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June 9, 2017

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

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

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Project No. 3698899

2016 Rate Design Application (the Application)

Response to the British Columbia Utilities Commission (BCUC or the Commission) Information Request (IR) No. 1

On December 19, 2016, FEI filed the Application referenced above. In accordance with Commission Order G-30-17 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

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A. CHAPTER 2 – APPROVALS SOUGHT

1.0 Reference: APPROVALS SOUGHT

Exhibit B-1, Section 2.3, pp. 2-5 to 2-6

Implementation

On page 2-5 of Exhibit B-1, FEI states:

> 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 then provides reasons for targeting a June 1, 2018 effective date on pages 2-5 and 2-6.

1.1 Please explain if an August 1, 2018 effective date for implementation could satisfy the reasons provided for FEI's target effective date.

Response:

August 1, 2018 as an effective date for implementation of the proposed rate design changes could work and satisfy the reasons provided above. As mentioned in the Application, the implementation date is a target date and is dependent on the Commission's ability to issue a decision early in 2018. In addition to the timing of a Commission decision, the effective date to implement rate design changes may also need to consider the timing of other Commission decisions, such as quarterly gas cost filings, which may also impact customer rates. Implementation timing objectives would be to allow for clear customer communication while minimizing potential confusion from multiple changes occurring at the same time.

1.2 Please state the latest date that the Commission could issue a decision on the FEI 2016 Rate Design Application that would allow FEI to implement the proposals by June 1, 2018.

Response:

FEI requests the Commission issue a decision by March 1, 2018 at the latest to allow adequate time for FEI to implement its rate design proposals by June 1, 2018.

B. CHAPTER 4 – STAKEHOLDER ENGAGEMENT

2.0 Reference: RESIDENTIAL CUSTOMER RESEARCH SURVEY

Exhibit B-1, Section 4.6.1, pp. 4-6 to 4-7; Section 7.4.5, p. 7-16; Appendix 4-5

FEI survey methodology and scope

On pages 4-6 and 4-7 of Exhibit B-1, FEI states:

- The survey of FEI's customers outside 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;

On page 7-16 of Exhibit B-1, FEI states:

> 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 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…

2.1 Please provide a table/chart/map showing the locations of the geographically weighted final data set for the FEI survey (i.e. percent from Vancouver, Victoria, Kelowna, etc.).

Response:

Sentis contributed to the following response.

The final dataset was weighted to reflect the distribution of FEI customers by region – Lower Mainland, Interior, and Vancouver Island. The dataset is not weighted by town/city in these regions.

The table below provides the weighted distribution of the sample by region:

Region/City	Weighted Percentage (N=753)
Lower Mainland	62%
Interior	27%
Vancouver Island	11%

2.2 Please elaborate on how FEI chose its sample of FEI's customers outside Fort Nelson.

Response:

Sentis provides the following response.

Sentis used a third-party research panel provider to invite a random sample of B.C. residents to this survey. Each B.C. resident was screened for the following:

- They must be aged 18 or older;
- They and no member of their immediate family or in their household were employed in the following sectors:
    - Utility Company;
    - Natural Gas Company or Gas Marketer;
    - Electricity Company;
    - Market Research Company;
    - Newspaper, Radio, or TV Network; and
    - Utility Regulatory Body;
- They must receive a natural gas bill from FortisBC; and
- They must be the person in the household who is responsible for, or who shares responsibility for, making payment decisions for energy bills.

2.2.1 Please confirm, or otherwise explain, that the sample was a random sample.

Response:

Confirmed. It was a random sample of B.C. residents that are FEI natural gas customers.

2.3 Please confirm, or explain otherwise, that this survey was only conducted in English and could only be completed on-line (i.e. the customer did not have the option to complete a survey over the phone or by mail).

Response:

Confirmed. The survey was conducted in English only and could be completed only online. There was no option to complete the survey by phone or mail.

2.3.1 Please discuss the advantages and disadvantages of online surveys.

Response:

Sentis provides the following response.

The advantages and disadvantages of online surveys are identified below.

Advantages:

- Less intrusive for respondents;
- Can usually be completed faster by the respondent than a telephone survey or paper survey;
- Has a faster turnaround time for data collection;
- Allows for visuals to be shown or audio to be played, if needed, as part of the survey;
- Costs less than telephone, mail or in-person surveying;
- More accurate since respondents are entering their responses directly into the system; more traditional survey methods require data entry by research personnel, meaning human error can be a factor;
- Can typically receive more honest and candid responses from respondents, since they do not have to give their responses to an interviewer; and
- Easier to pre-screen respondents to ensure that only those that meet the target profile are surveyed.

Disadvantages:

- Certain populations are less likely to have internet access and to respond to online questionnaires;
- Not as suitable for very complex questions that are more qualitative in nature and may need more explanation; and
- A lack of a trained interviewer to clarify and probe can possibly lead to less complete data on open-ended questions.

2.4 Please explain why the FEI and Fort Nelson surveys were conducted in the summer months rather than in the winter months when customers have a greater interest in their bills.

Response:

The timing of the survey was dictated by when FEI was preparing its Application. FEI was required to file the Application before the end of 2016. FEI was not in a position to conduct the survey in the winter of 2015/16.

A number of the survey questions are related to customers' knowledge and understanding of the current rate structure and bill components of their natural gas bill. These areas would not be affected by seasonality.

The remaining questions on principles important to customers when designing a rate structure, and which rate structure is preferred, could potentially be affected by seasonality. However, if that is the case, then no one season would be an ideal time to conduct the study. One could argue that a more measured response can be collected from customers during summer months, since they are not dealing with above-average natural gas bills which could inflate or exaggerate the influences that they consider important when it comes to rate design.

2.5 Please explain if FEI considers the FEI customer survey to be representative of the customers across FEI's system.

Response:

Yes. FEI considers the survey to be representative of the customers across FEI's system, subject to the limitations of all quantitative research. All research is subject to margins of error.

For this study, at the 95 percent level of confidence, the main sample of 753 has a margin of error of +/-4 percent and the Fort Nelson sample of 65 has a margin of error or +/-12 percent.

2.6 With regard to specific proposals in the Application, when does FEI take into consideration the FEI customer research survey results?

Response:

FEI considered the results of the residential customer research survey, along with other rate design considerations, in conducting a full review of FEI's rate design for residential customers.

The survey results are supportive of FEI's proposal to maintain the current flat rate structure.

FEI's proposal to limit the Basic Charge increase to 5 percent is also informed by the survey results. Respondents gave similar ratings to rate stability, fairness, efficiency and government policy, indicating that they prefer a balanced approach, and that the improvements from rate design in aligning with the cost causation principle should consider bill impacts as well as government energy policies.

2.6.1 Please explain how much weight is given to the customer research survey results when determining rate design proposals.

Response:

FEI does not apply any particular weighting to customer research survey results or any other individual rate design consideration. As explained in Section 1.2 of the Application, 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. The residential customer research survey results indicate that residential customers prefer rate design proposals that are easy to understand (ease of understanding principle) and that strike a balance among other competing rate design principles. This is what FEI's rate design proposals strive to achieve.

C. CHAPTER 5 – RATE DESIGN PRINCIPLES

3.0 Reference: RATE DESIGN PRINCIPLES

Exhibit B-1, Section 7.8.1, p. 7-22;

BC Hydro 2007 Rate Design Application Phase I Order G-130-07 and Decision dated October 26, 2007, p. 69

Rate impact considerations

On page 7-22 of Exhibit B-1, FEI states: "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 Commission, on page 69 of its October 2007 Decision on BC Hydro's 2007 Rate Design Application Phase 1, stated:

> With regard to acceptable level of bill impact, BC Hydro has endeavored to limit the combined annual impact of rebalancing and restructuring on any individual customer bill to no more than ten percent, exclusive of any changes arising from general increases. This is not a rule that is intended to be binding in every circumstance. For instance, BC Hydro believed that it is acceptable for bill impacts to exceed 10 percent per annum where the absolute dollar value of the increase is very small.

3.1 Please explain the guidelines which FEI uses to consider bill impact to customers and rate shock.

<u>Response:</u>

FEI agrees with the guidelines regarding rate design-related rate impacts expressed in the quote in the preamble from the Commission Decision on BC Hydro's 2007 Rate Design Application Phase 1.

FEI finds the definition of rate shock used by the South Dakota Supreme Court to be useful:[1]

> "Rate Shock" is a term used to describe "the effect on utility customers when a utility implements a significantly increased rate immediately or in a relatively short time span."

What constitutes rate shock must be assessed in the circumstances of each case. In its Decision on BC Hydro's 1992 Rate Design Application, the Commission stated the following with respect to what constitutes rate shock:

[1] US West Communications, Inc. v. AT&T Communications of the Midwest, Inc., Sprint Communications, Company, L.P., MCI Telecommunications Corporation, Telecommunications Action Group and Dakota Telecommunications Group [2000 SD 140].

> As indicated by the evidence, whether a particular increase constitutes rate shock depends on the overall rate environment and the circumstances of the particular customer (T. 175-178). It is the Commission's responsibility to assess these circumstances and determine when rate shock may be properly said to have occurred.

In its Decision on BC Hydro's Residential Inclining Block Application (Order No. G-124-08), p. 105, the Commission similarly stated that it should not adopt a "one size fits all" approach to rate shock, but "should evaluate each application on its own merits".

3.1.1 Does FEI consider that, in setting a maximum bill impact guideline, the focus of the percentage change should be based on the total customer bill, each component (commodity rate, delivery rate, fixed basic charge), or a combination of charges? Please explain.

Response:

FEI believes the appropriate point of reference for the rate design bill impact guideline is the total customer bill. The percentage changes in individual line items on the bill are of limited value since they do not express the full bill impact experienced by customers from the change. Further, some rate design changes are done in combinations, such as a shifting of cost recovery between the fixed and volumetric charges. In those situations, the impact of changes in individual line items are offset or partly offset by rate design changes affecting other line items.

FEI may analyze the bill impact for individual rate design proposals, but as a guideline in setting the maximum bill impact, FEI has considered the combined annual impact of rebalancing as well as the individual rate design proposals.

4.0 Reference: RATE DESIGN PRINCIPLES

Exhibit B-1, Section 5.3, p. 5-2;

BC Hydro Residential Inclining Block (RIB) Rate Re-Pricing Application, Order G-45-11 with Reasons for Decision dated March 14, 2011, Appendix A, p. 5;

Application for Approval of Rates between BC Hydro and FortisBC Inc. with regards to Rate Schedule 3808, Tariff Supplement No. 3 – Power Purchase and Associated Agreements, and Tariff Supplement No. 2 to Rate Schedule 3817 (BC Hydro RS 3808), Order G-60-14 and Decision dated May 6, 2014, pp. 32, 35;

FortisBC Inc. 2009 Rate Design and Cost of Service Analysis, Order G-156-10 and Decision dated October 19, 2010, p. 7;

BC Gas 1996 Rate Design Application, Volume 1, Exhibit 2A, Tab 3, p. 6;

FBC Application for Stepped and Stand-By Rates for Transmission Voltage Customers, Order G-67-14 and Decision dated May 26, 2014, pp. 15, 17–18

Evaluation framework

FEI describes its rate design principles on page 5-2 of Exhibit B-1.

> On page 5 of the BC Hydro RIB Rate Re-Pricing Application Reasons for Decision (Order G-45-11), the Commission lists eight Bonbright Principles. These principles were also included on page 32 of the Commission's 2014 Decision on BC Hydro RS 3808 and on page 7 of the Commission's decision on the FortisBC Inc. (FBC) 2009 Rate Design and Cost of Service Application, among others. Principle 3 speaks to efficiency and includes in brackets "consideration of social issues including environmental and energy policy."

BC Gas stated in Exhibit 2A, tab 3, page 6 of the 1996 Rate Design Application (RDA):

> The purpose of the rate design review is to help determine if cost burdens are properly borne by each class, if rates reflect the proper economic signals, if rates will provide stability both for the customer and for the utility, if the rates promote simplicity and administrative ease and allow for the recovery of the revenue requirement.

The Commission stated on pages 15, 17 and 18 of the 2014 FBC Industrial stepped and standby rate decision (Order G-67-14):

> … the Panel notes that any change in rate design naturally results in some initial increase in rate instability. As such, the Panel does not see the need to change an existing rate designs unless there is a clear need to do so. …

> The Panel considers that before making any changes to previously approved rate design, the Panel should be satisfied that greater efficiencies or cost savings would accrue to the benefit of ratepayers overall, or that the existing rate is now outside of fairness norms from a cost causation perspective. The Panel should also be satisfied before making any changes to previously approved rate design that the magnitude of the changes to the affected parties are acceptable and that benefits in the broad public interest would result.

The Commission stated on page 35 of the RS 3808 Decision (Order G-60-14):

> … the Commission Panel also acknowledges that existing rates are, by necessary implication, not unjust, unreasonable, unduly discriminatory or unduly preferential if they have already been approved by the Commission.
>
> Because the 1993 PPA was approved by the Commission as fair, the Commission Panel will only evaluate fairness where there is clear evidence that changes in circumstances require the previous fairness determination to be revisited.

4.1 Is FEI supportive of using the G-45-11 definition of the efficiency principle (including the brackets) for rate evaluation purposes? If no, please explain why not.

Response:

FEI is generally supportive of using the G-45-11 definition of the efficiency principle; however, FEI notes that for a natural gas distributor such as FEI, environmental and energy policies are not necessarily aligned with efficient use of the distributor's system and therefore should be considered separately as is done by FEI.

For electric utilities with generation assets, the marginal cost of new generation and other marginal costs of providing service are usually higher than the embedded costs, meaning that it is more economically efficient to conserve energy than to build new generation capacity to serve the new load. For FEI however, the marginal delivery cost of an additional unit of consumption is less than the average cost and, therefore, an increase in consumption does not reduce FEI's economic efficiency. For more information regarding FEI's marginal delivery cost, please refer to EES Consulting study provided in Appendix 4-4 of the Application.

4.2 Does FEI agree with the purpose of the rate design review as articulated by BC Gas in the 1996 RDA extract above? If no, please explain why not.

Response:

Yes. More specifically, the main objective of rate design is to strike a balance among all of the above mentioned considerations. The quote from the 1996 RDA is, in effect, a summary that directly or indirectly encompasses the eight Bonbright principles that have been articulated in this Application (Page 5-2) and, as noted in the preamble, other rate design applications before the Commission.

4.3 Does FEI agree with the conditions to be satisfied before making any changes to previously approved rate design as articulated in the G-67-14 and G-60-14 extracts above? If no, please explain why not.

Response:

Yes. FEI generally agrees that the conditions articulated in the extracts from Orders G-67-14 and G-60-14 should be considered before making rate design changes. FEI observes, however, that both of the decisions cited deal with much narrower rate design issues, such as one rate class or one contract. In this Application, FEI is addressing a wide scope of rate design issues, including minor ones, such as housekeeping changes to its General Terms & Conditions. Deciding whether the conditions cited in the two quotes are met involves a considerable amount of judgment, and should take into account the magnitude of the change and the applicable rate design considerations in each case.

D. CHAPTER 5 – GOVERNMENT POLICY

5.0 Reference: GOVERNMENT POLICY

Exhibit B-1, Section 5.4, p. 5-3, Section 7.5.1, p. 7-17, Section 8.3.5, p. 8-14

Government policy environment

FEI states on page 5-3 of Exhibit B-1:

> 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.

FEI states on page 7-17 of Exhibit B-1:

> 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.

On page 8-14 of Exhibit B-1, FEI states that one factor which mitigates "making significant changes to the Basic Charge" is "Government energy efficiency and conservation policies discourages higher fixed charges."

5.1 Does FEI consider that the government's focus on energy conservation has increased, decreased or stayed the same since the (i) 2001 and (ii) 2010-2011 rate design proceedings? Please explain.

<u>Response:</u>

FEI assumes that the question refers to the 2001 rate design and 2010-2011 revenue requirement proceedings.

The provincial government's focus on energy conservation and curbing GHG emissions has been trending upward both between 2001 and 2009 and between 2010-2011 to today. The difference is that while the majority of policies developed between 2001 and 2009 affecting natural gas utilities were focused on decreasing energy use in water heating and space heating applications through demand-side management, tax measures and improving energy efficiency in buildings, the policies developed since 2010 have expanded the focus to cover the transportation sector as well as other industrial and commercial sectors. This is explained further below.

<u>The evolution of government policies between 2001 and 2009:</u>

As explained in Section 5.4.1 of the Application, the main development in energy and climate change policy in this period relates to the 2007 BC Energy Plan. This was followed by government announcement in February 2008 to introduce the BC Carbon Tax. To implement the policy 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 cumulative and individual impacts of these pieces of legislation on the cost of natural gas for FEI's customers have been significant. In addition, these Acts, along with other exogenous factors such as the increasing share of multi-family dwellings in new housing starts, have led to a decline in market share of natural gas in space and water heating applications and declining use per customer in the residential sector.

<u>The evolution of government policies from 2010 to the Present:</u>

Since 2010, government energy and climate change related policies have evolved in two ways:

- Changes in existing regulations through amendments: For example, and as explained in Section 5.4.1 of the Application, the *Utilities Commission Amendment Act, 2008* introduced amendments to the *Utilities Commission Act* (UCA) that provided authority for the *Demand-Side Measures Regulation* (enacted in November 2008). In July 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.
- Introduction of new regulations or policies: This includes the *2010 Clean Energy Act* (CEA) and the subsequent enactment of *Greenhouse Gas Reduction (Clean Energy) Regulation* (GGRR) in 2012. 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. The GGRR has been amended several times since its initial inception to expand the eligibility criteria and/or increase related programs' expenditure caps. More recently, in August 2016, the GGRR was 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. (For more information regarding the CEA and GGRR please refer to the Section 5.4.2 of the Application).

Another example of developments since the 2010-2011 revenue requirement proceeding relates to the BC Climate Leadership Plan published in August of 2016 as well as recent tax measures announced in government's 2017 budget to gradually phase out the PST on electrical power for commercial and industrial sectors which will decrease the price competitiveness of natural gas in these sectors. The BC Climate Leadership Plan in particular noted the role of electrification in achieving BC's climate change policy goals, and included initiatives in several areas such as transportation and upstream natural gas production and processing that are expected to result in low-carbon electrification.

In March 2017, subsequent to the filing of the Rate Design Application, the BC government made further amendments to the GGRR by Orders-in-Council Nos. 101/2017 and 161/2017. OIC 161/2017 increases the amount that public utilities may spend in providing incentives and building infrastructure pertaining to NGT initiatives, with a particular focus on the marine sector. OIC 101/2017 adds a new section to the GGRR allowing public utilities to pursue low carbon electrification initiatives for the purpose of reducing greenhouse gas emissions by replacing higher emitting energy sources with electricity. OIC 101/2017 present risks for FEI since there is the potential for natural gas to be the fuel displaced by some of the low carbon electrification initiatives.

5.2 Does FEI consider that government's current energy conservation policies suggest that the Basic Charge should remain fixed, with no annual changes and only be updated periodically? Please explain your response.

Response:

The government's energy and climate policies provide high-level guidance and do not prescribe whether the Basic Charge should increase or not. Nevertheless, keeping the Basic Charge fixed with periodic updates in the context of rate design proceedings, and flowing general rate increases to the Delivery Charge is more aligned with government policies than flowing general rate increases to both the Basic Charge and Delivery Charge. The former approach increases the volumetric price signals and provides customers who want to invest in demand-side measures with more certainty that the potential savings will pay for the investment they have made.

5.3 Please explain what FEI considers to be a "significant change" to the Basic Charge?

Response:

Significant is a situation-specific concept, such that it cannot be quantified with a defined threshold or a formula. Significant can mean different things to different customer groups or to individual customers in the same customer group. FEI uses tools such as bill impact analysis and experience-based judgment, along with other rate design considerations (i.e., to establish an economic crossover point between two rate schedules), to decide how much the Basic Charge for a specific customer class should change (if any). For instance, in the case of the residential rate class, recovery of 100 percent of fixed delivery costs with fixed charges would be significant enough to discourage some customers from engaging in energy efficiency measures and, therefore, as explained in Section 7.5.2 of the Application, a complete alignment between fixed costs and fixed charges is not desirable from an energy conservation perspective.

5.3.1 Does FEI consider a "significant change" to the Basic Charge to be different for different customer groups?

Response:

Yes. Please refer to the response to BCUC-FEI IR 1.5.3.

6.0 Reference: GOVERNMENT POLICY

Exhibit B-1, Section 7.5.2, pp. 7-18 to 7-19;

BC Hydro RS 3808, Order G-60-14 and Decision dated May 6, 2014, p. 55;

FBC Application for Stepped and Stand-By Rates for Transmission Voltage Customers, Order G-67-14 and Decision dated May 26, 2014, p. 13

Conservation

FEI states on pages 7-18 and 7-19 of Exhibit B-1:

> 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. For the specific case of natural gas utilities, excessively high fixed charges, and correspondingly lower volumetric charges, may 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.

The Commission stated on page 55 of the BC Hydro RS 3808 Decision (Order G-60-14):

> Efficiency benefits can be described as promotion of: (i) efficient customer consumption and investment decisions, (ii) efficient utility investment and operational decisions and (iii) innovation. The Panel also considers any effect on British Columbia social issues, including environmental and energy policy.

The Commission stated on page 13 of the 2014 FBC Industrial stepped and standby rate decision (Order G-67-13):

> Therefore, the Panel agrees with BCPSO that the key question in determining if a need for the Stepped Rate exists is whether the Stepped Rate promotes efficient customer behaviour rather than merely results in less electricity consumption.

6.1 Does FEI consider that rate design evaluation requires consideration of whether the proposal promotes efficient customer behaviour, rather than merely whether it results in less gas consumption or whether the rate signals long-run marginal costs at the margin? Please explain.

Response:

Promoting efficient use of the products and services provided by the utility is one of the goals of rate design. This is articulated in rate design Principle 3 on page 5-2 of the Application (price signals that encourage efficient use and discourage inefficient use).

The preamble to this question refers to government policy considerations in FEI's rate design and, in particular, in relation to FEI's Basic Charge. Government energy and climate policies are predominately concerned with curbing GHG emissions. For the building sector, this mainly translates to "less natural gas consumption" in space and water heating (other than renewable natural gas consumption which is encouraged) through energy efficiency and conservation measures. Government policy does not concern itself with FEI's load factor (for a natural gas distributor, load factor is a measure of efficiency) or FEI's marginal delivery cost. Government policy considerations are only one item among others, and FEI strives to strike a balance among competing rate design considerations.

For instance, in Table 7-2 of the Application FEI evaluated different rate structure options based on major rate design principles including economic efficiency. This evaluation indicates that some rate structure options such as seasonal rates may provide better price signals from an economic efficiency perspective but considering all rate design principles, including customer bill impact, ease of understanding and administration, customer acceptance and government policy, the flat rate structure provides a better balance and is the preferred option.

Regarding marginal cost based rate signals, FEI asked its consultant, EES Consulting, to conduct a study of FEI's marginal delivery cost. The results of this study are provided in Appendix 4-4 to the Application and indicate that FEI's marginal delivery cost is lower than its historical embedded costs. This suggests that rate structures such as inclining block rates which charge more dollars per unit of consumption after a certain consumption threshold is passed are not appropriate for FEI as they send the wrong price signals.

6.2 Does FEI consider that its rate design evaluation requires consideration of how any change would affect customer decisions to: connect/disconnect to the gas line; make an investment in gas consuming equipment; decide how much gas to consume and when to consume it? Please explain.

Response:

FEI's connection and disconnection policies are discussed in Section 12 of its General Terms and Conditions (GT&C). FEI's new customer connection policy was recently reviewed by the Commission in FEI's 2015 System Extension application and decision (Order G-147-16, dated September 16, 2016) and therefore was excluded from the scope of this proceeding. The main extension test considers various factors, such as expected gas consumption over time as well as type and number of gas consuming appliances expected to be installed, to determine whether or not an extension can proceed without a contribution in aid of construction from customers wishing to connect to FEI's distribution system. A similar test exists for the service line cost allowance. Proposals to increase the share of fixed costs recovered by the Basic Charge can improve the results of extension test as it will slightly improve the reliability of the revenue stream forecast in the discounted cash flow models.

FEI's rate design evaluations did consider the impact of its proposals on customer behavior. For instance, FEI's proposal to limit the revenue-neutral increase to the Basic Charge for RS 1 to five percent was informed by the potential impact of much higher fixed charges on low-use customers, as well as its effect on customers' decisions in terms of investing in energy efficiency measures. Regarding the timing of consumption, FEI did consider seasonal rates for residential customers along with other potential rate structures, but decided that the existing flat rate structure provides the most balanced outcome. The timing of consumption was also considered for the rate design of some commercial and industrial rate classes. For instance, for RS 5/25, the mechanism to set contract demand for the upcoming year favors customers whose peak consumption occurs in the non-peak months (April 1st to October 31st) by halving the demand charge they would otherwise pay if their peak was in the winter months. Another example is RS 4, which is a seasonal service (firm in the summer and interruptible in the winter).

6.2.1 Does FEI consider that these considerations should not be affected by whether FEI does or does not supply the commodity? Please explain.

Response:

FEI agrees generally that the considerations identified in response to BCUC-FEI IR 1.6.2 should not be affected by whether FEI does or does not supply the commodity.

E. CHAPTER 6 – FEI COST OF SERVICE STUDY

7.0 Reference: FEI COST OF SERVICE STUDY

Exhibit B-1, Section 6.2.1.2, p. 6-4;; Section 6.3.5.4, pp. 6-18 to 6-19; Appendix 6-5, pp. 1-2; Appendix 6-6, p. 3;

New Brunswick Energy and Utilities Board (NBEUB) Decision in the matter of a Review of a Cost of Service Study filed by Enbridge Gas New Brunswick LP, December 21, 2010 (2010 Enbridge COSA Decision), p. 7

http://142.166.3.251/Documents/Decisions/NG/E/2010%2012%2021%20EGNB%20Cost%20of%20Service%20Decision%20-%20E.pdf

Minimum System Study and sizing of distribution pipe standards

On page 6-4 of Exhibit B-1, FEI states:

> The result of the MSS [Minimum System Study] determines the proportion of distribution mains costs that are customer related versus costs that are demand related.

On page 6-19 of Exhibit B-1, FEI states:

> The MSS results allocate 30% of the distribution system costs to the customer-related component and 70% to the demand-related component.

On page 1 of Exhibit B-1, Appendix 6-5, FEI states:

> To estimate the value of mains required from a customer connection vs. the demand component FEI follows the steps outlined below:
>
> … 4. Value FEI's mains at the minimum standard size and material (60mm PE)…

On page 3 of Exhibit B-1, Appendix 6-6, FEI states:

> 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. [Emphasis added]

On page 7 of the 2010 Enbridge COSA Decision, the NBEUB states:

> A specific issue in this cost of service analysis is whether to use 2-inch mains or 1¼-inch mains in the calculation of the minimum system. Dr. Overcast proposes to use 2-inch mains in the calculation. His position, based on discussions with

> EGNB engineers, is that this is the minimum sized main currently being installed. He does acknowledge that 1¼-inch pipe continues to be used to service certain areas like cul-de-sacs but he does not truly consider these to be mains.
>
> …For the purposes of the minimum system study, the Board orders that EGNB use a 1¼-inch main as the minimum.

7.1 Please provide document "IB 2008-43 Elimination of 88 mm PE pipe and restricted use of 42 mm PE Pipe".

Response:

Please refer to Attachment 7.1 for the requested document.

7.2 Please provide schedules of the mains installed in each of 2015 and 2016 in the same format as Table 1 in Exhibit B-1, Appendix 6-5, page 2. Please also provide the percentage of mains that are equal to or less than 60mm for each year.

Response:

The following two tables show the Distribution Mains addition by pipe size for 2015 and 2016. The percentage of mains length for 60mm pipe and smaller is shown, as well as the percentage of mains length for the sizes of pipe that are smaller than 60mm (i.e., excluding 60mm pipe).

In 2015, approximately 4.5 percent of the mains installed were 42mm or smaller. The dominant pipe size installed was the 60mm pipe at 108.75 kilometers or 66.1 percent (108.75 / 164.51) of the total.

In 2016, approximately 5.3 percent of the mains installed were 42mm or smaller, and since there were no mains at 48mm, the same 5.3 percent of mains installed were smaller than 60mm. The dominant pipe size installed in 2016 was 60mm pipe, at 65.57 kilometers, or 68.6 percent (65.57 / 95.63) of the total.

1

2015 Combined PE and Steel Mains					
Line No.	Diameter Inches	mm	Length (m.)	Cumulative Length (m.)	% of Length 60mm or less
1	0.6	15	763	763	
2	0.8	21	6	769	
3	1	26	5,825	6,593	
4	1.25	33	-	6,593	
5	1.7	42	766	7,360	4.5%
6	1.9	48	-	7,360	
7	2.4	60	108,753	116,113	70.6%
8	2.9	73	-	116,113	
9	3.5	88	159	116,272	
10	4	101	-	116,272	
11	4.5	114	26,276	142,547	
12	6.6	168	17,519	160,066	
13	8.6	219	3,722	163,788	
14	10.7	273	10	163,798	
15	12.7	323	708	164,506	
16	16	406	-	164,506	
17	18	457	-	164,506	
18	20	508	-	164,506	
19	24	609	-	164,506	
20	30	762	-	164,506	
21	36	914	-	164,506	
22	42	1066	-	164,506	
23	Total		164,506		

2016 Combined PE and Steel Mains					
	Diameter			Cumulative	% of Length 60mm or
Line No.	Inches	mm	Length (m.)	Length (m.)	less
1	0.6	15	144	144	
2	0.8	21	-	144	
3	1	26	4,365	4,509	
4	1.25	33	-	4,509	
5	1.7	42	561	5,070	
6	1.9	48	-	5,070	5.3%
7	2.4	60	65,570	70,640	73.9%
8	2.9	73	-	70,640	
9	3.5	88	93	70,733	
10	4	101	-	70,733	
11	4.5	114	15,001	85,735	
12	6.6	168	8,196	93,930	
13	8.6	219	1,702	95,632	
14	10.7	273	-	95,632	
15	12.7	323	-	95,632	
16	16	406	-	95,632	
17	18	457	-	95,632	
18	20	508	-	95,632	
19	24	609	-	95,632	
20	30	762	-	95,632	
21	36	914	-	95,632	
22	42	1066	-	95,632	
23	Total		95,632		

7.2.1 If FEI installed 42 mm mains in 2015 or 2016, please explain why 42 mm is not the minimum main size used in the Minimum System Study. In your response, please take into consideration the determination on page 7 of the 2010 Enbridge COSA Decision.

Response:

Since 2003, FEI's standard has been to connect customers to a new main that is at least a 60mm size and it is by exception only that a smaller main would be used. The use of 42mm pipe is infrequent and is only used for repairs to existing 42mm pipe, or for single services with no branches. Approximately 766 meters of 42mm pipe were installed in 2015 and 561 meters in 2016. In contrast, approximately 108,753 meters of 60mm pipe was installed in 2015 and 65,570 meters in 2016. FEI uses the 60mm size pipe almost exclusively as the minimum sized pipe for new mains installation (refer to the response to BCUC-FEI IR 1.7.2).

It is difficult to draw any implications for FEI's Minimum System Study from the 2010 Enbridge COSA Decision quoted in the preamble:

- As discussed in the quoted decision, Enbridge in that case had not completed a Minimum System Study, and the New Brunswick Energy Utilities Board had to make its determination "[i]n the absence of any detailed study of EGNB's own system".[2]
- The New Brunswick Energy Utilities Board provides no rationale in its decision for why it concludes that a system with 1¼-inch mains better calculates the appropriate minimum system for Enbridge's minimum system study, other than noting the use of 1¼-inch pipe on Enbridge's system. In the absence of any clear rationale for the Board's determination, it is difficult to determine if the decision is applicable to FEI's Minimum System Study.
- It is unclear what the rate impacts of using 1¼-inch mains for the minimum system were for Enbridge's customers, or how this interacted with any other rate design issues or considerations in that case.

For FEI's Minimum System Study, the use of 60 mm polyethylene pipe is appropriate as it has been FEI's minimum standard size and material since 2003, and is used more widely in the system than 42 mm pipe.

7.3 Please reproduce the following tables, to the best of your ability, to show the impact of using a minimum main size of 42mm in the Minimum System Study:

i. Table 1: Minimum System Results for All Mains (Exhibit B-1, Appendix 6-5, p. 2)

ii. Table 6-16: Delivery Cost of Service Allocation to Rate Schedules (Exhibit B-1, p. 6-27)

iii. Table 12-2: COSA R:C and M:C Results after Rate Design Proposals (Exhibit B-1, p. 12-5)

iv. Table 12-4: FEI Rate Proposal Summary (Exhibit B-1, p. 12-8)

[2] 2010 Enbridge COSA Decision, page 7. Online: http://142.166.3.251/Documents/Decisions/NG/E/2010%2012%2021%20EGNB%20Cost%20of%20Service%20Decision%20-%20E.pdf.

Response:

FEI considers that the Minimum System Study using 60 mm pipe is the correct approach as it is FEI's minimum standard in most cases when installing mains for the distribution system. As identified in response to BCUC-FEI IR 1.7.2, the number of 42 mm mains installed in 2015 and 2016 was small compared to FEI's standard of 60 mm.

Nevertheless, FEI has updated the Minimum System Study to use 42mm as the minimum as requested. FEI calculated the average replacement cost based on the 42 mm minimum system at $89.53 per meter. This amount is higher than the $55.68 per meter for the 60 mm that was used in the Application. Material (pipe) cost is only a small portion of the cost of installing a main; since the 42 mm is used in circumstances where existing 42 mm needs replacement, which are smaller scale jobs, the cost per meter is higher. When using the 42 mm as the minimum, distribution mains are split 40 percent Customer and 60 percent Demand as can be found in Table 1 below.

Table 1: Minimum System Results for All Mains

COMBINED STEEL & PLASTIC MAINS						
	Diameter					Minimum Size Cost
Line No.	Inches	mm	Length in Meters	Unit Cost / Length ($/m)	Weighted Cost	(All Pipe Valued at 60mm PE)
	(1)	(2)	(3)	(4)	(5)	(6)
1	0.6	15	201,739	$ 92.53	$ 18,667,526	$ 18,061,558
2	0.8	21	38,914	$ 240.94	$ 9,375,869	$ 3,483,990
3	1.0	26	1,491,415	$ 196.47	$ 293,012,603	$ 133,525,605
4	1.3	33	17,750	$ 240.56	$ 4,269,924	$ 1,589,152
5	1.7	42	8,176,149	$ 130.49	$ 1,066,929,326	$ 732,006,502
6	1.9	48	41,693	$ 241.46	$ 10,067,387	$ 3,732,769
7	2.4	60	9,344,973	$ 148.83	$ 1,390,781,394	$ 836,650,682
8	0.6	15.0	0		$ -	$ -
9	0.8	21.0	200	$ 241.73	$ 48,329	$ 17,900
10	1.0	26.0	2,303	$ 241.73	$ 556,680	$ 206,178
11	1.3	33.0	2	$ 241.73	$ 555	$ 206
12	1.7	42.0	9,481	$ 241.73	$ 2,291,804	$ 848,816
13	1.9	48.0	0		$ -	$ -
14	2.4	60.0	48,205	$ 241.73	$ 11,652,632	$ 4,315,790
15	2.9	73	585	$ 274.33	$ 160,579	$ 52,406
16	3.5	88	1,629,167	$ 167.72	$ 273,236,425	$ 145,858,462
17	4.0	101	592	$ 275.56	$ 163,058	$ 52,978
18	4.5	114	2,714,754	$ 208.66	$ 566,447,291	$ 243,050,523
19	6.6	168	1,190,799	$ 449.10	$ 534,788,514	$ 106,611,623
20	8.6	219	292,284	$ 1,876.21	$ 548,386,780	$ 26,168,078
21	10.7	273	49,070	$ 2,274.10	$ 111,590,603	$ 4,393,228
22	12.7	323	125,597	$ 2,274.19	$ 285,631,012	$ 11,244,615
23	16.0	406	33,359	$ 2,274.22	$ 75,866,002	$ 2,986,621
24	18.0	457	1,947	$ 2,274.22	$ 4,428,391	$ 174,333
25	20.0	508	57,658	$ 6,171.01	$ 355,805,428	$ 5,162,051
26	24.0	609	1,466	$ 6,171.01	$ 9,045,949	$ 131,239
27	30.0	762	11,779	$ 6,171.01	$ 72,687,404	$ 1,054,554
28	36.0	914	0		$ -	$ -
29	42.0	1066	0		$ -	$ -
32	**TOTAL**		**25,481,880**		**$ 5,645,891,466**	**$ 2,281,379,858**
33						
34	**Customer Related Component**			Line 32, Column (6) / Line 32, Column (5)		**40%**
35	**Demand Related Component**				1 - Line 34, Column (6)	**60%**

The PLCC is the peak load carrying capacity embedded in the minimum system. When using a 42 mm minimum system, a new PLCC must be calculated. When the minimum system is reduced from 60 mm to 42 mm, the PLCC adjustment is reduced from 0.205 to 0.113.

The combination of the increased customer component of distribution mains and the reduction of the PLCC results in an increase in the allocation of costs to RS 1 and a decrease in the costs allocated to most of FEI's other rate schedules as shown in Table 2 (updated Table 6-16) below.

Table 2: Delivery Cost of Service Allocation to Rate Schedules

Rate Schedule	$(000)	Percentage of total
1	524,102	66.9%
2	125,158	16.0%
3/23	89,052	11.4%
4	51	0.0%
5/25	32,573	4.2%
6	147	0.0%
7/27	1,544	0.2%
22	807	0.1%
22A	6,815	0.9%
22B	2,598	0.3%
Total	**782,847**	**100.0%**

Two of FEI's rate proposals are affected by the reallocation of costs as described above: RS 1 and RS 22. With less costs allocated to the proposed new RS 22 Firm, a larger downward adjustment to RS 22 customers revenue is required when setting the rates at a 100 percent R:C ratio. The adjustment decreases the proposed rates from the RS 22 Firm and increases the RS 1 revenue adjustment, ultimately increasing the RS 1 volumetric rate as can be seen in Table 3 (updated Table 12-2) and Table 4 (updated Table 12-4) below.

1 **Table 3: 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%	2,619.0	0.3%	94.9%	92.1%
Rate Schedule 2 *Small Commercial Service*	101.3%	102.5%	(1,174.1)	-0.5%	104.1%	107.7%
Rate Schedule 3/23 *Large Commercial Sales and Transportation Service*	101.6%	103.3%	1,174.1	0.6%	106.8%	114.7%
Rate Schedule 5/25 *General Firm Sales and Transportation Service*	104.9%	112.2%	45.2	0.0%	109.3%	124.7%
Rate Schedule 6/6P *Natural Gas Vehicle Service*	131.2%	159.1%			133.2%	163.9%
Rate Schedule 22A *Transportation Service (Closed) Inland Service Area*	109.5%	109.8%			113.2%	113.5%
Rate Schedule 22B *Transportation Service (Closed) Columbia Service Area*	99.7%	99.7%			103.2%	103.2%
Rate Schedule 22 *Large Volume Transportation Service*	1425.5%	1864.4%	(2,586.8)	-11.7%	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%	150.0%	573.0%
Rate Schedule 7/27 *General Interruptible Sales and Transportation Service*	139.6%	712.3%	(90.7)	-0.3%	139.2%	711.6%

2

3 **Table 4: FEI Rate Proposal Summary**

Rate Schedule	Estimated COSA-Based 2018 Rates	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	($0.050)	$4.771

Rate Schedule	Estimated COSA-Based 2018 Rates	Proposed Rate Changes	Estimated 2018 Rates After Proposed Changes
RS 2 – Small Commercial			
Basic Charge (daily)	$0.8161	$0.1324	$0.9485
Delivery Charge ($/GJ)	3.850	($0.186)	3.664
RS 3/RS 23 – Large Commercial			
Basic Charge (daily)	$4.3538	$0.4357	$4.7895
Delivery Charge ($/GJ)	$3.189	$0.001	$3.190
RS 4			
Basic Charge (Monthly)	$439	Nil	$439
Delivery Charge ($/GJ) Off Peak	$1.278	$0.114	$1.392
Delivery Charge ($/GJ) Extended Period	$2.183	($0.018)	$2.165
RS 5/RS 25			
Basic Charge (Monthly)	$587.00	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		$22.478
Firm MTQ ($/GJ)	n/a		$0.150
Interruptible MTQ ($/GJ)	$1.060	($0.171)	$0.889

7.4 Please complete the following table to summarize the impact of changing the minimum main size in the minimum system study on the allocation of distribution system costs between demand and customer components.

	Minimum System Study Results (2001 to 2016)			Alternate Scenario
	BC Gas 2001 Rate Design Application	**2012 COSA[(1)]**	**2016 FEI Rate Design Application**	**2016 FEI Rate Design Application**
Minimum Main Size			60 mm	42 mm
Customer Related Component			**30%**	
Demand Related Component			**70%**	

Notes

(1) Please use the minimum main size that was used in the development of the 2012 COSA that was used to inform the FEU 2012 Common Rates Amalgamation and Rate Design Application

Response:

Please refer to the table below.

Since FEI installs very small amounts of 42 mm pipe (refer to the response to BCUC-FEI IR 1.7.2), the pricing per unit length results were higher than when using the 60 mm pipe. This leads to a higher cost minimum system and, consequently, a larger Customer Related Component.

	Minimum System Study Results (2001 to 2016)			Alternate Scenario
	BC Gas 2001 Rate Design Application	**2012 COSA (1)**	**2016 FEI Rate Design Application**	**2016 FEI Rate Design Application**
Minimum Main Size	42 mm	60 mm	60 mm	42 mm
Customer Related Component	26%	39%	30%	40%
Demand Related Component	74%	61%	70%	60%

Note:

[1] Response to BCUC IR 1.135.11 from the FEU 2012 Common Rates Amalgamation and Rate Design Application.

8.0 Reference: FEI COST OF SERVICE STUDY

Exhibit B-1, Section 3.2.1.2, p. 3-5

Storage and Transport Costs

On page 3-5 of Exhibit B-1, FEI states:

> 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 … [Emphasis added]

8.1 When FEI says storage and transport costs are "primarily incurred," please state if there are reasons why FEI incurs storage and transport costs other than those discussed in the preamble above.

Response:

FEI clarifies that storage and transportation resources are fixed costs under the Annual Contracting Plan and are secured for the primary purpose of serving the load for core sales customers under Rate Schedules 1 through 7. A secondary benefit of these resources is that they are used to balance the system as a whole, including for customers served under the transportation model. A third benefit of holding these resources is to support FEI as the supplier of last resort. Should an operational upset occur, such as a reduction in pressure on FEI's transmission line or the interconnecting pipeline, these resources would be called upon to maintain system pressure and integrity.

8.1.1 Please elaborate as to what these reasons are.

Response:

Please refer to the response to BCUC-FEI IR 1.8.1.

8.2 Please explain if transportation customers balancing practices have had any impact on the storage and transport costs for the resources contracted.

Response:

Storage and transportation resources are fixed costs under the Annual Contracting Plan and are secured for the primary purpose of serving the load for core sales customers under Rate Schedules 1 through 7. The balancing practices of transportation customers have had no impact on these fixed costs. Transportation customers benefit from these resources when they are used to balance the system as a whole; however, FEI does not collect any fees from transportation customers for this balancing service to compensate for the cost to hold these resources.

Please also refer to BCOAPO-FEI IR 1.10.1b) for a discussion of the potential cost reduction to midstream resources if the proposed daily balancing and tolerances are implemented.

9.0 Reference: FEI COST OF SERVICE STUDY

Exhibit B-1, Section 6.3.1.1., p. 6-6; Section 6.3.2, Table 6-5, p. 6-10 to 6-12; Section 6.3.4.1, p. 6-13

Tilbury Expansion Project costs

On page 6-11 of Exhibit B-1, FEI states:

> 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 estimated to cost $400 million plus development costs and AFUDC. … 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.

On page 6-10 of Exhibit B-1, FEI provides Table 6-5 which presents the expected project in-service dates and COSA costs. Table 6-5 shows that in the COSA study, the Tilbury Expansion Project had a mid-year rate base addition of $399 million and a cost of service of $7 million.

9.1 Please prepare a schedule that reconciles the 2016 FEI approved revenue requirement of $1,237.5 million in Table 6-1 on page 6-6 to the 2016 delivery cost of service functionalization of $782.847 million in Table 6-8 on page 6-13.

Response:

Please find the requested reconciliation in the table below:

Particulars	$ million	$ million	Reference
2016 FEI Revenue Requirement		1,237.5	Table 6-1, Page 6-6
Cost of Gas		(477.7)	Table 6-1, Page 6-6
Bio-Methane Cost of Service in Bio-Methane Variance Account		(1.5)	
Lower Mainland Iintermediate Pressure System Upgrade Project		25.1	Table 6-5, Page 6-10
Coastal Transmission System		13.8	Table 6-5, Page 6-10
Tilbury Expansion			
Cost of Service	46.8		
RS 46 Delivery Revenue	(39.7)	7.0	Table 6-5, Page 6-10
BC Hydro IG Delivery Revenue		(15.7)	
Joint Venture Delivery Revenue		(4.6)	
Bypass Delivery Revenue		(1.1)	
Functionalized Cost of Service		782.8	Table 6-8, Page 6-13

9.2 Please provide a table which shows (i) the cost of service and (ii) RS 46 revenues for the Tilbury Expansion Project by year for the each of the ten years included in the levelized Tilbury Expansion Project cost of service.

Response:

The following paragraph describes the rationale for using a 10 year levelized approach for the Tilbury Expansion Project.

The Tilbury Expansion Project, which has both incremental volumes (revenues) and costs, is unlike the Lower Mainland Intermediate Pressure System Upgrade Projects and the Coastal Transmission System Project, which have costs but do not have incremental volumes associated with them. For the Tilbury Expansion Project, the incremental volumes are not all realized at the time that the full costs of the Tilbury Expansion Project are included in rate base. Reflecting only the first year of incremental revenues would not be representative of the longer term impact that the Tilbury Expansion Project will have on the revenue requirement. As such, and as described in Section 6.3.2.3, FEI used a 10-year levelized approach for inclusion of costs and revenues for the Tilbury Expansion Project.

The requested table is provided below:

$000	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
O&M	3,570	3,928	4,331	4,823	5,722	7,072	7,213	7,357	7,504	7,654
Depreciation										
Structures & Improvements	3,096	3,130	3,161	3,188	3,211	3,341	3,360	3,409	3,429	3,450
Gas Holders - Storage	2,211	2,236	2,258	2,277	2,294	2,387	2,400	2,435	2,450	2,464
Compressor Equipment	9,434	9,540	9,634	9,717	9,787	10,183	10,241	10,391	10,451	10,513
Negative Salvage Provision	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423	1,423
Income Tax	(751)	(174)	438	929	1,396	1,761	1,116	521	(131)	(750)
LNG Tax Credit	(425)	(842)	(962)	(1,342)	(1,494)	(2,252)	(2,350)	(2,421)	(2,465)	(2,510)
LNG Tax	0	39	63	165	186	380	393	406	419	432
Earned Return	28,425	27,682	26,895	26,062	25,268	24,432	23,514	22,590	21,636	20,798
Total Cost of Service (i)	**46,984**	**46,963**	**47,241**	**47,241**	**47,793**	**48,727**	**47,311**	**46,112**	**44,716**	**43,474**
RS46 Delivery Revenue (ii)	**11,220**	**21,463**	**23,770**	**32,204**	**34,893**	**51,278**	**52,300**	**53,343**	**54,406**	**55,490**

FEI notes that the LNG Tax and LNG Tax Credit included in the cost of service for the Tilbury Expansion Project have been enacted but have not been proclaimed in force by the Lieutenant Governor in Council for BC.

9.3 Please use calculations to explain what the cost of service included in the COSA would be for the Tilbury Expansion project if FEI used its general approach for known and measurable changes and included the estimated annual cost of service and revenue for only 2018 in the COSA.

Response:

If FEI had used the forecast 2018 costs and RS 46 revenues in the analysis, the total cost of service to be included would be $46,963 thousand and the RS 46 delivery revenue would be $21,463 thousand. Details are included in the table below.

$000	Year 2
O&M	3,928
Depreciation	
Structures & Improvements	3,130
Gas Holders - Storage	2,236
Compressor Equipment	9,540
Negative Salvage Provision	1,423
Income Tax	(174)
LNG Tax Credit	(842)
LNG Tax	39
Earned Return	27,682
Total Cost of Service (i)	**46,963**
RS46 Delivery Revenue (ii)	**21,463**
(i) less (ii)	25,500

9.3.1 Please reproduce the following tables to show the impact of using the estimated 2018 cost of service and revenue associated with the Tilbury Expansion project in the COSA:

i. Table 6-8: Delivery Cost of Service Functionalization Summary (Exhibit B-1, p. 6-13)

ii. Table 6-16: Delivery Cost of Service Allocation to Rate Schedules (Exhibit B-1, p. 6-27)

iii. Table 12-2: COSA R:C and M:C Results after Rate Design Proposals (Exhibit B-1, p. 12-5)

Response:

Please refer to the adjusted Table 6-8, Table 6-16 and Table 12-2 below.

The predominant change to the COSA from using 2018 Tilbury Expansion forecast costs and revenues[3] in the COSA is that the known and measurable changes are increased by $15,383 thousand. This increase is mainly due to the difference between the forecast revenues in 2018 compared to the ten-year levelized forecast revenues.

The results are minor changes to most of the R:C ratios, with only RS 22 Interruptible showing a significant change. RS 22 Interruptible attracts very few costs because it does not contribute to system peak demand, yet the net cost of Tilbury Expansion is allocated to all non-bypass customers based on margin. The table below shows the minor changes to the R:C ratios from treating Tilbury like the other two projects.

Rate Schedule	Change in R:C Ratio
RS 1	+0.2%
RS 2	-0.2%
RS 3/23	-0.3%
RS 5/25	-0.3%
RS 6/6P	+0.9%
RS 22A	+2.0%
RS 22B	+1.8%
RS 22	0.0%
RS 4	+1.1%
RS 7/27	+0.9%

Table 6-8 (Adjusted): Delivery Cost of Service Functionalization Summary

Function	$ thousands	Percentage of total
Gas Supply Operations	2,016	0.3
Tilbury LNG Storage	50,701	6.4
Mt. Hayes LNG Storage	7,577	0.9
Transmission	172,135	21.6
Distribution	463,423	58.1
Marketing	50,153	6.3
Customer Accounting	52,226	6.4
Total	**798,230**	**100.0**

[3] Treatment of Tilbury Expansion is in the same manner as the LMIPSU and CTS projects in the COSA. FEI has included the project costs and revenues as forecast for 2018.

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

Rate Schedule	$ thousands	Percentage of total
1	519,186	65.0%
2	133,067	16.7%
3/23	97,838	12.3%
4	51	0.0%
5/25	36,138	4.5%
6	152	0.0%
7/27	1,542	0.2%
22	808	0.1%
22A	6,840	0.9%
22B	2,608	0.3%
Total	**798,230**	**100.0%**

Table 12-2 (Adjusted): COSA R:C and M:C Results after Rate Design Proposals

Rate Schedule	Initial COSA		Revenue Shift ($000)	Approximate Annual Bill Change	COSA after Rate Design Proposals	
	R:C	M:C			R:C	M:C
Rate Schedule 1 *Residential Service*	95.7%	93.3%	757.4	0.1%	96.6%	94.7%
Rate Schedule 2 *Small Commercial Service*	101.1%	102.0%	(1,174.1)	-0.5%	102.0%	103.6%
Rate Schedule 3/23 *Large Commercial Sales and Transportation Service*	101.3%	102.6%	1,174.1	0.6%	103.3%	106.7%
Rate Schedule 5/25 *General Firm Sales and Transportation Service*	104.6%	111.2%	45.2	0.0%	106.0%	114.8%
Rate Schedule 6/6P *Natural Gas Vehicle Service*	132.0%	160.3%			132.6%	161.6%
Rate Schedule 22A *Transportation Service (Closed) Inland Service Area*	111.4%	111.7%			115.0%	115.4%
Rate Schedule 22B *Transportation Service (Closed) Columbia Service Area*	101.4%	101.4%			104.9%	104.9%
Rate Schedule 22 *Large Volume Transportation Service*	1451.3%	1898.1%	(725.2)	-3.3%	100.0%	100.0%

Rate Schedule *(rates not set using allocated costs)*	Initial COSA		Revenue Shift ($000)	Approximate Annual Bill Change	COSA after Rate Design Proposals	
	R:C	M:C			R:C	M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	148.5%	560.9%	13.3	1.9%	151.3%	588.6%
Rate Schedule 7/27 *General Interruptible Sales and Transportation Service*	140.5%	725.4%	(90.7)	-0.3%	140.2%	727.1%

9.4 If the cost for the Tilbury Expansion Project exceeded $400 million (excluding development costs and AFUDC) and was instead $450 million, please discuss how these additional costs ($50 million) would be treated in the COSA and recovered from customers.

Response:

The COSA treatment will be the same for all Tilbury Expansion Project costs as described in Section 6.3.2.3. Please also refer to the response to BCUC-FEI IR 1.9.5.

9.5 If the cost for the Tilbury Expansion Project exceeded $400 million (excluding development costs and AFUDC) and was instead $450 million, please discuss if it is within the Commission's jurisdiction to determine the rates and customers from whom these additional costs ($50 million) would be recovered.

Response:

The B.C. Government recently passed amendments to Direction No. 5 by Order in Council No. 162/2017 dated March 21, 2017, which included an increase in the spending limit for the Tilbury Phase 1A expansion from $400 million to $425 million. At this time, FEI expects the capital costs to be within the $425 million spending limit.

Direction No. 5 determines how and from whom the costs of the Tilbury Expansion Project are recovered. Specifically, under section 4(c) of Direction No. 5, the capital costs are recoverable from "applicable customers", which is a defined term. Section 4 of Special Direction 5 states in part:

> **4** (2) In setting rates under the Act for FortisBC Energy Inc., the commission must do <u>all</u> of the following:
>
> …
>
> (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
>
> <u>(iii) the capital costs</u>, construction carrying costs, sustaining capital costs, decommissioning and salvaging costs <u>and feasibility and development costs respecting phase 1A facilities</u> and phase 1B facilities;

Direction No. 5 defines "applicable customers" as being synonymous with FEI's non-bypass customers:

> **"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;

Non-bypass customers also obtain the benefit of the revenues from the Tilbury Expansion Project.

10.0 Reference: FEI COST OF SERVICE STUDY

Exhibit B-1, Section 6.3.4.3, p. 6-14; Section 6.3.4.4, p. 6-16

Tilbury Expansion Project costs

On page 6-14 of Exhibit B-1, FEI states:

> 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.

On page 6-14 of Exhibit B-1, FEI states "Mt. Hayes LNG Storage has a separate function from Tilbury LNG Storage."

10.1 Please confirm, or otherwise explain, that when FEI refers to the "LNG Storage" function in the above quote, FEI is referring to the Tilbury LNG Storage function which is a separate category from the Mt. Hayes Storage function.

Response:

Confirmed.

On page 6-16 of Exhibit B-1, FEI states that "In the near term, Mt. Hayes is expected to provide a small amount of LNG for the NGT market." In Table 6-10 (extracted below) FEI presents the forecast RS 46 demand 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

In Table 6-6 on page 6-12 of Exhibit B-1, FEI provides the forecast of RS 46 demand that forms the basis for the ten year levelized revenue included in the COSA model.

10.2 Please confirm that the RS 46 demand supplied by Mt. Hayes is included in the RS 46 demand forecast in Table 6-6 and the revenue from this demand is included in the ten year levelized RS 46 revenue that is used to offset the Tilbury Expansion Cost within the Tilbury LNG Storage function before the difference is allocated to all non-bypass customers.

Response:

Not confirmed. The RS 46 demand supplied by Mt. Hayes is not included in Table 6-6. Table 6-6 was provided to inform the reader of the RS 46 demand forecast to be produced by the Tilbury Expansion. FEI does confirm that the RS 46 demand supplied by Mt. Hayes is included in the revenue that is used to offset Tilbury Expansion costs within the Tilbury Storage function.

In addition to the volume included in Table 6-6, an RS 46 demand of 668.7 TJ[4] is embedded in FEI's 2016 test year. Included in the 668.7 TJ is the 20 TJ shown in Table 6-10 from the preamble. Within the COSA, both the levelized demand from RS 46 from Table 6-6 plus the 668.7 TJ demand embedded in FEI's test year are used to offset the Tilbury Expansion Cost within the Tilbury LNG Storage function before the difference is allocated to all non-bypass customers. A revised and expanded Table 6-6 is included below.

TJ	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Levelized and included in COSA
Tilbury Expansion	2,956	5,545	6,021	7,998	8,496	12,242	12,242	12,242	12,242	12,242	8,726
RS 46 demand included in Test Year (includes the 20 TJ demand served by Mt. Hayes in Table 6-10)											669
Total RS 46 demand included in COSA model											**9,395**

10.2.1 If not confirmed, please explain and provide an updated version of Table 6-6 with the RS 46 demand supplied by Mt. Hayes included.

Response:

Please refer to the response to BCUC-FEI IR 1.10.2.

10.3 Please provide the maximum annual liquefaction capacity at Mt. Hayes expressed in TJ.

Response:

Mt. Hayes has a liquefaction capacity of 8.2 TJ per day.

[4] Commission Order G-193-15, dated December 11, 2015, Compliance Filing, Schedule 18.

FEI's standard procedure is to limit liquefaction activities to the non-winter months, from April to October, for a maximum of 214 days. This means a theoretical 1,755 TJ total volume of liquefaction in a year, but plant maintenance activities will decrease this amount to some extent.

10.3.1 What is the maximum amount of Mt. Hayes liquefaction capacity that could be used to supply RS 46 demand without impacting the allocation of costs to Mt. Hayes LNG Storage function within the COSA model and/or to the Storage and Transport (Midstream) Costs component of the Gas Cost Allocation model.

Response:

The maximum liquefaction capacity that could be used to supply RS 46 customers is ninety days in the summer. Ninety days of liquefaction capacity at Mt. Hayes is equal to 729 TJ of LNG that could be produced for the NGT market before impacting the allocation of costs in the COSA.

11.0 Reference: FEI COST OF SERVICE STUDY

Exhibit B-1, Section 6.3.4.4, pp. 6-14 to 6-16;

Commission Letter L-20-16 dated August 4, 2016, appendix A; Non-confidential FEI 2016/2017 Annual Contracting Plan – Executive Summary, p. E-5;

FortisBC Energy Utility 2014 Long Term Resource Plan Application, Exhibit B-2, BCUC IR 1.58.1

LNG facility cost allocation

On page 6-14 of Exhibit B-1, FEI states:

> The existing Tilbury LNG Storage facility … serves as a needle peaking resource to support the CTS's [Coastal Transmission System] 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. … Mt. Hayes LNG Storage has a separate function from Tilbury LNG Storage. … 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.

11.1 Does the Mt. Hayes LNG facility also support transmission and distribution operations during maintenance and repair activities, emergency outages and supply constraints?

Response:

Yes. Mt. Hayes is included in FEI's resource portfolio as a peaking gas supply resource for RS 1-7 customers. It also serves as a replacement for transmission capacity by providing additional system capacity on Vancouver Island to serve customers in the same fashion that pipeline looping and compression could have provided such capacity. Furthermore, Mt. Hayes supports transmission and distribution operations during maintenance and repair activities, emergency outages and supply constraints.

On page E-5 of the non-confidential FEI 2016/2017 Annual Contracting Plan – Executive Summary that is Appendix A to Commission Letter L-20-16, FEI provides the following table summarizing the Midstream gas supply portfolio:

Table ES-2: Planned Peak Day Portfolio for 2016/17 vs. 2015/16 Portfolio

Peak Day Portfolio (TJ/d)	2016/17 Portfolio-Planned	2015/16 Portfolio
Fort Nelson Division	**5**	**5**
Alberta Baseload Supply (CCRA gas & Mktrs)	83	84
Station 2 Baseload Supply (CCRA gas & Mktrs)	248	251
Total Commodity Supply	**331**	**335**
Seasonal Supply	175	195
Seasonal Storage	196	197
Market Area Storage	210	210
Peaking Supply	-	-
Spot Supply	46	24
Mt. Hayes LNG	163	163
Tilbury LNG	163	163
Industrial Curtailment	28	28
Total Midstream Supply	**981**	**980**
Total Resources (TJ/d)	**1,317**	**1,320**
Peak Day Demand (TJ/d)	**1,317**	**1,320**

11.2 Please confirm that for the 2016/17 annual contracting plan, the Tilbury LNG and Mt. Hayes LNG resources respectively each constituted 12.4 percent of the total Midstream portfolio of resources required to meet the peak day demand.

Response:

The Tilbury LNG and Mt. Hayes LNG resources both constituted 16.6 percent of the total Midstream portfolio of resources required to meet the 2016/17 peak day demand, calculated as follows:

Tilbury LNG: 163 / 981 = 16.6%

Mt. Hayes LNG: 163 / 981 = 16.6%

In terms of the total peak day requirements (i.e., Commodity and Midstream) for the 2016/17 Annual Contracting Plan, each of Tilbury LNG and Mt. Hayes facility constitute 12.4 percent.

11.2.1 Does FEI anticipate any significant changes to the role that the Tilbury LNG and Mt. Hayes LNG resources play in the Midstream portfolio in the future? If so, please elaborate.

Response:

FEI does not anticipate any significant changes to the role that the existing Tilbury LNG and Mt. Hayes LNG resources play in the Midstream portfolio. Both will continue to provide peaking supply to Rate Schedules 1 to 7 customers as well as a small amount of LNG supply to RS 46 customers, if needed. As RS 46 sales increase in the future, it is possible that the production of LNG at the existing Tilbury and Mt. Hayes facilities will need to increase (on a temporary basis) requiring those facilities to operate more often than in the past. Increased RS 46 sales are expected to be served by additional LNG capacity at Tilbury, such as the current Phase 1A expansion nearing completion. Depending on how the growth of RS 46 and other LNG sales develop, FEI may be able to replace some of its downstream storage or alternative resources in the Midstream gas supply portfolio with storage, liquefaction and vaporization at Tilbury, if available.

11.2.2 Please describe the similarities and the differences in the roles of the Tilbury LNG facility and Mt. Hayes LNG facility, respectively, as a gas supply storage facilities in the Midstream portfolio.

Response:

The Tilbury LNG facility and Mt. Hayes LNG facility provide similar roles as gas supply storage facilities in the Midstream portfolio. Both are used to provide peaking supply for Rate Schedules 1 to 7 customers, and gas supply during emergency conditions. Although both facilities have the same withdrawal or vaporization capability of 163 TJ per day, Mt. Hayes provides approximately 10 days of supply while Tilbury provides approximately 4 days of supply, if withdrawn at the maximum daily capability. Given that Mt. Hayes holds more inventory, gas is usually sent out from Mt. Hayes before Tilbury, which tends to be reserved for the peak days with the highest demands.

11.3 Please populate the following table to illustrate the extent to which the Mt. Hayes LNG facility and the Tilbury LNG facility were used to supply the Midstream portfolio requirements over the past five contract years.

Contract Year	Mt. Hayes LNG Facility		Tilbury LNG Facility	
	No. of Days	Total TJs	No. of Days	Total TJs
Nov 1, 2011 to Oct 31, 2012				
Nov 1, 2012 to Oct 31, 2013				
Nov 1, 2013 to Oct 31, 2014				
Nov 1, 2014 to Oct 31, 2015				
Nov 1, 2015 to Oct 31, 2016				

Response:

The following table provides the gas sent out from the Mt. Hayes and Tilbury LNG facilities to supply the Midstream portfolio requirements over the past five contract years, plus the 2016/17 contract year up to May 2017.

Contract Year	Mt. Hayes LNG Facility		Tilbury LNG Facility	
	No. Days	Total TJs	No. Days	Total TJs
Nov 1, 2011 to Oct 31, 2012	5	143	2	38
Nov 1, 2012 to Oct 31, 2013	2	30	4	29
Nov 1, 2013 to Oct 31, 2014	12	539	18	148
Nov 1, 2014 to Oct 31, 2015	10	360	4	42
Nov 1, 2015 to Oct 31, 2016	2	43	4	25
Nov 1, 2016 to Oct 31, 2017	13	360	1	13

In the FortisBC Energy Utilities 2014 Long Term Resource Plan (FEU 2014 LTRP) proceeding, in response to BCUC IR 1.58.1 regarding FEU's consideration of the option of increasing either the number of days duration and/or peak day quantities sourced from the existing Tilbury and Mt. Hayes LNG storage facilities for the purpose of meeting the peak design day portfolio load requirements, FEU responded:

> The FEU also evaluate opportunities on an on-going basis within its own operating region to improve infrastructure leading to better diversity and reliability within the portfolio over the long term. For example, FEI is currently planning to expand the liquefaction and storage capacity at the Tilbury site, primarily to meet the growing market for LNG applications. This may provide an opportunity for the FEU to source additional on-system storage resources, in particular if additional vaporization facilities can be incorporated into the expanded facility. The addition of vaporization to the facility and ability to liquefy at a greater rate than the original peak shaving Tilbury facility could allow FEI to utilize this resource as a market area storage resource during cold weather events. FEI could potentially replace expiring Mist and NWP transportation contracts in the future or replace incremental resources that may be required to meet growing load requirements.

The FEU will continue to assess this potential opportunity as part of the annual contracting process.

11.4 If FEI were to add vaporization to the expanded Tilbury LNG facility in the future so it could be used to replace market area storage contracts such as the Mist and NWP transportation contracts in the Midstream portfolio, please describe how FEI would propose to address any associated cost allocation issues. For instance, would FEI anticipate it would propose an allocation of some portion of the Tilbury LNG Storage function to the Storage and Transport portion of the gas Allocation model?

Response:

If vaporization equipment was added to the expanded Tilbury LNG facility, it could be used to replace some portion of market area storage contracts. If this situation were to arise in the future, FEI would propose an allocation method to the Commission for its review and approval. The following comments represent FEI's current thinking about a potential allocation methodology, which are speculative at this time, and subject to change based on the facts and considerations relevant at the time FEI were to make its application to the Commission.

As discussed in Section 6.3.2.3 of the Application, the cost allocation under the Tilbury Expansion's current configuration of having no vaporization functionality is that the Tilbury Expansion costs are directly allocated to RS 46 and offset with RS 46 revenues, with the net difference being allocated to all non-bypass customers.

If vaporization equipment were added to the expanded Tilbury LNG facility, it would become a multi-purpose facility and be able to serve as (1) a RS 46 LNG demand facility, and (2) a gas supply storage facility. FEI expects that the allocation of costs with respect to the RS 46 LNG demand function would continue, as described above; however, FEI expects that there would also be an allocation of costs to FEI's midstream portfolio for the gas supply storage function.

A potential basis or benchmark for the allocation of costs to the midstream portfolio in this situation would be the estimated cost of avoided third party storage and transportation gas supply resources that would otherwise need to be contracted if available on behalf of the core market. FEI expects that the regulatory treatment to administer such a charge would be to credit or reduce the total delivery costs associated with FEI's operations with the appropriate amount, and debit or charge FEI's midstream portfolio with the equivalent amount (this follows the cost allocation described in Section 6.3.4.4). FEI expects that there would also be an allocation of the variable vaporization costs and a portion of the variable liquefaction costs to the midstream portfolio.

12.0 Reference: FEI COST OF SERVICE STUDY

Exhibit A2-2, Section 2, p. 5

Frequency of COSA studies

On page 5 of Exhibit A2-2, Elenchus states:

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

Elenchus further explains that Union Gas Limited conducts a cost of service study every five years, Enbridge Gas Distribution conducts a cost of service study every year, and ATCO Gas' most recent cost of service studies are from 2008/2009 and 2011/2012 general rate applications.

12.1 Please state the most recent time when FEI included a full and up-to-date COSA study for (i) FEI; and (ii) Fort Nelson in a regulatory application.

Response:

The most recent time when FEI included a full and up-to-date COSA study for FEI and Fort Nelson in a regulatory application was in 2012.

12.2 Please provide a detailed explanation of the costs, time and effort in person-hours to prepare a full and up-to-date COSA study for each of FEI and Fort Nelson (excluding rate design and rebalancing) for regulatory review. Please explain if any external resources are required.

Response:

The resources required to prepare a COSA can vary depending on factors such as the length of time that has passed since the previous COSA was undertaken, whether there are significant changes to the underlying costs or the introduction of known and measureable changes, the number of supporting studies that need to be done or updated and the extent to which external consultants are engaged. FEI will respond to this question in consideration of the resources required to complete the current COSAs for FEI and Fort Nelson.

Internal resources have been utilized extensively in the preparation of the COSA studies for FEI and Fort Nelson with this Application. Although FEI has not tracked the labour hours associated with the two COSAs, FEI estimates 2,000 hours in total for FEI and 900 hours in total for Fort

Nelson. In total, the internal fully-loaded labour cost is estimated in the range of $275 thousand, split 70 percent to FEI and 30 percent to Fort Nelson (FEI notes, however, that Fort Nelson will receive 0.00244 percent of FEI's labour costs through the shared services allocation and not a separate allocation for the internal costs of the COSA). In addition to internal labour, FEI has incurred $100 thousand of external consultant costs to review and provide an expert opinion on the COSA and supporting studies for FEI and $5 thousand for Fort Nelson to date.

12.3 Please explain the benefits and disadvantages of performing a full COSA study every five years as opposed to less frequently, for example every 10 years or longer.

Response:

Updating a COSA study every five years as opposed to every 10 years has the potential benefit of highlighting any changes among the rate groups that may require further examination and alerting the Commission and the utility of any rate design matters that should be considered. The disadvantage is the time and cost involved with more frequent reviews. For the internal resources, staff with the specific skillset to undertake rate design activities may not be available due to conflicts with other major applications that are underway, and for the external resources, there will be incremental costs involved.

A 10-year interval between full COSA studies would have the potential to leave important rate design issues unknown and unaddressed for an extended period of time.

FEI's predecessor companies from the 1980s through to 2001 have completed COSA studies every 3 to 7 years. FEI is of the opinion that a COSA study that is completed every 4 to 6 years is a reasonable time period to consider if there are issues that need to be raised in a regulatory proceeding, but that significant changes in FEI's business may require more frequent examination of specific limited scope issues. These issues could be raised by FEI, by the Commission or by interveners.

13.0 Reference: FEI COST OF SERVICE STUDY

Exhibit B-1, Section 6.5.2, Table 6-19, p. 6-36; Section 3.2.2, Table 3-2, p. 3-6

Additional data

Table 6-19 in Exhibit B-1 presents the revenue to cost (R:C) and margin to cost (M:C) ratio results for rate schedules that are not set using cost of service allocations. These include RS 4, RS 7, RS 27 and RS 22.

13.1 Please provide an updated version of Table 6-19 which includes the revenue to cost and margin to cost ratios from the COSA results and before rate design proposals and rebalancing for (i) RS 26; (ii) RS 46; (iii) the aggregate of customers with bypass agreements; and (iv) non-bypass contract customers.

Response:

FEI does not have any customers taking service under RS 26 so there is no revenue and no allocated costs to produce an R:C ratio. RS 46 revenues and directly assigned costs are used to produce the ratios in the table below. Bypass customers and non-bypass contract customers attract costs based on their contribution to the cost allocators in the COSA.

An updated Table 6-19 is provided below.

Rate Schedule / Customer	R:C	M:C
Rate Schedule 4 *Seasonal Firm Gas Service*	147.8%	548.9%
Rate Schedule 7/27 *General Interruptible Sales and Transportation Service*	140.1%	728.8%
Rate Schedule 22 *Large Volume Transportation Service*	1193.3%	1477.5%
(ii) Rate Schedule 46 *Liquefied Natural Gas*	90.0%	84.9%
(iii) Customers with Bypass Agreements	14.6%	14.6%
(iv) Non-Bypass Contract Customers	99.7%	99.7%

13.2 Table 3-2 on page 3-6 of Exhibit B-1 shows that RS 50 has no customers. Please state if FEI could obtain customers for RS 50 within the next five years and explain what their expected energy demand would be on FEI's system.

Response:

Yes, FEI may have RS 50 customers join the system within the next five years, although no project proponents have made final investment decisions at this time. For example, the Woodfibre LNG project is still under active development and would become an RS 50 customer if that project goes ahead. The expected energy demand on FEI's system for the Woodfibre LNG project would be up to 110 PJ / year[5]. There are other potential RS 50 customers in the Lower Mainland, including LNG projects of similar size to Woodfibre LNG, but FEI does not have certainty on whether they will proceed, and if they do, whether they will commence operations within the five-year period mentioned in the question.

[5] Woodfibre LNG's website identifies that the Export License is for 2.1 million tonnes of LNG per year which is approximately 110 PJ per year.

14.0 Reference: FEI COST OF SERVICE STUDY

Exhibit B-1, Section 3.3.2, p. 3-10

Historical R:C ratio range of reasonableness

On page 3-10 of Exhibit B-1, FEI states:

> 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. … 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.

14.1 Please explain the reasons behind the proposed R:C ratio range of 90% to 110% in the BC Gas 1993 Phase B Rate Design Application and discuss whether each of these reasons remain applicable for the FEI 2016 Rate Design Application.

Response:

The Commission's acceptance of a 90 percent to 110 percent range of reasonableness for R:C ratios in the BC Gas 1993 Phase B Rate Design proceeding relied on previous precedent. The following quote from page 11 of the 1993 Phase B decision (Order G-101-93) illustrates this:

> The BCGUL FDC study used three different methods of allocating capacity costs: peak responsibility, non-coincident peak, and average and excess demand. These three methods were identified by the Applicant, Intervenor and Commission staff expert witnesses as being the most commonly used in the gas industry in North America. All three methods indicated that BCGUL's current rates are less than the allocated historical costs for residential customers in all Divisions, although the revenue to cost ratios for Inland residential customers were within 10 percent of the theoretical ideal of a one-to-one correspondence between costs and revenues. *In previous decisions the Commission has accepted a 10 percent band as reasonable.* Similarly, all three methods indicated that Lower Mainland industrial customers were contributing revenues in excess of the costs allocated to them. (emphasis added)

FEI believes that a 90 percent to 110 percent range of reasonableness for R:C ratios in rate design represented an established practice for the Commission at the time.

An example of a recent precedent (at that time) accepting the 90 percent to 110 percent range of reasonableness is found in a 1991 reconsideration decision involving Ocelot Chemicals Inc. and Pacific Northern Gas. The following quote is taken from page 38 of the Decision attached to Order G-23-91 (dated February 27, 1991):

> Based on the above, the Commission finds the following:
>
> 1. The Commission accepts that firm rates should move as rapidly as possible towards costs, <u>*modified by the zone of reasonableness whereby, in the absence of compelling evidence to the contrary, a revenue to cost ratio of 90 to 110 percent shall be seen as revenue cost equality*</u>. Accordingly, the Commission orders that residential rates increase by five percent and commercial rates by three percent per annum for three years commencing in accord with the implementation date described in Section 6.2. (emphasis added)

The Commission made further findings with respect to COSA studies and range of reasonableness at pp. 28-29:

> A cost of service study is a guide to determine whether the revenues generated by the rates charged to a particular class of customer are sufficient to cover the cost of serving that class of customer. As such, cost of service studies should reflect costs only. Other considerations, while important in determining fair, just and reasonable rates, should be included following a review of the cost of service study results.
>
> Given the above, the results of cost of service studies should be seen as a tool to be used in the setting of fair, just and reasonable rates. They are not, in and of themselves, fair, just and reasonable rates.
>
> 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, compressor costs have been allocated 100 percent to capacity even though annual usage contributes to a decreased service life. Similarly, 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.
>
> Therefore, even as a tool for indicating the level of costs attributable to serving a particular class of customer, cost of service studies must be viewed as an indicator only, of the sufficiency or insufficiency of rates to cover a particular set of costs. 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.

The Commission Decision in the Columbia Natural Gas Rate Design and Fording Coal Ltd. Complaint May 17, 1988, pp. 52-53 found:

> The Commission is not, however, convinced of the wisdom of embracing a targetted (sic) revenue to cost ratio for any class. This imputes an absolute standard of correctness regarding revenue to cost ratios which is misplaced for several reasons:
>
> 1. Cost, especially in regard to joint use facilities, is not a precise concept. Using either the dd or the ps allocation methodology leads, for example, to a Fording net revenue to cost ratio range of some 35 percent (92 percent to 127 percent). Thus the notion of "true cost" in this situation is somewhat misleading.
>
> 2. Even for a given allocation methodology (dd or ps), there can be considerable variation in determining costs due to judgment and the various other refinements that can be used. During the Inland rate design hearing, the evidence indicated that costs could be out by as much as 10 percent. (See Inland Rate Design Hearing transcripts pp. 794, 6584, 6593-9).
>
> 3. Depreciation can be vulnerable to considerations other than physical life of property.
>
> 4. Revenues can vary significantly from year to year, especially for industrial gas use which is dependent on volatile international or national economic conditions.
>
> 5. The revenue to cost ratio also varies depending on whether or not the FACOS is prorated to revenues or revenues are prorated to the FACOS.
>
> 6. Historically, the gross revenue to cost ratio was used for comparative purposes. With the advent of direct gas purchasing, bypass and the segmented gas pricing policy, gross revenue to cost ratios have largely lost their meaning. Yet, net revenue to cost ratios are unstable in the sense that the biggest share of total costs is due to gas costs. The difference is margin or non-gas costs which result in exaggerated divergence of the revenue to cost ratio from unity. (emphasis added)

Although the Commission's reasons for acceptance of the 90 percent to 110 percent range of reasonableness in the 1993 Phase B Rate Design Decision were not directly stated, FEI believes it is reasonable to expect that the findings on range of reasonableness in then-current decisions, such as the 1988 Columbia Natural Gas – Fording Coal decision and the 1991 PNG-

Ocelot Chemicals decision (both cited above), were in view. The Commission's findings in those decisions continue to be applicable today. Please refer also to the discussion on the range of reasonableness in Section 6.5.1 of the Application.

In addition to the references cited above, FEI's review of the Commission Decisions with respect to the range of reasonableness for natural gas utilities indicate that R:C ratios within a range of 90 percent to 110 percent have been consistently found acceptable. The relevant excerpts from these decisions are reviewed below.

The Centra Gas Fort St. John Inc. 1996 and 1997 Revenue Requirements and Rate Design Application Phase II Rate Design Decision also used threshold limits, at p. 3:

> The Commission recognizes that judgment is involved in undertaking a cost of service study. Considerable judgment is involved not only in classifying costs into capacity, commodity and customer-related components, but also in determining the appropriate method of allocating these charges among different rate classes. In recognition of these inherent difficulties, the band of reasonableness for rate restructuring adopted by the Commission to date, is the commonly accepted band of plus or minus 10 percent around the ideal 1.0 benchmark ratio. In this Decision the Commission applies these threshold limits with the commodity cost of gas excluded from consideration.

In that case some rates were still outside the band, but the Commission found them acceptable, at page 12:

> The Commission anticipates that the resulting revenue to cost ratio will still be well above the band of reasonableness of 0.90 to 1.10 adopted by the Commission. As a move towards this objective the Commission is satisfied that the proposed rates are justified.

In the Centra Gas British Columbia Inc. 2002 Rate Design Application, the Commission indicated R:C ratios should tend toward the range of reasonableness, and also accepted a departure from the typical range on the basis of the immaturity of the utility, at pp. 40-41:

> For a financially healthy and mature utility, the Commission would expect the range of revenue to cost ratios across customer classes to tend toward 0.9 to 1.1, all other objectives being satisfied. The Commission finds that in the circumstances of an immature utility it would be unreasonable to limit revenue to cost ratios within a narrow range and thereby limit the consideration of other circumstances in the design of rates which meet the public interest. The Commission views Centra as an immature utility under its current circumstances.

The range of reasonableness of 90 to 110 percent was also used in:

- The FEI (then BC Gas) 1996 Rate Design, approved by the Commission in Order G-98-96 dated October 7, 1996.

- The FEI (then BC Gas) 2001 Rate Design, approved by the Commission in Order G-116-01 dated November 7, 2001.
- The FEI Common Rates, Amalgamation and Rate Design Application, decided by the Commission in Order G-26-13 dated February 25, 2013 and reconsidered by the Commission in Order G-21-14 dated February 26, 2014.

14.2 Please explain whether the quality of FEI's customer data, load data and costing data has improved since the 1993 Phase B Rate Design Application.

Response:

Although the customer data has improved since the 1993 Phase B Rate Design Application, in particular for General Firm Service, it has not sufficiently improved for the vast majority of FEI customers, i.e., Residential and Commercial Sales service, to warrant changing the range of reasonableness. General Firm Service (Rate Schedules 5 and 25) only accounts for approximately 775 customers, whereas Residential and Commercial Sales service (Rate Schedules 1, 2 and 3) represent approximately 995 thousand customers of the approximately 998 thousand total customers. In terms of 2017 annual forecast volumes, General Firm Service accounts for approximately 15,840 TJ, whereas Residential and Commercial Sales service accounts for approximately 121,480 TJ of the total forecast of 214,640 TJ[6].

For Residential, Small Commercial and Large Commercial Sales Service, which make up the majority of the customer demand, the available data is from monthly customer meter reads, which occur in multiple cycles throughout the month. This is an improvement from 1993 when these customers' meters were typically read every second month. However, even with these improvements the necessary data to know what actual customer consumption is during peak conditions is not available. As such, the load factors of individual customers, and even the residential and commercial classes as a whole, continue to be estimates, meaning there is still a measure of uncertainty in the demand allocators in the COSA.

Also, at the time of the 2001 Rate Design, while customers in the other Industrial rate schedules had demand meters and daily measurement data available, a large number of RS 5 customers' volume data were still based on monthly meter reads. This has now changed to all RS 5 measurement readings being available on a daily basis. This is also an improvement on the customer load data which allows for considering alternate methods of determining Daily Demand coupled with setting the Demand Charge to apply to General Firm Service customers.

The Company has made investments in tracking costing data when it switched its accounting and management systems to SAP, several years after the 1993 Rate Design, which tracks costs

[6] FEI's Compliance Filing dated December 12, 2016, Appendix A, Section 11, Schedules 17 and 19

on an activity basis. The activities cover an array of capital and operating activities, including those related to LNG assets and operations, Transmission assets and operations, and Distribution assets and operations.

15.0 Reference: FEI COST OF SERVICE STUDY

Exhibit B-1, Section 6.5, p. 6-31; Section 6.5.2, p. 6-34; Appendix 6-4, Schedule 1;

Exhibit A2-2, Section 6.1.1, p. 28

Use of the R:C ratio versus the M:C ratio range of reasonableness

On page 6-31 of Exhibit B-1, FEI states:

> 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

On page 6-34 of Exhibit B-1, FEI states:

> 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.

On page 28 of Exhibit A2-2, Elenchus states:

> The definition of R:C and M:C ratios implies that the calculated R:C ratio range would always be less than the calculated M:C ratio range. Specifically, the M:C ratio would be less than the calculated R:C ratio for the same rate schedule if the R:C ratio is less than 1.00 and the M:C ratio would be greater than the calculated R:C ratio for the same rate schedule if the R:C ratio is greater than 1.

15.1 Please explain, with calculations, how FEI imputes the cost of gas in order to be able to calculate the R:C ratio for RS 23, RS 25 and RS 27.

<u>Response:</u>

FEI uses the cost of gas from the companion Sales rate schedule and applies it to the companion Transport rate schedule. The companion rate schedule's cost of gas includes the appropriate commodity and storage and transport costs, which is different for all three sales rate schedules.

The companion Sales and Transport Rate Schedules are RS 3 and RS 23, RS 5 and RS 25, and RS 7 and RS 27.

As an example, the imputed cost of gas for RS 23 is derived by using the RS 3 cost of gas, divided by RS 3 volume and multiplied by RS 23 volume, as shown in the calculations in the following table.

Line No.	Particulars	Amount	Reference
1	RS 3 Cost of Gas ($000)	67,784	Appendix 6-2, Schedule 17, Line 6, Column 3
2	RS 3 Energy Volume Sold (TJ)	18,121.3	Appendix 6-2, Schedule 18, Line 6, Column 3
3	RS 23 Energy Volume Sold (TJ)	8,968.8	Appendix 6-2, Schedule 18, Line 7, Column 3
4	RS 23 Imputed Cost of Gas ($000)	33,548	Line 1 / Line 2 x Line 3

15.2 Please explain, with calculations, how FEI determined (i) the cost of gas; and (ii) the R:C ratio for each of RS 22A and RS 22B large volume transportation service customers as presented in Table 6-18 on page 6-35 of Exhibit B-1.

Response:

The R:C ratios are calculated in the same manner as all other R:C ratios in the COSA using revenue divided by allocated costs, where revenue equals delivery margin plus cost of gas, and allocated costs equals allocated delivery costs plus cost of gas.

The cost of gas for RS 22A and 22B is equal to these rate schedules allocation of unaccounted for (UAF) gas from FEI's test year revenue requirement. UAF refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use and is associated with both the transmission and distribution system.

Since FEI moves gas across its delivery system for both Sales and Transport customers, both Sales and Transport customers receive an allocation of UAF gas and that allocation is included in the COSA for calculating the R:C ratio for RS 22A and RS 22B. Given that the UAF gas cost is small, the R:C ratios are nearly equal to the M:C ratios for RS 22A and 22B.

15.3 Please take into consideration Schedule 1 (Fully Distributed Cost of Service Allocation with R:C and M:C ratios) in Appendix 6-4 of Exhibit B-1 and explain whether FEI is in agreement with Elenchus' statement shown in the preamble.

Response:

FEI agrees with Elenchus' statement in the preamble. Since the same cost of gas amount is added to both the numerator and denominator in the R:C ratio for each rate schedule, Elenchus' statement is a mathematical certainty.

15.4 Based on FEI's explanation of R:C and M:C ratios and Elenchus' statement on R:C and M:C ratios in the preamble, please explain if FEI considers that an R:C ratio range of 0.90 to 1.10 (+/- 10%) is equivalent to a M:C ratio range of the same 0.90 to 1.10 (+/- 10%).

Response:

No. R:C and M:C ratios are not mathematically equivalent, and an R:C ratio range of 0.90 to 1.10 (+/- 10 percent) is not equivalent to a M:C ratio range of the 0.90 to 1.10 (+/- 10 percent). As described in Section 6.5.1 of the Application, FEI considers 0.90 – 1.10 to be the appropriate range when examining R:C ratios. As described by Elenchus in the preamble, the equivalent M:C ratio range would be wider than 0.90 – 1.10.

15.5 Based on FEI's explanation of R:C and M:C ratios and Elenchus' statement on R:C and M:C ratios in the preamble, please explain if an R:C ratio range should be greater than a M:C ratio range in order to be applied in an equivalent manner during rate design.

Response:

To provide an equivalent basis for determining the need for rebalancing, the M:C ratio range should be wider than the R:C ratio range, not the reverse as the question suggests. As Elenchus' indicates, for any given R:C ratio, the M:C ratio will be further away from 100%, which means that a wider range of reasonableness should be applied to the M:C ratio.

FEI has included 2 tables below that demonstrate that for any R:C ratio not equal to 100 percent, the M:C ratio moves farther from 100 percent. For both of the following tables, the only input that is different is the Delivery Margin on Line 1. The R:C ratio includes cost of gas in both the revenue and cost side of the equation, because the cost of gas is a flow through. Customers pay exactly FEI's cost of gas so that revenue equals the cost. The M:C ratio excludes the cost of gas in both the numerator and denominator of the ratio calculation.

The first table calculates the R:C and M:C ratios when Delivery Margin is greater than the allocated cost.

Line	Particulars	R:C	M:C	Description / Reference
1	Delivery Margin	750	750	Delivery Margin based on volume and existing rates
2	Cost of Gas	300		Cost of Gas based on volume and market based gas costs
3	Total Revenue	1050	750	Line 1 + Line 2
4				
5	Allocated Delivery Cost	700	700	Allocated Delivery Cost of Service from COSA Study
6	Cost of Gas	300		Line 2
7	Total Cost	1000	700	Line 5 + Line 6
8				
9	**Ratio**	**105.0%**	**107.1%**	Line 3 / Line 7

As can be seen on line 9, the equivalent M:C is further from 100 percent than the R:C.

The second table calculates the R:C and M:C ratios when Delivery Margin is less than the allocated cost.

Line	Particulars	R:C	M:C	Description / Reference
1	Delivery Margin	650	650	Delivery Margin based on volume and existing rates
2	Cost of Gas	300		Cost of Gas based on volume and market based gas costs
3	Revenue	950	650	Line 1 + Line 2
4				
5	Allocated Delivery Cost of	700	700	Allocated Delivery Cost of Service from COSA Study
6	Cost of Gas	300		Line 2
7	Total	1000	700	Line 5 + Line 6
8				
9	**Ratio**	**95.0%**	**92.9%**	Line 3 / Line 7

As can be seen on line 9, the equivalent M:C is further from 100 percent than the R:C.

When the R:C is 100 percent, the M:C is also 100 percent.

15.6 Please complete the following table by placing the calculated figures in the cells highlighted in yellow to show the impact of the inclusion of different magnitudes of the cost of gas (gas and storage and transport costs) when calculating the R:C ratio from M:C ratios of 90%. As per Schedule 1, Total Gas Cost Revenue (Row 5) should be equal to Total Cost of Gas (Row 6).

	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7
		RS 1 (1) (000's)	Scenario A (2) (000's)	Scenario B (3) (000's)	Scenario C (4) (000's)	Scenario D (5) (000's)	Scenario E (6) (000's)
Row 1	Total Delivery Revenue Margin	$ 475,312	$ 450,000	$ 450,000	$ 450,000	$ 450,000	$ 450,000
Row 2	Allocated Cost of Service	$ 510,655	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
Row 3	**Margin to Cost (M:C) Ratio**	**93.1%**	**90.0%**	**90.0%**	**90.0%**	**90.0%**	**90.0%**
Row 4							
Row 5	Total Gas Cost Revenue	$ 287,646	$ 450,000				
Row 6	Total Cost of Gas	$ 287,646	$ 450,000				
Row 7							
Row 8	Total Revenue *(Row 1 + Row 5)*	$ 762,958	$ 900,000				
Row 9	Total Cost of Service *(Row 2 + Row 6)*	$ 798,301	$ 950,000				
Row 10							
Row 11	**Revenue to Cost (R:C) Ratio**	**95.6%**	**94.7%**				

Notes
(1) RS 1 figures taken from Exhibit B-1, Appendix 6-4, Schedule 1
(2) Scenario A: Delivery Revenue Margin (50%), Gas Cost Revenue (50%)
(3) Scenario B: Delivery Revenue Margin (60%), Gas Cost Revenues (40%)
(4) Scenario C: Delivery Revenue Margin (70%), Gas Cost Revenues (30%)
(5) Scenario D: Delivery Revenue Margin (40%), Gas Cost Revenues (60%)
(6) Scenario E: Delivery Revenue Margin (30%), Gas Cost Revenues (70%)

Response:

As demonstrated in the following table, as the proportion of the Delivery Margin to Total Revenue or Cost of Gas Revenue to Total Revenue changes by increments of 10 percent, while holding the Delivery Revenue Margin (Row 1) and the Allocated Cost of Service (Row 2) constant, the Revenue to Cost Ratio changes by 1 percent with each 10 percent change, from a low of 93 percent (Scenario C) to a high of 97 percent (Scenario E).

