)	☐ 5	☐ 5	☐ 5
Don't know	☐ 9	☐ 9	☐ 9

Tankless & Hybrid On-Demand Water Heaters

On-demand (tankless) water heaters, also known as instantaneous water heaters, are compact units that provide hot water on demand. Hybrid on-demand models use a small storage tank to reduce temperature fluctuations during use.

Hybrid heat pump water heaters combine a heat pump with an electric hot water tank to improve energy efficiency.

D7. If this residence has a conventional storage (tank) water heater, does it have a:

	Heater 1 (Main Unit)	Heater 2	Heater 3
Vent through the side wall	☐ 1	☐ 1	☐ 1
Vent through the roof	☐ 2	☐ 2	☐ 2
No vent (electric tank)	☐ 3	☐ 3	☐ 3
Don't know	☐ 9	☐ 9	☐ 9

D8. If this residence has an on-demand (tankless or hybrid) water heater, does it have a:

	Heater 1 (Main Unit)	Heater 2	Heater 3
Metal vent	☐ 1	☐ 1	☐ 1
Plastic vent	☐ 2	☐ 2	☐ 2
No vent (electric tankless)	☐ 3	☐ 3	☐ 3
Don't know	☐ 9	☐ 9	☐ 9

D9. How old is (are) your water heater(s)?

Heater 1 (Main Unit) ______ years Don't know ☐ 99
Heater 2 ______ years Don't know ☐ 99
Heater 3 ______ years Don't know ☐ 99

D10. What is the size (volume) of the largest hot water tank in your home? The size is printed on the label attached to your tank.

☐ 1 On-demand (tankless or hybrid)
☐ 2 10 imperial gallons (46 litres)
☐ 3 33 imperial gallons (150 litres)
☐ 4 40 imperial gallons (182 litres)
☐ 5 60 imperial gallons (273 litres)
☐ 6 Other (please specify): _______________
☐ 9 Don't know

D11. Have you installed a water heater within the past five years?

Yes ☐ 1 → **CONTINUE**
No ☐ 2 → **GO TO QUESTION D13**

D12. What was the main reason you installed the water heater? (Check one only)

New home	☐ 1
Wanted to change to gas	☐ 2
Wanted more efficient water heater	☐ 3
Water heater had failed	☐ 4
Anticipated water heater failure	☐ 5
Needed more hot water	☐ 6
Wanted faster hot water recovery	☐ 7
Wanted an environmentally friendly fuel	☐ 8
Wanted a cheaper fuel	☐ 9
Other	☐ 10

D13. Some energy-efficient gas water heaters require access to an electrical outlet. Is there an electrical outlet within 5 feet (1.5 metres) of your current water heater?

☐ 1 Yes ☐ 2 No ☐ 9 Don't know

D14. Drain water heat recovery systems capture heat from drain pipes in the home and use this heat to reduce the amount of energy used by the water heater. Does this home use a drain water heat recovery system?

☐ 1 Yes ☐ 2 No ☐ 9 Don't know

Drain Heat Recovery System

D15. Please indicate the total number of the following for your residence:

	Number
Showerheads (all kinds)	______
Low flow showerheads	______
Water heater blankets	______
Instant hot water dispensers	______
Bathroom and kitchen faucet aerators	______

D16. Please indicate the total number of the following for all members of your household:

	Number
Number of dishwasher loads per week	______
Number of baths per week	______
Number of showers per week	______

D17. Please estimate the total amount of time that shower(s) are used on a typical weekday (total for all members of this residence).

_____ minutes per day ☐ 1 No showers – take baths only

A FRIENDLY REMINDER

Please ensure your survey responses refer to the residence at the address identified on the front page of this survey. Your responses will be kept strictly confidential.

To ensure you are eligible to win one of the four $1,000 gift certificates, make sure you return your survey by December 24, 2012 using the self-addressed postage-paid return envelope included with your survey package. Easier still, complete your survey online by December 24, 2012 and double your chance at winning a $1,000 gift certificate. Only one survey (paper or online) will be accepted per household.

Thank you for completing this important survey.

E. Swimming Pools & Hot Tubs

E1. Do you have a swimming pool at this residence?

Yes, indoor ☐ 1 }
Yes, outdoor ☐ 2 } → **CONTINUE**
No ☐ 3 → **GO TO QUESTION E7**

E2. Is this pool for the exclusive use of this residence (example: backyard pools in single family dwellings) or shared with other residences (example: pools in apartments / condominiums / townhouse complexes)?

Exclusive use only ☐ 1 → **CONTINUE**
Share with others ☐ 2 → **GO TO QUESTION E7**

E3. Which fuel do you use to heat the water in your pool and do you use solar energy to help heat the water?

	Main pool heater fuel	Supplemented with solar heating
Solar	☐ 1	
Natural gas	☐ 2	☐ 2
Electricity	☐ 3	☐ 3
Propane	☐ 4	☐ 4
Other	☐ 5	☐ 5

Pool not heated ☐ 6 → **GO TO QUESTION E6**

Solar Heating

There are two main types of solar heating. Photovoltaic panels which use light to power an electric appliance and thermal solar which uses the sun's heat to warm tubes filled with water or diluted antifreeze.

E4. How many months per year is your pool heated? ______ months per-year

E5. During the months when you heat your pool, do you cover it when not in use? Yes ☐ 1 No ☐ 2

E6. Does your pool pump use a high efficiency motor (often called a variable speed motor or electronically controlled motor (ECM))?

☐ 1 Yes ☐ 2 No ☐ 9 Don't know ☐ 3 Not applicable

E7. Do you have a hot tub at this residence?

Yes, indoor ☐ 1 }
Yes, outdoor ☐ 2 } → **CONTINUE**
No ☐ 3 → **GO TO QUESTION E12**

E8. Is this hot tub for the exclusive use of this residence (example: hot tubs in single family dwellings) or shared with other residences (example: hot tubs in apartments / condominiums / townhouse complexes)?

Exclusive use only ☐ 1 → **CONTINUE**
Share with others ☐ 2 → **GO TO QUESTION E12**

E9. What fuel is used to heat the hot tub?

Natural gas ☐ 1 Solar ☐ 3 Other ☐ 5
Propane ☐ 2 Electricity ☐ 4

E10. How many months per year is your hot tub heated? _____ months

E11. During the months when you heat your hot tub, do you cover it when not in use? Yes ☐ 1 No ☐ 2

E12. Does this residence have a sauna that is for your exclusive use?

Yes ☐ 1 → **CONTINUE**
No ☐ 2 → **GO TO SECTION F**

E13. What fuel is used to heat the sauna?

Electricity ☐ 1 Propane ☐ 3 Don't know ☐ 9
Natural gas ☐ 2 Other ☐ 4

F. Appliances

F1. Please indicate the number of each of the following appliances in use in this residence. For each appliance please indicate the approximate age (your best guess is fine). If you do not have the appliance, please check the "0" box.

	Number in Use 0	1	2	3+	Age of Appliance (in years) #1	#2	#3
COOKING							
Electric range (cook top and oven)	☐ 0	☐ 1	☐ 2	☐ 3			
Gas range (cook top and oven)	☐ 0	☐ 1	☐ 2	☐ 3			
Dual fuel range (gas cook top, electric oven)	☐ 0	☐ 1	☐ 2	☐ 3			
Electric cook top	☐ 0	☐ 1	☐ 2	☐ 3			
Gas cook top	☐ 0	☐ 1	☐ 2	☐ 3			
Electric wall oven	☐ 0	☐ 1	☐ 2	☐ 3			
Gas wall oven	☐ 0	☐ 1	☐ 2	☐ 3			
Microwave oven	☐ 0	☐ 1	☐ 2	☐ 3			
Gas barbeque (piped gas)	☐ 0	☐ 1	☐ 2	☐ 3			
Gas barbeque (bottled gas)	☐ 0	☐ 1	☐ 2	☐ 3			
Commercial grade range hood	☐ 0	☐ 1	☐ 2	☐ 3			
REFRIGERATION							
Refrigerator – manual defrost	☐ 0	☐ 1	☐ 2	☐ 3			
Refrigerator – automatic defrost	☐ 0	☐ 1	☐ 2	☐ 3			
Stand alone freezer – upright	☐ 0	☐ 1	☐ 2	☐ 3			
Stand alone freezer – chest style	☐ 0	☐ 1	☐ 2	☐ 3			
CLEANING							
Dishwasher	☐ 0	☐ 1	☐ 2	☐ 3			
Clothes washer - top load	☐ 0	☐ 1	☐ 2	☐ 3			
Clothes washer - front load	☐ 0	☐ 1	☐ 2	☐ 3			
Electric clothes dryer	☐ 0	☐ 1	☐ 2	☐ 3			
Gas clothes dryer	☐ 0	☐ 1	☐ 2	☐ 3			
HEATING							
Air source heat pump	☐ 0	☐ 1	☐ 2	☐ 3			
Ground source heat pump	☐ 0	☐ 1	☐ 2	☐ 3			
Heat recovery ventilator/ make up air unit	☐ 0	☐ 1	☐ 2	☐ 3			
Gas outdoor heater (piped gas)	☐ 0	☐ 1	☐ 2	☐ 3			
Gas outdoor heater (bottled gas)	☐ 0	☐ 1	☐ 2	☐ 3			
Gas outdoor fire pit or fireplace	☐ 0	☐ 1	☐ 2	☐ 3			

F2. Please indicate below the number of each appliance in this residence, the months of the year the appliance is regularly used, and the average number of hours per day when in use. If an appliance is in use year-round, write in Jan – Dec for the months in use.

	Number in Use 0	1	2	3+	Used in a typical year From (month)	To (month)	Average # hours per day when used
Central air conditioner	☐ 0	☐ 1	☐ 2	☐ 3			
Portable air conditioner	☐ 0	☐ 1	☐ 2	☐ 3			
Room window air conditioner	☐ 0	☐ 1	☐ 2	☐ 3			
Portable fan	☐ 0	☐ 1	☐ 2	☐ 3			
Humidifier	☐ 0	☐ 1	☐ 2	☐ 3			
Dehumidifier	☐ 0	☐ 1	☐ 2	☐ 3			
Portable electric heater	☐ 0	☐ 1	☐ 2	☐ 3			
Rotating ceiling fans without light fixtures	☐ 0	☐ 1	☐ 2	☐ 3			
Rotating ceiling fans with light fixtures	☐ 0	☐ 1	☐ 2	☐ 3			

F3. How likely are you to buy a portable, room, or central air conditioner in the next 12 months?

	Definitely will	Most likely will	Might or might not	Most likely will not	Definitely will not
Portable air conditioner	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
Room or window air conditioner	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
Central air conditioner	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5

SECTIONS G AND H APPLY TO FORTISBC ELECTRICITY CUSTOMERS ONLY. THESE SECTIONS HAVE BEEN OMITTED FROM YOUR SURVEY.

I. Renovations & Energy Use

I1. Please indicate renovations or actions you have undertaken at this residence during the past five years, whether you received a government or utility rebate to complete them, and the renovations you plan to undertake within the next two years.

	Did this – past 5 years		Plan to do this – next 2 years
	With rebate	Without rebate	
Improve insulation in walls, attic, basement, or crawlspace	☐ 1	☐ 1	☐ 1
Install energy-efficient window(s)	☐ 2	☐ 2	☐ 2
Install insulated outside door(s) or storm doors	☐ 3	☐ 3	☐ 3
Install low flow showerhead(s)	☐ 4	☐ 4	☐ 4
Install programmable thermostat(s)	☐ 5	☐ 5	☐ 5
Install pipe wrap	☐ 6	☐ 6	☐ 6
Install weather stripping or caulking	☐ 7	☐ 7	☐ 7
Install hot water heater blanket	☐ 8	☐ 8	☐ 8
Install drain pipe waste heat recovery system	☐ 9	☐ 9	☐ 9
Install on-demand (tankless or hybrid) water heater	☐ 10	☐ 10	☐ 10
Install high efficiency hot water tank	☐ 11	☐ 11	☐ 11
EcoENERGY or LiveSmart BC certified energy audit completed	☐ 12	☐ 12	☐ 12
Install a sauna		☐ 13	☐ 13
Install heated swimming pool		☐ 14	☐ 14
Install hot tub		☐ 15	☐ 15
None of the above	☐ 0		☐ 0

I2. Did you undertake any renovations that involve fireplaces or heating stoves at this residence in the past five years, or plan to do so in the next two years?

☐ 1 Yes → **CONTINUE**
☐ 2 No → **GO TO QUESTION I5**

I3. Please indicate the renovations that involve fireplaces or heating stoves that you did at this residence during the past five years, whether you received a government or utility rebate to complete them, and those you plan to undertake within the next two years.

Note: there several types of fireplaces available in the market today. Please read carefully and select the category that best describes your renovation plan involving fireplaces.

	Did this – past 5 years		Plan to do this – next 2 years
	With rebate	Without rebate	
Install free standing gas fireplace or heating stove	☐ 1	☐ 1	☐ 1
Install wood stove	☐ 2	☐ 2	☐ 2
Install gas heater type fireplace insert in an existing wood fireplace	☐ 3	☐ 3	☐ 3
Replace decorative gas fireplace with gas heater type insert	☐ 4	☐ 4	☐ 4
Remove or disconnect gas fireplace		☐ 5	☐ 5
Remove wood fireplace or wood stove		☐ 6	☐ 6
Install decorative gas fireplace		☐ 7	☐ 7
Install electric fireplace		☐ 8	☐ 8
None of the above	☐ 0		☐ 0

I4. **IF YOU INSTALLED A GAS FIREPLACE IN THE PAST FIVE YEARS:** **Was this gas fireplace an ENERCHOICE model?**

☐ 1 Yes ☐ 2 No ☐ 9 Don't know

I5. Which of the following home renovations would you typically do yourself, use a contractor, or both do it yourself and use a contractor?

	Do it myself	Use a contractor	Both
Install new appliances (dishwashers, laundry machines, other)	☐ 1	☐ 2	☐ 3
Install / replace windows	☐ 1	☐ 2	☐ 3
Install low flow showerheads	☐ 1	☐ 2	☐ 3
Improve weather stripping / draft proofing	☐ 1	☐ 2	☐ 3
Improve insulation in walls, ceilings or attics	☐ 1	☐ 2	☐ 3

EnerChoice Gas Fireplaces

All new fireplaces and heater stoves are required to be CSA approved and display an EnerGuide label which shows how much energy they consume.

Fireplaces and heater stoves that also display an **ENERCHOICE** label are the most energy-efficient models on the market today.

ENER CHOICE
ENERCHOICE.ORG

I6. How influential are the following sources of information when purchasing a major appliance.

		Not at all Influential 1	2	3	4	Very Influential 5
a.	Contractors / tradespeople	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
b.	Customer ratings	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
c.	Expert reviews (e.g., magazines, websites, TV)	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
d.	Electric or gas utilities	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
e.	Government	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
f.	Appliance salespeople	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
g.	Knowledgeable family member, friend, or neighbour	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5

Thank you for participating in this important survey. You have completed about 70% of the survey.

J. Managing Energy Use

This section is intended to help FortisBC understand how you use / manage energy at this residence.

J1. At what temperature do you usually keep this residence during the winter (heating) season? If this residence has air conditioning (central, window, portable, or heat pump), also tell us what temperature you usually keep this residence during the summer (cooling) season.

	Winter (Heating)			Summer (Cooling)		
	Degrees C	or	Degrees F	Degrees C	or	Degrees F
When someone is at home	___		___	___		___
When no one is home	___		___	___		___
During the night	___		___	___		___

☐ Do not use air conditioning

Next, we would also like to understand the types of actions that you take to manage energy usage at this residence. Please check the answer that best describes what you normally do.

J2. Space Heating

		Always	Usually	Occasionally	Never	Don't Know	Not Applicable
a.	Close window coverings to keep in heat	☐1	☐2	☐3	☐4	☐5	☐6
b.	Turn down the heat at night either manually or using a programmable thermostat	☐1	☐2	☐3	☐4	☐5	☐6
c.	Turn down the heat either manually or using a programmable thermostat when no one is at home	☐1	☐2	☐3	☐4	☐5	☐6
d.	Reduce temperature in unused rooms by closing vents or turning down room thermostats	☐1	☐2	☐3	☐4	☐5	☐6
e.	Check and re-seal air leaks in the house at least once a year (weather stripping and caulking)	☐1	☐2	☐3	☐4	☐5	☐6
f.	If single pane windows, install storm windows each fall	☐1	☐2	☐3	☐4	☐5	☐6
g.	Install plastic window coverings on drafty windows during winter months	☐1	☐2	☐3	☐4	☐5	☐6

J3. Are you able to reduce the temperature in unoccupied rooms at this residence? This could be done by turning down individual room thermostats, closing doors, and closing vents?

☐ Yes ☐ No ☐ Don't Know

J4. Air Conditioning / Cooling

		Always	Usually	Occasion-ally	Never	Don't Know	Not Applicable
a.	Set the thermostat at 26 degrees C (78°F) or higher during the summer to save energy	☐1	☐2	☐3	☐4	☐5	☐6
b.	Close the window coverings (drapes, blinds, etc.) during hot weather to reduce heat in the dwelling	☐1	☐2	☐3	☐4	☐5	☐6
c.	Clean the air conditioner filter and coils at least once per season	☐1	☐2	☐3	☐4	☐5	☐6
d.	Turn on air conditioning only when very hot and natural ventilation is insufficient	☐1	☐2	☐3	☐4	☐5	☐6

J5. Have you done either of the following to keep this residence cool:

	Yes	No	Don't know
Planted trees or other vegetation	☐ 1	☐ 2	☐ 9
Installed shading devices (i.e., awnings, pergolas)	☐ 1	☐ 2	☐ 9

J6. Water Usage

		Always	Usually	Occasion-ally	Never	Don't Know	Not Applicable
a.	Turn off the water heater or use its "vacation setting" when no one is home for more than 2 or 3 days	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
b.	Only do laundry with full loads	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
c.	Clean the dryer lint filter before drying clothes	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
d.	Use the dryer's temperature / moisture sensor to turn off the dryer rather than using timed dry	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
e.	Hang clothes to dry rather than machine dry	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
f.	Only run dishwasher when full	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
g.	Air dry the dishes in the dishwasher rather than use the dry cycle	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6

J7. How many loads of laundry does your household do per week?

Number of loads done in cold, warm or hot water _____ per week
Number of loads using cold water wash and rinse only _____ per week
Number of dryer loads _____ per week
Number of loads dried using a clothes line or drying rack during SUMMER _____ per week
Number of loads dried using a clothes line or drying rack during WINTER _____ per week

J8. How much extra cold water wash and rinse could you do?

Number of loads more _____ per week ☐ 0 None, already doing all I can

J9. Lighting

		Always	Usually	Occasion-ally	Never	Don't Know	Not Applicable
a.	Only have the minimum number of lights on in a room for what I am doing	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
b.	Turn off the lights when on one is in the room	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
c.	Leave outdoor lights on at night (exclude those you do not control)	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
d.	Check timers to reflect daylight savings time	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6

J10. Refrigeration

		Always	Usually	Occasion-ally	Never	Don't Know	Not Applicable
a.	Clean the refrigerator coils at least once a year	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
b.	Check the temperature of the refrigerator to ensure food is not too cold or warm	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6
c.	Check the temperature of your freezer to ensure food remains frozen, but that the freezer is not too cold	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5	☐ 6

J11. Other

		Always	Usually	Occasion-ally	Never	Don't Know	Not Applicable
a.	Turn off TV / entertainment systems when no one is in the room and actively using them	☐1	☐2	☐3	☐4	☐5	☐6
b.	Turn off the computer and printers when not in use	☐1	☐2	☐3	☐4	☐5	☐6
c.	Unplug or use a power bar to turn off TVs, entertainment systems, and computers when not in use?	☐1	☐2	☐3	☐4	☐5	☐6
d.	Leave one or more windows open during winter	☐1	☐2	☐3	☐4	☐5	☐6

J12. What, if anything, would encourage you to use less energy at this residence?

____

____

J13. What prevents you from using less energy at this residence?

____

____

J14. Who makes the most effort to conserve electricity / gas in your household? Choose the most appropriate answer.

- ☐1 Myself
- ☐2 Someone else in the household
- ☐3 Most members of the household
- ☐4 All members of the household
- ☐0 None of us

K. Products & Services

K1. How familiar are you with the following brand names?

	1 (Not at all familiar)	2	3	4	5 (Very familiar)
PowerSense (FortisBC)	☐	☐	☐	☐	☐
PowerSmart (BC Hydro)	☐	☐	☐	☐	☐
ENERGY STAR	☐	☐	☐	☐	☐
LiveSmart BC	☐	☐	☐	☐	☐

K2. During the last five years, did your household participate in any of the following programs that offered rebates to reduce energy use in your home?

Check all that apply

- ecoENERGY / LiveSmart BC ☐1
- PowerSense (FortisBC Electric) ☐2
- FortisBC Energy (formerly Terasen Gas) ☐3
- PowerSmart (BC Hydro) ☐4
- None of the above ☐0

K3. On a scale of one to four, where one is not at all interested and four is very interested, how interested would you be in the following products and services?

		Not at all Interested 1	2	3	Very Interested 4
a.	Home energy audit to determine main energy uses in the home and identify opportunities to save energy	☐1	☐2	☐3	☐4
b.	Do-it-yourself online energy audit	☐1	☐2	☐3	☐4
c.	Furnace or heat pump tune-up to ensure they are working safely and efficiently	☐1	☐2	☐3	☐4
d.	Program to replace a low efficiency furnace with a high efficiency furnace	☐1	☐2	☐3	☐4
e.	Program to install high efficiency gas fireplace	☐1	☐2	☐3	☐4
f.	Program to replace standard efficiency clothes washer with high efficiency clothes washer	☐1	☐2	☐3	☐4
g.	Program to replace standard efficiency water heater with high efficiency water heater	☐1	☐2	☐3	☐4
h.	Program to upgrade attic and wall insulation	☐1	☐2	☐3	☐4
i.	Program to improve draft proofing	☐1	☐2	☐3	☐4
j.	Program to install programmable thermostats	☐1	☐2	☐3	☐4
k.	Program to install an in-home display that allows you to monitor your home's energy usage	☐1	☐2	☐3	☐4
l.	Program to purchase an electric automobile	☐1	☐2	☐3	☐4
m.	Program to compare your home's energy use with homes of comparable size and type	☐1	☐2	☐3	☐4
n.	Program that allows you to pay for energy-efficient improvements to your home via instalments on your utility bill	☐1	☐2	☐3	☐4

K4. Thinking about major appliance purchase decisions for this residence, please indicate your role in the decision making process.

☐1 I am the sole decision maker
☐2 Someone else in the house makes the decision
☐3 Decisions are made jointly between myself and another person

K5. Does this residence have access to the Internet?

☐1 Yes, high speed (ADSL, cable, smart phone, other)
☐2 Yes, dial up modem
☐3 No Internet access

K6. How comfortable are you with navigating the Internet?

☐1 Very comfortable
☐2 Somewhat comfortable
☐3 Not very comfortable
☐4 Not at all comfortable

L. Attitudes Towards Energy Use

L1. In order to serve you better, we would like to understand your views on a number of energy-related issues. For the following set of statements, please check the answer that most accurately reflects your agreement or disagreement with the statement.

On a scale of one to five, where one means that you strongly disagree and five means that you strongly agree, please indicate how much you agree or disagree with the following statements on energy and natural gas usage.

		Strongly Disagree 1	2	Neither Agree or Disagree 3	4	Strongly Agree 5
a.	There are many ways that a person can save energy when you add them up, they result in substantial savings	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
b.	By making my home more energy-efficient, I am helping to do my part for the environment	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
c.	I think natural gas is a clean and efficient energy source	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
d.	Members of my household regularly limit the length of their showers to save energy	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
e.	I don't want to think about natural gas or electricity, I simply want it to work	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
f.	I consider natural gas to be a safe energy source	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
g.	When something needs to be done around home, I usually hire someone	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
h.	I almost always have a home renovation on the go	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
i.	It is cheaper to heat a home with natural gas than it is with electricity	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
j.	Our household has reduced its energy use by as much as reasonably possible	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
k.	I am a busy person with little or no time to research ways to save energy	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
l.	I conserve energy because it saves money not because it helps the environment	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5

L2. On a scale of one to five, where one means that you strongly disagree and five means that you strongly agree, please indicate how much you agree or disagree with the following statements.

		Strongly Disagree 1	2	Neither Agree or Disagree 3	4	Strongly Agree 5
a.	I am usually the first one to try new products	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
b.	I am usually willing to pay more for brand name items	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
c.	I prefer dealing with British Columbia based companies	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
d.	I always look for the best price when buying products or services	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
e.	I usually take time to research issues thoroughly before making a decision	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5
f.	I am the type of person to have good insurance coverage	☐ 1	☐ 2	☐ 3	☐ 4	☐ 5

M. About your Household

The final questions are for classification purposes only and are completely confidential, as are all your answers.

QUESTIONS M1 & M2 APPLY TO FORTISBC ELECTRICITY CUSTOMERS ONLY. THESE QUESTIONS HAVE BEEN OMITTED FROM YOUR SURVEY.

M3. Into which of the following age categories do you fit?

18 years or under ☐ 1
19-24 years ☐ 2
25-34 years ☐ 3
35-44 years ☐ 4
45-54 years ☐ 5
55-64 years ☐ 6
65 years and older ☐ 7

M4. You are: Female ☐ 1 Male ☐ 2

M5. What is your marital status?

Single ☐ 1
Married/common law ☐ 2
Divorced/separated ☐ 3
Widowed ☐ 4

M6. How many people, including yourself, are currently living at this residence (please include any boarders or renters covered under your FortisBC account)

_____ number

M7. Please indicate the number of occupants by age categories

	0	1	2	3	4	5	6+
0 – 5 years	☐	☐	☐	☐	☐	☐	☐
6 - 12 years	☐	☐	☐	☐	☐	☐	☐
13 - 18 years	☐	☐	☐	☐	☐	☐	☐
19 - 24 years	☐	☐	☐	☐	☐	☐	☐
25 - 44 years	☐	☐	☐	☐	☐	☐	☐
45 - 64 years	☐	☐	☐	☐	☐	☐	☐
65 years and older	☐	☐	☐	☐	☐	☐	☐

M8. Has the number of people in this residence changed in the last two years?

Yes ☐ 1 No ☐ 2 → **GO TO QUESTION M10**

M9. How has the number of people in this residence changed over the past two years (please check the best answer)?

In the past there were more people in this residence ☐ 1
In the past there were fewer people in this residence ☐ 2
In the past there were sometimes more people and sometimes fewer people in this residence ☐ 3

M10. What is the highest level of education you have completed?

Some high school ☐ 1
Completed high school ☐ 2
Some trade/technical school ☐ 3
Completed trade/technical school ☐ 4
Some university/college ☐ 5
Completed university/college ☐ 6
Post graduate ☐ 7

M11. What was your total household income before taxes in 2011?

Less than $20,000	☐ 1	$60,000 to $79,999	☐ 6
$20,000 to $29,999	☐ 2	$80,000 to $99,999	☐ 7
$30,000 to $39,999	☐ 3	$100,000 to $124,999	☐ 8
$40,000 to $49,999	☐ 4	$125,000 or more	☐ 9
$50,000 to $59,999	☐ 5	Prefer not to answer	☐ 10

M12. What are the languages spoken at this residence?

	Main language *(check one only)*	**Other languages** *(check all that apply)*
English	☐ 1	☐ 1
Mandarin	☐ 2	☐ 2
Cantonese	☐ 3	☐ 3
Hindi	☐ 4	☐ 4
Punjabi	☐ 5	☐ 5
Tagalog	☐ 6	☐ 6
Farsi (Persian)	☐ 7	☐ 7
French	☐ 8	☐ 8
German	☐ 9	☐ 9
Other (please specify):	☐ 10 ______________	☐ 10 ________________

M13. From time to time, FortisBC hires market research contractors to conduct research. This is done to better understand our customers' needs and gather information to design programs to help you save money on your energy bill.

Do we have your permission to contact you in the future for the purpose of additional market research? If yes, please provide your name and telephone number below. This is only permission to contact you. You are not obligated to participate if contacted by us or a market research company we hire.

☐ 1 YES - it is OK to contact me for follow-up research

First name: ____________________

Last name: ____________________

Telephone: ____ - ____ - ______

Email: ___________________________ (optional)

FortisBC and Ipsos would like to thank you for your help and assistance.
If you have any questions please contact Walter Wright, Market Research, FortisBC, at 604-592-7653 or walter.wright@fortisbc.com.

Win a $ 1000 Gift Certificate

Contest Rules

1. All entries must be received by Ipsos by December 24, 2012. Limit of one entry per eligible entrant. A contestant's name will be determined by a random draw on January 21, 2013 from all entries received. To win, the selected contestant must answer a time limited mathematical skill-testing question, without mechanical or other assistance.
2. The selected contestant will be notified by telephone by Ipsos. Ipsos will attempt to reach the selected contestant no more than 3 times. If Ipsos is unable to contact him or her within 5 days of the draw date, Ipsos may draw the name of another contestant to be eligible for the prize.
3. Contestants who complete and return the survey form by mail will have their name entered once in the draw. Contestants who complete the survey form online will have their name entered into the draw twice.
4. Contestants must be residents of British Columbia.
5. FortisBC customers who have completed and returned the FortisBC 2012 Residential End-Use Survey by December 24, 2012 are automatically entered and no further action is required on the part of the customer. To enter without completing the survey, mail a letter with your name, telephone number and address to Ipsos, 1285 West Pender Street, 2nd Floor, Vancouver, BC, V6E 4B1. Mark the envelope "Residential Survey Contest".
6. Chances of winning are based on the number of eligible entries received via mail and online.
7. Employees or agents of FortisBC and their immediate families are not eligible to win.
8. There are four $1,000 prizes to be awarded, each prize is a $1,000 gift certificate from a home improvement store located near the prize winner.
9. FortisBC and Ipsos assume no responsibility for lost or misdirected entry forms.
10. By entering, contestants agree to abide by the contest rules and that the decision of the judge shall be final.

Appendix B

2012 REUS Conditional Demand Analysis Equations and Detailed Estimates

APPENDIX B

2012 REUS Conditional Demand Analysis Detailed Methodology

Conditional Demand Analysis (CDA) was used to disaggregate total household consumption into UECs for several residential end-uses. CDA is based on the notion that total household consumption is directly related to the stock of end-uses present in the dwelling and the energy consumption levels associated with these end-uses (UECs). The basic conditional demand model can be represented as:

$$HEC_{ht} = \sum_{all\ a} UEC_{aht} S_{ah}$$

where HEC_{ht} is the total energy consumption by household *h* in month *t*, UEC_{aht} is the energy consumption through end-use *a* by household *h* in month *t*, and S_{ah} is the presence or absence of end-use *a* in household *h*.

The UECs for these end-uses are modelled as functions of appropriate exogenous variables, such as end-use features, dwelling characteristics and household utilization patterns. In the remainder of this section, we describe the functional forms for each end-use.

B1. Primary Gas Space Heating

The primary gas space heating usage for household *h* in month *t* is based on a balance equation:

$$UEC_{gasheat,ht} = \frac{HEATLOSS_{ht} - SECHT_{ht}}{EFFH_h}$$

where $HEATLOSS_{ht}$ is the net heat loss, $SECHT_{ht}$ is the heat loss replaced by non-gas secondary heating systems, and $EFFH_h$ is the system efficiency.

B1.1 Net Heat Loss

The net heat loss of a structure can be expressed as:

$$HEATLOSS_{ht} = SURFLOSS_{ht} - SOLGAIN_{ht} - INTGAIN_{ht}$$

where $SURFLOSS_{ht}$ is the heat loss through envelope surfaces, $SOLGAIN_{ht}$ is the solar gain through all surfaces during heating periods, and $INTGAIN_{ht}$ is the internal gains during heating periods.

B1.1.1 Heat Loss through Envelope

The heat loss through envelope surfaces is given by:

$$SURFLOSS_h = \alpha_1 U_h AREA_h TDIFF_{ht}$$

APPENDIX B

where U_h is the overall conductivity of the shell, $AREA_h$ is the total surface area, and $TDIFF_{ht}$ is the differential between inside and outside temperature levels.

B1.1.2 Shell Conductivity

The conductivity of the shell is assumed to depend on dwelling type, the percentage of windows and doors that are insulated, and whether or not the attic, walls and basement are insulated:

$$U_h = \begin{cases} \alpha_1 + \alpha_2 MFD_h + \alpha_3 VS_h + \alpha_4 INSULA_h + \alpha_5 INSULW_h + \alpha_6 BASEMENT_h INSULB_h \\ + \alpha_7 DOORS_h + \alpha_8 WINDBL_h + \alpha_9 WINDBEST_h \end{cases}$$

where MFD_h equals one if the household dwelling is a multi-family dwelling (duplex or row/townhouse), VS_h equals one if the dwelling is a vertical subdivision (apartment/condominium), $INSULA_h$ equals one if the attic is insulated, $INSULW_h$ equals one if the walls are insulated, $BASEMENT_h$ equals one if a basement or crawl space is present, $BASEINSUL_h$ equals one if the basement or crawl space is insulated, $DOORS_h$ is the proportion of exterior doors that are insulated (aluminium storm doors or insulated doors), $WINDBL_h$ is the percentage of windows with double pane glass, and $WINBEST_h$ is the percentage of windows with more insulation than double pane (double pane low-E or triple pane, regular or low-E).

B1.1.3 Surface Area

The surface area of the structure is modelled as a function of the total floor area:

$$AREA_h = \alpha_1 SQFT_h^{\beta}$$

where $SQFT_h$ is the square footage of the household and β is the elasticity of surface area with respect to square footage. We assumed that β equals 0.5 (i.e. the square root) because the surface area of the building shell increases less than proportionately with floor area for standard shaped buildings.

B1.1.4 Temperature Differential

The differential between inside and outside temperature levels is modelled as a function of heating degree days and household heating behaviour[67]:

$$TDIFF_{ht} = HDD_{ht}\left(\alpha_1 + \alpha_2 TDNIGHT_h + \alpha_3 TDDAY_h + \alpha_4 TDUNUSED_h + \alpha_5 WINTER_t WINCVR_h\right)$$

where HDD_{ht} is heating degree days, $TDNIGHT_h$ is the frequency of turning down the heat at night either manually or using a programmable thermostat, $TDDAY_h$ is the frequency of turning down the heat either manually or using a programmable thermostat when no one is at home, $TDUNUSED_h$ is the frequency of reducing the temperature in unused rooms by closing vents or turning down room thermostats, and $WINCVR_{ht}$ is the frequency of using plastic window coverings on drafty windows during winter months.

[67] An attempt was made to include household income, but the variable was not retained in the final model because it was not statistically significant.

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B1.1.5 Solar Gain

The solar gain through all surfaces during heating periods is modelled as a function of the surface area of the home:

$$SOLGAIN_{ht} = \alpha_1 AREA_h WINTER_t$$

where $WINTER_t$ equals one if t is a winter month (December, January or February).

B1.1.6 Internal Gain

The internal gain during heating periods is also modelled as a function of the surface area of the home:

$$INTGAIN_{ht} = \alpha_1 AREA_h WINTER_t$$

B1.2 Non-gas Secondary Heating System

The heat loss replaced by a non-gas secondary heating system, given that a primary gas heating system is present, can be expressed as:

$$SECHT_{ht} = HDD_{ht} AREA_h \left(\alpha_1 NONGASSEC_h + \alpha_2 HEATPUMPSEC_h\right)$$

where $NONGASSEC_h$ equals one if non-gas secondary space heating is present (e.g. non-gas fireplace, woodstove, electric baseboards, etc.) and $HEATPUMPSEC_h$ equals one if a heat pump (air or ground) is used for secondary space heating.

B1.3 System Efficiency

An attempt was made to model system efficiencies in terms of the efficiency level of the gas furnace or boiler. However, this variable was not retained in the final model because there were too many missing values. Therefore, we assumed that $EFFH_h$ is constant across households.

B1.4 Overall Primary Gas Space Heating Model

Combining the preceding equations gives the overall model of primary gas space heating usage:

$$UEC_{gasheat,ht} = \begin{cases} HDD_{ht} AREA_h (\alpha_1 + \alpha_2 MFD_h + \alpha_3 VS_h + \alpha_4 INSULA_h + \alpha_5 INSULW_h \\ + \alpha_6 BASEMENT_h INSULB_h + \alpha_7 DOORS_h + \alpha_8 WINDBL_h + \alpha_9 WINBEST_h \\ + \alpha_{10} TDNIGHT_h + \alpha_{11} TDDAY_h + \alpha_{12} TDUNUSED_h + \alpha_{13} WINTER_t WINCVR_h \\ + \alpha_{14} NONGASSEC_h + \alpha_{15} HEATPUMPSEC_h) + \alpha_{16} AREA_h WINTER_t \end{cases}$$

In the specification above, most of the interaction terms are not shown because they were not statistically significant or produced unreasonable results.

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B2. Secondary Gas Space Heating

Secondary gas space heating includes any additional or supplementary use of gas to heat the residence (e.g., furnaces, gas wall heaters, etc.) The use of gas fireplaces and heater stoves is modelled separately.

The secondary gas space heating usage is modelled simply as a function of heating degree days, total surface area and dwelling type:

$$UEC_{gassecheat,ht} = HDD_{ht} AREA_h (\alpha_1 + \alpha_2 MFD_h + \alpha_3 VS_h)$$

B3. Fireplaces and Heater Stoves

The energy usage by gas fireplaces and heater stoves (decorative, heater type and freestanding) is assumed to depend on the number of fireplaces in use and heating degree days[68]:

$$UEC_{gasfiredec,ht} = GASFIREDEC_h (\alpha_1 + \alpha_2 HDD_{ht})$$

$$UEC_{gasfireheat,ht} = GASFIREHEAT_h (\alpha_1 + \alpha_2 HDD_{ht})$$

$$UEC_{gasfirefree,ht} = GASFIREFREE_h (\alpha_1 + \alpha_2 HDD_{ht})$$

where $GASFIREDEC_h$ is the number of declarative gas fireplaces, $GASFIREHEAT_h$ is the number of heater type gas fireplaces, and $GASFIREFREE_h$ is the number of free standing fireplaces or heater stoves in use.

B4. Water Heating

Gas water heating energy usage can be expressed as:

$$UEC_{gaswheat,ht} = \frac{WHLOSS_{ht} + VUSE_{ht}}{EFFWH_h}$$

where $WHLOSS_{ht}$ is the heat losses associated with standby losses from the heating unit, $VUSE_{ht}$ is the heat losses tied to water usage, and $EFFWH_h$ is the efficiency of the unit.

B4.1 Standby Losses

The heat losses associated with standby losses is assumed to depend on whether or not the home is new, whether solar energy is used to pre-warm or supplement the water heating process, whether an on-demand (tankless) water heater is used, and the temperature differential between the tank temperature and the inlet temperature[69]:

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[68] An attempt was made to include variables representing the average number of hours in use, the percentage of space heating requirements provided by the fireplace, and if the fireplace is used primarily for heating, ambiance or both. These variables were not retained in the final model because they were not statistically significant or produced unreasonable results.

[69] An attempt was made to include variables involving dwelling type, the size of the main hot water tank, number of household members (a proxy for tank size), and the presence or absence of water heater blankets. These variables were not retained in the final model because they were not statistically significant or produced unreasonable results.

$$WHLOSS_{ht} = WHTDIFF_{ht}(\alpha_1 + \alpha_2 NEWHOME_h + \alpha_3 SOLARSUP_h + \alpha_4 ONDEMAND_h)$$

where $WHTDIFF_{ht}$ is the differential between the tank temperature and the inlet temperature, $NEWHOME_h$ equals one if the home is new (2006 or later), $SOLARSUP_h$ equals one if the water heater uses solar energy to pre-warm or supplement the water heating process, and $ONDEMAND_h$ equals one if an on-demand (tankless) water heater is used.

The differential between tank temperature and inlet temperature is modelled simply as a function of heating degree days:

$$WHTDIFF_{ht} = \alpha_1 HDD_{ht}$$

B4.2 Water Usage

The heat losses tied to water usage is assumed to depend on the average number of dishwasher and clothes washer loads, the average number of baths and showers taken, whether or not a front loading clothes washer is present, the proportion of low-flow showerheads, and whether or not instant hot water dispensers are present:

$$VUSE_{ht} = \begin{cases} \alpha_1 DWASHLOADS_h + \alpha_2 CWASHLOADS_h + \alpha_3 BATHS_h + \alpha_4 SHOWERS_h \\ + \alpha_5 CWASHERFRONT_h + \alpha_6 PROPLOWFLOW_h + \alpha_7 INHOTWATERDISP_h \end{cases}$$

where $DWASHLOADS_h$ is the number of dishwasher loads per week, $CWASHLOADS_h$ is the number of clothes washer loads per week, $BATHS_h$ is the number of baths taken per week, $SHWRS_h$ is the number of showers taken per week, $CWASHERFRONT_h$ equals one if a front loading clothes washer is used, $PROPLOWFLOW_h$ is the proportion of low-flow showerheads, and $INHOTWATERDISP_h$ equals one if instant hot water dispensers are used.

B4.3 System Efficiency

An attempt was made to model system efficiencies in terms of the age of the water heater. However, this variable was not retained in the final model because there were too many missing values. Therefore, we assumed that $EFFWH_h$ is constant across households.

B4.4 Overall Gas Water Heating Model

Combining the preceding equations gives the overall model for gas water heating energy usage:

$$UEC_{gaswheatht} = \begin{cases} HDD_{ht}(\alpha_1 + \alpha_2 NEWHOME_h + \alpha_3 SOLARSUP_h + \alpha_4 ONDEMAND_h) \\ + \alpha_5 DWASHLOADS_h + \alpha_6 CWASHLOADS_h + \alpha_7 BATHS_h + \alpha_8 SHOWERS_h \\ + \alpha_9 CWASHERFRONT_h + \alpha_{10} PROPLOWFLOW_h + \alpha_{11} INHOTWATERDISP_h \end{cases}$$

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B5. Cooking

Energy consumption of gas cooking appliances (gas ranges, cook tops, ovens and duel fuel ranges) is assumed to depend on the number of these appliances in use[70]:

$$UEC_{gascook,ht} = \alpha_1 GASCOOK_h$$

where $GASCOOK_h$ is the number of gas ranges, cook tops, ovens and duel fuel ranges in use.

B6. Gas BBQs

Energy consumption of piped gas BBQs is modelled as a function of the number in use[71]:

$$UEC_{gasbbq,ht} = \alpha_1 GASBBQ_h$$

where $GASBBQ_h$ is the number of piped gas barbeques in use.