	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7
		RS 1(1) $000's	Scenario A (2) ($000's)	Scenario B (3) ($000's)	Scenario C (4) ($000's)	Scenario D (5) ($000's)	Scenario E (6) ($000's)
Row 1	Total Delivery Revenue Margin	$ 475,312	$ 450,000	$ 450,000	$ 450,000	$ 450,000	$ 450,000
Row 2	Allocated Cost of Service	$ 510,655	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
Row 3	**Margin to Cost Ratio (M:C) Ratio**	93.1%	90.0%	90.0%	90.0%	90.0%	90.0%
Row 4							
Row 5	Total Gas Cost Revenue	$ 287,646	$ 450,000	$ 300,000	$ 192,857	$ 675,000	$ 1,050,000
Row 6	Total Cost of Gas	$ 287,646	$ 450,000	$ 300,000	$ 192,857	$ 675,000	$ 1,050,000
Row 7							
Row 8	Total Revenue (Row 1 + Row 5)	$ 762,958	$ 900,000	$ 750,000	$ 642,857	$ 1,125,000	$ 1,500,000
Row 9	Total Cost of Service (Row 2 + Row 6)	$ 798,301	$ 950,000	$ 800,000	$ 692,857	$ 1,175,000	$ 1,550,000
Row 10							
Row 11	**Revenue to Cost (R:C) Ratio**	95.6%	94.7%	93.8%	92.8%	95.7%	96.8%

Notes
(1) RS 1 figures taken from Exhibit B-1, Appendix 6-4, Schedule 1
(2) Scenario A: Delivery Revenue Margin (50%), Gas Cost Revenue (50%)
(3) Scenario B: Delivery Revenue Margin (60%), Gas Cost Revenue (40%)
(4) Scenario C: Delivery Revenue Margin (70%), Gas Cost Revenue (30%)
(5) Scenario D: Delivery Revenue Margin (40%), Gas Cost Revenue (60%)
(6) Scenario E: Delivery Revenue Margin (30%), Gas Cost Revenue (70%)

15.7 Please complete the following table by placing the calculated figures in the cells highlighted in yellow to show the impact of the inclusion of different magnitudes of the cost of gas (gas and storage and transport costs) when calculating the R:C ratio from M:C ratios of 110%. As per Schedule 1, Total Gas Cost Revenue (Row 5) should be equal to Total Cost of Gas (Row 6).

	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7
		RS 2 (1) (000's)	Scenario A (2) (000's)	Scenario B (3) (000's)	Scenario C (4) (000's)	Scenario D (5) (000's)	Scenario E (6) (000's)
Row 1	Total Delivery Revenue Margin	$ 133,094	$ 143,000	$ 550,000	$ 550,000	$ 550,000	$ 550,000
Row 2	Allocated Cost of Service	$ 129,862	$ 130,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
Row 3	**Margin to Cost (M:C) Ratio**	**102.5%**	**110.0%**	**110.0%**	**110.0%**	**110.0%**	**110.0%**
Row 4							
Row 5	Total Gas Cost Revenue	$ 111,133	$ 143,000				
Row 6	Total Cost of Gas	$ 111,133	$ 143,000				
Row 7							
Row 8	Total Revenue *(Row 1 + Row 5)*	$ 244,227	$ 286,000				
Row 9	Total Cost of Service *(Row 2 + Row 6)*	$ 240,995	$ 273,000				
Row 10							
Row 11	**Revenue to Cost (R:C) Ratio**	**101.3%**	**104.8%**				

Notes

(1) RS 2 figures taken from Exhibit B-1, Appendix 6-4, Schedule 1

(2) Scenario A: Delivery Revenue Margin (50%), Gas Cost Revenue (50%)

(3) Scenario B: Delivery Revenue Margin (60%), Gas Cost Revenues (40%)

(4) Scenario C: Delivery Revenue Margin (70%), Gas Cost Revenues (30%)

(5) Scenario D: Delivery Revenue Margin (40%), Gas Cost Revenues (60%)

(6) Scenario E: Delivery Revenue Margin (30%), Gas Cost Revenues (70%)

Response:

Similar to the results in response to BCUC-FEI IR 1.15.6, the change in the revenue to cost ratio is 1 percent with each 10 percent increment in the proportion of delivery margin revenue to total revenue - the lowest being Scenario E at 103 percent and the highest being Scenario C at 107 percent. Although the Delivery Margin and Allocated Cost of Service (Row 2) change significantly from Scenario A to Scenario B, as long as the Delivery Margin share of the total revenue remains unchanged, the change in the Revenue to Cost Ratio is only 1 percent with each 10 percent change in the share of total revenue (i.e., 104.8 percent to 105.8 percent).

	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7
		RS 2[1] $000's	Scenario A[2] ($000's)	Scenario B[3] ($000's)	Scenario C[4] ($000's)	Scenario D[5] ($000's)	Scenario E[6] ($000's)
Row 1	Total Delivery Revenue Margin	$ 133,094	$ 143,000	$ 550,000	$ 550,000	$ 550,000	$ 550,000
Row 2	Allocated Cost of Service	$ 129,862	$ 130,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
Row 3	**Margin to Cost Ratio (M:C) Ratio**	102.5%	110.0%	110.0%	110.0%	110.0%	110.0%
Row 4							
Row 5	Total Gas Cost Revenue	$ 111,133	$ 143,000	$ 366,667	$ 235,714	$ 825,000	$ 1,283,333
Row 6	Total Cost of Gas	$ 111,133	$ 143,000	$ 366,667	$ 235,714	$ 825,000	$ 1,283,333
Row 7							
Row 8	Total Revenue (Row 1 + Row 5)	$ 244,227	$ 286,000	$ 916,667	$ 785,714	$ 1,375,000	$ 1,833,333
Row 9	Total Cost of Service (Row 2 + Row 6)	$ 240,995	$ 273,000	$ 866,667	$ 735,714	$ 1,325,000	$ 1,783,333
Row 10							
Row 11	**Revenue to Cost (R:C) Ratio**	101.3%	104.8%	105.8%	106.8%	103.8%	102.8%

Notes
(1) RS 1 figures taken from Exhibit B-1, Appendix 6-4, Schedule 1
(2) Scenario A: Delivery Revenue Margin (50%), Gas Cost Revenue (50%)
(3) Scenario B: Delivery Revenue Margin (60%), Gas Cost Revenue (40%)
(4) Scenario C: Delivery Revenue Margin (70%), Gas Cost Revenue (30%)
(5) Scenario D: Delivery Revenue Margin (40%), Gas Cost Revenue (60%)
(6) Scenario E: Delivery Revenue Margin (30%), Gas Cost Revenue (70%)

F. CHAPTER 7 – RATE DESIGN FOR RESIDENTIAL CUSTOMERS

16.0 Reference: RATE DESIGN FOR RESIDENTIAL CUSTOMERS

Exhibit B-1, Section 7.2.2, p. 7-4;

BC Hydro 2015 Rate Design Application, Exhibit B-23, BCUC IR 2.174.2;

FEU 2014 LTRP, Exhibit B-1, pp. 20, 21, Order G-189-14 and Decision dated December 3, 2014, p. 38

Cost competitiveness

FEI states on page 7-4 of the Application that there is an increasing share of electricity use for space heating for residential customers and domestic water heating.

BC Hydro stated in response to BCUC IR 2.174.2 in the 2015 Rate Design Application:

> There are a number of factors to consider when comparing the cost competitiveness between natural gas and electric space and water heating and individual consumers may put more or less weight on certain factors. As described in the preamble to this IR the FEU 2014 LTRP identified that natural gas is less expensive for space and water heating on an energy cost basis based on current market pricing, however, natural gas systems can carry a much higher up front cost than electric baseboards. BC Hydro agrees with FEU's view that the higher upfront capital cost of natural gas end-use applications erodes the cost advantage of natural gas compared to electricity and plays an important role in influencing customer energy choice for space and water heating.

The Commission's decision on the FEU 2014 LTRP states on page 38:

> Consistent with the Commission's determination in Order G-120-11, the Commission Panel finds that (i) the FEU's objective of maintaining the competitiveness of natural gas with other energy sources is inappropriate and should not be included in a future PRMP…

In the 2014 FEU LTRP Application, FEU provided a comparison of gas rates to BC Hydro Step 1 and Step 2 electricity rates (Figure 2-5, p. 20), and a comparison of the cost difference for space and water heating – natural gas vs. electricity (p. 21, Table 2-1).

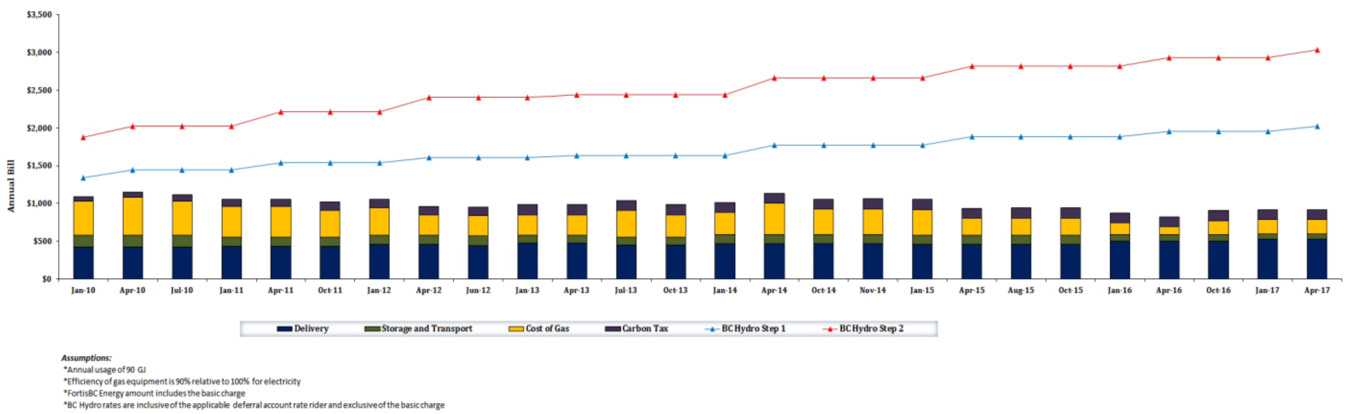
16.1 Please update Figure 2-5 and Table 2-1 provided in the 2014 FEU LTRP Application using BC Hydro's current rates and: (i) FEI's existing residential rate, and (ii) FEI's proposed residential rate.

<u>Response:</u>

Please refer to the figure and table below, which update Figure 2-5 and Table 2-1 provided in the 2014 FEU LTRP Application with BC Hydro's current Rate Schedule 1101 Residential rates effective April 1, 2017, and FEI's current RS 1 Residential rates effective January 1, 2017. FEI has also updated the capital and maintenance costs in Table 2-1 with more recent information that was filed in its Application for Common Equity Component and Return on Equity.

As set out in the Application, FEI is not requesting Commission approval of Residential rates effective June 1, 2018 (except for approval of a Basic Charge per Day of $0.4085 per day), but rather a specific amount of change to the Delivery Charge per GJ that will be in place at the time the rates are implemented. Therefore, FEI is not able to include specific proposed June 1, 2018 rates in the figure and table below.

FEI Residential Annual Natural Gas Rates Compared with BC Hydro Residential Electric Rates



Capital Cost Difference for Space and Water Heating – Natural Gas vs. Electricity[7,8]

	Space Heating	Water Heating
Capital costs for natural gas	$9,000	$2,000
Capital costs for electricity	$4,435	$1,000
Upfront capital cost premium for natural gas compared to electricity	**$4,565**	**$1,000**
Annual difference in capital costs[1]	$422	$116
Annual maintenance costs	$100	$0
Total annual difference in capital and maintenance costs	**$522**	**$116**
Energy consumption per year (GJ)	38	22
Difference in cost between natural gas and electricity over measurable life ($/GJ)	**$13.84**	**$5.25**

[1] Represents the difference in capital costs per year, assuming a stream of equal annual payments with an interest rate of 6% and a measureable life of 18 years for a space heating furnace and 13 years for a hot water tank.

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7 Analysis based on Tables C-6 and C-7 of Appendix C of the FEI Application for its Common Equity Component and Return on Equity for 2016.

8 Assumptions based on the new construction of a home in the Lower Mainland (Medium Size Dwelling at approximately 3,000 square feet).

17.0 Reference: RATE DESIGN FOR RESIDENTIAL CUSTOMERS

Exhibit B-1, Section 7.2.3, pp. 7-5 to 7-6

Residential consumption pattern

On page 7-5 of Exhibit B-1, FEI states:

> 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.

17.1 Please provide the standard deviation for the 2015 residential annual consumption.

Response:

The standard deviation for the 2015 residential annual consumption per customer as depicted in Figure 7-5, which excludes outliers, is approximately 44 GJ/year.

17.2 Please complete the following table, to the best of your ability, to provide a breakdown of the number of residential customers for different levels of annual normalized consumption from 2011 to 2015. Please use the increments provided in the table and the notes below the table.

Year	Number of FEI residential customers (1) with an annual normalized consumption of:							Total Residential Customers
	0 - 10 GJ	11 - 20 GJ	21 - 30 GJ	...	231 - 240 GJ	240 - 250 GJ	> 250 GJ	
2015								886,169
2014								873,661
2013								863,189
2012								854,050
2011								860,403

Notes:
(1) Use increments of 10 GJ
(2) Actual residential customer totals taken from Exhibit B-2, Appendix A2, Section 2, p. 2 of the FEI Annual Review for 2017 Rates proceeding

Response:

The requested data is provided below. Note that the table is split into three sections to accommodate all of the consumption ranges.

Year	0-10	10-20	20-30	30-40	40-50	50-60	60-70	70-80
2015	26,037	32,321	40,947	52,592	66,074	79,363	88,191	89,693
2014	26,368	30,991	37,739	49,266	62,545	76,296	86,084	89,247
2013	25,615	32,164	39,343	50,472	63,469	77,422	87,066	89,216
2012	25,111	31,161	36,618	46,474	57,730	71,428	81,255	85,952
2011	25,001	30,508	35,373	44,797	56,492	69,365	80,131	84,228

80-90	90-100	100-110	110-120	120-130	130-140	140-150	150-160	160-170
82,720	71,000	58,047	45,227	35,090	26,486	20,399	15,499	12,110
83,537	72,313	58,920	46,691	35,787	27,237	20,959	15,940	12,194
82,214	70,516	56,833	44,375	34,110	25,852	19,798	14,959	11,563
82,648	72,834	60,673	47,955	37,214	27,952	21,328	16,278	12,301
81,295	72,440	60,405	48,443	37,841	28,876	22,127	16,901	13,108

170-180	180-190	190-200	200-210	210-220	220-230	230-240	240-250	>250	Total
9,347	7,464	5,786	4,472	3,469	2,666	2,102	1,674	304	879,080
9,488	7,657	5,776	4,442	3,562	2,633	2,153	1,638	23	869,486
8,923	7,045	5,227	4,190	3,175	2,465	1,878	886	-	858,776
9,650	7,351	5,712	4,455	3,452	2,608	2,006	1,494	-	851,640
10,059	7,608	6,131	4,770	3,569	2,784	2,186	1,711	355	846,504

Note that the customer totals do not match those in the preamble but do reconcile to the numbers included in Figure 7-5. As noted on page 7-5 of the Application, Figure 7-5 excludes outliers, defined as those data points beyond the 99 percentile.

17.2.1 If FEI is unable to respond to the previous question, please explain why and explain the cost, time and effort in person-hours that is required to respond to this information request.

Response:

FEI was able to respond to the question. Please refer to the response to BCUC-FEI IR 1.17.2.

17.2.2 Please provide copies of Figure 7-5 showing the:

i. 2014 Residential Normalized Consumption Distribution

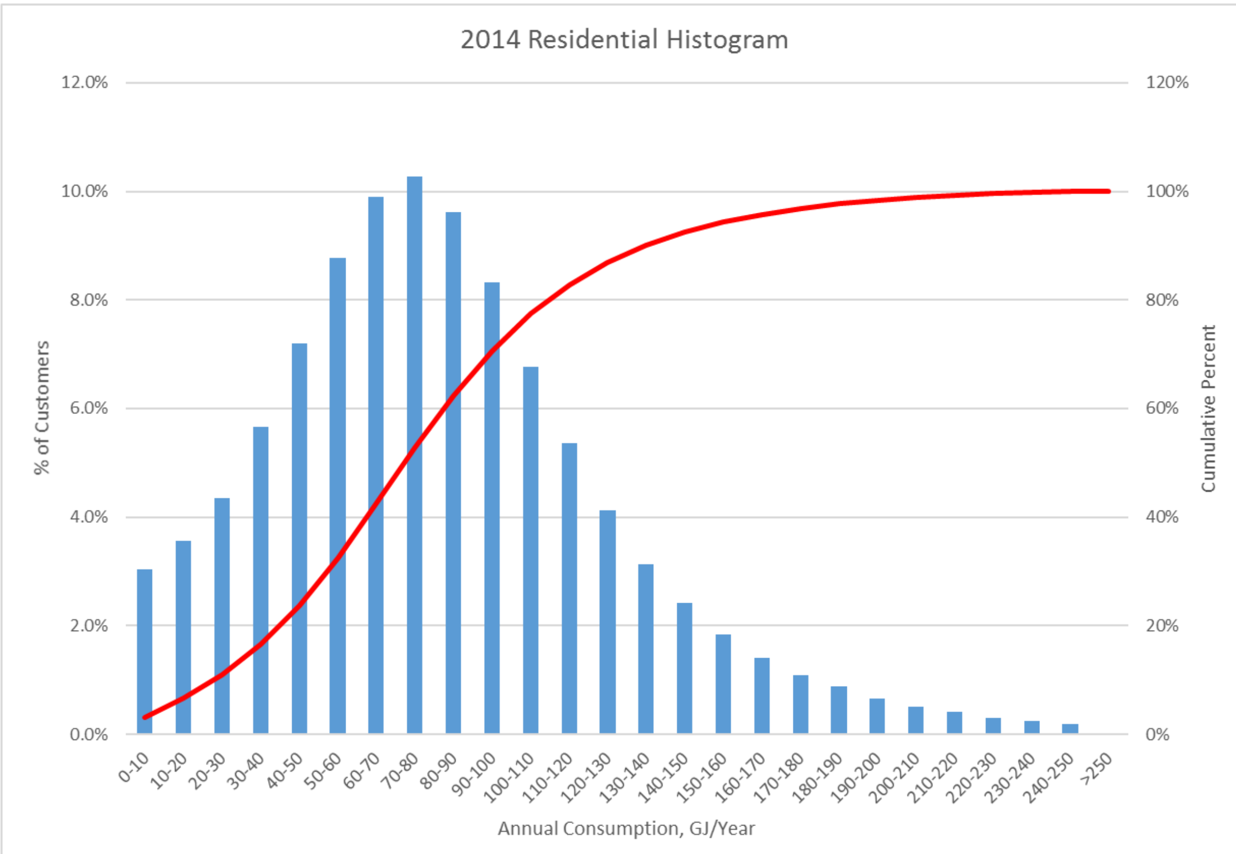
ii. 2013 Residential Normalized Consumption Distribution

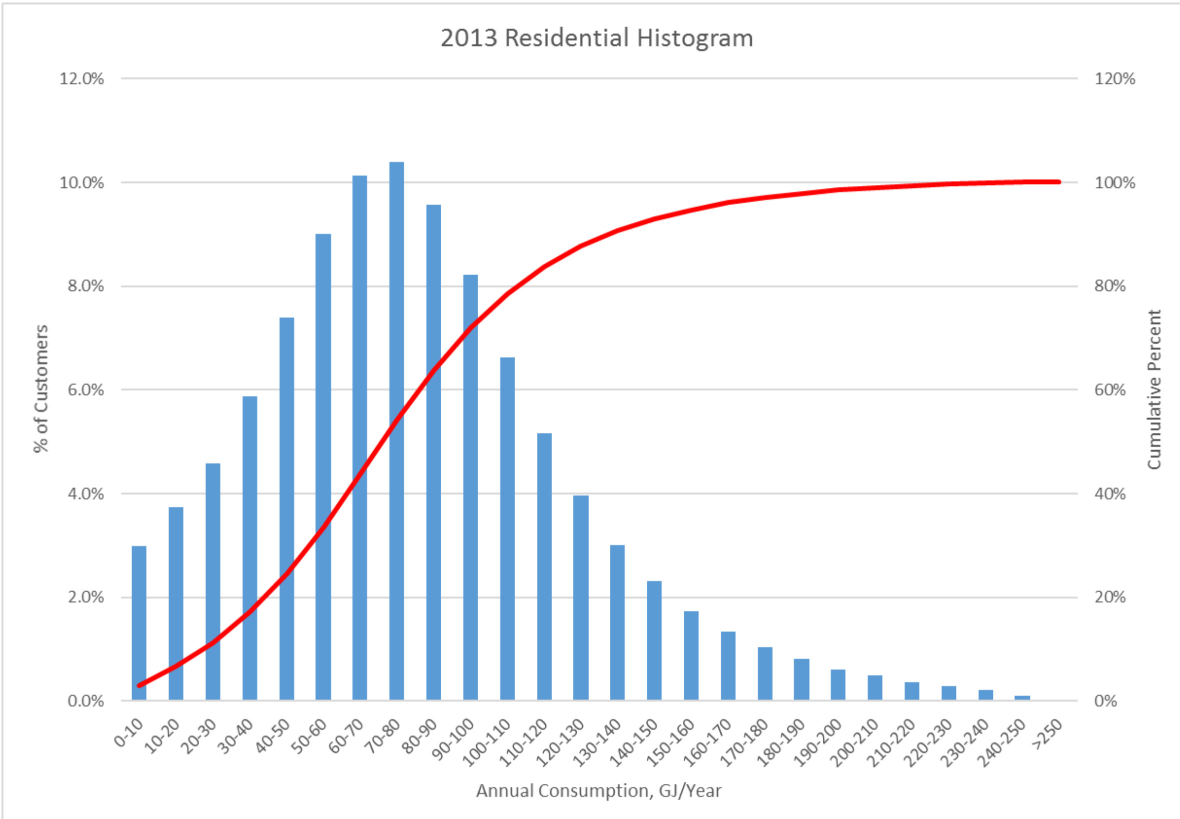
iii. 2012 Residential Normalized Consumption Distribution

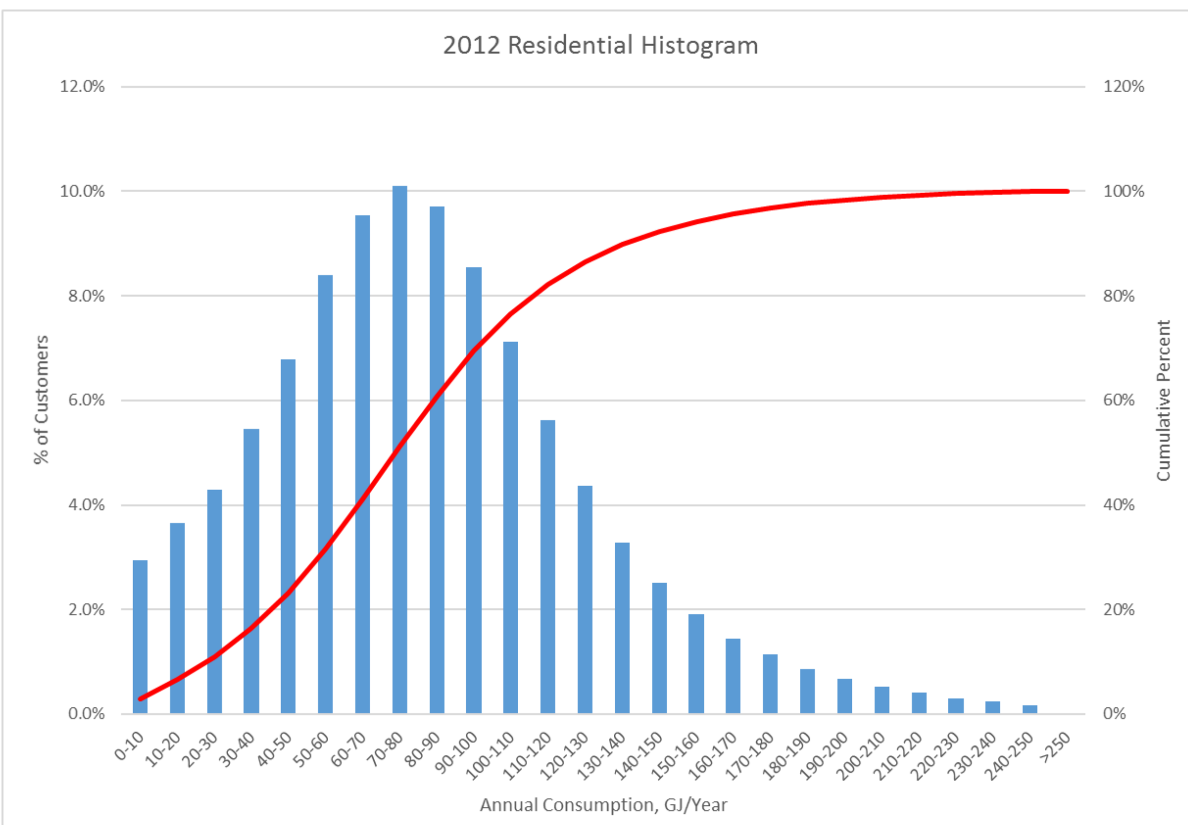
iv. 2011 Residential Normalized Consumption Distribution

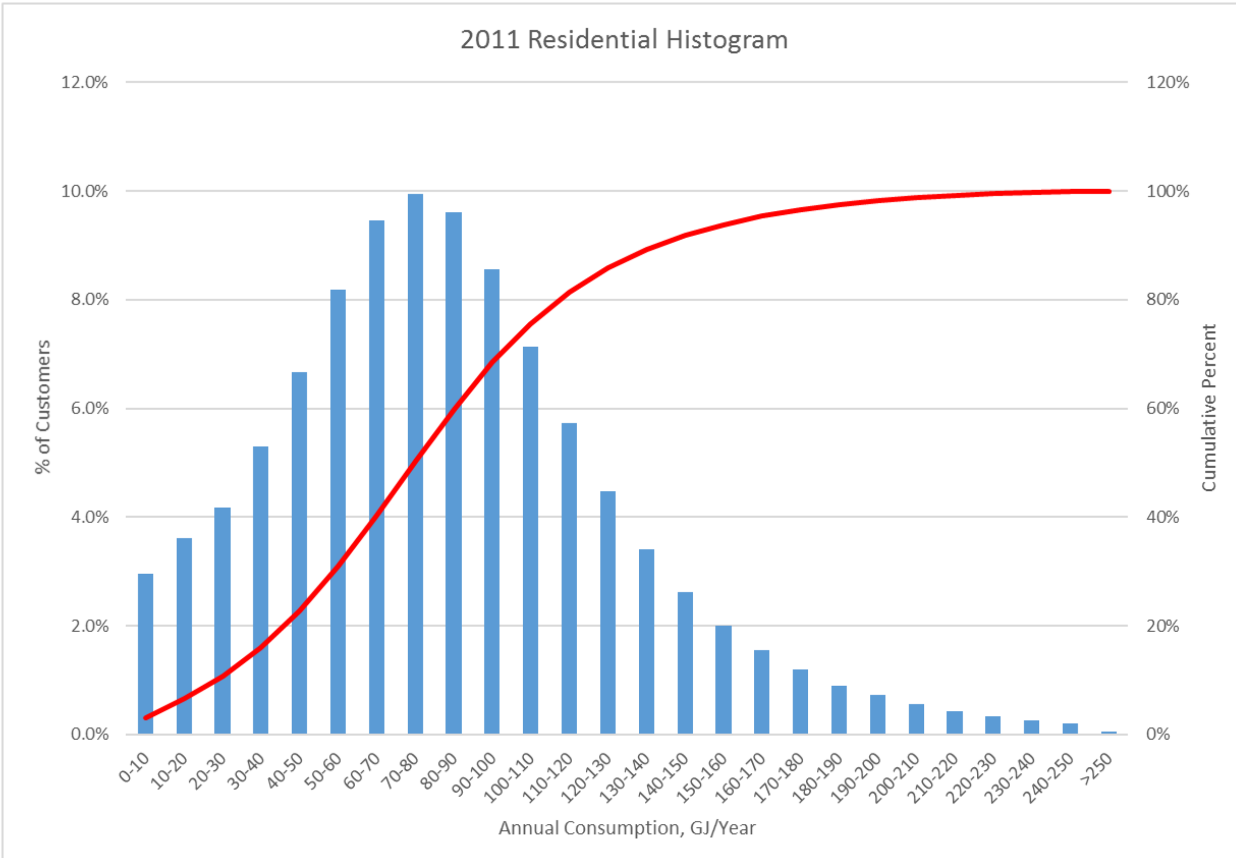
Response:

The requested histograms are provided below.



1

2013 Residential Histogram
% of Customers
Cumulative Percent
Annual Consumption, GJ/Year

2

2012 Residential Histogram
% of Customers
Cumulative Percent
Annual Consumption, GJ/Year



17.3 Please describe and compare the following attributes for (i) customers consuming equal to or less than 20 GJ/year; (ii) customers consuming from 70 to 90 GJ/year; and (iii) customers consuming greater than 140 GJ/year:

i. end uses (furnaces, boilers, domestic water heaters, and fireplaces, range and BBQ);

ii. typical load factor;

iii. price elasticity estimate as it relates to the variable charge; and

iv. any significant non-energy benefits (for example, environmental for BBQ use, customer satisfaction for cooking etc.)

Response:

FEI provides the following answers:

(i) End uses (furnaces, boilers, domestic water heaters, and fireplaces, ranges and BBQs): FEI does not have any record of the actual appliances used by its existing customers. Nevertheless, the results of the 2012 Residential End-Use survey (REUS) can be used to provide a general response to this question. The 2012 REUS indicates that the majority of customers consuming less than 20 GJ/year use electricity as their primary heating fuel source, with electric baseboards as the most used heating method. Almost half of these customers use natural gas fireplaces as their secondary space heating method. Similarly, electricity is the main fuel source for water heating in this group. Additionally, approximately 15 percent have natural gas ranges and 30 percent of these customers have natural gas BBQs.

(ii) The REUS shows that natural gas is the primary source of space and water heating for customers consuming between 70 and 90 GJ/year. The natural gas furnace is the primary space heating method for this group. Approximately 20% of customers in this group have natural gas ranges and natural gas BBQs.

(iii) The results for customers consuming more than 140 GJ/year is similar to the customers consuming between 70 and 90 GJ/year, as the majority of customers in this group use natural gas as their primary space and water heating fuel source. Similarly, natural gas furnaces are the primary space heating method. More than 25 percent of customers in this group have natural gas ranges and approximately 30 percent use natural gas BBQs as well.

(iv) Typical load factor: Figure 7-8 of the Application provides a scatter plot for the estimated load factor for RS 1 customers and their respective annual consumption. This figure demonstrates that customers consuming less than 20 GJ/year can have both high and low load factors indicating that there is no "typical" load factor associated with this group of residential customers. The customers consuming between 70 to 90 GJ per year also have a broad range of load factors with the majority of these customers having load factors between 20 to 40 percent. For customers consuming more than 140 GJ, the range of estimated load factors is slightly smaller and typically around 25 to 35 percent.

(v) Price elasticity estimate as it relates to the variable charge: The requested information is not available. The price elasticity studies are typically at a higher level of aggregation (residential, commercial and industrial) and do not separate customers based on consumption.

(vi) Any significant non-energy benefit (for example, environmental for BBQ use, customer satisfaction for cooking): There is no clear relationship between non-energy benefits of natural gas, such as customer preference and satisfaction for cooking with natural gas, and the individual customer's consumption level.

18.0 Reference: RATE DESIGN FOR RESIDENTIAL CUSTOMERS

Exhibit B-1, Appendix 7-1, p. 1;

BC Gas Utility Ltd. Phase B Rate Design Application, Order G-101-93 and Decision dated October 25, 1993, pp. 24–25

Low Use Residential Customers

Appendix 7-1 of Exhibit B-1 contains the 2012 FEU Residential End-Use Study (REUS) dated July 16, 2014. Page 1 of 2012 FEU REUS states:

> 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.

Page 1 of the 2012 REUS then provides reasons that result in the declining use rates.

18.1 Please explain if FEI considers that the trend of declining use rates across FEU's regions has continued since the 2012 FEU REUS.

<u>Response:</u>

The trend of declining residential use rates across FEI's service territory has continued since 2012. Please refer to Figure 7-6 of the Application entitled "FEI's historical residential normalized UPC". Figure 7-6 provides the residential UPC rates from 2006 until 2015. This graph indicates that UPC has decreased from 87.6 GJ in 2012 to 84.4 GJ in 2015. In addition, despite occasional year over year UPC increases, FEI's long-term resource plan forecasts indicate that in the medium and long-term, the declining residential use per customer trend will continue.

The Commission stated in the BC Gas Utility Ltd. Phase B Rate Design Application Decision (Order G-101-93), pp. 24, 25:

> When trying to meet the objective of aligning marginal rates with LRIC, variables that can be adjusted are (1) the basic charge and (2) the intra-marginal rate (this would be the summer rate in a seasonal rate design). Thus, changes to the basic charge may be required, simply to ensure that the Utility recovers its costs, and these changes may require decreases rather than increases, even though the FDC studies indicate that the customer related costs significantly exceed the current basic charge.

> The Commission is therefore unwilling at this time to accept the full increase in the basic charge proposed by BCGUL. …

18.2 Does FEI consider that increasing the residential fixed charge could result in low-use residential customers leaving FEI's system or being reluctant to connect to FEI's system? Please explain your response.

Response:

In general, residential customers are known to have low elasticity of demand, meaning that their demand for natural gas does not significantly change with changes in price levels. Therefore, it is unlikely that a small increase of 5 percent in Basic Charge along with a corresponding decrease in volumetric charge will lead to a material decrease in number of customers. Previous increases in FEI's Basic Charge, such as the 15 percent increase in the Basic Charge from the 2001 rate design decision, did not lead to a material decrease in the number of customers. Nevertheless, if the magnitude of increase in fixed charges is significant, low-use customers such as those with convenience load (for instance, customers who use natural gas only for fireplaces, BBQs or dryers) may decide to leave the system.

With regard to new customers, developers and builders are the primary decision-makers for attaching to the natural gas distribution network and small increases to fixed charges are unlikely to have a negative impact on their decisions. An increase to the Basic Charge could potentially have a positive impact on new connections, by increasing the economic viability of main extensions under the Main Extension test (MX test) as discussed in the response to BCUC-FEI IR 1.6.2.

18.3 Please explain, with calculations, if the (i) existing rate design; and (ii) the proposed rate design results in low-use customers paying less than their customer-related costs according to the COSA?

Response:

The table below provides the monthly bill amount as well as the percentage of customer attributed cost recovered from the monthly average bill amount for various low consumption levels under the two requested scenarios: (i) existing rate design (no change in Basic Charge) and (ii) proposed rate design (i.e., a 5 percent increase in the Basic Charge and offsetting decrease in the volumetric charge).

Annual Consumption (GJ)	Average Monthly Consumption (GJ)	Existing rate design (no change in basic charge)		Proposed rate design	
		Monthly bill amount	% of customer related cost recovery	Monthly bill amount	% of customer related cost recovery
0	0	$ 11.8	44%	$ 12.43	46%
6	0.5	$ 14.3	53%	$ 14.81	55%
12	1	$ 16.7	62%	$ 17.18	63%
18	1.5	$ 19.1	70%	$ 19.55	72%
24	2	$ 21.5	79%	$ 21.93	81%
30	2.5	$ 23.9	88%	$ 24.30	90%
36	3.0	$ 26.3	97%	$ 26.67	98%

As can be seen in the table above, in the extreme case of a customer with zero annual use, the monthly bill amount will only recover 44 percent and 46 percent of customer-related costs for the existing and proposed rate designs, respectively. With increases in consumption levels, the percentage of recovery gradually increases. For instance, at 24 GJ annual consumption, the average monthly bill amounts will recover 79 percent and 81 percent of average customer-related costs for the existing and proposed rate designs, respectively. At annual consumptions above 36 GJ, the percentage of recovery will be close to 100 percent. This analysis shows that the proposed rate design with a one-time revenue-neutral 5 percent increase in the Basic Charge improves the cost recovery by approximately 2 percent.

18.3.1 Please calculate the annual residential consumption in GJ that is required for FEI to recover customer-related costs as determined by the COSA study through:

i. The existing rate design; and

ii. The proposed rate design.

Response:

This response also addresses BCUC-FEI IR 1.18.3.2, which requests the same information but for the total of both the customer-related and demand-related costs.

The minimum annual consumption required can be calculated based on the following formula:

Minimum annual consumption = (Annual average cost[9] - Daily Basic Charge*365.25) / Volumetric charge

Based on the above formula and the average customer-related and total fixed costs (sum of demand and customer-related costs) provided in Table 7-5 of the Application, the annual consumption thresholds required to recover these costs under the two requested scenarios are as follows:

Description	Existing rate design	Proposed rate design
Daily Basic Charge	$ 0.3890	$ 0.4085
Volumetric Charge	$ 4.832	$ 4.746
Annual consumption to recover customer-related costs (GJ)	38	37
Annual consumption to recover sum of demand and customer-related costs (GJ)	80	80

As can be seen from the table, at the current Basic Charge level of $0.389 per day, customers consuming less than approximately 38 GJ per year do not pay all of their allocated customer-related costs. If the Basic Charge is increased by 5% and the volumetric charge decreased by an offsetting amount, the minimum annual consumption under which the customer does not pay the allocated customer-related costs decreases to approximately 37 GJ per year.

Similarly, the minimum annual consumption required to recover total fixed costs in both scenarios is close to FEI's average use at approximately 80 GJ. The approximately equal consumption level calculated in both scenarios reflects the fact that for an average use customer the proposed increase in the Basic Charge is revenue neutral.

18.3.2 Please calculate the annual residential consumption in GJ that is required for FEI to recover both customer-related costs and demand-related costs as determined by the COSA study through:

i. The existing rate design; and

ii. The proposed rate design.

Response:

Please refer to the response to BCUC-FEI IR 1.18.3.1.

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9 Customer-related or sum of demand and customer related costs.

18.4 If feasible, using the FEI COSA study, please unbundle the residential customer class into two segments: (i) consuming at or below 20 GJ/year, and (ii) consuming above 20 GJ/year. Please provide the R:C and M:C ratios of these two customer segments, and comment on whether FEI's analysis indicates that low-use residential customers could be set up as a separate rate class.

Response:

To respond to this question, in the COSA model FEI separated customers in RS 1 into two segments, RS 1 > 20 GJ per year (RS 1A) and RS 1 <= 20 GJ per year (RS 1B). FEI assumed that the customer weighting factors for both meters and services and administration and billing are the same for RS 1A and RS 1B. This is a reasonable assumption but FEI recognizes that the customer weighting factor for meters and services for RS 1B could be slightly less because of the nature of the location of these customers in multi-family dwellings, which can have multiple meters on one service line.

The R:C and M:C ratios for the two separated residential groups can be found in the following table.

Rate Schedule	R:C	M:C
RS 1A (Consumption > 20 GJ/yr)	96.6%	94.6%
RS 1B (Consumption <= 20 GJ/yr)	61.6%	57.0%

As can be seen in the table above, the R:C and M:C ratios for the RS 1B group are lower than that of RS 1A. The Basic Charge for the residential group collects approximately 45 percent of the customer and demand related costs; consequently, the balance of these costs must be recovered through the volumetric charge. With the lower volume customers consuming less than the average there is a smaller volume over which to collect the balance of the allocated costs resulting in lower R:C and M:C ratio.

While this exercise identifies that low consumers within a rate schedule pay less than their allocated cost, it is also true that customers consuming more than the average are paying more than their allocated costs. This is true for all rate schedules.

In the response to BCOAPO-FEI IR 1.7.4, FEI discusses the nature of customers and costs and contends that every customer ultimately has a different cost to serve. When considering how to resolve this perceived intra-class inequity other issues must be considered such as government policy, administrative burden and customer impact.

One way to solve much of the intra-class inequity might be to increase the Basic Charge to collect more or nearly all of the customer related charges, but this would be contrary to government policy as described in Section 5.4 of the Application regarding energy conservation as it reduces the conservation price signal to consumers.

Another option could be to create a separate rate schedule with a different rate structure for customers consuming between 0 and 20 GJ annually. There are approximately 62,000 RS 1 customers that fall into this consumption range and approximately 824,000 customers that consume more than 20 GJ annually. In this scenario, the customers from these two groups that fall near the 20 GJ threshold would have to be reviewed annually (as is done with FEI's small and large commercial customers) so that if the customer's consumption changed they could be moved to the correct rate schedule. This process would be administratively costly and could result in rate instability for customers and reduce customer satisfaction. In addition, creating a separate rate schedule for low consumption customers would increase the rates and the annual bills for these customers. The increase in rates may cause some of these customers to leave the system, which would in turn increase rates for all non-bypass customers.

Finally, the under recovery from this group of customers costs all other RS 1 customers approximately $0.19 per year or 0.02 percent on the annual bill. Considering this small cross subsidization, the similar characteristics of FEI's residential customers, government policy, rate stability and the administrative burden and the costs associated with separating residential customers into two classes, maintaining one residential rate class with the rates as proposed in the Application is a balanced solution.

18.4.1 If not feasible, please explain the costs, time and effort in person-hours that will be required in order to provide the information requested.

Response:

Please refer to the response to BCUC-FEI IR 1.18.4.

19.0 Reference: RATE DESIGN FOR RESIDENTIAL CUSTOMERS

Exhibit B-1, Section 7.5.2, p. 7-18, Sections 7.8 and 7.8.1, p. 7-22;

2017 RIB Rate Report, pp. 6, 8, 9;

BC Hydro 2015 Rate Design Application, Order G-5-17 and Decision dated January 20, 2017, p. 14

Proposal and problem definition

FEI compares the existing residential rate to the proposed residential rate on page 7-22 of Exhibit B-1. FEI states on page 7-18 of Exhibit B-1: "alignment with government's energy conservation policy was the basis for the 2009 decision to hold the Basic Charge constant."

The Commission states in the 2017 RIB Rate Report on page 6:

> The RIB rates are conservation rates; that is, their purpose is to conserve energy or promote energy efficiency by providing a higher incentive, in the form of a higher rate for electricity purchased in the second tier, for higher-use customers to reduce consumption. Since it is not the purpose of the RIB rates to benefit any customers at the expense of other customers, this supports the Commission's view based on the R/C ratios that there is no undue discrimination in the RIB rate.

The Commission states in the 2017 Decision on BC Hydro's 2015 RDA:

> …the Panel notes that one of the reasons BC Hydro maintains the RIB rate as status quo is because the rate structure appears to be achieving its overall objective of encouraging conservation through customer response to higher marginal prices at the Step 2 energy rate. In the Panel's view, in assessing the rate design proposals for the various customer classes it is important to consider the efficiency criterion in balance with other principles.

19.1 Please clearly identify the problem with the existing recovery of residential costs through fixed vs. variable charges that this Application is intended to address. If the problem relates to an efficiency concern, please identify the specific concern (i.e. how is it negatively affecting customer investment/consumption decisions), and if the problem relates to a fairness concern, please provide evidence that the existing level of cost recovery is outside of fairness norms.

Response:

The fixed vs. variable revenue recovery concern is mainly an intra-class fairness issue, which must be balanced with competing rate design issues or principles, such as cost recovery, bill impacts, revenue stability, or having rate structures that align with energy conservation objectives or other government policy objectives. As discussed below, FEI's proposed one-time adjustment to the residential Basic Charge and offsetting decrease to the Delivery Charge strikes an appropriate balance between these competing considerations.

The main objective in rate design is to improve the balance among various competing rate design considerations. With the passage of time, this balance may be shifted towards one rate design principle at the expense of others and therefore there might be a need to introduce measures that can improve the situation. The 5 percent increase in the Basic Charge and corresponding decrease in the volumetric Delivery Charge proposed by FEI for the residential rate class is in line with this objective. The evidence provided in Section 7.5.1 of the Application indicates that there is a need to improve the intra-rate schedule fairness within the residential rate class so that the balance among various rate design considerations is improved. This will also improve the balance of interests between low-use residential customers and medium and high use customers.

As shown in Figure 7-9 of the Application, during the last eight years and compared to low use customers, medium and high use customers have been bearing a greater share of delivery margin increases, which has led to the intra-rate schedule imbalance. (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 percent, 30 percent, and 36 percent, respectively). This is while all residential customers receive the same safe and reliable service irrespective of their consumption level. A one-time 5 percent increase in the Basic Charge and corresponding decrease in the Delivery Charge will help to improve the imbalance in intra-rate schedule fairness, and will not have any material impact on other rate design considerations such as rate impact or government energy policy.

As explained on page 7-17 of the Application, the Commission previously approved increases in FEI's Residential Basic Charge that were higher than the 5 percent increase proposed by FEI. For example, as part of the 1996 NSA, the monthly Basic Charge was increased by approximately 11 percent from $6.32 to $7.00. In the 2001 NSA, the monthly Basic Charge was increased by 15 percent from $8.66 to $10.00. These increases were deemed to be fair by the Commission. The proposed 5 percent increase in the Basic Charge and corresponding decrease in the Delivery Charge is similarly fair and reasonable.

19.1.1 Please identify the specific changes in circumstances since 2009 which have resulted in the creation of each identified problem.

Response:

Please refer to the response to BCUC-FEI IR 1.19.1.

20.0 Reference: RATE DESIGN FOR RESIDENTIAL CUSTOMERS

Exhibit B-1, Section 7.5.1, pp. 7-17 to 7-18, Section 7.8.1, pp. 7-23 to 7-25

Fixed and variable Cost Recovery

On page 7-17 of Exhibit B-1, FEI states:

> In the current residential rate structure, the current basic charge … recovers about 44% of the customer costs and only about 27% of the total of customer and demand costs allocated to the residential rate schedule. … <u>The misalignment between fixed costs and the Basic Charge has been a re-occurring issue in FEI's rate design proceedings</u>. 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. [Emphasis added]

On page 7-22 of Exhibit B-1, FEI recommends a rate design for residential customers which:

- <u>Improves the alignment between the fixed costs allocated to the residential rate schedule and the fixed charges recovered from residential customers</u> by a one-time 5% increase to Basic Charge and corresponding decrease in the volumetric Delivery Charge. [Emphasis Added]

On page 7-23 of Exhibit B-1, Section 7.8.1, FEI states:

> 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.

20.1 Please confirm, or otherwise explain, that 56% of the customer costs and 73% of the total of customer and demand costs allocated to the residential rate schedule is recovered through the variable charge(s).

<u>Response:</u>

Confirmed.

20.2 Please provide, for each year since 2009, the percentage of total residential delivery costs recovered through (i) fixed charges and (ii) variable charges.

Response:

FEI cannot provide the requested information for all years as it would require the creation of a COSA study for each year. FEI did prepare a COSA study in 2012 using 2013 test year data, and can provide the requested percentages for that year.

In its 2012 Common Rates, Amalgamation and Rate Design Application, FEI provided a COSA study that was an amalgamated COSA including Mainland (FEI), Vancouver Island (FEVI), Whistler (FEW) and Fort Nelson (FN). At that time, all four of these areas were separate utilities with separate rate structures. To provide the information requested in this question, FEI has utilized that COSA, but assumed that the Mainland rate structure was in place for this amalgamated entity (FEI + FEVI + FEW + FN) and has used this assumption to determine the following results.

In the 2013 amalgamated COSA (which included Fort Nelson), the Basic Charge recovered about 42 percent of the customer-related costs, and about 28 percent of the total of customer and demand-related costs allocated to the residential rate schedule. The balance of the total allocated costs would be recovered through the volumetric charge. These percentages are reasonably close to the results of the current COSA.

Another point of comparison available relates to the 2001-2002 period. In 2001 and before the Commission's decision to increase the share of fixed cost recovery in the Basic Charge, the Basic Charge recovered approximately 43 percent and 24 percent of customer-related and total customer-related and demand-related costs, respectively. After the Commission's decision to increase the Basic Charge by 15 percent, these percentages improved to approximately 50 percent and 27 percent, respectively.

20.3 Please explain if FEI's proposal for "a one-time 5% increase to Basic Charge and corresponding decrease in the volumetric Delivery Charge" will result in a misalignment between fixed costs and the Basic Charge over time as the volumetric Delivery Charge is changed annually.

Response:

The proposed 5 percent increase to the Basic Charge and offsetting decrease in volumetric charge does not result in misalignment, but rather decreases the misalignment. However, it is correct that over time, as the delivery margin increases and the Basic Charge is held constant, the impact of the proposed improvement in alignment will gradually diminish. For this reason, it is important to review and potentially adjust the recovery of fixed costs from time to time.

20.4 Please provide the increase in the daily Basic Charge and the corresponding decrease in the volumetric Delivery Charge from increasing the Basic Charge by 10 and 15 percent.

Response:

The requested information is provided in the table below.

Title	COSA after Rebalancing	10% Increase in Basic Charge and offsetting Decrease in Delivery Charge	15% Increase in Basic Charge and offsetting Decrease in Delivery Charge
Daily Basic Charge ($/day)	0.3890	0.4279	0.4474
Delivery Charge ($/GJ)	4.832	4.661	4.575

20.4.1 In the same format as Table 7-9 in Exhibit B-1, page 7-25, please provide the bill impact of increasing the Basic Charge by 10 percent and 15 percent.

Response:

The following table provides the bill impact of increasing the Basic Charge by 10 percent.

Annual Consumption	Annual Bill impact due to the 10% increase in Basic Charge	
	Dollar Amount	Percentage of Total Bill
0 GJ	$14.0	10.0%
40-45 GJ	$7.0	1.4%
60-65 GJ	$4.0	0.5%
80-85 GJ	$0.0	0.0%
100-105 GJ	$(3.0)	-0.3%
120-125 GJ	$(7.0)	-0.6%

The following table provides the bill impact of increasing the Basic Charge by 15 percent.

Annual Consumption	Annual Bill impact due to the 15% increase in Basic Charge	
	Dollar Amount	Percentage of Total Bill
0 GJ	$21.0	15.0%
40-45 GJ	$10.0	2.1%
60-65 GJ	$5.0	0.8%
80-85 GJ	$0.0	0.0%
100-105 GJ	$(5.0)	-0.5%
120-125 GJ	$(10.0)	-0.8%

20.5 For the proposed FEI residential, please complete the table below in 5 GJ increments for the 0–30 GJ range and 10 GJ increments for the 31–140 GJ range. Also include fully a functional electronic spreadsheet for the data in the table.

	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9
	Annual Consumption	Annual Revenue from Proposed Basic Charge (a)	Annual Fixed Cost based on COSA Results (b)	Difference (c) = (a) - (b)	Difference as a % of Annual Fixed Cost (c) / (b)	Annual Revenue from Proposed Variable Charge (d)	Annual Variable Cost based on COSA Results (e)	Difference (f) = (d) - (e)	Difference as a % of Annual Variable Cost (f) / (e)
Row 1	0 - 5 GJ								
Row 2	6 - 10 GJ								
Row 3	11 - 15 GJ								
Row 4	16 - 20 GJ								
Row 5	21 - 25 GJ								
Row 6	26 - 30 GJ								
Row 7	31 - 40 GJ								
Row 8	41 - 50 GJ								
Row 9	51 - 60 GJ								
...	...								
	131 - 140 GJ								

Response:

For clarity FEI has renamed the columns from the table provided in the following way:

- Column 3 renamed to Annual Customer Related Cost based on COSA Results;
- Column 5 renamed to Difference as a percent of Annual Customer Related Costs;
- Column 6 renamed to Annual Revenue from Proposed Volumetric Charge;
- Column 7 renamed to Total Annual Cost based on COSA Results to be recovered through Volumetric Charge; and

- Column 8 renamed to Difference as a percent of costs to be recovered through Volumetric Charge.

It is important to note that both customer-related and demand-related costs are predominantly fixed. Of the total delivery costs, there are very few costs that are variable with consumption. Because FEI's costs are predominantly fixed each customer within a rate schedule is responsible for the same amount, and for this response FEI is describing this as the annual revenue responsibility of each customer. FEI assumes that the annual revenue from proposed Basic Charge (column 2) plus the annual revenue from proposed volumetric charge (column 6) sums to the annual revenue responsibility of each customer.

The annual revenue responsibility of each customer is calculated in the following manner. The total RS 1 COSA allocated costs equal $504,452 thousand[10] multiplied by 94.4 percent M:C ratio[11] equals $476,203 thousand. This is the total annual revenue responsibility for all customers in RS 1 and when divided by 886,652 RS 1 customers[12] the annual revenue responsibility for each customer equals $537.

Column 2 is populated using the Proposed Daily Basic Charge of $0.4085 (as provided in Table 7-7) * 365.25.

To populate column 3 FEI has used the customer-related costs from the COSA. The customer related costs of $305,518 thousand[13] multiplied by 94.4 percent M:C ratio[14] equals $288,409 thousand divided by 886,652 customers[15] equals a customer related cost of $325[16] per customer.

Column 6 is populated using the Proposed Delivery Charge of $4.746/GJ (as provided in Table 7-7) multiplied by consumption from column 1.

Column 7 is the annual revenue responsibility per customer of $537 less recoveries from the proposed Basic Charge of $149 from column 2 which equals $388. This column represents the costs that need to be recovered through FEI's volumetric Delivery Charge.

The requested table is provided below.

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10 Appendix 12, Schedule 4, Line 36, Rate 1.
11 Appendix 12, Schedule 1, Line 32, Rate 1.
12 Appendix 12, Schedule 7, Line 6, Rate 1.
13 Appendix 12, Schedule 4, Line 39, Rate 1.
14 Appendix 12, Schedule 1, Line 32, Rate 1.
15 Appendix 12, Schedule 7, Line 6, Rate 1.
16 Alternate calculation: $27.10 per month (from Table 7-5) multiplied by 12 months.

	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9
	Annual Consumption (GJ)	Annual Revenue from Proposed Basic Charge	Annual Customer Related Cost based on COSA Results	Difference	Difference as a % of Annual Customer Related Costs	Annual Revenue from Proposed Volumetric Charge	Total Annual Cost based on COSA Results to be recovered through Volumetric Charge	Difference	Difference as a % of costs to be recovered through Volumetric Charge
		(a)	(b)	(c) = (a) - (b)	(c) / (b)	(d)	(e) = 537 - (a)	(f) = (d) - (e)	(f) / (e)
Row 1	5	149	325	(176)	-54%	24	388	(364)	-94%
Row 2	10	149	325	(176)	-54%	47	388	(340)	-88%
Row 3	15	149	325	(176)	-54%	71	388	(317)	-82%
Row 4	20	149	325	(176)	-54%	95	388	(293)	-76%
Row 5	25	149	325	(176)	-54%	119	388	(269)	-69%
Row 6	30	149	325	(176)	-54%	142	388	(245)	-63%
Row 7	40	149	325	(176)	-54%	190	388	(198)	-51%
Row 8	50	149	325	(176)	-54%	237	388	(151)	-39%
Row 9	60	149	325	(176)	-54%	285	388	(103)	-27%
Row 10	70	149	325	(176)	-54%	332	388	(56)	-14%
Row 11	80	149	325	(176)	-54%	380	388	(8)	-2%
Row 12	90	149	325	(176)	-54%	427	388	39	10%
Row 13	100	149	325	(176)	-54%	475	388	87	22%
Row 14	110	149	325	(176)	-54%	522	388	134	35%
Row 15	120	149	325	(176)	-54%	570	388	182	47%
Row 16	130	149	325	(176)	-54%	617	388	229	59%
Row 17	140	149	325	(176)	-54%	664	388	277	71%

G. CHAPTER 8 – RATE DESIGN FOR COMMERCIAL CUSTOMERS

21.0 Reference: RATE DESIGN FOR COMMERCIAL CUSTOMERS

Exhibit B-1, Section 8.3, p. 8-11, 8-12; FEI Rate Schedule 2[17]; FEI Rate Schedule 3[18]

Economic crossover point

FEI states on page 8-11 of Exhibit B-1 that "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."

Table 8-3 on page 8-12 of Exhibit B-1 shows the economic crossover volume for RS 2 and RS 3 is 1,457 GJ.

The current rates for RS 2 and RS 3 are shown in FEI's gas tariff.

21.1 Please explain when the economic crossover point was last re-aligned, and what the crossover point was set at.

Response:

The economic crossover point was last re-aligned in the 2001 Rate Design Application. At that time, the threshold, or crossover point, between Small Commercial and Large Commercial was 2,000 GJ/year. The threshold at 2,000 GJ/year has been the same since it was originally set in the 1993 Phase B Rate Design Application.

21.2 Please explain the methodology and inputs to calculate the economic crossover point when it was last re-aligned with the customer segmentation threshold between RS 2 and RS 3.

Response:

In FEI's 2001 Rate Design, a COSA study was performed which at that time indicated that there was no need for rebalancing, i.e., no revenue shift required between the various rate classes. However, FEI noted that the rates in place at that time resulted in a crossover at 1,280 GJ between the Commercial rate schedules, and that adjustments to the Basic Charge and Delivery Charge were necessary for Rate Schedules 2 and 3/23 to achieve an economic crossover at 2,000 GJ. Since no rebalancing was required between classes, a requirement was that the changes made to the rates for RS 2 would also need to yield the same total revenue for

[17] https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasTariffs/Documents/RateSchedule_2.pdf.
[18] https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasTariffs/Documents/RateSchedule_3.pdf.

RS 2 and similarly the changes to the rates for RS 3/23 would need to result in the same total revenue for RS 3/23. Inputs needed to complete this calculation were the Basic Charge ($/Month), Delivery Charge ($/GJ), Cost of Gas ($/GJ), the number of customers and annual volumes for each of the rate schedules.

The objective of the RS 2 and RS 3/23 changes was that the revised rates for RS 2 and RS 3 should result in the same annual customer bill at a consumption level of 2,000 GJ and achieve the same total revenues in each of RS 2 and RS 3/23. Achieving this required changes to the Basic Charge and Delivery Charge of both rate schedules.

21.3 Please explain whether the methodology to calculate the economic crossover point as presented in Table 8-3 differs from those described above. If yes, please elaborate and explain the rationale for any differences.

Response:

The methodology used to determine the economic crossover point is the same in the current Application as it was in FEI's 2001 RDA, except for one variation. In 2001 the total revenues from RS 2 and RS 3 were held unchanged. The changes in the Basic Charge and Delivery Charge moved the economic crossover to 2,000 GJ.

In the 2016 Rate Design Application the rates have been changed so that the economic crossover is at 2,000 GJ (same methodological result as in 2001), but the rates also result in an equal offsetting revenue shift between RS 2 and RS 3/23 (this is different from 2001). The reason for the revenue shift was to limit the maximum bill impact any customer would experience to a maximum of 10 percent. As can be seen in Exhibit B-1, Table 12-2, Page 12-5, an approximately $1.2 million revenue shift occurs between RS 2 and RS 3/23.

Also in the current Application, the rates used in Table 8-3 to calculate the crossover are the estimated COSA-Based rates (refer to Table 12-4 on Page 12-8 for the Basic Charge and Delivery Charge), i.e., the 2016 approved rates plus known and measureable changes (discussed in Section 6 of the Application). FEI views the inclusion of known and measurable changes as an appropriate refinement to the COSA study, rather than a change to the RS 2 / RS 3 economic crossover methodology.

If the statement in the preamble, "The current rates for RS 2 and RS 3 are shown in FEI's gas tariff", is implying that current RS 2 and RS 3 rates are used in the economic crossover calculation in the Application that would be incorrect. Please refer to the response to BCUC-FEI IR 1.21.5 where the crossover is calculated using the current tariff rates.

21.4 Please explain whether the rates used to calculate the economic crossover point as shown in Table 8-3 includes all rate riders. If not, why not?

Response:

The economic crossover rates as shown in Table 8-3 do not include rate riders. FEI has not included rate riders in the crossover calculation in its Rate Design Applications for the following reasons.

1. Rate rider recoveries are not part of the current period utility revenues from customers, but are recoveries or refunds of previous period deferred charges.
2. Rate riders related are generally temporary in duration, usually in place for a pre-determined period of time. For example, the amalgamation-related rate riders are only in place to phase in the transition to common rates over a three-year period, and are also set at different levels for different service areas.
3. An individual rate rider can vary between recoveries and refunds depending on whether there were over or under-recoveries of the relevant costs or revenues in the prior period.

21.5 Please replicate Table 8-3 using the current rates as referenced in the preamble, and reference the corresponding itemized rates contained in the Table of Charges in RS 2 and RS 3.

Response:

Based on approved current rates (excluding rate riders) effective April 1, 2017 applicable to Rate Schedules 2 and 3, the economic crossover point is at 1,716 GJ of annual consumption. Note that the Delivery Charge shown below is lower than those used in Table 8-3 because the original table includes known and measureable changes. Also, the Cost of Gas is lower than what was included in the 2016 Annual Review.

	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)	$ 3.523	$ 2.939		
5	Plus Cost of Gas ($/GJ)	$ 3.070	$ 2.901		
6	= Total Variable Cost ($/GJ)	$ 6.593	$ 5.840	$ 0.753	
7	Economic Crossover Point (Line 3 / Line 6)			1,716	GJ

The cost of gas for RS 2 is the sum of Storage and Transport Charge of $1.020 / GJ plus Commodity Cost Recovery Charge of $2.050 / GJ.

The cost of gas for RS 3 is the sum of Storage and Transport Charge of $0.851 / GJ plus Commodity Cost Recovery Charge of $2.050 / GJ.

21.6 Please explain what would be the threshold difference between the economic crossover point and the customer consumption threshold to require a re-alignment.

Response:

FEI recommends not specifying a threshold difference for when a realignment would be automatically triggered. The reasons for this are:

1. A review of revenue to cost ratios and rates is to be undertaken by FEI approximately every five years, and any necessary revenue rebalancing and changes to rates, including the realignment of the crossover point, can be done at that time.
2. Changes in rates will cause some misalignment. Gas cost changes can either increase or decrease the misalignment, causing the economic crossover to be greater or less than 2,000 GJ. As shown in the illustration below the $0.90/GJ – RS 2 / $0.84/GJ - RS 3 gas cost decrease only results in a $0.06/GJ gap at 2,000 GJ, but it increases the economic crossover above 2,000 GJ by approximately 180 GJ. These changes can then also reverse over a shorter time frame.

Regardless, if a trigger threshold difference were to be established, it should be large enough to leave a persistent price signal if left unaddressed. For that reason, FEI suggests that it be set at a plus or minus 500 GJ difference between the economic crossover point and the RS 2 – RS 3 consumption threshold. Where the economic crossover has moved to 500 GJ above or below the specified consumption threshold, the percentage difference at 2,000 GJ between RS 2 and RS 3 annual bills is still not large, but 500 GJ of annual load difference would be outside the year-to-year swings in consumption that might be expected to occur for customers with annual consumption near the 2,000 GJ level. A plus-or-minus 500 GJ movement in the economic crossover would also be outside the range of fluctuations in the economic crossover caused by gas cost changes.

The following illustration provides an example of how the economic threshold can change, using the change in cost of gas from the amounts included in the COSA rates to the cost of gas rates that the Commission has approved in 2017. The economic threshold moves from 2,004 GJ to 2,182 GJ and at 2,000 GJ the annual bill difference is $117. What this illustrates is that a rate change difference between RS 2 and RS 3 of approximately $0.06/GJ can cause the economic threshold to move by approximately 180 GJ. But the annual bill variance at 2,000 GJ is only $117, or less than 1 percent.

	Proposed Rates With Average Gas Costs From 2016 Annual Review			Proposed Rates With Current Cost of Gas April 1, 2017		
	RS 2	RS3	Difference	RS 2	RS3	Difference
Rate Components						
Basic Charge $ / Day	$ 0.9485	$ 4.7895		$ 0.9485	$ 4.7895	
Times number of days	365.25	365.25		365.25	365.25	
= Basic Charge Revenue	$ 346.44	$ 1,749.36	$ 1,402.93	$ 346.44	$ 1,749.36	$ 1,402.93
Delivery Charge ($ / GJ)	$ 3.664	$ 3.190		$ 3.664	$ 3.190	
Plus Cost of Gas ($/GJ)	$ 3.967	$ 3.741		$ 3.070	$ 2.901	
= Total Variable Cost ($/GJ)	$ 7.631	$ 6.931	$ 0.700	$ 6.734	$ 6.091	$ 0.643
Economic Crossover			2,004			2,182
Annual Bill at 2,000 GJ	$ 15,608.44	$ 15,611.36	$ 2.93	$ 13,814.44	$ 13,931.36	$ 116.93

22.0 Reference: RATE DESIGN FOR COMMERCIAL CUSTOMERS

Exhibit B-1, Section 8.5, p. 8-16;

BC Gas 2001 Rate Design Application Order G-116-01, Appendix 1, p. 2

Economic crossover point alignment

The Commission stated in Order G-116-01 on the BC Gas Utility Ltd. 2001 Rate Design Application (approval of the negotiated settlement, Appendix 1, p. 2):

> In order to achieve an economic breakpoint between Small Commercial Service (Rate Schedule 2) and Large Commercial Service (Rate Schedules 3/23) that approaches 2,000 GJ per year, Rate Schedules 2 and 3/23 will be revised as proposed by BC Gas in the Application under Tab 6, page 3.

On page 8-16 of Exhibit B-1, FEI explains that:

> 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.

22.1 With reference to the various components of RS 2 and RS 3, please explain the factors that contributed from an alignment to a misalignment of the economic crossover point with the customer segmentation threshold.

<u>Response:</u>

The factors that would have contributed to the misalignment over the past 15 years would be the changes in the Cost of Gas, Basic Charge, and Delivery Charge.

Since 2001 the average cost of gas has decreased significantly, albeit with periods of high gas costs such as around 2008. As demonstrated in the example in the response to BCUC-FEI IR 1.21.6, gas costs (combined commodity and midstream) declines at different rates between RS 2 and RS 3/23 can cause the economic crossover to move away from 2,000 GJ.

General increases from revenue requirements were applied to the Basic Charge and Delivery Charge in equal percentage until 2010. Since 2010, the recovery of increased revenue requirements has been flowed through only on the Delivery Charge. The practice since 2010 keeps the difference static between the RS 2 and RS 3 Basic Charges, but the difference in the RS 2 and RS 3 volumetric Delivery Charges tends to increase over time. The result is that, other components such as gas costs being equal, the economic crossover will decrease gradually.

22.2 Please explain whether the customer segmentation threshold between RS 2 and RS 3 was set at any other value than 2,000 GJ in the past.

Response:

Since the initial approval of RS 2 and RS 3 in the 1993 Phase B Rate Design the threshold between the two rate schedules has been at 2,000 GJ/year.

22.2.1 If yes, please explain the circumstance that supported a modification of the customer segmentation threshold to the existing 2,000 GJ threshold in favour of relying solely on rate changes.

Response:

Please refer to the response to BCUC-FEI IR 1.22.2.

22.3 Please explain how the proposed rate changes to the delivery and basic charge addresses each of the issues identified regarding the misalignment, namely (i) incentive to consume more, (ii) rate instability for the customer, and (iii) revenue instability for the utility.

Response:

Below is the response for each of the listed categories:

i) Incentive to Consume More – Figure 8-11 shows that for consumption above 1,500 GJ, customers would pay a lower effective rate under RS 3 than they would under RS 2. This could incent customers to move to RS 3 by consuming more gas. Under FEI's proposals, which are shown in Figure 8-12, the customer segmentation threshold and economic crossover are matched so that the incentive to increase consumption to achieve a lower rate is eliminated. For all volumes up to 2,000 GJ, a customer will pay less under RS 2 and, for all volumes above 2,000 GJ, a customer will pay less under RS 3.

ii) Customer Rate Instability – The proposed rates improve rate stability for customers. For those customers consuming at or near 2,000 GJ per year, the average cost for a customer will be the same (i.e., at 2,000 GJ) or close to being the same under either RS2 or RS 3. For customers whose normal annual consumption is close to 2,000 GJ, the current rates have a gap of approximately 25 cents per GJ; this is decreased by the proposed rates. For example, at consumption of 1,900 GJ, based on the proposed rates for RS 2 and 3 the difference in the average cost per GJ is only 3.2 cents per GJ, and at consumption of 2,100 GJ, the difference in the average cost per GJ is only 3.8 cents per GJ.

iii) Utility Revenue Instability – The increased Basic Charges for both RS 2 and RS 3/23 improves the utility revenue stability because less of the revenue is dependent on consumption. With the proposed rate realignment, the utility will experience improved revenue stability as customers are incented to receive service under the correct service offering of Small Commercial Service or Large Commercial Service and FEI will be better able to predict the revenues to be received under each of those rate schedules.

22.4 Please explain what would be the consequence of an economic crossover point that is higher than the customer segmentation threshold.

Response:

If the economic crossover point was greater than the customer segmentation threshold, customers whose normal expected consumption was greater than the customer segmentation point but less than the economic crossover point would be incented to be reclassified as Small Commercial and / or attempt to reduce their consumption to below the customer segmentation threshold.

23.0 Reference: RATE DESIGN FOR COMMERCIAL CUSTOMERS
Exhibit B-1, pp. 8-1, 8-14, 8-21
Proposed rate change

FEI states on page 8-1 of Exhibit B-1:

> FEI proposes to increase the Basic Charge 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.

In table 8-3 on page 8-21 of Exhibit B-1, FEI presents the proposed changes to the commercial rates:

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%

On page 8-14 of Exhibit B-1, FEI states

> - … 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.

23.1 Please provide the basic charge as a percentage of total bill for each of the average RS 2 and RS 3 customers.

Response:

Line 8 of the following table shows the Basic Charge as a percentage of the total customer bill for an average RS 2 customer and for an average RS 3 customer using the COSA Based Rate and the Proposed Rate for each rate schedule.

Line		RS 2 - Small Commercial COSA Based Rate	RS 2 - Small Commercial Proposed Rate	RS 3 - Large Commercial COSA Based Rate	RS 3 - Large Commercial Proposed Rate
1	Average # of Days	365.25	365.25	365.25	365.25
2	Use / Customer (GJ)	332.6	332.6	3,587	3,587
3	Basic Charge	$ 0.8161	$ 0.9485	$ 4.3538	$ 4.7895
4	Delivery Charge	$ 3.850	$ 3.664	$ 3.188	$ 3.189
5	Cost of Gas	$ 3.967	$ 3.967	$ 3.741	$ 3.741
6	Annual Basic Charge	$ 298.08	$ 346.44	$ 1,590.23	$ 1,749.36
7	Total Bill	$ 2,898.01	$ 2,884.51	$ 26,444.55	$ 26,607.27
8	Basic Charge as a % of Total Bill	10%	12%	6%	7%

23.2 Please elaborate on which competing principles support FEI's proposed changes to the basic and delivery charges for RS 2 and RS 3.

Response:

It is FEI's view, the proposed rates for Small and Large Commercial customers are in alignment with the eight Bonbright principles (Exhibit B-1, Page 5-2).

Principle 1: Recovering the Cost of Service - the proposed rates will continue to recover the cost of service.

Principle 2: Fair apportionment of costs among customers - the increase in the Basic Charges moves the Company to having appropriate cost recovery in rates.

Principle 3: Price signals that encourage efficient use and discourage inefficient use - the rate structure will encourage customers to focus on efficient consumption as there will not be a gap in the average cost at and around 2,000 GJ where it would encourage customers to consume more gas just to have a lower total bill (economic crossover consideration).

Principle 4: Customer understanding and acceptance and **Principle 5**: Practical and cost-effective to implement - no changes are being recommended as the same rate structures are being proposed.

Principle 6: Rate stability and **Principle 7**: Revenue stability – please refer to the response to BCUC-FEI IR 1.22.3.

Principle 8: Avoidance of undue discrimination - will be improved as the interclass equity will be enhanced as customers who consume approximately 2,000 GJ will have, approximately, the same cost.

23.2.1 In consideration of the competing principles, please explain FEI's process and analysis in determining the appropriate basic and delivery charges.

Response:

On page 8-14 of the Application, preceding the quoted points in the preamble, FEI stated that: *"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"*. At this point in the Commercial Rate Design discussion (i.e. on page 8-14), the analysis and assessment of what needs to be done is incomplete. Following page 8-14, FEI provides an assessment of Rate Design Options for changing the consumption threshold between Small and Large Commercial or adjusting the Basic Charges and Delivery Charges of RS 2 and RS 3. Part of the assessment took into consideration the impact on customers. The decision made by FEI was to propose to keep the threshold at 2,000 GJ/year and adjust the charges.

FEI's analysis in determining the appropriate basic and Delivery Charges were the following:

1. At the segmentation threshold of 2,000 GJ per year a customer that is in either RS 2 or RS 3 would have the same annual bill.

2. For annual volumes less than 2,000 GJ the lower annual cost should be achieved under RS 2 rates.

3. For annual volumes greater than 2,000 GJ the lower annual cost should be achieved under RS 3 rates.

4. The rates applied to the number of customers in each rate schedule and the volumes in each rate schedule will generate the same total revenue from existing rates for each rate schedule.
5. Minimize to the extent possible the bill impact for each customer.

In FEI's view, the proposed rate changes are not major, but rather adjustments to rates to balance complex rate design objectives.

23.3 Please explain whether FEI considered other rate adjustment options that can realign the economic crossover point at 2,000 GJ. If not, why not?

Response:

FEI did not consider any other rate structure options to realign the economic crossover at 2,000 GJ. In an effort to minimize bill impacts for RS 2 and RS 3/23 customers, FEI did try different Basic Charge and volumetric charge combinations to reset the economic crossover volume to 2,000 GJ per year. FEI used the Excel Solver function to derive the final proposed rates for RS 2 and RS 3/23 and used the constraints functionality in Excel Solver. The constraints (factors) that were used when solving for the 2,000 GJ economic crossover point, in priority order, included: minimize the revenue shift between small and large commercial rate schedules, eliminate any revenue shifts from commercial to other rate schedules, set maximum annual bill impact to any one customer to 10 percent and minimize the bill impact to customers consuming at the 2,000 GJ per year level.

23.3.1 If yes, please provide the comparative analysis of various rate changes considered by FEI, clearly explain the factors considered when comparing various rate change combinations/magnitudes, and explain why the proposed option is superior than other options considered.

Response:

Please refer to the response to BCUC-FEI IR 1.23.3.

24.0 Reference: RATE DESIGN FOR COMMERCIAL CUSTOMERS

Exhibit B-1, pp. 8-4, 8-8, 8-9, 8-22, 8-23

Impact of proposed rate change

FEI shows in Figure 8-1 on page 8-4 of Exhibit B-1 the commercial customer market segments. Figure 8-6 on page 8-8 and Figure 8-7 on page 8-9 show the small and large commercial customer bill frequency, respectively.

FEI presents the bill impact analysis of its proposed rate adjustment for RS 2 customers in figure 8-13 and for RS 3 customers in figure 8-14.

24.1 Please replicate Figure 8-13 and 8-14 in terms of actual bill change in dollar terms ($/year).

Response:

The first graph below is the bill impacts for RS 2 (Figure 8-13 using $ / Year) and the second graph is the bill impact for RS 3 / 23 (Figure 8-14 using $ / Year).

Figure 8-13 (adjusted): RS 2 Customer Bill Impacts ($ / Year)

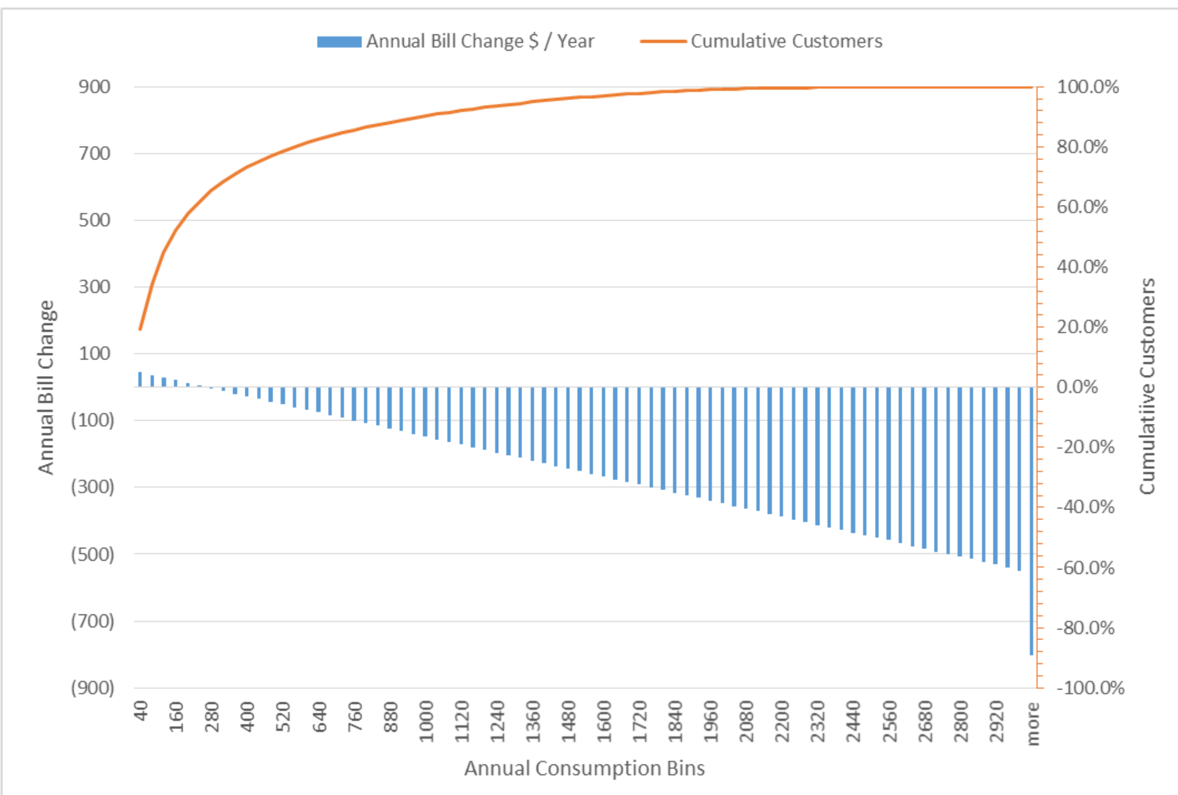
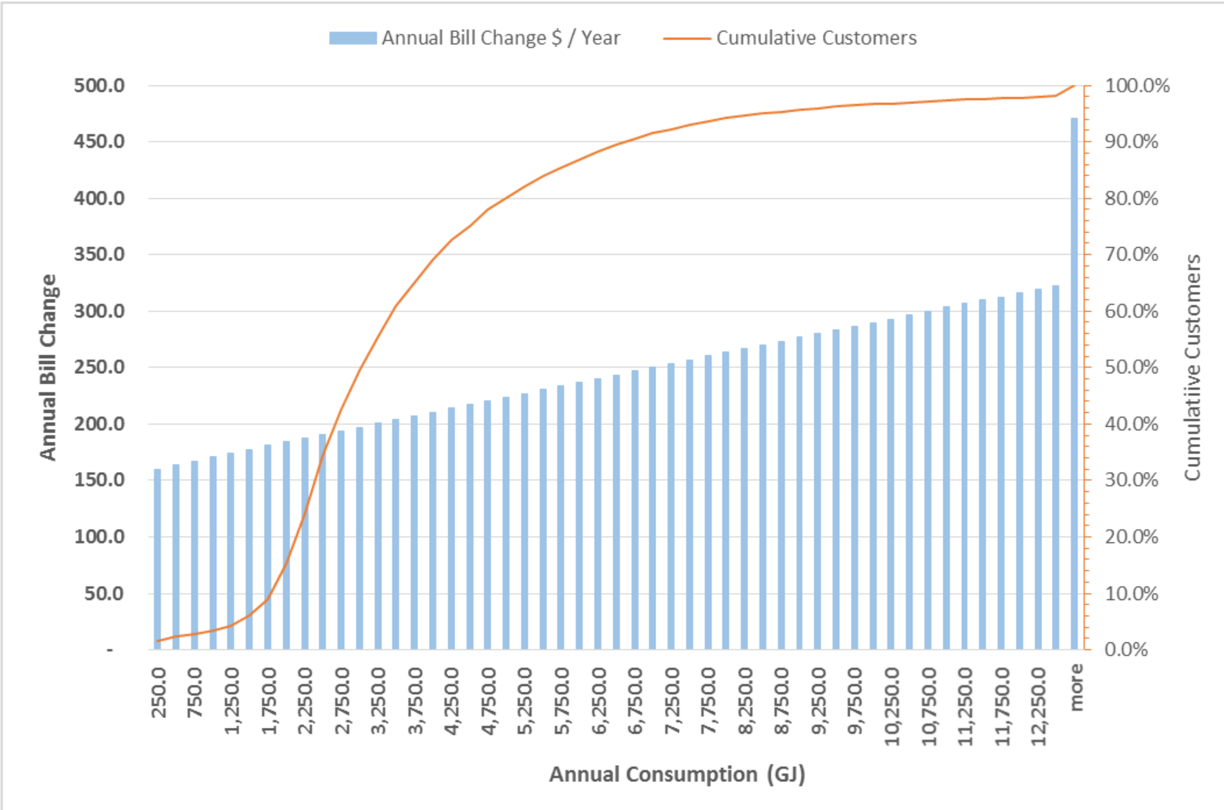


Figure 8-14 (adjusted): RS 3/23 Customer Bill Impacts ($ / Year)



24.1.1 In consideration of the magnitude of bill change for RS 2 and RS 3 customers, please comment on whether the proposed rate changes will result in a change in consumer behavior.

<u>Response:</u>

For RS 3/23 customers whose bill impact is between zero and one percent, FEI does not believe the changes will have an impact on consumer behavior.

Although for RS 2 customers in general FEI does not believe that the rate proposal will result in a noticeable change in consumer behavior, it is more difficult to assess what impact the change will have, as larger volume customers in this Rate Schedule will experience a 2 percent decrease in their bill, and the smallest volume users (less than 40 GJ per year) will have a 10 percent increase from the combined effect of the increased Basic Charge and Delivery Charge. For the smallest volume users who will experience a 10 percent increase, this will equate to an annual increase of $45 per year or an increase of less than $4 per month.

24.2 Please present the bill frequency of small commercial customers and large commercial customers similar to that presented in Figure 8-6 and Figure 8-7 for each customer market segments presented in Figure 8-1.

Response:

Below are the requested histograms for small and large commercial accounts by those market segments presented in Figure 8-1 that FEI has available data for from its billing system.

Small Commercial

Table 1: Retail Food

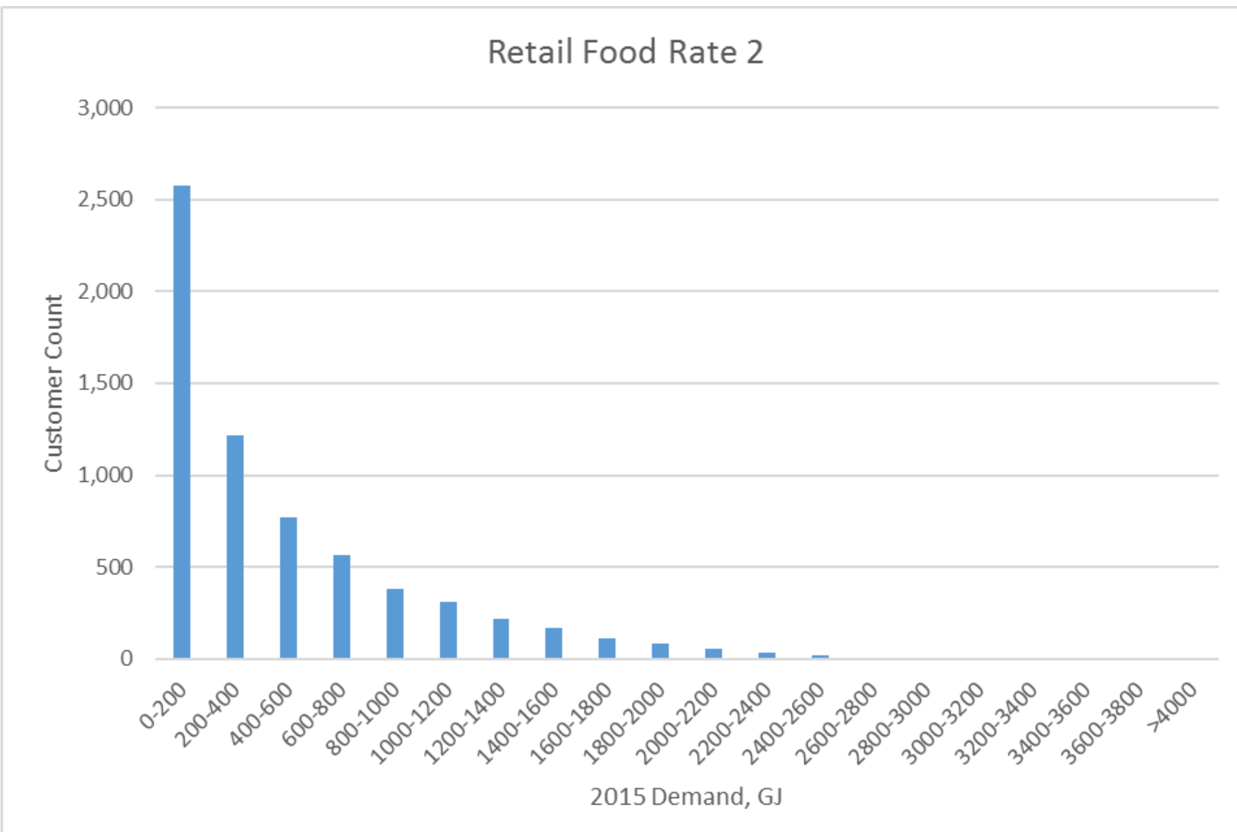


Table 2: College and Universities

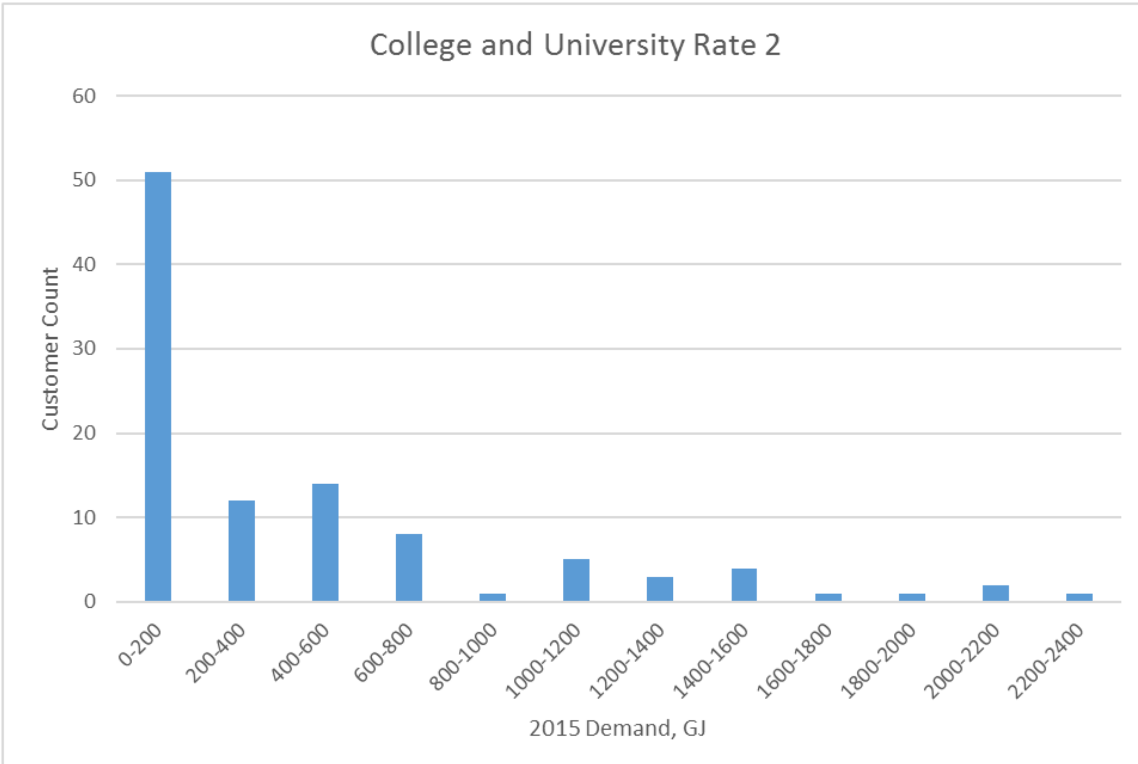
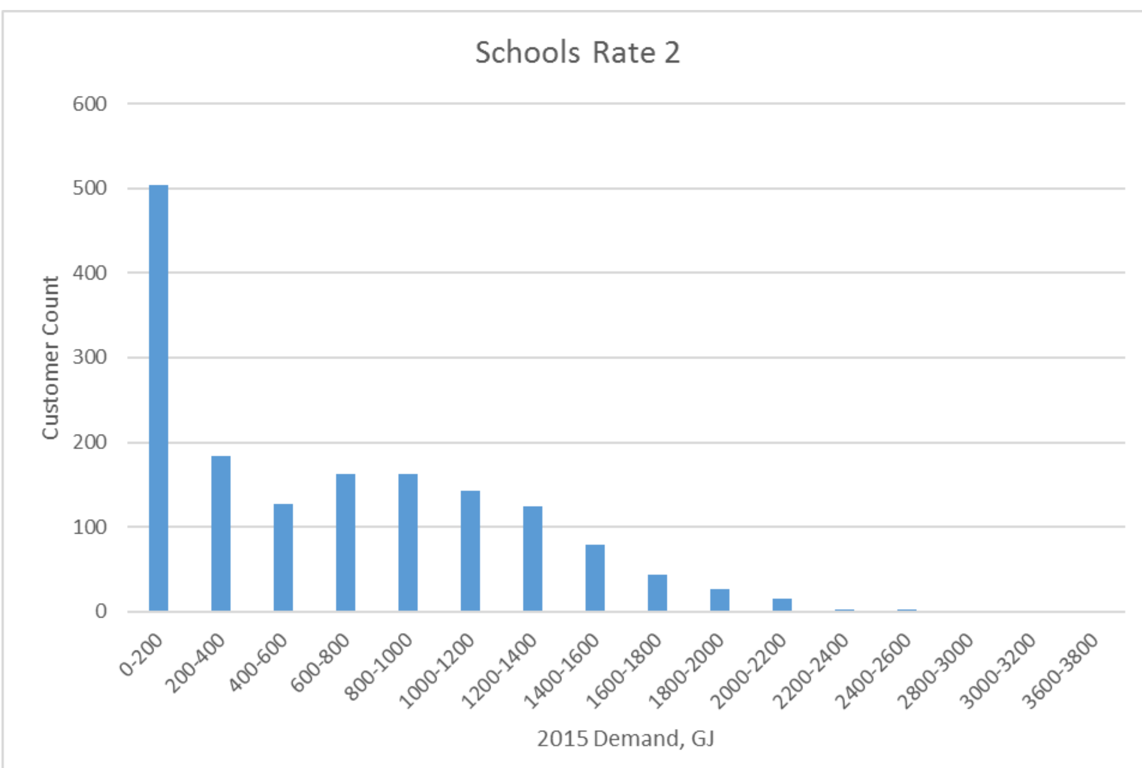
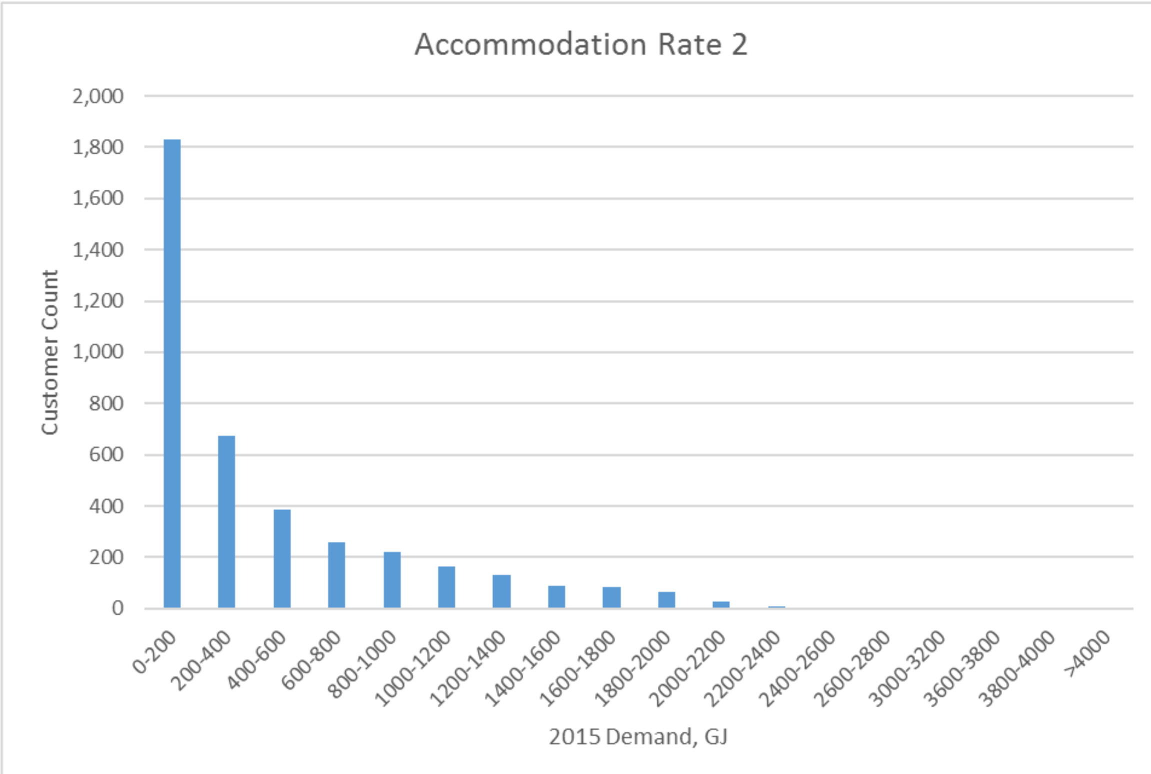


Table 3: Schools

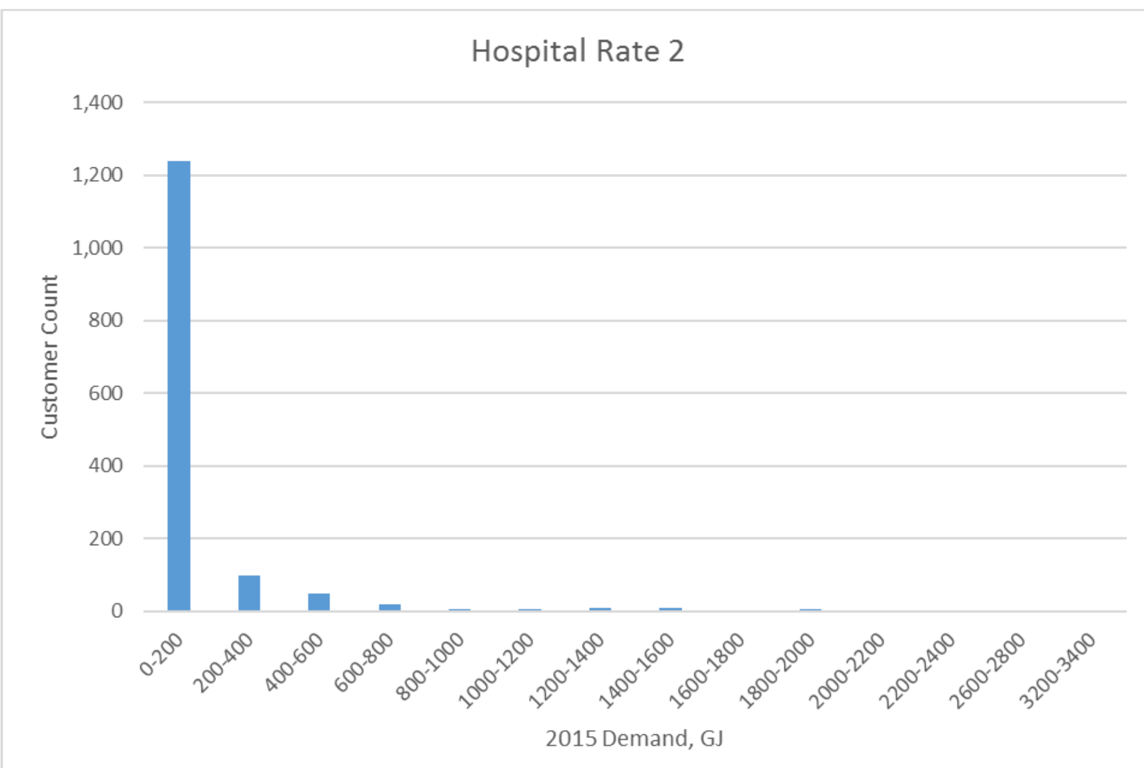


1 **Table 4: Accommodation**



2

3 **Table 5: Hospital**



4

Table 6: Retail – Non-Food

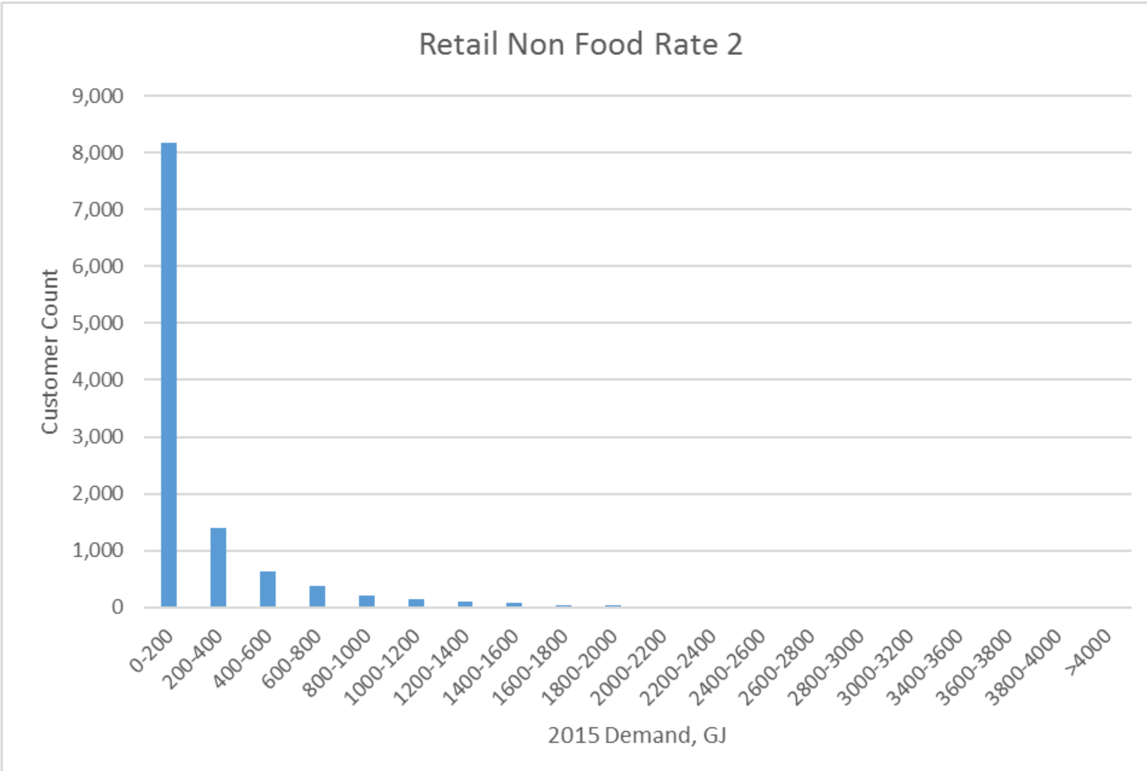


Table 7: Logistics and Warehouses

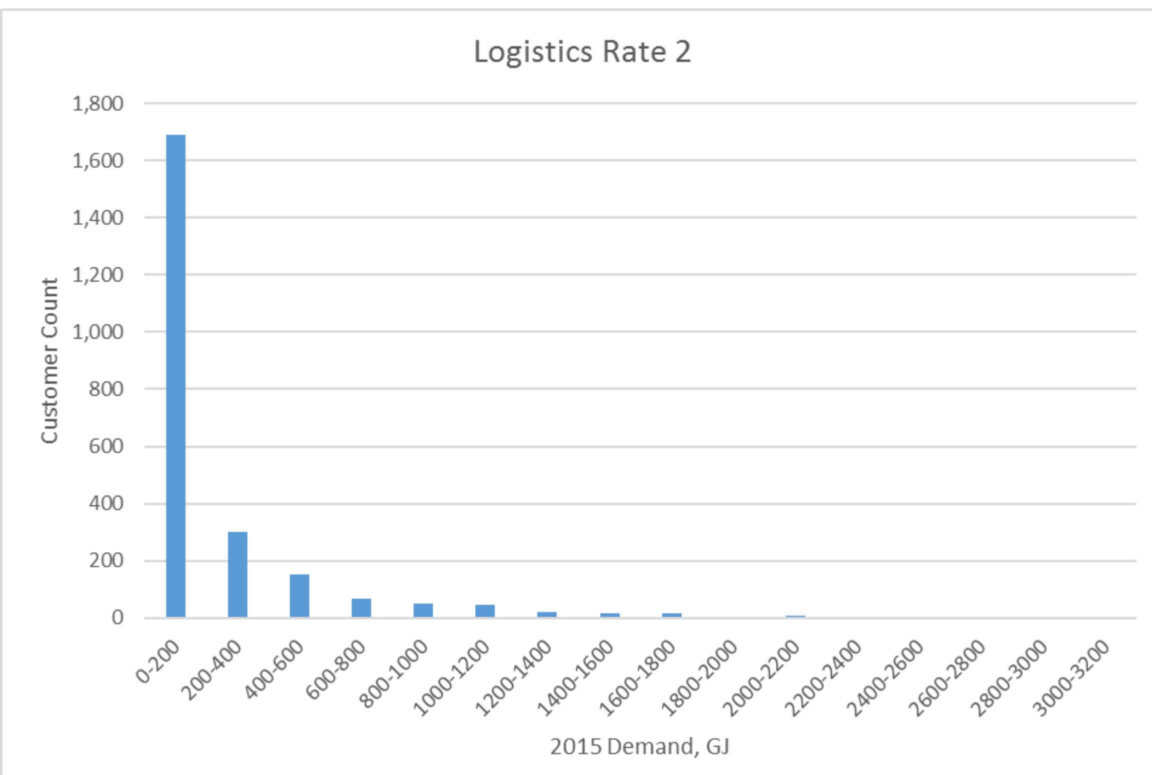


Table 8: Food Service

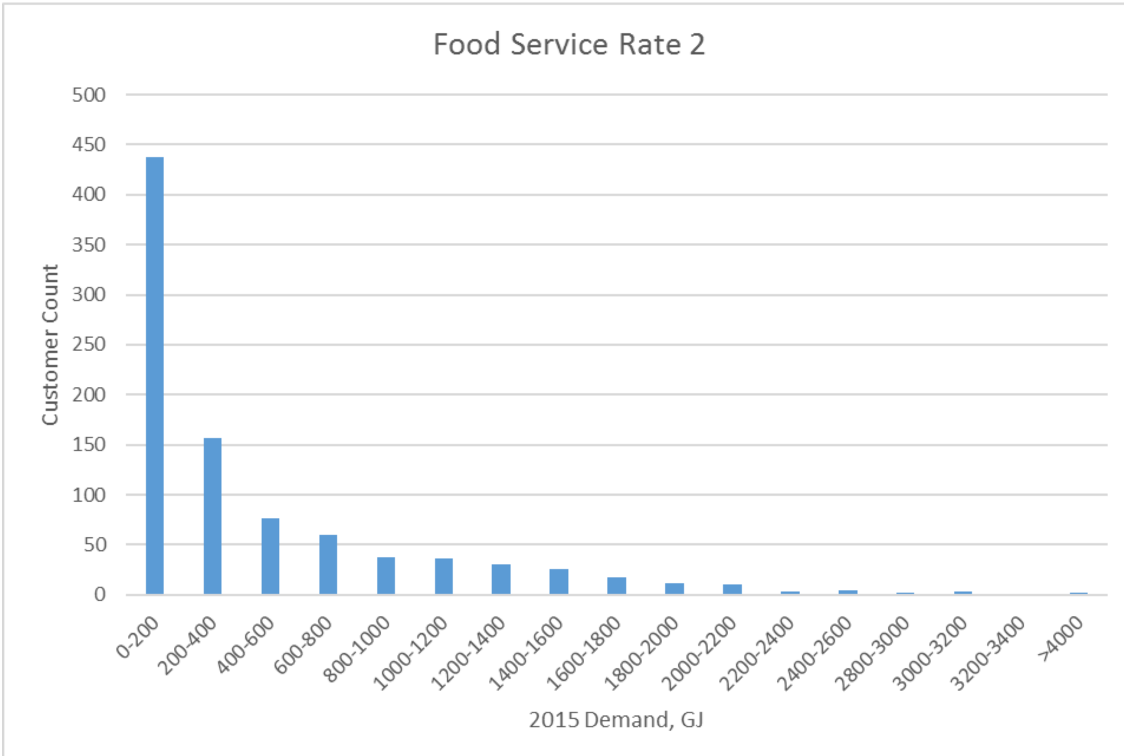


Table 9: Apartments

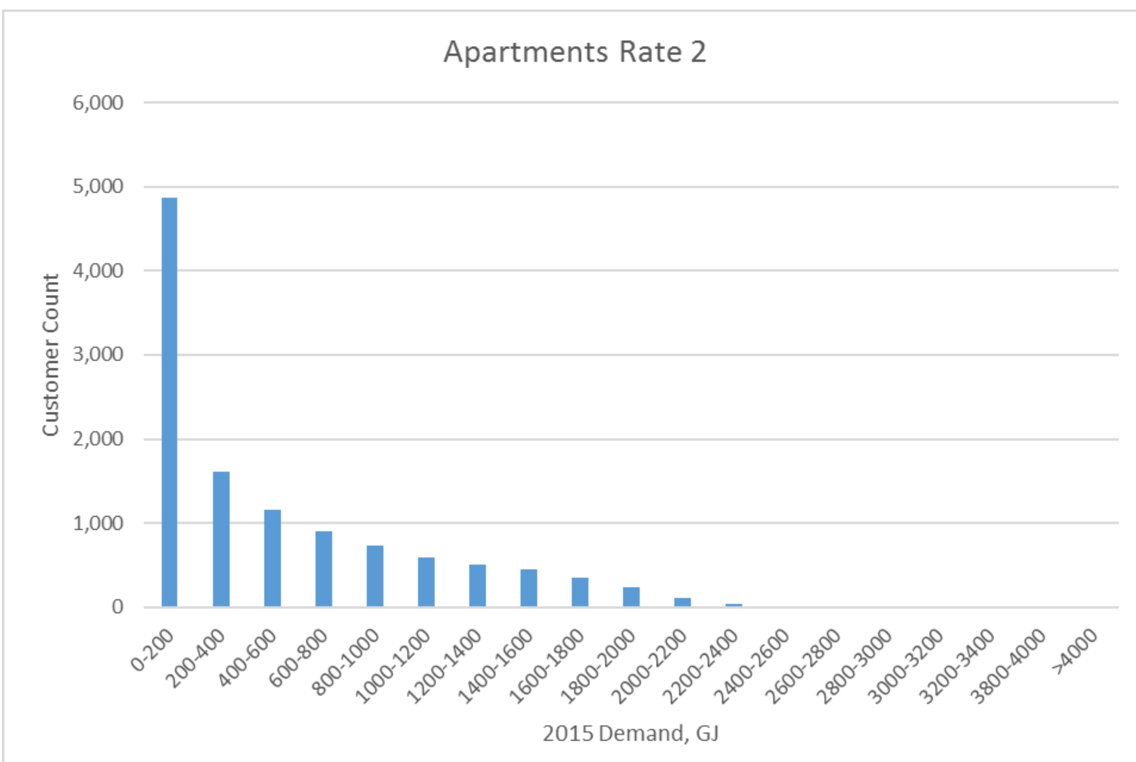
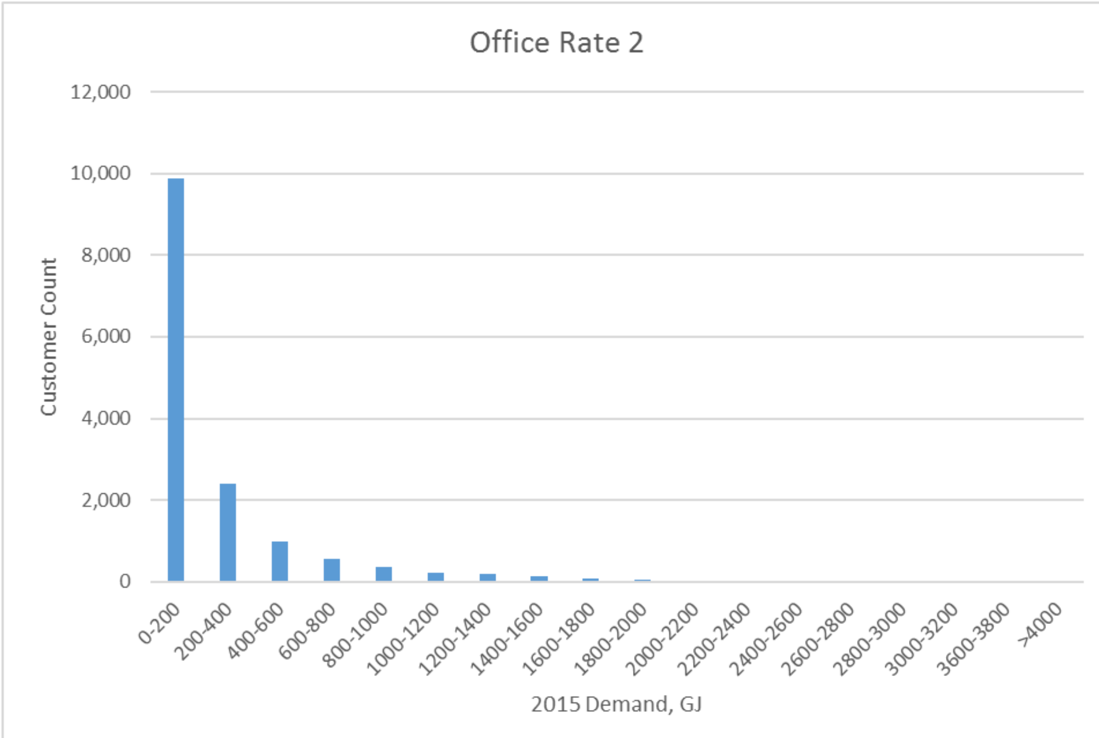


Table 10: Office



Large Commercial

Table 11: Retail Food

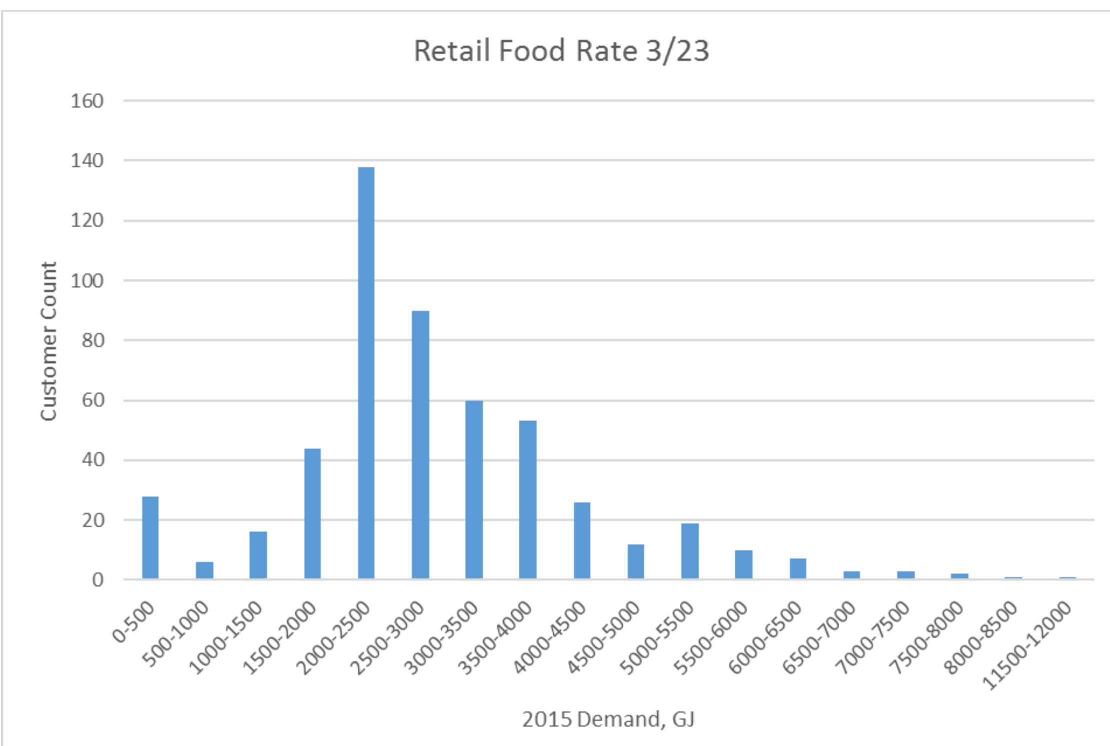


Table 12: College and Universities

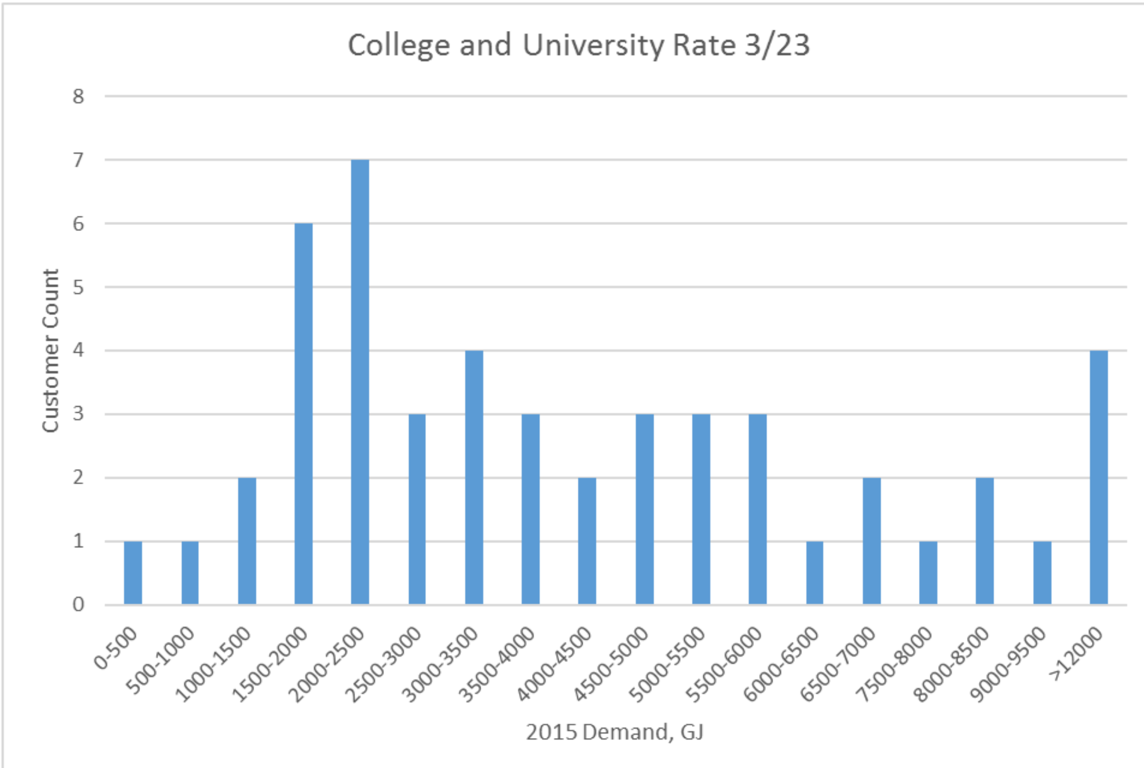


Table 13: Schools

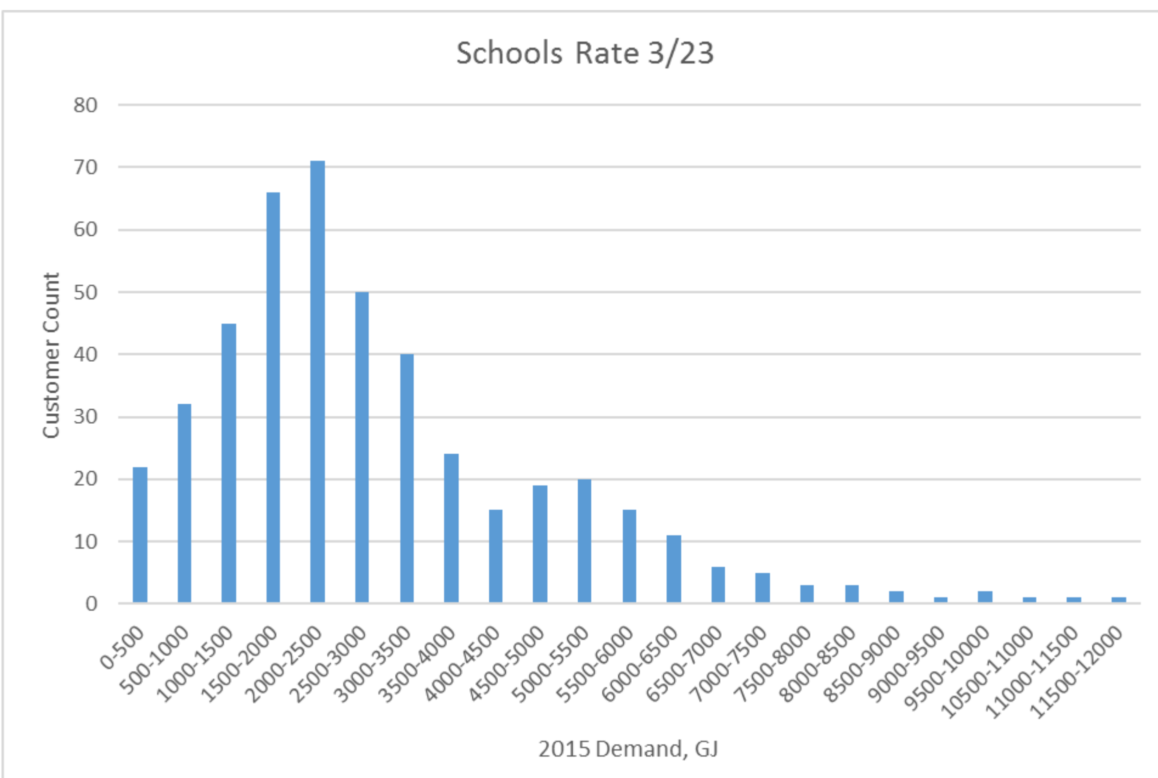


Table 14: Accommodation

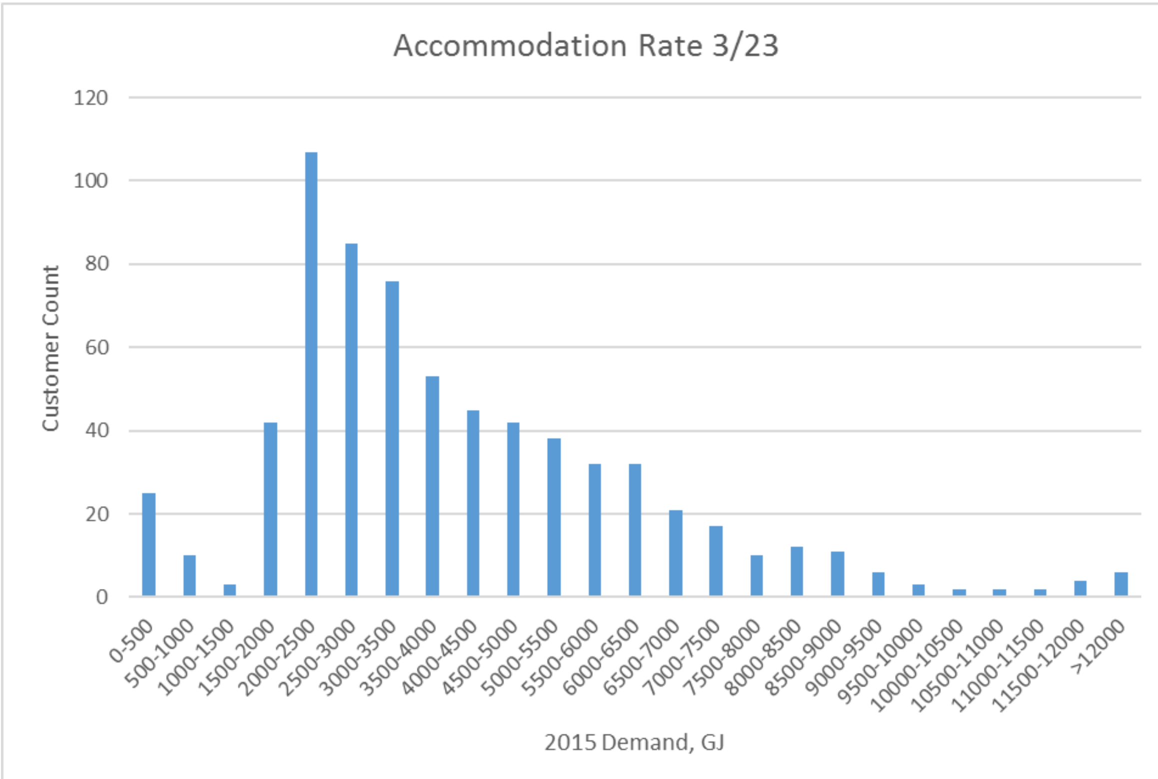


Table 15: Hospital

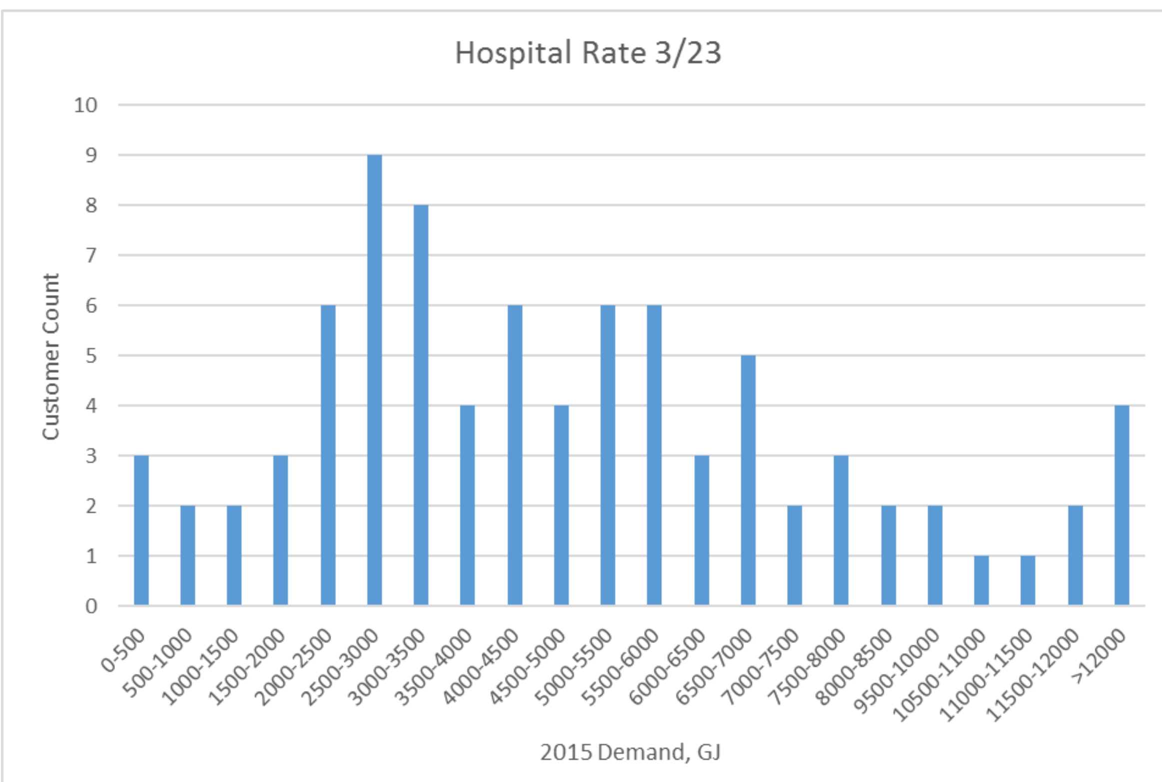


Table 16: Retail – Non Food

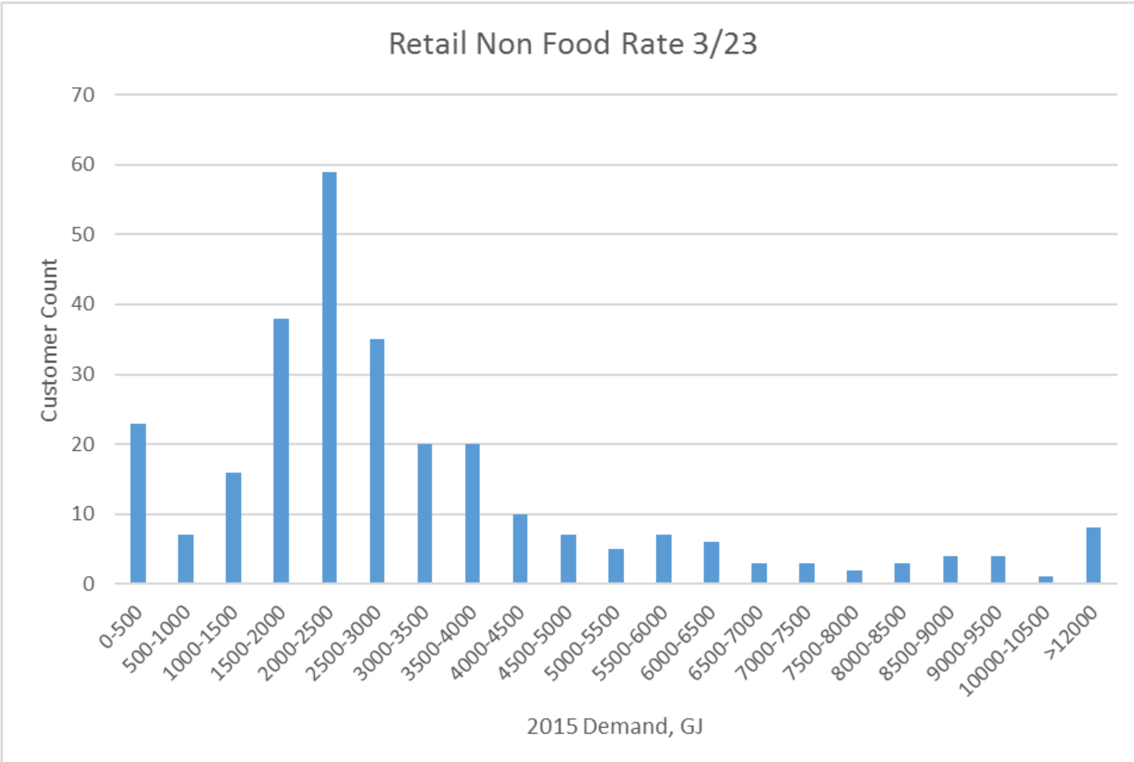


Table 17: Logistics and Warehouses

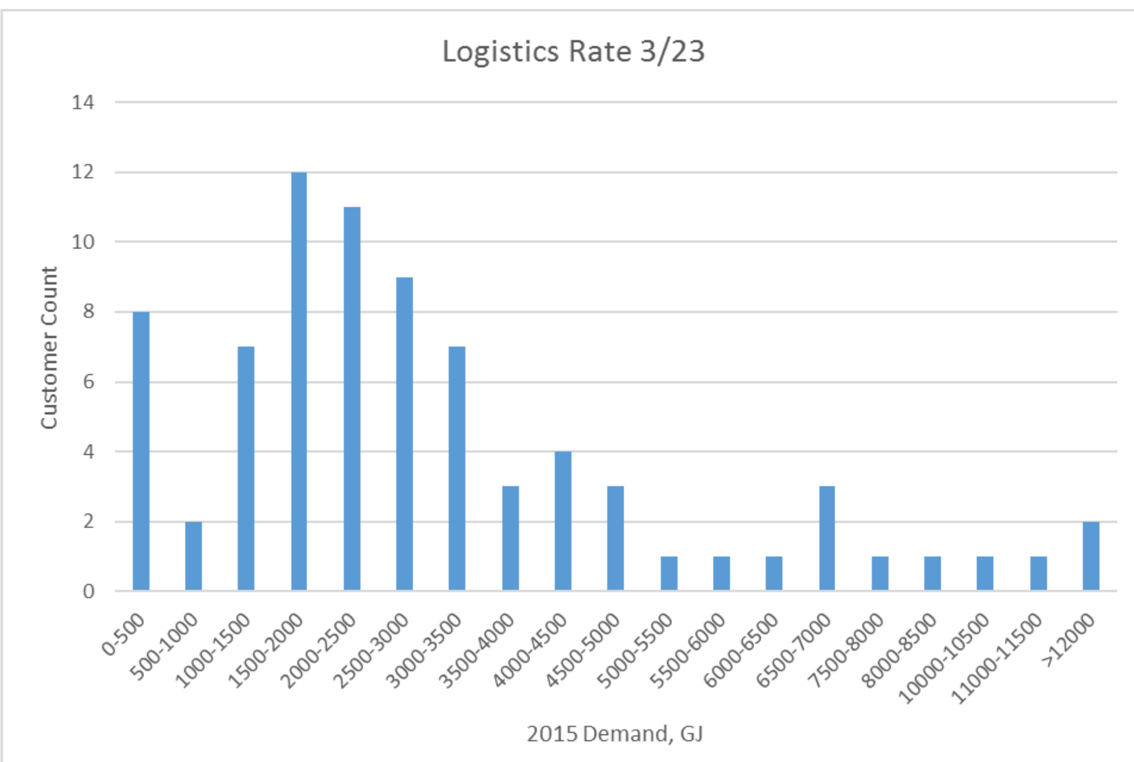


Table 18: Food Service

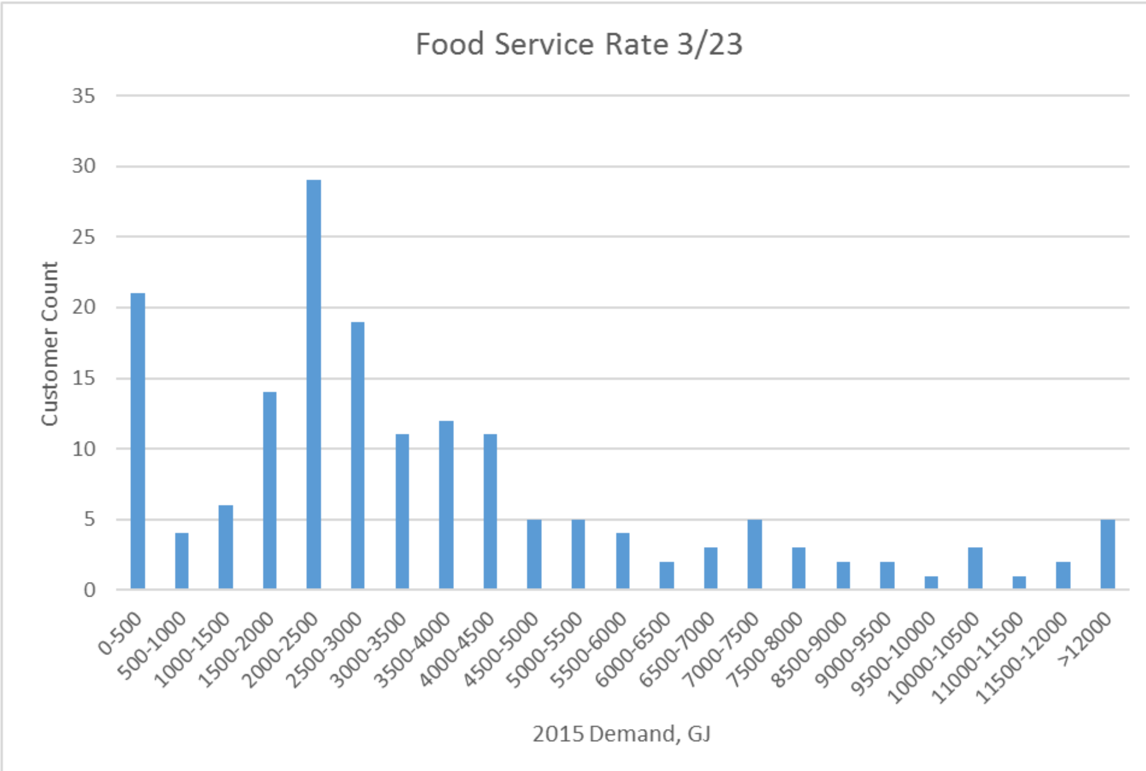


Table 19: Apartments

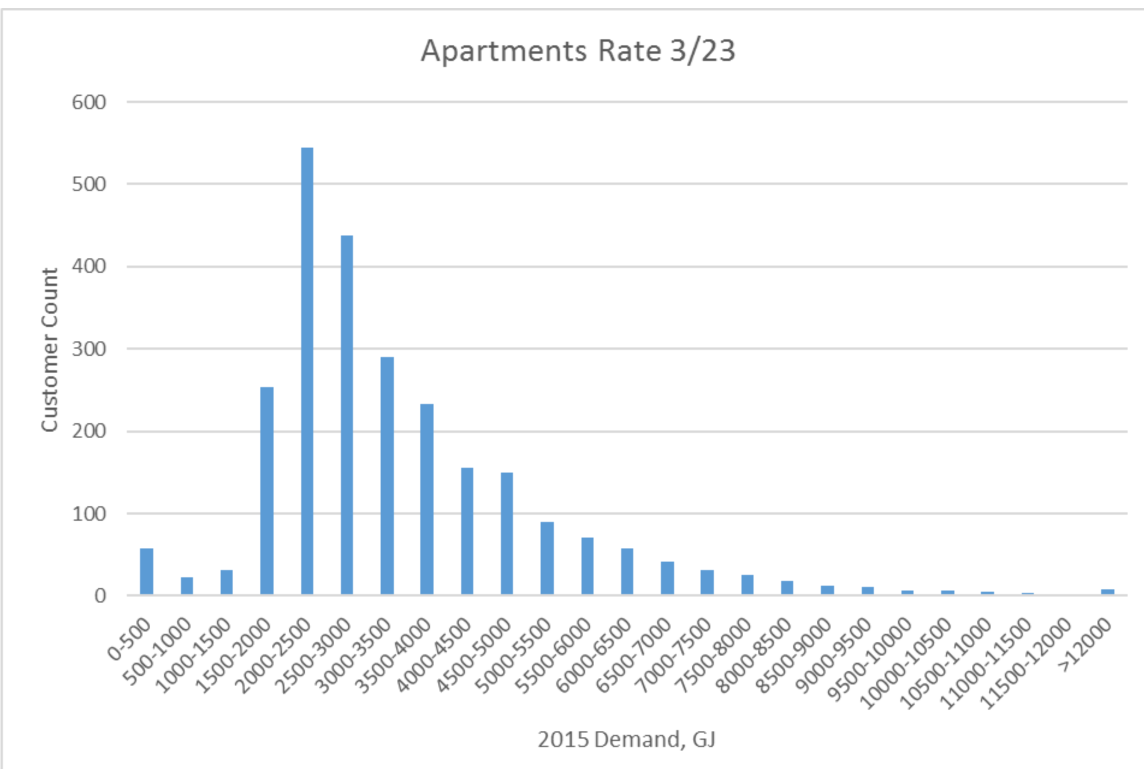
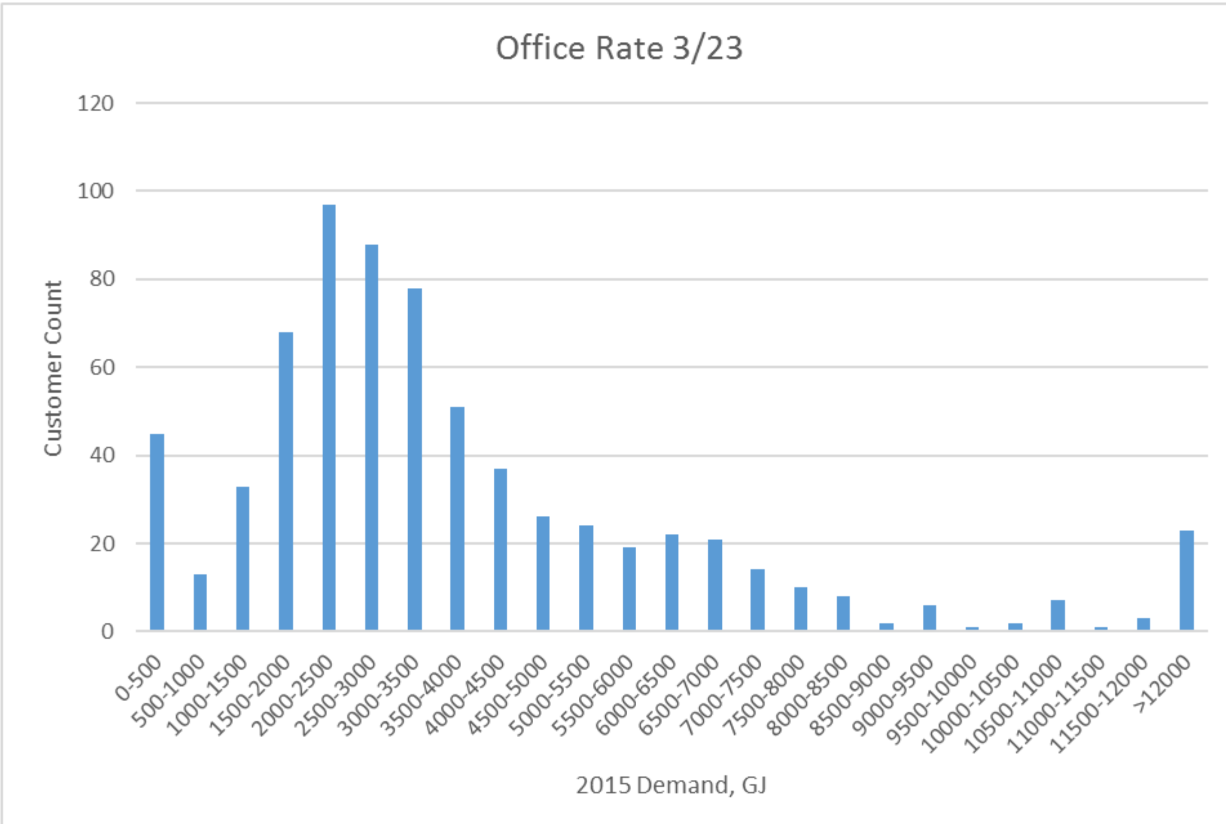


Table 20: Office



H. CHAPTER 9 – RATE DESIGN FOR INDUSTRIAL CUSTOMERS

25.0 Reference: RATE DESIGN FOR INDUSTRIAL CUSTOMERS

Exhibit B-1, Section 2.1, p. 2-2; Section 6.3.1.5, pp. 6-8 to 6-9; Section 9.8.1, pp. 9-37 to 9-38

Tariff supplements – bypass agreements and contract customers

On page 2-2 of Exhibit B-1, FEI states:

> 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.

On page 6-9 of Exhibit B-1, FEI presents Table 6-4 as follows:

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

Footnote 64 on page 6-9 of Exhibit B-1 states:

> FEI has included Teck Coal (Byron Creek) with bypass customers [in Table 6-4] 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.

25.1 Please confirm, or otherwise explain, that Teck Coal (Byron Creek) is not a customer with which FEI has a bypass agreement.

Response:

FEI confirms that Teck Coal (Byron Creek) is not a customer with which FEI has a bypass agreement. The agreement with Teck Coal is a Pipeline Agreement that was approved by the Commission effective January 1, 2003 by Order G-36-03. The charges to Teck Coal are based on the contract and are not subject to general rate changes that would be part of an annual review or revenue requirement application.

25.1.1 If confirmed, please provide an updated version of Table 6-4 which represents only customers with which FEI has bypass agreements and also explain any differences between the table in the response and Table 6-4 in Exhibit B-1.

Response:

An updated version of Table 6-4 that excludes Teck Coal (Byron Creek) is provided below with the additional rows requested in BCUC-FEI IR 1.25.2: (i) 2016 Forecast Peak Demand; (ii) 2016 Forecast Load Factor; and (iii) Costs determined by the COSA Study.

The 2016 Forecast Peak Day Demand is the Daily Transportation Quantity (DTQ's) of each of the Bypass customers. FEI does not forecast Load Factors for the Bypass customers and in the COSA Study there is no allocation of costs to Bypass customers, but the revenues from the Bypass customers have been allocated to all non-bypass customers as credits to their allocated cost of service in proportion to all non-bypass customers Delivery Margin allocated cost.

Table 6-4 (Updated): Information on Bypass Customers (excludes Teck Coal - Byron Creek)

	RS 22	RS 22A	RS 25	Total
Customer (#)	2	4	4	10
2016 Forecast Volume (TJ)	8,396		851	9,247
2016 Forecast Renenue ($000's)	$846		$435	$1,281
i) 2016 Forecast Peak Day Demand (GJ)	36,608		5,931	42,539
ii) 2016 Forecast Load Factor	Not Applicable			
iii) COSA Allocated Costs	Not Applicable			

25.2 Please add additional rows to Table 6-4 to provide the following additional information for FEI's Bypass customers only (i) 2016 Forecast Peak Demand; (ii) 2016 Forecast Load Factor; and (iii) Costs determined by the COSA Study.

Response:

Please refer to the response to BCUC-FEI IR 1.25.1.1.

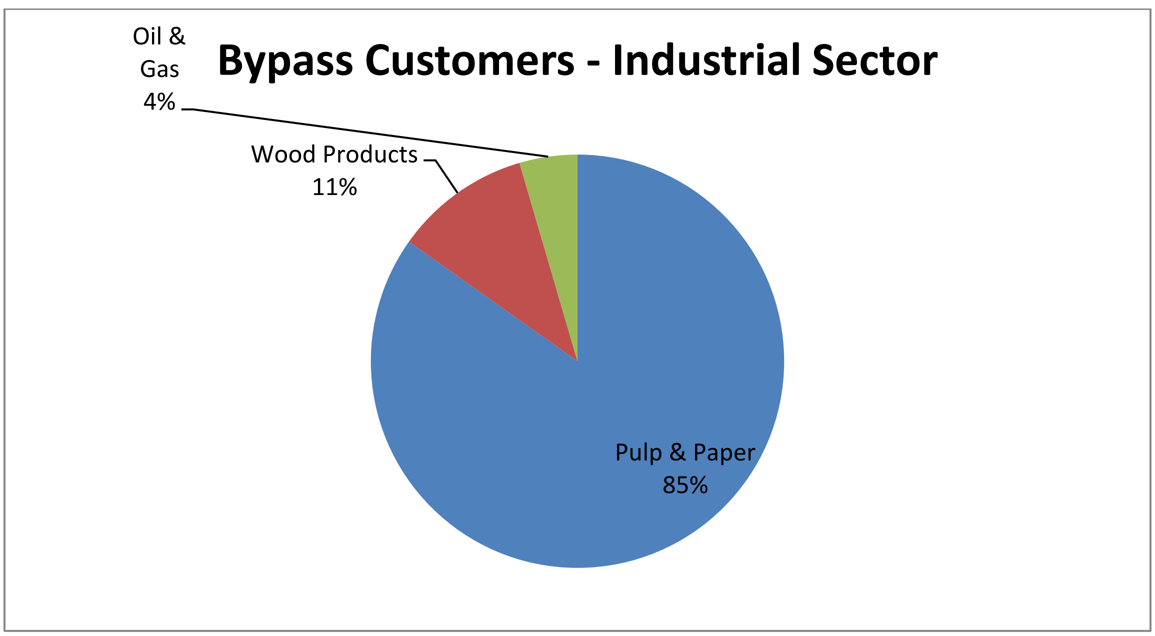
25.3 Please provide a list of the industrial sector makeup for (i) bypass customers; and (ii) non-bypass contract customers. Please provide a pie chart along with your responses that breakdown the industries by throughput for the most recent year of actual data (in a manner similar to Figure 9-1 on page 9-3 of Exhibit B-1).

Response:

(i) If FEI does not include Teck Coal (Byron Creek) with the Bypass Customers, there are then 10 bypass customers. The 10 bypass customers can be broken down into three segments as follows:

Industrial Sector	# Customers in Sector
Pulp & Paper	4
Wood Products	5
Oil & Gas	1
Total	**10**

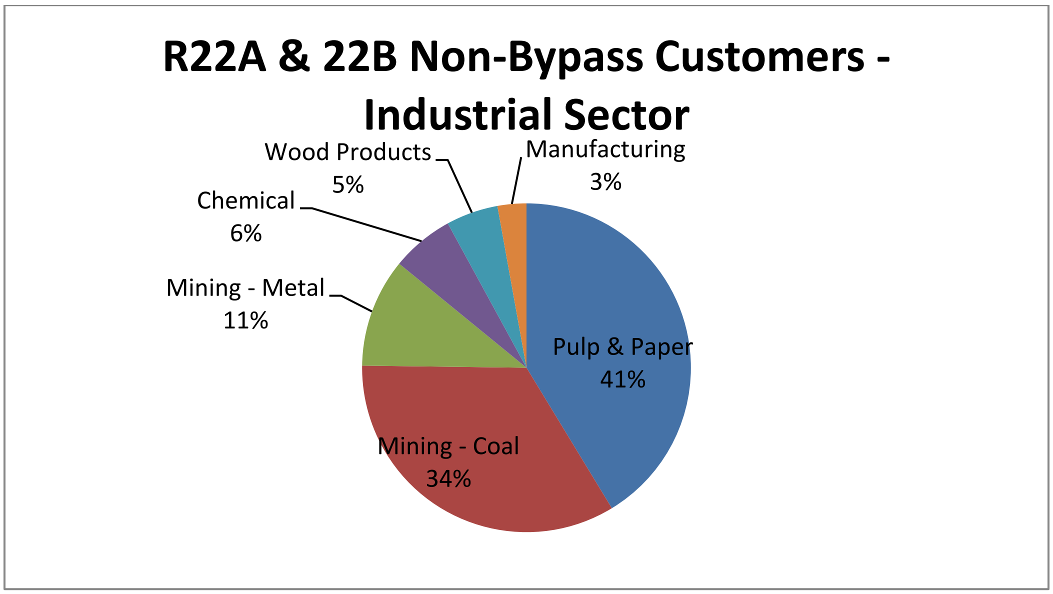
The following chart shows the bypass customers broken down into sector by 2016 throughput.



(ii) To answer this question FEI has assumed that "non-bypass contract customers" in the question is referring to the nine RS 22A customers and the five RS 22B customers. These 14 non-bypass RS 22A & 22B customers can be broken down into six segments as follows:

Industrial Sector	# Customers in Sector
Pulp & Paper	4
Mining - Coal	4
Mining - Metal	2
Chemical	1
Wood Products	2
Manufacturing	1
Total	**14**

The following chart shows the non-bypass contract customers broken down into sector by 2016 throughput.



25.4 Please explain how the costs and revenues associated with Teck Coal (Byron Creek) were treated in the COSA Study.

Response:

At the time that FEI developed the COSA Study, Teck included on their website that mining at Coal Mountain Operations will be completed by the end of 2017. Consequently, FEI eliminated their revenue of $44 thousand from the COSA model. The costs to serve Byron creek remain in the cost of the utility and are allocated to all other non-bypass customers.

25.5 Please explain if there are any other customers that are similar to FEI's bypass customers and was included in the data provided in Table 6-4 above.

Response:

No other customers that are not bypass customers, besides Teck Coal (Byron Creek), were included in Table 6-4.

On page 9-37 of Exhibit B-1, FEI provides Table 9-22 which states that the total number of Rate Schedule 22A customers is 9 and the total number of Rate Schedule 22B customers is 5. On page 9-38 FEI describes the history of Rate Schedules 22A and 22B and quotes the following from the 1993 Phase B Rate Design Decision:

> …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.

25.6 Please explain the key differences between a bypass customer and a non-bypass contract customer.

Response:

The key difference between a bypass customer and a non-bypass customer is that the non-bypass customer will pay the applicable Commission-approved rate schedule charges as endorsed in the Company's tariff. In contrast, bypass customers have negotiated a contract and rates that are different and lower than the standard approved applicable rate schedules.

The original bypass agreements arose because certain customers that were close to the upstream pipeline were seeking to build their own infrastructure and avoid purchase of service from the utility (i.e., bypass the utility). Rather than have the customer leave the utility service, bypass rates were negotiated. The negotiated bypass rates are long term contracts based upon the costs as if the customer left the system and built, owned and operated a pipeline from the upstream pipeline to their facility. The negotiated rates are approved by the Commission.

The principle for bypass rates is to recognize the possibility of a bypass and seek to retain the customer on the system to avoid stranding infrastructure and the complete loss of delivery revenue while avoiding the need for construction of a physical bypass pipeline. The concept of bypass rates was supported by government policy to urge the industrial customer and the utility to negotiate a competitive transportation agreement and to avoid building unnecessary infrastructure, while helping the utility maintain service to the customer.

25.6.1 For the five RS 22A customers that are not bypass customers, please describe the nature of the individually negotiated contracts and the associated rates for these customers.

Response:

The five RS 22A customers that are not bypass customers do not have individually negotiated contracts. The applicable associated rates are those found in the Company's tariff for Rate Schedule 22A – Transportation Service (Closed) Inland Service Area. The rates are comprised of the following:

- monthly Basic Charge;
- firm Delivery Charges;
- interruptible Delivery Charge;
- unauthorized overrun charges;
- balancing service charges;
- backstopping gas charge;
- replacement gas charge; and
- monthly administration charge.

25.6.2 Please describe the nature of the individually negotiated contracts and the associated rates for the five RS 22B customers. Please confirm that none of the RS 22B customers are considered to be bypass customers.

Response:

The five RS 22B customers do not have individually negotiated contracts. The applicable associated rates are those found in the Company's tariff for Rate Schedule 22B – Transportation Service (Closed) Columbia Service Area. In the RS 22B Table of Charges Elkview Coal Corporation rates are listed separately from the rates that are applicable to all other RS 22B customers. The rates are comprised of the following:

- monthly Basic Charge;
- firm Delivery Charges;
- interruptible Delivery Charge;
- unauthorized overrun charges;
- backstopping gas charge; and
- monthly administration charge.

Four of the five RS 22B customers that are coal mines do have Commission approved RS 22B tariff supplements with respect to the applicable RS 22B interruptible charges. The standard RS 22B interruptible charges are at a premium to firm service and the tariff supplements do not allow the four customers to decrease their firm contract demand but reduce the interruptible charges to be aligned with the RS 22B firm Delivery Charges. The customers requested such a tariff supplement so that if market conditions presented themselves the tariff supplements would, if interruptible pipeline capacity is available, remove any impediment to those customers who are mines of using more natural gas instead of coal, while maintaining the spirit of the rate schedule.

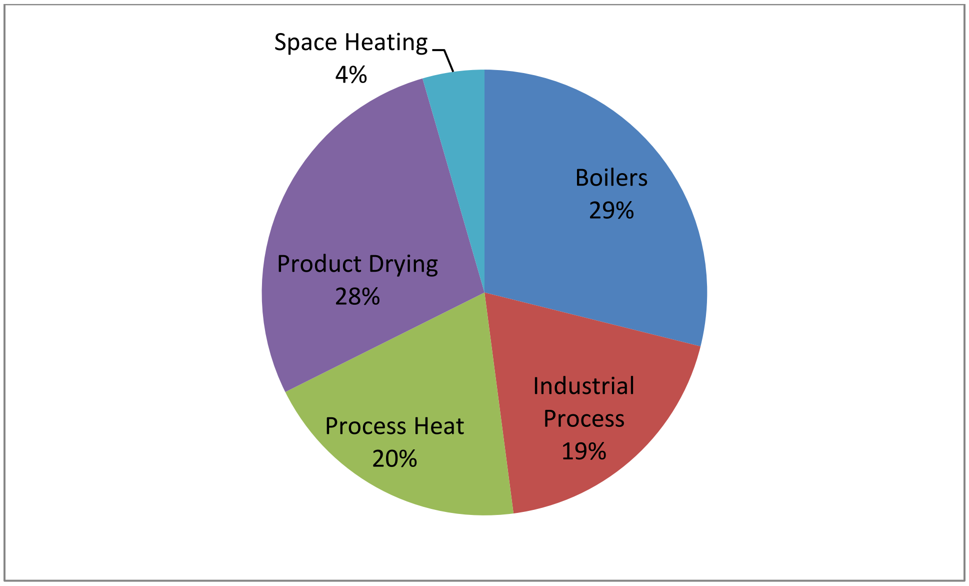
There are no RS 22B bypass customers.

25.7 Please provide a list describing the end-uses for (i) bypass customers; and (ii) non-bypass contract customers. Please provide a pie chart along with your responses that breaks down the end-uses by throughput for the most recent year of actual data (in a manner similar to Figure 9-2 on page 9-4 of Exhibit B-1).

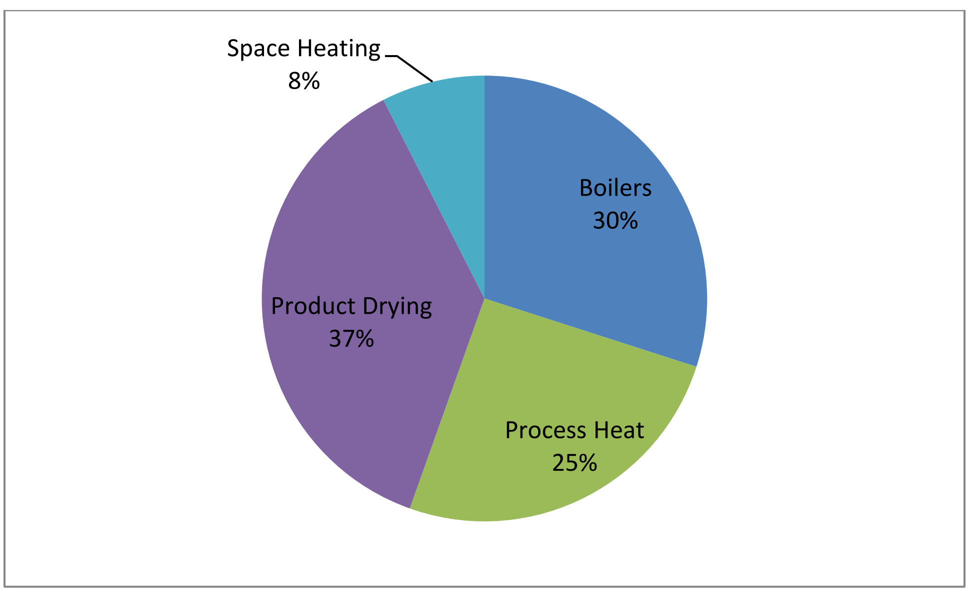
Response:

The following two pie charts provide a breakdown of the end-uses for the industry sectors as a whole that represent (i) 10 bypass customers and (ii) 14 RS 22A and RS 22B non-bypass contract customers. The source of the data is FEI's 2015 Conservation Potential Review (CPR) using a 2014 base year which is consistent with Figure 9-2 on page 9-4 of Exhibit B-1.

(i) The 10 bypass customers are in the Pulp & Paper, Wood Products and Oil & Gas industry sectors. The following pie chart provides the end-use breakdown for those industry sectors:



(ii) The 14 non-bypass customers within RS 22A and RS 22B are Pulp & Paper, Mining-Coal, Mining-Metal, Chemical, Wood Products and Manufacturing industry sectors. The following pie chart provides the end-use breakdown for those industry sectors:



25.8 Please explain the process for initiating a change in the terms or rates for bypass agreements.

Response:

To initiate a change to the terms or rates for bypass agreements, FEI would first need to have reason to believe, or direction from the Commission to the effect, that the existing bypass agreements were no longer just and reasonable. Second, any change to the terms or rates for any individual bypass agreement, through either an amendment or new agreement, would then need to be negotiated between FEI and each bypass customer, and filed with the Commission for approval. FEI would expect any new or amended agreement to commence following the end of the term of the existing agreement.

Given the different circumstances of each bypass customer, FEI's view is that negotiation of individual bypass agreements, subject to Commission approval, remains the best process. As stated by the Commission in the Inland Natural Gas Co.'s Rate Design Decision, Order No. G-80-87, dated December 11, 1987:

> Given this geographic variation, a bypass postage stamp rate would either have to be set low enough to keep the lowest cost bypass customers on the system, and thereby reduce the contributions of other higher cost bypass customers, or, risk losing those customers. Given this fact, and considering the time already spent in negotiations between the potential large bypass customers and Inland, the Commission concludes the negotiation process is most effective method for fixing individual rates to potential bypass customers.

At this time, it is unclear on what basis, or according to what principles, FEI would seek to renegotiate the bypass agreements, unless approached by the customer regarding changes to the agreement or a need for different service. The terms of the existing bypass agreements were negotiated and approved in accordance with the principles for a reasonably competitive bypass rate set out by Commissioner Millard in the 1987 BCUC Report and Recommendations to the Lieutenant-Governor in Council in the Matter of Applications for Energy Project Certificates, which were endorsed by the Commission in the Inland Natural Gas Co.'s Rate Design Decision, Order G-80-87, dated December 11, 1987. The charges in each bypass rate are set based on the costs that the customer would have incurred to construct, own and operate its own bypass pipeline. The bypass agreements rates include provisions to address changing circumstance, including:

- changes in costs that would have been incurred by the customer as result of increases in gas volume, increases in capacity or additional facilities that would have been required had the customer constructed and operated a bypass pipeline; and
- increases in FEI's costs, calculated as changes in the operating and other costs that the bypass customer would have incurred for the operation of a bypass pipeline.

The bypass agreements also contain provisions dealing with extension of the term of the agreements. At this time, FEI believes it continues to be reasonable to extend the agreements according to their terms.

25.8.1 Please describe FEI's rights with regard to termination of current bypass agreements.

Response:

FEI has individually negotiated bypass agreements with each customer and those agreements may have differing clauses, but generally FEI is permitted to terminate the current bypass agreements only if the Commission disallows FEI the recovery from other customers of any revenue shortfalls resulting from the negotiated rates under the bypass agreement. Please refer to the response to BCUC-FEI IR 1.25.10 for copies of the Commission approved bypass tariff supplements.

25.8.2 Please describe the bypass customers' rights to termination of current bypass agreements.

Response:

FEI has individually negotiated bypass agreements with each customer and those agreements may have differing clauses regarding the customers' rights of termination. Generally, some bypass agreements allow for termination by the customer on one year's notice, while other agreements allow for the customer to terminate the bypass agreement if the BCUC sets rates at a level in excess of the negotiated rates set out in the agreement. Some agreements also allow for termination by the customer under other circumstances, such as a permanent cessation of operations. Please refer to Attachment 25.10, provided in the response to BCUC-FEI IR 1.25.10 for copies of the Commission approved bypass tariff supplements.

25.8.3 If any of the bypass customers have had their bypass contracts renegotiated to accommodate increases in load, please describe the process that led to termination of the original bypass contract, renegotiation of a new bypass agreement and Commission approval of a new bypass agreement.

Response:

A portion of the response to this question is being filed confidentially with the Commission, pursuant to Section 18 of the Commission's Rules of Practice and Procedure regarding confidential documents, established by Order G-1-16. FEI requests that the response be kept confidential as it contains confidential customer information for which FEI does not have the authority or permission to disclose. Given the private and commercially sensitive nature of the information, FEI submits that only the Commission should have access to the unredacted confidential version of this IR response.

A redacted version of the response has been provided in the publicly available response

Two of the ten bypass customers have increased their load which has resulted in either a new bypass agreement being entered into (Husky Energy Marketing Inc.) or an amended and restated bypass agreement (Dunkley Lumber Limited).

Husky Energy's bypass agreement under RS 22A was terminated when Husky and FEI negotiated a new bypass agreement due to Husky wanting to increase the delivery pressure to 425 PSIG. This change was significant enough that under the 1993 Phase B Rate Design Decision the new agreement would have to be completed under RS 22 rather than RS 22A as the original agreement had been. This was a significant change to the model that the original bypass rate was based on. The new negotiated bypass agreement was submitted to the Commission and was approved by the Commission (refer to the response to BCUC-FEI IR 1.25.9 for more information).

In the case of Dunkley Lumber served under RS 25, there were two increases in load that resulted in amending the bypass agreement as a result of increased capital and operating costs. The amended bypass agreement was submitted to the Commission for each revision and was approved by the Commission. The table below provides the original agreement annual volumes and DTQ and subsequent amended volumes for Dunkley Lumber.

[redacted]

25.9 Please complete the following table summarizing each of FEI's current bypass agreements. Please add rows as necessary and provide the annual demand using the most recent year of actual data.

	FEI Bypass Agreements						
	Name of Customer	Commission Order approving Agreement	Effective date of Agreement	Current Term of Agreement	Tariff Supplement No.	Rate Schedule	Annual Demand (TJ)
Row 1							
Row 2							
Row 3							
...							

Response:

A portion of the response to this question is being filed confidentially with the Commission, pursuant to Section 18 of the Commission's Rules of Practice and Procedure regarding confidential documents, established by Order G-1-16. FEI requests that the response be kept confidential as it contains confidential customer information for which FEI does not have the authority or permission to disclose. Given the private and commercially sensitive nature of the information, FEI submits that only the Commission should have access to the unredacted confidential version of this IR response.

A redacted version of the response has been provided in the publicly available response

The following table provides the requested information. The last column Annual Demand (TJ) is the energy volumes for calendar 2016. Agreements that originated prior to the 1993 Phase B Rate Design Decision were amended and restated effective November 1, 1993. The Husky Energy original bypass agreement was dated November 1, 1987 and was amended and restated effective November 1, 1993 under RS 22A. The amended and restated agreement from November 1, 1993 was terminated and the current bypass agreement was entered into effective February 1, 2006.

FEI Bypass Agreements						
Name of Customer	Commission Order approving Agreement	Effective Date of Agreement	Current Term of Agreement	Tariff Supplement No.	Rate Schedule	[redacted]
Dunkley Lumber	G-35-04	Nov. 1, '04	11/01/04 – 11/01/18	E-2	RS 25	[redacted]
Tolko Industries		Nov. 1, '93	11/01/93 – 11/01/17	E-5	RS 25	[redacted]
Tolko Industries		Nov. 1, '93	11/01/93 – 11/01/17	E-6	RS 25	[redacted]
West Fraser Mills		Nov. 1, '93	11/01/93 – 11/01/20	E-8	RS 25	[redacted]
West Fraser	G-68-98	Nov. 1, '96	11/01/96 –	G-10	RS 22	[redacted]

FEI Bypass Agreements

Name of Customer	Commission Order approving Agreement	Effective Date of Agreement	Current Term of Agreement	Tariff Supplement No.	Rate Schedule	[redacted]
Mills (West Pine)			11/01/17 (autorenewal[19])			
Husky Energy	G-82-05	Feb. 1, '06	02/01/06 – 11/01/17 (autorenewal[20])	G-20	RS 22	[redacted]
Canadian Forest Products (Prince George Pulp & Paper)	G-33-03	Nov. 1, '93	11/01/93 – 11/01/17	G-5	RS 22A	[redacted]
West Fraser Mills	G-33-03	Nov. 1, '93	11/01/93 – 11/01/17	G-6	RS 22A	[redacted]
Canadian Forest Products (Northwood Pulp & Timber)	G-33-03	Nov. 1, '93	11/01/93 – 11/01/17	G-7	RS 22A	[redacted]
Cariboo Pulp & Paper	G-33-03	Nov. 1, '93	11/01/93 – 11/01/17	G-8	RS 22A	[redacted]

25.9.1 Please provide a bar chart showing the Annual Throughput on the y-axis for each bypass customer, using the most recent year of actual data.

Response:

The response to this question is being filed confidentially with the Commission, pursuant to Section 18 of the Commission's Rules of Practice and Procedure regarding confidential documents, established by Order G-1-16. FEI requests that the response be kept confidential as it contains confidential customer information for which FEI does not have the authority or permission to disclose. Given the private and commercially sensitive nature of the information, FEI submits that only the Commission should have access to the confidential version of this IR response.

[19] Evergreen clause of 1 year unless 6 months' notice prior to the end of the contract year then in effect.

[20] Evergreen clause of 1-year extension unless 12 months' notice prior to the end of the current termination date.

[redacted]

25.9.2 Please provide a bar chart showing the Annual Throughput on the y-axis for each non-bypass contract customer, using the most recent year of actual data.

Response:

The response to this question is being filed confidentially with the Commission, pursuant to Section 18 of the Commission's Rules of Practice and Procedure regarding confidential documents, established by Order G-1-16. FEI requests that the response be kept confidential as it contains confidential customer information for which FEI does not have the authority or permission to disclose. Given the private and commercially sensitive nature of the information, FEI submits that only the Commission should have access to the confidential version of this IR response.

[redacted]

25.10 For each of FEI’s current bypass customers, please provide a copy of the Commission approved tariff supplement.

Response:

Please refer to Attachment 25.10 for copies of the ten current bypass tariff supplements.

26.0 Reference: RATE DESIGN FOR INDUSTRIAL CUSTOMERS

Exhibit B-1, Section 9.3, Table 9-2, p. 9-7

Industrial customer data

26.1 Please state the percentage of the total 2016 sales customer demand forecast that is represented by RS 5 General Firm Sales.

Response:

2016 Forecast Sales Volumes for RS 5 are 1.8 percent of the total forecast sales volumes.

26.2 Please state the percentage of the total 2016 transportation customer throughput forecast that is represented by RS 25 General Firm Transportation.

Response:

2016 Forecast Transportation Service Volumes for RS 25 are 17.7 percent of the total non-bypass transportation service volumes (including BC Hydro IG and Vancouver Island Joint Venture volumes, but excluding Bypass customers and Teck Coal (Byron Creek) volumes). If the Bypass customers and Teck Coal (Byron Creek) volumes are included in the total, the RS 25 share becomes 15.7 percent.

26.3 Please provide an updated version of Table 9-2 by splitting the row with “RS 22 / 22A / 22B – Large Volume Transportation” into 3 rows: (i) RS 22; (ii) RS 22A; and (iii) RS22B.

Response:

An Updated Table 9-2 is provided below, with Large Volume Transportation RS 22, RS 22A and RS 22B number of customers and volumes shown separately.

Table 9-2 (updated): Industrial Customer Data[21]

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%
Large Volume Transportation			
RS 22	26	13.2	
22A	9	9.0	
22B	5	5.3	
Total Large Volume Transportation	40	27.6	39.6%
Large Industrial Contract	2	19.7	28.3%
Industrial Total	**984**	**69.7**	**100.0%**

[21] 2016 Forecast Customers and Energy from the compliance filing for the Annual Review for 2016 Rates (Order G-193-15).

27.0 Reference: RATE DESIGN FOR INDUSTRIAL CUSTOMERS

Exhibit B-1, Section 9.1, p. 9-1

General Firm Service (RS 5) and General Firm Transportation Service (RS 25)

On page 9-1 of Exhibit B-1, FEI states:

> 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.

On page 9-9 of Exhibit B-1, FEI states:

> 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. … FEI's analysis shows that the current method of using a multiplier of 1.25 is over-estimating the peak day demand. … FEI considered various options for calculating the Daily Demand. … 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.

27.1 Please state the number of years that the 1.25 multiplier has been resulting in an overestimation of peak day demand for RS 5 and RS 25 customers.

Response:

FEI does not know the number of years that the 1.25 multiplier has been resulting in an overestimation of customers' peak demand. However, FEI has undertaken the same analysis that yielded the 2015 results for the years 2011 to 2014 and 2016 and in each of the years the current formula results in a higher demand in almost all cases. For customers whose load factor was greater than 50 percent, the overestimation is approximately 35 percent to 43 percent (current method result divided by modified formula result minus one times 100) for the latest three years. The comparative results of the different methods to estimate daily demand as shown in Table 9-9 is provided below for the years 2011 through 2016.

Average Daily Demand (GJ) Per Customer (Combined Totals for RS 5 and RS 25 Customers)

2011	Method 1 Current Formula for Daily Demand	Method 2 Current Formula Updated Multiplier	Method 3 FEI System Maximum Day Send Out	Method 4 Average Consumption on Coldest 3 Days	Method 5 Average Consumption on Coldest 5 Days	Method 6 Modified Formula with 5 Day Average
< 40% Load Factor	129	107	178	195	172	172
40% to <45% Load Factor	145	124	111	128	150	150
45% to <50% Load Factor	112	127	102	92	87	87
>50% Load Factor	91	84	84	79	77	77
All Customers	99	87	93	86	84	84

Average Daily Demand (GJ) Per Customer (Combined Totals for RS 5 and RS 25 Customers)

2012	Method 1 Current Formula for Daily Demand	Method 2 Current Formula Updated Multiplier	Method 3 FEI System Maximum Day Send Out	Method 4 Average Consumption on Coldest 3 Days	Method 5 Average Consumption on Coldest 5 Days	Method 6 Modified Formula with 5 Day Average
< 40% Load Factor	164	208	160	164	170	170
40% to <45% Load Factor	118	129	105	109	119	119
45% to <50% Load Factor	93	111	94	87	90	90
>50% Load Factor	94	83	85	87	82	82
All Customers	99	87	100	100	94	94

Average Daily Demand (GJ) Per Customer (Combined Totals for RS 5 and RS 25 Customers)

2013	Method 1 Current Formula for Daily Demand	Method 2 Current Formula Updated Multiplier	Method 3 FEI System Maximum Day Send Out	Method 4 Average Consumption on Coldest 3 Days	Method 5 Average Consumption on Coldest 5 Days	Method 6 Modified Formula with 5 Day Average
< 40% Load Factor	171	195	157	151	165	176
40% to <45% Load Factor	104	127	103	104	106	113
45% to <50% Load Factor	83	98	98	81	85	91
>50% Load Factor	101	83	81	78	81	93
All Customers	101	89	93	86	89	103

Average Daily Demand (GJ) Per Customer (Combined Totals for RS 5 and RS 25 Customers)

2014	Method 1 Current Formula for Daily Demand	Method 2 Current Formula Updated Multiplier	Method 3 FEI System Maximum Day Send Out	Method 4 Average Consumption on Coldest 3 Days	Method 5 Average Consumption on Coldest 5 Days	Method 6 Modified Formula with 5 Day Average
< 40% Load Factor	131	97	150	125	118	118
40% to <45% Load Factor	99	128	110	103	109	109
45% to <50% Load Factor	71	91	75	92	76	76
>50% Load Factor	115	85	94	83	85	85
All Customers	101	89	100	90	88	89

Average Daily Demand (GJ) Per Customer (Combined Totals for RS 5 and RS 25 Customers)

2015	Method 1 Current Formula for Daily Demand	Method 2 Current Formula Updated Multiplier	Method 3 FEI System Maximum Day Send Out	Method 4 Average Consumption on Coldest 3 Days	Method 5 Average Consumption on Coldest 5 Days	Method 6 Modified Formula with 5 Day Average
< 40% Load Factor	174	149	160	150	159	152
40% to <45% Load Factor	93	169	89	97	109	109
45% to <50% Load Factor	73	87	82	77	72	72
>50% Load Factor	105	84	25	71	72	75
All Customers	100	88	82	77	77	80

Average Daily Demand (GJ) Per Customer (Combined Totals for RS 5 and RS 25 Customers)

2016	Method 1 Current Formula for Daily Demand	Method 2 Current Formula Updated Multiplier	Method 3 FEI System Maximum Day Send Out	Method 4 Average Consumption on Coldest 3 Days	Method 5 Average Consumption on Coldest 5 Days	Method 6 Modified Formula with 5 Day Average
< 40% Load Factor	120	142	134	134	134	132
40% to <45% Load Factor	83	79	99	85	88	88
45% to <50% Load Factor	79	74	83	78	76	76
>50% Load Factor	140	101	95	96	97	98
All Customers	110	97	101	97	98	98

27.2 Please explain the underlying reason(s) why the 1.25 multiplier is now overestimating peak day demand for RS 5 and RS 25 customers. For example:

i. did inadequate/inaccurate data lead to the development of an inappropriate multiplier initially?

ii. has the load factor/typical daily demand/typical peak day demand of RS 5/RS 25 customers changed overtime?

iii. any other reasons?

Response:

FEI believes the primary reason was that detailed data was not available at the time the multiplier was initially developed. However, the number of customers taking service under RS 5 and 25 has tripled since the 1.25 multiplier was adopted, so changes in demand profiles with this customer growth may provide some explanation of why the 1.25 multiplier is too high.

The 1.25 multiplier was derived and approved as part of the 1996 Rate Design Application. It was agreed to as part of the Negotiated Settlement which the Commission subsequently approved through Order G-98-96, dated, October 7, 1996. At that time FEI had approximately 250 customers in the General Firm Sales and Transportation Service customers. A number of those customers did not have daily measurement of consumption data and an estimation of peak day demand was calculated as part of a workshop in 1996, which resulted in a factor of 1.25 that represented estimated peak day consumption to highest average day consumption of any winter month.

Subsequently, all or almost all General Firm customers have metering that provides daily measurement and so it is possible to calculate a more accurate multiplier that takes into consideration the actual daily consumption measurement of all customers, which was not possible in 1996.

27.3 Please explain the issue(s) FEI or customers may experience due to an overestimation of the peak demand based on the multiplier of 1.25. Please use calculations to explain the impact to customer bills and FEI's operations.

Response:

The first issue FEI is addressing through the rate design for General Firm Service customers is to adopt a method that is a better estimation of customers' peak demand for billing purposes, i.e., the Daily Demand. The Daily Demand needs to be an appropriate billing determinant for customers' firm service use of the delivery system. This is particularly true for the majority of customers whose load factor is greater than 50 percent for which the 1.25 multiplier exceeds customers' peak demand (refer to response to BCUC-FEI IR 1.27.1).

The second issue is to have a Demand Charge rate that provides a price signal to attract customers whose loads are sufficiently large enough when coupled with their load profile for it to make economic sense to be served under RS 5/25 (refer to the response BCUC-FEI 1.31.2 for the economic crossover volumes at various load factors).

Total revenue from the RS 5/25 is not an issue as the R:C ratio is within the range of reasonableness. Please refer to Exhibit B-1, Table 12-2, Page 12-5, Initial COSA result and COSA after Rate Design Proposals.

The important point is that the two changes FEI has proposed will better align determination of customer peak for billing purposes and rates to incent customers with sufficient load and load factor to take service under the appropriate rate schedule, i.e., General Firm Service or Large Commercial Service. FEI's goal is to get the correct pricing signal for the service being provided and to appropriately recover the cost of service.

The first two rows in the following table provides the average customer bill impact using the 2015 Average Daily Demand for all customers using the 1.25 and 1.10 multipliers, respectively, times the COSA Based Demand Charge. The last row shows the Average Daily Demand using the proposed 1.10 multiplier times the Proposed Demand Charge.

2015 Average Daily Demand	Demand Charge $ / GJ	Annual Demand Charge Revenue
100	$21.596	$25,915
88	$21.596	$22,805
88	$24.596	$25,974

Using a more accurate multiplier for determining daily demand to be applied to the demand charge will have no effect on FEI operations.

27.4 Please calculate the difference to the bills of moving from a 1.25 multiplier to a 1.1 multiplier for the five largest RS 5/RS 25 customers based on 2015 actual consumption and load factor.

Response:

The following table shows, for the five largest RS 5/25 customers, the actual annual volumes, the daily demand using the 1.25 multiplier and using the 1.10 multiplier, the annual demand charges for each, and the difference. For the fifth largest customer the variance is approximately $19 thousand and for the largest customer it is approximately $52 thousand.

		Current Method		Proposed Method			Annual Demand Charges		
	Actual Annual Volume (GJ)	Daily Demand From 1.25 Multiplier (GJ)	Load Factor	Daily Demand From 1.1 Multiplier (GJ)	Load Factor	Demand Charge	From 1.25 Multiplier	From 1.10 Multiplier	Difference
Customer 1	384,477	1,666	63%	1,466	72%	$ 21.596	$ 431,747	$ 379,938	$ 51,810
Customer 2	293,681	1,369	59%	1,205	67%	$ 21.596	$ 354,779	$ 312,206	$ 42,573
Customer 3	214,147	1,035	57%	911	64%	$ 21.596	$ 268,222	$ 236,036	$ 32,187
Customer 4	200,759	982	56%	864	64%	$ 21.596	$ 254,487	$ 223,949	$ 30,538
Customer 5	176,803	619	78%	545	89%	$ 21.596	$ 160,415	$ 141,165	$ 19,250

The annual demand charge is calculated by multiplying the daily demand (GJ) x 12 x Demand Charge. Please note that the results in the table are reflective of the impact of the proposed change in the multiplier only, and do not include the mitigating effect of the proposed higher demand charge for RS 5/25. If both proposed changes are considered (i.e., a 1.10 multiplier and the higher proposed demand charge), the annual demand charges for these customers will be almost the same as under the current formula.

27.5 Please provide an updated version of Table 9-4 on page 9-11 of Exhibit B-1 to include (i) existing RS 5 and RS 25 charges; and (ii) FEI's proposed RS 5 and RS 25 charges.

Response:

The following table provides the existing charges, effective January 1, 2017 for Rate Schedules 5 and 25 and then provides the proposed charges for these two rate schedules. The increases in the Demand Charge and Delivery Charge from the existing rates to the proposed rates also include the effect of known and measurable changes as described in Exhibit B-1, Section 6.3.2 of the Application.

	RS 5	RS 25
Existing Charges effective January 1, 2017		
Basic Charge $ / Month	$587.00	$587.00
Demand Charge $ / Month / GJ of Daily Demand	$20.077	$20.077
Delivery Charge $ / GJ	$0.825	$0.825
Administration Charge $ / Month	N / A	$78.00
Multiplier for Daily Demand	1.25	1.25

	RS 5	RS 25
***Proposed Charges* [1)]**		
Basic Charge $ / Month	$587.00	$587.00
Demand Charge $ / Month / GJ of Daily Demand	$24.596	$24.596
Delivery Charge $ / GJ	$0.887	$0.887
Administration Charge $ / Month [2)]	N / A	$39.00
Multiplier for Daily Demand	1.10	1.10

Notes:

[1] See Exhibit B-1, Section 12.4, page 12-9 for proposed charges.

[2] See Exhibit B-1-1, Supplemental Filing, Appendix 11-4 Supporting Calculations for the Proposed Change to the Administration Charge.

27.6 Please provide in table form, for each of RS 5 and RS 25, the percentage of costs recovered through all fixed charges using (i) existing charges; and (ii) FEI's proposed charges.

<u>Response:</u>

From the following table the percentage of fixed revenue to total Delivery Margin Revenue for RS 5 at existing rates and proposed rates is 72 percent and 71 percent (Line 15), respectively. For RS 25 the corresponding percentage for both existing rates and proposed rates is approximately 65 percent (Line 15).

The source data for number of customers and annual volumes is from the 2015 actual billed data. Daily Demand using the 1.25 Multiplier is the summation of the daily demands for each customer using the current methodology to derive Daily Demand. Daily Demand using the 1.10 Multiplier is derived using the results for 1.25 Multiplier and dividing it by 1.25 times 1.1.

Line No.	Particulars	Existing Rates [1)] RS 5	Existing Rates [1)] RS 25	Proposed Rates RS 5	Proposed Rates RS 25
1	Number of Customers	239	535	239	535
2	Annual Volume (TJ)	2,280	12,751	2,280	12,751
3	Daily Demand Using 1.25 Multiplier (GJ)	12,784	64,537		
	Daily Demand Using 1.10 Multiplier (GJ)			11,250	56,792
4	Monthly Charges				
5	Basic Charge $ / Month	$ 587.00	$ 587.00	$ 587.00	$ 587.00
6	Administration Charge $ / Month	N / A	$ 78.00	N / A	$ 39.00
7	Demand Charge $ / Month / GJ of Daily Demand	$ 20.077	$ 20.077	$ 24.596	$ 24.596
8	Delivery Charge $ / GJ	$ 0.825	$ 0.825	$ 0.887	$ 0.887
9	**Revenues ($000's)**				
10	Total Monthly Charge Revenue [2)]	$ 1,684	$ 4,269	$ 1,684	$ 4,019
11	Demand Charge Revenue [3)]	3,080	15,548	3,320	16,762
12	Total Fixed Charges Revenues	4,763	19,818	5,004	20,781
13	Delivery Charge Revenue [4)]	1,881	10,519	2,022	11,310
14	Total Delivery Margin Revenue	$ 6,644	$ 30,337	$ 7,026	$ 32,091
15	**% of Fixed Charge Revenue to Total Delivery Margin Revenue** [5)]	71.7%	65.3%	71.2%	64.8%

1) Refer to the response to BCUC-FEI IR 1.27.5 for the existing charges and proposed charges.
2) Total Monthly Charge Revenue is equal to Line 1 x 12 months x Line 5 / 1,000 for RS 5 whereas for RS 25 it is the sum of Lines 5 and 6.
3) Demand Charge Revenue is equal to Line 3 x 12 months x Line 7 / 1,000.
4) Delivery Charge Revenue is equal to Line 2 x Line 8.
5) Percentage of Fixed Charge Revenue to Total Delivery Margin Revenue is equal to Line 12 / Line 14.