B7. Gas Dryers

Energy consumption of gas dryers is modelled as a function of the number in use[72]:

$$UEC_{gasdryer,ht} = \alpha_1 GASDRYER_h$$

where $GASDRYER_h$ is the number of gas dryers in use.

B8. Swimming Pools

Energy consumption through the operation of swimming pools is assumed to be constant for those households with gas-heated swimming pools[73]:

$$UEC_{gasheatpool,ht} = \alpha_1$$

[70] An attempt was made to include variables involving household size, income and the presence of a microwave. These variables were not retained in the final model because they were not statistically significant or produced unreasonable results.

[71] An attempt was made to include a variable involving household size. This variable was not retained in the final model because it was not statistically significant.

[72] An attempt was made to model the number of dryer loads done per week. This variable was not retained in the final model because it was not statistically significant.

[73] An attempt was made to model whether or not the pool is covered when not in use and whether or not solar supplementary heating is used. These variables were not retained in the final model because they were not statistically significant or produced unreasonable results.

B9. Hot Tubs

Energy consumption through the operation of hot tubs is assumed to be constant for those households with gas-heated hot tubs[74]:

$$UEC_{gashottub,ht} = \alpha_1$$

B10. Regional Analysis

CDA models typically require large sample sizes and depend on a mix or diversity of end-uses among survey respondents to isolate their UECs statistically. In contrast to the 2008 CDA[75], the larger sample sizes in the 2012 REUS allowed us to develop individual conditional demand models for the Lower Mainland, Vancouver Island and Interior regions. The benefit of this approach is that different model parameters are estimated for each region allowing for more robust UEC estimates.

The small sample sizes for Whistler and Fort Nelson, combined with low penetration rates for many of the end-uses, led to large variation and uncertainty in the UEC estimates for these regions. To ensure more stable and robust results, it was decided to revert to the overall conditional demand model constructed at the utility level to estimate UECs for these two smaller regions. With this approach, the overall model was able to capture some regional variation for key end-uses like space and water heating, but assumed constant UEC specifications for most other end-uses.

[74] An attempt was made to model whether or not the hot tub is covered when not in use. This variable was not retained in the final model because it was not statistically significant.

[75] In the 2008 study, a single overall model was developed for all regions, and then space and water heating UECs were derived for each region by using regional dummy (binary) variables, and other variables that naturally varied by region (e.g., weather, dwelling sizes, etc.)

APPENDIX B

B11. Regression Models

B11.1 Regression Model – FEU

Model Fit
Adjusted R-squared: 0.791
F statistic: 6,427.6

	Coefficient	SE	t-value	P-value
HDD x AREA x $S_{gasheat}$	0.001119	0.000012	91.7	0.000
HDD x AREA x MFD x $S_{gasheat}$	-0.000082	0.000004	-18.7	0.000
HDD x AREA x VS x $S_{gasheat}$	-0.000404	0.000018	-22.8	0.000
HDD x AREA x INSULA x $S_{gasheat}$	-0.000160	0.000010	-16.0	0.000
HDD x AREA x INSULW x $S_{gasheat}$	-0.000329	0.000010	-34.6	0.000
HDD x AREA x BASEMENT x INSULB x $S_{gasheat}$	-0.000088	0.000003	-27.9	0.000
HDD x AREA x DOORS x $S_{gasheat}$	-0.000087	0.000004	-24.9	0.000
HDD x AREA x WINDBL x $S_{gasheat}$	-0.000001	0.000000	-32.1	0.000
HDD x AREA x WINBEST x $S_{gasheat}$	-0.000001	0.000000	-24.5	0.000
HDD x AREA x TDNIGHT x $S_{gasheat}$	-0.000061	0.000005	-12.0	0.000
HDD x AREA x TDDAY x $S_{gasheat}$	-0.000027	0.000005	-5.5	0.000
HDD x AREA x TDUNUSED x $S_{gasheat}$	*	*	*	*
HDD x AREA x WINTER x WINCVR x $S_{gasheat}$	-0.000080	0.000005	-17.0	0.000
HDD x AREA x NONGASSEC x $S_{gasheat}$	-0.000014	0.000003	-5.4	0.000
HDD x AREA x HEATPUMPSEC x $S_{gasheat}$	-0.000074	0.000007	-10.3	0.000
AREA x WINTER x $S_{gasheat}$	0.054095	0.001848	29.3	0.000
HDD x AREA x $S_{gassecheat}$	0.000141	0.000007	20.1	0.000
HDD x AREA x MFD x $S_{gassecheat}$	0.000300	0.000031	9.8	0.000
HDD x AREA x VS x $S_{gassecheat}$	-0.000150	0.000057	-2.6	0.009
GASFIREDEC x $S_{gasfiredec}$	0.413238	0.057313	7.2	0.000
GASFIREHEAT x $S_{gasfireheat}$	0.279512	0.039778	7.0	0.000
GASFIREFREE x $S_{gasfirefree}$	-0.311960	0.097043	-3.2	0.001
HDD x GASFIREDEC x $S_{gasfiredec}$	0.003050	0.000187	16.3	0.000
HDD x GASFIREHEAT x $S_{gasfireheat}$	0.002626	0.000126	20.8	0.000
HDD x GASFIREFREE x $S_{gasfirefree}$	0.003051	0.000298	10.2	0.000
HDD x $S_{gaswheat}$	0.005070	0.000147	34.4	0.000
HDD x NEWHOME x $S_{gaswheat}$	-0.003633	0.000320	-11.4	0.000
HDD x SOLARSUP x $S_{gaswheat}$	*	*	*	*
HDD x ONDEMAND x $S_{gaswheat}$	-0.001623	0.000348	-4.7	0.000
DWASHLOADS x $S_{gaswheat}$	0.079778	0.008521	9.4	0.000
CWASHLOADS x $S_{gaswheat}$	0.029257	0.007888	3.7	0.000
BATHS x $S_{gaswheat}$	*	*	*	*
SHOWERS x $S_{gaswheat}$	0.058524	0.002450	23.9	0.000
CWASHERFRONT x $S_{gaswheat}$	-0.133411	0.042909	-3.1	0.002
PROPLOWFLOW x $S_{gaswheat}$	-0.543639	0.044223	-12.3	0.000
INHOTWATERDISP x $S_{gaswheat}$	1.130273	0.120449	9.4	0.000
GASCOOK x $S_{gascook}$	0.894339	0.032261	27.7	0.000
GASBBQ x S_{gasbbq}	0.022567	0.047206	0.5	0.633
GASDRYER x $S_{gasdryer}$	*	*	*	*
$S_{gasheatpool}$	3.591481	0.125215	28.7	0.000
$S_{gashottub}$	1.777150	0.195747	9.1	0.000

* Variable not retained in the final model because its regression coefficient was the wrong sign or insignificant.

APPENDIX B

B11.2 Regression Model – Lower Mainland

Model Fit
Adjusted R-squared: 0.781
F statistic: 1,500.0

	Coefficient	SE	t-value	P-value
HDD x AREA x $S_{gasheat}$	0.001102	0.000024	45.7	0.000
HDD x AREA x MFD x $S_{gasheat}$	-0.000058	0.000010	-6.0	0.000
HDD x AREA x VS x $S_{gasheat}$	-0.000376	0.000062	-6.1	0.000
HDD x AREA x INSULA x $S_{gasheat}$	-0.000172	0.000020	-8.7	0.000
HDD x AREA x INSULW x $S_{gasheat}$	-0.000350	0.000020	-17.5	0.000
HDD x AREA x BASEMENT x INSULB x $S_{gasheat}$	-0.000060	0.000007	-8.3	0.000
HDD x AREA x DOORS x $S_{gasheat}$	-0.000035	0.000009	-4.0	0.000
HDD x AREA x WINDBL x $S_{gasheat}$	-0.000001	0.000000	-14.5	0.000
HDD x AREA x WINBEST x $S_{gasheat}$	-0.000001	0.000000	-5.1	0.000
HDD x AREA x TDNIGHT x $S_{gasheat}$	-0.000056	0.000012	-4.6	0.000
HDD x AREA x TDDAY x $S_{gasheat}$	-0.000007	0.000012	-0.6	0.554
HDD x AREA x TDUNUSED x $S_{gasheat}$	*	*	*	*
HDD x AREA x WINTER x WINCVR x $S_{gasheat}$	-0.000052	0.000013	-4.1	0.000
HDD x AREA x NONGASSEC x $S_{gasheat}$	0.000000	0.000006	0.1	0.950
HDD x AREA x HEATPUMPSEC x $S_{gasheat}$	*	*	*	*
AREA x WINTER x $S_{gasheat}$	0.037974	0.004427	8.6	0.000
HDD x AREA x $S_{gassecheat}$	0.000271	0.000023	11.7	0.000
HDD x AREA x MFD x $S_{gassecheat}$	0.000305	0.000067	4.6	0.000
HDD x AREA x VS x $S_{gassecheat}$	*	*	*	*
GASFIREDEC x $S_{gasfiredec}$	0.431131	0.121198	3.6	0.000
GASFIREHEAT x $S_{gasfireheat}$	0.277730	0.090108	3.1	0.002
GASFIREFREE x $S_{gasfirefree}$	-0.202058	0.237760	-0.8	0.395
HDD x GASFIREDEC x $S_{gasfiredec}$	0.001733	0.000431	4.0	0.000
HDD x GASFIREHEAT x $S_{gasfireheat}$	0.001618	0.000318	5.1	0.000
HDD x GASFIREFREE x $S_{gasfirefree}$	0.002381	0.000828	2.9	0.004
HDD x $S_{gaswheat}$	0.008088	0.000410	19.7	0.000
HDD x NEWHOME x $S_{gaswheat}$	-0.003156	0.000902	-3.5	0.000
HDD x SOLARSUP x $S_{gaswheat}$	*	*	*	*
HDD x ONDEMAND x $S_{gaswheat}$	-0.003380	0.000874	-3.9	0.000
DWASHLOADS x $S_{gaswheat}$	0.100555	0.018624	5.4	0.000
CWASHLOADS x $S_{gaswheat}$	0.007190	0.017018	0.4	0.673
BATHS x $S_{gaswheat}$	*	*	*	*
SHOWERS x $S_{gaswheat}$	0.035921	0.005093	7.1	0.000
CWASHERFRONT x $S_{gaswheat}$	-0.110545	0.096188	-1.1	0.250
PROPLOWFLOW x $S_{gaswheat}$	-0.677407	0.097483	-6.9	0.000
INHOTWATERDISP x $S_{gaswheat}$	0.941486	0.254580	3.7	0.000
GASCOOK x $S_{gascook}$	0.648572	0.071241	9.1	0.000
GASBBQ x S_{gasbbq}	0.424672	0.116599	3.6	0.000
GASDRYER x $S_{gasdryer}$	*	*	*	*
$S_{gasheatpool}$	3.088034	0.272635	11.3	0.000
$S_{gashottub}$	1.796595	0.402498	4.5	0.000

* Variable not retained in the final model because its regression coefficient was the wrong sign or insignificant.

APPENDIX B

B11.3 Regression Model – Vancouver Island

Model Fit
Adjusted R-squared: 0.843
F statistic: 1,830.6

	Coefficient	SE	t-value	P-value
HDD x AREA x $S_{gasheat}$	0.000935	0.000028	32.9	0.000
HDD x AREA x MFD x $S_{gasheat}$	-0.000140	0.000008	-17.2	0.000
HDD x AREA x VS x $S_{gasheat}$	-0.000111	0.000024	-4.6	0.000
HDD x AREA x INSULA x $S_{gasheat}$	-0.000223	0.000023	-9.9	0.000
HDD x AREA x INSULW x $S_{gasheat}$	-0.000063	0.000017	-3.6	0.000
HDD x AREA x BASEMENT x INSULB x $S_{gasheat}$	-0.000024	0.000005	-4.4	0.000
HDD x AREA x DOORS x $S_{gasheat}$	-0.000084	0.000006	-13.1	0.000
HDD x AREA x WINDBL x $S_{gasheat}$	-0.000001	0.000000	-15.0	0.000
HDD x AREA x WINBEST x $S_{gasheat}$	-0.000002	0.000000	-16.9	0.000
HDD x AREA x TDNIGHT x $S_{gasheat}$	-0.000068	0.000010	-7.0	0.000
HDD x AREA x TDDAY x $S_{gasheat}$	-0.000028	0.000009	-3.2	0.002
HDD x AREA x TDUNUSED x $S_{gasheat}$	-0.000046	0.000006	-8.3	0.000
HDD x AREA x WINTER x WINCVR x $S_{gasheat}$	-0.000028	0.000009	-3.0	0.003
HDD x AREA x NONGASSEC x $S_{gasheat}$	-0.000087	0.000005	-19.0	0.000
HDD x AREA x HEATPUMPSEC x $S_{gasheat}$	-0.000126	0.000016	-7.9	0.000
AREA x WINTER x $S_{gasheat}$	0.029855	0.003057	9.8	0.000
HDD x AREA x $S_{gassecheat}$	0.000068	0.000009	7.3	0.000
HDD x AREA x MFD x $S_{gassecheat}$	-0.000187	0.000043	-4.4	0.000
HDD x AREA x VS x $S_{gassecheat}$	-0.000117	0.000046	-2.6	0.011
GASFIREDEC x $S_{gasfiredec}$	0.141570	0.107539	1.3	0.188
GASFIREHEAT x $S_{gasfireheat}$	0.077017	0.053833	1.4	0.153
GASFIREFREE x $S_{gasfirefree}$	-0.132509	0.111928	-1.2	0.236
HDD x GASFIREDEC x $S_{gasfiredec}$	0.002856	0.000372	7.7	0.000
HDD x GASFIREHEAT x $S_{gasfireheat}$	0.002779	0.000190	14.6	0.000
HDD x GASFIREFREE x $S_{gasfirefree}$	0.004549	0.000387	11.8	0.000
HDD x $S_{gaswheat}$	0.003948	0.000202	19.5	0.000
HDD x NEWHOME x $S_{gaswheat}$	-0.001468	0.000353	-4.2	0.000
HDD x SOLARSUP x $S_{gaswheat}$	-0.002912	0.000903	-3.2	0.001
HDD x ONDEMAND x $S_{gaswheat}$	*	*	*	*
DWASHLOADS x $S_{gaswheat}$	0.018252	0.012110	1.5	0.132
CWASHLOADS x $S_{gaswheat}$	0.085303	0.011127	7.7	0.000
BATHS x $S_{gaswheat}$	0.068738	0.009358	7.3	0.000
SHOWERS x $S_{gaswheat}$	0.013968	0.004641	3.0	0.003
CWASHERFRONT x $S_{gaswheat}$	-0.285933	0.056073	-5.1	0.000
PROPLOWFLOW x $S_{gaswheat}$	*	*	*	*
INHOTWATERDISP x $S_{gaswheat}$	*	*	*	*
GASCOOK x $S_{gascook}$	0.432258	0.046026	9.4	0.000
GASBBQ x S_{gasbbq}	0.090033	0.053304	1.7	0.091
GASDRYER x $S_{gasdryer}$	0.294242	0.085035	3.5	0.001
$S_{gasheatpool}$	4.275273	0.300897	14.2	0.000
$S_{gashottub}$	*	*	*	*

* Variable not retained in the final model because its regression coefficient was the wrong sign or insignificant.

APPENDIX B

B11.4 Regression Model – Interior

Model Fit
Adjusted R-squared: 0.865
F statistic: 3,747.8

	Coefficient	SE	t-value	P-value
HDD x AREA x $S_{gasheat}$	0.000841	0.000025	34.3	0.000
HDD x AREA x MFD x $S_{gasheat}$	-0.000178	0.000006	-30.9	0.000
HDD x AREA x VS x $S_{gasheat}$	-0.000416	0.000015	-27.2	0.000
HDD x AREA x INSULA x $S_{gasheat}$	-0.000248	0.000019	-12.8	0.000
HDD x AREA x INSULW x $S_{gasheat}$	-0.000160	0.000015	-10.5	0.000
HDD x AREA x BASEMENT x INSULB x $S_{gasheat}$	-0.000042	0.000004	-10.6	0.000
HDD x AREA x WINDBL x $S_{gasheat}$	*	*	*	*
HDD x AREA x WINBEST x $S_{gasheat}$	0.000000	0.000000	-6.2	0.000
HDD x AREA x DOORS x $S_{gasheat}$	-0.000037	0.000004	-10.2	0.000
HDD x AREA x TDNIGHT x $S_{gasheat}$	-0.000007	0.000006	-1.2	0.225
HDD x AREA x TDDAY x $S_{gasheat}$	-0.000071	0.000005	-13.0	0.000
HDD x AREA x TDUNUSED x $S_{gasheat}$	*	*	*	*
HDD x AREA x WINTER x WINCVR x $S_{gasheat}$	-0.000010	0.000005	-2.1	0.039
HDD x AREA x NONGASSEC x $S_{gasheat}$	-0.000040	0.000003	-15.1	0.000
HDD x AREA x HEATPUMPSEC x $S_{gasheat}$	-0.000124	0.000006	-20.4	0.000
AREA x WINTER x $S_{gasheat}$	0.028021	0.002767	10.1	0.000
HDD x AREA x $S_{gassecheat}$	0.000100	0.000006	16.9	0.000
HDD x AREA x MFD x $S_{gassecheat}$	0.000008	0.000045	0.2	0.864
HDD x AREA x VS x $S_{gassecheat}$	*	*	*	*
GASFIREDEC x $S_{gasfiredec}$	0.292616	0.092004	3.2	0.001
GASFIREHEAT x $S_{gasfireheat}$	0.397299	0.056256	7.1	0.000
GASFIREFREE x $S_{gasfirefree}$	-0.299528	0.125451	-2.4	0.017
HDD x GASFIREDEC x $S_{gasfiredec}$	0.003202	0.000227	14.1	0.000
HDD x GASFIREHEAT x $S_{gasfireheat}$	0.002782	0.000138	20.1	0.000
HDD x GASFIREFREE x $S_{gasfirefree}$	0.003311	0.000302	11.0	0.000
HDD x $S_{gaswheat}$	0.003015	0.000149	20.2	0.000
HDD x NEWHOME x $S_{gaswheat}$	-0.003979	0.000320	-12.4	0.000
HDD x SOLARSUP x $S_{gaswheat}$	-0.006273	0.000637	-9.9	0.000
HDD x ONDEMAND x $S_{gaswheat}$	*	*	*	*
DWASHLOADS x $S_{gaswheat}$	0.035500	0.012196	2.9	0.004
CWASHLOADS x $S_{gaswheat}$	0.059119	0.011800	5.0	0.000
BATHS x $S_{gaswheat}$	0.017867	0.009323	1.9	0.055
SHOWERS x $S_{gaswheat}$	0.062782	0.004301	14.6	0.000
CWASHERFRONT x $S_{gaswheat}$	-0.177154	0.056509	-3.1	0.002
PROPLOWFLOW x $S_{gaswheat}$	-0.315270	0.060475	-5.2	0.000
INHOTWATERDISP x $S_{gaswheat}$	*	*	*	*
GASCOOK x $S_{gascook}$	0.822360	0.047730	17.2	0.000
GASBBQ x S_{gasbbq}	0.154308	0.056500	2.7	0.006
GASDRYER x $S_{gasdryer}$	0.899920	0.111738	8.1	0.000
$S_{gasheatpool}$	4.886988	0.155597	31.4	0.000
$S_{gashottub}$	*	*	*	*

* Variable not retained in the final model because its regression coefficient was the wrong sign or insignificant.

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Appendix 7-2

EES JURISDICTIONAL COMPARISON OF RESIDENTIAL RATES

Gas Delivery Rate Comparison - Residential Rate Class

* - indicates cross-over rate (appears in multiple customer sectors; see Notes for details)

GJ 26.137 m3
GJ 9.4708 therm

	Rate Schedule	Class Description	Eligiblity	Type of Rate	Date	Customer Charge/Day	Customer Charge/Month	Base Delivery Charge	Base Delivery Charge (Converted to GJ)	Notes to Table
FEI	1	Residential	Single-family or separately metered multi-family	Flat	3/1/2016	$0.389	$11.83	$4.018 per GJ		
PNG	RS1 (West)	Residential	Single-family or separately metered multi-family	Flat	1/1/2016	$0.353	$10.75	$12.047 per GJ		
	RS1 (Dawson)	Residential	Single-family or separately metered multi-family	Flat	1/1/2016	$0.230	$7.00	$3.681 per GJ		
	RS1 (Fort SJ)	Residential	Single-family or separately metered multi-family	Flat	1/1/2016	$0.230	$7.00	$3.879 per GJ		
	RS1 (Tumbler)	Residential	Single-family or separately metered multi-family	Flat	1/1/2016	$0.279	$8.50	$6.464 per GJ		
ATCO	North	Low Use	< 1,200 GJ/year	Flat	6/1/2016	$0.964	$29.32	$1.694 per GJ		
	South	Low Use	< 1,200 GJ/year	Flat	6/1/2016	$0.815	$24.79	$1.714 per GJ		
AltaGas	1*	Small General Service	< 5,326 GJ/year	Flat	1/19/2016	$1.194	$36.32	$1.973 per GJ		1 - Also in commercial
SaskPower (SaskEnergy)	N/A	Residential	Individually metered	Flat	1/1/2016	$0.677	$20.60	$0.081 per m3	$2.120 per GJ	
Manitoba Hydro		Residential		Flat	5/1/2016	$0.460	$14.00	$0.112 per m3	$2.923 per GJ	
Union Gas	M1 (Southern Ontario)	Residential	<= 50,000 m3/year	Declining	10/1/2015	$0.690	$21.00	$0.037 first 100 m3 $0.036 next 150 m3 $0.031 over 250 m3	$0.979 first 3.8 GJ $0.929 next 5.7 GJ $0.799 over 9.5 GJ	
	101, 201, 301, 601 (Other Regions)	Residential	<= 50,000 m3/year	Declining	10/1/2015	$0.690	$21.00	$0.084 first 100 m3 $0.082 next 200 m3 $0.079 next 200 m3 $0.076 next 500 m3 $0.073 over 1000 m3	$2.208 first 3.8 GJ $2.152 next 7.6 GJ $2.063 next 7.6 GJ $1.982 next 19 GJ $1.915 next 38 GJ	
Enbridge	1	Residential	Single meter, no more than six units	Declining	10/1/2015	$0.658	$20.00	$0.095 first 30 m3 $0.090 next 55 m3 $0.086 next 85 m3 $0.083 over 170 m3	$2.482 first 1.15 GJ $2.348 next 2.1 GJ $2.244 next 3.25 GJ $2.166 over 6.5 GJ	
Gaz Metro	Rate D1*	Distribution	< 10,950 m3/year	Declining	2/1/2015	$0.535	$16.26	$0.267 first 900 m3 $0.183 over 900 m3	$6.990 first 34 GJ $4.780 over34 JG	D1 - Also in commercial and industrial
Gazifere	Rate 2	Residential	Single metering point, domestic use	Declining	4/1/2016	$0.330	$10.05	$0.265 first 50 m3 $0.258 next 50 m3 $0.250 next 220 m3 $0.243 next 680 m3 $0.235 over 1,000 m3	$6.932 first 1.9 GJ $6.730 next 1.9 GJ $6.534 next 8.42 GJ $6.341 next 26.02 GJ $6.140 over 38.26 GJ	
Avista	Schedule 101*	General Service	Single-family or separately metered multi-family	Inclining	1/11/2016	$0.296	$9.00	$0.793 first 70 therms $0.909 over 70 therms	$7.515 first 7.4 GJ $8.613 over 7.4 GJ	101 - Also in commercial Rate includes cost of gas
Puget Sound Energy	23	Residential	Single-family or separately metered multi-family	Flat	11/16/2013	$0.340	$10.34	$0.365 All therms	$3.456 per GJ	
Northwest Natural Gas	2	Residential	Single-family or separately metered multi-family	Flat	11/1/2015	$0.230	$7.00	$0.847 All therms	$8.025 per GJ	

Note: excludes various delivery price adjustments

Gas Delivery Rate Comparison - Residential Rates

* - indicates cross-over rate (appears in multiple customer sectors; see Notes for details)

GJ 26.137 m3
GJ 9.4708 therm

	Rate Schedule	Class Description	Eligiblity	Type of Rate	Date	Customer Charge/Day	Customer Charge/Month	Base Delivery Charge	Base Delivery Charge (Converted to GJ)	Notes to Table
FEI	1	Residential	Single-family or separately metered multi-family	Flat	3/1/2016	$0.389	$11.83	$4.018 per GJ		
PNG	RS1 (West)	Residential	Single-family or separately metered multi-family	Flat	1/1/2016	$0.353	$10.75	$12.047 per GJ		
	RS1 (Dawson)	Residential	Single-family or separately metered multi-family	Flat	1/1/2016	$0.230	$7.00	$3.681 per GJ		
	RS1 (Fort SJ)	Residential	Single-family or separately metered multi-family	Flat	1/1/2016	$0.230	$7.00	$3.879 per GJ		
	RS1 (Tumbler)	Residential	Single-family or separately metered multi-family	Flat	1/1/2016	$0.279	$8.50	$6.464 per GJ		
ATCO	North	Low Use	< 1,200 GJ/year	Flat	6/1/2016	$0.964	$29.32	$1.694 per GJ		
	South	Low Use	< 1,200 GJ/year	Flat	6/1/2016	$0.815	$24.79	$1.714 per GJ		
AltaGas	1*	Small General Service	< 5,326 GJ/year	Flat	1/19/2016	$1.194	$36.32	$1.973 per GJ		1 - Also in commercial
SaskPower (SaskEnergy)	N/A	Residential	Individually metered	Flat	1/1/2016	$0.677	$20.60	$0.081 per m3	$2.120 per GJ	
Manitoba Hydro		Residential		Flat	5/1/2016	$0.460	$14.00	$0.112 per m3	$2.923 per GJ	
Union Gas	M1 (Southern Ontario)	Residential	<= 50,000 m3/year	Declining	10/1/2015	$0.690	$21.00	$0.037 first 100 m3 $0.036 next 150 m3 $0.031 over 250 m3	$0.979 first 3.8 GJ $0.929 next 5.7 GJ $0.799 over 9.5 GJ	
	101, 201, 301, 601 (Other Regions)	Residential	<= 50,000 m3/year	Declining	10/1/2015	$0.690	$21.00	$0.084 first 100 m3 $0.082 next 200 m3 $0.079 next 200 m3 $0.076 next 500 m3 $0.073 over 1000 m3	$2.208 first 3.8 GJ $2.152 next 7.6 GJ $2.063 next 7.6 GJ $1.982 next 19 GJ $1.915 next 38 GJ	
Enbridge	1	Residential	Single meter, no more than six units	Declining	10/1/2015	$0.658	$20.00	$0.095 first 30 m3 $0.090 next 55 m3 $0.086 next 85 m3 $0.083 over 170 m3	$2.482 first 1.15 GJ $2.348 next 2.1 GJ $2.244 next 3.25 GJ $2.166 over 6.5 GJ	
Gaz Metro	Rate D1*	Distribution	< 10,950 m3/year	Declining	2/1/2015	$0.535	$16.26	$0.267 first 900 m3 $0.183 over 900 m3	$6.990 first 34 GJ $4.780 over34 JG	D1 - Also in commercial and industrial
Gazifere	Rate 2	Residential	Single metering point, domestic use	Declining	4/1/2016	$0.330	$10.05	$0.265 first 50 m3 $0.258 next 50 m3 $0.250 next 220 m3 $0.243 next 680 m3 $0.235 over 1,000 m3	$6.932 first 1.9 GJ $6.730 next 1.9 GJ $6.534 next 8.42 GJ $6.341 next 26.02 GJ $6.140 over 38.26 GJ	
Avista	Schedule 101*	General Service	Single-family or separately metered multi-family	Inclining	1/11/2016	$0.296	$9.00	$0.793 first 70 therms $0.909 over 70 therms	$7.515 first 7.4 GJ $8.613 over 7.4 GJ	101 - Also in commercial Rate includes cost of gas
Puget Sound Energy	23	Residential	Single-family or separately metered multi-family	Flat	11/16/2013	$0.340	$10.34	$0.365 All therms	$3.456 per GJ	
Northwest Natural Gas	2	Residential	Single-family or separately metered multi-family	Flat	11/1/2015	$0.230	$7.00	$0.847 All therms	$8.025 per GJ	

Note: excludes various delivery price adjustments

Appendix 8

EES JURISDICTIONAL COMPARISON OF COMMERCIAL RATES

Gas Delivery Rate Comparison - Commercial Rates

GJ 26.137 m3
GJ 9.4708 therm

* - indicates cross-over rate (appears in multiple customer sectors; see Notes for details)

	Rate Schedule	Class Description	Eligiblity	Type of Rate	Date	Customer Charge/Day	Customer Charge/Month	Base Delivery Charge	Base Delivery Charge (Converted to GJ)	Notes to Table
FEI	2	Commercial	< 2,000 GJ/yr	Flat	8/1/2015	$0.816	$24.82	$3.331 per GJ		
	3	Large Commercial	> 2,000 GJ/yr	Flat	8/1/2015	$4.354	$132.43	$2.809 per GJ		
	4	Off-Peak Seasonal	Off-peak	Seasonal	8/1/2015	$14.423	$438.70	$1.217 per GJ off-peak $1.994 per GJ on-peak		
	23	Commercial Transport	> 2,000 GJ/yr	Flat	8/1/2015	$4.357	$132.52	$2.939 per GJ		
PNG	RS2 (West)	Small Commercial	< 5,500 GJ	Flat	6/1/2015	$0.822	$25.00	$10.169 per GJ		
	RS2 (Dawson)	Small Commercial	< 5,500 GJ	Flat	6/1/2015	$0.230	$7.00	$2.579 per GJ		
	RS2 (Fort SJ)	Small Commercial	< 5,500 GJ	Flat	6/1/2015	$0.230	$7.00	$3.116 per GJ		
	RS2 (Tumbler)	Small Commercial	< 5,500 GJ	Flat	6/1/2015	$0.279	$8.50	$5.465 per GJ		
	RS3 (West)	Large Commercial	> 5,500 GJ	Flat	6/1/2015	$4.932	$150.00	$8.179 per GJ		
	RS3 (Dawson)	Large Commercial	> 5,500 GJ	Flat	6/1/2015	$4.932	$150.00	$1.802 per GJ		
	RS3 (Fort SJ)	Large Commercial	> 5,500 GJ	Flat	6/1/2015	$4.932	$150.00	$2.350 per GJ		
	RS3 (Tumbler)	Large Commercial	> 5,500 GJ	Flat	6/1/2015	$0.279	$8.50	$4.661 per GJ		
ATCO	North	Mid Use	1,200-8,000 GJ	Flat	6/27/2016	$0.964	$29.32	$1.716 per GJ		
	South	Mid Use	1,200-8,000 GJ	Flat	6/27/2016	$0.815	$24.79	$1.659 per GJ		
AltaGas	1*	Small General Service	< 5,326 GJ/year	Flat	1/19/2016	$1.194	$36.32	$1.973 per GJ		Also in residential
	2	Large General Service	> 5,326 GJ/year	Flat	1/19/2016	$13.576	$412.94	$1.070 per GJ		
SaskPower (SaskEnergy)	N/A	Commercial Small	< 100,000 m3	Flat	1/1/2016	$1.187	$36.10	$0.068 per m3	$1.783 per GJ	
	N/A	Commercial Large	100,000 - 660,000 m3	Flat	1/1/2016	$4.386	$133.40	$0.060 per m3	$1.560 per GJ	
	N/A*	Small Industrial	660,000 - 1,320,000 m3	Declining	1/1/2016	$7.101	$216.00	$0.041 first 40,000 m3 $0.035 over 40,000 m3	$1.059 first 1,530 GJ $0.904 over 1,530 GJ	Also in industrial
Manitoba		Small General Service	< 14,026 m3	Flat	5/1/2016	$0.460	$14.00	$0.119 per m3	$3.097 per GJ	
		Large General Service	14,026-680,000 m3	Flat	5/1/2016	$2.532	$77.00	$0.059 per m3	$1.547 per GJ	
Union Gas	M2 (Southern Ontario) *	Large Volume General Firm Service	> 50,000 m3/year	Declining	4/1/2016	$2.301	$70.00	$0.036 first 1,000 m3 $0.035 next 6,000 m3 $0.033 next 13,000 m3 $0.031 over 20,000 m3	$0.930 first 38 GJ $0.913 next 230 GJ $0.870 next 497 GJ $0.807 over 765 GJ	M2 - Also in industrial
	110/210/310/610 (Other regions) *	Large Volume General Firm Service	> 50,000 m3/year	Declining	10/1/2015	$2.301	$70.00	$0.071 first 1,000 m3 $0.058 next 9,000 m3 $0.051 next 20,000 m3 $0.046 next 70,000 m3 $0.028 over 100,000 m3	$1.866 first 38 GJ $1.522 next 344 GJ $1.334 next 765 GJ $1.208 next 2,678 GJ $0.730 over 3,826 GJ	10 - Also in industrial
Enbridge	Rate 6*	General Service	Single terminal, non-residential	Declining	10/1/2015	$2.301	$70.00	$0.091 first 500 m3 $0.073 next 1050 m3 $0.061 next 4500 m3 $0.052 next 7000 m3 $0.049 next 15,250 m $0.048 over 28,300 m3	$2.383 first 19 GJ $1.912 next 40 GJ $1.582 next 172 GJ $1.370 next 268 GJ $1.276 next 583 GJ $1.253 over 1,083 GJ	6 - Also in industrial
Gaz Metro	Rate D1*	Distribution	< 10,950 m3/year	Declining	2/1/2015	$0.535 0-10,950 m3/yr $1.089 10,950-36,500 m3/yr $1.299 36,500-109,500 m3/yr $1.371 109,500-365,000 m3/yr	$16.26 $33.12 $39.51 $41.70	$0.267 first 900 m3 $0.183 next 2100 m3 $0.160 next 6000 m3 $0.121 next 21,000 m3 $0.090 next 60,000 m3 $0.063 next 210,000 m3 $0.051 next 600,000 m3 $0.042 next 2,100,000 m3 $0.035 over 3,000,000 m3	$6.990 first 34 GJ $4.780 next 80 GJ $4.181 next 230 GJ $3.166 next 803 GJ $2.345 next 2,296 GJ $1.645 next 8,035 GJ $1.325 next 22,956 GJ $1.099 next 80,346 GJ $0.911 over 114,780 GJ	D1 - Also in residential and industrial

Gas Delivery Rate Comparison - Commercial Rates

* - indicates cross-over rate (appears in multiple customer sectors; see Notes for details)

GJ 26.137 m3
GJ 9.4708 therm

	Rate Schedule	Class Description	Eligiblity	Type of Rate	Date	Customer Charge/Day	Customer Charge/Month	Base Delivery Charge		Base Delivery Charge (Converted to GJ)		Notes to Table
Gazifere	Rate 1	General Service		Declining	10/1/2015	$0.563	$17.13	$0.181	first 100 m3	$4.718	first 3.8 GJ	
								$0.171	next 220 m3	$4.480	next 8.4 GJ	
								$0.163	next 680 m3	$4.252	next 26.0 GJ	
								$0.153	next 2,200 m3	$4.009	next 84.17 GJ	
								$0.136	next 6,800 m3	$3.544	next 260.2 GJ	
								$0.122	over 10,000 m3	$3.189	over 382.60	
	Rate 3	Low Volume Firm	300 - 2,800 m3/day and LF > 50%	Flat	10/1/2015	$0.207	$6.29	$0.077	per m3	$2.002	per GJ	
Puget Sound Energy	Schedule 31	Commercial & Industrial		Flat	10/1/2015	$1.099	$33.42	$0.306	per therm	$2.901	per GJ	
	Schedule 31T	Commercial & Industrial Transport		Flat	10/1/2015	$12.028	$365.85	$0.363	per therm	$3.434	per GJ	
Northwest Natural Gas	Schedule 3	Basic Firm Sales		Flat	11/1/2014	$0.493	$15.00	$0.848	per therm	$8.035	per GJ	Rate includes cost of gas
	Schedule 41	Non-Residential		Declining	11/1/2014	$8.219	$250.00	$0.605	first 2,000 therm	$5.725	first 211 GJ	31 - Also in commercial
								$0.566	over 2,000 therm	$5.363	over 211 GJ	Rate includes cost of gas
Avista	Schedule 101*	General Service		Inclining		$0.181	$5.50	$1.121	all therm	$10.614	first 7.4 GJ	101 - Also in residential
										$0.000	over 7.4 GJ	Rate includes cost of gas
	Schedule 111	Large General Service		Declining				$1.147	first 200 therms	$10.863	first 21 GJ	Rate includes cost of gas
								$1.075	next 800 therms	$10.185	next 85 GJ	
								$1.009	over 1,000 therms	$9.555	over 106 GJ	
	Schedule 58	High Annual Load Factor Large General Service		Declining				$0.913	first 500 therms	$8.651	first 53 GJ	121 - Also in industrial
								$0.766	next 500 therms	$7.251	next 53 GJ	Rate includes cost of gas
								$0.683	next 9,000 therms	$6.467	next 950 GJ	
								$0.631	next 15,000 therms	$5.975	next 1,584 GJ	
								$0.556	over 25,000 therms	$5.267	over 2,640 GJ	

Gas Delivery Rate Comparison - NGV and Other Classes

GJ 26.137 m3
GJ 9.4708 therm

	Rate Schedule	Class Description	Eligiblity	Type of Rate	Date	Customer Charge/Day	Customer Charge/Month	Base Delivery Charge	
FEI	6	NGV	Compression and dispensing as fuel	Flat	1/1/2016	$2.004	$60.96	$4.521	per GJ
	6A	GS Vehicle Refueling	Refueling through compressor <.03m3/minute	Flat	1/1/2016	$2.827	$86.00	$4.475	per GJ
	6P	PS - NGV Refueling	Refueling through FEI dispenser	Flat	1/1/2016			$4.499	per GJ
	46	LNG	All FEI plants, excluding marine loading facilities	Flat	1/1/2016			$3.680	per GJ
	26	NGV Transport		Flat	8/1/2015	$2.005	$61.00	$4.521	per GJ
PNG	RS7	NGV		Flat	1/1/2016	$0.353	$10.75	$3.586	per GJ
Gazifere	Rate 7	NGV	At least 30 m3/day in firm service	Declining	10/1/2015	$0.704	$21.42	$4.958	first 3.8 GJ
								$4.723	next 8.4 GJ
								$4.485	next 26.0 GJ
								$4.252	next 84.17 GJ
								$3.782	next 260.2 GJ
								$3.429	over 382.6 GJ
Avista	Schedule 149	Backup and Supplemental Compressed Gas	At Avista site only	Flat				$2.130	per Gasoline Gallon Equivalent

Appendix 9

RATE DESIGN FOR INDUSTRIAL CUSTOMERS

Appendix 9-1

EES JURISDICTIONAL COMPARISON OF INDUSTRIAL RATES

Gas Delivery Rate Comparison - Industrial Rates

* - indicates cross-over rate (appears in multiple customer sectors; see Notes for details)