27.6.1 Please discuss any considerations FEI made when determining the RS 5 and RS 25 proposals, regarding the percentage of costs recovered through fixed charges.

Response:

In the process of reviewing the charges applicable to RS 5 and RS 25, FEI did not consider it desirable or necessary to change the Basic Monthly Charge. As shown in the response to BCUC-FEI 1.27.6, the fixed charges for these rate schedules recover approximately 65 percent to 70 percent of the delivery cost of service. By way of a separate assessment, FEI is proposing to decrease the monthly Administration Charge applicable to RS 25.

In addition to already recovering a large portion of the overall costs through fixed charges, the rationale for not changing the Basic Monthly Charge is that the revenue to cost ratio and margin to cost ratio for RS 5 and RS 25 are reasonable and that the change to the determination of Daily Demand and Demand Charge is to incent smaller volume customers (generally less than 10,000 GJ per year of demand) and less than 40 percent Load Factor, to be served under Large Commercial Service (RS 3 or RS 23).

28.0 Reference: RATE DESIGN FOR INDUSTRIAL CUSTOMERS

Exhibit B-1, Section 9.5.5.1, Table 9-11, p. 9-20; Appendix 9-2, p. 1

RS 5 and RS 25 daily demand new multiplier calculation

28.1 On page 9-20 of Exhibit B-1, FEI states that Appendix 9-2 contains a detailed description of the method for deriving the RS 5 and RS 25 daily demand multiplier. Please provide a functional Excel spreadsheet showing the data and calculation of the multiplier (1.02) for 2015, as seen in Table 9-11. Please arrange the spreadsheet data and calculations in a way that follows the sequence of steps outlined in Appendix 9-2.

Response:

The functional Excel spreadsheet in Attachment 28.1 provided in response to this question is being filed confidentially with the Commission, pursuant to Section 18 of the Commission's Rules of Practice and Procedure regarding confidential documents, established by Order G-1-16. FEI requests that the response be kept confidential as it contains confidential customer information for which FEI does not have the authority or permission to disclose. Given the private and commercially sensitive nature of the information, FEI submits that only the Commission should have access to the confidential spreadsheet.

28.2 Appendix 9-2 shows that data from 2011 to 2015 was used to calculate the new multiplier for RS 5 and RS 25. Please explain the effort required to update the multiplier for RS 5 and RS 25 Daily Demand on an annual basis beginning with data from 2012 to 2016. Please include a discussion regarding costs, time and effort in person-hours.

Response:

FEI estimates based on managers' experience in performing the calculations that the incremental activity to calculate the year's multiplier from all General Firm customers is 3 days FTE equivalent. A significant portion of the time is reviewing the raw data for each customer to ensure the details do not include customers who are no longer in Rate Schedules 5 or 25, and that there are no anomalies or missing data. FEI expects that there would be no, or minimal, incremental costs associated with this effort.

28.3 Please explain the benefits and disadvantages of updating the multiplier on an annual or biennial basis using recent years of actuals, as was done for this Application.

Response:

The benefit of updating the multiplier on an annual or biennial basis would be that there would be assurance that the multiplier remains accurate. However, updating the multiplier on an annual or biennial basis using recent years' actuals is not necessary, and would lead to changes in other RS 5/25 charges and in other rate schedules, increasing rate instability and decreasing customer understanding:

- Given that the population size of the RS 5/25 rate class is more established now as compared to when the original multiplier was established, FEI does not expect there will be a need to change the multiplier from year to year.
- The multiplier should not be looked at in isolation. Updating the multiplier may require changes to the RS 5/25 demand and Delivery Charges to maintain the proper price signals.
- Updating the multiplier or other components of the RS 5/25 charges would impact the rates in other rate classes, especially RS 7, RS 27 and RS 4 which are derived from RS 5/25.
- Frequent changes to the RS 5/25 charges, and other industrial rates, will increase rate instability and decrease customer understanding of the multiplier billing determinants.

For these reasons, reviewing the multiplier as part of a general rate design application, rather than more frequently, is more appropriate.

29.0 Reference: RATE DESIGN FOR INDUSTRIAL CUSTOMERS

Exhibit B-1, Section 9.5.5, p. 9-16; Table 9-8, p. 9-17; Table 9-9, p. 9-18; Section 9.4, Table 9-3, pp. 9-8 to 9-9

RS 5 and RS 25 peak day demand estimate – options and evaluation

On page 9-17 of Exhibit B-1, FEI provides Table 9-8 which shows the number of customers by load factor segment with the combined total for RS 5 and RS 25.

On page 9-18 of Exhibit B-1, FEI provides Table 9-9 which shows the average daily demand by load factor segment with the combined total for RS 5 and RS 25.

On page 9-17 of Exhibit B-1, FEI states:

> [F]or 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).

29.1 Please confirm, or correct where necessary, the figures in the following table and that the highlighted section of the table refers to the quotation from 9-17 of Exhibit B-1 in the preamble.

	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6
	Load Factor Segment (RS 5/25 Combined)	Number of customers		Average Daily Demand (GJ) per Customer		Percentage difference [3]
		Method 1 [1] Current Formula for Daily Demand	Method 4 [1] Average Consumption on 5 Coldest Days	Method 1 [2] Current Formula for Daily Demand	Method 4 [2] Average Consumption on 5 Coldest Days	
Row 1	Customers with Zero Demand	1	4	--	--	--
Row 2	< 40% Load Factor	55	33	174	159	9%
Row 3	40% to < 45% Load Factor	75	43	93	109	-15%
Row 4	45% to < 50% Load Factor	196	87	73	72	1%
Row 5	> 50% Load Factor	447	607	105	72	46%
Row 6	All customers	774	774	100	77	30%

Notes

(1) Data from Exhibit B-1, Table 9-8, p. 9-17

(2) Data from Exhibit B-1, Table 9-9, p. 9-18

(3) This column shows the percentage difference between (i) the average daily demand determined using the current formula for daily demand; and (ii) the average consumption on the 5 coldest days using 2011 - 2015 historical data

Response:

FEI confirms the numbers in the table of this IR are consistent with the numbers contained in Exhibit B-1, Tables 9-8 and 9-9. FEI also confirms the quote from page 9-17 is related to the results highlighted in Row 5. Similar percentage differences relative to Table 9-9 can be achieved by comparing the average daily demand from the Current Formula (Method 1) to the average Daily Demand from Method 4 using the average on the coldest 3 days or the Modified Formula (Method 5). When choosing a method to calculate Daily Demand, it is important not to select a method that can result in an undesired anomalous consequence such as customers having a zero demand. The purpose of selecting the method for determining Daily Demand is not to estimate the peak day demand of General Firm customers, but rather to generate a billing determinant that can be applied to the demand charge for the firm service use of the delivery capacity of FEI's system. The results presented in Table 9-8 are supportive of using Method 2 – Current Formula Updated Multiplier (1.10) or Method 5 – Modified Formula with 5 Day Average, both of which have the least number of customers with a zero demand (i.e., 1 customer).

On page 9-16 of Exhibit B-1, FEI explained that they considered five options for estimating peak demand: (i) Status Quo/Current Formula; (ii) Current Formula with Updated Multiplier; (iii) FEI System Maximum Day Send Out; (iv) Average Consumption on 3 or 5 Coldest Days in Region; and (v) Modified Formula.

29.2 FEI conducted a review of industrial rates offered by Canadian natural gas utilities and summarized the results in Table 9-3 on pages 9-8 and 9-9 of Exhibit B-1. For each of the Canadian natural gas utilities that use a demand charge for industrial customers, please state which of FEI's five options listed in the preamble was used to estimate peak day demand or elsewhere in the determination of their demand charge.

Response:

Based on FEI's review it would appear that none of the other utilities use any of the five options employed by FEI in its analysis, and that there is diversity in what is done at each utility. For instance, the eastern utilities use cubic meter volume and contract demand for the billing determinant whereas Atco Gas and AltaGas use energy (gigajoules).

Union Gas Rate 100 and Enbridge Rate 110 use contracted demand in cubic meters. Union Gas Rate 2 makes a distinction for contract demand less than and greater than 70,000 cubic meters.

The Atco Gas and AltaGas billing determinant is expressed in energy (gigajoules), as is FEI's, versus the eastern Canadian utilities that use cubic volume (cubic meters). Another similar feature that AtcoGas and AltaGas employ is to divide the summer volumes by two, which FEI also does to determine the Daily Demand for the same April 1 to October 31 period. (For Atco Gas, if the customer is **only** taking service during the summer period then the amount of gas is **not** divided by 2 in determining the billing determinant).

The following table shows how the billing determinant is derived for service provided by the five utilities other than FEI that have demand charges – Atco Gas, Alta Gas, Union Gas, Enbridge and Gazifere.

Utility	Billing Determinant
Atco Gas and Pipelines Ltd. – North: High Use Delivery Service	Determination of Billing Demand: The Billing Demand for each billing period shall be the greatest amount of gas in GJ delivered in any Gas Day (i.e., 8:00 am to 8:00 am) during the current and preceding eleven billing periods provided that the greatest amount of gas delivered in any Gas Day in the summer period shall be divided by 2. Provided that for a Customer who elects to take service only during the summer period, the Billing Demand for each billing period shall be the greatest amount of gas in GJ in any Gas Day in that billing period. In the first contract year, the Company shall estimate the Billing Demand from information provided by the Customer.
Alta Gas: Optional Demand General Service – Rate No. 3	The billing demand shall be the greater of: i) 100 GJ or ii) The Contract Demand or iii) The greatest amount of gas in GJ in any consecutive 24-hour period during the current and preceding eleven billing periods provided that the greatest amount of delivered in any 24 consecutive hours in the summer period (April 1 to October 31) shall be divided by 2.
Union Gas: Rate 2 Medium Volume Firm Service & Rate 100: Large Volume High Load Factor Firm Service	Contracted Daily Demand in cubic meters
Enbridge: Rate 110 – Large Volume Load Factor Service	Contract Demand in cubic meters
Gazifere: Rate 5 – Large Volume Firm Service	Minimum annual volume: Subscribed Volume (m^3) x number of days in year x load factor provided for in the contract (Minimum load factor is 50%)

1

30.0 Reference: RATE DESIGN FOR INDUSTRIAL CUSTOMERS

Exhibit B-1, Section 9.4, Table 9-3, pp. 9-8 to 9-9; Section 9.5.3.3, pp. 9-12; Section 9.5.3.5, p. 9-14

Minimum load factor eligibility criterion for RS 5 and RS 25

On page 9-12 of Exhibit B-1, FEI states:

> 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.

On page 9-14 of Exhibit B-1, FEI states:

> 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%.

30.1 Please confirm, or otherwise explain, that when FEI is excluded from Table 9-3 it is five of nine utilities surveyed that used some form of demand charge.

Response:

Confirmed.

30.2 Please discuss the benefits and disadvantages of using a minimum load factor eligibility criterion for RS 5 and RS 25 in a manner similar to Union Gas, Enbridge Gas or Gazifere.

Response:

FEI considers that the preferable option is to design the rate so that it is “self-policing”, and allows customers to choose the service they would like or need on a prospective basis based on the customer’s economics and business needs. Rates should be designed so that customers can choose the appropriate service they need based on how the billing determinants, Daily Demand and Annual Demand, are derived, coupled with the price(s) for the Demand Charge and Delivery Charge. If the proper price signals are in place, as proposed, then customers without a sufficient load factor and / or annual load will not choose to take service under RS 5 or

RS 25. FEI believes that the RS 5 and RS 25 have been working in this way since 1996, and sees no need to impose a minimum load factor.

The benefits of using a minimum load factor include:

- Customers have an incentive to maintain a higher load factor (or manage peak demand use) to qualify for the higher load factor rate.

The disadvantages of using a minimum load factor include:

- The load factor threshold is somewhat arbitrary and customers that fall just under the threshold are penalized by being grouped along with low load factor customers.
- Customers with load factors less than the minimum load factor, but with sufficient annual volume would be harmed if forced to take service under a different service offering that had higher annual charges.
- Customers can be incented to 'flare' gas in off-peak period in order to achieve the minimum load factor to compensate for significant restart from a production downturn in an off-peak period for equipment maintenance or other customer economic/business reasons.
- Load factors can change from year to year, which may require customers to be moved to different rates from year to year leading to increased administrative burden and rate instability.
- The addition of a load factor threshold would have significant impacts on some customers.

Since the inception of a demand charge for RS 5 and 25 in 1996, the general assessment of FEI is that the service is working the way it was intended and what is required at this time is to make adjustments to how the Daily Demand is determined and to adjust the Demand Charge.

30.3 Please explain any differences in circumstances that would prevent FEI from using a minimum load factor eligibility criterion for RS 5 and RS 25 in a manner similar to Union Gas, Enbridge Gas or Gazifere.

Response:

Of the three other utilities mentioned in the question FEI does not believe that the Union Gas service offering is a relevant comparator in this case. The Union Gas Large Volume High Load Factor Firm service offering with a minimum volume of 3,825 GJ per day would be the equivalent of FEI's Large Transportation Service RS 22. This is not comparable to FEI's RS 5/25 service.

FEI is unaware of any circumstances related to types of customers that would prevent FEI from using a minimum load factor eligibility criterion. Implementing a minimum load factor eligibility criterion could require the collection of metered daily demand amounts and ongoing monitoring of whether each customer would still qualify based upon the minimum load factor criterion. The review of customer accounts to see if customers continue to meet the criterion and if the customer(s) should be transferred to another rate schedule would create unnecessary additional work for both FEI and the customer.

30.4 If FEI were to implement a minimum load factor eligibility criterion for RS 5 and RS 25:

i. Please explain what the desired minimum load factor would be; and

ii. Please explain how FEI could implement the minimum load factor and ensure customers are being placed in the appropriate rate class and being billed accordingly.

Response:

FEI does not recommend a minimum load factor eligibility criterion. The rest of the response is based on adopting a load factor eligibility criterion, contrary to FEI's recommendation.

Load Factor is a derived value of average consumption divided by peak consumption; for FEI, it is average day consumption divided by peak consumption. The derivation of the load factor is not as important as the derivation or definition of peak consumption. In response to the two questions posed above:

i) In FEI's judgment, the minimum Load Factor should be 40 percent; the class average is anticipated to be approximately 50 percent to 55 percent.

ii) FEI would review customers' historical daily demands and consequent load factors to see if the customer should be moved to an alternate rate schedule. The review would also consider the forecast demand and expected load factor as well.

Whether or not a minimum eligibility criterion is adopted, what is most important is the determination of the appropriate Daily Demand and the Demand Charge. A proper determination of Daily Demand with the Demand Charge should be 'self-policing' to incent customers on a prospective basis to take service under the most economic rate schedule. To ensure these firm customers have an appropriate billing determinant, FEI recommends using Method 2 or Method 5. With an appropriate determination of Daily Demand (or Peak), a customer's Load Factor can be derived. By adopting Method 2 or Method 5, all customers would fairly contribute to the recovery of the rate schedules' allocated cost of service.

With a minimum load factor requirement, similar to the Commercial customers, annual reviews of customers' consumption and load factor would need to be done to identify customers that should consider switching to another rate schedule.

31.0 Reference: RATE DESIGN FOR INDUSTRIAL CUSTOMERS

Exhibit B-1, Section 9.5.4, p. 9-15; Section 9.5.6, Table 9-14, p. 9-23

Economic crossover volume between RS 3/RS 23 and RS 5/RS 25 at proposed rates

On page 9-15 of Exhibit B-1, FEI states:

> 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%.

Table 9-14 on page 9-23 of Exhibit B-1 shows that at 40 percent load factor, the economic crossover volume between RS 3/RS 23 and RS 5/RS 25 at the proposed rates is 19,874 GJ.

31.1 Please state:

i. the number of RS 3/RS 23 customers currently above 19,874 GJ per year and the combined amount of throughput they represent;

ii. the number of RS 3/RS 23 customers currently below 19,874 GJ per year and the amount of throughput they represent;

iii. the number of RS 5/RS 25 customers currently above 19,874 GJ per year and the combined amount of throughput they represent; and

iv. the number of RS 5/RS 25 customers currently below 19,874 GJ per year and the amount of throughput they represent.

Response:

The requested information is provided in the table below. The number of customers and volumes are from the 2016 billed data. For RS 3/23, the volumes have been weather normalized. For RS 5/25 the number of customers and volumes do not include the four bypass customers and do not include customers that are new or left these rate schedules during the year, as these customers would not have a full 12 months of data.

Customer Count	Under 19,874 GJs	Over 19,874 GJs	Total
Rate Schedule 3/23	7,243	50	7,293
Rate Schedule 5/25	585	182	767
Total	7,828	232	8,080

Demand	Under 19,874 GJs	Over 19,874 GJs	Total
Rate Schedule 3/23[1]	27,071,860	1,763,043	28,834,903
Rate Schedule 5/25	5,864,854	9,709,772	15,574,626
Total	32,936,714	11,472,815	44,409,529

[1] 2016 Weather Normalized Actuals

31.2 Please state the annual throughput required to make RS 5/RS 25 economic at a load factor of (i) 35 percent and (ii) 30 percent based on: (a) 2016 COSA rates; and (b) FEI's proposed rates.

Response:

The following table provides the annual throughput required to make RS 5/RS 25 economic at a load factor of 35 percent and 30 percent based on the corrected (as discussed below) 2016 COSA rates and FEI's proposed rates:

Load Factor	Economic Crossover	
	2016 COSA Rates	Proposed Rates
35%	20,020 GJ	(716,705) GJ
30%	(83,029) GJ	(13,491) GJ

As shown in the table above, at the 2016 COSA Rates there is no economic crossover at a 30 percent load factor as the mathematical solution results in a negative volume. At the FEI proposed rates there is no economic crossover at either 35 percent or 30 percent as the mathematical solution results in negative volumes.

In preparing this response FEI noticed that some of the rates used in the tables were incorrect. The corrected rate changes are the following:

- Table 9-7 – RS 23 Delivery Charge was $3.161, should have been $3.188,
- Table 9-12 – RS 23 Delivery Charge was $3.175, should have been $3.190,
- Table 9-12 – RS 23 Monthly Charge was $223.78, should have been $184.78,

- Table 9-13 – RS 23 Delivery Charge was $3.175, should have been $3.190;
- Table 9-13 – RS 23 Monthly Charges was $223.78, should have been $184.78; and
- Table 9-13 – RS 25 Monthly Charges was $665.00, should have been $626.00.

Corrected tables are provided below. Table 9-7 and Table 9-13 have two additional rows added to show the results at a load factor of 35 percent and 30 percent at the 2016 COSA rates (corrected Table 9-7) and at FEI's proposed rates (corrected Table 9-13). Corrected Table 9-14 summarizes the corrected economic crossover volumes. Corrected Table 9-12 shows what the load factors and economic crossover volumes would be using RS 23 Proposed Rates and RS 25 COSA charges using the 1.1 multiplier for the Peak Winter Month and associated Daily Demand.

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

<table>
<tr><th colspan="2"></th><th colspan="2">RS 23</th><th>RS 25</th></tr>
<tr><td colspan="2">Monthly Charges (Basic + Admin. Fee)</td><td colspan="2">$210.52</td><td>$665.00</td></tr>
<tr><td colspan="2">Demand Charge</td><td colspan="2">N / A</td><td>$21.596</td></tr>
<tr><td colspan="2">Delivery Charge</td><td colspan="2">$3.188</td><td>$0.887</td></tr>
<tr><td colspan="2"></td><td>Economic Cross-over (GJ/Year)</td><td>Daily Demand</td><td>Peak Winter Month With 1.25 multiplier</td></tr>
<tr><td rowspan="7">Load Factor</td><td>50%</td><td>6,191 GJ</td><td>34 GJ</td><td>814 GJ</td></tr>
<tr><td>45%</td><td>7,541 GJ</td><td>46 GJ</td><td>1,102 GJ</td></tr>
<tr><td>40%</td><td>10,369 GJ</td><td>71 GJ</td><td>1,704 GJ</td></tr>
<tr><td>39%</td><td>11,351 GJ</td><td>80 GJ</td><td>1,914 GJ</td></tr>
<tr><td>38%</td><td>12,608 GJ</td><td>91 GJ</td><td>2,182 GJ</td></tr>
<tr><td>37%</td><td>14,274 GJ</td><td>106 GJ</td><td>2,537 GJ</td></tr>
<tr><td>36%</td><td>16,589 GJ</td><td>126 GJ</td><td>3,030 GJ</td></tr>
<tr><td></td><td>35%</td><td>20,020 GJ</td><td>157 GJ</td><td>3,761 GJ</td></tr>
<tr><td></td><td>30%</td><td>(83,029) GJ</td><td>(758) GJ</td><td>(18,198) GJ</td></tr>
</table>

Corrected 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		$184.78		$626.00	From Table 9-7 at 2016 COSA RATES	
Demand Charge $/GJ/Month		N / A		$24.596		
Delivery Charge $/GJ		$3.190		$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%	7,721 GJ	42 GJ	1,154 GJ	34 GJ	814 GJ
	45%	10,463 GJ	64 GJ	1,737 GJ	46 GJ	1,102 GJ
Load Factor	40%	18,815 GJ	129 GJ	3,515 GJ	71 GJ	1,704 GJ
	39%	23,063 GJ	162 GJ	4,419 GJ	80 GJ	1,914 GJ
	38%	30,253 GJ	218 GJ	5,949 GJ	91 GJ	2,182 GJ
	37%	45,061 GJ	334 GJ	9,100 GJ	106 GJ	2,537 GJ
	36%	93,232 GJ	710 GJ	19,351 GJ	126 GJ	3,030 GJ
	35%	(716,705) GJ	(5,610) GJ	(153,006) GJ	157 GJ	3,761 GJ
	30%	(13,491) GJ	(123) GJ	(3,360) GJ	(758) GJ	(18,198) GJ

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

Load Factor	Economic Crossover at Proposed Rates	Economic Crossover at 2016 COSA Rates
50%	7,721 GJ	6,191 GJ
45%	10,463 GJ	7,541 GJ
40%	18,815 GJ	10,369 GJ
39%	23,063 GJ	11,351 GJ
38%	30,253 GJ	12,608 GJ
37%	45,061 GJ	14,274 GJ
36%	93,232 GJ	16,589 GJ
35%	(716,705) GJ	20,020 GJ
30%	(13,491) GJ	(83,029) GJ

Corrected & Updated 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)		$184.78		$665.00
Demand Charge		N / A		$21.596
Delivery Charge		$3.190		$0.887
		Economic Cross-over (GJ/Year)	**Daily Demand**	**Peak Winter Month With 1.1 multiplier**
Load Factor	58.2%	5,800 GJ	27 GJ	745 GJ
	52.0%	7,075 GJ	37 GJ	1,016 GJ
	45.9%	9,785 GJ	58 GJ	1,593 GJ
	44.7%	10,755 GJ	66 GJ	1,799 GJ
	43.4%	12,000 GJ	76 GJ	2,064 GJ
	42.2%	13,680 GJ	89 GJ	2,422 GJ
	41.0%	16,060 GJ	107 GJ	2,928 GJ

31.3 Please explain if FEI considers that the customers with high annual volumes and with load factors below 40 percent should be classified as RS 3/RS 23.

Response:

No, FEI does not believe the relatively few customers with load factors below 40 percent but with sufficiently large enough loads to economically be better served under RS 5/25 should be forced to be served under RS 3/23. FEI believes what is important is to have an appropriate calculation of the Daily Demand and Demand Charge so that customers who have a sufficient annual demand and, generally, a load factor characteristic of 40 percent or higher would be best served under General Firm Service RS 5/25. Large volume customers that would be served in the General Firm rate schedules are sophisticated enough to determine which rate schedule would be the most appropriate for their needs and what it would cost them. The average Demand Charge of customers whose load factor is less than 40 percent will be higher than for a customer whose load factor is equal to or greater than 40 percent.

31.3.1 Please explain if the RS 5/RS 25 customers with high annual volumes and with load factors below 40 percent would pay a higher overall bill if they were reclassified as RS 3/RS 23 customers.

Response:

Based on the 2015 Billed Data, using the proposed charges for RS 3/23 and RS 5/25, and using the Current Method with the Updated Multiplier of 1.1 (Method 2) (Exhibit B-1, Table 9-8, Page 9-17), of the 26 customers whose load factors are less than 40 percent, 22 customers would have a lower annual bill on RS 3/23 and 4 customers would have a higher annual bill on RS 3/23.

After the Commission's Decision on this Application, FEI proposes to review the account history of all RS 3/23 and 5/25 customers to see if there are customers who should consider migrating from General Firm Service to Large Commercial Service or if there are Large Commercial Service customers who may be better off being served under General Firm Service. The discussions with customers will need to consider the customers' expected future consumption as well as their historical demand profile.

31.4 Please provide in table form, for each of RS 3 and RS 23, the percentage of costs recovered through all fixed charges using (i) existing charges; and (ii) FEI's proposed charges.

Response:

The requested information is provided in the table below. The percentage of revenue recovery from the Basic Charge is higher for RS 3 than it is for RS 23 because of the lower average annual use per customer for RS 3 sales customers. The result for RS 3 is a little over 13 percent whereas for RS 23 customers it averages approximately 9.5 percent.

The existing rates are those approved by the Commission effective January 1, 2017.

	Rate Schedule 3			Rate Schedule 23	
	Existing Rates	Proposed Rates		Existing Rates	Proposed Rates
Average Use per Customer (2015, Exhibit B-1, Figures 8-4 & 8-5, Page 8-6)	3,587	3,587		5,174	5,174
Basic Charge $ / Day	$ 4.3538	$ 4.7895			
Basic Charge $ / Month				$ 132.52	$ 145.78
Delivery Charge $ / GJ	$ 2.939	$ 3.190		$ 2.939	$ 3.190
Basic Charge Revenue	$ 1,590	$ 1,749		$ 1,590	$ 1,749
Delivery Charge Revenue	10,542	11,443		15,206	16,505
Total Delivery Margin Revenue	$ 12,132	$ 13,192		$ 16,797	$ 18,254
% of Basic Charge Revenue to Total Delivery Margin Revenue	13.1%	13.3%		9.5%	9.6%

1

2

32.0 Reference: RATE DESIGN FOR INDUSTRIAL CUSTOMERS

Exhibit B-1, Section 9.6.1, p. 9-25; Section 9.6.3.2, p. 26; Section 9.6.4, p. 9-21

RS 7 and RS 27 interruptible service charges

On page 9-25 of Exhibit B-1, FEI states:

> … 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. … 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 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.

32.1 Using FEI's proposed rates, please use calculations to show the percentage discount from the firm sales service would be for an interruptible sales customer using an average of 59,200 GJ per year based on a RS 5/RS 25 Demand Charge using a load factor of (i) 100 percent; (ii) 80 percent; (iii) 60 percent; and (iv) 40 percent.

<u>Response:</u>

The requested calculations and results are found in the table below. In responding to this IR for calculating the discount as a percent of Total Firm, it is important to note that for the customer Load Factor cases of 80 percent, 60 percent or 40 percent FEI made a simplifying assumption that the Peak Day is equal to the highest average day of any month. It is quite possible that a customer's actual peak day could be higher than the highest monthly average.

Line No.	Particulars	Scenarios i)	ii)	iii)	iv)	
1	Customers Operating Load Factor	100%	80%	60%	40%	
2	Proposed Multiplier	1.1	1.1	1.1	1.1	
3	Effective Load Factor	90.9%	72.7%	54.5%	36.4%	Line 1 / Line 2
4	Proposed Demand Charge	$ 24.596	$ 24.596	$ 24.596	$ 24.596	
5	Months in Year	12	12	12	12	
6	Days in Year	365	365	365	365	
7	Demand Charge Effective Rate $ / GJ	$ 0.889	$ 1.112	$ 1.482	$ 2.224	Line 4 x Line 5 / Line 6 / Line 3
8	Delivery Charge $ / GJ	0.887	0.887	0.887	0.887	
9	Total Effective Rate	$ 1.776	$ 1.999	$ 2.369	$ 3.111	Line 7 + Line 8
10	Proposed Interruptible Rate $ / GJ	$ 1.443	$ 1.443	$ 1.443	$ 1.443	
11	Differential $ / GJ	$ 0.333	$ 0.556	$ 0.926	$ 1.668	Line 9 - Line 10
12	Discount as a % of Total Firm	18.8%	27.8%	39.1%	53.6%	Line 11 / Line 9

As shown in the table above, a customer that takes natural gas service at a 100 percent Load Factor, an 80 percent Load Factor, a 60 percent Load Factor or a 40 percent Load Factor will have the following respective discounts as an Interruptible customer: 18.8 percent, 27.8 percent, 39.1 percent and 53.6 percent. A customer's annual volume has no effect on the determination of the relative percentage of the discounts; it is the customer's demand profile (i.e., load factor) and the proposed rates for firm and interruptible service that determine the percentage discount. As such, FEI did not utilize the customer usage of 59,200 GJ stated in the question.

It is important to note that the multiplier of 1.1 will limit the effective load factor of a customer to a maximum of 90.9 percent. The current methodology, using a multiplier of 1.25, will limit the effective load factor of a customer to a maximum of 80 percent. As an example, if a customer uses 100 GJ every day, i.e., operating at a 100 percent load factor, for billing under General Firm Service, that customer will have a Daily Demand of 110 GJ (i.e., 100 GJ x 1.1). The effective load factor then becomes 90.9 percent (average daily use of 100 GJ / Daily Demand of 110 GJ).

In conclusion, although the relative percentage of the discount significantly increases as the load factor decreases, the RS 7/27 customers provide significant benefits that exceed the total value of the discount. This is discussed in the response to BCUC-FEI IR 1.32.6.

32.2 Using FEI's proposed rates, please use calculations to show what the discount from the firm transportation service would be for an interruptible transportation customer using an average of 59,200 GJ per year based on a RS 5/RS 25 Demand Charge using a load factor of (i) 100 percent; (ii) 80 percent; (iii) 60 percent; and (iv) 40 percent.

Response:

The requested calculations and results are provided in the table below.

Line No.	Particulars	100%	80%	60%	40%	
1	Annual Volume (GJ)	59,200	59,200	59,200	59,200	
2	Days in Year	365	365	365	365	
3	Average Daily Volume	162.2	162.2	162.2	162.2	Line 1 / Line 2
4	**Customers Operation Load Factor**	100%	80%	60%	40%	
5	Customer's Operating Peak Day	162.2	202.7	270.3	405.5	Line 3 / Line 4
6	Proposed Multiplier	1.1	1.1	1.1	1.1	
7	Daily Demand	178.4	223.0	297.4	446.0	Line 5 x Line 6
8	**Effective Load Factor**	90.9%	72.7%	54.5%	36.4%	Line 3 / Line 7
9	**Rate Schedules 5 & 25**					
10	Proposed Demand Charge	$ 24.596	$ 24.596	$ 24.596	$ 24.596	
11	Proposed Delivery Charge	$ 0.887	$ 0.887	$ 0.887	$ 0.887	
12	Demand Charge Revenue	$ 52,658	$ 65,823	$ 87,764	$131,646	Line 7 x 12 months x Line 10
13	Delivery Charge Revenue	52,510	52,510	52,510	52,510	Line 1 x Line 11
14	Total RS 5 / 25 Demand & Delivery Revenue	$105,169	$118,333	$140,274	$184,156	Line 12 + Line 13
15	**Proposed Rate Schedules 7 & 27**					
16	Propsed Delivery Charge $ / GJ	$ 1.443	$ 1.443	$ 1.443	$ 1.443	
17	Delivery Charge Revenue	$ 85,426	$ 85,426	$ 85,426	$ 85,426	Line 1 x Line 16
18	Dollar Value of Discount from Firm	$ 19,743	$ 32,908	$ 54,849	$ 98,731	Line 14 - Line 17
19	Discount % of Firm	18.8%	27.8%	39.1%	53.6%	

As shown in the table, for a customer using 59,200 GJ per year at load factors of 100 percent, 80 percent, 60 percent or 40 percent the respective values of the discount would be $19,743; $32,908; $54,849; or $98,731. Line 19 shows the percentage of the discount which is the same as shown in the response to BCUC-FEI IR 1.32.1. In this case the size of the annual volume affects the dollar value of the discount, while not impacting the percentage of the discount. Although the value of the discount significantly increases as the load factor decreases, the RS

7/27 customers provide significant benefits that exceed the total value of the discount. This is discussed in the response to BCUC-FEI IR 1.32.6.

32.3 Please state the number of customers that have switched from interruptible service (RS 7/RS 27) to firm service (RS 5/RS 25) for each year of the last five years of actual data.

Response:

For the period of January 1, 2012 to December 31, 2016 (last five years of actual data) there was 1 customer that switched from interruptible service (RS 7/27) to firm service (RS 5/25), which was in 2014.

32.4 Please state the number of customers that have switched from firm service (RS 5/RS 25) to interruptible service (RS 7/RS 27) for each year of the last five years of actual data.

Response:

As shown in the table below, for the period from January 1, 2012 to December 31, 2016 (the last five years of actual data) there were 6 customers that switched from firm service (RS 5/25) to interruptible service (RS 7/27).

Year	# Customers
2012	3
2013	1
2014	0
2015	1
2016	1
Total	**6**

32.5 Does FEI consider that, in general, the discount provided for interruptible service should be based on marginal rather than sunk costs? For example, being based on the cost savings to the utility in providing interruptible instead of firm service and/or the discount required to shift consumption away from peak periods and so achieve cost savings for customers overall. Please explain.

Response:

FEI does not consider that the marginal cost should be used as the basis for setting the Delivery Charge discount for Interruptible service. The reason for this is the marginal costs for interruptible service on the Transmission system and Distribution mains-related system are very small or zero. For system planning on design day conditions, interruptible customers are a zero load and no capacity and associated costs are incurred for serving interruptible customers. Setting the pricing or discounts based on marginal costs would allow interruptible customers to be a 'free rider' on FEI's Transmission system and Distribution Mains system. In order to have interruptible customers contribute to the recovery of Transmission costs and Distribution Mains-related costs, the pricing for interruptible service should be based on a discount-based approach from firm service rates, as has been the case since the 1996 Rate Design.

32.6 Does FEI consider that it has optimized its use of interruptible rates to cost effectively defer the need for new infrastructure investment? Please explain.

Response:

Yes, FEI considers it has optimized its use of interruptible rates to cost effectively defer the need for new infrastructure investment. FEI has consistently shown in its 1993 Phase B, 1996, 2001 and 2016 Rate Design Applications that there is a net benefit in avoided capital costs and the associated avoided cost of service from interruptible customers not receiving firm service.

In Exhibit B-1, Appendix 9-3, pages 2 and 3 show that the avoided capital cost of all interruptible customers not taking firm service (Rate Schedules 7, 27 and 22) and RS 22 alone (page 3, Year 2016) is approximately $134.2 million and $40.15 million, respectively. From Table 9-19 on page 9-30, FEI calculates the net benefit for all customers from RS 7/27 not taking firm service to be $5.0 million per year. The net benefit is derived by subtracting the $2.3 million value of the discount from the avoided cost of service of $7.3 million.

On page 9-26 of Exhibit B-1, FEI states: "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."

32.7 Please state if FEI had proposed the use of an 80 percent factor in the 1996 Rate Design.

Response:

FEI confirms that FEI proposed the use of an 80 percent load factor in the 1996 Rate Design Application – Amendments (Exhibit 2A) filed on September 30, 1996, Tab 3, pages 10 and 11. The use of the 80 percent load factor was agreed to in the negotiated settlement that was approved by the Commission.

32.7.1 If FEI had originally proposed the use of an 80 percent load factor, please explain the reasons why and please discuss the applicability of these reasons to the proposals in the 2016 Rate Design Application.

Response:

FEI provides the rationale for both the 1996 and 2016 Rate Design Applications below.

Rationale in the 1996 Rate Design Application

In its 1996 Rate Design Application, FEI originally proposed a General Interruptible Rate at a discount from the average Firm Rate to reflect the customer costs of one to two days of curtailment per year or the risk of production losses. FEI proposed the following two adjustments to the Firm Rate:

- An alternative fuel adjustment, which deducted from the Firm Rate the incremental fuel cost of the customer for alternative fuels for two days of expected interruption over 365 days.
- An incentive adjustment, which deducted from the Firm Rate the estimated capital costs of the customer for equipment to burn the alternative fuel.

During the proceeding, FEI amended its proposal.[22] Instead of making the two adjustments described above, FEI proposed to reach the same result by calculating the delivery charge for the General Interruptible rate as equivalent to the firm demand charge at an 80 percent load factor. As the General Firm customers' average load factor was 55 percent, using an 80 percent load factor for interruptible customers yielded a discount from the General Firm Rate.

[22] 1996 Rate Design Application – Amended (Exhibit 2a).

The proposed effective average firm rate for General Firm Service was $0.78 per GJ, and the proposed General Interruptible Service was $0.64 per GJ. This resulted in a $0.14 per GJ or 18 percent discount.[23] The load factor approach was agreed to in the negotiated settlement approved by the Commission.

In summary, the General Interruptible rate was set at an 18 percent discount from the General Firm rate to approximate the customer costs of one or two days of curtailment per year, and was derived by using the equivalent of the firm demand charge at an 80 percent load factor for interruptible customers.

Rationale in the 2016 Rate Design Application

FEI is proposing to maintain the discount that was approved in 1996 and again in 2001, by updating the methodology to reflect the change in the Daily Demand formula (reducing the multiplier from 1.25 to 1.10). As described on page 9-31 of the Application, after the change in the Daily Demand formula, an 80 percent load factor firm customer would be a 90.9 percent load factor customer. The Delivery Charge for the General Interruptible rate is therefore proposed to be updated to be the equivalent of the firm demand charge at a 90.9 percent load factor. As shown in Table 9-20 of the Application, this results in an 18.8 percent discount from the firm rate.

32.7.2 If FEI had not originally proposed the use of an 80 percent load factor, please explain the reasons that led to the use of the 80 percent load factor.

Response:

Please refer to the response to BCUC-FEI IR 1.32.7.1.

On page 9-29 of Exhibit B-1, FEI states:

> 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. … Based upon cold weather days where

[23] Exhibit 2A, 1996 Rate Design Application – Amended, Tab 5, Page 18).

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.

32.8 Please state the actual number of (i) partial curtailments in 2016; and (ii) FEI system maintenance related curtailments in 2016.

Response:

FEI does not track the statistics related to partial curtailments or to system maintenance related curtailments as they often do not result in an actual curtailment for the customer, as described further below.

When FEI referred to partial curtailments in the quoted passage, it was referring to limiting the amount of interruptible capacity that may be available to those large industrial customers that would be over their contracted firm capacity. These limitations may be above a customer's expected consumption and therefore may not be a restriction at all.

FEI's system maintenance-related curtailments are usually in the summer and usually only place limits on the amount of interruptible capacity that may be available during the maintenance procedure. These limitations in many cases are above a customer's expected consumption and therefore not a restriction at all. FEI also makes efforts to coordinate maintenance procedures where possible with the large industrial customer's planned maintenance outages.

32.9 Please state the average duration of (i) all partial curtailments in 2016; and (ii) all FEI system maintenance related curtailments in 2016.

Response:

Please refer to the response to BCUC-FEI IR 1.32.8

32.10 Please state the longest duration of (i) all partial curtailments in 2016; and (ii) all FEI system maintenance related curtailments in 2016.

Response:

Please refer to the response to BCUC-FEI IR 1.32.8

32.11 Please explain if some interruptible customers experience more curtailments than other interruptible customers due to their location on the FEI system.

Response:

Some interruptible customers may experience more curtailments, partial curtailments and/or system maintenance-related curtailments than other interruptible customers due to their location on the FEI system. The reasons for the curtailments could be numerous. Maintenance-related curtailment work, for instance, may be more common for customers that are served directly off of the transmission line, as system pressures in the transmission lateral must be reduced during various aspects of the work for safety reasons, thereby reducing capacity on a temporary basis. Another possible reason that some customers may experience more curtailments or partial curtailments is that certain areas of the system are becoming or have become capacity constrained.

33.0 Reference: RATE DESIGN FOR INDUSTRIAL CUSTOMERS

Exhibit B-1, Section 9.8.1, Table 9-22, p. 9-37

Large volume transportation customers

Table 9-22 on page 9-37 of Exhibit B-1 shows large volume transportation customers and the 2016 annual demand forecast by rate schedule.

33.1 Please provide an updated version of Table 9-22 by splitting the Annual Demand Column into three showing the (i) Annual Firm Demand (TJ); (ii) Annual Interruptible Demand (TJ); and (iii) Annual Total Demand (TJ).

Response:

The requested information is provided in the following table.

Rate Schedule	Customers	Firm Demand	Interruptible Demand	Total Annual Demand
RS 22	26	732	12,457	13,189
RS 22A	9	10,878	0	9,030
RS 22B	5	4,215	1,061	5,277
Subtotal	**40**	**15,825**	**13,518**	**27,496**
Joint Venture	1	4,758	0	4,758
BC Hydro IG	1	16,425	0	16,425
Total	**42**	**37,008**	**13,518**	**48,679**

Units in the Demand Columns are all in TJ

33.2 Please state the percentage of the total FEI 2016 forecast throughput represented by large volume transportation customers, including RS 22, RS 22A, RS 22B, VIGJV and BC Hydro IG.

Response:

The forecast of volume for RS 22, 22A, 22B, VIGJV and BC Hydro IG as a percentage of the total 2016 forecast throughput is 22.7 percent.

Particulars	2016 Forecast (TJ)	% of Total Throughput
Total Sales Throughput (TJ)	121,772.2	58.6%
RS 22 Throughput (TJ)	13,164.9	6.3%
RS 22A Throughput (TJ)	9,048.5	4.4%

Particulars	2016 Forecast (TJ)	% of Total Throughput
RS 22B Throughput (TJ)	5,281.9	2.5%
VIGJV	4,758.0	2.3%
BC Hydro IG	14,945.0	7.2%
Subtotal – Large Industrial	47,198.3	22.7%
All Other T-Service Throughput (TJ)	38,804.2	18.7%
Total T-Service Throughput (TJ)	86,002.5	41.4%
Total Throughput (TJ)	207,774.7	100.0%

34.0 Reference: RATE DESIGN FOR INDUSTRIAL CUSTOMERS

Exhibit B-1, Section 9.8.1.4, p. 9-39; Section 9.8.3, pp. 9-42 to 9-43; Section 9.8.5.3, Table 9-27, p. 9-48; Section 9.8.5.4, p. 9-48

Large volume transportation – large industrial contract customers

On page 9-39 of Exhibit B-1, FEI states:

> … 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.

On pages 9-42 to 9-43 of Exhibit B-1, FEI states:

> 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).

On page 9-48 of Exhibit B-1, FEI states:

> … 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.

34.1 Please explain what FEI would do with the expiring VIGJC contract if the Commission does not approve FEI's proposal for RS 22 and VIGJV as described in the preamble.

Response:

If the Commission does not approve FEI's proposal for RS 22 and the VIGJV, then FEI would have to negotiate an extension or new agreement with the VIGJV that would need to be submitted to the Commission for review and approval.

34.2 If the Commission does not approve FEI's proposal for large volume transportation customers, could FEI establish new contracts based on cost-based rates with VIGJV and BC Hydro IG after the expiration of the current contracts? Please explain your response.

Response:

If the Commission does not approve FEI's proposal for large volume transportation customers, then FEI could negotiate and try to establish new contracts based on cost-based rates with the VIGJV and BC Hydro IG after the expiration of the current contracts. FEI's proposal for RS 22 firm service establishes cost-based firm rates for the current RS 22, VIGJV and BC Hydro IG combined, based on cost allocation from the COSA model for this group of customers.

34.3 Please produce a table to discuss the similarities and differences between (a) the average RS 22 customer, (b) Creative Energy, (c) VIGJV and (d) BC Hydro IG. Please use figures where necessary and include a discussion for each on the:

i. annual throughput and expected changes in throughput over time;

ii. existing R:C ratios and M:C ratios before rate design proposals and rebalancing;

iii. nature of the service (firm/interruptible) and the ability of the customer(s) to manage interruptions in FEI's service;

iv. customer attributes (including load factor);

v. location on FEI's system and any special circumstances unique to that customer or group of customers; and

vi. the incremental cost to FEI in providing service.

Response:

The following table provides the requested information:

	Particulars	RS 22[1]	Creative Energy	VIGJV	BCH IG
i)	# of Customers	26	1	1	1
	Forecast Annual Throughput (TJ)				
	2016	11,441 TJ	1,748 TJ:	4,758 TJ	14,945 TJ
	2017	11,323 TJ	1,748 TJ	4,380 TJ	14,600 TJ
	2018	11,359 TJ	1,748 TJ	4,380 TJ	14,600 TJ
	2019	11,385 TJ	1,748 TJ	4,380 TJ	14,600 TJ
	2020	11,381 TJ	1,748 TJ	4,392 TJ	14,600 TJ
	The forecasted demand for all customers in the group is currently expected to be stable over time. It should be noted that the VIGJV and BC Hydro IG forecasted throughput is currently tied to their contract demand. The VIGJV forecast is based upon their current firm contract demand of 13 TJ/day. BC Hydro IG is based on the current firm contract demand of 45 TJ/day; however, BC Hydro IG is a dispatchable facility and the facility only runs on certain days. The forecast for the RS 22 and Creative Energy includes both interruptible and firm projected consumption.				
ii)	Before Rate Design Proposals				
	R:C Ratio	1425.5%		N / A	N / A
	M:C Ratio	1864.4%		N / A	N / A
	The R:C & M:C ratio for the VIGJV and BC Hydro IG is not applicable, but what is important is that VIGJV and BC Hydro IG are paying FEI for capacity on a take-or-pay basis. The interruptible RS 22 customers are not allocated transmission and distribution costs on a peak day as they are deemed to be interrupted; therefore the M:C and R:C ratios are irrelevant.				
iii)	2016 Forecast Throughput (TJ)				
	Firm	Nil	732 TJ	4,758 TJ	14,945 TJ
	Interruptible	11,441 TJ	1,016 TJ	Nil	Nil
	Firm DTQ	Nil	2 TJ	13 TJ	45 TJ
	All these customers have an interruptible component to their agreement and need to be able to handle interruption of some capacity.				
iv)	Customers' Attributes				
	CP Load Factor[2)]	N / A	100%	97.1%	3.8%
	NCP Load Factor (2016 Billed Actual)	66.4%	35.8%	48.8%	2.4%
	Other Attributes				
v)	Location on FEI's System & Special Circumstances	Lower Mainland Transmission & Distribution System	Lower Mainland Transmission & Distribution System	Vancouver Island Transmission System	Vancouver Island Transmission System
	Although the RS 22 customers are all served off the Lower Mainland Distribution system, some of them are very close to the Transmission system and would generally all be served off larger distribution pipe. The VIGJV and BC Hydro are served from the Island Transmission system which is off of the FEI Lower Mainland transmission system.				

	Particulars	RS 22[1]	Creative Energy	VIGJV	BCH IG
vi)	Incremental Cost to Serve	Customer Stations, Measurement & Billing, Customer Relations, WINS & Gas Supply	Customer Station, Measurement & Billing, Customer Relations, WINS & Gas Supply	Customer Stations, Measurement & Billing, Customer Relations, WINS & Gas Supply	Customer Station, Measurement & Billing, Customer Relations, WINS & Gas Supply
	As all these customers are already on the system, the only incremental costs related to serve these customers is the ongoing O&M, taxes and depreciation.				

[1] Includes only the RS 22 Non-Bypass customers, but also excludes Creative Energy which is a RS 22 Non-Bypass customer, as it is shown separately.

[2] CP Load Factor is calculated based on Firm Load consumption, i.e., it excludes interruptible volume. The NCP Load Factor includes all volumes, i.e., both firm and interruptible volume. The reason for excluding the interruptible volume from the CP Load Factor is that the Company's obligation for delivery is the firm DTQ less any peak shaving arrangement FEI has with the customer.

34.4 Considering FEI's response to the previous question, please explain how FEI's proposal would be more aligned with the fair apportionment of costs and avoidance of undue discrimination among similar type customers, as described in the preamble.

Response:

As discussed in response to BCUC-FEI IR 1.34.8, moving towards postage stamps rates for large industrial customers would reduce the number of large industrial rate structures across the province and extend the principles of common rates to large industrial customers. FEI's cost allocation approach is transparent and consistent with the rate design principles of customer understanding and acceptance, fair apportionment of costs and avoidance of undue discrimination among similar types of customers.

Today, RS 22 serves a broad group of industrial customers (including Creative Energy). FEI's proposal seeks to potentially add the VIGJV and BC Hydro IG, which already have similar delivery rates, in order to streamline the number of industrial rates. The individual customer sites within the VIGJV have consumption that is close to other existing RS 22 customers and, prior to the termination of the agreement, BC Hydro's Burrard Thermal site was an RS 22 Bypass customer. FEI recognizes that today RS 22 is mostly an interruptible service, while the VIGJV and BC Hydro have a combination firm and interruptible service. FEI's proposal will allow industrials across the province more choice in contracting their gas supply requirements with different combinations of firm and interruptible capacity.

34.5 Please discuss if any of the current RS 22 customers or contract customers (Creative Energy, VIGJV, BC Hydro IG) had difficulty understanding and/or accepting the existing structure.

Response:

None of the existing RS 22 customers or contract customers have expressed any difficulty in understanding and/or accepting the existing rate structure. However, FEI is proposing to have postage stamp cost-based rates and similar rate structures for all large volume transportation industrial customers instead of relying on negotiated rates for contract customers. FEI believes that moving to common rates and rate structures for these customers as proposed will be more transparent and consistent with the rate design principle of customer understanding and acceptance.

34.6 Please discuss if any of the affected contract customers (Creative Energy, VIGJV, BC Hydro IG) are supportive or opposed to FEI's proposal.

Response:

FEI has met with both the VIGJV and BC Hydro regarding its rate design proposals. Neither party indicated either support or opposition to FEI's proposal. The proposed rates under RS 22 are very similar to the current approved rates of both the VIGJV and BC Hydro. The proposed changes to the Transportation model are also linked to the proposed RS 22; therefore, the VIGJV and BC Hydro have to look at these proposed changes in one package when comparing them to their current contracts. FEI has not met directly with Creative Energy about the proposal for RS 22; however, the proposed firm rates are lower than what their firm rates would be based upon their current tariff supplement as described as Option 1 in FEI's RS 22 proposal. Creative Energy's Shipper Agent is registered and participating in the proceeding on behalf of Creative Energy and its other customers.

34.7 Please explain why Tariff Supplement G-21 for Creative Energy would be terminated and Creative Energy would take firm service under the new charges from RS 22 firm service while VIGJV and BC Hydro would be allowed to choose to become a RS 22 customer after their contracts expire.

Response:

Creative Energy is currently a RS 22 customer with a Commission-approved RS 22 Tariff Supplement No. G-21 for firm transportation. Tariff Supplement G-21 was approved by Order G-128-05, dated December 1, 2005, subject to the review of firm rates for RS 22 in the next FEI rate design proceeding. If the Commission approves FEI's RS 22 firm rate proposal, there is no longer any need for the tariff supplement as there would then be an approved firm rate applicable to all RS 22 customers. Currently, the VIGJV and BC Hydro have separate contracts and are not RS 22 customers, and therefore after their contracts expire they would have to elect to sign up for service under RS 22 if FEI's rate design proposal is approved. If BC Hydro and the VIGJV elect to become RS 22 customers, FEI may still need to negotiate an RS 22 tariff supplement that would require Commission approval pertaining to any special terms that may be required for these customers.

34.7.1 Please explain options available to VIGJV and BC Hydro IG if they choose not to become a RS 22 customer.

Response:

If the VIGJV chooses not to become a RS 22 customer, then FEI would have to negotiate a rate under a new agreement with the VIGJV that would be subject to Commission approval. If BC Hydro elects not to become a RS 22 customer, BC Hydro could elect to become an RS 50 customer, if they meet the requirements of that rate schedule. BC Hydro could also elect to extend their current agreement, which would require negotiation of a rate that would need to be approved by the Commission.

34.8 Does FEI consider that a decision to consolidate one or more customer classes should consider whether they have similar revenue to cost ratios, customer attributes (for example, load factor), customer service type (for example, firmness of supply), and whether affected customers are supportive or opposed to the merger? Please explain.

Response:

FEI believes that similar types of customers (i.e., customers with similar customer load and service characteristics [load factors, volume, types of end use]), should be grouped together in the COSA model for cost allocation purposes. FEI consolidated RS22, VIGJV and BC Hydro IG to derive firm rates based on cost of service allocation results. FEI believes that this cost allocation approach is transparent, and consistent with the rate design principles of customer understanding and acceptance, fair apportionment of costs and avoidance of undue discrimination among similar types of customers.

In addition to the reasons outlined above, the proposal to merge RS 22, VIGJV and BC Hydro IG into a single rate schedule is related to amalgamation of FEI's Mainland, Vancouver Island / Sunshine Coast and Whistler utilities into one utility and the establishment of common or postage stamp rates, where possible, across FEI's service territory (except for Fort Nelson). FEI's Mainland pre-amalgamation rate schedules for residential, commercial and firm or interruptible general service were approved as the rate schedules for these types of services going forward for the amalgamated utility and as the basis for achieving the benefits of amalgamation and common rates. The proposal with respect to RS 22, VIGJV and BC Hydro IG seeks to extend these principles of amalgamation and common rates to large industrial customers, and to achieve the related benefits among customers in that category.

34.9 Does FEI consider that there are broader BC benefits arising from the proposal regarding large industrial contract customers? For example: economic development; environmental benefits? If yes, please describe.

Response:

FEI views its proposal with respect to large industrial transportation customers as an expansion of the postage stamp rate methodology that resulted from the Reconsideration Decision on FEI's Common Rates, Amalgamation and Rate Design Application (Order G-21-14, Decision). Section 3.1 of the Amalgamation Reconsideration Decision (pages 12 to 16) cited various benefits of amalgamation and postage stamp rates, including accepting or acknowledging the submissions in the proceeding by the Ministry of Energy and Mines that amalgamation and postage stamp rates would support the Province's Natural Gas Strategy, economic development and job creation, regulatory efficiency and rate stability. With respect to large industrial customers the proposal is to develop an industrial rate (RS 22) that is applicable to Vancouver Island, the Sunshine Coast and Whistler as well as to the Mainland, thereby expanding the postage stamp rate construct and creating the potential for these benefits to develop in the industrial sector. However, for large industrial contract customers the rate design proposal recognizes that FEI has existing contractual commitments that must be accommodated before these customers can move to the proposed RS 22.

34.9.1 Does FEI consider that there are efficiency benefits arising from the proposal, including the mitigation of uneconomic bypass risk? If yes, please describe.

Response:

FEI believes that efficiency benefits will generally accrue as its service offerings and the terms and conditions of service for industrial customers become standardized across the formerly separate Vancouver Island, Whistler and Mainland service territories. Traditionally, bypass risk has been more focused in the Interior of the province where some industrial customers are located in close proximity to the upstream pipelines. In the Lower Mainland and Vancouver Island areas bypass is generally not feasible, except possibly for the largest of customers. FEI established RS 50 to accommodate very large industrial loads, some of which may have bypass potential. Beyond the small group of Interior industrial customers already on bypass rates, FEI does not consider the bypass risk to be significant for the customers expected to take service under the proposed RS 22.

35.0 Reference: RATE DESIGN FOR INDUSTRIAL CUSTOMERS
Exhibit B-1, Section 6.5.2, p. 6-36;
RS 22 R:C and M:C ratios

Table 6-19 on page 6-36 of Exhibit B-1 shows the R:C and M:C ratio results for rate schedules not set using COSA allocations. This includes an R:C ratio and M:C ratio of 1425.5% and 1864.4% respectively for Rate Schedule 22.

35.1 Please provide a table showing the (i) Actual 2016 Revenues, (ii) Costs determined through the COSA, (iii) the corresponding R:C Ratio and (iv) the corresponding M:C Ratio for each of (a) Creative Energy, (b) VIGJV and (c) BC Hydro IG:

i. Under the existing rates and rate structure; and

ii. Using FEI's proposed rates and rate structures.

<u>Response:</u>

The COSA model does not have a separate cost allocation for Creative Energy; Creative Energy is an RS 22 customer and is included with all other RS 22 customers when allocating costs. Therefore, to derive an allocated cost for Creative Energy, FEI used 100 percent of the demand related costs for RS 22 since Creative Energy is the only RS 22 non-bypass customer with firm demand. FEI used 3.8 percent of the customer related costs and 13.3 percent of the energy related costs as these percentages represent Creative Energy's contribution to the customer and energy allocators. FEI has also included Creative Energy's allocation of UAF as its cost of gas. FEI has used the cost allocations from the COSA for BC Hydro IG and VIGJV.

The following table uses 2016 Actual Revenues under the existing rates and the cost allocation from the COSA. It is important to note that the costs from the COSA include known and measurable changes of 7.4 percent, which creates a deficiency from the 2016 Actual revenues in the table below. Also, on November 1, 2016, BC Hydro IG's rate and firm demand increased by $0.10 per GJ and 5 TJ/day firm demand (to 45 TJ/day total), respectively. The revenue in the following table for BC Hydro IG reflects this; however, the cost allocations and revenues in the COSA have been changed to show BC Hydro IG at $0.958 per GJ and 45 TJ/day firm demand for an entire year (not just November and December 2016), as this rate and level of firm demand is representative of what they will experience in 2018 (when approved rate design proposals are implemented).

To be comparable to the RS 22 R:C and M:C ratios referred to in the preamble of 1425.5 percent and 1864.4 percent respectively, FEI has presented the R:C and M:C ratios in Table 1 below, including IT revenue.

The R:C ratio is calculated by dividing Column 1 by (Column 2 plus Column 3), and M:C ratios are calculated by dividing (Column 1 less Column 2) by Column 3.

Table 1

$000 Customer	Column 1 Total Revenue	Column 2 Cost of Gas	Column 3 Allocated Costs	Column 4 R:C ratio	Column 5 M:C Ratio
BC Hydro IG	13,097	0	14,530	90.1%	90.1%
Joint Venture	7,106	0	5,837	121.7%	121.7%
Creative Energy	1,648	15	654	246.3%	249.7%

The following table uses the same revenue from the above table summed for BC Hydro IG, VIGJV and Creative Energy compared to the cost allocated to RS 22 as proposed.

Table 2

$000 Customer	Column 1 Total Revenue	Column 2 Cost of Gas	Column 3 Allocated Costs	Column 4 R:C ratio	Column 5 M:C Ratio
RS 22 Firm	21,851	15	21,021	103.9%	103.9%

It is important to note that while RS 22 Interruptible has high R:C and M:C ratios as described in the preamble, these customers, because they are interruptible, cause very few demand-related costs as their daily demand needs are not considered when planning and building the system. However, as a group of customers, including BC Hydro IG and VIGJV, the firm daily demand of this group now attracts demand related costs, thereby decreasing the R:C and M:C ratios. By grouping these like customers together, a firm service can be offered and cost-based firm charges can be derived.

35.2 Please compare and provide a discussion for any difference in R:C and M:C ratios for RS 22 as presented in Table 6-19 and RS 22 using FEI's proposed rates and rate structures. Please explain any shifts in revenues/costs that had an impact on the R:C ratio.

Response:

RS 22 as presented in Table 6-19 is not the same rate schedule as RS 22 as proposed and found in Table 12-2. The two main differences between these two views of RS 22 is the treatment of interruptible revenue and the amount of cost allocation.

RS 22 in Table 6-19 is the RS 22 that is in place today. The revenue included in the R:C and M:C ratios includes both firm and interruptible revenues. There is a small firm component of the revenues from Creative Energy based on 2 TJ firm demand per day, but the majority of the revenues are interruptible. The demand cost allocation for the existing RS 22 is small based on the fact that FEI has not built capacity to serve these customers on the peak day; consequently, RS 22 contributes only 2 TJ/Day or approximately 0.2 percent to peak day demand. As discussed in Section 6.5.2, the rates for FEI's existing RS 22 are not set based on COSA results.

RS 22 rates as proposed, for which the R:C ratio can be found in Table 12-2, are set based on COSA results. To set the rates and assess the R:C ratio appropriately FEI had to treat the interruptible revenues in a different manner. Because the interruptible revenues do not cause demand costs, if they are not removed from the revenues for the R:C ratio calculation, the revenues would not be comparable to the costs and the resulting R:C ratio would not be informative (i.e., would not inform the reader whether the firm revenues collect the allocated costs). Consequently, FEI treated the interruptible revenues (under the proposed RS 22) as credits to the cost of service and allocated them to all non-bypass customers. The revenues that are left are the firm revenues to be compared to the allocated costs. The proposed RS 22 has higher allocated demand costs based on the higher firm demand of 60 TJ/Day which is approximately 5 percent of peak day demand.

The different treatment of revenue and the different allocation of costs as described above result in the difference in the R:C (and M:C) ratios when comparing Table 6-19 and Table 12-2.

Under the proposed RS 22 there is a net decrease in revenue as compared to the existing RS 22 of $754 thousand as described in Section 12.1.3 of the Application. However, approximately 5 percent more of the revenue under the proposed RS 22 is firm when compared to the existing RS 22.

36.0 Reference: FEI COST OF SERVICE STUDY

FEI Certificate of Public Convenience and Necessity for Approval of Contracts and Rate for Public Utility Service to Provide Thermal Energy Service to Delta School District Number 37, Order G-31-12 and Decision dated March 9, 2012 (Delta School District 37 CPCN Decision), pp. 50 to 51

Low load factor "super-peaking" customers

In the Delta School District 37 CPCN Decision, the Commission stated on pages 50 and 51:

> Energy Consumption and Customer Forecast
>
> The SD is the sole thermal energy customer and each of the 19 sites has historical and ongoing energy consumption patterns. Because the Project is confined to the 19 sites it does not include energy requirements of other sites that may be added later. … The current annual natural gas load is 58,607 GJ per year and the current annual electricity load is equivalent to 4,684 GJ per year. … Once the proposed thermal energy systems are installed, the projected annual natural gas load is projected to decrease by 77 percent to 13,641 GJ per year … FEI shows the peak day gas demand is projected to drop from 553 GJ/day to 301 GJ/day. … The impact on the load factor (utilization rate) for natural gas is a drop from 29.0 percent to 12.1 percent because natural gas boilers at the GSHP sites are only required to provide supplemental energy on peak days. For sites with geothermal installations, the natural gas load factors average 4.4 percent.
>
> **Commission Determination**
>
> The Panel agrees that the Delta SD proceeding is not the appropriate forum for addressing poor load factor customer use and related issues such as the introduction of a super-peaking rate. However, the Panel encourages FEI to address these issues in a more suitable forum in the near future. …

36.1 Please explain if FEI has undertaken any research into the existence and impact of super-peaking customers since the Delta School District 37 CPCN Decision was issued in March 2012.

Response:

This response also addresses BCUC-FEI IRs 1.36.1.1 through 1.36.3.1.

FEI has conducted a high level review of customers that have access to an alternative energy source or service that results in a high peak day requirement relative to their average day and believes that it is still premature to analyze the impact of these customers on FEI's system. It is not possible at this time to propose rate design alternatives for these types of customers as FEI has only a small number of customers with limited history of these alternative energy systems to date. Also, many of these types of customers, particularly in district energy systems, have not converted from natural gas to their planned alternative energy source. Therefore, FEI will continue to use a tariff supplement approach until such time that FEI has suitable data available that might be analyzed to support a separate rate schedule or rate design alternative.

FEI does have customers, other than Delta School District, which have back-up gas space heating appliances that are used to provide supplemental energy on peak days. However, it is not appropriate, in many instances, to classify these customers only as super-peaking because they may have other gas loads, such as cooktops, barbeques, clothes drying, fireplaces, or water heaters that are used year round and are not weather dependent.

36.1.1 If FEI has conducted research, please provide the results from the reports/analysis completed.

Response:

Please refer to the response to BCUC-FEI IR 1.36.1.

36.2 Please explain the theoretical impact that super-peaking customers would have on FEI's system. Please include a look at system capacities, utilization and efficiency.

Response:

Please refer to the response to BCUC-FEI IR 1.36.1.

36.2.1 Please discuss how FEI could address any impact to its system caused by super-peaking customers.

Response:

Please refer to the response to BCUC-FEI IR 1.36.1.

36.3 Please state if FEI has customers, other than the Delta School District Number 37, that use natural gas only to provide supplemental energy on peak days (super-peaking customers).

Response:

Please refer to the response to BCUC-FEI IR 1.36.1.

36.3.1 If FEI has other super-peaking customers, please describe the different end-uses for these customers.

Response:

Please refer to the response to BCUC-FEI IR 1.36.1.

36.3.2 If FEI has super-peaking customers, please use the following template to provide information, to the best of your ability, for super-peaking customers for each year from 2011 to 2015.

	Super-peaking customers								
	2011			...			2015		
	Number	Demand	Load Factor	Number	Demand	Load Factor	Number	Demand	Load Factor
Residential									
Commercial									
Industrial									
Contract									
Total									
FEI Total System Throughput									
Super-peaking Demand as a % of Total Throughput									

Notes

(1) Number: The number of super-peaking customers.

(2) Demand: The total annual demand for super-peaking customers.

(3) Load Factor: The load factor for the group of super-peaking customers based on the average annual demand and the average peak demand.

Response:

FEI is unable to provide the requested information. The majority of FEI's customers, including nearly all residential and commercial accounts, do not have meters at their premises that would allow FEI to determine how much gas is being consumed in peak conditions as compared with non-peak conditions. FEI's billing information is based on monthly physical meter readings. This would provide an estimate of average daily consumption in the month but not the consumption increases or decreases due to weather variations within the month.

Another reason that FEI may not be able to identify customers that use gas only in peak conditions is that customers can reconfigure their heating systems without having to let FEI know that their gas use will be changing. For instance, a residential customer could install an air-source heat pump as the main thermal energy source, but still retain their gas furnace or possibly a heating fireplace for some of their thermal energy requirements. If they have a gas water heater or other convenience appliances, there may be continued gas consumption through the non-heating months of the year.

36.3.2.1 If FEI is unable to provide the information requested in the table above, please estimate the amount of effort in time and person-hours that would be required to complete the table.

Response:

Please refer to the response to BCUC-FEI IR 1.36.3.2.

I. CHAPTER 11 – FEI GENERAL TERMS AND CONDITIONS AND RATE SCHEDULES FOR SERVICE

37.0 Reference: RATE DESIGN FOR RESIDENTIAL CUSTOMERS

Exhibit B-1, Section 11.3.2, p. 11-28

Overhead and Marketing (OH&M) charge updated calculation

On page 11-28 of Exhibit B-1, FEI states:

> 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.
>
> …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.

37.1 Please update Table 11-6 in Exhibit B-1, page 11-28 to include the actual OH&M costs and volumes for 2012 to2016 and the average OH&M charge for 2012 to 2017.

<u>Response:</u>

The following provides the response for BCUC FEI IRs 1.37.1 and 1.37.2.

Table 11-6 in Exhibit B-1 on page 11-28 has been updated to include the actual OH&M costs and volumes from 2012 to 2016, as well as the forecast costs and volumes for 2017. The staffing resource costs are based on the previously determined resources and allocation of those resources that were established by the BCUC in Order G-78-13.

	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast 2017	Forecast Total
Staff Resources ($000's)	560	611	715	713	760	782	4,140
Customer Education ($000's)	0	54	93	58	27	100	331
Total Overhead ($000's)	560	665	808	770	786	882	4,472
Projected Volumes (000's GJs)	187	295	736	957	1,098	1,354	4,627
Average Annual OH&M Cost ($/GJ)	$3.00	$2.25	$1.10	$0.81	$0.72	$0.65	**$0.97**
Annual OH&M Charge ($/GJ)	$0.52	$0.52	$0.52	$0.52	$0.52	$0.52	**$0.52**

The table above indicates that the Average Annual OH&M Cost is $0.97 per GJ for the period from 2012-2017.

B.C. Reg. 214/2016, which was deposited on August 21, 2016, extended the term of the Greenhouse Gas Reduction Regulation to March 31, 2022.

Table 11-6 has therefore been updated to provide the OH&M costs and volumes for the period from 2012-2022.

	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022	Forecast Total 2012-2022
Staff Resources ($000's)	560	611	715	713	760	782	806	830	855	881	907	8,419
Customer Education ($000's)	0	54	93	58	27	100	130	150	150	100	50	911
Total Overhead ($000's)	560	665	808	770	786	882	936	980	1005	981	957	9,330
Projected Volumes (000's GJs)	187	295	736	957	1,098	1,354	1,839	2,936	5,254	6,479	9,522	30,657
Average Annual OH&M Cost ($/GJ)	$3.00	$2.25	$1.10	$0.81	$0.72	$0.65	$0.51	$0.33	$0.19	$0.15	$0.10	**$0.30**
Annual OH&M Charge ($/GJ)	$0.52	$0.52	$0.52	$0.52	$0.52	$0.52	$0.52	$0.52	$0.52	$0.52	$0.52	**$0.52**

As indicated in the table above, the Average Annual OH&M Cost over this period is forecast to be $0.30 per GJ. This table also shows that this cost has decreased from $3.00/GJ in 2012 to $0.72/GJ in 2016. This trend will continue as NGT volumes are forecast to increase, further decreasing the average OH&M cost. It can further be seen that the average OH&M cost is forecast to be $0.30/GJ over the GGRR period of 2012 to 2022 based on current demand forecasts, which is lower than the current OH&M charge of $0.52 per GJ. FEI therefore recommends that the OH&M charge remain unchanged at $0.52 per GJ at this time. FEI has commenced a consultation process with NGT stakeholders to gather information and considerations for the rate structures and rate offerings for NGT. FEI will also review the appropriate level for the OH&M charge as part of that analysis, and report its findings as part of an application to be filed in 2018.

37.2 In the same format as Table 11-6 in Exhibit B-1, page 11-28, please provide a forecast of the OH&M costs and volumes for 2018 to 2022.

Response:

Please refer to the response to BCUC-FEI IR 1.37.1.

38.0 Reference: FEI GENERAL TERMS AND CONDITIONS AND RATE SCHEDULES FOR SERVICE

Exhibit B-1, Section 11.1.2.1, p. 11-5, Appendix 11-1, p. Original Page 14-1

General Terms and Conditions (GT&C), Access to Premises and Equipment

On original page 14-1 of Exhibit B-1, Appendix 11-1, FEI proposes to add the following section to the FEI General Terms and Conditions:

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.

38.1 Please provide the number of customers impacted by the proposed addition of section 14.3 to FEI's GT&C.

Response:

There are no customers expected to be impacted at this time by the proposed addition of Section 14.3.

This is because remote meters that are installed today are driven by Company requirements such as safety and efficiency. Where there are access issues to the premise that are driven by the customer, the Company works with the contractor and the customer to find options that allow for a successful meter read; however, this process can be challenging and may result in several estimated reads, several visits to the premise and, if a resolution cannot be achieved, ultimately may result in disconnection of service.

The inclusion of this provision would provide the Company and the customer with a final option before having to consider disconnection of service and thus it is expected that the need to implement Section 14.3 would be rare. FEI cannot estimate the number of customers that Section 14.3 would apply to, given the unique customer-specific circumstances where this would be required. The addition of Section 14.3 would provide FEI with the ability to recover the costs of installing such a meter, when required, from the individual customer on their bill.

38.1.1 Please discuss the communication and consultation with the affected customers.

Response:

Please refer to the response to BCUC-FEI IR 1.38.1. There are no customers currently affected by proposed Section 14.3, thus communication or consultation was not necessary.

38.2 Please provide the estimated full cost of installing a remote meter including overheads and annual cost of maintaining the meter.

Response:

The estimated installation cost is approximately $180, including overhead and removal of the existing meter. There are no expected incremental annual operating costs associated with maintaining the remote meter. Further, there will be no meter reading cost reductions as the site will continue to be visited, as it is today, for meter reading purposes in order to receive the meter reading information from the remote meter signal.

38.3 Please provide the accounting treatment for the removal the inaccessible meter and the customer payments for “installing and maintaining the remote meter.”

Response:

If the proposed amendment to the FEI GT&Cs to include Section 14.3 (Installation of Remote Meter) is approved by the Commission, the accounting treatment for the removal of an inaccessible meter from a customer’s premise will be no different than the current accounting treatment for the removal of a meter from a customer’s premise for other various reasons. When meters are removed from a customer premise, depending on the condition of the meter, they are either returned to inventory and reused at another premise or scrapped. In the case where meters are scrapped, they are retired from the Distribution Meters (478.10) asset class.

With respect to customer payments for installing and maintaining the remote meter, please refer to the response to BCUC-FEI IR 1.38.2.

38.3.1 Please provide the depreciated cost of the inaccessible meters that FEI expects to remove.

Response:

As stated in the response to BCUC-FEI 1.38.1, there are no customers expected to be impacted at this time by the proposed addition of Section 14.3; therefore, there are currently no inaccessible meters that FEI expects to remove.

39.0 Reference: FEI GENERAL TERMS AND CONDITIONS AND RATE SCHEDULES FOR SERVICE

Exhibit B-1, Appendix 11-1, p. S-1; Appendix 11-2, p. 1

GT&C, Standard Charges Schedule – Application Charge

On page S-1 of the General Terms and Conditions in Appendix 11-1, FEI proposes a reduction in all Application Charges from $25 to $15. In Appendix 11-2, FEI provides the calculation of the proposed Application Charge.

39.1 Please provide justifications and calculations for the existing $25 Application Charge.

Response:

The current Application Fee of $25 for existing installations was approved by the Commission as part of the FEI Phase B RDA in the Decision and Order G-101-93 dated October 25, 1993, and became effective January 1, 1994. Within that application, FEI proposed the consolidation of three separate Application Fees for existing installations from the former Lower Mainland, Inland and Columbia divisions. Please refer to Attachment 39.1 which includes Tab 12, pages 7 to 12 of the Phase B RDA and provides the justifications and calculations for the current Application Fee of $25 for existing installations. Attachment 39.1 also contains page 49 of the Phase B RDA Decision which outlines the Commission approval of the FEI consolidated General Terms and Conditions and specifically the $25 Application Fee for existing installations, effective January 1, 1994.

39.2 Please explain, with calculations, why the Application Charge for a customer with an Existing Installation is equal to the Application Charge for a customer required a New Installation.

Response:

A single Application Charge applicable to both existing customers and new installations should remain for three reasons: 1) ease of understandability for customers; 2) ease of administration for FEI; and 3) the costs are comparable.

As shown in the table below, although a new installation may have a higher labour cost per transaction due to the longer call duration that is typically experienced, this is offset by meter reading costs that are not applicable to a new installation[24].

[24] Please refer to the response to BCUC-FEI IR 1.39.3 where FEI has updated the approximate customer service labour cost for moves and new service calls.

Line	Particulars for 2015	Moves	New Install	Notes
1	Number of times Application Fee was charged	91,474	16,898	
2	Approximate customer service labour cost for moves and new service calls	$ 817,086	$ 158,808	
3	Approximate labour cost per transaction	$ 8.93	$ 9.40	Line 2 / Line 1
4				
5	Credit check and ID validation per transaction	$ 1.65	$ 1.65	
6	Off-Cycle move-in/move-out per transaction	$ 4.50	$ -	
7				
8	Approximate Incremental Application Cost	$ 15.08	$ 11.05	Line 3 + Line 5 + Line 6

FEI's specific costs related to new installations are captured in the Service Line Cost Allowance.[25]

39.3 Please provide the calculations for the proposed application charge, in the same manner as on page 1 of Appendix 11-2, using figures from (i) 2014; (ii) 2013; (iii) 2012; and (iv) 2011.

Response:

As shown in the table below, analysis from 2012 through 2015 supports the proposed reduction of the Application Fee from $25 to $15.

Information available for the stabilization period of 2012 and 2013 is limited and as such, an estimate of call volumes and handle time has been used. Enhancements were made to the queue management system in 2014 that allows FortisBC to be able to track calls by more specific areas of customer call types. Prior to 2014, agents entered codes to indicate the reason for the call and these codes are what have been used to provide the estimates below. While the results are reasonable, they may be lower than if detailed queue information was available[26] and, as such, may not be directly comparable to 2014 and 2015 data.

Finally, please note that comparable data for 2011 is not available as the Customer Service function was outsourced at that time.

25 FEI GT&Cs, Standard Charges Schedule, Original Page S-1.

26 As a result of human error including, but not limited to, success rate of entering codes and code most applicable to the call.

Basis for Calculation of
Standard Charges Schedule

FEI Proposed Application Charge

Line	Particulars	2015 [1]	2014	2013	2012	Notes
1						
2	Total number of applications charged for new service and changes to existing accounts (moves)	108,372	102,277	94,368	98,032	
3						
4	Customer service labour costs related to processing applications	$ 975,894	$ 986,909	$ 788,671 [2]	$ 984,732 [2]	
5						
6	Approximate avg customer service labour cost	$ 9.01	$ 9.65	$ 8.36	$ 10.05	Line 4 / Line 2
7						
8	TransUnion credit check and ID validation cost per transaction	$ 1.65	$ 1.51	$ 1.51	$ 1.40	
9						
10	Off-cycle move-in/move-out meter cost per transaction	$ 4.50	$ 4.50	$ 4.50	$ 2.00 [3]	
11						
12	Approximate Incremental Application Cost	$ 15.16	$ 15.66	$ 14.37	$ 13.45	Line 6 + Line 8 + Line 10
13						
14						
15	**FEI proposed Application Charge for new and existing customers**	**$ 15.00**				
16						
17	[1] Restated to reflect update in average handle time and total calls for Construction Services in 2015. Update results in decrease of labour cost of approximately $5 thousand and corresponding decrease of $0.04 to approximate cost per Application.					
18	[2] Total service costs have been estimated for 2012 and 2013 based on call wrap codes entered by agents, and as such estimates are less precise then 2014 and 2015. Prior to queue management enhancements made in 2014, calls by moves/construction queue are not available.					
19	[3] Approximate average cost per read for 2012 as Services Contract with ABSU did not isolate a special read cost. Thus, likely understated and not directly comparable to off cycle read per read costs for 2013-2015.					

39.3.1 Please explain any significant changes over the years in the approximate average customer service labour cost related to processing applications for new service and changes to accounts (Line 6).

Response:

Please refer to the response to BCUC-FEI IR 1.39.3.

40.0 Reference: FEI GENERAL TERMS AND CONDITIONS AND RATE SCHEDULES FOR SERVICE

Exhibit B-1, Appendix 11-1, p. S-1; Appendix 11-2, p. 2;

FortisBC Inc. Electric Tariff BCUC No. 2, Sheet 39[27]

GT&C, Standard Charges Schedule – Returned Payment Charge

On page S-1 of the General Terms and Conditions in Appendix 11-1, FEI proposes a reduction in the Returned Payment Charge (currently called "Dishonoured Cheque Charge") from $20 to $8. On page 2 of Appendix 11-2, FEI provides the calculation of the proposed Returned Payment Charge.

FBC's Returned Cheque Service Charge is $19 as seen in the FBC Electric Tariff.

40.1 Please explain, with calculations, how the cost of return payments of $3.91 (Appendix 11-2, p. 2, line 15) was calculated.

Response:

The cost per return payment (Appendix 11-2, page 2, line 15) is calculated by dividing the total annual billing department labour costs for processing returned payments by the total number of returned payment items[28].

The following formula provides the calculation:

$$\frac{Labour\ Costs\ for\ Processing\ Returned\ Payments}{Total\ Number\ of\ Returned\ Payments} = Cost\ per\ Returned\ Payment$$

The following data provides the calculation supporting $3.91 as the average cost of return payments for 2015.

$$\frac{\$15{,}102}{3{,}862} = \$3.91$$

As noted in Appendix 11-2, FEI added its bank processing charges and finance department processing costs to the cost per returned payment item to inform its proposal to amend the Returned Payment Charge to $8.00.

40.2 If a customer living in an area served by both FEI and FBC, for example Trail, BC, provides dishonoured cheques to both entities, please explain why FEI

[27] https://www.fortisbc.com/About/RegulatoryAffairs/ElecUtility/Documents/FortisBCElectricTariff.pdf.

[28] Includes returned payment items for both electronic fund transfer returns and returned cheques.

would charge $8 and FBC would charge $19. Is the difference in costs stemming from the Finance Department or the Customer Service Billing Department?

Response:

FEI and FBC have their own cost structures upon which their fees and charges are based. From time to time, the companies review these fees and charges. When necessary, the companies apply to the Commission to amend these fees and charges when they no longer reflect the costs which they are intended to offset. The Commission reviews applications for changes to these fees and charges, and the currently approved fees and charges represent what the utilities are each allowed to collect. The timing of the review of these fees and charges differs for each utility.

If a customer's payment is returned (whether as a result of a dishonoured cheque or other reason) to both utilities, then the customer would be charged the appropriate Commission approved fee that was in place for each entity at the time.

FEI understands that FBC intends to review its Returned Cheque Service Charge as part of a broader review of the FBC Electric Tariff in its next Rate Design Application, expected to be filed late in 2017 or early 2018.

41.0 Reference: FEI GENERAL TERMS AND CONDITIONS AND RATE SCHEDULES FOR SERVICE

Exhibit B-1, Appendix 11-1, p. D-2

GT&C, Definitions – Carbon Offsets

On page D-2 of the General Terms and Conditions, when defining Carbon Offsets, FEI has replaced the word *'will'* with *'may'*:

> **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. [emphasis added]

41.1 Please explain if FEI has ever purchased carbon offsets to balance demand-supply for Biomethane in the event of an undersupply of Biomethane.

Response:

No, FEI has never purchased carbon offsets to balance demand and supply for Biomethane.

In the event that an annual undersupply of biomethane occurs and FEI purchases offsets, FEI would notify the Commission when filing the BVA Annual Report.

41.1.1 If FEI has purchased carbon offsets in the event of a Biomethane undersupply, please state the number of occurrences and, if feasible, discuss the nature of each occurrence.

Response:

Please refer to the response to BCUC-FEI IR 1.41.1.

41.2 Please provide the rationale for this change.

Response:

Due to evolving carbon markets, FEI is proposing a minor amendment to the definition of Carbon Offsets to allow for more flexibility in the future, if alternative replacement options for Biomethane become available. At this time FEI is not investigating any specific alternative to the purchase of Carbon Offsets. However, should alternatives to the purchase of Carbon Offsets become available in the future, prior to using such an alternative, FEI would ensure that the costs and benefits for its customers were equal to or better than the purchase of Carbon Offsets.

For clarity, the change to this section does not give FEI the authority to actually utilize options other than carbon offsets. Pursuant to the Commission-approved Biomethane Program, FEI only has approval to replace biomethane with carbon offsets. If FEI finds that there is another reasonable option other than the purchase of carbon offsets, FEI will seek approval to use that option as part of its Biomethane Program.

J. CHAPTER 12 – FEI FINAL COST OF SERVICE RESULTS AND REBALANCING

42.0 Reference: FEI FINAL COST OF SERVICE RESULTS AND REBALANCING

Exhibit B-1, Section 12.1.3, pp. 12-3 to 12-4; Section 6.5.1, p. 6-32; Section 12.2.1, Table 12-2, p. 12-5; Section 9.8.5.3, Table 9-27, p. 9-48

RS 22 R:C ratio and rebalancing based on rate design proposal

On page 12-3 of Exhibit B-1, FEI states:

> … 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.

On page 6-32 of Exhibit B-1, FEI states:

> 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.

42.1 Please explain why FEI is proposing to adjust RS 22 revenues to achieve an R:C ratio of 100% when the R:C ratio is 103.5%, which is within FEI’s R:C ratio range of reasonableness of 90% to 110%.

Response:

Describing FEI as moving RS 22 to a 100 percent R:C is not accurate. FEI is creating a new rate and rate structure for large volume industrial transportation customers, and has calculated the new rate to collect the allocated costs. When creating a new rate schedule and rate structure, there is no pre-existing R:C ratio and, therefore, no basis to set the R:C ratio at anything other than 100 percent. If an R:C ratio other than 100 percent were to be adopted for a new rate schedule or service, it would be equally as reasonable to propose 90 percent at the lower end of the range of reasonableness as 110 percent at the upper end. These considerations demonstrate that selecting 100 percent for the R:C ratio of a new service is the sensible approach.

42.2 Please explain if FEI's level of precision in the COSA study supports the use of a target R:C ratio of unity for its proposed RS 22.

Response:

The level of precision in the COSA does not support a target of unity for any existing rate class which is why FEI uses a range of reasonableness when considering rate rebalancing.

The proposal to set RS 22 rates on the basis of allocated costs is not related to a level of precision for this class. Instead, it is based on the fact that developing the proposed RS 22 firm rate as a new service offering is a different circumstance than looking at the R:C ratios for existing rate classes for rebalancing purposes.

42.3 Please explain the impact to the COSA R:C ratios and M:C ratios if FEI were to leave the R:C ratio for the proposed RS 22 unchanged at 103.5%. Please include updated version of Tables 12-2 and 12-3 showing the R:C and M:C ratio results after the COSA, after the rate design proposals and after rebalancing.

Response:

Eliminating the revenue shift to RS 1 from setting the proposed RS 22 R:C ratio to 1.0 will reduce the RS 1 revenue shift by $473 thousand from $786 thousand to $313 thousand. FEI has not eliminated all of the revenue shift from RS 22 because BC Hydro IG is under contract until 2022 and is paying a rate that is slightly below the proposed RS 22 rate: consequently there is a residual $281 thousand[29] revenue shortfall that is from RS 22 that is still being picked up by RS 1 (as proposed). After this adjustment, the final R:C for the proposed RS 22 equals 102.2 percent and RS 1 equals 96.4 percent.

FEI has included Tables 12-2 and 12-3, revised as requested, below.

[29] Section 12.1.3, pages 12-3 and 12-4

1 **Table 12-2 (Revised): COSA R:C and M:C Results after Rate Design Proposals**

Rate Schedule	Initial COSA		Revenue Shift ($000)	Approximate Annual Bill Change	COSA after Rate Design Proposals	
	R:C	M:C			R:C	M:C
Rate Schedule 1 *Residential Service*	95.6%	93.1%	312.9	0.0%	96.4%	94.3%
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%	(280.7)	-1.3%	102.2%	102.2%

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

2

Table 12-3 (Revised): COSA 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%	94.3%	61.7	0.0%	96.4%	94.3%
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*	102.2%	102.2%			102.2%	102.2%

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%

On pages 12-3 and 12-4 of Exhibit B-1, FEI states:

> 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.

Table 9-27 on page 9-48 of Exhibit B-1 shows the "Summary of Change in Revenue and Change in Rates for RS 22 and VIGJV." The final row of the table shows that under current rates the total RS 22 and VIGJV revenue is approximately $18,823 thousand while under FEI's proposed rates and rate structure the total revenue is $18,529 thousand, a difference of $294 thousand.

42.4 Please provide calculations to show how the difference of $473 thousand referenced in the preamble was calculated.

Response:

The $473 thousand in the preamble is the required revenue shift to bring the RS 22 proposed to a 100 percent R:C ratio.

Line	Particulars	Amount	Reference
1	BC Hydro IG rate ($/GJ)	0.958	Section 9, Table 9-26
2	Proposed RS 22 rate ($/GJ)	0.972	Section 9, Table 9-26
3	BC Hydro Firm Annual Volume (TJ)	16,425	
4	BC Hydro IG Revenue shortfall from retaining $.958 until 2022 ($000)	($236)	(Line 1 – Line 2) x Line 3 (small differences from rounding)
5	No Basic or Admin Charge from BC Hydro IG until 2022 ($000)	($45)	
6	Total Revenue Shortfall from BC Hydro IG retaining existing rate until 2022 ($000)	($281)	Line 4 + Line 5
7			
8	Revenue at 2016 Existing rates excluding known & measurable changes	22,183	Appendix 12-2, Schedule 1, Line 3
9	RS 22 Allocated Costs ($000)	21,429	Appendix 12-2, Schedule 1, Line 9
10	R:C adjusted for rate design proposals	102.2%	(Line 6 + Line 8) / Line 9
11	Revenue Rebalancing Adjustment	($473)	(-Line 10 + 1) x Line 9 (small differences from rounding)

42.5 Please explain why Table 9-27 shows a difference of $294 thousand and on page 12-3 of Exhibit B-1, FEI states that there is $473 thousand less revenue. Please include calculations in your response.

Response:

The difference calculated in Table 9-27 is not directly comparable to the rebalancing amount of $473 thousand on page 12-3. Table 9-27 is a calculation to show the difference between RS 22 existing customers plus VIGJV at existing rates compared to RS 22 existing customers plus VIGJV at proposed rates. To do this, IT revenue and system gas are included and BC Hydro IG revenues are excluded from the table. For the rebalancing amount referenced on page 12-3, BC Hydro IG revenues are included and IT revenue is treated as a credit to the cost of service and does not form part of the rebalancing calculation.

42.6 Please confirm, or otherwise explain, that regardless of the outcome of this Application, there will be no changes to BC Hydro IG rates or rate structure until its contract expires in 2022.

Response:

Confirmed.

42.6.1 If confirmed, please explain if the $281 thousand is a theoretical reduction in revenue since BC Hydro IG and FEI have an agreement in place to pay a particular rate using a particular rate structure until 2022.

Response:

BC Hydro IG will continue to pay their contract rate until 2022. The $281 thousand is a theoretical reduction in revenue.

42.6.2 Please explain the impact to the COSA R:C ratios and M:C ratios if FEI were to omit the $281 thousand related to BC Hydro IG. Please include updated version of Tables 12-2 and 12-3 showing the R:C and M:C ratio results after the COSA, after the rate design proposals and after rebalancing.

Response:

If FEI omitted the $281 thousand related to BC Hydro IG, the R:C and M:C ratios for RS 22 Firm would increase to 101.3 percent. RS 22 charges would need to be amended upwards to address the reduced rebalancing.

FORT NELSON SERVICE AREA

K. CHAPTER 13 – STAKEHOLDER ENGAGEMENT

43.0 Reference: STAKEHOLDER ENGAGEMENT

Exhibit B-1-1, Section 13.3.2, pp. 13-10 to 13-12; Exhibit B-1, Appendix 4-5, p. 7

Survey methodology and scope

On page 7 of Exhibit B-1, Appendix 4-5, FEI states:

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%

43.1 Please explain why Sentis did not increase the sample size of the Fort Nelson residential customers to reduce the margin of error to a level comparable to the FEI margin of error.

Response:

According to the 2016 Census, Fort Nelson has a population of 3,366 and has 1,682 private dwellings. To achieve the same margin of error for the Fort Nelson survey as comparable to the FEI margin of error would have required 500 complete surveys. Given the overall population size, attaining 500 complete surveys was not feasible.

On page 7 of Exhibit B-1, Appendix 4-5, FEI states:

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.

43.2 Please explain why Sentis used only residential phone listings to obtain their sample of Fort Nelson customers.

Response:

Sentis only used residential phone listings to obtain their sample of Fort Nelson customers for the following reasons:

- Only residential customers were eligible for the survey.
- Given the small overall population size, sufficient sample data was unavailable from online research panel providers.
- The only other options would be to mail letters out to Fort Nelson households asking for participation in the study or to hire interviewers to survey residents onsite in Fort Nelson. Both of these methodologies would have taken more time, adding several weeks to the study timeline, and would have been costlier.

43.2.1 Please confirm, or explain otherwise, that this survey was only conducted in English and could only be completed on-line (i.e. the customer did not have the option to complete a survey over the phone or a hard copy survey).

Response:

Confirmed. The Fort Nelson survey was only available in English and could only be completed online.

43.2.2 Please confirm, or otherwise explain, that the sample was a random sample.

Response:

Please refer to the response to BCUC IR 1.2.2.

43.3 Please explain if FEI considers the Fort Nelson customer survey to be representative of the customers in Fort Nelson.

Response:

All survey methodologies exclude some element of the overall population. An online method excludes those without access to the internet, whereas a phone methodology excludes those without a phone. In this instance those residents without a landline would not have been part of the overall sample pool.

The employment of a landline phone recruitment methodology likely contributed to an underrepresentation of residents between the ages of 18 and 34. While these age groups represent 36 percent of the Fort Nelson population, they only represent three percent of the survey participants.

However, a comparison of results between FEI customers and Fort Nelson customers does not reveal significant differences, which suggests that this under-representation had no material impact on the results and that the survey was representative of the views of Fort Nelson customers.

43.4 With regard to specific proposals in the Application, when does FEI take into consideration the Fort Nelson customer research survey results.

Response:

As described in Section 4.6 of the Application, the stakeholder engagement process, which includes the results of the residential customer research survey, is used as an input, among other rate design considerations, to conduct a full review of FEI's rate design for the residential rate class for all of FEI's service areas, including a survey specific to Fort Nelson.

The survey results for Fort Nelson are relatively supportive of FEI's proposal to transition from the current bundled declining block rate structure to an unbundled flat rate structure similar to the one that exists in the rest of the province. The survey results indicate that only 21 percent of Fort Nelson customers prefer the current bundled rates, and 42 percent prefer a structure that matches the rest of the province. In addition, as explained in Section 13.5.3 of the Supplementary Filing (Exhibit B-1-1), the customer research survey results indicate that the flat rate structure is preferred by the majority of Fort Nelson's residential customers as it received the highest marks on all rate design considerations compared to other rate structure options.

43.4.1 Please explain how much weight is given to the customer research survey results when determining rate design proposals.

Response:

Please refer to the response to BCUC-FEI IR 1.2.6.1.

L. CHAPTER 13 – FORT NELSON COST OF SERVICE ALLOCATION METHODOLOGY

44.0 Reference: Fort Nelson Cost of Service Allocation Methodology

Exhibit B-1-1-1, Section 13.4.1.5.3, p. 13-17, Section 13.7.2, p. 13-55, Appendix 13-1, p. 2

Minimum System Study

44.1 Please provide a breakdown of mains installed in 2015 and 2016 in the same format as Table 1 in Exhibit B-1-1, Appendix 13-1, p. 2.

Response:

The table below shows the combined steel and plastic mains installed in Fort Nelson in 2015 and 2016. The Unit Cost, Weighted Cost and Minimum Size Cost are the replacement cost from the Combined Steel and Plastic mains table in Appendix 13-1.

Diameter		Length	Unit Cost /	Weighted	Minimum Size Cost (All pipe valued
Inches	mm	in Meters	Length ($/m)	Cost	at 60 mm PE)
1.0	26	9	73.45	$ 661	$ 414
1.7	42	2	52.62	$ 118	$ 103
2.4	60	297	93.04	$ 27,636	$ 13,663
4.5	114	298	175.4	$ 52,213	$ 13,693

It is important to note that the table above includes only mains installed in 2015 and 2016, whereas the table included in Appendix 13-1 includes all the mains in place in Fort Nelson up to the time that the Minimum System Study was completed.

44.1.1 Please provide the percentage of mains that are equal to or less than 60 mm in Table 1 in Exhibit B-1-1, Appendix 13-1, page 2.

Response:

The percentage of all mains less than 60 mm from the referenced table equals 19.6 percent and less than or equal to 60 mm equals 83.9 percent. Further to the response to BCUC-FEI IR 1.44.1, only 1.8 percent of the mains installed in 2015 and 2016 were less than 60 mm.

44.1.2 Please revise the following tables to reflect a minimum main size of 42 mm:

i. Table 1 in Exhibit B-1-1, Appendix 13-1, p. 2

ii. Table 13-10 in Exhibit B-1-1-1, page 13-17

iii. Table 13-29 in Exhibit B1-1-1, page 13-55

Response:

The Minimum System Study using 60 mm pipe is the correct approach as it is FEI's minimum standard in most cases when installing mains for the distribution system. As identified in the response to BCUC-FEI IR 1.44.1, the number of 42 mm mains installed in 2015 and 2016 was small compared to FEI's standard of 60 mm.

FEI has updated the Minimum System Study to use 42mm as the minimum as requested. FEI calculated the average replacement cost based on the 42 mm minimum system at $40.80 per meter using geographic pricing. When using the 42 mm as the minimum, distribution mains are split 41 percent Customer and 59 percent Demand, as can be found in an adjusted Table 1 below.

Table 1: (Adjusted) Minimum System Results for All Mains

COMBINED STEEL & PLASTIC MAINS						
	Diameter			Unit Cost / Length		Minimum Size Cost
Line No.	Inches	mm	Length in Meters	($/m)	Weighted Cost	(All Pipe Valued at
	(1)	(2)	(3)	(4)	(5)	(6)
1	1.0	26	1,144	$ 65.15	$ 74,515.78	$ 46,666
2	1.7	42	19,282	$ 46.67	$ 899,964.07	$ 786,688
3	1.9	48	2,407	$ 124.20	$ 298,981.69	$ 98,216
4	2.4	60	74,794	$ 93.04	$ 6,959,133.02	$ 3,051,594
5	3.5	88	6,196	$ 165.10	$ 1,022,876.71	$ 252,780
6	4.5	114	12,148	$ 175.40	$ 2,130,834.89	$ 495,647
7	6.6	168	246	$ 354.13	$ 86,979.87	$ 10,021
8	Unknown		80		$ 8,789.67	$ 3,255
9	**TOTAL**		**116,296**		**$ 11,482,075.69**	**$ 4,744,867**
10						
11	**Customer Related Component**			Line 9, Column (6) / Line 9, Column (5)		**41%**
12	**Demand Related Component**				1 - Line 11, Column (6)	**59%**

The PLCC is the peak load carrying capacity of the minimum system. When using a 42 mm minimum system, a new PLCC must be calculated. When the minimum system is reduced from 60 mm to 42 mm, the PLCC adjustment is reduced from 1.178 to 0.577.

The combination of the decreased customer component of distribution mains and the reduction of the PLCC resulted in an increase in the allocation of costs to Rate 1 and a decrease in the cost allocated to Rate 2.1 and Rate 2.2.

Table 13-10: (Adjusted) Delivery Cost of Service Allocation to Rates Summary

Rate	($000s)	% of total
1	$1,354	54.4%
2.1	$843	33.9%
2.2	$158	6.3%
RS 25	$134	5.4%
Total	**$2,489**	**100.0%**

Three of FEI's rate classes for Fort Nelson would be affected by the reallocation of costs as described above: Rate 1 and Rates 2.1 and 2.2. With more costs allocated to Rate 1 the R:C ratio falls to 85.1 percent.

In rebalancing the above result, FEI has made the following assumptions which mirror the approach taken in the Application.

Rate 1 revenue responsibility is increased by $83 thousand, which brings Rate 1 to a 90 percent R:C ratio. The added revenue responsibility is recovered through an increased Basic Charge. As a group, Rate 1 customers will experience about a 7 percent annual bill increase from this rebalancing and individual customers will experience annual bill changes between -30 percent and +26 percent. The revenue shift from Rate 1 reduces the revenue responsibilities of Rate 2.1 and Rate 2.2. The $83 thousand is split between Rates 2.1 and 2.2 so that their final R:C ratios are similar at approximately 112 percent. Splitting the rebalancing dollar amount unevenly between Rate 2.1 and Rate 2.2 necessitates a recalculation of the proposed basic and volumetric charges for these two rates. FEI used the same parameters as described in Exhibit B-1-1-1 Sections 13.5.5.3.3 and 13.7.1.4. Rate 2.1 customers will experience about a 1 percent annual bill decrease from this rebalancing and individual customers will experience annual bill changes between -16 percent and +5 percent. Rate 2.2 customers will experience about a 16 percent annual bill decrease from this rebalancing and individual customers will experience annual bill changes between -22 percent and -3 percent. The table below presents the adjusted rates.

Table 13-29: (Adjusted) Fort Nelson Rate Proposal Summary

Rate Component	Rate 1	Rate 2.1	Rate 2.2	Rate 3.1	RS 25
Existing COSA Rates					
Minimum daily Charge incl. 1st 2 GJ/month	$0.5483	$1.4337	$1.4337		
Administration Charge (/month)					$202
Next 28 GJ/month	$4.885				
Excess over 30 GJ/month	$4.782				
Next 298 GJ/ month		$5.336	$5.336		
Excess over 300 GJ/month		$5.210	$5.210		
Delivery Charge First 20 GJ/month				$4.522	$4.522
Delivery Charge Next 260 GJ/month				$4.201	$4.201
Excess over 280 GJ/month				$3.450	$3.450
Minimum Delivery Charge/month				$1,826	$1,826
Total Annual Bill:[30]	**$742**	**$2,433**	**$28,546**	**n/a[31]**	**$148,664**
Proposed Rates					
Basic Charge/Day	$0.3929	$1.2078	$7.7630		
Basic Charge (/Month)				$600.00	$600.00
Administration Charge (/Month)					$39.00
Demand Charge (/GJ/Month)				$28.727	$28.727
Delivery Charge ($/GJ)	$3.512	$3.888	$2.691	$1.000	$1.000
Commodity Cost Recovery Charge ($/GJ)	$1.275	$1.275	$1.275	$1.275	
Storage and Transport Charge ($/GJ)	$0.019	$0.020	$0.017	$0.019	
Total Annual Bill:	**$792**	**$2,421**	**$24,070**	**n/a[32]**	**$148,243**

[30] Based on an average annual demand per customer of 135 GJ for Rate 1, 382 GJ for Rate 2.1 and 5,332 GJ for Rate 2.2 and 39,500 GJ for RS 25.

[31] There are no customers taking service under Rate 3.1, therefore Total Annual Bill shows as n/a.

[32] Ibid.

45.0 Reference: FORT NELSON COST OF SERVICE ALLOCATION METHODOLOGY

Exhibit B-1, Section 8.3.5, p. 8-14;

Exhibit B-1-1, Section 13.4.1.4, p. 13-15

Cost Allocation based on RS 25 Load Factor

On page 13-15 of Exhibit B-1-1, FEI states:

> Currently, there is one customer that is taking service in Fort Nelson under RS 25 and that customer has a load factor of 27%. This low load factor is a result of the customer scaling back on its operations and only using gas for space heating purposes. As in FEI, Fort Nelson's Rate Schedule 25 is intended to serve process load customers. … As described in Section 9.5.1, customers with load factors less than 40% are more heat sensitive than a typical process load and should be taking service under the large commercial rate. To allocate costs in accordance with the intended use of Rate Schedule 25, FEI has used a load factor of 40% for this rate schedule.

On page 8-14 of Exhibit B-1, FEI states:

> When reviewing existing rate design and setting rates, and according to the fair apportionment of cost principle [FEI Rate Design Principle 2], FEI seeks to align cost recovery with cost causality.

45.1 Please explain why FEI is allocating costs in accordance with the intended use of RS 25, as opposed to the actual use of RS 25. Please include in your response a discussion regarding the fair apportionment of cost principle and cost causality.

Response:

The single remaining RS 25 customer announced that it has permanently closed plant operations and has informed FEI that it will only be using gas for space heating for a few years to preserve its assets but will eventually no longer require gas. The customer's other site in Fort Nelson, which was formerly served under RS 25, also closed permanently in 2008 and has already gone to zero gas consumption as of December 2015, and has subsequently switched to Fort Nelson Rate 2.1.

FEI is allocating costs in accordance with the intended use of RS 25 as opposed to the actual use of RS 25 as the remaining customer could choose to switch to Fort Nelson Rate 2.1 or 2.2 at any time and is not representative of a RS 25 customer. Utilizing a customer with a heat sensitive load profile to design a rate intended for a process load would result in a rate and rate structure that would not be appropriate for any future customers.

FEI wants to maintain the RS 25 option for future customers based upon its intended use to maintain a rate structure for Fort Nelson that would support local economic development for a process load customer setting up business in the Fort Nelson community.

45.2 Please state the number of years that this RS 25 customer has only been using gas for space heating purposes.

Response:

The customer has only been using gas for space heating since 2008, so for approximately nine years to the end of 2016. To the best of FEI's knowledge, when this customer ran its production process, a biomass system provided the primary energy for the production process and gas was used to supplement the biomass system, or to provide space heating. This explains why annual gas consumption since the plant closed in 2008 has increased as is shown in the response to BCUC-FEI IR 1.45.2.1.

45.2.1 For each of the years included in the response to the previous question, please provide this RS 25 customer's load factor.

Response:

Please find in the table below the annual throughput and load factor for the three years prior to the customer ceasing production in 2008:

Year	Annual Throughput (GJ)	Load Factor
2005	39,647	21%
2006	28,050	15%
2007	25,997	14%

FEI also provides the response to BCUC-FEI IR 1.51.1 here, so that load factors can be easily compared across years. Please find in the table below the annual throughput and load factor for the customer since they permanently shut down production in 2008.

Year	Annual Throughput (GJ)	Load Factor
2008	38,418	27%
2009	46,111	25%
2010	37,616	20%
2011	37,460	20%

Year	Annual Throughput (GJ)	Load Factor
2012	37,610	20%
2013	40,642	22%
2014	47,039	25%
2015	39,684	28%
2016	41,110	26%

45.3 Please explain and quantify the impact to the COSA results and the R:C and M:C ratios of using the RS 25 customer's load factor of 27%, instead of 40%. Please include updated versions of Tables 13-7, 13-10 and 13-12 with your response.

Response:

By using the lower load factor of 27% for RS 25, a larger peak day demand is calculated and subsequently more costs are allocated to RS 25. With higher allocated costs both the R:C and M:C ratios decline. The updated tables are included below.

Table 13-7 (revised): Customers, Annual Volume, Load Factor and Peak Day by Rate

Rate	Customers	Annual Volume (TJ)	Load Factor	Peak Day Demand (TJ)
1	1,961	259.9	35.7%	2.0
2.1	480	203.7	33.4%	1.7
2.2	7	56.7	40.5%	0.4
RS 25	1	39.5	26.5%	0.4
Total	**2,449**	**559.8**		**4.6**

Table 13-10 (revised): Delivery Cost of Service Allocation to Rates Summary

Rate	($000s)	% of total
1	$1,233	49.5%
2.1	$902	36.3%
2.2	$191	7.7%
RS 25	$163	6.5%
Total	**$2,489**	**100.0%**

Table 13-12 (revised): Revenue to Cost and Margin to Cost Ratios

Rate	R:C	M:C
Rate 1 Domestic (Residential) Service	91.4%	89.0%
Rate 2.1 General (Small Commercial) Service	109.4%	112.2%
Rate 2.2 General (Large Commercial) Service	114.4%	119.8%
Rate Schedule 25 General Firm Transportation Service	92.4%	92.4%

M. CHAPTER 13 – RESIDENTIAL RATE DESIGN FOR FORT NELSON

46.0 Reference: RESIDENTIAL RATE DESIGN FOR FORT NELSON

Exhibit B-1, Section 7.2.4 p. 7-8

Exhibit B-1-1, Section 13.5.4.2.3, p. 13-28

Residential customer characteristics

On page 13-28 of Exhibit B-1-1, FEI states:

> As can be seen from the figure below, the 100–110 GJ annual consumption range has the highest density of customers (compared to 70–80 GJ for other FEI customers), followed closely by the 110–120 GJ and 120–130 GJ consumption ranges.

46.1 Please provide the standard deviation for the 2016 residential annual consumption.

Response:

The standard deviation for Fort Nelson's 2016 residential annual consumption per customer as provided in Figure 13-7 is approximately 70 GJ.

46.2 Please provide the average consumption range for the top and bottom 10 percent of Fort Nelson's residential customers.

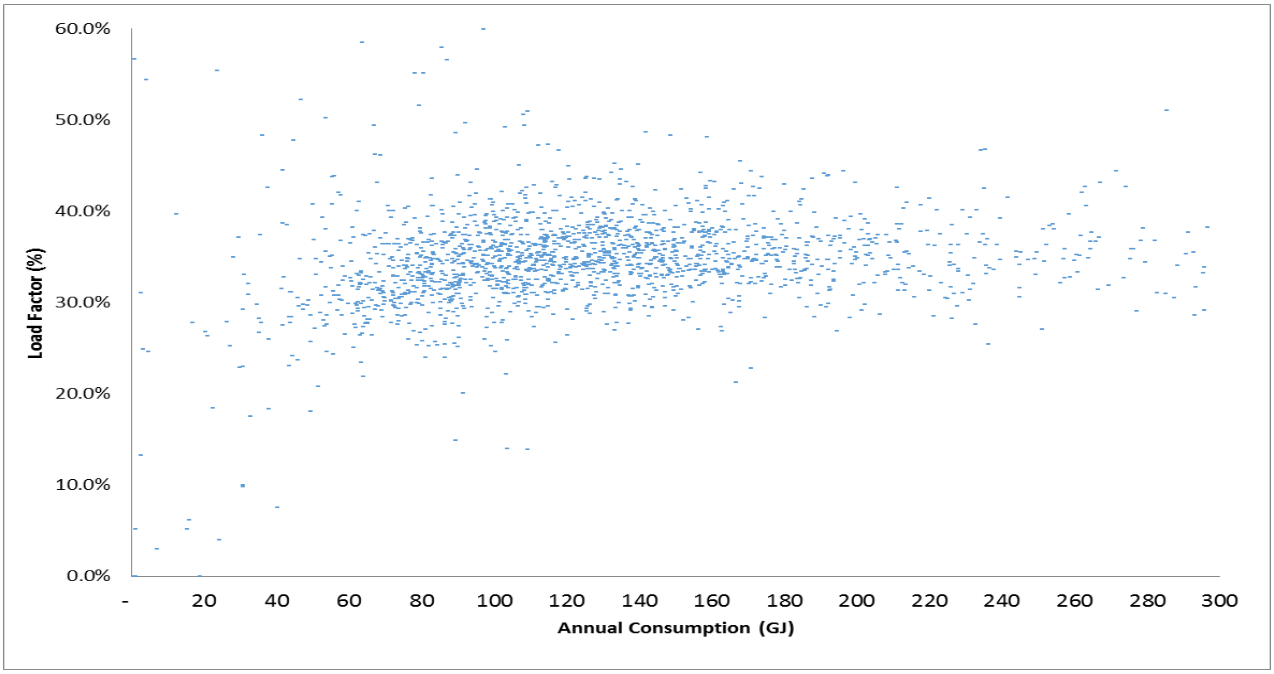
Response:

The average annual consumption per customer for the bottom and top 10 percent of Fort Nelson's residential customers are approximately 44 GJ and 279 GJ respectively.

46.3 Please provide a residential customer scatter plot in the same format as Figure 7-8 in Exhibit B 1, p. 7-8.

Response:

The requested scatter plot for Fort Nelson residential customers is provided below.

1 
60.0%
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
Load Factor (%)
-
20
40
60
80
100
120
140
160
180
200
220
240
260
280
300
Annual Consumption (GJ)

2

47.0 Reference: RESIDENTIAL RATE DESIGN FOR FORT NELSON

Exhibit B-1, Section 7.5.1, 7-17, Section 7.8.1, p. 7-24

Exhibit B-1-1, Section 13.5.4.4, p. 13-32

Bill impact and fixed cost recovery

On page 13-32 of Exhibit B-1-1, FEI states:

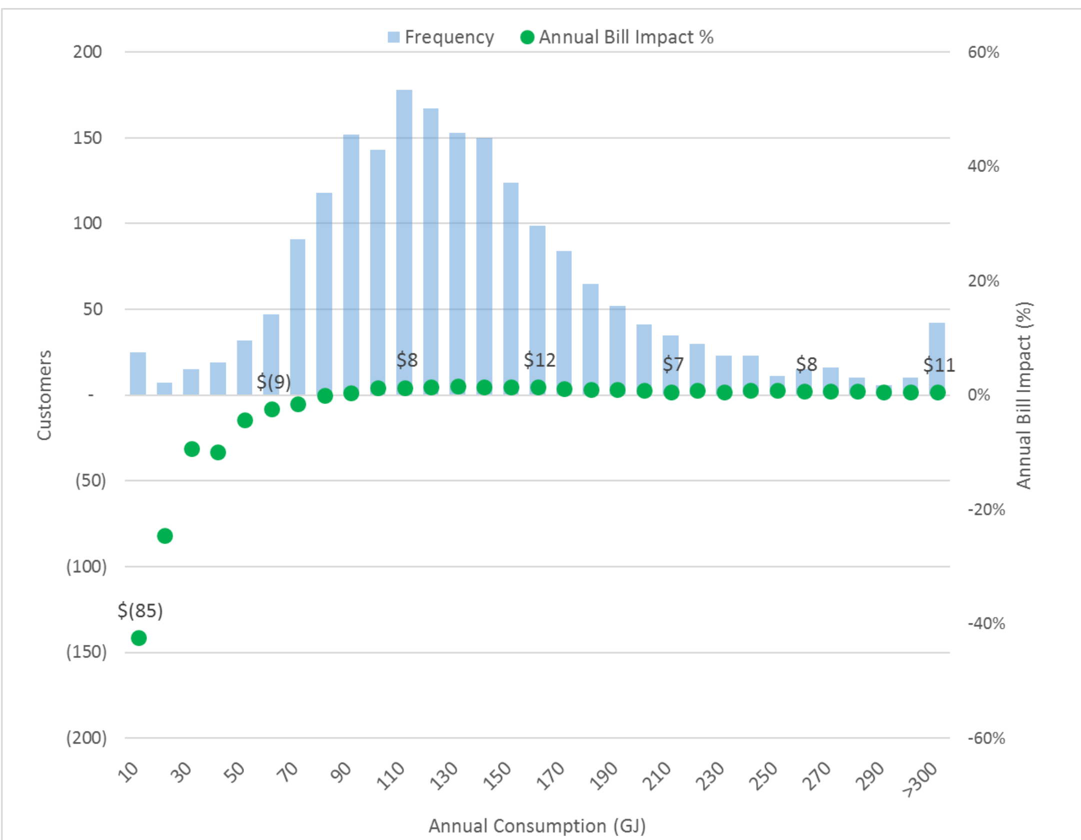
> The impact of the transition from a bundled declining block rate with a minimum charge to an unbundled flat rate with a daily Basic Charge is most favourable to customers with the most number of months of consumption less than 2 GJ (closer to zero consumption the more favourable) and no monthly consumption in excess of 30 GJ.

47.1 Please prepare a bill impact analysis for the proposed residential rates in the same format as Figure 7-11 in Exhibit B-1, page 7-24.

In the same format as Table 7-5 in Exhibit B-1, page 7-17, provide a comparison of the Fort Nelson residential customer fixed costs and fixed cost recoveries.

<u>Response:</u>

The figure below is the same format as Figure 7-11 in Exhibit B-1, but for Fort Nelson Rate 1.



The table below is in the same format as Table 7-5 in Exhibit B-1, but for Fort Nelson Rate 1.

Type of Cost	Unit Cost Based on COSA Results	Current Average Monthly Basic Charge	Difference
Customer-related cost	$29.18 per month		
Demand-related cost	$17.08 per month		
Total fixed costs	$46.26 per month	$14.10 per month	$32.16 per month

N. CHAPTER 13 – COMMERCIAL RATE DESIGN FOR FORT NELSON

48.0 Reference: COMMERCIAL RATE DESIGN FOR FORT NELSON

Exhibit B-1-1, Section 13.3.2, p. 13-23

Consultation

FEI states on page 13-10 of Exhibit B-1 that:

> FEI retained the services of Sentis to conduct an online survey to measure residential customers' knowledge of Fort Nelson's existing rate structure and bill components and to better understand customers' preference regarding various rate design considerations.

48.1 Please explain whether FEI has done any consultation with commercial customers on their preference on the rate structure. If yes, please provide the results. If not, why not?

Response:

FEI has conducted a robust stakeholder engagement process consisting of information sessions, stakeholder workshops, and a customer research online survey for residential customers. The Commercial Energy Association of British Columbia (CEC) participated actively in all the stakeholder sessions, including the workshops where rate design for commercial customers was reviewed, including evaluations of the existing commercial rate structures and other rate design options.

49.0 Reference: COMMERCIAL RATE DESIGN FOR FORT NELSON

Exhibit B-1, Table 8-4, p. 8-14; Exhibit B-1-1, p. 13-41

Customer data

Table 13-20 shows the Comparison between Small & Large Commercial using 6000 GJ Threshold, including the Average Customer-related Cost and Average Demand-Related & Energy-related Cost.

Table 8-4 on page 8-14 of Exhibit B-1 shows the comparison of fixed costs and fixed charge recoveries for RS 2 and RS 3/RS 23 customers.

49.1 Please replicate table 13-20 using the proposed 2000 GJ threshold.

Response:

The following table provides the same information as in Table 13-20, except it is adjusted for the changes applicable to Commercial customers with a 2,000 GJ threshold.

Comparison between Small & Large Commercial using 2000 GJ Threshold

	Rate 2.1	Rate 2.2
Customer Weighting Factor	1.6	5.7
Use per Customer	383 GJ	5,332 GJ
Load Factor	32.8%	38.8%
Average Customer-related Cost / Customer / Day	$1.394	$3.657
Average Demand-Related & Energy-related Cost / GJ	$3.306	$3.203

49.2 Please show, similar to in Table 8-4 in Exhibit B-1, what percentage of the functional unbundled costs allocated to commercial customers are recovered from the corresponding proposed rates (basic charge, delivery charge) for RS 2.1 and RS 2.2.

Response:

The following table compares the proposed rates, based on the results from the update to the PLCC factor for Fort Nelson (per Exhibit B-1-1-1), to the unit allocated costs in the final COSA which has the threshold at 2,000 GJ between Rate 2.1 and Rate 2.2.

	Proposed Rates	Unit Allocated Cost	% of Related Costs
Rate 2.1 Small Commercial			
Basic Charge / Customer $ / Day	$1.2008	$1.394	86%
Delivery Charge / Demand & Energy $ / GJ	$3.989	$3.306	121%
Rate 2.2 Large Commercial			
Basic Charge / Customer $ / Day	$3.1581	$3.657	86%
Delivery Charge / Demand & Energy $ / GJ	$3.631	$3.203	113%

50.0 Reference: COMMERCIAL RATE DESIGN FOR FORT NELSON

Exhibit B-1, p. 8-12; Exhibit B-1-1, p. 13-42

Proposed rate change

FEI states on page 13-42 of Exhibit B-1-1 that:

> Moving the threshold from 6,000 GJ/year to 2,000 GJ/year and setting the rates to result in an economic crossover at 2,000 GJ results in the following range of bill impacts when compared to existing bills.

Table 8-3 on page 8-12 of Exhibit B-1 shows the calculation of the economic crossover point between RS 2 and RS 3. Figure 8-12 on page 8-20 shows the shift in economic crossover point after the rate proposal.

50.1 Please replicate Table 8-3 and figure 8-20 in Exhibit B-1 for Fort Nelson's RS 2.1 and 2.2.

Response:

An economic crossover for Rate 2.1 and Rate 2.2 at existing rates cannot be calculated as it was in Table 8-3 because both Rate 2.1 and 2.2 have the same monthly Basic Charge.

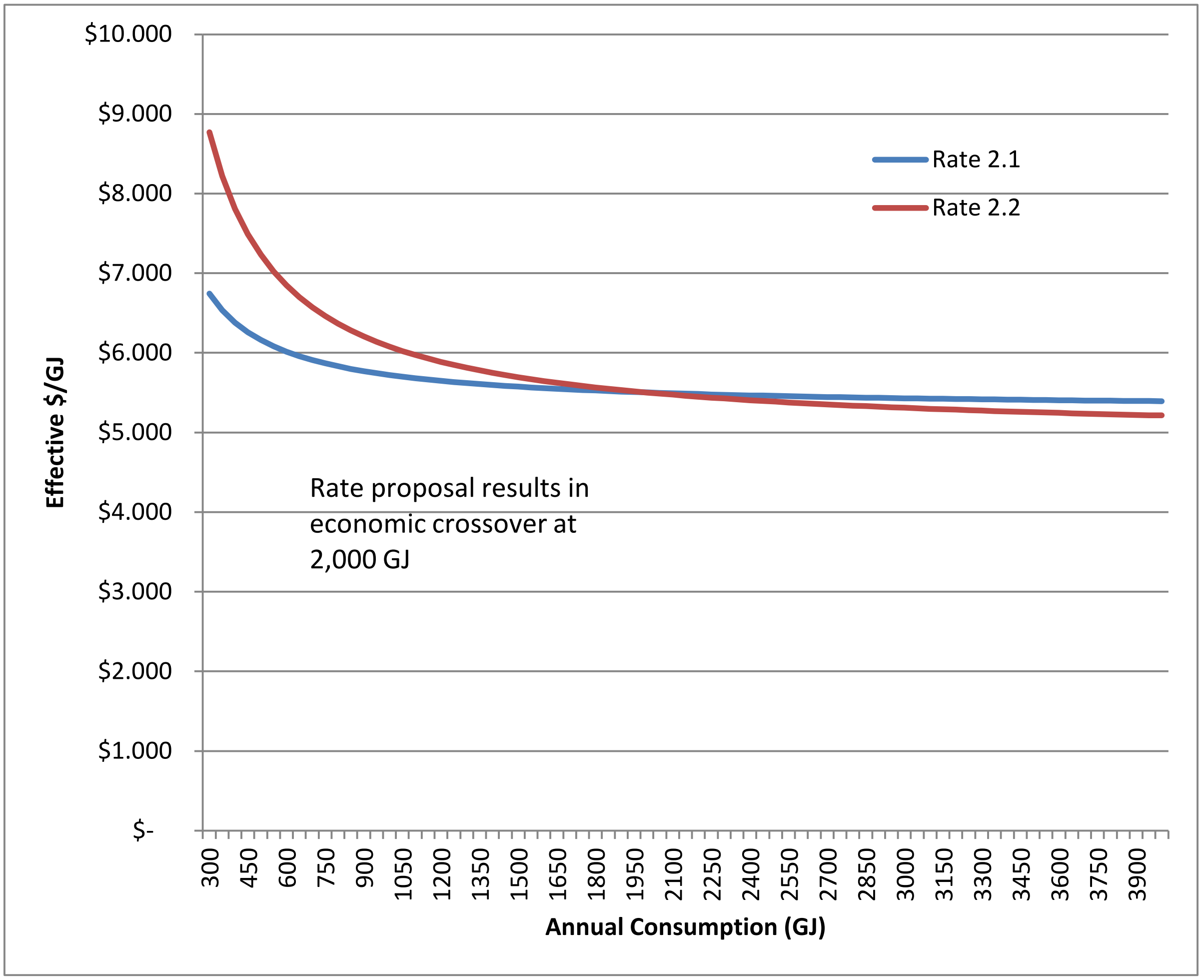
The table provided below at proposed rates demonstrates that the economic crossover is approximately 2,000 GJ.

Economic Crossover Volume for Rate 2.1 and Rate 2.2

Rate Components	Rate 2.1	Rate 2.2	Difference
1. Basic Charge (per day)	$1.2008	$3.1581	
2. Times number of days	365.25	365.25	
3. = Basic Charge Revenue	$438.59	$1,153.50	$714.91
4. Delivery Charge ($/GJ)	$3.989	$3.631	
5. Plus Cost of Gas ($/GJ)[33]	$1.294	$1.294	
6. = Total Variable Cost ($/GJ)	$5.283	$4.925	$0.358
7. Economic Crossover Point (Line 3/Line 6)			**1,997 GJ**

The following graph, similar to Figure 8-12 on Page 8-20 of Exhibit B-1, shows the average effective cost using the proposed rates for Rate 2.1 and Rate 2.2. Although visually it is difficult to see exactly where the crossover is, at 2,000 GJ the average effective rate for both Rate 2.1 and Rate 2.2 is $5.502 per GJ.

[33] 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).



Effective $/GJ
$10.000
$9.000
$8.000
$7.000
$6.000
$5.000
$4.000
$3.000
$2.000
$1.000
$-
Rate 2.1
Rate 2.2
Rate proposal results in economic crossover at 2,000 GJ
300
450
600
750
900
1050
1200
1350
1500
1650
1800
1950
2100
2250
2400
2550
2700
2850
3000
3150
3300
3450
3600
3750
3900
Annual Consumption (GJ)

O. CHAPTER 13 – INDUSTRIAL RATE DESIGN FOR FORT NELSON

51.0 Reference: INDUSTRIAL RATE DESIGN FOR FORT NELSON

Exhibit B-1-1, Section 13.5.6.2 and 13.5.6.3, p. 13-45

Fort Nelson industrial customer characteristics and bill impact

On page 13-45 of Exhibit B-1-1, FEI states:

> Fort Nelson has only one industrial customer taking service under RS 25 … The customer is no longer operating its production facility, but is still using natural gas for space heating to protect facilities and equipment from extreme cold weather damage. The customer's 2018 forecast demand is 40 TJ and its three year average load factor is 27%. … FEI is proposing to adopt the same rate structure for Fort Nelson as exists in FEI's other service areas. The charges included for the two industrial rate schedules would be: a Basic Charge, Demand Charge, and a Delivery Charge. … The proposed 2018 rates will be designed to collect the same revenue as was forecast in Fort Nelsons 2017-2018 Revenue Requirement so that no other Rate Schedules are affected by this change.

51.1 For the sole RS 25 industrial customer, please state the annual throughput and load factor for each of the three years prior to the customer ceasing operations at its production facility.

Response:

Please refer to the response to BCUC-FEI IR 1.45.2.1.

51.2 Please explain if, and when, FEI is expecting this RS 25 customer to resume regular operations in the near future.

Response:

FEI was informed by this RS 25 customer that the facility is closed permanently. FEI is hopeful an industrial customer will take over this site or that of the other former RS 25 customer site next door. FEI would like to maintain an Industrial Rate in Fort Nelson for economic development reasons to help attract a new customer and employer to this community.

51.3 Please produce a table to show:

i. the calculation of the total annual bill of the sole industrial's customer using the existing rate structure and rates, if the customer is operating its production facility;

ii. the calculation of the total annual bill of the sole industrial's customer using FEI's proposed rate structure and rates (as seen in Table 13-24), if the customer is operating its production facility; and

iii. the difference between the total bills calculated in response to (i) and (ii) above.

For your response, please use the average annual throughput of the three years prior to the customer ceasing operations at its production facility.

Response:

Please find below a comparison of the total annual bill under FEI's proposed rate structure and rates against the current rate structure and rates. Please refer to years 2005-2007 for the 3 years the facility was operating prior to it ceasing operations in 2008. Years 2009-2016 provide a comparison of the rates since they have ceased operations. It can be seen in the table that under FEI's proposed rates, the customer would have paid higher rates per GJ in the years when they were operating, as this particular facility had a biomass system that was the main source of heat for the process, and natural gas provided a backup and space heating role in those years. Since ceasing operations, the customer used gas only for space heating which has a slightly better load factor than when gas was also used as backup to the biomass system. If a new RS 25 customer came into Fort Nelson with a relatively flat load profile, their effective rate per GJ could be even lower, which is why FEI's proposed rate supports economic development to help attract potential new industry to this community.

Year	FN R25 Proposed ($)	($/GJ)	FN R25 Current ($)	($/GJ)	Difference ($)	Annual Volume (GJ)
2005	$ 168,940	$ 4.26	$ 136,076	$ 3.43	$ 32,865	39647
2006	$ 120,194	$ 4.29	$ 100,231	$ 3.57	$ 19,964	28050
2007	$ 112,403	$ 4.32	$ 92,252	$ 3.55	$ 20,151	25997
2008	$ 168,532	$ 4.39	$ 133,269	$ 3.47	$ 35,263	38418
2009	$ 184,241	$ 4.00	$ 158,481	$ 3.44	$ 25,760	46111
2010	$ 158,862	$ 4.22	$ 131,618	$ 3.50	$ 27,244	37616
2011	$ 149,481	$ 3.99	$ 131,735	$ 3.52	$ 17,745	37460
2012	$ 148,131	$ 3.94	$ 132,130	$ 3.51	$ 16,001	37610
2013	$ 156,000	$ 3.84	$ 139,471	$ 3.43	$ 16,530	40642
2014	$ 167,846	$ 3.57	$ 161,842	$ 3.44	$ 6,004	47039
2015	$ 148,239	$ 3.74	$ 138,666	$ 3.49	$ 9,574	39684
2016	$ 155,379	$ 3.78	$ 143,196	$ 3.48	$ 12,183	41110

51.4 Please produce a table to show the percentage of the total RS 25 revenues collected through (i) fixed charges; and (ii) variable charges using (a) the existing rate structure and rates; and (b) FEI's proposed rate structure and rates, based on the sole RS 25 customer's 2018 forecast demand of 40 TJ.

Response:

The following table provides the fixed charge revenue, variable revenue, total revenue and the percentage of fixed charge revenues to total revenues at existing and proposed rates. The second table shows the existing rates and proposed rates.

Particulars	Existing Rates	Proposed Rates
Fixed Charges Revenue	$ 27,936	$ 108,559
Variable Charge Revenue	114,333	39,684
Total Revenue	$ 142,269	$ 148,243
% of Fixed Charges Revenue to Total Revenue	20%	73%

Existing Rates	
Minimum Delivery Charge $ / Mo.	$ 1,826.00
1st 20 GJ $ / GJ	$ 4.186
Next 260 GJ $ / GJ	$ 3.884
Excess over 280 GJ $ / GJ	$ 3.179
Administration Charge $ / Mo	$ 502.00
Proposed Rates	
Basic Charge $ / Mo.	$ 600.00
Demand Charge $ / GJ of Daily Demand	$ 28.727
Delivery Charge $ / GJ	$ 1.000
Administration Charge $ / Mo.	$ 39.00

Under the existing rates, the fixed charge revenue includes the minimum Delivery Charge of $1,826.00 plus the administration charge of $502.00. The minimum Delivery Charge would include monthly volumes up to 510.4 GJ – effectively a take-or-pay. The variable revenue is the volume in each month that exceeds 510.4 GJ times the trailing block rate of $3.179. Every month the customer would have to consume 510.4 GJ for the Delivery Charges to equal the minimum Delivery Charge of $1,826.00. The first two blocks (i.e., 20 GJ plus 260 GJ) plus 230.4 GJ of the trailing block are embedded in the Minimum Delivery Charge.

Under proposed rates, the fixed charges include the monthly Basic Charge plus the Administration Charge plus the Demand Charge Revenue. The Demand Charge revenue is the Daily Demand volume times the Demand Charge of $28.727. The Daily Demand is the highest month average day in the preceding year times 1.1. For forecast 2017, the highest average day use is 266.1 in December which results in a Daily Demand of 292.7 GJ. The variable revenue is the 2018 forecast sales volumes times the Delivery Charge of $1.000 per GJ.

51.5 Please produce a table to show the percentage of the total RS 25 revenues collected through (i) fixed charges; and (ii) variable charges using (a) the existing rate structure and rates; and (b) FEI's proposed rate structure and rates, based on the average annual throughput of the three years prior to the customer ceasing operations at its production facility.

Response:

The following table provides the fixed charge revenue, variable revenue, total revenue and the percentage of fixed charges revenues to total revenues at existing and proposed rates. The second table shows the existing rates and proposed rates.

Particulars	Existing Rates	Proposed Rates
Fixed Charges Revenue	$ 27,936	$ 93,418
Variable Charge Revenue	84,590	31,231
Total Revenue	$ 112,526	$ 124,650
% of Fixed Charges	25%	75%

Existing Rates	
Minimum Delivery Charge $ / Mo.	$ 1,826.00
1st 20 GJ $ / GJ	$ 4.186
Next 260 GJ $ / GJ	$ 3.884
Excess over 280 GJ $ / GJ	$ 3.179
Administration Charge $ / Mo	$ 502.00
Proposed Rates	
Basic Charge $ / Mo.	$ 600.00
Demand Charge $ / GJ of Daily Demand	$ 28.727
Delivery Charge $ / GJ	$ 1.000
Administration Charge $ / Mo.	$ 39.00

The fixed charge revenue includes the minimum Delivery Charge of $1,826.00 plus the administration charge of $502.00. The minimum Delivery Charge would include monthly volumes up to 510.4 GJ – effectively, a take-or-pay. The variable revenue is the volume in each month that exceeds 510.4 GJ times the trailing block rate of $3.179.

Under proposed rates, the fixed charges include the monthly Basic Charge plus the Administration Charge plus the Demand Charge Revenue. The Demand Charge revenue is the Daily Demand volume times the Demand Charge of $28.727. The Daily Demand is the highest month average day (for April through October the average day is multiplied by 0.5) in the preceding year times 1.1. For the average of 2005 through 2007 the highest average day use is 226.1 in January which results in a Daily Demand of 248.8 GJ. The variable revenue is the three-year average (2005 to 2007) sales volumes times the Delivery Charge of $1.000 per GJ.

51.6 Please explain whether FEI has done any consultation with the RS 25 customer on their preference on the rate structure. If yes, please provide the results. If not, why not?

<u>Response:</u>

FEI has not done any specific consultation with the RS 25 customer on their preference on rate structure as the customer notified FEI that they are closed permanently. The customer will be using gas only for space heating for a period of time to preserve their assets and will eventually no longer require gas service at all.

P. CHAPTER 13 – FORT NELSON FINAL COST OF SERVICE RESULTS AND REBALANCING

52.0 Reference: FORT NELSON FINAL COST OF SERVICE RESULTS AND REBALANCING

Exhibit B-1-1-1, Section 13.7.1.4, p. 13-51

Impact to Rate 1 from rebalancing Rate 2.2

On page 13-51 of Exhibit B-1-1-1, FEI provides Table 13-27 and describes as follows:

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

52.1 Please produce a table to show the percentage of the total Rate 1 revenues collected through (i) fixed charges; and (ii) variable charges using (a) the existing rate structure and rates; and (b) FEI's proposed rate structure and rates.

Response:

Please refer to the table below for the requested information. The numbers in the table exclude the cost of gas.

$000	Existing Rate Structure	Proposed Rate Structure
Fixed Revenue	30%	19%
Variable Revenue	70%	81%
Total	**100%**	**100%**

52.2 Please calculate the Rate 1 Basic Charge if half of the $16 thousand in revenue shift was recovered through the Rate 1 Basic Charge and the other half was recovered through the variable charge.

Response:

The Fort Nelson Rate 1 Basic Charge would equal $0.2893 per day if only half of the $16 thousand revenue shift was recovered through the Basic Charge.

52.3 Please state the annual percentage bill impact that a Rate 1 customer with annual consumption of 34 GJ will experience after rebalancing, as proposed by FEI.

Response:

As discussed in Section 13.5.4.4 of the Supplemental Filing, due to the 2 GJ monthly threshold for the minimum daily charge calculations and the declining block rate structure of Fort Nelson's existing residential rates, the bill impact on individual customers will depend on their monthly consumption pattern. As such, customers with the same annual consumption level may experience different bill impacts. FEI reviewed nine customers consuming between 32 and 36 GJ per year and the annual bill impacts ranged from an increase of 0.5 percent to a decrease of 20.8 percent, and the group average is a decrease of 6.8 percent.

52.4 Please state the annual percentage bill impact that a Rate 1 customer with annual consumption of 34 GJ will experience after rebalancing, if half of the $16 thousand in revenue shift was recovered through the Rate 1 Basic Charge and the other half was recovered through the variable charge.

Response:

As discussed in the response to BCUC-FEI IR 1.52.3, due to the 2 GJ monthly threshold for the minimum daily charge calculations and the declining block rate structure of Fort Nelson's existing residential rates, the bill impact on individual customers will depend on their monthly consumption pattern. As such, customers with the same annual consumption level may experience different bill impacts.

FEI reviewed the same nine customers as in BCUC-FEI IR 1.52.3, consuming between 32 and 36 GJ per year. After rebalancing and recovering one half of the $16 thousand revenue shift through the Basic Charge and one half through the Delivery Charge, these customers will experience between a 0.6 percent and 21.7 percent decrease to their annual bills.

53.0 Reference: FORT NELSON FINAL COST OF SERVICE RESULTS AND REBALANCING

Exhibit B-1-1, Section 13.7.1.4, p. 13-51

Rebalancing RS 25

On page 13-51 of Exhibit B-1-1, FEI provides Table 13-27 as follows:

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

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

The table shows that after the rate design proposals the R:C ratios for Rate 2.2 (114.5%) and RS 25 (111%) are outside of FEI's R:C ratio range of reasonableness of 90% to 110%.

53.1 Please explain why FEI does not propose to rebalance RS 25 to within the R:C ratio range of reasonableness.

Response:

FEI considers the range of reasonableness of 90 percent to 110 percent to be a guideline, and not a rule that needs to be adhered to in all situations.

In this case, the sole RS 25 customer has ceased operations permanently and is using gas only for space heating purposes (and temporarily only), the proposed RS 25 rates are being designed for future RS 25 customers. In view of those circumstances, FEI does not consider it necessary that RS 25 has its rates lowered to achieve a 110 percent R:C ratio, particularly since any revenue shift would be allocated to the residential rate schedule.

53.2 Please provide an updated version of Table 13-27 which includes the rebalancing of RS 25 to within the R:C ratio range of reasonableness.

Please explain if Rate 1, 2.1 or 2.2 would experience rate shock when combining the rate design proposals within the Application with the rebalancing of RS 25 to within the R:C ratio range of reasonableness.

Response:

The requested update to Table 13-27 is found below.

Rebalancing RS 25 to within the range of reasonableness (90 percent - 110 percent) does not cause rate shock for any other rates. However, with the combined rate impact from the RRA for 2018 plus the Rate Design Application, the rate impact for residential customers is closer to 10 percent with this additional rebalancing. FEI has included an updated Table 13-27 below.

Rate Schedule	COSA after Rate Design Proposals		Rebalance Amount ($000)	Approximate Annual Bill Change	COSA after Rate Design Proposals and Rebalancing	
	R:C	M:C			R:C	M:C
Rate 1 *Domestic (Residential) Service*	90.9%	88.4%	17.4	2.0%	92.0%	89.8%
Rate 2.1 *General (Small Commercial) Service*	107.2%	109.4%			107.2%	109.4%
Rate 2.2 *General (Large Commercial) Service*	114.5%	118.4%	(16.0)	-3.2%	109.9%	112.6%
Rate Schedule 25 *General Firm Transportation Service*	111.0%	111.0%	(1.4)	-1.0%	110.0%	110.0%

TRANSPORTATION SERVICE REVIEW

Q. CHAPTER 10 – TRANSPORTATION SERVICE REVIEW

54.0 Reference: TRANSPORTATION SERVICE REVIEW

Exhibit B-1, Section 10.3.6, pp. 10-14, 10-15

Impact on core customers

In Figure 10-5 on page 10-15 of Exhibit B-1, FEI provides a graph that shows the aggregate actual daily supply and aggregate actual daily demand for transportation customers. On page 10-15, FEI also discusses how a number of factors contribute to the daily variance between supply and demand. On page 10-14 of Exhibit B-1 FEI states:

> As seen in Figure 1-15 below, gas supply frequently deviates from demand by as much as 50,000 GJ/day once the day comes to a close. … 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.

54.1 Please provide the data points for Figure 10-5 in a working Excel spreadsheet.

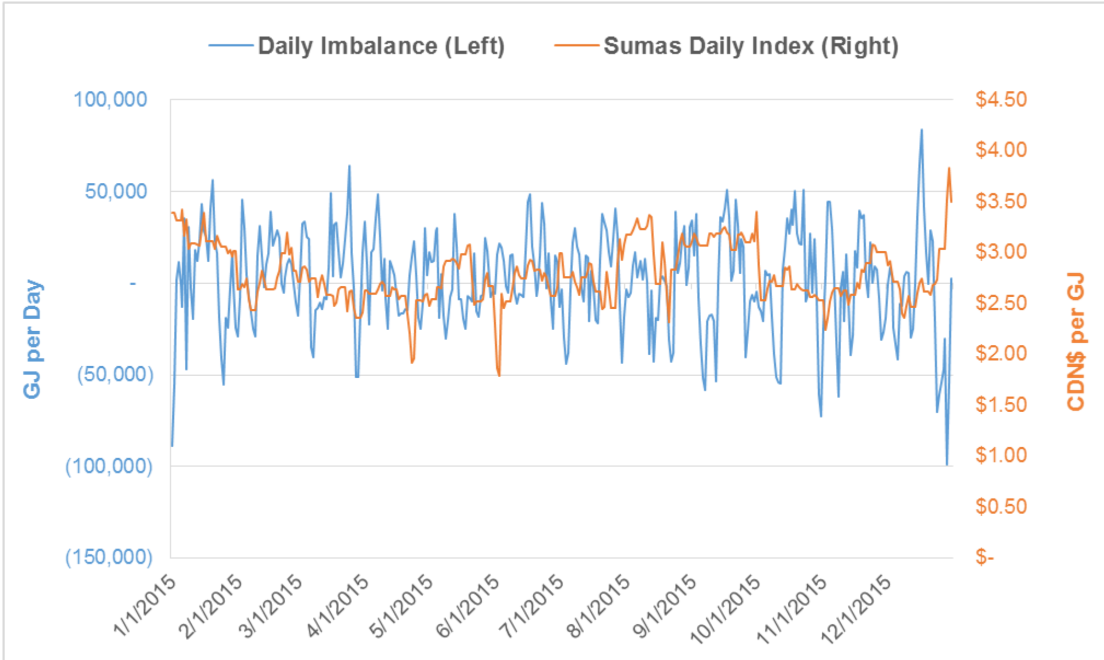
<u>Response:</u>

Please refer to Attachment 54.1 for the requested data points. The data points include supply and demand from both daily and monthly balanced transportation customers combined, in the year 2015.

54.2 Please provide a graph showing the difference between the aggregate actual daily supply and aggregate actual daily demand for transportation customers on a daily basis for 2015. On the same graph please add a line showing the Sumas daily index price.

<u>Response:</u>

The graph below shows the difference between the aggregate actual daily supply and aggregate actual daily demand for transportation customers as well as the Sumas daily index for 2015.



FEI is unable to draw correlations from the Sumas daily price to the daily variances. Like FEI, Shipper Agents forecast gas requirements for their transportation customers 24 hours in advance. Factors like weather and changes in consumption for process load customers may impact the supply/demand imbalance on a daily basis.

54.2.1 Please discuss the extent to which the Sumas daily price is correlated to the daily variance between the transportation customers' supply and demand.

Response:

Please refer to the response to BCUC-FEI IR 1.54.2.

54.2.2 Please populate the following table for each of the ten days in 2015 with the greatest absolute difference between the aggregate actual daily supply and aggregate actual daily demand for transportation service customers.

Date	Aggregate actual daily supply for transportation customers (GJ)	Aggregate actual daily demand for transportation customers (GJ)	Transportation customer daily imbalance (GJ)	Total daily system demand (GJ)	Daily transportation customer imbalance expressed as percentage of total system demand for day(%)	Description of midstream resources used to balance the FEI system on the day

Response:

The table below provides the ten days in 2015 with the greatest absolute difference between the aggregate actual daily supply and aggregate actual daily demand for both daily and monthly balanced transportation service customers combined. Positive imbalances reflect oversupply while negative imbalances reflect undersupply by Shipper Agents. The daily imbalance for transportation service customers varies from negative 10 percent to positive 14 percent of total system demand. The midstream resources used to balance the FEI system include Aitken Creek Storage, Mist Storage, Jackson Prairie Storage, and Westcoast (WEI) OBA. These storage assets help to balance the system as a whole because there are limited intra-day markets to buy and sell gas on the Westcoast system. Other ways to manage imbalances included adding to or subtracting from FEI line pack on a given day. More than likely, on any particular day, more than one of these resources/activities was used to manage the imbalance for the system as a whole.

Date	Aggregate actual daily supply for transportation customers (GJ)	Aggregate actual daily demand for transportation customers (GJ)	Transportation customer daily imbalance (GJ)	Total daily system demand (GJ)	Daily transportation customer imbalance expressed as percentage of total system demand for day(%)	Description of midstream resources used to balance the FEI system on the day
12/29/2015	362,507	263,835	98,672	960,833	10%	Aitken Creek Storage, Mist Storage, WEI OBA
1/1/2015	302,556	214,027	88,529	921,239	10%	Aitken Creek Storage, Mist Storage, WEI OBA
12/17/2015	221,049	304,730	(83,681)	996,778	-8%	Mist Storage, Jackson Prairie Storage, WEI OBA
10/31/2015	271,097	198,674	72,423	501,832	14%	WEI OBA
12/24/2015	293,822	223,560	70,262	871,932	8%	Aitken Creek Storage, Mist Storage, WEI OBA
12/16/2015	214,426	279,365	(64,939)	950,567	-7%	Mist Storage, Jackson Prairie Storage,WEI OBA
3/25/2015	196,617	260,433	(63,816)	666,286	-10%	WEI OBA
11/8/2015	253,862	191,644	62,218	588,859	11%	Aitken Creek Storage,WEI OBA
12/25/2015	276,326	215,628	60,698	886,939	7%	Aitken Creek Storage, WEI OBA
10/30/2015	273,926	213,271	60,655	492,381	12%	Aitken Creek Storage, WEI OBA

55.0 Reference: TRANSPORTATION SERVICE REVIEW
Exhibit B-1, Section 10.3.6, pp. 10-15 to 10-16
Shipper Agent inventory levels

In Figure 10-6 on page 10-16 of Exhibit B-1, FEI provides a graph showing the number of days of supply held on behalf of all Shipper Agents on FEI's system.

On pages 10-15 to 10-16 of Exhibit B-1, FEI states:

> 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 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.

55.1 Please clarify whether FEI requests that Shipper Agents stay within a tolerance band of 2 to 3 days of pack inventory level to 2 to 3 days of draft inventory level or whether FEI requests that Shipper Agents hold a pack inventory of 2 to 3 days inventory level.

Response:

FEI requests that Shipper Agents' overall inventory levels are maintained within a tolerance band of 2 to 3 days of pack, to 2 to 3 days of draft. Shipper Agents holding monthly balanced groups have the ability to both pack and/or draft the system, so the 2 to 3 days of tolerance applies to both pack or draft circumstances. The rules in the tariff generally incent Shipper Agents holding daily balanced groups to pack. For daily balanced customers, drafting is not permitted, and in cases where under-deliveries occur on the day, FEI balances the Shipper Agent's group by selling day gas. Given this, the 2 to 3 day pack only applies to Shipper Agents holding daily balanced groups.

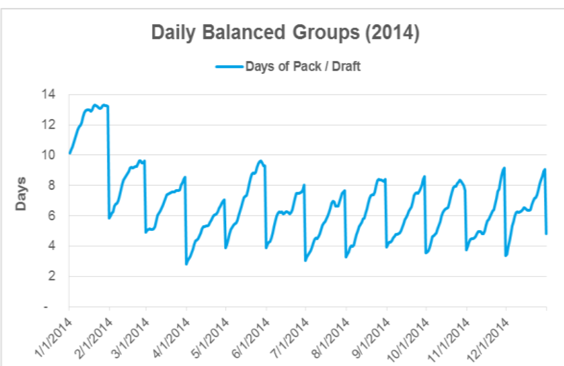
As demonstrated by this response, there are different bandwidths or tolerances for monthly and daily balanced customers. Some Shipper Agents hold and pool monthly balanced customers exclusively, some hold both daily and monthly balanced groups, and some marketers pool monthly balanced customers within a daily balanced group. In the interests of consistency, ease of administration and leveling the playing field, FEI would like to move to one set of rules to apply to all transportation customers.

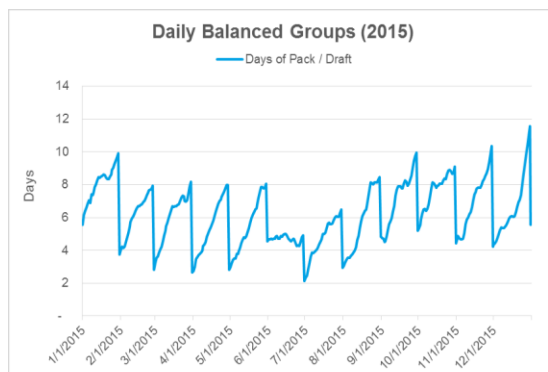
55.1.1 If FEI requests the former please explain why, as shown in Figure 10-6, the inventory levels are typically at least one day of pack inventory in aggregate for Shipper Agents (i.e. never in an aggregate draft position).

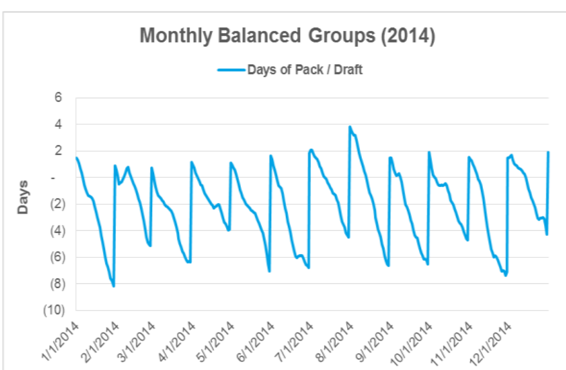
Response:

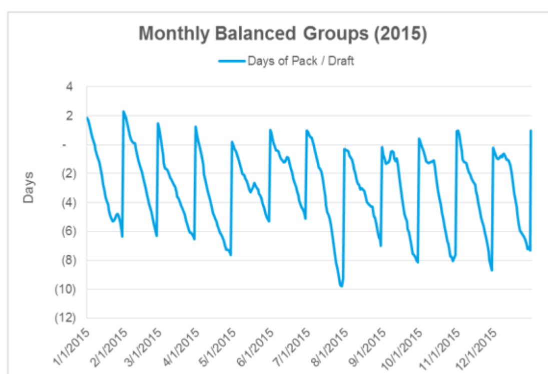
Figure 10-6 shows the days of inventory which are calculated by taking the aggregate of all Shipper Agents' inventory and dividing it by daily demand to determine how many days of supply the marketers have banked on the system at a given point in time. It does not go negative (below zero), as overall Shipper Agents almost always have positive inventory balances due to the net effect of packed or oversupply of daily customers and drafted or under-supplied monthly customers. For the days in which Shipper Agents run a net negative imbalance, this is represented by a negative slope or decline, rather than a subzero value.

The following charts show the days of inventory for daily and monthly balanced groups separately in 2014 and 2015. In general, daily balanced groups tend to pack while monthly balanced groups tend to draft the system. Although the aggregated inventory levels are typically positive, as indicated in the below figures, the two balancing practices clearly incent different behavior. FEI would like to remove monthly balancing provisions to incent consistent balancing behaviors across all Shipper Agents.









55.2 Does FEI request that Shipper Agents holding only a daily balanced group(s) keep to a 2 to 3 day pack/draft balancing inventory?

Response:

Please refer to the response to BCUC-FEI IR 1.55.1.

55.3 Does FEI request that Shipper Agents holding only a monthly balanced group(s) keep to a 2 to 3 day pack/draft balancing inventory?

Response:

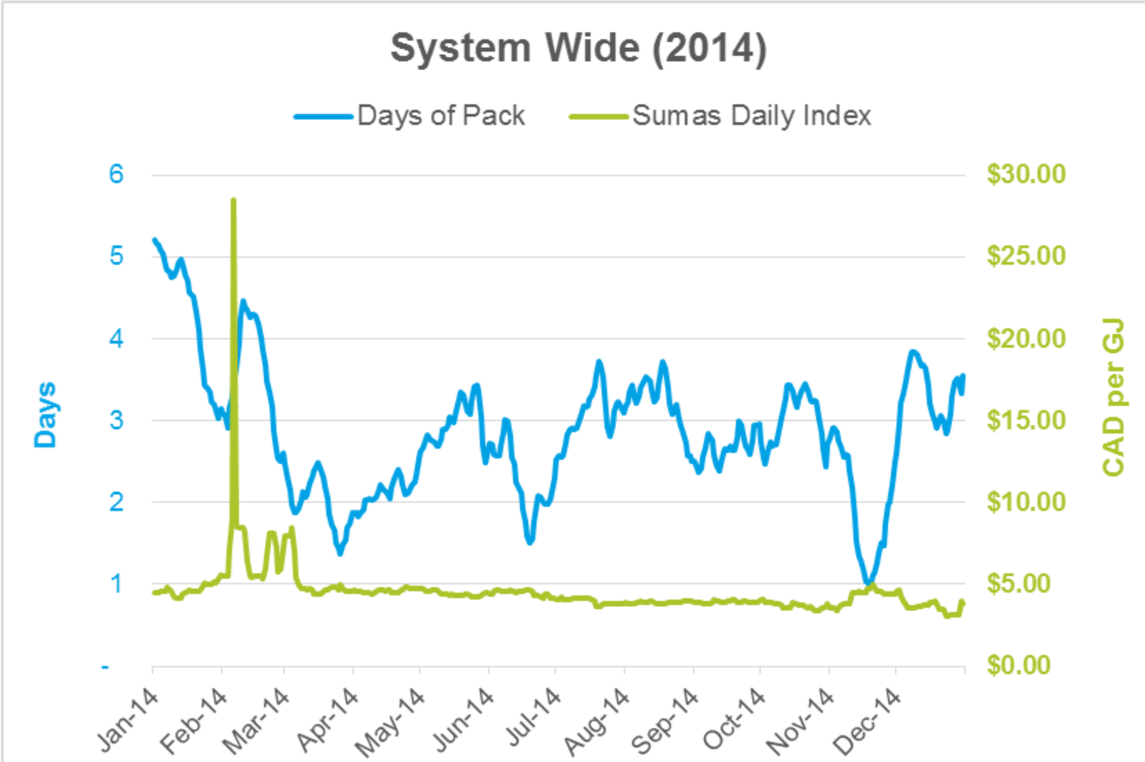
Please refer to the response to BCUC-FEI IR 1.55.1.

The inventory levels in Figure 10-6 show that FEI typically holds at least one day and sometimes as much as four days of pack inventory for Shipper Agents on FEI's system.

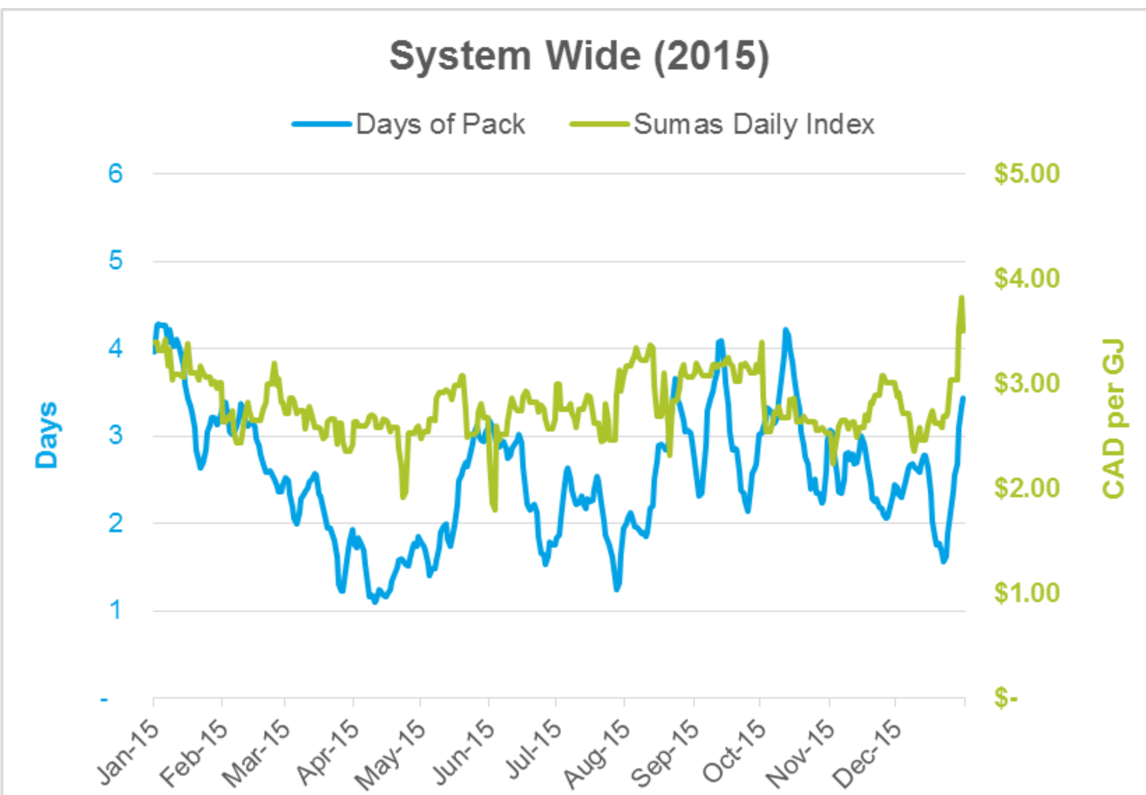
55.4 Please add a line to each of the graphs in Figure 10-6 showing the Sumas daily index price.

Response:

The following graphs provide the aggregate inventory of Shipper Agents and Sumas daily index price for 2014 and 2015. FEI is not able to identify a correlation between the inventory and the Sumas price.

1 

System Wide (2014)
Days of Pack
Sumas Daily Index
Days
CAD per GJ
6
5
4
3
2
1
-
$30.00
$25.00
$20.00
$15.00
$10.00
$5.00
$0.00
Jan-14
Feb-14
Mar-14
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14

2 

System Wide (2015)
Days of Pack
Sumas Daily Index
Days
CAD per GJ
6
5
4
3
2
1
-
$5.00
$4.00
$3.00
$2.00
$1.00
$-
Jan-15
Feb-15
Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15

55.5 Please explain whether FEI physically holds this pack inventory on the FEI system or, alternatively, whether the core sales customer inventory is necessarily in a corresponding draft inventory position in order to balance the FEI system.

Response:

When a Shipper Agent leaves excess gas on the system, FEI holds this packed or banked supply as inventory on their behalf. FEI returns this supply on a later date by way of the imbalance return mechanism. This is a paper transaction. Physically, FEI manages the system as a whole; when system imbalances occur from either sales or transportation customers, FEI responds in a timely manner to balance the system. Imbalances are managed using FEI's midstream resources including upstream and downstream storage, Westcoast OBA, or the buying and/or selling of gas on the day. In general FEI trends its overall OBAs[34] with upstream pipelines to zero on a daily basis.

55.5.1 If the core sales customer inventory is put in a corresponding draft inventory position to balance the transportation customers' pack inventory, please describe the midstream resources used and the nature of the associated costs borne by the core customers as a result.

Response:

As indicated in the response to BCUC-FEI IR 1.55.5, irrespective of the entity responsible for the imbalance (whether core customers or transportation customers), fixed resources acquired under the ACP on behalf of core customers are used to balance the system as a whole. Core customers pay for these resources through the Midstream charge. Thus, the imbalance for the whole system is managed by FEI line pack, OBAs, FEI storage accounts, or through sales/purchases of gas with counterparties. All of these activities and their associated costs flow through the Midstream account.

On any particular day, the Shipper Agents may pack the system as a whole, which may help to meet the core customers' load on that day. There is no savings to the core customer because

[34] FEI's has an Operational Balancing Agreement, or "OBA" with Spectra which 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 imbalance swings.

the underlying fixed costs of the ACP resources are there regardless. Further, the gas of the Shipper Agents has to be returned to them at some point in the future.

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. The research and analysis to derive an associated cost borne by core customers is included in Section 10.7.4 of the Application.

56.0 Reference: TRANSPORTATION SERVICE REVIEW

Exhibit B-1, Section 10.6.1, p. 10-24

Evolution of technology and systems

On page 10-24 of Exhibit B-1 FEI states:

> 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. ….. 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.

56.1 Please describe, for a typical Shipper Agent with a group of monthly balanced transportation customers, the evolution of the metering accuracy and the method and frequency of communicating the customers' daily consumption data to Shipper Agents since the time of inception of the transportation model in 1993 to today, including the timing and nature of significant improvements over this time. In particular, describe the degree of improvement in accuracy and reliability and in the amount of elapsed time from the time a Gas Day ends to the time the Shipper Agent receives its customers' consumption data for that Gas Day.

<u>Response:</u>

To clarify, Shipper Agents representing monthly balanced customers have the same access to customer consumption data as Shipper Agents with daily balanced customers. All Shipper Agents today have access to WINS, which is a self-serve web based application to view individual customer and group demand by day, historical customer consumption, authorized supply from the interconnects, system inventory and imbalances. All Shipper Agents also have the ability to make intraday nomination changes to reflect changes in demand caused by weather or customer behaviour.

Since the inception of the transportation services model in 1993, automatic meter readers or AMRs have routinely been installed at the transportation customers' sites (both daily and monthly balanced) in order for FEI to record the daily consumption of each individual customer. Historically the AMR required a dedicated fax line and power line to facilitate the daily upload of data to FEI. While the majority of the sites reported metered data on a daily basis, some locations were not successful, due to AMR failure, disconnected fax or power line. These trouble sites required a manual read at the end of the month, so, based on this, FEI would provide both metered and estimated daily consumption data to Shipper Agents.

With respect to improvements made to metering and reporting over time, through the 1990s, FEI provided daily consumption data for the month to date to Shipper Agents twice a week by fax or email. Shipper Agents would communicate nomination or supply requirements via fax and FEI would manually enter supply requests into a database. Imbalance positions would be relayed back to the Shipper Agent with requests to adjust supply accordingly via fax or email.

In 2001, Gas Connect was the first application made available to Shipper Agents which allowed users to manage nominations and scheduling. Subsequent phases of this application added functionality to perform balancing for customer groups, a front-end screen for Shipper Agents to manage their business and insert gas requests/nominations within the gas day cycles, intra-day nominations were introduced, electronic data exchange (EDI) for delivery of gas requests and receipt of scheduled results, all in accordance with the NAESB standards. Gas Connect was supported by external spreadsheets and a MS Access database application for manual workarounds.

In 2005/06, Gas Connect was replaced by the current WINS system, which provided Shipper Agents with a central portal to view metered consumption by customer and in group aggregate, historical data, and demand/supply imbalances. Authorized supply from the interconnecting pipelines was updated in WINS via EDI. The system supported nomination flexibility over four gas cycles, the system would email cut reports by cycle to Shipper Agents, and users could retrieve consumption and inventory reports as required. Updated metered consumption is updated on a daily basis. Shipper Agents can access their customer consumption in WINS 24 hours a day, 7 days a week.

In 2009 FEI's measurement department started a project to install wireless (cellular) AMR devices at sites where the customer-provided phone line (land line) was not functioning or access to a phone line was never provided by the customer. The adoption of wireless (cellular) AMR technologies has eliminated the reliance on a customer-supplied telephone connection for the transmission of the AMR device data to FEI's data collection servers. As a result of this project, there have been significant improvements in the sites that report actual metered data within 24 hours of the end of the gas day. Since 2009, the percentage of sites reporting actual metered data, as opposed to estimates, has increased from 75 percent to greater than 95 percent. FEI does not anticipate any further significant technology enhancements to its measurement gathering system at this time.

Regarding lapsed time in WINS, Shipper Agents have access to metered data two days previous to the current (48-hour time lag). The day immediately prior to the current day is always an estimated quantity, as the time over which the data is collected for the 24-hour gas day is not complete. For Shipper Agents that use the previous day's consumption for specific customers to forecast the next day's load, FEI recommends contacting the customers directly.

With respect to how FEI forecasts gas demand, Gas Control forecasts load based on the weather forecast, degree day calculation (also based on the forecast) and historical loads or trends. For the large industrial RS 22 customers on FEI's system, Gas Control also uses the SCADA system which provides consumption for the previous day, previous hourly flow and cumulative hourly flow of the current day. SCADA is a telemetered tool, which tracks the movement of gas across FEI's transmission system. FEI's large volume customers are monitored to this degree due to their location on FEI's system, their large volume swings which can impact pressure, and for the purpose of maintaining overall system integrity.

To assist in managing large volume customers on FEI's system, Shipper Agents have been provided with access to SCADA. Currently there are seven Shipper Agents accessing real time hourly flows for thirty-nine large volume customers. For Shipper Agents managing these customers, the elapsed reporting time in WINS is made up in the real time flow data in SCADA, which includes the previous day, and current day information.

With the available access to historical data from WINS, and from SCADA for large volume customers, combined with taking into account weather forecast and direct communication with customers, Shipper Agents have the tools to forecast customer demand within a tighter tolerance. As shown in Table 10-8 of the Application, nearly half of Shipper Agents today manage within a 10 percent tolerance, the majority of which have exclusively daily balanced groups. Based on this, the proposed changes to the transportation services model are reasonable and achievable.

56.1.1 Please provide a timeline showing, for a particular Gas Day, the nomination timelines and the timing for when supply and consumption data, respectively, are available to the Shipper Agent through WINS.

Response:

The table below shows the nomination deadline in Pacific Standard Time for each cycle in a given gas day.

Task	TIMELY	EVENING	ID1	ID2	ID3
Nomination Deadline	11:00	16:00	08:00	12:30	17:00

Timely and Evening cycles are done prior to the gas day which starts at 7 am the next day. ID1, ID2 and ID3 (i.e., intra-day 1, 2 and 3) cycles occur in the current gas day.

Shipper Agents can make changes to their nominated or requested supply up to five times for each gas day to best match their forecasted demand. Over time, more nominations cycles have been added to help the industry manage its business as the pipeline systems in general have moved to daily balanced systems. For example, the ID3 cycle was added just recently on April 1, 2016 to the WEI nomination system.

At Station #2 (WEI) and Huntington trading hubs, the majority of the gas is traded between 5:00-7:00 am for the Timely cycle, which is 24 to 26 hours prior to the beginning of the particular Gas Day.

Shipper Agents can view their authorized supply each cycle in WINS approximately 3-4 hours after the cycle deadline indicated above. Supply information would also be available directly from WEI nomination system as the cycles become authorized.

Consumption data for each transportation customer is uploaded daily within WINS at approximately 4 am each day for each day previous to the current. The data from the previous day relative to the current is always an estimate, as at the time data was collected, the 24-hour gas day is not complete. All other days contain metered daily consumption.

Please refer to BCUC-FEI IR 1.56.1 which details how FEI forecasts gas demand. Consumption data is one of a few factors that Shipper Agents should be monitoring to help them better forecast customer consumption. For customers with heat sensitive loads, other factors such as weather forecasts, degree day data and historical data or trends should also be considered.

56.1.2 For a Shipper Agent with a monthly balanced group, describe the current degree of accuracy of the consumption data provided to the Shipper Agent through WINS. In particular, to what degree are imbalances in a Shipper Agent's monthly balanced group due to inaccuracies in the consumption data initially communicate via WINS?

Response:

With respect to the accuracy of consumption data in WINS, please refer to the response to BCUC-FEI IR 1.56.1.

Shipper Agents holding monthly balanced groups have the same access to customer data as those managing daily balanced groups. Shipper Agents holding daily and/or monthly balanced groups are required to make best efforts to nominate appropriately based on their forecast customer demand. As indicated in response to BCUC-FEI IR 1.56.1, of the approximate 2,400 transportation customer sites, 99 percent of all customer sites have Automatic Meter Reading (AMR) which reports metered consumption daily.

In its response to BCUC-FEI IR 1.55.1.1, FEI provides graphs showing the packing and drafting patterns for Shipper Agents holding daily balanced groups and monthly balanced groups separately. The graphs show a *drafting* (i.e., negative imbalance) pattern for Shipper Agents holding monthly balanced groups, and a *packing* (i.e., positive imbalance) pattern for Shipper Agents holding daily balanced groups. FEI does not believe the data available to Shipper

Agents in WINS is responsible for the drafting pattern of Shipper Agents holding monthly balanced groups.

Given that many monthly balanced transportation customers have heat sensitive loads, historical consumption data combined with a weather forecast should enable Shipper Agents to derive a load forecast. Shipper Agents managing customers with more process driven loads should be in contact with those customers on a daily basis to forecast their gas requirements. SCADA consumption data by itself will not produce a reasonable forecast for customers because some of the customers within a Shipper Agent group are heat sensitive. FEI believes that Shipper Agents should be using weather forecasts, such as from Environment Canada for example, to produce better demand forecasts for their customers or groups.

56.2 To the extent there is a lag time in communicating customer consumption data to Shipper Agents after the end of the Gas Day, please describe any technological changes FEI anticipates will be available to implement in the next few years to further improve the accuracy and access to daily consumption data.

Response:

As the Gas Day goes from 7 am to 7am, daily consumption data is available to the Shipper Agents on less than a 24-hour time lag. The gas trading window is done a day out, usually between 5:30 am to 7:30 am, so Shipper Agents are usually trading for tomorrow's gas day prior to yesterday's gas day being completed. FEI does not anticipate any technological changes in the next few years to further improve the accuracy and access to daily consumption data.

56.2.1 Please elaborate on the extent to which FEI currently has SCADA data for monthly balanced transportation customers and the possibility and associated costs of providing such real-time SCADA data to Shipper Agents.

Response:

Generally, Shipper Agents managing monthly balanced customers would not have access to SCADA data for any of their monthly balanced customers. The SCADA system is primarily used by the Gas Control department to manage FEI's natural gas delivery system. Real-time SCADA data is usually only available for large gas users, namely RS 22 customers that are primarily served off the transmission pressure system. Gas Control has no need to have

SCADA data at all of the sites of monthly balanced customers, as they are usually too small individually and are mostly served off of the distribution system. As such, FEI has no plans to move towards that kind of SCADA solution. Monthly balanced customers are typically more heat sensitive, so the combination of historical data and trends and weather forecast information should be sufficient for Shipper Agents to determine the daily load requirements for these customers.

57.0 Reference: TRANSPORTATION SERVICE REVIEW

Exhibit B-1, Section 10.6.1, pp. 10-22; Exhibit B-1, Section 10.9, p. 10-41

Implementation of proposed changes

On page 10-22 of Exhibit B-1, FEI states:

> 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 the 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 monthly to their daily group to avoid imbalance charges at month end.

On page 10-41 of Exhibit B-1 FEI summarizes the changes it proposes to the transportation service balancing provisions as follows:

- Eliminate the existing monthly balanced 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.

57.1 Please discuss the pros and cons of a phased approach whereby monthly balancing is eliminated in the first phase and the tolerances are adjusted in a second phase with the opportunity to first assess the extent to which elimination of monthly balancing has reduced the magnitude of the aggregate daily transportation service imbalances on the FEI system.

<u>Response:</u>

FEI believes that Shipper Agents can and should be able to manage to the change of moving to exclusive daily balancing, as research conducted by Black & Veatch indicates this is a common industry standard. Implementing the proposed changes together should be a relatively seamless change, as many marketers today already hold exclusive daily groups and balance under a 10 percent tolerance. From FEI's perspective, there are no major pros or cons to a phased approach, as FEI is able to make these changes to the WINS system at any time. Implementing the changes in a phased approach would be acceptable to FEI, but given that some existing shippers are already managing within the 10 percent tolerance, FEI's preference would be to implement both changes at the same time.

57.1.1 Please discuss the extent to which FEI anticipates that elimination of the opportunity for Shipper Agents to transfer balances from daily balanced groups to monthly balanced groups to avoid balancing charges will incent Shipper Agents to balance more closely each day thereby reducing the magnitude of the aggregate daily transportation service imbalances on the FEI system.

Response:

FEI believes that imposing daily balancing provisions across all service areas will incent Shipper Agents to match supply and demand more closely on a daily basis. As shown in Table 10-8 in the Application, some marketers today hold exclusive daily balanced groups and maintain system imbalances within the 2 to 3 pack bandwidth.

58.0 Reference: TRANSPORTATION SERVICE REVIEW

Exhibit B-1, Section 10.9, p. 10-41;

Exhibit A2-3, FEI Application to Amend the Balancing Charges for RS 23, RS 25, RS 26 and RS 27 (Monthly Balancing Charge Application), Exhibit A-4, BCUC IR No. 2, Attachment ;

FEI Monthly Balancing Charge Application, Exhibit B-5, BCUC 2.7.1 and 2.7.3;

FEI Monthly Balancing Charge Application, Order G-187-14 and Decision dated December 1, 2014, p. 14

Implementation of proposed changes

In BCUC IR 2.7 in the FEI Monthly Balancing Charge Application, Commission staff constructed a table showing details of an example month of hypothetical data for a hypothetical Shipper Agent with a monthly balanced group with four scenarios of behavior using the same hypothetical load and Sumas Daily Index prices for each scenario. The details were set out in Attachment 1 in a PDF version of the data and live spreadsheet. A copy of the PDF version of Attachment 1 has been entered by Commission staff as evidence in this proceeding as Exhibit A2-3.

The four scenarios are:

Scenario 1 – The Shipper Agent makes an effort to balance to the group's load requirements on a daily basis and incurs a Balancing Gas quantity of 2,281 GJ.

Scenario 2 – The Shipper Agent generally makes an effort to balance to the group's load requirements on a daily basis with the exception of four days where the Shipper Agent does not increase its supply during a high price period, makes up part of the shortfall later in the month and incurs a Balancing Gas quantity of 2,281 GJ.

Scenario 3 – The Shipper Agent generally makes an effort to balance to the group's load requirements on a daily basis with the exception of four days where the Shipper Agent does not increase its supply during a high price period, makes up the entire monthly shortfall later in the month and incurs a Balancing Gas quantity of zero GJ.

Scenario 4 - The Shipper Agent generally makes an effort to balance to the group's load requirements on a daily basis with the exception of four days where the Shipper Agent significantly reduces its supply during a high price period, makes up part of this shortfall later in the month and incurs a Balancing Gas quantity of 2,281 GJ.

The example in Attachment 1 calculates Balancing Gas Charges and shows the Shipper Agent's cost of gas assuming the Shipper Agent pays the Daily Sumas Index Price for the purposes of showing the relative magnitude of the Balancing Gas Charges relative to the cost of gas. The example also shows the amount of Balancing Gas Charges for a number of Balancing Gas Charge alternatives.

In response to BCUC IR 2.7.1 in the Monthly Balancing Charge Application, FEI confirmed that the calculations and assumptions in regard to Balancing Gas volumes and Balancing Gas costs in Attachment 1 were accurate. In response to BCUC IR 2.7.3 FEI confirmed that, at that time, FEI would not have taken any action with the Shipper Agent in Scenario 4 in regard to in response to the decrease in the marketer nomination on the 8th day of the month.

In the FEI Monthly Balancing Charge Decision accompanying Order G-187-14, the Panel in that proceeding was of the view that FEI presently has the tools to ensure compliance with the tariff under sections 7.3 and 7.6 of the monthly balanced transportation service tariffs and FEI should endeavour to better utilize these tools and amend business practices to ensure compliance with the intent of the tariff.

58.1 Please describe any changes FEI has implemented to its business practices in regard to increased use of the tools already available to FEI under the monthly balanced transportation service tariffs since the Monthly Balancing Charge Decision was issued and the effectiveness of such changes.

Response:

Since the Monthly Balancing Gas Charge Decision was issued, FEI has exercised the tools within the tariff to ensure balancing compliance for both over-deliveries and under-deliveries. FEI has acted on its ability to change nominated quantities and issued notices specifically advising that Shipper Agents limit supply to no greater than 20 percent above forecasted demand.

Prior to the Decision, in monitoring imbalances on the system, FEI took the approach of leaving the nominating practices in the hands of the Shipper Agent in adhering to balancing requests from FEI. Following the Decision, FEI has on a few occasions taken a more “hands-on” approach, and intervened when FEI believed it was necessary.

58.2 Does FEI agree that Scenario 4 in Exhibit A2-1 is evidence that, under the current transportation service tariffs for monthly balanced transportation service, a Shipper Agent with a monthly balanced group behaving like the Shipper Agent in Scenario 4 could “game” the FEI system even without a daily balanced group to transfer balances from at the end of the month? If not, please explain.

Response:

Given that Shipper Agents have the ability to draft under the current monthly balancing provisions without incurring any charges, FEI agrees that under Scenario 4 a Shipper Agent could game the system. Some Shipper Agents today hold exclusive monthly balanced groups at a single location and despite requests made by FEI, these shipper agents bring varied supply on throughout the month. The Shipper Agents operating this way typically have varied balances at month end and often incur monthly balancing gas to balance the group.

58.3 Does FEI anticipate that FEI's proposal, on page 10-41 in Exhibit B-1, to eliminate monthly balancing and require daily balancing for all transportation service rate schedules would prevent the "gaming" exhibited by the Shipper Agent in Scenario 4? If not, please elaborate.

Response:

FEI cannot say with certainty that the elimination of monthly balancing would eliminate the potential for Shipper Agents to game the system. The shift to exclusive daily balancing will reduce "gaming", but it is difficult to say to what extent, as FEI is unaware of the commercial arrangements made by the Shipper Agents for themselves or on behalf of their customers. The proposals in the Application would effectively level the playing field across all Shipper Agents and their customers, and provide everyone with one set of rules to manage.

59.0 Reference: TRANSPORTATION SERVICE REVIEW

Exhibit B-1, Section 10.7.2, pp. 10-30 to 10-31;

Review of other jurisdictions

In Section 10.7.2 of Exhibit B-1, FEI describes industry balancing practices for local distribution companies across North America as per the research conducted for FEI by Black & Veatch. Figure 10-11 on page 10-31 shows a map of North America listing the utilities sampled by Black & Veatch and the Monthly deadband and Daily deadband tolerances expressed as percentages. On page 10-30 FEI states:

> Industry-wide, balancing provision can vary 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.

59.1 Please identify those LDCs sampled by Black & Veatch that FEI believes are most similar to FEI in terms of regional infrastructure and market hub characteristics.

Response:

Black & Veatch provides the following response.

FEI's regional infrastructure and market hub characteristics are as follows: diverse geographic service territory; served by one pipeline, limited connectivity to upstream pipelines and moderately liquid supply hubs with limited intraday gas trading activity. While one could argue that all LDCs are unique in one respect or another, the LDCs that are most similar are those within the Pacific Northwest, specifically Northwest Natural, Avista, Cascade and Puget Sound Energy. For example, Puget Sound Energy and Northwest Natural are served primarily by one pipeline, Northwest Pipeline, and indirectly by another, Gas Transmission Northwest. However, these LDCs are somewhat dissimilar as the primary upstream pipeline, Northwest Pipeline, does not require daily balancing, as well as their proximity and rights to underground storage. Balancing tolerances for these Pacific Northwest LDCs range between 3 percent and 5 percent depending on the time of year.

59.1.1 Please describe the balancing tolerances and applicable penalties of the transmission pipelines that FEI interconnects with.

Response:

An Operational Balancing Agreement (OBA) exists between natural gas pipelines and receipt/delivery parties at interconnects to describe the balancing provisions between nominated and scheduled quantities. OBAs are in place to help manage and maintain efficient pipeline operations on a daily basis for both upstream and downstream parties. OBAs are not a firm physical resource. The use of OBAs as a source of supply for either party is subject to daily operating conditions and availability by either Gas Control group to accommodate the request. FEI has no history of incurring penalties when OBA agreement balancing tolerances are exceeded.

FEI interconnects with the Westcoast Energy Inc. (WEI) system at four locations as listed below. Described with each OBA Location are the Daily Tolerance (DT) and Cumulative Tolerance (CT) in GJ:

1. BC Gas Interior Division (aggregated location including BC Gas Interior Off-line)

   DT – 15,000 GJ

   CT – 15,000 GJ

2. BC Gas Lower Mainland

   DT – 25,000 GJ

   CT – 50,000 GJ

3. Fort Nelson

   DT – 3,000 GJ

   CT – 6,000 GJ

4. Kingsvale

   DT – 10,000 GJ

   CT – 15,000 GJ

On a relative basis, the OBA tolerances between FEI and WEI are small, given the amount of gas that flows through those interconnect points on a daily basis. Therefore, while FEI does employ the use of OBAs to assist in balancing the system on a daily basis; the amount of supply available can be marginal and not always a reliable source. Overall, FEI works with upstream pipelines on a daily basis to trend these OBAs to zero.

FEI interconnects with the TransCanada Foothills BC system at seven locations as listed below. FEI does not have OBA tolerances at these interconnect locations, requiring FEI to continually trend to a zero imbalance.

1. East Kootenay Exchange

2. Cranbrook Sales Tap
3. Elko Sales Tap
4. Fernie Sales Tap
5. Galloway Sales Tap
6. Sparwood Sales Tap
7. Yahk Sales Tap

The FEI system interconnects with the Williams Northwest Pipeline system at Huntingdon. FEI does not have OBA tolerances at this interconnect location, requiring FEI to continually trend to a zero imbalance.

59.2 Do any of the LDCs sampled by Black & Veatch allow transfers between daily and monthly balanced groups? If so, which ones?

Response:

The following response was provided by Black & Veatch.

Based on the research conducted on over 20 LDCs by Black & Veatch, FEI's current policy allowing Shipper Agents to transfer imbalances between daily and monthly accounts is unique. In fact, most LDCs that have balancing provisions with daily and monthly timeframes require all Shipper Agents to balance both on a daily and monthly basis rather than one or the other. Black & Veatch notes that Pacific Gas & Electric allows customers to choose between monthly balancing and a daily balancing service (which it calls the "Self-Balancing" service), but it does not appear that Shipper Agents are permitted to participate in both schemes simultaneously or transfer imbalances between monthly and daily accounts.

Given FEI's proposal to eliminate monthly balancing and move exclusively to daily balancing, the transfers that occur today between daily and monthly groups will effectively go away if monthly balanced groups are eliminated.

59.3 Are the balancing tolerances of other LDCs typically applicable to both packing and drafting the LDC? Please identify any LDCs that have tolerances only applicable for drafting.

Response:

Black & Veatch provides the following response.

Black & Veatch has observed that LDCs' balancing tolerances are typically applicable for both positive imbalances (packing) and negative imbalances (drafting). In its review of the balancing provisions of more than 20 LDCs, Black & Veatch did not note any that had a tolerance that applied only to negative imbalance quantities.