GJ 26.137 m3

GJ 9.4708 therm

	Rate Schedule	Class Description	Eligiblity	Type of Rate	Date	Customer Charge/Day	Customer Charge/Month	Demand Charge	Base Delivery Charge	Demand Charge (Converted to GJ)	Base Delivery Charge (Converted to GJ)	Notes to Table
FEI	5/25	General Firm Service		Flat w/Demand	4/1/2016	$19.30	$587	$20.077 per GJ	$0.825 per GJ			
	7/27	General Interruptible		Flat	8/1/2015	$28.93	$880		$1.353 per GJ			
	22	Large Volume	> 144,000 GJ	Flat	8/1/2015	$120.46	$3,664		$0.982 per GJ			
	22A	Large Volume Inland	Certain Existing Customers	Flat w/Demand	8/1/2015	$158.14	$4,810	$15.399 per GJ Firm	$0.108 per GJ Firm $1.217 per GJ Interruptible			
	22B	Large Volume Columbia	Certain Existing Customers	Flat w/Demand	8/1/2015	$149.16	$4,537	$9.929 per GJ Firm	$0.106 per GJ Firm $0.990 per GJ Interruptible Non-Winter $1.425 per GJ Interruptible Winter			
PNG	RS4 (West)	Industrial	Industrial use	Flat	7/1/2015	$13.48	$410		$3.665 per GJ			
	RS4 (Dawson)	Industrial	Industrial use	Flat	7/1/2015	$13.48	$410		$1.605 per GJ			
	RS4 (Fort SJ)	Industrial	Industrial use	Flat	7/1/2015	$13.48	$410		$1.337 per GJ			
ATCO	North	High Use	> 8,000	Demand Rate	1/1/2014	$5.63	$171	$0.178 per max GJ per day				
	South	High Use	> 8,000	Demand Rate	1/1/2014	$4.90	$149	$0.147 per max GJ per day				
AltaGas	3	Demand General Service	> 10,125 GJ/year	Flat w/Demand	10/2/2015	$16.35	$497	$0.296 per max GJ per day	$0.034 per GJ			
SaskPower (SaskEnergy)	N/A*	Small Industrial	660,000 - 1,320,000 m3	Declining	9/1/2014	$7.10	$216		$0.041 first 40,000 m3 $0.035 over 40,000 m3		$1.059 first 1,530 GJ $0.904 over 1,530 GJ	Also in commercial
	N/A	Contract Industrial	> 660,000 m3	Negotiated	9/1/2014							
Manitoba		High Volume Firm	> 680,000 m3	Flat	5/1/2016	$40.16	$1,221		$0.027 per m3		$0.693 per GJ	
		Mainline Firm Service	> 680,000 m3 and high pressure	Flat	5/1/2016	$41.00	$1,247		$0.022 per m3		$0.578 per GJ	
		Interruptible	> 680,000 m3 and high pressure	Flat	5/1/2016	$41.24	$1,254		$0.011 per m3		$0.274 per GJ	
Union Gas	M2 (Southern Ontario) *	Large Volume General Service	> 50,000 m3/year, per location	Declining	4/1/2016	$2.30	$70		$0.036 first 1,000 m3 $0.035 next 6,000 m3 $0.033 next 13,000 m3 $0.031 over 20,000 m3		$0.930 first 38 GJ $0.913 next 230 GJ $0.870 next 497 GJ $0.807 over 765 GJ	M2 - Also in commercial
	M4 (Southern Ontario)	Firm Industrial and Commercial Contract Rate	2,400 to 60,000 m3/day	Declining w/ Demand	4/1/2016			$0.478 first 8,450 m3/day $0.215 next 19,700 m3/day $0.180 over 28,150 m3/day	$0.010 first 422,250 m3/mo. $0.010 next max day x 15 $0.004 remainder			
	110/210/310/610 (Other Regions) *	Large Volume General Service	> 50,000 m3/year, per location	Declining	4/1/2016	$2.30	$70		$0.066 first 1,000 m3 $0.054 next 9,000 m3 $0.048 next 20,000 m3 $0.043 next 70,000 m3 $0.026 over 100,000 m3		$1.736 first 38 GJ $1.413 next 344 GJ $1.249 next 765 GJ $1.129 next 2,678 GJ $0.675 over 3,826 GJ	10 - Also in commercial
	20 (Other Regions)	Medium Volume Firm	> 14,000 m3/day	Declining w/Demand	4/1/2016	$31.97	$972	$0.279 first 70,000 m3 $0.164 over 70,000 m3	$0.005 first 852,000 m3 $0.004 over 852,000 m3		$0.141 first 38 GJ $0.103 next 344 GJ	
	25 (Other Regions)	Large Volume Interruptible	> 14,000 m3/day and 3,000 m3/day interruptible	Negotiated	4/1/2016	$11.58	$352		$0.047 per m3 (maximum)			
	100 (Other Regions)	Large Volume High Load Factor Firm	> 100,000 m3 max GJ/day with > 70% LF	Flat w/ Demand	4/1/2016	$48.14	$1,464	$0.154 per m3	$0.002 per m3			
Enbridge	Rate 6*	General Service	Single terminal, non-residential	Declining	4/1/2016	$2.30	$70		$0.091 first 500 m3 $0.073 next 1050 m3 $0.061 next 4500 m3 $0.052 next 7000 m3 $0.049 next 15,250 m $0.048 over 28,300 m3		$2.383 first 19 GJ $1.912 next 40 GJ $1.582 next 172 GJ $1.370 next 268 GJ $1.276 next 583 GJ $1.253 over 1,083 GJ	6 - Also in commercial
	Rate 100	Large Volume (Firm Contract Service)	10,000 -150,000 m3/day	Flat w/Demand	4/1/2016	$4.01	$122	$0.360 Per m3 contract demand	$0.001 per m3			
	Rate 110	Large Volume Load Factor	>1,865 m3/day and > 40% LF	Declining w/Demand	4/1/2016	$19.31	$587	$0.229 Per m3 contract demand	$0.006 first 1,000,000 m3 $0.005 over 1,000,000 m3			
	Rate 115	Large Volume High Load Factor	>1,165 m3/day and > 80% LF	Declining w/Demand	4/1/2016	$20.47	$623	$0.244 Per m3 contract demand	$0.002 first 1,000,000 m3 $0.001 over 1,000,000 m3			
	Rate 125	Extra Large Volume Transport	>600,000 m3/day	Demand Only		$16.44	$500	$0.091 Per m3 contract demand				Requires AMR capability
Gaz Metro	Rate D1*	Distribution	< 10,950 m3/year	Declining	2/1/2015	$0.53 0-10,950 m3/yr $1.09 10,950-36,500 m3/yr $1.30 36,500-109,500 m3/yr $1.37 109,500-365,000 m3/yr	$16 $33 $40 $42		$0.267 first 900 m3 $0.183 next 2100 m3 $0.160 next 6000 m3 $0.121 next 21,000 m3 $0.090 next 60,000 m3 $0.063 next 210,000 m3 $0.051 next 600,000 m3 $0.042 next 2,100,000 m3 $0.035 over 3,000,000 m3		$6.990 first 34 GJ $4.780 next 80 GJ $4.181 next 230 GJ $3.166 next 803 GJ $2.345 next 2,296 GJ $1.645 next 8,035 GJ $1.325 next 22,956 GJ $1.099 next 80,346 GJ $0.911 over 114,780 GJ	D1 - Also in residential and commercial
	D3/D4	Stable Load	>333 m3/day and > 60% LF or >10,000 m3/day	Declining based on subscribed amount	2/1/2015				$0.098 first 333 m3/day $0.079 next 667 m3/day $0.054 next 2,000 m3/day $0.045 next 7,000 m3/day $0.033 next 20,000 m3/day $0.025 next 70,000 m3/day $0.018 next 200,000 m3/day $0.015 next 700,000 m3/day $0.010 over 1,000,000 m3/day		$2.571 first 12.7 GJ/day $2.077 next 25.5 GJ/day $1.409 next 77 GJ/day $1.168 next 268 GJ/day $0.849 next 765 GJ/day $0.664 next 2,678 GJ/day $0.472 next 7,652 GJ/day $0.383 next 26,782 GJ/day $0.254 over 38,260 GJ/day	
Gazifere	Rate 4	Moderate Volume Firm Service	2,800 - 28,000 m3/day and LF > 50%	Flat w/ Demand	10/1/2015			$0.209 per m3	$0.062 per m3 if LF <= 70% $0.053 per m3 if LF > 70%		$1.613 per GJ if LF <= 70% $1.385 per GJ if LF > 70%	
	Rate 5	Large Volume Firm Service	28,000 - 280,000 m3/day and LF > 50%	Flat w/ Demand	10/1/2015			$0.318 per m3	$0.024 per m3		$0.630 per GJ	
	Rate 6	Very Large Volume Firm Service	> 280,000 m3/day and LF > 50%	Flat w/ Demand	10/1/2015			$0.209 per m3	$0.022 max per m3 $0.005 min per m3		$0.585 max per GJ $0.141 min per GJ	

Gas Delivery Rate Comparison - Industrial Rates

* - indicates cross-over rate (appears in multiple customer sectors; see Notes for details)

GJ 26.137 m3

GJ 9.4708 therm

	Rate Schedule	Class Description	Eligiblity	Type of Rate	Date	Customer Charge/Day	Customer Charge/Month	Demand Charge	Base Delivery Charge	Demand Charge (Converted to GJ)	Base Delivery Charge (Converted to GJ)	Notes to Table
Puget Sound Energy	41T	Firm Large Volume High Load Factor		Declining w/Demand	1/1/2016	$14.48	$441	$1.250 per therm	$0.138 first 5000 therm $0.111 > 5,000 therm		$1.309 first 528 GJ $1.053 over 528 GJ	
	85T	Interruptible with Firm Option		Declining w/Demand	1/1/2016	$31.50	$958	$1.140 per therm (firm)	$0.102 first 25,000 therm $0.051 next 25,000 therm $0.048 over 50,000 therm		$0.967 first 2,640 GJ $0.478 next 2,640 GJ $0.458 over 5,279 GJ	
	86T	Interruptible with Firm Option	For steam boilers, gas engines or turbines and schools	Declining w/Demand	1/1/2016	$4.71	$143	$1.250 per therm	$0.199 first 1,000 therm $0.141 over 1,000 therms		$1.886 first 106 GJ $1.337 over 106 GJ	
	87T	Non-exclusive Interruptible with Firm Option	> 1,000,000 therms/year	Declining w/Demand	1/1/2016	$32.33	$983	$1.140 per therm	$0.145 first 25,000 therm $0.087 next 25,000 therm $0.056 next 50,000 therm $0.036 next 100,000 therm $0.026 next 300,000 therm $0.020 over 500,000 therm		$1.369 first 2,640 GJ $0.827 next 2,640 GJ $0.526 next 5,279 GJ $0.338 next 10,559 GJ $0.243 next 31,676 GJ $0.187 over 52,974 GJ	
Northwest Natural Gas	Schedule 31*	Non-Residential Transport Industrial		Declining	11/1/2014	$10.68	$325		$0.160 first 2,000 therm $0.145 over 2,000 therm		$1.514 first 211 GJ $1.369 over 211 GJ	Also in commercial
	Schedule 32	Large Volume Non-Residential Transport		Declining w/Demand	11/1/2014	$22.19	$675	$0.157 per therm (MDDV)	$0.095 first 10,000 therms $0.081 next 20,000 therms $0.057 next 20,000 therms $0.033 next 100,000 therms $0.019 next 600,000 therms $0.010 over 750,000 therms		$0.899 first 1,056 GJ $0.764 next 2,112 GJ $0.540 next 2,112 GJ $0.315 next 10,559 GJ $0.181 next 63,353 GJ $0.091 next 79,191 GJ	
	Schedule 33	High Volume Non-Residential Transport		Flat w/Demand	11/1/2014	$1,249.32	$38,000	$0.157 per therm (MDDV)	$0.006 per therm		$0.052 per GJ	
Avista	Schedule 121*	High Annual Load Factor Large General Service		Declining	1/7/2016				$0.913 first 500 therms $0.766 next 500 therms $0.683 next 9,000 therms $0.631 next 15,000 therms $0.556 over 25,000 therms		$8.651 first 53 GJ $7.251 next 53 GJ $6.467 next 950 GJ $5.975 next 1,584 GJ $5.267 over 2,640 GJ	Also in commercial Rate includes cost of gas.
	Schedule 146	Transport Service for Customer-Owned Gas	> 250,000 therms	Declining	1/7/2016	$17.26	$525		$0.102 First 20,000 therms $0.091 next 30,000 therms $0.082 next 250,000 therms $0.076 next 200,000 therms $0.057 over 500,000 therms		$0.962 first 2,112 GJ $0.858 next 3,168 GJ $0.775 next 26,397 GJ $0.718 next 21,118 GJ $0.543 over 52,794 GJ	

Appendix 9-2

RATE SCHEDULE 5/25 DAILY DEMAND NEW MULTIPLIER CALCULATION

RATE SCHEDULE 5/25 DAILY DEMAND NEW MULTIPLIER CALCULATION

- Gathered daily consumption history for all Rate 5/25 customers for period from 2011-2015
- Gathered historical daily weather data for all airports for same period of 2011-2015
- Sorted the airports into 3 weather zones
  - Northern Interior (N INT) - Quesnel, Prince George, Mackenzie and Williams Lake.
  - Southern Interior (S INT) - Kamloops, Kelowna, Cranbrook, Penticton and Castlegar.
  - Lower Mainland/Vancouver Island (LML/VI) - Whistler, Squamish, Hope, Vancouver, Abbotsford, Campbell River, Nanaimo, Powell River, Comox and Victoria.
- Calculated the average daily temperature of each weather zone by averaging the daily temperatures at each airport within each weather zone on a daily basis.
- Determined what the 5 coldest days were for each weather zone for each of the last 5 years from 2011-2015.
- Classified each customer into one of three weather zones LML/VI, S INT or N INT based upon there premise address.
- For each premise we then looked up and determined what their average daily consumption was during the 5 coldest days in each year from 2011-2015.
- For each premise we determined what the demand volume would be based upon the current formula before it is multiplied by 1.25. The current formula is as follows:
  - Daily Demand is equal to 1.25 multiplied by the greater of:
  - the Customer's highest average daily consumption of any month during the winter period (November1 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).
- For each Premise, the average consumption on the 5 coldest days determined in Step 7 is divided by the Daily demand before the multiplier of 1.25 determined in Step 8. This formula determines what the multiplier would need to be under the current formula to match the customers actual average consumption over the 5 coldest days for their weather zone for each premise.
- The average of all the premise level calculations for each calendar year are then determined for each calendar year. The results are shown in Table 9-12

Appendix 9-3

AVOIDED COST OF SERVICE RELATED TO INTERRUPTIBLE CUSTOMERS

AVOIDED COST OF SERVICE

The following two pages provide the avoided cost of service from interruptible customers choosing not to receive firm service. The first table shows the value of the avoided cost of service related to all interruptible customers served under RS 7 / 27 and 22 for 20 years. The second table shows the value of avoided cost of service related to just interruptible RS 22 customers. The difference of the value of the avoided cost of service between the two tables would be related to RS 7/27, i.e. approximately $0.04 per GJ (Line 26 average for 20 years $0.059 - $0.017).

The avoided direct capital cost is approximately $134.2 million for required system upgrades to the transmission system, distribution system and station upgrades related to all interruptible customers not being firm. The avoided direct capital cost for only RS 22 interruptible customers is $40.2 million.

Table 1: Estimated Avoided Cost of Service Related to All Interruptible Customers

Line No.	PARTICULARS	Escalation Rate	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	RATE BASE																					
2	Gas Plant in Service - Opening		$ 134,195	$134,200	$134,204	$134,209	$134,214	$134,220	$134,225	$134,230	$134,235	$134,241	$134,246	$134,252	$134,258	$134,264	$134,270	$134,276	$134,282	$134,288	$134,294	$134,301
3	Gas Plant in Service - Closing		134,200	134,204	134,209	134,214	134,220	134,225	134,230	134,235	134,241	134,246	134,252	134,258	134,264	134,270	134,276	134,282	134,288	134,294	134,301	134,307
4																						
5	Accumulated Depreciation - Opening		-	(2,365)	(4,730)	(7,095)	(9,460)	(11,825)	(14,190)	(16,556)	(18,922)	(21,288)	(23,654)	(26,020)	(28,386)	(30,752)	(33,119)	(35,486)	(37,853)	(40,220)	(42,587)	(44,955)
6	Accumulated Depreciation - Closing		(2,365)	(4,730)	(7,095)	(9,460)	(11,825)	(14,190)	(16,556)	(18,922)	(21,288)	(23,654)	(26,020)	(28,386)	(30,752)	(33,119)	(35,486)	(37,853)	(40,220)	(42,587)	(44,955)	(47,322)
7																						
8	Mid-Year Gas Plant in Service		$ 133,015	$130,655	$128,295	$125,935	$123,575	$121,214	$118,854	$116,494	$114,134	$111,773	$109,413	$107,052	$104,691	$102,331	$ 99,970	$ 97,609	$ 95,248	$ 92,887	$ 90,526	$ 88,165
9																						
10	Cost of Service																					
11	O&M Expense	1.627%	$ 40	$ 41	$ 41	$ 42	$ 43	$ 43	$ 44	$ 45	$ 46	$ 46	$ 47	$ 48	$ 49	$ 49	$ 50	$ 51	$ 52	$ 53	$ 53	$ 54
12	Overhead Capitalized	12%	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(6)	(7)
13	Net O&M		35	36	36	37	38	38	39	39	40	41	41	42	43	43	44	45	46	46	47	48
14																						
15	Property Taxes	1.627%	191	194	197	200	204	207	210	214	217	221	224	228	232	236	239	243	247	251	255	260
16	Depreciation Expense		2,365	2,365	2,365	2,365	2,365	2,365	2,366	2,366	2,366	2,366	2,366	2,366	2,366	2,367	2,367	2,367	2,367	2,367	2,367	2,368
17	Income Taxes		(600)	(433)	(280)	(138)	(8)	113	223	324	417	502	580	651	715	774	827	874	917	955	989	1,019
18	Earned Return		8,866	8,709	8,551	8,394	8,237	8,080	7,922	7,765	7,608	7,450	7,293	7,136	6,978	6,821	6,663	6,506	6,349	6,191	6,034	5,877
19	Total Cost of Service		10,858	10,870	10,870	10,859	10,836	10,803	10,760	10,708	10,648	10,580	10,505	10,423	10,335	10,240	10,140	10,036	9,926	9,812	9,693	9,571
20																						
21	Rate Schedule 7 / 27 Volumes		6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563	6,563
22	Rate Schedule 22 Interruptible Volumes		18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487
23	Total Interruptible Volumes		25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050	25,050
24																						
25	FEI Total Non-Bypass Volumes		182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942
26	Avoided Cost of Service $ / GJ		$ 0.059	$ 0.059	$ 0.059	$ 0.059	$ 0.059	$ 0.059	$ 0.059	$ 0.059	$ 0.058	$ 0.058	$ 0.057	$ 0.057	$ 0.056	$ 0.056	$ 0.055	$ 0.055	$ 0.054	$ 0.054	$ 0.053	$ 0.052

Table 2: Estimated Avoided Cost of Service Related to RS 22 Interruptible Customers

Line No.	PARTICULARS	Escalation Rate	1 2016	2 2017	3 2018	4 2019	5 2020	6 2021	7 2022	8 2023	9 2024	10 2025	11 2026	12 2027	13 2028	14 2029	15 2030	16 2031	17 2032	18 2033	19 2034	20 2035
1	RATE BASE																					
2	Gas Plant in Service - Opening		$ 40,150	$ 40,152	$ 40,154	$ 40,155	$ 40,157	$ 40,159	$ 40,161	$ 40,163	$ 40,165	$ 40,167	$ 40,169	$ 40,171	$ 40,173	$ 40,175	$ 40,177	$ 40,179	$ 40,182	$ 40,184	$ 40,186	$ 40,188
3	Gas Plant in Service - Closing		40,152	40,154	40,155	40,157	40,159	40,161	40,163	40,165	40,167	40,169	40,171	40,173	40,175	40,177	40,179	40,182	40,184	40,186	40,188	40,191
4																						
5	Accumulated Depreciation - Opening		-	(642)	(1,285)	(1,928)	(2,570)	(3,213)	(3,856)	(4,498)	(5,141)	(5,784)	(6,427)	(7,070)	(7,713)	(8,356)	(8,999)	(9,642)	(10,286)	(10,929)	(11,572)	(12,216)
6	Accumulated Depreciation - Closing		(642)	(1,285)	(1,928)	(2,570)	(3,213)	(3,856)	(4,498)	(5,141)	(5,784)	(6,427)	(7,070)	(7,713)	(8,356)	(8,999)	(9,642)	(10,286)	(10,929)	(11,572)	(12,216)	(12,859)
7																						
8	Mid-Year Gas Plant in Service		$ 39,830	$ 39,189	$ 38,548	$ 37,907	$ 37,267	$ 36,626	$ 35,985	$ 35,344	$ 34,703	$ 34,062	$ 33,421	$ 32,780	$ 32,139	$ 31,498	$ 30,857	$ 30,216	$ 29,575	$ 28,934	$ 28,293	$ 27,652
9																						
10	Cost of Service																					
11	O&M Expense	1.627%	$ 15	$ 15	$ 15	$ 15	$ 15	$ 16	$ 16	$ 16	$ 16	$ 17	$ 17	$ 17	$ 18	$ 18	$ 18	$ 18	$ 19	$ 19	$ 19	$ 20
12	Overhead Capitalized	12%	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
13	Net O&M		13	13	13	13	14	14	14	14	15	15	15	15	15	16	16	16	17	17	17	17
14																						
15	Property Taxes	1.627%	39	39	40	40	41	42	42	43	44	45	45	46	47	48	48	49	50	51	52	52
16	Depreciation Expense		642	643	643	643	643	643	643	643	643	643	643	643	643	643	643	643	643	643	643	644
17	Income Taxes		(149)	(106)	(66)	(29)	6	38	67	95	120	144	165	185	203	220	235	249	261	272	282	292
18	Earned Return		2,655	2,612	2,569	2,527	2,484	2,441	2,399	2,356	2,313	2,270	2,228	2,185	2,142	2,100	2,057	2,014	1,971	1,929	1,886	1,843
19	Total Cost of Service		3,199	3,201	3,199	3,194	3,187	3,177	3,165	3,151	3,135	3,116	3,096	3,074	3,051	3,026	2,999	2,971	2,942	2,912	2,880	2,848
20																						
21	Rate Schedule 7 / 27 Volumes																					
22	Rate Schedule 22 Interruptible Volumes		18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487	18,487
23	Total Interruptible Volumes																					
24																						
25	FEI Total Non-Bypass Volumes		182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942	182,942
26	Avoided Cost of Service $ / GJ		$ 0.017	$ 0.017	$ 0.017	$ 0.017	$ 0.017	$ 0.017	$ 0.017	$ 0.017	$ 0.017	$ 0.017	$ 0.017	$ 0.017	$ 0.017	$ 0.017	$ 0.016	$ 0.016	$ 0.016	$ 0.016	$ 0.016	$ 0.016

Appendix 10

TRANSPORTATION SERVICE REVIEW

Appendix 10-1

BLACK & VEATCH
TRANSPORTATION SERVICE MODEL REVIEW

FINAL

TRANSPORTATION SERVICE MODEL REVIEW

PREPARED FOR

FortisBC Energy, Inc.

7 DECEMBER 2016

BLACK & VEATCH
Building a world of difference.

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ATTACHMENT

PDF of Industry-wide Survey of Transportation Balancing Provisions

1.0 Introduction and Overview of Black & Veatch's Review

Black & Veatch was retained by FortisBC Energy, Inc. (FEI) to perform an overall review of FEI's Transportation Service Model. Our analysis was informed by the results of our review and analysis of FEI's various midstream capacity resources, with particular interest in their use in providing balancing of transportation customers' loads. The focus of our review included the physical diversity, functionality and flexibility provided by the various capacity resources. Black & Veatch worked closely with FortisBC to understand the historical perspectives related to the utilization of the various midstream capacity resources today for system balancing and the cost impact caused by transportation customers' imbalance levels.

Black & Veatch supplemented our evaluation of FEI's midstream transportation and storage capacity resources with a review and comparison of current industry-wide best practices, by regulatory jurisdiction, related to transportation balancing tariff provisions.

Black & Veatch constructed a spreadsheet based model for the purpose of analyzing FEI's daily and monthly balancing activity from available data as it relates to the Company's current tariffed balancing provisions; the model facilitated the evaluation of alternative scenarios. We provide a recommendation for changes to the current transportation balancing tolerance requirements and cost information to aid in determining corresponding balancing charges based on the results of our analysis, our prior case experience, and industry best practices.

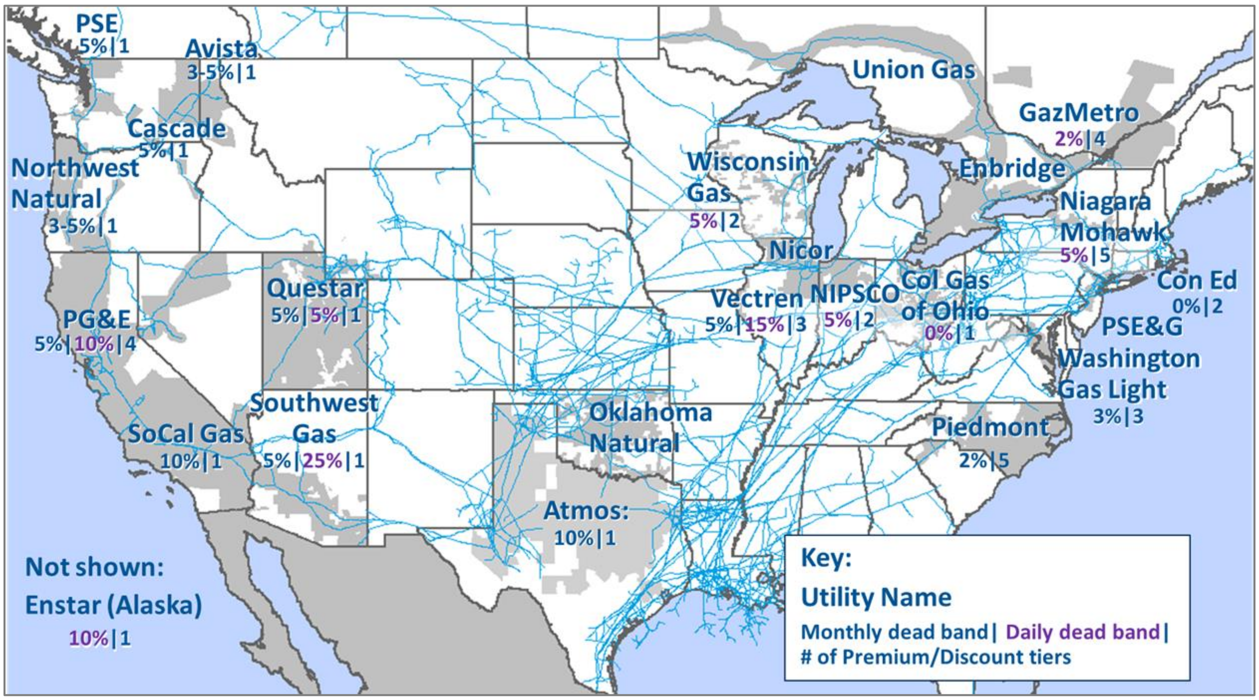
2.0 Balancing Provisions: Common Industry Practices

In the course of normal business, a gas utility's transportation customers can deliver and receive differing amounts of natural gas from the utility's distribution system on a day-to-day basis, which creates imbalances. Gas balancing provisions, as stated in a utility's tariff, detail the extent to which imbalances can be accrued, as well as set out the process by which these imbalances are accounted for and reconciled at the end of the balancing period. Industry-wide, balancing provisions can differ substantially between local distribution companies (LDCs) based on a given LDC's circumstances. For example, balancing provisions can be relatively stringent for LDCs with service territory adjacent to major natural gas market hubs in order to reduce the possibility 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 while allowing s 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 customer is then charged for quantities that exceed the threshold according to a schedule of imbalance charges, which is referred to as "cashing out." 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 those of an LDC's peers.

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 see how FEI's balancing provisions compare relative to its peers. 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 below, many LDCs across the U.S. and Canada set balancing thresholds at approximately 5%, a level that applies to both monthly and daily balanced transportation service customers. Thresholds rarely exceed 10%, and sometimes are as low as 0%.

Figure 1 Comparison of Selected Balancing Provisions among North American LDCs



Notes to Figure 1:

- Premium/Discount tiers are escalating levels of charges a customer must pay when its imbalances reach a certain level.
- LDCs with monthly and daily dead-bands typically apply both dead-bands to all transport customers.
- Enbridge offers services utilizing storage to shift imbalances between customers but does not mention dead-bands in its tariff.
- Nicor charges a flat per-Dth fee for balancing services in its tariff, but makes no mention of dead-bands.
- PSE&G charges a balancing fee based on the differential between average winter and average summer throughput differential.
- No specific balancing provisions were listed in the tariff for Oklahoma Natural and Union Gas.

All things considered, the analysis shows that FEI's current balancing provisions are substantially more accommodating than its North American LDC peers. Daily balancing is required by many LDCs, typically depending on proximity to major market hubs, and the corresponding balancing requirements for the pipelines upstream of an LDC's service territory. Some LDCs also require their customers to balance on both a daily and monthly basis. Further, the analysis supports the notion that it is feasible for transportation customers to balance their gas deliveries to a 10% threshold since it is common practice for LDCs elsewhere to require their customers to meet this level of balancing threshold.

3.0 FEI's Balancing Provisions

The balancing provisions and tolerance threshold currently set in FEI's Transportation Terms and Conditions of its transportation rate schedules provide a great deal of flexibility to transportation customers or the shipper agents that provide their gas supplies. For example, FEI currently allows its large volume transportation customers a 20% daily balancing tolerance; it allows shipper agents to pool their imbalances from multiple customers into aggregate accounts; and provides the option for monthly balancing for certain customer pools. Balancing the system when there is an imbalance between gas supply and demand requires FEI to utilize resources (storage and transportation capacity) that are designed to deliver relatively constant quantities of gas on a day-to-day basis. Since the underlying costs of these resources are recovered from FEI's sales customers, it is reasonable for transportation customers or their shipper agents to contribute to the recovery of the costs of the resources that FEI uses to balance the system.

The following section will provide a detailed description of a methodology developed by Black & Veatch to measure the value of the balancing resources provided by FEI to the shipper agents on its system. The objective of the analysis is to determine whether and to what extent there is value for these resources, rather than pinpointing an exact dollar amount that the shipper agents ought to be charged.

3.1 Black & Veatch's Replacement Cost Methodology

Black & Veatch developed a methodology to calculate the estimated replacement cost of FEI's storage and related pipeline capacity resources that are used for system balancing. As described below, the calculation shows that the resources FEI uses to balance its system have significant market value.

Using 2015 data[1] as an indicative year, the replacement cost analysis used shipper agents' daily deliveries (aggregated across all the accounts of each shipper agent) and adjusted imbalances data (imbalances were adjusted for end-of-month inventory adjustments and allowed imbalance return quantities). The absolute value of the daily imbalance was used, as the analysis needed to show costs associated with both positive and negative imbalances, since both lead to the utilization of the System resources (to inject or withdraw gas, for example). The daily delivered volume was multiplied by an assumed balancing threshold ranging from 5% to 20%, in 5% increments (replicating different balancing threshold levels that FEI could hypothetically set). The difference between these two adjusted figures was determined for each day of 2015. If the difference was negative, it was changed to zero, thereby eliminating any negative values. This amount is referred to as the "volumes in excess of the threshold".

A shipper agent looking at its projected imbalance volumes in excess of the threshold would likely want to balance its own risk tolerance with cost minimization when deciding what level of

[1] Black & Veatch also performed the same analysis for 2010-2014 data and found results very similar to those of the 2015 analysis. The data presented in this report will focus on 2015, as it is the most recent indicative year.

contracted firm storage and related pipeline capacity is necessary in order to meet its balancing needs for a given year. Contracting for sufficient firm capacity to meet its highest projected level of daily imbalance would entail over-contracting for capacity on every other day of the year. On the other hand, contracting for lower levels of capacity would leave a shipper agent subject to potentially expensive imbalance charges or other mitigation measures on a daily basis. To find a balance between these two objectives, the 3rd quartile of the "volumes in excess of the threshold" dataset was assessed in order to arrive at an estimate of the firmly contracted maximum daily quantity ("MDQ," the firm transportation quantity delivered during a month), that a shipper agent might purchase in order to meet its balancing needs. The 3rd quartile represents an MDQ level that could support the balancing required for the volumes in excess of the threshold for 75% of the days in 2015. This assumption provides a reasonable balance between a shipper agent paying demand charges or incurring potential imbalance charges and is based on FEI's historical transportation imbalance data reviewed by Black & Veatch. As a sensitivity check, the median of the "volumes in excess of the threshold" was calculated and the results seemed to leave shipper agents overly exposed to daily imbalance swings. Figure 2 below shows an example of the "volumes in excess of the threshold" plotted against the 3rd quartile of the data for an indicative shipper agent.

Figure 2 Daily Imbalance Quantity in Excess of 20% Threshold (2015)

From this point, various metrics were calculated to arrive at estimates of how much volume for the year was in excess of the threshold, how much of this volume would be subject to commodity charges on the upstream pipelines, and how much volume would be subject to FEI's applicable imbalance charges. To calculate the annual charges paid by each shipper agent, these metrics were multiplied by an assumed average portfolio reservation rate or a commodity rate, as applicable. The assumed portfolio consisted of maximum tariff rates for firm transportation service on Northwest Pipeline as well as firm storage service at the Jackson Prairie and Mist storage facilities.

A critical review of the methodology employed could yield possible alternative assumptions. For example, the tariff rates for Aitken Creek storage and T-South pipeline capacity could be used along with the previously mentioned assets to create a larger portfolio of resources. Black & Veatch chose not to use the Aitken Creek and T-South resources in its analysis, as Aitken Creek is periodically not available for balancing due to capacity constraints on T-South. Also, the current levels of unsubscribed capacity of the resources could be factored into the analysis, which could require estimations of incremental infrastructure and higher associated rates. Black & Veatch chose to aim for simplicity and transparency by using maximum pipeline and storage tariff rates.

An idea mentioned at the stakeholder workshop was to use spot prices to calculate the cost of meeting daily imbalances rather than assuming a shipper agent would have to contract for incremental firm transportation and storage to meet its balancing needs. However, this concept is likely not feasible in the British Columbia gas market. There is a limited intraday market for gas and no published intraday price indices in British Columbia, unlike in other regions such as Alberta. Since imbalances have to be corrected on an intraday basis, it is unclear how a shipper agent could rectify its imbalances intraday by paying a daily spot market price. Because of this, the British Columbian gas market is driven by fixed storage and transportation assets because the region does not have a robust and liquid market hub, and therefore Black & Veatch believes it is a better depiction of FEI's situation to use tariff rates that correspond to these pipeline and storage assets rather than assuming imbalances can be rectified by paying the daily spot market price.

As a final assumption, FEI imbalance charges were excluded in the base case version of this analysis in order to reflect the shipper agents' abilities to avoid these charges with mitigation measures and to arrive at a more conservative estimate of balancing costs. A sensitivity case was created to test the impact of including the cost of imbalance charges on FEI's System.

3.2 Base Case – Replacement Cost of Balancing Resources

The aggregate total of all shipper agents' annual balancing costs (consisting of reservation and commodity charges in the base case) was divided by the total transportation throughput on the System (72,381,734 GJ for 2015) to arrive at the average cost of securing balancing resources per GJ under various threshold cases (5-20%). The results are shown below in Table 1.

Table 1 Average Cost of Securing Balancing Resources (Base Case)

	Total Charges	$/GJ
5%	$15,073,449	$0.208
10%	$11,584,340	$0.160
15%	$8,564,864	$0.118
20%	$6,456,223	$0.089

From this point, one last calculation was made to arrive at the replacement cost of FEI's balancing resources. As discussed in Section 2.0, while balancing thresholds differ widely across LDCs, a 5% threshold is a fairly common "median" threshold often seen across the industry. The analysis measured the incremental value provided by FEI in setting a more flexible 20% threshold by taking the difference between the average cost of securing balancing resources per GJ for the 10%, 15%, and 20% threshold cases and the same metric for the 5% threshold case. The results are shown below in Table 2.

Table 2 Replacement Cost of FEI's Balancing Resources (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 base case analysis shows 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 balancing resources elsewhere. Furthermore, the value of FEI's balancing resources decreases with more stringent balancing tolerances. It is therefore important to consider that as the balancing tolerances and charges evolve through the regulatory process, it is reasonable to collect more revenue from shipper agents who require wider balancing tolerances to serve their customers when compared to shipper agents who routinely balance to tighter thresholds.

From the base case analysis, a few sensitivity cases were run whereby certain assumptions were varied to determine the impact on the implied value of balancing resources. Each sensitivity case was run in isolation, meaning that only a single assumption was changed in each sensitivity case.

3.3 Sensitivity Case – Imbalance Returns Excluded

The first sensitivity case examined estimated the impact of excluding the effect of imbalance returns from the "adjusted imbalance" dataset. Given that FEI utilizes the system resources to store the gas held in the shipper agents' inventory accounts on a daily basis, the sensitivity case was useful in calculating the value of imbalance returns. The results are shown in Table 3. Allowing imbalance returns to be deducted from a shipper agent's pool imbalance, which is subject to additional charges is worth roughly $0.015/GJ to the shipper agents for the 20% threshold case, though the value diminishes in the more stringent threshold cases.

Table 3 Imbalance Return Case Results

	Total Replacement Costs	$/GJ	Differential from Base Case*
10%	$3,541,598	$0.049	$0.001
15%	$6,821,694	$0.094	$0.004
20%	$9,699,556	$0.134	$0.015

* Comparable Base Case results are found in Table 2

3.4 Sensitivity Case – FEI Imbalance Charges Included

As mentioned previously, the effect of including imbalance charges for imbalance volumes that exceed the FEI threshold after accounting for a shipper agent's newly contracted capacity was examined as a sensitivity case. The results show that total charges increase drastically as shipper agents are subject to fees or imbalance charges due to frequent imbalances exceeding the threshold. However, the imbalance charges have a muted impact on the replacement cost of providing balancing resources since these charges were paid in substantial amounts in all threshold cases. Note that Table 4 below includes total charges incurred by all shipper agents in the first two columns, and then presents the replacement cost figures in the last three columns.

Table 4 Imbalance Charges Case Results

	Total Charges	Total Charges $/GJ	Total Replacement Costs	Replacement Costs $/GJ	Differential from Base Case*
5%	$26,167,190	$0.362	N/A	N/A	N/A
10%	$22,847,821	$0.316	$3,319,369	$0.046	($0.002)
15%	$19,720,060	$0.272	$6,447,129	$0.089	($0.001)
20%	$16,908,427	$0.234	$9,258,763	$0.128	$0.009

* Comparable Base Case results are found in Table 2

3.5 Sensitivity Case – Zero Percent Threshold

FEI assessed the value of the providing balancing resources it provides on an absolute basis, without taking into account the benchmark 5% threshold. For this sensitivity, a 0% threshold case was used to calculate the cost to procure resources to deal with a hypothetical 0% tolerance threshold. The results are shown below in Table 5.

Table 5 0% Threshold Case Results

	Total Charges	Total Charges $/GJ	Total Replacement Costs	Replacement Costs $/GJ	Differential from Base Case*
0%	$18,565,867	$0.256	N/A	N/A	N/A
5%	$15,073,449	$0.208	$3,492,418	$0.048	$0.048
10%	$11,584,340	$0.160	$6,981,527	$0.096	$0.048
15%	$8,564,864	$0.118	$10,001,003	$0.138	$0.048
20%	$6,456,223	$0.089	$12,109,644	$0.167	$0.048

* Comparable Base Case results are found in Table 2

3.6 Replacement Cost Analysis Summary

Taken as a whole, the replacement cost of providing balancing resources analysis shows that the balancing resources FEI provides have significant value in the market. 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 FEI's current balancing provisions, the calculated value ranges from $0.119/GJ (Table 2) to $0.167/GJ (Table 5).

3.7 Balancing Charges Methodology

The balancing charge assessed to shipper agents could take different forms. The two forms Black & Veatch examined for FEI are the two most commonly seen in the gas utility industry: a volumetric rate that each customer pays per GJ of annual transportation throughput, or a tiered charge that assesses higher charges as the size of a customer's imbalance increases.

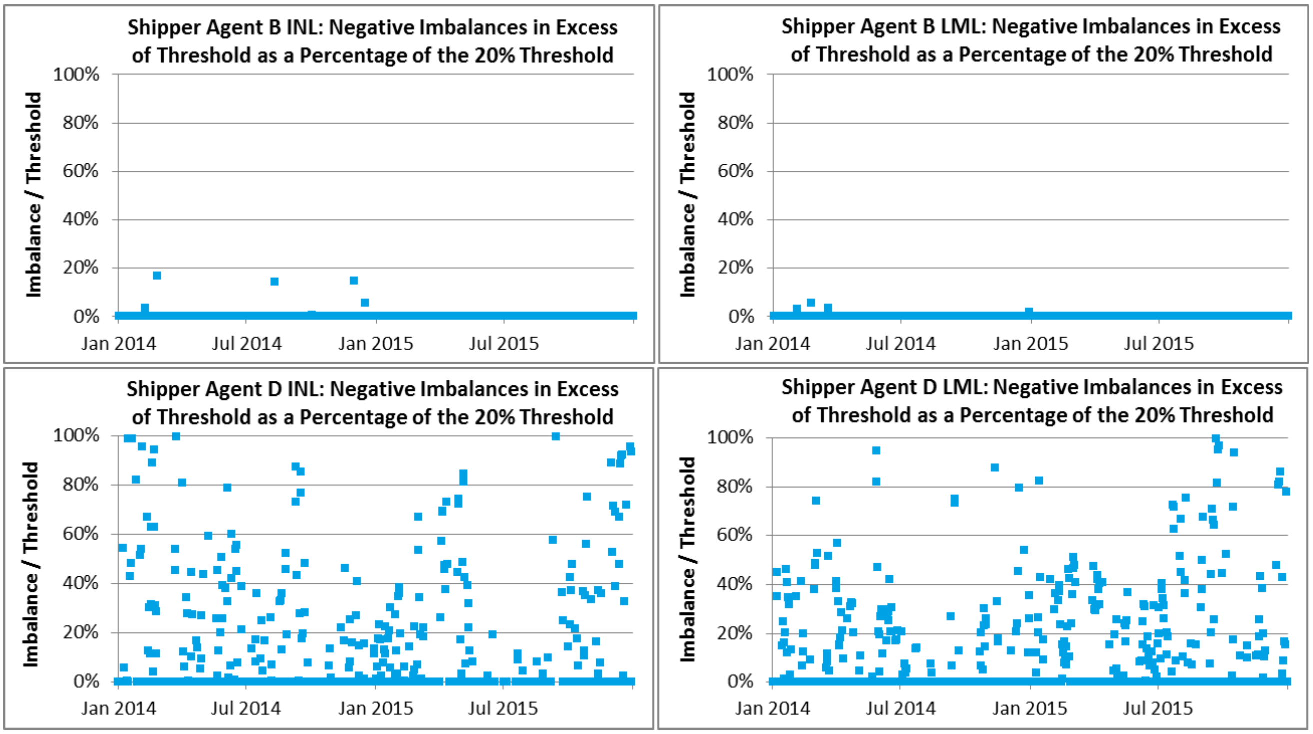
The volumetric rate has the benefit of being a straightforward charge, the impact of which is easy to project, as there is no incentive for transportation customers or their shipper agents to change their imbalance behaviour patterns. In fact, Black & Veatch reviewed data from 2010-2015 and found that annual transportation throughput within FEI's service territory has not varied substantially throughout that period. This charge can be thought of as reflecting the transportation customers' "option value" of the balancing resources; even if the resources are not used on a given day, transportation customers still benefit from the option of being able to use them for a relatively small volumetric charge.

However, an alternative method of assessing balancing charges is to incentivize the reduction of large imbalances on the system by charging progressively higher amounts for larger imbalances. This type of charge focuses on addressing an important goal for FEI, that is, to reduce the high daily imbalance levels on the system, rather than attempting to collect an amount based on the cost of the underlying resources or the benefit transportation customers receive from those balancing resources. In fact, charging customers based on the level of imbalance is an appropriate method that will allow FEI to reduce the level of imbalances on its system while also recovering the costs of providing balancing resources.

4.0 Identification of a Feasible Balancing Threshold

An examination of historical balancing data by shipper agent reveals a wide array of patterns and strategies employed by each shipper agent. Each shipper agent tends to operate the pools they run in similar ways, so if a shipper agent is frequently out of balance in its Lower Mainland (LML) pool, it is likely to be operating outside the tolerance levels in its Inland (INL) pool as well. While it is possible in some cases that shipper agents displaying this pattern are serving customers who have inconsistent gas demand in both territories, a more likely explanation is that each shipper agent has a strategy that they employ in nominating and supplying gas to the system, and they apply their strategies to any service territory they have a pool in. To illustrate an example of this, the charts below show that while "Shipper Agent B" is typically close to being in balance in its LML and INL service territories, "Shipper Agent D" is consistently out of balance.

Figure 3 Historical Balancing Data by Shipper Agent



* Shipper Agent D included some values in excess of 100%; Axis was limited to 100% to show detailed comparison

4.1 Review of Shipper Agents' Balancing History

Given the shipper agents' different strategies, FEI sought to determine if some strategies allow shipper agents to consistently balance their load to specific thresholds, namely 20% (the current threshold on the system), and 10%. The goal was to be able to assess the feasibility of balancing to these thresholds: if several shipper agents are currently balancing to a 10% or 20% level, it is reasonable to suggest that it is feasible for shipper agents not currently balancing to these thresholds to change their nomination patterns to also meet these thresholds.

An analysis of balancing data from 2014 and 2015 found that nearly half of the shipper agent pools are consistently balancing to 10% and 20% thresholds, while the other pools are frequently out of balance, in some cases by a large margin.

The primary metric the analysis considered was the number of days in an average year in which a negative imbalance quantity exceeded the given threshold. Negative imbalances were considered rather than all imbalances because of FEI's long-standing policy of encouraging shipper agents to leave 2-3 days of pack on the system and therefore only charging for imbalances if they are caused by under-delivering to the system. The number of days out of balance is the most important metric to consider because it captures the extent to which a pool is routinely able to balance to a threshold. Volumetric averages of negative imbalance quantities were also calculated, but these figures could be skewed by brief periods in which imbalances were unusually high or low, so they are not as reliable of a metric in showing the extent to which a pool is able to consistently operate within a given imbalance threshold.

The following tables of shipper agent imbalance results contain the fields of data 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 such that Shipper Agent A has more load than Shipper Agent B, etc.
- **Service Area**: Specifies whether the 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.
- # **Imb Days / Year**: Number of days in which a negative imbalance exceeded the given threshold in the years 2014 and 2015, divided by 2 (to annualize the figure). The red line drawn on each table on the following two pages differentiates the shipper agents in the respective Service Areas who are routinely operating within the given balancing threshold (below the line) from those who are not operating within that same threshold (above the line).
- **Annual Volume in Excess**: The negative imbalance quantity in excess of the threshold during the years 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

Table 6 Imbalance Data under a 20% Threshold

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	278	-1,976	-5	8	-65%
Shipper Agent M	LML	212	-71,729	-197	467	-42%
Shipper Agent N	LML	208	-29,385	-81	230	-35%
Shipper Agent I	INL	187	-23,514	-64	414	-16%
Shipper Agent E	INL	177	-187,630	-514	2,128	-24%
Shipper Agent C	LML	161	-697,892	-1,912	13,829	-14%
Shipper Agent D	INL	145	-175,478	-481	3,401	-14%
Shipper Agent D	LML	139	-505,481	-1,385	14,446	-10%
Shipper Agent E	LML	122	-569,679	-1,561	13,008	-12%
Shipper Agent O	LML	118	-3,241	-9	124	-7%
Shipper Agent C	INL	67	-89,044	-244	8,173	-3%
Shipper Agent I	LML	65	-39,951	-109	2,591	-4%
Shipper Agent A	LML	60	-91,188	-250	19,970	-1%
Shipper Agent A	INL	11	-47,194	-129	10,978	-1%
Shipper Agent H	INL	11	-14,863	-41	5,293	-1%
Shipper Agent F	INL	5	-13,781	-38	14,602	0%
Shipper Agent K	INL	4	-2,379	-7	1,199	-1%
Shipper Agent B	INL	3	-5,762	-16	15,191	0%
Shipper Agent B	LML	3	-1,542	-4	15,641	0%
Shipper Agent L	LML	3	-960	-3	1,155	0%
Shipper Agent H	LML	1	-71	0	3,027	0%
Shipper Agent J	LML	1	-8	0	1,435	0%
Shipper Agent G	INL	0	0	0	9,830	0%

Table 7 Imbalance Data under a 10% Threshold

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%

4.2 Recommendation and Concluding Remarks

FEI is proposing to transition its Transportation model along a continuum from one of liberal daily and monthly balancing tolerances with balancing charges based on daily gas commodity market pricing to a model that requires daily balancing for all transportation customers, with a tighter balancing threshold, and appropriate balancing charges.

In today's natural gas market, transportation customers or their shipper agents have access to services to amend their gas requirements on the day to reflect changes in load. Over the past several years, technology improvements and an increase in gas nomination cycles allow shipper agents to access and track supply and consumption habits within a tighter bandwidth. This has resulted in greater ability for the gas pipeline industry to match supply and demand through the use of various technologies, products, and services as compared to when FEI's transportation model was initially developed.

As described earlier in this document, the general gas industry practice is to require daily balancing. It is also industry practice upstream of FEI's system to balance daily and FEI's balancing agreements with third-party pipeline systems require daily balancing downstream.

As can be seen in the foregoing tables in Section 4.1, several shipper agents of different sizes operating in both the Inland and Lower Mainland are able to balance to the 10% threshold. This suggests that it is reasonable for shipper agents to nominate gas into their pools such that a 10% threshold is rarely breached, and therefore it is reasonable for FEI to set a 10% balancing threshold. In addition, FEI's balancing charges should reflect the costs of utilizing its pipeline and storage capacity resources that provide the intra-day nomination cycle flexibility to balance supply and demand on FEI's system, and support the overall objective of the transportation model, which is to provide customers with options to purchase their gas supply requirements.

FortisBC
Comparison of Balancing Provisions for Selected Companies

Line No.	Description	Piedmont Natural Gas	Washington Gas Light	Public Service Electric & Gas (PSE&G)	Consolidated Edison	Niagara Mohawk (National Grid)
				Mid-Atlantic		
		(1)	(2)	(3)	(4)	(5)
1	Balancing provisions (general)	Customer is responsible to proactively manage its balancing. Piedmont has the right to curtail deliveries to ensure operational integrity.	For firm, non-power generator customers, a monthly charge is determined by taking annualized peaking costs, dividing by the total firm throughput over the past year, dividing by 12 (to make it on a monthly basis), and then multiplying the customer's monthly capacity. Separate balancing provisions for power generators. MDQ based on rated capacity of the facility. Must be within +/- 20% of the MDQ every day or generator is subject to a $1/Dth penalty. Generators are also subject to a penalty if they exceed 100% of their MDQ on a cumulative basis. Penalty is 110% of cost of gas + $25/Dth. Also separate provision for IT customers. 3% dead band, 3 premium tiers.	Amount of usage in winter months that exceeds usage in summer months is called the "balancing use therms." Balancing use therms are subject to a surcharge that varies by rate schedule.	The only balancing provisions in the tariff are for the (Marketer) Transportation Receipt Service. ConEd provides several balancing services to its customers under this rate schedule, including: Load Following Service, Daily/Monthly Balancing Service, Automatic Netting of Imbalances, Monthly/Daily Imbalance Trading, Winter Bundled Sales Service, and Managed Supply Service. Multiple schedules for imbalance cash outs based on which rate schedule the Customer is under. The values below are for firm service. For off-peak or interruptible service, the dead band is 0%, and there are 5 premium/discount tiers, counting the two seasonal tiers at 20%.	Additional charges can be added if imbalance is greater than 50%. At the end of the month, the imbalance of "All Pools" is calculated, and marketers who are contribute to aggregate imbalances over 2% can be charged additional amounts based on a price index. These monthly charges can be avoided by trading imbalances with other marketers on the system.
2	Balancing: Dead-band	2%	For power gen only: 20% (daily), 100% (cumulative)	N/A	0%	5%
3	Balancing: # Premium/ Discount Tiers	5	For power gen only: 1 For IT customers only: 3	N/A	2	5
4	Balancing: Type of Charge	Transportation + Index (with lower of/higher of for under/over nomination)	For non-power gen customers: Pro rata share of WGL's peaking costs For power gen customers: Percentage of price of gas plus flat fee	Surcharge based on incremental seasonal demand	Fixed charge based on level of imbalance	Transportation + Index (midpoint)
5	Balancing: Time Period	Monthly	For non-power gen: Annual rate redetermination; monthly billing	Billed on a monthly basis	Monthly	Daily
6	Cash Out Entire Imbalance, or Imbalance in Excess of	All imbalances	Imbalance Volumes in excess	N/A	All imbalances	Imbalance Volumes in excess
7	Ability to Draw from Cumulative	Not specified	Not specified	N/A	Not specified	Not specified

FortisBC
Comparison of Balancing Provisions for Selected Companies

		Midwest				
Line No.	**Description**	**Northern Indiana Public Service Company (NIPSCO)**	**Vectren Energy Delivery of Ohio**	**Columbia Gas of Ohio**	**Northern Illinois Gas Co (Nicor)**	**Wisconsin Gas**
		(6)	**(7)**	**(8)**	**(9)**	**(10)**
1	Balancing provisions (general)	Customers must be administratively balanced on a daily basis. Balancing services include: -Nomination Exchange (trading imbalances between customers) -Interruptible Gas Overtake Service & Nominated Interruptible Gas Overtake Service - Company Balancing Service Category (B) (customer pays for a storage account to absorb imbalances; no negative balance allowed; subject to no notice charges) - Imbalance Netting Option (can incur additional charges) - Company Balancing Service Category (A) (similar to Category B, but for large transport customers) For both Category A&B, customers can carry over (positive) imbalances from one month to the next	Customers must balance on a daily and monthly basis. Customers are permitted to trade imbalances, even during OFO days. Daily Cash out terms: Under-Delivery (i.e., Usage is greater than Deliveries): Up to 15% is carried to the next month; 3 tiers in total Over-Delivery: Up to 15% is carried to the next month; two tiers beyond 15%. These rates escalate for shippers who exceed the 15% threshold on more than 36 days in a year Monthly Cash out terms: 5% dead-band, 3 tiers in total. During an OFO, imbalances larger than 5% are cashed out at more punitive rates	Customer may subscribe to a monthly Banking and Balancing Service. This establishes a Volume Bank with a set threshold (1-4% of Annual Transportation Volume, with higher per Mcf rates charged to higher thresholds). The amount in the bank goes up when a Customer takes less gas than it delivers to Columbia. Service is non-firm and subject to restriction due to OFOs and OMOs. Transfers can be made between customers. Customers not subscribed to the monthly Banking and Balancing Service are required to cash out all imbalances daily	Customers are charged a "Customer Select Balancing Charge" on a per-Dth of total usage basis	Two balancing services offered: Demand Aggregator Balancing Service (DABS), and Super Pooling - Cash Out Service (SPC). DABS enables customers to provide one aggregated gas supply total to Wisconsin Gas for redelivery to one or more of the customer's meters SPC nets out various overtake and undertake positions across a customer's pooling points to reduce net imbalances
2	Balancing: Dead-band	5%	15% (daily); 5% (monthly)	Can be set to different levels for a fee; 0% if opt out	N/A	5%
3	Balancing: # Premium/ Discount Tiers	3	3	1	N/A	2
4	Balancing: Type of Charge	Percentage of index price	Multiple of the daily/monthly under/over-delivery charge	Multiple of index price + transportation cost	Fixed fee charged on total usage regardless of imbalances	Index price + fixed fee
5	Balancing: Time Period	Daily	Daily and Monthly	Daily (with no service); Monthly (with service)	N/A	Daily
6	Cash Out Entire Imbalance, or Imbalance in Excess of	All imbalances (daily balancing)	Volumes in excess for daily balancing, All imbalances for monthly balancing	Imbalance volumes in excess for Banking service, all volumes for daily balancing	N/A	All imbalances
7	Ability to Draw from Cumulative	Yes	Not specified	Yes, monthly only	Not specified	Not specified

		FortisBC				
		Comparison of Balancing Provisions for Selected Companies				
				West		
Line No.	**Description**	**Atmos Energy Texas**	**Oklahoma Natural Gas (One Gas)**	**Questar**	**Southwest Gas Company**	**Southern California Gas (SoCalGas)**
		(11)	**(12)**	**(13)**	**(14)**	**(16)**
1	Balancing provisions (general)	Imbalances cannot be aggregated for a Customer with multiple transportation agreements	[No provisions specific to balancing in Oklahoma Natural's tariff. Tariff was specific to residential services, and was focused on the end customer.]	Customer is primarily responsible to ensure amount of gas delivered to the system is equal to customer's offtake. Questar can require customers to adjust nominations if an imbalance would affect system integrity or impact Questar's production or storage operations. Questar can charge up to $25/Dth penalty for repeatedly ignoring balancing restrictions. Customers can trade daily and monthly imbalances.	The following information applies to the rate schedule applicable to customers procuring their own gas. Customers must be balanced within the greater of +/- 25% or a set amount depending on location on a daily basis. Customers must be balanced within the greater of +/- 5% or 1,500 Dth on a monthly basis. During an OFO, there are multiple stages that have differing balancing requirements, the most stringent requiring a 0% threshold and the most lenient requiring a 20% threshold. Higher stages are also associated with higher fixed fees. The information below pertains to the Transportation Imbalance Service, which is available to customers who procure their own gas. The service allows customers to trade imbalances on a monthly and daily basis. However, customers with contracts with multiple meters cannot net imbalances across meters	Four monthly imbalance services [roughly in order of in which they might occur in practice]: - Imbalance trading - no-charge Balancing Service (10% monthly threshold) - Standby Procurement - Buy-Back Standby Procurement and Buy-Back serve as the cash out mechanisms. Standby is to correct an overtake position; Buy-Back is to correct an undertake position. During a Low OFO or Emergency Flow Order, imbalances are cashed out on a daily basis. Imbalance trading is not allowed during these periods
2	Balancing: Dead-band	10%	N/A	5%	5% (monthly); 25% (daily)	10%
3	Balancing: # Premium/ Discount Tiers	1	N/A	1	1	1
4	Balancing: Type of Charge	Difference of highest and lowest Index price multiplied by a penalty factor	N/A	Daily: $1/Dth or the abs value of the difference of Monthly and Daily Index + $0.25/Dth Monthly: Positive: lesser of transportation market index price or commodity rate less $1/Dth. Negative: greater of transportation market index or the commodity rate + $1/Dth	Higher of (negative imbalance) / lower of (positive imbalance) a multiple of a transportation fee set in the tariff OR the highest/lowest cost of incremental gas	Multiple of the index price + fees
5	Balancing: Time Period	Monthly	N/A	Daily and Monthly	Monthly and daily	Monthly
6	Cash Out Entire Imbalance, or Imbalance in Excess of	Imbalance Volumes in excess	N/A	All imbalances	Imbalance Volumes in excess	Imbalance Volumes in excess
7	Ability to Draw from Cumulative	Not specified	N/A	Not specified	Not specified	Yes

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Comparison of Balancing Provisions for Selected Companies

Line No.	Description	Pacific Gas & Electric (PG&E)	Northwest Natural	Avista (Oregon and Washington)	Cascade (Oregon and Washington)	Puget Sound Energy
				Pacific Northwest		
		(15)	**(17)**	**(18)**	**(19)**	**(20)**
1	Balancing provisions (general)	Imbalances maintained at the delivery point. Customers may pool delivery points together to balance on a cumulative basis. Customers may also assign a Balancing Agent to carry out balancing functions on their behalf. Two options for balancing: monthly balancing and "self balancing," which is on a daily basis. Self balancing is administered via PG&E's unbundled storage program. PG&E will allow storage balancing assets up to 1.1 Bcf. Self balanced customers are entitled to a per-Dth credit. Daily (self balancing) cash out terms: Daily imbalances are allowed up to +/- 10%, but only a +/-1% threshold is allowed on a cumulative daily basis for a given month. If customer is in noncompliance on a given day, a charge of 50% of the Citygate price is assessed (per Dth). The same fee applies to quantities exceeding the cumulative threshold (fees are additive with each other).	Balancing receipts & deliveries must be accomplished on a daily basis "to the extent possible" Imbalances are calculated daily & accumulated daily, but penalties and cash outs are not determined until the end of the month. Customer incurs a charge of $1/therm each month if they choose not to cash out their imbalance after 45 days following notice that they have exceeded the imbalance threshold. Cumulative imbalances less than the threshold at the end of the month are carried over.	The following provisions apply to customer-owned gas being transported on Avista's system. Customer and Avista will intend to match receipts to deliveries on a daily basis. Unintentionally day-to-day imbalances are subject to the balancing mechanism. Imbalances are calculated daily & accumulated daily, but penalties and cash outs are not determined until the end of the month. Customer incurs a charge of $1/therm each month after 45 days following notice that they have exceeded the imbalance threshold	Imbalances are calculated daily & accumulated daily, but penalties and cash outs are not determined until the end of the month. Customer incurs a charge of $1/therm each month after 45 days following notice that they have exceeded the imbalance threshold.	Balancing service charge of $0.00070/therm allows customer to run daily imbalances using PSE's storage. Imbalances are calculated daily & accumulated daily, but penalties and cash outs are not determined until the end of the month. Customer incurs a charge of $1/therm each month if they choose not to cash out their imbalance by the end of the 2nd billing period following notice that they have over/under-run quantities (defined as having an imbalance exceeding the threshold) 3% daily deadband during constraint periods for overrun; 5% daily deadband during constraint periods for underrun.
2	Balancing: Dead-band	5% (monthly); Self Balancing: 10% (daily), 1% (cumulative)	3% (Aug-Feb); 5% (Mar-Jul)	3% (Aug-Feb); 5% (Mar-Jul)	5%	5%
3	Balancing: # Premium/ Discount Tiers	4	1	1	1	1
4	Balancing: Type of Charge	Multiple of the index price	Multiple of highest monthly incremental cost of gas over last 3 months or multiple of WACOG	Fixed per-therm fee	Fixed per-therm fee	Multiple of index price or multiple of cost of gas, as specified in tariff
5	Balancing: Time Period	Monthly or daily	Monthly	Monthly	Monthly	Monthly
6	Cash Out Entire Imbalance, or Imbalance in Excess of	Imbalance Volumes in excess	All imbalances	Imbalance Volumes in excess	Imbalance Volumes in excess	Imbalance Volumes in excess
7	Ability to Draw from Cumulative	Not specified	Not specified	Not specified	Not specified	Not specified

FortisBC
Comparison of Balancing Provisions for Selected Companies

		Outside Continental U.S.				
Line No.	**Description**	**Enstar (Alaska)**	**Enbridge Gas Distribution**	**Union Gas**	**Gaz Metro**	**AltaGas**
		(21)	**(22)**	**(23)**	**(24)**	**(25)**
1	Balancing provisions (general)	Shippers allowed a Daily Balancing Tolerance Limit of the greater of 1,000 Mcf/d or 10% of Required Receipts. Imbalances beyond this are "generally expected to be balanced the next day" Over Supply can be rejected by Enstar. If accepted, the Over Supply should "normally" be returned within 14 days. Under Supply can be rectified at the sole determination of Enstar by curtailing deliveries and/or securing replacement gas, which the Shipper must pay for (plus transport charges). On a monthly basis, Enstar will deliver a Balancing Report to its Shippers; monthly balances are "generally expected" to be corrected in kind by the next month.	Three services offered: - In Franchise Title Transfer Service: transfer to another customer, subject to administration charge - Enhanced Title Transfer Service: Customer can transfer gas to another utility at Dawn, subject to administration charge & commodity charge - Gas in Storage Title Transfer: Storage customers may transfer title of gas in storage	[No information available on gas balancing services for regulated distribution, transmission, or storage customers] Two related services offered to unregulated storage customers: - Lending Service - Park and Loan Service	Two services offered: Distributor's Service and Customer-Provided Service. Volumes of gas can be withdrawn to balance a customer's load. Two price tiers for withdrawing, based on size of customer's annual quantity. For Customer-Provided Balancing, customer can sign up to provide a load balancing service using the natural gas it injects into the system.	[No mention of balancing in General Services, Optional Services, or Service Rules]
2	Balancing: Dead-band	10% or 1,000 Mcf (greater of)	N/A	N/A	2% (daily); 4% (cumulative)	N/A
3	Balancing: # Premium/ Discount Tiers	1	N/A	N/A	4 (daily); 2 (cumulative)	N/A
4	Balancing: Type of Charge	2.5x cost of gas + cost of replacement gas if overtake	N/A	N/A	Per cubic meter charge	N/A
5	Balancing: Time Period	Daily	N/A	N/A	Daily and cumulative	N/A
6	Cash Out Entire Imbalance, or Imbalance in Excess of	N/A	N/A		Imbalance Volumes in excess	
7	Ability to Draw from Cumulative	Enstar can reject any oversupply; but if they accept oversupply, it can be drawn from within 14 days	Not specified		Not specified	

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Comparison of Balancing Provisions for Selected Companies

Line No.	Description	Mid-Atlantic Piedmont Natural Gas	Washington Gas Light	Public Service Electric & Gas (PSE&G)	Consolidated Edison	Niagara Mohawk (National Grid)
		(1)	(2)	(3)	(4)	(5)
8	Upstream Pipeline Balancing	**Transcontinental**	**Transcontinental**	**Texas Eastern Transmission**	**Transcontinental**	**Dominion Transmission**
9	Upstream Pipeline (1): Dead-band	5% (monthly)	5% (monthly)	5% (monthly)	5% (monthly)	0% (15 day basis)
10	Upstream Pipeline (1): Cash Out	Percentage times spot price for a given zone; percentage escalates for 4 premium tiers. Only shippers with imbalance in the same positive or negative direction as the total imbalance in a given zone are subject to charges. All amounts are cashed out at the end of the month	Percentage times spot price for a given zone; percentage escalates for 4 premium tiers. Only shippers with imbalance in the same positive or negative direction as the total imbalance in a given zone are subject to charges. All amounts are cashed out at the end of the month	Percentage times spot price for a given zone; percentage escalates for 5 premium tiers. All amounts are cashed out at the end of the month	Percentage times spot price for a given zone; percentage escalates for 4 premium tiers. Only shippers with imbalance in the same positive or negative direction as the total imbalance in a given zone are subject to charges. All amounts are cashed out at the end of the month	2 x fuel retention % for Wheeling Service
11	Upstream Pipeline (1): Ancillary Services	Park and Loan service (interruptible); Pooling	Park and Loan service (interruptible); Pooling	Market Balancing Aggregation (imbalance trading/netting/storage services); Park and Loan service (interruptible)	Park and Loan service (interruptible); Pooling	Balancing Service (under rate schedule MCS) requires all balancing quantities to be repaid within 15 days; Imbalancing Netting and Trading

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Comparison of Balancing Provisions for Selected Companies

		Midwest				
Line No.	**Description**	**Northern Indiana Public Service Company (NIPSCO)**	**Vectren Energy Delivery of Ohio**	**Columbia Gas of Ohio**	**Northern Illinois Gas Co (Nicor)**	**Wisconsin Gas**
		(6)	**(7)**	**(8)**	**(9)**	**(10)**
8	Upstream Pipeline Balancing	**ANR Pipeline**	**Columbia Gas Transmission**	**Columbia Gas Transmission**	**NGPL**	**Guardian Pipeline**
9	Upstream Pipeline (1): Dead-band	5% (monthly)	3% (daily)	3% (daily)	5% (monthly)	2% (monthly)
10	Upstream Pipeline (1): Cash Out	4 premium tiers. Imbalances are aggregated based on each of four regions on the ANR system.	Interruptible balancing service: $5/Dth for first 3%, $10/Dth for other quantities Firm Balancing Service: 3 x index	Interruptible balancing service: $5/Dth for first 3%, $10/Dth for other quantities Firm Balancing Service: 3 x index	4 premium tiers, percentage of index. All imbalances are cashed out	5 premium tiers, based on percentage of index
11	Upstream Pipeline (1): Ancillary Services	Imbalance Netting & Trading; Interruptible Park & Lend	Two key balancing services: Storage in Transit service, Firm Balancing Service Storage in Transit Service is an interruptible storage service that injects/withdraws mismatched receipt & delivery quantities. Shippers are charged for this service and must also pay penalties if they fail to comply with a interruption order Firm Balancing Service also injects/withdraws mismatches in receipt & delivery quantities, but on a firm basis. Similar fee structure to SIT, but reservation charges are included ; also includes Park and Lend, Aggregation Service	Two key balancing services: Storage in Transit service, Firm Balancing Service Storage in Transit Service is an interruptible storage service that injects/withdraws mismatched receipt & delivery quantities. Shippers are charged for this service and must also pay penalties if they fail to comply with a interruption order Firm Balancing Service also injects/withdraws mismatches in receipt & delivery quantities, but on a firm basis. Similar fee structure to SIT, but reservation charges are included ; also includes Park and Lend, Aggregation Service	Imbalance Netting, Imbalance Offsetting (trading), Park and Loan, Line Pack Service (both interruptible, PAL services)	Load Balancing Service (allows additional or less gas (as needed) to be delivered to customer subject to a balancing MDQ and MSQ), Parking and Lending (interruptible), Market Aggregation Service, Imbalance Netting, Imbalance Trading

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Comparison of Balancing Provisions for Selected Companies

		West				
Line No.	**Description**	**Atmos Energy Texas**	**Oklahoma Natural Gas (One Gas)**	**Questar**	**Southwest Gas Company**	**Southern California Gas (SoCalGas)**
		(11)	**(12)**	**(13)**	**(14)**	**(16)**
8	Upstream Pipeline Balancing	**Transwestern**	**Southern Star Central**	**Questar Pipeline**	**El Paso Natural Gas**	**El Paso Natural Gas**
9	Upstream Pipeline (1): Dead-band	N/A	5% (monthly)	5% (daily), 5% (monthly)	2% (monthly)	2% (monthly)
10	Upstream Pipeline (1): Cash Out	No penalties; cash out is based on index price for each of five imbalance locations	Multiple of an index price, 3 premium tiers. Penalties are somewhat more punitive at the 5-20% level than other pipelines	Monthly: 2 premium tiers based on index plus 50 cents or one dollar	5 premium tiers, based on index price. Only monthly imbalances in excess of the threshold are subject to cash out. Threshold for Month 1 = 5%, Month 2= 3%, Month 3 = 0%.	5 premium tiers, based on index price. Only monthly imbalances in excess of the threshold are subject to cash out. Threshold for Month 1 = 5%, Month 2= 3%, Month 3 = 0%.
11	Upstream Pipeline (1): Ancillary Services	Park and loan service, Imbalance offsetting, Imbalance trading,	Pooling Service, Park and Loan Service, Imbalance Trading, Imbalance netting, injecting/withdrawing would-be imbalances into storage	Park and Loan (interruptible), Imbalance netting, Imbalance Trading, Imbalance Payback (in-kind)	Park and Lend Service (interruptible), Operator Point Aggregation Service, physical imbalance make-up and paybacks, Imbalance trades, Imbalance netting	Park and Lend Service (interruptible), Operator Point Aggregation Service, physical imbalance make-up and paybacks, Imbalance trades, Imbalance netting

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Comparison of Balancing Provisions for Selected Companies

Line No.	Description	Pacific Gas & Electric (PG&E)	Northwest Natural	Avista (Oregon and Washington)	Cascade (Oregon and Washington)	Puget Sound Energy
			Pacific Northwest			
		(15)	**(17)**	**(18)**	**(19)**	**(20)**
8	Upstream Pipeline Balancing	**Ruby Pipeline**	**Northwest Pipeline**	**Northwest Pipeline**	**Northwest Pipeline**	**Northwest Pipeline**
9	Upstream Pipeline (1): Dead-band	3% (monthly)	3% (monthly, Aug-Feb); 5% (monthly, Mar-Jul)	3% (monthly, Aug-Feb); 5% (monthly, Mar-Jul)	3% (monthly, Aug-Feb); 5% (monthly, Mar-Jul)	3% (monthly, Aug-Feb); 5% (monthly, Mar-Jul)
10	Upstream Pipeline (1): Cash Out	Imbalance does not have to be cashed out in full if it does not exceed the threshold; in this case it can carry over to the next month. No penalties are applied, cash outs are based on index prices.	Shipper has 45 days to correct imbalance after being notified that their monthly imbalance exceeds threshold. If shipper does not get into balance at any point during the 45 day period, shipper is subject to $10/Dth penalty	Shipper has 45 days to correct imbalance after being notified that their monthly imbalance exceeds threshold. If shipper does not get into balance at any point during the 45 day period, shipper is subject to $10/Dth penalty	Shipper has 45 days to correct imbalance after being notified that their monthly imbalance exceeds threshold. If shipper does not get into balance at any point during the 45 day period, shipper is subject to $10/Dth penalty	Shipper has 45 days to correct imbalance after being notified that their monthly imbalance exceeds threshold. If shipper does not get into balance at any point during the 45 day period, shipper is subject to $10/Dth penalty
11	Upstream Pipeline (1): Ancillary Services	Park and Lend, Imbalance Transfers, Imbalance Trades	Park and Loan (interruptible), Imbalance Netting,	Park and Loan (interruptible), Imbalance Netting,	Park and Loan (interruptible), Imbalance Netting,	Park and Loan (interruptible), Imbalance Netting,

		FortisBC				
		Comparison of Balancing Provisions for Selected Companies				
				Outside Continental U.S.		
Line No.	**Description**	**Enstar (Alaska)**	**Enbridge Gas Distribution**	**Union Gas**	**Gaz Metro**	**AltaGas**
		(21)	**(22)**	**(23)**	**(24)**	**(25)**
8	Upstream Pipeline Balancing					
9	Upstream Pipeline (1): Dead-band					
10	Upstream Pipeline (1): Cash Out					
11	Upstream Pipeline (1): Ancillary Services					

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Comparison of Balancing Provisions for Selected Companies

Line No.	Description	Piedmont Natural Gas	Washington Gas Light	Public Service Electric & Gas (PSE&G)	Consolidated Edison	Niagara Mohawk (National Grid)
		Mid-Atlantic				
		(1)	(2)	(3)	(4)	(5)
12	Upstream Pipeline Balancing Provisions (2)	**Midwestern Gas Transmission**	**Dominion Transmission**		**Texas Eastern Transmission**	**Iroquois Gas Transmission**
13	Upstream Pipeline (2): Dead-band	10% (daily); 5% (monthly)	0% (15 day basis)		5% (monthly)	4% (monthly and daily)
14	Upstream Pipeline (2): Cash Out	Daily: Cash out on daily basis required if daily imbalance is greater than 10% and cumulative imbalance is in the same direction as the pipeline's net imbalance. Charge is subject to 2 premium tiers, equal to 2 or 4*TGP PAL rate Monthly: All imbalances are cashed out. 4 premium tiers, charge is based on percentage of index price.	2 x fuel retention % for Wheeling Service		Percentage times spot price for a given zone; percentage escalates for 5 premium tiers. All amounts are cashed out at the end of the month	Commodity rate on IT for amounts in excess of 4%
15	Upstream Pipeline (2): Ancillary Services	Load Management Service (imbalance trading); Supply Aggregation; Third Party Balancing, Park and Loan	Balancing Service (under rate schedule MCS) requires all balancing quantities to be repaid within 15 days; Imbalancing Netting and Trading		Market Balancing Aggregation (imbalance trading/netting/storage services); Park and Loan service (interruptible)	Park and Loan

		FortisBC				
		Comparison of Balancing Provisions for Selected Companies				
				Midwest		
Line No.	**Description**	**Northern Indiana Public Service Company (NIPSCO)**	**Vectren Energy Delivery of Ohio**	**Columbia Gas of Ohio**	**Northern Illinois Gas Co (Nicor)**	**Wisconsin Gas**
		(6)	**(7)**	**(8)**	**(9)**	**(10)**
12	Upstream Pipeline Balancing Provisions (2)	**Panhandle Eastern**	**Panhandle Eastern**	**Columbia Gulf Transmission**	**ANR Pipeline**	**ANR Pipeline**
13	Upstream Pipeline (2): Dead-band	1.5 x MDQ (monthly), which translates to approximately 5%	1.5 x MDQ (monthly), which translates to approximately 5%	5% (monthly)	5% (monthly)	5% (monthly)
14	Upstream Pipeline (2): Cash Out	5 premium tiers, first tier begins at 0-5%. Based on multiple of an index	5 premium tiers, first tier begins at 0-5%. Based on multiple of an index	Multiple of index price, 4 premium tiers. Ambiguous as to whether monthly imbalances can rollover month-to-month	4 premium tiers. Imbalances are aggregated based on each of four regions on the ANR system.	4 premium tiers. Imbalances are aggregated based on each of four regions on the ANR system.
15	Upstream Pipeline (2): Ancillary Services	Transportation Balancing Service (PEPL will withdraw customer's stored gas to true-up end of month imbalance); Imbalance Netting	Transportation Balancing Service (PEPL will withdraw customer's stored gas to true-up end of month imbalance); Imbalance Netting	Imbalance Management Service, Parking and Lending Service (interruptible), Imbalance Transfers, Imbalance Trading and Netting	Imbalance Netting & Trading; Interruptible Park & Lend	Imbalance Netting & Trading; Interruptible Park & Lend

FortisBC
Comparison of Balancing Provisions for Selected Companies

Line No.	Description	Atmos Energy Texas	Oklahoma Natural Gas (One Gas)	Questar	Southwest Gas Company	Southern California Gas (SoCalGas)
		West				
		(11)	(12)	(13)	(14)	(16)
12	Upstream Pipeline Balancing Provisions (2)	**El Paso Natural Gas**	**Enable Transmission**	**Kern River Gas Transmission**	**Kern River Gas Transmission**	**Kern River Gas Transmission**
13	Upstream Pipeline (2): Dead-band	2% (monthly)	10% (monthly)	5% (daily), 0% (two months)	5% (daily), 0% (two months)	5% (daily), 0% (two months)
14	Upstream Pipeline (2): Cash Out	5 premium tiers, based on index price. Only monthly imbalances in excess of the threshold are subject to cash out. Threshold for Month 1 = 5%, Month 2= 3%, Month 3 = 0%.	3 premium tiers based on an index price	Must reconcile any imbalances within 30 days. If shipper fails to correct imbalance within 60 days, must pay $5 x quantity of imbalance.	Must reconcile any imbalances within 30 days. If shipper fails to correct imbalance within 60 days, must pay $5 x quantity of imbalance.	Must reconcile any imbalances within 30 days. If shipper fails to correct imbalance within 60 days, must pay $5 x quantity of imbalance.
15	Upstream Pipeline (2): Ancillary Services	Park and Lend Service (interruptible), Operator Point Aggregation Service, physical imbalance make-up and paybacks, Imbalance trades, Imbalance netting	Park and Loan (interruptible), Short-Term Balancing Service (similar to park & loan-interruptible), Perryville Hub Service (includes Nomination Balancing Service, which is also similar to a PAL service)	Park and Loan, Imbalance Netting, Imbalance Trading	Park and Loan, Imbalance Netting, Imbalance Trading	Park and Loan, Imbalance Netting, Imbalance Trading

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Comparison of Balancing Provisions for Selected Companies

				Pacific Northwest		
Line No.	**Description**	**Pacific Gas & Electric (PG&E)**	**Northwest Natural**	**Avista (Oregon and Washington)**	**Cascade (Oregon and Washington)**	**Puget Sound Energy**
		(15)	**(17)**	**(18)**	**(19)**	**(20)**
12	Upstream Pipeline Balancing Provisions (2)	**Gas Transmission Northwest**	**Gas Transmission Northwest**	**Gas Transmission Northwest**	**Gas Transmission Northwest**	**Gas Transmission Northwest**
13	Upstream Pipeline (2): Dead-band	10% (daily)	10% (daily)	10% (daily)	10% (daily)	10% (daily)
14	Upstream Pipeline (2): Cash Out	Penalties only apply during constraint periods. Daily imbalances must be corrected within 3 days. For overlifted quantities, If it is not corrected and the imbalance exceeds 10%, a $5/Dth penalty is charged. If the imbalance is still not corrected after 45 days, another $5/Dth fee will be charged. For underlifted quantities, a similar process applies, but with a $2/Dth penalty after 3 days, and GTN can keep the imbalance gas after 45 days.	Penalties only apply during constraint periods. Daily imbalances must be corrected within 3 days. For overlifted quantities, If it is not corrected and the imbalance exceeds 10%, a $5/Dth penalty is charged. If the imbalance is still not corrected after 45 days, another $5/Dth fee will be charged. For underlifted quantities, a similar process applies, but with a $2/Dth penalty after 3 days, and GTN can keep the imbalance gas after 45 days.	Penalties only apply during constraint periods. Daily imbalances must be corrected within 3 days. For overlifted quantities, If it is not corrected and the imbalance exceeds 10%, a $5/Dth penalty is charged. If the imbalance is still not corrected after 45 days, another $5/Dth fee will be charged. For underlifted quantities, a similar process applies, but with a $2/Dth penalty after 3 days, and GTN can keep the imbalance gas after 45 days.	Penalties only apply during constraint periods. Daily imbalances must be corrected within 3 days. For overlifted quantities, If it is not corrected and the imbalance exceeds 10%, a $5/Dth penalty is charged. If the imbalance is still not corrected after 45 days, another $5/Dth fee will be charged. For underlifted quantities, a similar process applies, but with a $2/Dth penalty after 3 days, and GTN can keep the imbalance gas after 45 days.	Penalties only apply during constraint periods. Daily imbalances must be corrected within 3 days. For overlifted quantities, If it is not corrected and the imbalance exceeds 10%, a $5/Dth penalty is charged. If the imbalance is still not corrected after 45 days, another $5/Dth fee will be charged. For underlifted quantities, a similar process applies, but with a $2/Dth penalty after 3 days, and GTN can keep the imbalance gas after 45 days.
15	Upstream Pipeline (2): Ancillary Services	Park and Lend (interruptible), imbalance trading, imbalance netting	Park and Lend (interruptible), imbalance trading, imbalance netting	Park and Lend (interruptible), imbalance trading, imbalance netting	Park and Lend (interruptible), imbalance trading, imbalance netting	Park and Lend (interruptible), imbalance trading, imbalance netting

		FortisBC				
		Comparison of Balancing Provisions for Selected Companies				
				Outside Continental U.S.		
Line No.	**Description**	**Enstar (Alaska)**	**Enbridge Gas Distribution**	**Union Gas**	**Gaz Metro**	**AltaGas**
		(21)	**(22)**	**(23)**	**(24)**	**(25)**
12	Upstream Pipeline Balancing Provisions (2)					
13	Upstream Pipeline (2): Dead-band					
14	Upstream Pipeline (2): Cash Out					
15	Upstream Pipeline (2): Ancillary Services					

		FortisBC				
		Comparison of Balancing Provisions for Selected Companies				
				Mid-Atlantic		
Line No.	**Description**	**Piedmont Natural Gas**	**Washington Gas Light**	**Public Service Electric & Gas (PSE&G)**	**Consolidated Edison**	**Niagara Mohawk (National Grid)**
		(1)	**(2)**	**(3)**	**(4)**	**(5)**
16	Upstream Pipeline Balancing Provisions (3)	**Columbia Gas Transmission**	**Columbia Gas Transmission**		**Millennium Pipeline**	
17	Upstream Pipeline (3): Dead-band	3% (daily)	3% (daily)		3% (daily), 10% (monthly)	
18	Upstream Pipeline (3): Cash Out	Interruptible balancing service: \$5/Dth for first 3%, \$10/Dth for other quantities Firm Balancing Service: 3 x index	Interruptible balancing service: \$5/Dth for first 3%, \$10/Dth for other quantities Firm Balancing Service: 3 x index		Daily: Higher of \$25/Dth or 3 x index; applies to all quantities if imbalance exceeds 3% Monthly: \$0.25/Dth on quantities in excess of 10% on a cumulative basis	
19	Upstream Pipeline (3): Ancillary Services	Two key balancing services: Storage in Transit service, Firm Balancing Service Storage in Transit Service is an interruptible storage service that injects/withdraws mismatched receipt & delivery quantities. Shippers are charged for this service and must also pay penalties if they fail to comply with a interruption order Firm Balancing Service also injects/withdraws mismatches in receipt & delivery quantities, but on a firm basis. Similar fee structure to SIT, but reservation charges are included ; also includes Park and Lend, Aggregation Service	Two key balancing services: Storage in Transit service, Firm Balancing Service Storage in Transit Service is an interruptible storage service that injects/withdraws mismatched receipt & delivery quantities. Shippers are charged for this service and must also pay penalties if they fail to comply with a interruption order Firm Balancing Service also injects/withdraws mismatches in receipt & delivery quantities, but on a firm basis. Similar fee structure to SIT, but reservation charges are included ; also includes Park and Lend, Aggregation Service		Imbalance Netting, Trading, and Transfer; Parking and Lending	
20	Transmission vs. LDC Provisions Analysis	Piedmont's monthly threshold more stringent than upstream pipelines	Power gen balancing allows a lot of flexibility; upstream pipelines offer average to below average flex	N/A	ConEd's monthly threshold more stringent than upstream pipelines	Niagara's daily threshold slightly less stringent than upstream pipelines

FortisBC
Comparison of Balancing Provisions for Selected Companies

		Midwest				
Line No.	**Description**	**Northern Indiana Public Service Company (NIPSCO)**	**Vectren Energy Delivery of Ohio**	**Columbia Gas of Ohio**	**Northern Illinois Gas Co (Nicor)**	**Wisconsin Gas**
		(6)	**(7)**	**(8)**	**(9)**	**(10)**
16	Upstream Pipeline Balancing Provisions (3)	**Trunkline**	**Texas Eastern Transmission**	**Tennessee Gas Pipeline**	**Northern Natural**	**Vector Pipeline**
17	Upstream Pipeline (3): Dead-band	5% (monthly)	5% (monthly)	5% (monthly); 10% (daily)	3% (monthly)	5% (cumulative)
18	Upstream Pipeline (3): Cash Out	Multiple of index price, 5 premium tiers. Imbalances aggregated to Operational Impact Areas	Percentage times spot price for a given zone; percentage escalates for 5 premium tiers. All amounts are cashed out at the end of the month	Under LMS (daily): 2 x TGP PAL rate for quantities between 10%-20% above MDQ if pool imbalance is 5% or higher on a given day and shipper's imbalance is in the same direction as the pool imbalance. 4 x PAL if > 20% Under LMS (monthly): multiple times an index, 4 premium tiers	Multiple of an index price, 5 premium tiers. First premium tier is 3-5% with only a 1.02 multiple	$0.10/Dth in excess of 5% Cumulative imbalances are the sum of daily imbalances
19	Upstream Pipeline (3): Ancillary Services	Transportation Aggregation Balancing Service (includes Imbalance transfer), Imbalance Netting, Imbalance Trading, Parking Service	Market Balancing Aggregation (imbalance trading/netting/storage services); Park and Loan service (interruptible)	Load Management Service, Storage Swing Option (imbalance quantities are automatically treated as injections or withdrawals), Imbalance Trading, Park and Loan	Auto-balancing (imbalances are automatically injected or withdrawn from storage), Imbalance Transfers, In-Kind Resolution, Imbalance Trading, Imbalance Trade Groups	Park and Loan Service (interruptible), Management of Balancing Agreement Service (provides for Third Party Balancing Provider with capacity on the system to provide balancing services to a Balancing Customer), Imbalance Netting, Imbalance Trading
20	Transmission vs. LDC Provisions Analysis	NIPSCO & upstream pipelines dead bands match; roughly average	Vectren's daily dead-band is less stringent than that of upstream pipelines; monthly dead-band is average & is the same	Col Gas's dead-bands are more stringent than that of upstream pipelines	N/A	Wisconsin Gas has daily balancing; upstream pipelines have monthly-only. Dead-band is roughly as stringent

		FortisBC				
		Comparison of Balancing Provisions for Selected Companies				
				West		
Line No.	**Description**	**Atmos Energy Texas**	**Oklahoma Natural Gas (One Gas)**	**Questar**	**Southwest Gas Company**	**Southern California Gas (SoCalGas)**
		(11)	**(12)**	**(13)**	**(14)**	**(16)**
16	Upstream Pipeline Balancing Provisions (3)	**Northern Natural**			**Paiute Pipeline**	**Transwestern**
17	Upstream Pipeline (3): Dead-band	3% (monthly)			5% (monthly); 5% (cumulative)	N/A
18	Upstream Pipeline (3): Cash Out	Multiple of an index price, 5 premium tiers. First premium tier is 3-5% with only a 1.02 multiple			Two penalty mechanisms: Penalty can be triggered when Paiute is hit with a penalty from an upstream pipeline. If Paiute's total imbalance exceeds 5%, shippers that are beyond 5% are subject to penalty, the amount of which is based on the charges Paiute receives from upstream pipelines. Penalty can also be triggered if shipper imbalance exceeds 5%. Penalty is $10/Dth times imbalance in excess of 5%	No penalties; cash out is based on index price for each of five imbalance locations
19	Upstream Pipeline (3): Ancillary Services	Auto-balancing (imbalances are automatically injected or withdrawn from storage), Imbalance Transfers, In-Kind Resolution, Imbalance Trading, Imbalance Trade Groups			Imbalance Trading	Park and loan service, Imbalance offsetting, Imbalance trading,
20	Transmission vs. LDC Provisions Analysis	Atmos's relatively relaxed dead-band is similar to that of Transwestern, but is in contrast to the other upstream pipelines	N/A	Questar Gas's dead-bands match that of its upstream pipelines	SW Gas's balancing dead-bands are slightly more lenient than that of its upstream pipelines	SoCalGas's dead-band is more lenient than that of its upstream pipelines

		FortisBC				
		Comparison of Balancing Provisions for Selected Companies				
				Pacific Northwest		
Line No.	**Description**	**Pacific Gas & Electric (PG&E)**	**Northwest Natural**	**Avista (Oregon and Washington)**	**Cascade (Oregon and Washington)**	**Puget Sound Energy**
		(15)	**(17)**	**(18)**	**(19)**	**(20)**
16	Upstream Pipeline Balancing Provisions (3)	**Transwestern**				
17	Upstream Pipeline (3): Dead-band	N/A				
18	Upstream Pipeline (3): Cash Out	No penalties; cash out is based on index price for each of five imbalance locations				
19	Upstream Pipeline (3): Ancillary Services	Park and loan service, Imbalance offsetting, Imbalance trading,				
20	Transmission vs. LDC Provisions Analysis	PG&E's thresholds are roughly average; upstream pipelines are a mix of stringent & lenient	Northwest Natural's dead-band matches that of Northwest Pipeline; more stringent than GTN's	Avista's dead-band matches that of Northwest Pipeline; more stringent than GTN's	Cascade's dead-band is similar to that of Northwest Pipeline; more stringent than GTN's (and also GTN's is daily, Cascade's is monthly)	Puget Sound's dead-band is similar to that of Northwest Pipeline; more stringent than GTN's (and also GTN's is daily, Puget's is monthly)

		FortisBC				
		Comparison of Balancing Provisions for Selected Companies				
				Outside Continental U.S.		
Line No.	**Description**	**Enstar (Alaska)**	**Enbridge Gas Distribution**	**Union Gas**	**Gaz Metro**	**AltaGas**
		(21)	**(22)**	**(23)**	**(24)**	**(25)**
16	Upstream Pipeline Balancing Provisions (3)					
17	Upstream Pipeline (3): Dead-band					
18	Upstream Pipeline (3): Cash Out					
19	Upstream Pipeline (3): Ancillary Services					
20	Transmission vs. LDC Provisions Analysis					

Appendix 10-2

FEI 2016-2017 ACP UPDATE ON T-SOUTH PIPELINE CAPACITY TO TRANSPORTATION SERVICE CUSTOMERS

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November 28, 2016

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Laurel Ross, Acting Commission Secretary and Director

Dear Ms. Ross:

Re: FortisBC Energy Inc. (FEI or FortisBC)

Update to Releasing Spectra Energy (Spectra) T-South Pipeline Capacity to Transportation Service Customers

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INTRODUCTION

On May 2, 2016, FEI filed, on a confidential basis, its 2016/17 Annual Contracting Plan (ACP). On August 4, 2016, the British Columbia Utilities Commission (the Commission) issued Order Letter L-20-16, accepted the 2016/17 ACP. L-20-16 requested, among other things, that FEI file the following, for informational purposes:

> A report summarizing the process and outcome of its plans to release a portion of its Spectra T-South pipeline capacity to transportation service customers for the 2016/17 gas year within 30 days of completing the release.