60.0 Reference: TRANSPORTATION SERVICE REVIEW

Exhibit B-1, Section 3.4, p. 3-18; Section 10, p. 10-35;

FEI Monthly Balancing Charge Application, Order G-187-14 and Decision dated December 1, 2014, p. 25;

Exhibit A2-4, FEI 2015–2016 Rate Schedule 14A Gas Purchases & Sales Summary – BCUC Order G-152-12 Compliance Filing

FEI as Shipper Agent/Rate Schedule 14A

On page 25 of the FEI Monthly Balancing Charge Decision, the Commission directed as follows:

> The Panel directs that when FEI makes its Monthly Balanced Transportation Service rate design application that it is to include a review of the impact of FEI acting as a Shipper Agent supplying gas under Rate Schedule 14A to Monthly Balanced Transportation Service Shippers. In the application FEI is directed to describe, in the context of Monthly Balanced Transportation Service, how FEI as a Shipper Agent procures gas under Rate Schedule 14A, how its practices are similar and dissimilar to other Shippers/Shipper Agents, how it impacts the costs to the core, and to provide information on FEI's use of Balancing Gas in a manner similar to all other Shippers/Shipper Agents.

In Table 3-4 on page 3-18 of Exhibit B-1, FEI provides a summary of the directives from past Commission decisions relevant to the Application. This table does not include the directives shown above from the FEI Monthly Balancing Charge Decision.

60.1 Please provide a reference to where in the FEI 2016 Rate Design Application FEI addresses the above directives. If FEI has not addressed these directives in the Application, please provide the review as directed in the Monthly Balancing Charge Decision.

<u>Response:</u>

FEI's proposal to eliminate monthly balancing altogether and move to daily balancing for all Shipper groups would include RS 14A. As a result of this daily balancing proposal, FEI inadvertently did not address the above directive and includes a review below as directed in the Monthly Balancing Charge Decision.

FEI as a Shipper Agent procures gas under RS 14A through FEI's gas supply department.

Rate Schedule 14A provides a positive benefit to the costs of the core. A market factor premium of the greater of $0.06 CDN per GJ or cost is added to all gas purchases. The core market receives any proceeds from the spread between market factor premium and actual costs, which are reported in the annual RS 14A Purchase and Sales Summary to the Commission. In Order G-64-04 regarding Rate Schedules 7, 10, 14 and 14A for the 2004/05

Gas Year, the Commission determined that the market factor premium should be increased from the greater of $0.05/GJ or cost, to the current level of the greater of $0.06/GJ or cost. The increase in the market factor premium of $0.01/GJ was to cover any potential core administration cost related to RS 14A gas supply purchases. The market factor premium is in addition to the RS 14A management fees of $0.05-$0.09 per GJ for administering RS 14A.

FEI's contracting practices in its role as a Shipper Agent supplying RS 14A customers are generally reflective of industry practice that would apply to other Shippers and/or Shipper Agents acquiring gas supply for delivery to the FEI system at Huntingdon. The main difference is that FEI is the sole source for purchases (including any incurred Balancing Gas) on behalf of RS 14A customers, whereas Shipper and/or Shipper Agents can purchase from the marketplace or potentially under-deliver on their supply requirements and incur Balancing Gas supply from FEI. Additionally, when compared to FEI, depending on the credit worthiness of the Shipper and or/ Shipper Agent, the Shipper/Shipper Agent may get charged higher premiums or prices in the marketplace because of this risk. Further, the number of counterparties available to supply gas to the Shipper and/ or Shipper Agents may be more limited.

Below is an update to the table provided in response to BCUC IR 2.1.3[35] from the FEI Monthly Balancing Charge Application that shows FEI's use of balancing gas under RS 14A. As discussed further in response to BCUC-FEI 1.60.9.2, FEI has improved its nomination processes in recent years. As a result, as shown in the table below, FEI has reduced balancing gas amounts, while also maintaining minimal month end inventory levels.

[35] FEI has identified that the original response to BCUC IR 2.1.3 for the FEI Monthly Balancing Charge Application contained a few errors. The confidential response to BCUC IR 2.1.4 had the correct numbers for FEI Rate Schedule 14A. This table now corrects and updates the information originally filed in BCUC IR 2.1.3 for the FEI Monthly Balancing Charge Application.

RS 14A Historical Balancing Gas and Month End Balance

Date	Monthly Load (GJ)	Balancing Gas (GJ)	Backstopping Gas (GJ)	Month End Balance	Balancing Gas as % of Total Load
2012	**987,041**	**72,191**	**-**		**7.31%**
January	116,738	16,280		-	13.95%
February	102,310	16,781		-	16.40%
March	105,811	12,780		-	12.08%
April	75,669	1,709		-	2.26%
May	63,056	1,931		-	3.06%
June	50,350	598		202	1.19%
July	34,086	864		88	2.53%
August	31,662	2,621		-	8.28%
September	39,701	6,561		-	16.53%
October	81,412	2,097		-	2.58%
November	131,328	7,198		-	5.48%
December	154,918	2,771		-	1.79%
2013	**1,475,482**	**76,608**	**-**		**5.19%**
January	175,009	3,653		-	2.09%
February	158,606	9,830		-	6.20%
March	149,672	854		-	0.57%
April	130,440	4,969		3,882	3.81%
May	87,332	6,908		-	7.91%
June	62,741	2,832		-	4.51%
July	50,282	4,632		10	9.21%
August	47,639	5,346		-	11.22%
September	66,493	16,988		-	25.55%
October	135,683	11,233		-	8.28%
November	177,194	3,139		-	1.77%
December	234,391	6,224		-	2.66%
2014	**1,534,479**	**40,722**	**-**		**2.65%**
January	219,452	12,154		-	5.54%
February	225,678	16,629		-	7.37%
March	185,718	2,544		3,052	1.37%
April	139,100	210		566	0.15%
May	97,455	379		566	0.39%
June	77,988	1,107		140	1.42%
July	59,137	351		87	0.59%
August	56,458	31		38	0.05%
September	65,681	1,165		9	1.77%
October	102,526	-		284	0.00%
November	147,428	3,553		397	2.41%
December	157,859	2,598		843	1.65%

Date	Monthly Load (GJ)	Balancing Gas (GJ)	Backstopping Gas (GJ)	Month End Balance	Balancing Gas as % of Total Load
2015	**1,263,635**	**6,278**	**-**		**0.50%**
January	154,504	1,292		451	0.84%
February	124,387	272		1,609	0.22%
March	124,187	-		2,268	0.00%
April	110,218	233		1,603	0.21%
May	79,113	183		12,257	0.23%
June	63,547	24		1,366	0.04%
July	56,603	-		205	0.00%
August	57,328	130		892	0.23%
September	76,631	858		296	1.12%
October	101,905	187		272	0.18%
November	153,432	1,509		17	0.98%
December	161,781	1,591		17	0.98%
2016	**1,333,094**	**16,209**	**-**		**1.22%**
January	160,655	1,104		17	0.69%
February	136,231	-		3,196	0.00%
March	129,759	-		3,444	0.00%
April	92,569	1,273		146	1.38%
May	84,286	427		26	0.51%
June	71,191	-		625	0.00%
July	65,414	6,064		399	9.27%
August	68,992	5,440		488	7.88%
September	83,080	737		-	0.89%
October	121,388	999		132	0.82%
November	127,008	167		201	0.13%
December	192,522	-		4,827	0.00%
2017					
January	187,936	16,135		6,467	8.59%
February	161,141	3,216		358	2.00%
March	161,719	-		2,700	0.00%
April	129,835	215		471	0.17%

60.2 Does FEI intend for the changes in the balancing rules proposed in the Application to apply to FEI in its role as Shipper Agent? If not, why not.

Response:

Confirmed. The proposed changes in the Application will apply to all Shipper Agents, including FEI acting as a Shipper Agent under RS 14A.

Exhibit A2-4 is FEI's 2015–2016 Rate Schedule 14A Gas Purchases & Sales Summary filed in compliance with Commission Order G-152-12. In the table included in the report, FEI reports purchases and sales to the transportation service customers that FEI procures supply for in three categories: Index Rate Option; Term Fixed price Option and RNG Option.

60.3 Please confirm, or otherwise explain, that the purchases listed in the categories of "Index Rate Option" and "Term Fixed Rate Option" are supplied to FEI's transportation service customers under Rate Schedule 14A.

Response:

Confirmed.

60.4 Please confirm, or otherwise explain, that the purchases listed in the categories of "RNG Option" are biomethane (also referred to as renewable natural gas or RNG) purchases supplied to FEI's transportation service customers under Rate Schedule 11B.

Response:

Confirmed.

60.5 Is the supply and demand for FEI's transportation service customers tracked in WINS? If not, why not?

Response:

Confirmed. Supply and demand data for all customers managed by Shipper Agents, including those under RS 14A, is tracked in WINS.

60.6 Do Shipper Agents other than FEI supply transportation service customers with RNG purchased under Rate Schedule 11B?

Response:

All individual transportation customers and/or their Shipper Agents have the opportunity to purchase RNG under RS 11B.

In addition to FEI, at present there are three other Shipper Agents representing six transportation customers that are actively purchasing RNG volumes from FEI under RS 11B.

60.7 Is RNG supply captured in WINS on a daily basis and is it factored into the daily balance of supply and demand for a Shipper Agent's Group for the purpose of determining balancing charges? If not, why not?

Response:

The RNG supply is captured in WINS and can be viewed in the Shipper Agent's Inventory Report.

In order to facilitate an RNG sale to a transportation customer, FEI transfers the purchased quantity of RNG into the Shipper Agent's group in which the transportation customer resides. RNG sale quantities are typically transferred into the group once a month in a lump sum. The purchased RNG supply is factored into the overall inventory of the group. It is not factored into or added to the direct physical supply on the day, but, given that the supply inflates the Shipper Agent's inventory, it does impact the determination of balancing charges.

In Table 10-8 on page 10-35 of Exhibit B-1, FEI provides data on the balancing performance of "shipper agents operating under the transportation service model today" listing individual Shipper Agents and identifying each with a unique letter.

60.8 Does Table 10-8 include all Shipper Agents active on the FEI system during this timeframe? If not, why not?

Response:

Table 10-8 includes all Shipper Agents with the exception of FEI acting as a Shipper Agent supplying gas under RS 14A. Please refer to the updated table in response to BCUC-FEI IR 1.60.9.1, which includes FEI.

60.9 Please identify which Shipper Agent in Table 10-8 is FEI.

Response:

Please refer to the response to BCUC-FEI IR 1.60.8.

60.9.1 If FEI is not included in Table 10-8, please explain why not and please provide a revised version of Table 10-8 including lines for FEI with FEI identified as "Shipper Agent FEI."

Response:

FEI was not included. FEI as a Shipper Agent is now included in the revised Table 10-8 below and is identified as Shipper Agent FEI.

Table 10-8 (Revised): Imbalance Date under a 10% Tolerance

Shipper Agent	Daily / Monthly	Service Area	# Imb Days / Year	Annual Volume in Excess	Volume in Excess / Day	Demand / Day	Volume in Excess / Demand
Shipper Agent N	M	INL	287	-2,010	-6	8	-67%
Shipper Agent FEI	M	LML	262	-526,205	-1,442	3,291	-44%
Shipper Agent N	M	LML	219	-30,843	-85	230	-37%
Shipper Agent M	M	LML	216	-74,312	-204	467	-44%
Shipper Agent I	M	INL	210	-28,100	-77	414	-19%
Shipper Agent E	D & M	INL	203	-209,596	-574	2,128	-27%
Shipper Agent C	D & M	LML	185	-848,871	-2,326	13,829	-17%
Shipper Agent O	M	LML	170	-4,442	-12	124	-10%
Shipper Agent D	M	INL	169	-210,408	-576	3,401	-17%
Shipper Agent D	M	LML	161	-652,440	-1,788	14,446	-12%
Shipper Agent E	D & M	LML	149	-691,630	-1,895	13,008	-15%
Shipper Agent A	D & M	LML	137	-256,193	-702	19,970	-4%
Shipper Agent C	D & M	INL	115	-143,545	-393	8,173	-5%
Shipper Agent I	D & M	LML	109	-56,657	-155	2,591	-6%
Shipper Agent FEI	M	INL	85	-24,633	-67	502	-13%
Shipper Agent H	D	INL	17	-21,248	-58	5,293	-1%
Shipper Agent B	D & M	INL	12	-13,784	-38	15,191	0%
Shipper Agent A	D & M	INL	11	-59,806	-164	10,978	-1%
Shipper Agent F	D	INL	7	-22,161	-61	14,602	0%
Shipper Agent B	D	LML	5	-7,141	-20	15,641	0%
Shipper Agent K	D	INL	4	-2,767	-8	1,199	-1%
Shipper Agent L	D	LML	3	-2,049	-6	1,155	0%
Shipper Agent H	D	LML	1	-405	-1	3,027	0%
Shipper Agent G	D	INL	1	-921	-3	9,830	0%
Shipper Agent J	D	LML	1	-69	0	1,435	0%

60.9.2 If FEI is one of the Shipper Agents above the red line on Table 10-8, please explain why FEI was not able to more closely balance supply and demand on a daily basis.

Response:

Over the two-year period from 2014 and 2015, Shipper Agent FEI is above the red line. As the table shows, however, the volume in excess on the day above the 10% threshold is relatively small for both groups.

Since the FEI monthly balancing gas charge proceeding in the second half of 2014, FEI has adjusted its nomination processes for RS 14A and is now more closely managing supply and demand. FEI has reduced balancing gas amounts, while also maintaining minimal month-end inventory levels. This trend can be seen in the table provided in response to BCUC-FEI IR 1.60.1, which shows a number of years of data for FEI, including 2016 and part of 2017.

61.0 Reference: TRANSPORTATION SERVICE REVIEW

Exhibit B-1, Section 10.8, p. 10-39;

T-South allocation to transportation service customers

In Section 10.8 of Exhibit B-1, FEI discusses the allocation of 40 TJ/day of firm transportation service from Spectra Energy south to the Huntingdon Delivery area (T-South Long-Haul) that FEI secured in late 2015. This capacity was contracted by FEI to provide additional T-South Long-Haul capacity for transportation service customers potentially seeking to return to bundled sales service.

61.1 Please confirm, or otherwise explain, that FEI contracted for the 40 TJ/day of excess T-South Long-Haul capacity primarily on the basis that should transportation service customers revert to bundled sales service FEI would have an obligation to serve these customers as bundled sales customers.

Response:

Confirmed. It is also important to note that the 40 TJ/day of T-South Long-Haul capacity[36] makes up only a portion of the transportation service customers' total load requirements. If all transportation service customers return back to the bundled service, FEI would have to contract additional resources.

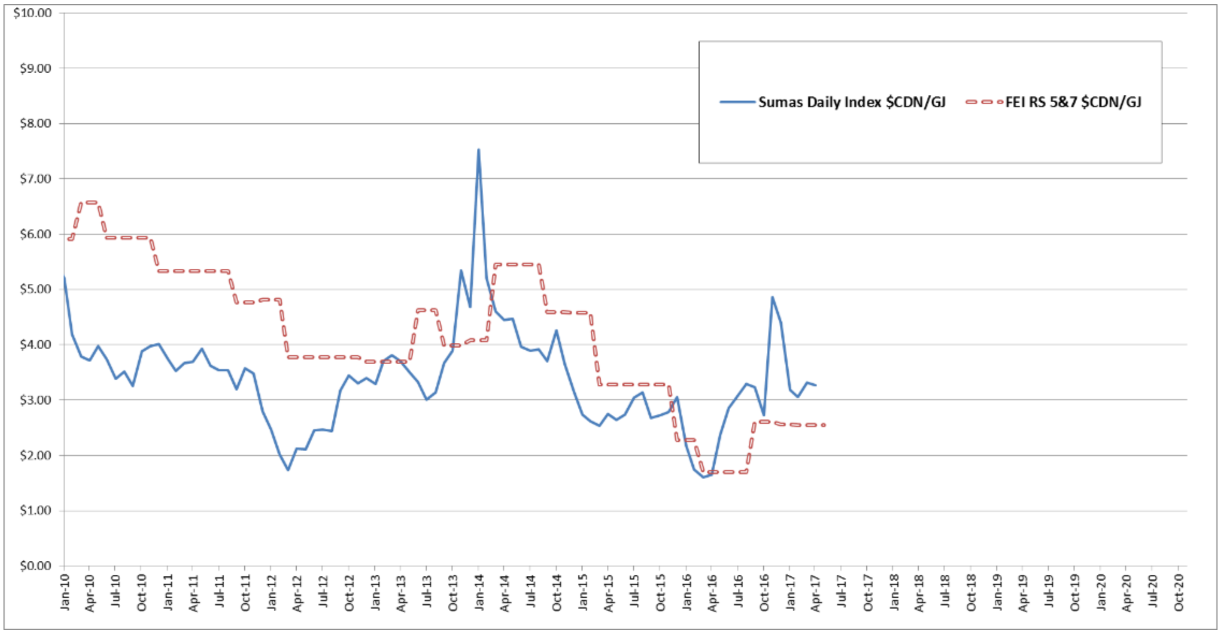
61.2 Have any transportation service customers reverted to bundled sales service since FEI contracted the 40 TJ/day of excess T-South Long-Haul capacity? If so, what amount of the 40 TJ/day of excess capacity is required to serve these customers.

Response:

Since FEI contracted the 40 TJ/day of excess T-South Long-Haul capacity, the customer movement between the bundled and unbundled sales service has been minimal, which is consistent with past years. However, as the chart below shows, the potential for customers to return to bundled service may increase compared to the past, as FEI's rate has been lower than the Sumas daily price over the past year. In recent weeks, FEI has been fielding inquiries from customers asking about returning to bundled service for November 1, 2017.

[36] T-South Long-Haul is also known as T-South Huntingdon Delivery Area, which is defined on page 1.11 of Westcoast Energy's General Terms and Conditions as the area comprised of the Export Delivery Area and the Lower Mainland Delivery Area.

FEI's RS 5&7 vs Sumas Daily Price



The risk that transportation service customers will come back to the bundled service remains, as customers relying on the Huntingdon market continue to face an uncertain future. The potential new incremental load from industrial projects within the Lower Mainland and the Pacific Northwest, and a fully contracted T-South pipeline, risks leaving transportation service customers without adequate gas supply or they will need to pay significantly higher commodity prices at Huntingdon. This risk will likely persist if this incremental new demand arrives before any additional infrastructure is completed.

61.3 Please confirm, or otherwise explain, that T-South Long-Haul capacity is currently fully contracted and not available on a firm basis regardless of Spectra Energy's credit requirements for contracting firm service.

Response:

Confirmed. Historically, Spectra offered up to 1,700 MMcf/d of contractible T-South Long-Haul firm 365-day transportation service based on the winter design capacity of its system. In October 2014, Spectra reduced contractable firm service to 1,450 MMcf/d based on its expected system capacity in the summer months. The announcement resulted in shippers, including FEI, contracting for the last remaining contractable 365-day Westcoast T-South Long-Haul capacity. In November 2016, upon receiving NEB approval, Westcoast conducted an open season to contract for 160 MMcf/d of T-South Long-Haul capacity for each November to March winter period commencing November 1, 2017 (Winter Firm Service). The Winter Firm Service capacity was 160 MMcf/d of the remaining 250 MMcf/d of T-South Long-Haul capacity. This capacity was purchased by Northwest Innovations Works, a Company that is proposing to construct methanol production plants in Washington and Oregon State, and Painted Pony, a major producer in Northeast BC.

Westcoast is currently conducting an Open Season for the remaining 90 MMcf/d of 365-day contractable portion of T-South Long-Haul capacity, and a small 100 MMcf/d expansion. This Open Season will be the last firm contractable pipeline capacity available to secure until a larger scale pipeline expansion is built, which would likely occur no earlier than 2023. However, that timeline could be pushed out even further, as there are still a number of uncertainties with a large scale pipeline expansion, such as new customers willing to underwrite the expansion and environmental/regulatory challenges.

61.4 Has FEI allocated any of the excess T-South Long-Haul capacity to FEI as Shipper Agent? If so, please elaborate.

Response:

FEI has not allocated any of the excess T-South Long-Haul capacity to FEI as a Shipper Agent.

Attachment 7.1

Terasen Gas

INFORMATION BULLETIN

Bulletin # (See Standard GEN 01-13)	Effective Date (Yr/Mth/Day)	Cross-references, if any (e.g., Operating Procedure SAF 30-7, dated 26 Jan 96)
2008-43	08/11/03	See standards listed below
Audience (e.g., engineers, install managers, construction personel)		Replaces (e.g., Information Bulletin CS/1995/12, dated 10 Sept 96)
See list below		
Originating Group or Department		
Engineering		
Subject Matter Expert Name		Subject Matter Expert Signature
Frank Mostad		
Owner's Title	Owner's Name	Owner's Signature
Dist Assets & Improvements Manager	Gary Johnson	

Note: The original of every Information Bulletin must always be sent to Engineering Governance

This bulletin is being issued to convey information of an urgent nature, of a general nature or information that clarifies, but does not alter the intent of, an approved policy or procedure.

Elimination of 88 mm PE Pipe and Restricted Usage of 42 mm PE Pipe

This bulletin is mandatory reading for the following job functions: Engineering, Capacity Planning, Procurement, Inventory Analysts, Training, Planning & Design, Install Managers, Install Crews, Contract Crews, and Project Management.

Effective immediately, 88 mm PE pipe is to be discontinued for all upgrades and new installations. 42 mm PE pipe is to be restricted to single services without branches only, and will no longer be permitted for use as mains or service headers.

88 mm PE pipe was deemed to be an impractical size that will be replaced by 114 mm PE pipe. Short 2 metre lengths of 88 mm PE pipe will continue to be stocked for emergency purposes only. These short lengths will be protected from UV radiation and contamination. See part number 250-2219.

42 mm PE pipe has had a number of fusion melt-through issues and therefore represents a greater risk in our system. This size will be replaced by 60 mm PE pipe.

For existing planned jobs where 42 mm PE pipe and 88 mm PE pipe has been nominated, these jobs do not need to be redesigned and may proceed as planned providing that there is sufficient material in inventory.

Parts affected within the Approved Product Catalogue include:

- 42 mm PE Coil Pipe, Part Number 250-2208 – use to depletion then delete part
- 42 mm PE Straight Pipe, Part Number 250-2230 – small quantities will be stocked for repairs and short replacements only, as well as single non-branched services
- 88 mm PE Straight Pipe, Part Number 250-2216 – use to depletion then delete part
- 88 mm PE Reeled Pipe, Part Number 250-2217/250-2218 – parts to be deleted
- 88 mm PE Straight Pipe, 2 m length, Part Number 250-2219 – new part

Designers, Planners, Install Managers, Install Crews, and Contractors are advised to start utilizing 60 mm PE pipe and 114 mm PE pipe instead of 42 mm PE pipe and 88 mm PE pipe in their planning, construction and maintenance jobs. The Training Department should revise their course contents to appropriately reflect this change.

Most of the related PE fittings will be stocked in quantities appropriated to these changes and these quantities will be adjusted as we gain experience through usage.

Impact on Standards

The following standards must be reviewed for impact and updated as required, prior or by June 1st, 2009, to reflect the changes.

Standard No.	Standard Name	Owner	SME
MAT 05-01	Polyethylene Pipe and Tubing	F Pataki	F Mostad
MAT 06-30	Polyethylene Ball and Plug Valves	F Pataki	F Mostad
DES 04-01-01	Distribution System Piping Design	F Pataki	F Mostad
DES 04-01-04	PE Pipe	F Pataki	F Mostad
DES 04-01-17	Use and Installation of PE Pipe	F Pataki	F Mostad
DES 04-02-06	PE Service Material	F Pataki	F Mostad
DES 04-01-08	Sizing of Distribution Pipe – Mains and Services	F Pataki	T Penner
CON 04-02	Socket Fusion	S Barbour	M Walls
CON 04-07	Fusion and Hot Tapping of Side Saddles	S Barbour	R Arnott
CON 04-09	Fusion Tests, Certificates, and Inspections	S Barbour	S Barbour
CON 06-02	Installing Stub Services – PE Main	D Johnston	R Arnott
CON 06-03	Installing PE Services	D Johnston	P Kropp
CON 06-06	Completing Stubbed Services	D Johnston	R Arnott
CON 11-04	Handling PE Pipe and Fitting	R Samels	V Triggiano
CON 11-08	Inserting PE into Ducts	S Barbour	P Tassie

If you have any questions with regards to these changes, please contact Gary Johnson in Asset Management at 604-592-7739, or Frank Mostad in Engineering Services at 604-592-7899.

Attachment 25.10

TARIFF SUPPLEMENT NO. E-2

FURTHER AMENDED AND RESTATED
BYPASS TRANSPORTATION AGREEMENT
RATE SCHEDULE 25

BETWEEN

DUNKLEY LUMBER LIMITED

AND

FORTISBC ENERGY INC.
(Formerly Terasen Gas Inc.)

Effective November 1, 2004

THIS AGREEMENT ("Agreement") made as of the 11th day of March, 2004, with effect as and from November 1, 2004 is a further amendment and restatement of an agreement made as of June 1st, 2002 with effect as and from November 1st, 2002, itself being an amendment and restatement of an agreement made as of December, 1989 between the parties noted below.

BETWEEN:

TERASEN GAS INC. (formerly known as BC Gas Utility Ltd. and BC Gas Inc.), a company incorporated under the laws of British Columbia having its registered office at 1111 West Georgia Street, Vancouver, British Columbia

(hereinafter called "Terasen Gas")

OF THE FIRST PART

AND:

DUNKLEY LUMBER LIMITED, a company incorporated under the laws of British Columbia having its registered office at P. O. Box 173, Prince George, British Columbia

(hereinafter called "Dunkley")

OF THE SECOND PART

RECITALS

WHEREAS:

A. Dunkley operates sawmill facilities near Prince George, British Columbia, and requires Gas for its sawmill operations located at Dunkley Road adjacent to Highway 97 North.

B. Terasen Gas owns and operates a Gas transmission pipeline which is connected to the sawmill operations of Dunkley near Prince George, British Columbia.

C. Dunkley entered into an agreement with BC Gas Inc. (now known as Terasen Gas Inc.) dated December, 1989 effective January 1, 1990 (the "1990 Bypass Agreement"), which allows Dunkley to receive transportation service from Terasen Gas at rates and on terms and conditions that are based on the principles of the British Columbia Utilities Commission decision of October 2, 1987 respecting a bypass pipeline application by Northwood Pulp and Timber Limited.

D. On April 15, 1993, BC Gas Inc. filed an application (the "Phase B Rate Design Application") with the British Columbia Utilities Commission for redesign of its Gas tariff Rate Schedules which, among other things, proposed the implementation of common Rate Schedules and General Terms and Conditions of service.

E. Following the completion of the hearing of the Phase B Rate Design Application, the British Columbia Utilities Commission issued its decision dated October 25, 1993, which, in part, approved the implementation of new Rate Schedules effective November 1, 1993 for industrial and general service.

F. As a result of the British Columbia Utilities Commission decision dated October 25, 1993, the parties entered into an amended and restated Agreement to clarify their respective rights and obligations effective November 1, 1993.

G. The forecast annual volume in the 1990 Bypass Agreement (Schedule 1) and in the 1995, effective November 1, 1993, Restated and Amended Agreement was 157,050 gigajoules (GJ). The Daily Transportation Quantity (DTQ) in that same Restated and Amended agreement was 617 gigajoules (GJ).

H. For the Further Amended and Restated Bypass Transportation Agreement dated June 1, 2002 and effective November 1, 2002 (the "2002 Agreement") the annual forecast volume was increased to 250,000 GJ and the DTQ was increased to 1,540 GJ. The daily capacity of the Bypass Pipeline was 1,855 GJ under the 2002 Agreement. The increased annual volumes and DTQ used for the 2002 Agreement exceeded 120 percent of the forecast volumes and DTQ in the Restated and Amended Agreement effective November 1, 1993. To deliver the increased annual volumes and the DTQ, additional line pressure equipment would have been incurred for the Bypass Pipeline. No incremental operating and maintenance expense and property tax was incurred. The resulting incremental annual cost to Dunkley under the 2002 Agreement was $36,327.

I. For this Agreement, the annual forecast volumes are 460,000 GJ and the DTQ is 4,153 GJ. The daily capacity of the Bypass Pipeline is 4,984 GJ. The increased annual volumes and DTQ used for this Agreement exceed 120 percent of the forecast volumes and DTQ in the 2002 Agreement. To deliver the increased annual volumes and the DTQ required under this Agreement, a 4.2 km loop and upgraded metering facilities would have been incurred for the Bypass Pipeline. Incremental operating and maintenance expense and property tax will be incurred under this Agreement.

J. Resulting incremental annual cost to Dunkley is $12,527 under this Agreement. Part of the annual cost will be recovered by the Delivery Charge that is related to the annual cost in Schedule 1 of the 1990 Bypass Agreement times the incremental volumes of 210,000 GJ (460,000 GJ – 250,000 GJ). $0.046 of the $0.07 Delivery Charge pertains to the annual cost of the 1990 Bypass Pipeline Agreement: $9,660 (210,000 GJ x $0.046). The incremental annual fixed cost under this Agreement is $2,867 ($12,527 - $9,660) or $239 per Month.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the premises, the covenants and agreements contained herein, the parties agree as follows:

ARTICLE 1

DEFINITIONS

1.01 Except where the context expressly states another meaning, the following words will have the following meaning:

"Bypass Pipeline" means those facilities which, but for this Agreement, would have been constructed by Dunkley in order to allow Dunkley to bypass the Terasen Gas transmission and distribution Gas system.

"DTQ" means Daily Transportation Quantity as defined in the Rate Schedule 25 Transportation Agreement or other transportation agreement related to a Rate Schedule for transportation under which Dunkley may elect to receive service.

"Terms and Conditions of the Transportation Rate Schedule" means the terms of the applicable transportation Rate Schedule and Transportation Agreement thereunder, and the General Terms and Conditions of Terasen Gas, as approved by the British Columbia Utilities Commission by its Decision of October 25, 1993 or any subsequent transportation Rate Schedule accepted for filing by the British Columbia Utilities Commission.

1.02 Except for those terms defined under Article 1.01, terms or expressions used in this Agreement will have the meanings described in the Terms and Conditions of the Transportation Rate Schedule.

ARTICLE 2

TRANSPORTATION SERVICE

2.01 Terasen Gas will provide firm transportation service to Dunkley for its sawmill operations near Prince George, British Columbia and Dunkley will accept such transportation service in accordance with the then prevailing provisions of Terasen Gas Rate Schedule 25 and the accompanying Transportation Agreement for the term of this Agreement and such provisions are incorporated herein by reference.

2.02 Notwithstanding the provisions of Article 2.01, where anything in the Terms and Conditions of the Transportation Rate Schedule conflicts or is inconsistent with the terms and conditions set out in this Agreement, this Agreement governs.

2.03 Dunkley shall be entitled to take service under a transportation Rate Schedule other than Rate Schedule 25 subject to the terms and conditions of such Rate Schedule. In such case, Article 2.01 and 2.02 will apply in the same way to the elected Rate Schedule.

ARTICLE 3

TERM OF AGREEMENT

3.01 Subject to Article 9, the initial term of this Agreement will be for a period of 10 Years, effective the 1st Day of November 2004 up to the 1st Day of November 2014.

3.02 The term of this Agreement shall be extended beyond the initial termination date or any subsequent extension thereof upon the terms and conditions of this Agreement, including the pricing provisions, upon Dunkley providing written notice to Terasen Gas of its desire to extend the term of the Agreement for a further specified period, at least 12 Months prior to the then current termination date and Terasen Gas agreeing to such extension of the term of this Agreement. Terasen Gas shall not unreasonably withhold agreement to such extension of the term of this Agreement. Notwithstanding the foregoing, any extension under this Agreement will be for a period of not less than 1 contract Year.

ARTICLE 4

RATES AND CHARGES

4.01 Subject to the adjustments hereinafter provided for, Dunkley will each Month pay to Terasen Gas for services provided hereunder from November 1, 2004 to the expiry of this Agreement the following rates:

(i) A monthly charge of $11,571.60;

(ii) A Delivery Charge of $0.07 / gigajoule; and.

(iii) Any charges pursuant to Articles 4.02, 4.03 and 4.04.

4.02 Upon changes in its DTQ pursuant to Article 5 or in the annual Gas quantity consumed under this Agreement in excess of 120 percent of those forecast in Recital I, the monthly charge will be adjusted by Terasen Gas to reflect any changes in costs which would have been incurred by Dunkley as a result of the change in the DTQ or annual Gas quantity had Dunkley constructed and operated the Bypass Pipeline.

4.03 The monthly charge and the Delivery Charge as specified under Article 4.01 will be adjusted effective November 1 of each contract Year on the following basis to compensate Terasen Gas for the following changes in its costs:

(i) the operating, maintenance and property tax expenses included in the monthly charge as at November 1, 2004 are $2,447.54 per Month and will be subject to the annual percentage change in the Consumer Price Index for the City of Vancouver for October, up to the contract Year expiring November 1, 2005. Thereafter, the Consumer Price Index for the Month of August will be used. The monthly charge will be adjusted by the calculated change in costs. The adjusted operating, maintenance and property tax expenses will form the basis for the following contract Year adjustment; and

(ii) any new or increased tax related to the operation of the Bypass Pipeline that would have been levied had it been constructed and operated by Dunkley will be calculated on a monthly basis (the annual cost divided by 12) and added to the monthly charge specified in Section 4.01 (i).

4.04 Unauthorized Overrun Gas will be charged for and paid by Dunkley in accordance with the rate set out in Rate Schedule 25.

ARTICLE 5

ADJUSTMENTS TO DTQ

5.01 The DTQ for the contract Year commencing November 1, 2004 is agreed to be 4,153 gigajoules. Dunkley will be responsible to ensure that its DTQ is adjusted on November 1 of each contract Year during the term of this Agreement by requesting an amended DTQ upon not less than 2 Months prior to the end of the contract Year then in effect.

ARTICLE 6

FORCE MAJEURE

6.01 Notwithstanding any of the provisions contained herein or in any transportation Rate Schedule under which Dunkley takes service, Dunkley will not be entitled to any monthly charge credits from Terasen Gas as a result of Force Majeure as defined in the Rate Schedule 25 General Firm Transportation Service Agreement.

ARTICLE 7

ARBITRATION

7.01 Any dispute between the parties arising from this Agreement will be resolved by a single arbitrator pursuant to the *Commercial Arbitration Act* of British Columbia or successor legislation, save as expressly provided herein.

7.02 Either party may commence arbitration proceedings by sending to the other party a demand for arbitration setting out the nature of the dispute.

7.03 The parties will have 10 Days from receipt of the demand referred to in section 7.02 of this Agreement to agree upon the arbitrator, failing which either party may apply to the Supreme Court of British Columbia to select the arbitrator. The arbitrator must be sufficiently qualified by education and training to decide the particular questions in dispute. Unless otherwise agreed, the arbitrator may not be a past or present employee, officer or director of any of the parties or their respective successors, permitted assigns or affiliates, any customer or supplier of Dunkley or Terasen Gas.

7.04 The arbitrator will proceed immediately to hear and determine the matter in dispute and will render a written decision, signed by the arbitrator, within 45 Days after the appointment, subject to any reasonable delay due to unforeseen circumstances. Notwithstanding the foregoing, if the arbitrator fails to render a decision within 60 Days after the appointment then either party may elect to have a new arbitrator appointed in like manner as if none had previously been appointed.

7.05 The decision of the arbitrator will be final and binding upon the parties and the parties will abide by the decision and perform the terms and conditions thereof.

ARTICLE 8

FRANCHISE FEES

8.01 Dunkley acknowledges that Terasen Gas is obligated to pay Franchise Fees to certain municipalities it serves. In the event that Terasen Gas is required by statute, agreement, regulation, an arbitrator, a court of competent jurisdiction, or the British Columbia Utilities Commission to pay Franchise Fees or like fees on revenues received from Dunkley, or in relation to services provided, in addition to those calculated and paid by Terasen Gas at the commencement of this Agreement, Dunkley will pay an amount equal to such additional fees to Terasen Gas and the rates and charges payable by Dunkley as set out in Article 4 will be adjusted to reflect this change.

ARTICLE 9

TERMINATION

9.01 In addition to any other rights either party may have to terminate this Agreement:

(i) Notwithstanding Article 3.01, Terasen Gas may terminate this Agreement if at any time the British Columbia Utilities Commission disallows Terasen Gas the recovery from the other customers of Terasen Gas of any revenue shortfalls, resulting from the negotiated rates under this Agreement;

(ii) Notwithstanding Article 3.01, Dunkley may terminate this Agreement by giving Terasen Gas at least 1 Year written notice of its intention to terminate and upon payment in full by Dunkley of the following amounts:

If termination is after November 1, 2003 and on or before November 1, 2004	$102,960
If termination is after November 1, 2004 and on or before November 1, 2005	$90,090
If termination is after November 1, 2005 and on or before November 1, 2006	$77,220
If termination is after November 1, 2006 and on or before November 1, 2007	$64,350
If termination is after November 1, 2007 and on or before November 1, 2008	$51,480
If termination is after November 1, 2008 and on or before November 1, 2009	$38,610
If termination is after November 1, 2009 and on or before November 1, 2010	$25,740
If termination is after November 1, 2010 and on or before November 1, 2011	$12,870

(iii) Notwithstanding Article 9.01(ii), Dunkley may terminate this Agreement at any time after November 1, 2011, without any payment under this Article.

9.02 Upon not less than 12 Months prior notice, any termination pursuant to Article 9.01 will take effect on the next November 1 following the giving of notice in writing by the party terminating this Agreement.

ARTICLE 10

NOTICES

10.01 If in any Year an executed Transportation Agreement is not in place, then the notice provisions of the latest executed Transportation Agreement and Rate Schedule will apply to this Agreement.

ARTICLE 11

MISCELLANEOUS

11.01 This Agreement will not be assigned without the written consent of the other party hereto, which consent will not be unreasonably withheld.

11.02 Notwithstanding Article 11.01, Terasen Gas may assign, without the consent of Dunkley, Terasen Gas' rights and obligations under this Agreement to a party which acquires all or substantially all of Terasen Gas' Gas utility operations.

11.03 Notwithstanding Article 11.01, Dunkley may assign, without the consent of Terasen Gas, Dunkley's rights and obligations under this Agreement to any party which acquires all or substantially all of Dunkley's sawmill operations served by Terasen Gas pursuant to this Agreement.

11.04 This Agreement will enure to the benefit of and be binding on the parties and their respective successors and permitted assigns including, without limitation successors by merger, amalgamation or consolidation.

11.05 This Agreement and all amendments, modifications, alterations or supplements hereto will be governed by the laws in force in the Province of British Columbia as to nature, validity and interpretation.

11.06 This Agreement is of no force or effect until accepted for filing by the British Columbia Utilities Commission. Upon acceptance for filing of this Agreement by the British Columbia Utilities Commission, the 2002 Agreement will be cancelled and deemed to have been replaced and superseded in its entirety by this Agreement.

11.07 In this Agreement the words, phrases or expressions which are not defined herein or in the Terasen Gas General Terms and Conditions or in the Rate Schedule 25 General Firm Transportation Service Agreement and which in the usage custom of the business of the production, transportation, distribution or sale of Gas has an accepted meaning will have that meaning.

IN WITNESS WHEREOF the parties have executed this Agreement.

AGREED TO AND ACCEPTED:

This 18 day of March, 2004.

TERASEN GAS INC.

By: ______________________
(Signature)

Rick Parnell
(Name – Please print)
Director, Large Commercial & Industrial Markets

AGREED TO AND ACCEPTED:

This 16 day of March, 2004.

DUNKLEY LUMBER LIMITED

By: ______________________
(Signature)

Blair Mayes
(Name – Please print)
General Manager

Dunkley
LUMBER LTD.

PHONE (250) 998-4421
FAX (250) 998-4513

P.O. BOX 173
PRINCE GEORGE, B.C.
CANADA V2L 4S1

October 7, 2013

Rajoo Jagtap
FortisBC
16705, Fraser Highway,
Surrey, BC
V4N 0E8

Re: Bypass Agreement extension request – E2 Dunkley Lumber Ltd. (Prince George)

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and FortisBC for a further period of 2 years for expiry November 1st, 2016. The current agreement expires November 1st, 2014.

Thank you.

Yours truly,
DUNKLEY LUMBER LTD.

Tony Mogus

Tony Mogus
General Manager

Dunkley LUMBER LTD.

PHONE (250) 998-4421
FAX (250) 998-4513

P.O. BOX 173
PRINCE GEORGE, B.C.
CANADA V2L 4S1

September 4, 2015

Rajoo Jagtap
FortisBC
16705, Fraser Highway,
Surrey, BC
V4N 0E8

Sent via Email: rajoo.jagtap@fortisbc.com

Re: Bypass Agreement extension request – E2 Dunkley Lumber Ltd. (Prince George)

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and FortisBC for a further period of 2 years for expiry November 1st, 2018. The current agreement expires November 1st, 2016.

Thank you.

Yours truly,
DUNKLEY LUMBER LTD.

Tony Mogus

Tony Mogus
General Manager

TARIFF SUPPLEMENT NO. E-5

AMENDED AND RESTATED
BYPASS TRANSPORTATION AGREEMENT
RATE SCHEDULE 25

BETWEEN

TOLKO INDUSTRIES LTD.
SODA CREEK DIVISION
(Formerly Riverside Forest Products Limited and Timberwest Forest Limited)

AND

FORTISBC ENERGY INC.
(Formerly Terasen Gas Inc. and BC Gas Utility Ltd.)

Effective November 1, 1993

THIS AGREEMENT made as of the 21st day of December 1994 with effect as and from November 1, 1993 is an amendment and restatement of an agreement made as of December, 1989 between the parties noted below.

BETWEEN:

BC GAS UTILITY LTD., a company incorporated under the laws of British Columbia having its registered office at 1111 West Georgia Street, Vancouver, British Columbia

(hereinafter called "BC Gas")

OF THE FIRST PART

AND:

TIMBERWEST FOREST LIMITED, a company incorporated under the laws of British Columbia having its registered office at 9th Floor, 700 West Georgia Street, Vancouver, British Columbia

(hereinafter called "Timberwest")

OF THE SECOND PART

WHEREAS:

A. Timberwest operates sawmill facilities in Williams Lake, British Columbia, and requires Gas for its Pinette & Thieran, Williams Lake Division sawmill operations located at North McKenzie Avenue;

B. BC Gas owns and operates a Gas transmission pipeline which is connected to the sawmill operations of Timberwest in Williams Lake, British Columbia;

C. Timberwest entered into an agreement with BC Gas' predecessor company, BC Gas Inc., dated December, 1989 effective January 1, 1990, which allows Timberwest to receive transportation service from BC Gas at rates and on terms and conditions that are based on the principles of the British Columbia Utilities Commission decision of October 22, 1987 respecting a bypass pipeline application by Northwood Pulp and Timber Limited.

D. On April 15, 1993, BC Gas filed an application (the "Phase B Rate Design Application") with the British Columbia Utilities Commission for redesign of its Gas tariff Rate Schedules which, among other things, proposed the implementation of common Rate Schedules and General Terms and Conditions of service.

E. Following the completion of the hearing of the Phase B Rate Design Application, the British Columbia Utilities Commission issued its decision dated October 25, 1993, which, in part, approved the implementation of new Rate Schedules effective November 1, 1993 for industrial and general service.

F. As a result of the British Columbia Utilities Commission decision dated October 25, 1993, the parties desire to enter into this amended and restated Agreement to clarify their respective rights and obligations.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the premises, the covenants and agreements contained herein, the parties agree as follows:

ARTICLE 1

DEFINITIONS

1.01 Except where the context expressly states another meaning, the following words will have the following meaning:

"Bypass Pipeline" means those facilities which, but for this Agreement, would have been constructed by Timberwest in order to allow Timberwest to bypass the BC Gas transmission and distribution Gas System.

"DTQ" means Daily Transportation Quantity as defined in the Rate Schedule 25 Transportation Agreement or other transportation agreement related to a Rate Schedule for transportation under which Timberwest may elect to receive service.

"Terms and Conditions of the Transportation Rate Schedule" means the terms of the applicable transportation Rate Schedule and Transportation Agreements thereunder, and the General Terms and Conditions of BC Gas, as approved by the British Columbia Utilities Commission by its decision of October 25, 1993 or any subsequent transportation Rate Schedule accepted for filing by the British Columbia Utilities

Commission.

<u>1.02</u> Except for those terms defined under Article 1.01, terms or expressions used in this Agreement will have the meanings described in the Terms and Conditions of the Transportation Rate Schedule.

ARTICLE 2

<u>TRANSPORTATION SERVICE</u>

<u>2.01</u> BC Gas will provide firm transportation service to Timberwest for its sawmill operations in Williams Lake, British Columbia and Timberwest will accept such transportation service in accordance with the then prevailing provisions of BC Gas Rate Schedule 25 and the accompanying Transportation Agreement for the term of this Agreement and such provisions are incorporated herein by reference.

<u>2.02</u> Notwithstanding the provisions of Article 2.01, where anything in the Terms and Conditions of the Transportation Rate Schedule conflicts or is inconsistent with the terms and conditions set out in this Agreement, this Agreement governs.

<u>2.03</u> Timberwest will be entitled to take service under a transportation or Sales Rate Schedule other than Rate Schedule 25 subject to the terms and conditions of such Rate Schedule. In such case, Article 2.01 and 2.02 will apply in the same way to the elected Rate Schedule.

ARTICLE 3

<u>TERM OF AGREEMENT</u>

<u>3.01</u> Subject to Article 9, the initial term of this Agreement shall be for a period of 6 years, effective the 1st Day of November 1993 up to the 1st Day of November 1999.

<u>3.02</u> The term of this Agreement, shall be extended beyond the initial termination date or any subsequent extension thereof upon the terms and conditions of this Agreement, including the pricing provisions, upon Timberwest providing written notice to BC Gas of its desire to extend the term of the Agreement for a further specified period, at least 12 months prior to the then current termination date and BC Gas agreeing to such extension of the term of this Agreement. BC Gas shall not unreasonably withhold agreement to such extension of the term of this Agreement. Notwithstanding the foregoing, any extension will be for a period of not less than 1 Contract Year.

ARTICLE 4

RATES AND CHARGES

4.01 Subject to the adjustments hereinafter provided for, Timberwest will each month pay to BC Gas for services provided hereunder from November 1, 1993 to the expiry of this Agreement the following rates:

(i) A monthly charge of $8,709.51.

(ii) A Delivery Charge of $0.059/gigajoule.

(iii) Any charges pursuant to Articles 4.02, 4.03 and 4.04.

4.02 Upon changes in its DTQ pursuant to Article 5 or in the annual Gas quantity consumed under this Agreement in excess of 120 percent of those forecast in Schedule 1, the monthly charge will be adjusted by BC Gas to reflect any changes in costs which would have been incurred by Timberwest as a result of the change in the DTQ or annual Gas quantity had Timberwest constructed and operated the Bypass Pipeline.

4.03 The monthly charge and the Delivery Charge as specified under Article 4.01 will be adjusted effective November 1 of each Contract Year on the following basis to compensate BC Gas for changes in its costs:

(i) the operating, maintenance and property tax expenses included in the monthly charge as at November 1, 1993 are $1,427.51 per month and will be subject to the annual percentage change in the Consumer Price Index for the City of Vancouver for October, up to the Contract Year expiring November 1, 1994. Thereafter, the Consumer Price Index for the month of August will be used. The monthly charge will be adjusted by the calculated change in costs. The adjusted operating, maintenance and property tax expenses will form the basis for the following Contract Year adjustment.

(ii) any new or increased tax related to the operation of the Bypass Pipeline that would have been levied had it been constructed and operated by Timberwest will be calculated on a monthly basis (the annual cost divided by 12) and added to the monthly charge.

<u>4.04</u> Unauthorized Overrun Gas will be charged for and paid by Timberwest in accordance with the rate set out in Rate Schedule 25.

ARTICLE 5

<u>ADJUSTMENTS TO DTQ</u>

<u>5.01</u> The DTQ for the Contract Year commencing November 1, 1993 is agreed to be 667 gigajoules. Timberwest will be responsible to ensure that its DTQ is adjusted on November 1 of each Contract Year during the term of this Agreement by requesting an amended DTQ upon not less than 2 months prior to the end of the Contract Year then in effect.

ARTICLE 6

<u>FORCE MAJEURE</u>

<u>6.01</u> Notwithstanding any of the provisions contained herein or in any transportation Rate Schedule under which Timberwest elects to receive service, Timberwest will not be entitled to any monthly charge credits from BC Gas as a result of Force Majeure.

ARTICLE 7

<u>ARBITRATION</u>

<u>7.01</u> Any dispute between the parties arising from this Agreement will be resolved by a single arbitrator pursuant to the *Commercial Arbitration Act* of British Columbia or successor legislation, save as expressly provided herein.

<u>7.02</u> Either party may commence arbitration proceedings by sending to the other party a demand for arbitration setting out the nature of the dispute.

<u>7.03</u> The parties will have 10 days from receipt of the demand referred to in section 7.02 of this Agreement to agree upon the arbitrator, failing which either party may apply to the Supreme Court of British Columbia to select the arbitrator. The arbitrator must be sufficiently qualified by education and training to decide the particular questions in dispute. Unless otherwise agreed, the arbitrator may not be a past or present employee, officer or director of any of the parties or their respective successors or affiliates, any customer or supplier of Timberwest or BC Gas.

<u>7.04</u> The arbitrator will proceed immediately to hear and determine the matter in dispute and will render a written decision, signed the arbitrator, within 45 days after the appointment, subject to any reasonable delay due to unforeseen circumstances. Notwithstanding the foregoing, if the arbitrator fails to render a decision within 60 days after the appointment then either party may elect to have a new arbitrator appointed in like manner as if none had previously been appointed.

<u>7.05</u> The decision of the arbitrator will be final and binding upon the parties and the parties will abide by the decision and perform the terms and conditions thereof.

ARTICLE 8

<u>FRANCHISE FEES</u>

<u>8.01</u> Timberwest acknowledges that BC Gas is obligated to pay Franchise Fees to certain municipalities it serves. In the event that BC Gas is required by statute, agreement, regulation, an arbitrator, a court of competent jurisdiction, or the British Columbia Utilities Commission to pay Franchise Fees or like fees on revenues received from Timberwest, or in relation to services provided, in addition to those calculated and paid by BC Gas at the commencement of this Agreement, Timberwest will pay an amount equal to such additional fees to BC Gas and the rates and charges payable by Timberwest as set out in Article 4 will be adjusted to reflect this change.

ARTICLE 9

<u>TERMINATION</u>

<u>9.01</u> In addition to any other rights either party may have to terminate this Agreement:

(i) Notwithstanding Article 3.01, BC Gas may terminate this Agreement if at any time the British Columbia Utilities Commission disallows BC Gas the recovery from the other customers of BC Gas of any revenue shortfalls, resulting from the negotiated rates;

(ii) Notwithstanding Article 3.01, Timberwest may terminate this Agreement by giving BC Gas at least 1 year written notice of its intention to terminate and upon payment in full by Timberwest of the following amounts:

(a) if termination is effective on November 1, 1995, the payment will be $122,751;

(b) if termination is effective on November 1, 1996, and each November 1 following, the payment specified in Article 9.01 (ii)(a) will be reduced by $13,550 per year. No payment will be required under this Article for termination effective on November 1, 1999 or on any subsequent extension of this Agreement.

(iii) Notwithstanding Article 9.01(ii), Timberwest may terminate this Agreement at any time after January 1, 1995, without further payment under this Article, if Timberwest, on a permanent basis, closes its operations at or near the site of its current sawmill facilities.

9.02 Any termination pursuant to Article 9.01 will take effect on the next November 1 following the giving of notice in writing by the party terminating this Agreement.

ARTICLE 10

NOTICES

10.01 If in any year an executed Transportation Agreement is not in place, then the notice provisions of the latest executed Transportation Agreement and Rate Schedule will apply to this Agreement.

ARTICLE 11

MISCELLANEOUS

11.01 This Agreement will not be assigned without the written consent of the other party hereto, which consent will not be unreasonably withheld.

11.02 Notwithstanding Article 11.01, BC Gas may assign, without the consent of Timberwest, BC Gas' rights and obligations under this Agreement to a party which acquires all or substantially all of BC Gas' Gas utility operations.

11.03 Notwithstanding Article 11.01, Timberwest may assign, without the consent of BC Gas, Timberwest's rights and obligations under this Agreement to any party which acquires all or substantially all of Timberwest's sawmill operations served by BC Gas pursuant to this Agreement.

11.04 This Agreement will enure to the benefit of and be binding on the parties and their respective successors and permitted assigns including, without limitation successors by merger, amalgamation or consolidation.

11.05 This Agreement and all amendments, modifications, alterations or supplements hereto will be governed by the laws in force in the Province of British Columbia as to nature, validity and interpretation.

11.06 This Agreement is of no force or effect until accepted for filing by the British Columbia Utilities Commission. Upon acceptance for filing of this Agreement by the British Columbia Utilities Commission, the agreement made between the parties as of December, 1989 will be cancelled.

11.07 In this Agreement the words, phrases or expressions which are not defined herein and which in the usage custom of the business of the production, transportation, distribution or sale of Gas has an accepted meaning will have that meaning.

IN WITNESS WHEREOF the parties have executed this Agreement.

BC GAS UTILITY LTD.	TIMBERWEST FOREST LIMITED
By: ______________ (Signature)	By: ______________ (Signature)
R. DINTER (Name - please print)	HUGH JONES (Name - please print)
Date: January 31/95	Date: Jan 25/95

Sep-16-98 09:34A CPMI 604 682 6447

ACSIMILE MESS

P Fagan

Re: **BC Gas Bypass Transportation Agreement**
Effective January 1, 1990 to November 1, 1999
Riverside Forest Products Ltd.
Williams Lake Division & Soda Creek #1 Division

Please accept this facsimile message as notification to extend the terms and rates of the above noted Transportation Agreements as amended from time to time, in accordance with clause 3.02. We would request that the Transportation Agreements be extended for 1 years to November 1, 2000

We understand that you will be preparing the necessary documentation to affect this extension.

We thank you for your past services provided and look forward to a mutually satisfactory arrangement in future.

Peter Fagan
Riverside Forest Products Ltd.

cc: Harry Chivers
Coast Pacific Management Inc.

FACSIMILE MESSAGE

Riverside - Soda Creek R

To: Ken Fuhr
BC Gas Utility Ltd.

Date: October 20,1999

Fax No: 443-6770

Pages (including this one) 1

Re: BC Gas Bypass Transportation Agreement
Effective November 1, 1998 to November 1, 2000

Please accept this facsimile message as notification to extend the terms and rates of the above noted Transportation Agreement as amended from time to time, in accordance with your Bypass Agreement. We would request that the Transportation Agreement be extended for 2 years to November 1, 2002.

We understand that you will be preparing the necessary documentation to affect this extension.

We thank you for your past services provided and look forward to a mutually satisfactory arrangement in future.

cc: Harry Chivers
Avista Energy Canada, Ltd.

RIVERSIDE
FOREST PRODUCTS LIMITED

Soda Creek Division
RR#3, 5000 Soda Creek Road
Williams Lake, B.C. Canada V2G 1M3
Telephone (250) 398-3600
Fax (250) 398-3649

October 23, 2001

Ms. Melissa Philion
BC Gas Utility Ltd.
16705 Fraser Highway
Surrey, B.C. V3S 2X7
Fax No: (604) 592-7894

Dear Melissa:

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and BC Gas Utility Ltd. for a further two years for expiry November 1, 2004. The current agreement expires November 1, 2002.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Avista Energy Canada, Ltd.

Thank you.

Yours truly,

Ian Fillinger
Manager

cc:
Spence Brigden
Peter Fagan
Dennis Szalkai
Dan Johnson
Richard Crowell
Mary McCordic

RIVERSIDE
FOREST PRODUCTS LIMITED

Soda Creek Division
RR#3, 6000 Soda Creek Road
Williams Lake, B.C. Canada V2G 1M3
Telephone (250) 398-3600
Fax (250) 398-3690

October 14, 2003

Ms. Melissa Phillon
BC Gas Utility Ltd.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7
Fax No: 604-592-7894

Dear Melissa:

RE: Bypass Agreement Extension Request

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and Terasen Gas for a further year for expiry November 1, 2005. The current agreement expires November 1, 2004.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Avista Energy Canada, Ltd.

Thank you.

Yours truly,

Richard Crowell

Richard Crowell
Cariboo Region Operations Manager
Riverside Forest Products Ltd.

cc: Mary McCordic, Avista Energy Canada, Ltd. (fax no: 604-682-6447)

RIVERSIDE
Forest Products Limited

Cariboo Manufacturing
180 Hodgson Road
Williams Lake, BC Canada V2G 3P6
T 250.392.3371 Fax 250.398.3909
www.riverside.bc.ca

October 27, 2004

Mr. Gordon Doyle
Terasen Gas
16705 Fraser Highway
Surrey, BC V3S 2X7
Fax No.: 604.592.7894

Dear Gordon:

Re: Bypass Agreement Extension Request
Reference No. Tarif Supplement E3 – Williams Lake
Reference No. Tarif Supplement E~~9~~5 – Soda Creek

Please accept this letter as notice of our desire to extend the existing Bypass Agreements as noted above between our firm and Terasen Gas for a further year for expiry November 1, 2006. The current agreement expires November 1, 2005.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Avista Energy Canada, Ltd.

Thank you.

Yours truly,

RIVERSIDE FOREST PRODUCTS LIMITED

Rob Therrien
Regional Administration Manager

RT/wa

Mary McCordic, Avista Energy Canada, Ltd. (fax no: 604.682.6447)

RIVERSIDE
Forest Products Limited

180 Hodgson Road
Williams Lake, BC
Canada V2G 3P6
Main: (250) 392-3371
Fax: (250) 398-3909

October 6, 2005

Mr. Gordon Doyle
BC Gas Utility Ltd.
16705 Fraser Highway
Surrey BC V3S 2X7
Fax: 604-592-7894

Dear Gord,

Re: Bypass Agreement Extension Request

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and Terasen Gas for a further year for expiry November 1, 2007. The current agreement expires November 1, 2006.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Avista Energy Canada Ltd.

Thank you,

Yours truly,

RIVERSIDE FOREST PRODUCTS LTD.

Rob Therrien
Regional Controller

cc: Mary McCordic, Avista Energy Canada Ltd. (Fax: 604-682-6447)

TOLKO
INDUSTRIES LTD.

Phone: (250) 392-3371
Fax: (250) 398-3909

VIA FAX (604.592.7894)

October 18, 2006

Kevin Hodgins
BC Gas Utility Ltd.
16705 Fraser Highway
Surrey BC V3S 2X7

Dear Kevin,

Re: Bypass Agreement Extension Request – E5 Soda Creek Division

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and Terasen Gas for a further year for expiry November 1, 2008. The current agreement expires November 1, 2007.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Avista Energy Canada Ltd.

Thank you.

Yours truly,

TOLKO INDUSTRIES LTD.

Rob Therrien
Regional Controller

RT/wd

cc: Mary McCordic, Avista Energy Canada Ltd. (fax 604.682.6447)

180 Hodgson Road
Williams Lake, BC
Canada V2G 3P6
www.tolko.com

Marketing and manufacturing specialty forest products

TOLKO
INDUSTRIES LTD.

Phone: (250) 392-3371
Fax: (250) 398-3909

VIA FAX (604.592.7894)

August 10, 2007

Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey BC V3S 2X7

Dear Kevin,

Re: Bypass Agreement Extension Request – E5 Williams Lake Division

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and Terasen Gas for a further year for expiry November 1, 2009. The current agreement expires November 1, 2008.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Coral Energy Canada Inc.

Thank you.

Yours truly,

TOLKO INDUSTRIES LTD.

Jay Harvey
Regional Controller

JH/wd

cc: Mary McCordic, Coral Energy Canada Inc. (fax 604.682.6447)

180 Hodgson Road
Williams Lake, BC
Canada V2G 3P6

www.tolko.com

TOLKO INDUSTRIES LTD.

Phone: (250) 392-3371
Fax: (250) 398-3909

VIA FAX: 604-592-7894

August 26, 2008

Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC
V3S 2X7

Dear Kevin,

Re: Bypass Agreement Extension Request – E5 Soda Creek Division

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and Terasen Gas for a further year for expiry November 1, 2010. The current agreement expires November 1, 2009.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Shell Energy North America (Canada) Inc.

Thank you.

Yours truly,

TOLKO INDUSTRIES LTD.

Jay Harvey
Regional Controller

JH/jc

cc: Mary McCordic, Shell Energy North America (Canada) Inc. (fax: 604-682-6447)

180 Hodgson Road
Williams Lake, BC
Canada V2G 3P6
www.tolko.com

Marketing and manufacturing specialty forest products

TOLKO INDUSTRIES LTD.

Phone: (250) 392-3371
Fax: (250) 398-3909

VIA FAX: 604-592-7894

October 13, 2009

Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC
V3S 2X7

Dear Kevin,

Re: Bypass Agreement Extension Request -- E5 Soda Creek Division

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and Terasen Gas for a further year for expiry November 1, 2011. The current agreement expires November 1, 2010.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Shell Energy North America (Canada) Inc.

Thank you.

Yours truly,

TOLKO INDUSTRIES LTD.

Jay Harvey
Regional Controller

cc: Mary McCordic, Shell Energy North America (Canada) Inc.
(fax: 604-682-6447)

180 Hodgson Roac
Williams Lake, BC
Canada V2G 3P
www.tolko.con

Marketing and manufacturing specialty forest products

TOLKO
INDUSTRIES LTD.

Phone: (250) 392-3371
Fax: (250) 398-3909

VIA email to Kevin.Hodgins@terasengas.com

October 12, 2010

Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC
V3S 2X7

Dear Kevin,

Re: Bypass Agreement Extension Request – E5 Soda Creek Division

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and Terasen Gas for a further year for expiry November 1, 2012. The current agreement expires November 1, 2011.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Shell Energy North America (Canada) Inc.

Thank you.

Yours truly,

TOLKO INDUSTRIES LTD.

Jay Harvey
Regional Controller

cc: Mary McCordic, Shell Energy North America (Canada) Inc.
(fax: 604-682-6447)

180 Hodgson Road
Williams Lake, BC
Canada V2G 3P6
www.tolko.com

Marketing and manufacturing specialty forest products

TOLKO INDUSTRIES LTD.

Phone: (250) 392-3371
Fax: (250) 398-3909

VIA email to Kevin.Hodgins@fortisbc.com

October 31, 2011

Kevin Hodgins
FortisBC
16705 Fraser Highway
Surrey, BC
V3S 2X7

Dear Kevin,

Re: Bypass Agreement Extension Request – E5 Soda Creek Division

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and FortisBC for a further year for expiry November 1, 2013. The current agreement expires November 1, 2012.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Absolute Energy Inc.

Thank you.

Yours truly,

TOLKO INDUSTRIES LTD.

Jay Harvey
Regional Controller

cc: Peter Kresnyak, Absolute Energy Inc. (Fax: 604-982-0467, e-mail Peter@absolute-energy.ca)

180 Hodgson Road
Williams Lake, BC
Canada V2G 3P6
www.tolko.com

Marketing and manufacturing specialty forest products

TOLKO INDUSTRIES LTD.

Phone: (250) 392-3371
Fax: (250) 398-3909

VIA email to Kevin.Hodgins@fortisbc.com

October 31, 2012

Kevin Hodgins
FortisBC
16705 Fraser Highway
Surrey, BC
V3S 2X7

Dear Kevin,

Re: Bypass Agreement Extension Request – E5 Soda Creek Division

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and FortisBC for a further year for expiry November 1, 2014. The current agreement expires November 1, 2013.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Absolute Energy Inc.

Thank you.

Yours truly,

TOLKO INDUSTRIES LTD.

Jay Harvey
Regional Controller

cc: Peter Kresnyak, Absolute Energy Inc. (Fax: 604-982-0467, e-mail Peter@absolute-energy.ca)

180 Hodgson Road
Williams Lake, BC
Canada V2G 3P6

www.tolko.com

Marketing and manufacturing specialty forest products

TOLKO INDUSTRIES LTD.
CARIBOO REGIONAL ADMIN

Main: 250 392 3371 Fax: 250 398 3909
180 Hodgson Road
Williams Lake, BC V2G 3P6

VIA email to Rajoo.Jagtap@fortisbc.com

October 31, 2013

Rajoo Jagtap
FortisBC
16705 Fraser Highway
Surrey, BC
V4N 0E8

Dear Rajoo,

Re: Bypass Agreement Extension Request – E5 Soda Creek Division

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and FortisBC for a further year for expiry November 1, 2015. The current agreement expires November 1, 2014.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Absolute Energy Inc.

Thank you.

Yours truly,

TOLKO INDUSTRIES LTD.

Jay Harvey
Regional Controller

cc: Peter Kresnyak, Absolute Energy Inc. (Fax: 604-982-0467, e-mail Peter@absolute-energy.ca)

www.tolko.com

Canadian Sustainable Forest Management
PEFC

TOLKO INDUSTRIES LTD.
CARIBOO REGIONAL ADMIN

Main: 250 392 3371 Fax: 250 398 3909
180 Hodgson Road
Williams Lake, BC V2G 3P6

VIA email to Rajoo.Jagtap@fortisbc.com

October 31, 2014

Rajoo Jagtap
FortisBC
16705 Fraser Highway
Surrey, BC
V4N 0E8

Dear Rajoo,

Re: Bypass Agreement Extension Request – E5 Soda Creek Division

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and FortisBC for a further year for expiry November 1, 2016. The current agreement expires November 1, 2015.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Absolute Energy Inc.

Thank you.

Yours truly,

TOLKO INDUSTRIES LTD.

Jay Harvey
Regional Controller

cc: Peter Kresnyak, Absolute Energy Inc. (Fax: 604-982-0467, e-mail Peter@absolute-energy.ca)

www.tolko.com

Canadian Sustainable Forest Management PEFC

TOLKO INDUSTRIES LTD.

Main: (250) 545-4411
Fax: (250) 549-5353

September 8, 2015

Rajoo Jagtap
Key Account Manager
FortisBC
16705 Fraser Highway
Surrey, BC

RE: Extension of Bypass Transportation Agreements

Rajoo,

This letter will serve as notice that Tolko Industries Ltd. wishes to extend the two Amended and Restated Bypass Transportation Agreements below for one year. This will extend the expiration date of these agreements to November 1, 2017.

E-5 Soda Creek Division
E-6 Quesnel Division

If you have any questions regarding this notice, please do not hesitate to contact me.

Sincerely,

Mike Towers

Michael Towers
Manager, Energy Supply and Systems
Tolko Industries Ltd.

cc: Fred Dupas, Tolko

PO Box 39
3000 - 28th Street
Vernon, BC
Canada V1T 6M1
www.tolko.com

Marketing and manufacturing specialty forest products

TARIFF SUPPLEMENT NO. E-6

AMENDED AND RESTATED
BYPASS TRANSPORTATION AGREEMENT
RATE SCHEDULE 25

BETWEEN

TOLKO INDUSTRIES LIMITED

AND

FORTISBC ENERGY INC.
(Formerly Terasen Gas Inc. and BC Gas Utility Ltd.)

Effective November 1, 1993

THIS AGREEMENT made as of the 21st day of December 1994 with effect as and from November 1, 1993 is an amendment and restatement of an agreement made as of December, 1989 between the parties noted below.

BETWEEN:

BC GAS UTILITY LTD., a company incorporated under the laws of British Columbia having its registered office at 1111 West Georgia Street, Vancouver, British Columbia

(hereinafter called "BC Gas")

OF THE FIRST PART

AND:

TOLKO INDUSTRIES LIMITED, a company incorporated under the laws of British Columbia having its registered office at 17th Floor, 1075 West Georgia Street, Vancouver, British Columbia

(hereinafter called "Tolko")

OF THE SECOND PART

WHEREAS:

A. Tolko operates dry kiln facilities in Quesnel, British Columbia, and requires Gas for its Quest Wood Products Division dry kiln operations located at 2 Mile Flat;

B. BC Gas owns and operates a Gas transmission pipeline which is connected to the dry kiln operations of Tolko in Quesnel, British Columbia;

C. Tolko entered into an agreement with BC Gas' predecessor company, BC Gas Inc., dated December, 1989 effective January 1, 1990, which allows Tolko to receive transportation service from BC Gas at rates and on terms and conditions that are based on the principles of the British Columbia Utilities Commission decision of October 22, 1987 respecting a bypass pipeline application by Northwood Pulp and Timber Limited.

D. On April 15, 1993, BC Gas filed an application (the "Phase B Rate Design Application") with the British Columbia Utilities Commission for redesign of its Gas tariff Rate Schedules which, among other things, proposed the implementation of common Rate Schedules and General Terms and Conditions of service.

E. Following the completion of the hearing of the Phase B Rate Design Application, the British Columbia Utilities Commission issued its decision dated October 25, 1993, which, in part, approved the implementation of new Rate Schedules effective November 1, 1993 for industrial and general service.

F. As a result of the British Columbia Utilities Commission decision dated October 25, 1993, the parties desire to enter into this amended and restated Agreement to clarify their respective rights and obligations.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the premises, the covenants and agreements contained herein, the parties agree as follows:

ARTICLE 1

DEFINITIONS

1.01 Except where the context expressly states another meaning, the following words will have the following meaning:

"Bypass Pipeline" means those facilities which, but for this Agreement, would have been constructed by Tolko in order to allow Tolko to bypass the BC Gas transmission and distribution Gas System.

"DTQ" means Daily Transportation Quantity as defined in the Rate Schedule 25 Transportation Agreement or other transportation agreement related to a Rate Schedule for transportation under which Tolko may elect to receive service.

"Terms and Conditions of the Transportation Rate Schedule" means the terms of the applicable transportation Rate Schedule and Transportation Agreement thereunder, and the General Terms and Conditions of BC Gas, as approved by the British Columbia Utilities Commission by its decision of October 25, 1993 or any subsequent transportation Rate Schedule accepted for filing by the British Columbia Utilities Commission.

1.02 Except for those terms defined under Article 1.01, terms or expressions used in this Agreement will have the meanings described in the Terms and Conditions of the Transportation Rate Schedule.

ARTICLE 2

TRANSPORTATION SERVICE

2.01 BC Gas will provide firm transportation service to Tolko for its dry kiln operations in Quesnel, British Columbia and Tolko will accept such transportation service in accordance with the then prevailing provisions of BC Gas Rate Schedule 25 and the accompanying Transportation Agreement for the term of this Agreement and such provisions are incorporated herein by reference.

2.02 Notwithstanding the provisions of Article 2.01, where anything in the Terms and Conditions of the Transportation Rate Schedule conflicts or is inconsistent with the terms and conditions set out in this Agreement, this Agreement governs.

2.03 Tolko will be entitled to take service under a transportation or Sales Rate schedule other than Rate Schedule 25 subject to the terms and conditions of such Rate Schedule. In such case, Article 2.01 and 2.02 will apply in the same way to the elected Rate Schedule.

ARTICLE 3

TERM OF AGREEMENT

3.01 Subject to Article 9 the initial term of this Agreement will be for a period of 6 years, effective the 1st Day of November 1993 up to the 1st Day of November 1999.

3.02 The term of this Agreement shall be extended beyond the initial termination date or any subsequent extension thereof upon the terms and conditions of this Agreement, including the pricing provisions, upon Tolko providing written notice to BC Gas of its desire to extend the term of the Agreement for a further specified period, at least 12 months prior to the then current termination date and BC Gas agreeing to such extension of the term of this Agreement. BC Gas shall not unreasonably withhold agreement to such extension of the term of this Agreement. Notwithstanding the foregoing, any extension under this Agreement will be for a period of not less than 1 Contract Year.

ARTICLE 4

RATES AND CHARGES

4.01 Subject to the adjustments hereinafter provided for, Tolko will each month pay to BC Gas for services provided hereunder from November 1, 1993 to the expiry of this Agreement the following rates:

(i) A monthly charge of $3,998.04.

(ii) A Delivery Charge of $0.064/gigajoule.

(iii) Any charges pursuant to Articles 4.02, 4.03 and 4.04.

4.02 Upon changes in its DTQ pursuant to Article 5 or in the annual Gas quantity consumed under this Agreement in excess of 120 percent of those forecast in Schedule 1, the monthly charge will be adjusted by BC Gas to reflect any changes in costs which would have been incurred by Tolko as a result of the change in the DTQ or annual Gas quantity had Tolko constructed and operated the Bypass Pipeline.

4.03 The monthly charge and the Delivery Charge as specified under Article 4.01 will be adjusted effective November 1 of each Contract Year on the following basis to compensate BC Gas for changes in its costs:

(i) the operating, maintenance and property tax expenses included in the monthly charge as at November 1, 1993 are $668.04 per month and will be subject to the annual percentage change in the Consumer Price Index for the City of Vancouver for October, up to the Contract Year expiring November 1, 1994. Thereafter, the Consumer Price Index for the month of August will be used. The monthly charge will be adjusted by the calculated change in costs. The adjusted operating, maintenance and property tax expenses will form the basis for the following Contract Year adjustment.

(ii) any new or increased tax related to the operation of the Bypass Pipeline that would have been levied had it been constructed and operated by Tolko will be calculated on a monthly basis (the annual cost divided by 12) and added to the monthly charge.

4.04 Unauthorized Overrun Gas will be charged for and paid by Tolko in accordance with the rate set out in Rate Schedule 25.

ARTICLE 5

ADJUSTMENTS TO DTQ

5.01 The DTQ for the Contract Year commencing November 1, 1993 is agreed to be 630 gigajoules. Tolko will be responsible to ensure that its DTQ is adjusted on November 1 of each Contract Year during the term of this Agreement by requesting an amended DTQ upon not less than 2 months prior to the end of the Contract Year then in effect.

ARTICLE 6

FORCE MAJEURE

6.01 Notwithstanding any of the provisions contained herein or in any transportation Rate Schedule under which Tolko takes service, Tolko will not be entitled to any monthly charge credits from BC Gas as a result of Force Majeure.

ARTICLE 7

ARBITRATION

7.01 Any dispute between the parties arising from this Agreement will be resolved by a single arbitrator pursuant to the *Commercial Arbitration Act* of British Columbia or successor legislation, save as expressly provided herein.

7.02 Either party may commence arbitration proceedings by sending to the other party a demand for arbitration setting out the nature of the dispute.

7.03 The parties will have 10 days from receipt of the demand referred to in section 7.02 of this Agreement to agree upon the arbitrator, failing which either party may apply to the Supreme Court of British Columbia to select the arbitrator. The arbitrator must be sufficiently qualified by education and training to decide the particular questions in dispute. Unless otherwise agreed, the arbitrator may not be a past or present employee, officer or director of any of the parties or their respective successors or affiliates, any customer or supplier of Tolko or BC Gas.

7.04 The arbitrator will proceed immediately to hear and determine the matter in dispute and will render a written decision, signed the arbitrator, within 45 days after the appointment, subject to any reasonable delay due to unforeseen circumstances. Notwithstanding the foregoing, if the arbitrator fails to render a decision within 60 days after the appointment then either party may elect to have a new arbitrator appointed in like manner as if none had previously been appointed.

7.05 The decision of the arbitrator will be final and binding upon the parties and the parties will abide by the decision and perform the terms and conditions thereof.

ARTICLE 8

FRANCHISE FEES

8.01 Tolko acknowledges that BC Gas is obligated to pay Franchise Fees to certain municipalities it serves. In the event that BC Gas is required by statute, agreement regulation, an arbitrator, a court of competent jurisdiction, or the British Columbia Utilities Commission to pay Franchise Fees or like fees on revenues received from Tolko, or in relation to services provided, in addition to those calculated and paid by BC Gas at the commencement of this Agreement, Tolko will pay an amount equal to such additional fees to BC Gas and the rates and charges payable by Tolko as set out in Article 4 will be adjusted to reflect this change.

ARTICLE 9

TERMINATION

9.01 In addition to any other rights either party may have to terminate this Agreement:

(i) Notwithstanding Article 3.01, BC Gas may terminate this Agreement if at any time the British Columbia Utilities Commission disallows BC Gas the recovery from the other customers of BC Gas of any revenue shortfalls, resulting from the negotiated rates;

(ii) Notwithstanding Article 3.01, Tolko may terminate this Agreement by giving BC Gas at least 1 year written notice of its intention to terminate and upon payment in full by Tolko of the following amounts:

(a) if termination is effective on November 1, 1995, the payment will be $55,816;

(b) if termination is effective on November 1, 1996, and each November 1 following, the payment specified in 9.01 (ii)(a) will be reduced by $6,202 per year. No payment shall be required under this Article for termination effective on November 1, 1999 or on any subsequent extension of this Agreement;

(iii) Notwithstanding Article 9.01(ii), Tolko may terminate this Agreement at any time after January 1, 1995, without any payment under this Article, if Tolko, on a permanent basis, closes its operation at or near the site of its current dry kiln facilities.

9.02 Any termination pursuant to Article 19.01 will take effect on the next November 1 following the giving of notice in writing by the party terminating this Agreement.

ARTICLE 10

NOTICES

10.01 If in any year an executed Transportation Agreement is not in place, then the notice provisions of the latest executed Transportation Agreement and Rate Schedule will apply to this Agreement.

ARTICLE 11

MISCELLANEOUS

11.01 This Agreement will not be assigned without the written consent of the other party hereto, which consent will not be unreasonably withheld.

11.02 Notwithstanding Article 11.01, BC Gas may assign, without the consent of Tolko, BC Gas' rights and obligations under this Agreement to a party which acquires all or substantially all of BC Gas' Gas utility operations.

11.03 Notwithstanding Article 11.01, Tolko may assign, without the consent of BC Gas, Tolko's rights and obligations under this Agreement to any party which acquires all or substantially all of Tolko's dry kiln operations served by BC Gas pursuant to this Agreement.

11.04 This Agreement will enure to the benefit of and be binding on the parties and their respective successors and permitted assigns including, without limitation successors by merger, amalgamation or consolidation.

11.05 This Agreement and all amendments, modifications, alterations or supplements hereto will be governed by the laws in force in the Province of British Columbia as to nature, validity and interpretation.

11.06 This Agreement is of no force or effect until accepted for filing by the British Columbia Utilities Commission. Upon acceptance for filing of this Agreement by the British Columbia Utilities Commission, the agreement made between the parties as of December, 1989 will be cancelled.

11.07 In this Agreement the words, phrases or expressions which are not defined herein and which in the usage custom of the business of the production, transportation, distribution or sale of Gas has an accepted meaning will have that meaning.

IN WITNESS WHEREOF the parties have executed this Agreement.

BC GAS UTILITY LTD.	TOLKO INDUSTRIES LIMITED
By: ______ (Signature)	By: ______ (Signature)
HENRY DINTER (Name - please print)	FRED H STEHLE (Name - please print)
Date: JAN 30, 1995	Date: Jan 19, 1995

TOLKO INDUSTRIES LTD.

Phone (250) 545-4411
Confidential Fax (250) 545-4383

FACSIMILE MESSAGE

DATE: September 16, 1998

TO: Ken Fuhr
BC Gas Utility Ltd.

FAX NO.: 443-6770

PAGES (including this one) 1

Re: BC Gas Bypass Transportation Agreement
Effective January 1, 1990 to November 1, 1999
Tolko Industries Ltd. – Quest Wood Division

Please accept this facsimile message as notification to extend the terms and rates of the above noted Transportation Agreement as amended from time to time, in accordance with clause 3.02. We would request that the Transportation Agreement to be extended for one (1) year to November 1, 2000.

We understand that you will be preparing the necessary documentation to affect this extension.

We thank you for your past services provided and look forward to a mutually satisfactory arrangement in future.

Fred Stahle
Tolko Industries Ltd.

cc: Harry Chivers – Coast Pacific Management Inc.
Arne Hanson – Tolko Industries Ltd. - Quest Wood Division

P.O. Box 39
3203 - 30th Avenue
Vernon, B.C. Canada V1T 6M1

Marketing and manufacturing solid wood products

TOLKO
INDUSTRIES LTD.

Main Office (250) 545-441
Confidential Fax (250) 545-47

DATE: October 29, 1999

TO: Ken Fuhr – BC Gas Utility Ltd.

FAX NO.: 443-6770

PAGES: (including this one) 1

RE: BC Gas Bypass Transportation Agreement
Effective November 1, 1998 to November 1, 2000

Please accept this facsimile message as notification to extend the terms and rates of the above noted Transportation Agreement as amended from time to time, in accordance with your Bypass Agreement. We would request that the Transportation Agreement be extended for 2 years to November 1, 2001.

We understand that you will be preparing the necessary documentation to affect this extension.

We thank you for your past services provided and look forward to a mutually satisfactory arrangement in future.

Yours truly,

TOLKO INDUSTRIES LTD.

Mr. Fred H. Stehle
Secretary / Treasurer

FHS/sh

c.c.: Harry Chivers
Avista Energy Canada, Ltd.

P.O. Box 39
3203 - 30th Avenue
Vernon, B.C. Canada V1T 6M1

Marketing and manufacturing solid wood products

TOLKO INDUSTRIES LTD.

Phone (250) 545-4411
Confidential Fax (250) 545-4783

August 15, 2000

B.C. Gas Utility Ltd.
Industrial Sales Representative
9th Floor – 1111 West Georgia
Vancouver, B.C.
V6E 4M3

Attention: Mr. Greg Simmons

Re: Extension of Bypass Agreement for Tolko – Quest Division

Dear Mr. Simmons,

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and B.C. Gas Utility Ltd. for a further 2 (two) years for expiry November 1, 2003. The current agreement expires November 1, 2001.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, as well as by a copy sent to our agent, Avista Energy Canada, Ltd. We look forward to your early response.

Yours very truly,

TOLKO INDUSTRIES LTD.
Per:

Fred H. Stehle
Secretary / Treasurer
FHS/tv

cc: Avista Energy Canada Ltd.
1006 – 1166 Alberni Street
Vancouver, B.C.
V6E 3Z3

P.O. Box 39
3203 - 30th Avenue
Vernon, B.C. Canada V1T 6M1

Marketing and manufacturing specialty forest products

TOLKO
INDUSTRIES LTD.

Phone: (250) 545-4411
Confidential Fax: (250) 545-4783

September 26, 2002

Via Courier

B.C. Gas Utility Ltd.
Industrial Sales Representative
9th Floor - 1111 West Georgia
Vancouver, B.C.
V6E 4M3

Attention: Mr. Greg Simmons

Dear Mr. Simmons:

Re: Extension of Bypass Agreement for Tolko - Quest Division

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and B.C. Gas Utility Ltd. for a further 2 (two) years for expiry November 1, 2005. The current agreement expires November 1, 2003.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, as well as by a copy sent to our agent, Avista Energy Canada Ltd. We look forward to your response in due course.

Yours very truly,

TOLKO INDUSTRIES LTD.
Per:

Fred H. Stehle
Secretary / Treasurer
FHS/bm

cc: Avista Energy Canada Ltd.
1006 - 1166 Alberni Street
Vancouver, B.C.
V6E 3Z3

PO Box 39
3203 - 30th Avenue
Vernon, BC Canada V1T 6M1

Marketing and manufacturing specialty forest products

TOLKO
INDUSTRIES LTD.
QUEST WOOD DIVISION

Telephone: (250) 992-1700
Fax: (250) 992-1701

October 5, 2004

Mr. Gordon Doyle
BC Gas Utility Ltd.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7
Fax No: 604-592-7894

Dear Gordon:

RE: Bypass Agreement Extension Request

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and Terasen Gas for a further year for expiry November 1, 2006. The current agreement expires November 1, 2005.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Avista Energy Canada, Ltd.

Thank you.

Yours truly,

MBrowne

Marina Browne, C.G.A.
Divisional Controller

cc: Mary McCordic, Avista Energy Canada, Ltd. (fax no: 604-682-6447)

1879 Brownmiller Road
Quesnel, BC
Canada V2J 6R9

TOLKO
INDUSTRIES LTD.
QUEST WOOD DIVISION

Main: (250) 992-1700
Fax: (250) 992-1701

September 16, 2005

Mr. Gordon Doyle
Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7
Fax No. 604-592-7894

Dear Gord:

Re: Bypass Agreement Extension Request

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and Terasen Gas for a further year for expiry November 1, 2007. The current agreement expires November 1, 2006.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Avista Energy Canada, Ltd.

Thank you,

Yours truly,

Marina Browne, C.G.A.
Divisional Controller

Cc Mary McCordic, Avista Energy Canada, Ltd.
(Fax # 604-682-6447)

1879 Brownmiller Road
Quesnel, BC
Canada V2J 6R9
www.tolko.com

TOLKO
INDUSTRIES LTD.

QUEST WOOD DIVISION

Main: (250) 991-1300
Fax: (250) 991-1301

October 18, 2006

Mr. Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7
Fax No: 604-592-7894

Dear Kevin:

RE: Bypass Agreement Extension Request

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and Terasen Gas for a further year for expiry November 1, 2008. The current agreement expires November 1, 2007.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Avista Energy Canada, Ltd.

Thank you.

Yours truly,

cc: Mary McCordic, Avista Energy Canada, Ltd. (fax no: 604-682-6447)

1879 Brownmiller Road
Quesnel, BC
Canada V2J 6R9
www.tolko.com

Marketing and manufacturing specialty forest products

TOLKO INDUSTRIES LTD.
QUEST WOOD DIVISION

Phone: (250) 992-1700
Fax: (250) 992-1701

October 9, 2007

Terasen Gas
16705 Fraser Highway
Surrey, BC

Attention Kevin Hodgins

RE: **Bypass Transportation Agreement Renewal**

Further to our discussion this morning, please accept this confirmation of Tolko Industries Ltd., Quest Wood Division's extension of our Bypass Agreement with Terasen Gas.

Sincerely,

Rob Beard

Rob Beard, CGA
Divisional Controller
Quest Wood Division
Tolko Industries Ltd.

1879 Brownmiller Road
Quesnel, BC
Canada V2J 6R9
www.tolko.com

Marketing and manufacturing specialty forest products

TOLKO
INDUSTRIES LTD.
QUEST WOOD DIVISION

Phone: (250) 992-1700
Fax: (250) 992-1701

October 15, 2008

Terasen Gas
16705 Fraser Highway
Surrey, BC V3S 2X7

Attention Kevin Hodgins

RE: Bypass Transportation Agreement Renewal

Further to our discussion this morning, please accept this confirmation of Tolko Industries Ltd., Quest Wood Division's extension of our Bypass Agreement with Terasen Gas.

Sincerely,

Hank Randrup

Hank Randrup
Plant Manager
Quest Wood Division
Tolko Industries Ltd.

cc: File. Terasen Gas

1879 Brownmiller Road
Quesnel, BC
Canada V2J 6R9
www.tolko.com

Marketing and manufacturing specialty forest products

TOLKO
INDUSTRIES LTD.
QUEST WOOD DIVISION

Telephone: (250) 992-1700
Fax: (250) 992-1701

October 31, 2009

Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC
V3S 2X7

Attn: Kevin Hodgins

Dear Sirs:

Re: Amended and Restated Bypass Transportation Agreement between Tolko Industries Limited and Terasen Gas Inc for Rate Schedule 25 (E-6 Quesnel)

Please accept this letter as notice of our desire to extend the bypass agreement between our firm and Terasen Gas for a further year for expiry November 1, 2011. The current agreement expires November 1, 2010.

Yours Truly,

Hank Randrup

Hank Randrup
Plant Manager,
Tolko Industries Ltd.
Quest Wood Division

1879 Brownmiller Road
Quesnel, BC
Canada V2J 6R9

Marketing and manufacturing specialty forest products

TOLKO
INDUSTRIES LTD.

Phone: (250) 392-3371
Fax: (250) 398-3909

VIA email to Kevin.Hodgins@terasengas.com

October 12, 2010

Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey, BC
V3S 2X7

Dear Kevin,

Re: Bypass Agreement Extension Request – E6 Quesnel Division

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and Terasen Gas for a further year for expiry November 1, 2012. The current agreement expires November 1, 2011.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Shell Energy North America (Canada) Inc.

Thank you.

Yours truly,

TOLKO INDUSTRIES LTD.

Jay Harvey
Regional Controller

cc: Mary McCordic, Shell Energy North America (Canada) Inc.
(fax: 604-682-6447)

180 Hodgson Road
Williams Lake, BC
Canada V2G 3P6

www.tolko.com

Marketing and manufacturing specialty forest products

TOLKO INDUSTRIES LTD.

Phone: (250) 392-3371
Fax: (250) 398-3909

VIA email to Kevin.Hodgins@fortisbc.com

October 31, 2011

Kevin Hodgins
FortisBC
16705 Fraser Highway
Surrey, BC
V3S 2X7

Dear Kevin,

Re: Bypass Agreement Extension Request – E6 Quesnel Division

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and FortisBC for a further year for expiry November 1, 2013. The current agreement expires November 1, 2012.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Absolute Energy Inc.

Thank you.

Yours truly,

TOLKO INDUSTRIES LTD.

Jay Harvey
Regional Controller

cc: Peter Kresnyak, Absolute Energy Inc. (Fax: 604-982-0467, e-mail Peter@absolute-energy.ca)

180 Hodgson Road
Williams Lake, BC
Canada V2G 3P6

www.tolko.com

Marketing and manufacturing specialty forest products

TOLKO INDUSTRIES LTD.

Phone: (250) 392-3371
Fax: (250) 398-3909

VIA email to Kevin.Hodgins@fortisbc.com

October 31, 2012

Kevin Hodgins
FortisBC
16705 Fraser Highway
Surrey, BC
V3S 2X7

Dear Kevin,

Re: Bypass Agreement Extension Request – E6 Quesnel Division

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and FortisBC for a further year for expiry November 1, 2014. The current agreement expires November 1, 2013.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Absolute Energy Inc.

Thank you.

Yours truly,

TOLKO INDUSTRIES LTD.

Jay Harvey
Regional Controller

cc: Peter Kresnyak, Absolute Energy Inc. (Fax: 604-982-0467, e-mail Peter@absolute-energy.ca)

180 Hodgson Road
Williams Lake, BC
Canada V2G 3P6

www.tolko.com

Marketing and manufacturing specialty forest products

TOLKO INDUSTRIES LTD.
CARIBOO REGIONAL ADMIN

Main: 250 392 3371 Fax: 250 398 3909
180 Hodgson Road
Williams Lake, BC V2G 3P6

VIA email to Rajoo.Jagtap@fortisbc.com

October 31, 2013

Rajoo Jagtap
FortisBC
16705 Fraser Highway
Surrey, BC
V4N 0E8

Dear Rajoo,

Re: Bypass Agreement Extension Request – E6 Quesnel Division

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and FortisBC for a further year for expiry November 1, 2015. The current agreement expires November 1, 2014.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Absolute Energy Inc.

Thank you.

Yours truly,

TOLKO INDUSTRIES LTD.