This report will detail the events to date, and provide suggestions on how this T-South Huntingdon Delivery (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 capacity allocation through the ACP filings each May.

BACKGROUND

2014/15 Amendment to the ACP

Due to market conditions affecting the future level of firm transportation contracting on Spectra Energy's British Columbia system, specifically T-South Long-Haul, FEI filed a request to amend the 2014/15 ACP that was accepted by the Commission in Letter L-53-14, dated October 2, 2014. A portion of the amendment involved the need to contract for additional T-South Long-Haul capacity for transportation service customers potentially seeking to return to bundled service. Please refer to Appendix A for more details regarding the Amendment to the 2014/15 ACP.

FEI was successful in contracting for an additional 75 TJ/d of T-South Long-Haul capacity effective November 1, 2015. Out of the 75 TJ/d in additional capacity, FEI planned to allocate 40 TJ/d to transportation service customers.[1]

DISCUSSIONS WITH MARKETERS AND CUSTOMERS

After receiving the additional T-South Long-Haul capacity in the open season, FEI began discussions and workshops with Marketers[2] and representatives of transportation service customers regarding the gas supply risks within the region. The presentation slides for these discussions are provided in Appendix B. The discussions focused on the reasons why FEI was pro-active in obtaining T-South Long-Haul capacity for the transportation service customers, which included the following:

- Transportation service customers and Marketers generally do not have the credit requirements to secure long-term firm T-South Long-Haul capacity. This may have been one of the reasons why they had not committed to holding this capacity in the past. Therefore, transportation service customers and Marketers have been relying on purchasing gas at the Huntingdon market.
- Existing load from transportation service customers who either rely on non-firm T-South Long-Haul capacity and/or purchase gas at the Huntingdon market are at risk if any new incremental demand in the region arrives (LNG and/or methanol exports). The risks include not receiving adequate gas supply and/or purchasing gas at significantly higher commodity prices at the Huntingdon market.

Generally, the Marketers and representatives of transportation service customers understood what FEI did, especially given the barriers that exist for them to secure T-South Long-Haul capacity on a long-term basis.

FEI also discussed the tariff requirements for transportation service customers who wish to return to bundled service (slide 8 and 9 of Appendix B). The stipulations found in Section 26 General Terms and Conditions of FEI's Tariff include the following.[3]

1. FortisBC may require that the Customer provide FortisBC up to one Year's written notice before the date on which the Customer wishes to return to system Gas supply;

1 The remaining 35 TJ/d of additional T-South Long-Haul capacity was reserved for the liquefaction capacity for Tilbury 1A to serve Rate Schedule 46 customers.
2 Marketers defined as shipper agents under the applicable FortisBC transportation service rate schedules.
3 Section 26 (Direct Purchase Agreements) FortisBC General Terms and Conditions.

2. FortisBC will supply the Customer with system Gas when the Customer wishes to return to system Gas supply if FortisBC is able to secure additional Gas supply and transportation to accommodate the Customer.

3. FortisBC may, subject to BCUC approval, charge the Customer for any costs associated with the Customer returning to system Gas supply. Such costs may include, among other things, the costs of securing additional Gas supply and transportation to accommodate the Customer. FortisBC can bill the Customer for such costs as part of the regular FortisBC bill for service.

After reviewing the regional issues, potential solutions were discussed that could be beneficial to FEI, transportation service customers and Marketers. One solution was to provide the transportation service customers with the additional T-South Long-Haul capacity as an allocation offering, instead of waiting for customers to return to bundled service. This would provide commercial certainty to the marketplace and give these transportation customers an additional option to discuss with their Marketer on how they want to purchase their gas supply requirements. Many of the Marketers were in favor of this idea, including some that sent FEI letters of interest. These letters were filed confidentially with the Commission in Appendix H of the 2016/17 ACP.

PROCESS

2016/17 Annual Contracting Plan

Each year FEI follows an interactive and consultative process with Commission staff prior to filing the Annual Contracting Plan. On April 7, 2016, FEI updated the Commission about its discussions with the Marketers and transportation service customers and presented potential alternatives that would help these customers receive T-South Long-Haul capacity on a temporary basis (for the 2016/17 gas year). On May 2, 2016 FEI filed, on a confidential basis, its 2016/17 ACP with the Commission. In the 2016/17 ACP, FEI discussed allocating 40 TJ/d[4] of additional T-South Long-Haul capacity for the 2016/17 gas year, and detailed the proposed terms and conditions of the allocation.

After the ACP was filed, FEI continued discussions with the Marketers, which helped not only increase participation on behalf of their transport service customers, but also further refined the terms and conditions related to the allocation and management of the T-South Long-Haul capacity. The decision was made to mitigate the T-South Long-Haul capacity with the Marketers similar to how FEI normally manages its seasonal capacity releases with its counterparties. To release capacity to the market, or now to a Marketer, a GasEDI contract between FEI and the counterparty must be executed. A GasEDI contract includes the necessary provisions for a contractual obligation between the two parties including payment terms, financial responsibilities, limitations and credit requirements. Once the GasEDI contract is executed, an additional T-South Capacity Release Letter Agreement (Letter Agreement) is signed between FEI and the counterparty, which further states the commercial

[4] The 40 TJ/d of capacity is for 2016/17 and could change over time.

terms of the capacity release. Once that is all completed, a capacity release arrangement between FEI, the counterparty and Spectra is finalized.

On May 30, 2016, FEI emailed all the Marketers a breakdown of the T-South Long-Haul allocation offering, which is provided in Appendix C. The email was sent to provide the Marketers enough time to begin communicating the potential offering with their customers, but it was still contingent upon Commission approval of the 2016/17 ACP. Notifying the Marketers prior to the acceptance of the 2016/17 ACP also allowed them sufficient time to make sure they had all the proper agreements and requirements in place to make this capacity release seamless. This included making sure they had an existing GasEDI contract with FEI, and to follow up on credit requirements with Spectra to temporarily hold capacity on their pipeline.

The Marketers that were interested in securing this capacity for their customers had to provide the following information to FEI by July 5, 2016:

- a list of the transportation service customers requesting the service;
- the amount of T-South Long-Haul capacity each customer requests; and
- their preferred option (Capacity Assignment or Buy and Sell).

By gathering this data on a customer-specific level, FEI was able to validate each customer request. Over time, having this data should also help transportation service customers understand the risks and benefits of holding the T-South capacity, which is further discussed below.

FEI provided a letter update to the Commission on June 23, 2016 regarding the details of the email sent to the Marketers, and the updated terms and conditions of the T-South Long-Haul allocation.[5]

ALLOCATION METHODOLOGY AND OUTCOME

After receiving the Marketer requests on July 5, 2016, FEI had sufficient time to confirm which customers the Marketers were requesting this T-South Long-Haul allocation offering for, and to evaluate the capacity requested by each Marketer on behalf of their customers. Additionally, FEI received requests from certain groups of customers, who wanted to determine how much T-South Long-Haul capacity they would be allocated before they chose a Marketer. That decision allowed those customers to work with the Marketers on valuing the T-South Long-Haul capacity they were awarded.[6]

All Marketers and transportation service customers elected the option of capacity assignment. However, the total capacity requested on July 5, 2016 far exceeded the capacity available for this offering. As a result, FEI had to prorate the capacity in a fair and equitable manner. This was done by comparing each transportation service customer's request with their historical consumption data. FEI chose to validate the requests using the

[5] FEI did not add this letter as an appendix because the information in the filing is provided within this report.
[6] FEI could provide a list of the Marketer's and transport service customers that participated in the T-South allocation to the Commission confidentially if required.

customer's historical 365-day consumption report, because the additional capacity should help to meet firm baseload supply, not peak day demand. Furthermore, the majority of the transportation service customer's requests were consistent with the 365-day (baseload) consumption approach. Once confirmed, their capacity requests were used for the final prorated allocation, which is shown in Figure 1 below.

FEI found only a few instances where the Marketer requests were deemed unreasonable:

- FEI rejected a Marketer request for capacity because their customer(s) did not have any firm load over the past two gas contracting years.
- A Marketer requested capacity on behalf of Interior customers which was denied because there are more cost effective ways for Interior customers to secure their gas supply needs.
- A Marketer requested capacity to meet all of their customer's peak day demands. FEI believed that this request was made to profit on the current T-South value, and not to secure a portion of their customer's gas supply requirements. Therefore, FEI reverted this request to the customer's 365-day average burn, which was also consistent with a majority of the other requests, as previously discussed.

Figure 1 below shows a sample of how FEI allocated the additional T-South Long-Haul capacity. The table on the left shows a sample of how much each Marketer or transportation service customer requested and how it matched up with their 365-day and seasonal load consumption. The table on the right shows how FEI prorated the capacity requests to total the available capacity for the offering. The information below does not provide the Marketer names and the numbers have been modified for confidentiality reasons.

Figure 1: Sample of FEI's Methodology in Allocation T-South Capacity

T-South Allocation Analysis				
Marketer	T-South Requested (GJ/d)	365-day Avg Burn (GJ/d)	Summer'15 (GJ/d)	Winter 15/16 (GJ/d)
1	1,311	1,213	1,100	2,500
2	18,321	18,521	18,942	25,032
3	42,000	17,823	11,060	24,043
4	21,054	21,001	20,873	22,053
5	980	784	856	1,035
Customer A	1,000	800	30	1,541
Customer B	200	187	90	234
Total	84,866	60,329	52,951	76,438

T-South Capacity Allocation Final Results			
Marketer	Option	Capacity Requested	Allocation Results
1	Cap Assign	1,311	864
2	Cap Assign	18,321	12,075
3*	Cap Assign	17,823	11,747
4	Cap Assign	21,054	13,877
5	Cap Assign	980	646
Customer A	Cap Assign	1,000	659
Customer B	Cap Assign	200	132
Total		60,689	40,000

*Requested 42,000 but will only provide average daily capacity based off current gas year. Also did not account for the Interior customer requests for Marketer 3

The Annual Contracting Plan was accepted by the Commission on August 4, 2016 by Letter L-20-16.

On August 9, 2016, shortly after receiving Commission acceptance of the 2016/2017 ACP, FEI emailed the Marketers and transportation service customers who requested T-South Long-Haul capacity, notifying them of the amount they would receive temporarily effective November 1, 2016.

To finalize the allocation offering, FEI put together a Letter Agreement which pertained to the release of pipeline capacity held by FEI on Spectra's T-South Huntingdon Delivery to the Marketers. The Letter Agreement also supplements and forms part of the terms and conditions in the GasEDI contract. Please see Appendix D for the Letter Agreement template. These agreements were sent to all the Marketers on September 12, 2016, which provided them with sufficient time to sign and accept the release electronically on Spectra's system. By September 29, 2016, all of the requests were completed and the capacity was released effective November 1, 2016 with no issues.

COSTS TO MIDSTREAM

The cost exposure to the midstream portfolio for holding this resource is the one year tolling cost for the T-South Long-Haul capacity because of Spectra's 13-month renewal provision. The reason why the exposure is not the entire duration of the transportation contract that FEI contracted for in October 2014 is because FEI's total T-South Long-Haul contract portfolio offers FEI the flexibility either to allow existing contracts to expire, or to decrease the contracted amounts once they are up for renewal. This was also discussed in the Amendment to the 2014/15 ACP (Appendix A).

As Figure 2 below shows, the cost exposure to the midstream since holding this capacity has been approximately $4.6 million a year. However, FEI's mitigation revenues have exceeded the costs by successfully releasing the capacity to the market in 2015/16 and now to the transportation service customers in 2016/17.[7] As Figure 2 shows, this mitigation has resulted in a net benefit to core customers of approximately $2.1 million.

Figure 2: Estimated FEI Cost for 40 TJ/d of T-South Long-Haul Capacity

Estimated FEI Cost for 40 TJ/d T-South Long-Haul Capacity				
2015/16	$0.331/GJ (FEI Tolling Cost)	40,000 GJ/d (Volume)	365 (Days)	$4.8 million (FEI's Cost)
2016/17	$0.307/GJ* (FEI Tolling Cost)	40,000 GJ/d (Volume)	365 (Days)	$4.5 million (FEI's Cost)
Total Estimated FEI Costs Since Receiving this T-South Capacity				$9.3 million
FEI's Mitigation of 40 TJ/d T-South Long-Haul Capacity				
2015/16	$0.40/GJ (FEI Mitigation Value)	40,000 GJ/d (Volume)	365 (Days)	$5.8 million (Mitigation Revenue)
2016/17	$0.38/GJ** (FEI Mitigation to Transport Customer)	40,000 GJ/d (Volume)	365 (Days)	$5.6 million (Mitigation Revenue)
Approximate FEI Mitigation Revenue Since Receiving this T-South Capacity				11.4 million
Approximate Net Benefit to FEI's Midstream				2.1 million

* 2016 Final Tolls. The 2017 Spectra Interim tolls will be available in December 2016.
** Toll number based on the 2016 Final Tolls. This number will change when the 2017 Spectra Interim tolls come out in December.

7 The net benefit is based on the 2016 Spectra Final Tolls. This could change on January 1, 2016 when the 2017 Interim Tolls are implemented.

Next Steps

Since FEI contracted for the additional T-South Long-Haul capacity, several of the large gas intensive projects in the region have been delayed. The project delays have been due to a number of factors including stiff environmental and regulatory hurdles, and the dramatic drop in global oil prices in 2014 and 2015. However, Woodfibre LNG recently announced that the funding for the 1.6 billion dollar project had been approved by the board of directors, and will begin gas shipments in 2020.[8] This will add incremental demand to the region and exemplifies the long term risks involved in relying heavily on the Huntingdon market until capacity expansions in the region are developed, built and in place. Therefore, it is prudent for FEI to continue working with Marketers, transportation service customers and the Commission on the T-South Long-Haul capacity release.

During a Rate Design Workshop on August 12, 2016, FEI set out 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 it in the transportation rate schedules for the upcoming rate design application so that transportation service customers could elect into the service within the tariff.

The feedback was in favor of keeping the T-South Long-Haul under FEI's ACP, due to the administrative challenges of having it included in the transportation rate schedules. For example, under the first option, all of the arrangements are between FEI and the Marketers on behalf of the transportation service customers. The second option would involve having signed transportation agreements in place between FEI, the Marketers, and all of the transportation service customers who wish to participate in the T-South Long-Haul capacity offering. Moreover, the Marketers provided potential solutions on how a long-term commitment and transparency could be achieved through the first option. One Marketer suggested that if this T-South Long-Haul allocation offering was going to continue, FEI could send a confirmation letter to each customer and its marketer detailing the capacity offering and its results on an annual basis.

Given this feedback, FEI will continue to seek approval to manage the additional T-South Long-Haul capacity on an annual basis through the ACP. This would also allow FEI to continue to manage all of the gas supply resources under its comprehensive contracting plan (i.e. ACP). The process FEI plans to follow is set out below:

- Total amount to be allocated to Marketers on behalf of the transportation service customers. At this time, FEI believes the T-South Long-Haul allocation offering should still be around 40 TJ/d.

- FEI will request the Marketers to provide a list of customers requesting the service and the amount each customer requests by the first week of July. This re-allocation would allow each transportation service customer and new transportation service customers a chance to participate in this offering.

[8] Vancouver Sun (November 4, 2016). "Woodfibre proceeding with B.C.'s first LNG project in Squamish."

- FEI will then allocate the capacity using the same methodology as used in 2016/17, as shown in Figure 1 above.
- FEI will send a Letter Agreement out to the Marketer similar to the 2016/17 agreement, but with renewal rights.[9] The Marketer would have to provide 13 month cancellation notice to FEI.[10]
- FEI will explore the possibility of sending a letter/email out to each of the transportation customers discussing the amount of capacity the Marketer has picked up on their behalf.

If you require further information or have any questions regarding this submission, please contact Jordan Cumming at (778) 578-3856.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

[9] Criteria within the renewal rights could include re-validation of customer consumption data and customer's representation (i.e. Customer request to change Marketer).
[10] In order to retain renewal rights on Spectra's system, contracted capacity must be renewed 13 months prior to its expiry.

Appendix A

Diane Roy
Director, Regulatory Affairs

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

~~CONFIDENTIAL~~

September 24, 2014

Via Email
Original via Mail

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI or the Company)

Amendment to the 2014/2015 Annual Contracting Plan (2014/15 ACP)

~~CONFIDENTIAL~~

On May 1, 2014, FEI filed, on a confidential basis, its 2014/15 Annual Contracting Plan. The Commission accepted the 2014/15 ACP on July 17, 2014.

Due to recent changes in market conditions affecting the future level of firm transportation contracting on the Spectra T-South system, FEI requests approval to amend the 2014/15 ACP in order to secure additional firm T-South transportation capacity for Rate Schedule 46 and industrial transportation customers seeking to return to bundled service.

Changing market conditions are occurring in response to a number of new industrial projects wanting to secure T-South transportation capacity on the Spectra system. In response to this change, Spectra is considering introducing a new service that would allow shippers to secure T-South capacity in the future. This new service will facilitate the orderly marketing of existing uncontracted T-South Huntingdon capacity and provide prospective markets with greater certainty that pipeline capacity will be available for future needs. This new service would provide shippers with another means of securing capacity for future use, in addition to the Bid Week process (13 month service) that is currently available.

It is expected that this new service from Spectra will require parties to make a commitment for a minimum of 10 years to secure T-South capacity and will provide the option to defer the commencement date of the first flow for a period of up to a maximum of 48 months. This commitment level is considerably greater than the two year renewable service that is currently available to parties under the 13 month Bid Week process. This new service should be of interest to shippers who need to secure firm transportation capacity to support industrial projects that will bring significant incremental loads to the region. However, committing to a 10 year contract may be difficult for some industrial customers currently participating in the FEI transportation model given the need to demonstrate credit worthiness that is required to secure firm transportation capacity.

Request for Acceptance

FEI seeks Commission approval to secure an additional 75 TJ/d of firm Spectra T-South transportation capacity for the winter of 2015/16 for Rate Schedule 46 and industrial customers. This new capacity would be secured either entirely during the next Bid Week or in stages over future Bid Weeks depending on developments affecting current market conditions. The next opportunity to bid for firm capacity on T-South is during the Bid Week that commences on October 1, 2014 and ends on October 7, 2014. Following this Bid Week in October, future Bid Weeks start on the first Wednesday of each month.

The total biddable capacity is adjusted for each Bid Week to reflect the amount of non-firm capacity remaining after accounting for firm capacity commitments. The advantage of securing firm capacity during these periods is that it will not start for 13 months. For example, for firm capacity secured during the October 2014 Bid Week, capacity will start to flow on November 1, 2015. Thus, there are no costs until the service starts. Although the service only has a two year commitment in order to secure renewal rights, FEI would secure this capacity for a minimum five year term in order to receive the maximum discount available at this time.

FEI requests an expeditious review of this request and requires a Decision no later than Friday, October 3, 2014. This timing is critical because it would allow FEI to participate in the next Bid Week before it closes (October 7, 2014).

Reasons for the Request

Earlier this month Spectra proposed a new service that involves offering shippers the ability to lock-in existing non-firm T-South Huntingdon capacity for the long term and well before the service commencement date. The offering of this service is driven by new demand from projects either announced or being considered in the Lower Mainland and US PNW that will require pipeline capacity as early as 2016/17.

A significant volume serving industrial customers in the Lower Mainland flows on an interruptible basis today. Any major decrease in the future availability of transportation capacity risks leaving these customers without adequate gas supply or they will need to pay significantly higher commodity prices at Huntingdon before any infrastructure expansions can be completed[1]. Given that these industrial customers may not generally have sufficient credit to secure long term firm transportation capacity, and have not made a commitment to

[1] This industrial load includes Rate Schedule 22, 23, 25, and 27 customers.

hold transportation capacity in the past, FEI faces the potential that these industrial customers will seek to return to it for bundled service. Importantly, this industrial load competes for T-South transportation capacity with industrial load located in the US PNW, which underscores the urgency in being in a position to be able to secure capacity soon.

The availability of sufficient T-South transportation capacity could also affect Rate Schedule 46 customers given the timing of when incremental supply is needed to serve them. The market change driven by Spectra's new service offering requires additional transportation capacity for these customers to be contracted for now rather than waiting. Rate Schedule 46 customers are forecast to require approximately 4 TJ/d by November 2015 and 9 TJ/d by November 2016. This volume is expected to increase as more customers enter into agreements for Rate Schedule 46 service. To serve this new demand, requires FEI to secure the equivalent transportation capacity to match the 35 TJ liquefaction capacity that is being constructed at Tilbury to serve this market.

It is for these reasons that FEI believes it is appropriate to secure new T-South capacity now for these two markets.

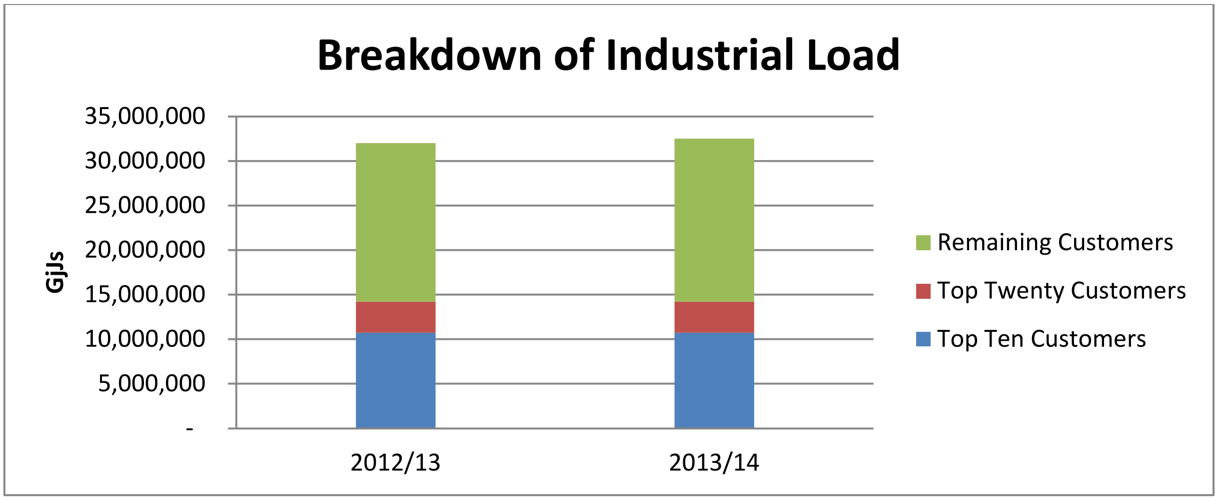
Analysis

The industrial demand under consideration is for Rate Schedule 22, 23, 25 and 27 customers located in the Lower Mainland only. Large industrial customers on Vancouver Island, like the Joint Venture and BC Hydro, are assumed to be directly involved in evaluating Spectra's new service offering and in a position to adequately respond to the pending market change. As a result, FEI has not included their volumes in its analysis.

Interior industrial customers on the FEI system are not at risk because alternatives are in place to serve their loads. Additionally, the competition for T-South Long Haul should not impact their ability to secure additional T-South Interior capacity should they chose to do so.

A review of actual consumption of Rate Schedule 22, 23, 25 and 27 customers located in the Lower Mainland over the last two years indicates that peak demand day occurred on February 5, 2014 when it reached 160 TJ. Although peak demand day reached 160 TJ, FEI does not believe is it necessary to pick up additional firm transportation capacity to match this full amount.

As shown in the following graph, the top 10 Lower Mainland industrial customers consume approximately 11 PJ annually or 30 TJ/d, which accounts for 33 percent of the total load. The combined top 20 industrial customers account for approximately 15 PJ or 40 TJ/d, which accounts for 44 percent of the total load. Given their size, FEI assumes that it is likely that these customers will be proactive in ensuring they have supply secured so that the entire load represented by these customers will not need to be served by FEI. Although these large volume customers are expected to adequately respond to this issue, FEI still faces the possibility that a lack of sufficient credit worthiness by some of these customers will result in them seeking to return to bundled service.



After adjusting the recent peak day demand of 160 TJ for load from larger customers, indicates that a portion of approximately 120 TJ would most likely need to be served. Given the uncertainty in estimating how many industrial customers may elect to return to bundled service, FEI believes it is reasonable to secure firm transportation capacity only for approximately one-third of this industrial demand, or 40 TJ/d, combined with the 35 TJ liquefaction capacity for Rate Schedule 46 service. Combined, these two requirements total 75 TJ/d and would be contracted for on a firm basis for a minimum five year term.

FEI will continue to monitor this situation, and as pointed out earlier, this new capacity would be secured either entirely during the next Bid Week or in stages over future Bid Weeks depending on developments affecting current market conditions. Furthermore, depending on how the market unfolds, FEI may need to secure still further T-South capacity in the future to serve this industrial demand. For now the request for additional T-South capacity is limited and would only serve a portion of the load if all of these customers return to a bundled service from FEI.

Incremental Costs

The following table sets out the total cost and the estimated mitigation value of the 75 TJ/d in incremental T-South transportation.

Cost Analysis for Additional Volume on T-South (Future Increase in T-South Capacity)			
$0.36/GJ *(Spectra Toll)*	75,000 GJ/d *(Incremental Volume)*	365 *(Days)*	$9.86 million (Approx. before mitigation)
$0.36/GJ *(Winter Mitigation)*	75,000 GJ/d *(Incremental Volume)*	151 *(Days)*	$4.08 million
Net Incremental Cost			$5.78 million

FORTIS BC™

The addition of 75 TJ/d of incremental T-South transportation capacity will result in a total cost of approximately $10 million. FEI expects that T-South will continue to hold value in the winter time so it is reasonable to expect full recovery of the demand charge in the winter period. FEI has not assumed any summer mitigation value, even though some value was realized over the last few summers. Net of the recovery during the winter, the incremental cost of the entire 75 TJ/d in T-South transportation capacity is estimated to be approximately $6 million. The impact of the incremental volume to midstream costs, considering an estimated total volume of 126 PJ, would be approximately 5 cents /GJ.

Additional Capacity Mitigation Options

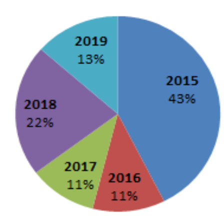
Should market developments proceed at a pace that do not result in a significant increase in additional firm transportation capacity being contracted, then FEI is able to defer entering into firm contracts and defer this for one or more Bid Weeks. This delay would result in avoiding the payment of firm transportation tolls for one or more months after November 2015.

Alternatively, should industrial customers not return to FEI in sufficient numbers to use the full 75 TJ/d in transportation capacity, FEI's contract portfolio offers the flexibility to either allow existing contracts to roll off, or decrease the contracted amounts once they are up for renewal. The table below shows the existing profile of T-South Long-Haul and Export Contracts, and when they would be renewed.

FEI T-South Contract Expiry Timeline

Year	10^3M^3	GJ	%
2015	4,126.40	157,835	43%
2016	1,108.70	42,408	11%
2017	1,045.10	39,975	11%
2018	2,109.40	80,685	22%
2019	1,310.10	50,111	14%
Total	9,699.70	371,014	100%

FEI T-South Long Hauls and Export Contract Expiry Timeline



Summary

With the recent changes occurring in the market for firm transportation capacity on T-South, FEI recommends acting proactively by contracting for an additional 75 TJ/d of capacity on T-South for a minimum five year term. Contracting for this capacity may occur as early as during the next Bid Week that is planned to start on October 1, 2014, with the actual contracted volume to be determined by FEI based on evolving market circumstances faced when the Bid Weeks take place. FEI has flexibility in its contracting portfolio to manage this additional transportation capacity by using it to replace expiring future contracts if sufficient demand does not materialize for all of this capacity.

This approach to securing additional firm transportation capacity is appropriate given the changing market conditions faced at this time.

~~CONFIDENTIALITY~~

Consistent with past practice, previous discussions and positions on the confidentiality of selected filings (and further emphasized in FEI's January 31, 1994 submission to the Commission), FEI is requesting that this information be filed on a confidential basis pursuant to Section 71(5) of the Utilities Commission Act and requests that the Commission exercise its discretion under Section 6.0 of the Rules for Natural Gas Energy Supply Contracts and allow these documents to remain confidential. FEI believes this will ensure that market sensitive information is protected, and the ability of FEI to obtain favourable commercial terms for future natural gas contracting is not impaired.

FEI further believes that the Core Market could be disadvantaged and may well shoulder incremental costs if utility gas supply procurement strategies as well as contracts are treated in a different manner than those of other gas purchasers, and believes that since it continues to operate within a competitive environment, there is no necessity for public disclosure and risk prejudice or influence in the negotiations or renegotiation of subsequent contracts.

If you require further information or have any questions regarding this submission, please contact Hans Mertins at (604) 592-7856.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

Appendix B

T-South Firm Contracting & Impact to Transportation Customers

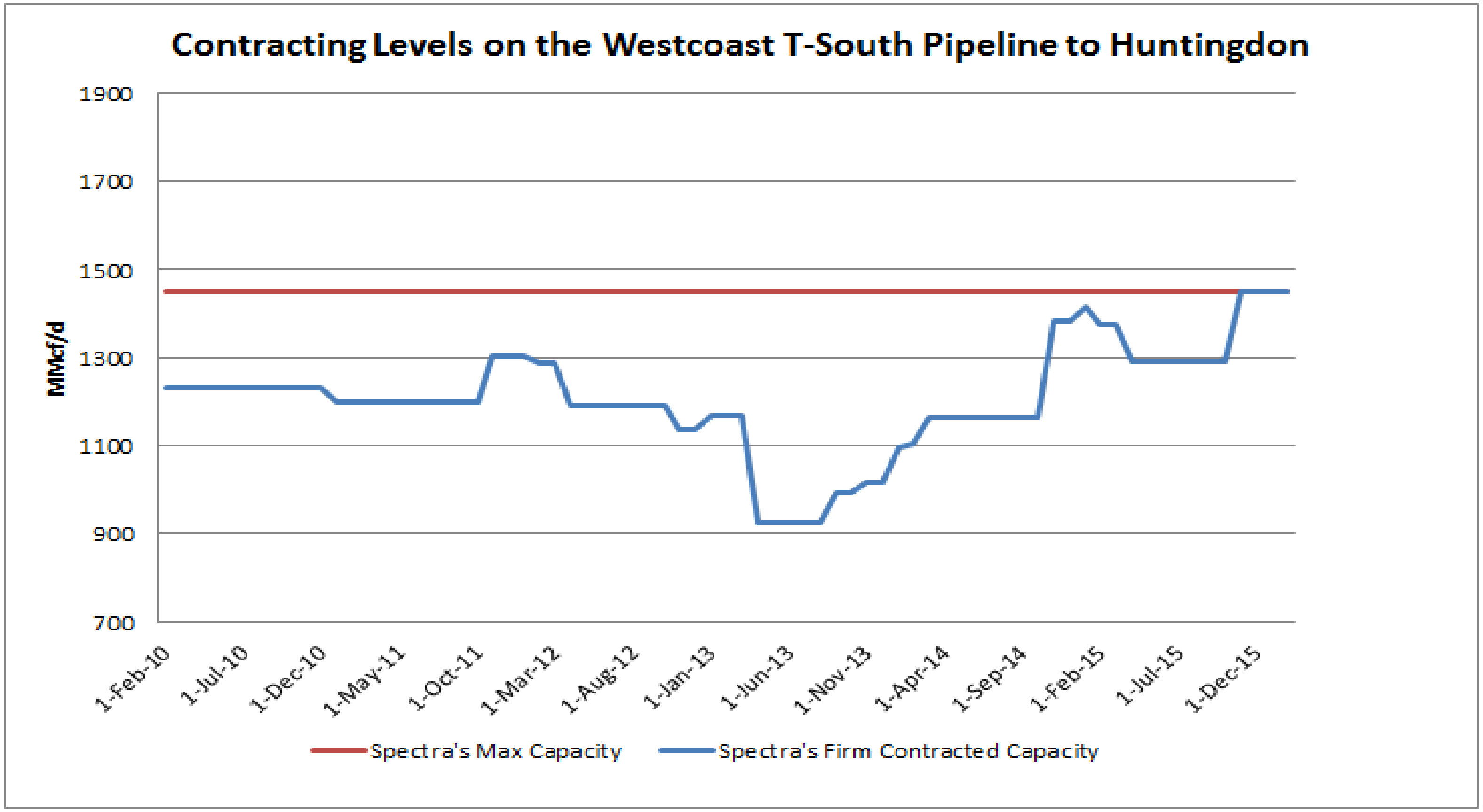
February 18, 2015

Meeting Discussion Points

- **Background to the Changing Regional Market Conditions**
  - Proposed industrial projects potentially adding demand to an constrained marketplace.
- **Business Risks and Challenges in FEI's Region**
  - FEI, Industrial and Regional Perspectives
  - Short and Long Term Risks
- **Potential Solutions**
  - Equitable
  - Consistent
  - Fair

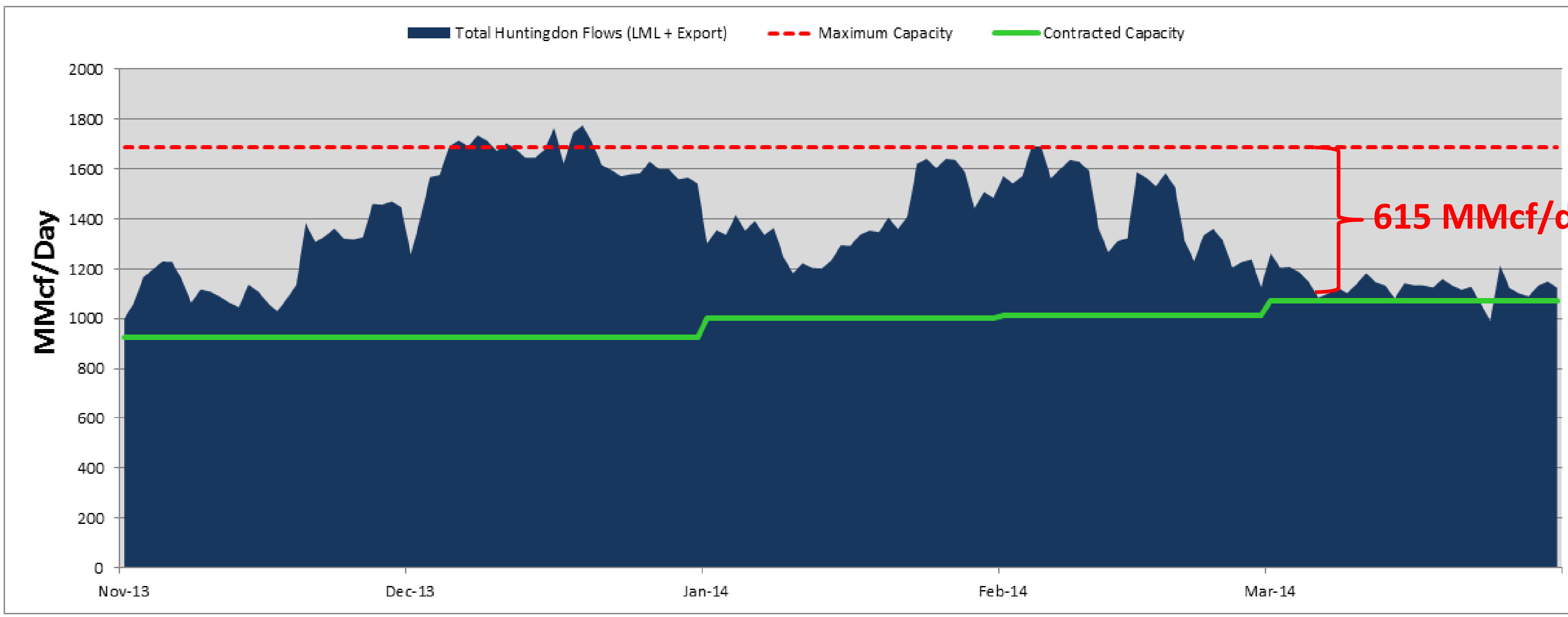
Background – De-contracted Levels on T-South

- **Fundamentals in the marketplace have led to a low level of firm contracted capacity on the T-South system.**



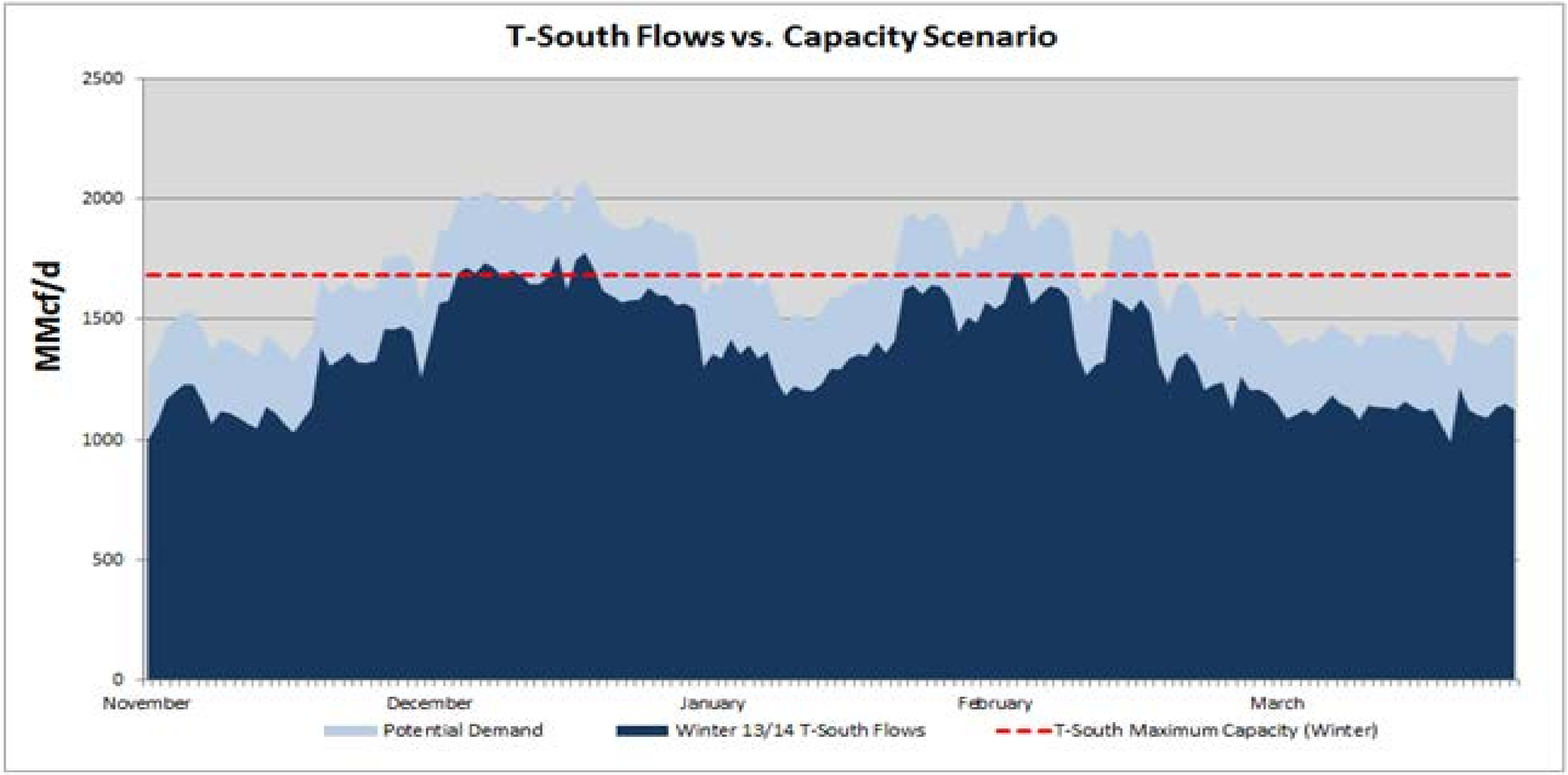
Background – T-South Flows

- **Despite low contracting levels, demand during the winter can increase close to Spectra's maximum pipeline capacity.**



Background – Potential of Additional Demand

- **Below graph shows the existing pipeline infrastructure can't meet this additional demand (ie/ 300 MMcf/day).**



Business Risks and Challenges

Long Term

- New Industrial Projects were able to lock in firm contracted capacity instead of underwriting new regional infrastructure.
- Risk of Industrial customers without adequate transportation or gas supply, or paying significantly higher commodity prices at Huntingdon.
- FEI runs the risk that Industrial customers will come back to bundled service.