Jay Harvey
Regional Controller

cc: Peter Kresnyak, Absolute Energy Inc. (Fax: 604-982-0467, e-mail Peter@absolute-energy.ca)

www.tolko.com

Canadian Sustainable Forest Management PEFC

TOLKO INDUSTRIES LTD.
CARIBOO REGIONAL ADMIN

Main: 250 392 3371 Fax: 250 398 3909
180 Hodgson Road
Williams Lake, BC V2G 3P6

VIA email to Rajoo.Jagtap@fortisbc.com

October 31, 2014

Rajoo Jagtap
FortisBC
16705 Fraser Highway
Surrey, BC
V4N 0E8

Dear Rajoo,

Re: Bypass Agreement Extension Request – E6 Quesnel Division

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and FortisBC for a further year for expiry November 1, 2016. The current agreement expires November 1, 2015.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Absolute Energy Inc.

Thank you.

Yours truly,

TOLKO INDUSTRIES LTD.

Jay Harvey
Regional Controller

cc: Peter Kresnyak, Absolute Energy Inc. (Fax: 604-982-0467, e-mail Peter@absolute-energy.ca)

TOLKO INDUSTRIES LTD.

Main: (250) 545-4411
Fax: (250) 549-5353

September 8, 2015

Rajoo Jagtap
Key Account Manager
FortisBC
16705 Fraser Highway
Surrey, BC

RE: Extension of Bypass Transportation Agreements

Rajoo,

This letter will serve as notice that Tolko Industries Ltd. wishes to extend the two Amended and Restated Bypass Transportation Agreements below for one year. This will extend the expiration date of these agreements to November 1, 2017.

E-5 Soda Creek Division
E-6 Quesnel Division

If you have any questions regarding this notice, please do not hesitate to contact me.

Sincerely,

Michael Towers
Manager, Energy Supply and Systems
Tolko Industries Ltd.

cc: Fred Dupas, Tolko

PO Box 39
3000 - 28th Street
Vernon, BC
Canada V1T 6M1
www.tolko.com

Marketing and manufacturing specialty forest products

TARIFF SUPPLEMENT NO. E-8

AMENDED AND RESTATED
BYPASS TRANSPORTATION AGREEMENT
RATE SCHEDULE 25

BETWEEN

WEST FRASER MILLS LIMITED

AND

FORTISBC ENERGY INC.
(Formerly Terasen Gas Inc. and BC Gas Utility Ltd.)

Effective November 1, 1993

THIS AGREEMENT made as of the 21st day of December 1994 with effect as and from November 1, 1993 is an amendment and restatement of an agreement made as of December, 1989 between the parties noted below.

BETWEEN:

BC GAS UTILITY LTD., a company incorporated under the laws of British Columbia having its registered office at 1111 West Georgia Street, Vancouver, British Columbia

(hereinafter called "BC Gas")

OF THE FIRST PART

AND:

WEST FRASER MILLS LIMITED, a company incorporated under the laws of British Columbia having its registered office at P.O. Box 4360, Williams Lake, British Columbia

(hereinafter called "West Fraser")

OF THE SECOND PART

WHEREAS:

A. West Fraser operates sawmill facilities in Williams Lake, British Columbia, and requires Gas for its sawmill operations located at McKenzie Avenue and Rottacker Road;

B. BC Gas owns and operates a Gas transmission pipeline which is connected to the sawmill operations of West Fraser in Williams Lake, British Columbia;

C. West Fraser entered into an agreement with BC Gas' predecessor company, BC Gas Inc., dated December, 1989 effective January 1, 1990, which allows West Fraser to receive transportation service from BC Gas at rates and on terms and conditions that are based on the principles of the British Columbia Utilities Commission decision of October 22, 1987 respecting a bypass pipeline application by Northwood Pulp and Timber Limited.

D. On April 15, 1993, BC Gas filed an application (the "Phase B Rate Design Application") with the British Columbia Utilities Commission for redesign of its Gas tariff Rate Schedules which, among other things, proposed the implementation of common Rate Schedules and General Terms and Conditions of service.

E. Following the completion of the hearing of the Phase B Rate Design Application, the British Columbia Utilities Commission issued its decision dated October 25, 1993, which, in part, approved the implementation of new Rate Schedules effective November 1, 1993 for industrial and general service.

F. As a result of the British Columbia Utilities Commission decision dated October 25, 1993, the parties desire to enter into this amended and restated Agreement to clarify their respective rights and obligations.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the premises, the covenants and agreements contained herein, the parties agree as follows:

ARTICLE 1

DEFINITIONS

1.01 Except where the context expressly states another meaning, the following words will have the following meaning:

"Bypass Pipeline" means those facilities which, but for this Agreement, would have been constructed by West Fraser in order to allow West Fraser to bypass the BC Gas transmission and distribution Gas System.

"DTQ" means Daily Transportation Quantity as defined in the Rate Schedule 25 Transportation Agreement or other transportation agreement related to a Rate Schedule for transportation under which West Fraser may elect to receive service.

"Terms and Conditions of the Transportation Rate Schedule" means the terms of the applicable transportation Rate Schedule and Transportation Agreement thereunder, and the General Terms and Conditions of BC Gas, as approved by the British Columbia Utilities Commission by its decision of October 25, 1993 or any subsequent transportation Rate Schedule accepted for filing by the British Columbia Utilities Commission.

1.02 Except for those terms defined under Article 1.01, terms or expressions used in this Agreement will have the meanings described in the Terms and Conditions of the Transportation Rate Schedule.

ARTICLE 2

TRANSPORTATION SERVICE

2.01 BC Gas will provide firm transportation service to West Fraser for its sawmill operations in Williams Lake, British Columbia and West Fraser will accept such transportation service in accordance with the then prevailing provisions of BC Gas Rate Schedule 25 and the accompanying Transportation Agreement for the term of this Agreement and such provisions are incorporated herein by reference.

2.02 Notwithstanding the provisions of Article 2.01, where anything in the Terms and Conditions of the Transportation Rate Schedule conflicts or is inconsistent with the terms and conditions set out in this Agreement, this Agreement governs.

2.03 West Fraser will be entitled to take service under a Transportation or Sales Rate Schedule other than Rate Schedule 25 subject to the terms and conditions of such Rate Schedule. In such case, Article 2.01 and 2.02 will apply in the same way to the elected Rate Schedule.

ARTICLE 3

TERM OF AGREEMENT

3.01 Subject to Article 9 the initial term of this Agreement will be for a period of 6 years effective the 1st Day of November 1993 up to the 1st Day of November 1999.

3.02 The term of this Agreement, shall be extended beyond the initial termination date or any subsequent extension thereof upon the terms and conditions of this Agreement, including the pricing provisions upon West Fraser providing written notice to BC Gas of its desire to extend the term of the Agreement for a further specified period, at least 12 months prior to the then current termination date. BC Gas shall not unreasonably withhold agreement to such extension of the term of this Agreement. Notwithstanding the foregoing, any extension will be for a period of not less than 1 Contract Year.

ARTICLE 4

RATES AND CHARGES

4.01 Subject to the adjustments hereinafter provided for, West Fraser will each month pay to BC Gas for services provided hereunder from November 1, 1993 to the expiry of this Agreement the following rates:

(i) A monthly charge of $5,843.85.

(ii) A Delivery Charge of $0.069/gigajoule.

(iii) Any charges pursuant to Articles 4.02, 4.03 and 4.04.

4.02 Upon changes in its DTQ pursuant to Article 5 or in the annual Gas quantity consumed under this Agreement in excess of 120 percent of those forecast in Schedule 1, the monthly charge will be adjusted by BC Gas to reflect any changes in costs which would have been incurred by West Fraser as a result of the change in the DTQ or annual Gas quantity had West Fraser constructed and operated the Bypass Pipeline.

4.03 The monthly charge and the Delivery Charge as specified under Article 4.01 will be adjusted effective November 1 of each Contract Year on the following basis to compensate BC Gas for changes in its costs:

(i) the operating, maintenance and property tax expenses included in the monthly charge as at November 1, 1993 are $843.85 per month and will be subject to the annual percentage change in the Consumer Price Index for the City of Vancouver for October, up to the Contract Year expiring November 1, 1994. Thereafter, the Consumer Price Index for the month of August will be used. The monthly charge will be adjusted by the calculated change in costs. The adjusted base operating, maintenance and property tax expenses will form the basis for the following Contract Year adjustment.

(ii) any new or increased tax related to the operation of the Bypass Pipeline that would have been levied had it been constructed and operated by West Fraser will be calculated on a monthly basis (the annual cost divided by 12) and added to the monthly charge.

4.04 Unauthorized Overrun Gas will be charged for and paid by West Fraser in accordance with the rate set out in Rate Schedule 25.

ARTICLE 5

ADJUSTMENTS TO DTQ

5.01 The DTQ for the Contract Year commencing November 1, 1993 is agreed to be 481 gigajoules. West Fraser will be responsible to ensure that its DTQ is adjusted on November 1 of each Contract Year during the term of this Agreement by requesting an amended DTQ upon not less than 2 months prior to the end of the Contract Year then in effect.

ARTICLE 6

FORCE MAJEURE

6.01 Notwithstanding any of the provisions contained herein or in any Ttransportation Rate Schedule under which West Fraser takes service, West Fraser will not be entitled to any monthly charge credits from BC Gas as a result of Force Majeure.

ARTICLE 7

ARBITRATION

7.01 Any dispute between the parties arising from this Agreement will be resolved by a single arbitrator pursuant to the *Commercial Arbitration Act* of British Columbia or successor legislation, save as expressly provided herein.

7.02 Either party may commence arbitration proceedings by sending to the other party a demand for arbitration setting out the nature of the dispute.

7.03 The parties will have 10 days from receipt of the demand referred to in section 7.02 of this Agreement to agree upon the arbitrator, failing which either party may apply to the Supreme Court of British Columbia to select the arbitrator. The arbitrator must be sufficiently qualified by education and training to decide the particular questions in dispute. Unless otherwise agreed, the arbitrator may not be a past or present employee, officer or director of any of the parties or their respective successors or affiliates, any customer or supplier of West Fraser or BC Gas.

7.04 The arbitrator will proceed immediately to hear and determine the matter in dispute and will render a written decision, signed the arbitrator, within 45 days after the appointment, subject to any reasonable delay due to unforeseen circumstances. Notwithstanding the foregoing, if the arbitrator fails to render a decision within 60 days after the appointment then either party may elect to have a new arbitrator appointed in like manner as if none had previously been appointed.

7.05 The decision of the arbitrator will be final and binding upon the parties and the parties will abide by the decision and perform the terms and conditions thereof.

ARTICLE 8

FRANCHISE FEES

8.01 West Fraser acknowledges that BC Gas is obligated to pay Franchise Fees to certain municipalities it serves. In the event that BC Gas is required by statute, agreement, regulation, an arbitrator, a court of competent jurisdiction, or the British Columbia Utilities Commission to pay Franchise Fees or like fees on revenues received from West Fraser, or in relation to services provided, in addition to those calculated and paid by BC Gas at the commencement of this Agreement, West Fraser will pay an amount equal to such additional fees to BC Gas and the rates and charges payable by West Fraser as set out in Article 4 will be adjusted to reflect this change.

ARTICLE 9

TERMINATION

9.01 In addition to any other rights either party may have to terminate this Agreement:

(i) Notwithstanding Article 3.01, BC Gas may terminate this Agreement if at any time the British Columbia Utilities Commission disallows BC Gas the recovery from the other customers of BC Gas of any revenue shortfalls, resulting from the negotiated rates;

(ii) Notwithstanding Article 3.01, West Fraser may terminate this Agreement by giving BC Gas at least 1 year written notice of its intention to terminate and upon payment in full by West Fraser of the following amounts:

(a) if termination is effective on November 1, 1995, the payment will be $83,716;

(b) if termination is effective on November 1, 1996, and each November 1 following, the payment specified in 9.01 (ii)(a) will be reduced by $9,302 per year. No payment shall be required under this Article for termination effective on November 1, 1999 or on any subsequent extension of this Agreement;

(iii) Notwithstanding Article 9.01(ii), West Fraser may terminate this Agreement at any time after January 1, 1995, without any payment under this Article, if West Fraser, on a permanent basis, closes its operations at or near the site of its current sawmill facilities.

9.02 Any termination pursuant to Article 9.01 will take effect on the next November 1 following the giving of notice in writing by the party terminating this Agreement.

ARTICLE 10

NOTICES

10.01 If in any year an executed Transportation Agreement is not in place, then the notice provisions of the latest executed Transportation Agreement and Rate Schedule will apply to this Agreement.

ARTICLE 11

MISCELLANEOUS

11.01 This Agreement will not be assigned without the written consent of the other party hereto, which consent will not be unreasonably withheld.

11.02 Notwithstanding Article 11.01, BC Gas may assign, without the consent of West Fraser, BC Gas' rights and obligations under this Agreement to a party which acquires all or substantially all of BC Gas' Gas utility operations.

11.03 Notwithstanding Article 11.01, West Fraser may assign, without the consent of BC Gas, West Fraser's rights and obligations under this Agreement to any party which acquires all or substantially all of West Fraser's sawmill operations served by BC Gas pursuant to this Agreement.

11.04 This Agreement will enure to the benefit of and be binding on the parties and their respective successors and permitted assigns including, without limitation successors by merger, amalgamation or consolidation.

11.05 This Agreement and all amendments, modifications, alterations or supplements hereto will be governed by the laws in force in the Province of British Columbia as to nature, validity and interpretation.

11.06 This Agreement is of no force or effect until accepted for filing by the British Columbia Utilities Commission. Upon acceptance for filing of this Agreement by the British Columbia Utilities Commission, the agreement made between the parties as of December, 1989 will be cancelled.

11.07 In this Agreement the words, phrases or expressions which are not defined herein and which in the usage custom of the business of the production, transportation, distribution or sale of Gas has an accepted meaning will have that meaning.

IN WITNESS WHEREOF the parties have executed this Agreement.

BC GAS UTILITY LTD.	WEST FRASER MILLS LIMITED
By: ______ (Signature)	By: ______ (Signature)
HENRY L. DINTER (Name - please print)	Grant Johnson (Name - please print)
Date: JANUARY 31, 1995	Date: Jan 24/95

West Fraser Mills Ltd
WILLIAMS LAKE DIVISION

P.O. Box 4360
Williams Lake, B.C.
Canada V2G 2V4

Phone: (250) 392-7784
FAX: (250) 392-7646

October 7, 1998

Mr. Ken Fuhr
BC Gas Utility Ltd.
1111 West Georgia Street
Vancouver, BC
V6E 4M4

Dear Mr. Fuhr:

**RE: BC GAS BYPASS TRANSPORTATION AGREEMENT
EFFECTIVE JANUARY 1, 1990 TO NOVEMBER 1, 1999 - REVISED**

Please accept this facsimile message as notification to extend the terms and rates of the above noted Transportation Agreement as amended from time to time, in accordance with clause 3.02. we would request that the Transportation Agreement be extended for 2 years to November 1, 2001.

We understand that you will be preparing the necessary documentation to affect this extension.

We thank you for your past service provided and look forward to a mutually satisfactory arrangement in future.

Sincerely,

Brad Hunt
West Fraser Mills Ltd.
Williams Lake Division

cc: Harry Chivers
Coast Pacific Management

West Fraser Mills Ltd

1250 Brownmiller Road
Quesnel, BC
Canada V2J 6P5

Telephone: (250) 992-9244
Fax: (250) 992-9233

August 25, 2000

Mr. Greg Simmons
BC Gas Utility Ltd.
1111 West Georgia St.
Vancouver, BC
V6E 4M4

Cc: Bill Legrow, West Fraser, Vancouver
Brad Hunt, West Fraser, Williams Lake

Re: BC Gas By-Pass Transportation Agreement; Williams Lake Division

Dear Sir,

The attached By-Pass Agreement, effective January 1, 1990 to November 1, 1999, was revised and extended to November 1, 2001.

In accordance with clause 3.02 we request that this agreement be extended for a period of two years, to November 1, 2003.

Sincerely,

David Humber
Manager, Technical Development
West Fraser Mills Ltd.

West Fraser Timber Co. Ltd

1000 – 1100 Melville Street
Vancouver, B.C.
Canada V6E 4A6
Telephone: (604) 895-2700
Fax: (604) 681-6061

September 25, 2002

BC Gas Utility Ltd.
16705 Fraser Highway
Surrey, BC
V3S 2X7

Attention: Melissa Philion
Account Manager
Fax: 604-592-7894

Dear Melissa:

Please extend the existing by pass agreement between BC Gas Utility Ltd. and West Fraser Mills, Williams Lake Division for a period of 2 years.

Yours truly,

David Humber
Manager, Technical Development

West Fraser Mills Ltd

1250 Brownmiller Road
Quesnel, B.C.
Canada
V2J 6P5

Phone: (250) 992-9244
Fax: (250) 992-8233

August 13, 2004

Terasen Gas Corporate Office
16705 Fraser Highway
Surrey, BC
V3S 2X7

Attention: Gord Doyle
Account Manager
Fax: (604) 592-7894

Re: Terasen Gas By-Pass Transportation Agreement – Williams Lake Division
Effective January 1, 1990 to November 1, 1990 - Revised

Dear Sir,

In accordance with clause 3.02, we request that the above noted agreement be extended for a period of two years to November 1, 2007.

Sincerely,

K Young

Kreshka Young
Energy Manager
West Fraser Mills Ltd.

West Fraser Mills Ltd

October 30, 2006

Terasen Gas Corporate Office
16705 Fraser Highway, Surrey
V3S 2X7

Attention: Kevin Hodgins
Key Account Manager

RE: Bypass Transportation Agreement – Williams Lake division.

Dear Kevin:

As per clause 3.02 of the above stated agreement, West Fraser Mills Ltd would like to request that the Bypass agreement be extended for a further period of **2 years** to November 1st 2009.

Sincerely,

Andrew K. Kim

Project Engineer
West Fraser Mills LTD.

1250 Brownmiller Road • Quesnel • B.C. • Canada • V2J 6P5 • (250) 992-9809 • (250) 992-9907 • http://www.westfrasertimber.ca

West Fraser Mills Ltd

September 22, 2008

Terasen Gas Corporate Office
16705 Fraser Highway, Surrey
V3S 2X7

Attention: Kevin Hodgins
Key Account Manager

RE: Bypass Transportation Agreement – Williams Lake division.

Dear Kevin:

As per clause 3.02 of the above stated agreement, West Fraser Mills Ltd would like to request that the Bypass agreement be extended for a further period of **3 years** to November 1st 2012.

Sincerely,

Andrew K. Kim

Project Engineer
West Fraser Mills LTD.

1250 Brownmiller Road • Quesnel • B.C. • Canada • V2J 6P5 • (250) 992-0609 • (250) 992-0807 • http://www.westfrasertimber.ca

West Fraser Mills Ltd

October 26, 2011

Terasen Gas Corporate Office
16705 Fraser Highway, Surrey
V3S 2X7

Attention: Kevin Hodgins
Key Account Manager

RE: Bypass Transportation Agreement – Williams Lake division.

Dear Kevin:

As per clause 3.02 of the above stated agreement, West Fraser Mills Ltd would like to request that the Bypass agreement be extended for a further period of **2 years** to November 1st 2014.

Sincerely,

Veikko Paivinen

Financial Manager, Energy & Carbon
West Fraser Mills Ltd.

West Fraser Mills Ltd

1250 Brownmiller Road
Quesnel, B.C.
Canada
V2J 6P5

Phone: (250) 992-9244
Fax: (250) 992-9233

October 31, 2013

VIA Email,

Attention Rajoo Jagtap,

Key Account Manager,
Industrial Energy Solutions,
FortisBC

Dear Rajoo,

Re: E-8 West Fraser Mills Ltd. (Williams Lake)-
Amended and Restated Bypass Transportation Agreement Rate Schedule 25 - dated November 1, 1993

Please be advised that west Fraser Mills Ltd. wishes to extend the Bypass agreement for another year, to November 1, 2015.

Yours Truly,

Veikko Paivinen, CA
Financial Manager, Energy & Carbon

West Fraser Mills Ltd

1250 Brownmiller Road
Quesnel, B.C.
Canada
V2J 6P5

Phone: (250) 992-9244
Fax: (250) 992-9233

October 15, 2014

VIA Email,

Attention Rajoo Jagtap,

Key Account Manager,
Industrial Energy Solutions,
FortisBC

Dear Rajoo,

Re: E-8 West Fraser Mills Ltd. (Williams Lake)-
Amended and Restated Bypass Transportation Agreement Rate Schedule 25 - dated November 1, 1993

Please be advised that west Fraser Mills Ltd. wishes to extend the Bypass agreement for another 5 years, to November 1, 2020.

Yours Truly,

Veikko Paivinen, CA
Financial Manager, Energy & Carbon

TARIFF SUPPLEMENT NO. G-5

AMENDED AND RESTATED
BYPASS TRANSPORTATION AGREEMENT
FOR RATE SCHEDULE 22A

BETWEEN

CANADIAN FOREST PRODUCTS LTD.
Prince George Pulp and Paper Limited

AND

FORTISBC ENERGY INC.
(Formerly Terasen Gas Inc. and BC Gas Utility Ltd.)

Effective November 1, 1993

THIS AGREEMENT made as of the 28th day of February, 2001, with effect as and from November 1, 1993, is an amendment and restatements of an agreement made as of October 20, 1988 between the parties noted below.

BETWEEN:

BC GAS UTILITY LTD., a company incorporated under the laws of British Columbia having its registered office at 1111 West Georgia Street, Vancouver, British Columbia

(hereinafter called "BC Gas")

OF THE FIRST PART

AND:

CANADIAN FOREST PRODUCTS LTD. incorporated under the laws of British Columbia having its registered office at 1055 Dunsmuir Street, Vancouver, British Columbia

(hereinafter called "Canfor")

OF THE SECOND PART

WHEREAS:

A. Canfor operates pulp and paper mills in the City of Prince George, British Columbia, previously operated by Prince George Pulp and Paper Limited, which company has amalgamated with Canfor, and requires Gas for its operations; for the purposes of this Agreement, references to "Canfor" include all predecessor corporations including Prince George Pulp & Paper Limited;

B. BC Gas owns and operates a Gas transmission pipeline, which is connected to the pulp and paper mills' operations of Canfor in Prince George, British Columbia;

C. Canfor made an application to the Province of British Columbia for an Energy Project Certificate pursuant to British Columbia Order-In-Council No. 552 dated March 19, 1987, which, if granted, would have allowed Canfor to construct a Bypass Pipeline (hereunder defined) from the Westcoast Energy Inc. pipeline system mainline to Canfor's facilities at Prince George;

D. Canfor entered into an agreement with BC Gas' predecessor company, Inland Natural Gas Co. Ltd. ("Inland") dated October 30, 1987 which was superseded and replaced by an agreement between Canfor and Inland dated October 20, 1988 effective November 1, 1987 which allowed Canfor to receive transportation service from BC Gas at rates reasonably equivalent to the costs that would have been incurred by Canfor had it constructed the Bypass Pipeline hereinafter defined in 1987;

E. The British Columbia Utilities Commission has endorsed the concept of negotiated rates that are competitive with the Bypass Pipeline alternative;

F. On April 15, 1993, BC Gas filed an application (the "Phase B Rate Design Application") with the British Columbia Utilities Commission for redesign of its Gas tariff Rate Schedules which, among other things, proposed the implementation of common Rate Schedules and General Terms and Conditions of service;

G. Following the completion of the hearing of the Phase B Rate Design Application, the British Columbia Utilities Commission issued its decision dated October 25, 1993, which, in part, approved the implementation of new Rate Schedules effective November 1, 1993 for industrial and general service; and

H. As a result of the British Columbia Utilities Commission decision dated October 25, 1993, the parties desire to enter into this amended and restated Agreement to clarify their respective rights and obligations.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the premises, the covenants and agreements contained herein, the parties agree as follows:

ARTICLE 1

DEFINITIONS

1.01 Except where the context expressly states another meaning, the following words will have the following meaning:

"Bypass Pipeline" means those facilities which, but for this Agreement, would have been constructed by Canfor in order to provide Gas service to their pulp mill operations in Prince George, British Columbia.

"ITR" means the annual total revenue received by BC Gas from Canfor for Gas transportation service and sales service to Canfor's Prince George, British Columbia pulp and paper mills operations.

"DTQ" means the Firm DTQ and Interruptible DTQ as defined in the Rate Schedule 22A Transportation Agreement or other transportation agreement related to a Rate Schedule for transportation under which Canfor may elect to receive service.

"Terms and Conditions of the Transportation Schedule" means the terms of the applicable Transportation Rate Schedule, and the Transportation Agreements thereunder, and the General Terms and Conditions of BC Gas, as approved by the British Columbia Utilities Commission by its decision of October 25, 1993 or any subsequent transportation or Gas sales service Rate Schedules accepted for filing by the British Columbia Utilities Commission.

1.02 Except for those terms defined under Article 1.01, terms or expressions used in this Agreement will have the meanings described in the Terms and Conditions of the Transportation Schedule.

ARTICLE 2

TRANSPORTATION SERVICE

2.01 BC Gas will provide firm and interruptible transportation service to Canfor for its pulp and paper mills operations in Prince George, British Columbia and Canfor will accept such transportation services in accordance with the then prevailing provisions of BC Gas Rate Schedule 22A and the accompanying Transportation Agreement for the term of this Agreement and such provisions are incorporated herein by reference.

2.02 Notwithstanding the provisions of Article 2.01, where anything in the Terms and Conditions of the Transportation Schedule conflicts or is inconsistent with the rates, terms and conditions set out in this Agreement, this Agreement governs.

2.03 Canfor will be entitled to elect to take transportation service under a Transportation Rate Schedule other than Schedule 22A subject to the terms and conditions of such Rate Schedule. In such case, Article 2.01 and 2.02 will apply in the same way to the elected Rate Schedule.

2.04 If Canfor in any Contract Year elects to take transportation service pursuant to a Rate Schedule under which monthly Gas balancing provisions result in benefits to Canfor which would not have been available if the Bypass Pipeline had been constructed, the rates specified in Article 4, will be increased for that Contract Year by an amount equal to Canfor's savings resulting from the provision of BC Gas' monthly Gas balancing on the tolls that would have been incurred on the Westcoast pipeline system had Canfor constructed the Bypass Pipeline. The said amount will be determined by BC Gas and paid to BC Gas at the end of the Contract Year.

ARTICLE 3

TERM OF AGREEMENT

3.01 Subject to Article 8, the initial term of this Agreement will be for a period of four (4) Contract Years, effective the 1st Day of November, 1993, up to the 1st Day of November 1997.

3.02 The term of this Agreement will be extended beyond the initial termination date or any subsequent extension thereof upon the terms and conditions of this Agreement, including the pricing provisions, upon Canfor providing written notice to BC Gas of its desire to extend the term of the Agreement for a further specified period, at least 12 months prior to the then current termination date and BC Gas agreeing to such extension of the term of this Agreement. Notwithstanding the foregoing, any extension of the term of this Agreement will be for a period of not less than one year.

ARTICLE 4

RATES AND CHARGES

4.01 Subject to the adjustments hereinafter provided for and based on a DTQ of 220 10^3m^3, Canfor each month will pay to BC Gas for services provided hereunder, from November 1, 1993 to the expiry of the Agreement, the following rates:

(i) A monthly charge of $9,973.00

(ii) Any charges pursuant to Articles 4.02, 4.03 and 4.04

4.02 The rates will be adjusted by BC Gas to reflect any changes in costs which would have been incurred by Canfor if it had constructed and operated the Bypass Pipeline as a result of an increase in the volume of Gas actually transported for Canfor to the extent that such increase would have necessitated an increase in the capacity of the Bypass Pipeline or a modification or addition to the Bypass Pipeline facilities.

4.03 In addition to the foregoing rates, Canfor will pay to BC Gas at the end of each Contract Year an annual surcharge for increases, if any, in BC Gas costs. The surcharge will be determined as the sum of the following:

(i) cost changes to the estimated 1987 costs set out in Schedule 1 for operation and maintenance expenses that would have been incurred had Canfor constructed and operated the Bypass Pipeline; without limiting the generality of the foregoing, such costs include odorant costs, heating fuel costs, cathodic protection costs and labour costs; and

(ii) costs changes in municipal, provincial or federal taxes and fees, including new taxes or fees, but excluding taxes on taxable income, related to the operation of the Bypass Pipeline that would have been levied had it been constructed and operated by Canfor from the 1987 tax costs set out in line 10 of Schedule 1. For greater clarity, the parties agree that changes in costs of either debt or equity capital and taxes on taxable income are not to be included in the surcharge.

4.04 Any disputes arising hereunder as to the amount of the annual surcharge or the appropriateness of including costs under this Article will be referred to arbitration in accordance with Article 6 of this Agreement.

ARTICLE 5

FORCE MAJEURE

5.01 Notwithstanding any of the provisions contained herein or in any Transportation Rate Schedule, Canfor will not be entitled to any monthly charge credits from BC Gas as a result of Force Majeure, as defined in BC Gas Rate Schedule 22, after November 1, 1993.

ARTICLE 6

ARBITRATION

6.01 Any dispute between the parties arising from this Agreement will be resolved by a single arbitrator pursuant to the *Commercial Arbitration Act* of British Columbia or successor legislation, save as expressly provided herein.

6.02 Either party may commence arbitration proceedings by sending to the other party a demand for arbitration setting out the nature of the dispute.

6.03 The parties will have 10 days from receipt of the demand referred to in section 6.02 of this Agreement to agree upon the arbitrator, failing which either party may apply to the Supreme Court of British Columbia to select the arbitrator. The arbitrator must be sufficiently qualified by education and training to decide the particular questions in dispute. Unless otherwise agreed, the arbitrator may not be a past or present employee, officer or director of any of the parties or their respective successors or affiliates, any customer or supplier of Canfor or BC Gas.

6.04 The arbitrator will proceed immediately to hear and determine the matter in dispute and will render a written decision, signed the arbitrator, within 45 days after the appointment, subject to any reasonable delay due to unforeseen circumstances. Notwithstanding the foregoing, if the arbitrator fails to render a decision within 60 days after the appointment then either party may elect to have a new arbitrator appointed in like manner as if none had previously been appointed.

6.05 The decision of the arbitrator will be final and binding upon the parties and the parties will abide by the decision and perform the terms and conditions thereof.

ARTICLE 7

FRANCHISE FEES

7.01 Canfor acknowledges that BC Gas is obligated to pay Franchise Fees to the City of Prince George in an amount equal to 3.09% of the revenues received in each calendar year by BC Gas for Gas consumed within the boundary limits of the City of Prince George.

7.02 The rates payable by Canfor pursuant to Article 4 hereof include a component for Franchise Fees which is calculated as follows:

F = ITR x .0309

Where F = the annual Franchise Fees payable by BC Gas in respect of the Gas consumed by Canfor.

7.03 BC Gas takes the position that the above calculation represents the correct amount for Franchise Fees payable to the City of Prince George in respect of Gas consumed by Canfor and will take all reasonable efforts to defend this position.

7.04 In the event that BC Gas is required by statute, regulation, a court of competent jurisdiction or the British Columbia Utilities Commission to pay the City of Prince George any additional or lesser amount for Franchise Fees in respect of the Gas consumed by Canfor, Canfor will pay BC Gas such additional amounts or BC Gas will refund Canfor such lesser amount and the rate payable by Canfor as set out in Article 4 respect of Franchise Fees will be adjusted to reflect this change.

ARTICLE 8

TERMINATION

8.01 In addition to any other rights to terminate this Agreement:

(i) BC Gas may terminate this Agreement if at any time the British Columbia Utilities Commission determines that a revenue shortfall exists on service under this Agreement and disallows BC Gas the recovery from other customers of BC Gas, of any revenue shortfall resulting from these negotiated rates;

(ii) Canfor may terminate this Agreement if at any time the British Columbia Utilities Commission sets rates for the Canfor pulp and paper mills at a level in excess of the negotiated rates set out or provided for herein.

8.02 Any termination pursuant to Article 8.01 will take effect on the next November 1 following the date of notice in writing by the party terminating this Agreement.

ARTICLE 9

NOTICES

9.01 If in any year an executed Transportation Agreement is not in place, then the notice provisions of the last executed Transportation Agreement and Rate Schedule will apply to this Agreement.

ARTICLE 10

MISCELLANEOUS

10.01 This Agreement will not be assigned without the written consent of the other party hereto, which consent will not be unreasonably withheld.

10.02 Notwithstanding Article 10.01, BC Gas may assign, without the consent of Canfor, BC Gas' rights and obligations under this Agreement to a party, which acquires all or substantially all of BC Gas' utility operations.

10.03 Notwithstanding Article 10.01, Canfor, may assign, without the consent of BC Gas, Canfor's rights and obligations under this Agreement to a party which acquires all or substantially all of Canfor's Prince George pulp mill operations served by BC Gas pursuant to this Agreement.

10.04 This Agreement will enure to the benefit of and be binding on the parties and their respective successors and permitted assigns, including without limitation, successors by merger, amalgamation or consolidation.

10.05 This Agreement and all amendments, modifications, alterations or supplements hereto will be governed by the laws in force in the Province of British Columbia as to nature, validity and interpretation.

10.06 This Agreement is of no force or effect until accepted for filing by the British Columbia Utilities Commission. Upon acceptance for filing of the Agreement by the British Columbia Utilities Commission, the Agreement made between the parties as of October 20, 1988 will be cancelled.

10.07 In this Agreement the words, phrases or expressions which are not defined herein and which in the usage custom of the business of the production, transportation, distribution or sale of Gas has an accepted meaning will have that meaning.

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

AGREED TO AND ACCEPTED:	AGREED TO AND ACCEPTED:
This 29 day of May, 2002	This 8 day of May, 2002
BC GAS UTILITY LTD.	CANADIAN FOREST PRODUCTS LTD.
BY: (Signature)	BY: (Signature)
Marketing Services Manager (Title)	Corporate Secretary (Title)
BILL HENNESSY (Name - Please Print)	David M Calabrigo (Name - Please Print)

SCHEDULE 1
PAGE 1 OF 4

03-Oct-88
Range I

INLAND NATURAL GAS CO. LTD.
BYPASS ANALYSIS
$750,000 PRINCE GEORGE PULP & PAPER
$90,950 CONNECTION FEE

CASE PGP NET 0.1%
$750,000 INVESTMENT
PAGE 1

Particulars		1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Total
Avoided Inlandnet costs		$643,945	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$1,721,066
Incurred WEIL costs		0	0	0	0	0	0	0	0	0	0	0
Total available		643,945	119,680	119,680	119,680	119,680	119,680	119,680	119,680	119,680	119,680	1,721,066
Operating & maintenance		(34,000)	(34,000)	(34,000)	(34,000)	(34,000)	(34,000)	(34,000)	(34,000)	(34,000)	(34,000)	(340,000)
Property taxes		(5,912)	(5,912)	(5,912)	(5,912)	(5,912)	(5,912)	(5,912)	(5,912)	(5,912)	(5,912)	(59,120)
Income before tax		604,034	79,768	79,768	79,768	79,768	79,768	79,768	79,768	79,768	79,768	1,321,946
Connection fee		(90,950)	0	0	0	0	0	0	0	0	0	(90,950)
Interest		(31,627)	(30,046)	(28,464)	(26,883)	(25,302)	(23,720)	(22,139)	(20,557)	(18,976)	(17,395)	(245,109)
Capital Cost Allowance		(13,660)	(26,813)	(25,740)	(24,711)	(23,722)	(22,773)	(21,862)	(20,988)	(20,148)	(19,343)	(219,760)
Taxable income		467,797	22,909	25,564	28,174	30,744	33,275	35,767	38,223	40,644	43,030	766,127
Connection fee		90,950	0	0	0	0	0	0	0	0	0	90,950
Income tax		(202,641)	(9,360)	(10,076)	(10,812)	(11,614)	(12,341)	(13,401)	(14,406)	(15,319)	(16,318)	(316,289)
Investment tax credit		34,000	0	0	0	0	0	0	0	0	0	34,000
Capital Cost Allowance		13,660	26,813	25,740	24,711	23,722	22,773	21,862	20,988	20,148	19,343	219,760
Operating cash flow		405,766	40,439	41,320	42,075	42,852	43,587	44,148	44,605	45,173	46,155	796,418
Debt repayment		(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(158,140)
Net cash flow		389,952	24,625	25,416	26,259	27,038	27,683	28,334	28,991	29,659	30,341	638,298
Income tax rate - current		43.380%	40.522%	39.420%	38.377%	37.778%	37.090%	37.090%	37.090%	37.090%	37.090%	
Debt repayment & interest												
Debt - B.O.T.	30.00%	316,271	300,457	284,643	268,829	253,015	237,201	221,387	205,573	189,759	173,945	
Repayment over 20 years		(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	
Debt - E.O.T.		300,457	284,643	268,829	253,015	237,201	221,387	205,573	189,759	173,945	158,131	
Interest @ 10%	10.00%	31,627	30,046	28,464	26,883	25,302	23,720	22,139	20,557	18,976	17,395	
NPV of net cash flow 1987 - 1996 @		10.998%	[illegible]									

SCHEDULE 1
PAGE 2 OF 4

Range J

INLAND NATURAL GAS CO. LTD.
BYPASS ANALYSIS
$750,000 PRINCE GEORGE PULP & PAPER
600,000 CONNECTION FEE

CASE PGP ... $750,000 INVESTMENT
PAGE 1.1

Line No.	Particulars	Bal.fwd.	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	Total
1	Avoided Inland/WCT costs	$1,751,064	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$3,067,544
3	Incurred WCTL costs	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total available	1,751,064	119,680	119,680	119,680	119,680	119,680	119,680	119,680	119,680	119,680	119,680	119,680	3,067,544
8	Operating & maintenance	(340,000)	(34,000)	(34,000)	(34,000)	(34,000)	(34,000)	(34,000)	(34,000)	(34,000)	(34,000)	(34,000)	(34,000)	(714,000)
10	Property taxes	(59,120)	(5,912)	(5,912)	(5,912)	(5,912)	(5,912)	(5,912)	(5,912)	(5,912)	(5,912)	(5,912)	(5,912)	(124,152)
12	Income before tax	1,351,944	79,768	79,768	79,768	79,768	79,768	79,768	79,768	79,768	79,768	79,768	79,768	2,229,392
13	Connection fee	(99,950)	0	0	0	0	0	0	0	0	0	0	0	(99,950)
14	Interest	(245,109)	(15,813)	(14,232)	(12,650)	(11,069)	(9,488)	(7,906)	(6,325)	(4,743)	(3,162)	(1,581)	0	(332,078)
16	Capital cost allowance	(219,780)	(18,549)	(17,826)	(17,115)	(16,435)	(15,771)	(15,141)	(14,535)	(13,953)	(13,395)	(12,860)	(12,345)	(387,716)
18	Taxable income	786,927	45,388	47,710	50,005	52,271	54,509	56,721	58,908	61,072	63,211	65,327	67,423	1,388,436
19	Connection fee	99,950	0	0	0	0	0	0	0	0	0	0	0	99,950
20	Income tax	(318,387)	(17,108)	(17,992)	(18,847)	(19,701)	(20,544)	(21,378)	(22,202)	(23,018)	(23,824)	(24,622)	(25,412)	(551,835)
21	Investment tax credit	36,000	0	0	0	0	0	0	0	0	0	0	0	36,000
22	Capital cost allowance	219,780	18,549	17,826	17,115	16,435	15,771	15,141	14,535	13,953	13,395	12,860	12,345	387,716
24	Operating cash flow	796,448	46,649	47,554	48,371	48,998	49,736	50,484	51,241	52,007	52,782	53,565	54,356	1,351,791
26	Debt repayment	(158,140)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,809)	0	(316,271)
28	Net cash flow	638,308	31,035	31,740	32,457	33,184	33,922	34,670	35,427	36,193	36,968	37,756	54,356	1,036,000
31	Income tax rate - current		37.690%	37.690%	37.690%	37.690%	37.690%	37.690%	37.690%	37.690%	37.690%	37.690%	37.690%	
33	Debt repayment & Interest													
34	Debt - B.O.Y.		158,131	142,317	126,503	110,689	94,875	79,061	63,247	47,433	31,619	15,805	0	
35	Repayment over 20 years		(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,814)	(15,805)	0	
37	Debt - E.O.Y.		142,317	126,503	110,689	94,875	79,061	63,247	47,433	31,619	15,805	0	0	
40	Interest @ 10.00%		15,813	14,232	12,650	11,069	9,488	7,906	6,325	4,743	3,162	1,581	0	
43	NPV of net cash flow 1997 - 2007 @ 15.000%		$0											

SCHEDULE 1
PAGE 2 OF 4

SCHEDULE 1
PAGE 3 OF 4

CASE P&P 001 0.18
$750,000 INVESTMENT
PAGE 2

INLAND NATURAL GAS CO. LTD.

BYPASS ANALYSIS
$750,000 PRINCE GEORGE PULP & PAPER

REVENUE - AVOIDED GAS PURCHASE COSTS

Range 1

Line No.	Particulars		1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Total
	SALES VOLUMES - GJ		3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	31,412,000
	Less - Ebrita adjustment	-0.0%	0	0	0	0	0	0	0	0	0	0	0
	NET SALES VOLUMES - GJ		3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	31,412,000
	AVOIDED COSTS $/GJ - IGS		$0.2053	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	
	- WCT		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
			0.2053	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	
	COST INCURRED * - WCT		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
			$0.2053	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	
	AVOIDED PURCHASE COSTS												
	Avoided costs		$643,414	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$1,721,066
	Cost incurred		0	0	0	0	0	0	0	0	0	0	0
	Total		$643,414	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$1,721,066

SCHEDULE 1
PAGE 3 OF 4

SCHEDULE 1
PAGE 4 OF 4

CASE $720,000 PGP 881 0.18 INVESTMENT PAGE 2.1

INLAND NATURAL GAS CO. LTD.

BYPASS ANALYSIS
$720,000 PRINCE GEORGE PULP & PAPER

REVENUE - REDUCED GAS PURCHASE COSTS

Range 6

Line No.	Particulars		Bal.Fwd.	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	Total
1	SALES VOLUMES - GJ		31,412,000	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	65,965,200
2	Less - Strike														
3	adjustment	0.0%	0	0	0	0	0	0	0	0	0	0	0	0	0
7	NET SALES VOLUMES - GJ		31,412,000	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	3,141,200	65,965,200
12	AVOIDED COSTS $/GJ - CMD			$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	
13	- VOL			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
16				0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	0.0381	
17	COST INCURRED - VOL			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
19				$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	$0.0381	
25	REDUCED PURCHASE COSTS														
27	Avoided costs		$1,721,066	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$3,037,546
29	Cost incurred		0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total		$1,721,066	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$119,680	$3,037,546

SCHEDULE 1
PAGE 4 OF 4

Canadian Forest Products Ltd.

and affiliated companies

October 31, 1996

File: 281.032

Mr. Henry Dinter
B.C. Gas
1111 West Georgia Street
Vancouver, B.C.
V6E 4M4

Dear Sirs:

Re: B.C. Gas Bypass Arrangement

Canadian Forest Products Ltd. hereby provide notice, pursuant to Article 3.02 of the Agreement, that it wishes to extend the Prince George Pulp and Paper Mills Bypass Agreement for an additional 10 year period commencing November 1, 1997.

Yours truly,

CANADIAN FOREST PRODUCTS LTD.

A.K. MacMillan, P.Eng
Vice-President, Environment and Energy

cc: Mr. Ken Fuhr

Canfor Pulp Holding Inc.

October 27, 2006

Mr. Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins:

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Prince George Pulpmill) – dated November 1, 1987.

This is to inform you that Canfor Pulp Limited Partnership ("CPLP"), pursuant to Clause 3.02 of the above agreement, wishes to extend the agreement for a period of one year commencing November 1, 2007 to October 31, 2008. It is CPLP's intent to re-examine the agreement in the coming twelve months to decide on further renewal.

Please acknowledge receipt of this letter.

Sincerely,

CANFOR PULP LIMITED PARTNERSHIP
by its General Partner, Canfor Pulp Holding Inc.

Thomas Sitar,
Chief Financial Officer and Secretary

Cc: Ms. Marie Moffat

1700 West 75th Avenue, Vancouver, British Columbia, Canada V6P 6G2
Telephone 604-661-5260 Fax 604-661-5226 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Intercontinental Pulp Mill

a business of Canfor Pulp Limited Partnership

September 25, 2007

Mr. Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Prince George Pulpmill) – dated November 1, 1987.

Canfor Pulp Limited Partnership, "CPLP" is writing to inform Terasen that pursuant to Clause 3.02 of the above agreement CPLP wishes to extend the agreement for a period of one year commencing November 1, 2008 to November 1, 2009. It is CPLP's intent to re-examine the agreement in the coming twelve months to decide on further renewal.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited Partnership
by its general partner Canfor Pulp Holding Inc.

M Moffat

Mario Moffat
Buyer/Energy Co-ordinator

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Intercontinental Pulp Mill

a business of Canfor Pulp Limited Partnership

September 9, 2008

Mr. Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Prince George Pulpmill) – dated November 1, 1987.

Canfor Pulp Limited Partnership, "CPLP" is writing to inform Terasen that pursuant to Clause 3.02 of the above agreement CPLP wishes to extend the agreement for a period of one year commencing November 1, 2009 to November 1, 2010.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

CANFOR PULP LIMITED
PARTNERSHIP, *by its General Partner,*
CANFOR PULP HOLDING INC.
By: ______________________
Rick Remesch, CA, Corporate Controller

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Intercontinental Pulp Mill

a business of Canfor Pulp Limited Partnership

September 29, 2009

Mr. Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Prince George Pulpmill) – dated November 1, 1987.

Canfor Pulp Limited Partnership, "CPLP" is writing to inform Terasen that pursuant to Clause 3.02 of the above agreement CPLP wishes to extend the agreement for a period of one year commencing November 1, 2010 to November 1, 2011.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited Partnership
by its general partner Canfor Pulp Holding Inc.

Rick Remesch, CA
Corporate Controller

cc. Marie Moffat, Canfor Pulp

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Intercontinental Pulp Mill

a business of Canfor Pulp Limited Partnership

October 29, 2010

Mr. Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Prince George Pulpmill) – dated November 1, 1987.

Canfor Pulp Limited Partnership, "CPLP" is writing to inform Terasen that pursuant to Clause 3.02 of the above agreement CPLP wishes to extend the agreement for a period of one year commencing November 1, 2011 to November 1, 2012.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited Partnership
by its general partner Canfor Pulp Holding Inc.

Rick Remesch

cc. Marie Moffat, Canfor Pulp

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Intercontinental Pulp Mill

a business of Canfor Pulp Limited Partnership

October 19, 2011

Mr. Kevin Hodgins
Fortis BC
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Prince George Pulpmill) – dated November 1, 1987.

Canfor Pulp Limited Partnership, "CPLP" is writing to inform Fortis BC that pursuant to Clause 3.02 of the above agreement CPLP wishes to extend the agreement for a period of one year commencing November 1, 2012 to November 1, 2013.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited Partnership
by its general partner Canfor Pulp Holding Inc.

Rick Remesch

cc. Marie Moffat, Canfor Pulp
Clarke Anderson, Canfor Pulp

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Intercontinental Pulp Mill

a business of Canfor Pulp Limited Partnership

September 25, 2012

Mr. Kevin Hodgins
Fortis BC
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Prince George Pulp mill) – dated November 1, 1987.

Canfor Pulp Limited Partnership, "CPLP" is writing to inform Fortis BC that pursuant to Clause 3.02 of the above agreement CPLP wishes to extend the agreement for a period of one year commencing November 1, 2013 to November 1, 2014.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited Partnership
by its general partner Canfor Pulp Holding Inc.

Rick Remesch, Corporate Controller

cc. Clarke Anderson, Canfor Pulp
Rajoo Jagtap, Fortis BC

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Intercontinental Pulp Mill

a business of Canfor Pulp Limited Partnership

October 31, 2013

Mr. Kevin Hodgins
Fortis BC
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Prince George Pulp mill) – dated November 1, 1987.

Canfor Pulp Limited Partnership, "CPLP" is writing to inform Fortis BC that pursuant to Clause 3.02 of the above agreement CPLP wishes to extend the agreement for a period of one year commencing November 1, 2014 to November 1, 2015.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited Partnership
by its general partner Canfor Pulp Holding Inc.

Rick Remesch, Corporate Controller

cc. Clarke Anderson, Canfor Pulp
Rajoo Jagtap, Fortis BC

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Intercontinental Pulp Mill

a business of Canfor Pulp Limited

October 2nd, 2014

Mr. Rajoo Jagtap
Fortis BC
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Prince George Pulp mill) – dated November 1, 1987.

Canfor Pulp Limited, "CPL" is writing to inform Fortis BC that pursuant to Clause 3.02 of the above agreement CPL wishes to extend the agreement for a period of one year commencing November 1, 2015 to November 1, 2016.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited
by its general partner Canfor Pulp Holding Inc.

Rick Remesch, Corporate Controller

cc. Clarke Anderson, Canfor Pulp
Kevin Hodgins, Fortis BC

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Intercontinental Pulp Mill

a business of Canfor Pulp Limited

September 10, 2015

Mr. Doug Tufts
Fortis BC
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Prince George Pulp mill) – dated November 1, 1987.

Canfor Pulp Limited, "CPL" is writing to inform Fortis BC that pursuant to Clause 3.02 of the above agreement CPL wishes to extend the agreement for a period of one year commencing November 1, 2016 to November 1, 2017.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited

Rick Remesch, Corporate Controller

cc. Clarke Anderson, Canfor Pulp
Kevin Hodgins, Fortis BC

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

TARIFF SUPPLEMENT NO. G-6

AMENDED AND RESTATED
BYPASS TRANSPORTATION AGREEMENT
FOR RATE SCHEDULE 22A

BETWEEN

WEST FRASER MILLS LTD.

AND

FORTISBC ENERGY INC.
(Formerly Terasen Gas Inc. and BC Gas Utility Ltd.)

Effective November 1, 1993

THIS AGREEMENT made as of the 21st day of November, 2002, with effect as and from November 1, 1993, is an amendment and restatements of an agreement made as of October 28, 1988 between the parties noted below.

BETWEEN:

BC GAS UTILITY LTD., a company incorporated under the laws of British Columbia having its registered office at 16705 Fraser Highway, Surrey, British Columbia

(hereinafter called "BC Gas")

OF THE FIRST PART

AND:

WEST FRASER MILLS LTD. Having an office at 2 Mile Flat, 1000 Fining Road, Quesnel, British Columbia

(hereinafter called "West Fraser")

OF THE SECOND PART

WHEREAS:

A. West Fraser operates a pulp mill in the City of Quesnel, British Columbia, and requires Gas for its operations;

B. BC Gas owns and operates a Gas transmission pipeline, which is connected to the pulp mill operations of West Fraser in Quesnel, British Columbia;

C. West Fraser entered into an agreement with BC Gas' predecessor company, Inland Natural Gas Co. Ltd. ("Inland") dated October 30, 1987 which was superceded and replaced by an agreement between West Fraser and Inland dated October 26, 1988 effective November 1, 1987 which allowed West Fraser to receive transportation service from BC Gas at rates reasonably equivalent to the costs that would have been incurred by West Fraser had it constructed the Bypass Pipeline hereinafter defined in 1987;

D. The British Columbia Utilities Commission has endorsed the concept of negotiated rates that are competitive with the Bypass Pipeline alternative;

E. On April 15, 1993, BC Gas filed an application (the "Phase B Rate Design Application") with the British Columbia Utilities Commission for redesign of its Gas tariff Rate Schedules which, among other things, proposed the implementation of common Rate Schedules and General Terms and Conditions of service;

F. Following the completion of the hearing of the Phase B Rate Design Application, the British Columbia Utilities Commission issued its decision dated October 25, 1993, which, in part, approved the implementation of new Rate Schedules effective November 1, 1993 for industrial and general service; and

G. As a result of the British Columbia Utilities Commission decision dated October 25, 1993, the parties desire to enter into this amended and restated Agreement to clarify their respective rights and obligations.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the premises, the covenants and agreements contained herein, the parties agree as follows:

ARTICLE 1

DEFINITIONS

1.01 Except where the context expressly states another meaning, the following words will have the following meaning:

"Bypass Pipeline" means those facilities which, but for this Agreement, would have been constructed by West Fraser in order to provide Gas service to their pulp mill operations in Quesnel, British Columbia.

"ITR" means the annual total revenue received by BC Gas from West Fraser for Gas transportation service and sales service to West Fraser's Quesnel, British Columbia pulp mill operations.

"DTQ" means the Firm DTQ and Interruptible DTQ as defined in the Rate Schedule 22A Transportation Agreement or other transportation agreement related to a Rate Schedule for transportation under which West Fraser may elect to receive service.

"Terms and Conditions of the Transportation Schedule" means the terms of the applicable Transportation Rate Schedule, and the Transportation Agreements thereunder, and the General Terms and Conditions of BC Gas, as approved by the British Columbia Utilities Commission by its decision of October 25, 1993 or any subsequent transportation or Gas sales service Rate Schedules accepted for filing by the British Columbia Utilities Commission.

1.02 Except for those terms defined under Article 1.01, terms or expressions used in this Agreement will have the meanings described in the Terms and Conditions of the Transportation Schedule.

ARTICLE 2

TRANSPORTATION SERVICE

2.01 BC Gas will provide firm and interruptible transportation service to West Fraser for its pulp mill operations in Quesnel, British Columbia and West Fraser will accept such transportation services in accordance with the then prevailing provisions of BC Gas Rate Schedule 22A and the accompanying Transportation Agreement for the term of this Agreement and such provisions are incorporated herein by reference.

2.02 Notwithstanding the provisions of Article 2.01, where anything in the Terms and Conditions of the Transportation Schedule conflicts or is inconsistent with the rates, terms and conditions set out in this Agreement, this Agreement governs.

2.03 West Fraser will be entitled to elect to take transportation service under a Transportation Rate Schedule other than Schedule 22A subject to the terms and conditions of such Rate Schedule. In such case, Article 2.01 and 2.02 will apply in the same way to the elected Rate Schedule.

2.04 If West Fraser in any Contract Year elects to take transportation service pursuant to a Rate Schedule under which monthly Gas balancing provisions result in benefits to West Fraser which would not have been available if the Bypass Pipeline had been constructed, the rates specified in Article 4, will be increased for that Contract Year by an amount equal to West Fraser's savings resulting from the provision of BC Gas' monthly Gas balancing on the tolls that would have been incurred on the Westcoast pipeline system had West Fraser constructed the Bypass Pipeline. The said amount will be determined by BC Gas and paid to BC Gas at the end of the Contract Year.

ARTICLE 3

TERM OF AGREEMENT

3.01 Subject to Article 8, the initial term of this Agreement will be for a period of four (4) Contract Years, effective the 1st Day of November, 1993, up to the 1st Day of November 1997.

3.02 The term of this Agreement will be extended beyond the initial termination date or any subsequent extension thereof upon the terms and conditions of this Agreement, including the pricing provisions, upon West Fraser providing written notice to BC Gas of its desire to extend the term of the Agreement for a further specified period, at least 12 months prior to the then current termination date and BC Gas agreeing to such extension of the term of this Agreement. Notwithstanding the foregoing, any extension of the term of this Agreement will be for a period of not less than one year.

ARTICLE 4

RATES AND CHARGES

4.01 Subject to the adjustments hereinafter provided for and based on a DTQ of 3090 gigajoules, West Fraser each month will pay to BC Gas for services provided hereunder, from November 1, 1993 to the expiry of the Agreement, the following rates:

(i) A monthly charge of $7,437.00

(ii) Any charges pursuant to Articles 4.02, 4.03 and 4.04

4.02 The rates will be adjusted by BC Gas to reflect any changes in costs which would have been incurred by West Fraser as a result of: a material increase in the annual Gas volume actually transported to West Fraser; or an increase in the capacity of the Bypass Pipeline to meet West Fraser's DTQ requirements; or modification or addition to facilities which may reasonably be required for any other reason, had West Fraser constructed and operated the Bypass Pipeline.

4.03 In addition to the foregoing rates, West Fraser will pay to BC Gas at the end of each Contract Year an annual surcharge for increases, if any, in BC Gas costs. The surcharge will be determined as the sum of the following:

(i) cost changes to the estimated 1987 costs set out in Schedule 1 for operation and maintenance expenses that would have been incurred had West Fraser constructed and operated the Bypass Pipeline; without limiting the generality of the foregoing, such costs include odorant costs, heating fuel costs, cathodic protection costs and labour costs; and

(ii) costs changes in municipal, provincial or federal taxes and fees, including new taxes or fees, but excluding taxes on taxable income, related to the operation of the Bypass Pipeline that would have been levied had it been constructed and operated by West Fraser from 1987 tax costs set out in line 10 of Schedule 1. For greater clarity, the parties agree that changes in costs of either debt or equity capital and taxes on taxable income are not to be included in the surcharge.

4.04 Any disputes arising hereunder as to the amount of the annual surcharge or the appropriateness of including costs under this Article will be referred to arbitration in accordance with Article 6 of this Agreement.

ARTICLE 5

FORCE MAJEURE

5.01 Notwithstanding any of the provisions contained herein or in any Transportation Rate Schedule, West Fraser will not be entitled to any monthly charge credits from BC Gas as a result of Force Majeure, as defined in BC Gas Rate Schedule 22, after November 1, 1993.

ARTICLE 6

ARBITRATION

6.01 Any dispute between the parties arising from this Agreement will be resolved by a single arbitrator pursuant to the *Commercial Arbitration Act* of British Columbia or successor legislation, save as expressly provided herein.

6.02 Either party may commence arbitration proceedings by sending to the other party a demand for arbitration setting out the nature of the dispute.

6.03 The parties will have 10 days from receipt of the demand referred to in section 6.02 of this Agreement to agree upon the arbitrator, failing which either party may apply to the Supreme Court of British Columbia to select the arbitrator. The arbitrator must be sufficiently qualified by education and training to decide the particular questions in dispute. Unless otherwise agreed, the arbitrator may not be a past or present employee, officer or director of any of the parties or their respective successors or affiliates, any customer or supplier of West Fraser or BC Gas.

6.04 The arbitrator will proceed immediately to hear and determine the matter in dispute and will render a written decision, signed the arbitrator, within 45 days after the appointment, subject to any reasonable delay due to unforeseen circumstances. Notwithstanding the foregoing, if the arbitrator fails to render a decision within 60 days after the appointment then either party may elect to have a new arbitrator appointed in like manner as if none had previously been appointed.

6.05 The decision of the arbitrator will be final and binding upon the parties and the parties will abide by the decision and perform the terms and conditions thereof.

ARTICLE 7

FRANCHISE FEES

7.01 West Fraser acknowledges that BC Gas is obligated to pay Franchise Fees to the City of Quesnel in an amount equal to 3.09% of the revenues received in each calendar year by BC Gas for Gas consumed within the boundary limits of the City of Quesnel.

7.02 The rates payable by West Fraser pursuant to Article 4 hereof include a component for Franchise Fees which is calculated as follows:

F = ITR x .0309

Where F = the annual Franchise Fees payable by BC Gas in respect of the Gas consumed by West Fraser.

7.03 BC Gas takes the position that the above calculation represents the correct amount for Franchise Fees payable to the City of Quesnel in respect of Gas consumed by West Fraser and will take all reasonable efforts to defend this position.

7.04 In the event that BC Gas is required by statute, regulation, a court of competent jurisdiction or the British Columbia Utilities Commission to pay the City of Quesnel any additional or lesser amount for Franchise Fees in respect of the Gas consumed by West Fraser, West Fraser will pay BC Gas such additional amounts or BC Gas will refund West Fraser such lesser amount and the rate payable by West Fraser as set out in Article 4 respect of Franchise Fees will be adjusted to reflect this change.

ARTICLE 8

TERMINATION

8.01 In addition to any other rights to terminate this Agreement:

(i) BC Gas may terminate this Agreement if at any time the British Columbia Utilities Commission determines that a revenue shortfall exists on service under this Agreement and disallows BC Gas the recovery from other customers of BC Gas, of any revenue shortfall resulting from these negotiated rates;

(ii) West Fraser may terminate this Agreement if at any time the British Columbia Utilities Commission sets rates for the West Fraser pulp mill at a level in excess of the negotiated rates set out or provided for herein.

8.02 Any termination pursuant to Article 8.01 will take effect on the next November 1 following the date of notice in writing by the party terminating this Agreement.

ARTICLE 9

NOTICES

9.01 If in any year an executed Transportation Agreement is not in place, then the notice provisions of the last executed Transportation Agreement and Rate Schedule will apply to this Agreement.

ARTICLE 10

MISCELLANEOUS

10.01 This Agreement will not be assigned without the written consent of the other party hereto, which consent will not be unreasonably withheld.

10.02 Notwithstanding Article 10.01, BC Gas may assign, without the consent of West Fraser, BC Gas' rights and obligations under this Agreement to a party, which acquires all or substantially all of BC Gas' utility operations.

10.03 Notwithstanding Article 10.01, West Fraser, may assign, without the consent of BC Gas, West Fraser's rights and obligations under this Agreement to a party which acquires all or substantially all of West Fraser's Quesnel pulp mill operations served by BC Gas pursuant to this Agreement.

10.04 This Agreement will enure to the benefit of and be binding on the parties and their respective successors and permitted assigns, including without limitation, successors by merger, amalgamation or consolidation.

10.05 This Agreement and all amendments, modifications, alterations or supplements hereto will be governed by the laws in force in the Province of British Columbia as to nature, validity and interpretation.

10.06 This Agreement is of no force or effect until accepted for filing by the British Columbia Utilities Commission. Upon acceptance for filing of the Agreement by the British Columbia Utilities Commission, the Agreement made between the parties as of October 20, 1988 will be cancelled.

10.07 In this Agreement the words, phrases or expressions which are not defined herein and which in the usage custom of the business of the production, transportation, distribution or sale of Gas has an accepted meaning will have that meaning.

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

AGREED TO AND ACCEPTED:	AGREED TO AND ACCEPTED:
This 3 day of February 2003	This 21st day of November 2002
BC GAS UTILITY LTD.	WEST FRASER MILLS LTD.
BY: Bill Hennessey (Signature)	BY: David Humber P. ENG (Signature)
	MANAGER, TECHNICAL DEVELOPMENT (Title)
Bill Hennessey, PEng. Marketing Services Manager Transportation and Marketing Services BC Gas Utility Ltd. (Name - Please Print)	DAVID HUMBER (Name - Please Print)

SCHEDULE 1
PAGE 1 OF 4

11-Oct-93
Range 1

INLAND NATURAL GAS CO. LTD.
PROJECT ANALYSIS
$337,000 ... PULP
$151,000 CONNECTION FEE

CASE $337,000 INVESTMENT PAGE 1

Line No.	Particulars		1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Total
1	Avoided INLAND/WCT basis		$274,439	$319,544	$319,544	$319,544	$319,544	$319,544	$319,544	$319,544	$319,544	$319,544	$3,150,335
3	Incurred WCTL basis		(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(2,303,030)
6	Total available		44,136	89,241	89,241	89,241	89,241	89,241	89,241	89,241	89,241	89,241	847,305
8	Operating & maintenance		(16,000)	(16,000)	(16,000)	(16,000)	(16,000)	(16,000)	(16,000)	(16,000)	(16,000)	(16,000)	(160,000)
10	Property taxes		(1,655)	(1,655)	(1,655)	(1,655)	(1,655)	(1,655)	(1,655)	(1,655)	(1,655)	(1,655)	(16,550)
12	Income before tax		26,481	71,586	71,586	71,586	71,586	71,586	71,586	71,586	71,586	71,586	670,755
14	Interest		(18,320)	(17,404)	(16,488)	(15,572)	(14,656)	(13,740)	(12,824)	(11,908)	(10,992)	(10,076)	(141,980)
15	Connection Fee		(151,000)	0	0	0	0	0	0	0	0	0	(151,000)
16	Capital Cost Allowance		(9,833)	(11,433)	(10,975)	(10,536)	(10,115)	(9,710)	(9,322)	(8,949)	(8,591)	(8,247)	(97,711)
18	Taxable Income		(152,672)	42,749	44,123	45,478	46,815	48,136	49,440	50,729	52,003	53,263	280,064
19	Income Tax		66,352	(18,096)	(18,677)	(19,251)	(19,817)	(20,376)	(20,928)	(21,474)	(22,013)	(22,546)	(116,826)
20	Investment Tax Credit		70,350	0	0	0	0	0	0	0	0	0	70,350
21	Connection Fee		151,000	0	0	0	0	0	0	0	0	0	151,000
22	Capital Cost Allowance		9,833	11,433	10,975	10,536	10,115	9,710	9,322	8,949	8,591	8,247	97,711
24	Operating cash flow		144,863	36,086	36,421	36,763	37,113	37,470	37,834	38,204	38,581	38,964	482,299
26	Debt repayment		(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(91,600)
28	Net cash flow		135,703	26,926	27,261	27,603	27,953	28,310	28,674	29,044	29,421	29,804	390,699
31	Income tax rate - current		43.460%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	
33	Debt repayment & interest	40.00%											
34	Debt - B.O.Y.		183,200	174,040	164,880	155,720	146,560	137,400	128,240	119,080	109,920	100,760	
35	Repayment over 20 years		(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	
37	Debt - E.O.Y.		174,040	164,880	155,720	146,560	137,400	128,240	119,080	109,920	100,760	91,600	
40	Interest @ 10%	10.00%	18,320	17,404	16,488	15,572	14,656	13,740	12,824	11,908	10,992	10,076	
43	NPV of Net cash flow 1988 - 1997 @		9.500%	(88)									

SCHEDULE 1
PAGE 2 OF 4

Range 3

INLAND NATURAL GAS CO. LTD.
UPGRADE ANALYSIS
$307,000 QUESNEL RIVER PULP
$151,000 CONNECTION FEE

CASE ### & 8.6?1
$307,000 INVESTMENT
PAGE 1.1

Line No.	Particulars	Est./Tot.	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	Total
1	Avoided Inland/WCT costs	$[illegible]	$219,544	$219,544	$219,544	$219,544	$219,544	$219,544	$219,544	$219,544	$219,544	$219,544	$219,544	$[illegible]
3	Incurred WCT costs	(2,303,830)	(130,303)	(130,303)	(130,303)	(130,303)	(130,303)	(130,303)	(130,303)	(130,303)	(130,303)	(130,303)	(130,303)	([illegible])
5	Total available	947,305	89,241	89,241	89,241	89,241	89,241	89,241	89,241	89,241	89,241	89,241	89,241	1,928,956
7	Operating & maintenance	(160,000)	(16,000)	(16,000)	(16,000)	(16,000)	(16,000)	(16,000)	(16,000)	(16,000)	(16,000)	(16,000)	(16,000)	(336,000)
9	Property taxes	(16,550)	(1,655)	(1,655)	(1,655)	(1,655)	(1,655)	(1,655)	(1,655)	(1,655)	(1,655)	(1,655)	(1,655)	(34,755)
11	Income before tax	770,755	71,586	71,586	71,586	71,586	71,586	71,586	71,586	71,586	71,586	71,586	71,586	1,558,201
13	Interest	([illegible])	(9,160)	(8,244)	(7,328)	(6,412)	(5,496)	(4,580)	(3,664)	(2,748)	(1,832)	(916)	0	([illegible])
14	Connection Fee	(151,000)	0	0	0	0	0	0	0	0	0	0	0	(151,000)
15	Capital Cost Allowance	(93,711)	(7,910)	(7,601)	(7,297)	(7,005)	(6,725)	(6,456)	(6,197)	(5,950)	(5,712)	(5,483)	(5,264)	([illegible])
17	Taxable Income	364,064	54,516	55,741	56,961	58,169	59,365	60,550	61,725	62,888	64,042	65,187	66,322	[illegible]
18	Income Tax	([illegible])	(23,073)	(23,585)	(24,111)	(24,622)	(25,129)	(25,631)	(26,128)	(26,620)	(27,109)	(27,594)	(28,075)	([illegible])
19	Investment Tax Credit	10,310	0	0	0	0	0	0	0	0	0	0	0	10,310
20	Connection Fee	151,000	0	0	0	0	0	0	0	0	0	0	0	151,000
21	Capital Cost Allowance	93,711	7,910	7,601	7,297	7,005	6,725	6,456	6,197	5,950	5,712	5,483	5,264	[illegible]
23	Operating cash flow	[illegible]	39,353	39,747	40,146	40,551	40,961	41,375	41,796	42,218	42,645	43,076	43,511	937,677
25	Debt repayment	(91,600)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	0	(183,200)
27	Net cash flow	[illegible]	30,193	30,587	30,986	31,391	31,801	32,215	32,636	33,058	33,485	33,916	43,511	754,477
30	Income tax rate - current		42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	
32	Debt repayment & interest													
33	Debt - B.O.Y.		91,600	82,440	73,280	64,120	54,960	45,800	36,640	27,480	18,320	9,160	0	
34	Repayment over 10 years		(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	(9,160)	0	
36	Debt - E.O.Y.		82,440	73,280	64,120	54,960	45,800	36,640	27,480	18,320	9,160	0	0	
40	Interest @ 10.00%		9,160	8,244	7,328	6,412	5,496	4,580	3,664	2,748	1,832	916	0	
43	NPV of net cash flow 1998 - 2003 @ 15.000%		$0											

SCHEDULE 1
PAGE 2 OF 4

SCHEDULE 1
PAGE 3 OF 4

INLAND NATURAL GAS CO. LTD.

BYPASS ANALYSIS
$327,000 BULKLEY RIVER PULP

REVENUE - REDUCED GAS PURCHASE COSTS

Range 5

CASE $327,000 INVESTMENT PAGE 2

Particulars		1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Total
SALES VOLUMES - GJ		749,027	749,027	749,027	749,027	749,027	749,027	749,027	749,027	749,027	749,027	7,490,270
Less - Strike adjustment	0.0%	0	0	0	0	0	0	0	0	0	0	0
NET SALES VOLUMES - GJ		749,027	749,027	749,027	749,027	749,027	749,027	749,027	749,027	749,027	749,027	7,490,270
AVOIDED COSTS $/GJ - INS		$0.4993	$0.4261	$0.4261	$0.4261	$0.4261	$0.4261	$0.4261	$0.4261	$0.4261	$0.4261	
- NGT		0.3071	0.3071	0.3071	0.3071	0.3071	0.3071	0.3071	0.3071	0.3071	0.3071	
COST INCURRED		0.4993	0.4261	0.4261	0.4261	0.4261	0.4261	0.4261	0.4261	0.4261	0.4261	
- NGT		(0.3071)	(0.3071)	(0.3071)	(0.3071)	(0.3071)	(0.3071)	(0.3071)	(0.3071)	(0.3071)	(0.3071)	
		$0.1922	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	
REDUCED PURCHASE COSTS												
Avoided costs		$374,439	$319,544	$319,544	$319,544	$319,544	$319,544	$319,544	$319,544	$319,544	$319,544	$3,250,335
Cost Incurred		(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(2,303,030)
Total		$144,136	$89,241	$89,241	$89,241	$89,241	$89,241	$89,241	$89,241	$89,241	$89,241	$947,305

SCHEDULE 1
PAGE 4 OF 4

CASE $307,000 INVESTMENT
PAGE 2.1

INLAND NATURAL GAS CO. LTD.

BYPASS ANALYSIS
$307,000 [illegible] RIVER PULP

REVENUE - REDUCED GAS PURCHASE COSTS

Range 4

Particulars		Bal. Fwd.	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	Total
SALES VOLUMES - GJ		7,499,270	749,927	749,927	749,927	749,927	749,927	749,927	749,927	749,927	749,927	749,927	749,927	15,748,467
Less - Shrinkage adjustment	0.0%	0	0	0	0	0	0	0	0	0	0	0	0	0
NET SALES VOLUMES - GJ		7,499,270	749,927	749,927	749,927	749,927	749,927	749,927	749,927	749,927	749,927	749,927	749,927	15,748,467
AVOIDED COSTS $/GJ - [illegible]			$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	
- NET			0.3071	0.3071	0.3071	0.3071	0.3071	0.3071	0.3071	0.3071	0.3071	0.3071	0.3071	
			0.4261	0.4261	0.4261	0.4261	0.4261	0.4261	0.4261	0.4261	0.4261	0.4261	0.4261	
			(0.3071)	(0.3071)	(0.3071)	(0.3071)	(0.3071)	(0.3071)	(0.3071)	(0.3071)	(0.3071)	(0.3071)	(0.3071)	
UNIT INCURRED - NET			$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	$0.1190	
REDUCED PURCHASE COSTS														
Avoided Costs		$3,195,435	$319,544	$319,544	$319,544	$319,544	$319,544	$319,544	$319,544	$319,544	$319,544	$319,544	$319,544	$6,710,419
Cost Incurred		(2,303,030)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(230,303)	(4,836,363)
Total		$892,405	$89,241	$89,241	$89,241	$89,241	$89,241	$89,241	$89,241	$89,241	$89,241	$89,241	$89,241	$1,874,056

SCHEDULE 1
PAGE 4 OF 4

Telephone: (250) 992-8919
Facsimile: (250) 992-2612

QUESNEL RIVER PULP COMPANY
1000 FINNING ROAD, QUESNEL, BRITISH COLUMBIA, CANADA V2J 6A1

August 13, 1997

Mr. Henry L. Dinter
Industrial and Transportation Services Manager
BC Gas
1111 West Georgia Street
Vancouver, BC

Re: QRP/BCG Bypass Agreement

As per clause 3.02 of the above stated agreement, this letter will confirm QRP's intention to renew the bypass agreement for a further period of ten years.

QRP recognizes that the agreement anticipates a renewal notice of one year. This late notice is a result of the unique nature of this agreement in requiring explicit renewal and the long period since this agreement was an issue between the two parties. In addition, QRP is of the understanding that the amortization period that derived the rates charged was twenty years and believes this would support QRP's election of a ten year extension.

Could you please forward an acknowledgement of our election for our files?

If any further information is required, please contact me directly.

Sincerely,

Steve Weatherall
Manager of Maintenance and Engineering
Quesnel River Pulp Company

SW/sdk
File: P-05

West Fraser Mills Ltd

October 30, 2006

Terasen Gas Corporate Office
16705 Fraser Highway, Surrey
V3S 2X7

Attention: Kevin Hodgins
Key Account Manager

RE: Bypass Transportation Agreement - Quesnel River Pulp division.

Dear Kevin:

As per clause 3.02 of the above stated agreement, West Fraser Mills Ltd would like to request that the Bypass agreement be extended for a further period of **5 years** to November 1st 2012.

Sincerely,

Andrew K. Kim

Project Engineer
West Fraser Mills LTD.

1250 Brownmiller Road • Quesnel • B.C. • Canada • V2J 6P5 • (250) 992-[illegible] • (250) 992-[illegible] • http://www.westfrasertimber.ca

West Fraser Mills Ltd

October 26, 2011

Terasen Gas Corporate Office
16705 Fraser Highway, Surrey
V3S 2X7

Attention: Kevin Hodgins
Key Account Manager

RE: Bypass Transportation Agreement - Quesnel River Pulp division.

Dear Kevin:

As per clause 3.02 of the above stated agreement, West Fraser Mills Ltd would like to request that the Bypass agreement be extended for a further period of **5 years** to November 1st 2017.

Sincerely,

Veikko Paivinen

Financial Manager, Energy & Carbon
West Fraser Mills Ltd.

TARIFF SUPPLEMENT NO. G-7

AMENDED AND RESTATED
BYPASS TRANSPORTATION AGREEMENT
FOR RATE SCHEDULE 22A

BETWEEN

CANADIAN FOREST PRODUCTS LTD.
Northwood Pulp and Timber Limited

AND

FORTISBC ENERGY INC.
(Formerly Terasen Gas Inc. and BC Gas Utility Ltd.)

Effective November 1, 1993

THIS AGREEMENT made as of the 28th day of February , 2001 , with effect as and from November 1, 1993, is an amendment and restatement of an agreement made as of May 25, 1992 between the parties noted below.

BETWEEN:

BC GAS UTILITY LTD., a company incorporated under the laws of British Columbia having its registered office at 1111 West Georgia Street, Vancouver, British Columbia

(hereinafter called "BC Gas")

OF THE FIRST PART

AND:

CANADIAN FOREST PRODUCTS LTD., incorporated under the laws of British Columbia having its registered office at 1055 Dunsmuir Street, Vancouver, British Columbia

(hereinafter called "Canfor")

OF THE SECOND PART

WHEREAS:

A. Canfor operates a pulp mill in the City of Prince George, British Columbia, and requires Gas for its operations (for the purposes of this Agreement all references to Canfor will include all predecessor corporations including Northwood Pulp and Timber Ltd.);

B. BC Gas owns and operates a Gas transmission pipeline, which is connected to the pulp mill operations of Canfor in Prince George, British Columbia;

C. Canfor made an application (the "Bypass Application") on August 24, 1987 to the Province of British Columbia for an Energy Project Certificate pursuant to British Columbia Order-in-Council No. 552 dated March 19, 1987, which, if granted, would have allowed Canfor to construct a Bypass Pipeline (hereunder defined) from the Westcoast Energy Inc. pipeline system mainline to Canfor facilities at Prince George;

D. The Bypass Application was heard by the British Columbia Utilities Commission at a hearing in Prince George commencing September 9, 1987.

E. Following the completion of the hearing of the Bypass Application, the British Columbia Utilities Commission submitted its report and recommendations dated October 22, 1987, to the Lieutenant-Governor in Council. The report recommended that "an Energy Project Certificate not be granted to Canfor providing that BC Gas, (formerly Inland Natural Gas Co. Ltd.) promptly offers Canfor a transportation contract with the rates and conditions specified in Section 6 of the report."

F. By Order-in-Council dated December 10, 1987, the Lieutenant-Governor in Council accepted the October 22, 1987 report of the British Columbia Utilities Commission.

G. Canfor entered into an Agreement with BC Gas dated May 25, 1992 which allows Canfor to receive transportation service from BC Gas at rates and on terms and conditions that are in accordance with the British Columbia Utilities Commission decision of October 22, 1987.

H. On April 15, 1993, BC Gas filed an application (the "Phase B Rate Design Application") with the British Columbia Utilities Commission for re-design of its Gas tariff Rate Schedules which, among other things, proposed the consolidation of BC Gas' operating divisions (excluding Fort Nelson), the implementation of "postage-stamp" rates for residential, commercial and small industrial customers (excluding those in Fort Nelson) and the implementation of common general terms and conditions of service to combine and eliminate certain tariffs and rates

I. Following the completion of the hearing of the Phase B Rate Design Application, the British Columbia Utilities Commission issued its decision dated October 25, 1993, which, in part, approved the consolidation and "postage stamp" rates in certain service areas of BC Gas and approved the implementation of new tariffs effective November 1, 1993 for industrial and general service and January 1, 1994 for residential and commercial tariffs.

J. As a result of the British Columbia Utilities Commission decision dated October 25, 1993, the parties desire to enter into this amending and re-stating Agreement to clarify their respective rights and obligations.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the premises, the covenants and agreements contained herein, the parties agree as follows:

ARTICLE 1

DEFINITIONS

1.01 Except where the context expressly states another meaning, the following words will have the following meaning:

"Bypass Pipeline" means those facilities which, but for this Agreement, would have been constructed by Canfor in order to provide Gas service to their pulp mill operations in Prince George, British Columbia.

"ITR" means the annual total revenue received by BC Gas from Canfor for Gas transportation service and sales service to Canfor's Prince George, British Columbia pulp mill operations.

"DTQ" means the Firm DTQ and Interruptible DTQ as defined in the Rate Schedule 22A Transportation Agreement or other transportation agreement related to a Rate Schedule for transportation under which Canfor may elect to receive service.

"Terms and Conditions of the Transportation Schedule" means the terms of the applicable Transportation Rate Schedule, and the Transportation Agreements thereunder, and the General Terms and Conditions of BC Gas, as approved by the British Columbia Utilities Commission by its decision of October 25, 1993 or any subsequent transportation or Gas sales service Rate Schedules accepted for filing by the British Columbia Utilities Commission.

1.02 Except for those terms defined under Article 1.01, terms or expressions used in this Agreement will have the meanings described in the Terms and Conditions of the Transportation Schedule.

ARTICLE 2

TRANSPORTATION SERVICE

2.01 BC Gas will provide firm and interruptible transportation service to Canfor for its pulp mill operations in Prince George, British Columbia and Canfor will accept such transportation services in accordance with the then prevailing provisions of BC Gas Rate Schedule 22A and the accompanying Transportation Agreement for the term of this Agreement and such provisions are incorporated herein by reference.

2.02 Notwithstanding the provisions of Article 2.01, where anything in the Terms and Conditions of the Transportation Schedule conflicts or is inconsistent with the rates, terms and conditions set out in this Agreement, this Agreement governs.

2.03 Canfor will be entitled to elect to take transportation service under a Transportation Rate Schedule other than Schedule 22A subject to the terms and conditions of such Rate Schedule. In such case, Article 2.01 and 2.02 will apply in the same way to the elected Rate Schedule.

2.04 If Canfor in any Contract Year elects to take transportation service pursuant to a Rate Schedule under which monthly Gas balancing provisions result in benefits to Canfor which would not have been available if the Bypass Pipeline had been constructed, the rates specified in Article 4, will be increased for that Contract Year by an amount equal to Canfor's savings resulting from the provision of BC Gas' monthly Gas balancing on the tolls that would have been incurred on the Westcoast pipeline system had Canfor constructed the Bypass Pipeline. The said amount will be determined by BC Gas and paid to BC Gas at the end of the Contract Year.

ARTICLE 3

TERM OF AGREEMENT

3.01 Subject to Article 8, the initial term of this Agreement will be for a period of four (4) Contract Years, effective the 1st Day of November, 1993, up to the 1st Day of November 1997.

3.02 The term of this Agreement may be extended beyond the initial termination date or any subsequent extension thereof upon the terms and conditions of this Agreement, including the pricing provisions, upon Canfor providing written notice to BC Gas of its desire to extend the term of the Agreement for a further specified period, at least 12 months prior to the then current termination date and BC Gas agreeing to such extension of the term of this Agreement. Notwithstanding the foregoing, any extension of the term of this Agreement will be for a period of not less than one year.

ARTICLE 4

RATES AND CHARGES

4.01 Subject to the adjustments hereinafter provided for and based on a DTQ of 226.5 10^3m^3, Canfor each month will pay to BC Gas for services provided hereunder, from November 1, 1988 to the expiry of the Agreement, the following rates:

(i) A monthly charge of $9,781.00

(ii) Any charges pursuant to Articles 4.02, 4.03 and 4.04

4.02 The rates will be adjusted by BC Gas to reflect any changes in costs which would have been incurred by Canfor if it had constructed and operated the Bypass Pipeline, as a result of an increase in the volume of gas actually transported for Canfor to the extent that such increase would have necessitated an increase in the capacity of the Bypass Pipeline or a modification or addition to Bypass Pipeline facilities.

4.03 In addition to the foregoing rates, Canfor will pay to BC Gas at the end of each Contract Year an annual surcharge for increases, if any, in BC Gas costs. The surcharge will be determined as the sum of the following:

(i) cost changes to the estimated 1987 costs set out in Schedule 1 for operation and maintenance expenses that would have been incurred had Canfor constructed and operated the Bypass Pipeline; without limiting the generality of the foregoing, such costs include odorant costs, heating fuel costs, cathodic protection costs and labour costs; and

(ii) costs changes in municipal, provincial or federal taxes and fees, including new taxes or fees, but excluding taxes on taxable income, related to the operation of the Bypass Pipeline that would have been levied had it been constructed and operated by Canfor from the 1987 tax costs set out in line 10 of Schedule 1. For greater clarity, the parties agree that changes in costs of either debt or equity capital and taxes on taxable income are not to be included in the surcharge.

4.04 Any disputes arising hereunder as to the amount of the annual surcharge or the appropriateness of including costs under this Article will be referred to arbitration in accordance with Article 6 of this Agreement.

ARTICLE 5

BYPASS FACILITIES

5.01 The rates herein are based upon the construction of a hypothetical 6.1 kilometers of 6 NPS steel Gas pipeline to service the Canfor, Northwood pulp mill located on the Fraser River in Prince George. The facilities include a measurement and pressure regulation (M & R) station at the mills site.

5.02 The firm capacity of the hypothetical pipeline is 40 10^3M^3 per Hour in order to provide 175 psig pressure to the M & R station. The design capacity of the M & R station is 24 10^3M^3 per Hour at 60 psig delivery pressure to the pulp mill.

5.03 The Firm DTQ permitted hereunder is the lesser of the firm pipeline capacity or M & R station design capacity expressed on a daily basis. In order to meet an hourly delivery obligation of 5% under Schedule 22A, the Firm DTQ is therefore 480 10^3M^3 per Day as at the date of this Agreement (24 Hours divided by the hourly percentage obligation of 0.05. The Firm DTQ shall be adjusted in accordance with changes in capacity as reflected in the rates, or changes in the Hourly delivery obligation under Schedule 22A.

ARTICLE 6

FORCE MAJEURE

6.01 Notwithstanding any of the provisions contained herein or in any Transportation Rate Schedule, Canfor will not be entitled to any monthly charge credits from BC Gas as a result of Force Majeure, as defined in BC Gas Rate Schedule 22, after November 1, 1993.

ARTICLE 7

ARBITRATION

7.01 Any dispute between the parties arising from this Agreement will be resolved by a single arbitrator pursuant to the *Commercial Arbitration Act* of British Columbia or successor legislation, save as expressly provided herein.

7.02 Either party may commence arbitration proceedings by sending to the other party a demand for arbitration setting out the nature of the dispute.

7.03 The parties will have 10 days from receipt of the demand referred to in section 7.02 of this Agreement to agree upon the arbitrator, failing which either party may apply to the Supreme Court of British Columbia to select the arbitrator. The arbitrator must be sufficiently qualified by education and training to decide the particular questions in dispute. Unless otherwise agreed, the arbitrator may not be a past or present employee, officer or director of any of the parties or their respective successors or affiliates, any customer or supplier of Canfor or BC Gas.

7.04 The arbitrator will proceed immediately to hear and determine the matter in dispute and will render a written decision, signed the arbitrator, within 45 days after the appointment, subject to any reasonable delay due to unforeseen circumstances. Notwithstanding the foregoing, if the arbitrator fails to render a decision within 60 days after the appointment then either party may elect to have a new arbitrator appointed in like manner as if none had previously been appointed.

7.05 The decision of the arbitrator will be final and binding upon the parties and the parties will abide by the decision and perform the terms and conditions thereof.

ARTICLE 8

FRANCHISE FEES

8.01 Canfor acknowledges that BC Gas is obligated to pay Franchise Fees to the City of Prince George in an amount equal to 3.09% of the revenues received in each calendar year by BC Gas for Gas consumed within the boundary limits of the City of Prince George.

8.02 Canfor acknowledges that the City of Prince George has disputed the method by which BC Gas will determine Franchise Fees payable to the City in respect of the Gas consumed by Canfor in any calendar year.

8.03 The rates payable by Canfor pursuant to Article 4 hereof include a component for Franchise Fees which is calculated as follows:

$$F = ITR \times .0309$$

Where F = the annual Franchise Fees payable by BC Gas in respect of the Gas consumed by Canfor.

8.04 BC Gas takes the position that the above calculation represents the correct amount for Franchise Fees payable to the City of Prince George in respect of Gas consumed by Canfor and will take all reasonable efforts to defend this position.

8.05 In the event that BC Gas is required by statute, regulation, a court of competent jurisdiction or the British Columbia Utilities Commission to pay the City of Prince George any additional or lesser amount for Franchise Fees in respect of the Gas consumed by Canfor, Canfor will pay BC Gas such additional amounts.

ARTICLE 9

TERMINATION

9.01 In addition to any other rights to terminate this Agreement:

(i) BC Gas may terminate this Agreement if at any time the British Columbia Utilities Commission determines that a revenue shortfall exists on service under this Agreement and disallows BC Gas the recovery from other customers of BC Gas, of any revenue shortfall resulting from these negotiated rates;

(ii) Canfor may terminate this Agreement if at any time the British Columbia Utilities Commission sets rates for the Canfor pulp mill at a level in excess of the negotiated rates set out or provided for herein.

9.02 Any termination pursuant to Article 9.01 will take effect on the next November 1 following the date of notice in writing by the party terminating this Agreement.

ARTICLE 10

NOTICES

10.01 If in any year an executed Transportation Agreement is not in place, then the notice provisions of the last executed Transportation Agreement and Rate Schedule will apply to this Agreement.

ARTICLE 11

MISCELLANEOUS

11.01 This Agreement will not be assigned without the written consent of the other party hereto, which consent will not be unreasonably withheld.

11.02 Notwithstanding Article 11.01, BC Gas may assign, without the consent of Canfor, BC Gas' rights and obligations under this Agreement to a party, which acquires all or substantially all of BC Gas' utility operations.

11.03 Notwithstanding Article 11.01, Canfor, may assign, without the consent of BC Gas, Canfor's rights and obligations under this Agreement to a party which acquires all or substantially all of Canfor's Prince George pulp mill operations served by BC Gas pursuant to this Agreement.

11.04 This Agreement will enure to the benefit of and be binding on the parties and their respective successors and permitted assigns, including without limitation, successors by merger, amalgamation or consolidation.

11.05 This Agreement and all amendments, modifications, alterations or supplements hereto will be governed by the laws in force in the Province of British Columbia as to nature, validity and interpretation.

11.06 This Agreement is of no force or effect until accepted for filing by the British Columbia Utilities Commission. Upon acceptance for filing of the Agreement by the British Columbia Utilities Commission, the Agreement made between the parties as of May 25, 1992 will be cancelled.

11.07 In this Agreement the words, phrases or expressions which are not defined herein and which in the usage custom of the business of the production, transportation, distribution or sale of Gas has an accepted meaning will have that meaning.

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

AGREED TO AND ACCEPTED:

This 29 day of May, 2002

BC GAS UTILITY LTD.

BY: Bill Hennessy
(Signature)

MARKETING SERVICES MANAGER
(Title)

BILL HENNESSY
(Name - Please Print)

AGREED TO AND ACCEPTED:

This 8 day of May, 2002

CANADIAN FOREST PRODUCTS LTD.