Business Risks and Challenges

Short Term

- FEI picked up additional 75 TJs/day of firm T-South capacity.
- Uncertainty remains how the marketplace will play out.
- Even when FID's are made, the market will still not see the new demand for awhile.
- As a result, FEI may be long transportation capacity in the short term.

Tariff Consideration

Section 26 discusses the stipulations for customers who have acquired Gas under a direct purchase agreement and later wish to return to the system Gas supply of FortisBC.

- **FortisBC may require that the Customer provide FortisBC up to one Year's written notice before the date on which the Customer wishes to return to system Gas supply.**
- **FortisBC will supply the Customer with system Gas when the Customer wishes to return to system Gas supply if FortisBC is able to secure additional Gas supply and transportation to accommodate the Customer.**
- **FortisBC may, subject to BCUC approval, charge the Customer for any costs associated with the Customer returning to system Gas supply. Such costs may include, among other things, the costs of securing additional Gas supply and transportation to accommodate the Customer. FortisBC can bill the Customer for such costs as part of the regular FortisBC bill for service.**

Tariff Consideration cont.

Most industrial customers that choose to return to the system Gas supply of FortisBC would fall under Rate Schedule 5.

Under the Tariff's Conditions of Service for Rate Schedule 5:

- **FortisBC will only sell Gas under this Rate Schedule to Customers if adequate Gas volumes for such services are available.**

- **FortisBC will make reasonable efforts to accommodate a Customer on less than 12 months prior notice if FortisBC is able, with such shorter notice, to arrange for the firm purchases and transportation of Gas for sales under this Rate Schedule**

Appendix C

---------- Forwarded message ----------
From: **Salbach, Stephanie** <Stephanie.Salbach@fortisbc.com>
Date: Monday, May 30, 2016
Subject: Transportation Service Offering
To: Peter Kresnyak <peter@absolute-energy.ca>, Tom Dixon <tom@accessgas.com>, "Lewis, Ryan (Ryan.Lewis@altagas.ca)" <Ryan.Lewis@altagas.ca>, "Gerilynne Colwell (Gerilynne_colwell@cargill.com)" <Gerilynne_colwell@cargill.com>, Nick Caumanns <nick@cascadiaenergy.ca>, "Patti Andersen (Patricia.Andersen@directenergy.com)" <Patricia.Andersen@directenergy.com>, "Ron Comfort (ron.comfort@huskyenergy.com)" <ron.comfort@huskyenergy.com>, "Coughlin, Becky (IGI Resources, Inc.)" <Becky.Meisner@bp.com>, "John Marcinko (JMarcinko@justenergy.com)" <JMarcinko@justenergy.com>, "Dalziel, Michael" <michael.dalziel@powerex.com>, "jim@seminc.ca" <jim@seminc.ca>, Mary McCordic <mary.mccordic@shell.com>
Cc: "Cumming, Jordan" <Jordan.Cumming@fortisbc.com>, "Hill, Shawn" <Shawn.Hill@fortisbc.com>, "Hodgins, Kevin" <Kevin.Hodgins@fortisbc.com>, "Braun, Christine" <Christine.Braun@fortisbc.com>, "Richardson, Doug" <Doug.Richardson@fortisbc.com>

Good Afternoon,

On September 24, 2014, FEI filed a request to amend the 2014/15 Annual Contracting Plan (ACP) that was accepted by the Commission in Letter L-53-14, dated October 2, 2014. The amendment involved a request for FEI to secure additional Spectra T-South transportation capacity, due to the prospect of new incremental industrial load in the region. This new incremental load could result in capacity being unavailable for existing customers under the Transportation Service Model. Additionally, FEI believes these customers may have had barriers securing infrastructure in the region and therefore rely heavily on the Sumas market (ie/ Sumas buyer). These customers are exposed to potential supply disruptions/price spikes during the winter, when demand exceeds pipeline capacity. As per the 2016/17 ACP filing, FEI has sought BCUC approval to assign a portion of this additional pipeline capacity as a temporary service offering for transportation customers, under the Transportation Service Model. Although this offering is still subject to BCUC approval, we wanted to provide a breakdown of the service offering now, to give you enough time to discuss this service with your customers.

Terms and Conditions

This service will require the marketer to follow certain terms and conditions laid out by FEI, including the following:

- Marketer must have an active GasEDI and comply with FEI’s credit requirements.

- The service will be based 100% on customer load factor, therefore the customer will pay for this pipeline capacity even if it is unutilized on a given day.

- The marketer will be invoiced a Reservation Charge on a monthly basis. This includes the prevailing demand portion of T-South Long Haul 103m3 Spectra IT rate multiplied by 365 days (366 on leap years), divided by 12 months for each month invoiced, and multiplied by the daily fixed 103m3 volume.

- Variable costs including MFT and Carbon charges will also be charged each month.

There are two options as to how the marketer can elect to participate in the service offering:

Option A – Capacity Assignment

Option A would entail FEI assigning the T-South capacity directly to the marketer. This will require the marketer to comply with Spectra's terms and conditions (ie. credit), as the T-South 1-Year Long Haul rate and the monthly variable costs (MFT and Carbon) would be invoiced from Spectra directly to the marketer. Additionally, FEI would invoice the marketer the difference between the current Spectra Toll and the Reservation Charge on a monthly basis.

Option B – Buy and Sell

Option B requires the marketer to provide the gas to FEI at Station 2 which would then be returned at the marketer's Lower Mainland pool on FEI's system. Under this option, the marketer would provide fuel in kind month-to-month, and would be invoiced the total Reservation Charge and the monthly variable costs (MFT and Carbon) by FEI only.

Next Steps

To participate in this service, the marketer must provide a breakdown of the customers requesting the service, the amount of T-South capacity each customer requires, and the preferred Option A or B. Please email Jordan Cumming at Jordan.Cumming@fortisbc.com with this required information. This request must be provided no later than July 5, 2016. This will give FEI sufficient time to evaluate the capacity requested by each customer. If the total requested capacity exceeds the capacity available for this new service, FEI would prorate the capacity requests in a fair and equitable manner.

Again, this service offering is dependent on the Commission accepting the 2016/17 ACP. Upon approval, FEI will implement the service for the start of the 2016/17 gas year, and it could potentially be rolled out for the new rate design for January 1, 2018. FEI will confirm with the marketers the customer capacity allocation by August

3, 2016.

Thank you, and feel free to email Jordan Cumming, Kevin Hodgins (both copied here), or myself if you have any questions.

Stephanie

Stephanie Salbach
Transportation Services Manager, Energy Supply
FortisBC Energy Inc.
Tel: 604-576-7056
Cell: 604-376-5434* NEW
Hotline: 604-592-7788
16705 Fraser Highway
Surrey, BC V4N 0E8

Appendix D

<<Date>>

<<Marketer Name>>
<<Street Address>>
<<City/Province>>
<<Postal Code>>

Dear Mr/Mrs. <<Name>>,

Re: Letter Agreement for Assignment of Spectra Energy Corp. (“Spectra Energy”) Firm Transportation Service – Southern to the Huntingdon Delivery Area (“T-South Huntingdon Delivery”) Capacity from FortisBC Energy Inc. (“FortisBC”) to <<Marketer Name>> (the “Marketer”)

This Letter Agreement covers the release of pipeline capacity held by FortisBC on Spectra Energy’s British Columbia system, specifically T-South Huntingdon Delivery to Marketer. This Letter Agreement supplements, and forms part of the terms and conditions in the GasEDI Contract for Short-Term Sale and Purchase of Natural Gas between FortisBC and <<Marketer Name>> (“GasEDI”). The release of the capacity will be in accordance with terms and conditions in the GasEDI and this Letter Agreement.

Service:	T-South Huntingdon Delivery (Stn. 2 to Huntingdon delivery area). The capacity to be released from FortisBC represents the total capacity allocated by FortisBC to the Marketer for and on behalf of the customers identified in Appendix A to this Letter Agreement and who have appointed <<Marketer Name>> as their agent pursuant to Notice of Appointment of Shipper Agent under the applicable FortisBC Transportation Service Rate Schedule.
Releasing Party:	FortisBC Energy Inc.
Acquiring Party:	<<Marketer Name>>
Capacity:	________ 10^3m^3 (approximately _______ GJ)
Term:	November 1, 2016 through October 31, 2017
Variable Charges:	<<Marketer Name>> to pay all variable charges to Spectra Energy including Motor Fuel Tax and Carbon Tax, pursuant to Spectra Energy’s toll schedules applicable to the T-South Huntingdon Delivery
Spectra Energy Toll:	<<Marketer Name>> to pay T-South Huntington Delivery 5 Year Toll to Spectra Energy pursuant to Spectra Energy’s toll schedules applicable to the T-South Huntingdon Delivery
FortisBC Reservation Charge:	Each month during the Term specified above, FortisBC will invoice <<Marketer Name>> a Reservation Charge which includes the difference between Spectra Energy’s T-South Huntingdon Delivery 5 Year Toll and the prevailing T-South Huntingdon Delivery 10^3m^3 Spectra Energy Interruptible Transportation Service rate published by Spectra Energy in its toll schedules for each specific month multiplied by 365 days, divided by 12 months and multiplied by the daily fixed 10^3m^3 capacity

This Letter Agreement is subject to the terms and conditions that have been set forth by Spectra Energy with regards to the assignment, allocation or release of firm gas transportation service rights to another party done on a temporary basis.

Please indicate your acceptance of the terms and conditions contained in this Letter Agreement by signing in the appropriate spaces provided below.

FortisBC Energy Inc.	**<<Marketer Name>>.**
______________________	______________________
Shawn Hill	<<Name>>

Appendix A –Customer Names

Appendix 11

GENERAL TERMS AND CONDITIONS AND RATE SCHEDULES

Appendix 11-1

PROPOSED GENERAL TERMS AND CONDITIONS EFFECTIVE JUNE 1, 2018 (BLACKLINED)

FORTISBC ENERGY INC.

GENERAL TERMS AND CONDITIONS

THESE GENERAL TERMS AND CONDITIONS ARE EFFECTIVE JUNE 1, 2018

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FORTISBC ENERGY INC. GENERAL TERMS AND CONDITIONS
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Definitions

Unless the context indicates otherwise, in the General Terms and Conditions of FortisBC Energy and in the rate schedules of FortisBC Energy the following words have the following meanings:

Application Charge Means the applicable charges as set out in the Standard Charges Schedule.

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Basic Charge 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 365.25-day year (to incorporate the leap year), and rounded to four decimal places.

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Biogas Means raw gas substantially composed of methane that is produced by the breakdown of organic matter in the absence of oxygen.

Biomethane Means Biogas purified or upgraded to pipeline quality gas, also referred to as renewable natural gas.

Biomethane Service Means the Service provided to Customers under Rate Schedules 1B for Residential Biomethane Service, 2B for Small Commercial Biomethane Service, 3B for Large Commercial Biomethane Service, 5B for General Firm Biomethane Service, 11B for Large Volume Interruptible Biomethane Service, 30 for Off-System Interruptible Biomethane Sales, or Long Term Biomethane Contracts.

British Columbia Utilities Commission Means the British Columbia Utilities Commission constituted under the *Utilities Commission Act* of British Columbia and includes and is also a reference to

(a) any commission that is a successor to such commission, and

(b) any commission that is constituted pursuant to any statute that may be passed which supplements or supersedes the *Utilities Commission Act* of British Columbia.

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Business Day	Means a Day that commences on other than a Saturday, a Sunday, or a statutory holiday in the Province of British Columbia.
Carbon Offsets	Means the number of metric tons of carbon dioxide or its equivalent volume in other greenhouse gas(es) that FortisBC Energy may purchase as a mechanism to balance demand-supply for Biomethane in the event of an undersupply of Biomethane in order to retain the greenhouse gas reductions that Customers would have received from Biomethane supply.
CNG	Means compressed natural gas.
CNG Service	Means compression and dispensing service for CNG as set out in Section 12B.1 (CNG Service and LNG Service).
Commercial Service	Means the provision of firm Gas supplied to one Delivery Point and through one Meter Set for use in approved appliances in commercial, institutional or small industrial operations.
Commodity Cost Recovery Charge	Means the commodity cost recovery charge defined in the Table of Charges of the applicable FortisBC Energy Rate Schedules.
Commodity Unbundling Service	Means the service provided to Customers under Rate Schedule 1U for Residential Commodity Unbundling Service, Rate Schedule 2U for Small Commercial Commodity Unbundling Service and Rate Schedule 3U for Large Commercial Commodity Unbundling Service.
Conversion Factor	Means a factor, or combination of factors, which converts gas meter data to Gigajoules or cubic metres for billing purposes.
Customer	Means a Person who is being provided Service or who has filed an application for Service with FortisBC Energy that has been approved by FortisBC Energy.
Day	Means any period of 24 consecutive Hours beginning and ending at 7:00 a.m. Pacific Standard Time or as otherwise specified in the applicable Service Agreement.
Delivery Charge	Means the delivery charge defined in the Table of Charges of the applicable Rate Schedules.

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Delivery Point	Means the outlet of the Meter Set unless otherwise specified in the applicable Service Agreement.
Delivery Pressure	Means the pressure of the Gas at the Delivery Point.
Financing Agreement	Means an agreement under which FortisBC Energy provides financing to a Customer for improving the energy efficiency of a Premises, or a part of a Premises.
First Nations	Means those First Nations that have attained self-government status pursuant to self-government agreements entered into with the Government of Canada and validly enacted self-government legislation in Canada.
FortisBC Energy	Means FortisBC Energy Inc., a body corporate incorporated pursuant to the laws of the Province of British Columbia under number 0778288.
FortisBC Energy System	Means the Gas transmission and distribution system owned and operated by FortisBC Energy, as such system is expanded, reduced or modified from time to time.
Franchise Fees	Has the same meaning as Municipal Operating Fees.
Gas	Means natural gas (including any added odorant), propane and Biomethane.
Gas Service	Means the delivery of Gas through a Meter Set.
General Terms and Conditions	Means these general terms and conditions of FortisBC Energy from time to time approved by the British Columbia Utilities Commission.
Gigajoule	Means a measure of energy equal to one billion joules.
Heat Content	Means the quantity of energy per unit volume of Gas measured under standardized conditions and expressed in megajoules per cubic metre (MJ/m^3).
Hour	Means any consecutive 60 minute period.

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Hydronic Heating System	Means a heating / cooling system where water is heated or cooled and where hot water is distributed through pipes to radiators or to another style of water-to-air heat exchanger.
Landlord	Means a Person who, being the owner of real property, or the agent of that owner, who has leased or rented the property to a Tenant.
LNG	Means liquefied natural gas (LNG).
LNG Service	Means LNG fueling and fuel storage and dispensing service as set out in Section 12B.1 (CNG Service and LNG Service).
Loan	Means the principal amount of financing provided by FortisBC Energy to a Customer, plus interest charged by FortisBC Energy on the amount of financing and any applicable fees and late payment charges.
Long Term Biomethane Contract	A long term contract entered into between FortisBC Energy and a Customer for Biomethane Service, filed as a tariff supplement, for a term of no less than five Years and no greater than ten Years, and for a commitment to purchase no less than 60,000 Gigajoules in aggregate over the term of the contract.
Main	Means pipe(s) used to carry Gas for general or collective use for the purposes of distribution.
Main Extension	Means an extension of one of FortisBC Energy's mains with low, distribution, intermediate or transmission pressures, and includes tapping of transmission pipelines, installing any required pressure regulating facilities and upgrading of existing Mains or pressure regulating facilities on private property.
Marketer	Means a Person who has entered into an agreement to supply a Customer under Commodity Unbundling Service.
Meter Set	Means an assembly of FortisBC Energy owned metering, including any ancillary equipment and piping.
Month or Monthly	Means a period of time, for billing purposes, of 27 to 34 consecutive Days.

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Municipal Operating Fees Means the monies payable by FortisBC Energy to municipalities and First Nations

(a) for the use of the streets and other property to construct and operate the utility business of FortisBC Energy within municipalities and First Nations lands (formerly, reserves within the *Indian Act*),

(b) relating to the revenues received by FortisBC Energy for Gas consumed within municipalities and First Nations lands (formerly, reserves within the *Indian Act*), or

(c) relating, where applicable, to the value of Gas transported by FortisBC Energy through municipalities and First Nations lands (formerly, reserves within the *Indian Act*).

Other Service Means the provision of Service other than Gas Service including, but not limited to rental of equipment, natural gas vehicle fuel compression, alterations and repairs, merchandise purchases, and financing.

Other Service Charges Means charges for rental, natural gas vehicle fuel compression service, damages, alterations and repairs, financing, insurance and merchandise purchases, and late payment charges, Municipal Operating Fees, Provincial Sales Tax, Goods and Services Tax or other taxes related to these charges.

Person Means a natural person, partnership, corporation, society, unincorporated entity or body politic.

Premises Means a building, a separate unit of a building, or machinery together with the surrounding land.

Profitability Index Means the revenue to cost ratio comparing the revenues expected from: a Main Extension, a connection to a Customer of Rate Schedule 3 or a Customer of a Rate Schedule numbered higher than Rate Schedule 3, or a connection to a Service Header (including Vertical Subdivisions), to the expected costs over a period of time of 40 Years.

Rate Schedule Means a schedule attached to and forming part of these General Terms and Conditions, which sets out the charges for Service and certain other related terms and conditions for a class of Service.

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Residential Premises	Means the Premises of a single Customer, whether single family dwelling, separately metered single-family townhouse, rowhouse, condominium, duplex or apartment, or single-metered apartment blocks with four or less apartments.
Residential Service	Means firm Gas Service provided to a Residential Premises.
Rider	Means an additional charge or credit attached to a rate.
Seasonal Service	Means firm Gas Service provided to a Customer during the period commencing April 1st and ending November 1st.
Service	Means the provision of Gas Service or other service by FortisBC Energy.
Service Agreement	Means an agreement between FortisBC Energy and a Customer for the provision of Service.
Service Area	Has the meaning set out at the end of the Definitions in these General Terms and Conditions.
Service Header	Means a Gas distribution pipeline located on private property connecting three or more Service Lines or Meter Sets to a Main.
Service Line	Means that portion of FortisBC Energy's gas distribution system extending from a Main or a Service Header to the inlet of the Meter Set. In case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the Customer's individual Premises, but not within the Customer's individual Premises.
Service Line Cost Allowance	Means the service line cost allowance as set out in the Standard Charges Schedule.
Service Related Charges	Means service related charges Including, but are not limited to, application charges, Municipal Operating Fees, and late payment charges, plus Provincial Sales Tax, Goods and Service Tax, or other taxes related to these charges.

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Standard Charges Schedule	Means the schedule attached to and forming part of the General Terms and Conditions which lists the various charges relating to Service provided by FortisBC Energy as approved from time to time by the British Columbia Utilities Commission.
Storage and Transport Charge	Means the storage and transport charge defined in the Table of Charges of the applicable Rate Schedules.
System Extension Fund Pilot	Means the fund available from FortisBC Energy, for the period beginning January 1, 2017 and ending December 31, 2020, to provide assistance to eligible new Customers who are required to pay a contribution in aid of construction in order for a system extension to proceed as set forth in these General Terms and Conditions.
Temporary Service	Means the provision of Service for what FortisBC Energy determines will be a limited period of time.
Tenant	Means a Person who has the temporary use and occupation of real property owned by another Person.
Thermal Energy	Means thermal energy supplied by a Gas fired hydronic heating system (where hydronic heating is the primary heating source), and measured by a thermal meter, to premises of a Vertical Subdivision where the thermal meter is used to apportion the Gigajoules of Gas consumed by the Gas fired hydronic heating system among the Premises in the Vertical Subdivision.
Thermal Metering	Means thermal / heat meters to measure the energy which, in a heat-exchange circuit, is absorbed or given up by the heat conveying liquid. The thermal / heat meter indicates the quantity of heat in legal units.
Unauthorized Transportation Service	Means any transportation service utilized in excess of the curtailed quantity specified in any notice to interrupt or curtail transportation service.
Vertical Subdivision	Means a multi-storey building that has individually metered units and a common Service Header connecting banks of meters, typically located on each floor.

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Year	Means a period of 12 consecutive Months totalling at least 365 Days.
10^3m^3	Means 1,000 cubic metres.

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Service Areas

These General Terms and Conditions refer to the following major Service Areas: Mainland and Vancouver Island (and where applicable, more specifically Lower Mainland, Inland, Columbia and Whistler) and Fort Nelson.

Mainland and Vancouver Island Service Area

Means the areas including, but not limited to, the following locations and surrounding areas of

100 Mile House	MacKenzie
108 Mile House	Maple Ridge
150 Mile House	Matsqui
Abbotsford	Merritt
Anmore	Merville
Armstrong	Metchosin
Ashcroft	Midway
Bear Lake	Mill Bay
Belcarra	Mission
Black Creek	Montrose
Brentwood Bay	Nanaimo
Burnaby	Nanoose Bay
Cache Creek	Naramata
Campbell River	Nelson
Castlegar	New Westminster
Cedar	North Cowichan
Central Saanich	North Saanich
Chase	North Vancouver City
Chemainus	North Vancouver District
Chetwynd	Oak Bay
Chilliwack	Okanagan Falls
Christina Lake	Oliver
Clinton	Osoyoos
Cobble Hill	Oyama
Coldstream	Parksville
Collettville	Peachland
Colwood	Penticton
Comox	Pitt Meadows
Coombs	Port Alberni

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FORTISBC ENERGY INC. GENERAL TERMS AND CONDITIONS
SECTION 1

Coquitlam	Port Coquitlam
Courtenay	Port Moody
Cowichan Bay	Powell River
Craigmont	Prince George
Cranbrook	Princeton
Creston	Qualicum Beach
Crofton	Quesnel
Cumberland	Revelstoke
Delta	Richmond
Duncan	Roberts Creek
Elkford	Robson
Esquimalt	Rossland
Falkland	Royston
Ferguson Lake	Saanich
Fernie	Saanichton
Fruitvale	Salmo
Galloway	Salmon Arm
Gibralter Mines	Savona
Gibsons	Sechelt
Grand Forks	Shawnigan Lake
Greenlake	Shelley
Greenwood	Sidney
Halfmoon Bay	Sooke
Harrison Hot Springs	Sorrento
Hedley	Spallumcheen
Highlands	Sparwood
Hixon	Squamish
Honeymoon Creek	Summerland
Hope	Surrey
Hudson's Hope	Trail
Jaffray	Vancouver
Kamloops	Vernon
Kelowna	Victoria
Kent	View Royal
Keremeos	Warfield
Kimberley	West Vancouver

Order No.: Issued By: Diane Roy, Vice-President, Regulatory Affairs

Effective Date: June 1, 2018 Accepted for Filing: ____________________

BCUC Secretary: ______________________

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Ladysmith	Westwold
Lakeview Heights	Whistler
Langford	White Rock
Langley City	Williams Lake
Langley District	Winfield
Lantzville	Woodsdale
Lazo	Yahk
Logan Lake	
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Fort Nelson Service Area	Means the areas including, but not limited to, the following locations and surrounding areas of Fort Nelson Prophet River

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1. Application Requirements

1.1 Requesting Services

A Person requesting FortisBC Energy:

(a) to provide Gas Service;

(b) to provide a new Service Line;

(c) to re-activate an existing Service Line;

(d) to transfer an existing account;

(e) to change the type of Service provided; or

(f) to make alterations to an existing Service Line or Meter Set;

must apply to FortisBC Energy at any of its office locations in person, by mail, by telephone, by facsimile or by other electronic means.

1.2 Required Documents

An applicant for:

(a) Residential Service may be required to sign an application and a Service Agreement provided by FortisBC Energy;

(b) Commercial Service may be required to sign an application and a Service Agreement provided by FortisBC Energy; or

(c) Service on Rate Schedules that are not for Residential Service or for Commercial Service must sign the applicable Service Agreement provided by FortisBC Energy.

1.3 Separate Premises / Businesses

If an applicant is requesting Service from FortisBC Energy at more than one Premises, or for more than one separately operated business, the applicant will be considered a separate Customer for each of the Premises and businesses. For the purposes of this provision, FortisBC Energy will determine whether or not any building contains one or more Premises or any business is separately operated.

1.4 Required References

FortisBC Energy may require an applicant for Service to provide reference information and identification acceptable to FortisBC Energy.

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1.5 Rental Premises

In the case of rental Premises, FortisBC Energy may:

(a) require a Landlord who wishes FortisBC Energy to contract directly with a Tenant to enter into an agreement with FortisBC Energy whereby the Landlord assumes responsibility for that Tenant's non-payment for Service to the Premises;

(b) contract directly with the Landlord as a Customer of FortisBC Energy with respect to any or all Services to the Premises; or

(c) contract directly with each Tenant as a Customer of FortisBC Energy.

1.6 Refusal of Application

FortisBC Energy may refuse to accept an application for Service for any of the reasons listed in Section 23 (Discontinuance of Service and Refusal of Service).

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2. Agreement to Provide Service

2.1 Service Agreement

The agreement for Service between a Customer and FortisBC Energy will be:

(a) the oral or written application of the Customer which has been approved by FortisBC Energy and which is deemed to include the General Terms and Conditions; or

(b) a Service Agreement signed by the Customer.

2.2 Customer Status

A Person becomes a Customer of FortisBC Energy when FortisBC Energy:

(a) approves the Person's application for Service; or

(b) provides Service to the Person.

A Person who is being provided Service by FortisBC Energy but who has not applied for Service will be served in accordance with these General Terms and Conditions.

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2.3 No Assignment / Transfer

A Customer may not transfer or assign an agreement for Service without the prior written approval of FortisBC Energy.

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3. Conditions on Use of Service

3.1 Authorized Consumption

A Customer must not increase the maximum rate of consumption of Gas delivered to it by FortisBC Energy from that which may be consumed by the Customer under the applicable Rate Schedule nor significantly change its connected load without the prior written approval of FortisBC Energy, which approval will not be unreasonably withheld.

3.2 Unauthorized Sale / Supply / Use

A Customer must not sell or supply Gas supplied to it by FortisBC Energy to other Persons or use Gas supplied to it by FortisBC Energy for any purpose other than as specified in the Service Agreement without the prior written approval of FortisBC Energy, at its sole discretion.

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4. Rate Classification

4.1 Rate Classification

Subject to Section 4.2(a) (Special Contracts and Tariff Supplements), a Customer may be provided Service under any Rate Schedule for which it meets the applicability criteria as set out in the appropriate Rate Schedule.

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4.2 Special Contracts and Tariff Supplements

In exceptional circumstances, special contracts and tariff supplements may be negotiated between FortisBC Energy and the Customer and submitted for British Columbia Utilities Commission approval where:

(a) a minimum rate or revenue stream is required by FortisBC Energy to ensure that Service to the Customer is economic; or

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(b) factors such as system by-pass opportunities exist or alternative fuel costs are such that a reduced rate is justified to continue to provide the Customer with Service.

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4.3 Periodic Review

FortisBC Energy may:

(a) conduct periodic reviews of the quantity of Gas delivered and the rate of delivery of Gas to a Customer to determine which Rate Schedule applies to the Customer;

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(b) change the Customer's charge to the appropriate charge calculated under the appropriate Rate Schedule; and

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(c) apply the appropriate Rate Schedule to the Customer.

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5. Application Charge and Other Charges

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5.1 Application Charge

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An applicant for Service must pay the applicable Application Charge set out in the Standard Charges Schedule.

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5.2 Application Charge for Manifold Meters and Vertical Subdivisions

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Where a new Service Line is required to serve more than one Customer at a Premises and the Service is provided with Gas meters connected to a meter manifold, the applicable Application Charge for manifold meters set out in the Standard Charges Schedule will apply. Where a new Service Header is required to serve a Vertical Subdivision, the applicable Application Charge set out in the Standard Charges Schedule will apply.

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5.3 Waiver of Application Charge

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(a) will be waived by FortisBC Energy if Service to a Customer is reactivated after it was discontinued for any of the reasons described in Section 13.2 (Right to Restrict); and

(b) may be waived by FortisBC Energy if a Landlord requires Gas Service between the time a previous Tenant moves out and a new Tenant moves in, up to a maximum of 31 Days.

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5.4 Reactivation Charges

If:

(a) Service is terminated:

(i) at the request of a Customer; or

(ii) for any of the reasons described in Section 23 (Discontinuance of Service and Refusal of Service); or

(iii) to permit Customers to make alterations to their Premises; and

(b) the same Customer or the spouse, employee, contractor, agent or partner of the same Customer requests reactivation of Service to the Premises within one Year,

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the applicant for reactivation must pay the greater of:

(i) the costs FortisBC Energy incurs in de-activating and re-activating the Service at the rates set out in the Standard Charges Schedule, or

(ii) the sum of the minimum charges set out in the applicable Rate Schedule which would have been paid by the Customer between the time of termination and the time of reactivation of Service.

5.5 Identifying Load or Premises Served by Meter Sets

If a Customer requests FortisBC Energy to identify the Meter Set that serves the Premises and/or load after the Meter Set was installed, the Customer will pay the cost FortisBC Energy incurs in re-identifying the Meter Set where:

(a) the Meter Set is found to be properly identified; or

(b) the Meter Set is found to be improperly identified as a result of Customer activity, including:

(i) a change in the legal civic address of the Premises;

(ii) renovating or partitioning the Premises; or

(iii) rerouting Gas lines after the Delivery Point.

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6. Security for Payment of Bills

6.1 Security for Payment of Bills

If a Customer or applicant cannot establish or maintain credit to the satisfaction of FortisBC Energy, the Customer or applicant may be required to make a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy. As security for payment of bills, all Customers who have not established or maintained credit to the satisfaction of FortisBC Energy, may be required to provide a security deposit or equivalent form of security, the amount of which may not:

(a) be less than $50; and

(b) exceed an amount equal to the estimate of the total bill for the two highest consecutive Months consumption of Gas by the applicable Premises.

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6.2 Interest

FortisBC Energy will pay interest to a Customer on a security deposit at the rate and at the times specified in the Standard Charges Schedule. Subject to Section 6.5 (Application of Deposit), if a security deposit in whole or in part is returned to the Customer for any reason, FortisBC Energy will credit any accrued interest to the Customer's account at that time.

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No interest is payable:

(a) on any unclaimed deposit left with FortisBC Energy after the account for which it is security is closed; and

(b) on a deposit held by FortisBC Energy in a form other than cash.

6.3 Refund of Deposit

A security deposit may be returned to the Customer at any time if, according to the records of FortisBC Energy, the Customer has at all times during the immediately preceding one Year period maintained an account with FortisBC Energy and paid in full all amounts when due in accordance with the Service Agreement. When the Customer pays the final bill, FortisBC Energy will refund any remaining security deposit plus any accrued interest or cancel the equivalent form of security.

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6.4 Unclaimed Refund

If FortisBC Energy is unable to locate the Customer to whom a security deposit is payable, FortisBC Energy will take reasonable steps to locate the Customer; but if the security deposit remains unclaimed 10 Years after the date on which it first became refundable, the deposit, together with any interest accrued thereon, will become the absolute property of FortisBC Energy.

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6.5 Application of Deposit

If a Customer's bill, including the Loan amount, is not paid when due, FortisBC Energy may apply all or any part of the Customer's security deposit or equivalent form of security and any accrued interest toward payment of the bill. Even if FortisBC Energy applies the security deposit or calls on the equivalent form of security, FortisBC Energy may, under Section 23 (Discontinuance of Service and Refusal of Service), discontinue Service to the Customer for failure to pay for Service on time.

6.6 Replenish Security Deposit

If a Customer's security deposit or equivalent form of security is called upon by FortisBC Energy towards paying an unpaid bill, the Customer may be required to re-establish the security deposit or equivalent form of security before FortisBC Energy will reconnect or continue Service to the Customer.

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6.7 Failure to Pay

Failure to pay a security deposit or to provide an equivalent form of security acceptable to FortisBC Energy may, in FortisBC Energy's discretion, result in discontinuance or refusal of Service as set out in Section 23 (Discontinuance of Service and Refusal of Service).

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7. Term of Service Agreement

7.1 Initial Term for Residential and Commercial Service

If a Customer is being provided Residential Service or Commercial Service, the initial term of the Service Agreement:

(a) when a new Service Line is required will be one Year; or

(b) when a Main Extension is required, will be for a period of time fixed by FortisBC Energy not exceeding the number of Years used to calculate the revenue in the Main Extension economic test used in Section 12 (Main Extensions).

7.2 Initial Term for Gas Service other than Residential or Commercial Service

If a Customer is being provided Gas Service other than Residential Service or Commercial Service, the initial term of the Service Agreement will be as specified in the Service Agreement or as specified in the appropriate Rate Schedule.

7.3 Transfer to Residential or Commercial Service

If a Customer is being provided Gas Service other than Residential Service or Commercial Service and transfers to Residential Service or Commercial Service, the initial term of the Service Agreement will be determined by the criteria set out in Section 7.1 (Initial Term for Residential and Commercial Service). A Customer may only transfer Service from one Rate Schedule to another Rate Schedule once a Year.

7.4 Renewal of Agreement

Unless:

(a) the Service Agreement or the applicable Rate Schedule specifies otherwise;

(b) the Service Agreement is terminated under Section 8 (Termination of Service Agreement);

(c) a refund has been made under Section 9.2 (Refund of Charges); or

(d) the Service Agreement is for Seasonal Service;

the Service Agreement will be automatically renewed at the end of its initial term from Month to Month for Residential Service or Commercial Service, and from Year to Year for all other types of Gas Service.

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8. Termination of Service Agreement

8.1 Termination by Customer

Unless the Service Agreement or applicable Rate Schedule specifies otherwise, the Customer may terminate the Service Agreement after the end of the initial term by giving FortisBC Energy at least 48 Hours notice.

8.2 Continuing Obligation

The Customer is responsible for, and must pay for, all Gas delivered to the Premises and is responsible for all damages to and loss of Meter Sets or other FortisBC Energy property on the Premises until the Service Agreement is terminated.

8.3 Effect of Termination

The Customer is not released from any previously existing obligations to FortisBC Energy under the Service Agreement or under the Financing Agreement by terminating the Service Agreement.

8.4 Sealing Service Line

After receiving a termination notice for a Premises and after a reasonable period of time during which a new Customer has not applied for Gas Service at the Premises, FortisBC Energy may seal off the Service Line to the Premises.

8.5 Termination by FortisBC Energy

Unless the Service Agreement or applicable Rate Schedule specifies otherwise, FortisBC Energy may terminate the Service Agreement for any reason by giving the Customer at least 48 Hours written notice.

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9. Delayed Consumption

9.1 Additional Charges

If a Customer has not consumed Gas:

(a) within 2 Months after the installation of the Service Line to the Customer's Premises, FortisBC Energy may charge the minimum charge under the appropriate Rate Schedule for each billing period after that; and

(b) within one Year after installation of the Service Line to the Customer's Premises, FortisBC Energy may charge the Customer the full cost of construction and installation of the Service Line and Meter Set less the total of the minimum charges under the appropriate Rate Schedule billed to the Customer to that date.

9.2 Refund of Charges

If a Customer who has paid the charges for a Service Line under Section 9.1(b) (Additional Charges) consumes Gas in the second Year after installation of the Service Line, FortisBC Energy will refund to the Customer the payments made under Section 9.1(b) (Additional Charges). If a refund is made under Section 9.2 (Refund of Charges), the term of the Service Agreement will be one Year from the time the Customer begins consuming Gas.

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10. Service Lines

10.1 Provided Installation

If FortisBC Energy's Main is adjacent to the Customer's Premises, FortisBC Energy:

(a) will designate the location of the Service Lines on the Customer's Premises and determine the amount of space that must be left unobstructed around them;

(b) will install for Rate Schedule 1 and Rate Schedule 2 Customers the Service Line from the Main to the Meter Set on the Customer's Premises at no additional cost to the Customer provided:

(i) the Service Line follows the route which is the most suitable to FortisBC Energy;

(ii) the estimated direct cost of the Service Line does not exceed the Service Line Cost Allowance set out in the Standard Charges Schedule; and

(iii) the distance from the front of the Customer's building or machinery to the meter does not exceed 1.5 metres;

(c) will charge Rate Schedule 1 and Rate Schedule 2 Customers for the estimated direct construction costs in excess of the Service Line Cost Allowance set out in the Standard Charges Schedule; and

(d) will perform an economic test for Customers of Rate Schedule 3 and Customers of Rate Schedules numbered higher than Rate Schedule 3, and for any Customers connecting to a Service Header including Vertical Subdivisions, and, when the Profitability Index of the test is less than 0.8, will charge the Customer a contribution sufficient to achieve a minimum Profitability Index of 0.8. The economic test will be discounted cash flow test, similar to the economic test for Main Extensions set out in Section 12 (Main Extensions).

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10.2 Extended Installation

The Customer may make application to FortisBC Energy to extend the Service Line beyond that described in Section 10.1 (Provided Installation) part (b)(iii). Upon approval by FortisBC Energy and agreement for payment by the Customer of the additional costs, FortisBC Energy will extend the Service Line only if it is on the route approved by FortisBC Energy.

10.3 Customer Requested Routing

If:

(a) FortisBC Energy's Main is adjacent to the Customer's Premises; and

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(b) the Customer requests that its piping or Service Line enter its Premises at a different point of entry or follow a different route from the point or route designated by FortisBC Energy;

FortisBC Energy may charge the Customer for all additional costs as determined by FortisBC Energy to install the Service Line in accordance with the Customer's request.

10.4 **Temporary Service**

A Customer applying for Temporary Service must pay FortisBC Energy in advance for the costs which FortisBC Energy estimates it will incur in the installation and subsequent removal of the facilities necessary to supply Gas to the Customer.

10.5 **Winter Construction**

If an applicant or Customer applies for Service which requires construction when, in FortisBC Energy's opinion, frost conditions may exist, FortisBC Energy may postpone the required construction until the frost conditions no longer exist.

If FortisBC Energy carries out the construction, the applicant or Customer may be required to pay all costs in excess of the Service Line Cost Allowance which are incurred due to the frost conditions.

10.6 **Additional Connections**

If a Customer requests more than one Service Line to the Premises, on the same Rate Schedule, FortisBC Energy may install the additional Service Line and may charge the Customer the applicable Application Charge as well as the full cost (including overheads) for the Service Line installation. FortisBC Energy will bill the additional Service Line from a separate meter and account. If the additional Service Line is requested by a spouse, contractor, employee, agent or partner of the existing Customer, the same charges will apply.

10.7 **Easement Required**

If an intervening property is located between the Customer's Premises and FortisBC Energy's Main, the Customer is responsible for the costs of obtaining an easement in favour of FortisBC Energy and in a form specified by FortisBC Energy, for the installation, operation and maintenance on the intervening property of all necessary facilities for supplying Gas to the Customer.

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10.8 **Ownership**

FortisBC Energy owns the entire Service Line from the Main up to and including the Meter Set, whether it is located inside or outside the Customer's Premises. In case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the Customer's individual Premises, but not within the Customer's individual Premises.

10.9 **Maintenance**

FortisBC Energy will maintain the Service Line, subject to Section 24.2 (Responsibility Before Delivery Point).

10.10 **Supply Cut Off**

If the supply of Gas to a Customer's Premises is cut off for any reason, FortisBC Energy is not required to remove the Service Line from the Customer's property or Premises.

10.11 **Damage Notice**

The Customer must advise FortisBC Energy immediately of any damage occurring to the Service Line.

10.12 **Prohibition**

A Customer must not construct any permanent structure over a Service Line or install any air intake openings or sources of ignition which contravene government regulations, codes or FortisBC Energy policies.

10.13 **No Unauthorized Changes**

No changes, extensions, connections to or replacement of, or disconnection from FortisBC Energy's Mains or Service Lines, will be made except by FortisBC Energy's authorized employees, contractors or agents or by other Persons authorized in writing by FortisBC Energy. Any change in the location of an existing Service Line:

(a) must be approved in writing by FortisBC Energy; and

(b) will be made at the expense of the Customer if the change is requested by the Customer or necessitated by the actions of the Customer.

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10.14 Site Preparation

The Customer will be responsible for all necessary site preparation including but not limited to clearing building materials, construction waste, equipment, soil and gravel piles over the proposed Service Line route to the standards established by FortisBC Energy. FortisBC Energy may recover any additional costs associated with delays or site visits necessitated by inadequate or substandard site preparation by the Customer.