BY:
(Signature)

Corporate Secretary
(Title)

David M Calabrigo
(Name - Please Print)

SCHEDULE 1
PAGE 1 OF 4

05-Oct-93
Range 1

INLAND NATURAL GAS CO. LTD.
BYPASS ANALYSIS
$700,000 NORTHWOOD PULP
$165,000 CONNECTION FEE

BASE $700,000 INVESTMENT PAGE 1

Line No.	Particulars		1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Total
1	Allocated Inland/NGT costs		$1,410,299	$915,026	$915,026	$915,026	$915,026	$915,026	$915,026	$915,026	$915,026	$915,026	$9,645,533
3	Incurred WCTL costs		(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(7,976,530)
6	Total available		612,646	117,373	117,373	117,373	117,373	117,373	117,373	117,373	117,373	117,373	1,669,003
8	Operating & maintenance		(30,000)	(30,000)	(30,000)	(30,000)	(30,000)	(30,000)	(30,000)	(30,000)	(30,000)	(30,000)	(300,000)
10	Property taxes		(6,304)	(6,304)	(6,304)	(6,304)	(6,304)	(6,304)	(6,304)	(6,304)	(6,304)	(6,304)	(63,040)
12	Income before tax		576,342	81,069	81,069	81,069	81,069	81,069	81,069	81,069	81,069	81,069	1,305,963
13	Connection fee		(165,000)	0	0	0	0	0	0	0	0	0	(165,000)
14	Interest		(44,250)	(42,038)	(39,825)	(37,613)	(35,400)	(33,188)	(30,975)	(28,763)	(26,550)	(24,338)	(342,940)
16	Capital Cost Allowance		(18,300)	(26,066)	(25,025)	(24,024)	(23,063)	(22,141)	(21,255)	(20,405)	(19,589)	(18,805)	(213,675)
18	Taxable income		333,792	12,965	16,219	19,432	22,606	25,740	28,839	31,901	34,930	37,926	564,348
19	Income tax		(166,425)	(5,420)	(6,536)	(7,625)	(8,638)	(9,701)	(10,869)	(12,022)	(13,165)	(14,294)	(260,700)
20	Investment Tax Credit		35,000	0	0	0	0	0	0	0	0	0	35,000
21	Connection fee		165,000	0	0	0	0	0	0	0	0	0	165,000
22	Capital Cost Allowance		18,300	26,066	25,025	24,024	23,063	22,141	21,255	20,405	19,589	18,805	213,675
24	Operating cash flow		400,457	33,411	34,706	35,831	37,031	38,180	39,225	40,283	41,354	42,437	763,315
25	Equity		(442,500)										
26	Debt repayment		(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(221,250)
28	Net cash flow		(43,968)	11,286	12,581	13,706	14,906	16,055	17,100	18,158	19,229	20,312	542,065
31	Income tax rate - current		43.470%	41.810%	40.310%	39.240%	38.210%	37.690%	37.690%	37.690%	37.690%	37.690%	
33	Debt repayment & interest	50.00%	442,500	420,375	398,250	376,125	354,000	331,875	309,750	287,625	265,500	243,375	
34	Debt - B.O.Y.												
35	Repayment over 20 years		(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	
37	Debt - E.O.Y.		420,375	398,250	376,125	354,000	331,875	309,750	287,625	265,500	243,375	221,250	
40	Interest @ 10%	10.00%	44,250	42,038	39,825	37,613	35,400	33,188	30,975	28,763	26,550	24,338	
43	NPV of net cash flow 1988 - 1997 @		8.450%	$0									
45			(442,500)										(442,500)
46			346,478	8,661	8,367	7,629	7,465	6,952	6,418	6,005	5,453	5,018	408,391
48	Discounted Cash Flows - Annual		(96,022)	8,661	8,367	7,629	7,465	6,952	6,418	6,005	5,453	5,018	(34,107)
49	- Cum.		(96,022)	(87,361)	(79,000)	(71,350)	(63,866)	(56,914)	(50,497)	(44,372)	(39,117)	(34,107)	

SCHEDULE 1
PAGE 2 OF 4

Page 1

INLAND NATURAL GAS CO. LTD.
DCF ANALYSIS
$700,000 [illegible] PULP
$[illegible] CONNECTION FEE

CASE [illegible]
$700,000 INVESTMENT
PAGE 1.1

Line No.	Particulars	Bal. Fwd.	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	Total
1	Avoided Inland/BCT costs	$9,445,[illegible]	$915,026	$915,026	$915,026	$915,026	$915,026	$915,026	$915,026	$915,026	$915,026	$915,026	$915,026	$19,710,[illegible]
3	Incurred WCTL costs	(7,976,[illegible])	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(16,750,711)
5	Total available	1,468,[illegible]	117,373	117,373	117,373	117,373	117,373	117,373	117,373	117,373	117,373	117,373	117,373	2,[illegible]
8	Operating & maintenance	(300,000)	(30,000)	(30,000)	(30,000)	(30,000)	(30,000)	(30,000)	(30,000)	(30,000)	(30,000)	(30,000)	(30,000)	(630,000)
10	Property taxes	(60,000)	(6,304)	(6,304)	(6,304)	(6,304)	(6,304)	(6,304)	(6,304)	(6,304)	(6,304)	(6,304)	(6,304)	(129,344)
12	Income before tax	1,108,[illegible]	81,069	81,069	81,069	81,069	81,069	81,069	81,069	81,069	81,069	81,069	81,069	2,[illegible]
13	Connection fee	(165,000)	0	0	0	0	0	0	0	0	0	0	0	(165,000)
14	Interest	(242,[illegible])	(22,125)	(19,913)	(17,700)	(15,488)	(13,275)	(11,063)	(8,850)	(6,638)	(4,425)	(2,213)	0	(364,[illegible])
16	Capital Cost Allowance	(313,875)	(18,003)	(17,331)	(16,656)	(15,975)	(15,323)	(14,720)	(14,151)	(13,566)	(13,003)	(12,500)	(12,003)	(376,[illegible])
18	Taxable Income	[illegible]	40,891	43,825	46,751	49,609	52,441	55,286	58,068	60,865	63,641	66,356	69,067	1,[illegible]
19	Income Tax	([illegible])	(15,412)	(16,518)	(17,612)	(18,699)	(19,772)	(20,827)	(21,892)	(22,940)	(23,979)	(25,009)	(26,031)	([illegible])
20	Investment Tax Credit	[illegible]	0	0	0	0	0	0	0	0	0	0	0	[illegible]
21	Connection Fee	[illegible]	0	0	0	0	0	0	0	0	0	0	0	[illegible]
22	Capital Cost Allowance	313,875	18,003	17,331	16,656	15,975	15,323	14,720	14,151	13,566	13,003	12,500	12,003	376,[illegible]
24	Operating cash flow	762,[illegible]	43,532	44,638	45,756	46,885	48,021	49,169	50,326	51,491	52,665	53,847	55,038	1,[illegible]
26	Debt repayment	(221,250)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	0	(442,500)
28	Net cash flow	541,[illegible]	21,407	22,513	23,631	24,756	25,896	27,044	28,201	29,366	30,540	31,722	55,038	860,[illegible]
31	Income tax rate - current		37.690%	37.690%	37.690%	37.690%	37.690%	37.690%	37.690%	37.690%	37.690%	37.690%	37.690%	
33	Debt repayment & Interest													
34	Debt - B.O.Y.		221,250	199,125	177,000	154,875	132,750	110,625	88,500	66,375	44,250	22,125	0	
35	Repayment over 10 years		(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	(22,125)	0	
37	Debt - E.O.Y.		199,125	177,000	154,875	132,750	110,625	88,500	66,375	44,250	22,125	0	0	
40	Interest @ 10.000		22,125	19,913	17,700	15,488	13,275	11,063	8,850	6,638	4,425	2,213	0	
43	NPV of net cash flow 1996 - 2006 @ 15.000%		$0											
45			4,590	4,187	3,650	3,466	3,175	2,886	2,611	2,348	2,157	1,950	2,911	34,107
48	Discounted Cash Flows - Annual		4,590	4,187	3,650	3,466	3,175	2,886	2,611	2,348	2,157	1,950	2,911	34,107
49	- Cum.		(29,517)	(25,331)	(21,681)	(18,083)	(14,501)	(11,951)	(9,340)	(6,977)	(4,843)	(2,911)	0	

SCHEDULE 1
PAGE 3 OF 4

SCHEDULE 1
PAGE 3 OF 4

INLAND NATURAL GAS CO. LTD.

BYPASS ANALYSIS
$700,000 NORTHWOOD PULP

REVENUE - AVOIDED GAS PURCHASE COSTS

Range 5

CASE $700,000 / AVG BE 0.294 INVESTMENT / PAGE 3

Line No.	Particulars		1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Total
1	SALES VOLUMES - GJ		3,032,900	3,032,900	3,032,900	3,032,900	3,032,900	3,032,900	3,032,900	3,032,900	3,032,900	3,032,900	30,329,000
2	Less - Bypass												0
3	adjustment	0.0%	0	0	0	0	0	0	0	0	0	0	0
4													
5													
6			3,032,900	3,032,900	3,032,900	3,032,900	3,032,900	3,032,900	3,032,900	3,032,900	3,032,900	3,032,900	30,329,000
7	NET SALES VOLUMES - GJ												
8													
9													
10													
11													
12	AVOIDED COSTS $/GJ - CDN		$0.2020	$0.0387	$0.0387	$0.0387	$0.0387	$0.0387	$0.0387	$0.0387	$0.0387	$0.0387	
13	- WCT		0.2630	0.2630	0.2630	0.2630	0.2630	0.2630	0.2630	0.2630	0.2630	0.2630	
14													
15			0.4650	0.3017	0.3017	0.3017	0.3017	0.3017	0.3017	0.3017	0.3017	0.3017	
16			(0.2630)	(0.2630)	(0.2630)	(0.2630)	(0.2630)	(0.2630)	(0.2630)	(0.2630)	(0.2630)	(0.2630)	
17	COST INCURRED - WCT												
18													
19			$0.2020	$0.0387	$0.0387	$0.0387	$0.0387	$0.0387	$0.0387	$0.0387	$0.0387	$0.0387	
20													
21													
22													
23													
24													
25	AVOIDED PURCHASE COSTS												
26													
27	Avoided costs		$1,410,299	$915,026	$915,026	$915,026	$915,026	$915,026	$915,026	$915,026	$915,026	$915,026	$9,645,533
28													
29	Cost incurred		(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(797,653)	(7,976,530)
30													
31													
32	Total		$612,646	$117,373	$117,373	$117,373	$117,373	$117,373	$117,373	$117,373	$117,373	$117,373	$1,669,003
33													
34													

SCHEDULE 1
PAGE 4 OF 4

CASE [illegible]
$700,000 INVESTMENT
PAGE 2.1

INLAND NATURAL GAS CO. LTD.

BYPASS ANALYSIS
$700,000 NORTHWOOD PULP

REVENUE - REDUCED GAS PURCHASE COSTS

[illegible]

Line No.	Particulars		Bal. Fwd.	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	Total
1	SALES VOLUMES - GJ		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2	Less - [illegible] adjustments	[illegible]	0	0	0	0	0	0	0	0	0	0	0	0	0
7	NET SALES VOLUMES - GJ		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
12	AVOIDED COSTS $/GJ - [illegible]			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
13	- NET			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
17	COST INCURRED - NET			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
				[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
				[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
	REDUCED PURCHASE COSTS														
	Avoided costs		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Cost Incurred		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	Total		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

northwood
pulp and timber limited

PO Box 9000
Prince George, BC Canada V2L 4W2
Tel (604) 962-9611 • Fax (604) 962-3582

August 13, 1997

Henry Dinter
Manager, Industrial Services
BC Gas Utility
1111 West Georgia
Vancouver, B.C.
V6E 4M4

Re: Transportation Agreement dated November 1, 1987

Dear Henry:

This letter will confirm Northwood Pulp's intention to renew the above referenced bypass agreement for a further period of ten years.

In reviewing this agreement clause 3.02 suggests that a twelve month notice period is to be provided. I hope that this later notice is not going to result in any difficulties to BC Gas. While there have been a number of personnel changes with both parties to the agreement I believe it is fair to say that there was a tacit understanding that Northwood's intention would be to renew the agreement.

If any further information is required please contact me directly.

Yours truly,

C. Miller
Manager Purchasing

Canfor Pulp Holding Inc.

October 27, 2006

Mr. Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins:

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Northwood Pulpmill) – dated November 1, 1986.

This is to inform you that Canfor Pulp Limited Partnership ("CPLP"), pursuant to Clause 3.02 of the above agreement, wishes to extend the agreement for a period of one year commencing November 1, 2007 to October 31, 2008. It is CPLP's intent to re-examine the agreement in the coming twelve months to decide on further renewal.

Please acknowledge receipt of this letter.

Sincerely,

CANFOR PULP LIMITED PARTNERSHIP
by its General Partner, Canfor Pulp Holding Inc.

Thomas Sitar,
Chief Financial Officer and Secretary

Cc: Ms. Marie Moffat

1700 West 75th Avenue, Vancouver, British Columbia, Canada V6P 6G2
Telephone 604-661-5269 Fax 604-661-5226 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Intercontinental Pulp Mill

a business of Canfor Pulp Limited Partnership

September 25, 2007

Mr. Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Northwood Pulpmill) – dated November 1, 1988.

Canfor Pulp Limited Partnership, "CPLP" is writing to inform Terasen that pursuant to Clause 3.02 of the above agreement CPLP wishes to extend the agreement for a period of one year commencing November 1, 2008 to November 1, 2009. It is CPLP's intent to re-examine the agreement in the coming twelve months to decide on further renewal.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited Partnership
by its general partner Canfor Pulp Holding Inc.

M Moffat

Marie Moffat
Buyer/Energy Co-ordinator

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Intercontinental Pulp Mill

a business of Canfor Pulp Limited Partnership

September 9, 2008

Mr. Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Northwood Pulpmill) – dated November 1, 1988.

Canfor Pulp Limited Partnership, "CPLP" is writing to inform Terasen that pursuant to Clause 3.02 of the above agreement CPLP wishes to extend the agreement for a period of one year commencing November 1, 2009 to November 1, 2010.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

CANFOR PULP LIMITED
PARTNERSHIP, *by its General Partner,*
CANFOR PULP HOLDING INC.
By:
Rick Remesch, CA, Corporate Controller

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Intercontinental Pulp Mill

a business of Canfor Pulp Limited Partnership

September 29, 2009

Mr. Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Northwood Pulpmill) – dated November 1, 1988.

Canfor Pulp Limited Partnership, "CPLP" is writing to inform Terasen that pursuant to Clause 3.02 of the above agreement CPLP wishes to extend the agreement for a period of one year commencing November 1, 2010 to November 1, 2011.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited Partnership
by its general partner Canfor Pulp Holding Inc.

Rick Remesch, CA
Corporate Controller

cc. Marie Moffat, Canfor Pulp

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
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Canfor Pulp and Paper
Intercontinental Pulp Mill

a business of Canfor Pulp Limited Partnership

October 29, 2010

Mr. Kevin Hodgins
Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Northwood Pulpmill) – dated November 1, 1988.

Canfor Pulp Limited Partnership, "CPLP" is writing to inform Terasen that pursuant to Clause 3.02 of the above agreement CPLP wishes to extend the agreement for a period of one year commencing November 1, 2011 to November 1, 2012.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited Partnership
by its general partner Canfor Pulp Holding Inc.

Rick Remesch

cc. Marie Moffat, Canfor Pulp

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Intercontinental Pulp Mill

a business of Canfor Pulp Limited Partnership

October 19, 2011

Mr. Kevin Hodgins
Fortis BC
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Northwood Pulpmill) – dated November 1, 1988.

Canfor Pulp Limited Partnership, "CPLP" is writing to inform Fortis BC that pursuant to Clause 3.02 of the above agreement CPLP wishes to extend the agreement for a period of one year commencing November 1, 2012 to November 1, 2013.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited Partnership
by its general partner Canfor Pulp Holding Inc.

Rick Remesch

cc. Marie Moffat, Canfor Pulp
Clarke Anderson, Canfor Pulp

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Northwood Pulp Mill

a business of Canfor Pulp Limited Partnership

September 25, 2012

Mr. Kevin Hodgins
Fortis BC
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Northwood Pulp mill) – dated November 1, 1988.

Canfor Pulp Limited Partnership, "CPLP" is writing to inform Fortis BC that pursuant to Clause 3.02 of the above agreement CPLP wishes to extend the agreement for a period of one year commencing November 1, 2013 to November 1, 2014.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited Partnership
by its general partner Canfor Pulp Holding Inc.

Rick Remesch, Corporate Controller

cc. Clarke Anderson, Canfor Pulp
Rajoo Jagtap, Fortis BC

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Northwood Pulp Mill

a business of Canfor Pulp Limited Partnership

CANFOR

October 31st, 2013

Mr. Kevin Hodgins
Fortis BC
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Northwood Pulp mill) – dated November 1, 1988.

Canfor Pulp Limited Partnership, "CPLP" is writing to inform Fortis BC that pursuant to Clause 3.02 of the above agreement CPLP wishes to extend the agreement for a period of one year commencing November 1, 2014 to November 1, 2015.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited Partnership
by its general partner Canfor Pulp Holding Inc.

Rick Remesch, Corporate Controller

cc. Clarke Anderson, Canfor Pulp
Rajoo Jagtap, Fortis BC

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Northwood Pulp Mill

a business of Canfor Pulp Limited

October 2nd, 2014

Mr. Rajoo Jagtap
Fortis BC
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Northwood Pulp mill) – dated November 1, 1988.

Canfor Pulp Limited, "CPL" is writing to inform Fortis BC that pursuant to Clause 3.02 of the above agreement CPL wishes to extend the agreement for a period of one year commencing November 1, 2015 to November 1, 2016.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited
by its general partner Canfor Pulp Holding Inc.

Rick Remesch, Corporate Controller

cc. Clarke Anderson, Canfor Pulp
Kevin Hodgins, Fortis BC

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

Canfor Pulp and Paper
Northwood Pulp Mill

a business of Canfor Pulp Limited

September 10, 2015

Mr. Doug Tufts
Fortis BC
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Dear Mr. Hodgins

RE: Amended and Restated Bypass Agreement for Rate Schedule 22A (Northwood Pulp mill) – dated November 1, 1988.

Canfor Pulp Limited, "CPL" is writing to inform Fortis BC that pursuant to Clause 3.02 of the above agreement CPL wishes to extend the agreement for a period of one year commencing November 1, 2016 to November 1, 2017.

Please acknowledge receipt of this letter so that I may add to my file.

Yours truly,

Canfor Pulp Limited

Rick Remesch, Corporate Controller

cc. Clarke Anderson, Canfor Pulp
Kevin Hodgins, Fortis BC

2533 Prince George Pulpmill Road, Post Office Box 6000, Prince George, British Columbia V2N 2K3
Telephone 250-563-0161 Fax 250-561-3921 info@canforpulp.com www.canforpulp.com

TARIFF SUPPLEMENT NO. G-8

AMENDED AND RESTATED
BYPASS TRANSPORTATION AGREEMENT
FOR RATE SCHEDULE 22A

BETWEEN

CARIBOO PULP & PAPER CO.

AND

FORTISBC ENERGY INC.
(Formerly Terasen Gas Inc. and BC Gas Utility Ltd.)

Effective November 1, 1993

THIS AGREEMENT made as of the 23rd day of March , 2001 , with effect as and from November 1, 1993, is an amendment and restatement of an agreement made as of October 26, 1988 between the parties noted below.

BETWEEN:

BC GAS UTILITY LTD., a company incorporated under the laws of British Columbia having its registered office at 1111 West Georgia Street, Vancouver, British Columbia

(hereinafter called "BC Gas")

OF THE FIRST PART

AND:

CARIBOO PULP & PAPER CO., a joint venture of WELDWOOD OF CANADA LTD. and DAISHOWA-MARUBENI INTERNATIONAL LIMITED, having their respective offices at 1055 and 1066 West Hastings Street, Vancouver, British Columbia

(hereinafter called "Cariboo")

OF THE SECOND PART

WHEREAS:

A. Cariboo operates a pulp mill in the City of Quesnel, British Columbia, and requires Gas for its operations;

B. BC Gas owns and operates a Gas transmission pipeline, which is connected to the pulp mill operations of Cariboo in Quesnel, British Columbia;

C. Cariboo entered into an agreement with BC Gas' predecessor company, Inland Natural Gas Co. Ltd. ("Inland") dated October 30, 1987 which was superceded and replaced by an agreement between Cariboo and Inland dated October 26, 1988 effective November 1, 1987 which allowed Cariboo to receive transportation service from BC Gas at rates reasonably equivalent to the costs that would have been incurred by Cariboo had it constructed the Bypass Pipeline hereinafter defined in 1987;

D. The British Columbia Utilities Commission has endorsed the concept of negotiated rates that are competitive with the Bypass Pipeline alternative.

E. On April 15, 1993, BC Gas filed an application (the "Phase B Rate Design Application") with the British Columbia Utilities Commission for redesign of its Gas tariff Rate Schedules which, among other things, proposed the implementation of common Rate Schedules and General Terms and Conditions of service.

F. Following the completion of the hearing of the Phase B Rate Design Application, the British Columbia Utilities Commission issued its decision dated October 25, 1993, which, in part, approved the implementation of new Rate Schedules effective November 1, 1993 for industrial and general service.

G. As a result of the British Columbia Utilities Commission decision dated October 25, 1993, the parties desire to enter into this amended and restated Agreement to clarify their respective rights and obligations.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the premises, the covenants and agreements contained herein, the parties agree as follows:

ARTICLE 1

DEFINITIONS

1.01 Except where the context expressly states another meaning, the following words will have the following meaning:

"Bypass Pipeline" means those facilities which, but for this Agreement, would have been constructed by Cariboo in order to provide Gas service to their pulp mill operations in Quesnel, British Columbia.

"ITR" means the annual total revenue received by BC Gas from Cariboo for Gas transportation service and sales service to Cariboo's Quesnel, British Columbia pulp mill operations.

"DTQ" means the Firm DTQ and Interruptible DTQ as defined in the Rate Schedule 22A Transportation Agreement or other transportation agreement related to a Rate Schedule for transportation under which Cariboo may elect to receive service.

"Terms and Conditions of the Transportation Schedule" means the terms of the applicable Transportation Rate Schedule, and the Transportation Agreements thereunder, and the General Terms and Conditions of BC Gas, as approved by the British Columbia Utilities Commission by its decision of October 25, 1993 or any subsequent transportation or Gas sales service Rate Schedules accepted for filing by the British Columbia Utilities Commission.

1.02 Except for those terms defined under Article 1.01, terms or expressions used in this Agreement will have the meanings described in the Terms and Conditions of the Transportation Schedule.

ARTICLE 2

TRANSPORTATION SERVICE

2.01 BC Gas will provide firm and interruptible transportation service to Cariboo for its pulp mill operations in Quesnel, British Columbia and Cariboo will accept such transportation services in accordance with the then prevailing provisions of BC Gas Rate Schedule 22A and the accompanying Transportation Agreement for the term of this Agreement and such provisions are incorporated herein by reference.

2.02 Notwithstanding the provisions of Article 2.01, where anything in the Terms and Conditions of Transportation Rate Schedule conflicts or is inconsistent with the rates, terms and conditions set out in this Agreement, this Agreement governs.

2.03 Cariboo will be entitled to elect to take transportation service under a Transportation Rate Schedule other than Schedule 22A subject to the terms and conditions of such Rate Schedule. In such case, Article 2.01 and 2.02 will apply in the same way to the elected Rate Schedule.

2.04 If Cariboo in any Contract Year elects to take transportation service pursuant to a Rate Schedule under which monthly Gas balancing provisions result in benefits to Cariboo which would not have been available if the Bypass Pipeline had been constructed, the rates specified in Article 4, will be increased for that Contract Year by an amount equal to Cariboo's savings resulting from the provision of BC Gas' monthly Gas balancing on the tolls that would have been incurred on the Westcoast pipeline system had Cariboo constructed the Bypass Pipeline. The said amount will be determined by BC Gas and paid to BC Gas at the end of the Contract Year.

ARTICLE 3

TERM OF AGREEMENT

3.01 Subject to Article 8, the initial term of this Agreement will be for a period of four (4) Contract Years, effective the 1st Day of November, 1993, up to the 1st Day of November 1997.

3.02 The term of this Agreement will be extended beyond the initial termination date or any subsequent extension thereof upon the terms and conditions of this Agreement, including the pricing provisions, upon Cariboo providing written notice to BC Gas of its desire to extend the term of the Agreement for a further specified period, at least 12 months prior to the then current termination date and BC Gas agreeing to such extension of the term of this Agreement. Notwithstanding the foregoing, any extension of the term of this Agreement will be for a period of not less than one year.

ARTICLE 4

RATES AND CHARGES

4.01 Subject to the adjustments hereinafter provided for and based on a DTQ of 3,552 gigajoules, Cariboo each month will pay to BC Gas for services provided hereunder, from November 1, 1993 to the expiry of the Agreement, the following rates:

(i) A Demand Charge of $5,868.00

(ii) Any charges pursuant to Articles 4.02, 4.03 and 4.04

4.02 The rates will be adjusted by BC Gas to reflect any changes in costs which would have been incurred by Cariboo as a result of: a material increase in the annual Gas volume actually transported to Cariboo; or an increase in the capacity of the Bypass Pipeline to meet Cariboo's DTQ requirements; or modification or addition to facilities which may reasonably be required for any other reason, had Cariboo constructed and operated the Bypass Pipeline.

4.03 In addition to the foregoing rates, Cariboo will pay to BC Gas at the end of each Contract Year an annual surcharge for increases, if any, in BC Gas' costs. The surcharge will be determined as the sum of the following:

(i) cost changes to the estimated 1987 costs set out in Schedule 1 for operation and maintenance expenses that would have been incurred had Cariboo constructed and operated the Bypass Pipeline; without limiting the generality of the foregoing, such costs include odorant costs, heating fuel costs, cathodic protection costs and labour costs; and

(ii) costs changes in municipal, provincial or federal taxes and fees, including new taxes or fees, but excluding taxes on taxable income, related to the operation of the Bypass Pipeline that would have been levied had it been constructed and operated by Cariboo from the 1987 tax costs set out in line 10 of Schedule 1. For greater clarity, the parties agree that changes in costs of either debt or equity capital and taxes on taxable income are not to be included in the surcharge.

4.04 Any disputes arising hereunder as to the amount of the annual surcharge or the appropriateness of including costs under this Article will be referred to arbitration in accordance with Article 6 of this Agreement.

ARTICLE 5

FORCE MAJEURE

5.01 Notwithstanding any of the provisions contained herein or in any Transportation Rate Schedule, Cariboo will not be entitled to any monthly charge credits from BC Gas as a result of Force Majeure, as defined in BC Gas Rate Schedule 22, after November 1, 1993.

ARTICLE 6

ARBITRATION

6.01 Any dispute between the parties arising from this Agreement will be resolved by a single arbitrator pursuant to the *Commercial Arbitration Act* of British Columbia or successor legislation, save as expressly provided herein.

6.02 Either party may commence arbitration proceedings by sending to the other party a demand for arbitration setting out the nature of the dispute.

6.03 The parties will have 10 days from receipt of the demand referred to in section 6.02 of this Agreement to agree upon the arbitrator, failing which either party may apply to the Supreme Court of British Columbia to select the arbitrator. The arbitrator must be sufficiently qualified by education and training to decide the particular questions in dispute. Unless otherwise agreed, the arbitrator may not be a past or present employee, officer or director of any of the parties or their respective successors or affiliates, any customer or supplier of Cariboo or BC Gas.

6.04 The arbitrator will proceed immediately to hear and determine the matter in dispute and will render a written decision, signed by the arbitrator, within 45 days after the appointment, subject to any reasonable delay due to unforeseen circumstances. Notwithstanding the foregoing, if the arbitrator fails to render a decision within 60 days after the appointment, then either party may elect to have a new arbitrator appointed in like manner as if none had previously been appointed.

6.05 The decision of the arbitrator will be final and binding upon the parties and the parties will abide by the decision and perform the terms and conditions thereof.

ARTICLE 7

FRANCHISE FEES

7.01 Cariboo acknowledges that BC Gas is obligated to pay Franchise Fees to the City of Quesnel, in an amount equal to 3.09% of the revenues received in each calendar year by BC Gas for Gas consumed within the boundary limits of the City of Quesnel.

7.02 The rates payable by Cariboo pursuant to Article 4 hereof include a component for Franchise Fees which is calculated as follows:

$$F = ITR \times .0309$$

Where F = the annual Franchise Fees payable by BC Gas in respect of the Gas consumed by Cariboo.

7.03 BC Gas takes the position that the above calculation represents the correct amount for Franchise Fees payable to the City of Quesnel in respect of Gas consumed by Cariboo and will take all reasonable efforts to defend this position.

7.04 In the event that BC Gas is required by statute, regulation, a court of competent jurisdiction or the British Columbia Utilities Commission to pay the City Quesnel any additional or lesser amount for Franchise Fees in respect of the Gas consumed by Cariboo, Cariboo will pay BC Gas such additional amounts or BC Gas will refund Cariboo such less amount and the rate payable by Cariboo as set out in Article 4 respect of Franchise Fees will be adjusted to reflect this change.

ARTICLE 8

TERMINATION

8.01 In addition to any other rights to terminate this Agreement:

(i) BC Gas may terminate this Agreement if at any time the British Columbia Utilities Commission determines that a revenue shortfall exists on service under this Agreement and disallows BC Gas the recovery from other customers of BC Gas, of any revenue shortfall resulting from these negotiated rates;

(ii) Cariboo may terminate this Agreement if at any time the British Columbia Utilities Commission sets rates for the Cariboo pulp mill operations at a level in excess of the negotiated rates set out or provided for herein.

8.02 Any termination pursuant to Article 8.01 will take effect on the next November 1 following the date of notice in writing by the party terminating this Agreement.

ARTICLE 9

NOTICES

9.01 If in any year an executed Transportation Agreement is not in place, then the notice provisions of the last executed Transportation Agreement and Rate Schedule will apply to this Agreement.

ARTICLE 10

MISCELLANEOUS

10.01 This Agreement will not be assigned without the written consent of the other party hereto, which consent will not be unreasonably withheld.

10.02 Notwithstanding Article 10.01, BC Gas may assign, without the consent of Cariboo, BC Gas' rights and obligations under this Agreement to a party, which acquires all or substantially all of BC Gas' utility operations.

10.03 Notwithstanding Article 10.01, Cariboo, may assign, without the consent of BC Gas, Cariboo's rights and obligations under this Agreement to a party which acquires all or substantially all of Cariboo's Quesnel pulp mill operations served by BC Gas pursuant to this Agreement.

10.04 This Agreement will enure to the benefit of and be binding on the parties and their respective successors and permitted assigns, including without limitation, successors by merger, amalgamation or consolidation.

10.05 This Agreement and all amendments, modifications, alterations or supplements hereto will be governed by the laws in force in the Province of British Columbia as to nature, validity and interpretation.

10.06 This Agreement is of no force or effect until accepted for filing by the British Columbia Utilities Commission. Upon acceptance for filing of the Agreement by the British Columbia Utilities Commission, the Agreement made between the parties as of October 26, 1988 will be cancelled.

10.07 In this Agreement the words, phrases or expressions which are not defined herein and which in the usage custom of the business of the production, transportation, distribution or sale of Gas has an accepted meaning will have that meaning.

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

AGREED TO AND ACCEPTED:

This 29 day of May, 2002

BC GAS UTILITY LTD.

BY: Bill Hennessey
(Signature)

Marketing Services Manager
(Title)

BILL HENNESSEY
(Name - Please Print)

AGREED TO AND ACCEPTED:

This 2ND day of April, 2001

WELDWOOD OF CANADA LTD.

BY: Paul Richards
(Signature)

VICE-PRESIDENT, PULP MANUFACTURING.
(Title)

PAUL RICHARDS
(Name - Please Print)

DAISHOWA-MARUBENI INTERNATIONAL LTD.

BY: T. Kawamura
(Signature)

PRESIDENT
(Title)

Tokiro Kawamura
(Name - Please Print)

SCHEDULE 1
PAGE 1 OF 4

SCHEDULE 1
PAGE 1 OF 4

11-Oct-88
Range I

INLAND NATURAL GAS CO. LTD.
BYPASS ANALYSIS
$391,000 CARIBOO PULP & PAPER
$15,000 CONNECTION FEE

CASE CPP T1 0.706
$391,000 INVESTMENT
PAGE 1

Line No.	Particulars		1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Total
1	Avoided Inland/VCT costs		$274,802	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$908,483
3	Incurred WCTL costs		0	0	0	0	0	0	0	0	0	0	0
6	Total available		274,802	70,409	70,409	70,409	70,409	70,409	70,409	70,409	70,409	70,409	908,483
8	Operating & maintenance		(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(180,000)
10	Property taxes		(1,451)	(1,451)	(1,451)	(1,451)	(1,451)	(1,451)	(1,451)	(1,451)	(1,451)	(1,451)	(14,510)
12	Income before tax		255,351	50,958	50,958	50,958	50,958	50,958	50,958	50,958	50,958	50,958	713,973
14	Interest		(16,240)	(15,428)	(14,616)	(13,804)	(12,992)	(12,180)	(11,368)	(10,556)	(9,744)	(8,932)	(125,860)
15	Connection fee		(15,000)	0	0	0	0	0	0	0	0	0	(15,000)
16	Capital Cost Allowance		(7,429)	(14,561)	(13,978)	(13,419)	(12,883)	(12,367)	(11,873)	(11,398)	(10,942)	(10,504)	(119,354)
18	Taxable income		216,682	20,969	22,364	23,735	25,083	26,411	27,717	29,004	30,272	31,522	453,759
19	Income Tax		(95,058)	(8,876)	(9,467)	(10,047)	(10,618)	(11,180)	(11,733)	(12,277)	(12,814)	(13,343)	(195,413)
20	Investment Tax Credit		19,550	0	0	0	0	0	0	0	0	0	19,550
21	Connection fee		15,000	0	0	0	0	0	0	0	0	0	15,000
22	Capital Cost Allowance		7,429	14,561	13,978	13,419	12,883	12,367	11,873	11,398	10,942	10,504	119,354
24	Operating cash flow		163,603	26,654	26,875	27,107	27,348	27,598	27,857	28,125	28,400	28,683	412,250
26	Debt repayment		(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(81,200)
28	Net cash flow		155,483	18,534	18,755	18,987	19,228	19,478	19,737	20,005	20,280	20,563	331,050
31	Income tax rate - current		43.870%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	
33	Debt repayment & interest												
34	Debt - B.O.Y.	40.00%	162,400	154,280	146,160	138,040	129,920	121,800	113,680	105,560	97,440	89,320	
35	Repayment over 20 years		(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	
37	Debt - E.O.Y.		154,280	146,160	138,040	129,920	121,800	113,680	105,560	97,440	89,320	81,200	
40	Interest @ 10%	10.00%	16,240	15,428	14,616	13,804	12,992	12,180	11,368	10,556	9,744	8,932	

NPV of net cash flow 1988 - 1997 @ 9.850% ($0)

SCHEDULE 1
PAGE 2 OF 4

Range J

INLAND NATURAL GAS CO. LTD.
BYPASS ANALYSIS
$391,000 CARIBOO PULP & PAPER
$15,000 CONNECTION FEE

CASE $391,000 CPP 11 0.708 INVESTMENT PAGE 1.1

Line No.	Particulars	Bal.Fwd.	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	Total
1	Avoided Inland/WCT costs	$908,483	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$1,682,982
3	Incurred WCTL costs	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total available	908,483	70,409	70,409	70,409	70,409	70,409	70,409	70,409	70,409	70,409	70,409	70,409	1,682,982
8	Operating & maintenance	(180,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(18,000)	(378,000)
10	Property taxes	(14,510)	(1,451)	(1,451)	(1,451)	(1,451)	(1,451)	(1,451)	(1,451)	(1,451)	(1,451)	(1,451)	(1,451)	(30,471)
12	Income before tax	713,973	50,958	50,958	50,958	50,958	50,958	50,958	50,958	50,958	50,958	50,958	50,958	1,274,511
14	Interest	(125,860)	(8,120)	(7,308)	(6,496)	(5,684)	(4,872)	(4,060)	(3,248)	(2,436)	(1,624)	(812)	0	(170,520)
15	Connection fee	(15,000)	0	0	0	0	0	0	0	0	0	0	0	(15,000)
16	Capital Cost Allowance	(119,354)	(10,084)	(9,680)	(9,293)	(8,922)	(8,565)	(8,222)	(7,893)	(7,577)	(7,274)	(6,983)	(6,704)	(210,551)
18	Taxable Income	453,759	32,754	33,970	35,169	36,352	37,521	38,676	39,817	40,945	42,060	43,163	44,254	878,440
19	Income Tax	(195,413)	(13,865)	(14,380)	(14,887)	(15,388)	(15,883)	(16,372)	(16,855)	(17,332)	(17,804)	(18,271)	(18,733)	(375,183)
20	Investment Tax Credit	19,550	0	0	0	0	0	0	0	0	0	0	0	19,550
21	Connection Fee	15,000	0	0	0	0	0	0	0	0	0	0	0	15,000
22	Capital Cost Allowance	119,354	10,084	9,680	9,293	8,922	8,565	8,222	7,893	7,577	7,274	6,983	6,704	210,551
24	Operating cash flow	412,250	28,973	29,270	29,575	29,886	30,203	30,526	30,855	31,190	31,530	31,875	32,225	746,358
26	Debt repayment	(81,200)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	0	(162,400)
28	Net cash flow	331,050	20,853	21,150	21,455	21,766	22,083	22,406	22,735	23,070	23,410	23,755	32,225	585,958
31	Income tax rate - current		42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	42.330%	
33	Debt repayment & interest													
34	Debt - B.O.T.		81,200	73,080	64,960	56,840	48,720	40,600	32,480	24,360	16,240	8,120	0	
35	Repayment over 20 years		(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	(8,120)	0	
37	Debt - E.O.T.		73,080	64,960	56,840	48,720	40,600	32,480	24,360	16,240	8,120	0	0	
40	Interest @ 10.00%		8,120	7,308	6,496	5,684	4,872	4,060	3,248	2,436	1,624	812	0	
43	NPV of net cash flow 1988 - 2008 @	15.000%	($0)											

SCHEDULE 1
PAGE 3 OF 4

INLAND NATURAL GAS CO. LTD.

BYPASS ANALYSIS
$391,000 CARIBOO PULP & PAPER

REVENUE - REDUCED GAS PURCHASE COSTS

Range 5

CASE CMP 11 0.7%
$391,000 INVESTMENT
PAGE 2

Line No.	Particulars		1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	Total
1	SALES VOLUMES - GJ		1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	13,671,740
2	Less - Strike												0
3	adjustment	0.0%	0	0	0	0	0	0	0	0	0	0	0
7	NET SALES VOLUMES - GJ		1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	13,671,740
12	AVOIDED COSTS $/GJ - INC		$0.2010	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	
13	- WCT		0.0000	0.0000	0.0000	0.0000	0.0000	5.0000	0.0000	0.0000	0.0000	0.0000	
16			0.2010	0.0515	0.0515	0.0515	0.0515	0.0515	0.0515	0.0515	0.0515	0.0515	
17	COST INCURRED - WCT		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
20			$0.2010	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	
25	REDUCED PURCHASE COSTS												
27	Avoided costs		$274,802	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$908,483
29	Cost Incurred		0	0	0	0	0	0	0	0	0	0	0
32	Total		$274,802	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$908,483

SCHEDULE 1
PAGE 4 OF 4

CASE $391,000 CPP T1 0.708 INVESTMENT PAGE 2.1

INLAND NATURAL GAS CO. LTD.

BYPASS ANALYSIS
$391,000 CARIBOO PULP & PAPER

REVENUE - REDUCED GAS PURCHASE COSTS

Range 4

Line No.	Particulars		Bal.Fwd.	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	Total
1	SALES VOLUMES - GJ		13,671,740	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	28,710,654
2	Less - Strike														
3	adjustment	0.0%	0	0	0	0	0	0	0	0	0	0	0	0	0
7	NET SALES VOLUMES - GJ		13,671,740	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	1,367,174	28,710,654
12	AVOIDED COSTS $/GJ - TMO			$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	
13	- WCT			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
15				0.0515	0.0515	0.0515	0.0515	0.0515	0.0515	0.0515	0.0515	0.0515	0.0515	0.0515	
16				0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
17	COST INCURRED - WCT														
20				$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	$0.0515	
25	REDUCED PURCHASE COSTS														
27	Avoided costs		$908,483	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$1,682,982
29	Cost incurred		0	0	0	0	0	0	0	0	0	0	0	0	0
32	Total		$908,483	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$70,409	$1,682,982

SCHEDULE 1
PAGE 4 OF 4

Cariboo

October 24, 1996

BC Gas Utility Ltd.
1111 West Georgia Street
Vancouver, BC
V6B 4M4

Attention: Mr. David M. Masuhara, Vice President
Legal and Regulatory Affairs

Dear Sir:

Pursuant to Clause 3.02 of the Service Agreement *(Agreement)* for Schedule 22 between Inland Natural Gas Co. Ltd. and Cariboo Pulp & Paper Company dated November 1, 1987, Cariboo hereby serves written notice of its desire to extend the term of the Agreement by three *(3)* years. The first extension Agreement term shall end at 0800 hrs. on November 1, 2000. Cariboo reserves the right to make further extensions pursuant to the provisions of Clause 3.02 of the Agreement.

Yours truly,

CARIBOO PULP & PAPER COMPANY

CKAlmond

Colin Almond,
Controller

CKA/rmk

\ABCGAgrmt.sam

FACSIMILE MESSAGE

To: Ken Fuhr
BC Gas Utility Ltd.

Date: October 20,1999

Fax No: 443-6770

Pages (including this one) 1

Re: BC Gas Bypass Transportation Agreement
Effective November 1, 1998 to November 1, 2000

Please accept this facsimile message as notification to extend the terms and rates of the above noted Transportation Agreement as amended from time to time, in accordance with your Bypass Agreement. We would request that the Transportation Agreement be extended for 2 years to November 1, 2002

We understand that you will be preparing the necessary documentation to affect this extension.

We thank you for your past services provided and look forward to a mutually satisfactory arrangement in future.

Roger Kreitzer
Purchasing Supervisor; Cariboo Pulp & Paper

cc: Harry Chivers
Avista Energy Canada, Ltd.

Cariboo

October 24, 2001

Ms. Melissa Philion
BC Gas Utility Ltd.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Fax No: (604) 592-7894

Dear Ms. Philion:

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and BC Gas Utility Ltd. for a further two years for expiry November 1, 2004. The current agreement expires November 1, 2002.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Avista Energy Canada, Ltd.

Thank you

Robert C. Hesketh
Materials Manager
Cariboo Pulp & Paper Company
PO Box 7500
Quesnel B.C.
V2J 3J6

Cariboo Pulp & Paper Company, P.O. Box 7500, Quesnel, B.C. V2J 3J6 Telephone: (250) 992-0200 Telefax: (250) 992-2164

Cariboo

October 14, 2003

Ms. Melissa Philion
BC Gas Utility Ltd.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7
Fax No: 604-592-7894

Dear Melissa:

RE: Bypass Agreement Extension Request

Please accept this letter as notice of our desire to extend the existing Bypass-Agreement between our firm and Terasen Gas for a further year for expiry November 1, 2005. The current agreement expires November 1, 2004.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Avista Energy Canada, Ltd.

Thank you.

Yours truly,

Robert C. Hesketh
Materials Manager

cc: Mary McCordic, Avista Energy Canada, Ltd. (fax no: 604-682-6447)

Cariboo Pulp & Paper Company, P.O. Box 7500, Quesnel, B.C. V2J 3J6 Telephone: (250) 992-0200 Telefax: (250) 992-2164

Cariboo

October 5, 2004

Mr. Gordon Doyle
BC Gas Utility Ltd.
16705 Fraser Highway
Surrey, B.C.
V3S 2X7
Fax No: 604-592-7894

Dear Gord:

RE: Bypass Agreement Extension Request

Please accept this letter as notice of our desire to extend the existing Bypass Agreement between our firm and Terasen Gas for a further year for expiry November 1, 2006. The current agreement expires November 1, 2005.

Please confirm receipt of this letter and the extension of the agreement in writing to the undersigned, along with a copy to our agent, Avista Energy Canada, Ltd.

Thank you.

Yours truly,

Robert C Hesketh
MATERIALS MANAGER

cc: Mary McCordic, Avista Energy Canada, Ltd. (fax no: 604-682-6447)

Cariboo Pulp & Paper Company, P.O. Box 7500, 600 North Star Road, Quesnel, B.C. V2J 3J6 Phone: (250) 992-0200 Fax: (250) 992-2164

Cariboo

Terasen Gas
16705 Fraser Highway
Surrey, British Columbia
V3S 2X7
Fax: (604) 592-7894

September 23, 2005

Attention: Kevin Hodgins

Re: Amended and Restated Bypass Transportation Agreement for Rate Schedule 22A Between Cariboo Pulp & Paper Co. and Terasen Gas Inc.

Dear Sir,

In accordance with Article 3.02, we request the above noted agreement be extended for a period of three (3) years, effective November 1, 2006.

Please do not hesitate to contact me if you have any questions or require further information.

Sincerely,

Bob Hesketh
Materials Manager
Cariboo Pulp & Paper Co.
Phone: (250) 992-0291

Cariboo Pulp & Paper Company, P.O. Box 7500, 600 North Star Road, Quesnel, B.C. V2J 3J6 Phone: (250) 992-0200 Fax: (250) 992-2164

Cariboo
Cariboo Pulp & Paper Company

P.O. Box 7500
Quesnel, B.C. V2J 3J6

August 22, 2008

Terasen Gas
16705 Fraser Highway
Surrey, British Columbia
V3S 2X7

Attention : Mr. Kevin Hodgins:

Re: Amended and Restated Bypass Transportation Agreement for Rate Schedule 22A Between Cariboo Pulp & Paper Company and Terasen Gas Inc..

Dear Mr. Hodgins,

In accordance with Article 3.02, we request the above noted agreement be extended for a period of three (3) years, effective November 1, 2009.

Please do not hesitate to contact me if you have any questions or require further information.

Regards,

Mike Pagurut
Controller
Cariboo Pulp & Paper Company
Phone : 250-992-0204
cc. ANDREW KIM

Cariboo Pulp & Paper Company

P.O. Box 7500
50 North Star Road
Quesnel, B.C. V2J 3J6

October 17, 2011

Terasen Gas Corporate Office
16705 Fraser Highway, Surrey
V3S 2X7

Attention: Kevin Hodgins
Key Account Manager

RE: Bypass Transportation Agreement – Cariboo Pulp & Paper Company

Dear Kevin:

As per clause 3.02 of the above stated agreement, Cariboo Pulp & Paper Company would like to request that the Bypass agreement be extended for a further period of **5 years** to November 1st 2017.

Sincerely,

Mike Pagurut

Mike Pagurut

Controller, Cariboo Pulp & Paper Company

TARIFF SUPPLEMENT NO. G-10

BYPASS TRANSPORTATION AGREEMENT
FOE RATE SCHEDULE 22

DATED MAY 1, 1998

BETWEEN

FORTISBC ENERGY INC.
(Formerly Terasen Gas Inc. and BC Gas Utility Ltd.)

AND

WEST FRASER MILLS LTD.
(WESTPINE)

THIS AGREEMENT made as of the 1st day of May, 1998, with effect as and from November 1, 1996.

BETWEEN:

BC GAS UTILITY LTD., a company incorporated under the laws of British Columbia having its registered office at 1111 West Georgia Street, Vancouver, British Columbia

(hereinafter called "BC Gas")

OF THE FIRST PART

AND:

WEST FRASER MILLS LTD., a company incorporated under the laws of British Columbia having its head office at Suite 1000, 1100 Melville Street, Vancouver, British Columbia

(hereinafter called "WestPine")

OF THE SECOND PART

WHEREAS:

A. WestPine operates an MDF plant in Quesnel, British Columbia, (the "MDF Plant"), and requires Gas for its operations;

B. BC Gas owns and operates a Gas transmission pipeline which is connected to the MDF Plant;

C. WestPine desires to enter into an agreement with BC Gas which allows WestPine to receive transportation service from BC Gas at rates reasonably equivalent to the costs that would have been incurred by WestPine had it constructed the Bypass Pipeline (hereinafter defined) in 1996;

D. The British Columbia Utilities Commission has endorsed the concept of negotiated rates that are competitive with a Bypass Pipeline alternative.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the premises, the covenants and agreements contained herein, the parties agree as follows:

ARTICLE 1

DEFINITIONS

1.01 Except where the context expressly states another meaning, the following words will have the following meaning:

"British Columbia Utilities Commission" means the British Columbia Utilities Commission established pursuant to the Utilities Commission Act or other regulatory tribunal having authority over the tariffs and rates of BC Gas.

"Bypass Pipeline" means those facilities which, but for this Agreement, would have been constructed by WestPine in order to provide Gas service to its MDF Plant.

"Contract Year" means a period of 12 consecutive months commencing on November 1 and ending on the next succeeding 1st day of November.

"DTQ" means the Firm DTQ as defined in the Rate Schedule 22 Transportation Agreement or other transportation agreement related to a Rate Schedule for transportation under which WestPine may receive service for the MDF Plant.

"Operating and Maintenance Expenses" means the expenses incurred by BC Gas to operate, maintain and administer its facilities.

"Property Taxes" means the payment required by municipalities or the provincial government to pay for services they deliver consistent with the legislative authority to do so.

"Terms and Conditions of the Transportation Schedule" means the terms of the applicable Transportation Rate Schedule as described in Article 2 and the Transportation Agreement thereunder, and the General Terms and Conditions of BC Gas, as approved by the British Columbia Utilities Commission effective November 1, 1996, or any subsequent Transportation Rate Schedules or Gas Sales Service Rate Schedules accepted for filing by the British Columbia Utilities Commission.

"Westcoast" means Westcoast Energy Inc.

1.02 Except for those terms defined under Article 1.01, terms or expressions used in this Agreement will have the meanings described in the Terms and Conditions of the Transportation Schedule.

ARTICLE 2

TRANSPORTATION SERVICE

2.01 BC Gas will provide firm and interruptible transportation service to WestPine for its MDF Plant, and WestPine will accept such transportation service in accordance with the then prevailing provisions of BC Gas Rate Schedule 22 and the accompanying Transportation Agreement, for the term of this Agreement and such provisions, except where specifically stated otherwise herein, are incorporated herein by reference.

2.02 Notwithstanding the provisions of Article 2.01, if anything in the Terms and Conditions of the Schedule conflicts or is inconsistent with the rates, terms and conditions set out in this Agreement, this Agreement shall govern.

2.03 The following terms and conditions set out in Rate Schedule 22 do not apply, and are not incorporated by reference, to this Agreement

-section 5 (Table of Charges items a), b) and g) relating to Basic, Delivery and Administration Charges)
-section 6 (Minimum Charge)

2.04 WestPine will be entitled to take transportation service under a Transportation Rate Schedule other than Rate Schedule 22 subject to the terms and conditions of such Rate Schedule. In such case, Articles 2.01, 2.02 and 2.03 will apply in the same way to the elected Rate Schedule.

ARTICLE 3

TERM OF AGREEMENT

3.01 Subject to Article 8, the initial term of this Agreement will be for a period of 20 Contract Years, effective the 1st Day of November, 1996, up to the 1st Day of November 1, 2016.

3.02 The term of this Agreement will continue from year to year after the expiry of the initial term unless cancelled by either BC Gas or WestPine upon not less than 6 months notice prior to the end of the Contract Year then in effect.

ARTICLE 4

RATES AND CHARGES

4.01 Subject to the adjustments hereinafter provided, WestPine will each month pay to BC Gas for services as defined in Rate Schedule 22 provided hereunder the following rates:

(i) a monthly charge composed of a monthly facilities charge, operating, maintenance and property taxes as specified in Schedule 1 attached hereto ("the Monthly Charge");

(ii) Franchise Fees, as defined in article 7 below, as required to be paid by BC Gas, as specified in Schedule 1 attached hereto; and

(iii) any charges pursuant to Articles 4.02, 4.03.

4.02 The rates contained herein are based upon capacity and demand assumptions for the Bypass Pipeline, as specified in Schedule 2 attached hereto. Should WestPine consumption exceed the contracted demand of 5,000 Gigajoules per day on more than ten days in the Contract Year, BC Gas may at its sole discretion adjust the rates on a go forward basis to reflect the incremental costs of a correspondingly larger pipeline and facilities.

4.03 The rates under 4.01 (b)(i) shall be adjusted on November 1 of each year of the Term or any renewal thereof, on the following basis to compensate BC Gas for changes in its cost, including;

(i) the Operating and Maintenance expenses shall be subject to the annual percentage change in the British Columbia Consumer Price Index. The Monthly Charge shall be adjusted by the calculated change in costs. The adjusted Operating and Maintenance expenses shall form the basis for the following Contract Year adjustment;

(ii) the Property Taxes shall be subject to adjustment based upon the most recent assessed values from the British Columbia Assessment Authority which would be applicable to the Bypass Pipeline multiplied by the most recent rates; and

(iii) any amounts to recover cost changes in Municipal, Provincial or Federal taxes and fees, including new taxes or fees, but excluding taxes on taxable income, related to the operation of the Bypass Pipeline that would have been levied had it been constructed and operated by WestPine, shall be added to the Monthly Charge.

4.04 Any disputes arising hereunder as to any costs, rates, or charges under Article 4.02 and 4.03 will be referred to arbitration in accordance with Article 5 or this Agreement.

4.05 The rates under 4.01 were based on the assumptions as specified in Schedule 2 attached hereto.

ARTICLE 5

ARBITRATION

5.01 Any dispute between the parties arising from this Agreement will be resolved by a single arbitrator pursuant to the *Commercial Arbitration Act* of British Columbia or successor legislation, save as expressly provided herein.

5.02 Either party may commence arbitration proceedings by sending to the other part a demand for arbitration setting out the nature of the dispute.

5.03 The parties will have 10 days from receipt of the demand referred to in section 7.2 of this Agreement to agree upon the arbitrator, failing which either party may apply to the Supreme Court of British Columbia to select the arbitrator. The arbitrator must be sufficiently qualified by education and training to decide the particular questions in dispute. Unless otherwise agreed, the arbitrator may not be a past or present employee, officer or director of any of the parties or their respective successors or affiliates, any customer or supplier of WestPine or BC Gas.

5.04 The arbitrator will proceed immediately to hear and determine the matter in dispute and will render a written decision, signed by the arbitrator, within 45 days after the appointment, subject to any reasonable delay due to unforeseen circumstances. Notwithstanding the foregoing, if the arbitrator fails to render a decision within 60 days after the appointment then either party may elect to have a new arbitrator appointed in like manner as if none had previously been appointed.

5.05 The decision of the arbitrator will be final and binding upon the parties and the parties will abide by the decision and perform the terms and conditions thereof.

ARTICLE 6

FORCE MAJEURE

6.01 Notwithstanding any of the provisions contained herein or in any transportation or sales Rate Schedule, WestPine will not be entitled to any monthly charge credits from BC Gas as a result of Force Majeure, as defined in BC Gas Rate Schedule 22.

ARTICLE 7

FRANCHISE FEES

7.01 WestPine acknowledges that BC Gas is obligated to pay Franchise Fees to Quesnel in an amount equal to 3% of the amount received in each calendar year by BC Gas for Gas consumed within the boundary limits of such municipality. It is acknowledged that the WestPine operations are within Quesnel. BC Gas covenants that it is obligated to pay franchise fees to Quesnel.

7.02 The rates payable by WestPine pursuant to Article 4 hereof include a component for franchise fees which is calculated as follows:

$$F = 0.03 \times AC / .097$$

Where F = the annual franchise fees payable by BC Gas in respect of the gas consumed by WestPine; and

Where AC = the annual total of the Monthly Charge, operating and maintenance expense and property, taxes as outlined in Article 4.

7.03 In the event that BC Gas is required by agreement, statute, regulation, an arbitrator, a court of competent jurisdiction or the British Columbia Utilities Commission to pay Quesnel any additional or lesser amount for franchise fees in respect of the gas consumed by WestPine, WestPine shall pay BC Gas such equal amount, and the rate payable by WestPine as set out in Article 4 shall be adjusted to reflect this additional or lesser charge.

ARTICLE 8

CONDITIONS PRECEDENT

8.01 All obligations of the parties to this Agreement are subject to formal execution of this Agreement and acceptance for filing by the British Columbia Utilities Commission of the rates and terms and conditions set out herein.

ARTICLE 9

TERMINATION

9.01 In addition to any other rights to terminate this Agreement:

(i) BC Gas may terminate this Agreement if at any time the British Columbia Utilities Commission determines that a revenue shortfall exists on service under this Agreement and disallows BC Gas the recovery from other customers of BC Gas, of any revenue shortfall resulting from these negotiated rates;

(ii) WestPine may terminate this Agreement if at any time the British Columbia Utilities Commission sets rates for the MDF Plant at a level in excess of the negotiated rates set out herein; and

(iii) WestPine may terminate this Agreement if the operations of its MDF Plant permanently cease or if the MDF Plant permanently ceases to use gas.

9.02 Any termination pursuant to Article 9.01 will take effect on the November 1 following the date of notice in writing by the party terminating this Agreement.

9.03 Termination of this Agreement by WestPine, unless pursuant to Article 9.01 (ii) will require immediate payment by WestPine to BC Gas of an amount equal to the monthly charge at the time of termination multiplied by the number of months remaining in the term of this Agreement.

Notwithstanding any such payment, all facilities serving the MDF Plant will remain the property of BC Gas.

9.04 If WestPine fails or neglects at any time to perform the obligations imposed upon WestPine under this Agreement, and does not, within 30 days after BC Gas has given notice of such failure or neglect, commence to remedy with due diligence and thereafter continue to remedy the matter in which it is in default, then BC Gas may discontinue the transportation of Gas to WestPine under this Agreement; but such discontinuance will not relieve WestPine from its obligations under this Agreement. BC Gas may resume the transportation of Gas under this Agreement after such failure or neglect has been fully remedied; or may at its sole discretion, terminate this Agreement.

9.05 If WestPine becomes bankrupt or insolvent or commits or suffers an act of bankruptcy or of insolvency or if a receiver is appointed over the operations of the MDF Plant pursuant to a statute or under a debt instrument or if WestPine seeks protection from the demands of its creditors pursuant to any legislation enacted for that purpose, BC Gas will have the right, at its sole discretion, to terminate this Agreement by giving notice in writing to WestPine and thereupon BC Gas may cease further transportation of Gas to the MDF Plant under this Agreement and BC Gas may terminate this Agreement.

9.06 Termination of this Agreement by BC Gas pursuant to Article 9.04 or 9.05 will entitle BC Gas to require immediate payment by WestPine to BC Gas of an amount equal to the monthly charge at the time of termination multiplied by the number of months remaining in the term of this Agreement.

Notwithstanding any such payment, all facilities serving the MDF Plant will remain the property of BC Gas.

9.07 Except if termination of this Agreement is pursuant to Article 9.05, any termination payment to be paid by WestPine in full in accordance with Articles 9.03 or 9.06 may be subject to a discount to reflect the earlier receipt by BC Gas of payments from WestPine due under this Agreement. The reduced amount of the payment will be based upon discounting the future payments to the date payment is made at BC Gas' average cost of funds. BC Gas' average costs of funds will be its weighted average before tax cost of short and long term debt and after tax return on preferred and common equity, at the time of termination.

9.08 It is understood that payment made under Articles 9.03, 9.06 or 9.07 is assumed to include any de-commissioning costs that WestPine would have incurred if WestPine owned the facilities and no further payment for de-commissioning costs will be required.

ARTICLE 10

GAS BALANCING

10.01 The MDF Plant will be subject to the Gas balancing provisions set out in Rate Schedule 22.

10.02 If WestPine in any Contract Year elects to take transportation service pursuant to a Rate Schedule under which the Gas balancing provisions result in benefits to WestPine which would not have been available if the Bypass Pipeline had been constructed, the rates specified in Article 4 will be increased for that Contract Year by an amount equal to WestPine's savings resulting from the provision of BC Gas' daily or monthly balancing on the tolls that would have been incurred on the Westcoast system. The said amount shall be determined and paid to BC Gas at the end of the Contract Year then in effect.

10.03 Notwithstanding Article 9.02 and provided that BC Gas waives its right to collect WestPine's benefits under Article 9.02, if at any time during the term of this Agreement the British Columbia Utilities Commission approves a specific rate for monthly Gas balancing, then WestPine agrees to pay such approved rate in addition to the rates specified in Article 4.

ARTICLE 11

NOMINATION

11.01 The MDF Plant will be subject to the nomination provisions set out in Rate Schedule 22.

ARTICLE 12

LIMITATION ON LIABILITY AND INDEMNITY

12.1 WestPine will indemnify, defend and hold harmless each of BC Gas, its officers, directors, employees, contractors and agents from all liability, adverse claims, losses, suits, actions, judgements, demands, debt, accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) for injury to, or death, of any and all persons; and for damage, destruction or loss (except consequential damages or loss) to or of any and all property, real or personal (including but not limited to damage to the facilities servicing the MDF Plant and the cost of any Gas loss due to the damage), resulting directly or indirectly from WestPine's negligent, wrongful or unlawful acts or omissions. WestPine will provide all necessary assistance and assurances as may be required to remit and recover any claims for loss or damage to facilities owned or operated by BC Gas, whether or not covered by insurance.

12.2 BC Gas will indemnify, defend and hold harmless each of WestPine, its officers, directors, employees, contractors and agents from all liability, adverse claims, losses, suits, actions, judgements, demands, debt accounts, damages, costs, penalties and expenses (including all legal fees and disbursements) for injury to, or death, of any and all persons; and for damage, destruction or loss (except consequential damages or loss) to any and all property, real or personal (including but not limited to damage to the facilities serving the MDF Plant and the cost of any Gas loss due to the damage), resulting directly or indirectly from BC Gas' negligent, wrongful or unlawful acts or omissions as related to BC Gas' provision of transportation services herein. BC Gas will provide all necessary assistance and assurances as may be required to remit and recover any claims for loss or damage to facilities owned by WestPine.

12.3 The indemnities in Article 12 shall survive the termination of this Agreement.

ARTICLE 13

MISCELLANEOUS

13.01 Miscellaneous terms of the applicable transportation Rate Schedule will apply to this Agreement. If in any year an executed Transportation Agreement is not in place, then the terms of the latest executed Transportation Agreement and Rate Schedule including the notice provisions will apply to this Agreement.

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

AGREED TO AND ACCEPTED:	AGREED TO AND ACCEPTED:
This ~~25~~ 4th day of ~~MAY~~ JUNE, 1998	This 25 day of MAY, 1998
BC GAS UTILITY LTD.	WEST FRASER MILLS LTD.
BY: (Signature)	BY: (Signature)
Manager, Marketing Services (Title)	GENERAL MANAGER (Title)
Steve Connelly (Name - Please Print)	DAVID HUMBER. (Name - Please Print)

SCHEDULE 1

BYPASS PIPELINE - MONTHLY CHARGES

	TOTAL MONTHLY COST
Monthly Facilities Charge, for the year ending October 31, 1997	$9,069
Operating and Maintenance for the year ending October 31, 1997	$1,066
Property Taxes for the year ending October 31, 1997	$1,475
Monthly Charge for the year ending October 31, 1997	$11,611
Franchise Fees @ 3.09% on the Monthly Facilities Charge, and Operating, Maintenance and Property Taxes, for the year ending October 31, 1997	$ 359
Total charge including Facilities Charge, Operating, Maintenance and Property Taxes and Franchise Fees for the year ending October 31, 1997	$11,970

The rates hereunder shall be subject to adjustment as provided under Article 4.

SCHEDULE 2

BYPASS ASSUMPTIONS

Bypass Pipeline Characteristics:

Length	4.62 km
Diameter	88 mm (3 inch)
Pipeline Pressure (PSIG)	Inlet 500
	Outlet 260
Regulating Station at WestPine Pressure (PSIG)	207
Pipeline Maximum Capacity (MSCFH)	233
Daily Contract Demand (Gigajoules per Day)	5,000
Expected Annual Consumption (Gigajoules per Year)	385,000
Growth Rate of Consumption	Nil

Financial Assumptions:

Capital Investment Required	$684,276
Operating and Maintenance Expenses (Year 1)	$12,797
Property Taxes (Year 1)	$17,699
Franchise Fees Percentage Gross Up	3.09%
Income Tax Rate	38.60%
Large Corporations Tax Rate	0.225%
Corporate Capital Tax Rate	0.300%
Capital Cost Allowance Rate	4.0%
Depreciation Rate	5.0%
Inflation rate included in Model	Nil
Amortization Period (& Contract Life)	20 years

Capital Structure Assumptions:

Debt Component	50.0%
Equity Component	50.0%
Cost of Debt	7.0%
Return on Equity	13.0%

TARIFF SUPPLEMENT NO. G-20

BYPASS TRANSPORTATION AGREEMENT
RATE SCHEDULE 22

BETWEEN

HUSKY ENERGY MARKETING INC.

AND

FORTISBC ENERGY INC.
(Formerly Terasen Gas Inc.)

Effective February 1, 2006

THIS AGREEMENT ("**Agreement**") made as of the 1st day of June, 2005, with effect as of and from February 1, 2006.

BETWEEN:

TERASEN GAS INC. (Inc. No. 368861), a company incorporated under the laws of British Columbia having an office at 24th Floor, 1111 West Georgia Street, Vancouver, British Columbia, V6E 4M4

(hereinafter called "**Terasen Gas**")

OF THE FIRST PART

AND:

HUSKY ENERGY MARKETING INC. (Inc. No. 208018507), a company incorporated under the laws of Alberta having an office in the City of Calgary, Alberta

(hereinafter called "**Husky**")

OF THE SECOND PART

<u>RECITALS</u>

WHEREAS:

A. Husky, or an affiliate of Husky, operates a plant ("**Plant**") in the city of Prince George, British Columbia, and requires Gas for its operations;

B. Terasen Gas owns and operates a Gas transmission pipeline which is connected to the Plant in Prince George, British Columbia;

C. Husky requires a Gas delivery pressure of 425 PSIG;

D. Terasen Gas has determined that adequate capacity exists on the Terasen Gas transmission pipeline to provide the DTQ hereinafter defined;

E. Husky and Terasen Gas agree to enter into a bypass agreement which allows Husky to receive firm transportation service at the required delivery pressure from Terasen Gas at rates reasonably equivalent to the costs that would have been incurred by Husky had it constructed the Bypass Pipeline hereinafter defined; and

F. The British Columbia Utilities Commission has endorsed the concept of negotiated rates that are competitive with the Bypass Pipeline alternative.

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the premises, the covenants and agreements contained herein, the parties agree as follows:

ARTICLE 1

DEFINITIONS

1.01 Except where the context expressly states another meaning, the following words will have the following meaning:

"**Bypass Pipeline**" means those facilities (4", 7.1 km pipeline) which, but for this Agreement, Husky would construct in order to allow Husky to bypass the Terasen Gas transmission and distribution Gas system and provide the DTQ by transporting Gas from the interconnect of Westcoast Energy Inc. to the Plant .

"**DTQ**" means, subject to Section 2.06, the quantity of Gas that Terasen Gas is obligated to transport on a firm basis to a shipper at the Delivery Point on any particular Day and is specified in a Transportation Agreement.

"**Terms and Conditions of the Transportation Rate Schedule**" means the terms of the applicable transportation Rate Schedule and Transportation Agreement thereunder, and the General Terms and Conditions of Terasen Gas, as accepted for filing or approved by the British Columbia Utilities Commission.

1.02 Except for those terms defined under Section 1.01, terms or expressions used in this Agreement will have the meanings described in the Terms and Conditions of the Transportation Rate Schedule.

ARTICLE 2

TRANSPORTATION SERVICE

2.01 Terasen Gas will provide firm transportation service to Husky for its Plant operations near Prince George, British Columbia and Husky will accept such transportation service in accordance with this Agreement, the then prevailing provisions of Terasen Gas Rate Schedule 22 and the accompanying Transportation Agreement for the term of this Agreement and such provisions are incorporated herein by reference.

2.02 Terasen Gas represents and warrants that adequate capacity exists on the Terasen Gas transmission system, and will continue to exist during the term of this Agreement, to provide the DTQ to Husky.

2.03 Notwithstanding the provisions of Section 2.01, where anything in the Terms and Conditions of the Transportation Rate Schedule conflicts or is inconsistent with the terms and conditions set out in this Agreement, this Agreement governs.

2.04 Husky shall be entitled to take service under a transportation Rate Schedule other than Rate Schedule 22 subject to the terms and conditions of such Rate Schedule. In such case, Sections 2.01 and 2.03 will apply in the same way to the elected Rate Schedule.

2.05 If Husky in any Contract Year elects to take transportation service pursuant to a Rate Schedule under which monthly Gas balancing provisions result in benefits to Husky which would not have been available if the Bypass Pipeline had been constructed, the rates specified in Article 4 will be increased for that Contract Year by an amount equal to Husky's savings resulting from Terasen Gas' monthly Gas balancing on the tolls that would have been incurred on the Westcoast pipeline system had Husky constructed the Bypass Pipeline. The said amount will be determined by Terasen Gas and subject to approval by Husky, such approval not to be unreasonably withheld or delayed. Husky shall pay the said amount, upon approval, to Terasen Gas at the end of that Contract Year.

2.06 Husky shall be entitled to the capacity on Terasen Gas' pipeline system as set out in Schedule 3. The minimum DTQ is 3,670 GJs at an after meter delivery pressure of 425 PSIG.

ARTICLE 3

TERM OF AGREEMENT

3.01 Subject to Article 9, the initial term ("**Term**") of this Agreement will be for a period of 10.75 Years, effective from the 1st Day of February 2006 up to the 1st Day of November 2016 ("**Termination Date**").

3.02 The Term of this Agreement will be extended by one full year beyond the initial Termination Date or any subsequent extension thereof upon the terms and conditions of this Agreement, including the rates and charges provided herein, unless Husky provides written notice to Terasen Gas of its desire to terminate this Agreement at least 12 months prior to the then current Termination Date. If it so desires, Husky may also extend the term of this Agreement by more than one year through written notice at least 12 months prior to the then current Termination Date, provided that such extension will be for increments of a full year in each case. Terasen Gas shall not unreasonably withhold agreement to such extension of the Term of this Agreement.

ARTICLE 4

RATES AND CHARGES

4.01 Other than as expressly provided in this Agreement, Husky will not be charged for, nor be liable for, any of the charges and costs set out in the Terms and Conditions of the Transportation Rate Schedule.

4.02 Subject to the adjustments hereinafter provided, Husky will, each Month, pay to Terasen Gas for services provided hereunder the following rates:

(i) subject to Section 4.04, the monthly charge ("**Monthly Charge**") as set out in Schedule 1; and

(ii) all charges pursuant to Sections 4.03, 4.04, 4.05 and 4.06.

4.03 The rates will be adjusted by Terasen Gas to reflect any changes in costs which would have been incurred by Husky as a result of: increasing the capacity of the Bypass Pipeline; or modification or addition to facilities which may reasonably be required for any other reason, had Husky constructed and operated the Bypass Pipeline. Any adjustments will be subject to approval by Husky, not to be unreasonably withheld or delayed.

4.04 The Monthly Charge as specified in Schedule 1 will be adjusted effective November 1 of each Contract Year on the following basis to compensate Terasen Gas for the following changes in its costs:

(i) the operating, maintenance and property tax expenses are included in the Monthly Charge and will be subject to adjustment to reflect the annual percentage change in the Consumer Price Index for the City of Vancouver for the Month of August. The adjusted operating, maintenance and property tax expenses will form the basis for the following Contract Year adjustment; and

(ii) any new or increased tax related to the operation of the Bypass Pipeline that would have been levied had it been constructed and operated by Husky will be calculated on a monthly basis (the annual cost divided by 12) and added to the Monthly Charge specified in Section 4.02 (i) and Schedule 1.

4.05 Unauthorized Overrun Gas, Backstopping Gas and Balancing Gas will be charged for and paid by Husky in accordance with the rate set out in Rate Schedule 22.

4.06 Husky acknowledges that Terasen Gas is obligated to pay Franchise Fees to certain municipalities in which Terasen Gas provides services to Customers. In the event that Terasen Gas is required by statute, agreement, regulation, an arbitrator, a court of competent jurisdiction, or the British Columbia Utilities Commission to pay Franchise Fees or similar or equivalent fees on revenues received from Husky, or in relation to services provided hereunder, in addition to those Franchise Fees calculated and paid by Terasen Gas at the commencement of this Agreement, Husky will pay an amount equal to such additional fees to Terasen Gas and the rates and charges payable by Husky as set out in Sections 4.02 to 4.05 above and the Schedules attached hereto will be adjusted to reflect such change.

ARTICLE 5

FACILITIES INSTALLED

5.01 The rates herein are based upon the costs associated with the construction of a hypothetical 4”, 7.1 km Bypass Pipeline to provide transportation service to Husky including facilities deemed by Terasen Gas to maintain the integrity of supply to other Customers. Such facilities include pipeline, metering, regulating, control and communications equipment. The Bypass Pipeline is based on the assumption that Terasen Gas controlled the design and installation of its facilities while Husky provided the following facilities to Terasen Gas requirements and specifications:

1. Foundation;
2. Foundations and building for meter and regulating housing;
3. Foundation and building for telemetry housing;
4. Secured compound;
5. Electrical service at 120/240 VAC (at delivery point), 70 A, 60 HZ, 1 phase;
6. Lighting and outlets to meter and regulating housing installed to Class1, Division 1, Group D, Canadian Electrical Code; and
7. Telephone Service.

ARTICLE 6

FORCE MAJEURE

6.01 Notwithstanding any of the provisions contained herein or in any transportation Rate Schedule under which Husky takes service. Husky will not be entitled to credits of any monthly charges from Terasen Gas as a result of Shipper being entitled to relief by reason of Force Majeure as defined in the Rate Schedule 22 Transportation Service Agreement.

ARTICLE 7

ARBITRATION

7.01 Any dispute between the parties arising from this Agreement will be resolved by a single arbitrator pursuant to the *Commercial Arbitration Act* of British Columbia or successor legislation, save as expressly provided herein.

7.02 Either party may commence arbitration proceedings by sending to the other party a demand for arbitration setting out the nature of the dispute.

7.03 The parties will have 10 Days from receipt of the demand referred to in Section 7.02 of this Agreement to agree upon the arbitrator, failing which either party may apply to the Supreme Court of British Columbia to select the arbitrator. The arbitrator must be sufficiently qualified by education and training to decide the particular questions in dispute. Unless otherwise agreed, the arbitrator may not be a past or present employee, officer or director of any of the parties or their respective successors, permitted assigns or affiliates, or any customer or supplier of Husky or Terasen Gas.

7.04 The arbitrator will proceed immediately to hear and determine the matter in dispute and will render a written decision, signed by the arbitrator, within 45 Days after the appointment, subject to any reasonable delay due to unforeseen circumstances. Notwithstanding the foregoing, if the arbitrator fails to render a decision within 60 Days after the appointment then either party may elect to have a new arbitrator appointed in like manner as if none had previously been appointed.

7.05 The decision of the arbitrator will be final and binding upon the parties and the parties will abide by the decision and perform the terms and conditions thereof. Notwithstanding the outcome of the arbitration proceeding, each party will bear its own costs, including third party costs, related to the arbitration but will share equally in the costs of the arbitrator.

ARTICLE 8

<u>CONDITIONS PRECEDENT</u>

8.01 All obligations of the parties to this Agreement are subject to their formal execution of this Agreement and acceptance for filing by the British Columbia Utilities Commission of the rates, terms and conditions set out herein.

ARTICLE 9

<u>TERMINATION</u>

9.01 In addition to any other rights either party may have to terminate this Agreement:

(i) Notwithstanding Article 3, Terasen Gas may terminate this Agreement if at any time the British Columbia Utilities Commission disallows Terasen Gas the recovery from the other Customers and/or Shippers of Terasen Gas of any revenue shortfalls, resulting from the negotiated rates under this Agreement;

(ii) Notwithstanding Article 3, Husky may terminate this Agreement if at any time the British Columbia Utilities Commission sets rates for Husky at a level in excess of the negotiated rates set out or provided for herein, or if the operations of Husky, or an affiliate of Husky, at the Plant permanently cease or if Husky, or an affiliate of Husky, ceases to use Gas permanently at the Plant; and

(iii) Notwithstanding Section 9.01(ii), Husky may terminate this Agreement at any time after November 1, 2026 without any payment under this Article 9.

9.02 Any termination pursuant to Section 9.01 will take effect on the next November 1 following a notice period of not less than 12 Months.

9.03 Except as otherwise stated in this Agreement, termination of this Agreement by Husky will require immediate payment by Husky to Terasen Gas of an amount equal to the undepreciated value of the Bypass Pipeline as specified in Schedule 2 as of the effective date of the termination and any additional costs pursuant to the application of Section 4.03 above. Notwithstanding any such payment, all Terasen Gas owned facilities serving Husky shall remain the property of Terasen Gas.

9.04 If Husky fails or neglects at any time to perform the obligations imposed upon Husky under this Agreement, and does not, within thirty (30) days after Terasen Gas has given notice of such failure or neglect, commence to remedy with due diligence and thereafter continue to remedy the matter with respect to which it is in default, then Terasen Gas, in its sole discretion, may terminate this Agreement, or may discontinue transportation of Gas to Husky under this Agreement but such discontinuance by Terasen Gas will not relieve Husky from its obligations under this Agreement after such failure has been fully remedied.

9.05 If Husky becomes bankrupt or insolvent or commits or suffers an act of bankruptcy or of insolvency or if a receiver is appointed over the Husky operations pursuant to a statute or under a debt instrument or if Husky seeks protection from the demands of its creditors pursuant to any legislation enacted for such purpose, Terasen Gas will have the right, at its sole discretion, to terminate this Agreement by giving notice in writing to Husky and thereupon Terasen Gas may cease further transportation of Gas to Husky under this Agreement.

9.06 Termination of this Agreement by Terasen Gas pursuant to Section 9.04 or 9.05 will entitle Terasen Gas to require immediate payment by Husky to Terasen Gas of an amount equal to the undepreciated value of the Bypass Pipeline as specified in Schedule 2 as of the effective date of the termination and any additional costs pursuant to the application of Section 4.03 above. Notwithstanding any such payment, all Terasen Gas facilities serving the Husky operations shall remain the property of Terasen Gas.

9.07 Any termination payment made in full in accordance with Section 9.03 or 9.06 shall be subject to a discount as determined by Terasen Gas to reflect the earlier receipt of payments due under this Agreement. The reduced amount of the payment will be based upon discounting the future payments to the date payment is made at Terasen Gas' average cost of funds. Terasen Gas' average cost of funds will include its weighted average before tax cost of short and long term debt and after tax return on preferred and common equity.

ARTICLE 10

NOTICES

10.01 If in any Year an executed Transportation Agreement is not in place, then the notice provisions of the latest executed Transportation Agreement and Rate Schedule will apply to this Agreement.

ARTICLE 11

MISCELLANEOUS

11.01 Husky shall have the right to release all or part of its DTQ in effect under this Agreement to Terasen Gas, provided Husky has obtained the prior written approval of Terasen Gas to absorb the capacity to meet incremental requirements on the distribution path. If Terasen Gas, in its sole discretion, determines that the requested release can be accommodated and absorbed without detrimental impact to its system or other Customers and/or Shippers, then Terasen Gas will prepare the necessary revisions to this Agreement, to reduce the volume appropriately. Husky will thereby be relieved of its obligations under this Agreement in respect of the DTQ or part thereof so released with the approval of Terasen Gas.

11.02 Notwithstanding Section 11.01, Terasen Gas may assign in its sole and absolute discretion, without the consent of Husky, Terasen Gas' rights and obligations under this Agreement to a party which acquires all or substantially all of Terasen Gas' Gas utility operations.

11.03 Notwithstanding Section 11.01, Husky may assign in its sole and absolute discretion, without the consent of Terasen Gas, Husky's rights and obligations under this Agreement to any party which acquires all or substantially all of Husky's Plant operations served by Terasen Gas pursuant to this Agreement.

11.04 This Agreement will enure to the benefit of and be binding on the parties and their respective successors and permitted assigns including, without limitation successors by merger, amalgamation or consolidation.

11.05 This Agreement and all amendments, modifications, alterations or supplements hereto will be governed by the laws in force in the Province of British Columbia.

11.06 In this Agreement the words, phrases or expressions which are not defined herein or in the Terms and Conditions of the Transportation Rate Schedule or in the Rate Schedule 22 and which in the usage custom of the business of the production, transportation, distribution or sale of Gas has a generally accepted industry meaning will bear that meaning.

11.07 A party shall have the right, at its own expense, upon reasonable notice and at reasonable times, to examine the books and records of the other party only to the extent reasonably necessary to verify the accuracy of any statement, charge, payment or computation made under this Agreement. This examination right shall not be available with respect to proprietary, confidential or personal information not directly relevant to this Agreement. All invoices and billings shall be conclusively presumed to be final and accurate unless objected to in writing, with adequate explanation and/or documentation, within two years of their issuance.

IN WITNESS WHEREOF the parties have executed this Agreement effective February 1, 2006.

AGREED TO AND ACCEPTED:

This 14th day of July, 2005.

TERASEN GAS INC.

BY: *Original signed by Rick Parnell*
(Signature)

RICK PARNELL
(Name – Please Print)

Director, Large Commercial & Industrial Markets
(Title)

AGREED TO AND ACCEPTED:

This 11th day of July, 2005.

HUSKY ENERGY MARKETING INC.

BY: *Original signed by Donald R. Ingram*
(Signature)

DONALD R. INGRAM
(Name – Please Print)

Senior Vice President
(Title)

BY: ____________________
(Signature)

____
(Name – Please Print)

____
(Title)

Schedule 1

Bypass Pipeline Monthly Charge

Monthly Facilities Charge	$ 14,740
Monthly Operation and Maintenance Charge (subject to increase as per Section 4.04)	$ 775
Monthly Property Taxes (subject to increase as per Section 4.04)	$ 2,365
Monthly Charge	$ 17,880

Schedule 2

Undepreciated Value of the Bypass Pipeline

Capital Cost Recovery for Early Termination of Contract

As at February 1, 2006	$	1,179,679
As at November 1, 2006	$	1,139,507
As at November 1, 2007	$	1,085,944
As at November 1, 2008	$	1,032,381
As at November 1, 2009	$	978,818
As at November 1, 2010	$	925,255
As at November 1, 2011	$	871,693
As at November 1, 2012	$	818,130
As at November 1, 2013	$	764,567
As at November 1, 2014	$	711,004
As at November 1, 2015	$	657,441
As at November 1, 2016	$	603,878
As at November 1, 2017	$	550,316
As at November 1, 2018	$	496,753
As at November 1, 2019	$	443,190
As at November 1, 2020	$	389,627
As at November 1, 2021	$	336,064
As at November 1, 2022	$	282,501
As at November 1, 2023	$	228,939
As at November 1, 2024	$	175,376
As at November 1, 2025	$	121,813
As at November 1, 2026	$	0

Schedule 3

Bypass Pipeline Capacity Based upon 425 PSIG

Duke Inlet Pressure	Capacity (10^3M^3/hr)	Capacity (GJs/hr)
500 - 549	4.1	153
550 - 599	7.297	273
600 - 649	9.661	361
650 - 699	11.712	418
>700	13.592	508

Note: Duke Inlet pressure is measured at Terasen Gas' Prince George #1 lateral.

Attachment 28.1

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Attachment 39.1

5.0 PROPOSED CHANGES TO SERVICE CHARGES

BC Gas proposes to revise a number of its customer related service charges to better reflect the real cost of providing such services. In particular, revising the Application for Service charges brings the charges more in line with the cost of providing service. A review of other utilities supports this revision.

Table A provides a review of the Application/Connection and Reconnection fees charged by the other British Columbia utilities. Table B summarizes the Application/Connection and Reconnection fees charged by some other major Canadian gas utilities. The activities associated with reconnection of a service after discontinuance at a customer's request are similar to the Application for Service, and the corresponding fees from various utilities are provided for comparison.

BC Gas currently charges $10 for each Application for Service, regardless of whether the application is simply to transfer an existing account from one person to another or to actually install a new service line and meter set. In many situations the $10 collected does not match the BC Gas administrative costs associated with providing the service.

5.1 Cost Analyses

BC Gas devotes considerable resources and incurs significant cost, to process requests to initiate or terminate gas service. However, the nature of the work required to process applications and terminations varies depending upon the circumstances. The following are the three basic application/termination scenarios that develop:

1) <u>Account Transfer - Existing Installation, Service Active</u>
In this case, the premise is already served with gas and

the gas is flowing at the time a new occupant calls to apply for service. The complete transaction can usually be dealt with over the telephone or at a branch office.

2) <u>Account Transfer - Existing Installation, Service Inactive</u>

In this case, the premise is aready serviced with gas but the gas is not flowing. While the administrative process can be completed over the telephone or at the branch office, BC Gas Customer Service personnel must be dispatched to reactivate gas service, including relighting the gas appliances.

3) <u>New Account - New Service Required</u>

In those situations where natural gas service is not currently available at the premises, a new gas service line installation is required. The customer must sign up for the new installation in person at a branch office.

In each scenario, some or all of the following activities occur:

a) The Applicant's information is obtained either over the telephone or at a branch office.

b) The Applicant's information is keyed into the Company's computer system.

c) An evaluation of the Applicant's credit worthiness is determined and, if any outstanding bills from other accounts exist, collection activities are undertaken before new service is provided.

d) Information regarding the terminating customer is sought, in particular a forwarding address for the final bill is obtained. Billing adjustments are required in some cases.

e) In some cases Customer Service personnel are dispatched to obtain a meter reading on the transfer date; in most situations the final meter reading is estimated.

f) When there is an existing service, but it is inactive, Customer Service personnel are dispatched to reactivate the service and relight the gas appliances. In some cases the gas meter must be reset.

g) In certain cases the account may be temporarily transferred into the landlord's name, for a period of time between tenants.

h) When a new service installation is required, additional information is required for permanent installation records and a site visit prior to installation is necessary for 20-25% of all installations. Following installation of the new service, site records are completed in greater detail.

The activities listed generate costs in the following areas:

- clerical time
- computer system utilization
- customer service personnel and vehicles
- mains and services representatives and vehicles
- associated overhead.

Given the various activities that are required to complete applications/terminations, the following cost estimates for each of the three scenarios has been developed.

Account Transfer - Existing Installation, Service Active

1. <u>Interior Costs</u>

Clerical Time:

Customer Service Representative 3

OTEU Collective Agreeement	$17.69/hr	
- Group 5 (3 yrs experience)		
Benefits @ 17.3%	$ 3.06	
Concessions @ 15.5%	$ 2.74	
Total	$23.49/hr	
Average total application processing time: .5 hrs =		$11.74
Computer System Utilization:		
On-screen average costs for interior billing system		$ 4.71
Total Interior =		$16.45

2. <u>Lower Mainland Costs</u>

1993 B.C. Hydro customer accounts, service and collection contracts average cost	$ 9.15

3. <u>Weighted Average</u>

Lower Mainland - B.C. Hydro billing system - 72% of customers x $9.15	$ 6.59
Interior billing system - 28% of customers x $16.45	$ 4.62
	$11.21

Account Transfer - Existing Installation, Service Inactive

1.	<u>Clerical time & computer system use, same as above</u>	$11.21

2. <u>Site Visit</u>

IBEW collective agreement	$21.77/hr	
Benefits @ 20.9%	$ 4.55	
Concessions @ 36%	$ 7.84	
Total	$34.16/hr	
Average service deactivation/reactivation time - 1.0 hr* =		$34.16
Vehicle costs @ $6.10/hr X 1.0 hr =		$ 6.10
Total =		$51.47

* Each time an account has to be reactivated, the cost of deactivating gas service has already been incurred.

New Account - New Service Required

1. Clerical Time

Construction Planning Clerk

OTEU Collective Agreement - Group 5 (3 yrs experience)	$17.69/hr	
Benefits @ 17.3%	$ 3.06	
Concessions @15.5%	$ 2.74	
Total	$23.49/hr	
Average total application processing time: 1.5 hrs =		$35.24

2. Computer System Utilization

On-screen average costs for interior billing system	$ 4.71

3. Site Visit/Confirmation (25% of installations are non-standard)

Mains & Service Representative

OTEU Collective Agreement - Group 8 (3 yrs experience)	$22.47/hr	
Benefits @ 17.3%	$ 3.89	
Concessions @15.5%	$ 3.48	
Total	$29.84/hr	
Average total application processing time: 1.5 hrs =		$44.76
Vehicle cost @ $6.10/hr X 1.5 hrs =		$ 9.15
Total:		$93.86

BC Gas proposes to recover a greater portion of the above costs through increased fees charged for Applications for Service as follows:

	Current Charge	Proposed Charge	Increase
1) Application for Service I - Existing Installation - Account Transfer	$10	$25	$15
2) Application for Service II - New service line installation	$10	$75	$65

During the year ending December 31st, 1992, BC Gas processed approximately 205,000 Applications for Service. Approximately 181,000 of these applications were for account transfers only and 24,000 applications were for new service installations. An increase of $15 per Application for Service I would generate an additional $2.715 million/year assuming 180,000 or more Applications for Service are received in future years. An increase of $65 in Application for Service II, where a new service line and meter set is required, would generate an additional $1.3 million per year assuming 20,000 such installations occurred each year. BC Gas has installed an average of 23,100 new services per year for the years 1990, 1991 and 1992.

The increased revenues arising from these revised charges serve to mitigate the impact of annual bill increases caused by the proposed rate design. The use of these funds is discussed in the "Implementation and Phase-in of the Proposed New BC Gas Rates" section for Residential, Commercial, General Service, and Industrial Customers in Tabs 6, 7, 8 and 9, respectively.

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The proposed General Terms and Conditions provoked relatively little discussion during the hearing. The large volume industrial customers objected to the unlimited right of BCGUL under Section 13.2, to curtail gas to any of its customers in the event of failure of BCGUL's gas supply for *any* reason, arguing that this should not include the case of failure to deliver gas by the Utility's own suppliers. However, the Commission rejects this argument and is satisfied that a utility must have the final decision on emergency curtailment but will use these broad powers responsibly.

The Commission believes the adoption of consolidated General Terms and Conditions is a logical accompaniment to consolidation for rate making purposes. Adoption of simplified and clearer Conditions should improve customer understanding and simplify contract administration by the Utility. **The Commission therefore approves adoption of the proposed consolidated General Terms and Conditions.**

11.3.1 Service Charges: Connection and Reconnection Fees

The proposed new General Terms and Conditions contain a supplemental schedule of standard fees and charges related to connection fees and disputed meter testing charges.

BCGUL proposes to set the fee for Account Transfers (whether service is active or inactive) at $25 and proposes a fee of $75 for new installations. In its application the Utility demonstrates that the former charge is close to the average cost of servicing active and inactive account transfers. The "new installation" charge moves much closer to full cost recovery than the formerly charged $10 fee, but still falls short of full cost recovery.

The Commission accepts that the proposed change in service charges is directionally correct, is satisfied that the charges are reasonably consistent with comparable charges of other Canadian utilities, and approves the application as filed.

11.4 BCGUL Application for Hearing Cost Recovery

By an August 9, 1993 letter addressed to the Commission, BCGUL requested permission to recover Phase B Rate Design hearing costs in the amount of $487,179, plus $52,944 of capitalized FDC modelling costs. These costs excluded any consideration of Commission costs arising from the hearing or any consideration of participant funding by the Utility which might arise from a Commission award under Section 133 of the Utilities Commission Act ("the Act").

Attachment 54.1

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