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11. Meter Sets and Metering

11.1 Installation

In order to bill the Customer for Gas delivered, FortisBC Energy will install one or more Meter Sets on the Customer's Premises. Unless approved by FortisBC Energy, all Meter Sets will be located on surrounding land outside of any buildings on the Customer's Premises at locations designated by FortisBC Energy.

11.2 Measurement

The quantity of Gas delivered to the Premises will be metered using apparatus approved by Measurement Canada. The amount of Gas registered by the Meter Set during each billing period will be converted to Gigajoules in accordance with the *Electricity and Gas Inspection Act (EGI Act)* and rounded to the nearest one-tenth of a Gigajoule.

11.3 Testing Meters

If a Customer applies for the testing of a Meter Set and:

(a) the Meter Set is found to be recording incorrectly, *EGI Act,* the cost of removing, replacing and testing the meter will be borne by FortisBC Energy subject to Section 24.4 (Responsibility for Meter Set); and

(b) the Meter Set is found to be recording correctly, as defined by the *EGI Act*, the Customer must pay FortisBC Energy for the cost of removing, replacing and testing the Meter Set as set out in the Standard Charges Schedule.

11.4 Defective Meter Set

If a Meter Set ceases to register, FortisBC Energy will estimate the volume of Gas delivered to the Customer according to the procedures set out in Section 16.6 (Incorrect Register).

11.5 Protection of Equipment

The Customer must take reasonable care of and protect all Meter Sets and related equipment on the Customer's Premises. The Customer's responsibility for expense, risk and liability with respect to all Meter Sets is set out in Section 24.4 (Responsibility for Meter Set).

11.6 No Unauthorized Changes

No Meter Set will be installed, connected, moved or disconnected except by FortisBC Energy's authorized employees, contractors or agents or by other Persons with the prior written approval of FortisBC Energy.

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11.7 Removal of Meter Set

At the termination of a Service Agreement, FortisBC Energy may disconnect or remove a Meter Set from the Premises if a new Customer is not expected to apply for Service for the Premises within a reasonable time.

11.8 Customer Requested Meter Relocation or Modifications

Any change in the location of a Meter Set or any modifications to the Meter Set, including automatic and/or remote meter reading:

(a) must be approved by FortisBC Energy in writing; and

(b) will be made at the expense of the Customer if the change or modification is requested by the Customer or necessitated by the actions of the Customer. If any of the changes to the Meter Set require FortisBC Energy to incur ongoing incremental operating and maintenance costs, FortisBC Energy may recover these costs from the Customer through a Monthly charge.

11.9 Meter Set Consolidations

A Customer who has more than one Meter Set at the same Premises or adjacent Premises may apply to FortisBC Energy to consolidate its Meter Sets. If FortisBC Energy approves the Customer's application, the Customer will be charged the value for all plant abandoned except for Meter Sets that are removed to facilitate Meter Set consolidations. In addition, the Customer will be charged FortisBC Energy's full costs, including overheads, for any abandonment, Meter Set removal and alteration downstream of the new Meter Set. If a new Service Line is required, FortisBC Energy will charge the Customer the applicable Application Charge. In addition, the Customer will be required to sign a release waiving FortisBC Energy's liability for any damages should the Customer decide to re-use the abandoned plant downstream of the new Meter Set.

11.10 Delivery Pressure

FortisBC Energy's normal Delivery Pressure is 1.75 kPa. FortisBC Energy may charge Customers who require Delivery Pressure at other than the normal Delivery Pressure the additional costs associated with providing other than the normal Delivery Pressure.

11.11 Customer Requested Mobile Service

The Customer will be charged the cost of providing temporary mobile Gas Service if the request for such Service is made by or necessitated by the actions of the Customer.

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12. Main Extensions

12.1 System Expansion

FortisBC Energy will make extensions of its Gas distribution system in accordance with system development requirements.

12.2 Ownership

All extensions of the Gas distribution system will be the property of FortisBC Energy.

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12.3 Economic Test

All applications to extend the Gas distribution system to one or more new Customers will be subject to an economic test approved by the British Columbia Utilities Commission. The economic test will be a discounted cash flow analysis of the projected revenue and costs associated with the Main Extension. The Main Extension will be deemed to be economic and will be constructed if the results of the economic test indicate a Profitability Index of 0.8 or greater for an individual Main Extension.

12.4 Revenue

The projected revenue to be used in the economic test will be determined by FortisBC Energy by:

(a) estimating the number of Customers to be served by the Main Extension;

(b) establishing consumption estimates for each Customer;

(c) projecting when the Customer will be connected to the Main Extension; and

(d) applying the appropriate revenue margins for each Customer's consumption.

The revenue projection will take into consideration the estimated number and type of Gas appliances used. In addition, the projected revenue from the applicable Application Charges will be included. Only those Customers expected to connect to the Main Extension within 5 Years of its completion, or within 10 Years of its completion for the Main Extension with a planning horizon longer than 5 Years as determined by FortisBC Energy will be considered.

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12.5 Costs

The total costs to be used in the economic test include, without limitation:

(a) the full labour, material, and other costs necessary to serve the new Customers including Mains, Service Lines, Meter Sets and any related facilities such as pressure reducing stations and pipelines;

(b) the appropriate allocation of FortisBC Energy's overheads based on the direct capital costs for the construction of the Main Extension;

(c) the incremental operating and maintenance expenses necessary to serve the Customers; and

(d) an allocation of system improvement costs.

In addition to the costs identified, the economic test will include applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

In cases where a larger Gas distribution Main is installed to satisfy future requirements, the difference in cost between the larger Main and the smaller Main necessary to serve the Customers supporting the application may be eliminated from the economic test.

12.6 Contributions in Aid of Construction

If the economic test results indicate a Profitability Index of less than 0.8, the Main Extension may proceed provided that the shortfall in revenue is eliminated by contributions in aid of construction by the Customers to be served by the Main Extension, their agents or other parties, or if there are non-financial factors offsetting the revenue shortfall that are deemed to be acceptable by the British Columbia Utilities Commission.

FortisBC Energy may finance the contributions in aid of construction for Customers. Contributions of less than $100 per Customer may be waived by FortisBC Energy.

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12.7 Contributions Paid by Connecting Customers

The total required contribution will be paid by the Customers connecting at the time the Main Extension is built. FortisBC Energy will collect contributions from all Customers connecting during the first five Years, or during the first 10 Years (if applicable) after the Main Extension is built. As additional contributions are received from Customers connecting to the Main Extension, partial refunds will be made to those Customers who had previously made contributions, except those Customers who have received funding under Section 12.11 (System Extension Fund Pilot). At the end of the fifth Year or tenth Year (if applicable), all Customers will have paid an equal contribution, after reconciliation and refunds.

For larger Main Extension projects, FortisBC Energy may use the Main Extension Contribution Agreement for initial contributions. Customers will be billed the contribution amount after the Main Extension is built.

12.8 Refund of Contributions

A review will be performed annually, or more often at FortisBC Energy's discretion, to determine if a refund is payable to all Customers who have contributed to the extension.

If the review of contributions indicates that refunds are due:

(a) individual refunds greater than $100 will be paid at the time of the review;

(b) individual refunds less than $100 will be held until a subsequent review increases the refund payable over $100, or until the end of the five-Year contributory period;

(c) no interest will be paid on contributions that are subsequently refunded;

(d) the total amount of refunds issued will not be greater than the original amount of the contribution; and

(e) if, after making all reasonable efforts, FortisBC Energy is unable to locate a Customer who is eligible for a refund, the Customer will be deemed to have forfeited the contribution refund and the refund will be credited to the other Customers who contributed towards the Main Extension.

For clarity, no refunds will be due to Customers who receive funding under Section 12.11 (System Extension Fund Pilot).

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12.9 **Extensions to Contributory Extensions**

When a Main Extension is attached to an existing contributory Main Extension within the five-Year contributory period for the existing extension or within the ten-Year contributory period for the existing extension (if applicable), the new extension will be evaluated using the Main Extension test to determine whether a contribution is required. A prorated portion of the total contribution for the existing contributory extension will be assigned to the new extension on the basis of expected use, point of connection, and other factors. Any contributions toward the cost of the existing extension from Customers on the new extension will be used to provide partial refunds to the contributing Customers on the existing extension, subject to Section 12.11 (System Extension Fund Pilot). The total refunds issued will not exceed the total amount of contributions paid by Customers on the existing extension.

12.10 **Security**

In those situations where the financial viability of a Main Extension is uncertain, FortisBC Energy may require a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy.

12.11 **System Extension Fund Pilot**

FortisBC Energy will budget funds annually for the period beginning January 1, 2017 and ending December 31, 2020 to its System Extension Fund Pilot, which is intended to provide limited assistance to eligible new Customers who are required to pay a contribution in aid of construction of a Main Extension.

Customers must apply to FEI for funding from the System Extension Fund Pilot.

The Customer applying for the System Extension Fund Pilot must meet the following requirements:

(a) The Customer must be located within FortisBC Energy's Mainland and Vancouver Island Service Area;

(b) The Customer's Premises must be a separately metered single-family dwelling or townhouse, that is the Customer's principal residence and is occupied for the majority of the year; and

(c) The result of the economic test for the Main Extension must indicate a Profitability Index of greater than 0.2 and less than 0.8, indicating that a contribution in aid of construction is required by the Customer.

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The number of Customers eligible to receive the System Extension Fund Pilot will be limited and the determination of eligibility will be made by FortisBC Energy in its sole discretion, acting reasonably. The maximum System Extension Fund Pilot available to a Customer is 50 percent of the required contribution in aid of construction from the Customer, up to a maximum of $10,000 per Customer.

A Main Extension may not proceed until funding has been approved and payment of the contribution is paid. Construction of the Main Extension must commence within nine calendar Months of the date FortisBC Energy approves the application for the System Extension Fund Pilot. Customers who provide a contribution in aid of construction for a Main Extension and who receive funding from the System Extension Fund Pilot will not be eligible for a refund as set forth in Section 12.8 (Refund of Contributions).

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12A. Section Reserved for Future Use

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12B. Vehicle Fueling Stations

12B.1 CNG Service and LNG Service

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FortisBC Energy will provide CNG Service and LNG Service to vehicles in accordance with the provisions of this Section 12B (Vehicle Fueling Stations).

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CNG Service or LNG Service will be provided under the terms and conditions of a Service Agreement between FortisBC Energy and the Customer. The Service Agreement must comply with the provisions of this Section12B (Vehicle Fueling Stations).

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The CNG Service and LNG Service are described below:

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CNG Service will typically consist of:

(a) installing and maintaining a CNG fueling station, including, but not limited to, the compressor, dryer /dehydrator, high pressure storage, dispensing equipment; and

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(b) dispensing of CNG.

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LNG Service will typically consist of:

(a) transport and delivery of the LNG from FortisBC Energy's LNG facilities to the Customer premises by LNG tankers, the charge for which will be determined pursuant to Rate Schedule 46;

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(b) installing and maintaining an LNG fueling station, including, but not limited to, the storage, vaporizer, pump, dispensing equipment; and

(c) dispensing of LNG.

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12B.2 Ownership

All CNG and LNG fueling stations, temporary or permanent, will remain the property of FortisBC Energy, regardless of whether they are located on the Customer's property. The ownership includes all components of the fueling station(s).

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12B.3 Cost of Service Recovery

Customers will be charged a "take-or-pay" rate (i.e. minimum contract demand) under the Service Agreement that recovers the present value of the cost of service associated with provision of CNG Service or LNG Service over the term of the Service Agreement, as calculated pursuant to Section 12B.4 (Calculation of Cost of Service), where the minimum contract demand stipulated in the Service Agreement is the forecast consumption based on the forecast number of vehicles served by the vehicle fueling station.

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12B.4 Calculation of Cost of Service

The total costs to be used in determining the cost of Service to be recovered from the Customer under the Service Agreement include, without limitation:

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(a) the actual capital investment in the fueling station including any associated labour, material, and other costs necessary to serve the Customer, less any contributions in aid of construction by the Customer or third parties, grants, tax credits or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;

(b) depreciation and net negative salvage rates and expenses related to the capital assets associated with the vehicle fueling station;

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(c) all operating and maintenance expenses, with no adjustment for capitalized overhead, necessary to serve the Customer, escalated annually by British Columbia consumer price index inflation rates as published by BC Stats Monthly; and

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(d) an allowance for overhead and marketing costs relating to developing natural gas vehicle fueling station agreements to be recovered from the Customer.

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In addition to the costs identified, the cost of Service recovery will include applicable property and incomes taxes and the appropriate return on rate base as approved by the British Columbia Utilities Commission for FortisBC Energy.

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12B.5 Customer's Obligation at the Expiration of Initial Term of the Service Agreement

If, at the expiry of the initial term of an executed Service Agreement, the Customer does not wish to renew the Service Agreement, the Customer can terminate the Service Agreement provided the Customer agrees to pay any unrecovered capital costs (including the positive or negative salvage value) associated with the fueling stations, or agrees to similar provisions that permit recovery from the Customer of the remaining un-depreciated capital costs of the fueling station. Examples of such provisions include, but are not limited to, adjusting the contract rate or adjusting the contract term.

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13. Interruption of Service

13.1 Regular Supply

FortisBC Energy will use its best efforts to provide the constant delivery of Gas and the maintenance of unvaried pressures.

13.2 Right to Restrict

FortisBC Energy may require any of its Customers, at all times or between specified Hours, to discontinue, interrupt or reduce to a specified degree or quantity, the delivery of Gas for any of the following purposes or reasons:

(a) in the event of a temporary or permanent shortage of Gas, whether actual or perceived by FortisBC Energy;

(b) in the event of a breakdown or failure of the supply of Gas to FortisBC Energy or of FortisBC Energy's Gas storage, distribution, or transmission systems;

(c) in order to comply with any legal requirements;

(d) in order to make repairs or improvements to any part of FortisBC Energy's Gas distribution, storage or transmission systems;

(e) in the event of fire, flood, explosion or other emergency in order to safeguard Persons or property against the possibility of injury or damage.

13.3 Notice

FortisBC Energy will, to the extent practicable, give notice of its requirements and removal of its requirements under Section 13.2 (Right to Restrict) to its Customers by:

(a) newspaper, radio or television announcement; or

(b) notice in writing that is:

(i) sent through the mail to the Customer's billing address;

(ii) left at the Premises where Gas is delivered;

(iii) served personally on the Customer; or

(iv) sent by facsimile or other electronic means to the Customer; or

(c) oral communication.

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13.4 Failure to Comply

If, in the opinion of FortisBC Energy, a Customer has failed to comply with any requirement under Section 13.2 (Right to Restrict), FortisBC Energy may, after providing notice to the Customer in the manner specified in Section 13.3 (Notice), discontinue Service to the Customer.

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14. Access to Premises and Equipment

14.1 Access to Premises

FortisBC Energy will have a right of entry to the Customer's Premises. The Customer must provide free access to its Premises at all reasonable times to FortisBC Energy's authorized employees, contractors and agents for the purpose of reading, testing, repairing or removing meters and ancillary equipment, turning Gas on or off, completing system leakage surveys, stopping leaks, examining pipes, connections, fittings and appliances and reviewing the use made of Gas delivered to the Customer, or for any other related purpose which FortisBC Energy requires.

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14.2 Access to Equipment

The Customer must provide clear access to FortisBC Energy's equipment. The equipment installed by FortisBC Energy on the Customer's Premises will remain the property of FortisBC Energy and may be removed by FortisBC Energy upon termination of Service.

14.3 Installation of Remote Meter

If a Customer fails to provide FortisBC Energy with access to the Customer's Premises as set out in Section 14.1 (Access to Premises) or to FortisBC Energy's equipment as set out in Section 14.2 (Access to Equipment), FortisBC Energy will be authorized to install a remote meter. The Customer will be responsible for FortisBC Energy's full costs (including overheads) associated with installing and maintaining the remote meter.

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15. Promotions and Incentives

15.1 Promotion of Gas Appliances

FortisBC Energy may promote, sell, rent, lease, or finance natural gas vehicle equipment, Gas appliances and related accessories and services on a cash or finance plan basis and make reasonable charges for these Services.

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15A. Section Reserved for Future Use

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Pursuant to section 17.1 of the Clean Energy Act and the Improvement Financing Regulation, for the period beginning November 1, 2012 and ending January 1, 2015, FortisBC Energy offers a Loan to eligible Customers located in the City of Kelowna and the Regional District of Okanagan-Similkameen, excluding the City of Penticton and the District of Summerland, for the energy efficiency improvement to an eligible Premises, or a part of an eligible Premises. ¶
<#>Eligible Customers¶
In order to be eligible for the Loan, the Customer must: ¶
<#>receive or will receive Service from FortisBC Energy;¶
<#>have paid on or before the due date, all or all but one of the FortisBC Energy bills issued during the twelve Month period preceding the date of the application for the Loan;¶
<#>as of the date for applying for the Loan, have a credit rating of at least 650 on the Equifax Beacon rating system (i.e. a credit rating of 650 or higher); and ¶
<#>be the lawful owner of an eligible Premises evidenced by a copy of the Land Title Certificate. ¶
If the copy of the Land Title Certificate is not available, the Customer must give consent to FortisBC Energy to conduct a search of the Land Title Office to verify ownership.¶
<#>Eligible Premises¶
The Loan is for improving energy efficiency to a Premises, or part of a Premises that is a residential building of three stories or less that occupies no more than 600 square meters of ground service, is habitable all Year and is:¶
<#>a detached home;¶
<#>a building that is part of a complex of side-by-side attached buildings; or¶
<#>a mobile home on a permanent foundation.¶
<#>Eligible Energy Efficiency Improvements¶
The energy efficiency improvements to a Premises or a part of a Premises eligible for the Loan must: ¶
<#>fall into one of the following cat ... [70]

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16. Billing

16.1 Basis for Billing

FortisBC Energy will bill the Customer in accordance with the Customer's Service Agreement, the Rate Schedule under which the Customer is provided Service, and the fees and charges contained in the General Terms and Conditions.

The Customer's payment due under the Financing Agreement under the On-Bill Financing Pilot Program, if any, will be billed by FortisBC Inc., will be shown on the Customer's bill for electricity services, and should be treated and paid as part of the Customer's bill for electricity services.

16.2 Meter Measurement

FortisBC Energy will measure the quantity of Gas delivered to a Customer using a Meter Set and the starting point for measuring delivered quantities during each billing period will be the finishing point of the preceding billing period.

16.3 Multiple Meters

Gas Service to each Meter Set will be billed separately for Customers who have more than one Meter Set on their Premises.

16.4 Estimates

For billing purposes, FortisBC Energy may estimate the Customer's meter readings if, for any reason, FortisBC Energy does not obtain a meter reading.

16.5 Estimated Final Reading

If a Service Agreement is terminated under Section 8.1 (Termination by Customer), FortisBC Energy may estimate the final meter reading for final billing.

16.6 Incorrect Register

If any Meter Set has failed to measure the delivered quantity of Gas correctly, FortisBC Energy may estimate the meter reading for billing purposes, subject to Section 19 (Back-Billing).

16.7 Bills Issued

FortisBC Energy may bill a Customer as often as FortisBC Energy considers necessary but generally will bill on a Monthly basis.

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16.8 **Bill Due Dates**

The Customer must pay FortisBC Energy's bill for Service on or before the due date shown on the bill which will be:

(a) the first business Day after the twenty-first calendar Day following the billing date, or

(b) such other period as may be agreed upon by the Customer and FortisBC Energy.

16.9 **Historical Billing Information**

Customers who request historical billing information may be charged the cost of processing and providing the information.

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17. Thermal Energy

17.1 All References to Gas

Will be deemed to include a reference to Thermal Energy. For example, Gas Service will be deemed to include the delivery of Thermal Energy through a Meter Set. Notwithstanding the foregoing, the meaning of Gas Distribution System will be deemed not to include a hydronic heating system that delivers energy to Residential Service Customers but will include the meters that measure the amount of energy by Residential Service Customers in a Vertical Subdivision.

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18. Section Reserved for Future Use

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19. Back-Billing

19.1 When Required

FortisBC Energy may, in the circumstances specified in this Section 19 (Back-Billing), charge, demand, collect or receive from its Customers in respect of a regulated Service rendered to its Customers a greater or lesser compensation than that specified in the Rate Schedules applicable to that Service.

In the case of a minor adjustment to a Customer's bill, such as an estimated bill or a Monthly Payment Plan bill, such adjustments do not require back-billing treatment to be applied.

19.2 Definition

Back-billing means the rebilling by FortisBC Energy for Services rendered to a Customer because the original billings are discovered to be either too high (over-billed) or too low (under-billed). The discovery may be made by either the Customer or FortisBC Energy, and may result from the conduct of an inspection under provisions of the federal statute, the *EGI Act*. The cause of the billing error may include any of the following non-exhaustive reasons or a combination of them:

(a) stopped meter;

(b) metering equipment failure;

(c) missing meter now found;

(d) switched meters;

(e) double metering;

(f) incorrect meter connections;

(g) incorrect use of any prescribed apparatus respecting the registration of a meter;

(h) incorrect meter multiplier;

(i) the application of an incorrect rate;

(j) incorrect reading of meters or data processing;

(k) tampering, fraud, theft or any other criminal act.

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19.3 Application of Act

Whenever the dispute procedure of the *EGI Act* is invoked, the provisions of that Act apply, except those which purport to determine the nature and extent of legal liability flowing from metering or billing errors.

19.4 Billing Basis

Where metering or billing errors occur and the dispute procedure under the *EGI Act* is not invoked, the consumption and demand will be based upon the records of FortisBC Energy for the Customer, or the Customer's own records to the extent they are available and accurate, or if not available, reasonable and fair estimates may be made by FortisBC Energy. Such estimates will be on a consistent basis within each Customer class or according to an agreement for Service with the Customer, if applicable.

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19.5 Tampering / Fraud

If there are reasonable grounds to believe that the Customer has tampered with or otherwise used FortisBC Energy's Service in an unauthorized way, or there is evidence of fraud, theft or other criminal acts, or if a reasonable Customer should have known of the under-billing and failed to promptly bring it to the attention of FortisBC Energy, then the extent of back-billing will be for the duration of the unauthorized use, and the provisions of Sections 19.8 (Under-billing) to 19.11 (Changes in Occupancy), below, do not apply.

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In addition, the Customer is liable for the direct (unburdened) administrative costs incurred by FortisBC Energy in the investigation of any incident of tampering, including the direct costs of repair, or replacement of equipment.

Under-billing resulting from circumstances described above will bear interest at the rate normally charged by FortisBC Energy on unpaid accounts from the date of the original under-billed invoice until the amount under-billed is paid in full.

19.6 Remedying Problem

In every case of under-billing or over-billing, the cause of the error will be remedied without delay, and the Customer will be promptly notified of the error and of the effect upon the Customer's ongoing bill.

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19.7 **Over-billing**

In every case of over-billing, FortisBC Energy will refund to the Customer all money incorrectly collected for the duration of the error; 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. Simple interest, computed at the short-term bank loan rate applicable to FortisBC Energy on a Monthly basis, will be paid to the Customer.

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19.8 **Under-billing**

Subject to Section 19.5 (Tampering / Fraud), above, in every case of under-billing, FortisBC Energy will back-bill the Customer for the shorter of

(a) the duration of the error;

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(b) six Months for Residential or Commercial Service; and

(c) one Year for all other Customers or as set out in a special or individually negotiated agreement for Service with FortisBC Energy.

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19.9 **Terms of Repayment**

Subject to Section 19.5 (Tampering / Fraud), above, in all cases of under-billing, FortisBC Energy will offer the Customer reasonable terms of repayment. If requested by the Customer, the repayment term will be equivalent in length to the back-billing period. The repayment will be interest free and in equal instalments corresponding to the normal billing cycle. However, delinquency in payment of such instalments will be subject to the usual late payment charges.

19.10 **Disputed Back-bills**

Subject to Section 19.5 (Tampering / Fraud), above, if a Customer disputes a portion of a back-billing due to under-billing based upon either consumption, demand or duration of the error, FortisBC Energy will not threaten or cause the discontinuance of Service for the Customer's failure to pay that portion of the back-billing, unless there are no reasonable grounds for the Customer to dispute that portion of the back-billing. The undisputed portion of the bill will be paid by the Customer and FortisBC Energy may threaten or cause the discontinuance of Service if such undisputed portion of the bill is not paid.

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19.11 **Changes in Occupancy**

Subject to Section 19.5 (Tampering / Fraud), above, in all instances where changes of occupancy have occurred, FortisBC Energy will make a reasonable attempt to locate the former Customer for back-billing. If, after a period of one Year, such Customer cannot be located, the applicable over or under billing will be cancelled.

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20. Monthly Payment Plan

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20.1 Definitions

In this Section 20 (Monthly Payment Plan), "Monthly Payment Plan Period" means a period of one Year commencing with a normal meter reading date at the Customer's Premises.

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20.2 Application for Plan

A Customer may apply to FortisBC Energy by mail, by telephone, by facsimile or by other electronic means to pay fixed Monthly instalments for Gas delivered to the Customer during the Monthly Payment Plan Period. Acceptance of the application will be subject to FortisBC Energy finding the Customer's credit to be satisfactory.

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20.3 Monthly Instalments

FortisBC Energy will fix Monthly instalments for a Customer so that the total sum of all the instalments to be paid during the Monthly Payment Plan Period will equal the total amount payable for the Gas which FortisBC Energy estimates the Customer will consume during the Monthly Payment Plan Period.

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20.4 Changes in Instalments

FortisBC Energy may, at any time, increase or decrease the amount of Monthly instalments payable by a Customer in light of new consumption information or changes to the Rate Schedules or the General Terms and Conditions.

20.5 End of Plan

Participation in the Monthly Payment Plan may be ended at any time:

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(a) by the Customer giving 5 Days' notice to FortisBC Energy; or

(b) by FortisBC Energy, without notice, if the Customer has not paid the Monthly instalments as required.

20.6 Payment Adjustment

At the earlier of the end of the Monthly Payment Plan Period for a Customer or the end of the Customer's participation in the Monthly Payment Plan under Section 20.5 (End of Plan), FortisBC Energy will:

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(a) compare the amount which is payable by the Customer to FortisBC Energy for Gas actually consumed on the Customer's Premises from the beginning of the Monthly Payment Plan period to the sum of the Monthly instalments billed to the Customer from the beginning of the Monthly Payment Plan Period, and

(b) pay to the Customer or credit to the Customer's account any excess amount or bill the Customer for any deficit amount payable.

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21. Late Payment Charge

21.1 Late Payment Charge

If the amount due for Service or Service Related Charges on any bill has not been received in full by FortisBC Energy or by an agent acting on behalf of FortisBC Energy on or before the due date specified on the bill, and the unpaid balance is $15 or more, FortisBC Energy may include in the next bill to the Customer the late payment charge specified in the Standard Charges Schedule.

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21.2 Monthly Payment Plan

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If the Monthly instalment, Service Related Charges and payment adjustment as defined under Section 20.6 (Payment Adjustment) due from a Customer billed under the Monthly Payment Plan set out in Section 20 (Monthly Payment Plan) have not been received by FortisBC Energy or by an agent acting on behalf of FortisBC Energy on or before the due date specified on the bill, FortisBC Energy may include in the next bill to the Customer the late payment charge in accordance with Section 21.1 (Late Payment Charge) on the amount due.

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22. Returned Payment Charge

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22.1 Returned Payment Charge

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If a cheque received by FortisBC Energy from a Customer in payment of a bill is not honoured by the Customer's financial institution for any reason other than clerical error, FortisBC Energy may include a charge specified in the Standard Charges Schedule in the next bill to the Customer for processing the returned cheque whether or not the Service has been disconnected.

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23. Discontinuance of Service and Refusal of Service

23.1 Discontinuance With Notice and Refusal Without Notice

FortisBC Energy may discontinue Service to a Customer with at least 48 Hours written notice to the Customer or Customer's Premises, or may refuse Service for any of the following reasons:

(a) the Customer has not fully paid FortisBC Energy's bill with respect to Services on or before the due date;

(b) the Customer or applicant has failed to pay any required security deposit, equivalent form of security, or post a guarantee or required increase in it by the specified date;

(c) the Customer or applicant has failed to pay FortisBC Energy's bill in respect of another Premises on or before the due date;

(d) the Customer or applicant occupies the Premises with another occupant who has failed to pay FortisBC Energy's bill, security deposit, or required increase in the security deposit in respect of another Premises which was occupied by that occupant and the Customer at the same time;

(e) the Customer or applicant is in receivership or bankruptcy, or operating under the protection of any insolvency legislation and has failed to pay any outstanding bills to FortisBC Energy;

(f) the Customer has failed to apply for Service;

(g) the Customer has failed to pay amounts due under the Financing Agreement on or before the due date; or

(h) the land or portion thereof on which FortisBC Energy's facilities are, or are proposed to be, located contains contamination which FortisBC Energy, acting reasonably, determines has adversely affected or has the potential to adversely affect FortisBC Energy's facilities, or the health or safety of its workers or which may cause FortisBC Energy to assume liability for clean-up and other costs associated with the contamination. If FortisBC Energy, acting reasonably, determines that contamination is present it is the obligation of the occupant of the land to satisfy FortisBC Energy that the contamination does not have the potential to adversely affect FortisBC Energy or its workers. For the purposes of this Section, "contamination" means the presence in the soil, sediment or groundwater of special waste or another substance in quantities or concentrations exceeding criteria, standards or conditions established by the British Columbia Ministry of Environment, Lands and Parks or as prescribed by present and future laws, rules, regulations and orders of any other legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction over the environment.

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23.2 Discontinuance or Refusal Without Notice

FortisBC Energy may discontinue without notice or refuse the supply of Gas or Service to a Customer for any of the following reasons:

(a) the Customer or applicant has failed to provide reference information and identification acceptable to FortisBC Energy, when applying for Service or at any subsequent time on request by FortisBC Energy;

(b) the Customer has defective pipe, appliances, or Gas fittings in the Premises;

(c) the Customer uses Gas in such a manner as in FortisBC Energy's opinion:

(i) may lead to a dangerous situation; or

(ii) may cause undue or abnormal fluctuations in the Gas pressure in FortisBC Energy's Gas transmission or distribution system;

(d) the Customer fails to make modifications or additions to the Customer's equipment which have been required by FortisBC Energy in order to prevent the danger or to control the undue or abnormal fluctuations described above under part (c);

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(e) the Customer modifies, tampers, other otherwise alters a Meter Set;

(f) the Customer breaches any of the terms and conditions upon which Service is provided to the Customer by FortisBC Energy;

(g) the Customer fraudulently misrepresents to FortisBC Energy its use of Gas or the volume delivered;

(h) the Customer vacates the Premises;

(i) the Customer's Service Agreement is terminated for any reason;

(j) the Customer breaches any of the terms and conditions under a Financing Agreement; or

(k) the Customer stops consuming Gas on the Premises.

23.3 Application to Former Tariffs

Section 23.1 (Discontinuance With Notice and Refusal Without Notice), parts (c), (d) and (e), apply to bills rendered under these General Terms and Conditions and under the following former tariffs:

(a) Lower Mainland - Gas Tariff;

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(b) Inland - Gas Tariff B.C.E.C. No. 2;

(c) Columbia - Gas Tariff B.C.U.C. No.1;

(d) BC Gas General Terms and Conditions;

(e) Terasen Gas Inc. General Terms and Conditions;

(f) FortisBC Energy Inc. General Terms and Conditions Originally Effective March 1, 2011 and all subsequent amendments up to and including December 31, 2014;

(g) FortisBC Energy (Vancouver Island) Inc. Gas Tariff Standard Terms and Conditions and Rates for Gas Service; and

(h) FortisBC Energy (Whistler) Inc. Tariff Stating Terms and Conditions and Rates for Gas Service.

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24. Limitations on Liability

24.1 Responsibility for Delivery of Gas

FortisBC Energy, its employees, contractors or agents are not responsible or liable for any loss, damage, costs or injury (including death) incurred by any Customer or any Person claiming by or through the Customer caused by or resulting from, directly or indirectly, any discontinuance, suspension or interruption of, or failure or defect in the supply or delivery or transportation of, or refusal to supply, deliver or transport Gas, or provide Service, unless the loss, damage, costs or injury (including death) is directly attributable to the gross negligence or wilful misconduct of FortisBC Energy, its employees, contractors or agents provided, however that FortisBC Energy, its employees, contractors and agents are not responsible or liable for any loss of profit, loss of revenues, or other economic loss even if the loss is directly attributable to the gross negligence or wilful misconduct of FortisBC Energy, its employees, contractors or agents.

24.2 Responsibility Before Delivery Point

The Customer is responsible for all expense, risk and liability with respect to:

(a) the use or presence of Gas before it passes the Delivery Point in the Customer's Premises; and

(b) FortisBC Energy-owned facilities serving the Customer's Premises;

if any loss or damage caused by or resulting from failure to meet that responsibility is caused, or contributed to, by the act or omission of the Customer or a Person for whom the Customer is responsible.

24.3 Responsibility After Delivery Point

The Customer is responsible for all expense, risk and liability with respect to the use or presence of Gas after it passes the Delivery Point.

24.4 Responsibility for Meter Set

The Customer is responsible for all expense, risk and liability with respect to all Meter Sets or related equipment at the Customer's Premises unless any loss or damage is:

(a) directly attributable to the negligence of FortisBC Energy, its employees, contractors or agents; or

(b) caused by or resulting from a defect in the equipment. The Customer must prove that negligence or defect.

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For greater certainty and without limiting the generality of the foregoing, the Customer is responsible for all expense, risk and liability arising from any measures required to be taken by FortisBC Energy in order to ensure that the Meter Sets or related equipment on the Customer's Premises are adequately protected, as well as any updates or alterations to the Service Line(s) on the Customer's Premises necessitated by changes to the grading or elevation of the Customer's Premises or obstructions placed on such Service Line(s).

24.5 **Customer Indemnification**

The Customer will indemnify and hold harmless FortisBC Energy, its employees, contractors and agents from all claims, loss, damage, costs or injury (including death) suffered by the Customer or any Person claiming by or through the Customer or any third party caused by or resulting from the use of Gas by the Customer or the presence of Gas in the Customer's Premises, or from the Customer or Customer's employees, contractors or agents damaging FortisBC Energy's facilities.

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25. Miscellaneous Provisions

25.1 Taxes

The rates and charges specified in the applicable Rate Schedules do not include any local, provincial or federal taxes, assessments or levies imposed by any competent taxing authorities which FortisBC Energy may be lawfully authorized or required to add to its normal rates and charges or to collect from or charge to the Customer.

25.2 Conflicting Terms and Conditions

Where anything in these General Terms and Conditions conflicts with special terms or conditions specified under an applicable Rate Schedule or Service Agreement, then the terms or conditions specified under the Rate Schedule or Service Agreement govern.

25.3 Authority of Agents of FortisBC Energy

No employee, contractor or agent of FortisBC Energy has authority to make any promise, agreement or representation not incorporated in these General Terms and Conditions or in a Service Agreement, and any such unauthorized promise, agreement or representation is not binding on FortisBC Energy.

25.4 Additions, Alterations and Amendments

The General Terms and Conditions, fees and charges, and Rate Schedules may, with the approval of the British Columbia Utilities Commission, be added to, cancelled, altered or amended by FortisBC Energy from time to time.

25.5 Headings

The headings of the Sections set forth in the General Terms and Conditions are for convenience of reference only and will not be considered in any interpretation of the General Terms and Conditions.

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26. Direct Purchase Agreements

26.1 Collection of Incremental Direct Purchase Costs

Where FortisBC Energy incurs any costs relating to implementing, providing or facilitating the direct purchase arrangements of a Customer, agent, broker or marketer, FortisBC Energy may, subject to British Columbia Utilities Commission approval, collect those costs from the Customer, agent, broker or marketer. Such costs may include the costs of arranging, acquiring or transporting substitute Gas supplies as well as any other costs or obligations relating to the direct purchase arrangement that are incurred by FortisBC Energy. FortisBC Energy can bill the Customer for such costs as part of the regular FortisBC Energy bill for Service.

26.2 Direct Purchase Customers Returning to FortisBC Energy System Supply

Where a Customer has acquired Gas under a direct purchase arrangement and later wishes to return to the system Gas supply of FortisBC Energy:

(a) FortisBC Energy may require that the Customer provide FortisBC Energy up to one Year's written notice before the date on which the Customer wishes to return to system Gas supply;

(b) FortisBC Energy will supply the Customer with system Gas when the Customer wishes to return to system Gas supply if FortisBC Energy is able to secure additional Gas supply and transportation to accommodate the Customer; and

(c) FortisBC Energy may, subject to British Columbia Utilities Commission approval, charge the Customer for any costs associated with the Customer returning to system Gas supply. Such costs may include, among other things, the costs of securing additional Gas supply and transportation to accommodate the Customer. FortisBC Energy may bill the Customer for such costs as part of the regular FortisBC Energy bill for Service.

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27. Commodity Unbundling Service

27.1 Unbundling Service Terms and Conditions

In the event a Customer enters into a Gas supply contract with a Marketer for Commodity Unbundling Service under Rate Schedule 1U, 2U or 3U, the following terms and conditions will apply:

(a) The Customer must sign a notice of appointment of Marketer, in a form acceptable to FortisBC Energy, as notification to FortisBC Energy that the Marketer has the authority to do what is required with respect to the Customer's enrolment in Commodity Unbundling Service, including entering into the necessary Commodity Unbundling Service agreements and related Rate Schedules. Such notice of appointment of Marketer must also authorize FortisBC Energy to share with the Marketer certain historical and ongoing consumption information and to verify the Commodity Cost Recovery Charge used to bill the Customer as directed by the Marketer;

(b) FortisBC Energy will be entitled to rely solely on communications from the Marketer with respect to the enrolment of the Customer in Commodity Unbundling Service and with respect to the termination or expiry of any contract between the Customer and Marketer;

(c) FortisBC Energy will bill the Customer a Commodity Cost Recovery Charge according to the price indicated by the Marketer. Such price will be expressed as a single fixed price per Gigajoule in Canadian dollars. Such price will not include amounts payable by the Customer to the Marketer for services other than the Gas commodity cost. The price may only be changed by Marketer no more than once per Year on the anniversary of the Customer's enrolment in Commodity Unbundling Service with such Marketer. FortisBC Energy will have no obligation to verify that the price communicated by the Marketer is the price agreed to between the Customer and the Marketer;

(d) FortisBC Energy will continue to bill the Customer as per the billing, payment, credit and collections policies set out in these General Terms and Conditions;

(e) The Customer must make payment to FortisBC Energy based on the total charges on the bill and under no circumstances will payments be prorated between the various charges on the bill. Payments made by Customers to FortisBC Energy pursuant to the bills rendered by FortisBC Energy must be made without any right of deduction or set-off and regardless of any rights or claims the Customers may have against the Marketer;

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(f) Non-payment of any amounts designated as Commodity Cost Recovery Charge charged on the bill will entitle FortisBC Energy to the same recourse as non-payment of any other FortisBC Energy Service charges and may result in termination of Service by FortisBC Energy in accordance with these General Terms and Conditions and any applicable Rate Schedules. In the event FortisBC Energy terminates the Customer's Service, the subject Customer will be removed from the Commodity Unbundling Service. Should the Customer wish to re-enrol in Commodity Unbundling Service, the Customer will be required to re-apply for Service with FortisBC Energy as per the then existing General Terms and Conditions and then be required to enrol as a new participant in order to be eligible for Commodity Unbundling Service;

(g) FortisBC Energy is not responsible for the terms of any of the Customer's contract(s) with the Marketer. Provision of Commodity Unbundling Service in no way makes FortisBC Energy liable for any obligation incurred by a Marketer vis-à-vis the Customer or third parties;

(h) In the event the British Columbia Utilities Commission issues an order to FortisBC Energy to return Customers to FortisBC Energy as supplier of last resort, the Customer will be returned with no notice to the FortisBC Energy standard system supply rate with no interruption of Service upon the then applicable terms and conditions of FortisBC Energy system supply Service. In the event there are incremental costs associated with returning the Customer to the standard system supply rate, these costs may be recovered by FortisBC Energy directly from the Customer; and

(i) The Customer's enrolment in Commodity Unbundling Service must be on a Premises specific basis.

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28. Biomethane Service

28.1 Notional Gas

Customers must recognize that the location of generation facilities will determine where Biomethane will physically be introduced to the FortisBC Energy System and that Customers receiving Biomethane Service may not receive actual Biomethane at their Premises, but may instead be contributing to the cost for FortisBC Energy to deliver an amount of Biomethane proportionate to the Customer's Gas usage into the FortisBC Energy System.

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28.2 Biomethane Physical Delivery

Customers located in the vicinity of Biomethane generation facilities may receive Biomethane as a component of Gas in such proportion as FortisBC Energy determines in its sole discretion.

28.3 Reduced Supply

Customers must recognize that the production of Biomethane is subject to biological processes and production levels may fluctuate. Customers registered for Biomethane Service for applicable Rate Schedules 1B, 2B, 3B and 5B, agree that in the event that Biomethane production does not provide sufficient gas supply, FortisBC Energy may purchase Carbon Offsets at a price not to exceed the funding received from Customers registered for Biomethane Service.

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28.4 Price Determination

Customers registered for Biomethane Service will be billed for Gas pursuant to their applicable Rate Schedule or Long Term Biomethane Contract.

(a) For those Customers who have entered into a Service Agreement with FortisBC Energy for Biomethane under Rate Schedule 1B, Rate Schedule 2B, Rate Schedule 3B, Rate Schedule 5B, or Rate Schedule 11B, the cost of Biomethane will be the sum of:

(i) the British Columbia Utilities Commission approved January 1st Commodity Cost Recovery Charge per Gigajoule;

(ii) the current British Columbia carbon tax applicable to conventional natural gas Customers;

(iii) any other taxes applicable to conventional natural gas sales; and

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(iv) a premium of $7.00 per Gigajoule.

(b) For those Customers who have entered into a Long Term Biomethane Contract, the cost of Biomethane, at the time the Long Term Biomethane Contract is entered into, will be calculated as the highest of;

(i) a $1.00 per Gigajoule discount from the price determination calculated in Section 28.4(a) above;

(ii) $10.00 per Gigajoule; or

(iii) in any period beyond year five of a Long Term Biomethane Contract, the sum of:

a. the British Columbia Utilities Commission approved January 1st Commodity Cost Recovery Charge per Gigajoule;

b. the current British Columbia carbon tax applicable to conventional natural gas Customers; and

c. any other taxes applicable to conventional natural gas sales.

28.5 **Biomethane Customers**

Customers registered for Biomethane Service will be charged a Biomethane Energy Recovery Charge based on a calculation that will deem the Customer's Gas usage to be a percentage of Biomethane and a percentage of conventional natural gas as elected by the Customer and determined by FortisBC Energy. Applicable Rate Schedules will be reviewed and updated quarterly with regard to the price of conventional natural gas and updated annually with regard to the price of Biomethane, with rate changes subject to British Columbia Utilities Commission approval.

28.6 **Enrolment**

In the event a Customer enters into a Service Agreement with FortisBC Energy for Biomethane Service under Rate Schedule 1B, Rate Schedule 2B, Rate Schedule 3B or Rate Schedule 5B, the following terms and conditions will apply:

(a) **Notice** – the Customer must provide notification to FortisBC Energy that he or she wishes to receive Biomethane Service, and FortisBC Energy will provide confirmation to the Customer once the Customer is registered for Biomethane Service.

(b) **Eligibility** – the number of Customers eligible to receive Biomethane Service will be limited and the determination of eligibility will be made by FortisBC Energy in its discretion, acting reasonably.

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(c) **Change in Rate** - Customers registered for Biomethane Service will be charged for Gas at the rates set out in Rate Schedule 1B, Rate Schedule 2B, Rate Schedule 3B or Rate Schedule 5B. FortisBC Energy will use reasonable efforts to switch Customers to Rate Schedule 1B, Rate Schedule 2B, Rate Schedule 3B or Rate Schedule 5B in a timely manner. However, Rate Schedule 1B, Rate Schedule 2B, Rate Schedule 3B or Rate Schedule 5B rates will only be commenced on the first day of a Month, therefore, Customers registered for Biomethane Service within one (1) week on the last day of a Month may not be switched to Rate Schedule 1B, Rate Schedule 2B, Rate Schedule 3B or Rate Schedule 5B until five (5) weeks after their registration date.

(d) **Availability of Biomethane Service** – Subject to availability specified in each applicable Rate Schedule, Biomethane Service is available in all FortisBC Energy Service Areas, provided adequate capacity exists on FortisBC Energy's System. Entry dates for commencing Biomethane Service will be the first day of each month. The number of Customers that may enrol in Biomethane Service under the applicable Rate Schedule for a given entry date may be limited. In the event that there is a limit to the total number of Customers that may be enrolled in Biomethane Service under the applicable Rate Schedule for a particular entry date, enrolments will be processed on a "first come, first served" basis, based on the date of application.

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(e) **Moving** – If a Customer registered for Biomethane Service moves to a new Premises where the Biomethane Service remains available under the applicable Rate Schedule, that Customer may remain registered for Biomethane Service at the new Premises.

(f) **Switching Back to FortisBC Energy Standard Rate Schedule** – Customers may at any time request to terminate Biomethane Service and be returned to an applicable FortisBC Energy Rate Schedule. On receiving notice that a Customer wishes to terminate Biomethane Service, FortisBC Energy will return that Customer to the applicable FortisBC Energy Rate Schedule in accordance with the FortisBC Energy General Terms and Conditions.

(g) **Switching to a Gas Marketer Contract** – Customers may at any time request to terminate Biomethane Service and receive their commodity from a Gas Marketer. On receiving notice that a Customer has entered into an agreement with a Gas Marketer, FortisBC Energy will process this request in accordance with Section 27 (Commodity Unbundling Service).

(h) **Program Termination** – FortisBC Energy reserves the right to remove and/or terminate Customers from Biomethane Service at any time.

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Standard Charges Schedule

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Application Charge	
Existing Installation	$15.00
New Installation	$15.00
New Installation - Manifold Meters	$15.00 per meter
New Installation - Vertical Subdivision	$15.00 per meter

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Service Line Cost Allowance	
Other than a duplex	$2,150.00
Duplex	$4,300.00

Administrative Charges

Late Payment Charge	1.5% per month (19.56% per annum) on outstanding balance
Returned Payment Charge	$8.00

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Interest on Cash Security Deposits

FortisBC Energy will pay interest on cash security deposits at FortisBC Energy's prime interest rate minus 2%. FortisBC Energy's 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.

Payment of interest will be credited to the Customer's account in January of each Year.

Metering Related Charges

Meter Testing Charges

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Meters rated at less than or equal to 14.2 m^3/Hour	$60.00
Meters rated greater than 14.2 m^3/Hour	Actual Costs of Removal and Replacement

Reactivation Charges

Performed During Regular Working Hours	$90.00 per hour
Performed After Regular Working Hours	$115.00 per hour

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Appendix 11-2

SUPPORTING CALCULATIONS FOR THE PROPOSED CHANGES TO THE STANDARD FEES AND CHARGES

Basis for Calculation of

Standard Charges Schedule

FEI Proposed Application Charge

Line	Particulars			Notes
1				
2	Total number of applications charged for new service and changes to existing accounts (moves) in 2015		108,372	
3				
4	Customer service labour costs related to processing applications for new service and changes to accounts for 2015	$	981,122	
5				
6	Approximate average customer service labour cost related to processing applications for new service and changes to accounts for 2015	$	9.05	Line 4 / Line 2
7				
8	TransUnion credit check and ID validation cost per transaction	$	1.65	
9				
10	Off-cycle move-in/move-out meter cost per transaction	$	4.50	
11				
12	Approximate Incremental Application Cost	$	15.20	Line 6 + Line 8 + Line 10
13				
14				
15	**FEI proposed Application Charge for new and existing customers**	**$**	**15.00**	

Basis for Calculation of

Standard Charges Schedule

FEI Proposed Returned Payment Charge

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

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

Appendix 11-3

PROPOSED FEI RATE SCHEDULES EFFECTIVE JUNE 1, 2018

To be filed on February 2, 2017 as part of the Supplemental Filing

Appendix 11-4

SUPPORTING CALCULATIONS FOR THE PROPOSED CHANGE TO THE ADMINISTRATION CHARGE

To be filed on February 2, 2017 as part of the Supplemental Filing

Appendix 12

FINAL COSA FINANCIAL SCHEDULES

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year **Schedule 1**
SUMMARY (000's)

Line No.	Particulars	Reference	Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22A NON-BYPASS	RATE 22 FIRM	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1													
2	**REVENUE TO COST**												
3	Revenue at 2016 Existing rates incl. known & measurable changes	Line 4 + Line 5	**$ 1,312,434**	**$ 730,278**	**$ 235,076**	**$ 694**	**$ 358**	**$ 7,160**	**$ 22,183**	**$ 2,456**	**$ 192,992**	**$ 88,732**	**$ 32,504**
4	Revenue Margin at Proposed 2016 Existing rates incl. known & measurable changes		$ 737,206	$ 442,632	$ 123,943	$ 261	$ 223	$ 6,977	$ 22,183	$ 2,415	$ 91,660	$ 36,698	$ 10,214
5	Total Cost of Gas (included imputed amounts for RS 23, 25 and 27)		$ 575,228	$ 287,646	$ 111,133	$ 433	$ 135	$ 183	$ -	$ 41	$ 101,332	$ 52,034	$ 22,290
6													
7	**COST OF SERVICE**												
8	Total Utility Cost of Service	Line 9 + Line 10	**$ 1,365,206**	**$ 792,098**	**$ 237,805**	**$ 484**	**$ 284**	**$ 6,791**	**$ 21,429**	**$ 2,556**	**$ 193,900**	**$ 86,045**	**$ 23,814**
9	Allocated Cost of Service with all proposals included		$ 789,979	$ 504,452	$ 126,672	$ 51	$ 149	$ 6,608	$ 21,429	$ 2,515	$ 92,568	$ 34,011	$ 1,524
10	Total Cost of Gas (included imputed amounts for RS 23, 25 and 27)		$ 575,228	$ 287,646	$ 111,133	$ 433	$ 135	$ 183	$ -	$ 41	$ 101,332	$ 52,034	$ 22,290
11													
12	**SURPLUS / DEFICIT**												
13	Total Surplus / (Deficit)	Line 3 - Line 8	**$ (52,772)**										
14	% Increase to Equal Allocated Costs	- Line 13 / Line 4	7.4%										
15													
16	**REVENUES (adjusted to equal COS)**												
17	Adjusted Revenue at 2016 Rates with known & measurable changes	Line 5 + Line 18	**$ 1,365,206**	**$ 762,946**	**$ 244,224**	**$ 713**	**$ 374**	**$ 7,675**	**$ 22,183**	**$ 2,634**	**$ 199,757**	**$ 91,441**	**$ 33,258**
18	Adjusted Revenue Margin at 2016 rates incl. known & measurable changes	Line 4 x (1 + Line 14)	$ 789,979	$ 475,300	$ 133,091	$ 280	$ 239	$ 7,492	$ 22,183	$ 2,593	$ 98,425	$ 39,406	$ 10,968
19													
20	REVENUES (adjusted for R/C ratio's)	Line 17	**$ 1,365,206**	**$ 762,946**	**$ 244,224**	**$ 713**	**$ 374**	**$ 7,675**	**$ 22,183**	**$ 2,634**	**$ 199,757**	**$ 91,441**	**$ 33,258**
21	COST OF SERVICE (adjusted for R/C ratio's)	Line 8	**$ 1,365,206**	**$ 792,098**	**$ 237,805**	**$ 484**	**$ 284**	**$ 6,791**	**$ 21,429**	**$ 2,556**	**$ 193,900**	**$ 86,045**	**$ 23,814**
22													
23	**REVENUE TO COST RATIO**												
24	Revenue to Cost Ratio before Rebalancing	Line 20 / Line 21	**100.0%**	**96.3%**	**102.7%**	**147.4%**	**131.7%**	**113.0%**	**103.5%**	**103.1%**	**103.0%**	**106.3%**	**139.7%**
25													
26	**REVENUE REBALANCING**												
27	Adjustment			$ 848	$ (1,174)	$ 13	$ (62)	$ -	$ (754)	$ -	$ 1,174	$ 45	$ (91)
28	Total Adjusted Revenue	Line 17 + Line 27	**$ 1,365,206**	**$ 763,794**	**$ 243,049**	**$ 727**	**$ 313**	**$ 7,675**	**$ 21,429**	**$ 2,634**	**$ 200,931**	**$ 91,486**	**$ 33,167**
29	Total Adjusted Revenue Margin	Line 18 + Line 27	$ 789,666	$ 475,836	$ 131,916	$ 294	$ 178	$ 7,492	$ 21,429	$ 2,593	$ 99,599	$ 39,452	$ 10,877
30													
31	**PROPOSED REVENUE TO COST RATIO**												
32	Margin to Cost Ratio including known and measurable changes	Line 29 / Line 9	**100.0%**	**94.4%**	**104.1%**	**578.3%**	**119.0%**	**113.4%**	**100.0%**	**103.1%**	**107.6%**	**116.0%**	**713.6%**
33	Revenue to Cost Ratio including known and measurable changes	Line 28 / Line 21	**100.0%**	**96.4%**	**102.2%**	**150.2%**	**110.0%**	**113.0%**	**100.0%**	**103.1%**	**103.6%**	**106.3%**	**139.3%**
34													
35													

36 **Note:**
37 1. Lines 3, 5, 8, 10, 17, 20 ,21, 28 include the imputed Cost of Gas for Rates 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios.
38 Please note that Rates 23, 25 and 27 do not pay for commodity and midstream charges.
39 2. Rate 4 is a seasonal service and Rates 22 and Rate7/27 are interruptible customer classes. Their rates are not set based on their allocated costs.
40 These rate classes do not drive system capacity additions and therefore, no demand-related costs are allocated to these customer classes in the COSA Study.
41 3. Revenue Margin includes UAF allocation to rate classes.

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
FUNCTIONALIZATION (000's)

Schedule 2

Line No.	Particulars	Total	Gas Supply Operations	LNG Storage Tilbury	LNG Storage Mt. Hayes	Transmission	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense	$ 243,000	$ 4,116	$ 15,930	$ 3,593	$ 39,307	$ 104,262	$ 35,029	$ 40,763
2	Property & Sundry Taxes	$ 63,840	$ -	$ 1,956	$ 371	$ 21,757	$ 39,756	$ -	$ -
3	Depreciation Expense	$ 181,504	$ -	$ 20,156	$ 6,654	$ 40,532	$ 105,416	$ -	$ 8,746
4	Amortization Expense	$ 42,339	$ (149)	$ 2,666	$ 159	$ 8,645	$ 22,225	$ 8,822	$ (29)
5	Other Operating Revenue	$ (95,622)	$ -	$ (39,745)	$ (18,039)	$ (29,860)	$ (5,664)	$ -	$ (2,314)
6	Income Tax	$ 44,864	$ (256)	$ 3,217	$ 1,933	$ 12,854	$ 25,656	$ 812	$ 648
7	Earned Return	$ 310,054	$ (1,707)	$ 32,095	$ 12,902	$ 85,787	$ 171,232	$ 5,420	$ 4,326
8	**Total Cost of Service Margin**	**$ 789,979**	**$ 2,004**	**$ 36,274**	**$ 7,573**	**$ 179,021**	**$ 462,883**	**$ 50,084**	**$ 52,140**
9									
10	Cost of Gas - Commodity & Midstream	$ 477,714	$ 477,714	$ -	$ -	$ -	$ -	$ -	$ -
11	**Total Utility Revenue Requirement**	**$ 1,267,693**	**$ 479,718**	**$ 36,274**	**$ 7,573**	**$ 179,021**	**$ 462,883**	**$ 50,084**	**$ 52,140**

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
Schedule 3
RATE BASE SUMMARY - CLASSIFICATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22A NON-BYPASS	RATE 22 FIRM	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Gas Plant in Service**												
2	Total Gas Plant in Service		**$ 6,478,628**	**$ 3,675,919**	**$ 1,037,726**	**$ 368**	**$ 746**	**$ 61,275**	**$ 200,317**	**$ 23,829**	**$ 728,301**	**$ 275,120**	**$ 7,792**
3		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Demand	$ 4,173,666	$ 1,786,629	$ 766,802	$ -	$ 405	$ 51,914	$ 186,034	$ 20,111	$ 639,649	$ 254,888	$ -
5		Customer	$ 2,304,962	$ 1,889,291	$ 270,924	$ 368	$ 340	$ 9,360	$ 14,283	$ 3,718	$ 88,652	$ 20,232	$ 7,792
6													
7	Total Accumulated Depreciation		**$ (1,812,500)**	**$ (1,073,178)**	**$ (299,599)**	**$ (108)**	**$ (227)**	**$ (19,952)**	**$ (56,810)**	**$ (7,946)**	**$ (211,357)**	**$ (79,703)**	**$ (2,363)**
8		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Demand	$ (1,125,078)	$ (514,401)	$ (219,758)	$ -	$ (116)	$ (15,043)	$ (52,621)	$ (5,829)	$ (183,098)	$ (72,954)	$ -
10		Customer	$ (687,421)	$ (558,776)	$ (79,841)	$ (108)	$ (111)	$ (4,909)	$ (4,189)	$ (2,117)	$ (28,259)	$ (6,748)	$ (2,363)
11													
12	TOTAL Net Plant		**$ 4,666,128**	**$ 2,602,741**	**$ 738,126**	**$ 260**	**$ 518**	**$ 41,323**	**$ 143,508**	**$ 15,883**	**$ 516,944**	**$ 195,418**	**$ 5,429**
13		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Demand	$ 3,048,588	$ 1,272,227	$ 547,043	$ -	$ 289	$ 36,872	$ 133,413	$ 14,282	$ 456,551	$ 181,934	$ -
15		Customer	$ 1,617,540	$ 1,330,514	$ 191,083	$ 260	$ 229	$ 4,451	$ 10,095	$ 1,601	$ 60,393	$ 13,484	$ 5,429
16													
17	**Contributions In Aid of Construction**												
18	Total Gas Plant in Service		**$ (424,193)**	**$ (261,006)**	**$ (73,056)**	**$ (28)**	**$ (51)**	**$ (4,228)**	**$ (14,347)**	**$ (1,644)**	**$ (50,357)**	**$ (18,925)**	**$ (551)**
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20		Demand	$ (255,076)	$ (122,057)	$ (52,927)	$ -	$ (28)	$ (3,522)	$ (13,267)	$ (1,364)	$ (44,267)	$ (17,643)	$ -
21		Customer	$ (169,117)	$ (138,949)	$ (20,129)	$ (28)	$ (23)	$ (706)	$ (1,080)	$ (280)	$ (6,089)	$ (1,282)	$ (551)
22													
23	Total Accumulated Depreciation		**$ 143,125**	**$ 88,445**	**$ 24,574**	**$ 10**	**$ 17**	**$ 1,377**	**$ 4,786**	**$ 536**	**$ 16,863**	**$ 6,326**	**$ 190**
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Demand	$ 84,745	$ 40,482	$ 17,627	$ -	$ 9	$ 1,134	$ 4,413	$ 439	$ 14,759	$ 5,883	$ -
26		Customer	$ 58,379	$ 47,964	$ 6,947	$ 10	$ 8	$ 244	$ 373	$ 97	$ 2,104	$ 444	$ 190
27													
28	TOTAL Net Plant		**$ (281,069)**	**$ (172,561)**	**$ (48,481)**	**$ (18)**	**$ (34)**	**$ (2,851)**	**$ (9,562)**	**$ (1,109)**	**$ (33,494)**	**$ (12,599)**	**$ (361)**
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Demand	$ (170,331)	$ (81,576)	$ (35,300)	$ -	$ (19)	$ (2,388)	$ (8,854)	$ (925)	$ (29,509)	$ (11,760)	$ -
31		Customer	$ (110,738)	$ (90,985)	$ (13,182)	$ (18)	$ (15)	$ (463)	$ (707)	$ (183)	$ (3,985)	$ (839)	$ (361)
32													

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
Schedule 3

RATE BASE SUMMARY - CLASSIFICATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22A NON-BYPASS	RATE 22 FIRM	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
33	**13 Month Adjustment**		**$ 3,685**	**$ 2,112**	**$ 673**	**$ 0**	**$ 0**	**$ 49**	**$ 128**	**$ 19**	**$ 505**	**$ 195**	**$ 3**
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35		Demand	$ 2,819	$ 1,402	$ 572	$ -	$ 0	$ 46	$ 123	$ 18	$ 471	$ 187	$ -
36		Customer	$ 866	$ 709	$ 101	$ 0	$ 0	$ 3	$ 5	$ 1	$ 34	$ 8	$ 3
37													
38	**Work in Process, no AFUDC**		**$ 35,156**	**$ 20,145**	**$ 6,421**	**$ 1**	**$ 4**	**$ 471**	**$ 1,221**	**$ 183**	**$ 4,817**	**$ 1,865**	**$ 28**
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Demand	$ 26,892	$ 13,380	$ 5,456	$ -	$ 3	$ 438	$ 1,170	$ 170	$ 4,489	$ 1,787	$ -
41		Customer	$ 8,264	$ 6,765	$ 965	$ 1	$ 1	$ 33	$ 50	$ 13	$ 328	$ 78	$ 28
42													
43	**Unamortized Deferred Charges**		**$ 24,791**	**$ 21,383**	**$ 5,683**	**$ (29)**	**$ 55**	**$ (740)**	**$ (1,236)**	**$ (239)**	**$ 9,599**	**$ (2,758)**	**$ 192**
44		Energy	$ 73,900	$ 41,431	$ 14,891	$ (28)	$ (10)	$ 236	$ 900	$ 138	$ 16,320	$ (116)	$ 138
45		Demand	$ (54,337)	$ (23,755)	$ (9,382)	$ -	$ 60	$ (963)	$ (2,112)	$ (373)	$ (7,651)	$ (3,044)	$ -
46		Customer	$ 5,228	$ 3,706	$ 174	$ (1)	$ 5	$ (13)	$ (24)	$ (4)	$ 930	$ 401	$ 55
47													
48	**Cash Working Capital**		**$ 2,129**	**$ 1,298**	**$ 419**	**$ 1**	**$ 1**	**$ 10**	**$ 26**	**$ 4**	**$ 295**	**$ 72**	**$ 4**
49		Energy	$ 1,188	$ 721	$ 268	$ 1	$ 1	$ -	$ -	$ -	$ 171	$ 24	$ 2
50		Demand	$ 568	$ 282	$ 115	$ -	$ 0	$ 9	$ 25	$ 4	$ 95	$ 38	$ -
51		Customer	$ 373	$ 295	$ 36	$ 0	$ 0	$ 1	$ 1	$ 0	$ 28	$ 10	$ 2
52													
53	**Other Working Capital**		**$ 1,567**	**$ 1,060**	**$ 250**	**$ 0**	**$ 0**	**$ 4**	**$ 41**	**$ 2**	**$ 152**	**$ 54**	**$ 3**
54		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55		Demand	$ 602	$ 267	$ 135	$ -	$ 0	$ 0	$ 35	$ 0	$ 117	$ 47	$ -
56		Customer	$ 965	$ 793	$ 115	$ 0	$ 0	$ 4	$ 6	$ 2	$ 35	$ 7	$ 3
57													
58	**LILO, Other Rate Base items**		**$ 56,701**	**$ 28,337**	**$ 11,115**	**$ (0)**	**$ 6**	**$ 1,353**	**$ 2,711**	**$ 524**	**$ 9,053**	**$ 3,604**	**$ (2)**
59		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60		Demand	$ 57,294	$ 28,824	$ 11,185	$ -	$ 6	$ 1,356	$ 2,715	$ 525	$ 9,074	$ 3,608	$ -
61		Customer	$ (593)	$ (487)	$ (71)	$ (0)	$ (0)	$ (2)	$ (4)	$ (1)	$ (21)	$ (4)	$ (2)
62													
63	**Total Utility Rate Base**		**$ 4,509,089**	**$ 2,504,514**	**$ 714,205**	**$ 216**	**$ 550**	**$ 39,620**	**$ 136,838**	**$ 15,267**	**$ 507,871**	**$ 185,851**	**$ 5,297**
64		Energy	$ 75,088	$ 42,152	$ 15,159	$ (27)	$ (10)	$ 236	$ 900	$ 138	$ 16,492	$ (92)	$ 139
65		Demand	$ 2,912,094	$ 1,211,051	$ 519,825	$ -	$ 339	$ 35,369	$ 126,516	$ 13,700	$ 433,638	$ 172,797	$ -
66		Customer	$ 1,521,907	$ 1,251,311	$ 179,221	$ 243	$ 220	$ 4,015	$ 9,423	$ 1,429	$ 57,742	$ 13,145	$ 5,158

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Schedule 4

Line No.	Particulars	Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22A NON-BYPASS	RATE 22 FIRM	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	**Operating & Maintenance Expense**	**$ 243,000**	**$ 158,944**	**$ 33,228**	**$ 15**	**$ 61**	**$ 1,556**	**$ 4,649**	**$ 613**	**$ 27,290**	**$ 10,236**	**$ 726**
2	Energy	$ 5,577	$ 3,337	$ 1,225	$ 5	$ 2	$ 5	$ 18	$ 3	$ 881	$ 91	$ 9
3	Demand	$ 99,531	$ 46,080	$ 19,301	$ -	$ 10	$ 1,330	$ 4,244	$ 515	$ 15,997	$ 6,372	$ -
4	Customer	$ 137,892	$ 109,527	$ 12,702	$ 10	$ 49	$ 222	$ 386	$ 95	$ 10,412	$ 3,772	$ 716
5												
6	**Property & Sundry Taxes**	**$ 63,840**	**$ 38,671**	**$ 11,209**	**$ 4**	**$ 7**	**$ 556**	**$ 2,172**	**$ 216**	**$ 7,906**	**$ 3,018**	**$ 81**
7	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Demand	$ 40,988	$ 19,738	$ 8,517	$ -	$ 5	$ 537	$ 2,033	$ 208	$ 7,115	$ 2,835	$ -
9	Customer	$ 22,852	$ 18,933	$ 2,691	$ 4	$ 3	$ 19	$ 139	$ 8	$ 791	$ 183	$ 81
10												
11	**Depreciation Expense**	**$ 181,504**	**$ 106,799**	**$ 27,026**	**$ 14**	**$ 25**	**$ 1,848**	**$ 4,587**	**$ 664**	**$ 18,300**	**$ 6,508**	**$ 219**
12	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Demand	$ 99,637	$ 41,088	$ 17,227	$ -	$ 9	$ 1,297	$ 4,028	$ 502	$ 14,282	$ 5,689	$ -
14	Customer	$ 81,866	$ 65,711	$ 9,799	$ 14	$ 16	$ 551	$ 559	$ 161	$ 4,017	$ 819	$ 219
15												
16	**Amortization Expense**	**$ 42,339**	**$ 23,788**	**$ 7,520**	**$ 2**	**$ 20**	**$ 454**	**$ 1,265**	**$ 182**	**$ 5,933**	**$ 1,701**	**$ 51**
17	Energy	$ 8,216	$ 4,715	$ 1,667	$ 0	$ 0	$ 27	$ 103	$ 16	$ 1,623	$ 44	$ 20
18	Demand	$ 24,958	$ 11,569	$ 4,781	$ -	$ 18	$ 390	$ 1,106	$ 151	$ 3,948	$ 1,572	$ -
19	Customer	$ 9,165	$ 7,505	$ 1,072	$ 1	$ 1	$ 37	$ 56	$ 15	$ 361	$ 85	$ 31
20												
21	**Other Operating Revenue**	**$ (95,622)**	**$ (31,871)**	**$ (9,994)**	**$ (2)**	**$ (8)**	**$ (929)**	**$ (1,776)**	**$ (359)**	**$ (7,860)**	**$ (3,051)**	**$ (28)**
22	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Demand	$ (89,819)	$ (27,243)	$ (9,410)	$ (1)	$ (6)	$ (913)	$ (1,752)	$ (353)	$ (7,474)	$ (2,921)	$ -
24	Customer	$ (5,804)	$ (4,627)	$ (584)	$ (1)	$ (2)	$ (16)	$ (23)	$ (7)	$ (386)	$ (130)	$ (28)
25												

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Schedule 4

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22A NON-BYPASS	RATE 22 FIRM	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
26	**Income Tax**		$ 44,864	$ 28,100	$ 7,898	$ 2	$ 6	$ 407	$ 1,372	$ 156	$ 5,652	$ 2,156	$ 62
27		Energy	$ (256)	$ (155)	$ (58)	$ (0)	$ (0)	$ -	$ -	$ -	$ (37)	$ (5)	$ (0)
28		Demand	$ 27,853	$ 14,121	$ 5,968	$ -	$ 3	$ 364	$ 1,271	$ 141	$ 4,958	$ 1,975	$ -
29		Customer	$ 17,267	$ 14,134	$ 1,988	$ 3	$ 3	$ 43	$ 101	$ 16	$ 731	$ 186	$ 62
30													
31	**Earned Return**		$ 310,054	$ 180,020	$ 49,785	$ 15	$ 38	$ 2,716	$ 9,159	$ 1,044	$ 35,347	$ 13,444	$ 413
32		Energy	$ (1,707)	$ (1,036)	$ (385)	$ (2)	$ (1)	$ -	$ -	$ -	$ (246)	$ (34)	$ (2)
33		Demand	$ 196,521	$ 86,721	$ 36,904	$ -	$ 19	$ 2,426	$ 8,485	$ 940	$ 30,716	$ 12,238	$ -
34		Customer	$ 115,241	$ 94,335	$ 13,266	$ 17	$ 19	$ 290	$ 675	$ 104	$ 4,878	$ 1,241	$ 416
35													
36	**Total Cost of Service Margin**		$ 789,979	$ 504,452	$ 126,672	$ 51	$ 149	$ 6,608	$ 21,429	$ 2,515	$ 92,568	$ 34,011	$ 1,524
37		Energy	$ 11,831	$ 6,861	$ 2,450	$ 3	$ 1	$ 32	$ 121	$ 19	$ 2,221	$ 96	$ 27
38		Demand	$ 399,670	$ 192,073	$ 83,287	$ (1)	$ 58	$ 5,430	$ 19,415	$ 2,104	$ 69,542	$ 27,760	$ -
39		Customer	$ 378,478	$ 305,518	$ 40,935	$ 49	$ 90	$ 1,146	$ 1,892	$ 392	$ 20,804	$ 6,155	$ 1,498
40													
41	**Cost of Gas Sold (Including Gas Lost)**		$ 475,641	$ 287,646	$ 111,133	$ 433	$ 135	$ 183	$ -	$ 41	$ 67,966	$ 7,458	$ 646
42		Energy	$ 475,641	$ 287,646	$ 111,133	$ 433	$ 135	$ 183	$ -	$ 41	$ 67,966	$ 7,458	$ 646
43		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45													
46	**Total Utility Revenue Require**		$ 1,265,620	$ 792,098	$ 237,805	$ 484	$ 284	$ 6,791	$ 21,429	$ 2,556	$ 160,534	$ 41,469	$ 2,170
47		Energy	$ 487,472	$ 294,507	$ 113,583	$ 436	$ 136	$ 215	$ 121	$ 60	$ 70,187	$ 7,554	$ 673
48		Demand	$ 399,670	$ 192,073	$ 83,287	$ (1)	$ 58	$ 5,430	$ 19,415	$ 2,104	$ 69,542	$ 27,760	$ -
49		Customer	$ 378,478	$ 305,518	$ 40,935	$ 49	$ 90	$ 1,146	$ 1,892	$ 392	$ 20,804	$ 6,155	$ 1,498

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 5

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22A NON-BYPASS	RATE 22 FIRM	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Gas Supply Operations		$ (24,823)	$ (15,066)	$ (5,597)	$ (30)	$ (11)	$ -	$ -	$ -	$ (3,582)	$ (502)	$ (36)
2		Energy	$ (24,823)	$ (15,066)	$ (5,597)	$ (30)	$ (11)	$ -	$ -	$ -	$ (3,582)	$ (502)	$ (36)
3		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5													
6	LNG Storage Tilbury		$ 466,757	$ 37,104	$ 14,423	$ -	$ 7	$ -	$ -	$ -	$ 11,707	$ 4,655	$ -
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 466,757	$ 37,104	$ 14,423	$ -	$ 7	$ -	$ -	$ -	$ 11,707	$ 4,655	$ -
9		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10													
11	LNG Storage Mt. Hayes		$ 187,625	$ 94,321	$ 36,665	$ -	$ 19	$ 4,411	$ 8,905	$ 1,709	$ 29,760	$ 11,835	$ -
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 187,625	$ 94,321	$ 36,665	$ -	$ 19	$ 4,411	$ 8,905	$ 1,709	$ 29,760	$ 11,835	$ -
14		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15													
16	Transmission		$ 1,247,585	$ 627,176	$ 243,800	$ -	$ 127	$ 29,330	$ 59,212	$ 11,366	$ 197,883	$ 78,692	$ -
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 1,247,585	$ 627,176	$ 243,800	$ -	$ 127	$ 29,330	$ 59,212	$ 11,366	$ 197,883	$ 78,692	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20													

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year

Schedule 5

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22A NON-BYPASS	RATE 22 FIRM	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
21	Distribution		**$ 2,490,203**	**$ 1,671,987**	**$ 401,121**	**$ 242**	**$ 319**	**$ 5,618**	**$ 67,803**	**$ 2,040**	**$ 247,327**	**$ 88,885**	**$ 4,860**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ 1,010,062	$ 452,450	$ 224,937	$ -	$ 122	$ 1,627	$ 58,399	$ 625	$ 194,288	$ 77,615	$ -
24		Customer	$ 1,480,141	$ 1,219,538	$ 176,185	$ 242	$ 197	$ 3,991	$ 9,404	$ 1,415	$ 53,039	$ 11,270	$ 4,860
25													
26	Marketing		**$ 78,828**	**$ 46,359**	**$ 15,233**	**$ 3**	**$ 69**	**$ 240**	**$ 902**	**$ 140**	**$ 14,985**	**$ 679**	**$ 218**
27		Energy	$ 72,770	$ 41,800	$ 14,797	$ 3	$ 1	$ 236	$ 900	$ 138	$ 14,310	$ 410	$ 175
28		Demand	$ 65	$ -	$ -	$ -	$ 65	$ -	$ -	$ -	$ -	$ -	$ -
29		Customer	$ 5,993	$ 4,559	$ 436	$ 0	$ 3	$ 3	$ 3	$ 2	$ 675	$ 269	$ 43
30													
31	Customer Accounting		**$ 62,914**	**$ 42,632**	**$ 8,561**	**$ 0**	**$ 20**	**$ 21**	**$ 16**	**$ 12**	**$ 9,791**	**$ 1,606**	**$ 255**
32		Energy	$ 27,141	$ 15,418	$ 5,960	$ -	$ -	$ -	$ -	$ -	$ 5,764	$ -	$ -
33		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Customer	$ 35,773	$ 27,214	$ 2,601	$ 0	$ 20	$ 21	$ 16	$ 12	$ 4,028	$ 1,606	$ 255
35													
36	**Total Utility Rate Base**		**$ 4,509,089**	**$ 2,504,514**	**$ 714,205**	**$ 216**	**$ 550**	**$ 39,620**	**$ 136,838**	**$ 15,267**	**$ 507,871**	**$ 185,851**	**$ 5,297**
37		Energy	$ 75,088	$ 42,152	$ 15,159	$ (27)	$ (10)	$ 236	$ 900	$ 138	$ 16,492	$ (92)	$ 139
38		Demand	$ 2,912,094	$ 1,211,051	$ 519,825	$ -	$ 339	$ 35,369	$ 126,516	$ 13,700	$ 433,638	$ 172,797	$ -
39		Customer	$ 1,521,907	$ 1,251,311	$ 179,221	$ 243	$ 220	$ 4,015	$ 9,423	$ 1,429	$ 57,742	$ 13,145	$ 5,158

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study **Schedule 6**
Rate Design Filing_Common Rates_ 2016 Test Year
COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22A NON-BYPASS	RATE 22 FIRM	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Gas Supply Operations		**$ 2,004**	**$ 1,216**	**$ 452**	**$ 2**	**$ 1**	**$ -**	**$ -**	**$ -**	**$ 289**	**$ 41**	**$ 3**
2		Energy	$ 2,004	$ 1,216	$ 452	$ 2	$ 1	$ -	$ -	$ -	$ 289	$ 41	$ 3
3		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5													
6	LNG Storage Tilbury		**$ 36,274**	**$ 19,823**	**$ 7,706**	**$ -**	**$ 4**	**$ -**	**$ -**	**$ -**	**$ 6,254**	**$ 2,487**	**$ -**
7		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Demand	$ 36,274	$ 19,823	$ 7,706	$ -	$ 4	$ -	$ -	$ -	$ 6,254	$ 2,487	$ -
9		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10													
11	LNG Storage Mt. Hayes		**$ 7,573**	**$ 3,807**	**$ 1,480**	**$ -**	**$ 1**	**$ 178**	**$ 359**	**$ 69**	**$ 1,201**	**$ 478**	**$ -**
12		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Demand	$ 7,573	$ 3,807	$ 1,480	$ -	$ 1	$ 178	$ 359	$ 69	$ 1,201	$ 478	$ -
14		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15													
16	Transmission		**$ 179,021**	**$ 87,798**	**$ 35,422**	**$ (1)**	**$ 17**	**$ 4,422**	**$ 9,145**	**$ 1,715**	**$ 28,942**	**$ 11,561**	**$ -**
17		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Demand	$ 179,021	$ 87,798	$ 35,422	$ (1)	$ 17	$ 4,422	$ 9,145	$ 1,715	$ 28,942	$ 11,561	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20													

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Schedule 6

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22A NON-BYPASS	RATE 22 FIRM	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
21	Distribution		**$ 462,883**	**$ 315,885**	**$ 72,898**	**$ 48**	**$ 60**	**$ 1,922**	**$ 11,762**	**$ 683**	**$ 43,547**	**$ 15,240**	**$ 839**
22		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		Demand	$ 176,786	$ 80,646	$ 38,679	$ -	$ 21	$ 830	$ 9,911	$ 321	$ 33,145	$ 13,233	$ -
24		Customer	$ 286,097	$ 235,239	$ 34,218	$ 48	$ 39	$ 1,092	$ 1,851	$ 362	$ 10,403	$ 2,007	$ 839
25													
26	Marketing		**$ 50,084**	**$ 36,258**	**$ 4,924**	**$ 1**	**$ 38**	**$ 55**	**$ 140**	**$ 32**	**$ 6,463**	**$ 1,862**	**$ 311**
27		Energy	$ 9,826	$ 5,644	$ 1,998	$ 0	$ 0	$ 32	$ 121	$ 19	$ 1,932	$ 55	$ 24
28		Demand	$ 16	$ -	$ -	$ -	$ 16	$ -	$ -	$ -	$ -	$ -	$ -
29		Customer	$ 40,241	$ 30,614	$ 2,926	$ 1	$ 22	$ 23	$ 18	$ 13	$ 4,531	$ 1,807	$ 287
30													
31	Customer Accounting		**$ 52,140**	**$ 39,666**	**$ 3,791**	**$ 1**	**$ 29**	**$ 30**	**$ 23**	**$ 17**	**$ 5,870**	**$ 2,341**	**$ 372**
32		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34		Customer	$ 52,140	$ 39,666	$ 3,791	$ 1	$ 29	$ 30	$ 23	$ 17	$ 5,870	$ 2,341	$ 372
35													
36	**Total Utility Cost of Service**		**$ 789,979**	**$ 504,452**	**$ 126,672**	**$ 51**	**$ 149**	**$ 6,608**	**$ 21,429**	**$ 2,515**	**$ 92,568**	**$ 34,011**	**$ 1,524**
37		Energy	$ 11,831	$ 6,861	$ 2,450	$ 3	$ 1	$ 32	$ 121	$ 19	$ 2,221	$ 96	$ 27
38		Demand	$ 399,670	$ 192,073	$ 83,287	$ (1)	$ 58	$ 5,430	$ 19,415	$ 2,104	$ 69,542	$ 27,760	$ -
39		Customer	$ 378,478	$ 305,518	$ 40,935	$ 49	$ 90	$ 1,146	$ 1,892	$ 392	$ 20,804	$ 6,155	$ 1,498

FORTISBC ENERGY INC.
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2016 Test Year
CLASSIFICATION SUMMARY (000's)

Schedule 7

Line No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22A NON-BYPASS	RATE 22 FIRM	RATE 22B NON-BYPASS	Rate 3/23	Rate 5/25	Rate 7/27
1	Billing Determinants												
2													
3	Sales Volume (TJ)		198,778	72,466	28,012	130	47	9,030	34,372	5,277	27,090	15,663	6,691
4	Midstream Sales Volume (TJ)		120,882	72,399	27,942	130	47	-	-	-	18,037	2,173	155
5	Commodity Sales Volume (TJ)		107,522	65,258	24,245	130	47	-	-	-	15,515	2,173	155
6	Average No. of Customers		979,061	886,652	84,737	18	15	9	7	5	6,709	796	113
7													
8	**Cost of Service Margin**		**$ 789,979**	**$ 504,452**	**$ 126,672**	**$ 51**	**$ 149**	**$ 6,608**	**$ 21,429**	**$ 2,515**	**$ 92,568**	**$ 34,011**	**$ 1,524**
9		Energy	$ 11,831	$ 6,861	$ 2,450	$ 3	$ 1	$ 32	$ 121	$ 19	$ 2,221	$ 96	$ 27
10	Unit Energy Charge ($/GJ)		0.060	0.095	0.087	0.022	0.022	0.004	0.004	0.004	0.082	0.006	0.004
11		Demand	$ 399,670	$ 192,073	$ 83,287	$ (1)	$ 58	$ 5,430	$ 19,415	$ 2,104	$ 69,542	$ 27,760	$ -
12	Unit Demand Charge ($/GJ)		2.011	2.651	2.973	-0.007	1.248	0.601	0.565	0.399	2.567	1.772	0.000
13		Customer	$ 378,478	$ 305,518	$ 40,935	$ 49	$ 90	$ 1,146	$ 1,892	$ 392	$ 20,804	$ 6,155	$ 1,498
14	Unit Customer Charge ($/Cust/Day)		1.058	0.943	1.323	7.427	16.407	348.587	740.142	214.626	3.101	7.733	13.254
15													
16	Unit Cost of Service Margin ($/GJ)		3.974	6.961	4.522	0.391	3.191	0.732	0.623	0.477	3.417	2.171	0.228
17													
18	**Cost of Gas - Commodity & Midstream**		**$ 475,641**	**$ 287,646**	**$ 111,133**	**$ 433**	**$ 135**	**$ 183**	**$ -**	**$ 41**	**$ 67,966**	**$ 7,458**	**$ 646**
19		Energy	$ 475,641	$ 287,646	$ 111,133	$ 433	$ 135	$ 183	$ -	$ 41	$ 67,966	$ 7,458	$ 646
20		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Unit Cost of Gas - Commodity ($/GJ)		2.393	3.969	3.967	3.333	2.885	0.020	0.000	0.008	2.509	0.476	0.097
23													
24	**Total Utility Cost of Service**		**$ 1,265,620**	**$ 792,098**	**$ 237,805**	**$ 484**	**$ 284**	**$ 6,791**	**$ 21,429**	**$ 2,556**	**$ 160,534**	**$ 41,469**	**$ 2,170**
25		Energy	$ 487,472	$ 294,507	$ 113,583	$ 436	$ 136	$ 215	$ 121	$ 60	$ 70,187	$ 7,554	$ 673
26		Demand	$ 399,670	$ 192,073	$ 83,287	$ (1)	$ 58	$ 5,430	$ 19,415	$ 2,104	$ 69,542	$ 27,760	$ -
27		Customer	$ 378,478	$ 305,518	$ 40,935	$ 49	$ 90	$ 1,146	$ 1,892	$ 392	$ 20,804	$ 6,155	$ 1,498
28	Unit Cost of Service ($/GJ)		6.367	10.931	8.489	3.724	6.075	0.752	0.623	0.484	5.926	2.648	0.324
29													
30	**Total Revenues @ Proposed Rates**		**$ 1,365,206**	**$ 763,794**	**$ 243,049**	**$ 727**	**$ 313**	**$ 7,675**	**$ 21,429**	**$ 2,634**	**$ 200,931**	**$ 91,486**	**$ 33,167**
31	Unit Rate ($/GJ)		6.868	10.540	8.677	5.593	6.683	0.850	0.623	0.499	7.417	5.841	4.957
32													
33	**Total Revenue Margin @ Proposed Rates**		**$ 789,979**	**$ 476,148**	**$ 131,916**	**$ 294**	**$ 178**	**$ 7,492**	**$ 21,429**	**$ 2,593**	**$ 99,599**	**$ 39,452**	**$ 10,877**
34	Unit Rate ($/GJ)		3.974	6.571	4.709	2.260	3.798	0.830	0.623	0.491	3.677	2.519	1.626

Appendix 13

PROPOSED FORT NELSON GAS TARIFF, EFFECTIVE JUNE 1, 2018 (BLACKLINED)

To be filed on February 2, 2017 as part of the Supplemental Filing